NORTHWESTERN ENERGY

VOLUME 2

2023

MONTANA IRP

NorthWestern Energy
Delivering a Bright Future

Contents

Executive Summary

Overview of the NorthWestern Energy 2023 Montana IRP

Volume 2 provides additional information and documentation in support of the 2023 Montana Integrated Resource Plan (IRP or Plan), which is contained in Volume 1. The chapters in Volume 2 correspond to the chapters in Volume 1.

2. Planning and Process History

2.1 Montana Planning Requirements

Montana Statutory Requirements

The requirements in Montana's Integrated Least-Cost Resource Planning and Acquisition Act (Montana Code Annotated Title 69, Chapter 3, Part 12) are listed below with the location in the IRP where the requirement is addressed. The requirements in the Act that were not implemented by the Montana Public Service Commission's rules until January 2023 are not listed.

Statute	Requirement	IRP Location
MCA § 69-3-1203(9)	the planning period is a minimum of 20 years and begins from the date the utility files its plan with the commission.	Volume 1, Chapter 1
MCA § 69-3-1204(2)(i)	an evaluation of the full range of cost-effective means for the public utility to meet the service requirements of its Montana customers, including conservation or similar improvements in the efficiency by which services are used and including demand-side management programs	Volume 1, Chapter 5.3 - DSM Acquisition and Programs Volume 1, Chapter 7.5 - Transmission System Physical Constraints Volume 1 and 2, Chapter 8 – Resource Planning and Analysis, multiple sections
MCA § 69-3-1204(2)(iv)	an assessment of the need for additional resources and the utility's plan for acquiring resources	Volume 1, Chapter 1.2 – NorthWestern's Need for Additional Capacity Volume 1, Chapter 2.5 – Resource Acquisition Strategy Volume 1, Chapter 6 – Existing Resource Portfolio Volume 1 and 2, Chapter 8 – Resource Planning and Analysis Volume 1, Chapter 10 – Action Plan
MCA § 69-3-1204(2)(v)	the proposed process the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive solicitation process	Volume 2, Chapter 2.5 - Resource Acquisition Strategy
MCA § 69-3-1205(1)	a public utility shall hold at least two public meetings in the utility's Montana service territory to ensure a plan best meets the diverse goals of shareholders, ratepayers, and society.	Volume 1, Chapter 2.4 - ETAC's Role In The Planning Process
MCA § 69-3-1208	a public utility shall maintain a broad-based advisory committee to review, evaluate, and make recommendations on technical, economic, and policy issues related to a utility's electricity system.	Volume 1, Chapter 2.4 - ETAC's Role In The Planning Process

Montana Regulatory Requirements

The guidance provided by the Montana Public Service Commission's Default Electric Supplier Procurement Guidelines (Administrative Rules of Montana Chapter 38, Part 5, Subchapter 82) are listed below with the location in the IRP where the guideline is addressed.

Rule	Guideline	IRP Location
ARM 38.5. 8210(2)(a)	resource needs assessment - analyses of customer loads including base load, intermediate load, peak load and ancillary service requirements, seasonal and daily load shapes and variability, the number and type of customers, load growth, trends in customer choice and retail markets, technology that may lead to substitutes for grid-based electricity service, impacts of demand-side management, and price elasticity of demand	Volumes 1 and 2, Chapter 5 – Load Service Requirement Volume 1, Chapter 8 - Resource Planning and Analysis Volume 1, Chapter 9 – Emerging Technologies
ARM 38.5. 8210(2)(b)	resource needs assessment - an assessment of the types of resources that are available and could contribute to meeting portfolio needs, including demand-side resources, supply-side resources, distributed resources, and rate design improvements	Volume 1 and 2, Chapter 8 - Resource Planning and Analysis
ARM 38.5. 8210(2)(c)	resource needs assessment - an assessment of the types of wholesale electricity products that could effectively and efficiently contribute to meeting portfolio needs including base load, heavy load, peak, dispatchable, curtailable, assignable, firm, full requirements, load following, unit contingent, slice of the system (fixed percentage of hourly system load requirements), and others	Chapters 7 and Chapter 8

Rule	Guideline	IRP Location
ARM 38.5. 8210(2)(d)	an assessment of resource diversity within the existing portfolio with respect to generation fuel and generation technology (e.g., conventional coal, clean coal, hydro, natural gas combined cycle, natural gas simple cycle, wind, fuel cell, etc.)	Volume 1, Chapter 4.5 – Renewable Energy Resources Volume 1 and 2, Chapter 6 – NorthWestern's Generation Portfolio
ARM 38.5. 8210(2)(e)	an assessment of the flexibility of the existing portfolio with respect to generation resources, suppliers, demand-side management resources, electricity products, contract lengths, contract terms and conditions, and market conditions.	Volume 1, Chapter 4.5 – Renewable Energy Resources Volume 1 and 2, Chapter 6 – NorthWestern's Generation Portfolio
ARM 38.5. 8210(3)	A utility's resource needs assessment should include analyses of how cost allocation and rate design decisions might impact future loads and resource needs.	Volume 1, Chapter 5 - Load Service Requirement. Related details are found in this section; however, rate design impacts are not explored in this Plan.
ARM 38.5. 8213(1)(a)	use modeling and analyses to evaluate and quantify probable load characteristics, including trends in load shapes, load growth, and price elasticity of demand;	Volume 1 and 2, Chapter 5 – Load Service Requirement PowerSimm modeled high load, gas, and power prices sensitivity (Chapter 8).
ARM 38.5. 8213(1)(b)	use modeling and analyses to evaluate the potential effect of various rate designs and demand-side management methods on future loads and resource needs;	Volume 1, Chapter 5 – Load Service Requirement. Related details are found in this section; however, rate design impacts are not explored in this Plan.
ARM 38.5. 8213(1)(c)	use modeling and analyses to evaluate and quantify projected electricity supply resource requirements over the planning horizon	Volume 1, Chapter 6 - Existing Resource Portfolio Volume 1 and 2, Chapter 8 - Resource Planning and Analysis
ARM 38.5. 8213(1)(f)	use modeling and analyses to evaluate the performance of alternative resources under various loads and resource combinations through: (i) scenario analyses; (ii) portfolio analyses; (iii) sensitivity analyses; and (iv) risk analyses;	Volume 1, Chapter 8 - Resource Planning and Analysis

Rule	Guideline	IRP Location
ARM 38.5. 8225(1)	A utility should maintain a broad-based advisory committee to review, evaluate, and make recommendations on technical, economic, and policy issues related to electricity supply resource portfolio planning, management, and procurement. A utility should also facilitate processes that provide opportunities for a broader array of stakeholders to comment. Such processes could include: (a) public meetings; (b) customer surveys (large and small customers); (c) other processes that may provide a utility information about public opinion on resource procurement matters.	Volume 1 and 2, Chapter 2.4

2.2.1 Findings from the 2019 Plan

In response to NorthWestern Energy's (NorthWestern) concern about its capacity position, the Montana Public Service Commission (MPSC) said the following:

> "The Commission acknowledges NorthWestern's conclusion in the 2019 Plan that, absent new resource development, the Pacific Northwest regional electrical system is likely to be inadequate within the next few years due to the retirement of significant coal-fueled generation capacity. The Commission also acknowledges that over a similar time horizon, NorthWestern's existing owned and contracted resources do not by themselves provide sufficient capacity and energy to satisfy typical industry standards for adequacy and reliability. Further, because NorthWestern's electrical system is integrated into the Pacific Northwest regional electrical system, regional resource inadequacy could potentially result in resource inadequacy on NorthWestern's system due to retirements of in-state coal-fueled generation capacity.
>
> The Commission agrees with the basic premise of the 2019 Plan that NorthWestern should take steps to assure that controlled capacity and energy resources are capable of providing retail customers adequate and reliable service. In addition, the Commission generally finds that the Action Plan Items of the 2019 Plan are reasonable. In particular, the Commission supports NorthWestern's plan to rely on an independently administered competitive solicitation process to identify available resource options."

2.2.2 MPSC Comments Regarding the 2019 Plan

1. NorthWestern's approach to a competitive solicitation for additional resources lacks clarity in how it will include a diverse set of resources, what it means by "short-term" and "long-term" resources and that a commitment to a 16% Planning Reserve Margin (PRM) is premature as it relates to the development of an organized market.
2. Synapse and the Commission agree that the 2019 Plan and PowerSIMM modeling does not allow for direct purchase of market-based capacity resources. The cost and risk of different capacity-based resources of variable lengths is not addressed in the modeling.
3. Key modeling assumptions of the 2019 plan were not explicitly stated. Synapse found wind was accredited with 1.9% of nameplate capacity and solar was accredited with 0%. Citing an E3 study suggesting wind will receive a 7% capacity and solar a 12% capacity in a regional Pacific Northwest market and given NorthWestern's assumption that it will be part of a Regional Transmission Organization (RTO) by 2025, the modeling did not adequately analyze new wind and solar resources.

4. The plan was deficient for not analyzing a scenario that combined lower cost curves for Variable Energy Resource (VER), high gas prices, and coupled with the presumption of an RTO.
5. The plan mistakenly used the base-case gas price curves when attempting to model the high-gas price curves. Further, the model did not account for the cost of moving gas supply across the system which would add approximately $4-$5/MWh to the cost of a new gas resource.
6. Given the observed capacity contributions of wind and solar by Synapse, NorthWestern should clearly state how Electric Load Carrying Capability (ELCC) values are derived and consider methodologies like the Southwest Power Pool (SPP) method, monthly values, local and regional ELCCs and advances in the NorthWest Power Pool (NWPP) Resource Adequacy (RA) initiative. Whatever method is chosen, it should be clearly stated in the next plan.
7. O&M for solar resources appear to be higher than NREL's 2019 data suggests.
8. The draft RFP by NorthWestern included an important resource characteristic called "ride-through capacity" that is not described. Without further clarification, any weight placed on this attribute for selection criteria should be ignored.
9. The plan does not explain the impact of ancillary services as a result of joining the Western Energy Imbalance Market (W-EIM). This is important as it is frequently a point of contention under Public Utility Regulatory Policies Act (PURPA) proceedings. The next plan should address this.
10. The plan does not explain whether investments in the transmission system could cost-effectively expand access to market or other supply resources.
11. Program lives of Demand Side Management (DSM) measures should not be 15 years, but rather 20 years to be equal to most Qualifying Facility (QF) resources. This gives demand and supply side resources equal treatment.
12. An updated DSM cost analysis should be included in future plans and included in any RFP.

2.2.3 NorthWestern's 2020 Supplement to the 2019 Plan

NorthWestern filed a 2020 Supplement to the 2019 Plan that addressed many of the MPSC and stakeholder comments. In the 2020 Supplement, NorthWestern:

1. Showed the various regional capacity deficit forecasts further emphasizing the risk of relying on market purchases to meet demand. These studies included how generation capacity across the region correlates with regional load and weather.
2. Identified an updated capacity deficit of 555 MW (increasing to 793 megawatts (MW) if Colstrip is retired) and widened the planning reserve margin (PRM) to include a possible range of 13%-18%.
3. Specified the need for "medium-term" resources to be 1-3 years and "long-term" resources to be 3-30 years.
4. Explained that joining the W-EIM would not result in any change in capacity planning needs and NorthWestern would still be required to have capacity available to meet incremental (INC) and decremental (DEC) reserve requirements.
5. Explained that transmission investments have been and will continue to be considered to enhance the reliability of the system. However, transmission availability alone will not enhance resource adequacy. Both transmission and firm generation together help provide reliable supply. Transmission service alone offers no guarantee of generation supply and as such, does not eliminate the need for evaluation independently of generation supply.
6. Provided detailed explanation of the capacity contribution of each resource as measured by the ELCC method, and showed how increasing the total ELCC supply decreased the frequency and length of deficit events.
7. Explained how short-term energy markets continue to be an important part of the supply stack. With an increase in VERs, NorthWestern expects more frequent low-price periods. During such times, dispatchable resources may be turned down to allow for market purchases at lower cost to customers. During high prices, NorthWestern increases generation from its dispatchable resources to meet its own load, and in cases when it has excess capacity, it will make wholesale sales whose revenue benefits customers by offsetting other costs.
8. Provided explanation and tables of incremental additions of various resources using the ELCC method.
9. Explained the PRM of 16% is consistent with North American Electric Reliability Corporation (NERC) standards for Western Electricity Coordinating Council (WECC), though NorthWestern's near-term capacity acquisitions still do not meet the 16% PRM. Further clarification on the PRM required for NorthWestern will materialize as the Western Resource Adequacy Program (WRAP) program is developed.
10. Issued an RFP for "short-term" capacity in July 2020. Responses confirmed that the market lacks depth for RA supporting products. With only 350 MW of capacity offered in response to the RFP, the lack of resources to meet NorthWestern's long-term needs is increasingly concerning. Modeling does not include procurement of short or medium term capacity contracts as the availability and price is uncertain.
11. Described the nature of electric and gas infrastructure upgrade costs associated with developing generation resources and explained that such costs vary significantly by project and location such that consideration of these costs for general resource planning by technology type are not considered. These costs are closely analyzed on a project-specific bases when evaluating specific resource options.
12. Provided details regarding its DSM activities and estimated potential capacity contributions to meet peak load. An explanation of the method for estimating capacity contributions and a table of historic costs was included.
13. Modeled 21 different portfolios of resources that each added 600MW of capacity. This served to simplify comparison of portfolios.
14. Ran a sensitivity to consider if ELCC values of wind and solar were increased by a factor of three.

2.4 Electric Technical Advisory Committee (ETAC)

2.4.1 ETAC Meetings

Northwestern held eight ETAC meetings (Table 2-1) in 2021 and 2022. Meeting materials can be found on the NorthWestern's website.

Electric Supply Planning (northwesternenergy.com)

Table 2-1. ETAC Meetings 2021 and 2022

Date	Topics
10/6/2022	Overview of NorthWestern's Draft 2023 MT IRP – Comments and responses are shown in section 2.4.2
7/13/2022	Role of IRP in NorthWestern resource procurement; modeling approach, status, and preliminary results
5/18/2022	Technology cost forecasts, candidate resource list
4/20/2022	Project status update, deep dive on scenarios and modeling process, long-term technology cost forecast
2/23/2022	Intro and discussion of Ascend Analytics, AMI and DMS updates, portfolio modeling update, proposed scenario review, resource capacity and costs, RA update
10/19/2021	Methodology for forecasting prices, results of forecasts, and scenario review
8/4/2021	Resource types, demand-side management, NorthWestern's existing resource portfolio, supply planning, load forecasts, Resource Adequacy
6/24/2021	Simulation modeling overview, review of 2019 Plan and 2020 Supplement, planning process and rules, role and objectives of ETAC, supply planning

2.4.2 Comments by Topic

2.4.2.1 Resource Alternatives

- In addition to those resource types listed in NorthWestern's presentation at the October 19, 2021, ETAC meeting, MPSC staff recommend that the resource types available to the model should include a proxy market capacity resource based on the Powerex contract that resulted from NorthWestern's January 2020 RFP. NorthWestern should consider whether it would be reasonable to adjust the contract capacity rate to reflect prices that may be available during the planning period.
    - ↳ ***NorthWestern's response:*** NorthWestern did not include capacity contracts in the PowerSIMM capacity expansion models. Capacity contracts are not widely available and NorthWestern is not certain that such contracts will be available in the future. NorthWestern's near term goal is to become resource adequate with firm capacity that will provide certainty for the long term.

2.4.2.2 Modeling

- MPSC staff recommend evaluating the following scenarios/future conditions through PowerSIMM modeling:
- A base case that assumes Colstrip Unit 4 continues to operate throughout the planning period
- An alternative case that assumes Colstrip Unit 4 retires in 2025
- An alternative case that assumes 85% of the total energy produced by the resource portfolio must be free of CO2 emissions in 2035
- An alternative case that combines the scenarios in 2 and 3
- An alternative case that evaluates scenarios 1-4 by applying E3's ELCC values for renewable and hybrid resources on NorthWestern's system through 2025 and either the regional capacity contributions from the Northwest Power and Conservation Council's draft or final regional power plan or preliminary capacity accreditation values applicable to NorthWestern under the Northwest Power Pool's WRAP after 2025
- The model should be set up with the objective of achieving resource adequacy while limiting the addition of new natural gas generating capacity to no more than 315 MW, which MPSC staff understand is necessary due to capacity constraints on NorthWestern's current natural gas system. To the extent NorthWestern assumes non-operational QF projects that have obtained MPSC rate orders are part of the existing resource portfolio, each of the above scenarios should also be modeled without the non-operational QF projects. Modeling for each scenario should be based on expected market prices for electricity, natural gas, and other fuel prices, and expected load growth. Sensitivity analyses should evaluate higher and lower than expected market prices and load growth.
- For each of the modeled scenarios/futures NorthWestern should provide the following information:
- Total net present value of portfolio costs
- The range of net present value portfolio costs resulting from the sensitivity analyses
- The percentage of total energy produced in 2035 that is free of CO2 emissions
- The amount of energy production in excess of retail load and a description of the range of wholesale market revenue shown in the simulation results
- The quantity of each resource type selected by the model and the timing of the selection
- ETAC Recommended:
- Model scenarios with multiple early coal retirement dates, including 2025
- When modeling additional gas generation, the analysis should assume "firm" gas is needed
- Model a scenario that considers limited availability of hydro resources due to aggressive drought
- Model standalone operation of Colstrip Unit 4 without Unit 3 after 2025
- Model how NWPP Resource Adequacy Program may change the planning reserve margin, and determine how that changes portfolio capacity and energy needs over the planning horizon
- Model higher price gas scenarios
- Model a scenario that analyzes various rate design impacts e.g. time of use rates applied to all customer classes, on load shifting as well as capacity/energy requirements. Model a range of Demand Response (DR) resources (irrigation, commercial, residential) to meet capacity needs after 2023
    - ↳ ***NorthWestern's response:*** The PowerSIMM modeling scenarios and results are presented in Chapter 8 of Vol. 1.
    - ↳ In all modeling scenarios, new natural gas resources were not allowed after 2035.
    - ↳ Natural gas is modeled in PowerSIMM with the assumption that the supply is adequate; the model doesn't specify firm gas contracts. Gas supply planning is an important process that NorthWestern Energy conducts for its gas burning resources as well as customer supply.
    - ↳ Half of the QFs were assumed to attain integration with NorthWestern's system in the scenarios. The models added capacity to maintain a 16% planning reserve margin.
    - ↳ Please refer to Chapter 8 of Vol. 1 for net present value of portfolio costs, carbon percentages, energy production/market amounts, and portfolio composition details.
    - ↳ Hydro resources are modeled using ELCCs that are based on historic generation. They are not forward looking for drought scenarios; however, by evaluating them regularly, they could pick up signals associated with longer term climate trends.
    - ↳ The IRP evaluates WRAP changes in both load and resource accreditation, please see Chapter 6 and 8 of Vol. 1.
    - ↳ The IRP includes a high gas scenario, please see Chapter 8 of Vol. 1.
    - ↳ Finally, time of use, DR, and load shifting impacts are not modeled but may be considered in the future based on results from our DSM RFP (Appendix E) in process.
- Evaluate risk systematically in assessing resource options and alternative portfolio structures—provide qualitative or quantitative measures of the risks of alternative capacity expansion paths.
    - ↳ ***NorthWestern's Response:*** Details can be found in Chapter 8. PowerSIMM addresses risks such as: energy deficits and financial risk.
- Include portfolio modeling results based on WRAP Qualifying Capacity Contribution (QCCs)
    - ↳ ***NorthWestern's Response:*** NorthWestern has implemented WRAP QCCs in PowerSIMM Modeling.

2.4.2.3 Climate Change and Conservation

- Concerns about climate change and carbon emissions were common themes.
- Net zero goal should be explained better. Better goal than net zero would be zero carbon by 2050.
- Desire for renewables, energy conservation, efficiency, and storage. Replace coal and gas resources with clean energy/renewables and paired projects (renewables + storage).
- NorthWestern should state what would be required to make these resources acceptable to NorthWestern.
- Desire for NorthWestern to include demand response to address resource adequacy.
- Implement and model smart grid projects such as time of demand, more efficient utilization of the transmission system and regionalization of markets.
    - ↳ ***NorthWestern's Response:*** NorthWestern has evaluated and modeled several renewable scenarios and replacement options, which include the important criteria of cost. Please see Chapter 8 of Vol.1. NorthWestern also issued an RFP on September 7, 2022 to select a consultant to conduct a study of energy efficiency potential in its supply territory, quantify the savings achievable through energy efficiency programs, and quantify savings achievable through demand response programs. The RFP is in Volume 2, Appendix E. This study will take place in 2023 and is a critical step in expanding NorthWestern's program offerings and updating the measures NorthWestern implements in future programs.
    - ↳ Please refer to NorthWestern's net zero plan for more details. https://www.northwesternenergy.com/clean-energy/net-zero-by-2050

2.4.2.4 Process

- Stakeholder process and online feedback form are providing limited value.
  - ↳ ***NorthWestern Response:*** NorthWestern will re-evaluate the stakeholder process prior to commencing the next planning cycle in order to differentiate designated technical advisory experts from public commenters.
- NorthWestern's supply problem is overstated.
  - ↳ ***NorthWestern Response:*** The supply issues in the region, and associated risks, are echoed by multiple entities and are not solely voiced by NorthWestern. Please see Volume 1 of the Plan for more information about regional energy concerns.
- The utility's three currently operative goals of reliability, affordability, and customer benefit are incomplete. The stated goal of "Net Zero by 2050" is inadequate. The only appropriate goal at this critical time of increasing climate change is the reduction of greenhouse gas emissions.
  - ↳ ***NorthWestern Response:*** NorthWestern's resource planning goals are consistent with the resource planning and acquisition policies and goals adopted in statute by the State of Montana and implemented by the MPSC through rulemaking.
- Commitment to cooperate with Montana communities interested in Community Renewable Energy Projects.
  - ↳ ***NorthWestern Response:*** Northwestern began developing a green power product with stakeholders in 2019, and we are currently working with several Montana communities to design a green power tariff option. NorthWestern remains committed to working on the green power option with our communities.
- Commitment to continue cooperation with Montana communities in establishing a Green Tariff.
  - ↳ ***NorthWestern Response:*** Northwestern is currently working with several Montana communities to develop a green power tariff option. NorthWestern seeks to develop options to meet the needs of all its customers while managing the costs of such options so that non-participating customers are not overly burdened.
- Consider using the ELCCs being developed as part of the WRAP.
  - ↳ ***NorthWestern's Response:*** Northwestern has performed portfolio analysis using WRAP accreditations in this Plan.

2.4.2.5 Plan Contents

- Describe the growth of demand with text and graph: a) "business as usual" and b) with electrification of transportation. Then, depict for each of these growth curves a reduction of demand that can be created by specifically quantified targets for these three elements, and perhaps others: CREP, demand response, energy efficiency.
- The 2023 Plan is a good place to at least begin attempting to quantify the increasing electricity demand that will be created along with the shift away from methane as a space heating fuel.
- Include social cost of carbon (SCC) for each resource. Compare the portfolio costs with three levels of SCC, zero, $25/ton CO2, $50/ton CO2.
- Renewables and storage – Include storage (4hr or 8hr, whichever results in the greater ELCC) with every portfolio resource having renewable generation. It may not be at all useful to consider renewable resource additions that lack storage.
- Geothermal – This highly reliable and emissions-free resource should be included among the portfolios considered.
- Consider hydrogen, coupled with or generated by renewables.
- Consider the costs of replacing renewable resources that reach end of life at ~ 20 years.
  - ↳ ***NorthWestern's Response:*** Details on the load forecast are presented in Chapter 5 of Vol. 1. Details on transportation electrification are shown in Chapter 9 of Vol. 2.
  - ↳ Migration of heating from gas to electricity—over time—would appear in the demand forecast that will pick up on longer term trends. NorthWestern does not have a specific gas conversion forecast.
  - ↳ The 2023 IRP includes carbon costs in some scenarios, please refer to Chapter 8 of Vol. 1 and 2 for more details.
  - ↳ Refer to the IRP for battery assumptions. Geothermal energy is not included in the portfolios due to high cost relative to other established energy options. Please see Vol. 2 Appendix F for resource cost estimates. Likewise, hydrogen, coupled with or generated by renewables, is not included due to lack of sources and infrastructure. Should either of these resources gain significant market share, NorthWestern will model them and consider them in future planning.
  - ↳ Renewable resources that reach end of life have the option of repowering. Repowering facilities need to be economically justified to extend the life of the facility.
- Transparently identify the designated ETAC members and explicitly describe the "joint environmental scenario," including which entities jointly submitted the scenario.
  - ↳ ***Northwestern's Response:*** ETAC is described in section 2.4 of Vol. 1. The Joint Environmental Scenario is described in section 8.6 of Vol. 1.
- Present a description of ETAC meetings, including dates and topics discussed.
  - ↳ ***NorthWestern's Response:*** The ETAC meeting information requested is included in section 2.4 of Vol. 2.
- Explain, in an understandable manner, why the 2,166 MW of import capacity on the four major transmission paths is not sufficient to maintain reliable operations in NorthWestern's balancing area while delivering generation to supply balancing area peak loads of less than 2,000 MW.
  - ↳ ***NorthWestern's Response:*** Please see the explanation in Chapter 7 of Vol. 1.
- The final plan should provide a more coherent explanation of how NorthWestern will evaluate the cost-effectiveness of opportunity resources not identified through a competitive solicitation.
  - ↳ ***NorthWestern's Response:*** Please see section 2.5.2 of Vol. 1.
- Regarding the effects of the COVID 19 pandemic on loads clarify whether the observed year-to-year percentage changes are stated in terms of weather-normalized loads.
  - ↳ ***NorthWestern's Response:*** Please see section 5.1 of Vol. 1.
- Include detail of load forecasting methods. Address how load uncertainty affects the risk of various resource acquisition strategies.
  - ↳ ***NorthWestern's Response:*** Please see Chapter 5 of Vol. 1 for more details on load forecasting. The largest risk NorthWestern sees is increasing loads due to electrification.
- Provide an explanation of the methodology used to estimate avoided costs for DSM resources. Also report the TRC cost effectiveness measures and/or levelized cost of energy and capacity for historical DSM acquisitions.
  - ↳ ***NorthWestern's Response:*** Volume 1, Chapter 5 discusses this methodology.
- Include a complete list of existing supply resources along with key resource characteristics. Explain the methodology used to assess the capacity value of thermal resources.
  - ↳ ***NorthWestern's Response:*** Chapter 6 of Vol. 2 contains resource characteristics. Thermal resource capacity is calculated considering generator outage data.
- Explain NorthWestern's concern of a lack of depth of capacity resources from the 2020 RFP
  - ↳ ***NorthWestern's Response:*** See section 6.2 of Vol. 1.
- Provide tables with the actual annual numerical values regarding capacity adequacy.
  - ↳ ***NorthWestern's Response:*** Table 6-1 of Vol. 2 summarizes the capacity number by season (higher resolution than annual).
- Provide the imports by NorthWestern supply as a percentage of retail customer peak load along with information about the coincidence of retail customer peak demand and balancing area peaks.
  - ↳ ***NorthWestern's Response:*** See Chapter 7 of Vol. 1 for additional information about NorthWestern's customer load peaks.

- List the 28 network customers in addition to NorthWestern supply along with their respective loads. Provide a breakdown of growth in balancing area coincident peak loads by customer type (i.e., retail utility supply, choice customers, co-op customer, power marketing authority, etc.).
  - ↳ ***NorthWestern's Response:*** Network customers are listed in Table 7-1 of Vol. 2. A load growth breakdown cannot be prepared in time for this Plan.
- Describe the drivers of the growth in Point to Point (PTP) sales referred to in this section.
  - ↳ ***NorthWestern's Response:*** See Chapter 7 of Vol. 1 for discussion on PTP service.
- Explain transmission matters in terms that are understandable to a non-transmission engineer.
  - ↳ ***NorthWestern's Response:*** See Chapter 7 of Vol. 1 & Vol. 2 for discussion on transmission.
- Explain whether an expansion of generation capacity at DGGS would help with transmission reliability in the Butte area, since that resource option has been evaluated in recent plans.
  - ↳ ***NorthWestern's Response:*** See Chapter 7 of Vol. 1. Further studies are warranted to evaluate the reliability options.
- Explain whether existing resources such as the Heartland capacity contract, or other similar resources, have been affected by transmission constraints?
  - ↳ ***NorthWestern's Response:*** See Chapter 7 of Vol. 1 for discussion on transmission constraints.
- Section 7.7 also states "NorthWestern's analysis concluded that to utilize these imports an immediate loss of Colstrip would create high voltage problems on the transmission system that would require an investment of $20-30 million of reactors to remedy. From a long term perspective, NorthWestern's Transmission function does not believe that reliance on off-system imports to completely replace the energy in the BA associated with Colstrip is a reliable or realistic assumption." The first sentence is confusing and should be rewritten. Presumably, the analysis concluded that replacing Colstrip generation with imports to the balancing area created high voltage problems. However, more information should be provided on where and why the voltage problems occur. Do the voltage problems occur on the import paths themselves or on internal transmission system facilities? The concluding sentence regarding whether reliance on off-system imports to replace Colstrip energy and capacity is "reliable or realistic" is not sufficiently supported by the information provided in Section 7, at least as currently written.
  - ↳ ***NorthWestern's Response:*** Additional details have been provided in section 7.7 of Vol. 1 and Appendix G of Vol. 2.
- Section 8.2 states "Primary inputs for the capacity expansion model include the candidate resource options, price forecasts (power, natural gas, coal, carbon), and model constraints such as capacity needs, energy needs, and resource build limitations." This language is confusing. While a reliability constraint or reserve margin constraint seems reasonable, capacity and energy needs seem to be functions of other inputs, rather than inputs themselves. For example, an analysis of the generation attributes and lives of existing resources, together with load forecasts, and reliability objectives may result in identifying a surplus or deficit capacity/energy condition (i.e., resource needs) that the model seeks to address through resource acquisitions.
  - ↳ ***NorthWestern's Response:*** See Chapter 8 of Vol. 1 and Vol. 2.
- Section 8.3 should describe NorthWestern's process and rationale for the model constraint that requires the portfolio to supply at least 80% of load with "NWE resources" and no more than 130% after 2030. In addition, this section states "The model considers full resource costs including capital costs, fixed costs, and variable costs (fuel, VOM, startup costs)." The final plan should clarify how undepreciated capital costs associated with early retirement of Colstrip are factored into the modeled portfolio costs.
  - ↳ ***NorthWestern's Response:*** See Chapter 8 of Vol. 1 for the model constraints utilized in this Plan. We assume all rate base value of Colstrip continues to be depreciated until 2042.
- The description of candidate resources in Section 8.3.1 should be accompanied by a more informative table that summarizes key information for each of the candidate resources, such as capital costs, fixed and variable O&M costs, heat rates, capacity factors, carbon emissions rates (as applicable), and annual carrying charge rates used to annualize costs in modeling. Table 8-1 in the draft is inadequate.
  - ↳ ***NorthWestern's Response:*** Volume 2, Appendix F presents these costs for various generator types.

- Section 8.3.2 should provide at least a summary explaining how it combined the multiple sources of cost data for candidate resources into the specific cost assumptions used in the model, in addition to providing the details in Volume 2.
  - ↳ ***NorthWestern's Response:*** All cost data were provided by Aion Energy as found in Volume 2, Appendix F. The exception is for SMR, which came from XEnergy and the costs are included in Vol. 1 Table 8.2.
- Figure 8-4 in Section 8.4 should include a legend that makes it clear which data series represents CIG prices and which represents AECO prices. In addition, this section should benchmark NorthWestern's natural gas and power price forecasts to forecasts from other regional utilities, the Northwest Power and Conservation Council, and other independent fundamentals-based forecasts. The graphs in Figure 8-5 should use the same scale on the Y axis to allow readers to visually compare the two forecasts more easily.
  - ↳ ***NorthWestern's Response:*** NorthWestern has updated this figure.
- Section 8.4.2 should more thoroughly describe the coal price forecast by specifying the expiration date for the current coal supply contract and justifying the assumed 2% annual escalation rate. A graph of historical and projected coal prices would be useful.
  - ↳ ***NorthWestern's Response:*** See Chapter 8 of Vol. 1.
- Regarding Section 8.4.3, the price data used to produce the graphs in Figure 8-6 should be included in Volume 2.
  - ↳ ***NorthWestern's Response:*** Please see the electronic files associated with this plan.
- Section 8.4.4 describes a modeling sensitivity based on an assumed carbon price. This section states "Carbon was modeled deterministically and operates as a cost added to the dispatch of carbon resources, meaning a greenhouse gas emitting resource would only dispatch if the power price was higher than the variable cost of the unit plus the carbon adder." NorthWestern should clarify how the assumed carbon cost influenced the wholesale power price forecast used in the model for this sensitivity.
  - ↳ ***NorthWestern's Response:*** NorthWestern did not assume any change in the market prices due to the carbon adder. The goal was to determine how a carbon adder would affect resource selection and dispatch.
- Table 8-3 in Section 8.7 should be expanded to provide information on the timing of capacity additions, by type, for each of the modeled scenarios.
  - ↳ ***NorthWestern's Response:*** See Figure 8-13 and Table 8-8 of Vol. 1.
- The cost comparisons for modeled scenarios in Section 8.9 should translate the estimated annual portfolio costs into bill impacts for residential and small commercial customers.
  - ↳ ***NorthWestern's Response:*** The residential impact was quantified in Vol. 1, section 8-9,
- Section 9 presents the results of an analysis of the load impacts of EV charging. The results appear to indicate that EV charging may increase load by an amount similar to the load reduction from DSM. Accordingly, NorthWestern should consider incorporating EV charging impacts into its load forecast used for portfolio modeling.
  - ↳ ***NorthWestern's Response:*** NorthWestern plans to assess current and future EV charging impacts on its Montana electric loads and will consider incorporating those impacts into its load forecast used for portfolio modeling.
- NorthWestern should consider scenarios with revised energy technology cost assumptions to include impacts of tax credit revisions and extensions under the IRA for both variable energy and high-capacity factor resources.
  - ↳ ***NorthWestern's response:*** NorthWestern incorporated effects of the IRA as explained in Chapter 8 of Vol. 1.
- Clarification on the difference in capacity contribution between QF/utility-scale solar and NEM solar.
  - ↳ ***NorthWestern's response:*** While both are solar energy sources, QF/utility-scale installations are not directly comparable to NEM solar, which is generated at the building level. The NEM solar capacity came from a Navigant study which used a different method of capacity ("SPP Renewable Net Capability Tool") than is used for QF ELCCs.

- What is the "Joint Environmental Group" scenario, what resources are in its portfolio, and does it satisfy winter and summer peak loads?
  - ↳ ***NorthWestern's response:*** This scenario has Colstrip retiring in 2025 and replacement options consisting of energy storage, wind, and solar (see Chapter 8 of the IRP). It assumes full QF completion. The environmental scenario indicated significant levels of energy storage, wind and solar. Existing carbon resources other than Colstrip remained in the model. After 2036, only two natural gas resources remain in the model, Yellowstone and Dave Gates Generating Stations. These remaining two gas units are assumed to stay in the Joint Environmental scenario. Initially the LOLH threshold was not met by the Joint Environmental Group preferred portfolio, which prohibited carbon-emitting resource additions. The modeling team added additional long-duration battery storage to firm up the portfolio such that it met the LOLE standard. The battery additions increased the cost of this scenario; it is the highest cost scenario.
- How does NorthWestern forecast Colstrip coal supply and operations and maintenance (O&M) costs? Will fewer owners increase O&M after 2025?
  - ↳ ***NorthWestern's response:*** NorthWestern escalated coal in future years; O&M was scaled up for the additional ownership.
- How will Colstrip capacity be used from 2025-2042, assuming there are fewer owners?
  - ↳ ***NorthWestern's response:*** Ownership changes for Colstrip capacity are important considerations and developments are ongoing. As a stakeholder, NorthWestern will monitor developments and will adjust its planning for associated impacts.
- How is demand response handled in the modeling?
  - ↳ ***NorthWestern's response:*** See Chapter 5 of Vol. 1.
- Demand response opportunities may not just be primarily in coastal areas.
  - ↳ ***NorthWestern's response:*** Our RFP should provide clarity on DR availability in our region. See Appendix E of Vol. 2
- Why do ELCCs go down with more QFs?
  - ↳ ***NorthWestern's response:*** As more variable QFs are added onto the system, energy production increases under certain conditions only (e.g., windy and/or sunny hours) which may not correlate with actual peak load hours. So adding more of these resources does not guarantee increased production and load serving ability for our peak loads. Consequently, adding more of these resource results in lower ELCCs for each increment of variable generation added. Put simply, there are conditions under which variable resources do not generate, regardless of how much nameplate capacity is added. While batteries may allow shifting energy from high production to deficit timeframes, they currently have short load carrying durations (a few hours). Energy from variable QFs is far less consistent than hydro and thermal resources that can be relied upon during long-duration high load events and have a bi-directional dispatchability (inc and dec).
- What do the plan's conclusions mean as far as price of delivered energy to customers?
  - ↳ ***NorthWestern's response:*** Chapter 8 of Vol. 1 presents resource costs for the base model. The cost to achieve the PRM in the base model is also discussed. While the IRP is not intended to speak directly to delivered cost of energy to customers, good resource planning is key to mitigating conditions that could lead to unacceptable risk and cost exposure. Having a sufficient, flexible, and reliable portfolio will minimize market price exposure during peak loads and (regional) price spikes, and may also lead to revenue opportunities from other markets (e.g., EIM, WRAP). In contrast, a variable and non-dispatchable resource mix increases the chances of being a price taker.
- Please explain the timing of adding resources to the portfolio. What does it mean if you add a gas plant with a 40 year life, while also saying you won't add fossil fuel resources after 2035.
  - ↳ ***NorthWestern's response:*** Per our net zero plan, after 2035 NorthWestern will only procure new resources that are carbon free. Please refer to the net zero plan for more details. The net zero plan can be found here: https://www.northwesternenergy.com/clean-energy/net-zero-by-2050
- Show carbon-free energy production graphs of all the modeled scenarios in 5-year increments.
- Show environmental impacts as part of the RFP scoring criteria.
- Provide better clarity on why cost-effective DSM will be more expensive to acquire. Why would urban versus rural affect DSM? Please model DSM as a selectable resource.
- Avoid assumption that DSM opportunities are constrained before the energy efficiency and demand response potential assessment for NorthWestern is completed.
  - ↳ ***Northwestern's response:*** NorthWestern shows the base case energy mix for the year 2025 and 2030. Immediately following that are carbon output emission graphs for the various Colstrip retirement scenarios.
  - ↳ The RFP scoring criteria presented in Volume 2 has yet to be finalized.
  - ↳ The most cost-effective DSM savings would be acquired first, leaving subsequent DSM savings to be more expensive. The NWPCC report stated more savings are available in urban versus rural areas presumably because there is a greater density of load. Nonetheless, NorthWestern has an RFP out to evaluate DSM savings and awaits the study's findings on the depth and applicability of DSM opportunities. Whether DSM is modeled as reducing load growth or as a selectable resource it will affect NorthWestern's needed capacity in a similar fashion.
- More details desired on contracted resources.
  - ↳ ***NorthWestern's response:*** The MW contract limits are presented in Chapter 6 of Vol. 2.
- What resources are anticipated to get to net zero? Does net zero mean that for every amount of fossil fuel generation added between now and 2035 there will be an equivalent amount of renewable energy added? What are the actual specifics of how "net zero" will affect greenhouse gas emissions?
  - ↳ ***NorthWestern's response:*** Please refer to NorthWestern's net zero plan for more details. https://www.northwesternenergy.com/clean-energy/net-zero-by-2050
  - ↳ We are anticipating future advancements in technology and markets that facilitate the transition to net zero by 2050. We'll provide more specifics in future plans as processes evolve and mature.
- Concerns about resource costs used in the plan.
  - ↳ ***NorthWestern's response:*** Resource costs are provided by Aion and presented in Vol. 2, Appendix F. Aion considers regional IRP data as well as industry publications to verify that the cost assumptions align with industry trends.
- Does NorthWestern have a history of percentage of sales and purchases that come from the market? How does that compare to industry average or requirements from NERC and ISO?
  - ↳ ***NorthWestern's response:*** NorthWestern does have historical information on market purchases and sales, but does not have an analysis on market comparisons at this time. We project the quantity of purchases and sales for all core scenarios in Chapter 8 of Vol. 1 and Vol. 2. We are not aware of any requirements by NERC or any ISO in that regard.
- A Vibrant Clean Energy (VCE) study was recently commissioned by 350Montana. The study appears to have concluded that all of Montana's energy demand could be met solely by renewable resources. VCE's modeling appears to be proprietary but the group appears to be credible and endorsed by climate scientist Steve Running. Has NorthWestern considered the results of the VCE study? If so, why has the VCE portfolio been ignored in NorthWestern's draft resource procurement plan.
  - ↳ ***NorthWestern's response:*** At the suggestion of ETAC, NorthWestern considered the results of this study. NorthWestern looks forward to further engagement regarding the implications and assumptions made in the VCE. As the modeling in this plan demonstrates, NorthWestern's need for capacity cannot be met by solely renewable sources.

2.5 Resource Acquisition Strategy

2.5.1 Competitive solicitations

This section provides a high level description of the process that NorthWestern anticipates it will follow, should NorthWestern decide to pursue a competitive solicitation for resources in the future. NorthWestern may issue all source RFPs or targeted RFPs depending on portfolio and planning needs.

In compliance with Montana's Integrated Least-Cost Resource Planning and Acquisition Act (§69-3-1201 et seq, MCA) and Commission rule ARM 38.5.2024-2025, a future RFP will focus on soliciting proposals for the most reliable, lowest long-term cost resources that meet NorthWestern's identified resource needs, which could include, but not be limited to, the following types of resources.

- Sale of all or part of existing resources.
- Engineer, procure and construct of new resource.
- New generation resources including:
    - ↳ Solar generation combined with storage.
    - ↳ Wind generation combined with storage.
    - ↳ Natural Gas-fired generation.
    - ↳ Other generation technologies, including hydro.
- Energy storage technologies including:
    - ↳ Pumped hydro energy storage.
    - ↳ Battery storage technologies.
    - ↳ Compressed air energy storage.

2.5.1.1 Draft RFP

NorthWestern will notify the Commission and the Montana Consumer Counsel of a decision to issue a competitive solicitation. NorthWestern will provide a draft RFP to the Commission who will provide notice of the draft RFP and receive comments from the public.

2.5.1.2 Announcement, Bidders List, and Release

Upon issuing the final solicitation, NorthWestern will concurrently submit the solicitation to the Commission. NorthWestern will announce the RFP and will also provide notice to developers that NorthWestern is aware of from prior solicitations. The announcement will instruct interested parties to submit a prequalification form and execute a non-disclosure agreement in order to receive the RFP documents. NorthWestern will include interested parties who satisfy the prequalification requirements and who execute a non-disclosure agreement in the bidders list and provide those bidders with the RFP documents. The prequalification requirements will include:

- experience in the energy industry
- creditworthiness
- insurance
- safety record

2.5.1.3 Proposal Development

After NorthWestern sends the RFP documents to the bidders list, the proposal development period begins. During the proposal development period, NorthWestern allows bidders to ask questions in accordance with the communications protocols as defined in the RFP document, visit sites, and participate in bidder conferences.

2.5.1.4 Role of RFP Administrator

Prior to issuing the RFP, NorthWestern will retain an RFP Administrator responsible for administering the entire RFP process. The RFP Administrator will be the main point of contact for bidders and all correspondence must be directed to the RFP Administrator unless otherwise directed. The RFP Administrator may be supported by a third-party engineering firm for technical specification development and proposal evaluation support. The RFP Administrator will follow and enforce communication protocols established prior to issuance of the RFP to ensure proposal confidentiality and, to the extent feasible, that NorthWestern is kept "blind" to bidder and proposal identification consistent with the communication protocols.

2.5.1.5 Role of RFP Sponsor

NorthWestern may assign an employee to serve as the RFP Sponsor to coordinate activities associated with the RFP process. The RFP Sponsor will be engaged throughout the RFP process for consistency.

2.5.1.6 Role of NorthWestern Staff

NorthWestern has subject matter experts (SMEs) in energy supply, electric transmission planning, natural gas fuel supply planning, portfolio modeling, and other functions who may be engaged throughout the process to support the RFP Administrator.

2.5.1.7 Role of the Independent Monitor

As provided in §69-3-1207, MCA, the Montana Consumer Counsel may retain an independent monitor to assist in providing comments on the RFP process, monitoring the RFP process, notifying NorthWestern of any discrepancies in the process, and preparing a report regarding the process.

2.5.1.8 Bidder Information and Evaluation

A variety of information is required to adequately and equally evaluate bidders. Factors such as experience in the industry, experience at scale, credit worthiness, and safety record are important considerations. The list below is not exhaustive and represents only some general requirements.

- **Resource Capacity Accreditation:** Capacity resources will be evaluated based on their contribution to serving peak loads and accredited capacity. Historically, ELCC values were used. In the future a more standardized approach using WRAP values may be employed.
- **Location, timing, and Site Control:** Capacity resources must be capable of serving Montana load and NorthWestern via direct connection or firm transmission service to its Montana system. NorthWestern desires that bidders offering market proposals have 100% site control at the proposal due date. Otherwise, the bidder must demonstrate capability to achieve adequate site control to support the project in-service date/delivery start date.
- **Operational Flexibility:** NorthWestern will specify the operational flexibility and dispatch control desired in the RFP.
- **Fuel, Charging, and Permit Requirements:** The information required for fuel supply, charging arrangements, and permitting status for energy resources will be specified at the time of the RFP.

2.5.2 RFP Proposal Evaluation

2.5.2.1 Proposal Evaluation Criteria

In evaluating proposals, NorthWestern will consider quantitative and qualitative factors, such as those described below. Note, these factors are subject to change when the actual RFP is developed.

- **Evaluated Price:** Economics associated with a proposed asset's contribution to NorthWestern's capacity position as well as flexibility attributes may be considered.
- **Commercial:** Commercial amenability to associated terms and conditions, credit quality, safety record, experience and overall assessment of project execution risk.
- **Development:** Status, plan and expected timeline associated with key development factors including, but not limited to, electric transmission interconnection and service, fuel supply sourcing/charging arrangements (as applicable), permitting and site control.
- **Technical:** Technology attributes and operating capability including, but not limited to, dispatchability, reliability, ancillary services and technology maturity.

2.5.2.2 Proposal Evaluation Process Overview

The evaluation of proposals may progress in similar phases to those listed below.

- **Phase 1:** Initial bidder and proposal review, proposal clarifications, and satisfaction of RFP minimum requirements;

- **Phase 2:** Additional evaluation, bidder clarifications and development of shortlist; and
- **Phase 3:** Negotiations and selection (potential).

2.5.2.2.1 Phase 1 – Initial Review

Proposals will be reviewed against the requirements included in the RFP. Bidders may be contacted for missing information and any required clarifications associated with the proposals. Proposals may be eliminated based on not satisfying the minimum requirements established in the RFP.

2.5.2.2.2 Phase 2 – Detailed Review and Establishment of a Shortlist

Detailed technical and commercial evaluation will commence and will include evaluation of the conformance to technical requirements and amenability to commercial terms and conditions. Bidders may be contacted with additional clarifications and questions and invited to participate in Bidder meetings.

Based on this additional review and evaluation, one or more Bidders may be shortlisted for additional technical conformance and commercial evaluation and negotiation.

2.5.2.2.3 Phase 3 – Shortlist Negotiations and Selection

NorthWestern may advance to technical and commercial negotiations with one or more bidders. Bidders may be requested to refresh their proposals during the shortlist evaluation. Selection of none, one, or multiple proposals will be at the sole discretion of NorthWestern.

2.5.3 The QF Process

2.5.3.1 Process Overview

NorthWestern acquires resources for its portfolio pursuant to its obligations under PURPA to purchase power from QF. Upon receiving contact from a potential QF, NorthWestern provides that QF with:

- a copy of the Commission's rules pertaining to QFs and the Commission's complaint procedure,
- a copy of the tariff applicable to QF projects less than 3 MW in size or a list of information need to calculate avoided cost for projects greater than 3 MW in size, and
- When requested, an applicable Commission-approved standard power purchase agreement.

The list of information NorthWestern needs to calculate avoided cost for projects greater than 3 MW in size includes:

- Documentation establishing status as a QF (FERC Form 556)
- Commercial Operation Date – month, day, year
- Project size – Nameplate Capacity/Delivered Capacity
- Generation Type and Equipment Description
- The average annual estimated output delivered to NorthWestern for the term of the agreement.
- The most recent 3 calendar years of calculated hourly (8760) production data estimating the hourly production using the specified equipment for the project. This hourly data should have a timestamp in hour-ending Pacific-Prevailing Time ("PPT") or be clearly specified if another timestamp is used. This is necessary for the wind, solar, or hydro generators included in the project. In the case of a hybrid with battery storage, it is optional for the combined output of the project. Typically, the battery is modeled as a separate component based on the operating specifications requested below.
- QF Battery Specification Details sheet to be completed by the developer. This includes key operating characteristics of the battery related to capacity, storage, efficiencies, outages, leakage, and dispatch control. These allow the battery to be dispatched based on hourly conditions in the model.

2.5.3.2 Rates for QF Purchases

For QF projects less three MW in size, NorthWestern offers a rate pursuant to a standard tariff. For QF projects greater than three MW in size NorthWestern purchases power at a rate pursuant to a negotiated contract or as determined by the MPSC.

The Commission's rules require that the avoided cost of energy be calculated at the time of delivery, unless NorthWestern and the QF agree upon a different rate.

NorthWestern's current method for calculating an energy rate at the time of delivery is to use the real-time Locational Marginal Price (LMP) for the node closest to the generator. The LMP reflects the true price of energy at the time and place it is generated, compared to the prior method of using a fixed price for the contract period.

To calculate rates forecasted as of the date of a Legally Enforceable Obligation (LEO), NorthWestern uses the PowerSIMM production cost model. PowerSIMM modeling is used to simulate future weather conditions and hourly-level customer loads, market prices, and generation from wind, solar, and hydro resources. The model simulates the economic dispatch of resources and market purchases to serve load. An avoided cost of energy script is run that uses the modeling output results and compares the costs of serving load with the existing resource portfolio to the cost of serving load with the new QF resource added to the resource portfolio.

The PowerSIMM modeling steps and inputs to calculate a fixed energy price include:

- The QF provides hourly estimated historical data. NorthWestern validates the data for potential modeling issues and creates monthly forecast values for energy and capacity, which are entered into PowerSIMM for the resource definition.
- The inputs to the modeling include forward market curves for electricity and natural gas, forward market data for Mid-C and AECO and NorthWestern's power price forecast.
- The QF resource is added to a new portfolio containing NorthWestern's existing, contracted for resources, and all QF resources ahead of the modeled QF in the QF queue.
- The QF data, market forward curves, and portfolio are used to run a production cost study in PowerSIMM for the years covering the proposed QF contract. The PowerSIMM study simulates NorthWestern's system at an hourly basis for the entire study period. For the purpose of avoided cost studies, NorthWestern runs 10 independent simulations in PowerSIMM to capture a range of potential future states when calculating the avoided cost.
- The outputs from the PowerSIMM study are used for the calculation of the avoided cost. The important variables for an avoided cost analysis are hourly load, simulated generation from wind, solar, and hydro resources, generation output from dispatchable resources (or charge/discharge amounts for storage), market prices and QF generation. A programming script written in SAS pulls the values from PowerSIMM to determine hourly supply stacks and compare the supply stacks with NorthWestern load to determine the marginal unit serving NorthWestern load. The marginal unit could be market purchases, thermal resources, wind, hydro, or solar depending on the load level and generation from resources. The cost of the marginal unit is the avoided cost for the hour. Hourly values for avoided cost are aggregated as a weighted average by the QF generation for all months in the study. Monthly average avoided costs are levelized over the contract period to provide a final, fixed avoided energy cost.
- The results are reviewed and validated, considering recent avoided cost calculation results and differences in market forecasts, technologies, and changes in the base portfolio. After internal review, NorthWestern sends the avoided costs to the QF.

2.5.3.3 Rates for Capacity

For purchases subject to an established LEO, the avoided cost of capacity is calculated at the time the LEO was formed. The avoided cost of capacity is calculated using NorthWestern's projected capacity position, the QF resource's ELCC value, and the revenue requirement associated with the least cost, proxy capacity resource that NorthWestern would build, but for the QF.[1] This value is used to define the amount of compensation a QF receives for their project's accredited capacity.

1 More detail on ELCC analysis is contained in section 8.5 of the Plan

NorthWestern's capacity position is based on the resources in NorthWestern's portfolio, considering the date the resource established a LEO. The ELCC values associated with resources in NorthWestern's portfolio are used to forecast NorthWestern's capacity position over the term of the QF contract. In years where NorthWestern is short of capacity, the QF will receive a capacity payment up to the ELCC value of the facility. Should NorthWestern not have a shortage equal to or greater than the ELCC value of the QF, the QF project would receive a partial capacity payment equal to the monetary value of the amount of capacity NorthWestern is short. In years that NorthWestern meets or exceeds its forecast capacity needs, the QF would not be compensated for capacity.

The avoided cost of capacity payment amount is determined using the revenue requirement of the least cost proxy resource. The next, least cost resource is re-evaluated or changed when NorthWestern receives updated pricing information suggesting a change in cost associated with new resources (generally in an RFP or IRP). The total revenue requirement is split into an annual price that is used to define the amount one kW of capacity is worth. The QF project size and NorthWestern's projected capacity position are used to adjust the capacity price to an appropriate capacity payment that is generally levelized and paid out over the life of the contract.

The following figures (2-1 and 2-2) show NorthWestern's capacity position with all current QFs. QFs are split into two categories, "QF Advanced" and "QF Potential", based on the stage of their development. "QF Advanced Resources" have an order from the MPSC, but have not executed a contract. "QF Potential Resources" have no MPSC order or executed contract but have engaged in substantive negotiations with NorthWestern for a contract. These figures are made with best available assumptions for WRAP capacities, which are expected to evolve as the process matures. The forecast load for each season and the forecast plus a WRAP specific planning reserve margin (PRM) are plotted to facilitate evaluation of resource adequacy over time. In the WRAP views below, NorthWestern has a significant energy surplus for multiple years and then smaller deficits later in the planning period.

Figure 2-1 – NorthWestern's Capacity Position Under WRAP with QFs (Winter)

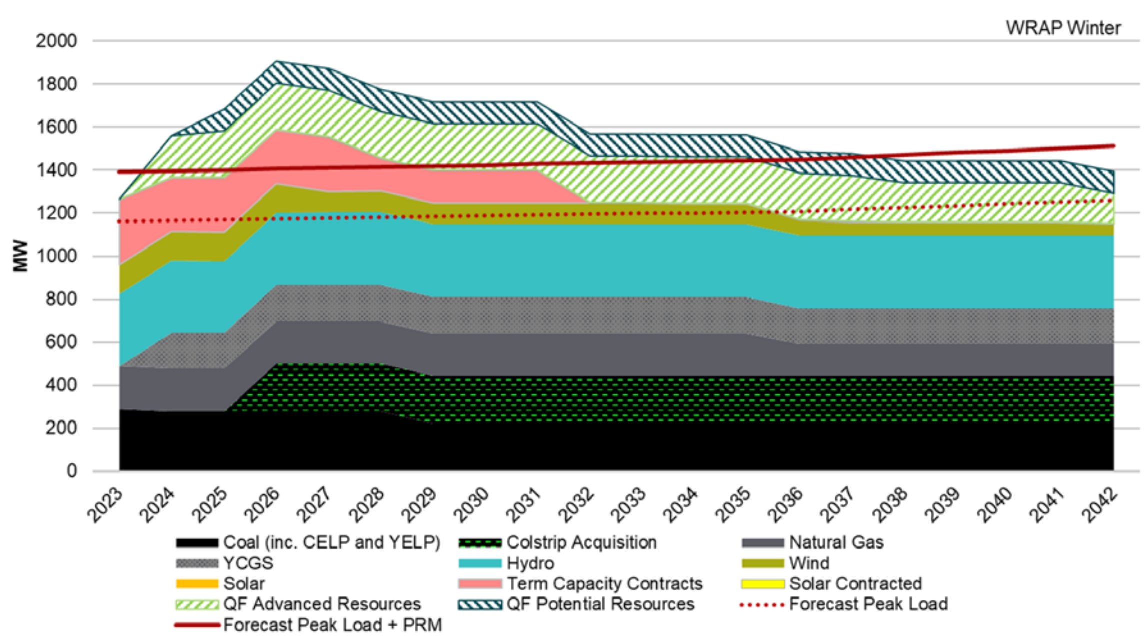
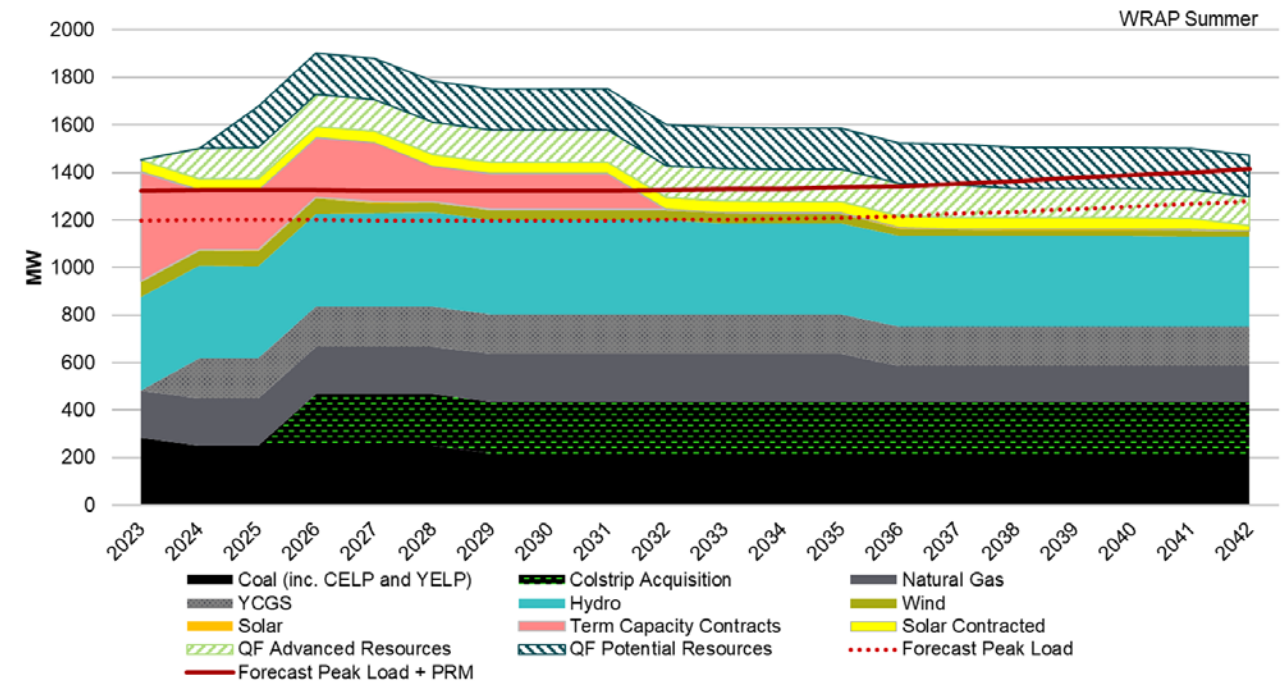
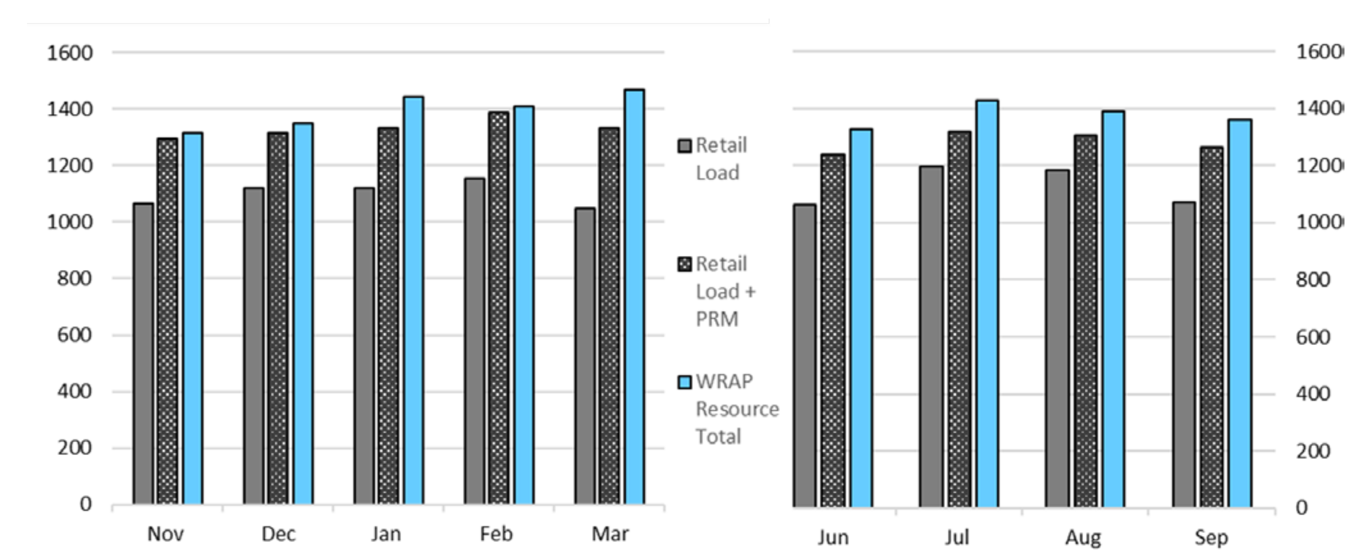


Figure 2-2 – NorthWestern's Capacity Position Under WRAP with QFs (Summer)



While the preceding graphs show seasonal views under WRAP, WRAP will calculate ELCC values and a PRM on a monthly basis. Figure 2-3 compares the monthly WRAP load forecast, WRAP load forecast + PRM, and WRAP-based sum of capacities for the upcoming winter and summer of 2023, using best estimates for monthly WRAP capacity. The winter months are Nov 2022 – Mar 2023; the summer months are Jun 2023 – Sep 2023. Existing energy contracts are included as capacity at the contract limits. This near-term view shows NorthWestern's resources exceeding the load + PRM for the months considered.

Figure 2-3. Near-term View of WRAP load vs. Resources Winter 2022/2023 and Summer 2023 (MW)



Underlying WRAP values are provisional and subject to change.

3. Regional Outlook

No Additional Data

4. Energy and Environmental Policy

No Additional Data

5. Load Service Requirement

Table 5-1. Actual and Forecasted Summer and Winter Peak Demand Default Supply

Summer Peak Demand Forecast (MW)				
Historic and Forecast Values Include Losses				
Year	2022 Actual/ Regression	Less DSM[2]	Less NEM[1,2]	2022 Forecast
2012	1133			1133
2013	1162			1162
2014	1115			1115
2015	1146			1146
2016	1147			1147
2017	1210			1210
2018	1196			1196
2019	1119			1119
2020	1171			1171
2021	1248			1248
2022	1221	6	5	1210
2023	1235	12	10	1213
2024	1249	18	17	1215
2025	1263	24	24	1215
2026	1277	30	33	1214
2027	1291	35	42	1213
2028	1304	41	51	1212
2029	1318	47	59	1212
2030	1332	53	66	1213
2031	1345	59	73	1214
2032	1359	65	79	1215
2033	1372	71	84	1218
2034	1385	77	87	1221
2035	1398	83	90	1225
2036	1411	89	93	1229
2037	1423	89	95	1240
2038	1436	89	96	1251
2039	1448	89	98	1262
2040	1461	89	99	1273
2041	1473	89	100	1284
2042	1485	89	101	1296
20 Year CAGR	1.0%			0.3%
20 Yr Avg Increase (MW)	13			4

1 Navigant LOW case solar pv - net meter forecast
2 Incremental DSM and NEM

Winter Peak Demand Forecast (MW)				
Historic and Forecast Values Include Losses				
Year	2022 Actual/ Regression	Less DSM[2]	Less NEM[1]	2022 Forecast
2012	1074			1074
2013	1272			1272
2014	1176			1176
2015	1054			1054
2016	1163			1163
2017	1119			1119
2018	1171			1171
2019	1165			1165
2020	1190			1190
2021	1182			1182
2022	1205	6		1199
2023	1216	13		1203
2024	1227	19		1208
2025	1237	25		1211
2026	1247	32		1215
2027	1258	38		1219
2028	1268	45		1223
2029	1278	51		1227
2030	1289	57		1231
2031	1299	64		1235
2032	1309	70		1239
2033	1319	76		1242
2034	1329	83		1246
2035	1338	89		1249
2036	1348	95		1252
2037	1357	95		1262
2038	1367	95		1271
2039	1376	95		1281
2040	1385	95		1290
2041	1395	95		1299
2042	1404	95		1308
20 Year CAGR	0.8%			0.4%
20 Yr Avg Increase (MW)	10			5

1 No NEM impact on Winter peak assumed
2 Incremental DSM

Figure 5-1. Peak load by Month Plot 2017 – 2021.

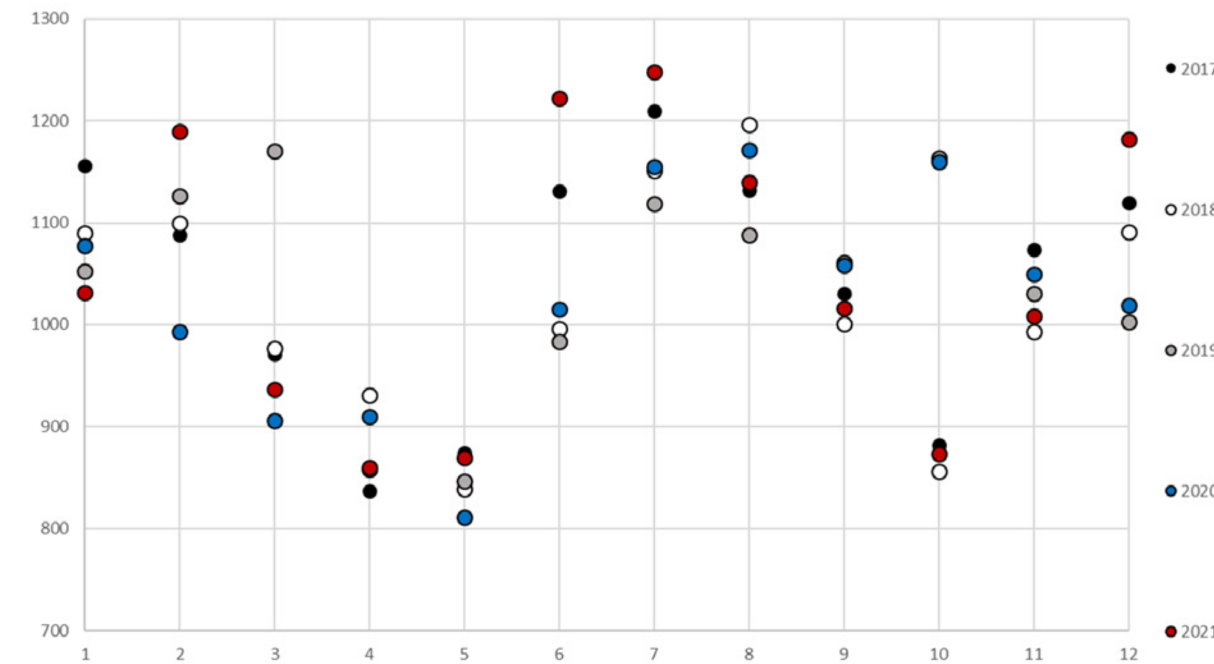
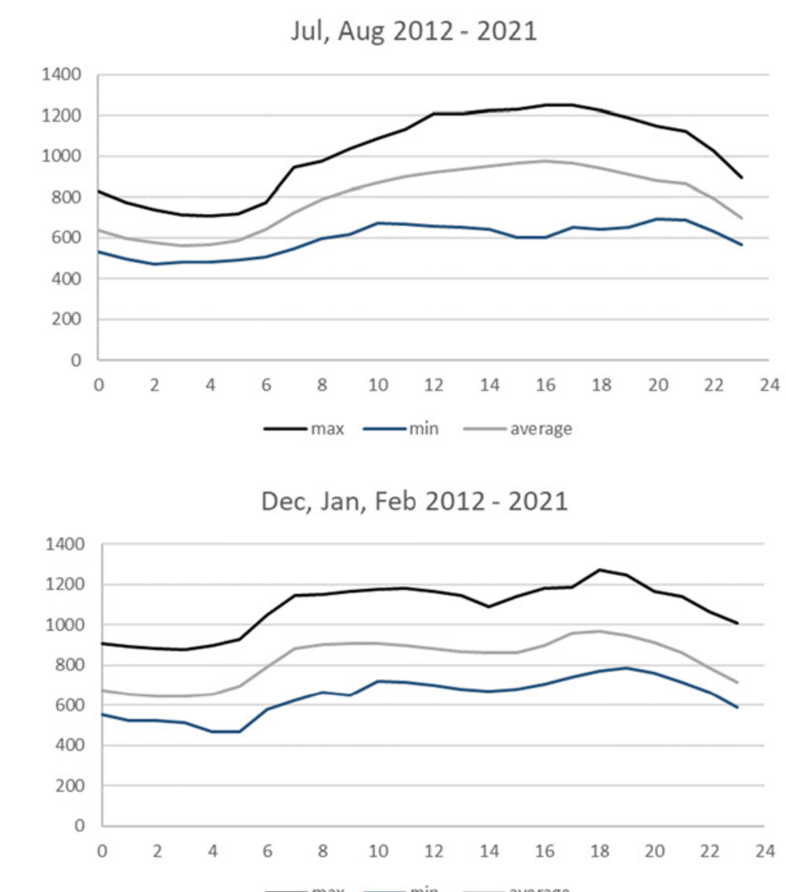


Figure 5-1 extracts the peak hourly load observed for each month for each year in the period from 2017 – 2021. It shows the range of peak load and also seasonal max load shape and variability across the period.

Figure 5-2. Load Shapes by Season



For Figure 5-2, the min, average, and maximum of observed loads associated with each hour are plotted for the summer (Jul, Aug) and winter (Dec, Jan, Feb) months for the period from 2012 to 2021. These figures also give a view of hourly variation in load (spread) and seasonal variation associated with each hour for the 10 year period.

5.1 DSM RFP

See Appendix E for exhibit.

6. Existing Resource Portfolio

6.1 NorthWestern's Generation Portfolio

Resource characteristics are shown in table 6.1. The capacity factor in this table is derived from dividing the 3 year average production by the year equivalent of the maximum capacity (nameplate*8760). As such, it differs from the ELCC values. The historic ELCC values have been presented in figure 6-3 of the main IRP, but can also be derived by dividing the accredited capacities in this table by the maximum. WRAP accredited values are also displayed although they should be considered provisional and subject to change.

Table 6-1: NWE Portfolio, Contracted, and Expected Generation Characteristics[2,3]

Hydro Generation - Online	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%) (gen/nameplate)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
Thompson Falls	94	56	38	73	84	57%	466,231	1915	Rate Based
Cochrane	62	37	25	64	64	52%	283,280	1958	Rate Based
Ryan	72	43	29	54	52	70%	443,480	1915	Rate Based
Rainbow	64	38	26	37	46	69%	387,983	1910	Rate Based
Holter	50	30	20	29	34	64%	281,236	1918	Rate Based
Morony	49	29	20	28	33	67%	285,862	1930	Rate Based
Black Eagle	23	14	9	13	15	60%	120,201	1927	Rate Based
Hauser	21	13	8	14	14	64%	118,538	1911	Rate Based
Mystic	12	7.2	4.8	5.8	11	53%	55,727	1925	Rate Based
Madison	12	7.2	4.8	5.1	7	17%	17,493	1906	Rate Based
Turnbull Hydro LLC	13	7.8	5.2	0.0	13	24%	27,104	2011	2032
State of MT DNRC (Broadwater Dam)	10	6.0	4.0	4.7	6	49%	42,827	1989	2024
Tiber Montana LLC	7.5	4.5	3.0	5.0	5	82%	53,546	2004	2025
Flint Creek Hydroelectric LLC	2	1.2	0.8	0.9	2	75%	13,141	2013	2037
Hydrodynamics Inc (South Dry Creek)	2	1.2	0.8	0.0	2.0	22%	3,775	1985	2041
Wisconsin Creek LTD LC	0.6	0.3	0.2	0.2	0.4	16%	775	1989	2024
Boulder Hydro Limited Partnership	0.5	0.3	0.2	0.2	0.4	31%	1,369	1988	2022
Lower South Fork LLC	0.5	0.3	0.2	0.2	0.4	15%	584	2012	2037
Ross Creek Hydro LC	0.5	0.3	0.2	0.2	0.4	58%	2,296	1996	2032
Gerald Ohs (Pony Generating Station)	0.4	0.2	0.2	0.2	0.3	23%	821	1989	2025
Allen R. Carter (Pine Creek)	0.3	0.2	0.1	0.1	0.2	49%	1,278	1989	2024
Donald Fred Jenni (Hanover Hydro)	0.2	0.1	0.1	0.1	0.2	15%	326	1988	2034
Hydrodynamics Inc (Strawberry Creek)	0.2	0.1	0.1	0.1	0.2	67%	1,112	1987	2023
Total	**497**	**298**	**199**	**333**	**390**		**2,608,984**		

Hydro Generation - "Additions" (max)	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
Black Eagle U3 *	2.0	1.2	0.8	1.2	1.3	TBD	TBD	2023	Rate Based
Hauser U1 *	1.4	0.8	0.6	0.9	0.9	TBD	TBD	2025	Rate Based
Hauser U3 *	1.4	0.8	0.6	0.9	0.9	TBD	TBD	2027	Rate Based
Holter U1 *	2.0	1.2	0.8	1.2	1.4	TBD	TBD	2023	Rate Based
Holter U2 *	2.0	1.2	0.8	1.2	1.4	TBD	TBD	2024	Rate Based
Holter U4 *	2.0	1.2	0.8	1.2	1.4	TBD	TBD	2025	Rate Based
Cochrane U2 *	2.0	1.2	0.8	2.0	2.1	TBD	TBD	2024	Rate Based
Cochrane U1 *	2.0	1.2	0.8	2.0	2.1	TBD	TBD	2026	Rate Based
Morony U1 *	1.7	1.0	0.7	1.0	1.2	TBD	TBD	2026	Rate Based
Morony U2 *	1.7	1.0	0.7	1.0	1.2	TBD	TBD	2028	Rate Based
Thompson Falls U6 *	1.3	0.8	0.5	1.0	1.1	TBD	TBD	2025	Rate Based
Thompson Falls U5 *	1.3	0.8	0.5	1.0	1.1	TBD	TBD	2026	Rate Based
Thompson Falls U2 *	1.3	0.8	0.5	1.0	1.1	TBD	TBD	2027	Rate Based
Thompson Falls U4 *	1.3	0.8	0.5	1.0	1.1	TBD	TBD	2028	Rate Based
Total	**23**	**14**	**9**	**16**	**18**				

Thermal/Natural Gas Generation - Online	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
Basin Creek	52	49	49	52	51	24%	111,126	2006	2036
DGGS 1	50	49	49	50	50				
DGGS 2	50	49	49	48	49	17%	221,910	2011	Rate Based
DGGS 3	50	49	49	50	49				
Total	**202**	**195**	**195**	**199**	**199**		**333,036**		

Thermal/Coal Generation - Online	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
Colstrip	222	204	204	221	218	66%	1,286,568	1984	Rate Based
Colstrip Aquistion (Effective 2026)	222	204	204	221	218	--	--	2026	--
Yellowstone Energy Limited Partnership (BGI)	52	50	50	57	32	100%	459,361	1995	2028
Colstrip Energy Limited Partnership	42	34	34	12	33	81%	298,510	1990	2024
Total	**538**	**492**	**492**	**511**	**501**		**2,044,439**		

2 Thermal ELCCs based on Generating Availability Data System (GADS) data
3 Other resource ELCCs sourced from E3 and Ascend

Wind Generation - Online	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
Judith Gap Energy LLC	135	17.6	17.6	37.9	22.4	40%	473,068	2006	2026
Stillwater Wind LLC (WKN)	80	10.4	10.4	27.6	10.3	39%	274,858	2018	2043
South Peak Wind LLC	80	10.4	10.4	26.1	10.0	TBD	TBD	2020	2035
Spion Kop Wind	40	5.2	5.2	10.1	4.9	37%	128,502	2012	Rate Based
Greenfield Wind LLC	25	3.3	3.3	8.5	3.5	39%	85,721	2016	2041
Big Timber Wind LLC (Greycliff)	25	3.3	3.3	8.5	3.4	38%	84,203	2018	2043
Two Dot Wind Farm LLC	11	1.5	1.5	3.0	1.6	36%	36,063	2014	Rate Based
Fairfield Wind LLC (Greenbacker)	10	1.3	1.3	2.7	1.8	34%	29,905	2014	2033
Musselshell Wind Project LLC	10	1.3	1.3	2.1	1.4	27%	23,824	2013	2036
Musselshell Wind Project Two LLC	10	1.3	1.3	2.3	1.8	32%	28,403	2013	2036
Gordon Butte Wind LLC	9.6	1.2	1.2	3.2	1.5	46%	38,739	2012	2036
71 Ranch LP	2.7	0.4	0.4	0.9	0.3	47%	11,025	2018	2043
DA Wind Investors LLC	2.7	0.4	0.4	0.9	0.3	48%	11,431	2018	2043
Oversight Resources LLC	2.7	0.4	0.4	0.9	0.3	41%	9,691	2018	2043
Cycle Horseshoe Bend Wind LLC	9.0	1.2	1.2	0.0	0.0	30%	23,775	2006	2025
Two Dot Wind LLC (Broadview East Wind)	1.6	0.2	0.2	0.4	0.2	34%	4,807	2018	2043
Total	**455**	**59**	**59**	**135**	**64**		**1,264,015**		

Wind Generation - "Advanced"	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
Wheatland Wind LLC	75	9.8	9.8	22.9	9.5	TBD	TBD	2024	
Pondera Wind LLC	20	2.6	2.6	6.1	2.5	TBD	TBD	2024	
Teton Wind LLC	19	2.5	2.5	5.9	2.4	TBD	TBD	2024	
Jawbone	80	10.4	10.4	24.5	10.1	TBD	TBD	2025	
Total	**194**	**25**	**25**	**59**	**24**				

Solar Generation - Online	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
Green Meadow Solar LLC	3	0.03	0.9	0.09	1.1	21%	5,444	2017	2042
South Mills Solar 1 LLC	3	0.03	0.9	0.08	0.9	21%	5,457	2017	2042
Black Eagle Solar LLC	3	0.03	0.9	0.08	0.8	22%	5,839	2017	2042
Great Divide Solar LLC	3	0.03	0.9	0.08	0.8	24%	6,229	2017	2042
Magpie Solar LLC	3	0.03	0.9	0.08	0.7	22%	5,726	2017	2042
River Bend Solar LLC	2	0.02	0.6	0.05	0.7	19%	3,333	2017	2042
Total	**17**	**0.2**	**5**	**0.5**	**5**		**32,027**		

Solar Generation - "Contracted"	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
MTSun LLC	80	0.8	24.0	2.2	24.0	TBD	TBD	2023	Est 2047
Clenera Apex I	80	0.8	24.0	2.2	24.0	TBD	TBD	Est 2023	Est 2043
Total	**160**	**2**	**48**	**4**	**48**				

Hybrid QF - "Advanced"	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
Caithness Beaver Creek 2 (60 MW Wind)	60	7.8	7.8	18.4	7.6	TBD	TBD	2024	
Caithness Beaver Creek 2 (20 MW BESS)	20	10.0	10.0	7.0	7.0	TBD	TBD	2024	
Caithness Beaver Creek 3 (60 MW Wind)	60	7.8	7.8	18.4	7.6	TBD	TBD	2024	
Caithness Beaver Creek 3 (20 MW BESS)	20	10.0	10.0	7.0	7.0	TBD	TBD	2024	
Caithness Beaver Creek 1 (50 MW Wind)	50	6.5	6.5	15.3	6.3	TBD	TBD	2025	
Caithness Beaver Creek 1 (30 MW BESS)	30	15.0	15.0	18.0	18.0	TBD	TBD	2025	
Caithness Beaver Creek 4 (50 MW Wind)	50	6.5	6.5	15.3	6.3	TBD	TBD	2025	
Caithness Beaver Creek 4 (30 MW BESS)	30	15.0	15.0	19.0	19.0	TBD	TBD	2025	
Total	**320**	**79**	**79**	**118**	**79**				

Short and Medium Term Contracts - Online	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
Contract 1	50	--	50	--	50			2020	2023
Contract 2	50	--	50	--	50			2021	2023
Contract 3	60	--	60	--	60			2021	2023
Contract 4 (max)	200	200	200	200	200			2022	2031
Total	**360**	**200**	**360**	**200**	**360**				

2020 RFP	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
Yellowstone County Generating Station (YCGS)	170	164	164	168.5	167.5	TBD	TBD	Est 2024	Rate Based
Contract 6	100	100	100	100	100	TBD	TBD	2023	2027
Total	**270**	**264**	**264**	**269**	**267**				

QF Potential Resources	Maximum Capacity (MW)	Winter Accredited Capacity (MW)	Summer Accredited Capacity (MW)	WRAP Winter Accredited Capacity (MW)	WRAP Summer Accredited Capacity (MW)	Capacity Factor (%)	3 Year Avg. Production (2019 - 2021; MW)	Online Date	Expiration Date
Trident (160 MW Solar)	160	0.8	24.0	2.2	24.0	TBD	TBD	2025	
Trident (80 MW BESS)	80	62.4	44.0	56.0	56.0	TBD	TBD	2025	
Broadview (160 MW Solar)	160	0.8	24.0	2.2	24.0	TBD	TBD	2025	
Broadview (50 MW BESS)	50	39.0	27.5	32.5	32.5	TBD	TBD	2025	
Meadowlark (20 MW Solar)	20	0.2	6.0	0.5	6.0	TBD	TBD	2025	
Meadowlark (12.5 MW BESS)	12.5	9.8	6.9	6.0	6.0	TBD	TBD	2025	
Upland Dillon Argenta (80 MW Solar)	80	0.8	24.0	2.2	24.0	TBD	TBD	2025	
Total	**563**	**114**	**156**	**101**	**173**				

Thermal/Natural Gas Generation - Online	Forced Outage Rate (%)	2020 Emissions (Metric Tons)	2020 Emissions Rates (lbs/MWh)
Basin Creek	5%	28,315	1,094
DGGS 1			
DGGS 2	3.3%	126,339	1,570
DGGS 3			
Thermal/Coal Generation - Online	**Forced Outage Rate (%)**	**2020 Emissions (Metric Tons)**	**2020 Emissions Rates (lbs/MWh)**
Colstrip (NWE Share Only)	8.23%	1,238,294	2,798
Yellowstone Energy Limited Partnership (BGI)	3.3%	370,283	4,171
Colstrip Energy Limited Partnership	3.3%	870,129	3,000
2020 RFP - "Expected"	**Forced Outage Rate (%)**	**2020 Emissions (Metric Tons)**	**2020 Emissions Rates (lbs/MWh)**
Yellowstone County	TBD	N/A	N/A

Hydro Generation - Online	Estimated Usable Storage (MWh)
Cochrane	100
Ryan	172
Thompson Falls	71

Table 6-2. NorthWestern Energy's Capacity Position by Year and Season with Expected Resources – WRAP ELCCs

NorthWestern's Capacity Position (MW)		
	WRAP ELCC	
Target PRM %	19.9	10.4
	Winter	Summer
2023	-126	129
2024	-27	49
2025	-34	45
2026	186	269
2027	146	250
2028	43	154
2029	-18	122
2030	-23	121
2031	-27	119
2032	-181	-32
2033	-186	-48
2034	-192	-53
2035	-196	-58
2036	-278	-124
2037	-297	-142
2038	-308	-154
2039	-319	-166
2040	-330	-179
2041	-340	-193
2042	-362	-235

Table 6-2 shows NorthWestern's capacity position, by year and season, for the planning period relative to the peak load forecast + the applicable planning reserve margins. The capacity position is calculated using the WRAP accreditation values and is a tabular view of the information that is shown in graphs 6-5 and 6-7 of the Plan. The

WRAP capacity positon values should be considered provisional as the ELCCs are still subject to change.

Figure 6-1 shows a comparison of nameplate capacity with seasonal accredited capacity based on historic ELCC as well as peak load and market-aquired capacity contracts for 2023. ELCC values are shown separately for winter and summer seasons. The WRAP version of this graph is shown in Volume 1.

Figure 6-1. Capacity Comparison by Season (2023), Historic ELCC

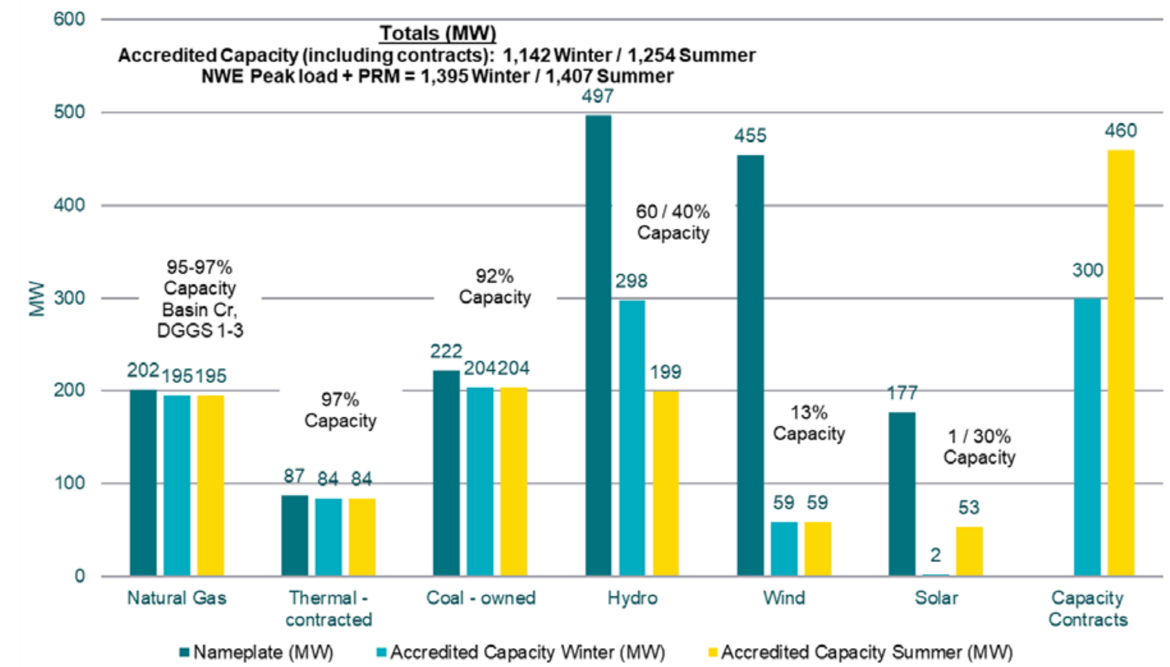


Figure 6-2. Distribution of Hourly Loads 2017 – 2021

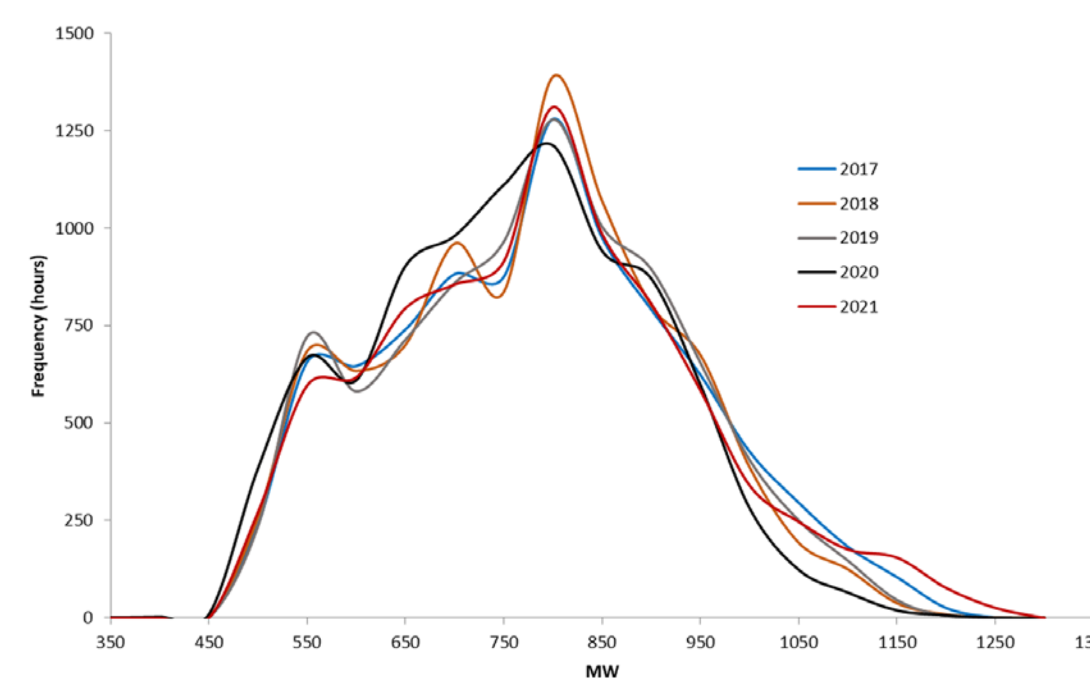


Figure 6-2 shows the grouped frequency (count) of load observations for period of 2017 to 2021. It is a way of looking at the distribution of load, from typical load levels, to the more extreme minimum and maximum loads observed. Observed loads were grouped into load groups of 50 MWs (bins) and then counted. For the period analyzed, the most frequent load range is ~800 MWs. This could be considered a "base load need", with flexible resources needed to reduce or increase generation to accommodate the minima and maxima.

Table 6-3. Capacity and Energy by Fuel Type

Capacity by Fuel Type				
Fuel Type	Maximum (Nameplate) Capacity		2021 Annual Energy	
	(MW)	(% of total)	(GWh)	(% of total)
Hydro	490	33%	2,156	34%
Wind	455	31%	1,509	24%
Solar	17	1%	34	1%
Carbon-free subtotal	962	65%	3,699	59%
Coal	222	15%	1,455	23%
Natural Gas	202	14%	383	6%
Thermal QF* (CELP and YELP)	87	6%	781	12%
Total	1,473	100%	6,318	100%

Table 6-3 shows the aggregate nameplate capacity and energy produced in 2021 for the generation fuel types in NorthWestern's portfolio. Values are expressed in MWs, GWh, and percent of total.

6.2 Planning for the Future

See Appendix F for Exhibit on candidate resource cost estimates.

6.4 Resource Duration

Table 6-4. Long duration Resources in NorthWestern's Portfolio

HYDRO	SMALL HYDRO
Thompson Falls	Turnbull Hydro LLC
Cochrane	State of MT DNRC (Broadwater Dam)
Ryan	Tiber Montana LLC
Rainbow	Flint Creek Hydroelectric LLC (QF)
Holter	Hydrodynamics Inc (South Dry Creek) (QF)
Morony	Wisconsin Creek LTD LC (QF)
Black Eagle	Boulder Hydro Limited Partnership (QF)
Hauser	Lower South Fork LLC (QF)
Mystic	Ross Creek Hydro LC (QF)
Madison	Gerald Ohs (Pony Generating Station) (QF)
	Allen R. Carter (Pine Creek) (QF)
	Donald Fred Jenni (Hanover Hydro) (QF)
	Hydrodynamics Inc (Strawberry Creek) (QF)
GAS	Mammoth Hydro
Basin Creek	**COAL**
DGGS 1	Colstrip 30% U4
DGGS 2	Yellowstone Energy Limited Partnership (BGI) (QF)
DGGS 3	Colstrip Energy Limited Partnership (QF)

7. Transmission

7.1 Electric Transmission System - Chapter Overview

NorthWestern transmission serves 28 network customers, in addition to NorthWestern Supply, who represent about one third of the loads in NorthWestern's BA Area. These customers include electric supply choice customers, electric cooperatives, and federal power marketing agencies. The network customers and their 2022 peak load are listed in Table 7.1.

Table 7-1. NorthWestern's Transmission Network Customers.

Network Customer	2022 Peak (MW)
Ash Grove Cement Company	6.1
Aspen Air US, LLC	8.5
Atlas Power, LLC	65.6
Basin Electric	165.3
Barretts Minerals	5.0
Beartooth Electric Cooperative	22.4
Benefis Health Systems	6.4
Big Horn County Electric Cooperative	15.9
Bonneville Power Administration	202.8
Calumet Refining, LLC	14.6
CHS Inc.	47.1
City of Great Falls	4.1
Colstrip Steam Electric Station	6.3
ExxonMobil Corporation	33.7
General Mills Operations, LLC	3.3
Great Falls Public Schools	2.0
GCC Three Forks, LLC	6.9
Magris Talc USA	5.2
Montana Resources	47.1
Phillips 66 Company	66.7
Town of Philipsburg	0.2
REC	102.9
Roseburg Forest Products	7.2
Suiza Dairy Group (Meadow Gold)	1.1
Stillwater Mining Company	39.9
Western Area Power Administration (WAPA) Irrigation	2.0
WAPA Bozeman MSU	4.0
WAPA Great Falls Malmstrom	4.0

7.7 Loss of Colstrip Analysis

The Loss of Colstrip study was an in-depth look at NorthWestern's transmission system to assess the potential of an early retirement for Colstrip Units 3 and 4. The Loss of Colstrip study is provided in Appendix G.

8. Resource Planning and Analysis

8.3 PowerSIMM Model Framework

The 2023 plan considers different combinations of thermal, storage, nuclear, wind, and solar resources as potential additions to the portfolio. These resources were analyzed using portfolios of interest defined by NorthWestern, see discussion in Chapter 9 of Vol. 2.

8.3.1 Candidate Resources

8.3.1.1 Thermal Resource Options

SC Aero CT

When directly compared with industrial frame combustion turbines (CT), aero derivative CTs are lighter weight, have a smaller size footprint, and are made of more advanced, lightweight materials, because the design is adopted from aerospace designs for use in power applications. Due to this, Aero CTs can handle a greater number of starts and stops during their lifecycle.

Aero CTs require a higher gas pressure to operate making it difficult or costly to site. The effective heat rate of CT units increases significantly as the unit is dispatched at lower output levels below maximum capability and may not be able to run effectively below 50% capacity.

Simple Cycle Reciprocating Internal Combustion Engine (RICE)

A simple cycle RICE facility is evaluated as a potential future resource in this plan. RICE units are internal combustion engines, mechanically analogous to an automobile engine. Similar to simple cycle CT plants, simple cycle RICE installations are used to supply peaking power and to operate in load following scenarios. RICE technology is favorable for peaking applications due to its wide range of operability and rapid response capability. Generally, in utility power generation applications, RICE technology is smaller in scale and has better efficiency as compared to simple cycle CT technology.

8.3.1.2 Storage Resource Options

NorthWestern considers a Battery Energy Storage System (BESS) as a potential future storage resource in this plan. Utility-scale energy storage systems deployment is poised to continue to grow in the US.[4] BESS technology is useful in the following applications:

- meet normal demand
- help minimize peak demand
- smooth load variations due to renewables integration
- improve local grid resilience and availability
- provide ancillary services.

BESS can be comprised of many technologies, but this plan models the most common, which is a 4-hour lithium-ion (Li-ion) battery. Li-ion batteries provide a high energy storage density that has resulted in adoption across the transportation, technology and power generation markets Due to its characteristics, Li-ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term spinning reserve.

An important consideration of BESS is round trip energy efficiency, which is the amount of AC energy the system can deliver relative to the amount of AC energy used by the system during the preceding charge. Losses experienced in the charge/discharge cycle include those from the PCS (inverters), heating and ventilation, control system, and auxiliary systems. Li-ion technology experiences degradation both in terms of capacity and round-trip efficiency with time due to a variety of factors including number of full charge/discharge cycles and environmental exposure.

4 See EIA's Today in Energy https://www.eia.gov/todayinenergy/detail.php?id=49236#:~:text=U.S.%20large%2Dscale%20battery%20storage,rapid%20growth%20set%20to%20continue

Batteries are housed within shipping containers for protection against the elements. The containers house battery racks that hold individual battery cells. This allows for the replacement of individual components.

In addition to stand alone storage options, batteries can also be paired with a wind or solar resources to create a hybrid project. It is beneficial to pair these technologies together because it allows for the shift in energy from lower need hours to peak load hours. In general, the battery is connected to the VER resource that is used to charge the battery. The battery is then dispatched to market and load signals. Some configurations allow for the battery to be charged from both a VER and the grid while others only allow charging from the VER.

The configuration and sizing of hybrids varies vastly making it difficult to model a representative hybrid resource.

Utility scale battery disposal is an ongoing question that is still being explored at the time of this Plan's publication. According to the "National Blueprint for Lithium Batteries", major goals include the development of a recycling program. The document states that near-term objectives, with a target implementation date of 2025, include developing sorting and processing methodologies, creating technologies that allow for the re-introduction of materials to the supply chain, and implementing federal incentives to promote battery recycling[5]. NorthWestern will continue to monitor the development of battery disposal techniques.

8.3.1.3 Nuclear Resource Options

Small Modular Reactors (SMRs) are becoming a realistic energy producing technology capable of providing reliable, safe, and carbon-free power. There are numerous SMR designs utilizing different technologies, with the most advanced and safest being those that fall under Generation III and IV designs. Since the publication of the 2020 IRP, the development of Generation III and IV SMRs has advanced quickly, with numerous countries deploying their own designs. In the U.S. designs including X-Energy, TerraPower, and NuScale have been leading the way for SMR development.

As an example, NuScale has successfully created partnerships with many different entities including the Department of Energy. These partnerships have led to participation in Utah Associated Municipal Power Systems' (UAMPS) Carbon Free Power Project (CFPP). Part of this project will include siting a NuScale 12-module reference plant in Idaho. This plant is expected to reach COD in 2027.[6]

X-Energy is working to deploy its first reactor through the Department of Energy's Advanced Reactor Demonstration Program in 2027. As part of this process, X-Energy and other participants must secure Nuclear Regulatory Commission (NRC) licensing approval for their designs.

Many Generation III and Generation IV reactors do not require safety level electrical power, active systems, or operator action to keep the public safe. The NRC provides additional information on many topics, including safety of these reactors.[7] The SMR modeled in this plan is a 1 reactor facility that can ramp up or down between 40 and 100 percent power in increments of 5 percent per minute. This resource can be easily scaled to a 320 MW (4 reactor) plant depending on system needs.[8]

Small SMR's, like the Xe-100, significantly minimize environmental impact. The Xe-100 Standard Plant 4-reactor modules operate on a site footprint of only 27 acres, reducing its land-use impact compared to other energy sources. All spent fuel will be stored on-site in air-cooled dry storage casks in a below-ground storage vault. This disposal method is extremely safe in the interim until long-term storage is developed by the federal government. Permanent storage options will be made final as part of the NRC decommissioning plan. Once the plant reaches its end of life, the detailed decommissioning plan will be implemented. The site will be dismantled and restored to "greenfield" status in accordance with the most current regulations, codes and standards.

5 See the National Blueprint for Lithium Batteries 2021–2030 https://www.energy.gov/sites/default/files/2021-06/FCAB%20National%20Blueprint%20Lithium%20Batteries%200621_0.pdf
6 See NuScale's DOE Partnership https://www.nuscalepower.com/about-us/doe-partnership.
7 See the U.S. NRC website Advanced Reactors (non-LWR Designs) | NRC.gov
8 See the Advanced Nuclear Power Reactors page https://world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/advanced-nuclear-power-reactors.aspx

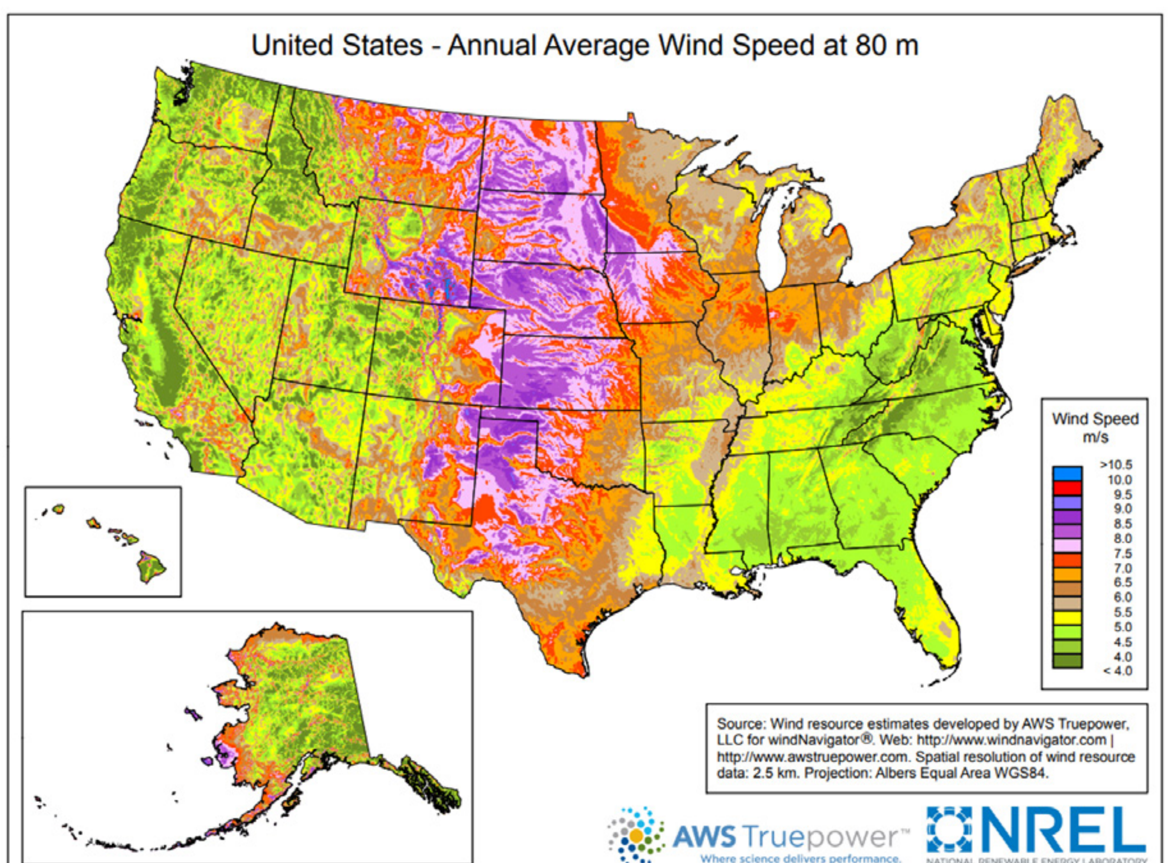
Figure 8-1: X-Energy Site Overview (4-Pack, 320 MWe)

8.3.1.4 Wind Resource Options

Installation of wind generation in the US has grown considerably in recent years and is expected to continue; therefore, wind is included as a potential resource in this IRP. Generally, the costs of building new wind resources are decreasing and the size of wind farms is increasing.

Wind turbines can be designed for sizes between 1.5 – 5 MW. Capacity is based on blade length. Longer blades require a taller turbine installation. Figure 8-2 below shows average wind speeds across the United States.

Figure 8-2. United States Average Wind Speeds[9]



9 See U.S. Average Annual Wind Speed at 80 Meters https://windexchange.energy.gov/maps-data/319

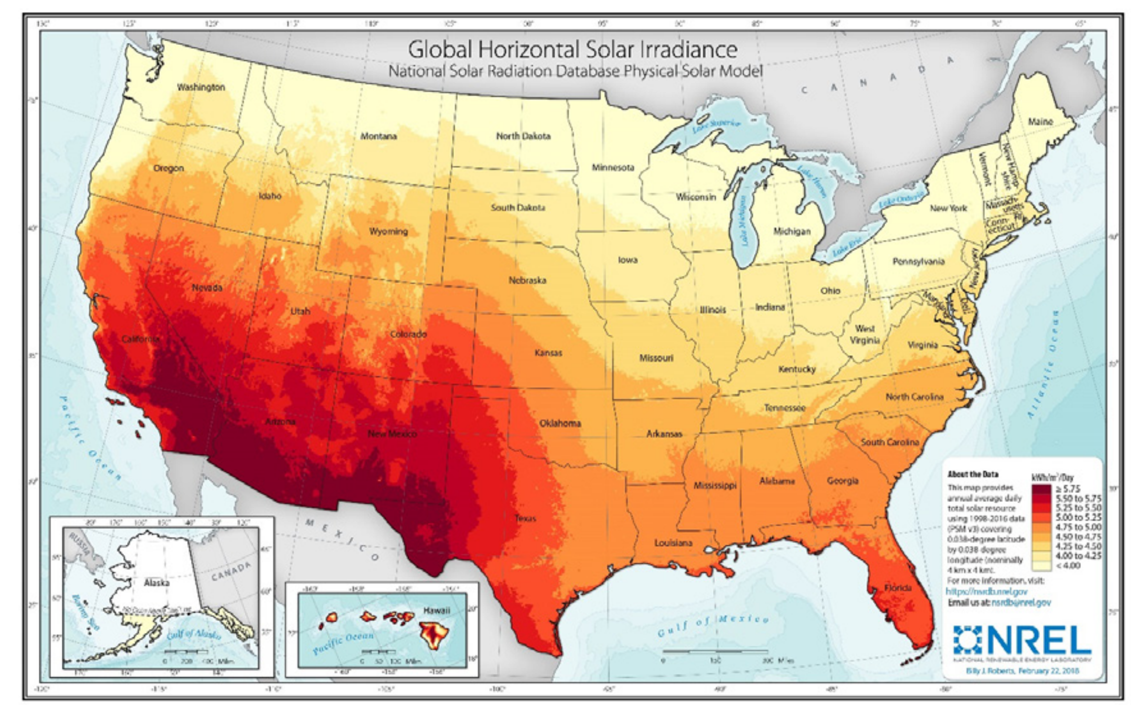
While wind farm growth is expected to continue into the future, it is important to acknowledge that wind turbine blades cannot be recycled. Blades are large, durable pieces of fiberglass that are challenging to cut, bend, or otherwise repurpose. According to an article published by Bloomberg, many spent blades are currently being disposed of in landfills. That said, the article mentions that a start-up company, Global Fiberglass Solutions, has created a method to repurpose the fiberglass blades. While this is a step in the right direction, until the business is able to substantially scale up operations or others are able to adopt their methods, recycling will not be readily available for spent blades.[10]

8.3.1.5 Solar Resource Options

NorthWestern evaluates a solar facility as a potential resource in this Plan. Solar PV technology uses photovoltaic cell (PV) arrays to convert light from the sun directly into electricity. PV cells are made of different semiconductor materials and come in many sizes, shapes, and ratings. Solar cells produce direct current (DC) electricity and require a DC to alternating current (AC) converter to allow for grid connected installations. Solar PV arrays are mounted on structures that can either tilt the PV array at a fixed angle or incorporate tracking mechanisms that automatically move the panels to follow the sun across the sky. The fixed angle is determined by local latitude, orientation of the structure, and electrical load requirements. Tracking systems provide more energy production. Single-axis trackers are designed to track the sun from east to west and dual axis trackers allow for modules to remain pointed directly at the sun throughout the day.

The major components of a PV system include the PV modules/arrays, DC to AC converters/inverters, and mounting structures. An average capacity factor range for a solar power facility is typically in the range of 10 to 30 percent, with annual averages around 25 percent depending upon solar resources within the region.

Figure 8-3: Solar Irradiance across the United States[11]



Similar to battery storage, nuclear, and wind facilities, there are questions surrounding the disposal methods for solar projects once they reach end of life. Many materials in a solar panel can be recycled, but panels also contain components such as valuable or toxic metals and critical materials that are not recyclable. The EPA notes that while recycling practices are currently being developed, none are available on a large scale.[12]

10 See Bloomberg's Gr Wind Turbine Blades Can't Be Recycled, So They're Piling Up in Landfills article https://www.bloomberg.com/news/features/2020-02-05/wind-turbine-blades-can-t-be-recycled-so-they-re-piling-up-in-landfills

11 See NREL's Solar Resource Maps and Data https://www.nrel.gov/gis/solar-resource-maps.html.

12 See the EPA's Solar Panel Recycling page https://www.epa.gov/hw/solar-panel-recycling#How%20Solar%20Panels%20are%20Recycled

8.3.1.6 Hydrogen

Hydrogen is generally considered an energy storage medium where energy inputs are required to generate the hydrogen which is then used to produce electricity. The role and magnitude of hydrogen as an energy resource is unknown although its role could grow in the future if the economics and infrastructure are developed. There are a number of different types of hydrogen described by colors to indicate the source of the hydrogen production. Table 8-1 shows an explanation of the different types.

Table 8-1. Types of Hydrogen[13]

Hydrogen Colors	Production Process
Green Hydrogen	Electrolysis of water using clean electricity from renewable energy sources.
Blue Hydrogen	Steam reforming of natural gas using CSS technology
Grey Hydrogen	Steam reforming of natural gas without CSS technology
Black and Brown Hydrogen	Steam reforming of black or brown coals
Pink Hydrogen	Water electrolysis using nuclear energy
Turquoise Hydrogen	Methane pyrolysis
Yellow Hydrogen	Electrolysis using solar power
Red Hydrogen	High-temperature catalytic process using nuclear power
White Hydrogen	Naturally occurring Hydrogen

One potential use of hydrogen is to blend hydrogen with natural gas. Blending the two essentially dilutes the methane content of the natural gas leading to fewer carbon emissions.[14] While this blending technique is still in its infancy, NorthWestern plans to monitor its development and potential use in future applications.

While the direct combustion of hydrogen is commonly studied for grid applications, hydrogen fuel cells are also a potential resource. Fuel cells generate electricity through a chemical reaction with hydrogen and oxygen that does not use combustion. There are several hydrogen fuel cell projects in operation across the globe with sizes generation in the 1 to 10 MW range. Many of the existing projects create hydrogen through the electrolysis of water creating hydro gen and oxygen (requiring electricity as an input). The hydrogen and oxygen are fed into the fuel cell to create the electricity.[15]

According to the Office of Energy Efficiency and Renewable Energy, while this technology will likely have a place in energy production in the future, it is important to be mindful that the energy needed to create hydrogen is much higher than the electric energy created from using hydrogen in combustion or fuel cell technology. Hydrogen is expected to play a role in shifting energy produced by intermittent resources, like wind farms.[16] NorthWestern will continue to monitor hydrogen's development and feasibility as a future resource.

13 See the Color of Hydrogen article https://whatispiping.com/colors-of-hydrogen/.
14 See the FCHEA's Hydrogen Blending page https://www.fchea.org/in-transition/2021/3/8/hydrogen-blending#:~:text=As%20the%20name%20would%20suggest,mix%20to%20the%20intended%20location
15 See The Office of Energy Efficiency & Renewable Energy's Fuel Cell Basics https://www.energy.gov/eere/fuelcells/fuel-cell-basics.
16 See The Office of Energy Efficiency & Renewable Energy's Hydrogen Production: Electrolysis https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

8.5 ELCC Analysis

The analysis process for this resource plan assumed capacity accreditation based on the WRAP analysis for NorthWestern resources. However, prior to WRAP participation, NorthWestern calculated the ELCC of resources using the method described in the following section.

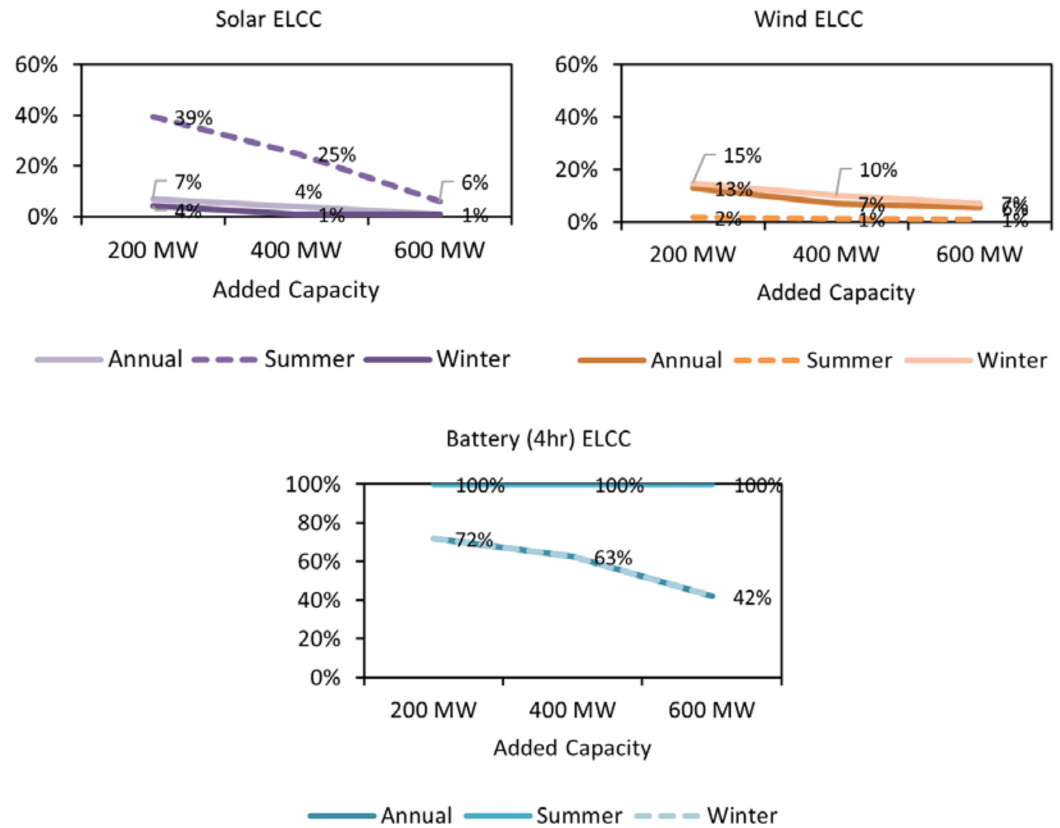
The ELCC metric provides a capacity accreditation value for variable and energy limited resources such as wind, solar, and storage. ELCC is the standard method for the determination of accredited capacity value throughout most of the US. The process to calculate ELCC relies on multiple resource adequacy models that ultimately determine the resource adequacy benefit attributed to a test resource (wind, solar, or storage). There are five steps in calculating the ELCC of a test resource.

1. Calculate the loss of load expectation (LOLE) of the base portfolio.
2. Calibrate the base portfolio by adding firm generation until the LOLE is equal to 0.1 days per year of loss of load.
3. Add the test resource to the base portfolio and recalculate the LOLE, which will be lower than 0.1 with the new item.
4. Remove the test resource and add firm generation to match the LOLE value from step 3.
5. The ELCC value for the test resource is equal to the amount of firm generation from step 4, commonly provided as a percentage of the test resource nameplate capacity (e.g. if a 100 MW wind farm provides resource adequacy benefits equal to 15 MW of firm generation, the ELCC would be 15%)

The ELCC value of a resource depends on several factors including the base portfolio used in the model, and the generation properties of the ELCC resource. A resource that often delivers energy during periods of system stress will have a higher ELCC. As more solar or wind are added to the system, ELCC values for those specific resources decline. Increased solar or wind in a portfolio will shift the timing of system stress making the next wind or solar item less able to contribute energy during times when it is most needed.

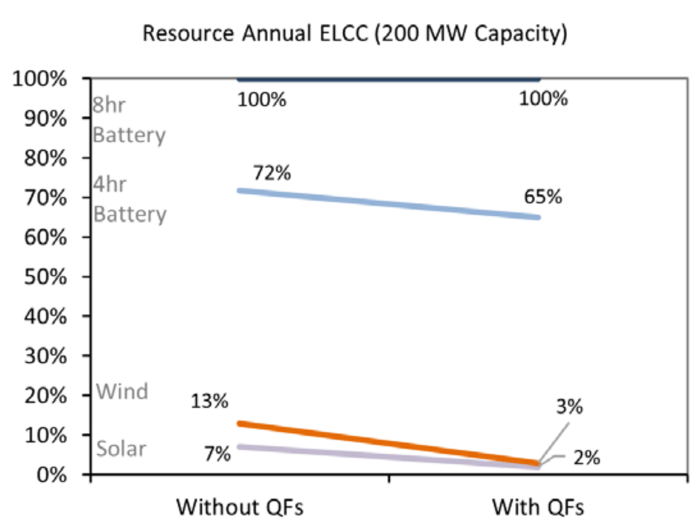
ELCC results are shown in figure 8-4 for solar, wind and storage. Summer ELCC values were calculated using outputs for May-September while winter values were calculated for the months October to February, according to WRAP. As expected, solar provides more capacity in the summer compared to the winter. Wind provides more capacity value during winter months compared to summer months. For both resources, ELCC values decline as more of the variable resource is added. Declining ELCC curves are normal for renewables and storage resources because additional resources provide less capacity value to the portfolio. As wind, solar or storage are added to the portfolio, the critical hours with the highest probability of load shed, shift to periods when wind, solar, or storage are less frequently available.

Figure 8-4. ELCC Values for Solar, Wind and 4hr Battery



NorthWestern's base portfolio is subject to change if QF projects in the queue, listed in Table 8-7, Volume 1, reach commercial operation. NorthWestern evaluated the effect of these QF projects. Figure 8-5 shows the effect of the QFs on the ELCC calculations for solar, wind, and storage. Note that storage, especially eight-hour storage, does not show as substantial ELCC declines as wind and solar.

Figure 8-5. ELCC for Solar, Wind and Batteries with and without QFs



ELCC calculations provide the capacity accreditation for candidate resources in the capacity expansion model, ARS, used to indicate the least cost combination of future resources to serve NorthWestern load.

NorthWestern's capacity over the planning period is shown in Figures 8-6 and 8-7. The queue of QF projects creates uncertainty in the capacity position. Projects in the QF queue are shown in the top two hatched layers of the capacity graphs. The capacity charts use historic ELCC values as opposed to the WRAP accreditations.

Resources labeled "QF Advanced Resources" have an order from the MPSC, but have not executed a contract. Resources labeled "QF Potential Resources" have no MPSC order or executed contract but have engaged in substantive negotiations with NorthWestern for a contract. Including both categories of QF resources substantially changes the NorthWestern's capacity position, with NorthWestern attaining resource adequacy for multiple years in both winter and summer views. While NorthWestern's base scenario for modeling is using WRAP values, these graphs for ELCC values are included partly as a comparison of NorthWestern's capacity position outside of WRAP.

Figure 8-6. Accredited Capacity by Resource Type in Winter, Including QF resources, Historic ELCCs

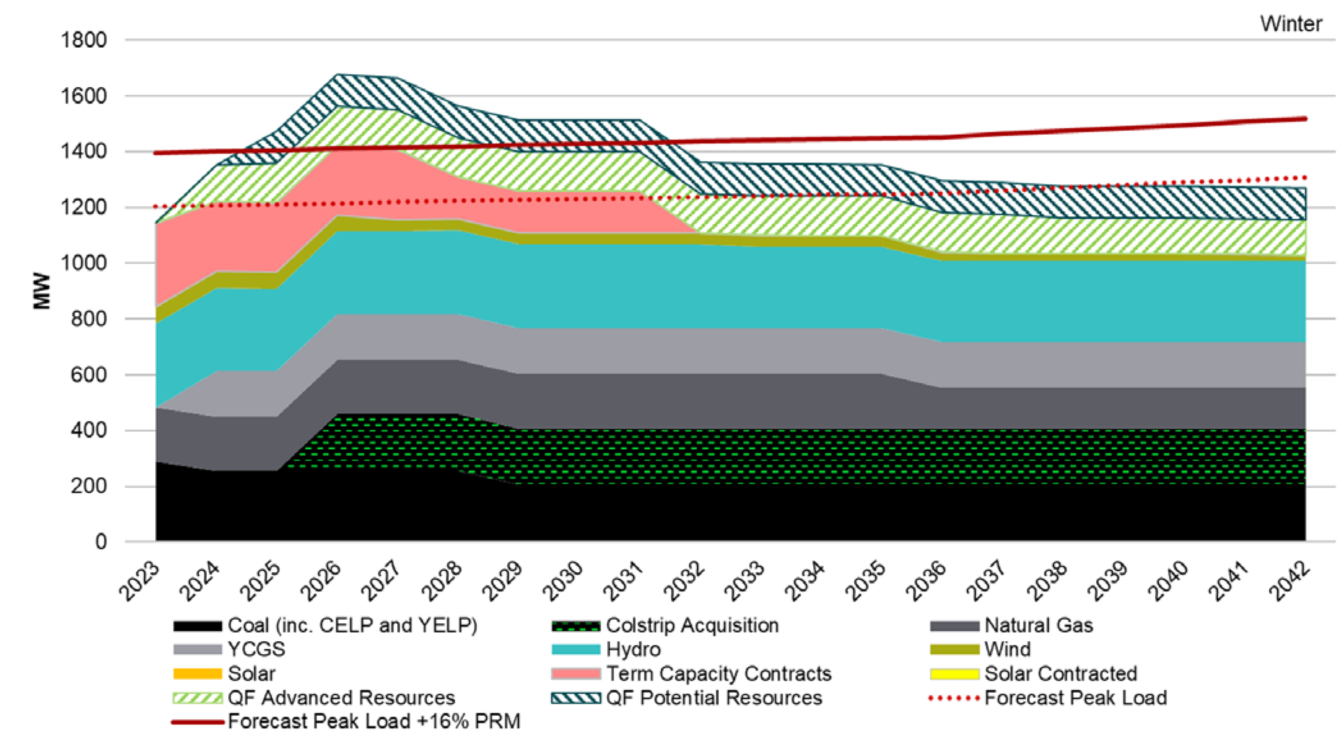
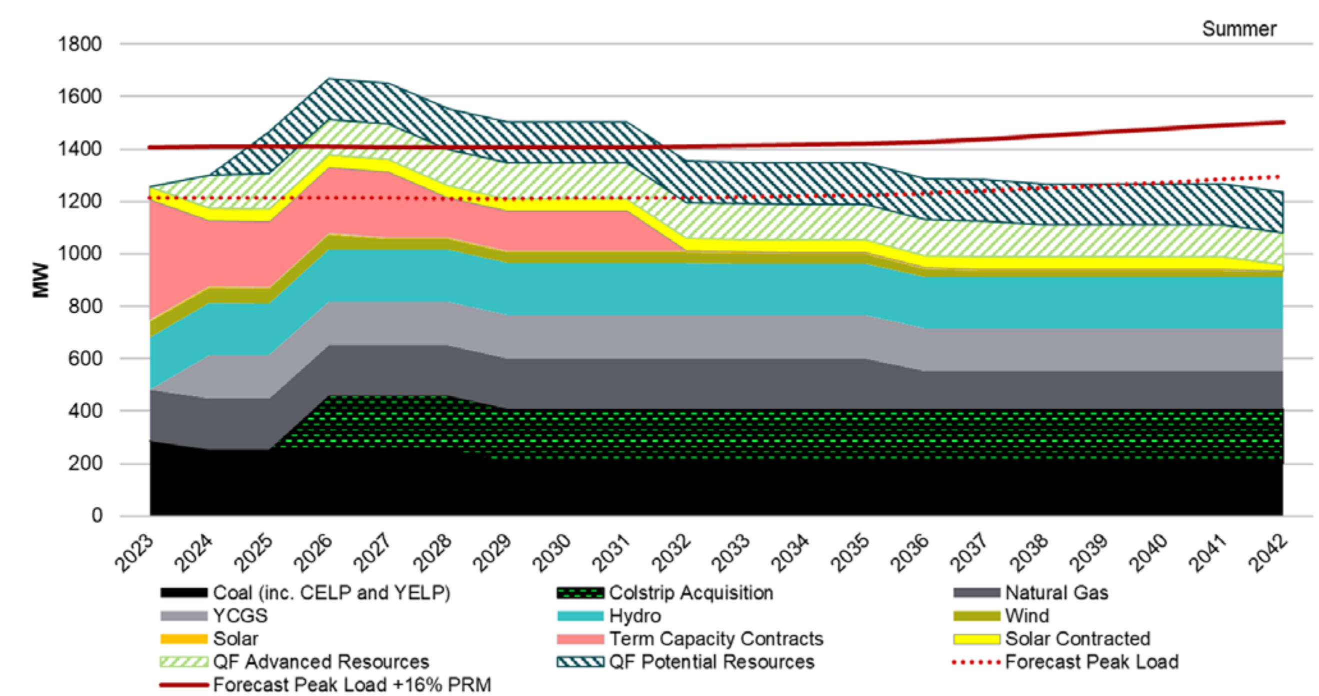


Figure 8-7. Accredited Capacity by Resource Type in Summer, Including QF Resources, Historic ELCCs



8.7 Capacity Results

Volume 1 of this plan shows the capacity expansion results for the core scenarios. The following charts show the core scenarios with all sensitivities included in the analysis. The charts show only small changes over the sensitivities considered. Higher load leads to additional resources to meet the high reserve margins. Increased gas and power prices have little effect on the outputs. Carbon costs also have little effect on the outputs since the natural gas resources have low capacity factors and low carbon emissions.

Figure 8-8. ARS Results for the Core Scenarios

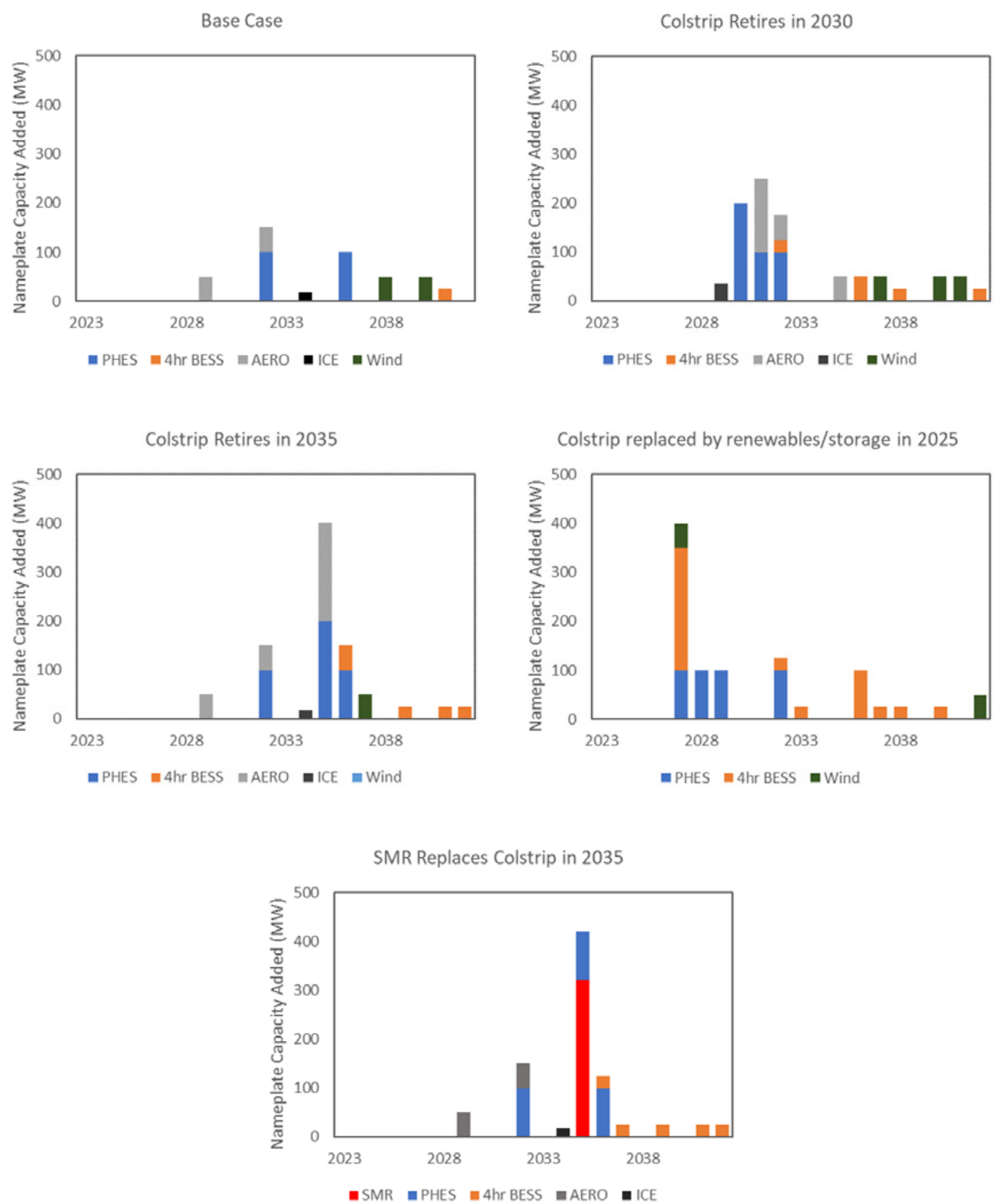


Figure 8-9. ARS results for the High Load Sensitivity cases

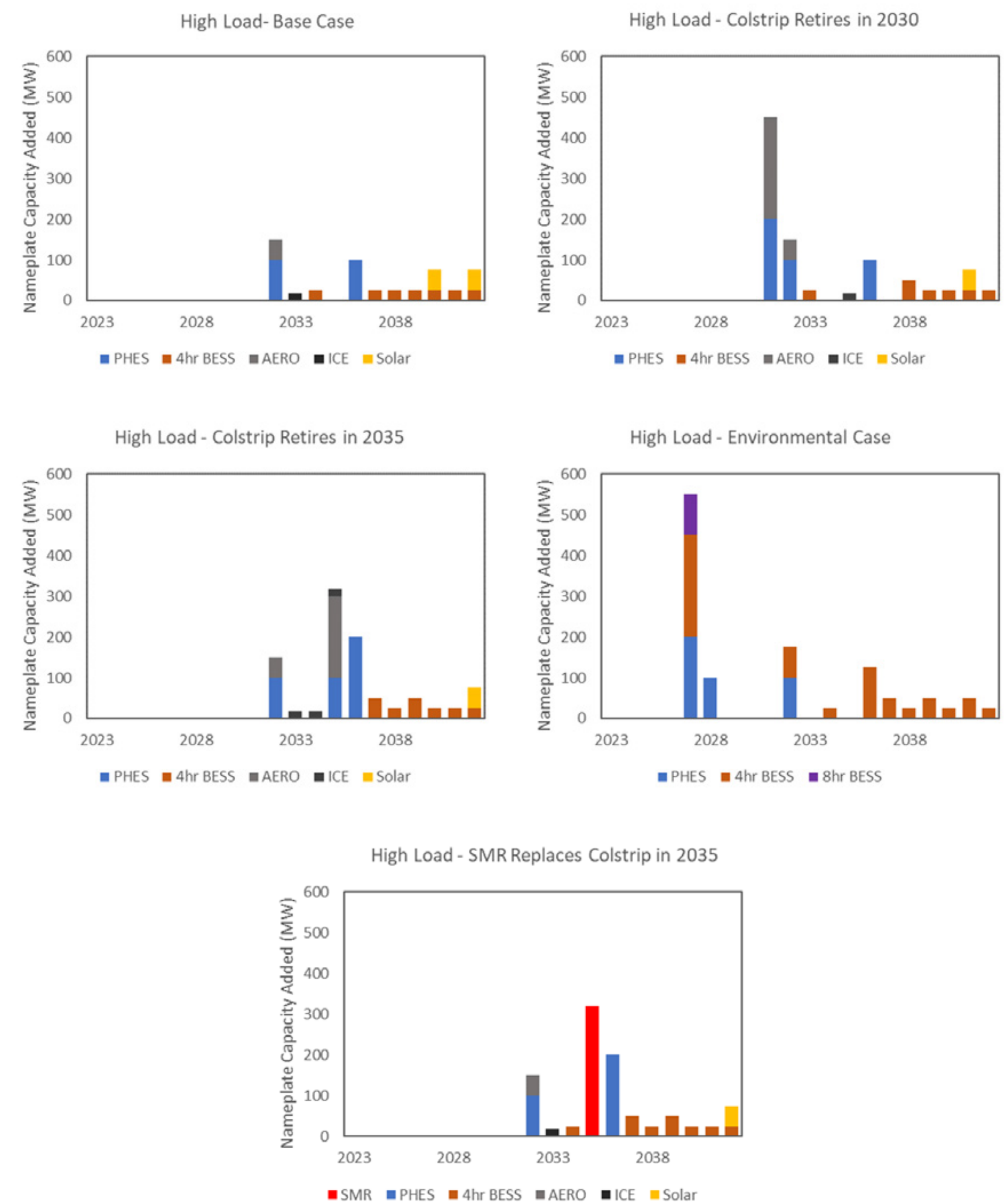


Figure 8-10. ARS results for the High Gas Price Sensitivity cases

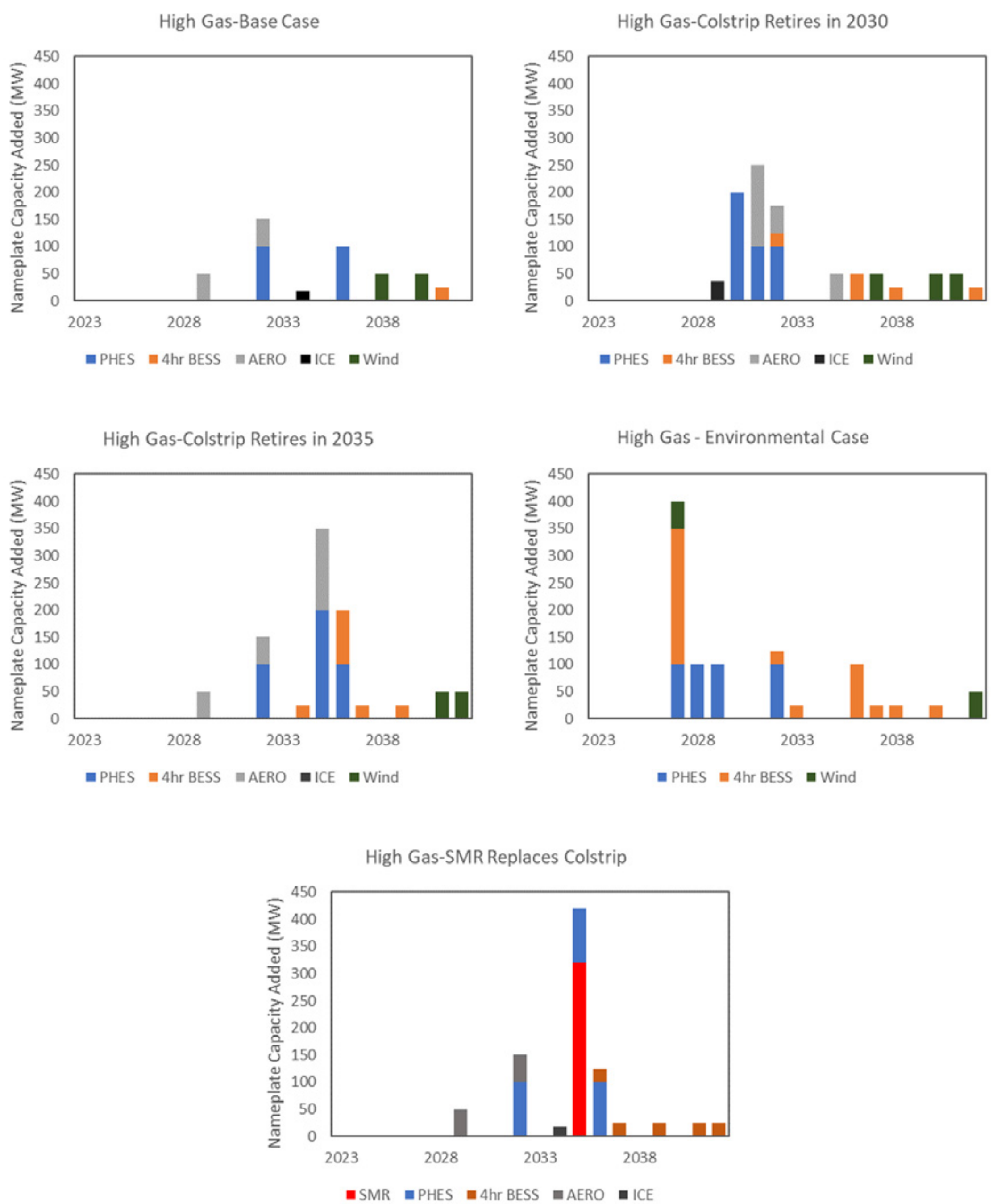


Figure 8-11. ARS results for the High Gas and Power Price Sensitivity cases

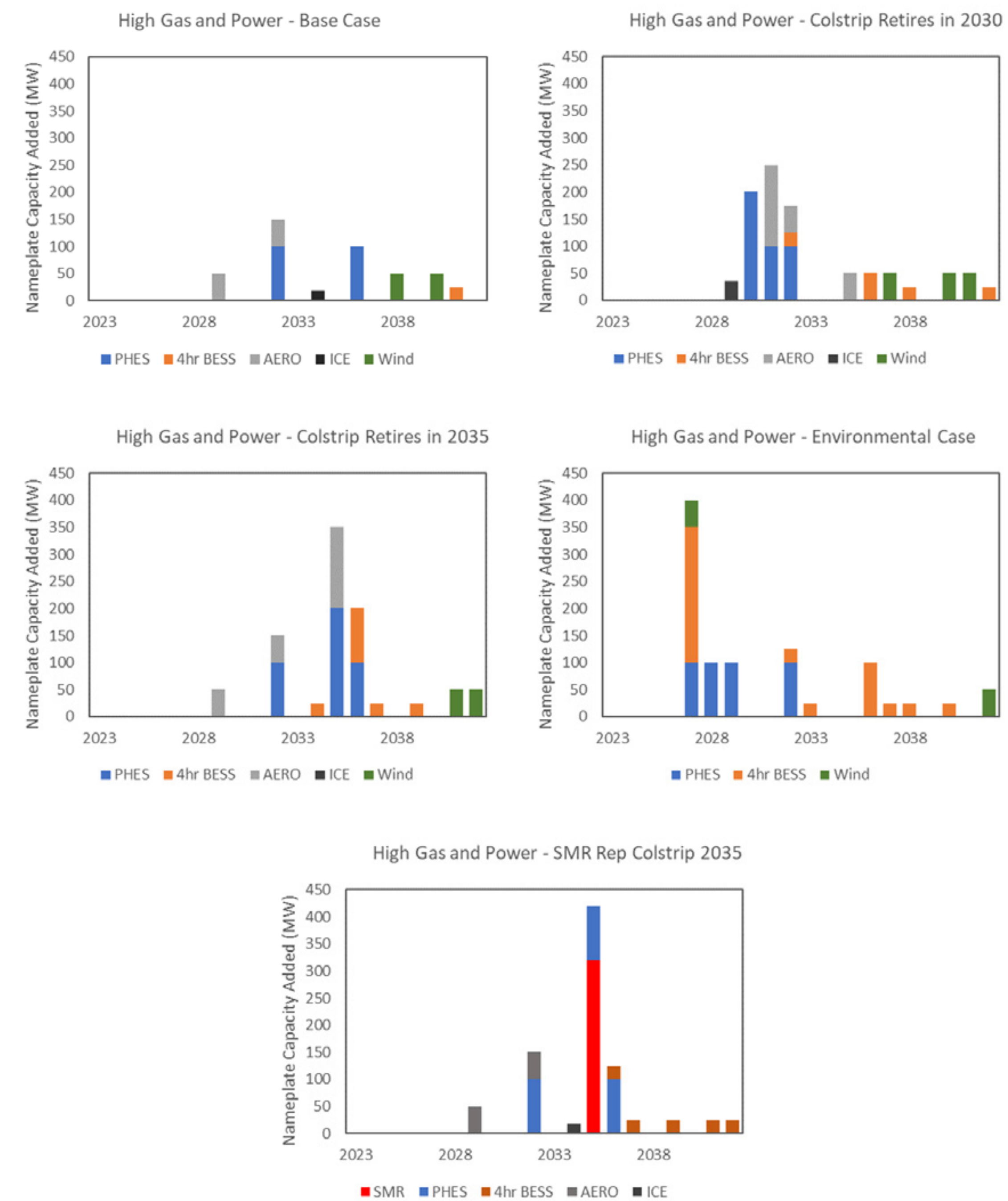


Figure 8-12. **ARS results for the Carbon Price Sensitivity cases**

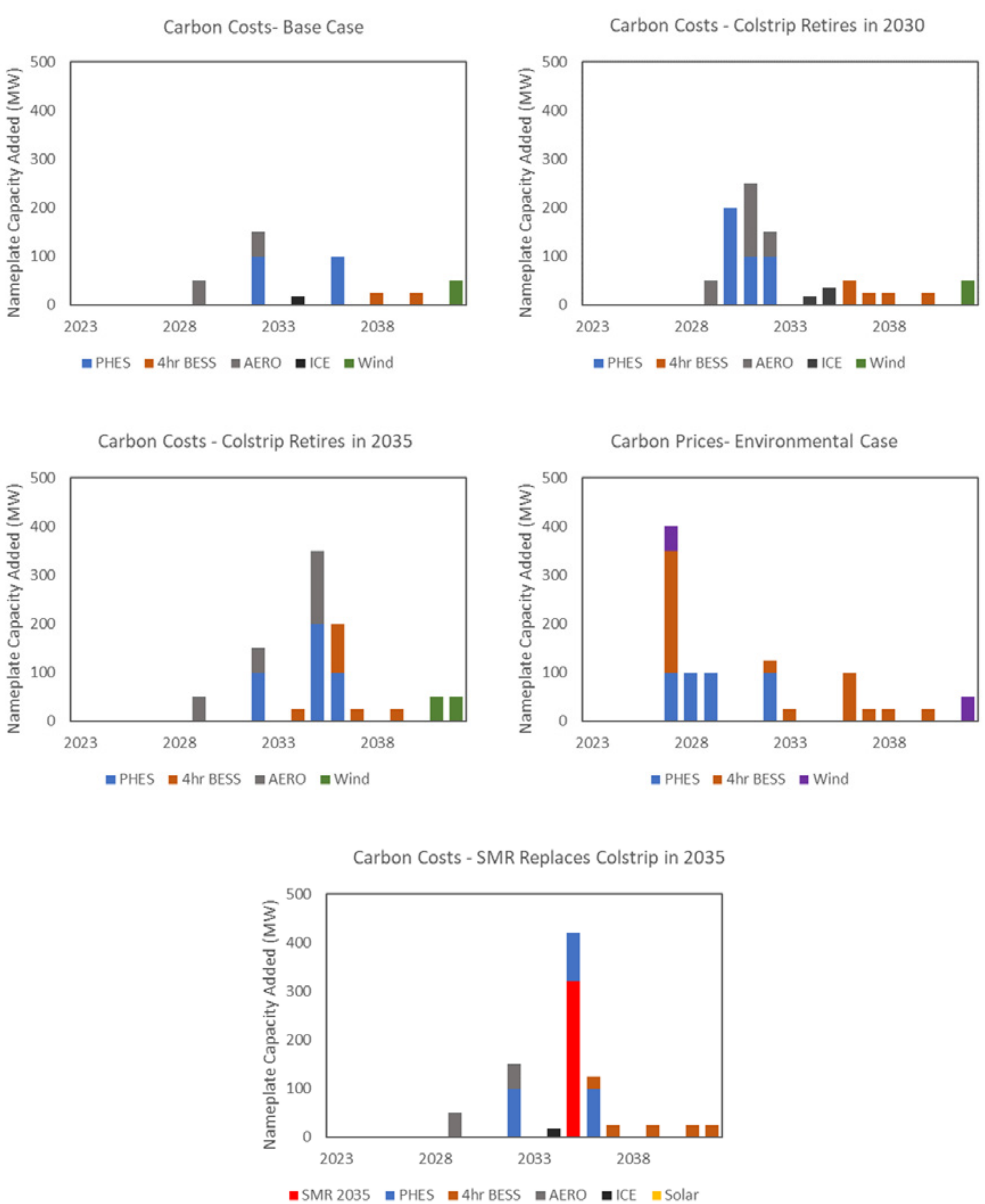


Table 8-2. **Summary of ARS nameplate capacity results for all modeled scenarios**

		PHES	4hr BESS	8hr BESS	AERO	ICE	Wind	Solar	SMR
Core Assumptions	Base	200	25	0	100	18	100	0	0
	Colstrip ret 2030	400	125	0	250	36	150	0	0
	Colstrip ret 2035	400	125	0	300	18	50	0	0
	Renew Rep 2025	400	475	0	0	0	100	0	0
	SMR Rep 2035	300	125	0	100	18	0	0	320
High Load	Base	200	175	0	50	18	0	100	0
	Colstrip ret 2030	400	175	0	300	18	0	50	0
	Colstrip ret 2035	400	200	0	250	54	0	50	0
	Renew Rep 2025	400	700	100	0	0	0	0	0
	SMR Rep 2035	300	225	0	50	18	0	50	320
High Gas Prices	Base	200	25	0	100	18	100	0	0
	Colstrip ret 2030	400	125	0	250	36	150	0	0
	Colstrip ret 2035	400	175	0	250	0	100	0	0
	Renew Rep 2025	400	475	0	0	0	100	0	0
	SMR Rep 2035	300	125	0	100	18	0	0	320
High Gas and Power Prices	Base	200	25	0	100	18	100	0	0
	Colstrip ret 2030	400	125	0	250	36	150	0	0
	Colstrip ret 2035	400	175	0	250	0	100	0	0
	Renew Rep 2025	400	475	0	0	0	100	0	0
	SMR Rep 2035	300	125	0	100	18	0	0	320
Carbon Costs	Base	200	50	0	100	18	50	0	0
	Colstrip ret 2030	400	125	0	250	54	50	0	0
	Colstrip ret 2035	400	175	0	250	0	100	0	0
	Renew Rep 2025	400	475	0	0	0	100	0	0
	SMR Rep 2035	300	225	0	50	18	0	0	320
Additional Studies	Base half QFs	200	75	0	50	36	50	0	0
	Base Full QFs	200	50	0	0	0	0	0	0
	SMR Rep 2030	400	25	0	150	36	0	0	320
	No Colstrip Exp	400	50	0	100	36	50	0	0

8.8 Resource Adequacy

The duration of time that an energy resource can provide energy to serve load is an important resource attribute. Peak load events can span many consecutive hours and days requiring long-duration energy resources. An example is provided from a recent high load event that occurred in February of 2021. Data are provided from 2/1/21 to 2/16/21 (384 hours) to bracket the peak load event and provide context. This cold weather event led to near peak load, and long durations of time when load exceeded 800 MWs, with significant daily intervals above 900 MWs (e.g., Figure 8-13, blue arrow). The significant duration of time that load remained high indicates that increasing amounts of 4-hour energy storage does not lend itself to solving resource adequacy concerns in Montana. Table 8-3 shows the duration and amount of capacity needed during this time period, by observed load level. It is a numeric representation of the graphed data.

Figure 8-13. Load Graph 2/1/21 – 2/16/21

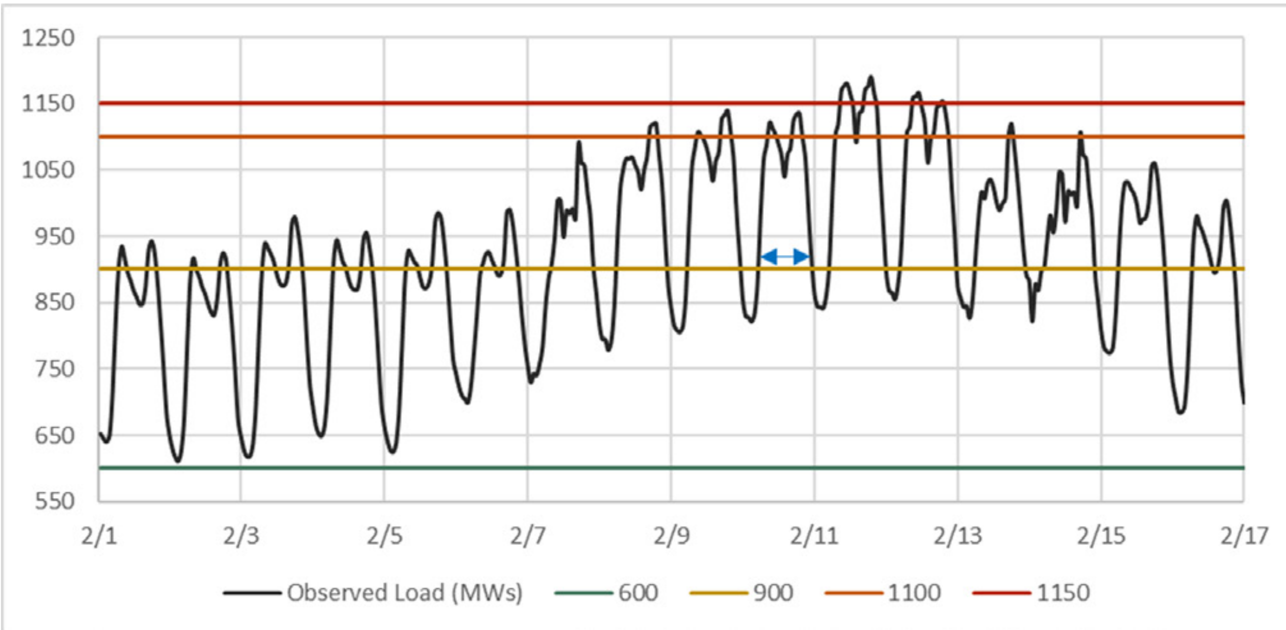


Table 8-3. Deficit Event Analysis for 2/1/21 – 2/16/21

Accredited Capacity (MW)	Total Deficit Events	Distribution of Event Durations (Hours)		Total Deficit (MWh)	Max Depth (MW)
		P99.97 *	P100 (Max)		
1250	0	0	0	0	0
1200	2	1	1	7	6
1150	4	5	5	372	56
1100	7	8	8	1,521	106
1050	8	16	16	3,709	156
1000	13	18	18	7,065	206
950	20	18	18	12,346	256
900	25	21	21	20,464	306
850	16	63	69	32,594	356
800	12	109	120	47,082	406
750	9	167	186	62,974	456
700	8	191	213	79,737	506
650	5	254	284	97,633	556
600	1	384	384	116,369	606

* P99.97 corresponds to 1 day in 10 years loss of load expectation.

8.9 Cost Analysis

The production cost modeling for all scenarios and sensitivities provide the cost, market interactions, carbon emissions, and other outcomes. A big factor driving the results is the operation of thermal resources. The following charts show NorthWestern thermal resource production over the next twenty years. Figure 8-14 shows the base case scenario production from thermal resources.

All capacity expansion results were used to create portfolios for analysis in production cost models. Total supply costs, market interactions and carbon emissions were driven in part by the production from NorthWestern's thermal resources. The Base Case scenario was used to create Figures 8-14 and 8-15 which show the production of all thermal resources and the market sales and purchases. Note the drop in generation over the first five years which is due to the decline in market prices. Current prices are exceptionally high in the Pacific Northwest. The market price forecast in the model projects a decline in power prices back to historical levels by 2030 when natural gas units will run at production factors in the 10% range which is normal for fast-ramping gas generation. Market sales also decline to historical levels as prices come down while purchases increase slightly. Colstrip generation declines less compared to natural gas generation because Colstrip is not affected by the increasing natural gas costs in the model. Note that in 2024 and 2025 Colstrip has scheduled maintenance periods that bring down production a small amount.

Figure 8-14. Thermal production for the base case scenario

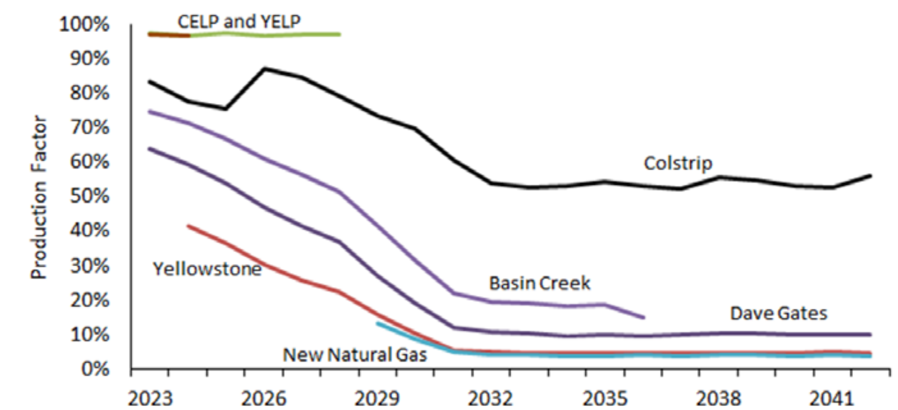
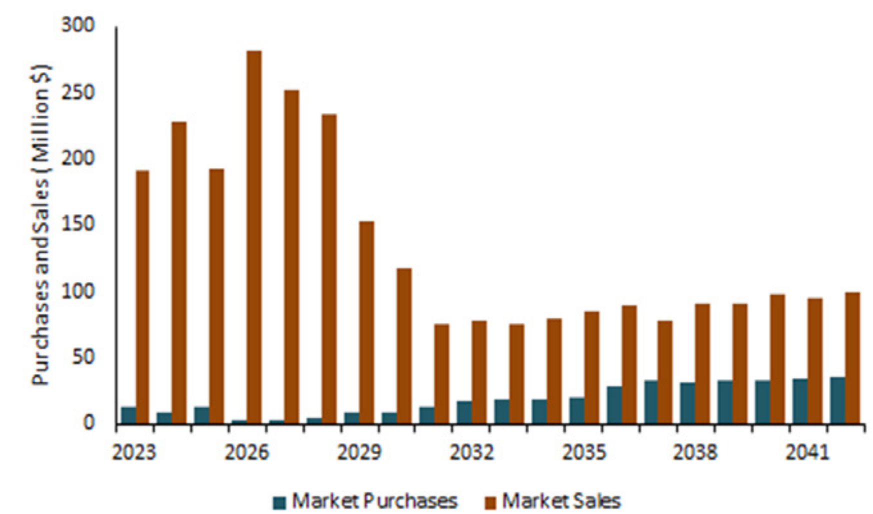


Figure 8-15. Market purchases and sales by year for the base case scenario



The high load sensitivity resulted in similar higher production to from resources to serve increased load as shown in Figures 8-16 and 8-17.

Figure 8-16. Thermal production for the base case with high load

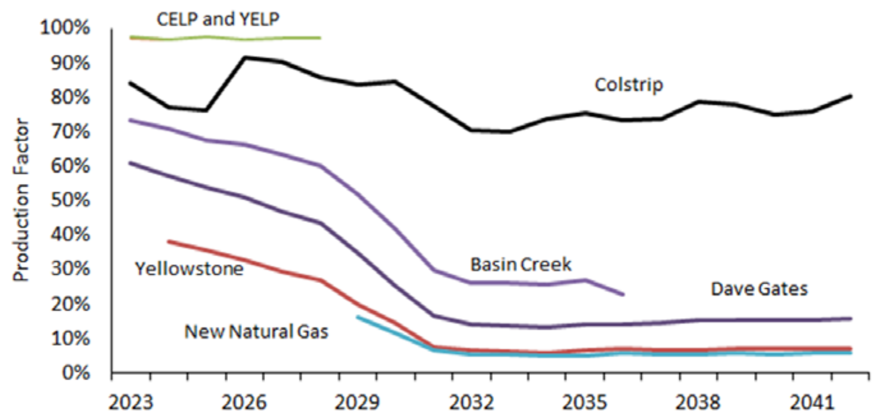
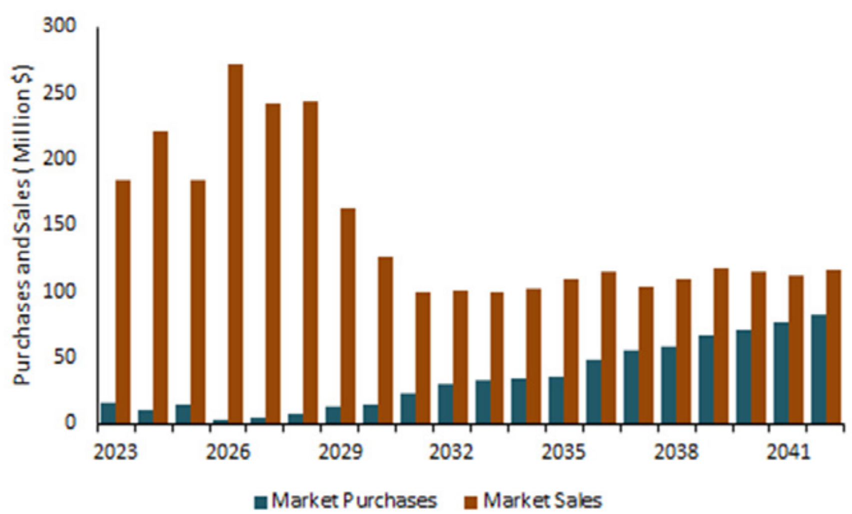


Figure 8-17. Market purchases and sales by year for the base case with high load



In the high gas price sensitivity, gas resources produced less while Colstrip, which is not affected by the gas price, ran more. Figures 8-18 and 8-19 show that Colstrip replaces some of the generation declines from natural gas.

Figure 8-18. Thermal production for the base case with high gas prices

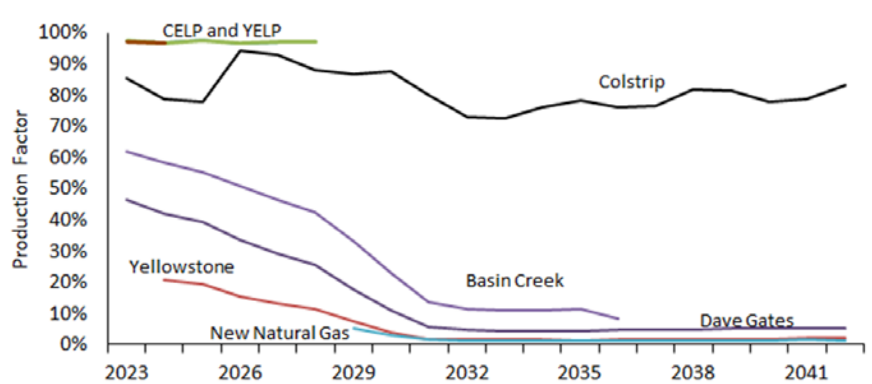
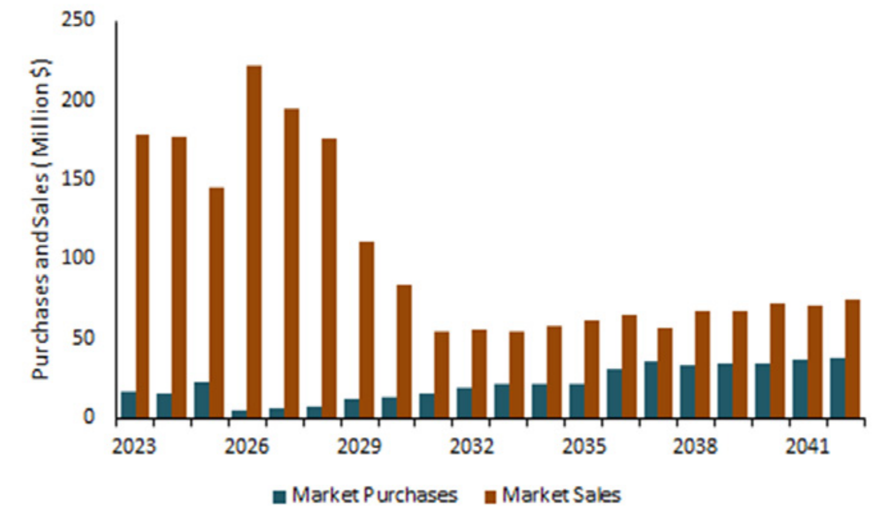


Figure 8-19. Market purchases and sales by year for the base case with high gas prices



When power prices increased with the gas prices, resource production for natural gas resources was similar to the original base case outputs with core assumptions because the implied heat rate over time closely matched the original base case. However, Colstrip production increases a significant amount because the high power prices incentivize Colstrip to generate more. Figures 8-20 and 8-21 show that Colstrip generation leads to very high sales.

Figure 8-20. Thermal production for the base case with high gas and high power prices

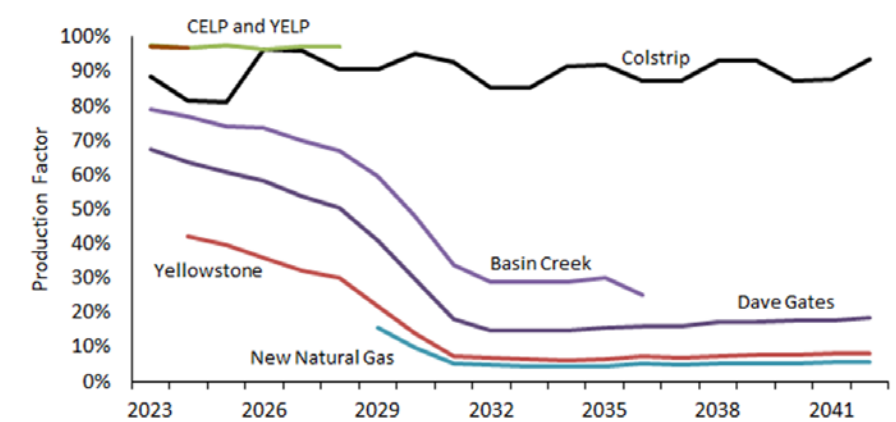
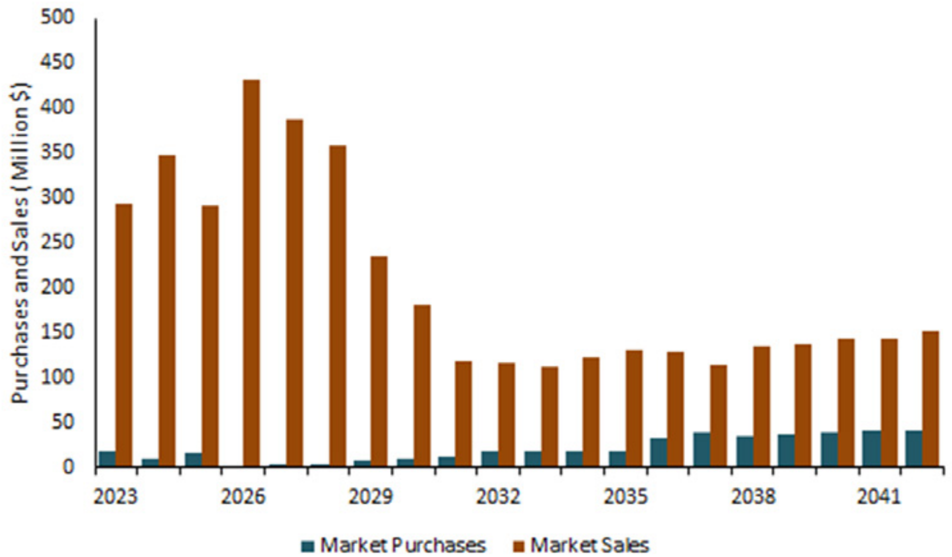


Figure 8-21. Market purchases and sales by year for the base case with high gas and power prices



Finally, the sensitivity for carbon prices results in a large drop in production from all thermal resources and higher market purchases as shown in Figures 8-22 and 8-23.

Figure 8-22. Thermal production for the base case with carbon prices

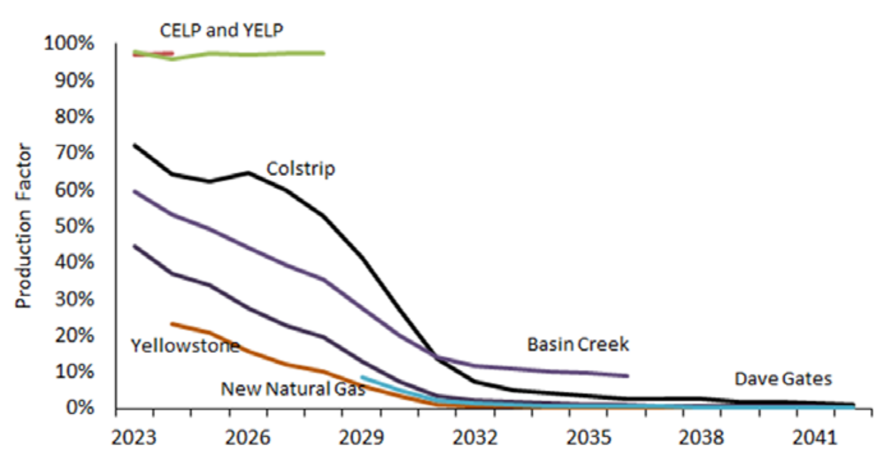


Figure 8-23. Market purchases and sales by year for the base case with carbon prices

Finally, the total portfolio costs are shown in Figures 8-24 to 8-28 for all scenarios and sensitivities. Total costs for each scenario includes the following.

1. Revenue requirements – Costs to cover resource investment and rate of return
2. Variable costs – Operations and maintenance costs that varying with generation
3. Fuel costs – Cost of natural gas and coal to run the plants
4. Fixed costs – Costs associated with owning resources that remain constant over time such as property taxes, labor costs, etc.
5. Power purchase agreement (PPA) costs – Costs for power deliveries from resources under a PPA contract
6. Power purchases – Costs to buy power when needed from the markets
7. Power sales – Revenue from power sales to the market

The total costs are shown for the five scenarios for each of the sensitivities considered.

Figure 8-24. Total cost by scenario for case assumptions

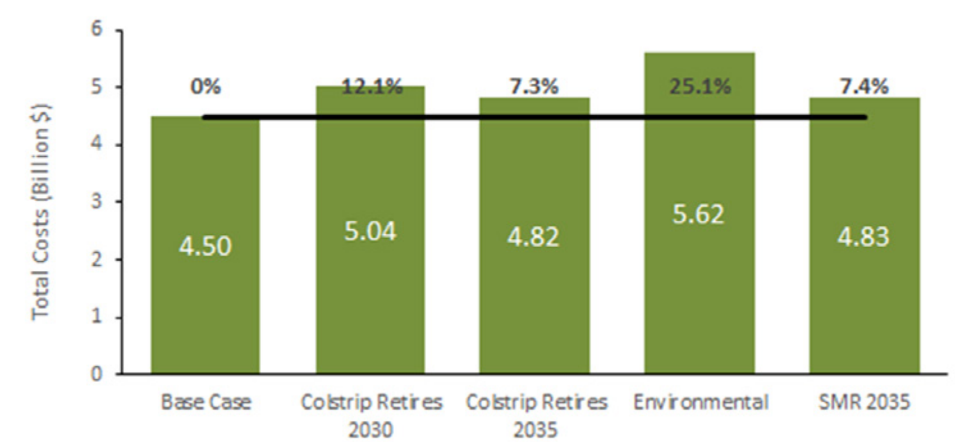


Figure 8-25. **Total cost by scenario for high load sensitivity**

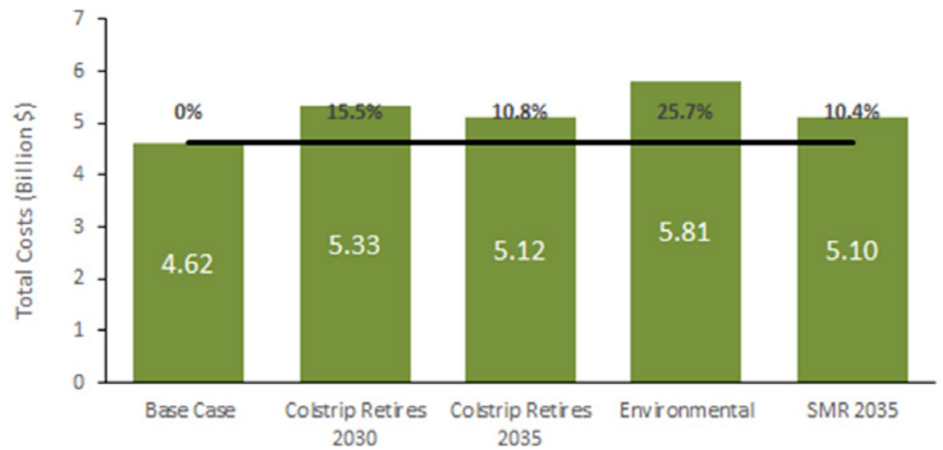


Figure 8-26. **Total cost by scenario for high gas price sensitivity**

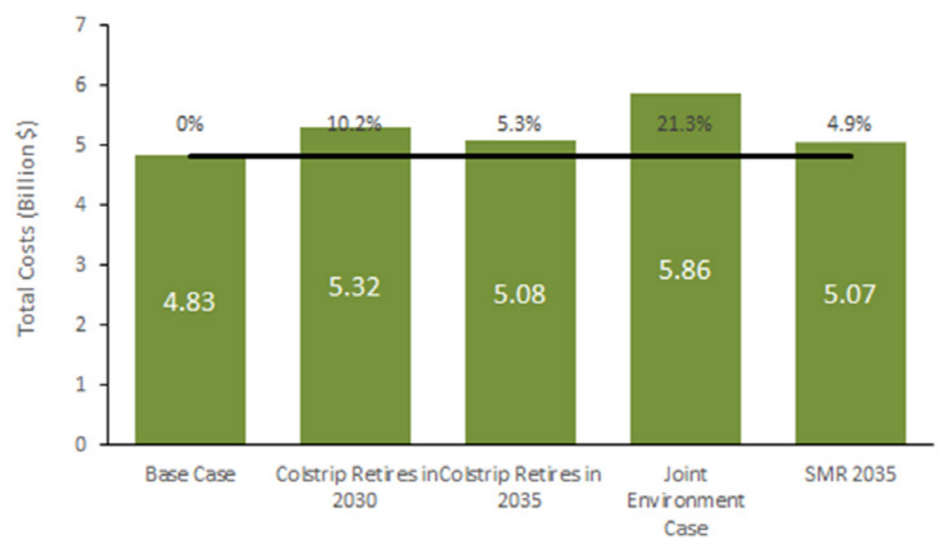


Figure 8-27. **Total cost by scenario for high gas and power price sensitivity**

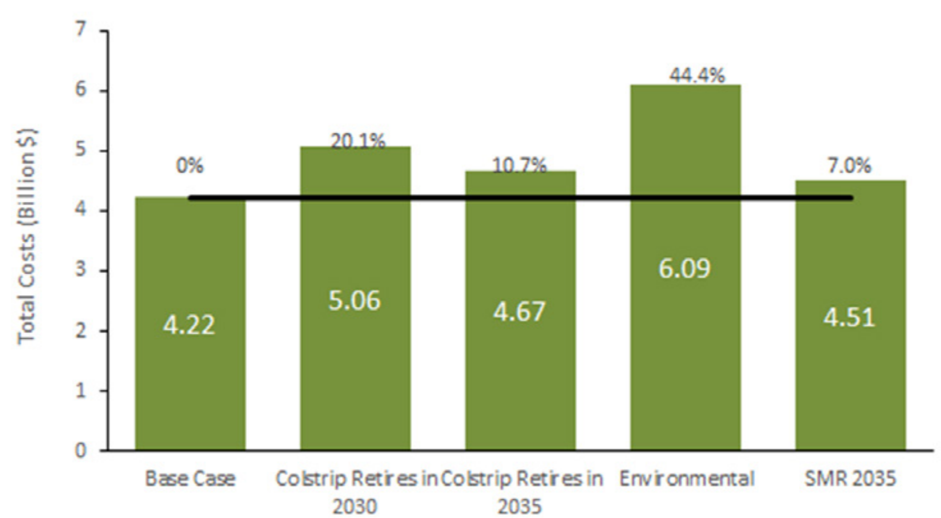
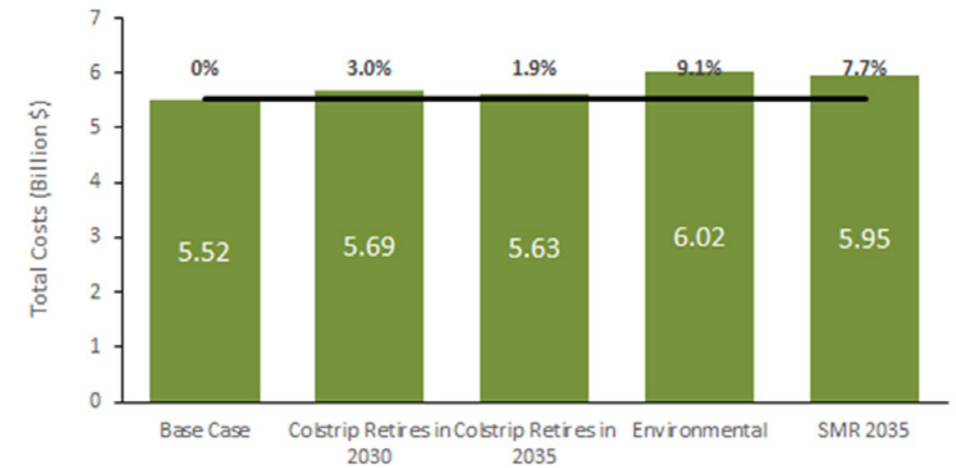


Figure 8-28. **Total cost by scenario for carbon price sensitivity**



9. Emerging Technologies

9.1 Electric Vehicles

NorthWestern has been monitoring electric vehicle (EV) adoption to better understand, and plan for, the system and supply impacts of EVs and electric vehicle supply equipment (EVSE). Due to distinct differences in electric vehicle charging equipment as well as utilization of the various technologies available today, NorthWestern has chosen to evaluate the impacts of EV charging infrastructure in terms of two distinct markets – charging conducted in the private sector and charging conducted in the public sector.

Private charging, which accounts for approximately 80-90% of all EV charging, tends to be performed during the afternoon and nighttime hours in garages, parking lots, and businesses using "Level 1" (L1) or "Level 2" (L2) chargers which range from 1 to 20 kW.[17,18,19,20] Conversely, public charging infrastructure is primarily used during daytime hours by travelers and/or visitors travelling large distances who prefer to charge quickly and near highway or interstate corridors. This infrastructure is largely comprised of "Level 3" or "Direct Current Fast Charger" (DCFC) equipment which ranges from 50 to 350 kW.

In the context of NorthWestern's Montana service territory today, the growth of private L2 charging is tied, in large part, to EV adoption rates within Montana whereas the utilization of public DCFC is more directly coupled with Montana's travel and tourism trends and with national EV adoption rates. Due to these differences in utilization, growth, and electrical demands, NWE has conducted separate analyses for each sector to evaluate the current and future impacts of EVs and EVSE on NorthWestern's system.

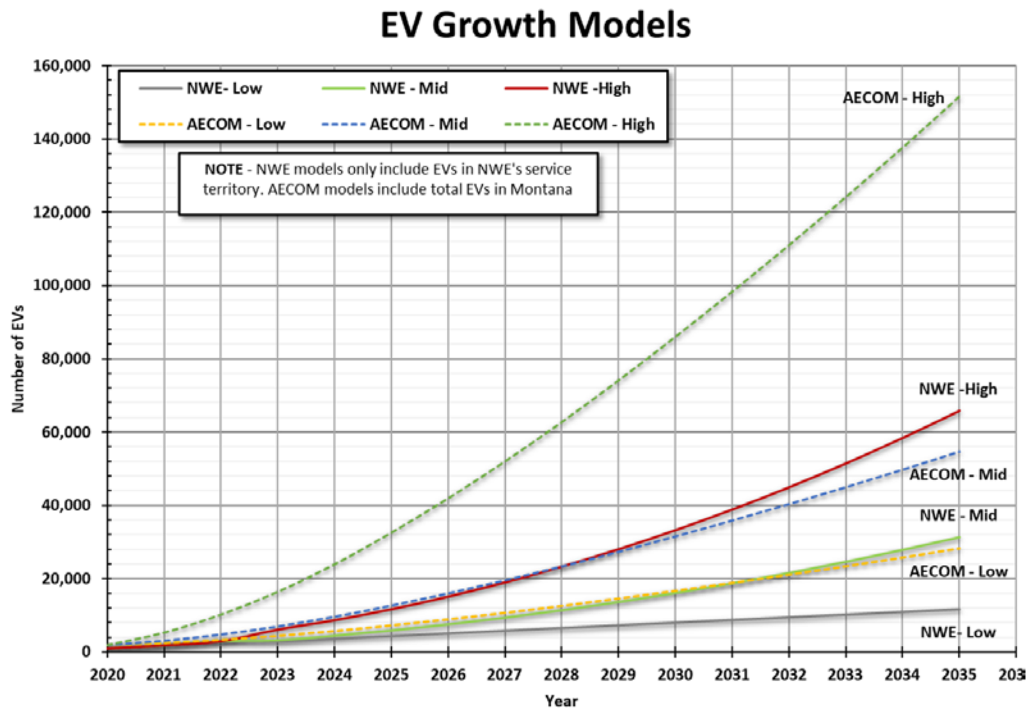
9.1.1 Private Charging:

To fully characterize the future impacts of private charging, it was necessary to utilize both an EV growth model to forecast the rate at which customers will adopt EVs in Montana, and a loading model to describe the charging patterns of those customers. For the EV growth model, NorthWestern developed three growth forecasts representing low-, mid-, and high-adoption cases. Each of these models were based on various curve fits of the actual 2020-2022 battery electric vehicle (BEV) and plug-in hybrid electric vehicle (PHEV) adoption in NorthWestern's service territory.[21] Of these three models, the mid-adoption case was chosen to study the system and supply impacts of private charging because it was believed to be most consistent with the historical adoption rates of other similar technologies and because it was closely aligned with the recently-published forecasts

17 PluggedInSummaryReport.pdf (inl.gov)
18 EV-Consumer-Behavior-Report.pdf (fuelsinstitute.org)
19 Guide on charging your electric vehicle at home | ChargeHub
20 JD Power Study: Electric Vehicle Owners Prefer Dedicated Home Charging Stations - Forbes Wheels
21 State EV Registration Data – Atlas EV Hub

supplied by the Montana Department of Environmental Quality (MDEQ) via its contractor AECOM (Figure 9-1).[22]

Figure 9-1. NorthWestern and AECOM EV Growth Models



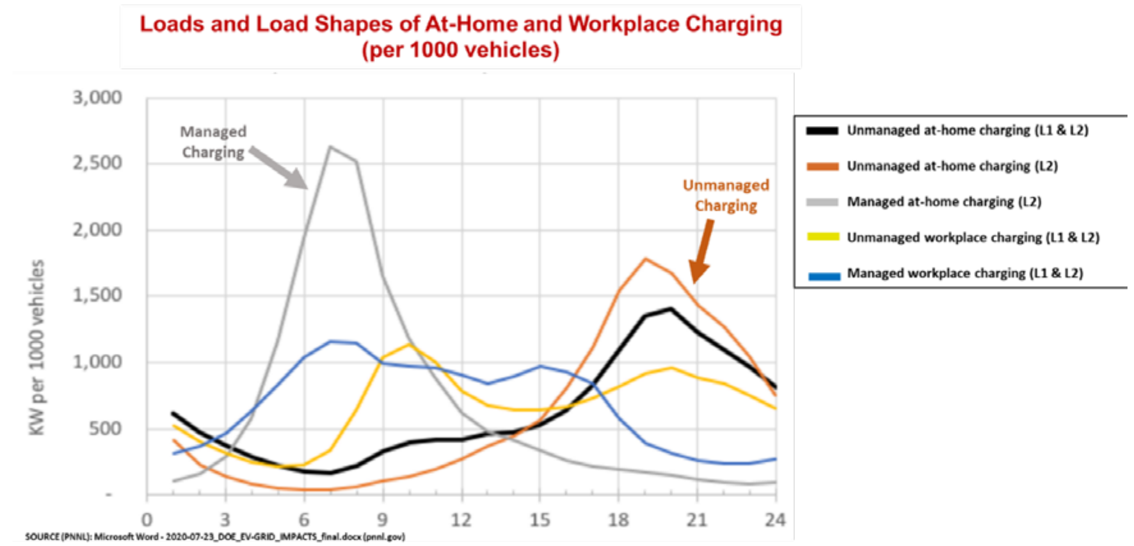
After establishing an EV growth model for NorthWestern's service territory, NorthWestern then selected a loading model developed by the Pacific Northwest National Laboratory (PNNL) to describe the magnitude and shape of the load profiles of private charging.[23] PNNL's study defined 5 models to represent a variety of potential charging preferences. These included:

1. a scenario in which most EV drivers charge at home using a combination of L1 and L2 charging equipment and the timing of that charging is not managed by either direct (e.g., active control of the EV or EVSE) or indirect means (e.g., time-of-use rates),
2. a scenario in which most EV drivers charge at home using primarily L2 charging equipment and the timing of that charging is not managed by either direct or indirect means,
3. a scenario in which most EV drivers charge at home using primarily L2 charging equipment, but the timing of that charging is managed by either direct or indirect means,
4. a scenario in which most EV drivers charge at work using a combination of L1 and L2 charging equipment and the timing of that charging is not managed by either direct or indirect means,
5. and a scenario in which most EV drivers charge at work using a combination of L1 and L2 charging equipment, but the timing of that charging is managed by either direct or indirect means.

The two models selected for NorthWestern's analyses were scenarios 2 and 3. Scenario 2 was selected because NorthWestern anticipates that L2 charging equipment will continue to be the dominant private charging technology, and most EV drivers will charge at home during the afternoon and nighttime hours rather than at work. Similarly, NorthWestern also chose to include scenario 3 in its analyses to better understand and quantify the potential system and supply benefits of an EV charging management program as many other peer utilities offer today. As can be seen, the unmanaged L2 charging behavior results in an afternoon peak of approximately 1.75 MW per 1,000 EVs whereas the managed L2 charging behavior results in an afternoon peak of only about 0.25 MW per 1,000 EVs and an overnight/morning peak of approximately 2.5 MW per 1,000 EVs (Figure 9-2). In other words, these results indicate that managing private EV charging through mechanisms such as time-of-use rates and/or active EV/EVSE management could represent approximately 1.5 MW of flexible load per 1,000 EVs.

22 https://deq.mt.gov/files/Energy/Transportation/MDEQ_EV_InfrastructurePrioritizationStudy_Final.pdf
23 https://www.pnnl.gov/sites/default/files/media/file/EV-AT-SCALE_1_IMPACTS_final.pdf

Figure 9-2. Load and Load Shapes of EV charging



After defining both an EV growth model and a loading model for EV charging, NorthWestern was then able to summarize the findings in terms of anticipated load during afternoon peak hours due to private charging of electric vehicles for both managed and unmanaged charging behavior (Table 9-1).

Table 9-1. Summary of potential load during afternoon peak hours due to at-home charging of electric vehicles for both managed and unmanaged charging behavior

Estimated Afternoon Peak Loads Due to At-Home EV Charging[24]			
	2022	2027	2032
Number of EVs in NWE's MT Service Territory ***NWE mid-adoption forecast***	**2,171**	**9,351**	**21,553**
Unmanaged At-Home L2 Charging Load	3.8 MW	16.4 MW	37.7 MW
Managed At-Home L2 Charging Load	NA	2.3 MW	5.4 MW
Number of EVs in Montana ***AECOM mid-adoption forecast***	**4,720**	**19,470**	**40,300**
Unmanaged At-Home L2 Charging Load	8.3 MW	34.1 MW	70.5 MW
Managed At-Home L2 Charging Load	NA	4.9 MW	9.1 MW

9.1.2 Public Charging

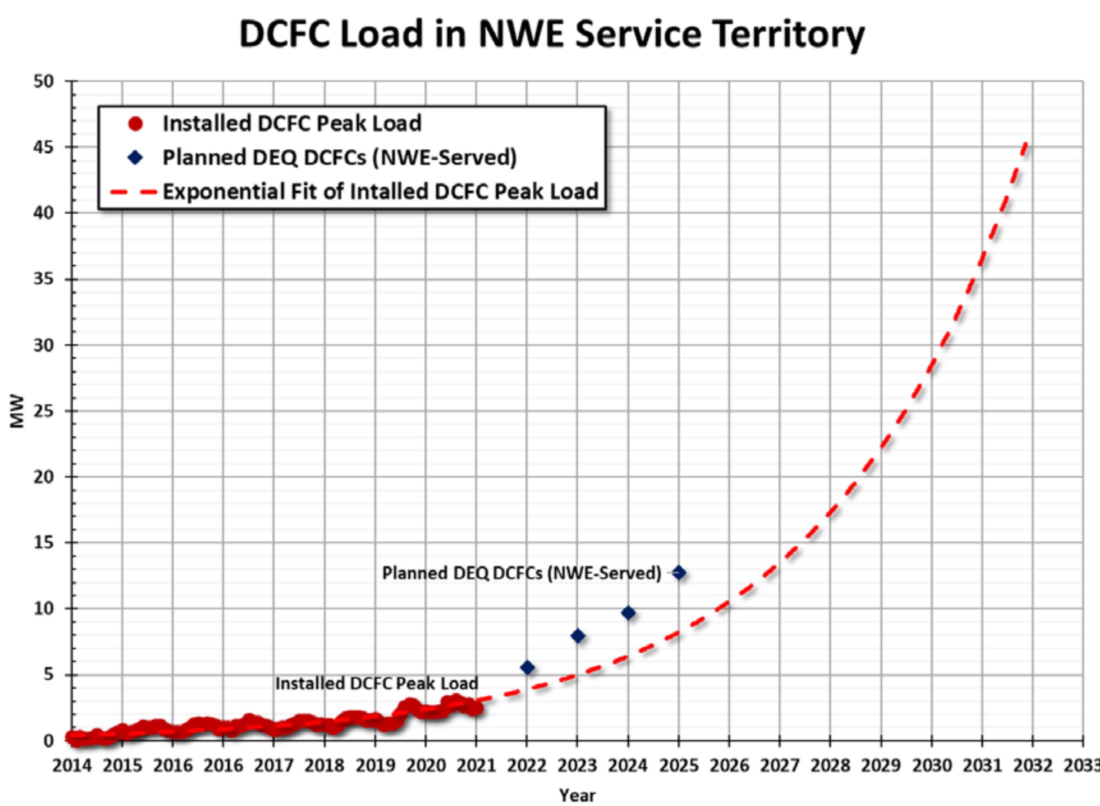
NorthWestern also chose to include public charging in its analysis of system and supply impacts due to EVs and EVSE. As mentioned above, the utilization, and thus demands, of public charging is not only tied to EV adoption within Montana, but it is also (and perhaps to a greater extent) tied to traditional tourism and travel trends within the state as well as national EV adoption since much of this infrastructure is used by travelers or by people who may be unable to use private/L2 charging. As a result, it is challenging to forecast public/DCFC load growth in the same manner as was done for private charging – especially because the actual load growth is largely dependent upon the installation of DCFC infrastructure. Instead, NorthWestern chose to evaluate the historical demands of currently-installed DCFC infrastructure as well as consider both the near-term/planned buildout of a DCFC network (as proposed in MDEQ's Montana Electric Vehicle Infrastructure Deployment Plan)[25] and the longer-term potential buildout of a more extensive DCFC network.

For its assessment of currently-installed infrastructure, NorthWestern reviewed its historical monthly loading data for many of the largest DCFC stations it serves around Montana. For the purpose of this analysis, all monthly peaks were assumed to be coincident, which is almost certainly an overestimate of system demands, but serves

24 Load estimates are based on the EV forecast model specified in the table and on Pacific Northwest National Laboratory's, Electric Vehicles at Scale – Phase 1: High EV Adoption Impacts on the Wester U.S. Power Grid research paper. PNNL's "at-home" charging scenarios are utilized which assume 91% of private EV charging is done at home.
25 State Plan Template for Electric Vehicle Infrastructure Deployment (mt.gov)

to provide an upper limit of the potential demands of installed DCFC since 2014 (Figure 9-3) . As shown, the maximum monthly coincident peak in 2021 was about 3 MW.

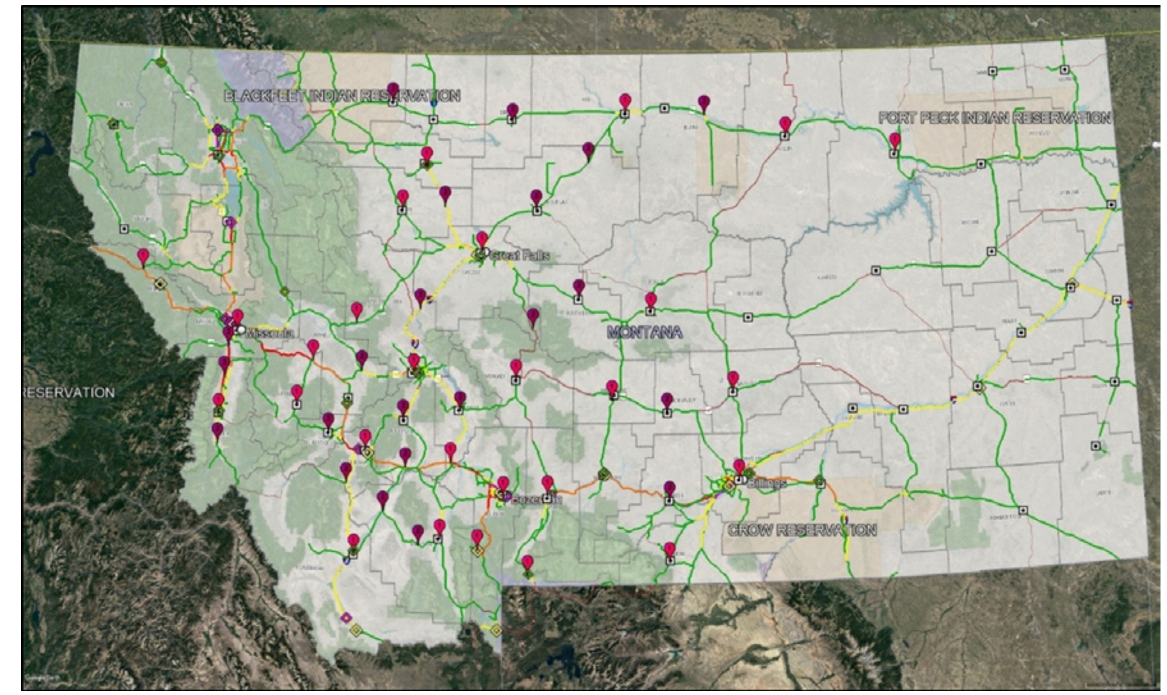
Figure 9-3. Installed and proposed DCFC load (assuming coincident peaks) in NorthWestern Energy's Montana service territory



In addition, NorthWestern also included a forward-looking analysis of the demands associated with the buildout of a statewide DCFC network. For the near-term and likely scenario, NorthWestern utilized the Montana Electric Vehicle Infrastructure Deployment Plan developed by MDEQ in response to the National Electric Vehicle Infrastructure program. This plan details the 5-year phased installation of 36 DCFC stations, each with an installed capacity of 600 kW. Of these 36 stations, NWE would likely serve 16 – resulting in a load growth of about 9.6 MW (Figure 9-3).

However, as noted in the MDEQ plan, both MDEQ and many of the public commenters recognized the need to likely grow this DCFC network beyond the 36 proposed locations in subsequent years. As a result, NorthWestern also considered a more-extensive buildout to provide DCFC infrastructure to areas around its service territory not included in MDEQ's plan (Figure 9-4). Although the eventual buildout of a DCFC network will likely look vastly different than shown, this serves to provide insight into the magnitude of a more comprehensive DCFC network. This more extensive buildout includes a total of 48 DCFC stations within NorthWestern's service territory ranging from an installed capacity of 600 kW in smaller communities to 1.9 MW in larger/more trafficked communities. In total, this buildout would represent an increase in DCFC load of about 42 MW.

Figure 9-4. Example of a more extensive buildout of a DCFC network across NorthWestern Energy's Montana service territory



By considering the current, planned, and potential DCFC load across Montana and NorthWestern's service territory (Table 9-2), NorthWestern can more effectively plan for this load growth and develop tools to manage it.

Table 9-2. Summary of the estimated current, planned, and potential DCFC load in NWE's service territory

Estimated Current, Planned, and Potential DCFC Load[26]			
	2022	2027	2032
DCFC Load	~ 3 MW	12.6 MW	9 W

9.1.3 Tools for Managing Growing EV Loads

Though there are still many uncertainties in the future of electric vehicles in Montana, it is still crucial that NorthWestern consider and understand the current system and supply impacts of EVs and EVSE while also planning for the future growth of EV charging load across all EV charging sectors. Analyses, such as those described above, are helpful for estimating and quantifying the potential impacts to NorthWestern's electrical supply. These efforts also help to recognize the potential value and urgency of developing effective tools for managing this new and growing load. Based on these analyses, NorthWestern is already working to develop a range of tools that could be used to manage growing EV load for both private and public charging. Some of the tools being evaluated include developing program(s) to support both active and passive management of private/L2 charging loads and installing battery storage alongside private or public charging installations to enable load shifting.

10. Action Plan

No additional data.

26 2022 load estimates are based on 2014-2021 monthly usage data for NWE-served DCFCs. 2027 load estimates are based on the Montana Department of Environmental Quality's planned DCFC installations in NWE's service territory as part of their Montana Electric Vehicle Infrastructure Deployment Plan to satisfy the National Electric Vehicle Infrastructure program requirements. 2032 estimates are based on an exponential curve fit of the 2014-2021 historical usage data.

Appendix D

Note: This section presented for reader convenience only. It should not be considered an authoritative reference to all applicable and current laws and should not be construed as legal advice.

MONTANA CODE ANNOTATED

TITLE 69. PUBLIC UTILITIES AND CARRIERS

CHAPTER 3. REGULATION OF UTILITIES

Part 2. Requirements for Public Utilities[27]

69-3-201. Utilities to provide adequate service at reasonable charges. Every public utility is required to furnish reasonably adequate service and facilities. The charge made by any public utility for any heat, light, power, water, or regulated telecommunications service produced, transmitted, delivered, or furnished or for any service to be rendered as or in connection with any public utility shall be reasonable and just, and every unjust and unreasonable charge is prohibited and declared unlawful.

History: En. Sec. 5, Ch. 52, L. 1913; re-en. Sec. 3883, R.C.M. 1921; re-en. Sec. 3883, R.C.M. 1935; R.C.M. 1947, 70-105; amd. Sec. 12, Ch. 546, L. 1985.

Part 12. Public Utilities, Cooperative Utilities, and Electricity Suppliers[28]

69-3-1202. Policy -- planning. (1) (a) It is the policy of the state to supervise, regulate, and control public utilities. To the extent that it is consistent with the policy and in order to benefit society, the state requires efficient utility operations, efficient use of utility services, and efficient rates.

(b) It is further the policy of the state to encourage utilities to acquire resources using a competitive solicitation process and in a manner that will help ensure a clean, healthful, safe, and economically productive environment.

(2) (a) The legislature finds that the commission may include in rates any costs that are associated with acquiring resources referred to in subsection (1) and that are consistent with this policy if the resources are actually used and useful for the convenience of the public.

(b) To advance this policy, the commission shall require long-range plans every 3 years from utilities that provide electric and natural gas service in a form and manner determined by the commission. The commission shall receive comments on the plans.

(3) This part does not constrain or limit the commission's existing statutory duties or responsibilities.

History: En. Sec. 2, Ch. 157, L. 1993; amd. Sec. 10, Ch. 449, L. 2019.

69-3-1203. Definitions. As used in this part, unless the context requires otherwise, the following definitions apply:

(1) "Abandonment costs" means the costs incurred for resources acquired and abandoned pursuant to a plan.

(2) "Consumer counsel" means the consumer counsel provided for in 5-15-201.

(3) "Demand-side management programs" means energy efficiency, energy conservation, load management, and demand response or any combination of these measures implemented by an electric utility.

(4) "Energy conservation" means the decrease in electricity requirements of specific customers during any selected time period, resulting in a reduction in end-use services.

(5) "Energy efficiency" means the decrease in electricity requirements of specific customers during any selected period with end-use services of those customers held constant.

27 Available at Part 2. Requirements for Public Utilities - Table of Contents, Title 69, Chapter 3, MCA (mt.gov)
28 Available at Part 12. Integrated Least-Cost Resource Planning and Acquisition Act - Table of Contents, Title 69, Chapter 3, MCA (mt.gov)

(6) "Externalities" mean the impacts on society that are not directly borne by the producer in production and delivery activities, which due to imperfections in or the absence of markets are not accounted for in the producer's production and pricing decisions.

(7) "Plan" means an integrated least-cost resource plan submitted by a utility in accordance with this part and the rules adopted under this part.

(8) "Planning costs" means the costs of evaluating the future demand for services and of evaluating alternative methods of satisfying future demand.

(9) "Planning period" means the future period for which a utility develops its plan, and the period over which net present value of revenue requirements for resources is calculated. For purposes of this part, the planning period is a minimum of 20 years and begins from the date the utility files its plan with the commission.

(10) "Portfolio development costs" means the costs of preparing a resource in a portfolio for prompt and timely acquisition of the resource.

(11) "Public utility" means a public utility, as defined in 69-3-101, that provides electric or natural gas service. The term does not include municipal utilities.

History: En. Sec. 3, Ch. 157, L. 1993; amd. Sec. 11, Ch. 449, L. 2019.

69-3-1204. Integrated least-cost plan. (1) (a) The commission shall adopt rules requiring a public utility to prepare and file a plan every 3 years for meeting the requirements of its customers in the most cost-effective manner consistent with the public utility's obligation to serve and in accordance with this part.

(b) The rules must prescribe the content and the time for filing a plan.

(2) (a) A plan must contain but is not limited to:

(i) an evaluation of the full range of cost-effective means for the public utility to meet the service requirements of its Montana customers, including conservation or similar improvements in the efficiency by which services are used and including demand-side management programs in accordance with 69-3-1209;

(ii) an annual electric demand and energy forecast developed pursuant to commission rules that includes energy and demand forecasts for each year within the planning period and historical data, as required by commission rule;

(iii) an assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to commission rules;

(iv) an assessment of the need for additional resources and the utility's plan for acquiring resources;

(v) the proposed process the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive solicitation process in accordance with 69-3-1207; and

(vi) descriptions of at least two alternate scenarios that can be used to represent the costs and benefits from increasing amounts of renewable energy resources and demand-side management programs, based on rules developed by the commission.

(b) The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs on which it relied to develop information required in subsection (2)(a).

(3) (a) The commission may adopt rules providing guidelines to be used in preparing a plan and identifying the criteria to be used in determining cost-effectiveness.

(b) The criteria may include externalities associated with the acquisition of a resource by a public utility.

(c) The rules must establish the minimum filing requirements for acceptance of a plan by the commission for further review. If a plan does not meet the minimum filing requirements, it must be returned to the public utility with a list of deficiencies. A corrected plan must be submitted within the time established by the commission.

(4) A plan filed with the commission by a utility, as defined in 75-20-104, must be provided to the department of environmental quality and the consumer counsel.

(5) The commission shall:

(a) review the plan;

(b) publish a copy of the plan;

(c) allow for a minimum of 60 days for the public to comment on the plan; and

(d) provide public meetings in accordance with 69-3-1205.

(6) (a) The commission may identify deficiencies in the plan, including:

(i) any concerns of the commission regarding the public utility's compliance with commission rules; and

(ii) ways to remedy the concerns.

(b) The commission may engage independent engineering, financial, and management consultants or advisory services to evaluate a public utility's plan. The consultants must have demonstrated knowledge and experience with resource procurement and resource portfolio management, modeling, risk management, and engineering practices. The commission shall charge a fee to the public utility to pay for the costs of consultants or advisory services. These costs are recoverable in rates.

History: En. Sec. 4, Ch. 157, L. 1993; amd. Sec. 173, Ch. 418, L. 1995; amd. Sec. 12, Ch. 449, L. 2019.

69-3-1205. Public comment -- public meetings. (1) When developing a plan in accordance with this part and prior to submitting a plan to the commission, a public utility shall hold at least two public meetings in the utility's Montana service territory to ensure a plan best meets the diverse goals of shareholders, ratepayers, and society.

(2) After a plan is submitted, the commission shall conduct two public meetings for the purpose of receiving comment on a plan. The commission or the department of public service regulation may comment on the plan. A comment by the commission or the department may not be construed as preapproval by the commission of rate treatment for any proposed resource.

(3) The department of environmental quality:

(a) shall review a plan submitted to the commission and comment on the need for new resources, the alternatives evaluated to meet the need, the environmental implications of the resource choices, and other related issues that it considers important. The department shall coordinate and deliver all comments from other executive branch agencies.

(b) may use a plan in the development of studies for a specific energy facility for which an application for a certificate of compliance is submitted under Title 75, chapter 20.

(4) The consumer counsel shall review and may comment on a submitted plan.

History: En. Sec. 5, Ch. 157, L. 1993; amd. Sec. 174, Ch. 418, L. 1995; amd. Sec. 2, Ch. 217, L. 2003; amd. Sec. 13, Ch. 449, L. 2019.

69-3-1206. Rate treatment. (1) The commission may include in a public utility's rates:

(a) the cost of resources acquired in accordance with a plan;

(b) demand-side management programs established and implemented in accordance with 69-3-1209;

(c) the cost-effective expenditures for improving the efficiency with which the public utility provides and its customers use utility services;

(d) the costs of complying with the planning requirements of this part; and

(e) the costs of complying with a competitive solicitation process conducted in accordance with 69-3-1207.

(2) The commission may adopt rules establishing criteria governing the extent of recovery of abandonment costs.

(3) The commission may not approve a bonus or adder in the cost of a new resource acquired after April 28, 2021, to provide additional compensation for costs such as environmental externalities unless the bonus or adder is necessary to compensate for a real and actual cost required by existing regulation or existing law.

History: En. Sec. 6, Ch. 157, L. 1993; amd. Sec. 14, Ch. 449, L. 2019; amd. Sec. 2, Ch. 300, L. 2021.

69-3-1207. Competitive solicitation process -- Montana consumer counsel role. (1) (a) Except as provided in subsection (5), a public utility that intends to seek approval by the commission pursuant to 69-8-421 for the acquisition, construction, or purchase of an electricity supply resource shall conduct a competitive solicitation process.

(b) A public utility may not prohibit a qualifying small power production facility as defined in 69-3-601 or another utility or supplier that owns an electricity supply resource or intends to construct an electricity supply resource from participating in a competitive solicitation process.

(c) A competitive solicitation process that is open to bids that would result in the ownership of an electricity supply resource by the public utility issuing the solicitation must include the use of a third-party administrator selected by the public utility to open, consider, and evaluate bids submitted pursuant to a solicitation.

(2) A public utility that plans to conduct a competitive solicitation process shall submit the following information to the commission:

(a) a description of the competitive solicitation process that the public utility will use and proof of compliance with subsections (1)(b) and (1)(c), if applicable; and

(b) a complete draft of the proposal soliciting electricity supply resources, citing the need for resources.

(3) The commission may accept public comment on the information.

(4) (a) The Montana consumer counsel may request, select, and retain a person or organization to act as an independent monitor for a competitive solicitation process.

(b) The commission shall charge a fee to the public utility to pay for the costs of an independent monitor. These costs are recoverable in rates.

(c) The independent monitor may assist the Montana consumer counsel by:

(i) providing comments on the consistency of the competitive solicitation process with industry standards;

(ii) monitoring and observing the competitive solicitation process, paying particular attention to the public utility's evaluation of electricity supply resources that may result in utility ownership of the resource, to ensure that the utility conducts a fair and proper process in accordance with industry standards;

(iii) notifying the utility and the consumer counsel on a timely basis prior to the utility's selection of the resources of any discrepancies observed in the process and resolving any differences of opinion; and

(iv) preparing a closing report prior to the final selection of the resources regarding the consistency of the process, including selection and notification of electricity supply resources taking part in the solicitation process based on industry standards.

(5) This section does not apply to:

(a) a request for proposals or purchase by a public utility intended solely to meet the short-term operational needs of the utility for a period of less than 12 months; or

(b) an application made to the commission by a public utility to acquire, construct, or purchase an opportunity resource.

(6) For the purposes of this section, “opportunity resource” means an electricity supply resource necessary to meet a need demonstrated in a plan in accordance with 69-3-1204(2)(a)(iv) that is either new or existing and that remains unknown as to its availability for purchase until an opportunity to purchase arises.

History: En. Sec. 1, Ch. 449, L. 2019.

69-3-1208. Resource planning -- advisory committee. (1) A public utility shall maintain a broad-based advisory committee to review, evaluate, and make recommendations on technical, economic, and policy issues related to a utility’s electricity system.

(2) The committee may advise the utility on demand-side management, portfolio planning, and management and procurement completed in accordance with this part.

History: En. Sec. 2, Ch. 449, L. 2019.

69-3-1209. Electric utility demand-side management programs. (1) The commission may establish energy savings and peak demand reduction goals for an electric utility, taking into account the utility’s cost-effective demand-side management potential and the need for electricity resources.

(2) The commission shall permit electric utilities to implement cost-effective electricity demand-side management programs and conservation in accordance with 69-3-701 through 69-3-712 and this part to reduce the need for additional resources.

(3) Every 3 years, an electric utility shall submit a report to the commission describing the demand-side management programs and conservation implemented by the electric utility in the previous year. The report must document:

(a) program expenditures, including incentive payments;

(b) peak demand and energy savings impacts and the techniques used to estimate those impacts;

(c) avoided costs and the techniques used to estimate those costs;

(d) the estimated cost-effectiveness of the programs;

(e) the net economic benefits of the programs; and

(f) any other information required by the commission.

History: En. Sec. 3, Ch. 449, L. 2019; amd. Sec. 2, Ch. 11, L. 2021.

CHAPTER 8. ELECTRIC UTILITY INDUSTRY GENERATION REGULATION

Part 4. Public Utilities, Cooperative Utilities, and Electricity Suppliers[29]

69-8-401. Maintaining safety and reliability. Utilities shall maintain standards of safety and reliability of the electric delivery system and existing customer service requirements.

History: En. Sec. 21, Ch. 505, L. 1997.

69-8-402. Universal system benefits programs. (1) Universal system benefits programs are established for the state of Montana to ensure continued funding of and new expenditures for energy conservation, renewable resource projects and applications, and low-income energy assistance.

(2) (a) Except as provided in subsection (11), beginning January 1, 1999, 2.4% of each utility’s annual retail sales revenue in Montana for the calendar year ending December 31, 1995, is established as the initial funding level for universal system benefits programs. To collect this amount of funds on an annualized basis in 1999, the commission shall establish rates for utilities subject to its jurisdiction and the governing boards of cooperatives shall establish rates for the cooperatives.

(b) The recovery of all universal system benefits programs costs imposed pursuant to this section is authorized through the imposition of a universal system benefits charge assessed at the meter for each local utility system customer as provided in this section.

(c) A utility must receive credit toward annual funding requirements for the utility’s internal programs or activities that qualify as universal system benefits programs, including those amortized or nonamortized portions of expenditures for the purchase of power that are for the acquisition or support of renewable energy, conservation-related activities, or low-income energy assistance, and for large customers’ programs or activities as provided in subsection (7). The department of revenue shall review claimed credits of the utilities and large customers pursuant to 69-8-414.

(d) A utility at which the sale of power for final end use occurs is the utility that receives credit for the universal system benefits programs expenditure.

(e) A customer’s utility shall collect universal system benefits funds less any allowable credits.

(f) For a utility to receive credit for low-income-related expenditures, the activity must have taken place in Montana.

(g) If a utility’s or a large customer’s credit for internal activities does not satisfy the annual funding provisions of this subsection (2), then the utility or large customer shall make a payment to the universal system benefits fund established in 69-8-412 for any difference.

(3) Cooperative utilities may collectively pool their statewide credits to satisfy their annual funding requirements for universal system benefits programs and low-income energy assistance.

(4) A utility’s transition plan must describe how the utility proposes to provide for universal system benefits programs, including the methodologies, such as cost-effectiveness and need determination, used to measure the utility’s level of contribution to each program.

(5) (a) A cooperative utility’s minimum annual funding requirement for low-income energy and weatherization assistance is established at 17% of the cooperative utility’s annual universal system benefits funding level and is inclusive within the overall universal system benefits funding level.

(b) Except as provided in subsection (11), a public utility’s minimum annual funding requirement for low-income energy and weatherization assistance is established at 50% of the public utility’s annual universal system benefits funding level and is inclusive within the overall universal system benefits funding level.

(c) A utility must receive credit toward the utility’s low-income energy assistance annual funding requirement for the utility’s internal low-income energy assistance programs or activities. Internal programs and activities may include providing low-income energy and weatherization assistance on Indian reservations.

(d) If a utility’s credit for internal activities does not satisfy its annual funding requirement, then the utility shall make a payment for any difference to the universal low-income energy assistance fund established in 69-8-412.

(6) An individual customer may not bear a disproportionate share of the local utility’s funding requirements, and a sliding scale must be implemented to provide a more equitable distribution of program costs.

(7) (a) A large customer:

(i) shall pay a universal system benefits programs charge with respect to the large customer’s qualifying load equal to the lesser of:

(A) $500,000, less the large customer credits provided for in this subsection (7); or

(B) the product of 0.9 mills per kilowatt hour multiplied by the large customer’s total kilowatt hour purchases, less large customer credits with respect to that qualifying load provided for in this subsection (7);

29 Available at [Part 4. Public Utilities, Cooperative Utilities, and Electricity Suppliers - Table of Contents, Title 69, Chapter 8, MCA (mt.gov)]

(ii) must receive credit toward that large customer's universal system benefits charge for internal expenditures and activities that qualify as a universal system benefits programs expenditure, and these internal expenditures must include but not be limited to:

(A) expenditures that result in a reduction in the consumption of electrical energy in the large customer's facility; and

(B) those amortized or nonamortized portions of expenditures for the purchase of power at retail or wholesale that are for the acquisition or support of renewable energy or conservation-related activities.

(b) Large customers making these expenditures must receive a credit against the large customer's universal system benefits charge, except that any of those amounts expended in a calendar year that exceed that large customer's universal system benefits charge for the calendar year must be used as a credit against those charges in future years until the total amount of those expenditures has been credited against that large customer's universal system benefits charges.

(8) (a) Except as provided in subsection (11), a public utility shall prepare and submit an annual summary report of the public utility's activities relating to all universal system benefits programs to the commission, the department of revenue, and the energy and telecommunications interim committee in accordance with 5-11-210. A cooperative utility shall prepare and submit annual summary reports of activities to the cooperative utility's respective local governing body, the statewide cooperative utility office, and the energy and telecommunications interim committee in accordance with 5-11-210. The statewide cooperative utility office shall prepare and submit an annual summary report of the activities of individual cooperative utilities, including a summary of the pooling of statewide credits, as provided in subsection (3), to the department of revenue and the energy and telecommunications interim committee in accordance with 5-11-210. The annual report of a public utility or of the statewide cooperative utility office must include but is not limited to:

(i) the types of internal utility and customer programs being used to satisfy the provisions of this chapter;

(ii) the level of funding for those programs relative to the annual funding requirements prescribed in subsection (2);

(iii) any payments made to the statewide funds in the event that internal funding was below the prescribed annual funding requirements; and

(iv) the names of all large customers who either utilized credits to minimize or eliminate their charge pursuant to subsection (7) or received a reimbursement for universal system benefits related to expenditures from the utility during the previous reporting year.

(b) Before September 15 of the year preceding a legislative session, the energy and telecommunications interim committee shall:

(i) review the universal system benefits programs and, if necessary, submit recommendations regarding these programs to the legislature; and

(ii) review annual universal system benefits reports provided by utilities in accordance with subsection (8)(a) and compare those reports with reports provided by large customers to the department of revenue in accordance with subsection (10)(a) and identify large customers, if any, who are not in compliance with reporting requirements in accordance with this subsection (8) and subsection (10).

(9) A utility or large customer filing for a credit shall develop and maintain appropriate documentation to support the utility's or the large customer's claim for the credit.

(10) (a) A large customer claiming credits for a calendar year shall submit an annual summary report of its universal system benefits programs activities and expenditures to the department of revenue and to the large customer's utility. The department shall annually make the reports available to the energy and telecommunications interim committee in accordance with 5-11-210. A report must be filed with the department even if a large customer is being reimbursed for a prior year's project. The annual report of a large customer must identify each qualifying project or expenditure for which it has claimed a credit and the amount of the credit. Prior approval by the utility is not required, except as provided in subsection (10)(b).

(b) If a large customer claims a credit that the department of revenue disallows in whole or in part, the large customer is financially responsible for the disallowance. A large customer and the large customer's utility may mutually agree that credits claimed by the large customer be first approved by the utility. If the utility approves the large customer credit, the utility may be financially responsible for any subsequent disallowance.

(11) A public utility with fewer than 50 customers is exempt from the requirements of this section.

History: En. Sec. 22, Ch. 505, L. 1997; amd. Sec. 3, Ch. 580, L. 1999; amd. Sec. 1, Ch. 188, L. 2001; amd. Sec. 14, Ch. 577, L. 2001 (voided by I.R. No. 117, Nov. 5, 2002); amd. Sec. 1, Ch. 290, L. 2003; amd. Sec. 15, Ch. 565, L. 2003; amd. Sec. 1, Ch. 256, L. 2005; amd. Sec. 10, Ch. 491, L. 2007; amd. Sec. 1, Ch. 55, L. 2009; amd. Sec. 3, Ch. 252, L. 2015; amd. Sec. 1, Ch. 393, L. 2015; amd. Sec. 19, Ch. 275, L. 2017; amd. Sec. 97, Ch. 261, L. 2021.

69-8-421. Approval of electricity supply resources.[30] (1) A public utility that removed its generation assets from its rate base pursuant to this chapter prior to October 1, 2007, may apply to the commission for approval of an electricity supply resource that:

(a) is not yet procured; and

(b) is subject to a competitive solicitation process when applicable in accordance with 69-3-1207.

(2) Within 45 days of the public utility's submission of an application for approval, the commission shall determine whether or not the application is adequate and in compliance with the commission's minimum filing requirements. If the commission determines that the application is inadequate, it shall explain the deficiencies.

(3) The commission shall issue an order within 180 days of receipt of an adequate application for approval of a power purchase agreement from an existing generating resource unless it determines that extraordinary circumstances require additional time.

(4) (a) Except as provided in subsections (4)(b) through (4)(d), the commission shall issue an order within 270 days of receipt of an adequate application for approval of a lease, an acquisition of an equity interest in a new or existing plant or equipment used to generate electricity, or a power purchase agreement for which approval would result in construction of a new electric generating resource. The commission may extend the time limit up to an additional 90 days if it determines that extraordinary circumstances require it.

(b) If an air quality permit pursuant to Title 75, chapter 2, is required for a new electrical generation resource or a modification to an existing resource, the commission shall hold the public meetings on the application for approval in accordance with 69-3-1205(2) at least 30 days after the issuance of the final air quality permit.

(c) If a final air quality permit is not issued within the time limit pursuant to subsection (4)(a), the commission shall extend the time limit in order to comply with subsection (4)(b).

(d) The commission may extend the time limit for issuing an order for an additional 60 days following the meetings pursuant to subsection (4)(b).

(5) To facilitate timely consideration of an application, the commission may initiate proceedings to evaluate planning and procurement activities related to a potential resource procurement, if necessary, in accordance with 69-3-1207 prior to the public utility's submission of an application for approval.

(6) (a) The commission may approve or deny, in whole or in part, an application for approval of an electricity supply resource.

(b) The commission may consider all relevant information known up to the time that the administrative record in the proceeding is closed in the evaluation of an application for approval.

(c) A commission order granting approval of an application must include the following findings:

30 On May 6, 2022, a Montana district court declared § 69-8-421, MCA—otherwise known as the "preapproval statute"—unconstitutional, in violation of Article 2, Section 31 and Article 5, Section 12 of the Montana Constitution. NorthWestern and the State of Montana have appealed the district court's decision to the Montana Supreme Court.

(i) approval, in whole or in part, is in the public interest; and

(ii) procurement of the electricity supply resource is consistent with the requirements and objectives in 69-3-201, 69-3-1201 through 69-3-1209, and commission rules.

(d) The commission order may include a provision for allowable generation assets cost of service when the utility has filed an application for the lease or acquisition of an equity interest in a plant or equipment used to generate electricity.

(e) When issuing an order for the acquisition of an equity interest or lease in a facility or equipment that is constructed after January 1, 2007, and that is used to generate electricity that is primarily fueled by natural or synthetic gas, the commission shall require the applicant to implement cost-effective carbon offsets. Expenditures required for cost-effective carbon offsets pursuant to this subsection (6)(e) are fully recoverable in rates. By March 31, 2008, the commission shall adopt rules for the implementation of this subsection (6)(e).

(f) The commission order may include other findings that the commission determines are necessary.

(g) A commission order that denies approval must describe why the findings required in subsection (6)(c) could not be reached.

(7) Notwithstanding any provision of this chapter to the contrary, if the commission has issued an order containing the findings required under subsection (6)(c), the commission may not subsequently disallow the recovery of costs related to the approved electricity supply resource based on contrary findings.

(8) Until the state or federal government has adopted uniformly applicable statewide standards for the capture and sequestration of carbon dioxide, the commission may not approve an application for the acquisition of an equity interest or lease in a facility or equipment used to generate electricity that is primarily fueled by coal and that is constructed after January 1, 2007, unless the facility or equipment captures and sequesters a minimum of 50% of the carbon dioxide produced by the facility. Carbon dioxide captured by a facility or equipment may be sequestered offsite from the facility or equipment.

(9) Nothing limits the commission's ability to subsequently, in any future rate proceeding, inquire into the manner in which the public utility has managed, dispatched, operated, or maintained any resource or managed any power purchase agreement as part of its overall resource portfolio. The commission may subsequently disallow rate recovery for the costs that result from the failure of a public utility to reasonably manage, dispatch, operate, maintain, or administer electricity supply resources in a manner consistent with 69-3-201 and commission rules.

(10) The commission shall adopt rules prescribing minimum filing requirements for applications filed pursuant to this part.

History: En. Sec. 3, Ch. 509, L. 2003; amd. Sec. 15, Ch. 491, L. 2007; amd. Sec. 94, Ch. 2, L. 2009; amd. Sec. 15, Ch. 449, L. 2019.

69-8-426. Use of generation assets. Generation assets acquired by a public utility pursuant to this chapter:

(1) must be used by the public utility to serve and benefit customers within the public utility's Montana service territory; and

(2) may not be removed from the rate base unless the commission finds that customers of the public utility will not be adversely affected.

History: En. Sec. 19, Ch. 491, L. 2007.

ADMINISTRATIVE RULES OF MONTANA
DEPARTMENT 38: PUBLIC SERVICE REGULATION
CHAPTER 38.5 UTILITY DIVISION

38.5.82: Default Electric Supplier Procurement Guidelines[31,32],

31 The Commission repealed and replaced these rules in January 2023.

32 Available at [Subchapter Home: - Administrative Rules of the State of Montana (mt.gov).](https://rules.mt.gov)

RULE 38.5.8201. INTRODUCTION AND APPLICABILITY

(1) These guidelines apply to electric utilities subject to the provisions of 69-8-419 through 69-8-421, MCA.

(2) These guidelines provide policy guidance on long-term electricity supply resource planning and procurement. With the exception of ARM 38.5.8301, the guidelines do not impose specific resource procurement processes or mandate particular resource acquisitions. Instead, the guidelines describe a process framework for considering resource needs and suggest optimal ways of meeting those needs. Electricity supply resource decisions affect the public interest. A utility can better fulfill its obligations, mitigate risks, and achieve resource procurement goals if it includes the public in the electricity supply resource portfolio planning process. An independent advisory committee of respected technical and public policy experts may offer the utility an excellent source of up-front, substantive input that would help mitigate risk and improve resource procurement outcomes in a manner consistent with these guidelines. Consistent with these guidelines, and after an opportunity for public input, the utility must ultimately make electricity supply resource acquisition decisions based on economics, reliability, management expertise, and sound judgment.

(3) A utility should thoroughly document its portfolio planning processes, resource procurement processes, and management decision-making so that it can fully demonstrate to the commission and stakeholders the prudence of supply-related costs and/or justify requests for approval of electricity supply resources. A utility should routinely communicate with the commission and stakeholders regarding portfolio planning and resource procurement activities.

(4) These guidelines provide the basis for commission review and consideration of the prudence of a utility's electricity supply resource planning and procurement actions, and are the standards against which the commission will evaluate electricity supply resources for which a utility requests approval under 69-8-421, MCA. As such, the guidelines should assist utilities in making prudent decisions and in fully recovering supply-related costs. Successful application of the guidelines will require a commitment from the commission, utilities, and stakeholders to honor the spirit and intent of the guidelines.

(5) These guidelines supersede the commission's electric least cost planning rules (ARM 38.5.2001 through 38.5.2012) solely with respect to electricity supply resource planning and procurement functions.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2003 MAR p. 2894, Eff. 12/25/03; AMD, 2006 MAR p. 1461, Eff. 6/2/06; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-3-2006, 69-8-403, 69-8-419, MCA; IMP, 69-3-2004, 69-3-2005, 69-8-403, MCA;

RULE 38.5.8202. DEFINITIONS

For the purpose of this subchapter, the following definitions are applicable:

(1) "Carbon offset provider" means a third party entity that:

(a) arranges for projects or actions that either reduce carbon dioxide emissions or that increase the absorption of carbon dioxide; and

(b) has been determined to be qualified by the commission in an order addressing a utility's application for approval of an acquisition of an equity interest or lease in a facility or equipment constructed after January 1, 2007 that generates electricity primarily by combusting natural or synthetic gas.

(2) "Cost-effective carbon offsets" means actions taken by a utility or a carbon offset provider on behalf of a utility or both which reduce carbon dioxide emissions or increase the absorption of carbon dioxide and which collectively do not increase the annual cost of producing electricity from a facility or equipment that generates electricity primarily by combusting natural or synthetic gas by more than 2.5%.

(3) "Electricity supply costs" means the actual costs incurred in providing electricity supply service through power purchase agreements, demand-side management, and energy efficiency programs, including but not limited to: capacity costs, energy costs, fuel costs, ancillary service costs, transmission costs (including congestion and losses), planning and administrative costs, and any other costs directly related to the purchase of electricity and

the management and provision of power purchase agreements.

(4) “Electricity supply resource” means:

(a) a wholesale power transaction, including bilateral contracts, however structured, and spot energy purchases;

(b) a plant or equipment owned or leased, in whole or in part, by a utility for purposes of generating electricity and used to serve the utility’s native load;

(c) a demand-side management activity, including energy efficiency and conservation programs, load control programs, and pricing mechanisms; or

(d) a combination of (4)(a), (b), and (c).

(5) “Environmentally responsible” means explicitly recognizing and incorporating into electricity supply resource portfolio planning, management, and procurement processes and decision-making the policy of the state of Montana to encourage utilities to acquire resources in a manner that will help ensure a clean, healthful, safe, and economically productive environment.

(6) “External costs” means costs incurred by society but not incorporated directly into electricity production and delivery activities, or retail prices for electricity services directly paid by consumers.

(7) “Long-term” means a time period at least as long as a utility’s electricity supply resource planning horizon.

(8) “Planning horizon” means the longer of:

(a) the longest remaining contract term in a utility’s electricity supply resource portfolio;

(b) the period of the longest lived electricity supply resource being considered for acquisition; or

(c) ten years.

(9) “Pre-filing communication” means, with respect to an application by a utility for approval of a electricity supply resource, informal information exchange, including oral dialogue and written discovery, between the utility and members of its stakeholder advisory committee, the Montana Consumer Counsel, other stakeholders, and commission staff that occurs after the utility files a notice of intent to request approval of a new electricity supply resource pursuant to ARM 38.5.8228 up to the date the utility files the application.

(10) “Rate stability” means minimal price variation, both month-to-month and year-to-year, and minimal price inflation over time.

(11) “Stakeholder” means a member of the public (individual, corporation, organization, group, etc.) who may have a special interest in, or may be especially affected by, these rules.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2003 MAR p. 2894, Eff. 12/25/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8203. GOALS

(1) The goals of these electricity supply resource planning and procurement guidelines are:

(a) to facilitate a utility’s provision of adequate and reliable electricity supply services, stably and reasonably priced, at the lowest long-term total cost;

(b) to promote economic efficiency and environmental responsibility;

(c) to facilitate a utility’s financial health;

(d) to facilitate a process through which a utility identifies and cost-effectively manages and mitigates risks related to its obligation to provide electricity supply service; and

(e) to build on the fundamental rate making relationship between the commission and the utility to advance these goals.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8204. OBJECTIVES

(1) In order to satisfy its electricity supply service responsibilities, a utility should pursue the following objectives in assembling and managing an electricity supply resource portfolio:

(a) provide customers adequate and reliable electricity supply services, stably and reasonably priced, at the lowest long-term total cost;

(b) design rates that are equitable and promote rational, economically efficient consumption decisions;

(c) assemble and maintain a balanced, environmentally responsible portfolio of electricity supply resources coordinated with economically efficient cost allocation and rate design that most efficiently provides electricity supply services to customers over the planning horizon;

(d) maintain an optimal mix of electricity supply resources with respect to underlying fuels, technologies, and associated environmental impacts, and a diverse mix of long, medium, and short duration power supply contracts with staggered start and expiration dates; and

(e) maximize the dissemination of information to customers regarding the mix of resources and the corresponding level of emissions and other environmental impacts associated with electricity supply service through itemized labeling and reporting of the portfolio’s energy products.

(2) These objectives are listed in order of importance, but no single objective should be pursued such that others are ignored. Simultaneously achieving these multiple objectives will require a balanced approach. A utility should apply the recommendations in ARM 38.5.8209 through 38.5.8213, 38.5.8218 through 38.5.8221, 38.5.8225, and 38.5.8226, in addition to relevant commission orders, to achieve these goals and objectives.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8209. UTILITY EMERGENCY SERVICE RESPONSIBILITY

(1) A utility’s electricity supply service responsibility is to provide all or a substantial amount of the emergency electricity supply requirements of retail customers who have electricity supply service contracts with a nonutility electricity supplier or marketer that has failed to deliver the required electricity supply. (A utility is not required to maintain a reserve of electricity supply to fulfill its emergency supply responsibilities. To the greatest extent practicable, a utility should recover the costs of providing emergency service from the supplier or marketer that failed to deliver the required electricity or the customers that directly benefited from the utility’s provision of emergency service. A utility must provide emergency service according to commission-approved tariff schedules.).

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2006 MAR p. 1461, Eff. 6/2/06; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, 69-8-419, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8210. RESOURCE NEEDS ASSESSMENT

(1) Before acquiring multi-year electricity supply resources, a utility should evaluate its existing resources and analyze future resource needs in the context of the goals and objectives of these guidelines. A utility should use a planning horizon as defined in these rules.

(2) A utility’s resource needs assessment should include:

(a) analyses of customer loads including base load, intermediate load, peak load and ancillary service requirements, seasonal and daily load shapes and variability, the number and type of customers, load growth, trends in customer choice and retail markets, technology that may lead to substitutes for grid-based electricity service, impacts of demand-side management, and price elasticity of demand;

(b) an assessment of the types of resources that are available and could contribute to meeting portfolio needs, including demand-side resources, supply-side resources, distributed resources, and rate design improvements;

(c) an assessment of the types of wholesale electricity products that could effectively and efficiently contribute to meeting portfolio needs including base load, heavy load, peak, dispatchable, curtailable, assignable, firm, full requirements, load following, unit contingent, slice of the system (fixed percentage of hourly system load requirements), and others;

(d) an assessment of resource diversity within the existing portfolio with respect to generation fuel and generation technology (e.g., conventional coal, clean coal, hydro, natural gas combined cycle, natural gas simple cycle, wind, fuel cell, etc.); and

(e) an assessment of the flexibility of the existing portfolio with respect to generation resources, suppliers, demand-side management resources, electricity products, contract lengths, contract terms and conditions, and market conditions.

(3) A utility's resource needs assessment should include analyses of how cost allocation and rate design decisions might impact future loads and resource needs. A utility's cost allocation and rate design practices should support and complement the goals and objectives of these guidelines.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8212. RESOURCE ACQUISITION

(1) A utility should apply industry standard procurement practices to acquire electricity supply resources. The commission cannot prescribe in advance the precise industry standards a utility must apply since industry standards vary depending on context and circumstances. Generally, an acceptable approach to resource procurement should encompass the following basic steps:

(a) obtain and consider upfront input and recommendations from an advisory committee throughout planning and procurement processes, as described in ARM 38.5.8225;

(b) explore a wide variety of alternative electricity supply resources;

(c) collect proposals from various parties offering electricity supply resources;

(d) analyze the feasibility and economic costs, risks, and benefits of rate basing versus alternative electricity supply arrangements;

(e) analyze alternative electricity supply resources with respect to price and nonprice factors in the context of the goals and objectives of these guidelines;

(f) select the most appropriate options and develop a shortlist;

(g) refine the analysis of short-listed options and select the most appropriate option; and

(h) anticipate changing circumstances and remain flexible.

(2) Although these basic steps could be achieved through a variety of methods, a utility should use competitive solicitations with short-list negotiations as a preferred procurement method. A utility should design requests for proposals based on its resource needs assessment. Competitive solicitations should treat bidders fairly, promote transparent portfolio planning and electricity supply resource procurement processes and contribute to achieving the goals and objectives of these guidelines. A utility's resource acquisition process should conform to the following principles:

(a) A utility should clearly define the resources, products, and services it needs before issuing a resource solicitation and clearly communicate these needs to potential bidders in the request(s) for proposals. Multiple solicitations and/or solicitations for multiple resources, products, and services may be necessary to obtain information sufficient for prudent analyses and decision-making;

(b) A utility should establish bid evaluation and bidder qualification standards and criteria it will use to select from among offers before issuing a resource solicitation and clearly communicate these standards and criteria to potential bidders in the request for proposals. Once bids are received, a utility should apply its bid evaluation and bidder qualification standards and criteria firmly and consistently;

(c) A utility should develop a systematic rating mechanism that allows it to objectively rank bids with respect to price and nonprice attributes. A utility is not required to reveal to bidders the specific ranking method used to select preferred bids, however a utility should thoroughly document the development and use of the method for later presentation to the commission;

(d) A utility should establish a shortlist of offers from bidders with which the utility will pursue contract negotiations. A utility should complete due diligence regarding bid qualifications, bidder credit worthiness and experience and project feasibility before selecting an offer for the shortlist. A utility should not indicate to a bidder that its offer is being considered for the shortlist while performing initial due diligence;

(e) If, in evaluating offers, a utility determines that a previously unidentified resource attribute should be considered in the bid evaluation, or that additional evaluation criteria should be used, all bidders should be given an opportunity to supplement their offering to address the utility's desire for the new attribute or the new criteria. The utility should attempt to minimize such occurrences;

(f) A utility should not reassign or "flip" supply contracts to an additional third party(ies) after the original bid activity and during the evaluation of bids. A utility must notify the commission before reassigning any fully executed contract;

(g) During competitive solicitation and resource acquisition processes, a utility should not publicly disclose specific information related to particular bids, including price, before the utility completes its resource acquisition process and has signed contracts with the selected bidder(s);

(h) The utility should obtain input and recommendations from an advisory committee regarding any procurement process that may involve projects or proposals by an affiliate of the utility. The utility should employ an independent third party to develop competitive solicitations if affiliate interests could be involved. An independent third party should review the contract terms and conditions in any power purchase agreement between a utility and an affiliate before the utility signs the agreement. A utility should consult with its advisory committee before selecting the independent third party and should evaluate the third party's findings with the advisory committee. The utility should be prepared to offer substantially the same form of contract to other bidders for similar products to the extent procuring such products is otherwise justified under the goals, objectives, and procedures established in these guidelines; and

(i) A utility should not provide any information to an affiliate with respect to the utility's resource needs assessment, evaluation criteria, bidder qualification criteria, due diligence, or any other relevant resource procurement information unless such information is simultaneously provided to all other prospective bidders.

(3) To the extent a utility does not use competitive solicitations to acquire electricity supply resources it should thoroughly document the exercise of its judgment in evaluating and selecting resource options, including the decision not to use competitive solicitations.

(4) A decision by a utility regarding the acquisition of an equity interest in an electricity generating plant or equipment or the construction of such a resource on its own should be thoroughly evaluated against available market-based alternatives.

(5) Use of competitive solicitations as the preferred method for procuring electricity supply resources may not

adequately achieve the goals and objectives of these guidelines with respect to demand-side resources. A utility should design programs and associated marketing and verification measures, as necessary, to ensure that its procurement of demand-side resources is optimized in the context of the goals and objectives of these guidelines.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8213. MODELING AND ANALYSIS

(1) A utility's electricity supply resource planning, procurement, and decision-making processes should incorporate proven, cost-effective computer modeling and rigorous analyses. A utility should use modeling and analyses to:

(a) evaluate and quantify probable load characteristics, including trends in load shapes, load growth, and price elasticity of demand;

(b) evaluate the potential effect of various rate designs and demand-side management methods on future loads and resource needs;

(c) evaluate and quantify projected electricity supply resource requirements over the planning horizon;

(d) develop competitive resource solicitations, including associated bid evaluation and selection criteria, and/or develop alternative candidate resources for utility construction and ownership;

(e) develop methods for weighting resource attributes and ranking bid offers and alternative candidate owned resources. Resource attributes may include, but are not necessarily limited to:

(i) underlying fuel source and associated price volatility and risk, including risks related to future regulatory constraints on environmental impacts such as emissions of carbon dioxide, sulfur dioxide, nitrogen oxides and mercury;

(ii) contributions to achieving the lowest, long-term portfolio cost;

(iii) total life cycle resource costs;

(iv) contributions to achieving optimal resource diversity;

(v) external costs related to environmental emissions and intrusions;

(vi) direct or indirect transmission costs and/or benefits;

(vii) project feasibility, including engineering, development and financing;

(viii) resource availability, reliability and dispatchability;

(ix) supplier/developer creditworthiness; and

(x) supplier/developer experience;

(f) evaluate the performance of alternative resources under various loads and resource combinations through:

(i) scenario analyses;

(ii) portfolio analyses;

(iii) sensitivity analyses; and

(iv) risk analyses;

(g) help the utility, with input from an advisory committee, inject prudent and informed judgments into the electricity supply resource planning and acquisition process;

(h) optimize the mix of electricity supply resources in the context of the goals and objectives of these guidelines; and

(i) meet the utility's burden of proof in prudence and cost recovery filings before the commission.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8218. DEMAND-SIDE RESOURCES

(1) Energy efficiency and conservation measures can effectively contribute to serving total electricity load requirements at the lowest long-term total cost. A utility should develop a comprehensive inventory of all potentially cost-effective demand-side resources available in its service area and optimize the acquisition of demand-side resources over its planning horizon.

(2) A utility should evaluate the cost-effectiveness of demand-side resources and programs based on its long-term avoidable costs. Cost-effectiveness evaluations of demand-side resources should encompass avoidable electricity supply, transmission, and distribution costs.

(3) A nonparticipant (no-losers) test considers utility-sponsored demand-side management programs cost effective only if rates to customers that do not participate in the program are not affected by the program. A utility should not evaluate the cost-effectiveness of demand-side resources using a nonparticipant test.

(4) A utility should develop and strive to achieve targets for steady, sustainable investments in cost-effective, long-term demand-side resources. A utility's investment in demand-side resources should be coordinated with and complement its universal system benefits activities.

(5) Except when the entire resource would otherwise be lost, a utility's demand-side management programs should not be focused on "cream skimming;" the least expensive and most readily obtainable resource potential should be acquired in conjunction with other measures that are cost-effective only if acquired in a package with the least expensive, most readily available resources.

(6) Prudently incurred costs related to procuring demand-side resources are fully recoverable in rates. The commission will evaluate the prudence with which demand-side resources are procured, including resources acquired through programs, subcontractors, and competitive solicitations consistent with evaluations of supply-side resources.

(7) A utility's development of demand-side resources should include an examination of innovative methods to address cost recovery issues related to demand-side resource investments and expenses, including undesirable effects on revenues related to the provision of transmission and distribution services.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8219. RISK MANAGEMENT AND MITIGATION

(1) Prudent electricity supply resource planning and procurement includes evaluating, managing, and mitigating risks associated with the inherent uncertainty of wholesale electricity markets and customer load. A utility should identify and analyze sources of risk using its own techniques, market intelligence, risk management policies, and judgment. The utility should apply industry standard instruments and strategies, document decisions to use various instruments and strategies, and monitor the ongoing appropriateness of such instruments and strategies. Sources of risk that should be evaluated may include, but are not limited to:

Underlying Risk Factor	Price/Cost Uncertainty Risk	Load Uncertainty Risk
(a) Fuel prices and price volatility	X	X
(b) Environmental regulations and taxes	X	X
(c) Retail supply rates	X	X
(d) Competitive suppliers' prices	X	
(e) Transmission constraints	X	
(f) Weather	X	X
(g) Supplier capabilities	X	X
(h) Supplier creditworthiness	X	
(i) Contract terms and conditions	X	X
(j) Construction costs	X	X

(2) A utility's strategy for managing and mitigating risks associated with the identified risk factors should be developed in the context of the goals and objectives of these guidelines and include an evaluation of relevant opportunity costs.

(3) A utility should manage and mitigate risk through adequate utility staffing and technical resources (e.g., computer modeling), diversity (fuels, technology, contract terms), and contingency planning.

(4) A utility should use an independent advisory committee of respected technical and public policy experts as a source of upfront, substantive input to mitigate risk and optimize resource procurement outcomes in a manner consistent with these guidelines.

(5) A utility should use cost-effective resource planning and acquisition techniques to manage and mitigate risks associated with the above identified risk factors, including, but not limited to:

(a) modeling and analyzing the relative risks of alternative resources, individually and integrated with all portfolio resources;

(b) acquiring resources which enhance scheduling flexibility;

(c) acquiring an optimal mix of small, short lead-time resources that better match load requirements;

(d) diversifying the resource portfolio to accommodate a broad range of future outcomes; and

(e) maintaining a transparent planning and procurement process (i.e., one which produces resource plans that can be reasonably understood by the public and the commission.)

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8220. TRANSPARENCY AND DOCUMENTATION

(1) A utility should thoroughly document the exercise of its judgment in implementing all aspects of the guidelines, including any deviations from the framework set forth in these guidelines.

(2) A utility must procure and manage a portfolio of electricity supply resources to serve the full load requirements of its customers. The commission must allow a utility to recover all costs it prudently incurs to perform this function. Whether the costs a utility incurs are prudent is, in part, directly related to whether its resource procurement process was conducted prudently. It is vital that a utility document its portfolio planning, management and electricity supply resource procurement activities to justify the prudence of its resource procurement decisions. The better a utility documents the steps involved in its resource procurement process and explains how and why decisions were made during procurement and in developing management strategies, the easier it is to satisfy its burden of proof. When a utility requests cost recovery related to the procurement of electricity supply resources it should, as applicable:

(a) document and explain all due diligence regarding the qualification of bidders and resource offers, including why selected bidders were sufficiently qualified financially and technically to warrant further evaluation of the offer based on the resource needs assessment;

(b) provide and explain the calculation of all cost estimates for all resource alternatives considered;

(c) list and describe all resource attributes considered in evaluating resource alternatives and how the attributes are relevant to the evaluation of potential resources based on the resource needs assessment;

(d) explain how the identified resource attributes were weighted as part of the resource evaluation and discuss the trade-offs between alternative resources that have different attributes and various weights;

(e) document and explain the use of the ranking methodology and decision criteria used to evaluate resource alternatives;

(f) document and explain computer modeling and analysis designed to assess how various potential resources fit with existing resources and contribute to optimizing the overall portfolio;

(g) document relevant industry practices, instruments, and actions to procure resources and manage risk observed in other utilities in the Western Electricity Coordinating Council regarding portfolio design, to the extent such practices form the basis for a utility's decisions;

(h) document and explain how and when management injected its judgment onto analyses of resource alternatives, final selection, and contract negotiations, and the impact of management judgment; and

(i) document the discussion and recommendations of the utility's advisory committee.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8221. AFFILIATE TRANSACTIONS

(1) The commission subjects transactions between a utility and any of its affiliates to close scrutiny. A utility should not acquire resources involving affiliate transactions except through competitive solicitations that are consistent with these guidelines. A utility should sufficiently demonstrate through transparent, documented modeling, analysis, and judgment that any resource acquired from an affiliate corresponds to a predetermined portfolio need.

(2) To the extent a utility procures resources involving affiliate transactions it should respond to the following primary regulatory concerns:

(a) A utility should demonstrate that it has not subordinated its electricity supply service obligations in favor of an affiliate;

(b) The burden of proof is on a utility to demonstrate that costs it incurs through any affiliate transactions are just and reasonable and in the public interest and, as such, are recoverable through regulated rates. Since, by definition, such transactions cannot be presumed to be conducted on a truly arm's-length basis, inevitably leaving room for gaming, self dealing, and certain subsidies, the commission will subject these transactions to greater scrutiny to reasonably protect ratepayers served under regulated rates from harm. This higher level of protection is referred to as the "no harm to ratepayer" standard. This standard has evolved over time from long standing regulatory practices and policies that require affiliated transactions to be fair, reasonable, and in the public interest before the associated costs are recoverable through rates. In keeping with the "no harm to ratepayer" standard, the commission generally will judge the reasonableness of affiliate transactions-related costs in relation to the lower of cost or market at the time of contract execution. For purposes of this rule, cost, by definition, is the applicable regulated cost of service structure, including a return on the capital invested, to provide the relevant affiliated services;

(c) A utility must reasonably assure that costs and revenues are accurately and properly segregated between regulated and nonregulated affiliated entities in order to protect captive customers served under regulated rates, and avoid subsidies to, and excess charges by, nonregulated affiliates;

(d) The "no harm to ratepayer" standard requires that the books of account and related records of any affiliate transacting business with the utility must be available for audit and review purposes. A utility should impute the estimated costs of necessary audit activity into affiliate resource costs when evaluating resource alternatives according to these guidelines. As reasonable and necessary and when lawful, the commission will protect affiliate information through confidentiality agreements;

(e) In order to provide for ongoing regulatory review, a utility should separately report on its on-going affiliated transactions and relationships in the context of the issues identified in this rule. Such reporting should be sufficient to allow the commission to adequately monitor whether affiliate transactions-related costs are prudent and, therefore, recoverable through regulated rates; and

(f) A utility must implement a code of conduct to guide management and other employees regarding standards for day-to-day business activities with affiliates and to guard against self-dealing, gaming, and resulting subsidies.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8225. STAKEHOLDER INPUT

(1) A utility should maintain a broad-based advisory committee to review, evaluate, and make recommendations on technical, economic, and policy issues related to electricity supply resource portfolio planning, management, and procurement. An independent advisory committee of respected technical and public policy experts may provide an excellent source of upfront, substantive input to mitigate risk and optimize resource procurement outcomes consistent with these guidelines. Maintaining an effective advisory committee could involve funding certain member participation. A utility should also facilitate processes that provide opportunities for a broader array of stakeholders to comment. Such processes could include:

(a) public meetings;

(b) customer surveys (large and small customers);

(c) other processes that may provide a utility information about public opinion on resource procurement matters.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8226. ELECTRICITY SUPPLY RESOURCE PLANNING AND PROCUREMENT FILINGS

(1) A utility must file a comprehensive, long-term portfolio management and electricity supply resource procurement plan by December 15 in each odd-numbered year.

(2) As necessary, a utility's periodic electricity supply cost tracking filings should include the information, analyses, and documentation recommended in these guidelines to support its request for cost recovery related to electricity supply cost additions or changes.

(3) A periodic cost tracking filing should document the status of on-going portfolio planning, management, and electricity supply resource procurement activities and include rolling three-year action plans. Action plans should include a discussion of activities involving transmission and distribution functions and services.

(4) The commission may implement a utility's periodic electricity supply cost recovery request on an interim basis, subject to retroactive adjustment, to allow adequate time to process such requests and render a final order.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2003 MAR p. 2894, Eff. 12/25/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8227. REWARD FOR SUPERIOR ELECTRICITY SUPPLY SERVICE

(1) The commission will evaluate a utility's performance in providing service pursuant to the goals and objectives of these guidelines and may reward the utility monetarily for superior performance at a level commensurate with such performance.

History: NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-8-403, MCA;

RULE 38.5.8228. MINIMUM FILING REQUIREMENTS FOR UTILITY APPLICATIONS FOR APPROVAL OF ELECTRICITY SUPPLY RESOURCES

(1) If a utility intends to file an application for approval of a electricity supply resource that is not yet procured, it must notify the commission and the Montana Consumer Counsel far enough in advance of filing to accommodate adequate pre-filing communication. If the resource will result from a competitive solicitation, notice must be provided before the utility issues a request for proposals.

(2) An application by a utility for approval of a electricity supply resource must include, as applicable:

(a) a complete and thorough explanation and justification of all changes to the utility's most recent long-term resource plan and three year action plan, including how the utility has responded to all commission written comments;

(b) a statement explaining whether the application pertains to a power purchase agreement with an existing generating resource, a lease or acquisition of an equity interest in a new or existing generating resource, or a power purchase agreement for which approval will result in construction of a new generating resource;

(c) testimony and supporting work papers describing the resource and stating the facts (not conclusory statements) that show that acquiring the resource is in the public interest and is consistent with the requirements in 69-3-201 and 69-8-419, MCA, the utility's most recent long-term resource plan (as modified by (2)(a)), and these rules;

(d) testimony and supporting work papers demonstrating the utility's estimates of the cost of the resource compared to the cost of each alternative resource the utility considered and all relevant functional differences between each alternative;

(e) testimony and supporting work papers demonstrating the implementation of cost-effective carbon offsets for a electricity supply resource fueled primarily by natural or synthetic gas constructed after January 1, 2007;

(f) testimony and supporting work papers demonstrating the capture and sequestration of 50% of the carbon dioxide produced by a electricity supply resource fueled primarily by coal constructed after January 1, 2007;

(g) a copy of the proposed power purchase agreement, including all appendices and attachments;

(h) a copy of any request for proposals issued in connection with acquisition of the electricity supply resource;

(i) testimony and supporting work papers comparing all bids received in connection with any request for proposals with respect to price and nonprice factors;

(j) testimony and work papers describing all due diligence and bid evaluation in connection with any request for proposals, including the ranking of bids and reliance on management judgment;

(k) thorough explanation and justification for any terms, other than price, quantity, and contract duration, in a power purchase agreement for which the utility is requesting approval;

(l) a complete description of each aspect of the resource for which the utility requests approval; and

(m) testimony and supporting documentation describing all pre-filing communication.

History: NEW, 2003 MAR p. 2894, Eff. 12/25/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, 69-8-419, MCA; IMP, 69-8-403, 69-8-419, MCA;

RULE 38.5.8229. CONSULTANT FEES

(1) When the commission engages independent consultants or advisory services to evaluate a utility's resource procurement plans and proposed electricity supply resources pursuant to 69-8-421, MCA, the commission will charge the utility a fee commensurate with the costs of the consultant or advisory services. The utility, at the commission's direction, will deposit the fee into the commission's account in the special revenue fund pursuant to 69-8-421, MCA. The initial fee charged to the utility will be based upon the commission's estimate of costs for the consultant or advisory services. The commission may revise the fee amount as the actual costs become known.

History: NEW, 2003 MAR p. 2894, Eff. 12/25/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Note: 69-8-403, MCA; IMP, 69-1-114, 69-8-421, MCA;

Appendix E

NorthWestern Energy | Efficiency Plus

REQUEST FOR PROPOSALS

To Provide Evaluation Services for:

- End-use and Load Profile Study (Electric & Natural Gas)
- Electric Energy Efficiency Potential Assessment
- Electric Energy Efficiency Supply Curve Analysis
- Electric Demand Response Potential Assessment

Issued: September 7, 2022

Due: October 14, 2022

REQUEST FOR PROPOSALS
ENERGY END-USE AND LOAD PROFILE STUDY,
ELECTRIC ENERGY EFFICIENCY POTENTIAL ASSESSMENT WITH SUPPLY CURVE ANALYIS, AND
ELECTRIC DEMAND RESPONSE POTENTIAL ASSESSMENT

A. INTRODUCTION

NorthWestern Energy (NorthWestern) is seeking expert assistance to identify and characterize the remaining, achievable, cost-effective electric energy efficiency potential in NorthWestern's Montana electric supply territory, to quantify the amount of electric energy usage savings achievable through energy efficiency programs, and to quantify the amount of demand response savings achievable through demand response programs.[33,34,35] Assessment of achievable electric energy efficiency potential and demand response potential requires a detailed understanding of the energy end-use characteristics of customers in the NorthWestern electric and natural gas supply territories in Montana.[36] Specifically, NorthWestern requests consideration of unique aspects of its service territory including variations in climate (cold, dry climate with pockets of summer A/C) between eastern Montana

33 For purposes of this assessment NorthWestern's Montana electric supply territory is defined as those customers who take electric supply (formerly called default supply) service from NorthWestern. Generally, such customers are residential and General Service (small to large commercial, and small industrial) in nature. Other customers, primarily industrial in nature, are located within NorthWestern's electric service territory and take electric delivery services from NorthWestern, but do not take electric supply service. Only those customers who take electric and natural gas supply service from NorthWestern are included in this assessment.
34 NorthWestern's energy efficiency programs currently include both Demand Side Management (DSM) and Universal System Benefits (USB) programs as summarized on Appendix 1.
35 NorthWestern's energy efficiency programs currently include both Demand Side Management (DSM) and Universal System Benefits programs as summarized on Appendix 1.
36 For example, NorthWestern has significant cooling loads in eastern Montana (e.g., Billings, Great Falls, Havre, and Colstrip), yet the state is generally a heating climate without much humidity. Hence, state climate averages do not reflect differences within NorthWestern's service territory. Moreover, few high rise buildings exist with large HVAC potential (either residential or commercial). Few buildings are greater than ten stories or larger than 100,000 sq. ft.

and western Montana as well as influences on end-uses due to the financial incentives from other utilities' (e.g., rebates for natural gas conversion to electricity). Overall, the purpose of the tasks shown herein is to acquire data needed to inform energy efficiency and demand response programs to be influenced by a representative cross-section of housing and commercial building stock tied back to the end-use study.

This is a three-part evaluation. In order to determine the achievable electric energy efficiency in NorthWestern's Montana electric supply territory, first perform an end-use and load profile study and determine the energy-efficient measures to be addressed in this evaluation. End-use energy sources in part one of the evaluation shall include but should not be limited to electricity, natural gas, propane, fuel oil, wood, and renewable energies. In the second part of the evaluation, compare the costs and savings of energy-efficient measures relative to standard equipment and practices to determine what electric energy efficiency is technically feasible, economically feasible, and achievable in NorthWestern's electric supply market, including efficiency supply curves, for a range of avoided costs. In the third part of the evaluation, compare the costs and savings of demand response measures relative to standard practices to determine what electric demand response is technically feasible, economically feasible, and achievable in NorthWestern's electric supply market for a range of avoided costs.

Considerations in the evaluation shall include, but should not be limited to, impacts to utility costs, impacts to consumers, and opportunities for reduction in energy consumption or demand. To the extent it relies on experience from other jurisdictions, the analysis should account for unique characteristics of NorthWestern's Montana service territory, including regulatory structure, demographics (rural lagging market), growth and development, climate, end-uses, and overall electric consumption levels.

NorthWestern is administering this Request for Proposals (RFP) and will serve as the point of contact with bidders. **Any inquiries or correspondence regarding this RFP should be directed to NorthWestern staff.** NorthWestern contact information is provided in Section F of this RFP.

NorthWestern prefers and bidders are strongly encouraged to provide responses encompassing the entire scope of services; however, consideration will be given to bids on specific deliverable tasks. The selected contractor(s) should be available to start immediately upon execution of a contract. **Proposals are due by 5:00 P.M. Mountain Time on Friday, October 14, 2022.**

Background

NorthWestern Energy is an investor-owned utility serving electric and natural gas customers in the states of Montana, South Dakota, and Nebraska. The scope of this Request for Proposals relates only to the Montana electric and natural gas supply territories supported through NorthWestern's electric and natural gas supply portfolios

In Montana, NorthWestern provides electric service in 208 communities across approximately 24,996 miles of overhead and underground transmission and distribution lines covering approximately 73 percent of Montana's land area. The total control area peak demand was approximately 1,909 megawatts (MWs) on July 27, 2021. NorthWestern's control area average demand for 2021 was approximately 1,321 MWs per hour for the year on average, with total energy delivered of more than 11.57 million MWhs, for year ended December 31, 2021. NorthWestern also provides natural gas service in 118 communities with 7,111 miles of underground transmission and distribution natural gas lines throughout Montana. NorthWestern's electric utility service includes the largest communities excluding Kalispell and the natural gas service includes the largest communities excluding almost all of Billings and Great Falls.

In NorthWestern's Montana service territory, legislation was enacted in the late 1990's to allow customers to make arrangements to secure their electric power and natural gas energy supply from the competitive markets on a limited basis. This resulted in the largest electric customers (e.g., primarily industrial customers and one city/school district) moving to competitive supply markets with limited movement by smaller commercial electric customers. NorthWestern retained the obligation to provide electric supply to those customers who did not, or could not, elect electric choice. On October 1, 2007, state legislation was enacted that effectively prevented further movement of NorthWestern's customers away from NorthWestern as the supplier. Most natural gas industrial, large commercial including healthcare, state and local government, public school, and university customers buy their natural gas energy supplies from the competitive markets with limited other participation in the commercial sector and minimal residential customer participation in natural gas supply choice. NorthWestern secures it's natural gas supply primarily through contracts and spot market purchases and its electrical energy supply through a combination of owned generation, and purchased generation. Details on NorthWestern's Montana supply portfolio can be found in its annual publication Montana At A Glance.

NorthWestern has continuing responsibility to secure electric and natural gas supply for customers that have not moved to competitive supply markets. NorthWestern currently provides natural gas and electric energy supply, transmission, and distribution services to the following mix of customers in its Montana service territory:

Electric	Count	Natural Gas	Count
Residential	311,922	Residential[37]	179,637
Commercial	71,605	Commercial	24,927
Industrial	77	Industrial	229
Other[38]	5,915	Other[39]	1,045

The selected bidder (or team of bidders) will provide evaluation services for energy end-use and load profiles throughout NorthWestern's Montana electric and natural gas supply territories and characterization of electric energy efficiency potential throughout the electric supply territory. A map of the NorthWestern electric service territory in Montana is included as Appendix 3. A map of the NorthWestern natural gas service territory in Montana is included as Appendix 4. The selected bidder should be prepared for travel within the state as necessary to coordinate evaluation efforts statewide.

NorthWestern has been conducting energy efficiency programs since the early 1980's to help customers save energy and improve efficiency. In 2004, NorthWestern expanded its energy efficiency programs as part of its effort to secure supply resources for electric and natural gas supply customers. Current energy efficiency programs are marketed under the NorthWestern Energy sub-brand of Efficiency Plus (E+) name and include offerings for all classes of electric and natural gas customers in the NorthWestern Energy Montana service territory.

In addition to funding energy efficiency programs through its supply portfolios, NorthWestern operates certain energy efficiency and renewable energy programs that are funded through a public purpose charge, the Universal Systems Benefits (USB) Charge. While USB electric offerings cross all customer sectors, natural gas offerings are limited to residential and low income programs. Similar energy efficient supply and USB programs do not exist in NorthWestern's South Dakota and Nebraska service territories.

NorthWestern uses third-party implementation contractors to operate its programs. Contractor services include operation and administration, direct interface with program participants, technical assistance, some marketing and promotion, limited distribution and/or installation of measures, inspection/verification of installed measures, and collection and maintenance of program records and databases about participants, installed measures, estimated energy savings, reported energy savings, program rebates, and other related costs. The primary public promotional messages for E+ offerings are developed and implemented through NorthWestern Energy rather than by the implementation contractors.

A basic overview of NorthWestern's existing programs is shown in Table 1. Appendix 1 provides a more detailed description of each program. These descriptions include information about program concepts, target markets, customer eligibility, and products and services provided. Additional information about NorthWestern and its energy efficiency programs is available on the NorthWestern Energy website.

Table 1: NorthWestern Energy Program Groups

Program Groups	Customer Sector
Group 1: Electric Supply Programs	

37 Customer counts for propane customers are included in natural gas totals. Commercial and Residential Propane customers account for approximately 600 customers.
38 Electric "Other" customer category includes electric lighting, irrigation, interdepartmental & Yellowstone Park customers.
39 Natural gas "Other" includes governmental and interdepartmental customers. In Billings and Great Falls, there is some limited natural gas service in surrounding communities; check for availability. Only those customers taking natural gas supply service from Northwestern are included in this assessment.

Program Groups	Customer Sector
E+ Home Lighting Rebate Program	Residential
E+ Residential Electric Savings Program	Residential
E+ Residential New Construction Program	Residential
E+ Commercial Lighting Rebate Program	Commercial/Industrial
E+ Commercial Electric Rebate Program	Commercial/Industrial
E+ Business Partners Program	Commercial/Industrial
E+ Electric Motor Rebate Program	Commercial/Industrial
Northwest Energy Efficiency Alliance (NEEA) (Savings claimed by NWE)	All
Group 2: USB Programs	
E+ Home EnergyCheck (natural gas and electric)	Residential
E+ Irrigator Program (electric)	Agricultural
E+ Free Weatherization Program (natural gas and electric)	Residential
E+ Renewable Energy (electric)	Commercial
Group 3: Natural Gas Supply Programs	
E+ Residential Natural Gas Existing Rebate Program	Residential
E+ Residential Natural Gas New Construction Rebate Program	Residential
E+ Commercial Natural Gas Existing Rebate Program	Commercial/Industrial

NorthWestern must acquire all cost-effective energy efficient resources for the electric and natural gas supply portfolios. USB programs deliver public purpose benefits consistent with statute, administrative rule, and regulatory orders and are not held to the same cost-effectiveness standards as DSM.

B. DESCRIPTION OF WORK TO BE PERFORMED

Description of Tasks

The tasks listed below provide a general description of the type of work that the selected contractor will be asked to perform. Bidders should explain how they intend to complete each task and provide a timeline for each expected deliverable. Bidders are encouraged to propose additional tasks deemed necessary to complete the work in an efficient and effective manner.

Task 1: Project Plan
Task 2: Project Management
Task 3: Energy End-use and Load Profile Summary (Electric and Natural Gas)
Task 4: Electric Energy Efficiency Potential Assessment
Task 5: Electric Energy Efficiency Supply Curve Analysis
Task 6: Electric Demand Response Potential Assessment
Task 7: Comparison Study to the Northwest Power and Conservation Council's (Council's) 2021 Power Plan
Task 8: Comparison Study to the 2015-2016 NorthWestern Energy Assessment of Energy Efficiency Potentials
Task 9: Project Final Report
Task 10: Additional Support Activities

Deliverables

Eight distinct deliverables (shown in underlined bold here) will be provided that describe and document the results of evaluation activities.

Deliverable 1, also Task 1 described below, develop a comprehensive **Project Plan** that includes a description of the work to be done for Tasks 2, 3, 4, 5, 6, 7 and 8.

Deliverable 2, also Task 3 described below, prepare a comprehensive **Energy End-use and Load Profile Summary** tabulating the energy end-use profiles including supporting data and calculations to inform Tasks 4 and 5.

Deliverable 3, also Task 4, prepare a comprehensive **Energy Efficiency Potential Assessment.**

Deliverable 4, also Task 5, prepare a comprehensive **Electric Energy Efficiency Supply Curve Analysis.**

Deliverable 5, also Task 6, prepare a comprehensive **Demand Response Potential Assessment.**

Deliverable 6, also Task 7 described below, prepare a comprehensive **Comparison Study to the Council's 2021 Power Plan** comparing the objectives, methodologies, and measure input data from Tasks 3, 4 and 5 to explain potential similarities and differences.

Deliverable 7, also Task 8 described below, prepare a comprehensive **Comparison Study to the 2015-2016 NorthWestern Energy Assessment of Energy Efficiency Potentials** comparing the objectives, methodologies, and measure input data from Tasks 3, 4 and 5 to explain potential similarities and differences.

Deliverable 8, also Task 9, described below, prepare a comprehensive **Project Final Report** describing the work performed, research methodologies and instruments used, supporting data and calculations, and presentation of findings and recommendations.

Task 1: Project Plan

Develop a comprehensive plan to cover all tasks associated with the management (Task 2) of evaluation of electric and natural gas end-use and load profile study (together Task 3), electric energy efficiency potential (Task 4), electric energy efficiency supply curve analysis (Task 5), and electric demand response assessment (Task 6). This will involve the following:

- Work closely with NorthWestern to identify existing data, records, previous studies and documents that relate to energy efficiency programs offered to its customers.
- Identify other research needs related to the analysis and assessments.
- Describe how energy end-use data, electric energy efficiency measure, and demand response data will be collected, organized, compiled, and reported.
- Prepare an evaluation timeline consistent with the goal of fulfilling contract obligations by no later than three weeks after contracting.

Task 2: Project Management

Designate a project manager to be NorthWestern's key contact and maintain sufficient staff resources to effectively and efficiently complete the work on the timeline developed in Task 1. The project manager must:

- Maintain direct communication with NorthWestern.
- Interface with NorthWestern energy efficiency program implementation contractors.
- Comply with the timeline developed in Task 1.
- Provide quality control and assurance that work conforms to the scope of analysis and assessment work.
- Provide monthly project status reports including:
    - ↳ Current progress and results to date.
    - ↳ Tasks to be accomplished in the next month/near future.
    - ↳ Problems/issues that have been encountered.
    - ↳ Items that require NorthWestern action or approval.

Task 3: Energy End-use and Load Profile Study

As an initial research step, a comprehensive study of energy use at the end-use level for residential, commercial, and industrial customer sectors will be performed. End-use energy sources in this study shall include but not be limited to electric, natural gas, propane, fuel oil, wood, and renewable energies. Perform the necessary fieldwork and follow-up analysis to fully describe the energy usage in the NorthWestern Montana electric and natural gas service territory.

Assessing the potential for electric energy efficiency improvements involves comparison of the consumption of existing, base-case building stock and technologies with those of more efficient alternatives. This, in turn, will require a relatively detailed understanding of the energy usage characteristics of the customers in NorthWestern's electric and natural gas supply territory in Montana. The purpose of this end-use study is to inform the other research, findings and conclusions in this scope of work, and also to provide NorthWestern with useful information for supply load forecasting in the future. This work will result in the following at a minimum:

- Capture and organize detailed building systems data, building geometry, floor stocks, fuel shares, energy usage, thermal shell characteristics, equipment inventories, operating schedules, and other residential, commercial, and industrial building and equipment characteristics. Assess number of buildings by construction type and customer segment. This work will be completed through secondary research (existing customer information) and primary research (customer, contractor, and vendor surveys and customer site inspections). The number of on-site inspections will be determined at a later time, based on customer segment sizes received from NorthWestern Energy.
- Inventory and profile energy end-uses, equipment/appliance saturations, and energy intensities for electric, natural gas, and other energies (Energy Utilization Index (EUI) or other measure) by building construction type and customer segment. Evaluate market shares of key electric and natural gas consuming equipment and market shares of energy efficient technologies and practices. Include lighting saturation data for sockets for energy efficient types. This work will be completed through secondary research (existing customer information, ENERGY STAR data, and other sources) and primary research (customer, contractor, and vendor surveys and customer site inspections). The number of on-site inspections will be determined at a later time, based on customer segment sizes received from NorthWestern Energy.
- Create end-use load profiles, energy consumption estimates, and capacity contribution by end-use for the residential, commercial, and industrial (supply customers) market segments and calibrate to historical consumption data. Evaluate end-use consumption load patterns by time of day and year (e.g., load shapes).
- Identify and assess with research the customer's willingness to participate with respect to free riders and spillover. Provide informative high impact measure sensitivity to free rider and spillover evaluation results based on NorthWestern's current program designs.
- Specify whether heating load profiles provide granularity differentiating between customers in towns and rural areas and whether this is contemplated to have material differences.

Tabulate the results of work from this task and present data by residential, commercial, and industrial end-use, segment and in aggregate. Provide sectors and categories similar to those evaluated in the 2015-2016 NorthWestern Energy Assessment of Energy Efficiency Potentials and the 2014 Natural Gas Energy Efficiency Market Potential Study. Compile energy use profiles (hourly, monthly, and seasonal) and peak load for both electric and natural gas usage (including class contribution to system peak by season). Use results from this task to support analysis, findings and conclusions of other tasks (e.g., Tasks 4, 5 and 6) as relevant and appropriate. Although data collected in Task 3 will be used to support work on other tasks in this evaluation, Task 3 must be complete enough to stand-alone. While work on Task 3 may be performed in parallel with work on other tasks, be aware that completion of this assessment as a whole depends on NorthWestern approval of the Task 3 results. Send the draft final energy end-use and load profile study (Task 3) to NorthWestern for review and feedback before issuing the draft project final report (Task 9), which includes all tasks.

Task 4: Electric Energy Efficiency Potential Assessment

This assessment consists of a number of subtasks: development of electric efficiency measure data, development of other required data inputs, and modeling of electric energy efficiency potential following industry standards for energy efficiency evaluation.

Measure Data Development

Develop all the necessary energy efficiency measure data required for the project. Energy efficiency measure data elements include costs, savings, expected useful life, current measure saturations, and feasibility of installation.

Energy Efficiency Measure List

Establish a list of individual base-case and change-case energy efficiency measures or opportunities to be addressed in the assessment. Measures from NorthWestern's current energy efficiency programs shall be included.

Send the draft final list of energy-efficiency measures to NorthWestern for review and feedback. NorthWestern will likely add to the list of measures to be evaluated. The list will address measures that are most appropriate for NorthWestern's electric supply territory in Montana. The lists will contain:

- A detailed description, with qualifications, for each base-case and change-case measure.
- Measure lives in years. The number of years the measure is expected to provide savings.
- Measure costs, installed cost of measure, incremental cost to base-case or full cost as applicable. Each measure cost will be designated as increments or full cost.
- Measure savings in units applicable to a prescriptive rebate or custom incentive program
- A designation indicating if the measure more applicable to a prescriptive rebate or custom incentive program.
- Measure capacity contribution on peak for applicable measures.

Information on applicability or longevity as the measure relates to code change or Federal standards (Note: Current code in Montana is the 2021 IECC with amendments and/or ASHRAE 90.1-2010.)

Energy Efficient Measure Costs, Savings, and Capacity Contributions

Estimating the potential to acquire electric energy efficiency supply requires a comparison of the costs and savings of energy efficiency measures relative to standard equipment and practices. Standard equipment and practices are often referred to in energy efficiency analyses as base-cases whereas the energy efficiency measures are considered the change-cases. The base-cases will be informed by the energy end-use and load profile study completed in Task 3.

Develop estimates of energy efficiency measure savings compared to base-case equipment usage. Review and adjust all measure cost and savings data to ensure that it reflects best available information and costs pertinent to NorthWestern's electric service territory. Investigate the use of targeted simulation modeling, if necessary, to improve the accuracy of the estimated impacts of selected measures.

Provide a written description of all base-case equipment and practices and describe why each item was chosen to best represent the base-case. The same detail shall be provided for the energy efficiency measures or "change-case". Show all calculations used to determine energy saving potential and provide all assumptions and data used in the calculations. Provide an extract of all relevant data inputs and outputs used for the project in a form such as Microsoft Excel that readily facilitates data transfer.

Development of Other Required Data Inputs

Key additional data components include:

- Load growth
- Avoided cost forecasts
- Inflation rate assumptions
- Discount rate assumptions
- Current and forecasted retail electric prices
- Current and forecasted costs of electricity generation
- Estimates of potential benefits of reducing electric supply
- Estimate non-energy benefits (costs and benefits that are not part of the costs, or the avoided cost, of direct energy efficiency savings, including natural gas savings
- Provide non-energy benefits (NEBs) for unit energy savings (UES) measures where applicable. NEBs are those

costs and benefits that are not part of the costs, or the avoided cost, of direct energy efficiency savings, including natural gas savings. Multiple non-energy benefits include lower home maintenance costs, improved air quality and less sick days for adults and children, greater resiliency, and lower emissions.

- Quantify effects of codes and standards at the state and federal level.
- Current program data (e.g., budgets and accomplishments)
- Overview of represented claimed savings of utilities that have implemented behavioral programs following evaluation, measurement, and verification (EM&V)
- Provide preliminary estimates of the impacts on energy efficiency savings of the Inflation Reduction Act. (This is a placeholder for inserting further details upon availability in the coming weeks prior to distribution to the bidders list.)

Work with NorthWestern to access and/or develop these data elements. Some of these data may be readily available, but other components (such as avoided cost forecasts and rate forecasts) may be less available or in need of further adjustment in order to integrate them with the modeling structure.

Sources of data for UES measures, either as an aggregated compilation or by specific measure, should be specified. Also include the efficacy of any that are sensitive to cold and/or hot climates, either due to temperature or standard installation differences from milder climates (e.g., physical location of heat pump water heaters in residential premises). Source data should be articulated with how to leverage data beyond regional averages and what is different from other public data sources (e.g., MN, CO, RTF, etc.).

Montana has an average population density of 7.5 people per square mile. While NorthWestern serves most of the larger communities, it does have geographically dispersed customer base spread over a relatively large area. This should be addressed to determine whether this effects the potential for achieved energy efficiency penetration due to fewer retail stores, fewer consolidated media outlets for marketing, and other factors. If the potential penetration for energy efficiency measures appears to be lessened compared to utilities serving more densely populated communities (population/sq. mi) within smaller geographic spreads (distance between homes/businesses/retailers/trade allies), determine if alternative program delivery actions alleviate some or all of this decrement.

Energy Efficiency Potential Assessment Modeling

Determine technical, economic, and achievable potential for energy efficiency for NorthWestern's electric supply customers in Montana. Develop and provide energy efficiency potential estimates for new and existing construction by building type and customer segment. Develop forecasts for potential that integrate projected changes in the marketplace, reflecting both changes in energy usage patterns and changes in energy efficiency technologies.

Technical Potential

Technical potential refers to the amount of electric energy savings that would occur with the complete penetration of all energy efficiency measures analyzed in applications where they were deemed technically feasible from an engineering perspective. Match and integrate data on energy efficiency measures to data on existing building characteristics to produce estimates of the technical potential of electric energy savings for each measure.

Economic Potential

Economic potential is typically used to refer to the technical potential of those energy efficiency measures that are cost-effective when compared to either supply-side alternatives or the price of energy. Economic potential takes into account the fact that many energy-efficiency measures cost more to purchase initially than do their standard-efficiency counterparts.

To estimate economic potential, it is necessary to develop a method by which it can be determined that a measure or program is economic. There is a large body of literature that debates the merits of different approaches to calculating whether a public purpose investment in energy efficiency is cost-effective. Tests that have been used in analysis of program cost-effectiveness by energy efficiency analysts include the total resource cost, utility cost, ratepayer impact, and participant tests. Based on the results of the cost-effectiveness screening, measures are either eliminated because they fail the minimum cost-effectiveness criteria, or they are selected for further analysis in programs.

Given the magnitude of energy savings for the particular technology, compare the costs and benefits of installing each measure. Match and integrate data on existing building characteristics to cost and benefits of each energy efficiency measure to produce indicators of costs from different viewpoints (e.g., utility, societal, and consumer). Compare estimates of electric energy efficiency resource costs to estimates of other resources such as building and operating new power plants.

Achievable Potential

Estimate the maximum achievable program and naturally occurring potential for electric energy efficiency and calibrate achievable and naturally occurring potential to recent program and market data.

Gather and develop estimates of program costs (e.g., for administration and marketing) and historic electric energy efficiency program savings. Develop estimates of customer adoption of energy-efficiency measures as a function of the economic attractiveness of the measures, barriers to their adoption, and the effects of program intervention.

Describe impacts of inflation on cost effectiveness and potential savings:

- Incorporating the recent (2022) high inflation rate environment, and
- Estimating future kilowatt hour (kWh) savings potential over the next ten years under:
    - ↳ Historic inflation rates and,
    - ↳ Continued higher inflation rates

Describe how the pandemic has effected kWh savings in the past three years as it relates to onsite installations, consumer-shopping patterns, and supply chain issues. Provide estimated changes to future kWh savings with an assumption of continuing pandemic issues including, but not limited to, the issues included above.

Assess achievable electric energy efficiency potential associated with alternative program scenarios. These program scenarios should address factors such as varying incentive levels and delivery mechanisms (rebates, direct install, and information only). Adjust the customer forecast such that the electric energy efficiency forecast only reflects the potential for NorthWestern's electric supply customers. Compare the savings and the program costs with the currently funded programs.

Task 5: Electric Energy Efficiency Supply Curve Analysis

Rerun the Electric energy efficiency measure screening analysis described in Task 4, for a range of avoided electric costs as specified by NorthWestern. Provide updated benefit-cost ratios for energy efficiency measures for each of the different electric avoided costs.

The technical and economic potential analysis will include basic results for each listed energy efficiency measure and associated cost-effectiveness parameters that relate to each avoided cost scenario. The electric energy efficiency assessment results will include tables of net savings (energy and capacity) and program costs by scenario. Additional work will include set up of program parameter files for each scenario, running models for each scenario, and developing results tables for each scenario.

Task 6: Electric Demand Response Assessment

Determine electric potential demand response for NorthWestern's Montana service territory to include methodology description for measure selection and analysis, end-effects analysis, summary resource potential by segment, construction type, and year with measure list comparison to the Council Plan. Include level to indicate how much capability in megawatts is available during winter and summer peak periods.

As background, NorthWestern's Montana Metering Project has embarked on upgrades of existing one-way meters to two-way meters that communicate over a secure wireless network. The meters cannot communicate with electrical appliances, electrical equipment, or electrical devices within a customer's residence or business, and they cannot estimate or record electrical energy usage by types of appliances, electrical equipment, or electrical devices. They are not "advanced metering devices" as defined by Montana Code.[40] These two-way meters are phased in over 590,000 meters/modules to be replaced with 90% installed in Phase 1, (called Combo Areas, MESH Network). Four percent are to be replaced in Phase 2 (Difficult Combo Areas with MESH, Cellular, PLC, or Mobile) and 6% to be replaced in Phase 3 (for natural gas only areas with STAR, Cellular, Mobile). This is a networked solution that covers approximately two-thirds of Montana. Benefits include two-way, on-demand network, move in/move outs, meter disconnects/reconnects, 99% read rates, events (e.g., outages, voltages, etc.), and is intended to be foundational technology for the future. Much of the technology is still being developed by the metering vendor and will require system and endpoint upgrades (specifically demand controls, home areas network, street lighting). The meters are not currently capable of estimating and/or recording electrical energy usage by type of appliances within the home or business or programmed to communicate with any home device. More information about NorthWestern's metering project can be found here.

NorthWestern requests several factors be addressed including, but not limited to, the following.

Given the status of NorthWestern's metering infrastructure, the Company is interested in potential demand response programs that can be phased in over time and, more specifically, what is contemplated to be such an approach based on future modifications or needed expansion of the existing metering infrastructure.

NorthWestern requests to what extent, if any, can the Energy Supply Department rely on proposed or potential demand response measures for planning purposes (with known firm reduction in customer usage during peak periods). NorthWestern also seeks affirmation that actions such as calls for voluntary customer curtailment are considered demand response but are operational actions and may not be counted on by the Energy Supply Department for planning purposes.

NorthWestern requests determination if certain activities to-be-specified in this Demand Potential Assessment can be achieved in an early time horizon.

NorthWestern requests review of its assigned capacity valuation relating to various UES's.

NorthWestern is interested in information regarding national best-in-class demand response programs in recent years to include references to such programs as Peak Reward Credits or their equivalent, curtailable commercial contracts, and relevant recent experiences from states experiencing issues specifically those with similar market conditions with similar peak day events.

As stated in Section B, Description of Work to be Performed, bidders are encouraged to propose additional items deemed necessary to complete this work. NorthWestern recognizes its informational needs may require differing levels of activity by bidders. Responders may provide cost estimates by certain activities in addition to a standard bundle. This à la carte approach will provide the Company with the ability to choose options that are cost-effective.

Task 7: Comparison Study to the Council 2021 Power Plan

Review the energy efficiency assessment embodied in the Northwest Power and Conservation Council's (Council) 2021 Power Plan and related materials to gain an understanding of the methodology and results. Also compare the Council's energy efficiency targets for NorthWestern's service territory with the results of the Electric Energy Efficiency Potential Assessment currently being conducted in Task 4.

The review of the Council's assessment will include the following:

- General review of the 2021 Plan including the background methodology and overall findings.
- Examine supply curves and other work completed by Council to determine how the energy efficiency targets were produced.
- Compare and contrast the work completed by the Council and its applicability to NorthWestern with current work being completed in Task 4 (Electric Energy Efficiency Potential Assessment). Specifically, the following is requested.
  - ↳ How do the priorities and target measures of the Council's Plan align with the potential in NorthWestern's service territory?
  - ↳ How much of the regional energy efficiency targets are anticipated to come from customer education or customer behavioral changes as opposed to equipment based conservation?
  - ↳ How is NorthWestern's electric service area defined in the 2021 Power Plan compared to the actual NorthWestern electric service area?
  - ↳ Does the Power Plan anticipate energy efficiency savings from future improvements in codes and standards? If yes, what, when and how much?
  - ↳ How does the regional end-use load research study, funded by the Council and others, apply to NorthWestern's service territory?

Task 8: Comparison Study to the 2016 NorthWestern Energy Assessment of Energy Efficiency Potentials

Review the supply curves developed in Task 5 as compared to the supply curves developed in the 2015-2016 NorthWestern Energy Assessment of Energy Efficiency Potentials including water heater saturation, space heat saturation, and choice versus non-choice.[41] Provide explanations of all differences in methodologies and technologies that result in substantial differences between the two studies. Assess the similarity and differences in achievable electric energy efficiency potential associated with alternative program scenarios. Consider the factors such as varying incentive levels and delivery mechanisms (rebates, direct install, and information only) and provide a clear comparison of the findings. Compare the savings and the program costs with the currently funded programs.

Task 9: Reporting

The project work in the previous tasks will be documented in a draft and final report. Prepare a high-quality, detailed, and comprehensive report, including an executive summary that describes and documents the evaluation of electric energy efficiency potential and presents findings and recommendations of the multiple analysis scenarios in a clear, understandable manner. The project final report, in hard copy and electronic form, will include a summary presentation that is accessible and understandable by the general public, legislature, utility personnel, advisory committees, and the Montana Public Service Commission. Present the project approach and results to NorthWestern staff, and others, as part of the finalization of the work.

In addition to a final project report, provide memorandums documenting the results of the evaluations. Provide an extract of all relevant data inputs and outputs used for the project in a form such as Microsoft Excel that readily facilitates data transfer.

Work closely with NorthWestern regarding the layout, organization, and task completeness of this report prior to its completion. It is expected this report will be used in contested regulatory proceedings.

Task 10: Additional Support Activities

Support services will be directed by NorthWestern. Such activities may include, but are not necessarily limited to, developing testimony and exhibits to support the Assessment results, assisting with responding to discovery, participating in pre-hearing preparation activities, reviewing of intervener testimony and participating in development of related discovery and cross examination, and/or participation in the development of post hearing briefs.

C. GENERAL PROPOSAL REQUIREMENTS

Bidders are strongly encouraged to follow the contents of this RFP closely when assembling proposals. The proposal shall include a statement affirming the bidder's intention to conduct an independent, objective, and

40 Montana Code Annotated (MCA) 69-4-1001 was established after NorthWestern received approval from the PSC to invest in its metering programs in Montana. This states that a utility cannot control end-uses on the customer side of the meter; hence NorthWestern's metering project focuses on the items described.

41 This is to determine what differences have occurred in the methodology between the 2016 assessment and the current analyses. As one example, this is intended to address, in essence, how many water heaters have the potential to be actionable for NorthWestern's associated programs.

unbiased third-party analysis that can, if needed, be used in a proceeding before the MPSC.

Proposals should include the following information:

- State the full name and address of the organization and, if applicable, subcontractors that will perform, or assist in performing, the work. Include a brief description of the organization history, structure, and size and a description of the company's background and any relationship to the utility industry.
- Describe the project approach and scope of work. Describe in narrative form the plan for accomplishing the tasks outlined in the RFP, including technical approaches and an explanation of why the proposed approach is superior to other approaches. Provide statements and discussion of anticipated major difficulties and problem areas, with potential or recommended approaches for their solution.
- Provide a list of all project deliverables by task (see Proposal Deliverables below).
- Include a breakdown by task of resources required from NorthWestern – office space, data sets, etc.
- Provide a breakdown by task of all staffing and resource requirements. Indicate the number of hours allocated to each task for each project and which individual will complete the tasks. Also include an explanation of why the number of hours proposed is both necessary and sufficient to complete the task.
- Identify all staff and subcontractors that will perform work on this project. Include a list of key personnel by task with biographical information. Indicate the role of each team member on this project as well as which team members will be based in Montana. If some of the people have not been identified at this time, at a minimum, describe the different job positions, functions, and roles. Each organization submitting a proposal under this RFP shall have demonstrable knowledge, skills, and experience as it relates to the required work. The proposal must identify all persons that will be employed in the proposed work by skill and qualifications and identify key personnel by name and title and provide a resume for each. Subcontractors must be listed, including the firm name and address, contact person, and complete description of work to be subcontracted. Include descriptive information concerning subcontractor's organization and abilities. References for the lead contractor and any subcontractors included in the proposal should be provided.
- Include the proposed schedule and/or work flow chart. Indicate key tasks and timelines for completion of them. This project must be completed in its entirety and a final report submitted to NorthWestern by July 31, 2023. Include a scheduling proposal and work plan specifying the date upon which the applicant would be ready to commence work, and any other appropriate scheduling of specific tasks. Also provide an explanation of all known or probable scheduling constraints, or limitations on staff availability, within timeframe of the project. Include a statement that bidder is willing and able to provide ongoing regulatory support following conclusion of the project as necessary, to be billed on the basis of reasonable time, materials and travel expenses.
- Provide a cost breakdown for each task for these evaluation services. The preferred compensation method is a fixed fee with a not-to-exceed limit. Provide a projected payment (cash flow) schedule and describe how it is related to the level of effort and deliverable associated with each task. The following cost elements should be included:
- Personnel (position, rate, hours)
- Travel (include mileage rate, lodging, etc.)
- Supplies & materials
- Other (specify)
- Total direct costs
- Indirect costs (may not exceed 24% of direct costs)
- Budget total

In addition, applicants must submit an hourly billable rate in the event they are needed for testimony, discovery preparation and response, brief preparation, rulemaking assistance, and/or other services to be provided following the completion of and in addition to the scope of services detailed above.

- Provide proof of qualification/references from successful projects of a similar nature. Proposals should demonstrate significant, in-depth knowledge of and experience in conducting end-use/load profile and DSM potential studies.

- Describe the features and benefits of the proposal that may be unique and more desirable than that of the competitors.
- Indicate whether the company is currently certified as a minority or woman-owned business—for reporting purposes.
- Include the names and phone numbers of personnel authorized to negotiate the proposed contract with NorthWestern. All proposals must be signed by a duly authorized representative of the party (or parties) submitting the proposal.
- Include any other information that is believed to be pertinent, but not specifically requested elsewhere in this RFP.

Proposal Deliverables

Eight distinct deliverables will be provided that describe and document the results of evaluation activities. The eight deliverables are composed of ten tasks as follows:

Task 1: Project Plan
Task 2: Project Management
Task 3: Energy End-use and Load Profile Summary (Electric and Natural Gas)
Task 4: Electric Energy Efficiency Potential Assessment
Task 5: Electric Energy Efficiency Supply Curve Analysis
Task 6: Electric Demand Response Potential Assessment
Task 7: Comparison Study to the Northwest Power and Conservation Council's (Council's) 2021 Power Plan
Task 8: Comparison Study to the 2015-2016 NorthWestern Energy Assessment of Energy Efficiency Potentials
Task 9: Project Final Report
Task 10: Additional Support Activities

Deliverable 1: Project Plan Provide a description of the work to be done for Tasks 2, 3, 4, 5, 6, 7 and 8. Describe how projects will be monitored and how to ensure any samples are representative of all completed projects. Describe how data will be collected, compiled, and reported. Discuss the recommended approach to this project and provide a timeline for all deliverables. Describe any additional documents that may require review and identify all such documents you anticipate will be provided by NorthWestern.

Deliverable 2: Energy End-Use and Load Profile Study Prepare a comprehensive Energy End-Use and Load Profile Summary for electric and natural gas tabulating the energy end-use profiles including supporting data and calculations to inform Tasks 4 and 5. This deliverable should describe the steps taken to research, profile, and evaluate the energy end-uses of the NorthWestern supply customers in Montana. Samples of data collection forms and discussion of data collection protocol, sampling strategy, samples of sampling instruments used in the study should be included. Describe the key types of data collected for each end-use and for each building type and each sub-sector in the residential, commercial, and industrial customer classes. Describe how findings were calibrated on end-uses to the historical electric and natural gas consumption records of the customer base. Describe how the results of this work inform the electric energy efficiency potential assessment portion of the project.

Deliverable 3: Electric Energy Efficiency Potential Assessment Describe the process used to determine a list of individual electric energy-efficient measures to be considered in the assessment of electric energy efficiency potential across all sectors of NorthWestern's electric supply market to support Task 4. Discuss how costs and savings associated with each measure specific to NorthWestern's electric supply territory in Montana were calculated. Describe data collection protocol and how these activities were integrated with NorthWestern's energy efficiency program implementation contractors. Identify key types of data that was required and how this data was obtained. Discuss the determination of the cost-effectiveness of each measure for different market sectors and different building characteristics. Describe how the results of this work are to be used to make conclusions relative to the potential for energy efficiency in different building types across all NorthWestern electric supply customer segments. Identify and describe the models used, whether energy simulation, economic or other, including strengths and weaknesses specific to this assessment.

Deliverable 4: Electric Energy Efficiency Supply Curve Analysis Describe the methods used to analyze the cost-effectiveness of each energy efficient measure, responsive to Task 5. Discuss the economic tests used to analyze program economics and what avoided costs were considered. Describe how data and how the results of this work were used to make conclusions relative to the potential for energy efficiency in different building types across all NorthWestern electric supply customer segments.

Deliverable 5: Electric Demand Response Assessment Determine electric potential demand response, to support Task 6, for NorthWestern's Montana service territory. To include methodology description for measure selection and analysis, end-effects analysis, summary resource potential by segment, construction type, and year with measure list. Include level to indicate how much capability in megawatts is available during winter and summer peak periods.

Deliverable 6: Comparison Study to the Council 2021 Power Plan Review the DSM assessment embodied in the Northwest Power and Conservation Council's (NWPCC) 2021 Power Plan (NWPCC Regional DSM Assessment or RDA) and other materials developed in relation to the RDA to gain an understanding of the methodology and results. Also compare the NWPCC's DSM targets for NorthWestern Energy's service territory with the results of the Electric Energy Efficiency Potential Assessment currently being conducted in Task 4.

Deliverable 7: Comparison Study to the 2016 NorthWestern Energy Assessment of Energy Efficiency Potentials Review the supply curves developed in Task 5 as compared to the supply curves developed in the 2015-2016 NorthWestern Energy Assessment of Energy Efficiency Potentials. Provide explanations of all differences in methodologies and technologies that result in substantial differences between the two studies. Assess the similarity and differences in achievable electric energy efficiency potential associated with alternative program scenarios. Consider the factors such as varying incentive levels and delivery mechanisms (rebates, direct install, and information only) and provide a clear comparison of the findings. Compare the savings and the program costs with the currently funded programs.

Deliverable 8: Reporting The project work will be documented in a draft and final report. Prepare a high-quality, detailed, and comprehensive report, including an executive summary that describes and documents the evaluation of electric energy efficiency potential and presents findings and recommendations of the multiple analysis scenarios in a clear, understandable manner. The project final report, in hard copy and electronic form, will include a summary presentation that is accessible and understandable by the general public, legislature, utility personnel, advisory committees, and the Montana Public Service Commission. Present the project approach and results to NorthWestern staff, and others, as part of the finalization of the work.

D. EVALUATION PROCEDURE

Successful proposals must include all of the required information outlined above. Proposals will be evaluated based on an assessment of the bidder's ability to provide quality deliverables in a timely and cost-effective manner.

NorthWestern prefers responses encompassing the entire scope of services; however consideration will be given to bids on specific deliverable tasks. The selected contractor should be available to start immediately upon selection of the winning bidder.

NorthWestern will evaluate all proposals received based upon reasonableness of cost, completeness, and quality of the proposal, qualifications of the individuals proposed to perform the work, relevance of previous experience, and any other criteria it deems relevant. Acceptance or rejection of any or all proposals will be NorthWestern's sole discretion. NorthWestern reserves the right (but in no way is obligated) to interview the top prospective candidates to aid in the selection process.

Proposals will be evaluated and the award of the contract will be made based on the following criteria:

- Demonstrated ability to perform scope of work outlined in this document.
- Demonstrated understanding of end-use research and analysis, energy efficient technologies, and NorthWestern customers.
- A clear explanation of the strategy and logic behind the proposed approach.
- Quality of Work Plan, including financial management, including oversight of subcontractor(s) and the ability to deliver work in a timely manner.
- Demonstrated experience completing similar successful projects.
- Cost of the work to be performed as specified in the proposal.
- Demonstrated ability (through examples) to provide clear written reports.
- References.

A short list of bidders will be developed. From those bidders, additional information may be required to demonstrate proof of deliverables such as examples of past reports addressing end-use and load profile studies and energy efficiency potential assessment processes and economic evaluations.

Awarding Projects

NorthWestern reserves the right at its sole discretion to choose not to award this project. NorthWestern reserves the right to reject any and all proposals received as a result of this RFP for any reason, to waive minor irregularities in any proposals received, and to negotiate with any party in any manner deemed necessary to best serve the interests of NorthWestern and its customers.

E. ADDITIONAL PROVISIONS

Evaluation contractors must not be currently employed by any person or company that sells, transmits, or generates electricity in Montana. Identify any other potential conflicts of interest and state the reason(s) why the evaluation contractor believes they would not detrimentally affect performance of the work requested herein and what steps to be put in place to ensure that such detrimental effect does not occur.

NorthWestern reserves the right to approve or reject key personnel both in the proposal selection process and in the on-going performance of the scope of work.

The evaluation contractor must agree to participate in regulatory proceedings, and interactions with NorthWestern's Advisory committees, for an agreed-to pricing. This pricing is not to be included as part of this bid. NorthWestern will pay, as needed, time plus reasonable travel for appropriate individuals on the evaluation team to perform this work.

NorthWestern is not responsible for costs incurred by bidders in preparation of this proposal.

The work described in this RFP will be performed in accordance with NorthWestern general contract standards. A sample copy of the basic agreement that the winning bidder will be required to sign is in Appendix 2.

News releases pertaining to this RFP, contract award, or the project shall **not** be made without prior written approval from NorthWestern.

NorthWestern will pay for actual work performed and expenses incurred under this project up to the specified contract amount. Specific payment provisions will be arrived at upon mutual agreement of the parties. All payments will require the submission of an itemized billing of work performed to date in sufficient detail to justify payment. Reimbursement for time and materials will be by voucher based upon the actual staff time assigned at the rates provided and upon actual costs incurred based upon documentation acceptable to NorthWestern.

All parties submitting proposals shall be Equal Opportunity Employers. During the duration of the performance of this contract, the contractor will be expected to comply with all federal, state and local laws respecting non-discrimination in employment.

All deliverables submitted by the selected contractor shall become the property of NorthWestern.

NorthWestern assumes no liability in any fashion with respect to this RFP or any matters related thereto. All prospective contractors and their subcontractors or successors, by their participation in the RFP process, shall indemnify, save and hold NorthWestern and its employees and agents free and harmless from all lawsuits, causes of action, debts, rights, judgments, claims, demands, damages, losses and expenses or whatsoever kind in law or equity, known and unknown, foreseen and unforeseen, arising from or out of this RFP and/or any subsequent acts related thereto, including but not limited to the recommendation of a contractor and any action brought by an unsuccessful applicant.

Parties agree to sign confidentiality agreements prior to NorthWestern providing customer information, if necessary.

Northwestern is a public utility regulated by the Montana Public Service Commission. It is highly likely it will become necessary for NorthWestern to produce all proposals, as well as the contract with the successful bidder(s), submitted in response to this RFP to MPSC. NWE will not seek to protect the confidentiality of any bid, contract, or other material submitted in response to this RFP by any bidder(s) (successful or otherwise) for any reason. It is the responsibility of those responding to this RFP to take whatever action deemed necessary, at its own expense, to protect its interest(s) in maintaining the confidentiality of any bid, contract, or other material submitted in response to this RFP. By responding to this RFP, bidder(s) are considered to be on notice, aware, accept their responsibility to preserve their interest in confidential material.

Notwithstanding the foregoing, any material deemed by the bidder to be confidential, trade secret, or proprietary must be clearly marked with particularity. Generic claims of confidentiality, trade secret or proprietary information are not acceptable and maybe, in NorthWestern's sole discretion, cause to reject the bid(s) as non-conforming in whole or in part.

F. SCHEDULE AND ADMINISTRATION

Schedule

The following proposal schedule is an estimate of when major milestones will occur relative to this RFP. Timing may change due to unanticipated delays.

RFP distributed to bidders	(September 7, 2022)
Deadline for questions on RFP	(September 19, 2022)
Reponses to questions submitted to all bidders	(September 26, 2022)
Deadline for receipt of proposals	(October 14, 2022)
Selection of final three bidders	(October 21, 2022)
Oral presentations by finalists	(Early November 2022)
Final selection completed	(Late November 2022)

Proposal Submission

Bidders shall submit a total of four (4) electronic copies of the proposal; one copy showing pricing and submitted in both protected PDF format and unprotected Microsoft Word format, and one copy without pricing in each format. These four electronic copies are to be forwarded along with any related documents to the address listed below. NorthWestern will not be obligated to consider information received outside the time intervals specified in this section. All RFP proposals should be addressed to the following:

NorthWestern Energy
Attn.: Tucker Kramer
11 E Park St.
Butte, MT 59701
(406) 497-2322
Questions/Inquiries: E+Programs@northwestern.com
RFP Submittals: https://send.northwesternenergy.com/filedrop/~EDrMTH

Proposals should be clearly marked "NorthWestern Request for Proposals – Energy End-Use and Electric Energy Efficiency Potential Evaluation"

Proposals as described in this document must be submitted by **October 14, 2022**. Failure to submit required information within the specified time frame could be considered cause for rejection of this or any subsequent proposals.

Inquiries

Any requests for clarification or additional information regarding this RFP shall be submitted in writing via mail, fax, or e-mail to/at the following by the deadline specified above to:

NorthWestern Energy
Attn.: Tucker Kramer
11 E Park St.
Butte, MT 59701
(406) 497-2322
E+Programs@northwestern.com

Appendix F

NorthWestern Energy

Montana 2023 Plan

New Resource Cost Estimates

Revision 2

February 2023

TABLE OF CONTENTS

1 Introduction

NorthWestern Energy (NorthWestern) develops an Integrated Resource Plan (Plan) every three years for Montana and is currently updating its 2023 Plan. In support of this, NorthWestern retained Aion Energy LLC (Aion) to perform an update to the new resource capital and operations and maintenance (O&M) cost estimates developed for previous planning activities. The resources considered in this update include a variety of generation, storage, and combined generation and storage resources as summarized in the table below. As noted in the table, NorthWestern is also reviewing battery energy storage system (BESS), simple cycle (SC) combustion turbine (CT), and SC reciprocating internal combustion engine (RICE) resources as candidate resources for the determination of the avoided cost of capacity within NorthWestern's system.

Table 1. New Supply-Side Resource Options.

		Generation	Storage		
No.	Resource Type	Scale (MW_{ac})	Scale (MW_{ac})	Duration (hours)	Capability (MWh)
1	Wind	100	-	-	-
2	Wind	300	-	-	-
3	Solar PV	100	-	-	-
4	Solar PV	300	-	-	-
5	BESS	-	25	2	50
6	BESS	-	25	5	125
7	BESS	-	50	4	200
8	BESS*	-	50	5	250
9	BESS	-	50	8	400
10	BESS	-	100	5	500
11	Wind + BESS	100	50	5	250
12	Solar + BESS	100	50	5	250
13	Solar + BESS	100	100	5	500
14	Solar + BESS	300	150	5	750
15	PHES	-	100	8	800
16	Geothermal	20	-	-	-
17	SC CT - Aero*	50	-	-	-
18	SC RICE*	50	-	-	-
19	SC RICE*	150	-	-	-
20	CCCT	250	-	-	-

*Proxy capacity candidate resource (subject to further analysis by NorthWestern)

The purpose of this document is to summarize the basis of the new resource cost estimates and associated forecasts, to provide a high-level overview of the associated results, and to summarize general industry integrated resource planning (IRP) observations. This evaluation does not consider detailed cost estimate development and is based on general trends observed in previous NorthWestern Plans, responses to requests for proposals (RFPs), and other industry IRP reference data. The findings included herein are considered to be suitable for planning purposes and based on the best available information at the time of the evaluation as evaluated for NorthWestern operating regions.

2 Inputs and Assumptions

This evaluation is based on estimated 2023 costs with an earliest notice-to-proceed (NTP) in 2024. As such, new resource capital and O&M costs are presented in January 2023 dollars considering the inflation/escalation assumptions noted herein. Additionally, representative cost forecasts are included for each resource type for subsequent planning years.

Estimated capital costs are presented as overnight, installed costs based on an engineer, procure, construct (EPC) project execution and are inclusive of owner's costs (excluding an allowance for funds used during construction (AFUDC)). The estimated capital costs do not include "outside-the-fence" electrical and/or natural gas infrastructure and are generally based on scope within the project boundary/fence line (to the high-side of the generator step-up transformer, on-site gas-yard, etc.). Owner's costs are assumed and presented as a percentage of total EPC project costs and are based on previous NorthWestern planning and RFP activities. General assumptions considered in the evaluation are summarized below.

Table 2. General Estimating Assumptions.

Resource Type	Cost Estimate (Year)	Earliest NTP (Year)	Earliest In-Service (Year)	Construction Schedule (Months)	Owner's Costs (%)
Wind	2023	2024	2026	24	10%
Solar PV	2023	2024	2025	18	10%
BESS	2023	2024	2025	14	5%
Wind + BESS	2023	2024	2026	24	10%
Solar + BESS	2023	2024	2025	18	10%
PHES	2023	2024	2029	60	14%
Geothermal	2023	2024	2027	36	14%
SC CT - Aero	2023	2024	2026	22	12%
SC RICE	2023	2024	2026	22	15%
CCCT	2023	2024	2027	36	14%

As a basis of adjusting previous NorthWestern Plan inputs as well as observed costs from other data sources, this evaluation assumed the following average annual inflation rates.

Table 3. Average Annual Inflation Assumptions.

Inflation	2021	2022	2023	2024	2025+
Assumed Inflation (%)	4.70%	7.50%	2.50%	2.50%	2.50%

The assumed 2021 and 2022 inflation rates are based on published Consumer Price Index (CPI) data. The inflation rates assumed for 2023 and later are consistent with those assumed in the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB). As further discussed in Section 3.4, the assumed 2021 and 2022 inflation rates are higher than those observed in other recent industry IRPs/publications but commensurate as compared to as-received bid data/actual project developments.

Additionally, IRPs as well as industry publications account for technology-specific cost increases or declines for future planning purposes as a function of industry, material supply and manufacturing influences. The table below summarizes the annual cost adjustment factors utilized in this analysis for each resource type considered. At the time of the analysis, the rates are based on observed market trends/bid data for 2021 and 2022 and are assumed to offset the assumed inflation rate for 2023 and 2024 such that the combined cost impacts from inflation and technology considerations realized in 2023 and 2024 are assumed to be zero percent. As with the inflation rates, published IRP data and industry publications generally showed technology cost declines in 2021 through 2024 as compared to increases actually experienced/observed from bid data received and project developments pursued in 2021 and 2022 as well as costs expected for 2023 and 2024. The rates for 2025 and later are based on trends observed in the NREL 2022 ATB.

The rates assumed and summarized in Table 4 are indicative assumptions based on observed industry data and trends.

Table 4. Technological Advancement Assumptions.

Resource	2021	2022	2023	2024	2025+
Wind	5.00%	10.00%	-2.44%	-2.44%	NREL 2022 ATB Trends
Solar PV	10.00%	12.50%	-2.44%	-2.44%	
BESS	10.00%	12.50%	-2.44%	-2.44%	
Wind + BESS	5.00%	10.00%	-2.44%	-2.44%	
Solar + BESS	10.00%	12.50%	-2.44%	-2.44%	
PHES	5.00%	10.00%	-2.44%	-2.44%	
Geothermal	0.00%	10.00%	-2.44%	-2.44%	
SC CT - Aero	5.00%	10.00%	-2.44%	-2.44%	
SC RICE	5.00%	10.00%	-2.44%	-2.44%	
CCCT	5.00%	10.00%	-2.44%	-2.44%	

3 Findings and Observations

3.1 New Resource Cost Estimates

Estimated new resource capital and O&M costs are included in Attachment A to this document. The estimated costs are based on previous NorthWestern planning assumptions and account for the adjustments discussed throughout this document. Estimates were initially developed based on previous planning analyses and then adjusted, as applicable, for a generic Montana location based on location adjustment factors included in the Energy Information Administration (EIA) 2020 Annual Energy Outlook (AEO), consistent with previous NorthWestern planning efforts.

3.2 New Resource Cost Forecasts

Representative new resource capital cost forecasts are included in Attachment B to this document. The forecasts are based on flat/constant resource costs until 2025, followed by cost trends observed in the NREL 2022 ATB.

3.3 Regional IRP/Industry Publication Review

As part of this effort, regional IRP data as well as industry publications were reviewed. This included IRPs issued in 2019, 2020, and 2021 for peer utilities including, but not limited to:

1. Avista;
2. Black Hills Energy;
3. Idaho Power;
4. Montana-Dakota Utilities:
5. PacifiCorp;
6. Puget Sound Energy; and
7. Xcel.

Additionally, this evaluation considered industry publications including, but not limited to:

1. NREL 2020 ATB;
2. NREL 2021 ATB;
3. NREL 2022 ATB;
4. EIA 2020 AEO;
5. EIA 2021 AEO;
6. Northwest Power and Conservation Council – The 2021 Northwest Power Plan (DRAFT);
7. Lazard's Levelized Cost of Energy Analysis – Version 15.0; and
8. Lazard's Levelized Cost of Storage Analysis – Version 7.0.

While this data was reviewed, it was used solely as a basis of comparative validation of the results derived by Aion via adjustment to the previously developed NorthWestern Plan inputs. Additionally, as noted herein, some of the inflation and escalation values were derived directly from the NREL ATB data.

3.4 Inflation/Escalation

As noted, many recent IRPs/industry publications do not appear to account for the major supply chain disruptions and inflationary environment observed in 2021 and 2022. This is not surprising given that many of the inputs into these documents are developed months, if not years, in advance. Regardless, in an attempt to capture some of the trends observed in 2021 and 2022, this analysis includes elevated inflation rates in 2021 and 2022, based on actual CPI data, that are 2% to 5% higher than those reflected in other industry references. Additionally, specific technology cost escalators are included for 2021 through 2024 as compared to general de-escalation observed in other references. As noted in Table 4, costs for some technologies were assumed to increase more than others in 2021 and 2022 as a function of demand and sourcing challenges for those technologies.

While resource capital costs were assumed to be impacted by both the inflation and technology escalation rates indicated herein, O&M costs were assumed to only be subject to the noted inflation rates.

4 Summary Discussion

With NorthWestern's Plan update underway, the capital and O&M metrics estimated as part of this evaluation are intended to represent a reasonable indication of current and near-term forecasted resource cost trends. The capital and O&M cost metrics were developed consistently, regardless of technology, representing a consistent basis for modeling purposes, and appear to trend consistently with observed industry trends as well as previous NorthWestern planning data when considering the disruptions observed in 2021 and 2022. The metrics developed as part of this evaluation are based upon the assumptions noted herein, subject to change based on further review and evaluation, and are intended for planning purposes only.

Montana 2023 Plan
New Resource Cost Estimates
Attachment A
Resource Cost Estimates
January 2023 Cost Basis
Revision

Aion's resource cost table (Rev 2) shown below was updated in January 2023 to reflect recent changes in cost estimates and the effects of inflation. These values do not include Inflation Reduction Act ("IRA") impacts to any Investment Tax Credit ("ITC") or Production Tax Credit ("PTC") that may be applicable. Not all of these resources were modeled for the plan.

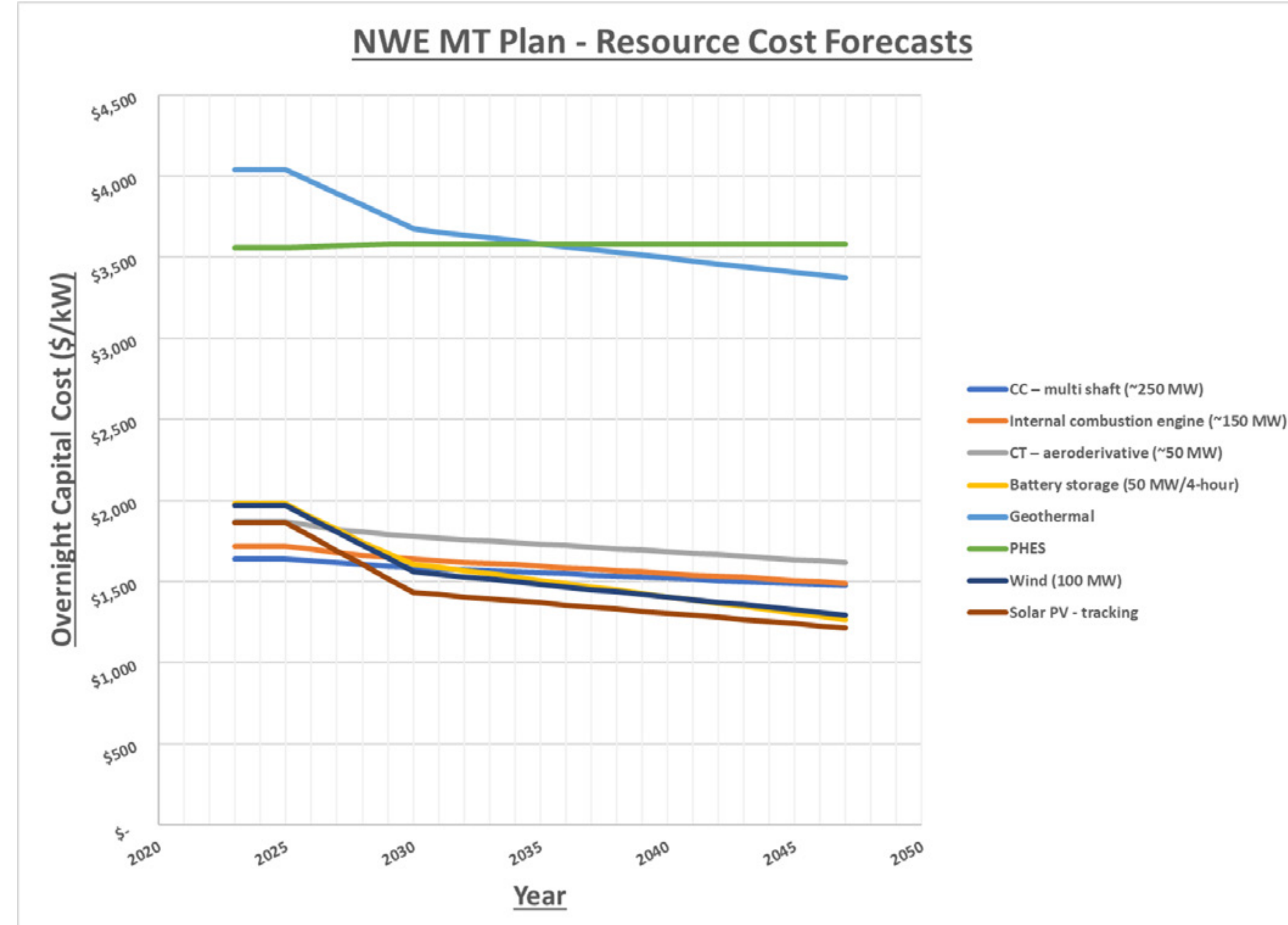
NWE MT 2023 Plan - Resource Cost Estimates
MT Plan Update - Rev2

		Generation		Storage											
No.	Montana	Scale (MW_{ac})	Heat Rate (Btu/kWh-HHV)	Scale (MW_{ac})	Duration (hours)	Capability (MWh)	Installed Overnight[1,2] ($/kW)	FCRC - 20-Yr Levelized (%)	Revenue Requirement ($/yr - fixed)	Revenue Requirement ($/kW-yr - fixed)	Fixed O&M[2] ($/kW-yr)	Fixed Hourly Fee ($/hour)	Start Fee ($/start)	Variable O&M ($/MWh)	Total Non-Fuel Variable Costs ($/MWh)
1	Wind	100	-	-	-	-	$ 1,970	9.84%	$ 19,381,018	$ 193.81	$ 40.89	$ -	$ -	$ -	$ -
2	Wind	300	-	-	-	-	$ 1,764	9.84%	$ 52,079,514	$ 173.60	$ 33.41	$ -	$ -	$ -	$ -
3	Solar PV - SAT	100	-	-	-	-	$ 1,864	10.70%	$ 19,949,057	$ 199.49	$ 23.17	$ -	$ -	$ -	$ -
4	Solar PV - SAT	300	-	-	-	-	$ 1,662	10.70%	$ 53,338,846	$ 177.80	$ 20.76	$ -	$ -	$ -	$ -
5	BESS - Li-Ion[3]	-	-	25	2	50	$ 1,242	11.18%	$ 3,470,846	$ 138.83	$ 14.14	$ -	$ -	$ -	$ -
6	BESS - Li-Ion	-	-	25	5	125	$ 2,570	11.18%	$ 7,184,689	$ 287.39	$ 34.70	$ -	$ -	$ -	$ -
7	BESS - Li-Ion	-	-	50	4	200	$ 1,984	11.18%	$ 11,090,763	$ 221.82	$ 27.50	$ -	$ -	$ -	$ -
8	BESS - Li-Ion*	-	-	50	5	250	$ 2,398	11.18%	$ 13,407,103	$ 268.14	$ 34.22	$ -	$ -	$ -	$ -
9	BESS - Li-Ion	-	-	50	8	400	$ 3,576	11.18%	$ 19,991,111	$ 399.82	$ 54.24	$ -	$ -	$ -	$ -
10	BESS - Li-Ion	-	-	100	5	500	$ 2,237	11.18%	$ 25,018,539	$ 250.19	$ 33.75	$ -	$ -	$ -	$ -
11	Wind + BESS	100	-	50	5	250	$ 3,147	10.38%	$ 32,667,870	$ 326.68	$ 56.55	$ -	$ -	$ -	$ -
12	Solar + BESS[4]	100	-	50	5	250	$ 2,993	10.88%	$ 32,562,799	$ 325.63	$ 38.82	$ -	$ -	$ -	$ -
13	Solar + BESS	100	-	100	5	500	$ 4,009	10.95%	$ 43,915,897	$ 439.16	$ 54.11	$ -	$ -	$ -	$ -
14	Solar + BESS	300	-	150	5	750	$ 2,673	10.88%	$ 87,251,144	$ 290.84	$ 36.14	$ -	$ -	$ -	$ -
15	PHES (Slice of Larger Project)	-	-	100	8	800	$ 3,561	9.31%	$ 33,135,816	$ 331.36	$ 17.47	$ -	$ -	$ 1.08	$ 1.08
16	Geothermal	20	-	-	-	-	$ 4,038	10.94%	$ 8,833,750	$ 441.69	$ 148.81	$ -	$ -	$ 11.86	$ 11.86
17	SC CT - Aero[5]*	50	9,300	-	-	-	$ 1,867	10.94%	$ 10,209,178	$ 204.18	$ 19.32	$ 250	$ -	$ 0.48	$ 5.48
18	SC RICE[5]*	50	8,750	-	-	-	$ 2,141	10.94%	$ 11,710,990	$ 234.22	$ 27.00	$ 385	$ -	$ 2.31	$ 10.01
19	SC RICE[5]*	150	8,700	-	-	-	$ 1,719	10.94%	$ 28,202,696	$ 188.02	$ 17.00	$ 1,100	$ -	$ 2.31	$ 9.64
20	CCCT[6]	250	6,750	-	-	-	$ 1,640	10.94%	$ 44,855,046	$ 179.42	$ 18.50	$ 1,000	$ -	$ 1.34	$ 5.34

*Proxy capacity candidate resource (subject to further analysis by NorthWestern)

Notes
1. Overnight installed costs include direct and indirect EPC project costs and owner's cost but exclude AFUDC, electric transmission network upgrades, and bulk gas system upgrades, as applicable.
2. Overnight installed ($/kW) and fixed O&M ($/kW-yr) costs expressed based on dividing total costs by the renewable component output.
3. BESS resources based on lithium ion technology, 365 equivalent cycles per year, and capacity augmentation throughout the study period.
4. Solar + BESS hybrid resources based on dc-connected, SAT solar PV.
5. O&M costs for simple cycle configurations assume a dispatch profile of 100 starts per year and 1,000 hours of operation per year.
6. O&M costs for combined cycle configurations assume a dispatch profile of 150 starts per year and 4,000 hours of operation per year.

Montana 2023 Plan
New Resource Cost Estimates
Attachment B
Resource Cost Forecasts
Revision 2



Appendix G

LOSS OF COLSTRIP:
A TRANSMISSION SYSTEM STUDY
OF THE POTENTIAL
SHUTDOWN OF COLSTRIP UNITS 3 & 4
8/22/2022
ELECTRIC TRANSMISSION PLANNING

1. Study Objective

Evaluate the expected operation, performance, constraints and potential needs of the Montana Transmission System with the potential shutdown of Colstrip Units 3 and 4 in 2025. Where issues were found, operational mitigation has been evaluated as well as potential hard mitigation (i.e. voltage control devices, lines, etc.) to limit the amount of operational mitigation required.

The study includes the following phases:

6. 1. Baseline study with Colstrip units 3 and 4 online (existing 2021 base case projected out to 2025 with and without additional planned generation additions (generator interconnection projects in construction only)
7. 2. Colstrip units 3 and 4 offline with generation offset by Mid-C. Generation inside NWMT's system was not be re-dispatched to account for the 1500MW reduction.
8. 3. Colstrip units 3 and 4 offline with generation offset by 750 MW of wind interconnection projects (234 in the interconnection queue) at the Colstrip 500 kV Bus and the remaining offset by Mid-C. Note this produces the same result as shutting down only a single Colstrip Unit.
9. 4. Colstrip units 3 and 4 offline with generation offset by 2250MW of wind interconnection projects (234, 356, and 357 in the interconnection queue) at the Colstrip 500 kV Bus. Remaining generation surplus to be offset at Mid-C.

Each Phase studied the following system conditions (Appendix 1 contains a list of study Cases):

- 2025 Heavy Summer dispatch (low wind, low hydro, high solar, summer peak Load)
- 2025 Light Summer Dispatch (high Wind, high hydro, no solar, off-peak load)
- 2025 Heavy Winter dispatch (low wind, low hydro, no solar, winter peak load)
- 2025 Light Winter dispatch (no wind, low hydro, medium solar, winter off peak load)
- 2025 Light Spring dispatch low (low wind, high hydro, medium solar, off peak spring load)
- 2025 Light Spring dispatch low (high wind, high hydro, high solar, off peak spring load, 0MW net imports)

Additionally, the study addresses the Available Transfer Capacity of interties into NorthWestern Energy's system with the shutdown of Colstrip Units 3 & 4.

2. Assumptions

Base Case

The following assumptions were used for the base cases used for Study. A comprehensive list of cases, dispatches and Path flows can be found in Appendix 1 at the end of the report.

Phase 1

- All units 3 & 4 at Colstrip set to output maximum (1500MW) generation at the high side of the GSU.

Phase 2

- Colstrip units 3 and 4 (and associated station service power) turned offline

Phase 3

- 750 MW of wind generation added to the system at the Colstrip 500kV yard.
  - ↳ This particular study used interconnection project 234
- PSTs on Paths 18, 80, and 83 adjusted to their Phase 1 MW values
- Phase 3 produces the same results as the shutdown of 1 Colstrip Unit

Phase 4

- 2250 MW of wind generation added to the system at the Colstrip 500kV yard.
  - ↳ This particular study used interconnection projects 234, 356, and 357
- PSTs on Paths 18, 80, and 83 adjusted to their Phase 1 MW values

General Assumptions

- Seasonal Cases include planned capital projects to be complete prior to the case year.
- Seasonal Cases include Generator Interconnection project In Construction with an interconnection date prior to the case year (interconnection projects 303, 340, 341, 376, and 378)
  - ↳ A comprehensive list of dispatch levels for these generator interconnection projects can be found in Appendix 2.
- Two sensitivity cases were created based on the 2025 Heavy Summer and 2025 Heavy Winter Seasonal Cases above. These cases assumed no new generation interconnection projects built out before the 2025 date.
  - ↳ Path flows and generation dispatches can be seen in Appendix 3.

3. Supply Considerations

There is roughly 444MW of load served from NorthWestern Energy and Talen's portion of Colstrip, 222MW of which is NorthWestern Energy Retail Load. The remainder of the 1500MW supplies off-system load. The retirement of Colstrip would necessitate that the existing Montana load be supplied with either new on-system generation resources or firm imports into NorthWestern's system. At the time of this study, the firm Available Transfer Capacity indicates that there is minimal import capacity left available on the predominate paths 8 and 18 into NorthWestern Energy's system. See the ATC section of this report nature.

4. Physical Power Flow Findings

The physics of removing the entirety of 1500MW of generation from the eastern part of NorthWestern's system had several notable impacts on the typical flow direction and expected operation of NorthWestern's system.

High Voltage Issues

During light case dispatches with low generation, not surprisingly, it was found that the removal of Colstrip permanently caused a significant reduction on 500kV line flows from Colstrip to Broadview to Garrison. This reduction in MW flows caused the line charging seen by the 500kV lines to increase causing high voltage. The initial light load cases showed high voltages on approximately 32 non-BES buses, mostly in eastern Montana, for an outage at BPA's Garrison Substation. With the additional line charging from the unloaded 500kV lines with the reduction of Colstrip, approximately 72 buses including BES buses in eastern Montana exceeded voltage criteria for an outage at BPA's Garrison Substation. These high voltage conditions will require either day to day operational mitigation or permanent hard mitigation.

The addition of 750MW and then 2250MW of wind in the Phase 3 and 4 cases does increase 500kV line flows and subsequently reduce line charging on the 500kV. However, in the cases with reduced wind dispatch to represent low wind periods, the high voltage issue persisted. Voltage control provided by the wind resources is a scalar resource and when the wind is at lower output levels, the ability and requirement for the interconnection project to control voltage is reduced.

A typical operational procedure to reduce high voltage during periods of light loading when Colstrip is been down for maintenance is to de-energize one or more of the 500kV line segments. This is an acceptable operational solution when the generation source is highly predictable and planned. Intermittent wind at low output may ramp up and down causing the system operators to have to re-energize and de-energize multiple unplanned times during a day to utilize this method as mitigation. If lines were de-energized and unplanned outages occurred on remaining lines, the Eastern Montana Remedial Action Scheme would likely trigger and shed generation serving load in neighboring entities. Operational mitigation is not recommended for these reasons.

It is recommended that approximately 200MVAr of reactors be installed at the Broadview 500kV bus in two stages (approximately 100MVAr per stage) to control voltage on the 500kV during the situations described above.

Typical Flow Changes on South of Great Falls

NorthWestern's South of Great Falls (SOGF) internal path has several limiting elements in the Lewistown, Helena and Great Falls Areas. In the Phase 1 cases with Colstrip online during high SOGF flows southbound, there is a limiting contingency where loss of the Judith Gap South – Broadview 230kV line can cause overloads on the Judith Gap – Broadview 'B' 100kV line. Removing the 1500MW of generation at Colstrip in the Phase 2 cases causes that overload to increase by 28%. The Addition of 750MW and 2250MW of wind in the Phase 3 and Phase 4 cases directly replaces Colstrip's influence on the situation. However, firm path limits cannot be defined on the availability of intermittent resources to counter flow overloaded elements. A permanent shutdown of Colstrip will cause a new normal situation where the existing constraints on SOGF surrounding Judith Gap Auto are loaded heavier and the firm Available Transfer Capability of SOGF will need to be reduced further. Prior identified SOGF Upgrades will likely need to be expedited to avoid further SOGF curtailments because of impacts to the loss of Colstrip.

Short Circuit Reductions

Large synchronous generation is a significant source of short circuit strength on transmission systems. The loss of Colstrip will cause a significant reduction in short circuit strength across the eastern Montana system. Such reductions can be seen in Table 1 below. The Colstrip and Broadview 500kV and 230kV buses see an average reduction of approximately 46% with the removal of Colstrip. 2250MW of wind generation at the Colstrip 500kV bus does contribute short circuit MVA, but due to the type of generation, it is a reduced contribution per installed turbine MVA. At the monitored buses, there is still an average of 28% less short circuit MVA in the Phase 4 cases with the additional wind resources.

Table 0-1: Short Circuit MVA changes with the changes in Colstrip generation.

Short Circuit Three Phase MVA					
Case	**Colstrip 500 kV**	**Colstrip 230 kV**	**Broadview 500 kV**	**Broadview 230 kV**	**% Reduction**
Phase 1	9191	4941	8462	5915	0%
Phase 2	3717	2911	4730	4149	46%
Phase 3	4341	3231	5289	4468	39%
Phase 4	5508	3753	6224	4953	28%

Compliance criteria specify that yearly, protective devices settings need to be reviewed on buses where there is a change in short circuit MVA of 15% or greater. Overall, there are 32 Buses on NorthWestern's system that would require settings review with the permanent shutdown of Colstrip. It is recommended that the Substation Relay group review protective device settings to determine potential impacts.

Short Circuit strength is also a dynamic dampener; typically, systems with weaker short circuit levels will experience wider steady state, transient and sub-transient voltage fluctuations. The removal of Colstrip as a dampening force for the significant number of non-synchronous generator requests on the 500kV system inside NorthWestern's Balancing Area may have dynamic stability implications that are being investigated in the Generator Interconnection queue through a consultant using EMT studies.

Summary of Physical Impacts

The study indicates there are several measureable impacts to the physics of NorthWestern's Transmission System. Reduced and intermittent 500kV line flows from more intermittent resources are going to place NorthWestern facilities in greater occurrences of high voltage conditions due to capacitive line charging. The ability of NorthWestern's operators to take operational steps to compensate for these voltage issues will also be reduced by the intermittent nature of newly connecting resources. It is recommended that approximately 200MVAr of reactors be installed at the Broadview 500kV bus in two stages (approximately 100MVAr per stage) to control voltage on the 500kV during the situations described above.

There will be a significant reduction in short circuit strength in Eastern Montana, which, at a minimum, will require a time intensive review of the protection settings in a significant number of substations. It is recommended that the Substation Relay group review protective settings to better quantify impacts.

Lastly, typical system flows from east to west in Montana will be affected as such that there are implications on South of Great Falls elements on the eastern side of the system, these issues exist today but will be worsened with the permanent change in typical flows under the removal of Colstrip. This is likely to cause further constraints and curtailments on the SOGF path greater than those experienced today and the need to further expedite SOGF network upgrades.

5. Available Transfer Capacity (ATC)

Of the total Colstrip units 3 & 4 capacity of 1480 MW, approximately 444 MW serves designated load in Montana. The other 1036 MW is telemeter scheduled off system to serve the other Colstrip owners loads west of Montana. This study utilized posted 2024 import ATC on the NWMT external transmission paths to simulate scheduled flows to serve the 444 MW of Montana Colstrip designated load to determine if the assumed loss of remaining Colstrip generation in 2025 could be substituted with off system resources to serve Montana load utilizing available firm ATC.

Existing Path TTC and Generation Capacity

NorthWestern's transmission interties currently have a firm import Total Transfer Capacity (TTC) of 2,401 MW, as seen in Table 2. With no new generation interconnected, there is approximately 1720MW of nameplate Designated Network Generation in NorthWestern's BAA (without Colstrip generation and the 385MW of Designated off system Resources as seen in Appendix 5). The average output of this 1720 MW of nameplate resources is 581MW considering the capacity factor value. NWE and Talen ownership shares of Colstrip generation serve approximately 444MW of load in NorthWestern's BAA.

From a system reliability standpoint when analyzing any of the Paths, Electric Transmission Planning will stress the cases by operating the Paths to the TTC, instead of the Schedule value, which is typically a less stressed flow value. Firm transmission requests are not studied on a net firm schedule, as the possibility exists for an issue to arise when someone releases their firm rights that may have been counter-flowing other firm rights, thus potentially causing higher actual flows than anticipated and the necessity of curtailment of firm service based on the reduction of firm service. As such, Firm TSRs are studied with the path at the direction and level of total firm in that direction (import or export) as it relates to the TSR.

Table 0-1: Path Import TTC

Path	Firm Import TTC
Path 8	1245
Path 18	256
Path 80	600
Path 83	300
Sum	**2401**

*see Appendix 4 for Map of ATC

Future Available Transfer Capacity (ATC)

Not all of the Total Transfer Capacity (TTC) is available and not all of the Designated Network Resources are available 100% of the time (variable energy resources for example have a min capacity of 0MW). Table 3 shows the Path TTC and ATC with the firm reservations taken out. Out of the 2401MW of TTC there is 1073MW of ATC remaining in 2024 split between the four Interconnection paths. 385MW of the total 2401MW TTC is currently secured long-term firm to supply NorthWestern's default supply load. With the reduction of Colstrip generation there is 444MW of firm ATC or new on-system generation that needs to be secured to make up for the lost supply that serves NWE default supply or Choice Customers with designations from Colstrip. Electric Transmission Planning analyzed the concept of utilizing existing firm import ATC to make up for the loss of Colstrip generation that serves Montana designated load. This was achieved through the blue highlighted "New Import" cells in Table 3. Path 8 and Path 18 were prioritized for the majority of the import as they were deemed the most likely and reliable Paths with external supply to be purchased. As a result of this assumed dispatch, Path 8 and 18 full available ATC was utilized leaving 629MW of remaining ATC on Paths 80 and 83. Although path 80 appears to have remaining ATC, both transmission and resource constraints south of Path 80 preclude the ability to secure reliable resource from that direction.

Table 0-1: Available ATC and Imports

Path 8	TTC	TRM/CU	Firm PTP	Firm NITS	Firm ATC	2025HS Phase 1 Case Colstrip Online	2025HS Phase 2 Case Colstrip Offline	Remaining ATC
Export	890	170	340	0	380	510	510	-380
Import	-1245	-170	-101	-697	-277	-968	-1245	0
					Schedule	-458	-735	
							277	New Import
Path 18	**TTC**	**TRM/CU**	**Firm PTP**	**Firm NITS**	**Firm ATC**	**2025HS Phase 1 Case Colstrip Online**	**2025HS Phase 2 Case Colstrip Offline**	**Remaining ATC**
BRDY Export	296	170	101	0	25	271	271	-25
BRDY Import	-184	-125	0	0	-59	-125	-184	0
Jeff Export	87	0	7	0	80	7	7	-80
Jeff Import	-72	0	0	0	-72	0	-72	0
					Schedule	153	22	
							131	New Import
Path 80	**TTC**	**TRM/CU**	**Firm PTP**	**Firm NITS**	**Firm ATC**	**2025HS Phase 1 Case Colstrip Online**	**2025HS Phase 2 Case Colstrip Offline**	**Remaining ATC**
Export	600	0	0	0	600	0	0	-600
Import	-600	0	-31	-29	-540	-60	-96	504
					Schedule	-60	-96	
							36	New Import
Path 83	**TTC**	**TRM/CU**	**Firm PTP**	**Firm NITS**	**Firm ATC**	**2025HS Phase 1 Case Colstrip Online**	**2025HS Phase 2 Case Colstrip Offline**	**Remaining ATC**
Export	325	15	0	0	310	15	15	-310
Import	-300	0	0	-175	-125	-175	-175	125
					Schedule	-160	-160	
							0	New Import
							444	Total New Imports

Minimum Operable Generation

Minimum Operable Generation would be the amount of Megawatts required to be generated inside NorthWestern's system once all of the Path ATC has been reserved. Based on the ATC in Table 3 and a NorthWestern obligation to supply its load and Colstrip's portion of Choice Customer load inside NorthWestern's system (~1444MW for a close approximation), there is a deficit of 371MW after 1073MW of the load has been supplied by the assumed available firm ATC (no specific available resource was assumed for this exercise). Assuming Path 80 cannot be relied upon for firm import capacity, the actual amount of available firm ATC is actually 1073MW minus 504MW or 569 MW of reliable ATC. This makes the actual deficit closer to 875 MW with that consideration. This means that at a minimum there must be 875 MW of the 1720 MW (2024-projected) of generation capacity on NorthWestern's system that is designated firm and is reliable, to serve Network Load. As system load grows, the deficit will also grow. A decision should be made to decide what the minimum amount of generation we should plan to, which would help define how much firm ATC is required to maintain system reliability.

Summary of Findings

The study utilized all available ATC on paths 8 and 18 (277MW & 131MW respectfully) with an additional 36 MW imported on path 80 or 83 to make up the total 444 MW of necessary import replacement power for loss of Colstrip generation. This analysis was based on a 2025 base case with 2025-forecasted load. Based on these results, zero firm transmission would be left available on paths 8 or 18 with no margin of error assumed. This deficit will grow year over year as load in MT increases. Path 80 still contains approximately 504 MW of ATC; however, transmission and supply constraints south of path 80 indicate no reliable resources are available.

Purely attempting to substitute off system resources requiring additional firm transmission rights after the loss of Colstrip to serve MT load without new additional baseload on-system resources or increased secured firm ATC is risky and is not a realistic or a sustainable substitute. There is no guarantee current posted ATC will be available unless that ATC is immediately secured. The study results indicates no supply margin of error, or assumed load growth beyond 2025 is available in the total import capacity, which is unrealistic. These study results indicate that with the loss of Colstrip generation, either A) new on-system base load resources are required to reliably serve MT load or B) new additional transmission import ATC should be sought in the form or new transmission or transmission upgrades to increase import ATC.

A detailed business assessment & risk analysis is recommended to confer these results.

6. Conclusion

There are both physical and supply impacts because of the potential shutdown of Colstrip Units 3 and 4 as described in the Summary of Physical Impacts and Summary of ATC Findings above. In short, NorthWestern will experience more high voltage conditions under the loss of Colstrip and it is recommended that additional reactive resources be installed on the 500kV system at Broadview. A reduction of short circuit current will require in depth protection setting review and a permanent change to typical system flows will require modification of existing internal path limits or upgrades. In regards to the loss of Colstrip generation resource, it is shown that there is a need for increased resources in the form of new off system resources and increased secured firm Transfer Capacity (transmission rights) into NorthWestern's system or additional on system baseload or balancing resources to compliment NorthWestern's existing renewable rich supply portfolio.

Appendix 1 Base Case Scenario Descriptions

Phase	Case Load Dispatch	Colstrip 3 & 4	Clearwater	Wind Gen	Hydro Gen	Solar Gen	In Construction GIAs	8 (E-W)	18 (N-S)	80 (N-S)	83 (S-N)	SOGF (N-S)
Phase 1	2025 HEAVY SUMMER	1500MW	0MW	25%	42%	100%	YES	152	183	54	56	-111
Phase 2	2025 HEAVY SUMMER	0MW	0MW	25%	42%	100%	YES	-1340	186	57	59	-113
Phase 3	2025 HEAVY SUMMER	0MW	750MW	25%	42%	100%	YES	-1149	184	57	58	-111
Phase 4	2025 HEAVY SUMMER	0MW	2250MW	25%	42%	100%	YES	-783	184	58	58	-112
Phase 1	2025 HEAVY WINTER	1500MW	0MW	25%	60%	0%	YES	151	156	79	51	-16

Phase	Case Load Dispatch	Colstrip 3 & 4	Clearwater	Wind Gen	Hydro Gen	Solar Gen	In Construction GIAs	8 (E-W)	18 (N-S)	80 (N-S)	83 (S-N)	SOGF (N-S)
Phase 2	2025 HEAVY WINTER	0MW	0MW	25%	60%	0%	YES	-1340	158	81	53	-17
Phase 3	2025 HEAVY WINTER	0MW	750MW	25%	60%	0%	YES	-1153	158	81	53	-17
Phase 4	2025 HEAVY WINTER	0MW	2250MW	25%	60%	0%	YES	-786	159	81	53	-17
Phase 1	2025 LIGHT WINTER	1500MW	0MW	0%	60%	50%	YES	1501	143	-324	-53	85
Phase 2	2025 LIGHT WINTER	0MW	0MW	0%	60%	50%	YES	108	82	-324	-53	85
Phase 3	2025 LIGHT WINTER	0MW	750MW	0%	60%	50%	YES	108	82	-325	-53	85
Phase 4	2025 LIGHT WINTER	0MW	2250MW	0%	60%	50%	YES	106	82	-326	-53	86
Phase 1	2025 LIGHT SUMMER	1500MW	0MW	100%	88%	0%	YES	1445	157	29	174	473
Phase 2	2025 LIGHT SUMMER	0MW	0MW	100%	88%	0%	YES	-20	156	29	172	476
Phase 3	2025 LIGHT SUMMER	0MW	750MW	100%	88%	0%	YES	686	156	28	172	476
Phase 4	2025 LIGHT SUMMER	0MW	2250MW	100%	88%	0%	YES	1964	167	91	172	469
Phase 1	2025 LIGHT SPRING HIGH	1500MW	0MW	100%	88%	100%	YES	1507	260	-6	275	411
Phase 2	2025 LIGHT SPRING HIGH	0MW	0MW	100%	88%	100%	YES	41	258	-5	275	412
Phase 3	2025 LIGHT SPRING HIGH	0MW	750MW	100%	88%	100%	YES	749	261	-7	274	413
Phase 4	2025 LIGHT SPRING HIGH	0MW	2250MW	100%	88%	100%	YES	2120	261	-14	271	415
Phase 1	2025 LIGHT SPRING LOW	1500MW	0MW	25%	88%	50%	YES	1500	111	-194	-98	388
Phase 2	2025 LIGHT SPRING LOW	0MW	0MW	25%	88%	50%	YES	33	111	-194	-98	388
Phase 3	2025 LIGHT SPRING LOW	0MW	750MW	25%	88%	50%	YES	217	111	-194	-97	388
Phase 4	2025 LIGHT SPRING LOW	0MW	2250MW	25%	88%	50%	YES	586	109	-196	-100	390

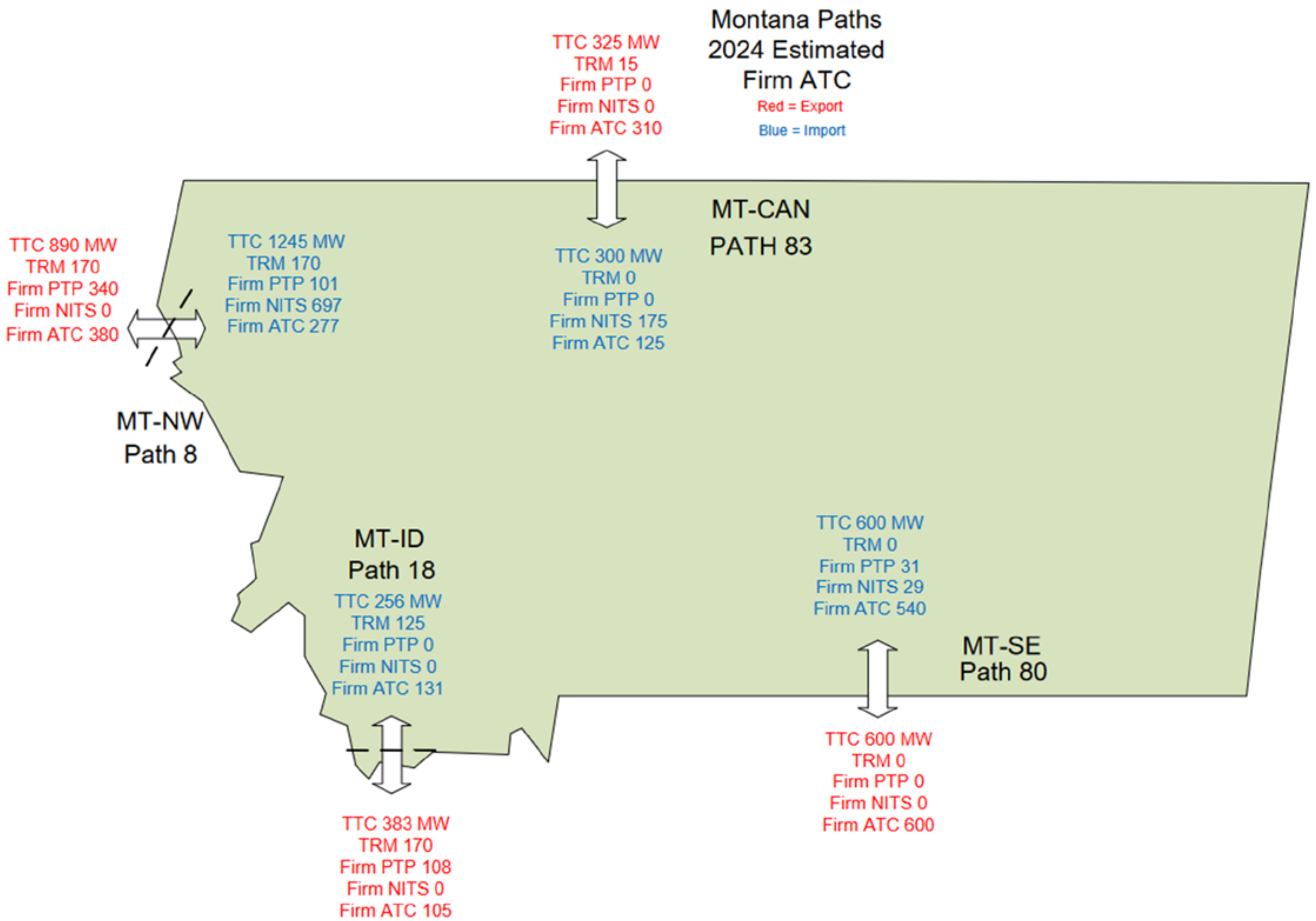
Appendix 2 Generator Interconnection Projects In Construction

GIA	303 MW	340 MW	341 MW	376 MW	378 MW	TOTAL MW
2025 HEAVY SUMMER	79	24	160	49	138	450
2025 HEAVY WINTER	0	0	0	0	174	174
2025 LIGHT SPRING HIGH	79	24	160	0	0	263
2025 LIGHT SPRING LOW	39	12	80	0	0	131
2025 LIGHT SUMMER	0	0	0	49	174	223
2025 LIGHT WINTER	39	12	80	49	174	354

Appendix 3 Sensitivity Base Case Descriptions

Phase	Case Load Dispatch	Colstrip 3 & 4	Wind Gen	Hydro Gen	Solar Gen	In Construction GIAs	8 (E-W)	18 (N-S)	80 (N-S)	83 (S-N)	SOGF (N-S)
Phase 2 Sensitivity	2025 HEAVY SUMMER	0MW	25%	42%	100%	NO	-1284	103	-138	-192	126
Phase 2 Sensitivity	2025 HEAVY WINTER	0MW	25%	60%	0%	NO	-1322	29	65	53	-17
Phase 2 Extreme Sensitivity	2025 HEAVY SUMMER	0MW	0%	30%	0%	NO	-1202	-106	-438	-295	55

Appendix 4 2024 Montana Path ATC Map



Appendix 5 Designated Network Resources updated 5.5.2022 for 2024

Designated Network Loads and Resources									
Network Resources	NWMT Point of Receipt (POR)	Firm Point of Delivery for Load to be Served	Desig. MW	Notes	Resource Type	Capacity Factor 2021	Average MW	Min	Minimum MW
APEX Solar	APEXSOLAR	NWMT.SYSTEM	80	NEW	SOLAR+BA	22.61%	18	0%	0
Basin Creek	BASINCREEK	NWMT.SYSTEM	52		GAS	26.30%	14	0%	0
Bearthooth Battery	BEARBATT	NWMT.SYSTEM	50	NEW	BATT		0	0%	0
BGI	BGI	NWMT.SYSTEM	60		COAL	87.51%	53	33%	20
Black Eagle	BLACKEAGLE	NWMT.SYSYTEM	5		HYDRO	48.94%	2	45%	2
Black Eagle	BLACKEAGLE	GTFALLSNWMT	17		HYDRO	48.94%	8	45%	8
Black Eagle Solar	QFS	GTFALLSNWMT	3		SOLAR	21.71%	1	0%	0
Broadview East Wind, QF	QFS	NWMT.SYSTEM	1.6		WIND	35.01%	1	0%	0
Broadwater Dam	BROADWATER	NWMT.SYSTEM	10		HYDRO	24.29%	2	0%	0
Crooked Falls - (Ryan, Morony,	CROOKEDFALLS	NWMT.SYSTEM	81		HYDRO	43.46%	35	13%	11
Crooked Falls - (Ryan, Morony,	CROOKEDFALLS	GTFALLSNWMT	130		HYDRO	43.46%	56	13%	17
Crooked Falls - (Ryan, Morony,	CROOKEDFALLS	Great Falls	40		HYDRO	43.46%	17	13%	5
TEA PPA	CROSSOVER	NWMT.SYSTEM	25		IMPORT	100.00%	25	100%	25
Fairfield Wind	FAIRFIELD	GTFALLSNWMT	10		WIND	31.68%	3	0%	0
Flint Creek Hydro	QFS	NWMT.SYSTEM	2		HYDRO	62.65%	1	20%	0
Green Meadow Solar, QF	QFS	NMWT.SYSTEM	3		SOLAR	22.31%	1	0%	0
Greenfield Wind	GREENFIELD	GTFALLSNWMT	25		WIND	39.26%	10	0%	0
Big Timber Wind	BIGTIMBER	NWMT.SYSTEM	25		WIND	36.01%	9	0%	0
Gordon Butte, QF	GORDONBUTTE	NWMT.SYSTEM	10		WIND	42.41%	4	0%	0
Gordon Butte, QF	GORDONBUTTE	NWMT.SYSTEM	9		WIND	40.46%	4	0%	0
Great Divide Solar	QFS	NWMT.SYSTEM	3		SOLAR	23.71%	1	0%	0
Hauser	HAUSER	NWMT.SYSTEM	19		HYDRO	66.54%	13	63%	12
Heartland PPA	MATL.NWMT		150		IMPORT	100.00%	150	100%	150
Holter	HOLTER	NWMT.SYSTEM	48		HYDRO	47.34%	23	25%	12
Judith Gap	JUDITHGAP	NWMT.SYSTEM	135		WIND	38.78%	52	0%	0
Laurel	LAUREL	NWMT.SYSTEM	175	NEW	GAS		0		0
Lower South Fork	QFS	NWMT.SYSTEM	1		HYDRO	5.23%	0	0%	0
Madison	MADISON	NWMT.SYSTEM	13		HYDRO	0.90%	0	0%	0
Magpie Solar	QFS	NWMT.SYSTEM	3		SOLAR	21.50%	1	0%	0
Meadowlark Solar	MEADOWLARK	NWMT.SYSTEM	20	NEW	SOLAR	22.61%	5	0%	0
Mill Creek Generating Station	DAVEGATES	NWMT.SYSTEM	218	Increasing to 218 1/1/2023 - 1/1/2048	GAS	19.95%	43	6%	14
Montana Sun	MTSUN	NWMT.SYSTEM	80	NEW	SOLAR	22.61%	18	0%	0
Montana 1	MT1	NWMT.SYSTEM	35		COAL	105.35%	37	30%	11
Morgan Stanley PPA	BPAT.NWMT	NWMT.SYSTEM	50		IMPORT	100.00%	50		0
Musselshell Wind, QF	MUSSELSHELL	NWMT.SYSTEM	20		WIND	30.18%	6	0%	0
Mystic	MYSTIC	NWMT.SYSTEM	12		HYDRO	46.92%	6	25%	3
Powerex PPA	BPAT.NWMT	NWMT.SYSTEM	100		IMPORT	100.00%	100	100%	100
Powerex PPA	BPAT.NWMT	NWMT.SYSTEM	60		IMPORT	100.00%	60	100%	60
Qualifying Facilities	Various	NWMT.SYSTEM	2		HYDRO	0.00%	0	0%	0
River Bend Solar, QF	QFS	NWMT.SYSTEM	2		SOLAR	21.95%	0	0%	0
South Mills Solar 1, LLC	QFS	NWMT.SYSTEM	3		SOLAR	24.45%	1	0%	0
Spion Kop	SPIONKOP	GTFALLSNWMT	40		WIND	33.70%	13	0%	0
South Peak Wind	SOUTHPEAK	GTFALLSNWMT	80		WIND	41.89%	34	0%	0
Stillwater Wind	STILLWIND	NWMT.SYSTEM	80		WIND	37.12%	30	0%	0
Thompson Falls	TFALLS	NWMT.SYSTEM	94		HYDRO	56.98%	54	29%	27
Two Dot Wind, QF	TWODOT	NWMT.SYSTEM	10		WIND	38.51%	4	0%	0
Turnbull Hydro	TURNBULL	GTFALLSNWMT	13		HYDRO	21.46%	3	0%	0
		Total Designated Capacity	2105			Total Average MW	966	Total Minimum MW	477

* New solar resources inherit average capacity factor of existing resources
** New Battery and Gas resources have no assumed capacity factor or minimum

Appendix H

Resource Cost Estimates with WRAP and IRA Assumptions

The table below presents resource costs as adjusted by the resource's capacity accreditation and estimated IRA-related reductions (as applicable). The values utilize WRAP summer and winter ELCC estimates, and assume 30% IRA tax credits for the applicable resources. The calculated effects of IRA credits presented here are rough estimates only and do not necessarily reflect actual deductions as those would be based on developer-specific requirements. The cost of capacity is presented as the levelized Revenue Requirement (including credits) plus first year Fixed O&M costs divided by the accredited capacity ($/kWQCC-yr). The underlying calculations are provided in the electronic files.

		Nameplate Capacity				Summer WRAP ELCC			Winter WRAP ELCC		
No.		Generation (MW_{ac})	Storage (MW_{ac})	Installed Overnight[1,2] ($/kW)	Installed Overnight w/ IRA Tax Credits[7] ($/kW)	Qualifying Capacity Credit (MW_{QCC})	RR + Fixed O&M ($/$kW_{QCC}$-yr)	RR w/ IRA Tax Credits + Fixed O&M[7] ($/$kW_{QCC}$-yr)	Qualifying Capacity Credit (MW_{QCC})	RR + Fixed O&M ($/$kW_{QCC}$-yr)	RR w/ IRA Tax Credits + Fixed O&M[7] ($/$kW_{QCC}$-yr)
1	Wind	100	-	$ 1,970	$ 1,379	14.2	$ 1,652.85	$ 1,243.39	30.0	$ 782.35	$ 588.54
2	Wind	300	-	$ 1,764	$ 1,235	42.6	$ 1,457.77	$ 1,091.02	90.0	$ 690.01	$ 516.41
3	Solar PV - SAT	100	-	$ 1,864	$ 1,305	30.4	$ 732.45	$ 535.58	2.7	$ 8,246.83	$ 6,030.27
4	Solar PV - SAT	300	-	$ 1,662	$ 1,163	91.2	$ 653.15	$ 477.70	8.1	$ 7,354.04	$ 5,378.52
5	BESS - Li-Ion[3] - 2hr duration	-	25	$ 1,242	$ 869	10.0	$ 382.43	$ 278.30	10.0	$ 382.43	$ 278.30
6	BESS - Li-Ion - 5hr duration	-	25	$ 2,570	$ 1,799	25.0	$ 322.09	$ 235.87	25.0	$ 322.09	$ 235.87
7	BESS - Li-Ion - 4hr duration	-	50	$ 1,984	$ 1,389	40.0	$ 311.64	$ 228.46	40.0	$ 311.64	$ 228.46
8	BESS - Li-Ion - 5hr duration	-	50	$ 2,398	$ 1,679	50.0	$ 302.36	$ 221.92	50.0	$ 302.36	$ 221.92
9	BESS - Li-Ion - 8hr duration	-	50	$ 3,576	$ 2,503	50.0	$ 454.07	$ 334.12	50.0	$ 454.07	$ 334.12
10	BESS - Li-Ion - 5hr duration	-	100	$ 2,237	$ 1,566	100.0	$ 283.94	$ 208.88	100.0	$ 283.94	$ 208.88
11	Wind + BESS - 5hr duration	100	50	$ 3,147	$ 2,203	42.8	$ 895.39	$ 666.41	53.3	$ 718.55	$ 534.79
12	Solar + BESS[4] - 5hr duration	100	50	$ 2,993	$ 2,095	53.6	$ 679.95	$ 497.69	35.1	$ 1,037.34	$ 759.29
13	Solar + BESS - 5hr duration	100	100	$ 4,009	$ 2,806	65.2	$ 756.55	$ 554.48	51.4	$ 960.60	$ 704.03
14	Solar + BESS - 5hr duration	300	150	$ 2,673	$ 1,871	160.8	$ 610.03	$ 447.25	105.4	$ 930.68	$ 682.33
15	PHES (Slice of Larger Project)	-	100	$ 3,561	$ 2,493	100.0	$ 348.82	$ 249.42	100.0	$ 348.82	$ 249.42
16	Geothermal	20	-	$ 4,038	$ 2,827	19.0	$ 621.58	$ 482.10	19.0	$ 621.58	$ 482.10
17	SC CT - Aero[5]	50	-	$ 1,867	$ 1,867	49.3	$ 226.68	$ 226.68	49.3	$ 226.91	$ 226.91
18	SC RICE[5]	50	-	$ 2,141	$ 2,141	49.3	$ 265.20	$ 265.20	49.6	$ 263.59	$ 263.59
19	SC RICE[5]	150	-	$ 1,719	$ 1,719	147.8	$ 208.14	$ 208.14	148.7	$ 206.88	$ 206.88
20	CCCT[6]	250	-	$ 1,640	$ 1,640	246.5	$ 200.73	$ 200.73	246.3	$ 200.93	$ 200.93
Definitions: RR = Revenue Requirement, QCC = Qualified Capacity Credit											

Notes

1. Overnight installed costs include direct and indirect EPC project costs and owner's cost but exclude AFUDC, electric transmission network upgrades, and bulk gas system upgrades, as applicable.
2. Overnight installed ($/kW) and fixed O&M ($/kW-yr) costs expressed based on dividing total costs by the renewable component output.
3. BESS resources based on lithium ion technology, 365 equivalent cycles per year, and capacity augmentation throughout the study period.
4. Solar + BESS hybrid resources based on dc-connected, SAT solar PV.
5. O&M costs for simple cycle configurations assume a dispatch profile of 100 starts per year and 1,000 hours of operation per year.
6. O&M costs for combined cycle configurations assume a dispatch profile of 150 starts per year and 4,000 hours of operation per year.
7. This table presents IRA credits as a 30% reduction to the cost estimates