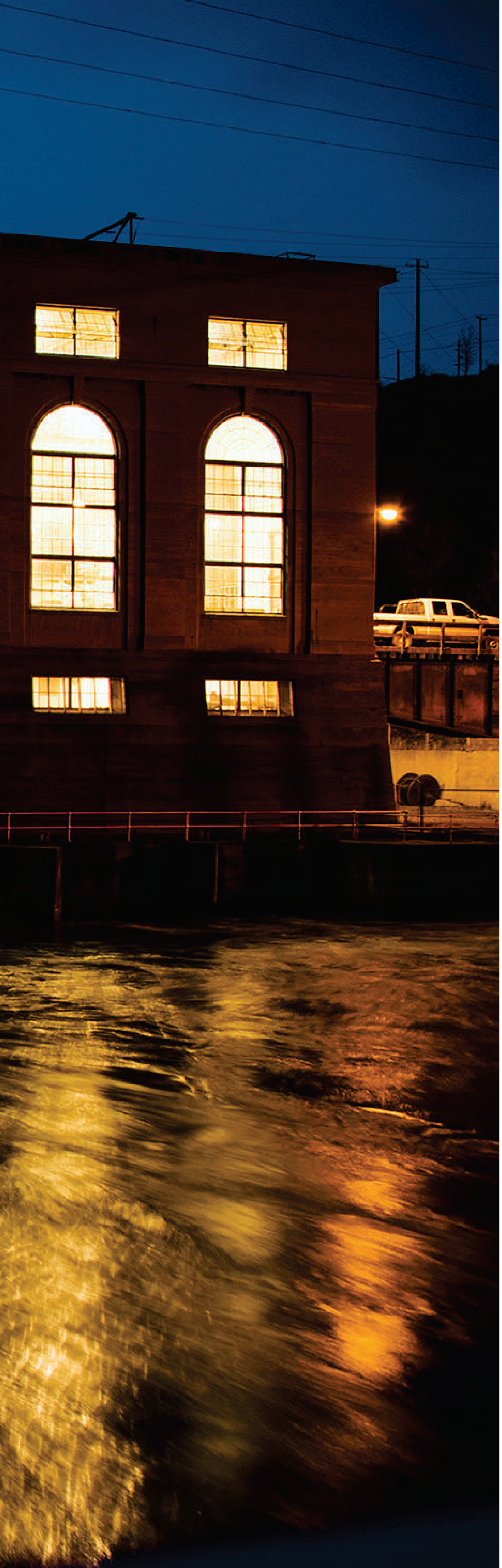

2019 Electricity Supply Resource Procurement Plan

Docket No. N2018.11.78

August 2019

Delivering a Bright Future

NORTHWESTERN ENERGY

2019 ELECTRICITY SUPPLY RESOURCE

PROCUREMENT PLAN

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NORTHWESTERN ENERGY

2019 ELECTRICITY SUPPLY RESOURCE PROCUREMENT PLAN

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CHAPTER 1
EXECUTIVE SUMMARY

Montana's energy landscape is evolving, changing from a state that produces more electricity than our citizens can use 24x7, 365 days a year, to a state where there is a growing risk there won't be enough electricity to serve our citizens at critical times of peak load. A similar situation is occurring throughout the Pacific Northwest – a key source for NorthWestern's market purchases. The NorthWestern Energy Electricity Supply Resource Procurement Plan addresses this critical risk and outlines how the company's Montana customers' energy needs will be met with reliable energy at the lowest cost.

Reductions in regional and in-state coal generation are limiting the ability of Montana to import and export energy, and growth in customer energy demand across the Pacific Northwest means the energy available from the market will be less certain at key times and prices will be more volatile. NorthWestern Energy has been reducing our customers' exposure to the market by developing a portfolio that includes hydro, natural gas, coal, wind, and solar generation. However, in order to manage the increasing risk to our customers and continue providing them with reliable energy, NorthWestern Energy must work quickly to reduce our customers' exposure to power markets, especially for certain types of power products.

In early March 2019, Mid-C peak bulk power prices reached nearly $1,000/MWh for the first time since 2000 and natural gas also traded at record high prices. While the region was experiencing extreme weather, analysis indicates that decreased market liquidity was also a significant factor. NorthWestern is concerned events like this may become more frequent and is taking steps to mitigate current wholesale market exposure. Continuing to assume the market will always be able to provide customers with sufficient electricity at affordable prices is a reckless approach that could have severe reliability and cost consequences.

OUR CUSTOMERS' MAJOR RISK IS NOT HAVING SUFFICIENT ENERGY WHEN THEY NEED IT MOST.

- NorthWestern Energy's current peak requirement (the amount of electricity needed to service all customers at the times of highest demand plus a planning reserve margin) is about 1,400 megawatts (MW). This is 645 MW more than the peak capability of NorthWestern's current portfolio.
- Planned regional retirement of 3,600 MW of coal-fired generation will cause regional peak energy shortages as early as 2021.
- Due to planned Montana coal generation retirements (and potential unplanned retirements), critical transmission capacity and access to other states' power markets will be limited.
- NorthWestern is planning to join the Western Energy Imbalance Market (EIM) in 2021 which will bring many benefits to our customers. However, this will require NorthWestern to control sufficient supply to meet hourly loads – including peak loads.
- Regional discussions are currently underway to build upon the EIM and develop a more fully organized market which will require NorthWestern to control the full amount of peak energy to serve demand, plus a reserve margin.

The Colstrip Transmission System was designed to primarily export energy, but it is also used to import energy from out-of-state sources, especially during critical times. Due to its designed purpose, under many circumstances the Colstrip Transmission System may not be adequate to import energy from markets outside of Montana to replace the power used in Montana that is generated now at the Colstrip units.

Planning For the Future

Capacity Needs

NorthWestern Energy's current resources provide about 755 MW of peaking capacity, which is the energy available during periods of our customers' highest demand. An additional 645 MW of peaking capacity must currently be purchased from the market to meet our needs.[1] Without new peaking capacity, the market exposure will increase to about 725 MW by 2025 (including reserve margins). This peaking need assumes continued development of cost-effective demand side management (conservation) and small distributed generators (net-metering). Meeting peak load with market purchases means being exposed to the market at the worst possible time – when the market is volatile and prices are high.

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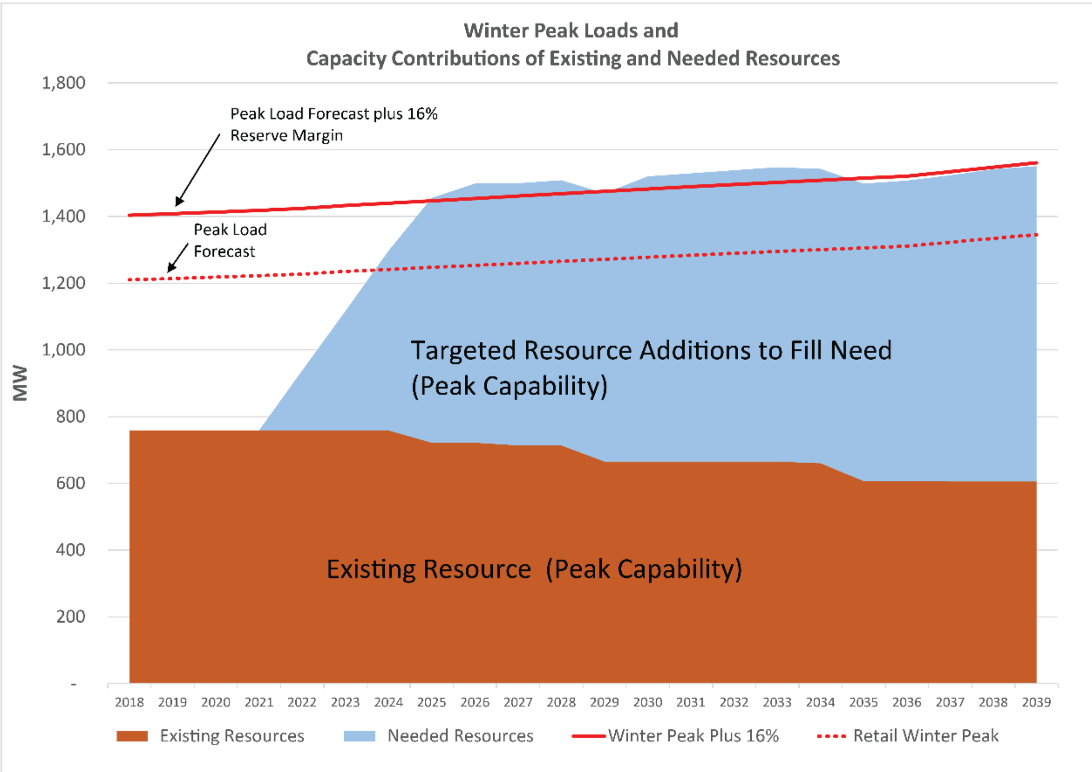
[1] 455 MW not including our required reserve margin

Figure 1-1. Peaking Capacity Needs



NorthWestern Energy's customers require the most energy during times of extreme hot or extreme cold temperatures. Fast, dispatchable generation resources are needed to provide reliable service to our customers during these times of high demand. Wind generation is low during these periods due to the low or nonexistent winds associated with high pressure systems accompanying temperature extremes. Solar generation contributes to summer peak loads but provides no significant contribution to address winter peak loads, which occur after sunset.

Flexible Capacity Needs

NorthWestern's customers need resources capable of providing more than just energy and peaking capacity. NorthWestern's resource portfolio generally generates enough energy to serve average load, but is significantly short both peaking and flexible capacity.

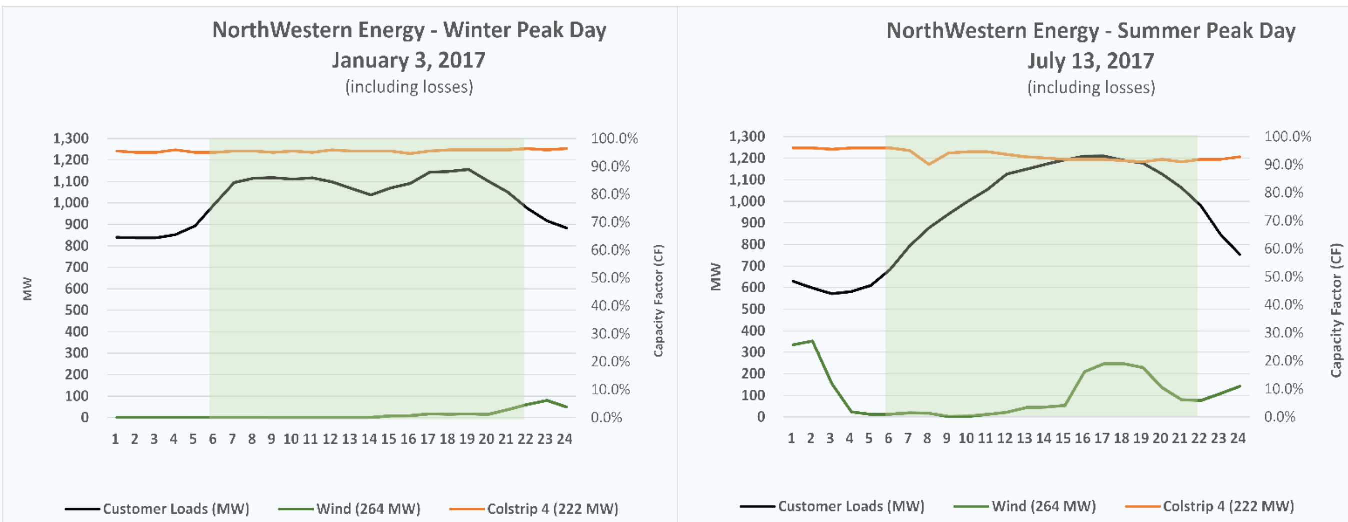
Resources that can be dispatched on-demand to ramp up or shut down relatively quickly are identified as flexible capacity. Flexible capacity is needed to match generation to short-term variations in load. Additionally, variable energy resources like wind and solar require dispatchable energy resources to balance the energy grid and assure reliability. NorthWestern Energy's current levels of flexible capacity resources are adequate for the existing resource portfolio, but will fall short following the current planned (and future unplanned) additions of wind and solar resources. *(Unplanned additions come mainly through "Qualifying Facilities" that our customers are required to purchase by law.)*

Energy Needs

While NorthWestern Energy has an immediate need for resources during periods of highest demand, our current portfolio is much better off when looking at customers' average energy needs. The type of products generation resources can produce is critical to ensure the specific needs of the portfolio are met without having to acquire excess generation. During heavy load hours, the current resource portfolio produces a little less energy (on a monthly basis) than customers consume. During light load hours, the portfolio produces more energy (on a monthly basis) than customers consume. Excess energy is sold into the wholesale electricity market at lower prices, often lower than the cost of the energy being produced. This is done because NorthWestern must take the energy from variable resources like wind even if it is not needed, and the hydro and thermal resources like Colstrip have minimum production levels or must be operating in order to respond to changes in wind generation or loads.

Wind and solar are capable of providing low-cost energy but are generally not available when customers need it most, such as after sunset on the coldest winter days in December and January. The Winter and Summer peak load days of 2017 (January 3rd and July 13th) are shown in Figure 1-2 below. The black line represents customer load - shown as MW on the left hand scale. The dashed green line shows wind production as percentage of its nameplate capacity on the right hand scale. The orange line represents Colstrip 4 production, also shown as a percentage of its nameplate capacity on the right hand scale. NorthWestern has seen this pattern repeatedly since 2017, most recently during a cold spell occurring the week of February 4th, 2019.

Figure 1-2. 2017 Peak Load Days

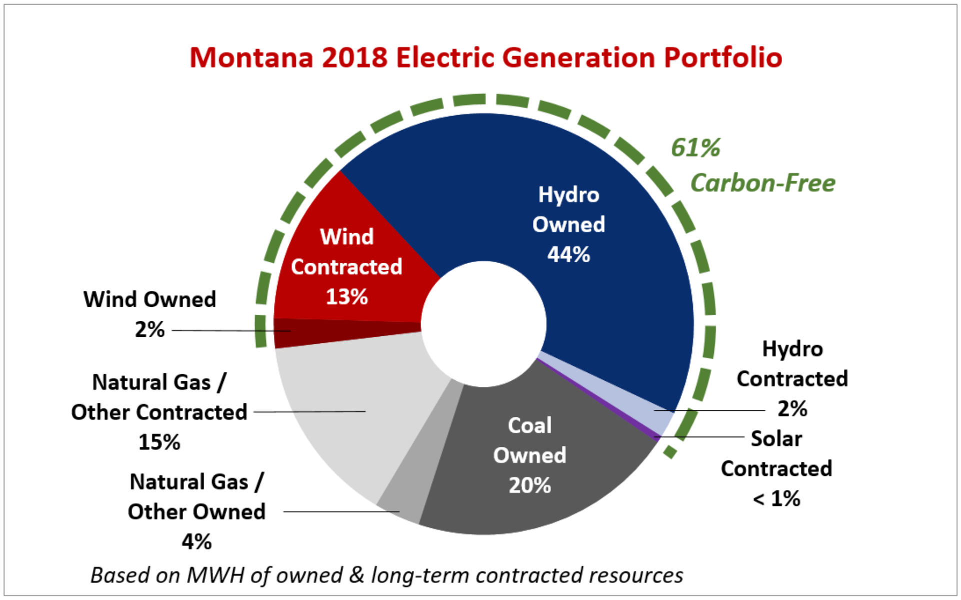


As illustrated above, wind contributed very little of its maximum generation capability (especially on the critical winter peak day), while Colstrip 4 generated at 90 to 95 percent of its maximum capability. During peak load periods, customers need resources that NorthWestern can call upon as needed, 24 hours a day, 7 days a week.

Carbon Emissions

NorthWestern Energy purchased 11 hydroelectric facilities in 2014 with a current generating capacity of 448 MW (with potential for future upgrades). The hydroelectric system is primarily a run-of-the-river system which provides a large part of the backbone of our generation portfolio, contributes significantly to our low cost carbon-free energy production, and provides system reliability for our customers. In 2018 NorthWestern's energy portfolio produced 61% carbon free energy.

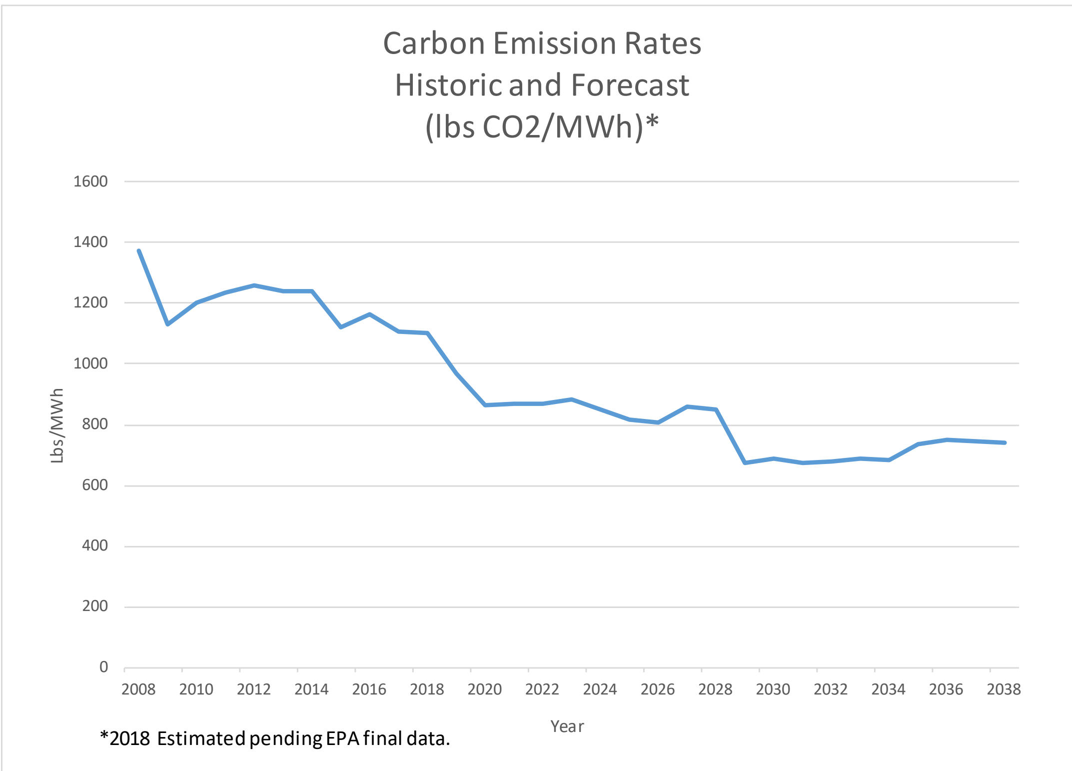
Figure 1-3. Percent of 2018 Electric Generation Portfolio



With the help of Montana's generation portfolio, NorthWestern continues to be one of the leaders in the industry for carbon free portfolios. Carbon dioxide emissions associated with NorthWestern's Montana portfolio have been significantly less than nearly all of our peer utilities.

From 2008 to 2018, carbon dioxide emissions associated with NorthWestern's resource portfolio have declined, and they are forecast to continue to decline. Resource opportunities, technology improvements, and technology cost reductions could also reduce emissions. As shown in Figure 1-4, carbon emissions associated with the Base portfolio decline over the term of the plan. Significant declines occur when Colstrip Energy Limited Partnership (CELP) and Yellowstone Energy Limited Partnership (YELP) leave the portfolio.[2] Together, CELP and YELP provide about 11% of the energy in our portfolio but contribute about 35% of the carbon dioxide emissions.

Figure 1-4. Historic and Future Carbon Emissions



From 2008 to 2018 carbon dioxide emissions associated with NorthWestern's resource portfolio have declined, and are forecast to continue to decline (Base portfolio shown above).

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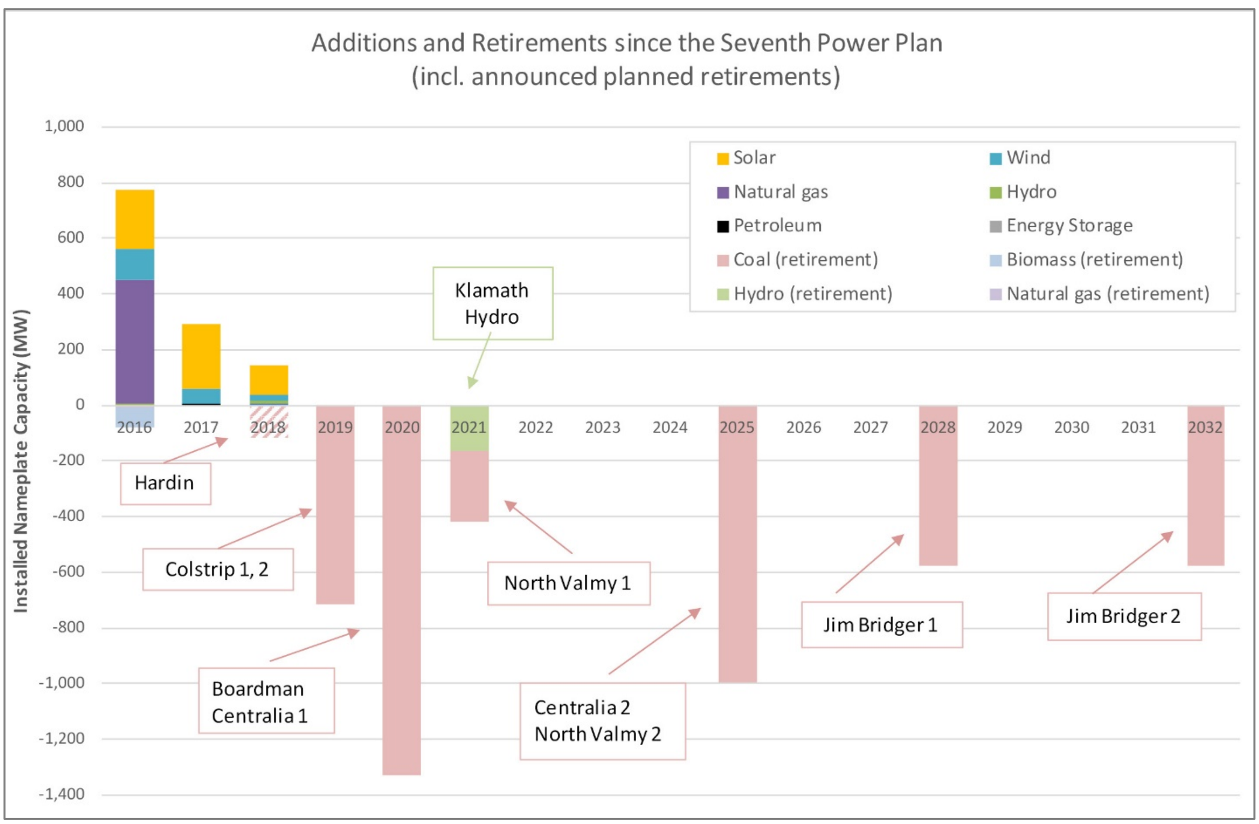
[2] CELP is a 41.5 MW waste coal-fired Qualifying Facility with a contract that expires 6/30/2024.

YELP is a 65 MW petroleum coke-fired Qualifying Facility with a contract that expires 12/31/2028.

State and Regional Coal Retirements

Planned retirements in the Pacific Northwest region exceed 3,600 MW and the Northwest Power and Conservation Council forecasts regional capacity shortfalls as early as 2021. NorthWestern Energy's continued reliance on the market to purchase energy to fill the gap during peak customer demand will significantly increase price and reliability risk for NorthWestern Energy's customers because of the reduced energy supply availability. Future technological advances will help mitigate this risk, but NorthWestern Energy has an ongoing obligation to plan for affordable and reliable resources.

Figure 1-5. Planned Generation Retirements



Source: Northwest Power and Conservation Council

Note: Hardin is idle, but has not been retired.

Transmission Constraints

Transmission capacity is necessary for market access in order to purchase (import) and sell (export) power. During the most critical periods, NorthWestern Energy relies heavily on imports into our system in order to meet customer needs. The transmission system in Montana was constructed around, and is heavily reliant on, the generating resources and their location, including the entire Colstrip Power Plant. Retirement of Colstrip units will impact NorthWestern Energy's ability to import sufficient power to meet peak energy demand. As discussed earlier (page 1-3), the transmission lines at Colstrip are limited for the import of energy because they are designed to export energy. Another concern is that if no additional generation is built to justify keeping the current Colstrip transmission lines, those lines could also be retired, which will contribute to bottlenecks in the remaining energy transmission system used in Montana to serve NorthWestern Energy customers.

Integrating Our Grid and Markets

A significant event affecting NorthWestern's 2019 Resource Procurement Plan process was the decision by NorthWestern to join the EIM. On November 8, 2018, NorthWestern announced our intent to enter the Western EIM in the spring of 2021. With NorthWestern's execution of an Implementation Agreement, the total number of active and pending participants in the Western EIM now totals 14 utilities serving 80 percent of customer loads within the US portion of the WECC. Additionally, Bonneville Power Administration is currently undertaking a stakeholder process to consider EIM entry, and could join as early as 2022.

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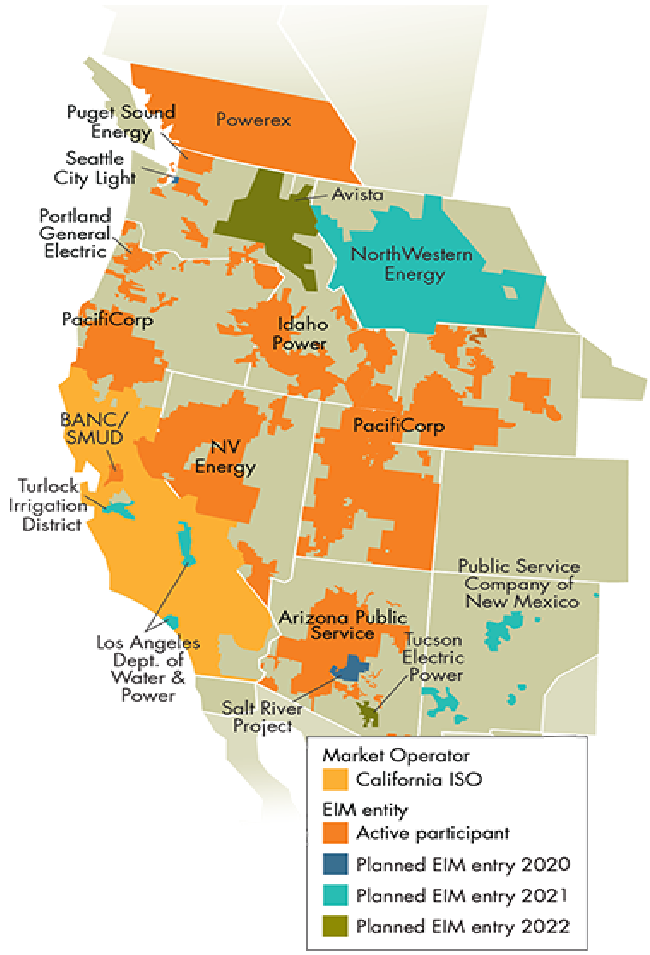
Figure 1-6. EIM Active and Pending Participants



Active Participants

- PacifiCorp, 2014
- NV Energy, 2015
- Puget Sound Energy, 2016
- Arizona Public Service, 2016
- Portland General Electric, 2017
- Idaho Power, 2018
- Powerex, 2018
- BANC/SMUD, 2019

Pending Participants

- Salt River Project, 2020
- Seattle City Light, 2020
- Public Service of NM, 2021
- NorthWestern Energy, 2021
- Avista, 2022
- LADWP, 2021
- Tulock Irrigation Dist, 2021
- Tucson Electric, 2022

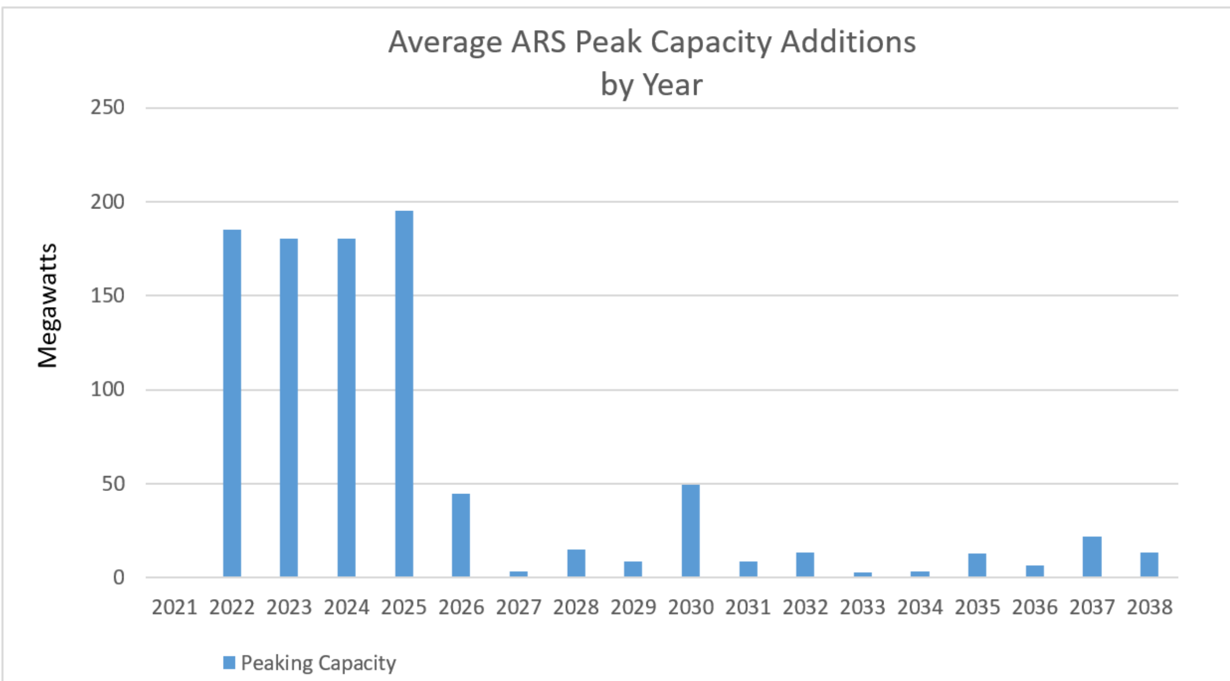
Regional Transmission Organization (RTO)

In early 2018, the California Independent System Operator (ISO) began a process to enhance the day-ahead market within the full Independent System Operators footprint (the EDAM initiative). The enhancements to CAISO's day-ahead market are targeted to go live in 2019 with a platform that will allow the addition of a day-ahead market to the Western EIM. The extension of the day-ahead market to EIM participants, if supported by EIM members and CAISO, could go live as early as 2022. NorthWestern Energy assumes for the purposes of the 2019 Resource Procurement Plan that EIM entry will occur in 2021, and that a full RTO/ISO will develop by 2025.

Resource Portfolios

NorthWestern's resource plan shows the results of thirteen "future" resource portfolios. Each portfolio satisfies our peak capacity needs by adding resources that achieve resource adequacy by 2025 and maintain resource adequacy throughout the plan period. The graph below shows average peak capacity additions by year for all portfolios using automatic resource selection (ARS) to achieve a 16 percent reserve margin by 2025.

Figure 1-7. Peaking Capacity Additions by Year



The portfolios identify resources with known costs and indicate that thermal resources provide the best value (lowest cost) to meet our customers' future needs for peak capacity. Renewable resources and energy storage technologies are projected to continue to decline in cost, but are still more expensive than natural gas fired resources, and were not selected by the model. A portfolio which meets our customers' future resource needs without the addition of any new carbon producing resources would lower carbon emissions, but at a cost. Meeting our customers' future needs by adding carbon free resources is projected to cost $523,000,000 more than meeting their needs using natural gas fired resources. Moving to a 100% carbon free portfolio was not modeled, but a recent regional analysis indicates that it would be cost prohibitive.[3]

While our portfolio modeling shows that natural gas resources provide the lowest cost portfolio, competitive solicitations open to a wide variety of technologies will be used to determine which resources will ultimately serve our customers' needs as identified in this Plan at lowest cost.

Strategy in Action

In order to have adequate energy supplies to meet peak load requirements by 2025, NorthWestern Energy will solicit competitive proposals from a variety of resources and will also consider opportunity resource purchases. The model used to evaluate resources in this plan will also be used to evaluate resources submitted in competitive solicitations or opportunity resources. Opportunity resources consist of existing resources that become available for purchase and cannot be known or modeled in advance (the purchase of the hydroelectric system is a good example of an opportunity resource).

NorthWestern will use a staged approach, issuing a solicitation for short term capacity resources, an initial solicitation for up to 400 MW of long term capacity, followed by additional solicitations. NorthWestern Energy will evaluate all resources which can meet the portfolios' needs, including renewable and thermal based generation, power purchase agreements, and owned energy resources comprised of different structures, terms, and

[3] Resource Adequacy in the Pacific Northwest study to be released March 2019 by Energy + Environmental Economics (E3).

technologies with the long term objective of a lowest cost, stable, and reliable energy portfolio. NorthWestern's incremental approach will provide opportunities for different resource types and new technologies while also building a reliable portfolio to meet local and regional conditions and minimizing customer impacts.

In the past, NorthWestern has updated our Electricity Supply Plan every two years, involving a technical advisory committee with third party facilitators and multiple public meetings. With the passage of HB-597 NorthWestern will move to a three year planning cycle and will revisit the best structure and use of the technical advisory committee.

NorthWestern Energy will consider all opportunity resources and solicit competitive proposals to meet customers' future energy resource needs. NorthWestern Energy will use an independent evaluator to conduct a proposal solicitation process open to all resources (including "demand side" resources) for up to 400 MW of peaking capacity, which is about one-quarter of NorthWestern Energy's projected need in 2025. The proposal solicitation process will consider a wide variety of resource options, resource sizing, ownership options and contract lengths.

CHAPTER 2
PLANNING PROCESS AND HISTORY

NorthWestern Resource Planning Process and History

Montana Planning Requirements

The electricity supply resource planning process followed by NorthWestern complies with Montana Code Annotated (MCA) Title 69, Chapter 8, Part 4 (MCA 69-8) and Administrative Rules of Montana (ARM) Title 38, Chapter 5, Subchapter 82 (ARM 38.5.82: Default Electric Supplier Procurement Guidelines or "guidelines"). MCA 69-8-419 requires NorthWestern to plan for future electricity supply resource needs, manage a portfolio of electricity supply resources, and procure new electricity supply resources when needed while pursuing the following objectives:

- Provide adequate and reliable electricity supply service at the lowest long-term total cost;
- Conduct an efficient electricity supply resource planning and procurement process that evaluates the full range of cost effective electricity supply and demand side management options;
- Identify and cost effectively manage and mitigate risks related to its obligation to provide electricity supply service;
- Use open, fair, and competitive procurement processes whenever possible; and,
- Provide electricity supply service and related services at just and reasonable rates.

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."

NorthWestern has historically submitted biennial plans under these provisions every odd numbered year. In its comments on NorthWestern's 2015 Plan, the Montana Public Service Commission (MPSC) indicated Northwestern should file the next plan, which is this one, by December 15, 2018. On November 13, 2018, NorthWestern filed a Motion for Extension to file the 2019 Electricity Supply Resource Procurement Plan (2019 Plan), requesting an extension until February 15, 2019. On December 5, 2018, the MPSC issued a Notice of Commission Action which granted an extension of the deadline, with the following conditions:

- NorthWestern must file a draft plan for public review by March 15, 2019;
- Stakeholders must be given 60 days to provide comment on the draft plan;
- The final plan must contain a section which explains how NorthWestern considered and addressed public comments; and,
- Northwestern must file a final resource plan after the public comment period, but before December 15, 2019.

NorthWestern Resource Planning – Historical Context

NorthWestern's 2013 Plan

Shortly before submitting the 2013 Plan, NorthWestern announced an agreement to purchase the hydro assets of PPL Montana, LLC (referred to as the "hydro acquisition"). This was an "opportunity acquisition" as envisioned in our 2011 Plan. The 2013 Plan identified a portfolio with the hydro resources as having the lowest expected long-term cost relative to portfolios comprised of market transactions and combined cycle (natural gas) generation.

The 2013 Plan also recognized the potential for future imbalances between regional loads and resources due to the announced closures of several coal plants and plans by other utilities in the region to rely more heavily on market purchases to serve their loads. The potential for such regional imbalances continues to contribute to the Northwest Power and Conservation Council's (NWPCC) concerns about the adequacy of the regional power supply (these concerns are discussed in further detail below). The hydro acquisition significantly reduced NorthWestern's reliance on the market and exposure of supply costs to market price volatility, which increased NorthWestern's cost certainty and rate stability. The hydro acquisition marked an important step in NorthWestern's transition out of the planning paradigm that resulted from Montana's period of energy deregulation, during which time NorthWestern's predecessor divested itself of all generation assets.

NorthWestern's 2015 Plan

In our 2015 Plan (submitted to the MPSC in March of 2016), NorthWestern included analyses of the potential needs for additional capacity to address the large imbalance between projected peak loads and the maximum generation possible from the portfolio of owned and contracted resources. Despite NorthWestern's acquisition of the Hydros and other resources over the preceding ten years, peak loads still significantly exceeded NorthWestern's resource capacity. NorthWestern has historically overcome this imbalance through hourly market purchases of firm energy that replaced capacity. The 2015 Plan focused on the long-term uncertainty associated with over reliance on market transactions and the reliability concerns from assuming there will always be sufficient depth in the wholesale energy market to meet NorthWestern's capacity requirements. Regional supply conditions were undergoing fundamental changes (and still are) due to substantial additions of intermittent wind and solar resources, hydrologic flow restrictions, and planned retirements of coal resources which were (and are) anticipated to contribute to the increasing inadequacy of the regional supply portfolio (this is discussed below).

NorthWestern's capacity needs were also increasing as a result of new operating requirements, in particular the Reliability Based Control (RBC) standards required by the North American Electric Reliability Corporation (NERC).

As with the 2013 Plan, NorthWestern used the PowerSimm modeling software to analyze the performance of the energy supply portfolio and potential new resources across a wide range of possible future conditions. The model identified a portfolio comprised of dispatchable flexible generating capacity capable of providing ancillary services[1], load-following, and serving peak demand as the Economically Optimal Portfolio. The model also evaluated whether wind and solar photovoltaic (PV) resources could contribute to meeting NorthWestern's winter peak capacity demand and found neither resource to be a cost-effective alternative to gas-fired generation options because wind and solar are unable to serve as dispatchable resources and have low (wind) or zero (solar) capacity contributions during periods of peak winter loads.

MPSC Comments on the 2015 Plan

In its comments on the 2015 Plan,[2] the MPSC stated that the action items were generally reasonable but that NorthWestern should pursue a rigorous stakeholder process to validate the conclusions of the 2015 Plan rather than proceed directly with requesting proposals for a new flexible capacity resource[3]. The MPSC questioned the reasonableness of the economically optimal portfolio and identified five main concerns it had with the 2015 Plan.

[1] Ancillary services are those necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system and include: providing increases (INC) or decreases (DEC) in output on short notice; spinning and non-spinning contingency reserves; and, frequency response.

[2] The MPSC's complete comments on NorthWestern's 2015 Plan are available at http://psc2.mt.gov/Docs/ElectronicDocuments/getDocumentsInfo.asp?docketId=11712&do=false

[3] The MPSC's comments came 11 days prior to the release of a competitive solicitation for resources

A general overview of these concerns is provided below, followed by a description of NorthWestern's efforts to address the MPSC's concerns in the 2019 Plan.

1. The MPSC stated its primary concern with the 2015 Plan was that the resource adequacy constraint imposed in NorthWestern's portfolio analyses was not sufficiently justified and no support was offered for the proposed rate of acquiring capacity. The MPSC stated NorthWestern's resource adequacy should be measured by comparing NorthWestern's peak retail load position to the regional or interconnection peak demand accounting for import limitations. The MPSC also inferred that NorthWestern's objective of meeting "minimal resource adequacy" by 2021 appeared to refer to a portfolio of physical resources equal to retail peak load (rather than relying on market transactions). In its explanations of these concerns, the MPSC also requested that NorthWestern be more clear and precise in discussions of different types of capacity, and that NorthWestern make a determination of the base capacity capability of its current portfolio.

2. The MPSC expressed the concern that the resource alternatives NorthWestern evaluated in the 2015 Plan fell short of "the full range of cost effective supply and demand-side management options" as required in MCA § 69-8-419.

3. The MPSC stated the 2015 Plan did not sufficiently consider multiple sources of uncertainties that NorthWestern and customers may face in the future, including uncertainty in resource costs, capacity contributions and integration requirements for wind and solar resources, implications of transitioning to RBC standards, load forecasts and impacts of behind-the-meter distributed generation (including seasonality, capacity value, and energy production), natural gas price forecasts, carbon regulation, infrastructure costs (electric and natural gas), participation in the

EIM and associated impacts on the liquidity of energy and capacity markets, and the development of a regional ISO or RTO.

4. The MPSC stated the stakeholder process used in developing the 2015 Plan was insufficient and NorthWestern should pursue a rigorous stakeholder process to validate the conclusions in the 2015 Plan, including more frequent contact with Electric Technical Advisory Committee (ETAC), more timely provision of meeting materials, more information about NorthWestern's modeling and analyses, and greater representation of viewpoints on ETAC.

5. The MPSC stated the 2015 Plan did not demonstrate how a subsequent resource procurement process would be open, fair, and competitive and expressed that any requirements for minimum service periods ought to be well-justified and not exclude short-term options such as those potentially provided by existing resources. The MPSC also stated the owners of long-lived resources should bear some of the risk in the later years of such resources' lives that the performance of the resource differs, relative to market prices, from expectations.

NorthWestern Response to MPSC Comments

Following are descriptions how NorthWestern's 2019 Plan, and 2019 resource planning process, address the concerns raised in the MPSC's comments.

1. NorthWestern's 2019 Plan includes an analysis of the coincidence of NorthWestern's peak load hours with the region's peak load hours[4]. Additionally, the 2019 Plan discusses the continuing work of NWPCC on regional resource adequacy.

[4] Region in this context is the geographic area of concern for the NWPCC.

Concerning the Commission's comments that "minimal resource adequacy" by 2021 appeared to refer to a portfolio of physical resources, the comment comes from a misunderstanding of the 2015 Plan. The Commission should have been aware that NorthWestern planned to meet "minimal resource adequacy" through a competitive solicitation of proposals from a wide variety of resources under a wide variety of ownership positions.[5]

The MPSC asked NorthWestern to be more precise in our discussion of the different types of capacity that generation resources may provide and requested that NorthWestern determine the capacity capabilities of our existing resource portfolio. The 2019 Plan defines the various capacity attributes of our existing resource portfolio, identifies the capacity needs of our customers, identifies the capacity needs required to integrate additional variable energy resources into NorthWestern's resource portfolio, and identifies the peaking resources that NorthWestern will need to control as wholesale energy markets evolve.

2. NorthWestern did not analyze an expanded list of resource costs in the 2015 Plan because a very wide array of resource options were given an equal footing to compete in the 2017 flexible capacity RFP. In response to Commission comments, NorthWestern expanded the number of resource options for consideration in the 2019 Plan and retained HDR Engineering, Inc. (HDR) to analyze the costs and performance of a wide variety of new build resource options. HDR also conducted

[5] The 2015 Plan was filed on March 31, 2016. The Flexible capacity request-for-proposals (RFP) was discussed with ETAC at a meeting held on November 10, 2016. The MPSC is a member of ETAC. The MPSC issued its comments on February 2, 2017; NorthWestern issued its Competitive solicitation on February 13, 2017 (after a 30-day public comment period on the draft RFP). The RFP is provided in Volume 2, Chapter 2.

a request for interest ("RFI") to identify existing resources (also known as opportunity resources) for potential inclusion in the 2019 Plan analysis.[6]

3. The MPSC's comments identified a number of risk variables NorthWestern did not sufficiently address in the 2015 Plan. In some instances, issues could not have been addressed during the timing of the 2015 Plan due to lack of information. Following is the list of risk issues raised by the MPSC along with a discussion of how these risks are addressed in the 2019 Plan.
   - **Resource Costs**: HDR provided cost and performance characteristics for a wide variety of resource options, and also conducted an RFI. NorthWestern will conduct an RFP process to acquire our customers' future resource needs. The RFP process will provide the best available resource information and costs, far surpassing NorthWestern's "snapshot in time" analysis.
   - **Capacity contributions and integration of wind and solar**: North-Western's transmission group conducted a variable energy resource (VER) study to identify resource requirements for additional wind and solar generation.
   - **Transition to RBC**: A study to address the transition to RBC was not performed for the 2015 plan because the data did not exist and implementation of RBC was compulsory. RBC test period operations started in March of 2016 and full implementation didn't occur until July of 2016. RBC data was used in the VER Study mentioned above.
   - **Net metering impacts**: NorthWestern retained Navigant to conduct an economic analysis and evaluation of solar PV net energy metering (NEM) costs and benefits in Montana and to submit the study to the MPSC before

[6] The RFI is provided in Volume 2, Chapter 2.

April 1, 2018. The Navigant NEM study is explained in more detail in Chapter 3.

4. NorthWestern conducted a rigorous stakeholder process for the 2019 Plan. We believe the participation of ETAC, the public, and several supporting studies have helped foster a greater understanding of the needs of our retail customers, the various types of resources and the current and anticipated state of the markets. Following are some highlights of the stakeholder process.
   - NorthWestern retained a moderator for ETAC meetings to guide meetings and encourage input from ETAC members.
   - The number of ETAC meetings increased from five for the 2015 Plan, to eighteen for this plan.
   - Four PowerSimm modeling workshops were held for the benefit of ETAC members.
   - Three public meetings were held prior to the release of the draft plan for public comment. ETAC and the public were given 60 days to provide comments on the draft plan.

NorthWestern Resource Planning – Regional Context

The Pacific Northwest has historically had a surplus of generating capacity. However, recent studies question the ability of the regional power supply to meet future capacity needs. In the broader regional context of the Pacific Northwest, NorthWestern is a relatively small player whose peak retail loads of around 1,200 MW amount to less than 4 percent of the regional peak, which has recently reached nearly 35,000 MW. Additionally, relative to other investor-owned utilities in the region, NorthWestern serves a much smaller share of our retail load with utility-owned resources. The remainder of this section discusses these factors in more detail.

Regional Resource Adequacy

The most recent assessment of the adequacy of the regional power supply in the Pacific Northwest is from the NWPCC dated June 14, 2018 and entitled "Pacific Northwest Power Supply Adequacy Assessment for 2023".[7]

Executive Summary – Pacific Northwest Power Supply Adequacy Assessment for 2023

> Accounting for existing resources, planned resources that are sited and licensed, and the implementation of the NWPCC's energy efficiency targets, the Northwest power supply is likely to become inadequate by 2021, primarily due to the retirement of the Centralia 1 and Boardman coal plants (1,330 MW combined). The loss-of-load probability (LOLP) for that year is estimated to be over 6 percent, which exceeds the NWPCC's standard of 5 percent.
>
> By 2022 the LOLP is projected to rise to about 7 percent, due to the additional retirements of the North Valmy 1 coal plant, the Colstrip 1 and 2 coal plants and the Pasco gas-fired plant (479 MW combined). In 2023 the LOLP is expected to remain at about 7 percent. The increase in LOLP would be higher except for the NWPCC's targeted energy efficiency savings and savings from codes and federal standards. Additional capacity needed to maintain adequacy is estimated to be on the order of 300 MW in 2021 with an additional need for 300 to 400 MW in 2022.

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[7] Pacific Northwest Power Supply Adequacy Assessment for 2023. NWPCC, June 14, 2018, available at https://www.nwcouncil.org/reports/pacific-northwest-power-supply-adequacy-assessment-2023.

It should be noted that this analysis examines the adequacy of the aggregate regional power supply. Individual utilities within the Northwest have varying resource mixes and loads and, therefore, have varying needs for new resources. In aggregate, Northwest utilities have identified 540 MW of wind, about 800 MW of unspecified fuel source capacity and other small resources that could be developed by 2021, if needed. These planned resources are not included in this assessment because they are not sited and licensed. Also excluded from this analysis are approximately 400 MW of demand response, which is the remaining part of the 600 MW identified in the NWPCC's Seventh Power Plan as likely being available by 2021. While the NWPCC believes this level of demand response will be available, it is not included in this analysis because of ongoing concerns regarding barriers to its acquisition.

While it appears that regional utilities are well positioned to face the anticipated shortfall beginning in 2021, different manifestations of future uncertainties could significantly alter the outcome. For example, the results provided above are based on medium load growth. Reducing the 2023 load forecast by 2 percent results in an LOLP of just under 5 percent and has roughly the same effect as adding 650 MW of capacity. Increasing the load forecast by 2 percent raises the 2023 LOLP to about 10 percent and almost doubles the amount of capacity needed (from 650 to 1,000 MW) to satisfy the NWPCC's 5 percent standard.

The reference case results assume a conservative level of available Southwest market supply. Increasing that supply by 500 MW lowers the 2023 LOLP to a little over 5 percent and only about 50 MW of additional capacity are needed to meet the NWPCC's 5 percent standard. However, decreasing the Southwest market supply by 500 MW raises the LOLP to 8.6 percent and would require 1,050 MW of additional capacity.

Reducing the load forecast by 2 percent and increasing the Southwest market availability by 500 MW lowers the LOLP to 3.5 percent and no additional capacity is required for adequacy. However, increasing the load forecast by 2 percent and decreasing the Southwest market by 500 MW raises the LOLP to 12 percent and requires about 1,500 MW of additional capacity to satisfy the NWPCC's adequacy standard.[8]

The Relationship between NorthWestern's and the Region's Peak Loads

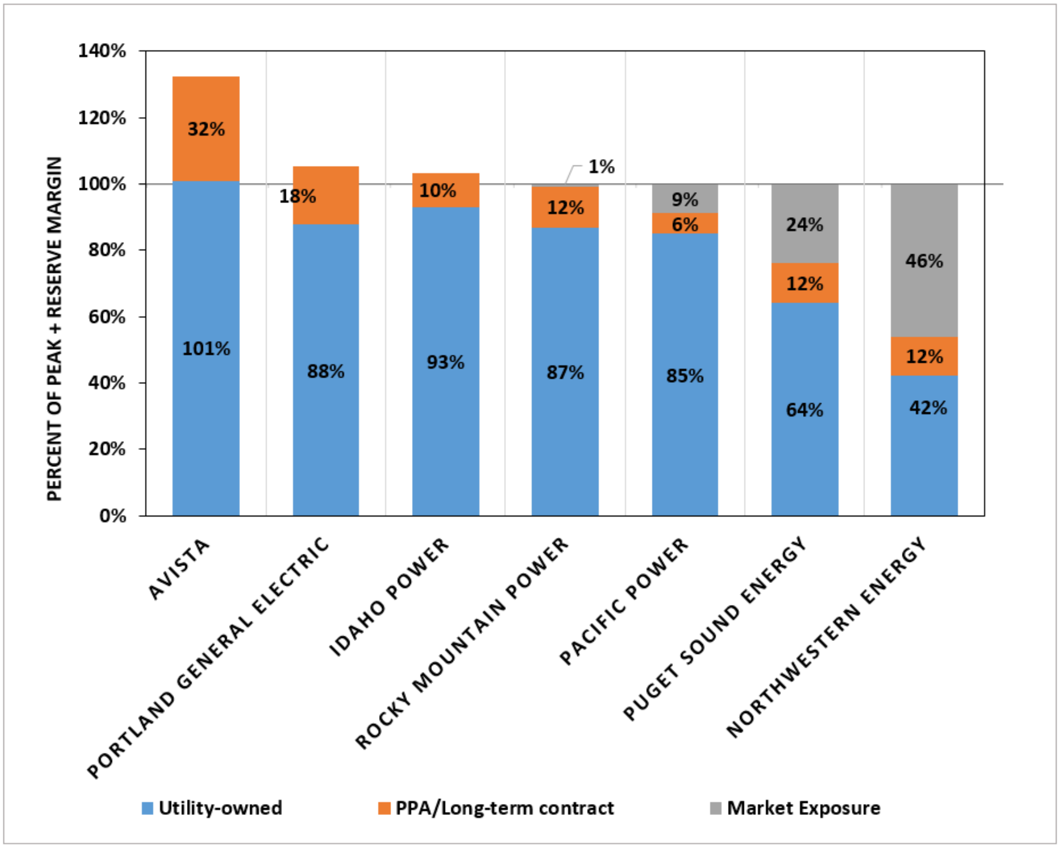
The NWPCC's assessment predicts the region will have a capacity deficit in the next 3 to 4 years, though it notes there are a wide range of uncertainties that could lead to substantially different levels of regional adequacy. These uncertainties arise from the uncertainty in future regional loads, the level of imports that may be available from the Southwest market, and developments in energy efficiency and demand response. Additionally, the area considered in the NWPCC's assessment extends to the continental divide and thus includes only a portion of NorthWestern's balancing area. Furthermore, as the NWPCC explains, "individual utilities within the Northwest have varying resource mixes and loads and, therefore, have varying needs for new resources."

Compared to other investor-owned utilities in the region, NorthWestern's load to resource balance is the shortest. This means the generating capacity of NorthWestern's resource portfolio relative to our peak load is smaller than any of the other utilities' resource portfolios. Therefore, to meet peak load responsibilities, NorthWestern relies more heavily on short-term market purchases of hourly firm energy for our capacity than any of these

[8] Executive summary from the Pacific Northwest Power Supply Adequacy Assessment for 2023. NWPCC, June 14, 2018, available at https://www.nwcouncil.org/reports/pacific-northwest-power-supply-adequacy-assessment-2023.

other utilities. See the following figure, which shows the current capacity positions for 7 investor-owned utilities in the Pacific Northwest.

Figure 2-1. Capacity Position as a Percentage of Peak Load + Planning Reserve Margin[9]



[9] Notes on Figure 2-1: This figure was constructed using data from each utility's most recently available Integrated Resource Plan and reflects the year of data closest to the present (which was 2017 for some utilities and 2018 for others). The breakdown of utility-owned versus contracted resources is approximate because some utilities report some long-term contracts together with their utility-owned resources. Market exposure is calculated by adding each utility's stated Planning Reserve Margin to its expected peak load and then subtracting from this its owned resources and PPAs/long-term contracts. NorthWestern's is calculated with a 16 percent planning reserve margin (PRM), which is consistent with that used elsewhere in this plan for portfolio modeling and approximately equal to the 16.4 percent PRM assigned by NERC to the Pacific Northwest (WECC NWPP-US) in NERC's 2017 Long-term Reliability Assessment.

NorthWestern's heavy reliance on the market is apparent not only when expressed as a percentage of peak load but in absolute terms as well. NorthWestern's market exposure is approximately 645 MW. Compared to other utilities, even those much larger than NorthWestern, this is significant. For example, Pacific Power's market exposure is only equal to about half of NorthWestern's (330 MW vs 645 MW), even though Pacific Power's peak load is 2.7 times greater. Rocky Mountain Power's peak is five times larger than NorthWestern's, yet their market exposure is 90 percent *less* than NorthWestern's. Similar patterns also hold for Avista, Portland General Electric, and Idaho Power, who each have *larger loads* than NorthWestern but *less exposure to the market*.

NorthWestern's load generally peaks during the same seasons and hours as the region. Like the region, NorthWestern has a winter-peaking load and the months identified by the NWPCC as the periods most likely to experience inadequacy—December, January, and February—correspond to NorthWestern's times of greatest need.[10] The similarities in the seasonal patterns between NorthWestern's load and the regional load can be seen in the following figure.

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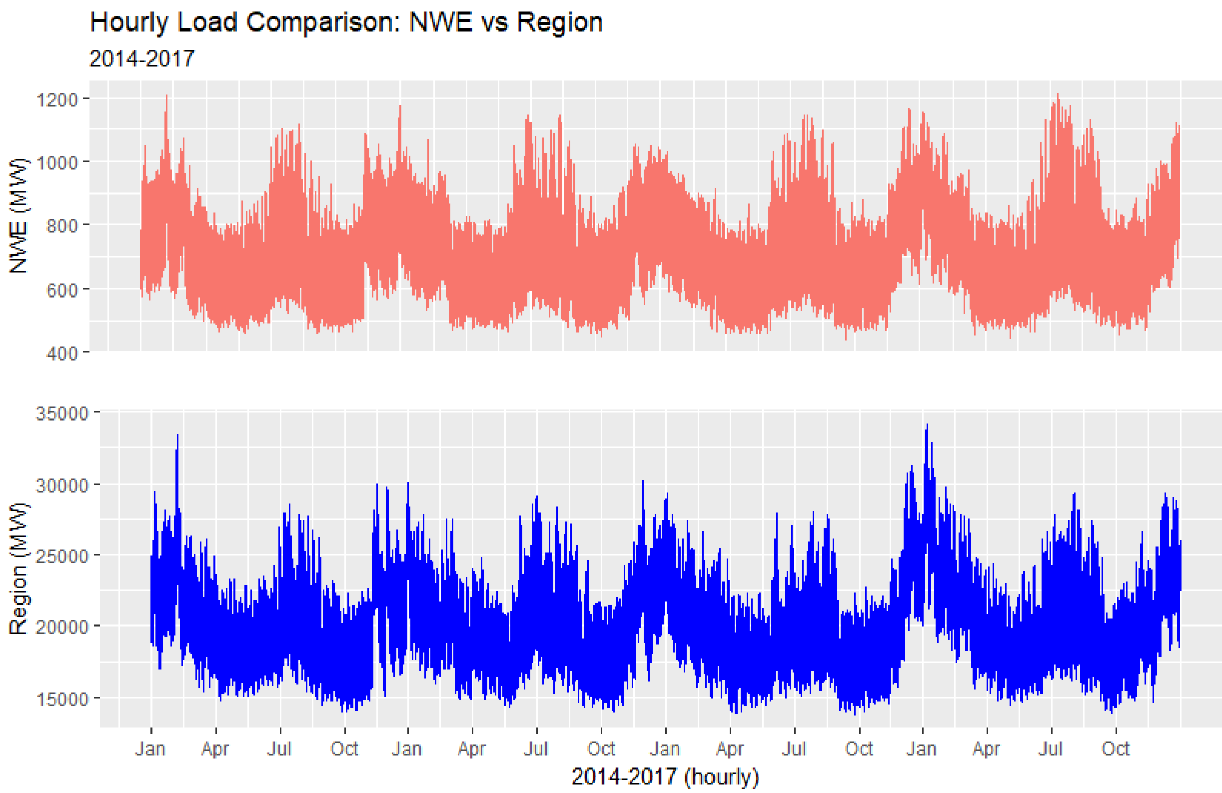
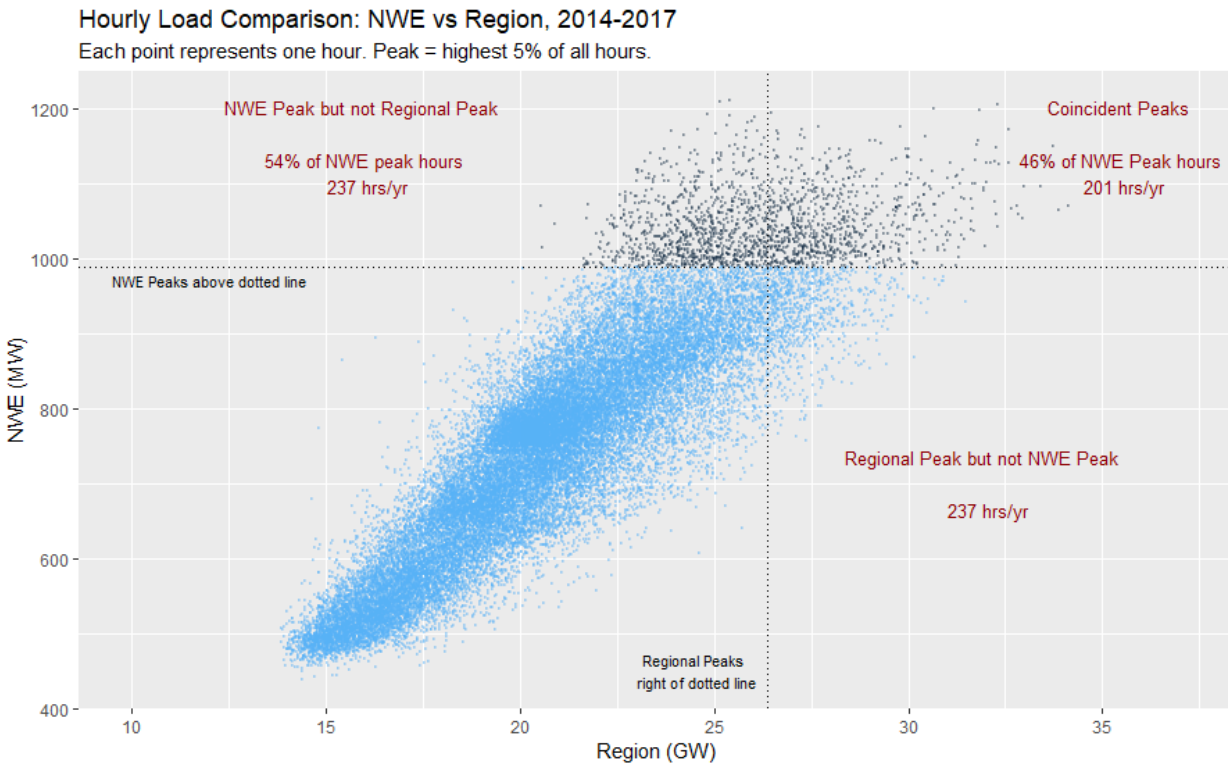
[10] Pacific Northwest Power Supply Adequacy Assessment for 2023, page 13, Figure 1. NWPCC, June 14, 2018.

Figure 2-2. Hourly Loads: NorthWestern vs. Regional



At an hourly level, NorthWestern's load and the regional load are highly correlated (correlation coefficient of 0.89). The following graph shows this relationship. From 2014 to 2017, about half of the time when NorthWestern's load was peaking (defined here as the top 5 percent of loads), the region was also peaking. Clearly, the coincidence of NorthWestern's peak load hours to regional peak load hours means that NorthWestern should not continue to rely on the short term regional energy market to meet our future capacity needs.

Figure 2-3. NorthWestern vs. Pacific NW Load



CHAPTER 3
LOAD SERVICE REQUIREMENT

2018 Customer, Energy, and Peak Demand Forecasts

Energy Forecast

Overview and Background

NorthWestern has developed our customer, energy, and peak demand forecasts in a consistent manner for several planning cycles. The basis for the customer forecast is population within NorthWestern's service territory, and the primary basis for the energy and peak demand forecasts are the customer forecast and normal weather forecast. Other than a few variations that have been interjected into the process from time to time, these components have and continue to serve as the explanatory variables in the linear regression models that produce the forecasts.

NorthWestern's Demand Side Management (DSM) programs have been and continue to be incorporated into the energy and peak demand forecasts as well. Prior year DSM acquisition is inherent in the energy and peak demand regression results, while future DSM acquisition is forecasted and applied to the regression results to reflect both a "gross" and "net" of DSM value for the energy and peak demand forecasts. NorthWestern plans to acquire an average of 4 MW per year or over 78 average megawatts (MWa) in DSM energy savings between 2017 and 2036, excluding losses, with contributions to 2036 summer and winter peaks projected at 117 MW and 134 MW, respectively.

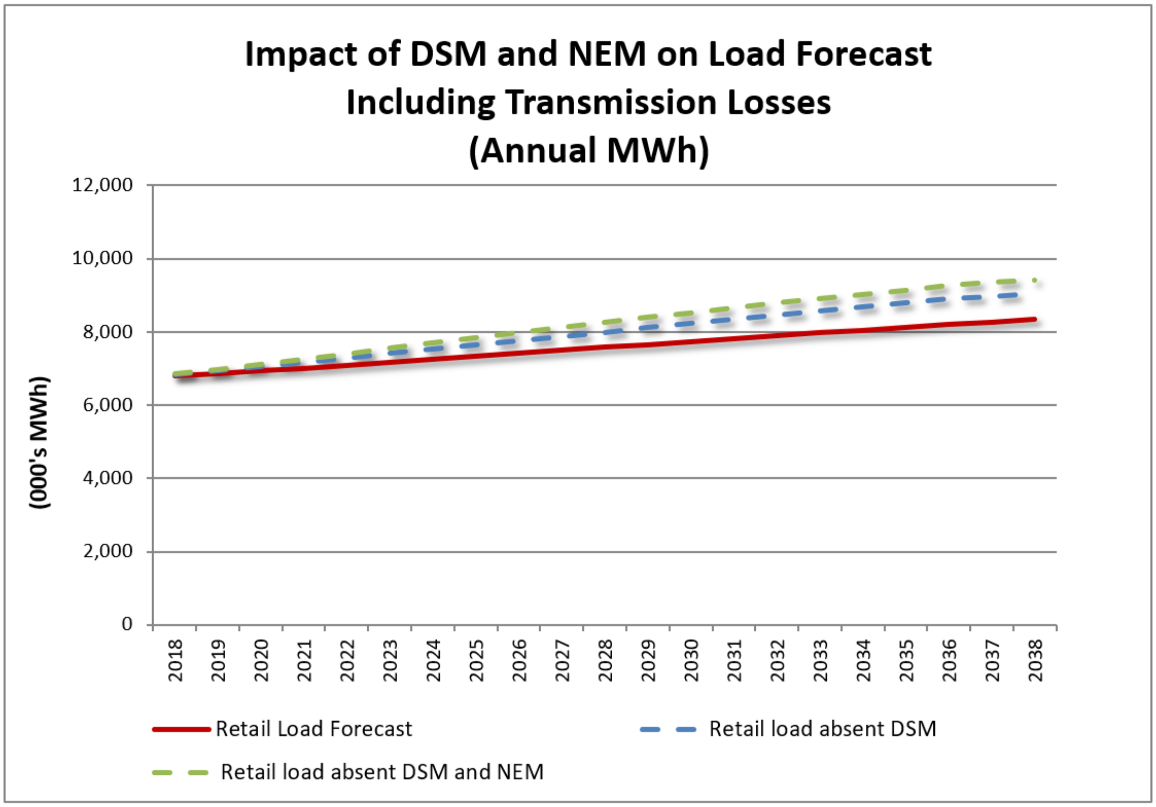
The impact of NEM is a variable introduced into the 2018 forecast. An NEM penetration study conducted by the National Renewable Energy Laboratory (NREL) on behalf of the MPSC and subsequently refined by Navigant to tailor to NorthWestern's distribution and transmission system, concluded that, barring any changes to existing tariffs in which NEM customers receive the full retail value for energy generated, installed capacity of NEM solar PV systems will grow from about 11 MW in 2017 to 270 MW in 2038. The result of this growth is over 40 MWa in energy and a contribution to the summer peak of 146 MW in 2038, excluding losses. Both the NREL study and the Navigant study can be found in Volume 2, Chapter 3.

Methodology and Energy Forecast

The methods of estimating future energy usage are rate class specific. Residential and GS-1 Secondary usage combined represents approximately 85% of the total energy load-serving obligation so these forecasts are based on more detailed regression models using the specific customer-class forecast and normal weather, defined as the 10-year average historical total degree days (heating plus cooling), as the explanatory variables. Usage for all other customer classes is based on historical actual usage coupled with adjustments for known changes to future usage. In addition, transmission line losses are included in all customer classes' forecasts.

Expected DSM and NEM are also projected throughout the 20-year forecast period and subtracted from Residential and GS1-Secondary energy forecasts as well as the winter and summer peak forecasts. The projected DSM and NEM have a substantial impact on projected annual load; the forecasted average annual growth rate for the Default Supply load-serving obligation excluding future DSM and NEM is 1.0%, while the average annual growth rate when including future DSM and NEM is 0.4%. Figure 3-1 illustrates the impact of DSM and NEM on future energy usage. Historic DSM and NEM energy and peak impacts are inherent in the regression results in that they are included in historic load figures, the basis for forecasting future loads.

Figure 3-1. Retail Load Forecast



The energy forecast including line losses, DSM, and Solar-PV NEM is presented in Table 3-1.

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Table 3-1. Actual and Forecasted Default Supply Loads

Year	Default Supply (MWh)	Annual Growth Rate	Commercial (MWh)	Annual Growth Rate	Residential (MWh)	Annual Growth Rate	Other (MWh)	Annual Growth Rate
2000	5,624,145		2,987,179		2,149,361		487,606	
2005	5,980,373	1.2%	3,230,839	1.6%	2,244,640	0.9%	504,895	0.7%
2010	6,218,232	0.8%	3,401,472	1.0%	2,518,232	2.3%	298,528	-10.0%
2015	6,434,595	0.7%	3,454,868	0.3%	2,555,131	0.3%	424,597	7.3%
2020	6,758,899	1.0%	3,582,170	0.7%	2,743,708	1.4%	433,021	0.4%
2025	6,828,790	0.2%	3,607,169	0.1%	2,781,879	0.3%	439,742	0.3%
2030	6,942,619	0.3%	3,656,734	0.3%	2,846,143	0.5%	439,742	0.0%
2035	7,094,165	0.4%	3,743,862	0.5%	2,910,562	0.4%	439,742	0.0%
20-YR CAGR		0.4%		0.5%		0.4%		1.2%

Note: Includes losses, DSM, and Solar PV-NEM

Customer Forecast

Residential and GS-1 Secondary (small commercial) customers make up 85% of NorthWestern Energy's load serving obligation but they make up 98% of the company's electric customers. The primary driver of the customer forecast is the projected population in NorthWestern's service territory, which is comprised of 37 of Montana's 56 counties. For the 2018 customer forecast, NorthWestern used an econometric population forecast developed by Woods & Poole Economics, Inc. The forecast is constructed using an independent econometric model and provides county population projections through 2050. As shown in Table 3-2, actual and expected population growth for the state of Montana and NorthWestern's service territory is about the same; approximately 0.9%. Total Accounts are projected to grow at about a 1.2% annual rate, higher than the population growth rate because of total new connects in residential single and multi-family housing units and commercial buildings.

Table 3-2. Actual and Forecasted Population and Customers

Year	Montana Population	Annual Growth Rate	NWE Service Territory Population	Annual Growth Rate	NWE Total Accounts	Annual Growth Rate	NWE Residential Accounts	Annual Growth Rate	NWE GS1-Secondary Accounts	Annual Growth Rate
2000	903,773		705,765		292,437		235,784		49,759	
2005	940,102	0.8%	734,415	0.8%	315,755	1.5%	253,124	1.4%	55,491	2.2%
2010	990,507	1.1%	774,998	1.1%	338,804	1.4%	270,571	1.3%	60,872	1.9%
2015	1,028,317	0.8%	805,975	0.8%	359,565	1.2%	287,387	1.2%	64,554	1.2%
2020	1,080,979	1.0%	844,416	0.9%	383,698	1.3%	306,290	1.3%	69,643	1.5%
2025	1,132,055	0.9%	884,368	0.9%	407,986	1.2%	324,862	1.2%	75,354	1.6%
2030	1,184,310	0.9%	925,163	0.9%	432,722	1.2%	343,826	1.1%	81,121	1.5%
2035	1,234,745	0.8%	964,449	0.8%	456,542	1.1%	362,089	1.0%	86,673	1.3%
2040	1,282,411	0.8%	1,001,481	0.8%	479,055	1.0%	379,303	0.9%	91,967	1.2%

Peak Demand Forecast

Summer and Winter Peaks

NorthWestern's Default Supply peak demand forecast was developed using a linear regression model with weather (cooling degree day (CDD) and heating degree day (HDD)), temperature, monthly energy, and total customers serving as the explanatory variables. Projected DSM and NEM values were then subtracted from the regression results to calculate the peak demand forecasts. NEM is not a factor on the winter peak but it does have a strong impact on the summer peak. The summer peak growth rate is projected to fall from greater than 1% values in previous forecasts to 0.2% in the 2018 forecast, see Table 3-3 below for Default Supply actual and forecasted summer and winter peak demand.

(Remaining page blank for table.)

Table 3-3. Actual and Forecasted Summer and Winter Peak Demand Default Supply

Summer Peak Demand Forecast (MW)				
Historic and Forecast Values Include Losses				
	2018	Less	Less	2018
Year	Actual/ Regression	DSM[2]	NEM[1,2]	Forecast
2012	1133			1133
2013	1162			1162
2014	1115			1115
2015	1146			1146
2016	1147			1147
2017	1210			1210
2018	1197	7	5	1186
2019	1212	14	12	1186
2020	1226	21	20	1185
2021	1241	28	32	1182
2022	1255	34	44	1178
2023	1272	40	55	1178
2024	1287	45	66	1176
2025	1303	51	76	1175
2026	1318	57	86	1175
2027	1334	63	96	1175
2028	1349	69	104	1176
2029	1365	75	111	1178
2030	1380	81	117	1182
2031	1396	87	122	1186
2032	1411	93	127	1191
2033	1426	99	131	1195
2034	1440	105	134	1201
2035	1455	111	137	1206
2036	1469	117	140	1212
2037	1483	117	143	1223
2038	1498	117	146	1234
20 Year CAGR	1.1%			0.2%
Avg Increase (MW)	15			2

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

Winter Peak Demand Forecast (MW)				
Historic and Forecast Values Include Losses				
	2018	Less	Less	2018
Year	Actual/ Regression	DSM[2]	NEM[1]	Forecast
2012	1074			1074
2013	1272			1272
2014	1176			1176
2015	1050			1050
2016	1163			1163
2017	1119			1119
2018	1225	15		1210
2019	1236	22		1214
2020	1248	30		1218
2021	1260	37		1223
2022	1271	44		1227
2023	1285	50		1235
2024	1298	56		1241
2025	1310	63		1247
2026	1323	69		1253
2027	1335	76		1259
2028	1348	82		1266
2029	1360	89		1272
2030	1373	95		1278
2031	1385	101		1284
2032	1397	108		1289
2033	1409	114		1295
2034	1421	121		1301
2035	1433	127		1306
2036	1445	134		1311
2037	1456	134		1323
2038	1468	134		1334
20 Year CAGR	0.9%			0.5%
20 Yr Avg Increase	12			6

1. No NEM impact on Winter peak assumed
2. Incremental DSM

Variable Generation Resources Study

Variable Energy Resources Integration Study

Background

To understand how increasing generation from VERs, such as wind and solar, will impact the operational needs of NorthWestern's system, NorthWestern retained Navigant to analyze the minute-by-minute variation in NorthWestern's load over the course of a test year (July 2016 to June 2017).[1] The results of this study provide estimates of the additional regulation and load-following resources needed to integrate increasing amounts of wind and solar generation into NorthWestern's system while still meeting the requirements of NERC's Reliability Based Control Standard.[2]

In this context, "regulation" refers to the use of generation that is on-line, equipped with Automatic Generation Control (AGC), and capable of ramping up or down its full capacity within one minute. This type of resource can change its output quickly to track the minute-by-minute fluctuations in load and output from VERs. "Load following" refers to the use of on-line generation to track intra- and inter-hour changes in load and generation from VERs. Load-following resources are assumed to be able to reach their full capacity in 15 minutes and are split into INC and DEC resources[3].

[1] Navigant's complete VER report can be found in Volume 2, Chapter 3.

[2] The purpose of this standard is to keep the frequency of the interconnection within acceptable limits.

[3] INC and DEC are defined on page 4-3.

Flexible Capacity Need

Based on the conditions experienced during the test year, Navigant concluded that NorthWestern's system should have a baseline of 120 MW of INC, 155 MW of DEC, and regulation capacity of +/-25 MW (i.e., 50 MW of total regulation comprised of +25MW and -25 MW). Navigant based this recommendation on the expected number of violations of NERC standards that would occur in the test year given the recommend resource levels, as well as the expected Control Performance Standard 1 (CPS1) score and levels of inadvertent generation. Refer to Chapter 4 Existing Resources for information regarding NorthWestern's ability to provide flexible capacity.

Flexible Capacity Need with Additional Renewables

After establishing the baseline levels mentioned above, Navigant examined the incremental INC and DEC needs under three scenarios of higher levels of VERs on the system. These scenarios were designed to reflect the renewable resources that are expected to be built in NorthWestern's balancing area in the near term and the potential for significant additional quantities of wind and solar that could be added to the system.[4] The scenarios are:

Scenario A: +185 MW of planned wind

Scenario B: +185 MW of planned wind and +320 MW of additional wind

Scenario C: +185 MW of planned wind and +100 MW of additional solar

To evaluate these scenarios, Navigant simulated hundreds of possible operational profiles for these renewable resources and then layered these profiles onto a wide range of load-

[4] Information on the precise locations of the simulated VERs can be found on page 12 of the Navigant report in Volume 2, Chapter 3.

following events that NorthWestern experienced during the test year.[5] A key feature of these simulations is that they reflect the real historical operating conditions that these resources would have experienced during the test year, including the impacts of regional weather and the locational diversity of the resources.

The locational diversity of the additional VERs considered in the study is particularly important because it plays a large role in determining the degree to which the energy production of these resources is correlated (a higher correlation of output from VERs is more likely to increase the need for load-following resources). In this study, the wind sites were selected to be consistent with NorthWestern's current wind generation portfolio and the locations where proposed wind plants are expected to be built. If the actual development of VERs occurs in locations that are less geographically diverse than the sites included in this study, the results are likely to be an underestimate of the actual INC and DEC needed for integration. This is because VERs that are located closer together would be more likely to experience the same swings in generation and therefore more likely to cause or contribute to load following events.

For each of the scenarios, Navigant determined the levels of INC and DEC that would be needed to limit the expected number of simulations in which a NERC violation occurs to one percent.[6] The resulting levels of INC and DEC needed for integration under each scenario are presented in Table 3-4.

[5] These simulations were based on data from the National Renewable Energy Lab.

[6] Navigant recommended the one percent threshold as the appropriate level because it reasonably balances costs and risks and because it would be very expensive to have sufficient resources to fully eliminate the chance of a NERC violation because there are diminishing returns from further increasing the amount of INC or DEC resources available on the system.

Table 3-4. Navigant VER INC & DEC Recommendation

Navigant Recommendation Under VER Study		
VER Integration Scenario	**Additional INC Capacity**	**Additional DEC Capacity**
Scenario A: 185 MW Planned Wind	60 MW	55 MW
Scenario B: 185 MW Planned Wind & 320 MW New Wind	80 MW	120 MW
Scenario C: 185 MW Planned Wind & 100 MW New Solar	60 MW	50 MW

With an increase of 185 MW of wind as in Scenario A, Navigant recommends an additional 60 MW of INC and 55 MW of DEC (these amounts are incremental to the recommended baseline levels, discussed above). With the significantly higher level of wind under Scenario B, relative to Scenario A, Navigant recommends increases of 80 MW of INC and 120 MW of DEC, relative to the baseline levels. The incremental needs under Scenario B are less, relative to the size of the increase in VERs, than under Scenario A because there is a benefit from the geographic diversity in the additional 320 MW of wind, which proportionally lessens the associated load-following impacts.

Despite the additional solar generation in Scenario C, Navigant does not recommend any more load-following resources than under Scenario A. This is because the additional 100 MW of solar does not increase the load-following capacity necessary to achieve the established risk threshold during the worst-case events in the test year, even though it does increase the need for INC and DEC during certain events. However, Navigant notes that with increasing amounts of solar on the system, it expects that solar variability will begin to drive some of the most challenging load-following events. Additionally, because these results are based off of only one year of load data, it will be particularly important for NorthWestern to monitor the regulation and load-following needs under higher levels of solar generation.

Future Capacity Needs

The North American Electric Reliability Corporation (NERC) Reliability Standards as updated through July 3, 2018, defines adequacy as the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Refer to Chapter 2 for a discussion of NorthWestern's NERC reserve margin rate of 16.4%.

According to an article published in the Energy Activist on July 27, 2018 by the NW Energy Coalition, the summer of 2018 saw temperatures topping 90 degrees which caused power prices in the Northwest to exceed $500/MWh. "What these high prices tell us is that it's time to get into overdrive to address our common capacity and flexibility needs…in the western grid as a whole."

Energy Load – Balance

NorthWestern's load-serving obligation requires that Energy Supply acquire resources sufficient to achieve a balance between loads and resources. Load-resource balance is achieved when resources equal loads. The amount and timing of resource acquisitions is determined by comparing the existing resources portfolio to forecast need. Additionally, differences in need between heavy-load and light-load periods must also be considered. Simply averaging or ignoring these differences would not balance either load-serving period and would likely lead to energy deficits during heavy load (HL) hours and energy surpluses during light load (LL) hours.

Figures 3-2 and 3-3 illustrate NorthWestern's HL and LL load-resource balance over the next 10 years using forecast loads and existing resources. Each figure is compiled using monthly load values and reflects the seasonality of loads, resulting in a “spiky” appearance. The red line represents loads, while NorthWestern’s existing resources are shown as a resource stack. Comparing forecast loads to the existing resource stack in each figure indicates the energy needed to meet forecast loads.

The resource stack in each figure is constructed using monthly energy production for each existing resource. Existing wind resources are shown in the resource stack at their average annual energy production, which is equal to about 38% (also known as annual capacity factor). However, in any one hour, cumulative wind may vary between 0% and 91% of total installed capacity.[7]

Several conclusions can be drawn from Figures 3-2 and 3-3. First, NorthWestern has some ongoing need for resources that produce or can be called on to produce energy during HL hours. Second, NorthWestern has no need for resources that produce energy during LL hours. Must-take resources that are not dispatchable, like wind, fall in to the category of providing energy when it is generally not needed, or valued. Additionally, the potential swing in wind production from hour to hour requires flexible, or ramping, resources.

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[7] NorthWestern has observed hourly historical coincident wind production equal to 91% of cumulative installed capacity.

Figure 3-2. Current plus Market 5-Year Heavy Load Hours MWh

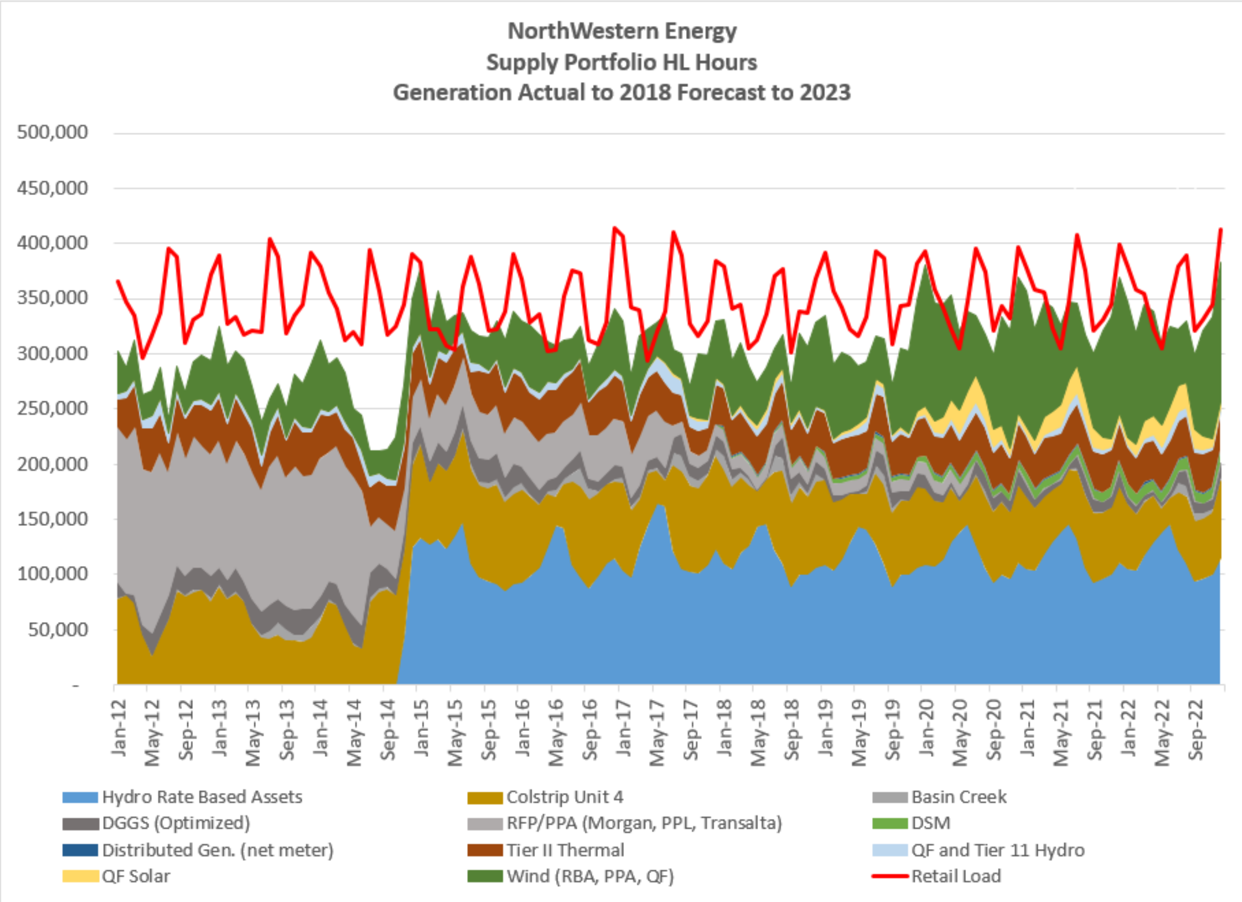

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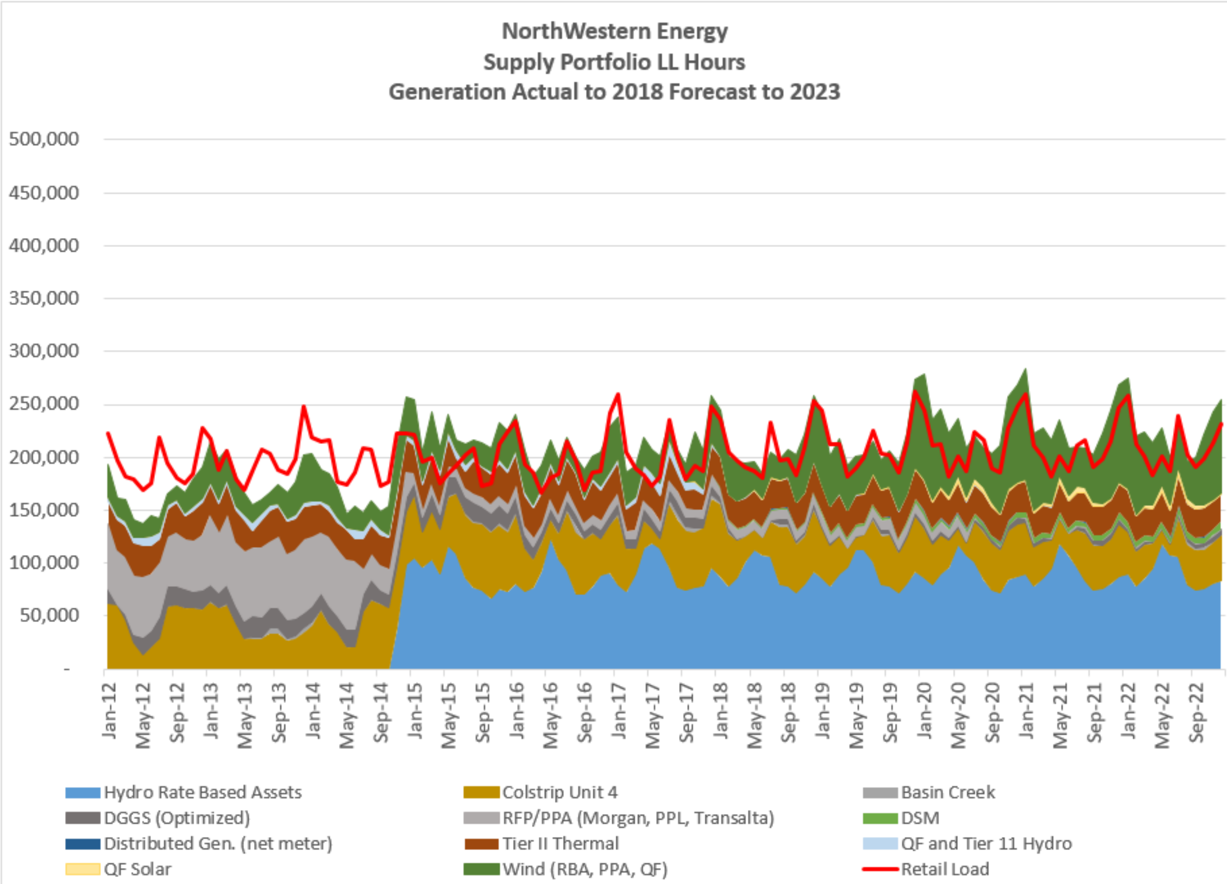
Figure 3-3. Current plus Market 5-Year Light Load Hours MWh



Conclusion

NorthWestern's resource needs assessment, combined with our current portfolio of resources, drives the selection of resources and portfolio modeling. Other factors driving resource selection are the need to provide system reliability and the integration of variable energy resources, like wind and solar.

CHAPTER 4
EXISTING RESOURCE PORTFOLIO

Large Generation Resources

Background

NorthWestern serves our retail customers with a diverse mix of hydro, wind, solar and thermal generation resources. NorthWestern owns some of these resources and we have power purchase agreements (PPAs) with other resource owners. Energy provided by small distributed generation and other demand-side resources is taken into account in our load forecasts. Therefore, these resources are not included as supply-side resources but are discussed separately in a section near the end of this chapter.

Figure 4-1 indicates the approximate locations of all large resources included in NorthWestern's resource portfolio for the 2019 Plan. Some of the resources included in the figure are not yet delivering energy to our system but are included because they have MPSC-ordered rates in place.

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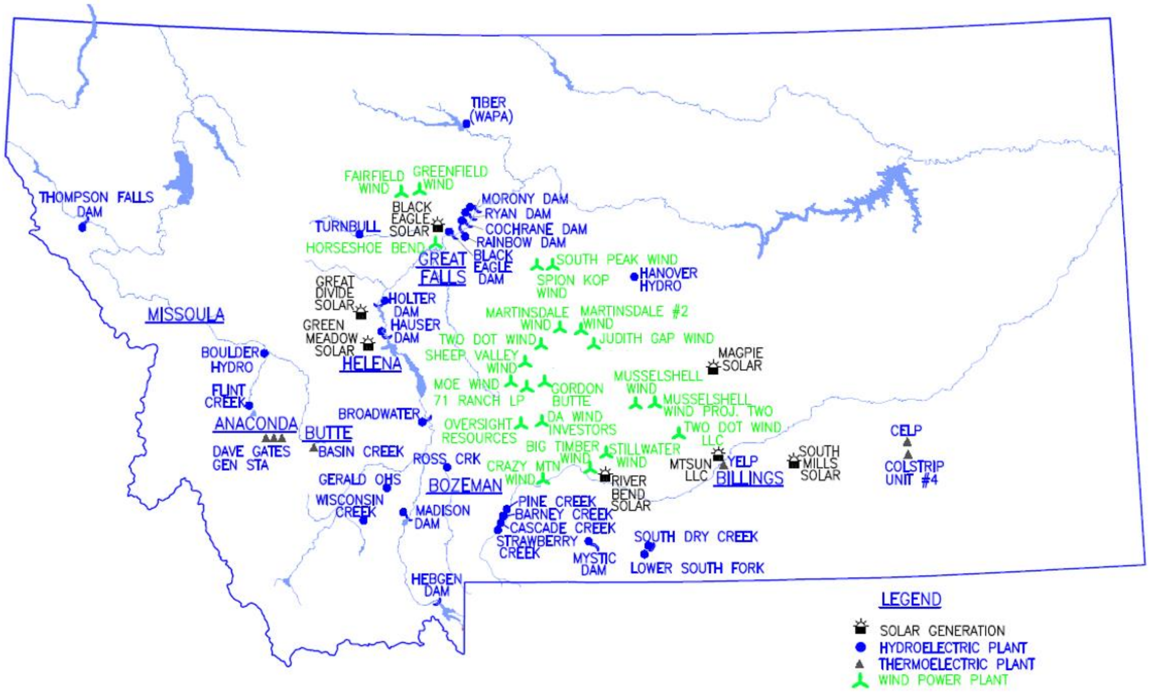
Figure 4-1. Montana Electric Generation Facilities



Key Terms and Definitions

Capacity: the maximum electric output that a facility can produce under certain conditions.

Ancillary Services: services that are necessary to support the transmission of capacity and energy from resource to loads while maintaining reliable operation of the transmission system in accordance with good utility practice, including regulation, incremental and decremental capacity, and contingency reserves.

Automatic Generation Control: Equipment that automatically adjusts generation in a balancing authority area from a central location to maintain the balancing authority's interchange schedule and frequency bias. In other words, generation that is controlled automatically to respond to moment-to-moment fluctuations in the balance of load and generation.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

Regulation: reserves that are responsive to automatic generation control and are sufficient to provide normal regulating margin.

Contingency Reserves: Capacity held for deployment in the event of a contingency, such as a generator or transmission line tripping (becoming unavailable). Contingency reserves are comprised of Spinning and Non-spinning reserves.

Spinning Reserves: reserve resources that are online and immediately and automatically responsive to frequency deviations and fully deployable within 10 minutes. Also described as unloaded generation that is synchronized with the grid and ready to serve additional demand.

Non-spinning Reserves: reserves that are not online but are capable of coming online to serve demand within 10 minutes or interruptible loads that can be removed from the system within a similar timeframe. Also known as supplemental reserves.

INC: Capacity to increase generation output on short notice (sub-hourly, typically within the 10 to 15 minute timeframe). Also known as incremental capacity.

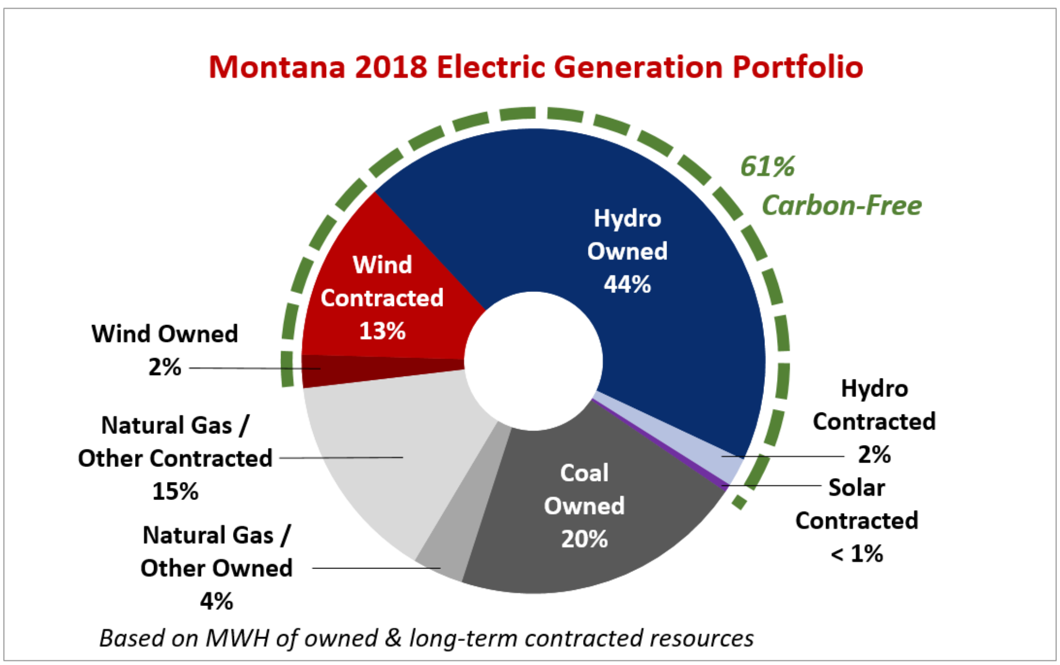
DEC: Capacity to decrease generation output on short notice (sub-hourly, typically within the 10 to 15-minute timeframe). Also known as decremental capacity.

Flexible Capacity Resource: a resource that can be dispatched to provide ancillary services such as regulation, spinning reserve, non-spinning reserve, INC, or DEC. This could include storage and demand response as well as generation.

Energy Production

NorthWestern's portfolio of resources generated about 88 percent of the energy required to serve our customers during 2017. In 2018, our owned resources and the long-term PPAs in the energy supply portfolio generated just over 6 million MWh of energy. As shown in Figure 4-2, 61 percent of these MWh were generated by clean energy resources including hydro, wind and solar.

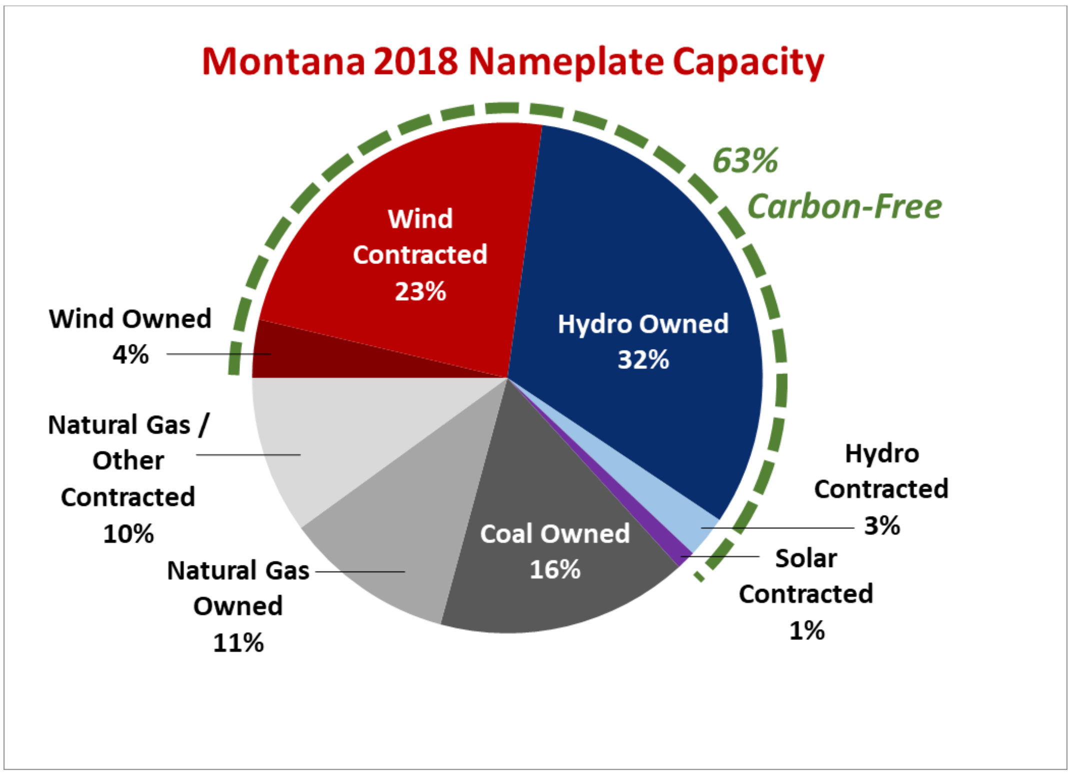
Figure 4-2 2018 Energy Produced by Fuel Source



While Figure 4-2 illustrates the percentages of energy produced from each fuel source, these percentages are not representative of the nameplate capacity of each type of resource.

Figure 4-3 illustrates the nameplate capacity percentages by generation type for the resources in our 2018 portfolio.

Figure 4-3 Nameplate Capacity by Generation Type



As Figures 4-2 and 4-3 indicate, nameplate capacity isn't necessarily indicative of the total energy a particular type of resource generates to serve customers. For example, owned and contracted hydro made up 35% of the nameplate capacity of the portfolio but provided 46% of the energy delivered to customers. On the other hand, owned and contracted wind and solar made up 28% of the nameplate capacity but provided only 15% of the energy delivered to customers.

Existing Large Resources

Summary

NorthWestern's current portfolio of resources is shown in Table 4-1.[1] The large resources in the portfolio have a total nameplate capacity of 1,631 MWs and include hydro, wind, natural gas, coal, and solar generation resources.[2] A summary of each type of generation resource is provided below.

- Hydro: 484.9 MWs comprised of 448 MWs from rate-based assets, 20.5 MWs from PPAs, and 16.4 MWs from QF agreements.
- Wind: 538.1 MWs comprised of 51.3 MWs of rate-based assets, 135 MWs from PPAs, and 351.5 MWs from QF agreements.
- Natural Gas: 202 MWs comprised of 150 MWs from a rate-based asset and 52 MWs from a capacity purchase agreement.
- Solar: 97 MWs comprised of 17 MWs from QF agreements and 80 MWs from a large QF project with MPSC-ordered rates. Smaller net metering facilities are accounted for by deducting their production from NorthWestern's load forecast.
- Coal: 309 MWs comprised of 222 MWs from a rate-based asset, 35 MWs from a waste coal-fired QF facility, and 52 MWs from a petroleum coke-fired QF facility.[3]

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[1] Note that South Peak Wind, Crazy Mountain Wind and MTSun are not yet commercially operable; all have estimated commercial operation dates of December 2019.

[2] The capacity of each facility is generally equal to the nameplate capacity but may vary based upon limitations to dispatch, generator or turbine limitations, or equipment upgrades.

[3] The QFs in this category have a total capacity of 106.5 MWs, however their contracted capacity is only 87 MWs, which includes 35 MWs from the CELP waste coal facility and 52 MWs from the YELP petroleum coke facility.

Table 4-1. NorthWestern's Resource Portfolio

Portfolio Resources	Facility Capacity (MW)	Expiratiion (Date)	Peak Load Contribution (MW)	Reg UP (MW)	Reg Down (MW)	Spin (MW)	Non-spin (MW)	INC (MW)	DEC (MW)
Hydro Generation									
Thompson Falls*	94.00	Rate Based	43.00	Varies	Varies	0 to 17	0	0	0
Cochrane*	62.00	Rate Based	25.00	Varies	Varies	1 to 6	0	0 - 18	-6 to -29
Ryan*	68.00	Rate Based	40.00	Varies	Varies	0	0	2 - 10	-26 to -36
Rainbow*	64.00	Rate Based	33.70	0	0	5 to 10	0	0	0
Holter*	53.00	Rate Based	32.00	0	0	0	0	0	0
Morony*	49.00	Rate Based	24.00	0	0	0	0	0	0
Black Eagle*	21.00	Rate Based	12.00	0	0	0	0	0	0
Hauser*	17.00	Rate Based	14.00	0	0	0	0	0	0
Turnbull Hydro LLC	13.00	12/31/2032	0.00	0	0	0	0	0	0
Mystic*	12.00	Rate Based	5.00	Varies	Varies	0 to 7	0	0	0
State of MT DNRC (Broadwater Dam)	10.00	6/30/2024	2.80	0	0	0	0	0	0
Madison*	8.00	Rate Based	6.00	0	0	0	0	0	0
Small Hydro Aggregate (See Below)	13.92	Various	1.70	0	0	0	0	0	0
Tiber Montana LLC	7.50	6/1/2024							
Flint Creek Hydroelectric LLC	2.00	1/16/2037							
Hydrodynamics Inc (South Dry Creek)	1.20	6/30/2021							
Wisconsin Creek LTD LC	0.55	7/1/2019							
Boulder Hydro Limited Partnership	0.51	6/30/2022							
Lower South Fork LLC	0.46	1/16/2037							
Ross Creek Hydro LC	0.45	6/30/2032							
Gerald Ohs (Pony Generating Station)	0.40	12/10/2020							
Allen R. Carter (Pine Creek)	0.30	6/30/2024							
Donald Fred Jenni (Hanover Hydro)	0.24	6/30/2034							
Hydrodynamics Inc (Strawberry Creek)	0.19	6/30/2023							
James Walker Sievers (Cascade Creek)	0.07	10/1/2019							
James Walker Sievers (Barney Creek)	0.06	11/14/2019							
Natural Gas Generation									
Basin Creek	52.00	12/31/2034	49.40	0	0	0	52	52	-52
DGGS 1	50.00	Rate Based	47.50	43	43	43	50	50	-50
DGGS 2	50.00	Rate Based	47.50	43	43	43	50	50	-50
DGGS 3	50.00	Rate Based	47.50	43	43	43	50	50	-50
Thermal/Coal Generation									
Colstrip Unit 4	222.00	Rate Based	206.46	0	0	24	24	100	-100
Yellowstone Energy Limited Partnership (BGI)	52.00	12/31/2028	48.36	0	0	0	0	0	0
Colstrip Energy Limited Partnership	35.00	6/30/2024	32.55	0	0	0	0	0	0
Wind Generation									
Judith Gap Energy LLC	135.00	12/31/2026	8.20	0	0	0	0	0	-135
Stillwater Wind LLC (WKN)	80.00	1/11/2043	TBD	0	0	0	0	0	-80
South Peak Wind LLC	80.00	Est 12/1/2034	TBD	0	0	0	0	0	-80
Crazy Mountain Wind LLC	79.50	Est 1/1/2045	TBD	0	0	0	0	0	-79.5
Spion Kop Wind	40.00	Rate Based	1.20	0	0	0	0	0	-40
Greenfield Wind LLC	25.00	11/1/2041	2.20	0	0	0	0	0	-25
Big Timber Wind LLC (Greycliff)	25.00	4/1/2043	TBD	0	0	0	0	0	-25
Fairfield Wind LLC (Greenbacker)	10.00	12/31/2033	0.10	0	0	0	0	0	0
Musselshell Wind Project LLC	10.00	3/24/2036	0.20	0	0	0	0	0	-10
Musselshell Wind Project Two LLC	10.00	3/24/2036	0.30	0	0	0	0	0	-10
Two Dot Wind Farm LLC	11.28	Rate Based	0.10	0	0	0	0	0	-11.28
Gordon Butte Wind LLC	9.60	3/21/2036	0.40	0	0	0	0	0	-9.6
Cycle Horseshoe Bend Wiind LLC	9.00	8/31/2035	0.00	0	0	0	0	0	0
71 Ranch LP	2.70	1/1/2024	TBD	0	0	0	0	0	-2.7
DA Wind Investors LLC	2.70	1/1/2024	TBD	0	0	0	0	0	-2.7
Oversight Resources LLC	2.70	1/1/2024	TBD	0	0	0	0	0	-2.7
Small Wind Aggregate (See Below)	5.26	Various	0.00	0	0	0	0	0	0
Two Dot Wind LLC (Martinsdale Colony South)	2.00	4/23/2028							
Two Dot Wind LLC (Broadview East Wind)	1.60	1/11/2043							
Two Dot Wind LLC (Martinsdale Colony)	0.75	4/23/2028							
Two Dot Wind LLC (Sheep Valley Ranch)	0.46	4/23/2028							
Two Dot Wind LLC (Moe Wind)	0.45	4/23/2028							
Solar Generation									
MTSun LLC (MPSC Final Order 7535a)	80.00	Est 1/1/2030	TBD	0	0	0	0	0	0
Green Meadow Solar LLC	3.00	4/1/2042	TBD	0	0	0	0	0	3
South Mills Solar 1 LLC	3.00	4/1/2042	TBD	0	0	0	0	0	3
Black Eagle Solar LLC	3.00	10/1/2042	TBD	0	0	0	0	0	3
Great Divide Solar LLC	3.00	10/1/2042	TBD	0	0	0	0	0	3
Magpie Solar LLC	3.00	10/1/2042	TBD	0	0	0	0	0	3
River Bend Solar LLC	2.00	4/1/2042	TBD	0	0	0	0	0	2

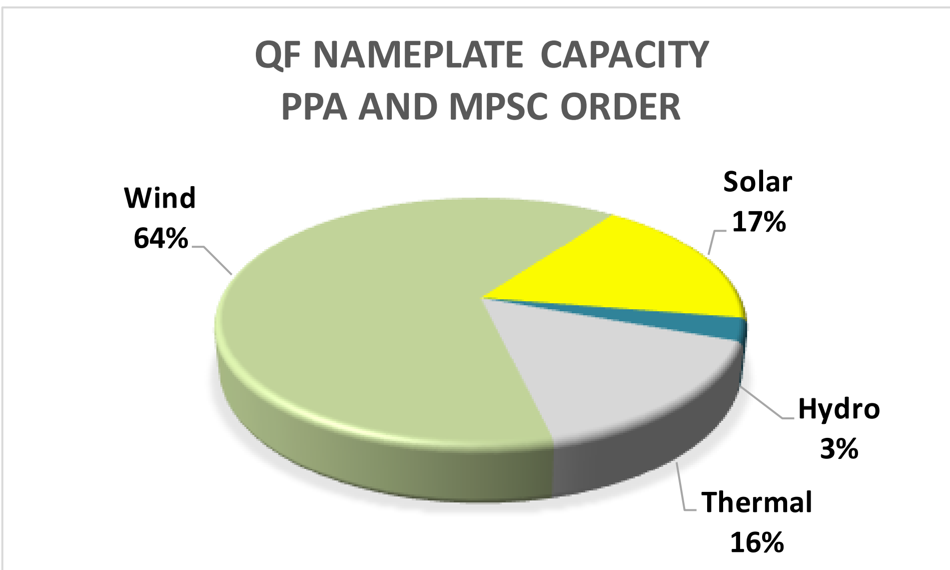
TBD = To be determined
Note: * Updated from 2015 Plan.

Significant Additions of Qualifying Facilities

Recently, NorthWestern has had requests from an additional 2,545 MWs of QF projects for avoided cost calculations or draft PPAs. Of these requests, 104.8 MWs fall under the 3 MW standard offer limit for the QF-1 Tariff. The larger projects, up to 80 MWs in size, include 1,417 MWs of solar, 888 MWs of wind, and 134.7 MWs of other technologies or combination projects. NorthWestern's average retail load is only 747 MWs.

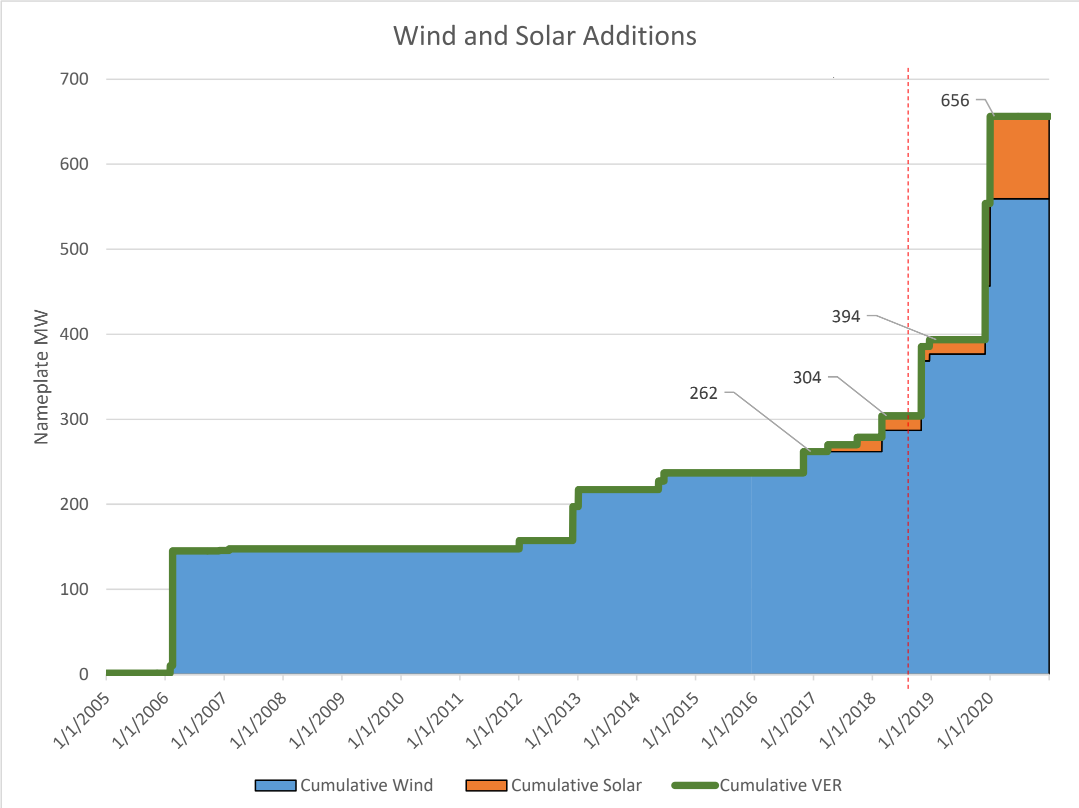
In 2017, the nameplate capacity of the QFs in NorthWestern's portfolio totaled just over 550 MWs and, over half of the contracts for those QFs were added after the beginning of 2016.

Figure 4-4. QF Capacity by Fuel Type



The historical and anticipated additions of QF variable energy resources to NorthWestern's portfolio system are in Figure 4-5.

Figure 4-5. Nameplate MW Additions of Variable Resources – Historical and Future

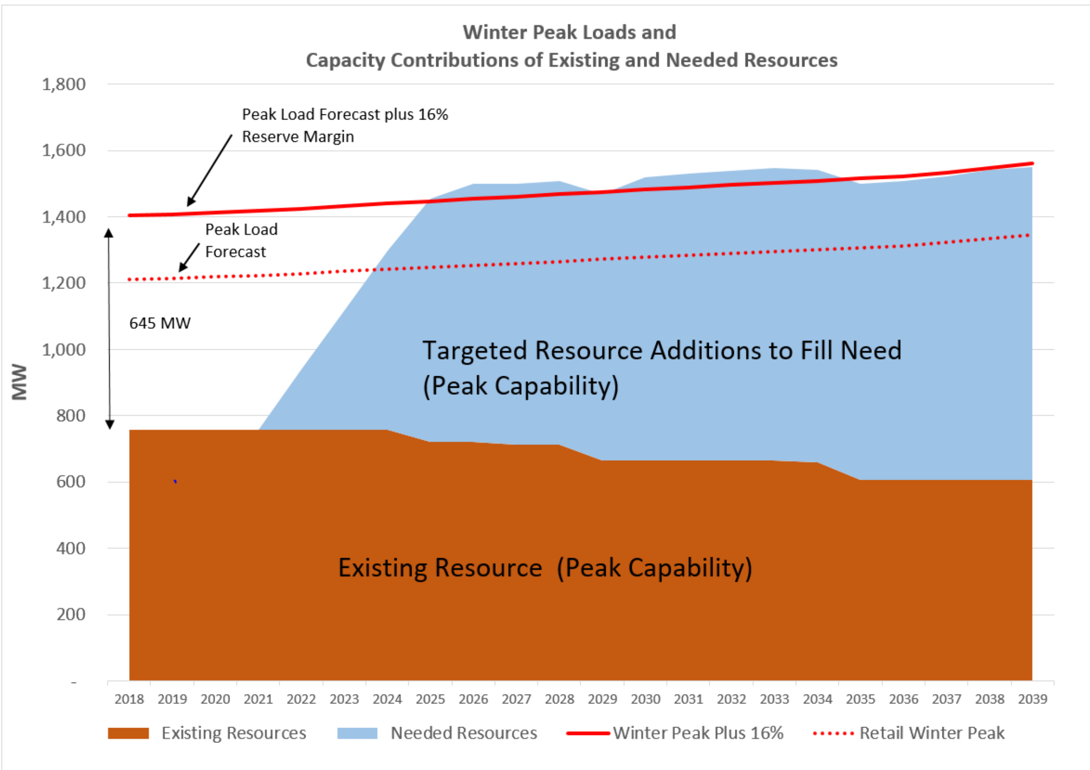


Peaking Load Contribution (Capacity at time of system peak)

The "peak load contribution" column of Table 4-1 indicates the level of capacity each resource is expected to contribute during peak load periods. For thermal resources, peak load contribution is calculated as the nameplate capacity less lost capacity due to forced outages. For hydro, solar, and wind resources, the peak load contribution is determined by examining each resource's historic level of production during historic peak load periods on our system.

Figure 4-6 compares the combined peaking capacity of the existing resources in NorthWestern's portfolio with our peak load forecasts. The figure shows the peaking capacity of our portfolio is currently about 645 MWs short of the peak load forecast including reserve margin. The peaking capacity deficit is forecast to increase to 955 MWs over the forecast period without the addition of resources capable of providing peaking capacity.

Figure 4-6. Capacity Contribution and Resource Adequacy



Approximately 755 MWs of capacity is expected to be available from our current portfolio of resources during peak load events which is about 63% of our customers' needs during peak load hours. However, the capacity contribution percentage will vary based on actual circumstances during a peak load event as shown in Figure 4-7 which depicts the capacity contributions and loads during the 2017 peak load day.

Figure 4-7. Capacity Contribution on Peak Load Day

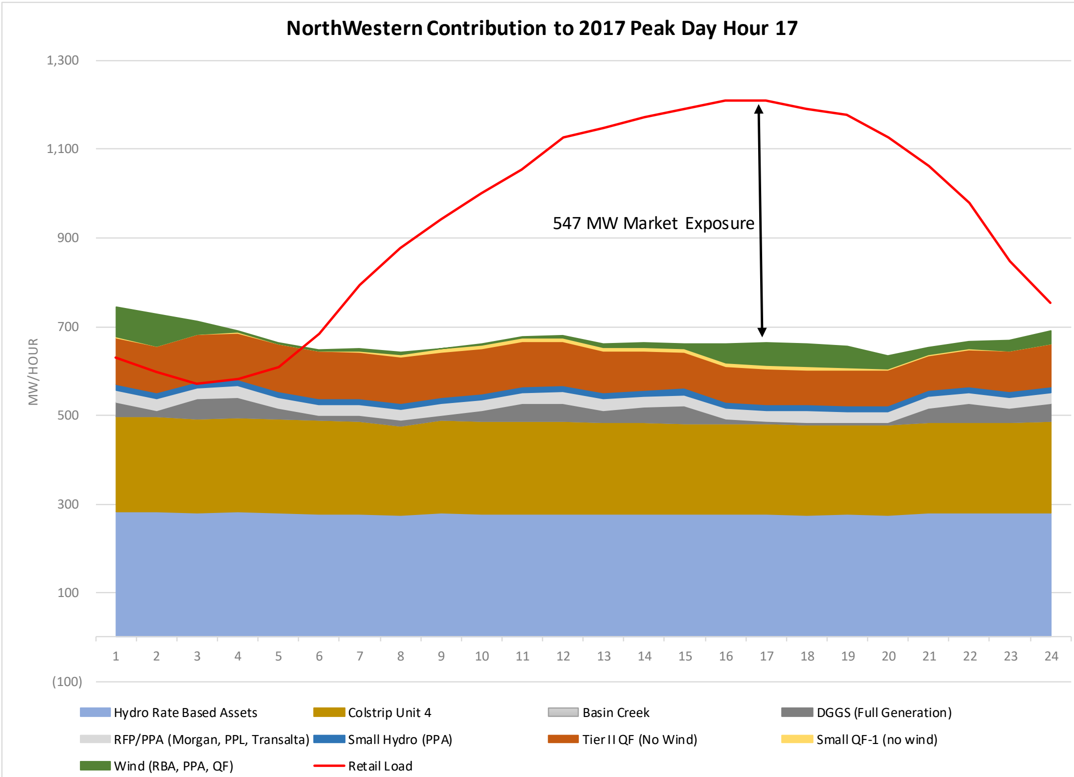


Table 4-2 provides the percentages each resource category was contributing to the 2017 peak load day.

Table 4-2. Capacity Contribution on 2017 Peak Day

MW Contribution to Peak 2017	
Hydro Rate Based Assets	22.9%
Colstrip Unit 4	16.9%
Basin Creek	0.0%
DGGS (Full Generation)	0.5%
RFP/PPA (Morgan, PPL, Transalta)	2.1%
Small Hydro (PPA)	1.1%
Tier II QF (No Wind)	6.6%
Small QF-1 (no wind)	0.7%
Wind (RBA, PPA, QF)	4.1%
Market	45.2%
Total Peak Requirement 1,210	100%

Dispatchable Capacity

Dispatchable capacity is important in that it allows NorthWestern to integrate variable resources including renewable generation and follow load within our system while maintaining the reliability BAL-001-2 NERC requirements for the Balancing Authority. Refer to chapter 5 for additional explanation of capacity requirements.

NorthWestern's current portfolio has limited capacity that can ramp up within the hour (see Table 4-3). The primary INC capacity comes from Colstrip Unit 4, DGGS, Basin Creek, and some from Cochrane and Ryan dams. Multiple resources in the portfolio can provide DEC, including some QF resources, but requesting a QF resource to provide DEC typically requires compensation that would reflect monetary loss for the project owners and it is therefore rarely economic to call on them for this capability. It is important to note that some resources may be able to provide multiple ancillary services but they cannot be used for these two requirements at the same time (because if they are called upon to provide one service they are no longer available to provide the other).

Table 4-3. Percent of Intra-Hour Plant use for RBC

2017	Basin Creek	Colstrip Unit 4	Cochran Ryan	DGGS	Mystic	Thompson Falls	Contracted	Total
INC	37%	22%	17%	25%				100%
DEC	16%	47%	31%	6%				100%
Spin		19%	51%		10%	18%	2%	100%
NonSpin	4%			96%				100%

The intra-hour capacity available from the hydro resources, presented in Table 4-4, varies with the seasons and generation facility flows.

Table 4-4. Hydro Intra-Hour Capacity

Intra-Hour Facility		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Thompson Falls	Capacity	94	94	94	94	94	94	94	94	94	94	94	94
	Spin MW	10	8	9	1	0	3	14	10	4	7	14	17
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Cochrane	Capacity	62	62	62	62	62	62	62	62	62	62	62	62
	Spin MW	3	3	1	6	6	3	4	5	5	5	5	4
	INC MW	13	17	12	6	0	3	11	5	12	13	12	18
	DEC MW	-10	-11	-19	-23	-29	-22	-12	-7	-6	-6	-8	-10
Ryan	Capacity	68	68	68	68	68	68	68	68	68	68	68	68
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	7	10	8	2	3	3	2	5	8	7	5	5
	DEC MW	-34	-32	-36	-43	-35	-28	-30	-26	-30	-29	-35	-34
Rainbow	Capacity	64	64	64	64	64	64	64	64	64	64	64	64
	Spin MW	10	10	10	7	7	5	10	10	10	10	10	10
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Mystic	Capacity	12	12	12	12	12	12	12	12	12	12	12	12
	Spin MW	3	2	2	1	1	0	0	0	4	6	7	4
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Holter	Capacity	53	53	53	53	53	53	53	53	53	53	53	53
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Morony	Capacity	49	49	49	49	49	49	49	49	49	49	49	49
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Black Eagle	Capacity	21	21	21	21	21	21	21	21	21	21	21	21
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Hauser	Capacity	17	17	17	17	17	17	17	17	17	17	17	17
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Madison	Capacity	8	8	8	8	8	8	8	8	8	8	8	8
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Hydro System Total		448	448	448	448	448	448	448	448	448	448	448	448
	Spin MW	26	23	22	15	14	11	28	25	23	28	36	35
	INC MW	20	27	20	8	3	6	13	10	20	20	17	23
	DEC MW	-44	-43	-55	-66	-64	-50	-42	-33	-36	-35	-43	-44

Monthly hourly averages or calculated based on history available and INC.
Note: Hydro updated from 2015 Plan.

Demand Side Resources

Demand Side Resources – Acquisition and Programs

DSM Goals

Since the 2015 Plan, NorthWestern has received from Nexant Consulting Inc. (Nexant) an updated Electricity Energy Efficiency Market Potential Study ("Electric Energy Potential Study") which provided information about the amount of remaining achievable, cost-effective electric energy savings through Demand Side Management (DSM) based upon the availability in NorthWestern's Montana service territory[4]. This study estimated the remaining potential of annual incremental energy savings for the time period of 2015-2034 to be 61.7 average megawatts (aMW) or 7% of the baseline sales. Based on that value for DSM measures, and including estimates for energy savings through the Northwest Energy Efficiency Alliance (NEEA) market transformation activities, as well as energy savings acquired through activities funded with Universal System Benefits (USB) dollars, NorthWestern has established our annual energy savings acquisition goal at the level of 4.35 aMW each year for 5 years (2016-2017 through 2020-2021) and a goal of 3.77 aMW each year for the next 15 years (2021-2022 through 2035-2036). The DSM measures savings reflect incentive levels at 50% of incremental measure costs and a moderate market adoption rate from the study. While estimated savings from USB-funded programs are included as noted in this Plan, the expenses are not included as they are covered with USB revenues.

[4] The Nexant study Electricity Energy Efficiency Market Potential Study, is provided in Volume 2, Chapter 4.

NorthWestern evaluates DSM opportunities for cost effectiveness where electric avoided costs are a primary determinant. Consistent with previous years, NorthWestern uses the Total Resource Cost ("TRC") test to evaluate DSM cost effectiveness. The Electric Energy Potential Study evaluated the cost effectiveness of DSM energy savings based on the TRC test. The TRC test is a ratio of benefits (the avoided cost value of energy saved) to the total program costs (utility program implementation costs and estimated customer costs). Nexant assessed the cost-effectiveness of measures based on an avoided cost derived from the 2015 Plan at $40.70 per megawatt-hour ("MWh") and applied a TRC ratio of 1.0.

Previously, NorthWestern used a 10% factor as a surrogate to recognize DSM-related environmental benefits. The inclusion of this environmental benefits factor resulted in a TRC benefit-to-cost ratio of 0.90 as the cost effectiveness benchmark. More recently, environmental benefits have been factored in to DSM avoided costs by way of a carbon cost adder. This effectively replaced the 10% environmental benefit surrogate, and NorthWestern determined that using a 0.90 TRC benefit-to-cost ratio as the DSM cost effectiveness benchmark would have double-counted environmental benefits.

As a result, for the foreseeable future, NorthWestern will evaluate DSM cost-effectiveness using a TRC benefit-to-cost ratio of 1.0 or greater and will restrict DSM measure and program lives to 15 years for analysis purposes. This treatment of DSM cost-effectiveness is based on Order No. 7500d in Docket No. D2016.5.39 (the last QF-1 rate docket) and the Commission's Supplemental Comments in Docket No. N2015.11.91 (the last Electricity Supply Resource Procurement Plan docket).

Cost effective DSM will continue to be acquired in the same manner as in the past – through operation of the E+ Rebate and E+ Business Partners programs, and the regional Simple

Steps lighting program. NorthWestern has renewed our contract with DNV GL to encourage additional energy savings by persuading customers, through NorthWestern's E+ Commercial Lighting Programs, to purchase LEDs or other lighting technologies instead of less efficient bulbs. DNV GL also supports energy savings through the E+ Commercial Electric Rebate Program for New or Existing facilities.

NorthWestern has continued our focus on acquiring energy efficiency in the commercial sector and has contracts in place with several firms for services in support of the E+ Business Partners Program, the E+ Commercial Lighting Rebate Program, and the E+ Commercial Electric Program for New or Existing facilities. The firms are:

- Associated Construction Engineering, Inc.
- CLEAResult Consulting, Inc.
- CTA Associates, Inc.
- Energy Resource Management, Inc.
- McKinstry Essention
- National Center for Appropriate Technology

Services provided by these contractors include marketing to architect/engineering firms and trade/industry associations in Montana, direct contact with candidate businesses with energy savings potential, surveys and assessments of buildings and facilities, technical assistance for building owners, assistance with required engineering analysis and modeling, and assistance to customers with forms, contracts, and other paperwork used in and necessary for participation in the program. These contractors are compensated by NorthWestern on a performance basis, with payment based on a percentage of the energy conservation resource value of each individual DSM project that is completed with the contractor's involvement.

These contractors are supported by DNV GL employees who have responsibility for communication of E+ programs to commercial/small industrial customers in an effort to identify, qualify, and cultivate energy saving projects for follow-up by the contractors.

Historic DSM, NEEA, USB

Table 4-5 shows budget and spend for DSM and NEEA and acquisition target and acquisition reported for DSM, NEEA, and USB.

Table 4-5. Historical DSM NEEA USB

Historic: Budget, Acquisition Target, Spend, Acquisition Reported (no USB Budget or Spend inluded)							
Tracker Year	DSM + NEEA Budget	DSM NEEA USB Acquisition Target (aMW)	DSM Spend	DSM Acquisition Reported (aMW)	NEEA Spend	NEEA Acquisition Reported (aMW)	USB Acquisition Reported (aMW)
2013-2014	$15,455,132	6.00	$ 9,339,577	4.90	$1,812,813	1.14	0.59
2014-2015	$16,440,140	6.00	$ 5,414,378	3.99	$1,015,012	1.32	0.38
2015-2016	$17,979,217	6.00	$ 6,051,582	3.41	$1,219,625	1.14	0.58
2016-2017	$ 5,883,338	4.35	$ 6,524,555	4.25	$1,221,149	1.23	0.35
2017-2018	$ 6,417,962	4.35	$ 7,807,527	5.26	$1,523,720	1.54	0.27
Cumulative	$62,175,790	26.70	$35,137,618	21.81	$6,792,319	6.37	2.17

DSM Budget and Spending

The tables below show the Electric DSM Acquisition Goals that include energy savings estimates from DSM, NEEA, and USB for each year and forecast program expenses for DSM and NEEA over the 20-year period. The DSM savings component is developed from the Electric Potential Study; the NEEA component represents NorthWestern's expectation of the electric savings produced through NEEA activities for NorthWestern's Montana service territory; and the USB component represents NorthWestern's current expectations of the electric savings that will be generated by USB programs.

Table 4-6. DSM Forecast Acquisition

Forecast Electric DSM Acquisition				
Tracker Year	DSM Acquisition (aMW)	NEEA DSM Acquisition (aMW)	USB Acquisition (aMW)	Total DSM NEEA USB
2018-2019	3.49	0.41	0.45	4.35
2019-2020	3.49	0.41	0.45	4.35
2020-2021	3.49	0.41	0.45	4.35
2021-2022	2.95	0.40	0.42	3.77
2022-2023	2.95	0.40	0.42	3.77
2023-2024	2.95	0.40	0.42	3.77
2024-2025	2.95	0.40	0.42	3.77
2025-2026	2.95	0.40	0.42	3.77
2026-2027	2.95	0.40	0.42	3.77
2027-2028	2.95	0.40	0.42	3.77
2028-2029	2.95	0.40	0.42	3.77
2029-2030	2.95	0.40	0.42	3.77
2030-2031	2.95	0.40	0.42	3.77
2031-2032	2.95	0.40	0.42	3.77
2032-2033	2.95	0.40	0.42	3.77
2033-2034	2.95	0.40	0.42	3.77
2034-2035	2.95	0.40	0.42	3.77
2035-2036	2.95	0.40	0.42	3.77
Cumulative	54.72	7.23	7.65	69.60

Table 4-7. DSM Forecast Acquisition Expense

Forecast Electric DSM Expense			
Tracker Year	DSM Forecast Incremental Program Expense	NEEA Forecast Program Expense	Total Forecast Incremental Program Expense DSM + NEEA
2018-2019	$ 6,177,071	$ 1,523,720	$ 7,700,792
2019-2020	$ 5,422,054	$ 1,500,000	$ 6,922,054
2020-2021	$ 5,693,156	$ 1,500,000	$ 7,193,156
2021-2022	$ 5,041,324	$ 1,500,000	$ 6,541,324
2022-2023	$ 5,293,390	$ 1,500,000	$ 6,793,390
2023-2024	$ 5,558,059	$ 1,500,000	$ 7,058,059
2024-2025	$ 5,835,962	$ 1,500,000	$ 7,335,962
2025-2026	$ 6,127,760	$ 1,500,000	$ 7,627,760
2026-2027	$ 6,434,148	$ 1,500,000	$ 7,934,148
2027-2028	$ 6,755,856	$ 1,500,000	$ 8,255,856
2028-2029	$ 7,093,649	$ 1,500,000	$ 8,593,649
2029-2030	$ 7,448,331	$ 1,500,000	$ 8,948,331
2030-2031	$ 7,820,748	$ 1,500,000	$ 9,320,748
2031-2032	$ 8,211,785	$ 1,500,000	$ 9,711,785
2032-2033	$ 8,622,374	$ 1,500,000	$ 10,122,374
2033-2034	$ 9,053,493	$ 1,500,000	$ 10,553,493
2034-2035	$ 9,506,168	$ 1,500,000	$ 11,006,168
2035-2036	$ 9,981,476	$ 1,500,000	$ 11,481,476
Cumulative	$ 126,076,806	$ 27,023,720	$ 153,100,526

NorthWestern notes that a future DSM budget is a long-term estimate that may be used for long range resource planning. Each one-year budget forecast is based on current year results and knowledge gained from past program operation and is likely to deviate from the values established in the long range budget forecast presented above, and as evidenced by the five years of data in the DSM and NEEA Spend columns of Table 4-5 above.

DSM Programs and NEEA

NorthWestern continues to offer a variety of programs, services and resources to help our Montana customers to better manage energy costs. The following are electric DSM Programs funded through energy supply rates:

- **Simple Steps Program** – This program buys down LED prices for residential customers at retailers through a regional campaign facilitated by the Bonneville Power Administration.
- **E+ Commercial Lighting Rebate Program** – Offers prescriptive and custom rebates for the replacement of less efficient lighting products with high efficiency technologies.
- **E+ Commercial Electric Rebate Program for New or Existing Facilities** – Rebates are available to electric customers for qualifying electric measures.
- **E+ Business Partners Program** – Provides customized incentives to commercial and industrial customers for electric and natural gas conservation. Examples of projects include measures to improve lighting, heating, ventilating and cooling (HVAC) systems, refrigeration, air handling, and pumping systems. New and existing facilities are eligible.
- **Northwest Energy Efficiency Alliance (NEEA)** – NEEA is a regional non-profit organization supported by utilities, public benefits administrators, state governments, public interest groups, and energy efficiency industry representatives. Through regional leveraging, NEEA accelerates "market transformation" or the development and adoption of energy efficient products and services in Montana, Washington, Idaho, and Oregon. NEEA's regional market transformation activities target the residential, commercial, industrial and agricultural sectors.

USB Programs

Additional electric energy savings are produced from Universal System Benefits (USB) funded programs that will continue into the foreseeable future. The electric energy savings produced from these USB programs are counted toward annual DSM goals. The costs to operate these programs are not included in the energy supply resource planning process. The following energy saving programs are supported through USB funds:

- **E+ Free Weatherization Program** – Provides insulation and other efficiency improvements at no cost to Low Income Energy Assistance Program (LIEAP) qualified space-heating customers of NorthWestern.
- **E+ Energy Audit for the Home** – Free onsite energy audit and mail-in survey audit.
- **E+ Energy Appraisal for Businesses** – Free onsite energy audit that focuses on identifying electric conservation opportunities for small commercial customers on NorthWestern's electric distribution system. The customer receives a report with recommendations customized to the facility.
- **E+ Irrigator Program** – Provides financial incentives for the installation of energy efficient electric conservation in irrigation systems.
- **Building Operator Certification** – Building Operator Certification is an international professional development program for managers and operating engineers of commercial and public facilities and is available to commercial customers in partnership with the Northwest Energy Efficiency Council.
- **E+ Renewable Energy Program –** Provides financial incentives to non-profit and government/public electric customers for qualifying small-scale solar photovoltaic, wind, and hydroelectric systems in Montana.

Future Updates

NorthWestern is updating the Electric Potential Study in an effort to define the demand or capacity savings potential in NorthWestern's Montana electric service territory and inform DSM-based avoided capacity cost values. NorthWestern has contracted with Nexant to complete this work, which is expected to be finalized in 2019. NorthWestern will be evaluating the savings estimates for our Montana service territory and contract associated with NEEA's 2020-2024 Business Plan. The results of these activities may result in adjustments to the forecasts noted in this plan.

Additional information on the programs listed is available at NorthWestern's website at www.NorthWesternEnergy.com/Eplus.

Small Distributed Generation Resources

Net Energy Metering Study

NorthWestern currently has about 2,400 customers that have their own small-scale solar PV systems that provide power to NorthWestern's electrical grid. The customers that own these systems are net metering customers and they are able to offset their electric use and receive a credit for the excess energy produced, above use. This credit is currently equal to NorthWestern's full $/kWh retail rate.

In April 2017, the Montana Legislature passed House Bill 219, which was signed by the Governor of Montana on May 3, 2017. The legislation required NorthWestern to conduct an economic analysis and evaluation of solar PV NEM benefits and costs in the State of

Montana. NorthWestern was required to conduct a NEM study of the costs and benefits of customer-generators and submit the study to the Montana Public Service Commission (MPSC) before April 1, 2018. Navigant was retained by NorthWestern to conduct the study. The results of Navigant's NEM study complies with the law, and could support the development of a new rate class for NEM solar if the results of the study justify the need to create a separate NEM rate class.[5]

Navigant estimated the value streams for NEM resources across a range of benefit and cost categories and under three different 25-year scenarios reflecting different potential rates of solar adoption in Montana.[6] These scenarios were derived from a study prepared in 2017 for the MPSC by the NREL, with adjustments to ensure that the forecasts were realistic in the context of the NEM Study. The three scenarios Navigant considered were:

- **Low Adoption**: equivalent to NREL's "unfavorable" scenario
- **Medium Adoption**: the average of the Low and High Scenarios
- **High Adoption**: adoption not to exceed substation-level limits based on reverse power thresholds, the exceedance of which would require upgrades to NorthWestern's distribution system to avoid reverse power flows or thermal voltage violations when midday load is low but solar output is high

[5] The full report can be found in Volume 2, Chapter 3.

[6] The benefits and costs derived in the study are based on the categories outlined in the Minimum Information Requirements in Attachment 1 of the MPSC Notice of Commission Action dated August 9, 2017. The categories considered in the study are: avoided energy costs, avoided capacity costs, avoided transmission and distribution capacity costs, avoided system losses, avoided RPS compliance costs, avoided environmental compliance costs, market price suppression effects (fuel hedging), avoided risk (e.g., reduced price volatility), avoided costs for grid support services, avoided outages costs, non-energy benefits, reduced revenue, administrative costs, interconnection costs, and integration costs.

Because the High Adoption scenario is limited to adoption levels that are low enough to avoid upgrade costs on the distribution system, other upgrade costs that would be necessary at higher levels of adoption—such as those for interconnection and integration—can also be avoided. Thus, these costs are estimated at zero throughout the study period. The adoption levels over the 25-year study period for each scenario are presented in Table 4-8.

Table 4-8. Navigant NEM Adoption Scenarios

Adoption Scenario (MW)			
Year	Low	Medium	High
2018	16	19	22
2019	22	31	40
2020	29	47	65
2021	37	67	97
2022	45	88	131
2023	55	108	161
2024	67	128	189
2025	80	146	212
2026	95	163	231
2027	112	180	248
2028	129	196	262
2029	142	208	273
2030	155	218	281
2031	167	227	288
2032	177	236	294
2033	186	243	299
2034	193	249	305
2035	199	254	310
2036	203	259	316
2037	206	265	323
2038	209	270	330
2039	212	275	338
2040	214	280	346
2041	215	284	353
2042	217	288	358

To determine how much power is likely to be generated from customer-owned solar generation, and the hourly production over the year, Navigant followed the production shape methodology used in NREL's study. This method uses a weighted mixture of rooftop orientations and locations that exist on NorthWestern's system in 2018.

Using these generation profiles, Navigant estimated the value streams associated with each category of cost and benefit for each solar adoption scenario (Low, Medium, and High). The study also estimated how these values would change if the government imposed a tax on carbon emissions starting in 2028. The estimated values for each category of benefits and costs are presented in the following table.[7]

Table 4-9. Navigant NEM Value Streams

Carbon Price	Yes	Yes	Yes	No	No	No
Adoption Scenario	**Low**	**Med**	**High**	**Low**	**Med**	**High**
Avoided Energy Costs	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
Avoided Capacity Costs	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Avoided T&D Capacity Costs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided System Losses	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided RPS Compliance Costs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Environmental Compliance Costs	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00
Market Price Suppression Effects (Fuel Hedging)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Risk (e.g., reduced price volatility)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Grid Support Services Costs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Outages Costs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Non-Energy Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Reduced Revenue	($0.15)	($0.14)	($0.14)	($0.15)	($0.14)	($0.14)
Administrative Costs	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)
Interconnection Costs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Integration Costs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Net Value	($0.10)	($0.10)	($0.10)	($0.11)	($0.11)	($0.11)

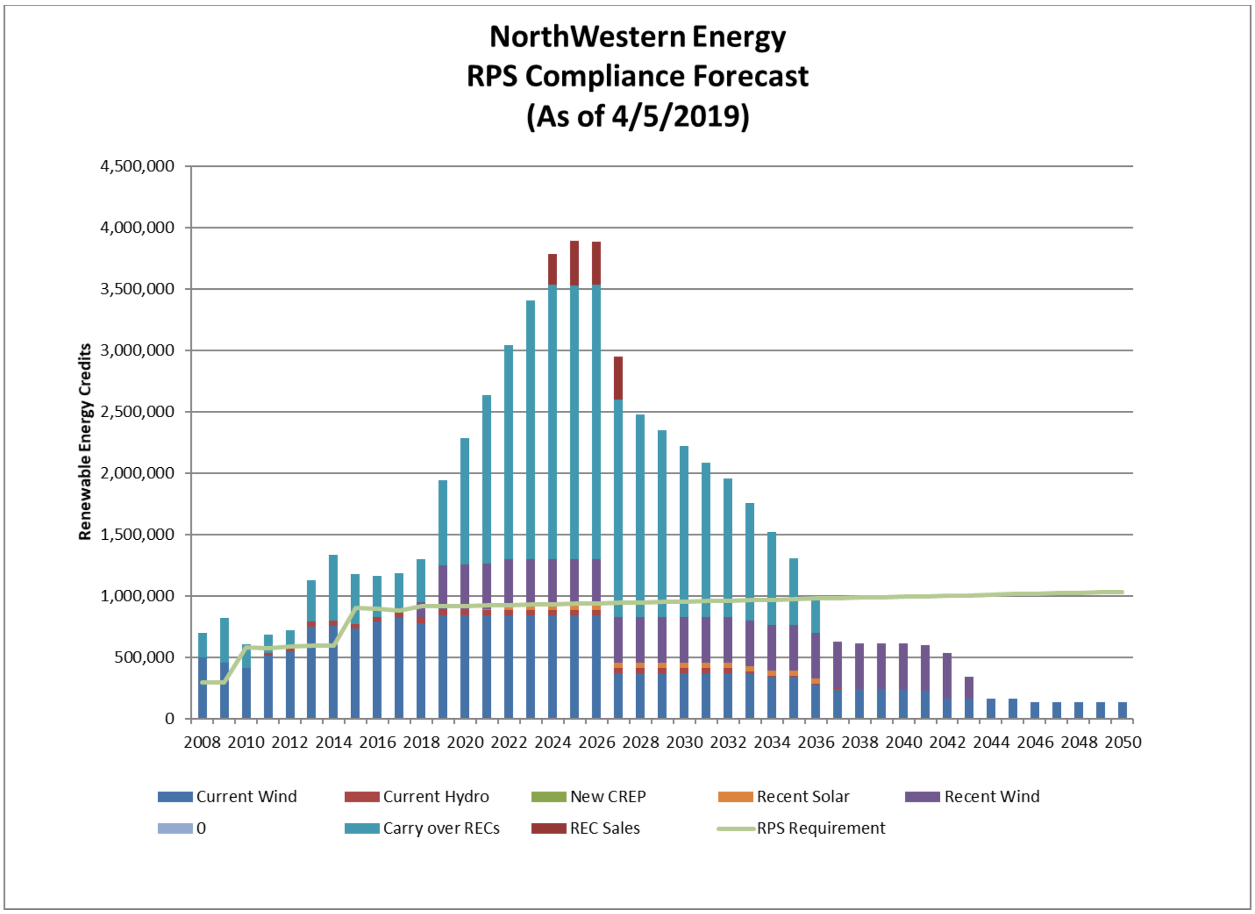
Renewable Portfolio Standards

NorthWestern maintains our commitment to do everything we can to meet the requirements imposed upon it under the Montana Renewable Power Production and Rural Economic Development Act, §69-3-2001, MCA, et. Seq., labeled as the Renewable Resource

[7] More detailed information on the calculation of these costs and benefits can be found in the NEM study Volume 2, Chapter 3.

Standard but commonly referred to as the Renewable Portfolio Standard (RPS). NorthWestern's current requirement is to meet an energy requirement of 15% of our yearly retail sales (MWh) from eligible renewable resources and for an additional capacity (MW) requirement under our share of purchases from a state total of 75 MWs of community renewable energy projects (CREP). NorthWestern's share of the CREP requirement has been established at 65.4 MWs.

Figure 4-8. Montana RPS Compliance



Renewable Energy Credits (REC)

Under the MCA, a "Renewable Energy Credit" means a tradable certificate of proof of 1 megawatt hour of electricity generated by an eligible renewable resource that is tracked and verified by the commission and includes all of the environmental attributes associated with that 1 megawatt-hour unit of electricity production. Montana requires NorthWestern to validate all RECs we acquire and use to meet our obligation through the WECC established Western Renewable Energy Generation Information System (WREGIS).

Based on its current contractual commitments and forecasted energy generation from the RPS qualified facilities, NorthWestern anticipates we will meet the required 15% of sales through 2035. During 2017 the RPS facilities generated 862,980 RECs with NorthWestern's 15% of sales equaling 542,553 RECs that were required to be retired to meet its 2017 obligation. WREGIS reports that the volumes allowed to be carried forward into future years are 320,427 RECs. Under the MCA, RECs that are not retired to meet a utility obligation can be carried forward for up to two years. Based on forecasted RPS generation NorthWestern anticipates that around the year 2024, we will have more RECs than we require to meet our obligations and will have to sell excess RECs before they are no longer able to be used for compliance.

Community Renewable Energy Projects

NorthWestern currently has 36.335 MWs of our CREP capacity requirement obligation under the MCA. In our attempt to meet the total required capacity, NorthWestern has issued multiple RFPs and negotiated PPAs for additional CREP projects that have either been deemed to not qualify or otherwise meet the MCA rules. The following outlines NorthWestern's current CREP activities:

- In 2018, NorthWestern acquired Two Dot Wind, making it eligible to qualify as a CREP resource. At a work session held on November 28th, 2018, the MPSC certified Two Dot wind as an 11 MW CREP resource.

- On April 1, 2019, NorthWestern signed a power purchase agreement to acquire the output of a 20 MW CREP resource from Meadowlark Solar, LLC. Meadowlark submitted the project in response to NorthWestern's 2018 CREP RFP and the contract was the result of that process.
- NorthWestern is currently upgrading a generation turbine at Hauser and one turbine at Ryan.
- NorthWestern is planning to upgrade all four turbines at Madison, an additional two turbines at Hauser, and an additional turbine at Ryan, all before 2022. The increase in capacity from these upgrades will be eligible for CREP.

NorthWestern continues to pursue all available avenues to meet our remaining CREP obligation as soon as possible.

CHAPTER 5
REGIONAL MARKET TRANSFORMATION

NorthWestern's Path to the Western Energy Imbalance Market ("EIM") and Beyond

Regional Market Development

Background

There are two full regional markets in the WECC: The California Independent System Operator (CAISO) and the Alberta Electric System Operator (AESO). CAISO manages the transmission system owned by the three large investor-owned utilities in California and operates full day-ahead and realtime markets. AESO manages and operates the provincial electric grid. ISOs and RTOs are independent entities that operate transmission facilities owned by others, coordinate planning of the transmission system, and operate markets. ISOs typically include both day-ahead markets and realtime markets for energy and ancillary services. Some also include capacity markets. ISOs dispatch generation resources owned by others to economically meet customer loads within the market footprint. Both CAISO and AESO have been operating for over twenty years.

Stakeholders in other areas of the WECC have been discussing, analyzing, and attempting to develop organized markets since the 1990s. In the last five to ten years, those efforts have moved away from full ISO development to the development of EIMs. EIMs share some characteristics of RTOs and ISOs, but there are key differences. The major similarity is that all of these entities operate markets which accept offers and dispatch resources on a sub-hourly basis to meet load requirements. Unlike RTOs and ISOs, EIMs do not provide ancillary services, manage congestion, or administer an Open Access Same-time Information System (OASIS) site, and they do not take on reliability responsibility.

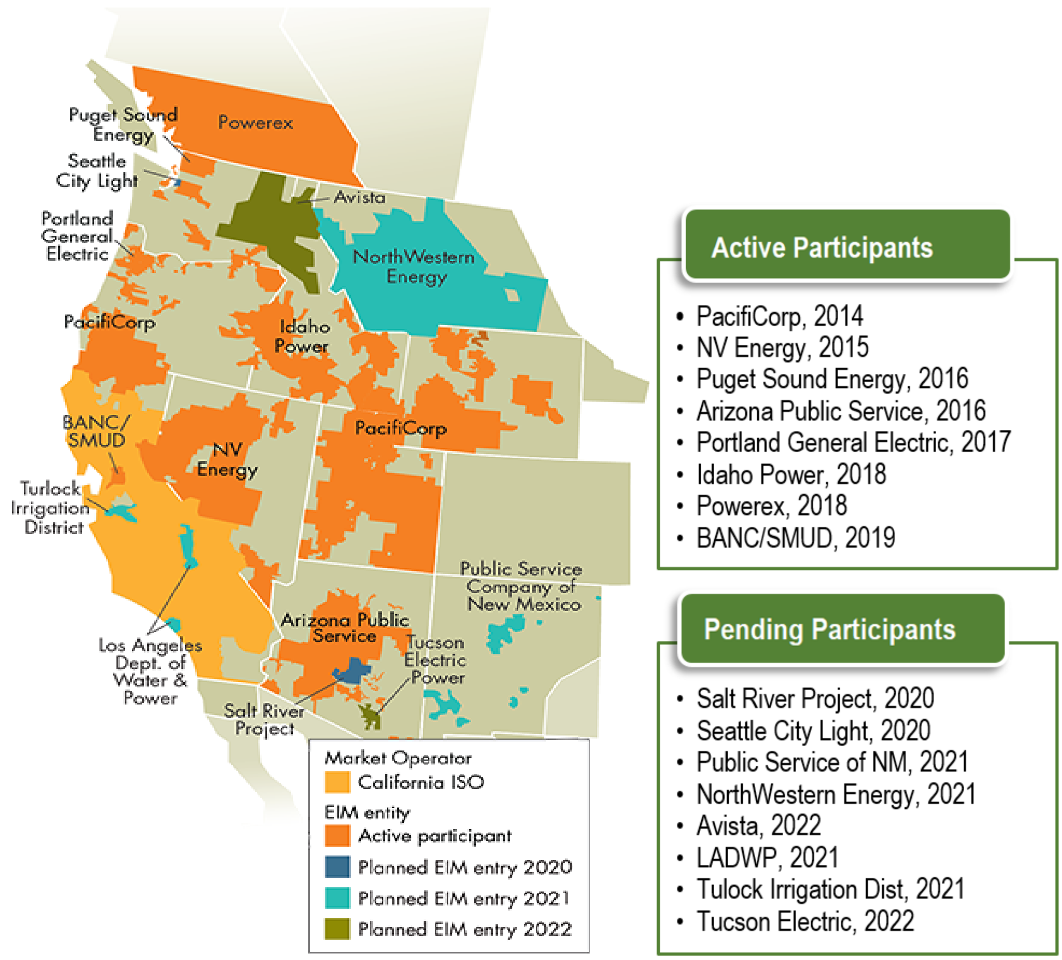
The efforts to develop EIMs have occurred for both reliability and economic reasons. Both the reliability and economic aspects are driven in large part by the need to integrate increasing amounts of intermittent generation (VERs) into the portfolios of virtually all utilities in the region. EIMs improve reliability by providing increased region-wide situational awareness to Balancing Authorities (BAs) and making better use of available generating capacity in the region. They also improve economics by efficiently dispatching generators to meet loads across a regional footprint rather than within BAs.

While the individual BAs retain their reliability responsibility, EIMs have resource sufficiency requirements that obligate participating BAs to carry enough capacity to meet their own internal needs. These requirements are designed to keep a participating BA from entering an hour in a capacity- or energy-short position and relying on the EIM to meet its load-serving obligations. Participation in an EIM helps make efficient use of resources, but it does not reduce a BA's need for capacity. Depending on the specifics of the resource sufficiency requirement, participation in an EIM could drive the need for additional capacity.

Western EIM

In 2011, efforts to develop an EIM in the West began ramping up. A number of groups, including WECC, the Western Interstate Energy Board, and WSPP explored the ideas and issues surrounding the potential creation of the market. These efforts resulted in an initiative sponsored by the Northwest Power Pool (NWPP) that would have created an EIM for the Pacific Northwest. NorthWestern was an active participant in the NWPP effort, which ultimately failed in 2015.

Figure 5-1. EIM Active and Pending Participants



Meanwhile, in 2013, PacifiCorp and the CAISO announced their plans to form what would become the Western EIM. The Western EIM went live in October of 2014, and since that time, NV Energy, Arizona Public Service, Puget Sound Energy, Portland General Electric, Idaho Power, Powerex, and Balancing Authority of Northern California / Sacramento Municipal Utility District have joined the market. Seven additional utilities (Seattle City Light, Salt River Project, Los Angeles Department of Water and Power, Public Service Company of New Mexico, Turlock Irrigation District, Tucson Electric Power, and Avista

Corporation) have signed implementation agreements to join in the next few years. Figure 5-1 shows the current and planned market participants.

The Western EIM has provided significant value to the customers of participating utilities. CAISO estimates that the total gross economic benefits for participating entities have totaled over $700 million from the inception of the market through June of 2019. The economic benefits come primarily from efficient economic dispatch of resources across the market footprint to meet customer load on a realtime basis. In addition, the market benefits customers by enhancing reliability through improved operational visibility and by improving the integration of renewables by taking advantage of weather and load diversity across the wide geographic area covered by the market.

NorthWestern Analysis of the Western EIM

In 2016, NorthWestern began an in-depth analysis of the Western EIM to determine whether joining the market would make sense for the company and our customers. We engaged two consultants to help with the analysis. Utilicast performed a market assessment and gap analysis, and Energy and Environmental Economics (E3) performed a benefits study.

Utilicast Study

Utilicast performed a high-level assessment of the potential market options available to NorthWestern and the system, process, organizational, and personnel changes that would be necessary to operate in organized markets.

Utilicast worked with NorthWestern to identify several existing and potential wholesale markets in the West. These included the Western EIM, the AESO, the Mountain West Transmission Group (MWTG), the Southwest Power Pool (SPP), regionalization of the

CAISO, and a Northwest market. While several of these potential alternatives had appealing aspects, they had significant challenges as well. The Northwest market, MWTG, and the regionalized CAISO were conceptual and would require several years of development; and participation in AESO and SPP would likely require transmission construction. This left the Western EIM as the only viable market alternative that was worth detailed analysis.

The remainder of the Utilicast assessment focused on understanding the current state of NorthWestern's technology, processes, infrastructure, and personnel and what would be necessary to participate in the Western EIM. Utilicast performed an in-depth analysis of NorthWestern's operations, including transmission, energy supply, load forecasting, metering, and other areas. This analysis also included cost estimates for the implementation of the software, hardware, processes, staffing, and other changes that would need to take place. This work served as an initial roadmap for the path NorthWestern would follow if we made the decision to pursue the EIM.

E3 Study

E3 performed a detailed analysis of the potential economic benefits of NorthWestern participation in the EIM. The modeling approach was to use production cost modeling to estimate the benefits resulting from participation in the EIM by comparing NorthWestern's generation costs, market revenues, and market costs as an EIM participant with those of a business as usual (BAU) case in which NorthWestern does not participate in EIM.

As a starting point, E3 used the PLEXOS database that was developed by the Pacific Northwest National Laboratory for the WECC study in 2012. E3 updated the database during its 2015 EIM study for Portland General Electric and subsequent EIM study for

Idaho Power Company and made revisions specific to the NorthWestern BA and neighboring systems in this study.

The study calculated benefits in two categories, sub hourly dispatch benefits and savings from reductions in flexibility reserves. The dispatch benefits were calculated by running a realtime BAU case that held energy transfers (purchases and sales) between non-participating BAs equal to the hour-ahead scheduled amounts, and comparing that to an EIM case that allowed NorthWestern to transact energy within the hour with other EIM entities. The savings from reduced flexibility reserves were calculated based on the CAISO methodology for calculating the savings from diversity across the market footprint.

E3 analyzed a base case and two alternative scenarios. The base scenario reflected EIM membership of the entities who were participating at the time of the study and those who had announced plans to join and reflected renewables penetration levels consistent with then-existing RPS targets in the states within the EIM footprint. The first alternative case examined an expanded EIM footprint that includes all northwest BAs in addition to those in the base scenario. The second alternative scenario modeled high renewables buildouts in California and Oregon that were under consideration at the time.

The study results indicated that annual benefits for NorthWestern would range from $1.3 million to $3.0 million, with a base case of $1.8 million.

<u>Other Considerations and NorthWestern's Decision to Join EIM</u>

Based on the results of the Utilicast and E3 studies, NorthWestern determined that there would be customer benefit in joining the EIM. However, at the time the work was completed in early 2017, other market development activity had advanced to the point that it warranted further consideration.

Specifically, the MWTG had announced that it intended to become a part of SPP. SPP began a stakeholder process to work toward the integration of the MWTG footprint into the market, with a target go-live date of October of 2019. NorthWestern's South Dakota operations are already in the SPP market, so the potential to integrate Montana operations into that market had some appeal. However, NorthWestern does not have direct transmission interconnection with the MWTG members, so there were significant challenges to address as well. We began discussions with MWTG members and other neighboring utilities about the potential to expand the SPP market beyond the MWTG footprint. We also participated in the integration discussions in the SPP stakeholder process from the perspective of our existing South Dakota membership.

The MWTG plans to join SPP were abruptly derailed in April of 2018 when one of the key members of the group, Xcel Energy's Public Service Company of Colorado (PSCo), announced that they were leaving the group and discontinuing their consideration of joining SPP. The remaining members of MWTG indicated that they would continue their efforts, but PSCo's departure significantly changed their situation. MWTG began analysis on whether it would make sense to continue to proceed without PSCo. The results of the analysis were not made public, but in October, Black Hills Energy announced that it would not pursue membership in SPP at this time, and the Western Area Power Authority (WAPA) announced that it was suspending MWTG activity.

Meanwhile, in late 2017, Peak Reliability and PJM Connext announced plans to explore the development of an organized market in the West. This effort continued through the spring of 2018, but ultimately did not gain enough support among utilities and others to survive. The effort ceased in July of 2018.

In the summer of 2018, the Bonneville Power Administration (BPA) announced that it was initiating a public stakeholder process regarding the potential for BPA to join the EIM in 2022. BPA hosted several public meetings and webinars and accepted comments from stakeholders. In June of 2019, BPA issued a Letter to the Region stating its intention to sign an implementation agreement in September and go live in EIM in 2022.

Throughout this period, NorthWestern continued to meet with MWTG members, SPP staff, current and planned EIM members, CAISO staff, and utilities that have not yet committed to joining a market. We also made two, day-long site visits to current EIM members to gain a better understanding of the operational impacts of EIM membership.

Through these discussions and through several internal meetings, the EIM emerged as the most appropriate path forward for NorthWestern. We met with MPSC staff and Montana Consumer Counsel (MCC) in June to update them on the status of NorthWestern's views, and we indicated at that time that the EIM appeared to be the most likely path. We also presented material to ETAC in February and July of 2018, describing the market development activity and indicating that a NorthWestern decision to join EIM was likely.

BPA's move toward the EIM, along with the number and size of the current and planned members, as well as others that appear likely to announce their plans in the coming months, have given the EIM significant size. The total load of the EIM members and those who have signed implementation agreements is about 80% of the load in the Western Interconnection. For a number of reasons, NorthWestern is wary of the prospect of existing outside of the organized market while an increasing number of our neighbors and peers become part of the market. One consideration is whether a robust bilateral market will continue to exist outside of EIM as the market continues to develop. A second is that as an outsider, NorthWestern does not have a voice in the specific rules and market structure as they are updated and change over time. Additionally, if there is a future move toward a full RTO market in the West, the transition will be much easier if NorthWestern is aligned with our peers as a member of EIM than it would be if NorthWestern was one of the few parties operating outside of that market.

The NorthWestern executive team formally approved the decision to join EIM in September of 2018. We negotiated an implementation agreement with CAISO and executed it on November 8, 2018 with a go-live date of April 2021.

Future Market Development

EIM Enhanced Day-Ahead Market (EDAM)

In early 2018, CAISO kicked off a process to enhance the day-ahead market within the full ISO footprint. The changes are primarily geared toward improving the operation within California in the full ISO, but the changes will also create a platform that would allow for the EIM to be extended to include a day-ahead market. The enhancements to the ISO's day-ahead market are targeted to go live in 2021. The extension to EIM participants would occur in a second phase. This extension has not yet been formally introduced as a stakeholder process, but CAISO has been working with current EIM members and organizations that have executed implementation agreements to assess the feasibility of pursuing this initiative. Once this work is complete, if current members and CAISO support moving forward, a stakeholder process will be initiated regarding the day ahead extension of the EIM.

An organized day-ahead market across the EIM footprint could be a significant development. The EIM has provided value for the participants, but a day-ahead market that optimizes resources across a wide footprint over multiple hours could provide even more value, depending on the market construct. As is the case with the existing EIM, EDAM would include a resource sufficiency requirement. This means that, in order to participate, NorthWestern would need to demonstrate on a day-ahead basis the ability to meet its load, ramps, and uncertainty throughout the day.

Potential Future Western RTO

With the increased pace of market development in the West over the last five years, NorthWestern views the development of a full RTO as extremely likely. There are several reasons for this. The continued fast pace of solar and wind generation throughout the region will continue to increase the need for flexible resources and market structures to accommodate them. The EIM helps in the realtime horizon. The EDAM, if it is implemented across the EIM footprint, could be even more valuable because it would allow for the day-ahead commitment of resources to meet net load ramps in the market. A full RTO or ISO, without transmission pancaking issues and with broad transmission planning, could ultimately provide the most value. For this Plan, we are assuming that full RTO will be implemented in 2025.

EIM Operations

Changes from Current Operations

NorthWestern's Energy Supply and Transmission operations will change significantly when we join EIM. The following section describes, at a high level, some of the expected impacts from the Energy Supply perspective.

The current structure of the non-EIM electricity market consists of bilateral transactions. This means that the terms of energy purchases and sales are negotiated directly between the two counterparties to a transaction or trade. While there may be some effects from EIM on day-ahead and longer transactions, the market itself addresses intra-hour balancing, so its biggest effect will be on hourly operations.

In non-EIM operations, the NorthWestern Energy Supply realtime scheduler makes hour-ahead bilateral purchases or sales to balance forecasted supply with forecasted load. Within the hour, any deviations from that balance either from load or generation is countered with NorthWestern's flexible resources. Because of this need, NorthWestern must set aside or reserve flexible capacity to increase generation (INC) and decrease generation (DEC) to be used to make up any differences that occur within the hour. For example, if wind generation is lower than expected, NorthWestern may have to increase generation from a flexible resource in our portfolio (for example, DGGS) to keep the system in balance and comply with NERC standards. If wind generation is higher than expected, NorthWestern may have to decrease a flexible resource in order to keep the system in balance and in compliance. Note that in EIM, NorthWestern will remain a BA with responsibility to comply with all applicable reliability standards, but instead of just the resources in NorthWestern's own fleet, resources from throughout the market footprint are potentially available to help meet imbalances.

EIM addresses only within-hour balancing, so NorthWestern will still engage in bilateral trading up to the hour-ahead time horizon. A key difference in EIM will be that, instead of reserving resources to increase or decrease going into an hour, NorthWestern will offer these flexible resources into the market. Within the hour, the EIM will meet load and imbalances across the market area by economically dispatching resources every five minutes. The market uses security constrained dispatch, meaning that transmission and reliability constraints are honored. The EIM uses dynamic schedules to transfer energy among EIM Entities, meaning that the schedules for these transfers are created automatically by the market.

In EIM, the BA or transmission function within NorthWestern will be the EIM Entity. In addition to all of its current responsibility as a BA, the EIM Entity is responsible for monitoring generation and transmission information within its boundaries and communicating this information to the EIM Market Operator on a realtime basis. NorthWestern's Energy Supply group will be responsible for determining which resources will participate in the market (Participating Resources) and which will not (Non-Participating Resources). The Energy Supply group's role is known as the Participating Resource Scheduling Coordinator (PRSC). The PRSC will also determine the prices at which to offer resources into the market.

Resource Sufficiency & Capacity Requirements

A key element of the EIM is that EIM Entities cannot rely on the market for capacity. Each EIM Entity must demonstrate on an hourly basis that it has the resources and ramping capability available to meet its own needs as a BA (less an allowance for the benefit created by the load and generation diversity across the footprint). This requirement takes the form of the Resource Sufficiency (RS) tests. These tests occur three times in each hourly cycle, at T-75 (75 minutes before the start of the clock hour), T-55, and T-40. The tests are intended to ensure that each EIM Entity can meet its own reliability obligations. If an EIM Entity fails any of the RS tests for any hour, intra-hour EIM transfers to or from other EIM Entities will not be allowed during that hour. The RS evaluation consists of four components: 1) Balancing Test; 2) Bid Capacity Test; 3) Flexible Ramping Sufficiency Test; and 4) Feasibility Test.

The Balancing Test ensures that each EIM Entity has scheduled resources that match (within a tolerance) its forecasted load. This test compares the base schedules with the hourly demand forecast. The scheduled resources must be within 1% of the demand forecast to pass the screen.

The Bid Capacity Test compares the total INC and DEC bid range from Participating Resources within the EIM Entity with the demand forecast plus and minus historical intertie deviations. The EIM Entity passes the Bid Capacity Test if there is sufficient capacity to meet the forecast plus historical deviation and the forecast minus the historical deviation.

The Flexible Ramping Sufficiency Test ensures that each EIM Entity has enough ramping resources to meet expected upward and downward ramping needs. This is similar to the Bid Capacity Test except that it also includes the ramp rates of the Participating Resources.

The Feasibility Test uses base schedules submitted to the market to perform a power flow feasibility test. This test determines if the base schedules submitted by participants would violate any transmission constraints.

CHAPTER 6
TRANSMISSION SYSTEM

NorthWestern's Electric Transmission System

Overview

NorthWestern's Montana electric transmission system covers over 97,000 square miles in the western two-thirds of Montana. The system includes about 7,000 miles of transmission and sub transmission facilities with voltages ranging from 50 kilovolt (kV) to 500 kV. The system includes over 280 circuit segments, 79 transmission or transmission/distribution substations, and over 100,000 poles/structures.

Key Concepts and Definitions

A review of key concepts and definitions is useful for understanding NorthWestern's transmission system and some of the issues and challenges facing NorthWestern.

- NorthWestern's transmission system is made up of 230 kV, 161 kV, 115 kV, and 100 kV systems that connect the various load centers in the state as well as sub-transmission 50 kV and 69 kV systems that serve many local areas.
- The jointly owned Colstrip 500 kV transmission system makes its way from Colstrip in eastern Montana to western Montana where it interconnects with the Bonneville Power Administration's (BPA) 500 kV Montana Intertie facilities at Townsend. BPA's 500 kV Montana Intertie extends from Townsend to the Garrison substation. NorthWestern and the other Colstrip owners hold firm transmission rights on the Montana Intertie facilities.

- Open Access - Federal Energy Regulatory Commission (FERC) Order 890: provides for non-discriminatory access to jurisdictional transmission systems to all eligible customers.
    - NorthWestern has an Open Access Transmission Tariff (OATT) on file with FERC.
- Total Transmission Capacity (TTC): total designed and approved transmission capacity of a transmission path.
- Available Transmission Capacity (ATC): available transmission capacity after considering firm commitments.
- Reliability: adequacy and security of the transmission system to operate properly under stressed conditions.
- The current transmission system was not planned and designed to serve all of NorthWestern's Balancing Authority (BA) load by importing energy into Montana over the transmission interties. The system was designed with a significant amount of in-state generation available to also serve the BA load. Over reliance on short term transmission availability and external generation capacity is a significant risk to NorthWestern's ability to serve the BA load in Montana.

The Colstrip 500 kV Transmission System

It is well known the 500 kV transmission lines were built at the time the Colstrip generation plants were constructed and the transmission lines are the primary asset used to export the other Colstrip owners' shares of the generation out of Montana to load centers in Washington and Oregon. What may not be as well understood is the value of the 500 kV system to Montana customers. The 500 kV system is the backbone of the Montana transmission system, and it provides NorthWestern with a very strong path from east to west across the state with which to reliably serve all of our Montana customers. The 500 kV system effectively ties together the lower transmission voltage systems in the state at three substations – Colstrip, Broadview and Garrison. The Garrison substation is owned by BPA and in addition to NorthWestern's rights on the Montana Intertie, NorthWestern also has other transmission facilities that terminate at Garrison. In addition, the 500 kV system provides the greatest access to and from the regional market. This is extremely important to allow NorthWestern the ability to import power into Montana to serve our customers – both our retail energy supply customers and the unbundled customers that receive transmission service under our OATT described in more detail below. This import capability is especially important as Montana generation is slated to be shuttered.

Customers Served by the Transmission System

NorthWestern's transmission system serves four types of customers – retail, network, interconnection, and point to point (PTP).

- The retail customers are NorthWestern's bundled transmission, distribution and energy supply customers. The Montana Public Service Commission (MPSC) approves rates for NorthWestern's service to retail customers.
- Network customers are generally electric cooperatives and federal power marketing agencies, such as the BPA, as well as "choice customers." Choice customers elected, under deregulation, to purchase electric commodity service from a supplier other than MPC (now NorthWestern), or are new customers since then with loads that do not qualify for electric supply service from NorthWestern. Network customers take transmission delivery service under NorthWestern's FERC OATT to serve load within NorthWestern's footprint.
    - It is extremely relevant to note NorthWestern's belief that there is no entity "planning" for the electricity supply for the choice customers in Montana. The choice customer group relies on the market and as generation in Montana is reduced, there will be more competition for

available resources and transmission capacity which will increase the risk associated with NorthWestern relying too heavily on the outside market to import energy to serve our retail customers.
    - To be clear, NorthWestern has the responsibility to reliably deliver energy to all of our customers even though we do not have control of the resources used to serve a large percentage of our customers.

- Interconnection customers are generation customers seeking interconnection to NorthWestern's transmission system. One example of an interconnection customer is a Qualifying Facility (QF). While NorthWestern processes QF interconnections under the FERC generation interconnection rules with MPSC permission, as a general rule, QFs are under the jurisdiction of the MPSC. Non-QF generation interconnection customers are provided service under NorthWestern's FERC OATT.
- PTP customers move power into and out of NorthWestern's system using the transmission system. NorthWestern serves PTP customers through our FERC OATT.

Other Services Provided by the Transmission System

NorthWestern also manages the transmission system as a Balancing Authority (BA), with responsibility for ensuring that system demand and supply are in constant balance. To support the continuous flow of electricity, NorthWestern provides ancillary services which are services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice. Ancillary services include regulation, incremental and decremental capacity, and contingency reserves. When demand and supply are not in balance, equipment damages, cascading outages, or blackouts can result. As a BA, NorthWestern must comply with the North American Electric Reliability Corporation's (NERC) reliability standards. One of the greatest challenges faced by NorthWestern as a BA is being able to balance loads and resources as more and more variable energy resources (VERs) are added to the energy supply portfolio and remain compliant with NERC standards.

In April of 2015, FERC approved NERC Standard BAL-001-2 – Real Power Balancing Control Performance (aka, Reliability Based Control (RBC)). This was a significant change from the former Control Performance Standard 2 (CPS2). In early 2016, NorthWestern began operating under RBC. Under RBC, performance includes a component directly tied to the Western Electricity Coordinating Council's (WECC) overall operating frequency (measured in hertz). This allows for some flexibility to BA operators if their own system variance is "helpful" to the WECC system variance. This would occur if a BA was in a frequency position opposite that of the overall WECC. However, if an individual BA's variance is detrimental to the operation of the WECC, RBC requires the BA to take more immediate action than was required under the old CPS2 standard. While CPS2 compliance was measured on a monthly basis, RBC requires compliance within 30 minutes of when the BA's variance moves out of tolerance limits. In addition to the moment-to-moment changes in generation provided by resources on automatic generation control, the system balancing efforts now require additional flexible generation facilities capable of increasing or decreasing generation within minutes. NorthWestern uses the Dave Gates Generating Station (DGGS), Colstrip Unit 4, the Hydros, and Basin Creek to meet RBC requirements.

As more and more variable resources like wind and solar are connected to the transmission system and become part of NorthWestern's energy supply portfolio, additional flexible capacity resources are required to ensure compliance with RBC requirements.[1] Since 2008,

[1] Refer to the Navigant VER Study discussed in Chapter 3 and provided in Volume 2, Chapter 3.

248 MWs nameplate capacity of VERs have interconnected to the transmission system and become a part of NorthWestern's supply portfolio. Our portfolio had 147 MWs nameplate capacity of VER on the system in 2008, and now has executed PPAs for a total of 555 MWs nameplate capacity of VER.[2] The total nameplate capacity of VER in the portfolio is currently equivalent to about 125 percent of NorthWestern's retail supply minimum load of 443 MW.[3]

It is NorthWestern's responsibility to balance essentially all of this retail variable generation on behalf of our retail customers. As a result, NorthWestern has had to use more and more of the flexibility inherent in our resource portfolio to meet this increasing balancing need on behalf of our retail customers. As the amount of VERs on NorthWestern's system continues to grow, NorthWestern will need to contract for or acquire additional flexible resources to meet the requirements driven by the increased variability as supported by the VER study referred to previously.

Transmission Interconnections with Other BAs

Figure 6-1 below depicts the amount of total transmission capacity (TTC) at the major interconnections of NorthWestern's system with other transmission systems. The following are important points of emphasis.

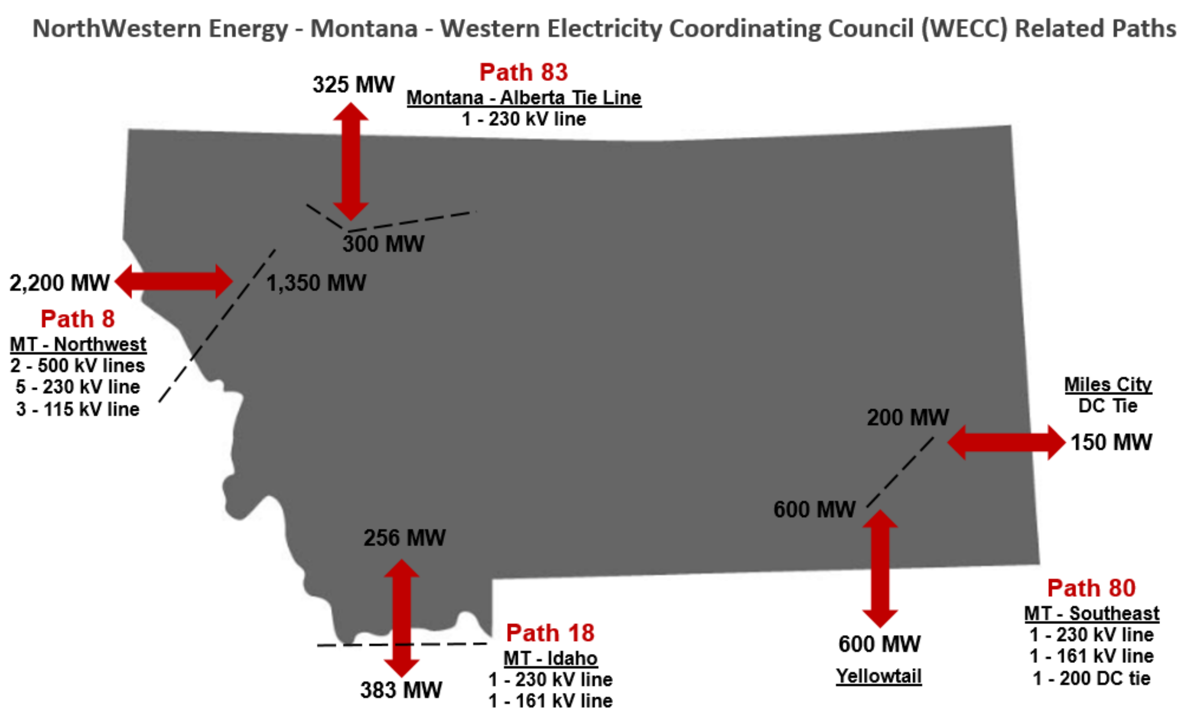
- The largest interconnection is to the West on WECC Path 8.
- Path 8 provides access to the Mid-C Market through the BPA. It is the largest physical, electrical interconnection made up of multiple transmission lines.

[2] There has been no variable generation interconnected since 2008 for use by FERC load customers or to be delivered to customers outside of NorthWestern's BA.

[3] Energy Supply minimum hourly load during 2017 was set on May 7.

- The other paths are not directly connected with the Mid-C Market and there are intermediate transmission systems with potentially significant transmission congestion issues associated with those paths.
- TTC is not ATC (the importance of this is explained below).

Figure 6-1. NorthWestern Interconnections to WECC



Transmission System Challenges

As noted above, ATC is transmission capacity available after accounting for all long term firm commitments. Once long term firm commitments are considered, parties may use remaining ATC on a short term basis.

Table 6-1 shows the estimated future long term export and import ATC considering firm transmission service requests as of June 25, 2019 for each path. As is indicated in the table, import ATC is quite limited compared to import TTC, including at the most utilized Path 8 interface with BPAT which is currently only 52 MW. This is of great concern because NorthWestern must currently purchase about 455 MW of peaking capacity from the market to serve retail customers (not considering network customer's shortfalls), and closure of Colstrip Units 1 and 2 eliminates approximately 310 MW of in-state capacity that could be used to serve load in Montana.

NorthWestern's experience from actual operations is that the Path 8 interface at BPAT and the Path 18 interface at Brady are the most commonly used and desired paths for importing power. Table 6-1 includes "long term" pending and confirmed commitments used to determine long term ATC, and does not consider any short term use. This is important because NorthWestern, and the choice customers on our system, commonly use short term service to serve loads. This is further discussed in the three actual events described later in this Chapter.

Table 6-1. Estimated Long Term Firm Path Availability

Estimated Future Long Term Firm ATC (MW) by Path (data as of June 25, 2019)					
Path	**Export TTC**	**Export ATC**	**Import TTC**	**Firm Commitments (Importing)**	**Import ATC**
Path 8					
NWE - MT to Bonneville Power Administration Transmission (BPAT)	492	252	863	811	52
NWE - MT to Avista Corp Transmission	382	297	382	170	212
Path 18					
NWE - MT (Anaconda) to Brady (ID)	296	0	184	184	0
NWE - MT System to Jefferson (ID)	87	73	72	0	72
Path 80					
NWE - MT System to SE MT (PAC & WAUW)	600	600	600	52	548
Path 83					
NWE - MT NW (Great Falls) to NW MT (MT- Alberta Tie Line)	300	300	300	74	226
TTC = Total Transmission Capacity (designed and approved)					
ATC = Available Transmission Capacity (accessible after confirmed and pending obligations)					

ATC is typically used during peak periods on an "as-available basis" and can easily be "used up" during periods of peak demand. NorthWestern is not the only party that uses ATC; it is also used by network customers under the NorthWestern OATT to serve their loads on a short term basis, and by marketers to wheel power through Montana to other regions which increases the risk associated with NorthWestern relying too heavily on the outside market to serve customers. NorthWestern considers over reliance on outside markets to serve our customers to be risky due to dependence on short term markets and the availability of transmission capacity on our system and adjoining transmission systems.

At first glance, Table 6-1 appears to indicate plenty of surplus ATC that a customer could reserve to import energy. However, there are other factors to consider such as constraints on the other transmission systems, desired market paths for power imports and market conditions for energy costs that all affect ATC. As an example, there is a fair amount of ATC indicated for importing energy from Avista (on Path 8) and PacifiCorp and WAUW (on Path 80). This is misleading due to constraints to the south of Path 80 that may prevent it from being used for imports when it is needed most to serve load in Montana. The same is true for Avista, where power from the Mid-C market must go across the BPA system first in order to utilize the Avista capacity. With the recent announcement of the early closure of Colstrip Units 1 and 2, it appears there soon may not be adequate designated network resources in Montana to serve network customers. This shortfall is in addition to NorthWestern's Energy Supply portfolio capacity needs.

Conditions Experienced During Spring and Summer 2018 and Winter 2018 / 2019

Conditions in NorthWestern's BA during the spring and summer of 2018, and during NorthWestern's all-time record peak load on February 5, 2019, highlighted significant concerns we have had for some time.

- The owned or controlled energy supply for NorthWestern's retail customers is significantly deficit during peak hours.
- The transmission capacity from the energy markets is limited.
- Non-Firm short term (or "Just in Time") use of the transmission Path's available import transmission service capacity resulted in zero MW of Available Transmission Capability.

Figures 6-2 and 6-3 were developed using actual BA conditions during two days in 2018 and illustrate these concerns.

Figure 6-2. June 30, 2018 BA Needs and Scheduled Interchange

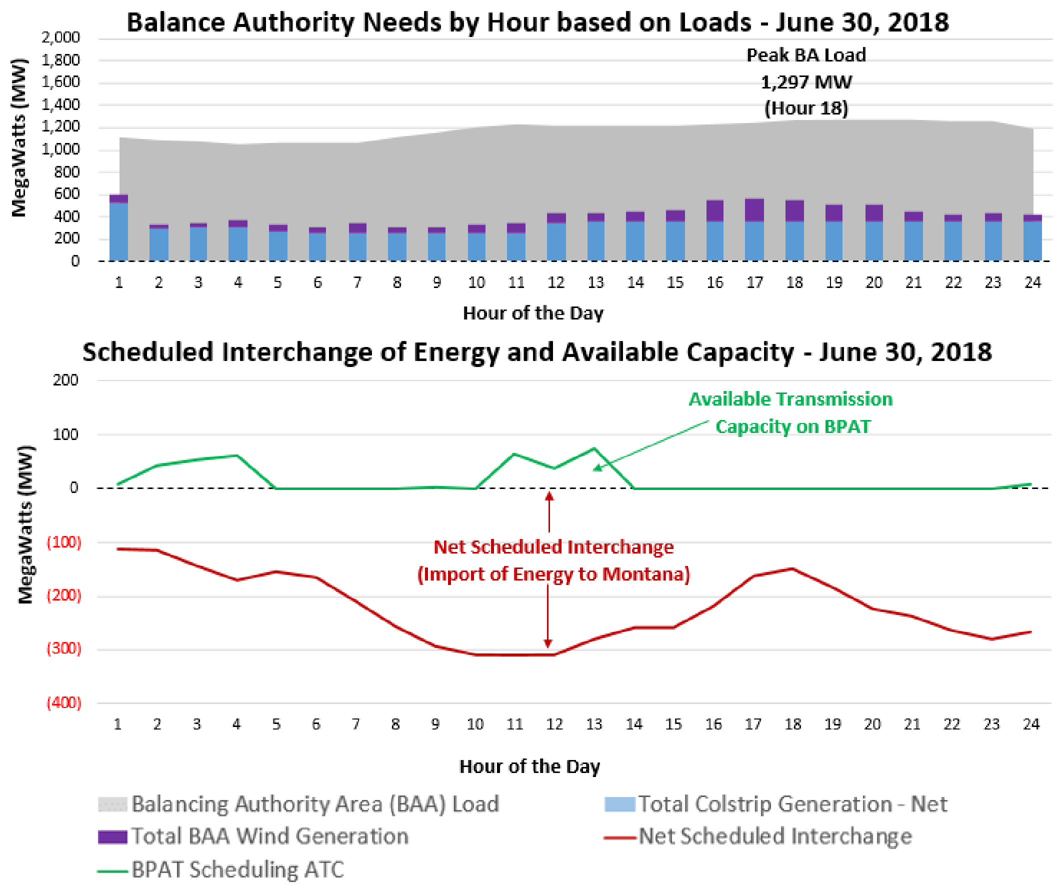


Figure 6-2 illustrates conditions on June 30, 2018. Elements of Figure 6-2 and salient circumstances specific to June 30, 2018 are described below.

1. The shaded gray area of the bar chart indicates the changes to peak load on NorthWestern's BA during the day. The maximum peak load of 1,297 MWs, which is a relatively low peak, occurred during the hour ending 18 on that day.

2. The blue portions of the bars indicate the total generation from the Colstrip Facility (Total Colstrip Generation – Net). During the peak, the Colstrip Facility output was about 450 MWs.[4]

3. The purple portions of the bars indicate the output from all of the wind generation in NorthWestern's BA area (Total BAA wind generation). Total BAA wind generation fluctuated throughout the day and peaked at about 206 MWs during the hour ending 1600.

4. The green line on the line graph represents the available import transmission capacity from BPA throughout the day (BPAT Scheduling ATC). Note there was no available transmission capacity to import electricity from BPA during most hours, including peak hours.

5. The red line on the line graph represents the net scheduled interchange. Scheduled imports into the BA are represented by negative numbers. Net imports to the BA

[4] Colstrip Facility output was reduced at this time due to issues with some air emission control equipment. Those issues have since been remedied.

were scheduled during all hours with a peak scheduled import of about 310 MWs near mid-day.

6. During the peak load hour (hour ending 18:00 MDT) there was no ATC to use for importing energy from BPA. Table 6-2 shows the Transmission Service Reservations (TSRs) during that time. It's notable there were 355 MW of non-firm secondary network capacity reserved to serve load during this peak hour.

Table 6-2. Reservations on 6/30/2018 HE 18:00 BPAT Import

Firm TSR's		**796**
NWMT_RESERVES	35	
CHS Inc.	25	
BPA	186	
Network Firm	246	
Morgan Stanley	326	
PowerEX	69	
EDF Trading	155	
Firm Point To Point	550	
Non Firm TSR's		**408**
Point-To-Point		
PowerEx	3	
Morgan Stanley	50	
Non Firm Point to Point	53	
Network Secondary		
Default Supply	100	
REC Silicon	80	
Basin Electric	36	
CHS Inc.	25	
Stillwater Mine	25	
MRI	25	
Exxon	25	
Other 6NN	39	
Network Secondary	355	

Figure 6-3. July 21, 2018 BA Needs and Scheduled Interchange

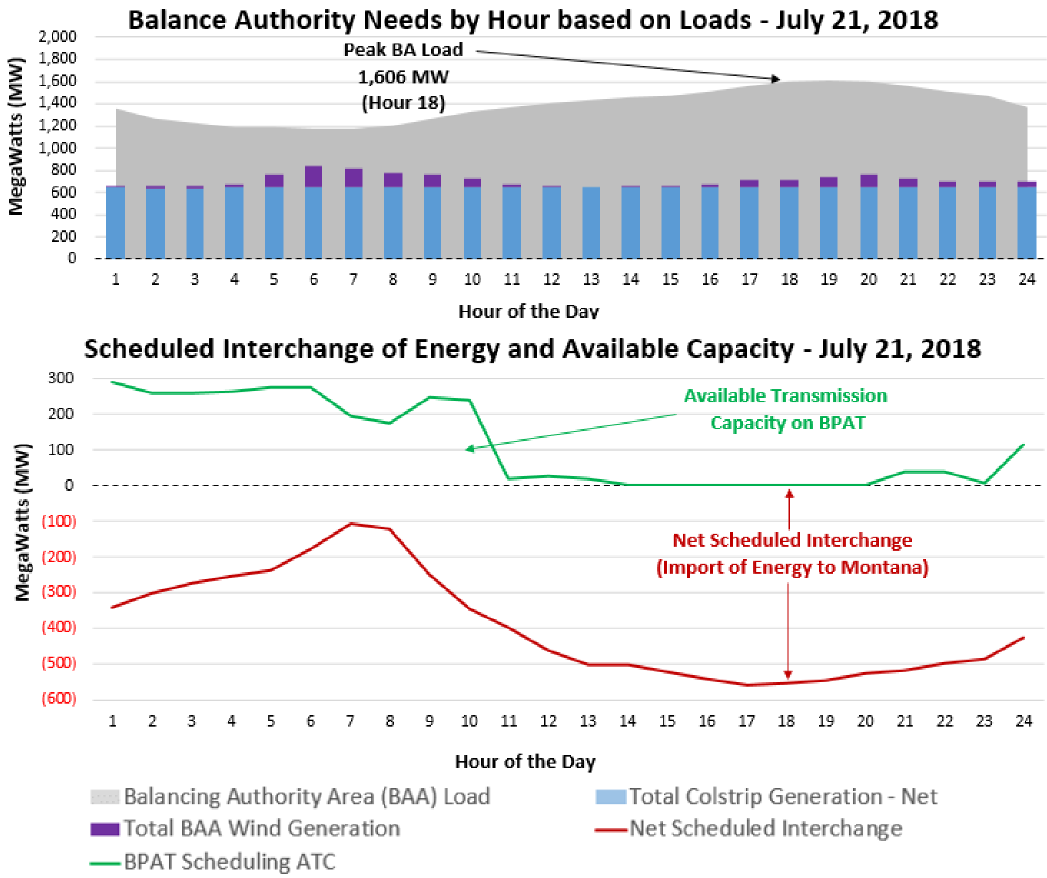


Figure 6-3 illustrates conditions on July 21, 2018. Elements of Figure 6-3 and salient circumstances specific to July 21, 2018 are described below. Note that the lines, bars and colors in Figure 6-3 have the same meanings as those in Figure 6-2. Their meanings are repeated however, in order to aid the reader's understanding of Figure 6-3.

1. The shaded gray area of the bar chart indicates the changes to peak load on NorthWestern's BA during the day. The maximum peak load of 1,606 MWs

occurred during the hour ending 18, a 309 MW increase over the peak on June 30, 2018.

2. The blue portions of the bars indicate the total generation from the Colstrip Facility (Total Colstrip Generation – Net). During the peak, the Colstrip Facility output was about 650 MWs.[5]

3. The purple portions of the bars indicate the output from all of the wind generation in NorthWestern's BA area (Total BAA wind generation). Total BAA wind generation fluctuated throughout the day, provided very little generation during some hours of the day, and peaked at about 114 MWs (out of a nameplate capacity of 338 MWs) during the peak hours of the day.

4. The green line on the line graph represents the available import transmission capacity from BPA throughout the day (BPAT Scheduling ATC). Note there was no available transmission capacity to import electricity from BPA during peak hours.

5. The red line on the line graph represents the net scheduled interchange. Scheduled imports into the BA are represented by negative numbers. Net imports to the BA were scheduled during all hours with a peak scheduled import of about 550 MWs coincident with the peak hours of the day; a 240 MW increase over the peak scheduled import on June 30, 2018.

[5] See footnote 4.

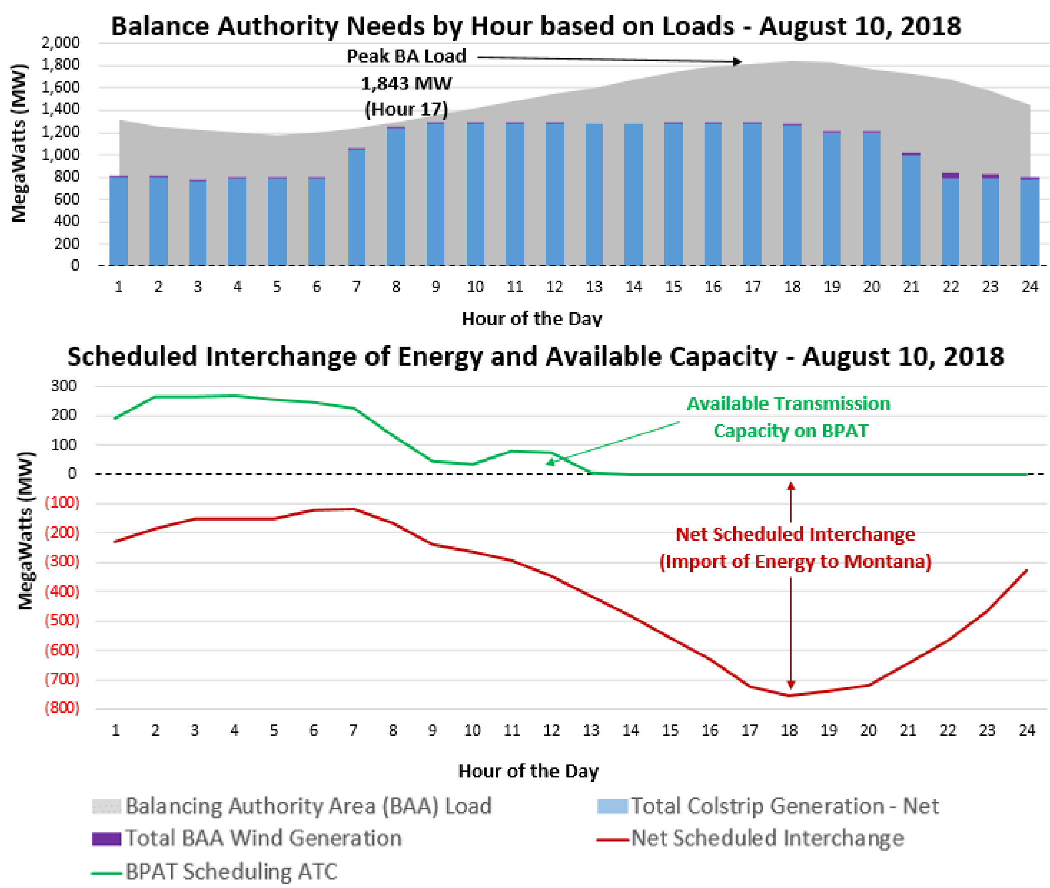
6. During the peak load hour (hour ending 18:00 MDT) there was no ATC to use for importing energy from BPA. Table 6-3 shows the Transmission Service Reservations (TSRs) during this time. It's notable that there were 325 MW of non-firm secondary network capacity reserved to serve load during this peak hour.

Table 6-3. Reservations on 7/21/2018 HE 18:00 BPAT Import

Firm TSR's		**642**
NWMT_RESERVES	35	
CHS Inc.	25	
BPA	186	
Network Firm	246	
Morgan Stanley	247	
PowerEX	69	
EDF Trading	80	
Firm Point To Point	396	
Non Firm TSR's		**412**
Point-To-Point		
PowerEx	3	
Morgan Stanley	67	
Puget Sound Energy	9	
Portland General Electric	8	
Non Firm Point to Point	87	
Network Secondary		
Default Supply	198	
REC Silcon	90	
CHS Inc.	25	
Beartooth Electric	12	
Network Secondary	325	

A new summer peak load record for NorthWestern's BA was set on August 10, 2018 (this peak was ultimately eclipsed in February 2019). Conditions during the August 10, 2018 peak are illustrated in Figure 6-4.

Figure 6-4. August 10, 2018 BA Needs and Scheduled Interchange



Note that the lines, bars and colors in Figure 6-4 have the same meanings as those in Figures 6-2 and 6-3. While this is a notable day due to the magnitude of the peak load, close analysis of the situation is important for future transmission and energy supply resource planning.

1. As indicated by the gray area of the bar chart, the maximum peak load of 1,843 MWs on NorthWestern's BA occurred during the hour ending 17. This peak load

was a 546 MW increase over the peak on June 30 and a 237 MW increase over the peak on July 21, 2018.

2. The blue bars on the bar chart indicate the total generation from the Colstrip Facility was about 1,270 MWs during most hours of the day including during peak hours.[6]

3. The purple bars on the bar chart indicate the total BAA wind generation was significantly below the nameplate capacity of 338 MWs most of the day and peaked at about 48 MWs during the hour ending 21.

4. The green line on the line graph indicates there was no available transmission capacity to import electricity from BPA during peak hours.

5. The red line on the line graph represents the net scheduled interchange. Scheduled imports into the BA are represented by negative numbers. Net imports to the BA were scheduled during all hours with a peak scheduled import of about 755 MWs coincident with the peak hours of the day; a 445 MW increase over the peak scheduled import on June 30 and a 205 MW increase over the peak scheduled import on July 21, 2018.

6. During the peak load hour (hour ending 18:00 MDT) there was no ATC remaining to use for importing energy from BPA. Table 6-4 shows the Transmission Service Reservations (TSRs) during that time. It's notable that there were 275 MW of non-firm secondary network capacity reserved to serve load during this peak hour.

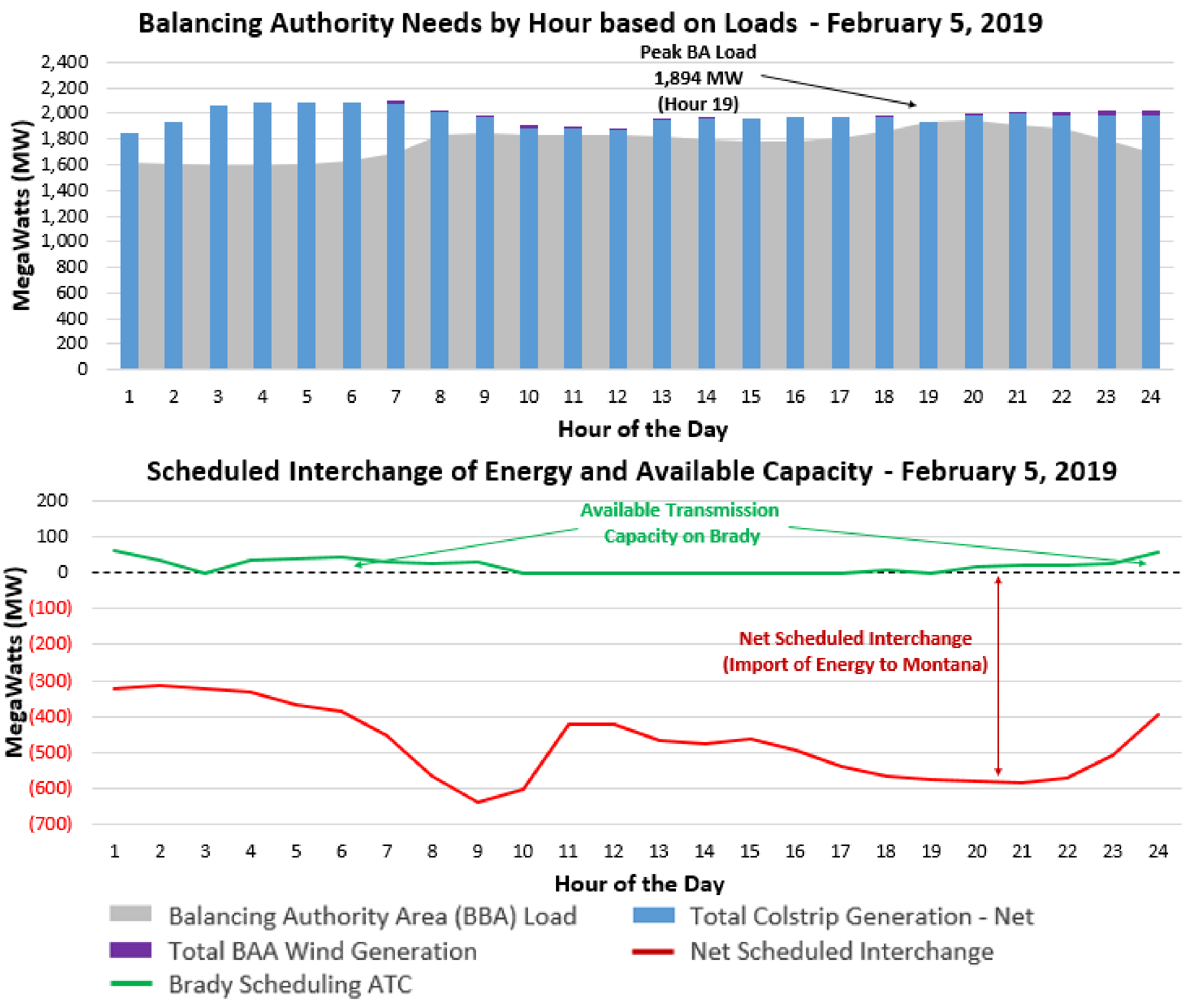
[6] Refer to footnote 4.

Table 6-4. Reservations on 8/10/2018 HE 18:00 BPAT Import

Firm TSR's		**737**
NWMT_RESERVES	35	
CHS Inc.	25	
BPA	186	
Network Firm	246	
Morgan Stanley	242	
PowerEX	69	
EDF Trading	180	
Firm Point To Point	491	
Non Firm TSR's		**519**
Point-To-Point		
PowerEx	3	
Morgan Stanley	200	
BPA	41	
Non Firm Point to Point	244	
Network Secondary		
Default Supply	250	
Conoco	25	
Network Secondary	275	

7. The WECC regional forecast for load as a percentage of seasonal peak in the Northwest United States was 96%. When load in the Northwest is this high, it will increase demand for generation resources in the Northwest.

Figure 6-5. February 5, 2019 BA Needs and Scheduled Interchange



For the full day on February 5, 2019, with good generation from Colstrip, but little generation from Wind in Montana, there was a continuous import of energy (Net Scheduled Interchange) - red line above - to meet energy demands. The green line shows there was some available transmission capacity earlier in the day but little to no availability from Brady in Idaho during the peak hours (hours 8-22).

Figure 6-5 illustrates conditions on February 5, 2019. Peak load that day was a record high of 1,894 MW, and the state of Montana was experiencing wide-spread below zero temperatures. Notable items specific to February 5, 2019 are described below.

1. The shaded gray area of the bar chart indicates very high peak loading, throughout the day including the all-time Balancing Authority peak of 1,894 MW.

2. The blue portions of the bars indicate the total generation from the Colstrip Facility (Total Colstrip Generation – Net). During the peak, the Colstrip Facility output was at near maximum levels. Even with this, load internal to the NorthWestern BA was relying heavily on importing power to serve load during this cold period.

3. The purple portions of the bars indicate the output from all of the wind generation in NorthWestern's BA area (Total BAA wind generation). This is important to note, as wind provides energy, and not dispatchable capacity. When we most need capacity to serve load (i.e. during high load periods and cold / hot periods), the wind is often not available. This forces the utility to import power from the markets over the interties to make up the deficit.

4. The green line on the line graph represents the available import transmission capacity from Brady throughout the day. This displays a market shift from where the parties are importing power from Brady (PacifiCorp) in Idaho up the 230 kV Mill Creek to Anaconda line in addition to BPA. Note there was no available transmission capacity to import electricity from Brady during most hours, including peak hours.

5. The red line on the line graph represents the net scheduled interchange. Scheduled imports into the BA are represented by negative numbers. Net imports to the BA were scheduled during all hours with a peak scheduled import of about 638 MWs.

6. During several of the highest loading hours (hour ending 17:00 MDT) there was no ATC to use for importing energy from Brady. Tables 6-5 and 6-6 show the Transmission Service Reservations (TSRs) during this time. BPA imports are also included because significant capacity was reserved to import power on that path in

addition to the Brady path. It's notable there were 414 MW of non-firm secondary network capacity reserved to serve load during this peak hour (this includes 146 MW from Brady and 268 MW from BPAT).

Table 6-5. Reservations on 2/05/19 HE 17:00 Brady Import

Firm TSR's			**14**
	Idaho Power	14	
	Firm Point To Point	14	
Non Firm TSR's			**190**
	Point-To-Point		
	Morgan Stanley	44	
	Non Firm Point to Point	44	
	Network Secondary		
	Basin Electric	96	
	Default Supply	50	
	Network Secondary	146	
*IPCo and PAC have 125 MW of rights on this path			

Table 6-6. Reservations on 2/05/19 HE 17:00 BPAT Import

Firm TSR's		**583**
NWMT_RESERVES	35	
Basin Electric	100	
CHS Inc.	25	
BPA	186	
Network Firm	346	
Morgan Stanley	177	
PowerEX	10	
EDF Trading	50	
Firm Point To Point	237	
Non Firm TSR's		**434**
Point-To-Point		
PowerEx	123	
Morgan Stanley	43	
Non Firm Point to Point	166	
Network Secondary		
Default Supply	86	
CHS Inc.	63	
REC Silicon	90	
Beartooth Electric	13	
Big Horn Electric	10	
NWMT-Reserves	6	
Network Secondary	268	

Not surprisingly, during the on-peak hours of the summer of 2018, the market price of energy at the Mid-C spiked dramatically illustrating the exposure to market volatility and the risk of being overly reliant on the market. During the 2018/2019 winter season when we experienced below zero temperatures in February and March, day ahead Mid-C pricing for energy reached $900 / MWh. See Figures 6-6 and 6-7.

Figure 6-6. Mid-C Index Average On-Peak Prices

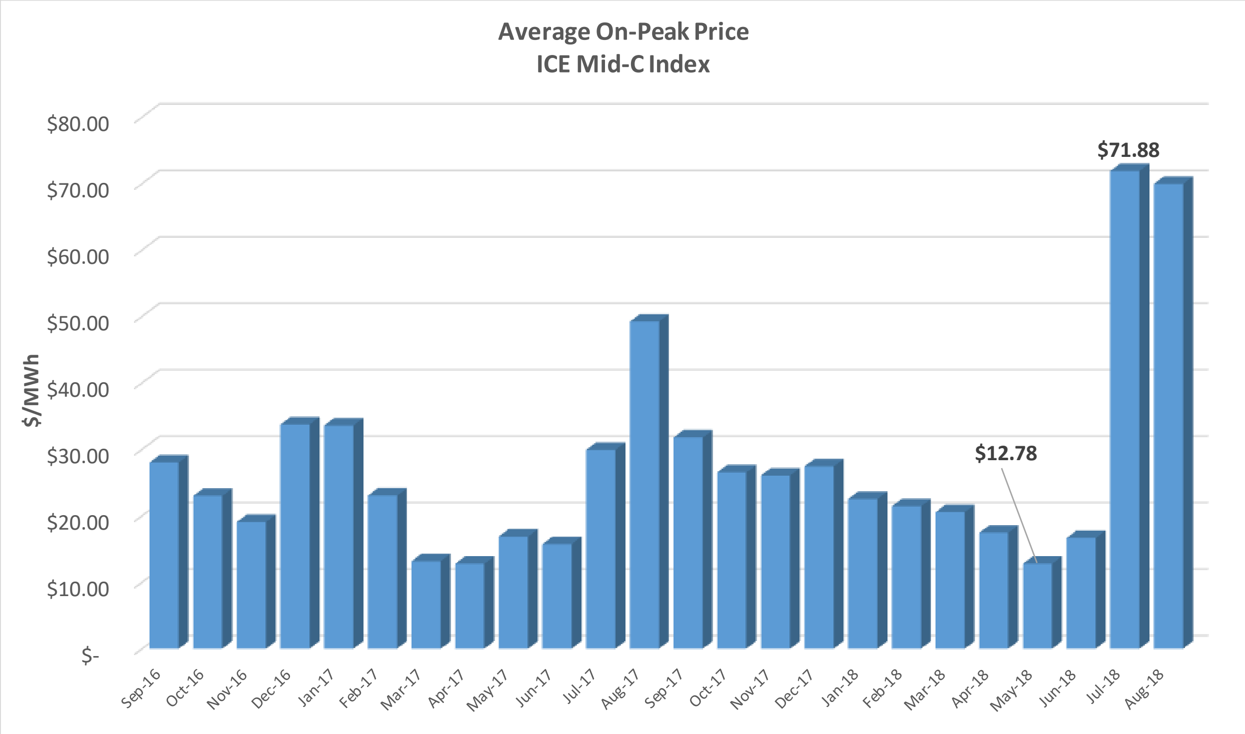
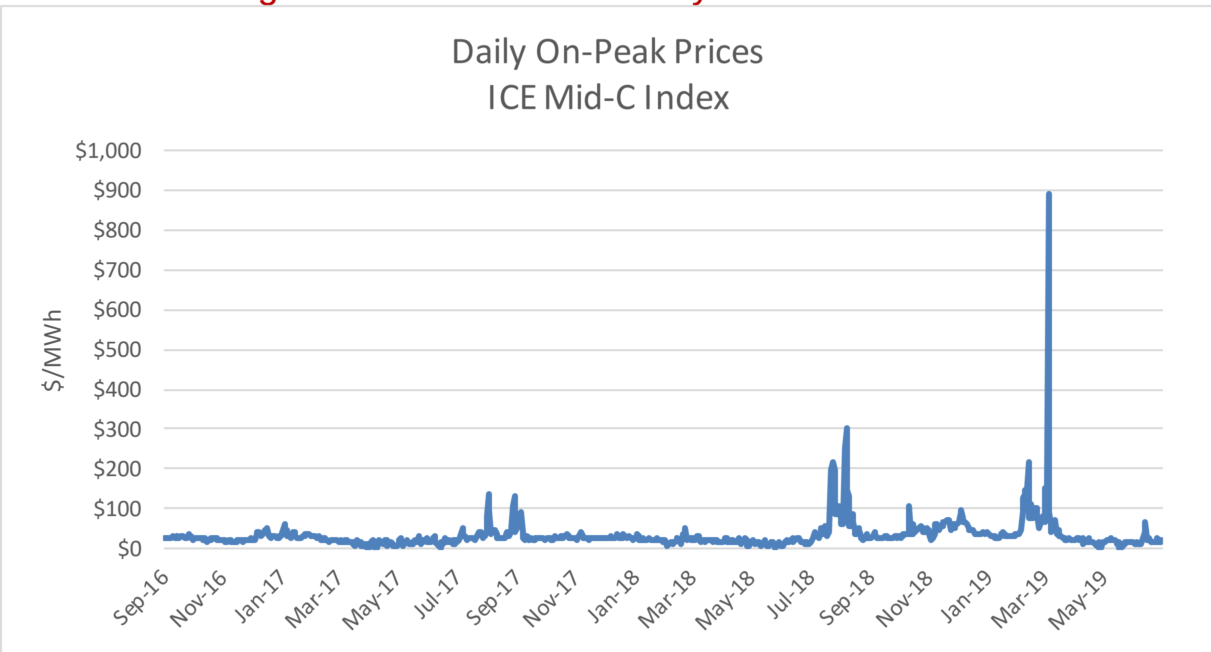


Figure 6-7. Mid-C Index Daily On-Peak Prices



There are several key takeaways from the discussion above about the conditions experienced during the spring /summer of 2018 and the winter of 2018 / 2019 which are summarized below.

- During peak/heavy load hours for the BA, NorthWestern relies heavily on imports into our system in order to meet customers' needs. Importantly, over 80 percent of the imports NorthWestern required to supply the very high loads on August 10th came from Path 8 (see Figure 6-1) and 100 percent of the imports NorthWestern required on August 11th came from Path 8.
- During peak/heavy load hours for the BA, the available transmission capacity at NorthWestern's interface with BPA is scarce and was routinely zero during peak hours.
    - While NorthWestern has other interties to other transmission systems, the interconnection to BPA is the largest and is a direct interconnection to the prevailing market in the Pacific Northwest, the Mid-C Market. Other routes to market are indirect, costlier and experience transmission congestion.
- The potential for BA load growth, (choice or non-retail customers) exceeds the projected growth of NorthWestern's bundled retail load due to the increase in load interconnection activity associated with blockchain and other data centers. This has the potential to further strain transmission import paths.
- During the days described above, part of the Colstrip facility's generation was reduced due to issues with some air emissions control equipment. Those issues have been remedied, however, the reductions foreshadow what will happen when Colstrip Units 1 & 2 cease operations at the end of 2019.
- Wind generation did not significantly contribute to customers' needs during peak load hours.

- During the highest load hours on August 10, 2018 NorthWestern was importing nearly 400 MWs to serve retail customers. This represents over 30% of the retail load requirement.
- The market price for energy reacts to load serving requirements and transmission availability.
- Over reliance on market purchases from outside the BA can result in significant reliability issues compared to having access to flexible capacity resources within the BA.
- The status quo of significant reliance on the market for peaking supply needs will become increasingly risky as generation in Montana is shut down, loads increase, and existing generation resources are held in reserve in order to balance the significant growth of intermittent, variable energy resources.
- The data from February 5, 2019, reinforces the takeaways from the summer of 2018.

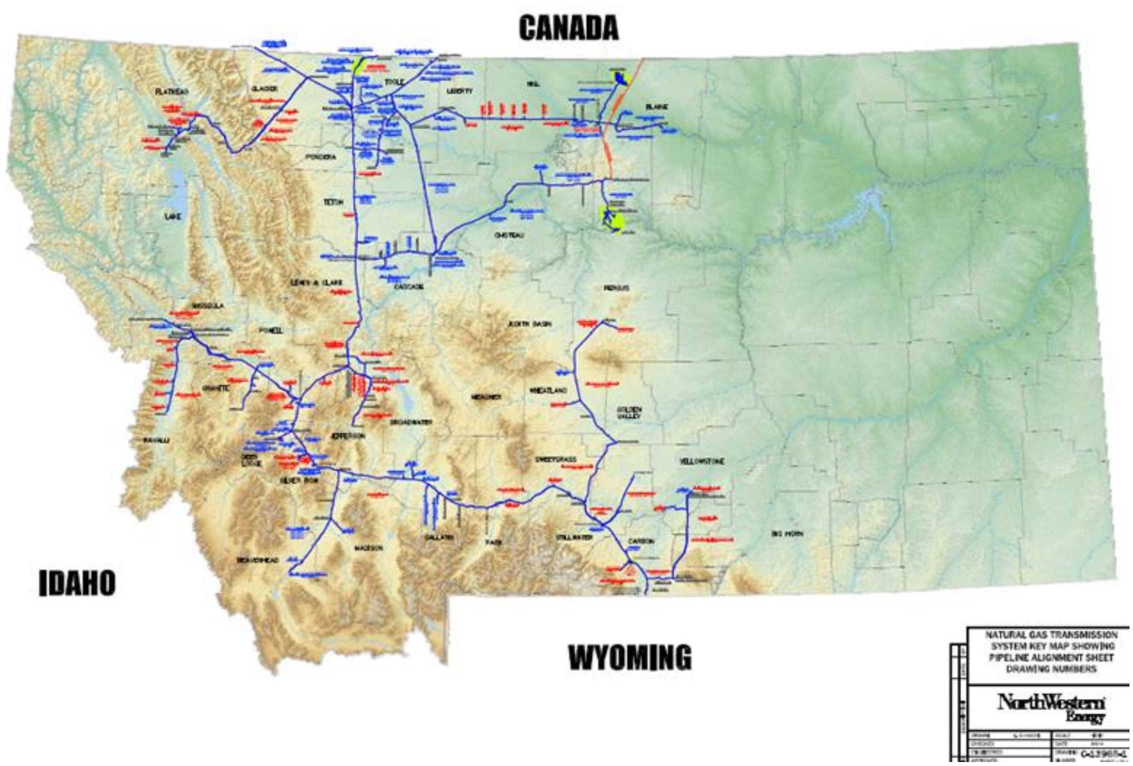
NorthWestern's Natural Gas Transmission System

NorthWestern is including an analysis of the natural gas transmission system in this Plan to support modeling of cost effective natural gas resources.

NorthWestern's natural gas transmission system consists of more than 2,000 miles of pipeline and serves more than 153 city gate and meter stations where pressure is reduced to distribution level and measured. Pipeline diameter ranges from one inch to 24 inches. NorthWestern provides service to approximately 189,400 customers located in 117 Montana communities as well as to several smaller natural gas distribution companies that provide service to about 31,000 customers collectively. There are 92 individual compression units totaling almost 80,000 horsepower dedicated to our Montana gas transmission, storage and gathering operations. In addition, NorthWestern owns and operates a pipeline which crosses into Canada through our wholly owned subsidiary, Canadian-Montana Pipeline Company (CMPL). This pipeline is critical because it enables us to receive gas from Canadian markets.

NorthWestern owns and operates three working natural gas storage fields in Montana: Dry Creek in southeast Montana with deliverability of about 44 million cubic feet per day (MMcfd): Cobb Storage north of Cut Bank with deliverability of about 115 MMcfd; and Box Elder Storage near Havre with deliverability of about 10 MMcfd. This totals 169 MMcfd of peak deliverability in the gas storage system. There are 34 receipt points where gas enters our natural gas transmission system. In our three active storage reservoirs, we cycle about 10 billion cubic feet (Bcf) in and out of storage annually. Figure 6-8 below is a high level gas transmission system map.

Figure 6-8. Montana Gas Transmission System



Peak deliverability needs occur during the heating season, generally November through March. Typically, the colder the weather, the higher the daily deliverability need.

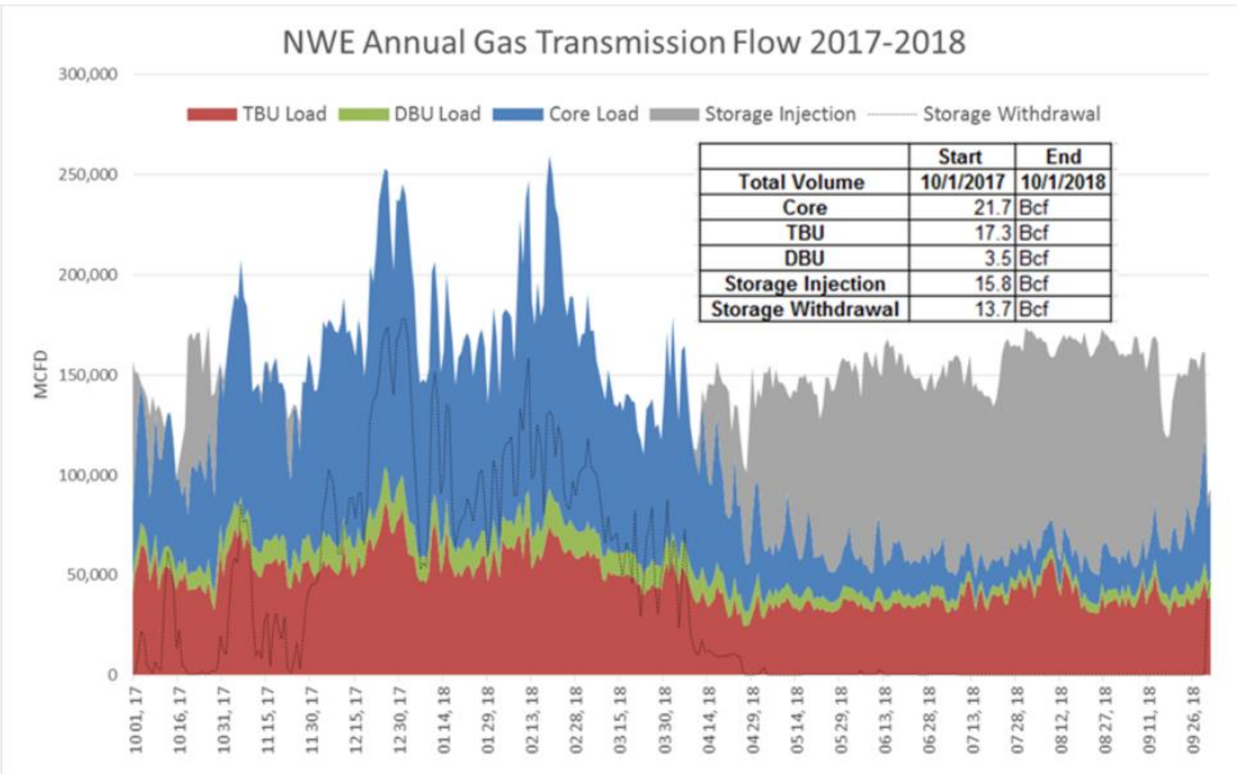
The natural gas supply provided to our customers during the heating season comes from three main sources and the transmission and storage system is key to delivering this gas: 1) flowing gas, which is produced in Montana and has no other place to flow except onto NorthWestern's system; 2) interconnect gas, which is produced outside of Montana but is delivered under contracts with interconnected pipelines to supply gas to NorthWestern's system; and 3) storage gas, which is brought onto the system in the "off season" and injected into NorthWestern's storage fields for use during the heating season.

Nearly one-half of transmission system deliverability comes from our storage reservoir capacity. NorthWestern also has interconnections with five other major pipelines: the TransCanada pipeline system at Carway northwest of Cut Bank via our CMPL subsidiary; Pine Cliff Energy northeast of Cut Bank at Aden; the TransGas system northeast of Havre (north flow only); Colorado Interstate Gas (CIG); and, WBI Energy in southeast Montana. These interconnections represent more than 39% of our peaking capability. However, the only interconnections that provide an effective interconnection to markets are at Carway to the north and CIG to the southeast. The balance of our peak day requirement comes from gas produced within Montana (flowing gas) with interconnections to our system. With on-system flowing gas depleting and heating loads growing, NorthWestern has been increasing deliverability at Carway and CIG through contracts with the upstream pipelines and infrastructure improvements on the NorthWestern system.

Currently, gas-fired generation on the system operates utilizing interruptible gas transportation arrangements. As a result, during the coldest days of the year, gas supply to electric generation is subject to curtailment.

Figure 6-9 below shows the overall usage of the gas transmission system for the October 2017 to October 2018 annual cycle. Usage of the system is high during both the heating season and the off-season because the system capacity in the off-season is used to refill storage for the next heating season.

Figure 6-9. Oct. 2017 to Oct. 2018 Gas Transmission Flow



NorthWestern plans carefully and the gas compression system includes a certain amount of redundancy; however, events out of our control can occur. These include much colder weather than design or expected conditions (or for a longer period of time) or unexpected equipment outages on our system or on adjacent systems delivering to our interconnections. As a result, beginning with the 2015-2016 heating season, NorthWestern developed a Gas Curtailment Plan that allows us to interrupt gas use through careful curtailment of NorthWestern electric customers who are also served by NorthWestern's natural gas system. For many years we have had curtailment plans on the electric system that are part of our overall planning and compliance requirements. It is prudent to also have a curtailment plan for gas operations in order to avoid more prolonged, difficult outages. We update the Gas Curtailment Plan as required and plan for its use in our operations during each heating season.

Similar to the electric transmission system, the gas transmission system was deregulated in the 1990s and as a result, NorthWestern provides transmission service to both bundled retail or "core" customers as well as "non-core" customers – those customers to whom NorthWestern provides transmission service, but is not responsible for providing natural gas supply.

Transmission Systems Summary

From a transmission perspective, NorthWestern must plan for both our retail customers and other customers served from the electric transmission system, but procure their supply from sources other than NorthWestern. Electric transmission capacity is critical for market access in order to purchase power when short and sell power when long however, it is limited. During the most critical periods, NorthWestern relies heavily on electricity imports into our system in order to meet customers' needs. The transmission system was constructed around, and is heavily reliant on, the generation resources in Montana and their locations in the BA. As a result, current reliability is based on access to imports, the 500 kV transmission system and an operating Colstrip generation facility. The retirement of Units 1 and 2 at Colstrip now planned for December 31, 2019, and potential outages or reductions of Units 3 and 4 or other state generation resources, will severely impact NorthWestern's ability to serve our customers reliably. Absent significant flexible generation capacity additions in Montana, current transmission congestion and Montana's shift from an energy surplus state to an energy deficit state will result in unacceptable risk for Montana consumers.

CHAPTER 7
NEW RESOURCES

Overview

A key component of resource planning is the identification of the resources to consider for inclusion in the modeling analysis phase of the planning process. Reasonable estimates of resource costs and operating characteristics must be known to consider the resource for potential inclusion in the portfolio modeling analysis. In response to MPSC comments, NorthWestern retained HDR Engineering, Inc. (HDR) to prepare a Request For Information (RFI) in order to solicit information regarding potentially available resource alternatives. NorthWestern also retained HDR to characterize the operational and cost attributes of various power generation and energy storage technologies.[1]

Request for Information

NorthWestern retained HDR to solicit information regarding potentially available resources for potential inclusion in capacity planning as part of the 2019 Plan. The RFI was issued on July 9, 2018 to over 350 energy producers and consumers, including large industrial customers, developers, and utilities in the Pacific Northwest. A total of 19 responses were received with several respondents submitting multiple options.

Table 7-1 provides a summary of the responses received. Sections grayed out require a protective order and are confidential. The data presented is "as-reported" by the ~~respondents (minimal evalua~~tion/validation was completed).

[1] The HDR Study is provided in Volume 2, Chapter 7.

Table 7-1. Summary of RFI Responses

Type	No. of Resp.	Scale			New / Existing	Ownership	PPA	
		Generation	Storage/Demand Side			Capital Costs	Capacity Cost	Energy Cost
-	(no.)	(Size)	(Size)	(Duration)	-	($/kW)	($/kW-yr)	($/MWh)
Energy Storage	5	-	250 kW to 400 MW	2 Min. to 9 hours	New	$1,000 to $8,000	-	-
Hydro	3	1.5 to 175 MW	-	-	Both	~$3,100	**TBD**	**TBD**
Wind	4	35 to 400 MW	-	-	New	-	-	$27 to $36
Wind + Storage	1	[redacted]						
Solar	1	[redacted]						
Solar + Storage	5	[redacted]						
CT/RICE	6	50 to 200 MW	-	-	New	$500 to $2,300	$70 to $250	$3 to $10
CT/RICE + Storage	2	[redacted]						
Coal	2	[redacted]						
DR/DSM	2	-	6 kW to 2 MW	2 to 4 hours	New	TBD		

Notes:

(1) Data has been redacted to maintain confidentiality.

(2) Data is "as-reported" by Respondents.

(3) Responses included existing assets, project developments, and standalone technologies.

(4) For cost reporting, "main" capacity cost presented; other costs may be applicable (e.g. operations and maintenance (O&M) costs).

(5) PPA pricing assumes year 1 costs (escalation not evaluated in detail).

(6) Production Tax Credit (PTC) and Investment Tax Credit (ITC) treatment not investigated.

(7) Natural gas PPA energy costs do not include fuel costs (i.e. tolling PPA structure).

The RFI process validated HDR's definitions for certain resources, and provided limited information on existing resources that could potentially be used to serve customers' future resource needs. Additionally, the RFI identified some of the technologies that could appear in responses to future NorthWestern RFPs.

New Resources – New Build Costs

NorthWestern retained HDR to characterize the operational and cost attributes of various power generation and energy storage technologies considered in the 2019 plan. Several natural gas-fired generating technologies, renewable technologies and energy storage options were evaluated including reciprocating internal combustion engines (RICE), combustion turbines (CTs), combined cycle combustion turbines (CCCTs), pumped storage hydro, wind, solar PV, and battery energy storage resources. HDR also researched compressed air energy storage (CAES) and geothermal generation resources, but those were eliminated from consideration in the 2019 Plan due to higher cost. The evaluation of new-build resource costs involved analysis and contributions from HDR, Ascend Analytics, ETAC, and other sources.

Wind Resources

Overview

Wind power is a widely adopted generation technology. Improvements in efficiencies and the availability of Federal PTCs have been instrumental in the growth of wind energy. The current PTC is $0.010/kWh over a 10-year time period for wind facilities commencing construction in 2019. PTCs are being phased out and this tax credit value represents a 60% reduction from the $0.024/kWh PTC credit originally available under this program. The tax credit is not available for projects commencing construction after 2019. The phase out of the PTC is summarized in Table 7-2 below.

Table 7-2. Federal Wind PTC Phase-Out

Federal PTC Phase Out					
Year Construction Begins	2016	2017	2018	2019	Future
Wind PTC ($/kWh)	$0.024	$0.019	$0.014	$0.010	$0.000

Performance

Wind generation projects are typically designed for a 20-year life, but well maintained turbines can last up to 25 years depending on the service conditions at the site and historical maintenance practices. Typical wind turbine sizes range from nominally 1.5 MWs to 5 MWs. For the 2019 Plan, the turbine design has a rated power of approximately 2.5 MWs and a hub height of 100 meters (m).

Wind turbine capacity is based largely on the length of the blades. Taller turbines are not only able to use longer blades for higher output capacity, but are also able to take advantage of the better wind speeds available at greater heights (while also considering related aviation regulations and requirements). An average net capacity factor (NCF) for a wind power facility is typically in the range of 25 to 50 percent depending on available wind energy within the region. The estimated NCF for the Montana locations shown in Figure 7.1, is 44.13% for Western Montana and 44.35% for Eastern Montana.

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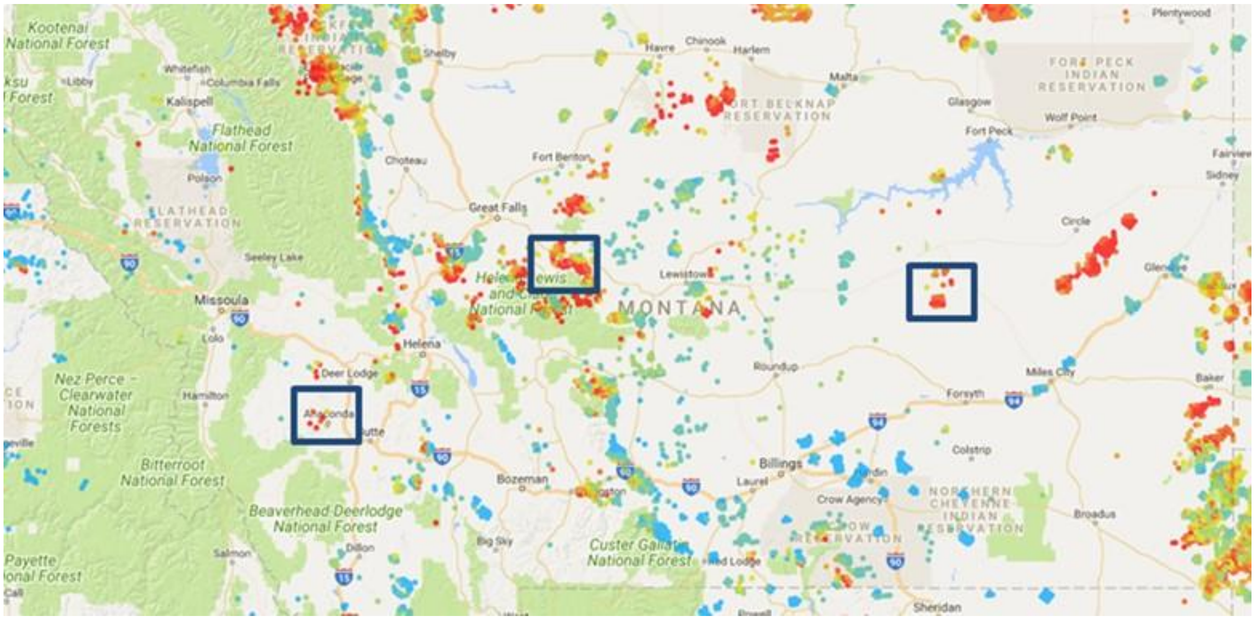
Figure 7-1. Wind Location - Montana Analysis



NREL WIND Toolkit application was used to provide wind resource production data. The estimated power production at each site was developed using wind data at a 100 meter hub height and site-appropriate turbine power curves.

Cost Estimates

The project cost for a 100 MW, 40-turbine wind generation project located in western or eastern Montana was estimated by HDR to be $1,410/kW. This conceptual engineering, procurement, and construction (EPC) cost includes the wind turbines, foundations, generator step-up transformers (GSUs), electrical systems up to the high side of the facility GSU, and instrumentation and controls. It was assumed that the turbines would be installed on land not owned by NorthWestern resulting in an assumed land lease cost, which is not included in the capital costs (typically included in O&M costs).

Fixed O&M costs for wind projects include staffing, major turbine parts, replacement parts and outsourced labor to perform major maintenance. Staffing for a proposed 100 MW wind power plant generally assumes the utilization of a remote monitoring/operating system. Typical staffing requirements are minimal and for the purpose of this analysis, include one salaried and two hourly staff. First year fixed O&M costs for a proxy 100 MW wind power plant are estimated at $37.00/kW-yr. There are typically no variable O&M costs associated with wind power generation.

Currently, wind projects have a timeline of nominally two years from contractor notice-to-proceed (NTP) through commercial operation date (COD). The 2019 Plan assumes a COD of 2020 for a 100 MW utility-scale wind project.

Utility Scale Solar PV

Overview

Solar PV technology uses solar cells or 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 therefore 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 the 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.

For the purposes of modeling solar PV in the 2019 Plan, NorthWestern assumes a 100 MW Solar PV facility with single-axis tracking configuration.

The Federal ITC has been instrumental in supporting the deployment and growth of solar energy in the U.S. The ITC currently offers a 30% tax credit towards the investment cost of solar systems. For a solar project to get the 30% ITC, it must begin construction by December 31, 2019, but it does not have to go into service until December 31, 2023. The percentage steps down to 26% and 22% for projects that start construction in 2020 in 2021, respectively. For all scenarios where a solar project receives greater than a 10% ITC, the project must be placed into service by December 31, 2023. A summary of the Federal ITC phase down is provided in Table 7-3.

Table 7-3. Federal ITC Phase-Down

Federal ITC Phase Down								
Year Construction Begins	2016	2017	2018	2019	2020	2021	2022	Future
Solar ITC	30%	30%	30%	30%	26%	22%	10%	10%

In January 2018, the U.S. imposed a 30% tariff on imported crystalline-silicon solar cells and modules that went into effect February 7, 2018. The tariffs start at 30% of the cell price in 2018 and then gradually drop to 15% by February 7, 2021. Per the Solar Energy Industries Association (SEIA), the 30% tariff can be expected to increase year 1 PV module prices by roughly $0.10/W or $100/kW.

Cost Estimates

A 100 MW solar PV installation would include approximately 40, 2.5 MW arrays each consisting of about 8,764 modules of 370 watt-peak-capacity (Wp). The land area required for this application could be about 400 to 700 acres.

The major components for the 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. The estimated average annual capacity factors for the Montana sites were estimated using NREL's Sam and the PVSyst program, and determined by HDR to be 24.2% in western Montana and 24.5% in eastern Montana.

HDR estimated the project cost for a solar plant located in both western and eastern Montana at nominally $1,330/kW prior to implementation of the U.S. imposed tariff. Based upon the estimated impact of solar tariffs identified by the SEIA, costs could be expected to increase as a result of the tariff to $1,430/kW.

First year fixed O&M costs for a 100 MW solar power plant are estimated to be $21.60/kW-yr. There are typically no variable O&M costs associated with solar power generation. Typical staffing requirements are minimal and, for the purpose of this analysis, include one salaried and two hourly staff.

Battery Energy Storage

Overview

Grid-connected battery energy storage systems (BESS) are a maturing storage technology in the electric industry, with increasing commercial deployment. BESS technology can be used to help meet the overall electricity demands of an electric utility, help minimize peak demand, smooth load variations due to renewables integration, and help with local grid resilience and availability.

Lithium Ion (Li-ion) batteries utilize the exchange of lithium ions between electrodes to charge and discharge the battery. When the battery is in use and discharging the charged electrons move from the anode to the cathode and in the process, energize the connected circuit. Electrons flow in the reverse direction during a charge cycle when energy is drawn from the grid. Due to its characteristics, Li-ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term spinning reserve applications. Additionally, compared to other BESS, the Li-ion technology provides the highest energy storage density resulting in its adoption in several different markets ranging from consumer electronics to transportation (electric vehicles) and power generation.

Vanadium redox flow batteries are based on the redox reaction between electrolytes in the system. There is significant interest in these flow batteries as they have a high cycle life, a large allowable operating temperature range, and longer storage durations. Vanadium redox systems consist of two liquid electrolytes in tanks (vanadium ions in different oxidation states) separated by a proton exchange membrane. The membrane permits ion flow but prevents mixing of the liquids. Electrical contact is made through inert conductors in the liquids. As the ions flow across the membrane, an electrical current is induced in the conductors to charge the battery. This process is reversed during the discharge cycle. The liquid electrolyte used for charge-discharge reactions is stored externally and pumped through the cell. A typical vanadium redox flow battery includes large electrolyte storage tanks and pumps, limiting this technology to certain applications.

Other battery storage technologies include sodium sulfur, lead-acid, zinc iron and zinc bromine flow technologies; however, Li-ion is the most prominent and widely used for utility scale BESS.

On February 15, 2018 FERC issued Order 841 that directs the operators of wholesale markets, RTOs and ISOs to develop market rules for energy storage to participate in wholesale energy, capacity, and ancillary service markets. The order essentially ensures that an energy storage resource can be dispatched and can set market clearing places as both a buyer and seller. RTOs and ISOs have nine months to file tariffs that comply with the order and another year to implement the tariff provisions.

For the 2019 Plan, HDR evaluated a proxy 25 MW, 100 MWh (25 MWs for 4 hours = 100 MWh) BESS with one discharge cycle per day. The basis of capacity sizing was to provide NorthWestern with about 4 hours of dispatch capability enabling demand management/load shifting as well as provide temporary local service restoration during an outage.

Performance

HDR contacted numerous BESS companies[2] (aka "integrators") for technical and commercial data. Technical information as well as experience, scope of supply, schedule of delivery, pricing and O&M details were solicited from the integrators that responded. Information received was specific to Li-ion technology, largely due to its prevalence in the industry. Some information was also gathered from vanadium redox flow battery integrators.

Major components of a BESS station include the battery containers, battery management system (BMS), power conversion system (PCS), enclosures, plant control system, cooling

[2] Greensmith Energy, ABB Inc., Renewable Energy Systems Americas Inc., S&C Electric Company, AES Energy Storage, Uni Energy Technologies, ViZn Energy Systems, Vinox Energy and Primus Power.

system, station load transformers, pad mounted medium/high voltage transformers, grid interconnection gear with metering, site utilities, foundations and plant fencing.

Table 7-4. Battery Energy Storage System Performance Data

Parameter / Technology	Lithium Ion	Vanadium Redox Flow
Capacity (MW)	25	25
Max Storage Limit (MWh)	100	100
Min Storage Limit (MWh)	2	2
Leakage Rate (%/hr)	0.05%	0.00%
Discharge Duration (hrs)	4	4
Recharge Time (hrs)	4	6.5
Round Trip Efficiency	85%	73%
Cycle Life (1 cycle/day 20 yrs)	7500	Over 7,500
Expected Annual Availability	96%	95%
Ancillary Service Capability	Reg up/down, spin/non-spin, reserve	Reg up/down, spin/non-spin, reserve

Table 7-4 summarizes estimated performance data for a typical 25 MW, 100 MWh BESS. 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. Typically, integrators employ augmentation strategies such as oversizing and/or periodic replacement, to ensure the grid connected BESS is supplying the necessary MWhrs and has the expected cycle life during the performance period. To meet electric utility customer needs, BESS integrators are willing to provide a guaranteed equipment life of about 20 years with an appropriate augmentation strategy. Integrator strategies can be different and there are no set industry standards.

Vanadium redox flow batteries on the other hand, do not experience significant performance degradation due to the fact that the charged electrons are stored in the liquid (vanadium) form that has limited self-discharge characteristics and they also exhibit almost no degradation when the system is left discharged for long periods of time. However, given the large volume of solution that must be pumped, the auxiliary load and recharge time of a similarly sized flow battery system is higher when compared to the Li-ion technology.

Cost Estimates

The capital cost for an installed BESS includes the energy storage equipment, power conversion equipment, power control system, site utilities, electric scope to the high side of the GSU transformer, and installation costs.

For Li-Ion systems, battery cells are arranged and connected into strings, modules, and packs which are then packaged into a DC system meeting the required power and energy specifications of the project. The DC system includes internal wiring, temperature and voltage monitoring equipment, and an associated battery management system responsible for managing low-level safety and performance of the DC battery system. For vanadium redox flow batteries, the DC system costs include electrolyte storage tanks, membrane power stacks, and container costs for the system along with associated cycling pumps and battery management controls. Each system requires a PCS to convert the produced DC power to AC power for ultimate grid utilization. The high level capital costs for a 25 MW/100 MWh Li-ion and vanadium redox flow BESS are estimated by HDR to be $1,660/kW and $1,700/kW, respectively.

The major component of the O&M cost for a Li-ion BESS system is related to energy and capacity augmentation. Augmentation maintains the BESS capability to serve the Owner's requirement for the term of the agreement. The total annual augmentation costs are estimated based on 1 full cycle/day discharge rate and these costs are typically covered in the fixed O&M costs. Variable O&M costs include a discharging or cycling charge which is the variable component of the augmentation service agreement[3]. For the Li-ion BESS, conceptual first year fixed and variable O&M costs are estimated at $39.61/kW-yr and $7.00/MWh, respectively. No staffing costs are included and the variable O&M costs do not include electric purchases made to charge the batteries; charging cost can vary and is a function of energy costs at the time of charging.

For the vanadium redox flow BESS, conceptual first year fixed O&M costs are estimated at $34.01/kW-yr4; there are typically no variable O&M costs associated with this technology.

The BESS integrator's scope of supply typically includes most of the systems up to the inverter terminal where AC power is available to the GSU transformer. Accordingly, the BESS integrator can deliver the major systems within 9 months from NTP. Additional site engineering, foundation and substructure work, permitting, site utilities and utility interconnection work is generally completed by a general/EPC contractor. A typical 25 MW BESS project can be commissioned and in commercial operation within 14 months from NTP. The 2019 Plan assumes a COD of 2020 for the BESS project being modeled.

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[3] BESS O&M costs are sometimes expressed on a fixed O&M basis only.

[4] This is the second year cost as the first year fixed O&M component is typically included in the project capital costs.

Pumped Hydropower Energy Storage

Overview

Pumped hydro energy storage (PHES) facilities store potential energy in the form of water in an upper reservoir, pumped from another reservoir at a lower elevation. During periods of high electricity demand, electricity is generated by releasing the stored water through pump-turbines in the same manner as a conventional hydro station. In periods of low energy demand or low energy cost, historically during the night or weekends, water is pumped back into the upper reservoir.

Reversible pump-turbine/generator-motor assemblies can act as both pumps and turbines. Pumped storage stations are a net consumer of electricity, due to hydraulic and electrical losses incurred in the cycle of pumping from the lower reservoir to the upper reservoir. However, these plants typically perform well economically, capturing peak to off-peak energy price differentials, and providing ancillary services to support the overall electric grid. HDR evaluated a 500 MW, 4,500 MWh closed-loop PHES facility.

PHES Technology

The first U.S. pumped-storage plant was commissioned in 1929 to help balance the grid. Today, there are approximately 40 pumped storage projects operating in the U.S. and pumped energy storage is considered commercially available and mature as many plants were installed throughout the U.S. in the 1970's and 1980's. The generating equipment for the majority of the existing pumped storage plants in the U.S. is the reversible, single-stage Francis pump-turbine. The technology for single-stage units continues to advance, and a broad range of equipment configurations are available depending upon the available head, site layout, and desired operation. The technology is considered partially dispatchable (limited based on reservoir volume) and generally possesses the operational flexibility to provide ancillary services.

Operational Considerations

A PHES facility requires specific geology, the potential to create two reservoirs, and acceptable topography. For the 2019 Plan, HDR selected a 500 MW PHES resource with 9 hours of dispatch capability located within NorthWestern's Montana service territory.

A pumped storage project would typically be designed to have between 6 to 20 hours of hydraulic reservoir storage for operation at full generating capacity. By increasing plant capacity in terms of size and number of units, hydroelectric pumped storage generation can be concentrated and shaped to match periods of highest demand, when it has the greatest value. Existing pumped storage projects range in capacity from 9 to 2,700 MWs, and in available energy storage from 87 MWh to 370,000 MWh.

Water-to-wire efficiencies vary based on individual equipment designs, age of the project, and site hydraulics, and include the pump-turbine, generator-motor and transformer efficiencies. Water-to-wire efficiency is typically near 85 to 90 percent for pumping mode and approximately 88 percent for generating mode for fixed speed Francis pump-turbines, resulting in a turnaround or cycle efficiency of approximately 80 percent. Table 7-5 summarizes estimated performance data for a 500 MW-4,500 MWh PHES.

Table 7-5. PHES Performance Data

PHES Performance		
Net Capacity	MW	500
Max Storage Limit	MWh	4,500
Min Storage Limit	MWh	0
Discharge Duration	Hours	9
Net Turnaround Efficiency (1st Year)	%	80

Cost Estimates

Conceptual EPC project costs for a 500 MW PHES project is estimated to range from $1,700/kW to $3,000/kW. The costs for a variable speed facility are expected to be approximately 20 percent greater than a single speed facility. No land procurement costs or Owner's costs are included.

Land requirements for PHES can vary considerably depending upon the specific project. PHES land requirements can be over a few hundred acres for the reservoir alone. This is highly dependent on the depth of the reservoirs and the amount of storage capacity required to meet peak load periods.

Operations and maintenance costs for pumped energy storage have been estimated assuming a daily dispatch profile with approximately 9 hours of electric production daily. The estimated fixed and variable O&M costs are based on work for recent confidential pumped storage projects and comparable industry data. The first year fixed O&M cost is estimated to be $14.55/kW-yr. A variable O&M cost of $0.90/MWH is estimated as a function of the number of starts and stops per day. Additionally, the variable O&M costs associated with charging the upper reservoir can vary as a function of the energy costs at the time of charging. The variable costs to charge the PHES system have not been included in the technology summary tables herein.

Thermal Resources

Overview

Thermal generation options considered in the 2019 Plan include CT and RICE technologies in either simple cycle or combined cycle configuration. Both are commercially proven and commonly implemented technologies for utility scale power generation applications using pipeline natural gas as the primary fuel source.

Simple cycle CT plants are generally used to supply power during periods of peak electric demand (peaking power) due to their low capital cost, short construction schedule, rapid response (e.g. quick start capability), and ability to operate cost effectively at low capacity factors compared to other power generation alternatives. Similar to simple cycle CT plants, simple cycle RICE installations are generally 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. As compared to simple cycle CTs, RICE facilities are less susceptible to thermal performance variances due to changes in ambient conditions such as temperature and elevation.

A combined cycle facility involves the addition of a heat recovery steam generator (HRSG) to the exhaust of a CT or RICE unit for the conversion of exhaust heat into steam that drives a steam turbine generator. The result is a significant increase in thermal efficiency over that of a simple cycle configuration. As compared to simple cycle technologies, the attributes of a combined cycle configuration include higher thermal efficiencies and less responsiveness in terms of starting and ramping, which make this technology more suitable for base load or intermediate load electrical supply.

Two of the simple cycle options considered in the Plan, the 50 MW aeroderivative CT and the 18 MW RICE, include the option to switch to a backup fuel in the event that the natural gas supply to the power generation facility is curtailed. Two different backup fuels were considered for these options: diesel fuel oil (FO) and liquefied natural gas (LNG). All other thermal options consider natural gas fuel only.

Simple Cycle Frame Combustion Turbine

This thermal resource option consists of a nominal 50 MW frame-type gas CT operating in a simple cycle configuration using natural gas fuel. This option includes the costs of an inlet air evaporative cooler and a selective catalytic reduction (SCR) system/oxidation catalyst to control emissions.

Simple Cycle Aeroderivative Combustion Turbine

Aeroderivative CTs differ from their heavy duty frame counterparts in that their designs are derived from aircraft engines. These CTs are especially well-suited for peaking applications given short start times and rapid ramp rates. Aeroderivative turbines are generally also able to handle a greater number of starts throughout their lifecycle. Two aeroderivative CTs are considered in this Plan.

The nominal 25 MW aeroderivative CT option is assumed to operate using only natural gas in simple cycle. The 50 MW aeroderivative CT option includes a base option and two derivatives. The base option is a single simple cycle aeroderivative CT operating on natural gas fuel only. One derivative assumes using diesel fuel as a backup fuel and the other derivative assumes using LNG as a backup fuel. All aeroderivative options include costs for an inlet air evaporative cooler and exhaust SCR system/oxidation catalyst.

Adding diesel fuel backup capability involves the addition of a diesel storage tank, additional fuel forwarding pumps, and a modification of the CT to allow operation on both gaseous and liquid fuels. When operating on diesel fuel the CT will experience derated output and efficiency. Adding LNG backup capability involves the addition of a cryogenic tank, a re-gasifier which converts the LNG back to its original gaseous state, and a system for disposing of the LNG boil off during storage of the fuel. LNG is assumed to be trucked in therefore this configuration does not include a natural gas liquefaction plant. When operating on LNG supply, the turbine output and efficiency are similar to that when the CT is operating on natural gas. Equipping a facility with LNG storage tends to be more complicated and, as a result, has higher capital cost than equipping a facility with diesel fuel storage.

Combined Cycle Combustion Turbine

Two combined cycle options were considered in the Plan, a 150 MW option with supplemental duct firing and a 130 MW option without supplemental duct firing[5]. Both options consist of two nominal 50 MW frame CTs paired with dual pressure Heat Recovery Steam Generator (HRSG) units. The HRSGs generate high and intermediate pressure steam using the hot exhaust gas from the CTs. This steam is fed to a single steam turbine generator to generate additional electrical output. The assumed configuration for these options includes an air cooled condenser (ACC) for thermal cycle heat rejection, inlet air evaporative coolers and SCR system/oxidation catalysts for emissions control.

[5] Supplemental duct firing increases output due to additional steam generated from adding heat in the HRSGs. This configuration offers the added flexibility of being able to cycle the duct burners on and off.

Reciprocating Engines (RICE)

Two RICE options were considered in this Plan. The first consists of a single nominal 18 MW RICE burning natural gas as a primary fuel. The engine is assumed to have an SCR system/oxidation catalysts for emissions reduction and fin-fan radiators for engine cooling. Both diesel fuel oil and LNG are assumed as backup fuels. The natural gas/diesel dual fuel RICE requires a liquid oil pilot system even when operating on natural gas fuel which increases cost.

The other option consists of a single 9 MW RICE operating on natural gas as the only fuel source. This engine is also assumed to be equipped with an SCR system/oxidation catalyst for emissions control and fin-fan radiators for engine cooling.

Dave Gates Generating Station – RICE Generation Addition

Overview

This resource option includes the addition of a nominal 50 MW, three-unit RICE generation facility at the DGGS. The modeled facility consists of three nominal 18 MW dual-fueled RICE burning natural gas as a primary fuel and ultra-low sulfur diesel (ULSD) as a backup fuel. The DGGS site is an attractive option to explore since it is an existing generation site adjacent to a NorthWestern transmission substation with significant existing infrastructure, an existing natural gas radial pipeline and associated metering station, an available unused generator step-up transformer and an existing large generator interconnection agreement (LGIA) with an additional available capacity of 63 MW.

Cost Estimates

The estimated total capital cost of this project is about $1,482 per kW for a 2018 COD based on an Association for the Advancement of Cost Estimating (AACE) Class 3 cost estimate for an EPC lump sum turnkey (LSTK) project. To be conservative, the estimate includes $2.5M for upgrades to the existing natural gas delivery system and $1.5M for electrical transmission interconnection work including possible relocation of transmission lines inside the DGGS facility. The necessity of the fuel delivery system upgrades and transmission interconnection work along with their associated costs would be further refined in a more detailed engineering design assessment and cost estimate. Conceptual first year fixed and variable O&M costs are estimated at $10.29/kW-yr and $6.57/MWh, respectively.

Other Generation Technologies

HDR also provided cost estimates for Compressed air energy storage (CAES) technology, and geothermal generation technology. However, these technologies are higher cost and were not selected in the automated resource selection process. Please refer to the full HDR study, which is included in Volume 2, Chapter 7, for a full description of these resource options and their costs.

Characteristics of Production and Summary of Costs

New Resource Cost Summary Tables

Tables 7-6 and 7-7 below summarize the costs of the generation and storage technologies presented in this chapter. Table 7-6 shows the operating characteristics and costs for resources developed in Western Montana, and Table 7-7 shows the operating characteristics and costs for resources developed in Eastern Montana. These costs compare favorably with the costs of resources in the NWPCC's Seventh Power Plan Mid-Term Assessment, released February 26, 2019.[6]

Table 7-6. New Resources Cost Summary for Western Montana

Western Montana ($2018)	Fuel	Nameplate Capacity (Nominal)	Design Life	Net Output - Winter	Net Heat Rate Winter (HHV)[1]	Capital Cost[2]	Fixed O&M (Yr 1)	Variable O&M (Yr 1)
Technology	(Type)	(MW)	(Years)	(MW)	(Btu/kWH)	($/kW)	($/kW-yr)	($/MWH)
Combustion Turbine - Dry Cooling								
Simple Cycle 1x0 CT - 50 MW Frame	NG	48.1	30	45.8	9,986	$1,433	$13.18	$8.73
Simple Cycle 1x0 CT - 25 MW Aeroderivative	NG	28.1	30	26.7	9,902	$1,659	$20.42	$5.58
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	47.4	30	45.2	9,388	$1,336	$13.38	$4.38
Combined Cycle 2x1 CT - Frame/Industrial CT	NG	133.3	30	127.0	7,210	$1,323	$25.75	$6.30
Reciprocating Internal Combustion Engine								
DGGS Buildout 3x0 RICE - 18 MW Class NG Only	NG	3x19.4	30	50.0	8,503	$1,482	$10.29	$6.57
Simple Cycle 1x0 RICE - 18 MW Class NG Only	NG	19.4	30	18.5	8,329	$1,833	$23.26	$4.68
Simple Cycle 1x0 RICE - 9 MW Class NG Only Western	NG	9.6	30	9.2	8,103	$2,324	$54.62	$4.55
Wind Energy								
Wind Energy	N/A	105.0	25	100.0	N/A	$1,410	$37.00	N/A
Solar Photovoltaic (PV)								
Solar PV - Single Axis Tracking	N/A	105.0	20	100.0	N/A	$1,330	$21.60	N/A
Geothermal								
Geothermal - Flash Steam	N/A	21.0	30	20.0	1,000	$2,800	$123.98	$9.88
Pumped Hydro Energy Storage (PHES)								
PHES - Closed Loop (9 Hour)	Elec. Grid	525.0	30	500.0	N/A	$1,700-$3,000	$14.55	$0.90
Compressed Air Energy Storage (CAES)								
CAES - Diabatic (8 Hour)	Elec. Grid / NG	105.0	30	100.0	4,500	$1,500-$2,300	$15.27	$8.53
Battery Energy Storage System (BESS)								
BESS - Lithium Ion (4 Hour)	N/A	26.3	20	25.0	N/A	$1,660	$39.61	$7.00
BESS - Vanadium Flow (4 Hour)	N/A	26.3	20	25.0	N/A	$1,700	$34.01	N/A

[1] Thermal heat rates are presented on a higher heating value (HHV) basis.
[2] $/kW capital cost metrics divide estimated project costs by the net winter output for a given technology.
[3] Capacity factors for dispatchable technologies assumed in order to develop O&M costs.
[4] Dual fuel performance and costs are presented as a blend of NG and alternative fuel (NG or FO) operations (1,034 hours on NG and 263 hours on alternate fuel)

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[6] Included in Volume 2, Chapter 7, and available at https://www.nwcouncil.org/reports/midterm-assessment-seventh-power-plan

Table 7-7. New Resources Cost Summary for Eastern Montana

Eastern Montana ($2018)	Fuel	Nameplate Capacity (Nominal)	Design Life	Net Output - Winter	Net Heat Rate - Winter (HHV)	Capital Cost	Fixed O&M (Yr 1)	Variable O&M (Yr 1)
Technology	(Type)	(MW)	(Years)	(MW)	(Btu/kWH)	($/kW)	($/kW-yr)	($/MWH)
Simple Cycle 1x0 CT - 50 MW Frame	NG	51.4	30	48.9	9,970	$1,361	$12.52	$8.30
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	49.6	30	47.3	9,369	$1,276	$12.78	$4.05
Combined Cycle 2x1 CT - Frame/Industrial CT	NG	140.2	30	133.5	7,213	$1,259	$24.49	$5.99
Reciprocating Internal Combustion Engine								
Simple Cycle 1x0 RICE - 18 MW Class NG Only	NG	19.4	30	18.5	8,318	$1,833	$23.07	$4.64
Simple Cycle 1x0 RICE - 9 MW Class NG Only	NG	9.6	30	9.2	8,103	$2,306	$54.20	$4.52
Wind Energy								
Wind Energy	N/A	105.0	25	100.0	N/A	$1,410	$37.00	N/A
Solar Photovoltaic (PV)								
Solar PV - Single Axis Tracking	N/A	105.0	20	100.0	N/A	$1,330	$21.60	N/A
Geothermal								
Geothermal - Flash Steam	N/A	21.0	30	20.0	1,000	$2,800	$123.98	$9.88
Pumped Hydro Energy Storage (PHES)								
PHES - Closed Loop (9 Hour)	Elec. Grid	525.0	30	500.0	N/A	$1,700-$3,000	$14.55	$0.90
Compressed Air Energy Storage (CAES)								
CAES - Diabatic (8 Hour)	Elec. Grid / NG	105.0	30	100.0	4,500	$1,500-$2,300	$15.27	$8.53
Battery Energy Storage System (BESS)								
BESS - Lithium Ion (4 Hour)	N/A	26.3	20	25.0	N/A	$1,660	$39.61	$7.00
BESS - Vanadium Flow (4 Hour)	N/A	26.3	20	25.0	N/A	$1,700	$34.01	N/A

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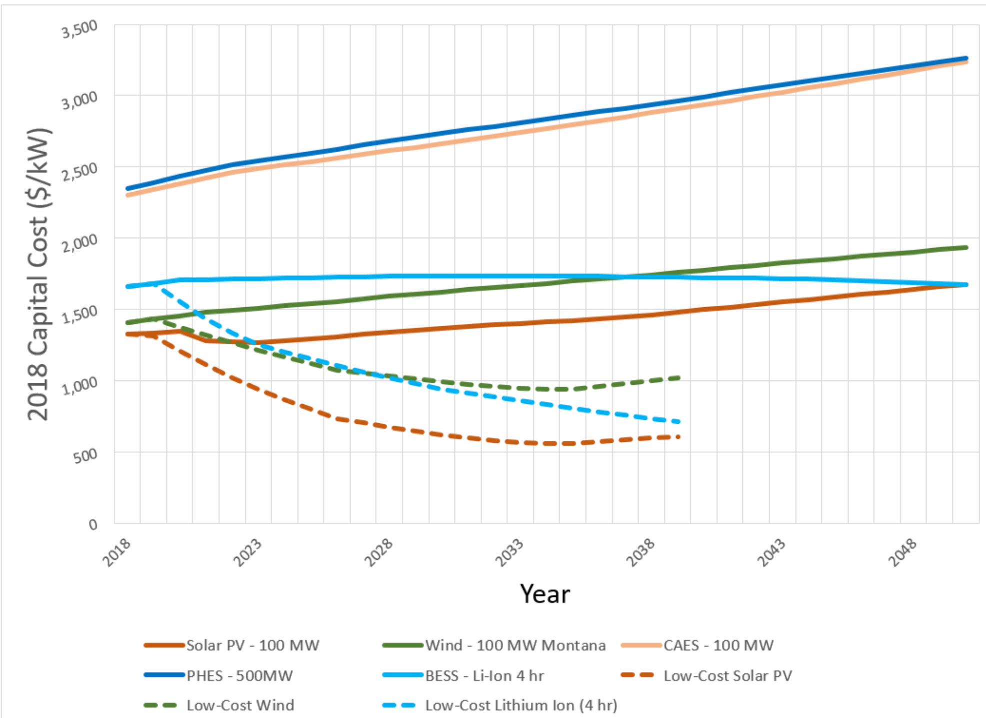
New Resource Cost Trends

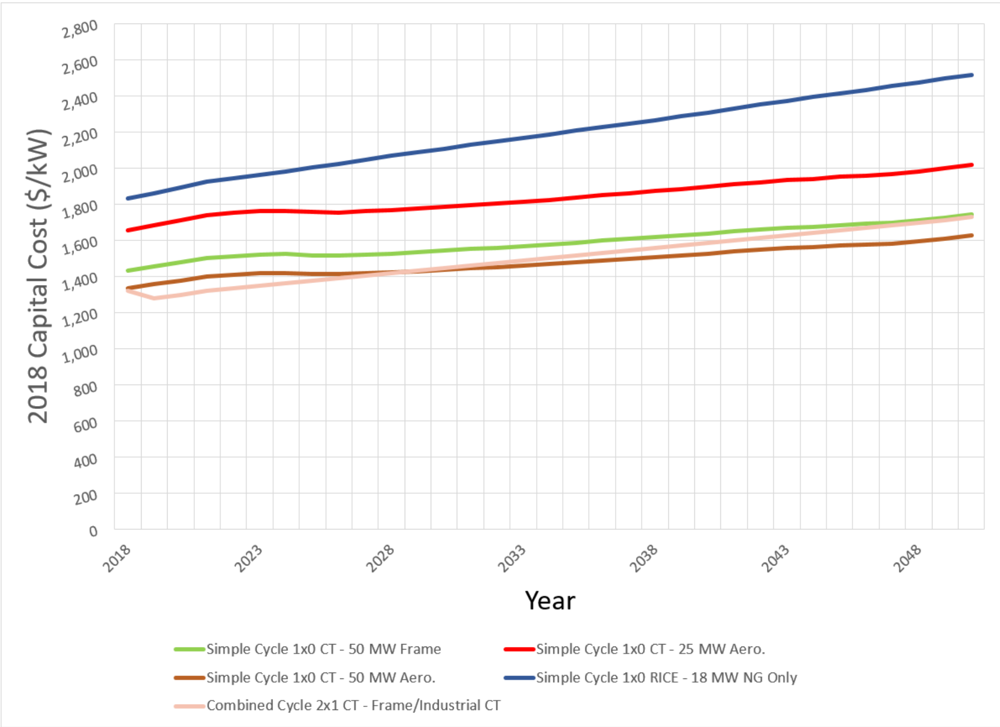
Figures 7-2 and 7-3 show the future cost curves for renewable and thermal resources, and Li-Ion battery storage technology.

Figure 7-2. New Resources Cost Trends for Renewables and Batteries



These cost curves were included in Automated Resource Selection (ARS) so that future resource additions reflect these future cost curves. The results of portfolio modeling results are presented in Chapter 10. The "lower cost" cost curves for wind, solar PV, Li-ion batteries shown in Figure 7-2 were developed by Ascend Analytics. These lower cost futures were included in the constrained cost ARS model run; the run that resulted in the "Base Case." The addition of the lower cost futures for wind, solar PV, Li-ion batteries did not change ARS resource selection. There was no further use or consideration of the "lower cost" scenarios in the Plan.

Figure 7-3. New Resources Cost Trends for Thermal Resources



CHAPTER 8
EMERGING TECHNOLOGIES

NorthWestern's Distribution System

Overview

This chapter includes a discussion of technologies that will impact NorthWestern's future energy supply, and explores resource options that may have the potential to serve our customers' future resource needs. The chapter includes a discussion of smart grid technologies, smart metering infrastructure, NorthWestern supported solar PV projects, and new technologies for energy storage and generation.

Building the Foundation for the Future

NorthWestern is investing in building a smarter energy infrastructure. In 2013 we began the Distribution System Infrastructure Project (DSIP). DSIP helps position NorthWestern so we can adopt new, cost-effective, energy technologies by modernizing aging infrastructure, enhancing reliability and providing margin (i.e. additional capacity) for the distribution system. Most of DSIP was completed in 2017; however, part of DSIP includes extending our communication network and establishing the groundwork for automating principal distribution substations and this portion of the project will conclude in 2020.

Automation is a key component of a smarter energy infrastructure and of participation in organized markets such as the EIM. Our work includes expanding NorthWestern's wireless communication system using two newly purchased communication radio spectrums along with our existing backbone fiber optic and

microwave communication

system. We have established a separate distribution communications network and it is now routine business practice to extend our communications network during capital projects that require the use of this network. Presently this network is being used by our "pilot" distribution SCADA[1] system to communicate with electronic relays and reclosers[2] that are being added or upgraded within distribution substations. In 2019, the "pilot" SCADA will transition to a new Advanced Distribution Management System (ADMS). ADMS will assist our distribution system operators, engineers, technicians and managers in optimizing the efficiency, reliability, and overall performance of the electric distribution system.

Smart Metering Infrastructure

Today, our smart metering network is used for automated meter reading, automated outage alarms integrated into the ADMS, and automated electric meter disconnects/reconnects. Additionally, NorthWestern has deployed a new version of the smart metering field area network which provides the foundation for incorporating multiple networks, applications, and devices within a single, unified communications architecture. This communication network extends to each customer's meter and can extend to Building Management Systems, Home Area Networks, and other intelligent devices such as load control modules.

Demand Response

NorthWestern continues to explore demand response technology to determine how it may best fit with customer needs and energy capacity requirements. Initially, NorthWestern explored demand response during the Pacific Northwest Smart Grid Demonstration Project with residential customers and a commercial customer. In residential homes, quarterly

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[1] SCADA is an acronym for Supervisory Control And Data Acquisition, a computer system for gathering and analyzing real time data.

[2] A class of switchgear designed for use on electric networks to detect and interrupt momentary faults.

events were tested that involved multiple phases of customer load reduction. These events allowed customers the freedom of participating in a demand response event or opting out using their home equipment. The software used during the demonstration project calculated the load reduction capability based on customer supplied data that was gathered at the initial phase of the project.

The commercial application was to be a test of demand response during a peak pricing event. For this test, a pricing signal was to be sent to a building automation control system and the building system was to respond according to a predetermined load curtailment schedule to reduce load based on price. Unfortunately, the software was never fully developed due to time and cost constraints and the commercial system was never tested.
We are also investigating the use of advanced software applications within our smart metering network that include distributed intelligence which can be used to segregate meters to enable surgical reductions in demand based on individual customer profiles and their ability to shed load. This software can allow dispatch of multiple demand response programs including direct load control and voluntary pricing programs. Additionally, optimization and dispatch of complex portfolios including traditional and renewable distributed generation, storage, and curtailable load are being investigated along with forecasting and dispatching of distributed energy resources to support load relief on our distribution grid.

Distributed Energy Resources (DERs)

The ADMS software also has a module with the capability to integrate power distribution networks by connecting DERs like private solar and battery energy storage. NorthWestern's current plan is to employ the ADMS DER module within the next five years. This future application will help our distribution network keep the grid balanced and optimized in real-time while maintaining system reliability and power quality

Review of NorthWestern's Technology Projects

NorthWestern continues to develop or co-develop pilot scale projects in order to investigate and demonstrate various aspects of how solar PV and battery storage can be used on our distribution system. The Community Sustainable Energy Working Group (CSEWG) which is comprised of a diverse group of local and state government representatives, environmental and customer advocates, and local renewable developers, assisted in selecting project technologies and locations. With assistance from the Smart Electric Power Alliance (formerly known as the Solar Electric Power Association) four pilot projects focused on customer enabling initiatives and grid integrated technologies were selected.

These projects are designed to create opportunities for consumers to become familiar with integrated energy grid technologies and become more engaged with how they consume energy. The projects are truly "smart community" projects and provide opportunities to work with communities as partners to help meet their goals while generating hands-on knowledge and data for NorthWestern's system planners and others. The information is being used to analyze possible sustainable business models for adding renewable technology to our energy grid.

A summary of each project is provided in Table 8-1. Following the table are a brief description and status of each project. Two of the four projects, located in Deer Lodge and Bozeman, are installed and operational. The remaining two projects will be installed in Missoula and Helena in the next two to three years. These projects represent a small part of NorthWestern's efforts to develop additional renewable energy in Montana.

Table 8-1. NorthWestern Supported Solar Projects

Project	Location	Target Customers	Description	Technologies Deployed	Desired Learnings
Deer Lodge Microgrid	Beck Hill (Approx. 7 miles N. of Deer Lodge, MT)	Customers with rural reliability issues	~160 kWh of battery storage paired with 40 kW of Solar	Communications	Value of energy storage in rural applications
				Lead acid battery storage	Storage optimization
				DC coupled solar	Benefits of solar in microgrid applications
				AC coupled solar (string inverter)	Development cost models
				AC coupled solar (Micro-inverters)	Microgrid controls including ancillary services provided by energy storage
				Electronic reclosers	
Bozeman Solar Project	Bozeman Water Treatment Facility	Diversity of residential, commercial, & industrial customers	380 kW PV array with smart inverters and 60 volunteer customers with advanced metering	Utility-scale solar	Peak shaving
				Smart inverters	MSU educational component
				Advanced Metering Infrastructure (AMI)	Community solar rate modeling
				Virtual net-metering	Development process/cost
				West facing panels	Integrating solar to grid
					Distribution management system
					Data on energy production & user consumption
Missoula Solar Project	Schools in Missoula	School property: Big Sky, Sentinel, Hellgate, Willard	Multiple size solar PV and energy storage	Solar PV	Identification of customers and data collection
				Automated metering	Establishing school & utility solar partnerships
				Energy storage	Student involvement & education
				EDI dashboard - usage	Scalability
Helena Solar Project	Existing footprint of Smart Grid Demonstration Project, 6th ward	Expanded footprint focused on low-income	Utility owned / controlled solar paired with AMI, advanced inverters, and energy storage	Advanced inverters	Conservation savings through Volt/VAR
				Solar PV	Ride through capabilities of inverters
				AMI	Value & use of energy storage at different points on the grid
				Energy storage	Test utility owned distributed solar / inverters
				Communication	Tipping point of circuit capacity
					Customer interest & engagement

Deer Lodge (Beck Hill) Microgrid Project

NorthWestern Energy developed and commissioned this project in 2015 in order to provide data on how small microgrids can increase reliability, better manage load, defer asset acquisition and provide greater system efficiency. The project uses a 40-kilowatt solar system and an 80-kilowatt battery bank to provide electricity for seventeen customers for two to four hours during a feeder outage. The project is helping us further assess the potential of solar generation across our Montana electric service territory. Additionally, the project has provided an opportunity for Montana State University seniors to engage in a renewable energy project and help evaluate inverter improvements.

NorthWestern provided approximately $600,000 for this project which is expected to have a lifespan of five to 10 years

Figure 8-1. Deer Lodge Solar PV Inverters and Battery Racks

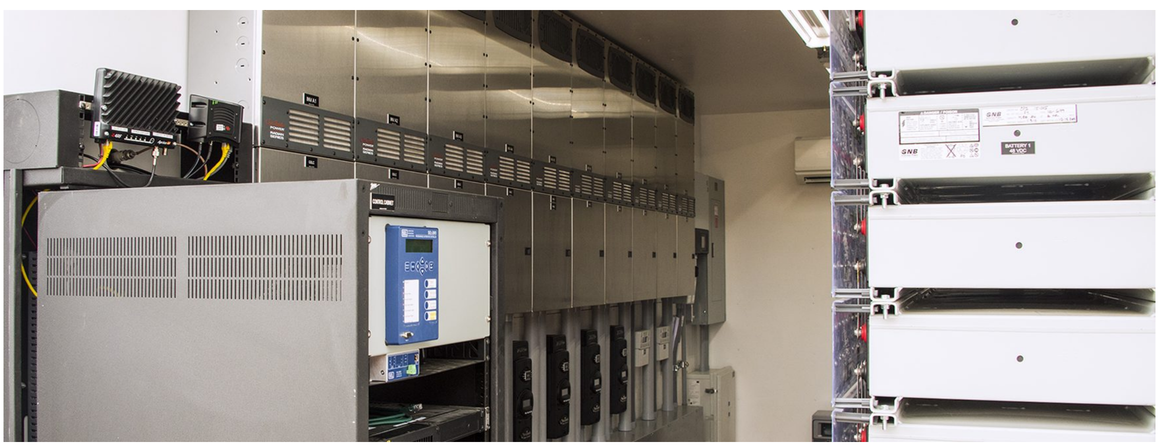
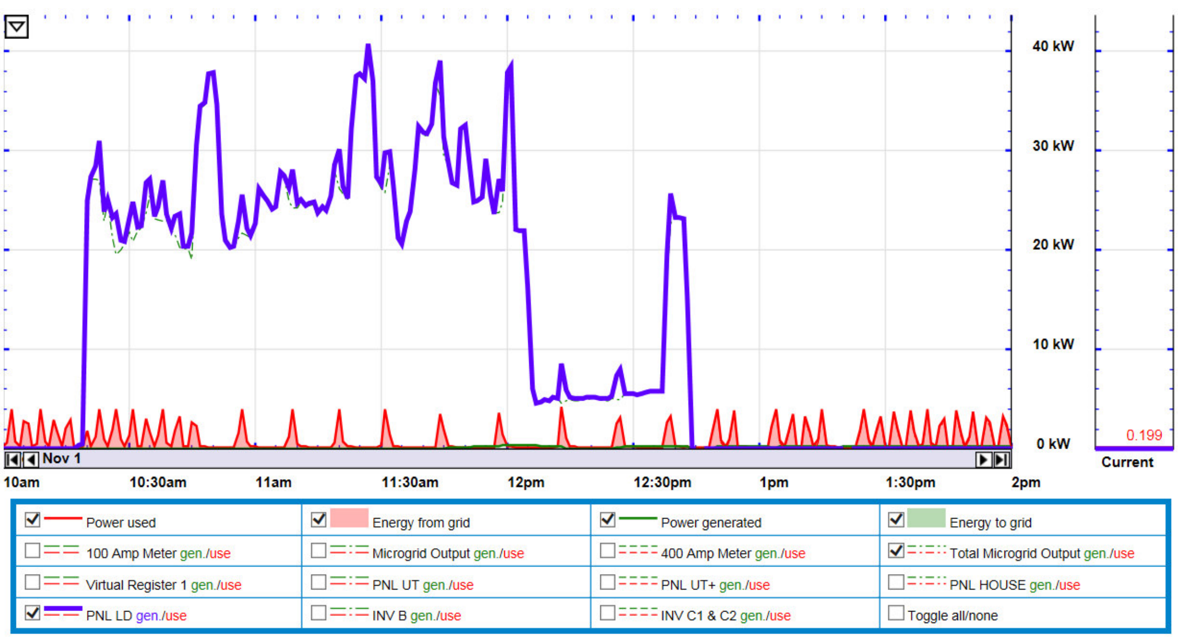


Figure 8-2. Deer Lodge Microgrid Solar PV Array and Containers

Figure 8-3 illustrates the microgrid production on November 1, 2017 during a distribution feeder outage of approximately 3.5 hours.

Figure 8-3. Deer Lodge Solar Microgrid Operation During Feeder Outage



Bozeman Solar Project

The Bozeman Solar Project was commissioned in 2016 and is a pilot scale community solar project for the City of Bozeman. The project is a partnership between three entities, NorthWestern Energy, the City of Bozeman and Montana State University.

This solar project will generate about 533,000 kilowatt-hours of energy per year. Along with solar PV panels and smart inverters, the project uses 40 residential and 20 commercial advanced smart meters to help the project partners better understand how solar power aligns with customer needs.

NorthWestern's goals of providing our customers reliable energy service from a diversified portfolio and to work with our customers to develop solutions to meet their particular needs is demonstrated in the Bozeman Solar Project. This project will provide valuable data about community solar models and will also help the City of Bozeman achieve its climate action plan goals and plan for future renewable energy projects.

NorthWestern committed $1 million for the construction and operation of the project. The City of Bozeman has agreed to provide use of the land but has no additional financial responsibility tied to the project. MSU is helping with research tied to the five-year pilot through two senior design projects. See Figures 8-4 through 8-6.

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Figure 8-4. Bozeman Solar Microgrid Output Profile

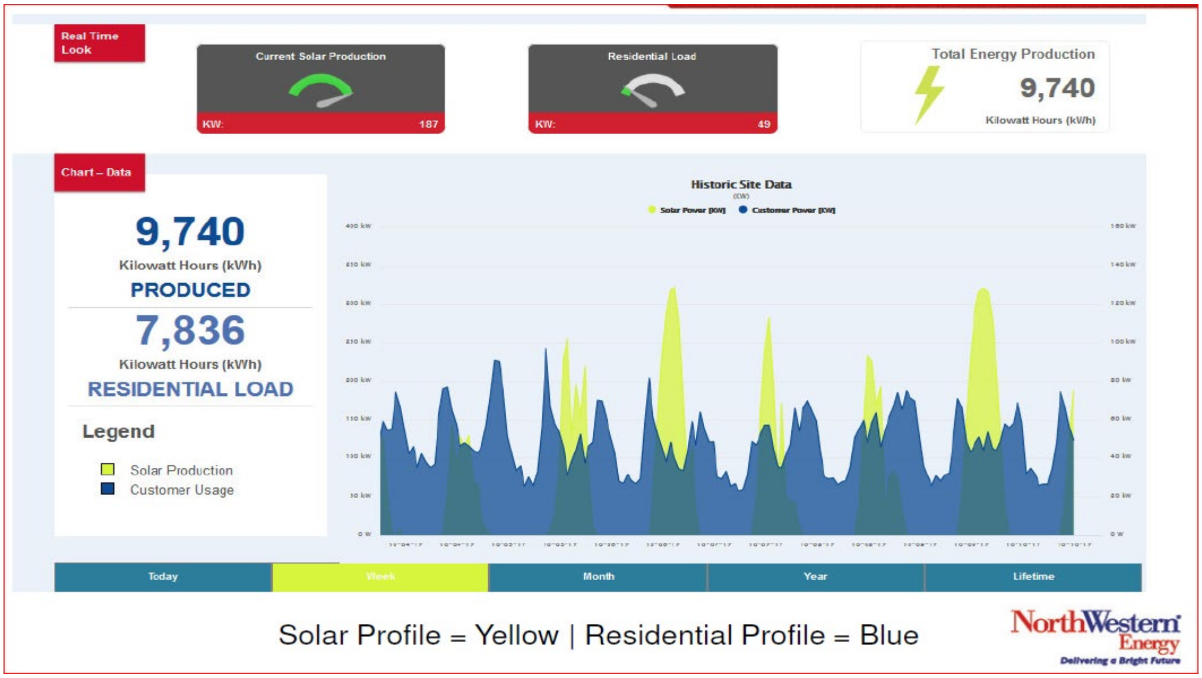


Figure 8-5. Bozeman Solar Microgrid Container Boxes and Controllers

Figure 8-6. Bozeman Solar Microgrid 380 kilowatt Array

Missoula Solar Projects

NorthWestern Energy, Missoula County Public Schools and the City of Missoula are developing collaborative solar projects designed to learn more about the performance of solar energy on our distribution system in the Missoula area. Construction of the projects will begin in the spring of 2019 and include installation of solar technology at Hellgate, Sentinel, Big Sky and Willard high schools. Different locations will integrate different solar PV technology and the Big Sky installation will include energy storage. Willard alternative high school will utilize a solar fence with PV panels mounted vertical that will produce energy that better aligns with each school's consumption pattern, as well as help with snow shedding during winter months.

Figure 8-7 is an example of the proposed design at Sentinel High School and Figure 8-8 and Figure 8-9 are examples of the proposed design at Hellgate High School.

Figure 8-7. Sentinel High Solar PV Project Vertical Array Sketch

Figure 8-8. Hellgate High Solar PV Project Vertical Options Sketch

Figure 8-9. Hellgate High See-Through/Bifacial and Opaque Solar PV Options

Willard High School will use a solar fence concept to demonstrate new solar PV technology as seen in Figure 8-10.

Figure 8-10. Fence Solar PV Options

Figure 8-11.

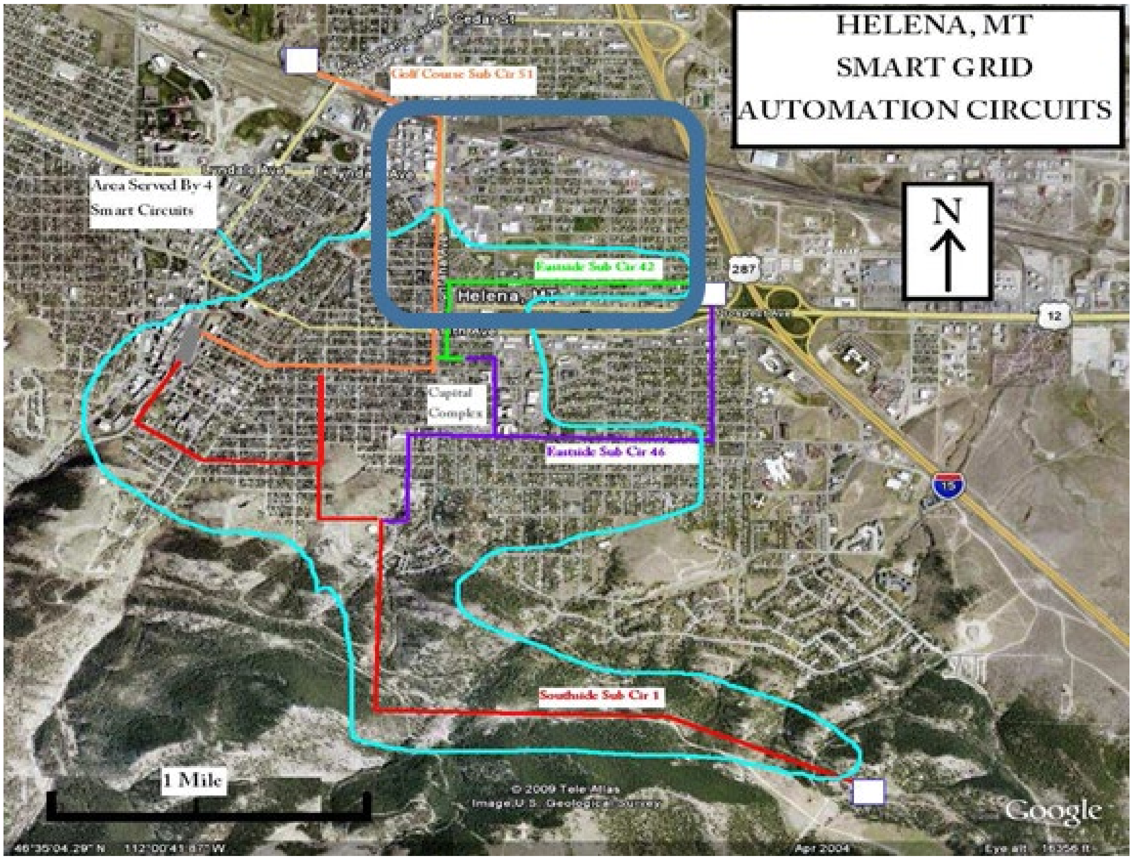
Big Sky High Solar PV Project Walkway Canopy Example

Big Sky High School's proposed installation will use a solar walkway to provide shading along with an energy storage element to demonstrate new solar PV technology. Energy storage will be charged from the onsite solar production and provide power to loads located in the gym for community events. Figure 8-11 is an example of the proposed design at Big Sky High School.

Helena Solar Project

The Helena Solar Project is slated to begin design in fall 2019 and will be installed in Helena's 6th Ward Area. This project will be a test of utility owned rooftop solar PV and utilize the existing distribution and communication system of the NorthWestern Smart Grid Pilot Project. Figure 8-12 shows the preliminary location of the project.

Figure 8-12. Helena Solar PV Project Area



Super-Capacitor Energy Storage

In November of 2018, NorthWestern announced an investment of $2.5 million in Kilowatt Labs, Inc. (KLI), a New York-headquartered designer and manufacturer of innovative super-capacitor energy storage and power management solutions. KLI super-capacitor technology aligns closely with our thinking about the evolution of the infrastructure that serves our customers, from rural to industrial, and at multiple layers of our network. NorthWestern will be working with KLI to develop potential solutions throughout our network.

Small Modular Nuclear Reactors (SMRs)

SMRs are a promising technology capable of providing reliable, non-variable, clean, and carbon-free power. SMRs have an output of 300 MWs or less and are comprised of factory-fabricated components transported to a nuclear power plant location for on-site assembly. Some SMR designs allow for output to be varied over days, hours, or minutes, enabling the SMR to be used for flexible capacity and grid balancing.

In 2018, the US Department of Energy's (DOE) Office of Nuclear Energy announced an agreement with Utah Associated Municipal Power Systems and Battelle Energy Alliance (DOE contractor operating the Idaho National Laboratory (INL)) to construct twelve, 50 MW capacity SMRs at the INL site near Idaho Falls, Idaho with a commercial operation date sometime in 2026. NorthWestern will be involved in this project because we own and operate an affected transmission system.

CHAPTER 9
ENVIRONMENTAL

Environmental Issues that Influence the 2019 Plan

Introductory Statement

NorthWestern Energy provides affordable, reliable, and safe energy services while responsibly managing the natural resources under our stewardship. We support using renewable resources when consistent with the needs of the portfolio and our commitment to ensure our customers always get the energy they need in all weather conditions. Our commitment to environmental stewardship and compliance affects all facets of our business, including our resource procurement planning.

All forms of electric generation involve environmental impacts and mitigation requirements and NorthWestern Energy employs a team of experts to ensure our projects are operated in compliance with environmental regulations and operating license requirements. We prepare an annual publication called "Environmental Stewardship: Our Commitment in Action" which is available on our website.[1] We encourage those interested to review this publication.

River Management Partnerships

Partnering with agencies and private parties, NorthWestern employs an innovative approach to complying with our hydroelectric project FERC license requirements. Under

[1]http://www.northwesternenergy.com/docs/default-source/documents/environment/nwe_enviroreport_2017_web.pdf

a Memorandum of Understanding (MOU), NorthWestern, the US Fish & Wildlife Service, Montana Department of fish, Wildlife and Parks, US Forest Service, US Bureau of Reclamation, and the US Bureau of Land Management work collaboratively to implement studies and projects to protect, mitigate and enhance fish, wildlife, habitat and water quality and improve public recreation. Habitat improvement on rivers and tributaries is a high priority as is our program to protect and enhance endangered species and species of special concern. NorthWestern has funded and partnered with agencies to expand populations of genetically pure native westslope cutthroat trout, recover pallid sturgeon and establish new breeding pairs of trumpeter swans (following photo).

NorthWestern Energy has provided funding each of the last 10 years to support the installation and operation of a system of 12 remote fish-tracking stations located on a 225-mile stretch of the Missouri River from Great Falls to Fort Peck Reservoir.

In recent years, we have assisted in population surveys and funded research on softshell turtles (pictured below), a Montana species of special concern. Our employees worked with representatives from the Montana Department of Fish Wildlife and Parks and Montana

State University during the summer of 2017 to obtain turtle-population density information in a 10-mile stretch of the Missouri River. We will use this information as the baseline for long-term monitoring of population stability of this sensitive species.

Avian Protection Program

	Researchers conduct a post-construction inspection of a wind generation facility in order to assess the effects of bird and bat collisions.

NorthWestern Energy has a long standing commitment to deter birds from colliding with wind farm turbines and power lines, and nesting on energized structures. To reduce the risk of power outages and osprey mortality, we install deterrents on energized structures to prevent osprey from starting new nests and often install nesting platforms nearby. This provides both a safe nesting location for osprey, which return to the same nest every year, and more reliable service for our customers. Currently on our Montana electric system, we have more than 150 osprey platforms, providing a safe home for these amazing birds. In addition, we actively communicate the threat baling twine presents to osprey when they use discarded twine in their nests.

A NorthWestern Energy Lineman assists a university biologist in studying active osprey nests.

NorthWestern's raptor biologist was awarded the Montana Chapter of the Wildlife Society's Distinguished Service Award in 2017 for "tireless commitment to the protection, conservation and enjoyment of Montana's wildlife." In NorthWestern Energy's pursuit of additional sources of renewable energy in the state, our raptor biologist ensures projects conduct the necessary studies in order to minimize impacts to migratory birds and wildlife in general. In 2012, when NorthWestern purchased the Spion Kop wind project near Great

Falls, we did not follow the wind industry standard of hiring 3rd party consultants to do post-construction monitoring – we surpassed it. NorthWestern implemented an innovative approach by proposing the Montana Fish, Wildlife and Parks (MFWP) design and implement wildlife monitoring with guidance from a Technical Advisory Committee (TAC) (which includes representatives of MFWP, the USFWS, Montana Audubon, the University of Montana, and NorthWestern). This approach ensured monitoring was completely transparent, produced public data available to state and federal wildlife managers and also gave the MFWP direct experience to better prepare for consultations with developers. Spion Kop is only the second wind farm in Montana to use a TAC, the only wind farm in Montana to make all data publicly available, and the first (and perhaps still the only) wind farm in the nation to employ a state wildlife agency in wildlife monitoring.

NorthWestern Energy's Balanced Energy Mix

We are committed to providing a diverse, balanced, cost-effective and reliable portfolio of resources that isn't overly dependent on a single technology. As previously mentioned in Chapter 4, about 63% of the nameplate capacity of our supply portfolio is from owned and contracted clean hydro, wind and solar resources.

Renewable Energy Resources

NorthWestern Energy has invested approximately $2.2 billion in renewable resources and cost-effective demand side management. This includes the hydro acquisition, which provides our customers long-term price stability for a significant portion of the portfolio that serves them, from a clean, renewable and carbon-free resource. Unlike other renewables, hydroelectric generation provides carbon-free energy and capacity as well as additional, or ancillary, services required for a reliable system (spinning and non-spinning reserves as well as on-demand generation increases or decreases).

As indicated in Chapter 4 we have numerous contracts with small renewable projects using hydro, wind and solar generation. Since late 2016, we have added about 159 MWs of long-term energy supply contracts with third-party wind and solar developers, and this figure will grow to 398 MWs by the end of 2019 (see Figure 4-5 in Chapter 4). As stated in Chapter 4, NorthWestern currently has requests from an additional 2,545 MWs of QF projects for avoided cost calculations or draft PPAs. Several more MWs of renewable generation will be added in the next two years which will increase the percentage of variable generation in our portfolio and increase the need for reliable, flexible capacity resources so we can continually balance supply and demand and prevent service disruptions. Of these requests, 104.8 MWs fall under the 3 MW standard offer limit for the QF-1 Tariff. The larger projects, up to 80 MWs in size, include 1,417 MWs of solar, 888 MWs of wind, and 134.7 MWs of other technologies or combination projects.

For more than 17 years, NorthWestern Energy has helped fund installation of photovoltaic solar and wind systems through our USB program. In Bozeman, Montana we partnered with the City of Bozeman, Montana State University and Schweitzer Engineering Laboratories to build a 385 kw solar project that we are using to pilot community solar models, test the applications of advanced inverters and determine the value to the grid.

Greenhouse Gas Emissions

In 1990, NorthWestern's predecessor company in Montana, the Montana Power Company, began a voluntary greenhouse gas reduction plan to reduce carbon dioxide emissions by using demand side management programs, improving hydroelectric generation at existing hydro plants, promoting renewable energy, reducing electrical losses from generation and transmission, and implementing a forest carbon management plan.

NorthWestern's ownership of coal-fired generation is less than 10% of the total in the state of Montana. The contracted waste coal and petroleum coke resources in our portfolio are QFs, which we are required by law to use, and account for about 11% of the energy provided by our portfolio yet contribute an annual average of about 35% of the CO2 emissions associated with our portfolio. Carbon dioxide emissions are also associated with energy we need to purchase from the market.

As previously stated in this Plan our portfolio requires the addition of a considerable amount of capacity. Resources chosen to fill the large capacity deficit must be able to provide a reliable source of flexible generation and be controlled by NorthWestern using AGC. NorthWestern cannot simply choose resources based solely on levels of greenhouse gas emissions. The capacity resources will be chosen using a competitive, all source, technology agnostic, RFP process in order to identify the most cost-effective resources.

Regulation of Greenhouse Gas (GHG) Emissions

For context we feel it's important to understand the history of efforts to regulate GHG emissions. The following sections discuss this history.

Clean Power Plan

The Environmental Protection Agency (EPA) published a proposal to regulate CO_2 emissions from existing power plants on June 2nd, 2014. NorthWestern Energy actively engaged with EPA, state agencies, state governments, utility regulatory commissions, utilities, business groups, the Edison Electric Institute, the Coalition for Innovative Climate Solutions and others, analyzing the proposed rule in order to identify opportunities and also areas where more work and analysis were required before states could draft implementable compliance plans and ensure. Concerned our customers were being punished rather than rewarded for their low carbon energy use, NorthWestern submitted constructive comments to EPA. The comments focused on some of the significant practical problems and challenges associated with the proposed rule, along with recommendations/requests for EPA to consider for the final rule to help EPA ensure the final rule addressed the economical, technical and physical realities as well as the environmental factors associated with delivering electricity safely, reliably and securely.

The final Clean Power Plan (CPP) was published in the Federal Register on October 23rd, 2015. Citing a range of legal and technical concerns, several states, utilities and trade groups filed petitions for review in the US Court of Appeals for the District of Columbia (DC Circuit). By December of 2015, a bipartisan majority of the US Congress formally disapproved of the CPP pursuant to the Congressional Review Act. On February 9th, 2016, the US Supreme Court issued a stay pending resolution of the case by the DC Circuit. On March 28th, 2017, President Trump signed the Energy Independence Executive Order (Executive Order) which, among other things, directed EPA to review and, if appropriate, suspend, revise or rescind the CPP. Due in part to this development, EPA requested the DC Circuit hold the court case in abeyance and the DC Circuit has incrementally granted EPA's requests.

Affordable Clean Energy Rule

On October 16th, 2017 a notice of EPA's proposal to repeal the CPP was published in the Federal Register (FR). EPA proposed to repeal the CPP because it was premised on a novel and expansive view of EPA's authority which was inconsistent with the Clean Air Act (CAA). On August 21, 2018, EPA proposed the Affordable Clean Energy rule (ACER) which would establish emission guidelines to be used by States to develop plans to address GHG emissions from existing coal-fired EGUs. EPA released the final version of ACER on June 19th, 2019; it was published in the FR on July 8th, 2019 with an effective date of September 6th, 2019. EPA finalized three distinct rulemakings: repeal of the CPP; finalization of ACER; and, finalization of new regulations for implementation of ACER and any future emission guidelines issued under CAA section 111(d).

EPA Determined the Best System of Emissions Reduction (BSER) for existing coal-fired power plants to be heat rate efficiency improvements (HRI) based on a range of "candidate technologies" that can be applied inside the fence-line. States are to establish a unit-specific performance standard in the form of an allowable emission rate (i.e., lbs of CO2 per MWh-gross generation) by evaluating the HRI technologies while also considering remaining useful plant life, reasonableness of cost, prior installation/application of efficiency improvement technologies and other factors. States have three years from the date the final rule was published in the FR to submit a plan to EPA. If a State does not submit a plan or a submitted plan is not acceptable, EPA has two years to develop a federal plan. Compliance will generally begin two years following the date State plans are due (assuming EPA doesn't need to develop a federal plan) and if a compliance schedule extends past July of 2024, the State's plan must include enforceable incremental standards of performance.

It is expected that there will be legal challenges to the final rule. At this time, NorthWestern cannot predict how ACER may, or may not, affect resources in our portfolio and will be closely monitoring the status of ACER.

Carbon Cost Forecasting

Prior Resource Plans

The 2013 Plan considered carbon costs in the context of the information provided in the 2013 U.S. Energy Information Administration (EIA) Annual Energy Outlook and in advance of the EPA 111(d) proposed rules for existing CO_2 emitting sources. NorthWestern incorporated the carbon penalty forecast into our planning work as a proxy for the eventual form of greenhouse gas regulation implemented. In selecting the EIA GHG15 carbon case as the base carbon assumption, NorthWestern derived a base carbon pricing assumption of $21.11/ton starting in 2021 and escalating annually at 5% over the 20-year planning horizon and through 2043. For stochastic modeling purposes, the carbon price was varied above and below the annual base value according to a triangular distribution in recognition of the high degree of uncertainty associated with the carbon price variable and how it might actually materialize over time. One hundred iterations of the model were executed to create a distribution of total portfolio cost where carbon cost, like other stochastic variables such as electricity and natural gas price, varied above and below the starting value defined by the forecast schedule. Values never went below zero.
In its comments on the 2013 Plan, the PSC directed NorthWestern to make changes to our evaluation of future carbon costs. Specifically, the PSC requested the following: a more rigorous evaluation of potential CO_2 costs, evaluation of alternative CO_2 price trajectories, alternative ways of defining the CO_2 price distribution, and specific guidance on CO_2 from ETAC.

For the 2015 Plan, based on the PSC comments, NorthWestern did the following: (1) solicited input from ETAC about carbon costs and the use of a triangular distribution in stochastic simulations; (2) identified and considered additional sources of price forecasts for CO_2 and shared them with ETAC; (3) employed a base case carbon pricing assumption and two alternatives including a zero carbon cost case and a high carbon cost case in the 2015 Plan; and (4) completed portfolio simulations for the base capacity plan using all three carbon pricing trajectories.

Prior resource planning cycles recognized the EIA Annual Energy Outlook as a guiding source of carbon cost planning information. However, the 2015 EIA Annual Energy Outlook excluded projections of carbon prices. This left NorthWestern, and our advisory group to identify and select carbon cost estimates without the use of information from EIA. The following sources were reviewed to inform NorthWestern's 2015 Plan: CO_2 Price Report January 2016 (Synapse Energy Economics), PacifiCorp 2015 Integrated Resource Plan, Xcel Energy 2015 IRP (preferred portfolio), Puget Sound Energy 2015 IRP (low, mid, and high case), Portland General Electric 2015 Update.

2019 Plan Carbon Cost

NorthWestern is not including a carbon cost in the base case for the 2019 Plan. Instead, carbon is considered in a two separate scenarios. For the Carbon Cost portfolio, NorthWestern relies on the NEM Study conducted by Navigant Consulting. For the High Carbon Cost portfolio, NorthWestern relies on the carbon costs contained in the 2015 Plan, but with implementation delayed until 2025. The following sections describe the methodology and background behind Navigant's CO_2 price forecast.

Navigant's CO_2 Price Forecast

<u>Methodology</u>

Navigant produced its CO_2 price forecast using the proprietary Portfolio Optimization Model (POM) to simulate economic investment decisions and power plant dispatch. The model simultaneously performs least-cost optimization of the electric power system expansion and dispatch over multiple decades. POM can optimize based on a cost-minimization objective or on other considerations such as sustainability, technological innovation, or impacts on other sectors, such as natural gas. POM was used to determine the CO_2 prices that would result from a likely CO_2 emission reduction policy.

Assumptions

The two major assumptions used in Navigant's modeling were natural gas prices and capacity additions and retirements in the NWPP sub-region of WECC, in which the majority of Montana is located. Natural gas prices at the major gas hubs in NWPP were forecasted to be approximately $3.00 per MMBtu in 2017 and increase to between $5.00 and $6.00 per MMBtu by 2040. Resource additions in the region were assumed to consist of some near and mid-term natural gas combined-cycle capacity, substantial renewable resource additions, and generic simple-cycle capacity needed to maintain generation reserves. There were significant coal retirements assumed, driven primarily by the EPA's regional haze determinations, which would lead to significant reduction in CO_2 emissions.

CO_2 Policy

Navigant assumed a cap-and-trade policy that targets 28% reductions of CO_2 emissions from the power generation sector from 2005 levels in 2028, ramping up 1% each year to 50% in 2050. This cap-and-trade program would apply to the entire WECC region, except for California, whose current program targets getting to 1990 emission levels overall by 2020 and 80% below 1990 levels by 2050.

Results

Table 9-1 shows forecasted annual CO_2 prices through 2050; prices are shown in real 2016 dollars per short ton and nominal dollars per short ton. Nominal prices were determined using a 2% annual inflation rate based on a 20-year average inflation escalation for Gross Domestic Product, provided by the U.S. Bureau of Economic Analysis.

Table 9-1. Forecasts of CO_2 Prices

Year	CO2 Prices		High CO2 Prices	
	2016 Dollars ($/ton)	Nominal ($/ton)	2016 Dollars ($/ton)	Nominal ($/ton)
2019	-	-	-	-
2020	-	-	-	-
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	$16.74	$20.00
2026	-	-	$17.09	$20.83
2027	-	-	$17.44	$21.69
2028	$4.50	$5.71	$17.81	$22.59
2029	$5.50	$7.11	$18.19	$23.53
2030	$7.50	$9.90	$18.58	$24.51
2031	$8.50	$11.44	$18.97	$25.53
2032	$9.50	$13.04	$19.37	$26.59
2033	$10.50	$14.70	$19.78	$27.69
2034	$11.50	$16.42	$20.19	$28.84
2035	$12.00	$17.48	$20.61	$30.03
2036	$12.50	$18.57	$21.05	$31.28
2037	$14.00	$21.22	$21.50	$32.58
2038	$14.50	$22.42	$21.95	$33.93
2039	$15.00	$23.65	$22.41	$35.34
2040	$15.50	$24.93	$22.89	$36.81
2041	$17.15	$28.14	$23.36	$38.33
2042	$18.05	$30.21	$23.86	$39.92
2043	$18.95	$32.34	$24.36	$41.58
2044	$19.85	$34.55	$24.88	$43.31
2045	$20.74	$36.84	$25.40	$45.10
2046	$21.64	$39.20	$25.93	$46.97
2047	$22.54	$41.65	$26.48	$48.92
2048	$23.44	$44.17	$27.04	$50.95
2049	$24.34	$46.78	$27.61	$53.07
2050	$25.23	$49.84	$28.19	$55.27

High CO_2 Prices

Table 9-1 includes a second set of CO_2 costs labeled High CO_2 Prices. These CO_2 prices are derived from NorthWestern's 2015 resource plan, but the implementation of those costs has been delayed three years from that contained in the 2015 Plan. The higher CO_2 costs start sooner than the Navigant derived costs, are higher, and are consistent with a prior MPSC order. These costs are used in the High Carbon Cost portfolio (discussed in Chapter 10).

New Sources - Performance Standards for Carbon Emissions

In 2015, EPA finalized standards to limit carbon dioxide emissions from new, modified and reconstructed power plants. The Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units regulation. EPA used its authority under Section 111(b) of the Clean Air Act to set standards to limit CO_2 emissions for two types of fossil-fuel fired sources:

- Stationary Combustion Turbines (natural gas and oil fired, with provisions for other fuels)
- Steam Electric Generating Units (coal-fired, with provisions for other solid fuels)

EPA selected specific technologies representing the BSER for the two regulated source types above. Specifically related to this Plan is EPA's BSER for new Stationary CTs which is based on emissions of CO_2 achievable from a natural gas combined-cycle (NGCC) plant. The CO_2 emission standard is 1,000 lbs of CO_2 per gross MWh produced. There are exceptions if the CT serves a generator less than 25 MWs or the hours of operation are limited. In scenarios where CTs are included in the modeling inputs, hours of operation are restricted in order to comply with this regulation.

On April 4, 2017, pursuant to the aforementioned Executive Order, EPA announced it was reviewing and, if appropriate, would initiate proceedings to suspend, revise or rescind this regulation. On December 6, 2018 EPA proposed revisions to this regulation and is accepting comments through February 19, 2019. EPA is not proposing any changes to the performance standards for newly constructed or reconstructed stationary CTs, however they are taking comment regarding the increased use of simple cycle aeroderivative CTs, including as back-up generation for wind and solar resources, whose operation may exceed the non-base load threshold described in the 2015 rule. NorthWestern will monitor the status of EPA's proposed revisions and determine if any changes are necessary to the assumptions used for the modeled scenarios in this plan.

Summary of Key Colstrip Environmental Risks

Regional Haze Rule

The EPA's regional haze rule (RHR) finalized in 1999, requires states to develop and implement plans to improve visibility in certain national park and wilderness areas. On June 15, 2005, the EPA issued final amendments to its Regional Haze Rule. These amendments require emission controls known as the Best Available Retrofit Technology (BART) for emissions of certain pollutants that have the potential to impact visibility. These pollutants include fine particulate matter (PM), nitrogen oxides, sulfur dioxide, certain volatile organic compounds, and ammonia. States were given until December 2007 to develop state implementation plans (SIPs) to comply with the Regional Haze Rule. Montana did not develop a plan to comply, and EPA subsequently developed a Federal Implementation Plan (FIP) for Montana in September of 2012 to cover the first planning period (2008 – 2018). The FIP included requirements for upgrades to Colstrip Units 1 & 2 but did not include immediate requirements for Units 3 & 4.

States are expected to submit SIPs for the second planning period (2018-2028) no later than July 2021. If a state fails to submit a SIP by that time, EPA would again be responsible for publishing a FIP to ensure progress toward natural visibility conditions. At this time, the state of Montana plans to take the lead on all aspects of the RHR. Montana is planning on replacing the existing FIP with a SIP by incorporating the BART requirements into Montana state regulation. Montana is working toward submitting a SIP for the second planning period on an accelerated timeline by early 2020, if possible. It is likely that Colstrip Units 3 and 4 will undergo analysis to determine whether additional controls will be required. NorthWestern cannot predict how the results of this analysis may, or may not, affect Colstrip Units 3 and 4. For purposes of the Plan, we assume Colstrip Units 3 and 4 will not require additional material upgrades to comply with the RHR during the 20-year planning period of the Plan. Obviously, should Montana conclude Units 3 and 4 require material upgrades a detailed analysis would be required at that time.

Mercury and Air Toxics

The Mercury and Air Toxics Rule (MATS) became effective April 16, 2012. The MATS rule requires new and existing coal-fueled facilities achieve emissions standards for mercury, acid gases, and other hazardous pollutants. Measurements of filterable PM are used as a surrogate to determine compliance with the emissions standards for non-mercury metals. Existing sources were required to comply with the new standards by April 16, 2015. As allowed by the rule, the Colstrip facility requested a one-year extension to allow time for all units at Colstrip (1 through 4) to become compliant as a facility.

The Colstrip facility was in compliance with all MATS requirements from April of 2016 until June of 2018. In June of 2018, measurements of particulate matter were above allowable limits for Units 3 and 4; all other MATS requirements were in compliance. After extensive investigation, corrective actions were implemented and the units were tested and back in full operation in September of 2018. No additional actions or upgrades are anticipated at this time. Therefore, for this Plan we assume there will be no additional material upgrades required for compliance with the MATS rule.

Coal Combustion Residuals

Coal Combustion Residuals (CCRs) including coal ash, are byproducts from the combustion of coal in power plants. The EPA issued a final rule in April of 2015 to regulate CCRs as a nonhazardous waste under Subtitle D of Resource Conservation and Recovery Act and establish minimum nationwide standards for the disposal of coal combustion residuals.

The Colstrip facility is complying with the CCR rule and the operator is implementing required actions. See the discussion below regarding wastewater.

National Ambient Air Quality Standards (NAAQS)

The Clean Air Act sets allowable ambient air quality standards for six "criteria" pollutants. The rule requires periodic review of the science used to establish the standards and the standards themselves. With each review, the standards are compared to ambient air quality in each state or part of each state to determine if the state or part of each state is in "attainment" or "non-attainment." If a state contains any areas of "non-attainment", the state must propose a plan and schedule to reduce emissions to achieve attainment.

Currently, the Colstrip area of Montana is in attainment for all criteria pollutants. Further reductions in emissions resulting from compliance with MATs are expected to keep the Colstrip area in attainment with future NAAQS reviews/revisions. NorthWestern does not expect additional material cost impacts related to NAAQS compliance. Therefore, we did not include any additional costs related to NAAQS compliance in our modeling scenarios.

Wastewater

In August 2012, Talen Energy (Talen) (the Colstrip Plant Operator) and the Montana Department of Environmental Quality (MDEQ) signed an Administrative Order on Consent Regarding Impacts from Wastewater Facilities (AOC). The AOC sets up a comprehensive program for investigation, interim response, remediation and closure of the holding ponds and covers the same facilities required to comply with the CCR rule. Talen is implementing AOC requirements as they are approved by MDEQ. NorthWestern's share of the capital and financial assurance costs associated with the AOC were incorporated in the cost structure for Colstrip in this Plan.

CHAPTER 10
PORTFOLIO MODELING

NorthWestern's Portfolio Modeling

Overview

NorthWestern uses PowerSimm™, a modeling and simulation software tool, to analyze the performance of different energy supply portfolios under a wide range of possible future conditions. PowerSimm models the variability of key factors like weather, electric load, renewable generation, and gas and electricity market prices and their associated impacts on power costs, and the optimal dispatch of the resources in NorthWestern's energy supply portfolio. These analyses are performed at an hourly time-step, which provides insight into the unique operating characteristics of renewable resources and the flexibility of dispatchable resources to respond optimally, and rapidly, to changing market conditions. Portfolio model runs are summarized by aggregating their costs across many simulations to produce a measure of their levelized, risk-adjusted, net present value of revenue requirements and their estimated carbon dioxide emissions by resource (measured in pounds of CO_2 per MWh).

Portfolio Modeling Platform

NorthWestern uses the PowerSimm™ modeling platform developed by Ascend Analytics to assess various resource portfolios. The PowerSimm platform consists of multiple modules.

Automatic Resource Selection

The Automatic Resource Selection (ARS) module identifies resources that perform best across a wide range of modeled conditions and could be used to best serve our customers' future resource needs (a more detailed description of PowerSimm's ARS module can be found in Volume 2, Chapter 10). NorthWestern cannot predict all resources or combinations of resources that may be proposed during a competitive solicitation process, or which may be offered for opportunity purchase. Therefore, modeling is limited to resources with known and measureable operating characteristics in order to provide insight about resources that could potentially serve customers in the future. The list of resources considered for ARS is limited to those identified in Chapter 7, Figures 7-6 and 7-7. However, the set of candidate resources evaluated in the portfolio analyses is in no way meant to exclude other technologies or resource types from receiving a full and fair evaluation during any future competitive solicitation processes.

Resource planning involves a trade-off between long-term capital investment decisions and variable operating costs; the 'best' resource (or combination of resources, if multiple resources perform better than one) is typically one that minimizes the net present value of the revenue requirement, which includes the recovery of capital expenditures and fixed and variable costs.

ARS uses overnight capital costs[1], expected revenues, and both fixed and variable O&M costs to calculate a levelized annual revenue requirement for each portfolio that is modeled. The analysis also accounts for the residual value of capital investments that are not fully amortized over the planning horizon. These calculations are dependent on general

[1] Overnight cost is the cost of a construction project if no interest was incurred during construction, as if the project was completed "overnight."

economic assumptions including inflation rates, relevant tax rates, NorthWestern's weighted average cost of capital (WACC), and the depreciation life of the resource.

ARS analysis seeks a resource portfolio that minimizes the net present value of capital expenditures and production costs, subject to constraints. The model must be constrained so that it produces realistic results. Constraints include limits on market sales and purchases of energy and capacity, and reserve margin requirements. Constraints can be defined to vary over the planning horizon to reflect changing market conditions or other factors, such as the requirements to participate in an organized market.

For this Plan, the ARS analysis included the following constraints.

- Resource additions were limited to about 200 MW per year.[2] This constraint prevents ARS from selecting an unrealistically aggressive build-out of new resources to achieve NorthWestern's reserve margin in the first year, but it allows the achievement of the targeted 16% reserve margin by 2025. However, this modeling constraint does not mean NorthWestern would decline to take advantage of cost-effective resources above the 200 MW limit if such resources are bid during a competitive solicitation process.
- No new resources are placed in service prior to 2022. This restriction reflects the required timeline to file the 2019 Plan, conduct a competitive solicitation, negotiate contracts, and allow time for construction of a new resource, should a new resource win a competitive solicitation.
- Market sales were constrained to no more than 10% over annual customer load. This restriction prevents the model from overbuilding resources for the express purpose

[2] As explained in Chapter 5, NorthWestern will be joining the EIM in 2021 and assumes entry into an RTO by 2025. The 200 MW/year limitation allows NorthWestern to reach a 16% reserve margin by 2025. This constraint will be subject to ongoing review.

of selling energy into the market. The quantity of intermittent resources already in NorthWestern's portfolio puts NorthWestern in the position of being long on energy (i.e., resources are generating more energy than our customers can use because we don't control the output of the intermittent resources), and therefore forced to sell energy to the market, often at times when prices are lower than the price we must pay for the energy from the intermittent resources. However, the use of this modeling constraint does not mean NorthWestern would decline to evaluate a resource that pushed sales over the 10% threshold, should such a resource be bid during a competitive solicitation and is cost effective.

Figure 10-1 shows the ARS peak capacity additions by year for each portfolio except the Short Term Current and Short Term Base portfolios. The chart shows that constrained ARS adds approximately the same quantity of peaking capacity to each portfolio throughout the planning horizon. Detailed tables showing resource additions by portfolio and year are included in Volume 2, Chapter 10. Unconstrained portfolio was excluded from this chart due to its unrealistic schedule of buildout. The 15-year Short Term Base was excluded because the 15 year portfolios are not comparable to the 20 year portfolios.

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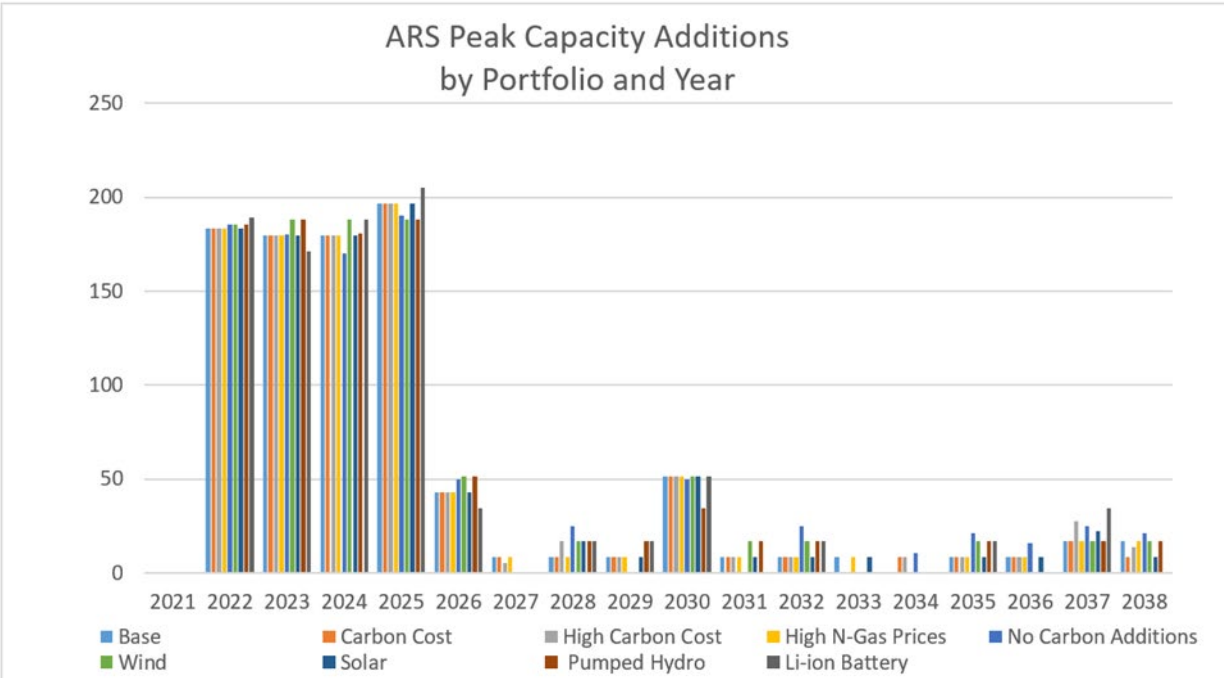
Figure 10-1. ARS Peak Capacity Additions by Portfolio and Year



PowerSimm Hourly Model

PowerSimm explicitly models the impacts that variations of load, market prices, weather conditions and renewable generation have on the performance of different resource portfolio scenarios. PowerSimm's model is stochastic[3], which means that each key variable in the model (e.g., market prices, weather, load, renewable generation, etc.) varies

[3] Stochastic simulation methods capture key short- and long-term uncertainties that are fundamental to estimating fuel prices, market electricity prices, generating plant outages, production from renewable energy resources, and hydrological conditions. Stochastic analysis enables the model to explicitly capture the impact that uncertainty in key variables can have on the expected value (and likely range of values) for each portfolio.

according to the underlying statistical distributions of each variable and the expected correlations[4] between variables.

The PowerSimm model begins by generating weather simulations. Weather is modeled as the key driver of electric load, wind, solar and hydro generation, and spot gas prices. Spot prices for electricity are then determined as a function of these variables. Based on the simulations of these variables, PowerSimm then determines the economically-optimal hourly generation from NorthWestern's dispatchable resource fleet to find a cost-optimized dispatch schedule for each resource portfolio scenario. The use of stochastic analysis allows NorthWestern to examine how a portfolio may perform under a wide range of potential conditions. Each portfolio scenario undergoes 100 simulations, each one representing 20 years of hourly analysis and each representing a unique combination of weather, prices, loads, and renewable resource production.

Simulation Inputs

The following key types of historical data are used to model future conditions and the performance of different energy supply portfolios:

- Historical weather data (daily minimum and maximum dry bulb temperatures),
- Historical load data (both NorthWestern's load and WECC-wide load),
- Historical generation data from NorthWestern's wind, hydro, and solar resources,
- Historical power prices at the Mid-Columbia trading hub (Mid-C), and
- Historical natural gas prices at the Alberta Energy Company (AECO) trading hub.

[4] Correlation means the mutual relationship or connection between two or more things; the interdependence of two or more variables. The expected correlations between PowerSimm variables are determined through an analysis of historical relationships and observed trends.

In addition to the data sources named above, PowerSimm includes the following projections:

- **Forward price curves for electricity.** The price curves are based on a 15 calendar day average of monthly Intercontinental Exchange (ICE) forward prices for Peak and Off-Peak periods at Mid-C through 2021 until the markets are illiquid; heat rate projections based on a fundamental modeling approach that takes into account structural changes associated with the increasing penetration of variable renewable resources in the WECC[5]; and, assumptions that long-term equilibrium prices will be effectively bounded by the marginal cost of a new capacity resource[6].
- **Forward price curves for natural gas.** These are based on a 15 calendar day average of monthly Natural Gas Exchange (NGX) forward prices for the AECO hub through 2021, after which prices are escalated using the EIA's 2018 annual escalation rates for natural gas at Henry Hub.
- **Hourly price shapes.** These are projected forward using an analysis of the fundamentals of the WECC generation mix and the expected trend of increasing penetration of variable renewable resources and announced retirements of thermal resources.
- **Spot price volatility.** This is projected forward based on the observed relationship between levels of variable renewable resources and observed price volatility. Spot price volatility is expected to continue increasing as more renewable resources come online, but is assumed to slow after 2030.

[5] See *Ascend Analytics – WECC Market Outlook and Modeling* included in Volume 2 of this plan.

[6] For more analysis on future market prices and the effects of increasing variable renewable generation, see Berkley Lab's *Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making,* https://emp.lbl.gov/publications/impacts-high-variable-renewable

Evaluating Risk Premium

By simulating the performance of a resource portfolio under a wide range of possible future conditions, different portfolios can be compared based on "expected" (i.e., average) cost across all future conditions considered, as well as the uncertainty of possible costs. The uncertainty reflected in the estimated economic values and costs for different portfolios can be compared by estimating the likelihood that future conditions may result in a portfolio being extremely costly. This is measured by a portfolio's "risk premium," which is the difference between (a) the probability-weighted average of the estimated costs for each portfolio above the median cost and (b) the median cost. The risk premium for each portfolio is added to the portfolio's estimated cost, effectively "penalizing" riskier portfolios relative to less risky ones. Combining cost and risk into one value allows for a simple comparison of costs and risks associated with portfolio scenarios.

Loss of Load Probability

A foundational goal of resource planning is to ensure that there is a sufficient amount of energy and capacity to serve the load at all times. Reliability can be examined by determining the expected LOLP for each portfolio. Ascend calculates the annual LOLP for each portfolio scenario over the entire planning horizon based on stochastic simulation of weather, load, renewable and thermal generation, and unplanned outages for thermal resources. Simulation results are compared to generation capacity and firm power contracts available in each hour. A loss of load occurs during the hours in which load requirements exceed available capacity (known as "loss of load hours" or LOLH). LOLHs are calculated based only on the generation assets and firm contracts in a portfolio. This calculation does not include day-ahead or real-time market purchases. LOLP is calculated as the percentage of hours in which a loss of load occurs. The resulting estimated LOLPs for each portfolio and each year can then be used to determine how much additional capacity might be needed to meet reliability targets. NERC uses a standard of no more than one day in ten years for the probability of a loss-of-load (equivalent to a LOLP of 0.0274%, or 2.4 hours per year).[7]

Ancillary Services

The need for ancillary services[8] in each portfolio is based on the relationship between the minute-to-minute variations in NorthWestern's historical load and generation available from variable renewable resources on the system. The simulation determines how much of the variation in load can be met with resources which can respond within 10 to 15 minutes to increase or decrease their output (i.e. INC or DEC resources), and how much must be met with more expensive regulation resources that can increase or decrease output moment to moment. Ancillary service needs for each portfolio are determined by scaling this relationship to the amount and type of renewable resources in the portfolio in each year.

Structural Relationships between Input Variables

PowerSimm preserves many important correlations and structural relationships historically observed between key input variables. For example, weather conditions drive electric load. Thus, PowerSimm's simulation engine is based on the assumption that the historically observed relationship between loads and temperatures is a good representation of the likely future relationship between loads and temperatures. The same is true for the relationship between weather and wind generation, solar generation, and hydro generation.

[7] Note that LOLP can be expressed in a variety of ways, including as a percentage of time, as the number of expected hours per year with a loss of load, or the amount of capacity (MW) short per year.

[8] Ancillary services are those necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system. See Chapter 3 for a complete description.

PowerSimm does not assume that historical electricity price patterns continue unchanged because price levels and price variability have both changed in recent years. This change is attributable to the growing penetration of variable renewable resources. Based on numerous analyses of power systems across the country and in the WECC, Ascend Analytics (the developer of PowerSimm) expects the continued development of renewable resources, which will continue to put downward pressure on energy prices (since they have zero variable cost) in the WECC and increase the volatility of energy prices. Ascend anticipates these trends will continue in the WECC, therefore PowerSimm simulations are based on assumptions of decreasing average prices (and, thus, decreasing implied market heat rates) and increasing price volatility. Ascend also anticipates continuing changes in the daily price shape, which is now driven by net load. Net load is gross loads minus generation from renewables.

Carbon Costs

Two separate carbon scenarios are considered in the 2019 Plan. For the base carbon scenario, NorthWestern relied on the carbon costs included in the NEM Study conducted by Navigant Consulting. For the High-cost carbon price scenario, NorthWestern relied upon the carbon price forecast from the 2015 Plan, but delayed implementation by three years.[9]

Modeled Resource Portfolios

Even though resource acquisition will be based on a competitive proposal solicitation process or, in the case of opportunity resources, in a manner consistent with resource planning methodologies, NorthWestern is required to identify an optimal resource mix

[9] The development of carbon costs is discussed in Chapter 9.

given the goals and objectives of the resource planning guidelines (ARM 38.5.82213, 1(h)). In past resource plans, resource portfolios provided varying degrees of resource adequacy, or reserve margins. The result was that comparison of cost between different portfolios was not possible (because they achieved different degrees of resource adequacy). In the 2019 Plan, NorthWestern uses the ARS module to add resources to achieve the same level of resource adequacy for each portfolio, which allows for an "apples-to-apples" comparison between portfolios.[10] Table 10-1 lists the assumptions for each portfolio modeled in the 2019 Plan and a short description of each portfolio follows the table. All of the portfolios are modeled with the same assumptions and constraints, which are described on pages 10-1 to 10-8, unless explicitly stated otherwise in the description of each portfolio. The candidate resources available for selection in each portfolio are the same across all portfolios (which are described in Chapter 7 and listed, along with their estimated costs, in Figures 7-6 and 7-7).

(Remaining page blank for table.)

[10] Each portfolio except the Current portfolio.

Table 10-1. Resource Portfolios and Assumptions[11]

Resource Portfolio	Portfolio Assumptions
Current	• 20 year planning horizon • Life cycle capital cost recovery • No carbon cost • N-gas forward market prices based upon forward market prices and EIA-AEO Henry Hub escalation • Forward market electricity prices with declining market heat rates and increased volatility
Unconstrained Expansion	**Current,** with unconstrained ARS
Base	**Current,** with constrained ARS
Pumped Hydro	**Current**, 100 MW pumped hydro storage, constrained ARS
Wind	**Current**, plus 210 MW wind, constrained ARS
Solar PV	**Current**, plus 210 MW solar PV, constrained ARS
Li-Ion Battery	**Current**, 105 MW Li-Ion battery storage, constrained ARS
Carbon Cost	**Base**, with carbon cost adder
High Carbon Cost	**Base**, with high carbon costs
High Natural Gas Prices	**Base**, with high natural gas prices
No Carbon Additions	**Current,** with constrained ARS, limited to non-carbon producing resources
Short Term Current	**Current**, but with 15 year planning horizon and • 15 year planning horizon • 15 year capital cost recovery
Short Term Base	**Short Term Current,** with constrained ARS

[11] All portfolios are modeled using the same candidate resource additions and the same assumptions and constraints, as described on pages 10-2 to 10-4, with the exception that the Unconstrained Expansion portfolio does not include the constraint that limits resource additions to about 200 MW per year. The remaining portfolios use a "constrained ARS" that limits resource additions to about 200 MW per year, along with the other constraints that are used for all portfolios. Refer to pages 10-2 to 10-4.

Current: This portfolio models the resource portfolio as it currently exists and does not add any new resources to the portfolio. Natural gas prices are based on forward natural gas prices and 2018 AEO escalation. Forward electric market prices reflect declining market heat rates and increased price volatility. Additionally, the Current portfolio does not include an explicit carbon cost adder. NorthWestern Energy is continuing our use of a 20-year planning horizon and a life-cycle approach to capital cost recovery in the 2019 Plan.[12] The Current portfolio serves as the base for all other portfolios.

Unconstrained Expansion: This portfolio is based upon the Current portfolio assumptions and adds new resources using an ARS analysis that includes no constraints on the timing of resource additions to achieve a 16% reserve margin. The remaining portfolios described below include an annual constraint that limits the quantity of new resources that may be added each year to around 200 MW to reflect the realities of building new resources. However, this modeling constraint does not mean NorthWestern would decline to take advantage of cost-effective resources above the 200 MW limit if such resources are bid into a competitive solicitation.

Base: This portfolio is based upon the Current portfolio assumptions and adds new resources to the portfolio using constrained ARS analysis. Constrained ARS analysis adds about 200 MW of capacity (peaking contribution) per year from 2022 through 2025 to achieve a 16% reserve margin.

[12] The Default Electricity Supplier Procurement Guidelines define "planning horizon" as the longer of the longest remaining contract in the portfolio, the longest lived resource being considered, or ten years; Admin R. Mont. 38.5.8202.

Pumped Hydro: This portfolio is based upon the Current portfolio assumptions and adds 100 MW of pumped hydro in 2026.[13] After pumped hydro, additional resources were selected using constrained ARS analysis.

Wind: This portfolio is based upon the Current portfolio assumptions and adds 210 MW of wind in 2022. After wind is added, additional resources were selected using constrained ARS analysis.

Solar: This portfolio is based upon the Current portfolio assumptions and adds 210 MWs of solar PV in 2022. After solar was added to the portfolio, additional resources were selected using constrained ARS analysis.

Li-Ion: This portfolio is based upon the Current portfolio assumptions and adds 105 MWs of Li-ion batteries in 2022. After Li-ion batteries were added to the portfolio, additional resources were selected using constrained ARS analysis.

Carbon Cost: This portfolio includes all the assumptions of the Base portfolio and adds carbon costs. As in the Base portfolio, resources were added to the portfolio using constrained ARS analysis.

High Carbon Cost: This portfolio includes all the assumptions of the Base portfolio and increases the cost of carbon above those contained in the Carbon Cost analysis. As in the Base portfolio, resources were added to the portfolio using constrained ARS analysis.

[13] 2026 is assumed to be the first year that a pumped hydro facility could be in-service following the filing of this plan and allowing time for a competitive solicitation process and construction of the resource.

High Natural Gas Prices: This portfolio includes all the assumptions of the Base portfolio except natural gas prices are escalated at 150% of the Base case escalation. As in the Base portfolio, resources were added to the portfolio using constrained ARS analysis.

No Carbon Additions: This portfolio is based on the Current portfolio, but ARS analysis was limited to the selection of non-carbon producing resources. As in the Base portfolio, resources were added to the portfolio using constrained ARS analysis, but in this portfolio the analysis is limited to the selection of non-carbon producing resources.

Short Term Current: The Commission's comments requested a 15 year planning horizon, and two portfolios are based on a shortened 15 year analysis. This portfolio is based on the Current portfolio, but the planning horizon is limited to 15 years.

Short Term Base: This portfolio includes the assumptions of the Short Term Current portfolio, but includes a 15-year capital cost recovery for new resources selected by constrained ARS analysis.

PowerSimm Modeling and Results of Analysis

The resource portfolios listed in Table 10-1 were modeled using the PowerSimm hourly model described earlier in this chapter. The results are presented in tables showing resource additions, and in graphical form showing the net present value (NPV) of the revenue requirement of each portfolio and the associated carbon intensity. Most portfolios shown add resources using ARS analysis to achieve a 16% reserve margin. The exceptions are the Current and Current Short Term portfolios, which do not achieve a reserve margin and are not comparable to other portfolios. Additionally, the short term portfolios are not comparable to longer term portfolios, short term portfolios are an NPV of 15 years of revenue requirement while longer term portfolios are an NPV of 20 years of revenue requirement.

Current, Unconstrained Expansion, and Base Portfolios

Table 10-2 and Figure 10-2 show PowerSimm modeling results for the Current, Unconstrained, and Base portfolios. As previously mentioned, the Current portfolio is not comparable to other portfolios because it does not add new resources or achieve resource adequacy. Using an unconstrained ARS process, the analysis adds 716 MW of thermal resources in 2022 with a total of about 930 MW of thermal over the 20 year planning horizon. This rate of resource acquisition is unrealistic. ARS for the Base portfolio was constrained and adds 193 MW of thermal resources in 2022, 189 MW of thermal resources in 2023, 189 MW of thermal resources in 2024, 207 MW of thermal resources in 2025 (778 MW in four years), and a total of about 985 MW of thermal resources over the 20 year planning horizon.

Table 10-2. Unconstrained and Base Portfolios - ARS Resource Selection

Resource	Portfolio		
	Current (MW)	Unconstrained Expansion (MW)	Base (MW)
105 MW Solar	0	0	0
105 MW Wind	0	0	0
100 MW Pumped Hydro	0	0	0
26.3 MW Li-ion Battery	0	0	0
25 MW Aero	0	525	0
18 MW Rice	0	162	738
9 MW Rice	0	180	189
19.4 MW Rice - DGGS	0	58.2	58.2
Total Additions:*	0	925.2	985.2

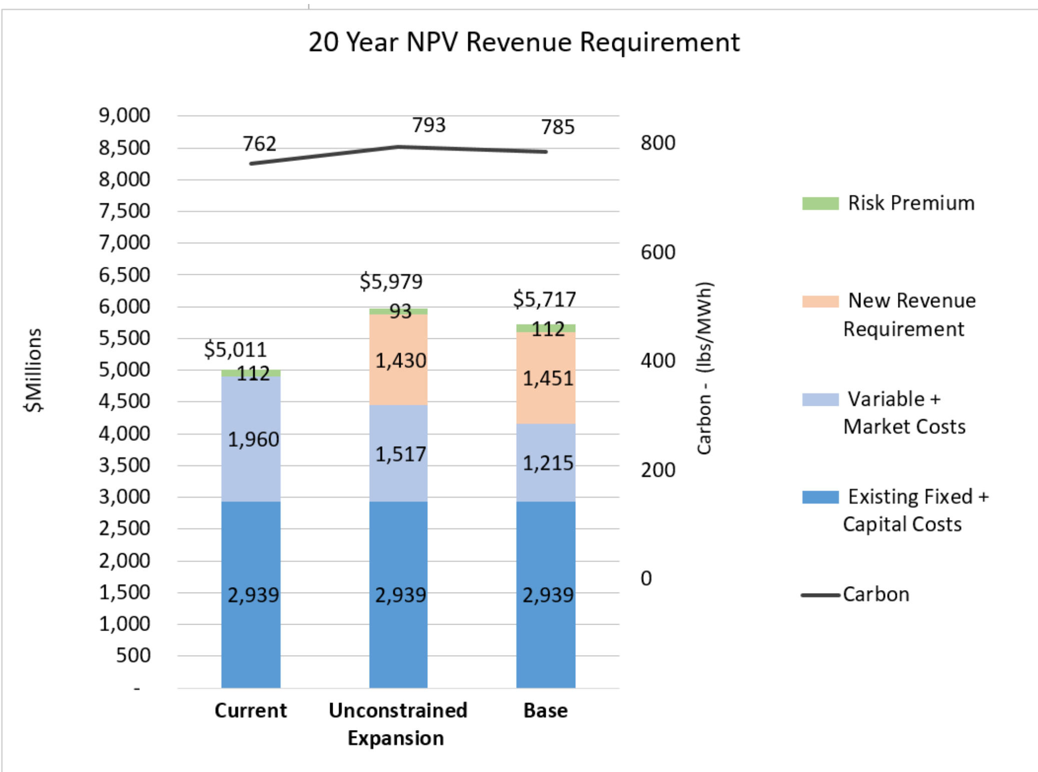
* Portfolio additions over 20 year planning horizon

The ARS analysis in this Plan generally selects natural gas fired thermal generation. However, no one reading this plan should jump to the conclusion that NorthWestern is planning to acquire natural gas fired generation without first testing the market and soliciting proposals for resources (existing and new build) capable of reliably serving our customers' needs at lower cost. For a further discussion of NorthWestern's resource additions strategy, please see Chapter 13.

As shown in Figure 10-2, compared to the Current portfolio the Base portfolio adds about \$1.4 billion of capital investment and fixed O&M costs to the portfolio while reducing variable and market costs by about \$745 million. The risk-adjusted NPV revenue requirement of the Unconstrained Expansion portfolio is about \$262 million higher than the Base portfolio. The average annual carbon intensity (lbs of CO_2/MWh) of each portfolio is represented by the black line and increases due to the additional thermal resources ARS adds to the resource portfolio.

(Remaining page blank for figure.)

Figure 10-2. Net Present Value Revenue Requirement for Current, Unconstrained, and Base Portfolios



Base, Pumped Hydro, Wind, Solar PV and Li-ion Battery Portfolios

Table 10-3 and Figure 10-3 show PowerSimm modeling results for the Base, Pumped Hydro, Wind, Solar PV and Li-ion Battery portfolios. ARS analysis for the Base portfolio did not select wind, solar PV, pumped hydro, or Li-ion battery technologies, even when low-cost futures for wind, solar PV, and Li-ion (see Figure 7-2) were included for selection in the ARS model.

For the Pumped Hydro portfolio, 100 MW of generic pumped hydro storage was added to the resource portfolio in 2024. The remainder of the resource portfolio was then selected using ARS. The 100 MW pumped hydro addition offsets about 100 MW of thermal resources, but 210 MW of additional wind is also selected because pumped hydro doesn't provide for customers' energy needs. The Pumped Hydro portfolio has a lower carbon intensity than the Base portfolio (716 lbs/MWh vs. 785 lbs/MWh) but the risk-adjusted NPV is $206 million more than Base.

Table 10-3. Base, Pumped Hydro, Wind, Solar PV, and Li-ion Portfolios ARS Resource Selection

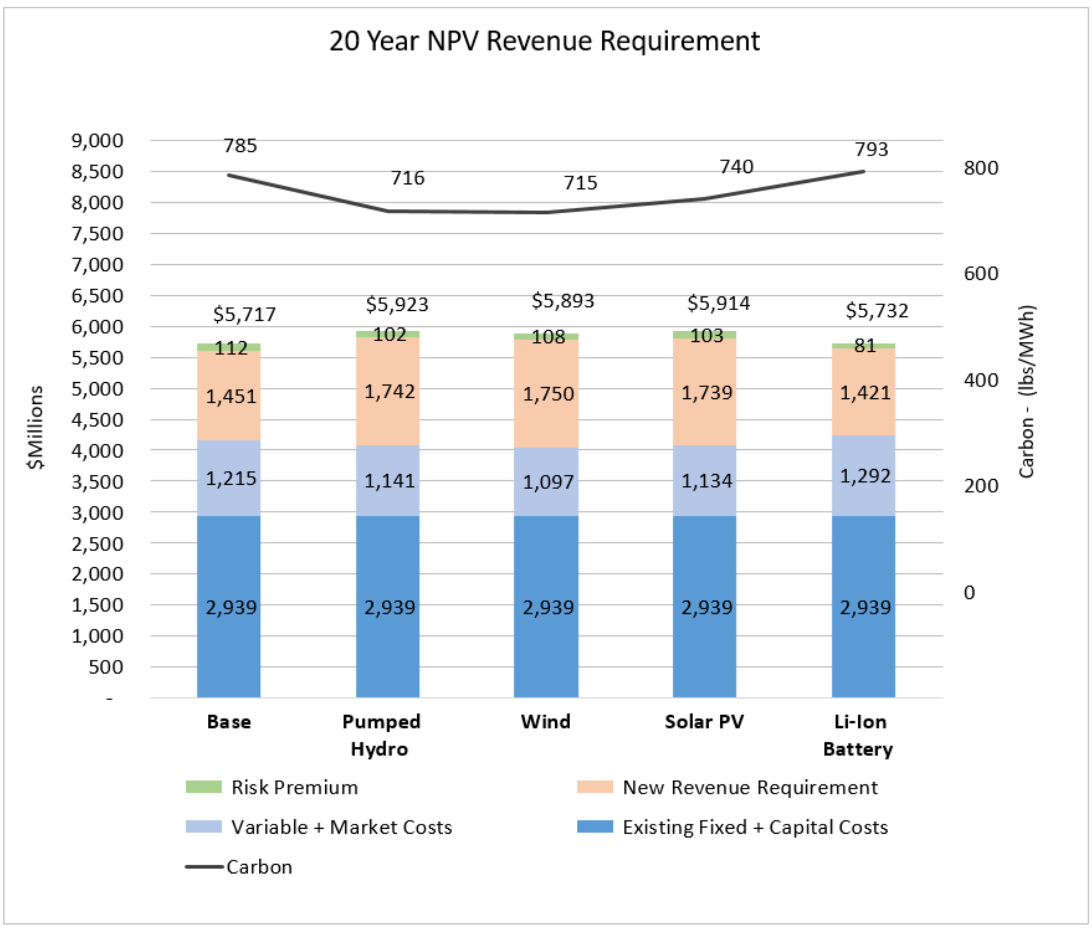
Resource	Portfolio Base (MW)	Pumped Hydro (MW)	Wind (MW)	Solar (MW)	Li-ion Battery (MW)
105 MW Solar	0	0	0	210	0
105 MW Wind	0	210	210	105	0
100 MW Pumped Hydro	0	100	0	0	0
26.3 MW Li-ion Battery	0	0	0	0	105.2
18 MW Rice	738	828	936	720	828
9 MW Rice	189	0	0	198	0
19.4 MW Rice - DGGS	58.2	58.2	58.2	58.2	58.2
Total Additions:*	985.2	1196.2	1204.2	1291.2	991.4
*Portfolio additions over 20 year planning horizon.					

In the Wind portfolio, 210 MW of wind was added to the resource portfolio in 2022. The remainder of the resource portfolio was then selected using ARS. Because of its low capacity contribution during peak load hours, 210 MW of wind does not offset the capacity required from thermal generation resources. The Wind portfolio does have a lower carbon intensity than the Base portfolio (715 lbs/MWh vs. 785 lbs/MWh) because the energy from wind generation offsets some energy from thermal generation, but the risk-adjusted NPV is $176 million more than Base.

In the Solar PV portfolio, 210 MW of solar PV was added to the resource portfolio in 2022. The remainder of the resource portfolio was then selected using ARS. Because solar PV does not contribute to the capacity required during NorthWestern's winter peak load hours, Solar PV does not offset any of the thermal resources. The Solar PV portfolio has a lower carbon intensity than the Base portfolio (740 lbs/MWh vs. 785 lbs/MWh) but the risk-adjusted NPV is $197 million more.

For the Li-ion Battery portfolio, 105 MW of Li-ion battery storage is added to the resource portfolio in 2022. The remainder of the resource portfolio was then selected using ARS. The addition of 105 MW of Li-ion battery storage offsets 90 MW of the thermal resources selected from 2022 to 2025 in the Base portfolio. The Li-ion Battery portfolio has a higher carbon intensity than the Base portfolio (793 lbs/MWh vs. 785 lbs/MWh) and the risk-adjusted NPV is $15 million more.

Figure 10-3. Net Present Value Revenue Requirement for Base, Pumped Hydro, Wind, Solar, and Li-ion Battery Portfolios



Base, Carbon Cost, High Carbon Cost, and High Natural Gas Prices, No Carbon Additions Portfolios

Table 10-4 and Figure 10-4 show PowerSimm modeling results for the Base, Carbon Cost, High Carbon Cost, High Natural Gas Prices, and No Carbon Additions portfolios. The Base portfolio has been included for comparison and is discussed above. The remaining portfolios in this section are scenarios designed to test resource selection under various futures (or scenarios). The Carbon Cost scenario tests the selection of resources when a cost for carbon is included in the analysis.[14] The High Carbon Cost scenario tests the selection of resources at a higher carbon cost. The High Natural Gas Costs scenario tests whether high gas costs affect resource selection. Lastly, the No New Carbon scenario explores what resources are selected if ARS analysis is limited to the selection of non-carbon producing resources.

The results of ARS selection are shown in Table 10-4. The addition of a carbon cost does little to affect thermal resource selection in the Carbon Cost, High Carbon Cost, and High Natural Gas Prices scenarios. However, the High Carbon Cost scenario adds 420 MW of wind resources over the 20 year planning horizon. The High Natural Gas Prices scenario had no effect on resource selection.

(Remaining page blank for table.)

[14] The development of the carbon cost is discussed in Chapter 9.

Table 10-4. ARS Selection Under Various Conditions

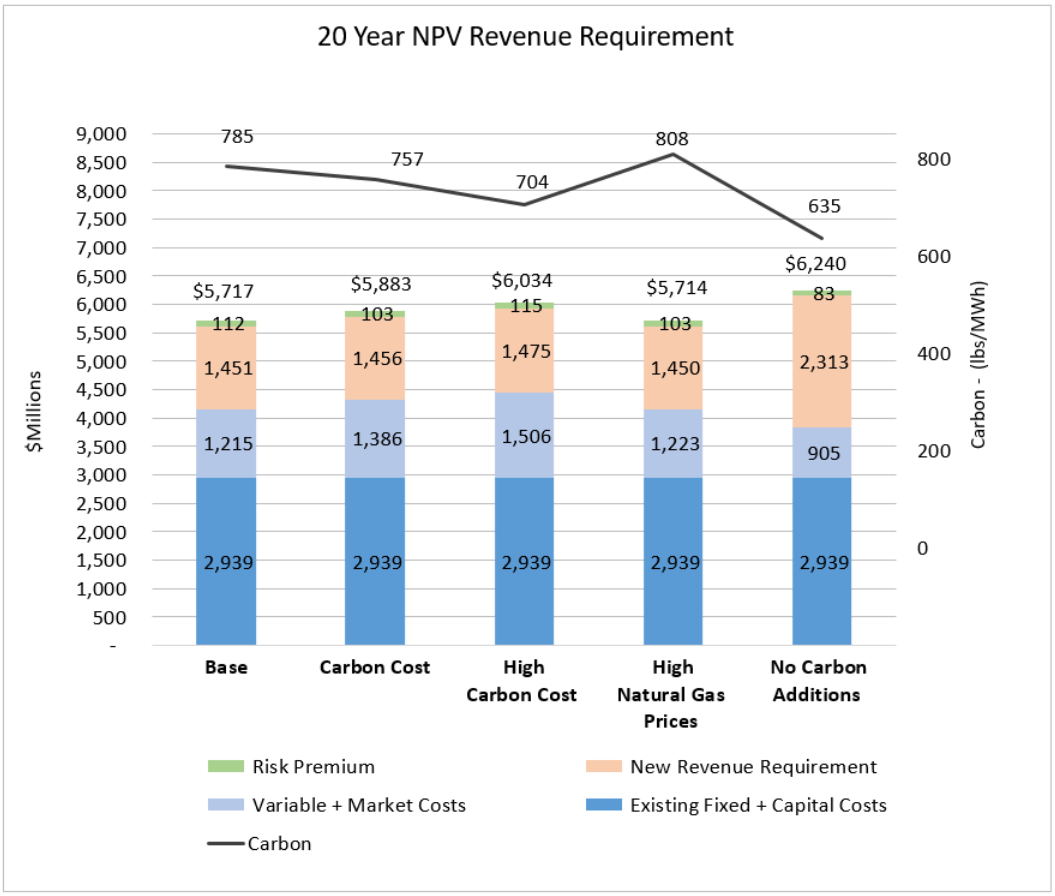
Resource	Portfolio				
	Base (MW)	Carbon Cost (MW)	High Carbon Cost (MW)	High Natural Gas Prices (MW)	No Carbon Additions (MW)
105 MW Wind	0	0	420	0	1680
100 MW Pumped Hydro	0	0	0	0	300
26.3 MW Li-ion Battery	0	0	0	0	631.2
18 MW Rice	738	702	756	738	0
9 MW Rice	189	216	162	189	0
19.4 MW Rice - DGGS	58.2	58.2	58.2	58.2	0
Total Additions:*	985.2	976.2	1396.2	985.2	2611.2

* Portfolio additions over 20 year planning horizon

The No Carbon Additions scenario does result in a significant change in the resources selected in ARS analysis. When thermal generation is excluded, the ARS selects 1,680 MW of wind, 300 MW of pumped hydro, and 631 MW of Li-ion batteries. The carbon intensity is lower (635 lbs/MWh vs. 785 lbs/MWh), but at a significant cost. As shown in Figure 10-4 below, the risk-adjusted NPV of the No Carbon Additions is $523 million more than that of the Base portfolio.

Other significant non-quantified costs are incurred with a No Carbon Additions scenario. For example, the footprint of nearly 1,700 MW of wind is estimated to be 300 to 350 square miles. Siting that much wind in Montana could be problematic and the NPV costs do not include any infrastructure costs, such as upgrades and additions to the electric transmission system, which would be required to add that much wind to the system. One of the largest Li-ion battery installation in the US is a 30 MW/120MWh facility. 631 MW of Li-ion batteries would require over 20 similar sized facilities, each requiring about 1.5 acres. Lastly, the 300 MW of Pumped Hydro that ARS selected does not include any potential transmission upgrade costs that may be required.

Figure 10-4. Net Present Value Revenue Requirement for Base, Carbon Cost, High Carbon Cost, High Natural Gas Prices, and No Carbon Additions Portfolios

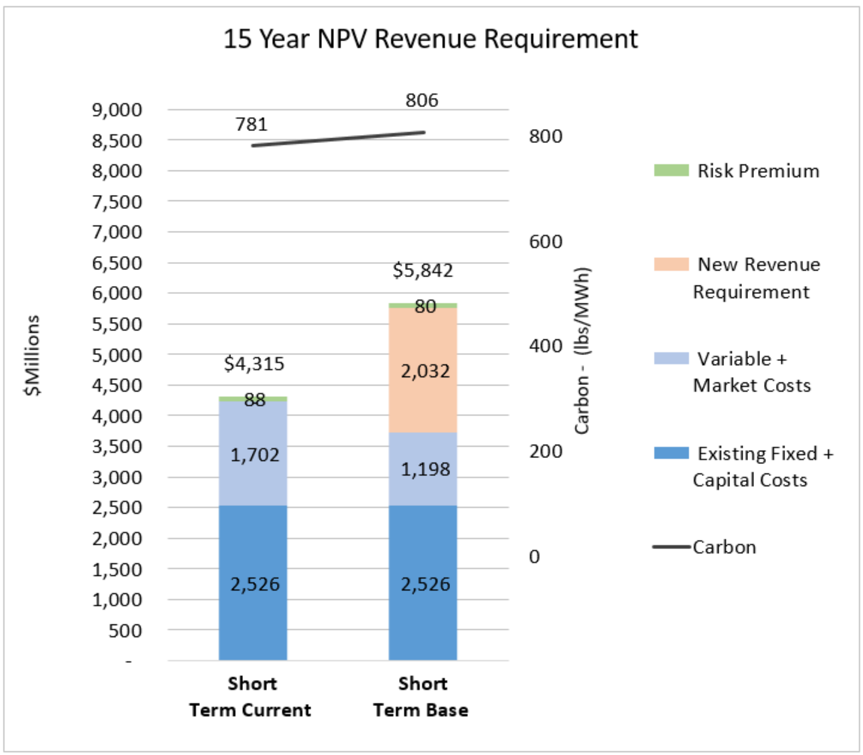


The Carbon Cost, High Carbon Cost, and High Natural Gas portfolios test the resource selection of the ARS under Base portfolio assumptions. The Base, Carbon Cost and High Natural Gas portfolios all add similar amounts of natural gas fired resources to the portfolio. The High Carbon Cost portfolio selects a little less natural gas and also selects some wind. The Carbon Cost NPV is about $166 million more than the Base portfolio, the High Carbon Cost NPV is about $317 million more than the Base portfolio, and the High Natural Gas NPV is about $3 million less than the Base portfolio.

Short Term Current and Short Term Base Portfolios

Figure 10-5 shows PowerSimm modeling results for the Short Term Current and Short Term Base portfolios. The Short Term Base portfolio has the lowest NPV revenue requirement, but has the highest rate impact. As stated earlier, the 15 year portfolios are not comparable to the 20 year portfolios.

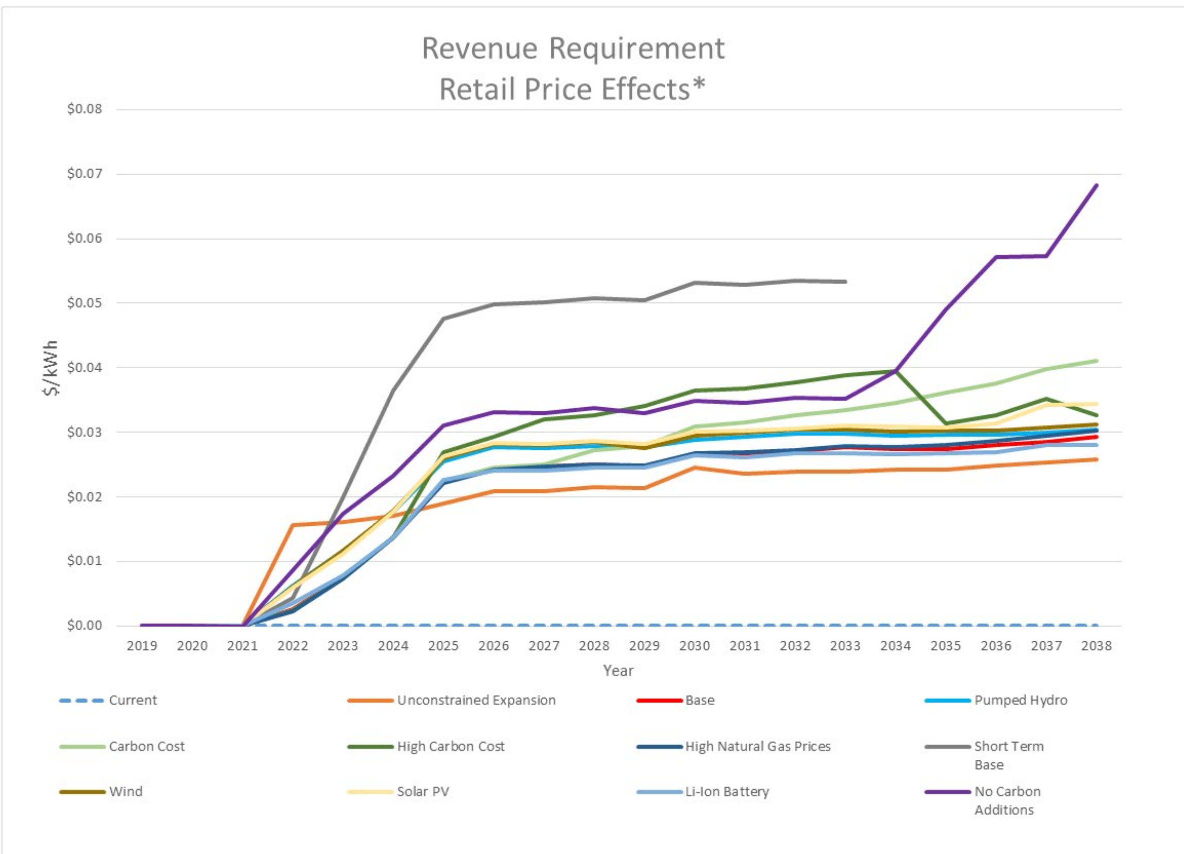
Figure 10-5. Net Present Value Revenue Requirement for Short Term Current and Short Term Base Portfolios



Estimated Retail Rate Impacts

Figure 10-7 below shows the estimated retail energy price impact of each portfolio throughout the planning horizon. Many of the portfolios show similar rate impacts due to the fact that all portfolios shown achieve the same level of resource adequacy. The highest initial, but lowest long term, rate impact is the Unconstrained portfolio. The Li-ion Battery, Base, High Natural Gas Prices, Carbon Cost, and High Carbon Cost portfolios are grouped very close together until the Carbon Cost and High Carbon Cost portfolio diverge in about 2024. A second tight grouping occurs, consisting of the Wind, Pumped Hydro (hidden by Wind) and Solar PV portfolios. The No Carbon Additions portfolio has a higher retail price impact which becomes very high towards the end of the planning horizon as about 1,700 MW of wind are added to the portfolio.[15] The Short Term Base portfolio had the lowest NPV revenue requirement, but has the highest retail price impact due to the recovery of investment over a shorter period of time.

Figure 10-7. Estimated Retail Impacts by Portfolio

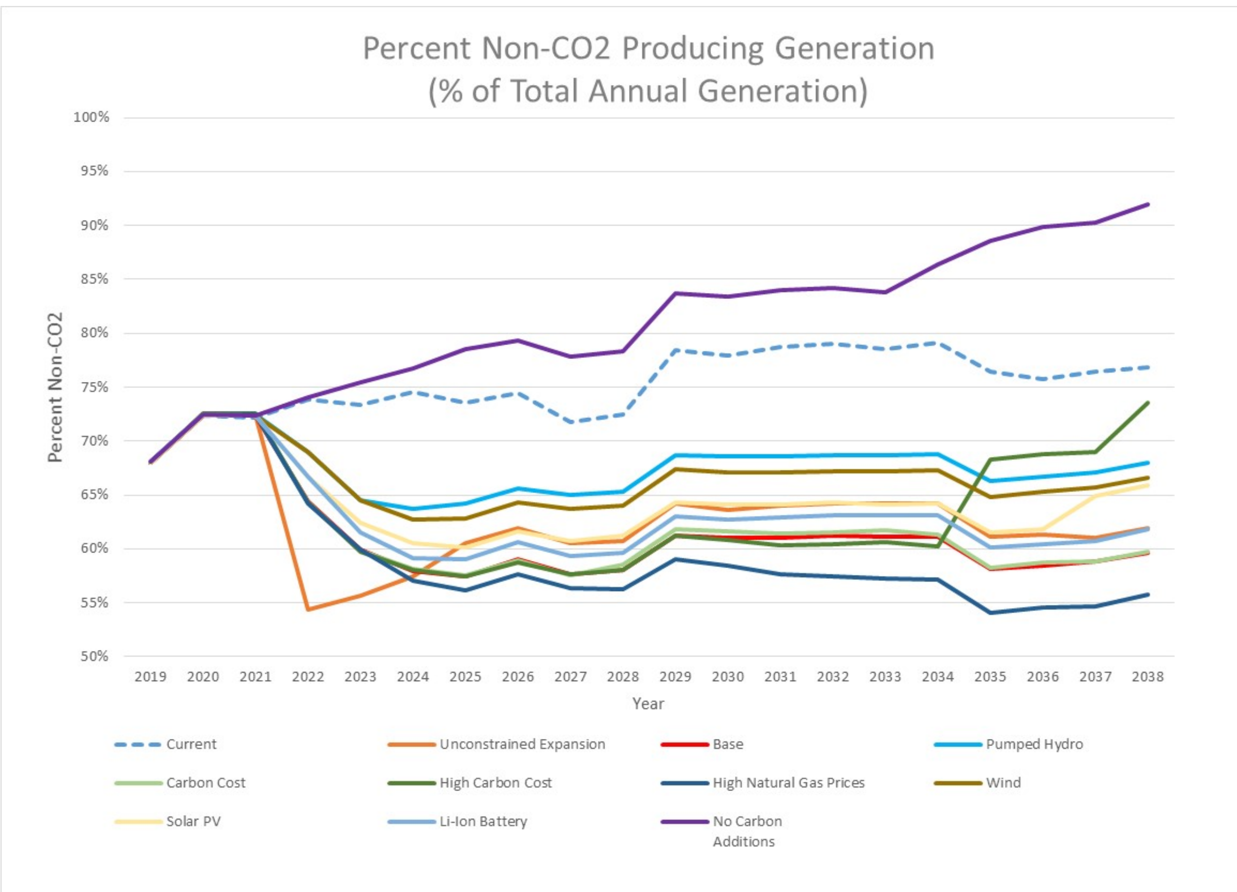


[15] This aligns with the findings of the regional study "Resource Adequacy in the Pacific Northwest" conducted by Energy + Environmental Economics (E3). The study is scheduled to be released March 2019.

Carbon Impacts

Figure 10-8 below shows the estimated percentage of non-carbon producing generation by portfolio and by year. The Current portfolio is included in this graph, but as stated elsewhere, the Current portfolio does not result in a resource adequate or reliable portfolio, so is not comparable to the other portfolios in this figure. The No Carbon Additions portfolio results in 90% carbon-free generation, but also has the highest retail price impact (Figure 10-7).

Figure 10-8. Percent Carbon-Free Generation by Portfolio



Conclusion

The portfolio models discussed in this chapter should be regarded as indicative of which resources could be used to meet the future resource needs of customers at lowest long-term total cost. Even though portfolio modeling and analysis identifies specific resources and specific portfolios, NorthWestern's energy procurement strategy will rely on competitive solicitations of proposals, also known as Requests for Proposals (RFPs).[16] The model and modeling framework used to evaluate resource portfolios in this plan will be used to evaluate proposals submitted in future RFPs and will also be used to evaluate opportunity purchases.

[16] See Chapter 13.

CHAPTER 11
RESPONSE TO COMMENTS

NorthWestern's Response to Public Comments

Background

NorthWestern is required to file an electricity supply resource procurement plan by December 15 in each odd-numbered year. For the 2017 biennial requirement, the Commission extended the deadline until December 15, 2018. On November 13, 2018, NorthWestern filed a Motion for Extension to file the 2019 Plan, requesting an extension to file until February 15, 2019. On December 5, 2018, the Commission issued an Notice of Commission Action approving NorthWestern's request for extension with the following conditions: 1) NorthWestern must issue a draft resource plan by March 15, 2019; 2) NorthWestern shall allow stakeholders a minimum of 60 days to review the draft plan and provide NorthWestern with written comments; 3) NorthWestern shall file its final resource plan at its discretion any time between the end of the 60-day comment period and December 15, 2019; and 4) the final plan must contain a section which explains how NorthWestern considered and addressed the comments received on the draft 2019 Plan.

On March 4, 2019, NorthWestern posted the draft 2019 Plan on our website along with a link on our homepage directing the interested persons to the draft 2019 Plan and a comment form. The comment form remained active for 60 days and comments were received through May 5, 2019. This chapter provides a general overview of the comments received on the draft 2019 Plan and NorthWestern's response to those comments.

NorthWestern's resource planning process is directed by Montana Statutes and Commission rule. MCA 69-8-419 specifies the duties of a public utility and states that the utility shall pursue the following objectives in fulfilling its duties:

- Provide adequate and reliable electricity supply service at the lowest long-term total cost;
- conduct an efficient electricity supply resource planning and procurement process that evaluates the full range of cost-effective electricity supply and demand-side management options;
- identify and cost-effectively manage and mitigate risks related to its obligation to provide electricity supply service;
- use open, fair, and competitive procurement processes whenever possible; and
- provide electricity supply service and related services at just and reasonable rates.

Beyond these factors, NorthWestern considers risk and environmental externalities by modeling a high fuel cost future, and by modeling futures with carbon costs and high carbon costs. The Commission's rules also state that, "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." (MCA 38.5.8201 (2)).

Response to Comments

Summary of Public Comments

NorthWestern received approximately 500 comments on the draft 2019 Plan, most from individuals. The following is a summary of the public comments submitted via the web-based form from people who explicitly stated their support /opposition on issues:

- 72% opposed coal
- 64% support more renewables

- 31% oppose all fossil fuels
- 11% support coal
- 2% support natural gas
- 2% support nuclear

Interested Party Comments

NorthWestern received 15 sets of comments that were more expansive and more detailed in nature. Detailed comments were received from (in alphabetical order):

- City of Missoula
- Climate Smart, Missoula
- Forward Montana
- Gordon Butte
- Haymaker Wind, LLC
- Missoula Public Health
- Montana Department of Environmental Quality (DEQ)
- Montana Environmental Information Center (MEIC)
- Montana Public Service Commission Staff (MPSC-staff)
- Montana Renewable Energy Association (MREA)
- NW Energy Coalition (NWEC)
- Renewable Northwest (RN)
- Synapse Energy Economics, Inc. (Synapse)

The remainder of this chapter provides generalized responses to those comments by topic. Detailed responses to comments by interested parties are included in Chapter 11 of Volume 2.

General Response by Topic

Cleaner Resource Portfolio: Many of the public comments that were submitted indicated a desire to increase the amount of renewables in NorthWestern's resource portfolio, or limit CO2 producing resources. NorthWestern sees value in renewable and carbon free resources; over 60% of NorthWestern Energy's current generation portfolio is carbon free. As outlined above, NorthWestern is required to meets customers' resource needs at lowest long term total cost. More importantly, NorthWestern will select resources based on competitive solicitation processes which will identify the resources that provide the most value to our customers at lowest long term total cost. Ultimately, the competitive process will determine resource selection, not the resource planning process or the resource plan.

Preferred portfolio: NorthWestern received comments regarding concerns with the Electricity Supply Resource Planning process, and how it has failed to identify a specific resource(s) that would meet the capacity shortfall identified in the plan. As explained in the draft Plan, the selection of a specific resource is not the objective of this planning process. As stated above, the Plan does not select a preferred portfolio, NorthWestern will use competitive solicitation and RFP processes to identify least cost resources to meet customers' resource needs.

Renewable Resource Costs: NorthWestern received a number of comments claiming the unsubsidized cost of renewable resources in the Plan are too high.[1] These commenters relied upon the publicly available annual Lazard levelized cost of energy ("LCOE") study. Lazard's LCOE analysis is a limited analysis[2] and NorthWestern retained HDR to provide

[1] Sierra Club, Renewable Northwest and MEIC cite Lazard costs for renewables.

[2] On page one, and throughout its study, Lazard mentions numerous factors that it has not considered in its analysis, but that would have an impact on the LCOE.https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf at Pages 1, 2 and 19.

generic resource costs for the Plan.[3] A better comparison for benchmarking HDR's resource costs is the Northwest Power and Conservation Council ("NWPCC") Mid-Term Assessment. HDR's costs, when compared to those used in the NWPCC's Mid-Term Assessment, are favorable, as indicated in Table 11-1 below[4]. As previously mentioned, NorthWestern will select resources based on competitive solicitation processes which will identify the resources that provide the most value to our customers at lowest long term total cost.

Table 11-1. HDR / NWPCC Renewables Cost Comparison

Resource	NWPCC - Mid-term Assessment Capital Cost ($2016)	HDR - NWE 2019 Plan Capital Cost ($2018)
Technology	**($/kW)**	**($/kW)**
Wind Energy	$1,500 - $1,700	$1,410
Solar PV	$1,350 - $1,500	$1,330

As several comments correctly noted, NorthWestern does include a set of "lower cost futures" for wind, solar and li-ion batteries in Figure 7-2, but does not include those costs in portfolio modeling. The use of these trends was not adequately explained in the draft Plan.

NorthWestern performed constrained Automatic Resource Selection (ARS) PowerSimm model runs, using HDR's resource definitions and costs, which resulted in a resource expansion path that didn't select wind, solar, or batteries (the Base Case). Alternative, lower cost futures for wind, solar and Li-ion batteries were developed by Ascend Analytics. The original constrained ARS model was re-examined but with the ability to

[3]See Chapter 7.

[4] The NWPCC's Mid-Term Assessment is included in Volume 2, Chapter 7.

select the "low cost futures" for wind, solar, and battery resources. The addition of the lower cost futures had no effect upon the Base case resource selection, so NorthWestern reverted to the HDR costs for portfolio analysis. NorthWestern will include an explanation of how the lower cost futures were used in Chapter 7 of the Final Plan. Once again, the 2019 Resource Plan does not select a preferred portfolio, instead the results of portfolio analysis are only indicative of resources that may be selected in a competitive solicitation process. NorthWestern will rely on competitive solicitations to identify a portfolio of resources that will meet our customers' needs at least cost; not the portfolio analysis contained in the 2019 Plan.

Capacity Contribution: Several commenters stated that NorthWestern did not give renewable resources (both existing and new) enough credit for their capacity contribution during peak load periods. For the existing renewable resources (listed in Table 4-1), peak load contribution was determined using the Southwest Power Pool (SPP) Criteria, which is a method that has been accepted by the Commission. One comment remarked that the capacity contribution of 8.3 MW for Spion Kop looked high; having checked the results, NorthWestern agrees. A clerical error occurred when developing the table and the capacity contribution of Spion Kop has been changed to 1.2 MW in the final plan.

Additionally, several commenters requested that NorthWestern incorporate the Montana Eighth Judicial District Court decision in Cause No. BDV-17-0776 into the final Plan.[5] The decision was issued on April 2, 2019, well after NorthWestern issued the draft Plan, and has been has been appealed to the Montana Supreme Court. Additionally, the Commission will have opportunities to address this issue prior to NorthWestern's next resource planning process, which will be the 2022 resource plan.

[5] MEIC, MREA, and DEQ

Infrastructure costs: NorthWestern received multiple comments about not including the cost of new transmission and natural gas infrastructure needed to serve new resources. In particular, interested parties commented on the lack of natural gas infrastructure upgrade costs. HDR's resource cost assumptions did include capital costs which included dual-fuel capability, but not potential natural gas transmission upgrades. Transmission upgrade costs were also excluded from the analysis for all new resources considered in Chapter 7. This approach was necessary because the resource plan is a generic look at potential future resources, and infrastructure upgrade costs are resource and location specific.

The 2019 Plan and planning results are only indicative of resources that may be selected in a competitive solicitation process. NorthWestern will rely on competitive solicitations to identify a portfolio of resources that will meet our customers' needs at least cost; not the portfolio analysis contained in the 2019 Plan. Competitive bids will include the cost of resources with specific locations and specific infrastructure upgrade costs.

Transmission: MPSC staff, Synapse, and Forward Montana submitted comments on Chapter 6, the Transmission chapter, including the following comments:

- MPSC Staff commented that the numbers within Chapter 6 do not always seem to add up.
- MPSC Staff commented that NorthWestern could do a better job of explaining what entities are using capacity on each of the transmission paths delivering energy in and out of Montana.
- Synapse commented that NorthWestern's transmission queue contains over 5,000 MW of wind, solar, hydro, and gas on the system, and recommends that the final Plan assume "a high likelihood of full capability of the transmission system that

> allow for imports into the NWE territory from the broader Pacific Northwest systems."

In response to the MPSC Staff comments, NorthWestern has updated Chapter 6 to include additional data and discussion of the customers using short term transmission capacity to serve load. In response to Synapse comments, only 150 MW of the over 5,000 MW referenced by Synapse would be considered dispatchable, the remainder is intermittent generation (which cannot be dispatched to serve peak load needs). More importantly, NorthWestern's resource plans have never limited the import capability from the Pacific Northwest, but included Chapter 6 to alert the Commission and interested parties that it may need to change those assumptions in future plans as NorthWestern's transmission system becomes increasingly constrained.

Additional Model Runs: Several sets of comments requested model runs to explore alternative planning scenarios, including:

- Retire CU4 by 2025 (MEIC),
- CU4 closure no later than 2030 (NWEC),
- Run scenarios other than RTO by 2025 (MEIC),
- Rely on the market (Synapse),
- 100 percent renewables future (General Public), and
- Increase CU4 ownership per SB331 (MPSC Staff).

Colstrip Unit No. 4 (CU4) continues to provide value to NorthWestern's resource portfolio throughout the 20-year planning horizon. Early retirement scenarios will not result in a portfolio that provides adequate and reliable electricity supply service at the lowest long-term total cost due to the need to recover both the remaining depreciation in CU4 and the capital costs of replacement resources. Lastly, the appropriate time to address any potential closure of CU 4 is after a closure date has been determined.

Regarding the MPSC Staff request to model SB331; given that SB331 did not become law, a SB331 scenario is not relevant and would provide no useful information in this planning process.

Regional Capacity: Several sets of comments questioned NorthWestern's assumptions about regional generation and capacity in the Pacific Northwest as a whole.

- Sierra Club is concerned with the potential for over investment in capacity in the Pacific Northwest
- NWEC and MEIC would both would like to see NorthWestern examine both the generation retirement and planned new builds in the Pacific Northwest.
- Forward Montana seeks to understand how much capacity new generation will add to regional energy supply
- Synapse asserts that, "a significant part of the economically optimum outcome for ratepayers in the region is to "share" (i.e., buy and sell) capacity resources and not overbuild."

NorthWestern and all other utilities in the Northwest Power Pool have an obligation to carry a reserve margin, which NorthWestern has not had for many years. This obligation is imputed by NERC to WECC. The fact that WECC does not enforce the reserve margin requirement does not alleviate NorthWestern's obligation to meet our WECC capacity reserve margin. The region is facing a looming capacity deficit which reduces NorthWestern's ability to rely on wholesale market power and threatens regional reliability:

- The Northwest Power and Conservation Council's "Pacific Northwest Power Supply Adequacy Assessment for 2023" states that the Northwest power supply is likely to become inadequate by 2021, primarily due to the retirement of the Centralia

1 and Boardman coal plants (1,330 MW combined). The loss-of-load probability (LOLP) for that year is estimated to be over 6 percent, which exceeds the NWPCC's standard of 5 percent. Preliminary results of the 2019 assessment show that the region will be inadequate in 2024 as well.[6]

- An October 2018 study conducted by E3 for Portland General Electric (PGE) addressed the "rely on the market" question directly. Except for the low regional need scenario, E3 found there is very little capacity (~100 MW) available through 2020.[7]

- On March 5, 2019, Mid-C wholesale market prices surged to prices not seen since the 2000-2001 west coast power crises.[8]

- On April 23, 2019, PNUCC (Pacific Northwest Utility Conference Committee) issued its annual forecast; the 2019 Northwest Regional Forecast.[9] The PNUCC forecast noted several trends in the region, including:

    - Serving winter peak remains a concern... focusing planners on peak capacity needs.
    - The loss of several coal-fired power plants over the next decade will contribute to the challenges of maintaining an adequate, reliable power supply.

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[6] See Chapter 11, Volume 2.

[7] See Chapter 11, Volume 2.

[8] "NW Power Prices Soar With Pinched Supplies and Low Temperatures" - Clearing Up, March 8, 2019, Issue no. 1892. See Chapter 11, Volume 2.

[9] See Chapter 11 Volume 2.

  - Current planned construction of new wind and solar cannot be expected to fully offset the anticipated loss of generation from coal-fired power plant retirements.

- In response to the March 2019 power market excursion, the Northwest Power Pool (NWPP) launched an initiative to address resource adequacy in a coordinated manner across the region. NorthWestern is participating in this study, and expects that the result of this effort will be generally consistent with the goals identified in the 2019 Plan.

Given NorthWestern's and the region's shortage of resources to serve peak load and the coincidence of NorthWestern's peak loads with the region's peak load, it would be irresponsible for NorthWestern to continue to rely on the market to provide capacity as it has in the past. To be clear, NorthWestern will continue to rely on wholesale power markets to meet some portion of our capacity need, but we must reduce current market exposure and prepare for the development of day-ahead energy markets and participation in an RTO.

Regarding Synapse's comments; NorthWestern expects that bilateral transactions will continue to be a part of the supply portfolio into the foreseeable future. However, a distinction must be made between long-term bilateral transactions and short-term bilateral transactions. Long-term bilateral capacity transactions have a potential place in the resource planning process, and as we have stated, NorthWestern expects to solicit bids from potential sellers of existing capacity and capacity that is in development during the competitive solicitation process. Short-term transactions, on the other hand, cannot be relied upon from a planning perspective unless a regional resource adequacy program, either through an organized market or other entity, is in place. Such a resource adequacy program would likely include a limit on the amount of capacity that could be procured on a short-term basis. For example, the current resource adequacy program in SPP allows seasonal capacity purchases, only up to 25% of the planning requirement. The remaining 75% must be owned or procured for terms of more than one year. Any limits on the amount of short-term capacity that could be used in a future northwest resource adequacy program would be based on the specifics of this region.

As described in the draft Plan and in the E3 study, the region is facing a capacity shortage, not an economic problem of overbuilding capacity. This is particularly true of NorthWestern, which has leaned on the capacity owned by others for many years and is far short of controlling the capacity to meet our own requirements.

EIM is not a capacity market; it is an intra-hour energy market. It does not address capacity margins or any other aspect of resource planning. To the contrary, a key feature of that market is that each entity must be self-sufficient and not lean on the EIM. The fact that Avista or any other entity has announced plans to join the EIM is irrelevant from a resource adequacy perspective. It is also important to note that the EIM does not allow for sharing of flexible capacity. Each entity must hold sufficient flexible capacity on its own. The EIM facilitates efficient dispatch of that capacity. It is true that the overall need for flexible capacity is reduced in the EIM footprint compared to what each entity would need on its own due to the diversity of loads and generation across the footprint. However, this does not mean that the capacity to meet this need is shared or traded in the EIM market.

RTO Assumptions: Sierra Club, MEIC and Synapse submitted comments questioning whether NorthWestern's assumptions regarding RTO development are well founded. The message from a number of studies examining regional capacity adequacy, the lesson learned by the early March 2019 Mid-C power markets and the follow up study launched by the NWPP indicate that the region is facing a capacity deficit. The RTO development assumptions in this Plan provide a target for achieving resource adequacy, but are subject to change as NorthWestern implements the action plan items contained in Chapter 13.

Externalities: Many public comments and a few of the more detailed comments recommend that NorthWestern include externalities (societal costs) in its analysis. NorthWestern does not include externalities beyond those currently included in the cost of resources and market prices. A carbon cost scenario is included in NorthWestern's analysis to test whether the inclusion of a carbon cost would affect resource selection (it did not). NorthWestern's discussion of carbon costs is contained in Chapter 9.

Rate Design and Rate Impacts: MPSC Staff commented that plan should do a better job of addressing rate impacts associated with resource procurement, and potential rate designs that promote the utility's financial health while simultaneously achieving public policy goals (such as economic efficiency and environmental responsibility). In response, NorthWestern has added Chapter 12 to the 2019 Plan, which addresses rate impacts and rate design.

Automatic Resource Selection (ARS): Comments from MEIC and Forward Montana expressed concerns with Automatic Resource Selection (ARS).

- MEIC commented that resources, "are not described and neither are the ARS constraints."
- Additionally, MEIC believes that the Automatic Resource Selection (ARS) favors and selects gas generation.
- Forward Montana raises concerns about the meaning of "lowest cost" relative to Automatic Resource Selection, correctly suggesting that ARS does not include externalities.

From these and other comments received, it is clear that NorthWestern must provide a more detailed description of how resource costs and revenues are determined in ARS, and a better explanation of how resource selection occurs in ARS. In response, NorthWestern has expanded the description of ARS in Chapter 10.

While ARS is an important component of the 2019 Plan, the results of ARS and portfolio modeling using PowerSimm will not determine the resources that NorthWestern will acquire to serve customers' resource needs. As explained in Chapter 13, NorthWestern will use competitive solicitations to identify resources.

Planning Horizon: Synapse commented that by selecting a 20-year planning horizon, rather than a 15-year horizon, NorthWestern did not follow the spirit of the Commission's recommendation.

The Commission's "symmetry" rulings in QF orders are currently under legal review. More importantly, there is a conflict between the 15-year requirement and the Commission's planning rules, which defines "planning horizon" as the longer of the longest remaining contract in the portfolio, the longest lived resource being considered, or ten years. (ARM 38.5.8202). NWE stands by the decision to use a 20-year planning horizon in the 2019 Plan.

QF Resources: MEIC raised concerns about the inclusion of QF (Qualifying Facilities) renewable resources, which are not yet operating, in modeling. NorthWestern includes QF projects as a resource in the portfolio when there is either a docketed proceeding with the Montana Public Service Commission, or there is a signed Power Purchase Agreement. This is because under these two conditions there is, or is anticipated to be, an enforceable obligation to purchase QF power. NorthWestern includes QF power in the portfolio until there is a withdrawal of a petition or contract, or the QF defaults on the contract and all cures are exhausted.

ETAC and Stakeholder Engagement: NorthWestern received comments from Northwest Energy Council, Synapse, MREA, and DEQ about the ETAC process. The comments, which were largely positive, presented some ideas for additional consideration.

- NWEC supports the retention and potential expansion of the ETAC
- Synapse believes ETAC should be expanded
- MREA supports the ETAC process, but believes it should be expanded
- DEQ's Montana Energy Office voiced several concerns:
    - ETAC process was improved [over 2015 process]
    - NorthWestern did not provide sufficient explanation when ETAC member recommendations were not followed
    - No ETAC meeting was held on the draft plan
    - Volume 2 should have been provided with the draft

NorthWestern conducted a rigorous ETAC process, increasing the total number of meetings from five (2015 Plan) to twenty-three:

- Eighteen ETAC meetings
- Four PowerSimm modeling workshops
- Three public meetings

Additionally, the time to review the draft Plan increased from seven days to 60 days.

With the filing of this Plan, the passage of HB-597 (which contains resource planning requirements), and the potential Commission adoption of a stipulation between NorthWestern and Northwest Energy Coalition, NorthWestern will reexamine the resource planning processes and adjust committee structure, membership, and processes as necessary.

Regarding the comment on not issuing Volume 2 information with the draft, NorthWestern would like to provide clarity. Due to the voluminous amount of material to be included in Volume 2, and the formatting that needs to occur to prepare modeling reports for inclusion in Volume 2, those materials have never been provided with the drafts of resource plans. However, NorthWestern did offer on a "best efforts" basis to provide Volume 2 materials to ETAC members. While no ETAC members took NorthWestern up on our offer, we did provide Volume 2 materials to Renewable Northwest upon request.

Response to Specific Comments

Chapter 11 provides a general overview of the comments received on the draft 2019 Plan and NorthWestern's response to those comments. For responses to the specific comments submitted by the parties listed at the beginning of this chapter, please see Volume 2, Chapter 11, of the 2019 Plan.

CHAPTER 12
RATE DESIGN AND RATE IMPACTS

Rate Design

ARM 38.5.8210(3) states that a utility "should include analysis of how cost allocation and rate design decisions might impact future loads and resource needs." The traditional way to address rate design, particularly at the residential level, would have been to implement inverted block or declining block rate structures, with the rate block set a marginal cost. The goal of this rate design is to allow consumers a chance to avoid the marginal resource by altering their pattern of consumption.

More currently, the trend in rate design is to adopt demand charges and/or time-of-day rates to reflect time-of-day energy costs in time-of-use rates. This is an efficient way to provide marginal cost pricing signals so customers can alter their use, as they choose, to avoid higher cost pricing periods and shift load to lower cost periods. This rate design can also have the effect of reducing peak loads.

NorthWestern is currently installing smart meters in South Dakota and is planning to deploy smart meters in Montana. Smart meters will allow NorthWestern to offer advanced rate options and customer services which are not currently practical or possible. Smart meters will enable future rate options that may allow NorthWestern to manage growth in peak loads through rate design.

ARM 38.5.8211 addresses a utility's cost allocation and rate design practice in the context of cost of service and rate design filings.

ARM 38.5.8213(1)(a) states that a utility should "evaluate and quantify probable load characteristics, including trends in load shapes, load growth and price elasticity of demand." As shown in Table 3-1, NorthWestern is anticipating low load growth throughout the planning period. Peak loads are forecast to grow at 0.2% and winter peak loads are projected to grow at 0.5% annually. Once they are installed in Montana, the smart meters (mentioned above) will allow NorthWestern to incorporate much more detailed data on load shapes and trends in load shapes.

Price elasticity is used to measure the responsiveness, or elasticity, in the amount of consumption in relation to the change in the electricity price. The price elasticity of demand is difficult to quantify due to a lack of meaningful price signals within the historical consumption data of customers. The deployment of smart metering will allow NorthWestern to offer rates which will allow those customers with higher elasticities of demand rate options to help them manage consumption and bills.

Rate Impacts

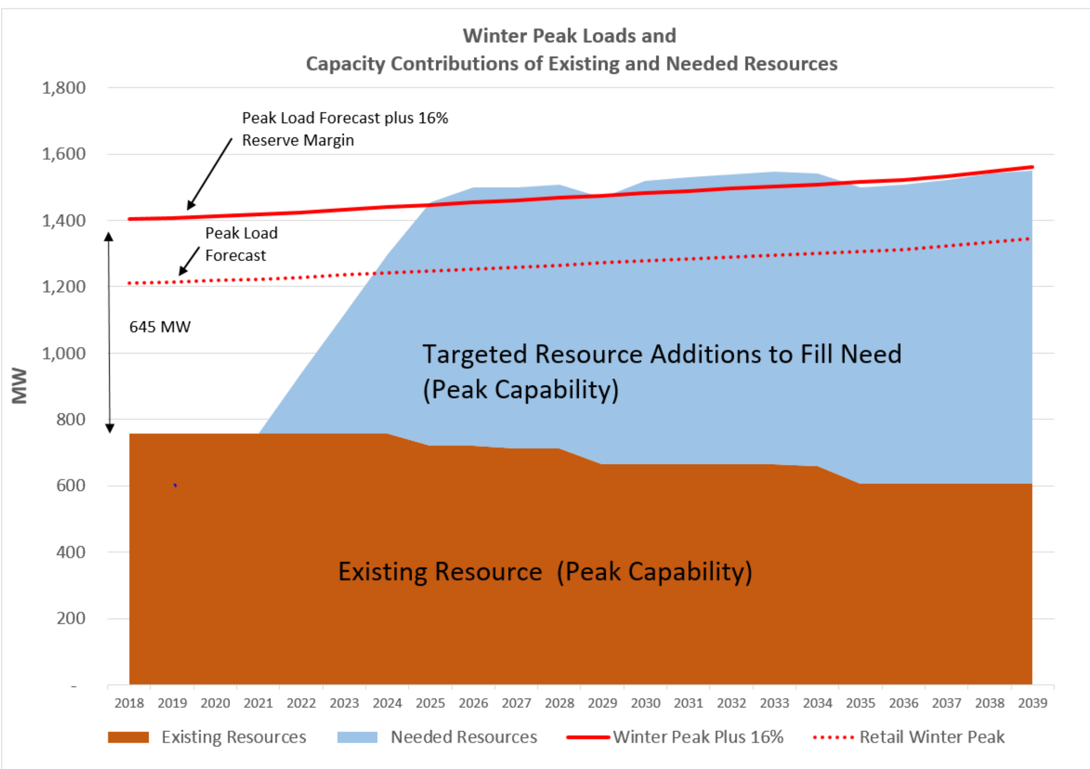
In past plans, NorthWestern has presented modeling results in terms of "net present value of system costs." Chapter 10 of this plan presents the results of portfolio modeling in terms of risk-adjusted net present value revenue requirements (NPVRR). This means that every comparison between portfolios in Chapter 10 is effectively a rate impacts comparison because each portfolio's cost is expressed in terms of its revenue requirement.

CHAPTER 13
PORTFOLIO ADDITIONS STRATEGY AND ACTION PLAN

NorthWestern's Portfolio Additions Strategy

This chapter describes the strategy and action plan NorthWestern will use when considering additions to our supply portfolio. Figure 13-1 below illustrates the peak load forecasts, the capacity contributions of existing resources, and the additional capacity contributions needed to mitigate market risk and to participate in a full market by 2025.

Figure 13-1. Additional Need for Peaking Capacity



NorthWestern Energy's current resources provide about 755 MW of peaking capacity, which is the energy available during periods of our customers' highest demand. An additional 645 MW of peaking capacity must currently be purchased from the market to meet our needs. Without new peaking capacity, the market exposure will increase to about 725 MW by 2025 (including reserve margins). This peaking need assumes continued development of cost-effective demand side management (conservation) and small distributed generators (net-metering).

The figure illustrates the need for NorthWestern to begin arranging for peaking capacity resources. Resource additions are shown to begin in 2022 because that is the soonest timeframe in which NorthWestern could file the 2019 Plan, solicit proposals using a competitive Request For Proposals (RFP) process, and allow for construction of new-build resources (should those resources win the solicitation). NorthWestern's strategy includes the following steps.

1. Seek short term capacity to help bridge the gap until long term capacity can be added to the portfolio.
2. Conduct an initial competitive solicitation RFP process for up to 400 MW of capacity.
3. Solicit additional competitive proposals with the goal of meeting peak loads plus a 16% capacity reserve margin by 2025.

Acquiring short term capacity will reduce NorthWestern's wholesale market exposure during times when electricity prices may be high due to high demand and market liquidity problems, like those experienced in March of 2019.

NorthWestern will solicit competitive proposals in order to evaluate all cost-effective resources including power purchase agreements and owned energy resources comprised of different structures, terms, and technologies with the long term objective of a clean, stable, and reliable energy portfolio. Proposals, and combinations of proposals if appropriate, will be evaluated for their ability to meet our customers' needs and for their ability to add value to our resource portfolio at lowest long-term total cost.

Resource Acquisitions Strategy

Competitive Solicitations of Proposals for Resource Acquisitions

ARM 38.5.8212 states that "a utility should use competitive solicitations with short-list negotiations as a preferred procurement method", and "to the extent that a utility does not use competitive solicitations to acquire electricity supply it should thoroughly document the exercise of its judgement." It is clear that opportunity resources may be obtained outside of a competitive solicitation process.[1] NorthWestern's initial proposal solicitation will seek to acquire up to 400 MW of new resources.

The competitive solicitation process may result in the acquisition of resources identified in the modeling conducted for this plan. However, it is more likely resources that were not identified or modeled, or could not be identified during the planning process, will be acquired. For example, NorthWestern issued a Request for Interest (RFI) that identified a number of new and existing resources that could potentially be acquired, but the RFI did not result in resource definitions for inclusion in the modeling portion of the Plan.[2]

[1] Opportunity resources are those generation resources, either existing or new-build, which remain unknown as to their availability until an opportunity to purchase arises. Opportunity resources cannot be known or modeled in a resource planning process, but will be evaluated in a manner consistent with portfolio evaluation methodology in the 2019 Plan.

[2] The RFI responses did provide validation of the new build resource options included in HDR's resource definitions study (Chapter 7).

Request for Proposal (RFP) Process

In compliance with Montana statutes under SS 69-8-419, MCA and Commission rules under ARM 38.5.8212, any future RFP will focus on the most reliable, lowest long-term cost bids that meet NorthWestern's identified resource needs, and could include, but not be limited to, the following types of resources.

- Sale of all or part of existing resources.
- Engineer, procure and construct project at the DGGS facility.
- 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.
- Demand response resources under automated control.

As with the 2017 Flexible Capacity RFP, NorthWestern intends to use an independent, third–party administrator (RFP Administrator) to conduct any future RFP process. In order to ensure equitable treatment of each proposal, the RFP Administrator will be instructed to not identify any bidders by name until the resources have been selected for final negotiations. The RFP will be publicly noticed and sent to any party expressing a desire to receive one, and to developers that NorthWestern is aware of from prior solicitations. Proposals will be evaluated using the same modeling method used in the 2019 Plan to determine their value to customers. The RFP will request the following information.

- Developers must demonstrate a proven safety record.

- Developers must demonstrate their proposed project can be completed on the timeline included in the proposal.
- Developers will be required to provide references to similar projects, or at a minimum, demonstrate that capital markets support the proposed project.
- Developers will be required to demonstrate their financial worthiness to perform.

Opportunity Resources

Opportunity resources are those resources that NorthWestern cannot foresee or model in a resource planning process. Typically, opportunity resources are existing assets that become available for acquisition on short notice and with a short time-frame for transaction completion. Usually the owner (or owners) of opportunity resources control the process, usually their own RFP process, and NorthWestern has no control over that process. NorthWestern evaluates opportunity resources in a manner consistent with the methodologies contained in the most current resource plan to determine if the opportunity resource could fill a portfolio need in an economical manner.

Action Plan

Action Plan Items

1. **Regional Market Transformation:** NorthWestern has committed to join the Western EIM in 2021 and will continue to work toward that goal. NorthWestern will also participate in the developing energy day-ahead market discussions and will continue to monitor and participate in the development of proposed RTOs/ISOs.
2. **Competitive Solicitation:** As explained above, NorthWestern will use a competitive proposal solicitation process using an independent RFP Administrator to initially acquire up to 400 MW of flexible capacity. NorthWestern plans to follow up with an

additional competitive solicitation, reassessing customers' needs and building upon the information gained from the previous solicitation.

3. **Resource Optimization:** NorthWestern remains committed to the efficient and cost effective optimization of the existing fleet of company-controlled resources. NorthWestern will continue to explore additional operational efficiencies, including the operational efficiencies that may be realized by using battery storage technologies.
4. **RPS Obligations**: NorthWestern will continue to manage and pursue resources to meet ongoing RPS and CREP obligations.
5. **Regional Resource Adequacy:** NorthWestern is currently participating in the Northwest Power Pool Resource (NWPP) Adequacy Evaluation. The intent of this initiative is to develop a program to address resource adequacy in a coordinated manner across the region. NorthWestern expects the result of this effort will be generally consistent with the goals identified in the 2019 Plan. However, the specific planning reserve targets and timing that result from the NWPP effort may differ from the targets and timing identified in the Plan. NorthWestern will report the results of this initiative by filing an addendum to the 2019 Plan.
6. **Demand Response:** NorthWestern will consider Demand Response (DR) technology in competitive solicitations, and will also actively seek opportunities to develop mutually beneficial DR programs with larger loads.
7. **Emerging Technologies:** NorthWestern will continue to monitor the development and application of emerging technologies which have the potential to help meet our customer's future energy needs.
8. **Implementation of Action Plan Items:** This Plan provides a path forward for NorthWestern to achieve resource adequacy for our customers. NorthWestern will continually evaluate the policies and assumptions in this Plan and will adjust our actions as necessary.

APPENDIX

APPENDIX A
MONTANA STATUES & RULES

TITLE 69. PUBLIC UTILITIES AND CARRIERS
CHAPTER 8. ELECTRIC UTILITY INDUSTRY GENERATION REINTEGRATION

Part 4. Public Utilities, Cooperative Utilities, and Electricity Suppliers

69-8-419. Electricity supply resource planning and procurement -- duties of public utility - objectives -- commission rules. (1) The public utility shall:

(a) plan for future electricity supply resource needs;

(b) manage a portfolio of electricity supply resources; and

(c) procure new electricity supply resources when needed.

(2) The public utility shall pursue the following objectives in fulfilling its duties pursuant to subsection (1):

(a) provide adequate and reliable electricity supply service at the lowest long-term total cost;

(b) conduct an efficient electricity supply resource planning and procurement process that evaluates the full range of cost-effective electricity supply and demand-side management options;

(c) identify and cost-effectively manage and mitigate risks related to its obligation to provide electricity supply service;

(d) use open, fair, and competitive procurement processes whenever possible; and

(e) provide electricity supply service and related services at just and reasonable rates.

(3) By March 31, 2008, the commission shall adopt rules that guide the electricity supply resource planning and procurement processes used by the public utility and facilitate the achievement of the objectives in subsection (2) by the public utility. The rules must establish:

(a) goals, objectives, and guidelines that are consistent with the objectives in subsection (2) for:

(i) planning for future electricity supply resource needs;

(ii) managing the portfolio of electricity supply resources; and

(iii) procuring new electricity supply resources;

(b) standards for the evaluation by the commission of the reasonableness of a power purchase agreement proposed by the public utility; and

(c) minimum filing requirements for an application by the public utility for approval of an electricity supply resource.

69-8-420. Electricity supply resource procurement plans -- comment on plans. (1) The public utility shall develop electricity supply resource procurement plans. The plans must be submitted to the commission at intervals determined in rules adopted by the commission.

(2) An electricity supply resource procurement plan must demonstrate the public utility's achievement of the objectives provided in **69-8-419** and compliance with commission rules.

(3) The commission shall:

(a) review the electricity supply resource procurement plan;

(b) provide an opportunity to the public to comment on the plan in accordance with subsection (4); and

(c) issue written comments within 9 months after the plan is submitted to the commission that identify:

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

(ii) ways to remedy any concerns.

(4) The commission shall hold two public meetings in an area of the state encompassed by the plan. Notice of the meetings must be published once a week for 2 consecutive weeks in a newspaper of general circulation at least 30 days prior to each meeting.

69-8-421. Approval of electricity supply resources. (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 is not yet procured.

(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 hearing on the application for approval 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 hearing 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 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:

(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 in **69-3-201**, the objectives in **69-8-419**, 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**, **69-8-419**, and commission rules.

(10) The commission may engage independent engineering, financial, and management consultants or advisory services to evaluate a public utility's electricity supply resource procurement plans and proposed electricity supply resources. The consultants must have demonstrated knowledge and experience with electricity supply 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.

(11) By March 31, 2008, 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.

38.5.82: Default Electric Supplier Procurement Guidelines

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

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

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: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

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: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Rules 38.5.8205 through 38.5.8208 reserved

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

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: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

38.5.8211 COST ALLOCATION AND RATE DESIGN

(1) A utility's cost allocation and rate design practices and rate case proposals should support and complement the goals and objectives of these guidelines. Different approaches to allocating costs and designing rates have different advantages and disadvantages. A utility should consider these advantages and disadvantages in the context of the goals and objectives of these guidelines when proposing particular cost allocations and rate designs. A utility should evaluate and consider the following items when allocating costs and designing rates:

(a) the ability of opportunity cost-based prices to increase economic efficiency;

(b) cost allocation among customer segments and services based on cost causation and equity considerations;

(c) customer desire for long-term rate stability and understandable price structures;

(d) costs and benefits of implementing various rate types/structures consistent with recognized rate design principles, including:

(i) time-of-use;

(ii) seasonal;

(iii) blocked;

(iv) tiered;

(v) commitment-based; and

(vi) other structures as may be reasonable and consistent with the goals and objectives of these guidelines;

(e) the potential for retail demand-response to cost-effectively enhance economic efficiency and promote the other goals and objectives of these guidelines; and

(f) the potential for direct load control to cost-effectively contribute to retail demand response.

History: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

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: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

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: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Rules 38.5.8214 through 38.5.8217 reserved

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: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

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: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

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: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

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: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

Rules 38.5.8222 through 38.5.8224 reserved

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: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

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

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: 69-8-403, MCA; IMP, 69-8-403, MCA; NEW, 2003 MAR p. 654, Eff. 4/11/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

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: 69-8-403, 69-8-419, MCA; IMP, 69-8-403, 69-8-419, MCA; NEW, 2003 MAR p. 2894, Eff. 12/25/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

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: 69-8-403, MCA; IMP, 69-1-114, 69-8-421, MCA; NEW, 2003 MAR p. 2894, Eff. 12/25/03; AMD, 2008 MAR p. 575, Eff. 3/28/08.

APPENDIX B
FREQUENTLY ASKED QUESTIONS

Q. I see the terms capacity and energy being used a lot in the plan. What is the difference between energy and capacity?

A. Electricity is measured in both capacity and energy. Capacity is measured in watts, kilowatts (kW), and megawatts (MW). In this plan we most often use megawatts (MW) when talking about capacity. Energy is measured in kilowatt-hours (kWh) and megawatt-hours (MWh). In this plan, we most often use the term megawatt-hours (MWh). The terms capacity and energy are used to describe generation characteristics of resources, and are also used to describe customers' loads. Understanding the difference between energy and capacity is critical to understanding the resource needs of our customers and the generation capabilities of different types of generation.

The term "capacity" is used in many different ways, but the two primary definitions used when describing a generation facility are 1.) nameplate capacity, which is the maximum output (MW) a generation facility can physically produce, and 2.) peaking capacity, which is the reliable level of output (MW) that a generation facility is able to produce during a peak load event. Most generators do not operate at their full nameplate capacity except in limited circumstances.

For example, for a small hydro facility with a nameplate capacity of 19 MW, the facility may be capable of producing at the full 19 MW for every hour in a day during the month of May when runoff is high. However, on a cold day in January, when loads are at their highest (peaking) and stream flows are lower, the facility may only be capable of producing 9 MW during the highest load hours of the day. If so, it would be appropriate to say that that facility has a peaking capacity of 9 MW, or that it has a peak capability of 47% (peaking capacity divided by nameplate, or 9 MW / 19 MW).

The term "energy" refers to the amount of electricity a generation facility produces over a specific period of time, normally over an hour, month or year. Energy production is generally less than maximum capability for most of the year.

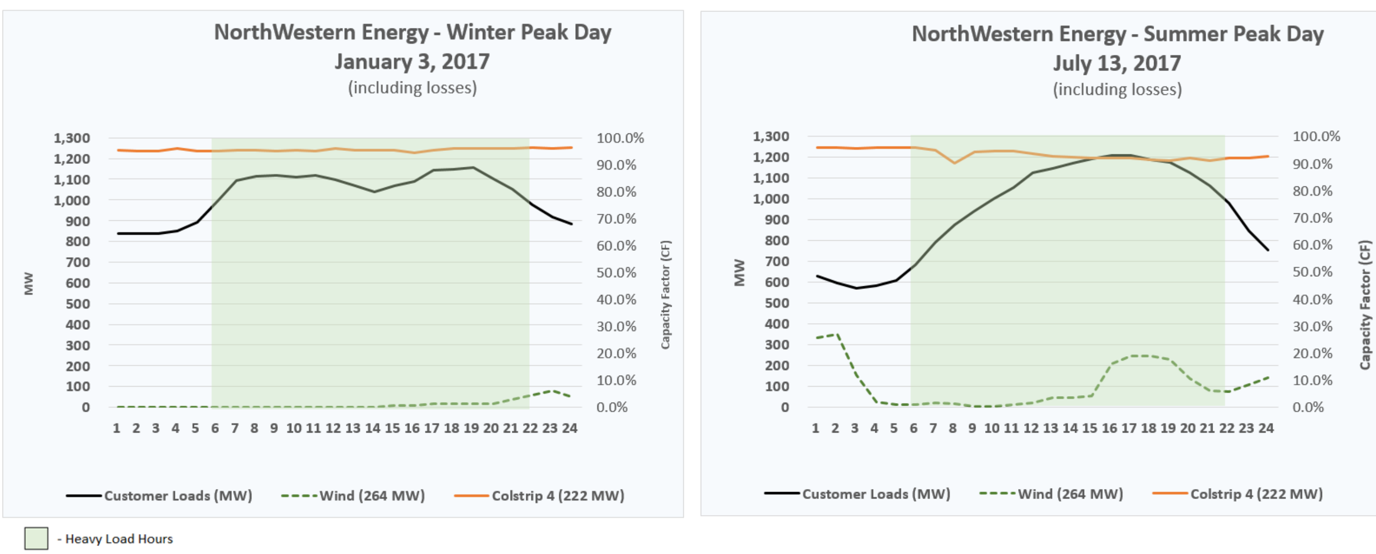
For example, using the same 19 MW hydro facility producing at the full 19 MW per hour for every hour during a day in May when runoff is high, it would be appropriate to say that that facility produced 456 MWh on that day (19 MW x 24 hours). On a day in January, when stream flows are lower, the facility might produce an average of 8 MW for every hour in a day. If so, it would be appropriate to say that the facility produced 192 MWh on that day (8 MW x 24 hours).

Q. Wind and solar appear to be a low-cost resources. Why does your model select natural gas generation over wind and solar?

A. Wind and solar are capable of providing low-cost energy but are generally not available to provide capacity when customers need it most, like after sunset on the coldest winter days in December and January.

Wind is typically only producing about five percent of its maximum capability on those days (5% of nameplate capacity). Theoretically, this means NorthWestern would need to build a wind facility that is about twenty times larger than a natural gas facility to obtain about the same amount of capacity needed to serve customers during peak loads. However, the capacity provided by a wind facility is not reliable enough to plan on being available during peak loads and in periods when twenty times larger isn't enough to provide reliable service.

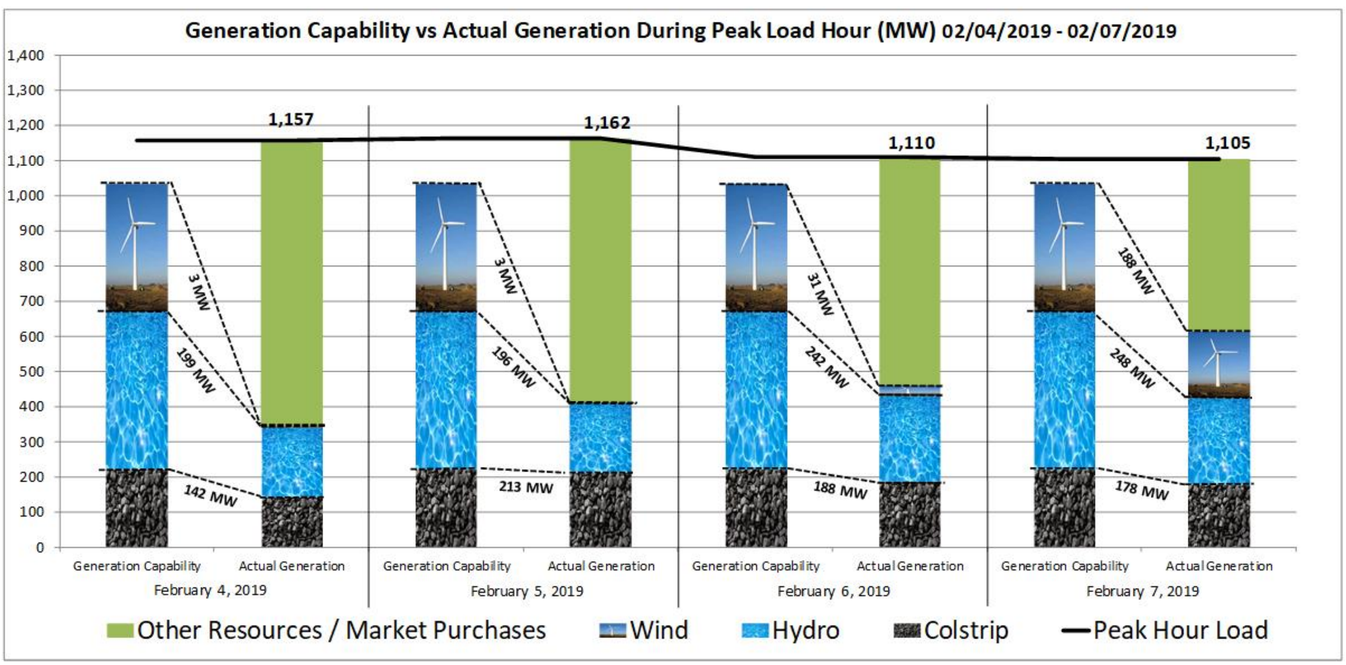
To illustrate this point, the graphs below show NorthWestern's peak load days for 2017. The black line represents customer load (shown as megawatts on the left hand scale), while the dashed green line shows wind production as percentage of its nameplate capacity on the right hand scale. The orange line represents Colstrip 4 production, also shown as a percentage of its nameplate capacity on the right hand scale.



As illustrated in the graphs, wind contributed very little of its maximum generation capability (especially on the critical winter peak day), while Colstrip 4 generated at 90 to 95 percent of its maximum capability. During peak load periods, customers need resources that NorthWestern can call upon as needed, 24 hours a day, 7 days a week. One way to increase the reliability of wind to provide capacity during peak load periods is to add battery storage. However, adding the battery storage needed makes the wind/battery combination much more expensive.

NorthWestern didn't include solar on the above graph because we did not have very much solar operating on our system in 2017. However, we have modeled solar production and have found that when compared to wind solar has a higher capacity contribution during the summer, but provides no capacity contribution during the winter when peak load hours occur after sunset.

Another example comes from the recent cold spell the week of February 4th, 2019. The figure below shows that wind generation contributed very little to NorthWestern Energy's peak load capacity need during that cold weather period. During the peak load hours on February 4th and 5th, wind was generating at 1% or less of its total nameplate capacity (3.2 MW and 2.5 MW respectively out of a nameplate capacity of 364 MW).



It's important to note that wind generation can vary several MW from hour-to-hour or even within the hour. NorthWestern cannot control the output from wind generation like we can with other resources. Because of this, NorthWestern must set aside (reserve) the generation capability of other resources on our system to balance variations in wind. Colstrip is one of our primary resources used to offset variations in wind and load; therefore, NorthWestern cannot simply maintain Colstrip at its maximum generation capability of 222 MW.

Q. As I read the Plan, I see that the lowest cost 20-year portfolio is the Base model, which adds a lot of natural-gas generation over the planning horizon. Is NorthWestern planning to build natural gas generation?

A. No. NorthWestern is not planning to build a bunch of natural gas fired generation. NorthWestern is required to model a number of portfolios to evaluate the costs and risks of different potential future conditions. Given the information currently available, natural gas appears to be a low cost resource. However, NorthWestern will use a series of competitive solicitation processes (also known as requests-for-proposals or RFPs), which will be conducted, monitored, evaluated and scored by an independent evaluator, to acquire the necessary resources to serve our customers. This method ensures all viable technologies or resources can submit proposals and each will be evaluated in order to determine which can most cost-effectively and reliably serve our customers. During the competitive solicitations, bidders will be able to submit proposals for a wide variety of resources including:

- Purchases from existing generation facilities
- Solar generation combined with energy storage
- Wind generation combined with energy storag,
- Energy storage technologies (pumped hydro, battery, compressed air)
- Natural gas generation facilities
- Demand response (paying participants to curtail energy use during times of peak loads)

Q. You say that you are going to provide for customers' needs using competitive solicitations. What kind of resources do you expect to be bid into a competitive solicitation?

A. NorthWestern conducted a competitive solicitation in 2017 and received proposals from a number of different resource technologies, including:

- Wind plus battery
- Solar plus battery
- Wind and solar
- Wind and solar plus battery
- Battery storage technologies
- Pumped hydroelectric storage
- Existing hydroelectric resources
- Compressed air energy storage plus battery
- Reciprocating engine technologies
- Combustion turbine technologies
- Combustion turbine plus battery

We anticipate receiving proposals from a similar, if not greater, range of technologies during the competitive solicitation process that will be initiated following the filing of this plan. The resources chosen from the process will be based on costs and performance.

Q. Why doesn't the plan include an early closure for Colstrip 4 as a scenario?

A. First and foremost, Colstrip 4 is a valued generation resource that provides continued value to customers over the twenty year planning horizon of this plan. This is a "lowest reasonable cost" resource plan in which we have included and modeled a number of scenarios to test the viability of alternative resources. An early closure of Colstrip 4 could not possibly result in overall savings to the resource portfolio, and could not result in a lowest reasonable cost future.

To date, all announced closures of regional coal plants have closure dates that are well into future. NorthWestern would expect no different treatment for Colstrip 3 and 4. NorthWestern anticipates that any announcement would allow enough time to plan and seek alternative resources, should that occur. Potentially, NorthWestern could hold one or more resource planning cycles to evaluate alternative resources.

Q. The resource plan has a lot of abbreviations and terms that I am unfamiliar with. Do you have a way for me to translate?

A. Yes. At the back of the plan we have included a list of abbreviations and a glossary defining many, if not all, of the terms used in the plan.

Q. The resource plan includes a chapter on transmission and its criticality to serving load. What would happen if the Colstrip Transmission System and/or the Colstrip generation facility were not available?

A. As noted in the Transmission Chapter, the transmission system and the generation system were developed together and rely upon each other to provide reliable service to our customers. A reduced or total shutdown of the Colstrip generation facility will place much more burden on the Colstrip Transmission System and the rest of NorthWestern's system to import power into Montana during critical peaking periods, potentially exceeding import limits. This could lead to reliability issues and a lack of supply resources to meet customers' energy needs. Additionally, the Colstrip Transmission system is the backbone of the Montana transmission system, and it provides NorthWestern with a very strong path from east to west across the state with which to reliably serve all of our Montana customers.

Q. If reducing exposure to the market is one of the goals of acquiring resources, why is NorthWestern joining the Energy Imbalance Market (EIM)?

A. NorthWestern's customers already have exposure to increased market prices for energy and capacity because we are short capacity needed during peak load times. Currently, NorthWestern transacts bilaterally with other companies, meaning that it makes purchase or sale arrangements directly with those companies. The EIM will change how some transactions are conducted, but it won't increase the market exposure that NorthWestern's customers already have.

Q. You discuss the possibility of NorthWestern eventually being part of a full organized market such as a Regional Transmission Organization (RTO), and that this market would likely have a specific capacity reserve requirement. Could NorthWestern avoid the need to procure capacity by choosing not to join an RTO?

A. No. NorthWestern already has the need for capacity. The rules of an RTO would specify how to calculate this need, and how different types of resources are counted toward meeting this need, but joining an RTO would not fundamentally change the need to have capacity in place.

APPENDIX C

GLOSSARY

A

Acre-foot	A unit of volume used for reservoirs (1 acre-foot = 43,560 cubic feet).
Ancillary Services	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice. These services include, among others, Regulation and Frequency Response, Reactive Power, Contingency Reserve, incremental and decremental capacity.
Attainment	National ambient air quality standards (NAAQS) air quality status for an area with concentrations of criteria pollutants that are below levels established by NAAQS.
Automatic Generation Control (AGC)	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule.
Available Transmission Capacity	(ATC) Available transmission capacity after considering firm commitments.

Average Annual Energy	The total amount of energy, measured in kWh or MWh, delivered over a period of one year divided by 8,760 hours per year.
Avoided Costs	Incremental cost to an electric utility of electric energy or capacity which, but for the purchase from the Qualifying Facility, such utility would generate itself or purchase from another source.

B

BAL-001-2	FERC approved NERC standard for Real Power Balancing Control Performance or Reliability Based Control (RBC).
Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.
Balancing Authority Area	The collection of generation, transmission, distribution infrastructure, and load-resource balance within the metered boundaries of the Balancing Authority.
Baseload	The minimum amount of electric power delivered or required over a given period at a constant rate.

C

Capacity	The maximum electric output that a facility can produce under certain conditions.
Capacity Factor	The ratio of actual output to potential output over a period of time. Normally calculated by actual output in MWh divided by the product of nameplate capacity times 8,760 hours.

Choice Customer	(NorthWestern) A NorthWestern electric service customer with an average monthly demand greater than or equal to 5,000 kW who chooses to buy power from a third party but uses NorthWestern transmission distribution, and other ancillary services (defined in § 69-8-201, MCA).
Community Renewable Energy Project	A Montana eligible renewable resource that is either owned by a public utility, or by specifically defined local owners that have a controlling interest, and is less than or equal to 25 MW in nameplate capacity, (defined in § 69-3-2003(4), MCA).
Contingency Reserves	As defined by NERC Standard BAL-002-WECC-2a, capacity held for deployment in the event of a contingency such as a generator or transmission trip. Contingency Reserve is comprised of Spinning and Non-spinning Reserves.
Cooling Degree Day	(CDD) A measurement used to indicate a building's cooling (air conditioning) energy consumption, defined relative to an outside (base) temperature, below which the building needs no cooling.
CPS1	(NERC Control Performance Standard 1) A regulating standard for calculating the frequency error for a balancing authority.
CPS2	(NERC Control Performance Standard 2) A regulating standard for balancing authorities intended to minimize excessive power flows due to corrections to CPS1 scores. Refer to BAL-001-2.
Criteria Pollutants	EPA identified pollutants under the 1970 Clean Air Act amendments setting standards for total suspended particulates, sulfur dioxide, nitrogen oxide, ozone, carbon monoxide, and lead.

Customer-generator	A user of a net metering system.

D

DEC	Capacity to decrease generation output on short notice (sub-hourly, typically within the 10 to 15 minute timeframe). Also called decremental capacity.
Demand	The highest rate of electrical use during a period of time.
Demand Response	Programs used by utilities as resource options for balancing supply and demand with methods such as time-based rates, peak pricing rates, and direct load control.
Demand Side Management	The potential for reduction of consumer demand for energy through various methods such as financial incentives and behavioral change.
Deterministic	Process or model in which the output is fully determined by inputs, thus containing no variability or risk.
Development	(Specifically as used in reference to Hydros projects) Refers to replacing units or adding new equipment, as defined by IEEE STD 1147-1991.
Dispatchability	The ability of a generating resource to deliver its output on demand.
Distributed Energy Resources	Small generation resources, energy storage, energy efficiency, and demand response resources on the distribution system, substation, or behind a customer meter that store or produce electricity and are not otherwise included in the formal NERC definition of the Bulk Electric System or at levels below 100kV.

E

Economic Derate	A reduction in generation due to availability of cheaper energy.
EIM	Western Energy Imbalance Market is a real-time bulk power trading market system that automatically finds the lowest-cost energy to serve real-time customer demand. The Balancing Areas joining the EIM remain responsible for their reliability standards as well as the requirement to enter with sufficient capacity.
ETAC	Electric Technical Advisory Committee is a diverse group of business, government, and energy professionals that advise NorthWestern on its energy supply planning.

F

Flexible Capacity Resource	A resource that can be dispatched (operated) relatively quickly to provide ancillary services such as regulation, spinning reserve, non-spinning reserve, INC, or DEC. This could include storage and demand response as well as generation.
Fly Ash	Non-combustible residual particles from the combustion process carried by flue gas.
Fundamental Market Relationships	The market price for electricity is governed by supply and demand economics, and is partially dependent on the market price of natural gas, through the spark spread and, more directly, the heat rate of natural gas-fired generation.

G

Geothermal Energy	Heat energy generated and stored in the Earth, which can potentially be converted to create steam to generate electricity.

H

Head	(Hydraulic head across a dam) A measure of water pressure based on height differences in water upstream and downstream of a dam.
Heating Degree Day	(HDD) A measurement used to indicate a building's heating energy consumption, defined relative to an outside (base) temperature, above which the building needs no heating.
Heat Rate	The amount of thermal energy (Btus) required by a generating unit to produce 1 kWh of electrical energy, expressed in this Plan as the higher heating value heat rate.
Heavy Load Hours	(On-Peak Hours) The periods of the week designated as traditionally having higher energy use; defined as hour ending 7 through hour ending 22 (inclusive) from Monday – Saturday.
Henry Hub	Natural gas distribution pipeline hub in Louisiana referenced as the principle pricing reference point in North America.
Higher Heating Value	(Heat Rate) A specific measure of the heat of combustion, the total energy released as heat, which is determined by bringing all products of combustion back to pre-combustion temperature and condensing any vapor produced.

Hydraulic Capacity	(Hydroelectric dam reference) A measure of the potential power generation for a hydroelectric dam based on current head and flow conditions.
Hydros	The system comprised of 11 hydroelectric dams and 1 storage dam purchased by NorthWestern in 2014 from PPL Montana.

I

INC	Capacity to increase generation output on short notice (sub-hourly, typically within the 10 to 15 minute timeframe). Also called incremental capacity.
Independent System Operator	An independent Federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and to ensure the safety and reliability of the electric system. ISOs typically include day-ahead and real-time markets for energy and ancillary services, with some including capacity markets.
Intercontinental Exchange	A trading platform that helps to define markets through an electronic exchange including energy commodities and other products.
Illiquid	(Market) Condition where commodities are not easily sold or exchanged for cash without significant loss in value or due to a lack of buyers and sellers.
Implied (Market) Heat Rate	A calculation of the day-ahead electric price divided by the day-ahead natural gas price. (Note that only a generation source with an operating heat rate efficiency below the calculated value can make money in the market.)

Implied Volatility	A measure of future potential market price moves; high IV indicates large price swings (either positive or negative) while low IV indicates smaller price swings.
Inadvertent Generation	An unintended power exchange that was either not agreed upon or in an amount different from the amount scheduled, and is usually attributed to the variable energy resources.
Integration	(Resource use) The process of adding new generation resources and rebalancing the operations of existing resources in a portfolio to continue to meet load and other balancing authority requirements, including regulation reserves, imbalance service, and scheduling.
Interconnected	(Transmission Grid use) The condition of being electrically connected and in synchronous operation with the electric transmission system operated by a BA.
Intermittent	(Resource use) Not continuously available, random, or varying in output.
Inverter	An electronic device that converts direct current (DC) to alternating current (AC), i.e., solar PV generation to grid-compatible power.

J

K

L

Light Induced Degradation	The initial process of declining efficiency in solar PV cells after first exposure to sunlight. It results in a permanent reduction in nameplate capacity.

Light Load Hours	(Off-Peak Hours) The periods of the week designated as traditionally having lower system demand; hours not included in the definition of Heavy Load Hours.
Liquid	(Market) Condition where many buyers and sellers exist and commodities can be easily exchanged for cash without significant loss in value.
Load	The net use of electric power from the transmission and distribution system for customers or devices.
Load Following	The use of on-line generation, storage, or load equipment to track the intra- and inter-hour changes in customer loads, similar to regulation, but over longer periods of time.
Load Shifting	Moving the time period of a portion of electricity demand from higher demand hours to lower demand hours.
Loss of Load Expectation	(as defined by NERC) The expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand (load). The LOLE is usually measured in days/year or hours/year. The convention is that when given in days/year, it represents a comparison between daily peak values and available generation. When given in hours/year, it represents a comparison of hourly load to available generation. LOLE is sometimes referred to as loss of load probability (LOLP). Also see LOLP.
Loss of Load Probability	(as defined by NERC) The proportion (probability) of days per year, hours per year, or events per season that available generating capacity/energy is insufficient to serve the daily peak or hourly demand. This analysis is generally performed for several years into the future and the typical standard metric is the loss of load probability of one day in ten years or 0.1 day/year. Also see LOLE. The NWPCC uses a metric, which establishes a minimum threshold LOLP standard of 5% for the Columbia River Basin (Region).

M

Marginal Unit of Generation	The next higher cost of generating an additional MWh (energy) compared to the current cost of energy supply.
Market Taker	An entity that must accept whatever price the market dictates.
Mass-based	EPA CPP methodology for reducing CO_2 emissions by using goals specifying the total weight of CO_2 emissions measured in tons of CO_2.
Mean	(Statistical) Average or expected value of a set of values.
Meaningful Uncertainty	A stochastic modeling term that recognizes the need to produce plausible ranges of results that inform rather than providing results which effectively have no useful application.
Mean Reversion	The assumption that prices will eventually move towards the average price over time.
Microgrid	A localized electrical grid or system with at least one distributed energy resource and one demand source which is considered as controllable load from a utility or that can be disconnected from the traditional grid.
Minimum Down Time	(Generator use) A constraint on the least amount of time that a generating unit must be off after shutdown, typically due to necessary maintenance.
Minimum Up Time	(Generator use) A constraint on the least amount of time that a generating unit must be on once it starts, typically to minimize thermal stresses in the equipment.
Mode	(Statistical) The most often occurring value in a set of values.

Monte Carlo	Modeling method that uses probability distributions for input values that have uncertainty, and produces distributions of possible outcomes.
Mountain Prevailing Time	Time of day based on the Mountain Time Zone and either Standard or Daylight Saving Time, whichever is applicable.
Must-take	(Resource use) A plant that requires, by physical design or contractual agreement, that the owner or purchasing customer accept all power production as it is generated.

N

Nameplate Capacity	The maximum rated generating output of a facility under specific conditions defined by the manufacturer.
NERC	North American Electric Reliability Corporation is a nonprofit corporation formed by the electric utility industry to promote the reliability and adequacy of bulk power transmission in the electric utility systems of North America.
Net Energy Metering	(NEM) Measuring the difference between the electricity distributed to and the electricity generated by a customer-generator that is fed back to the distribution system during the applicable billing period.
Net Present Value	The present value of future cash flows at a determined rate of return, used to discount future values back to today's dollars for a cost comparison of multiple projects, for example, alternative energy supply portfolios.
New Source Review	A CAA permitting program that requires industrial facilities to install modern pollution control equipment when they are built or when making a change that increases emissions significantly (as defined by EPA).

NGX	(TMX Group Limited – NGX) A Canadian natural gas exchange, trading, and clearing market.
Nodal Prices	Prices for a commodity such as electricity and natural gas determined by location or supply (interconnect) points and conditions of supply and demand associated with that location.
Non-attainment	(NAAQS use) Air quality status for an area with concentrations of criteria pollutants that are above levels established by NAAQS.
Non-Spinning Reserves	Also known as "Operating Reserve – Supplemental." Reserves that are not online but are capable of coming online to serve demand within 10 minutes or interruptible loads that can be removed from the system within a similar timeframe.
Northwest Power Pool	A voluntary organization of utilities in the Northwestern U.S., British Columbia, and Alberta Canada focusing on reaching maximum benefits of coordinated operations of its members.
NREL SAM	National Renewable Energy Laboratory's system advisor model for systems-based analysis of solar technology improvement.
NREL Wind Toolkit	A national dataset of meteorlogical conditions and turbine power for over 126,000 sites across the U.S. provided by the National Renewable Energy Laboratory.

O

Off-Peak Hours	Those hours defined by NAESB business practices, contracts, agreements, or guides as periods of lower electric demand and also may be those hours not included in On-Peak Hours (as defined in the QF-1 Tariff).

On-Peak Hours	Those hours defined by NAESB business practices, contracts, agreements, or guides as periods of higher electric demand and also may be the Heavy Load hours for the months of January, February, July, August, and December (as defined in the QF-1 Tariff).
One in two (1 in 2) Peak Demand Forecast	A forecast based on a 50% probability that the forecasted value will be less than the actual peak demand, and a 50% probability that the forecasted value will be greater than the actual peak demand.
Open Access	Federal Energy Regulatory Commission (FERC) Order 890: provides for non-discriminatory access to jurisdictional transmission systems to all eligible customers. NorthWestern has an Open Access Transmission Tariff.
Optimization	Process of determining the lowest NPV utilization of resources to reliably meet energy, capacity, and ancillary needs.

P

P5	The 5th percentile of a sample is the value below which 5% of all values within that sample occur.
P95	The 95th percentile of a sample is the value below which 95% of all values within that sample occur.
Pacific Prevailing Time	Time based on the Pacific Time Zone and either Standard or Daylight Saving Time, whichever is applicable.
Parasitic Load	The power consumed by a generating device or system for its own operation and/or when not generating, such as transformer losses in a solar PV system at night.
Particulate Matter	Microscopic solid or liquid particles suspended in the Earth's atmosphere.

Peak Demand	The highest hourly net energy consumption for load.
Peak Shaving	Process of reducing the amount of energy purchased from a utility company during peak demand hours.
Performance Ratio	(Solar PV system) Ratio between actual annual production of AC energy and the theoretical annual production of energy.
Pet Coke	(Petroleum coke) A solid by-product of oil refineries that can be used as a fuel.
Photovoltaic	An electricity generation system that converts sunlight (photons) into electric current (voltage) within a semiconductor panel.
PM_{10}	Particulate matter smaller than 10 microns in diameter.
Portfolio	A specified mix of actual resources or selection by software, of various combinations of resources used to meet electric load demand.
PPA	(Power Purchase Agreement) is a contract between the utility and generation facility owner that defines the terms of the purchase and sale of energy and/or capacity production.
Prevention of Significant Deterioration	(as defined by EPA) A CAA New Source Review permitting program that applies to new major sources or major modifications at existing sources for pollutants where the area in which the source is located is in attainment or unclassifiable with the NAAQS. It requires the following: 1. installation of the "Best Available Control Technology" (BACT);

	2. an air quality analysis; 3. an additional impacts analysis; and 4. public involvement.
Price-Taker	Company or resource that is not significant enough to influence the price of a good or service.
Procurement	The process of acquiring new resources.
Pro Forma	(Accounting use) A statement of a company's financial activities excluding unusual or non-recurring transactions.
Pumped Hydro Energy Storage	A type of hydroelectric energy storage used by electric power systems for load balancing. The method stores energy in the form of gravitational potential energy of water, pumped from a lower elevation reservoir to a higher elevation.
PVsyst	Photovoltaic generation modeling software designed by PVsyst SA.

Q

Qualifying Facility	A small power production or cogeneration facility that meets either the renewable fuel or secondary recovery criteria for the generation of electricity and capacity, set forth by PURPA, including all pertinent requirements of Code of Federal Regulations Title 18 Conservation of Power and Water Resources and state law corollaries.
QF-1 Tariff	A MPSC approved electric tariff schedule that specifies rates and conditions for standard offer contracted renewable generation (Qualifying Facilities or QFs) power purchase terms between the utility (NorthWestern Energy) and the QF owner.

R

Ramp Rate	Speed at which a generator can increase or decrease generation, typically measured in units of MW/minute during the ramp period.
Regional Haze Rule	(CO_2 Emissions use) EPA CPP methodology for reducing CO_2 emissions that uses goals specifying the ratio of pounds of CO_2 emissions to the net energy produced, measured in units of (lbs. CO_2/net MWh).
Rate-based	(Resource use) A utility-owned generation resource in which the costs to purchase or build the resource are paid by the utility's customers through billed electric rates.
Rate of Return	The profit on an investment over a period of time, expressed as a proportion of the original investment.
Realtime	The balancing and marketing of electric energy in the present-time as opposed to any future time. Also referred to as 24 hours a day, seven days a week.
Regional Transmission Organization	An independent Federally regulated entity established to coordinate interstate transmission facilities in a non-discriminatory manner and to ensure the safety and reliability of the electric system.
Regression model	A technique to analyze a dependent variable's reaction to changes in other independent (explanatory) variables.
Regulation	An ancillary service consisting of reserves that are responsive to automatic generation control and are sufficient to provide normal regulating margin..
Rehabilitation	(Hydro Project use) Remanufacturing or refurbishing existing units, as defined by IEEE STD 1147-1991.

Reliability	Adequacy and security of the transmission system to operate properly under stressed conditions.
Reliability-Based Control	Refers to NERC Standard BAL-001-2, Real Power Balancing Control Performance. Among other things, the Standard requires a Balancing Authority to operate such that its Area Control Error does not exceed defined limits for more than 30 consecutive clock minutes. The Standard becomes effective July 1, 2016.
Renewable	A type of energy, or resource that generates the energy, that is produced from essentially sustainable fuel, such as falling water, wind, geothermal, or solar radiation.
Renewable Energy Credit	One megawatt-hour of renewable energy generation from an eligible renewable resource (defined by § 69-3-2003, MCA).
Reserve margin	Excess generating capacity above expected peak demand normally used in recovering from contingencies (unexpected events) within the BA.
Resource Plan	Administrative Rules of Montana (ARM) 38.5.2001 sets forth that electric utilities in Montana should plan to meet customers' needs for adequate, reliable and efficient energy services at the lowest total cost while remaining financially sound. ARM 38.5.2012 sets forth the utility requirement to file plans with the commission on a two year cycle.
Risk premium	A monetary value associated with the risk of a specific portfolio, defined as the integral of the cost distribution above the mean.
Run-of-the-river	A FERC designation for a hydroelectric dam that must maintain minimum differences in upstream and downstream flow rates, and minimum storage reservoir level fluctuations, so that only water from upstream is

	available for generation at that moment and any unused amount must be spilled.

S

Scrubbers	Systems that remove particles or gases from industrial exhaust streams.
Solar PV	(see Photovoltaic) An electricity generating resource that uses sunlight as fuel to create an electric charge in semiconductor panels.
Spark Spread	The gross-generation profit margin earned by buying natural gas and burning it to produce electricity (compared to purchasing electricity from the market), which depends on energy prices and generator efficiency (heat rate), measured in units of ($/MWh).
Spinning Reserves	Also known as “Operating Reserve – Spinning.” Must be online and immediately and automatically responsive to frequency deviations and fully deployable within 10 minutes.
Stochastic	A process in which there is inherent randomness; where the same inputs will produce a distribution of outcomes through iterative sampling of variables.
Sub-bituminous	An intermediate coal with properties between lignite and bituminous coal.
Supervisory Control and Data Acquisition (SCADA)	A computer-based system for remotely monitoring and controlling processes, such as power generation, electric transmission, and distribution.

T

Tier II	QF power purchase agreements that are subject to MPSC Docket Nos. D97.7.90 and D2001.1.5, Order Nos. 5986w and 6353c.
Time of Use	A variable rate structure that charges customers a rate dependent on the time of day and season the energy is used.
Tolling PPA	A power purchase agreement where the buyer provides fuel as needed to meet the generation which is controlled and purchased by the buyer.
Total Transmission Capacity	Total designed and approved transmission capacity of a transmission path (TTC).
Transmission Constraint	A condition where the electric transmission system is not able to transmit power to the location of demand, due to congestion at one or more points of the transmission network.
Turbine	A rotary mechanical device that extracts energy from a fluid (i.e. water) or the wind and converts it into work, such as turning a rotor.

U

Utility System	The interconnected grid within the BA area consisting of generation, transmission, and distribution equipment.

V

Variable Energy Resource	A renewable energy source that is non-dispatchable either due to its fluctuating nature or must-take contract requirements.
Volatility	The degree of variation of a market price over a period of time.

W

Waste Coal	A usable material byproduct of a previous coal processing operation.
Waste Coke	(Petroleum coke) A solid by-product of oil refineries that can be used as a fuel.
Weighted Average Cost of Capital	The rate that a company is expected to pay on average to all its security holders to finance assets. It is used to discount all costs back to present value in order to compare portfolio cash flows in the future. At the time of this Plan, NorthWestern used a WACC of 7.03%.

Z

Zero discharge	Permit requirement prohibiting waste water discharge from a site.

APPENDIX D

ABBREVIATIONS

2019 Plan	2019 Electricity Supply Resource Procurement Plan
AACE	Advancement of cost estimating
AC	Alternating current
ACC	Air cooled condenser
ACE	Area control error
ACER	Affordable clean energy rule under the U.S. EPA
ADMS	Advanced distribution management system
AECO	Alberta Energy Company
AESO	Alberta Electric System Operator
AGC	Automatic Generation Control
ANPRM	Advance notice of proposed rulemaking
AOC	Administrative Order on Consent
ARM	Administrative Rules of Montana
ARS	Automatic resource selection
Available TC	Available Transmission Capacity
BA	Balancing Authority
BART	Best available retrofit technology
BAU	Business as usual
Bcf	Billion cubic feet
BESS	battery energy storage system
BMS	Battery management systems
BPA	Bonneville Power Administration
BSER	Best system of emission reduction
CAA	Clean air act

CAES	Compressed air energy storage
CAES	Compressed air energy storage
CAISO	California Independent System Operator
CCCT	Combined cycle combustion turbines
CDD	Cooling degree day
CFL	Compact Fluorescent lamp
CIG	Colorado Interstate Gas
CMPL	Canadian-Montana Pipeline Company
CO_2	Carbon dioxide
CPP	Clean Power Plan
CPS1	Control Performance Standard 1
CPS2	Control Performance Standard 2
CREP	Community Renewable Energy Projects
CRR	Coal combustion residuals
CSEWG	Community Sustainable Energy Working Group
CT	Combustion turbines
DC	Direct current
DEC	Decreases in capacity output
DER	Distributed Energy Resource
DGGS	Dave Gates Generating Station
DOE	Department of Energy
DSIP	Distribution system infrastructure project
DSM	Demand Side Management
E3	Energy and Environmental Economics
EDAM	Enhanced Day Ahead Market
EIA	U.S. Energy Information Administration
EIM	Energy Imbalance Market
EPA	U.S. Environmental Protection Agency

EPC	engineer, procurement, and construction
ETAC	Electric Technical Advisory Committee
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
FO	Fuel Oil
FR	Federal Register
GHG	Greenhouse Gas
GSU	Generator step-up transformers
HDD	Heating degree day
HDR	HDR Engineering, Inc.
HDR	HDR Engineering, Inc.
HL	Heavy Load (used when referring to the weekday and Saturday hours ending 7 through hour ending 22 inclusive, Pacific Prevailing Time)
HRI	Heat rate improvements
HRSG	Heat recovery steam generator
HVAC	Heating, ventilating, and cooling
ICE	Intercontinental Exchange
INC	Increases in capacity output
INL	Idaho National Laboratory
ISO	Independent System Operator
ITC	Investment tax credit
KLI	Kilowatt Labs, Inc.
kV	kilovolt
kW	Kilowatt
kWh	Killowatt hour
LED	Light-emitting diode
LGIA	Large generator interconnection agreement

LIEAP	Low Income Energy Assistance Program
Li-ion	Lithium Ion
LL	Light Load (used when referring to those hours not included in the definition of Heavy Load Hours)
LNG	Liquified natural gas
LOLH	Loss of load hours
LOLP	Loss of load probability
LSTK	Lump sum turnkey
M	meters
MATS	Mercury and Air Toxics Rule
MCA	Montana Code Annotated
MCA	Montana Consumer Counsel
MDEQ	Montana Department of Environmental Quality
MFWP	Montana Fish Wildlife and Parks
MMBtu	Million British thermal units
MMcfd	Million cubic feet per day
MOU	Memorandum of understanding
MPSC	The Montana Public Service Commission
MW	Megawatt
MWa	Average megawatts
MWh	megawatt hour
MWTG	Mountain West Transmission Group
NAAQS	National Ambient Air Quality Standards
NCF	Net capacity factor
NEEA	Northwest Energy Efficiency Alliances
NEM	Net energy metering
NERC	North American Electric Reliability Corporation
NERC	North American Reliability Corporation

NGCC	natural gas combined-cycle
NREL	National Renewable Energy Laboratory
NTP	Notice to proceed
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
O&M	Operation and maintenance
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff
PCS	Power Conversion Systems
PHES	Pumped hydro energy storage
PM	Particulate matter
POM	Portfolio optimization model
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PRSC	Participating Resource Scheduling Coordinator
PSCo	Public Service Company of Colorado
PTC	Production tax credit
PTP	Point-to-point
PV	Photovoltaic
RBC	Reliability Based Control
REC	Renewable Energy Credit
RFI	Request for Interest
RFP	Request for Proposal
RHR	Regional haze rule
RICE	Reciprocating internal combustion engines
RPS	Renewable Portfolio Standard
RS	Resource sufficiency
RTO	Regional Transmission Organization

SCADA	Supervisory control and data acquisition
SEIA	Solar Energy Industries Association
SIP	State implementation plan
SMR	Small modular nuclear reactor
SPP	Southwest Power Pool
SRC	Selective catalytic reduction
TAC	Technical advisory committee
Talen	Talen Energy
Total TC	Total Transmission Capacity
ULSD	Ultra-low sulfur diesel
USB	Universal system benefits
VER	Variable energy resource
WACC	Weighted average cost of capital
WAPA	Western Area Power Authority
WECC	Western Electricity Coordinating Council
Wp	watt-peak capacity
WREGIS	Western Renewable Energy Generation System