2020 Supplement to the 2019 Electricity Supply Resource Procurement Plan

December 2020

NorthWestern Energy

Delivering a Bright Future

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1. INTRODUCTION

NorthWestern Energy (NorthWestern) has assembled this 2020 Supplement to the 2019 Electricity Supply Resource Procurement Plan (2019 Plan) to provide additional information about certain key aspects of the 2019 Plan and ongoing developments in regional markets and supply planning efforts in the Pacific Northwest. The key issues addressed in this 2020 Supplement include:

- The development of a Resource Adequacy program for our region;
- The application of Effective Load Carrying Capability (ELCC) as a measurement of the capacity contribution provided by variable energy resources like wind and solar and energy-limited resources like batteries and pumped hydroelectric (hydro) energy storage;
- An analysis of the duration of events when NorthWestern is capacity deficit and discussion of the implications this has for future resource considerations; and
- Additional modeling scenarios.

The key conclusion of the 2019 Plan remains the same: the region faces an increasing probability of near-term deficits in its power supply during peak load conditions, and the chance of shortages is expected to grow unless the region invests in new capacity.[1] Recent outages in California suggest that shortages may be arriving sooner than expected. According to the California system operator, these shortages occurred in part because "resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours."[2] NorthWestern currently stands out among our regional neighbors as the utility that relies most heavily on others to meet peak needs. Although other utilities are seeking to add new capacity to serve their customers' peak needs, it is unwise and unreasonable for NorthWestern to expect these utilities to add sufficient extra capacity that would be necessary to meet our peak needs in addition to their own.

Utilities across the region, including NorthWestern, are taking action to maximize the cost-savings from coordinated and efficient sharing of generation resources by taking advantage of geographic diversity in the timing of renewable generation and peak loads. While the timing of peak electricity demands across the region is correlated (the weather patterns are generally similar), there is some variation across different utilities' service areas. Efforts to develop a program to coordinate the sharing of resources will allow the region's utilities to capture potential benefits of diversity in loads and weather-driven generation and thereby reduce the total cost of a reliable and adequate power supply for the region as a whole and to the participants. The development of this program is being led by the Northwest Power Pool and is described more in Chapter 2 Developments in Regional Markets. Though the program is still in development, it is likely that utilities that participate will be required to meet the program's resource adequacy standards or will be assessed penalties for failing to meet those standards.

The Appendix and other supporting files for the 2020 Supplement are available for download at http://www.northwesternenergy.com/2019-resource-plan.

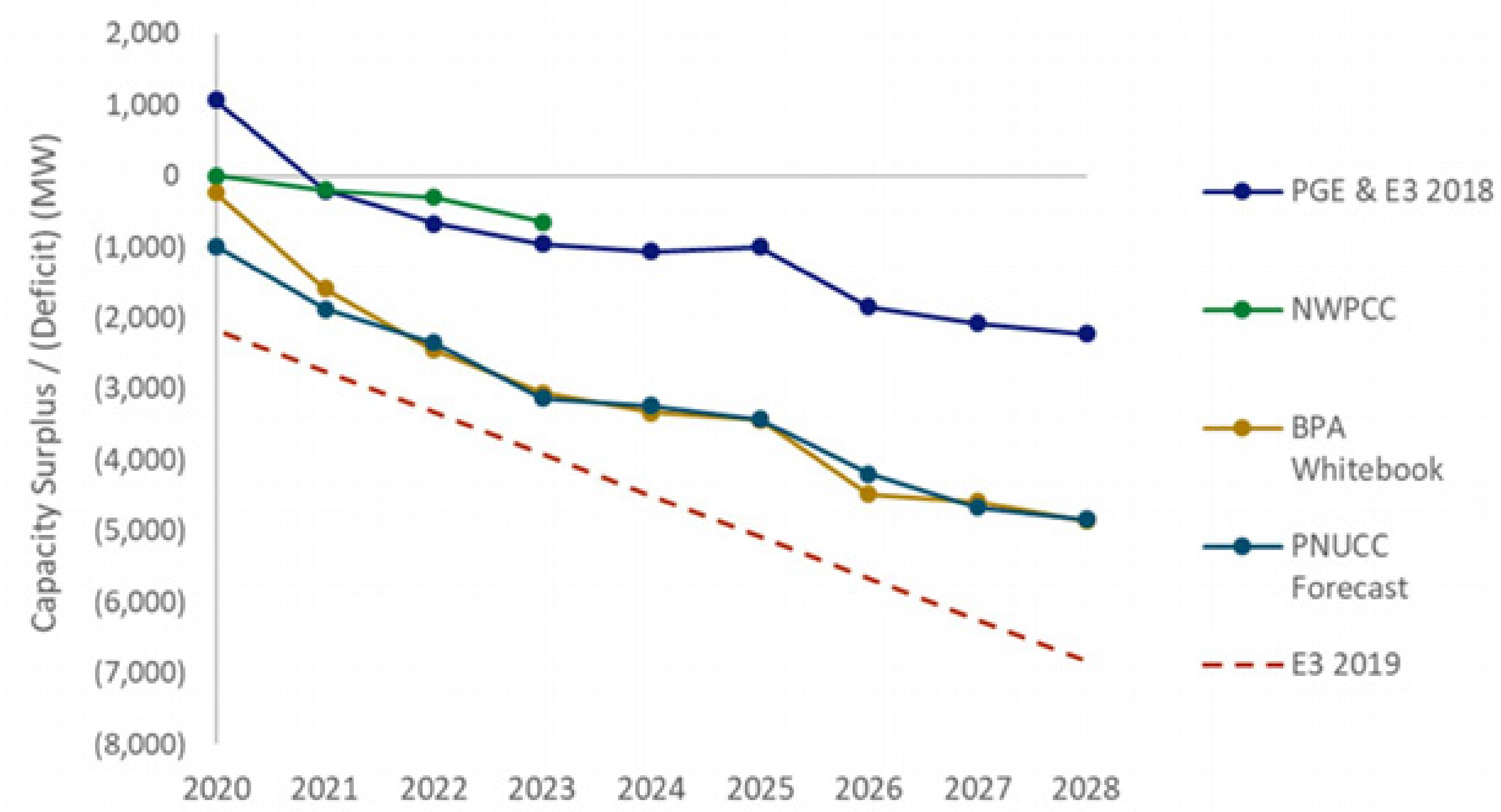
The Regional Capacity Position

A range of recent analyses conclude that the Pacific Northwest faces a near-term shortage of power supplies during peak load conditions. These include studies by the Northwest Power and Conservation Council (NWPCC), the Bonneville Power Administration (BPA), the Northwest Power Pool, and consultants.[3] The Northwest Power Pool offers a clear summary: "Although each study differs in scope and methods, a common finding across most of these studies is that the Northwest is either capacity-short today or will be within the next two years."[4]

Depending on the particular methods and assumptions, these studies place the probability of demand exceeding supply in the range of 7 percent as soon as 2021 and up to 26 percent in 2026 (NWPCC). This is well above the 5 percent threshold that has been established as the limit for an adequate power supply. One study estimates that the need for new firm capacity rises to 16,000 megawatts (MW) by 2030 if all coal in the region is retired.[5] This represents a substantial regional shortfall (for comparison, 16,000 MW is about 13 times larger than NorthWestern's peak capacity needs). Figure 1 shows the region's deficits forecast by these studies.

1 Northwest Power and Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2024.
2 California Independent System Operator, California Public Utilities Commission, and California Energy Commission, Preliminary Root Cause Analysis – Mid-August 2020 Heat Storm. Available at http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf.
3 These studies (including links) are discussed further in Section 2.1 Load-Resource Balance in the Region
4 Northwest Power Pool, (2019). "Exploring a Resource Adequacy Program for the Pacific Northwest." Page 20. Available at https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf
5 Energy and Environmental Economics (2019). "Resource Adequacy in the Pacific Northwest." Available at https://www.publicgeneratingpool.com/s/E3_NW_RA_Presentation-2018-01-05.pdf

Figure 1. Summary of the Region's Capacity Position Across Multiple Studies (reproduced from NWPP, 2019[6])



The Pacific Northwest's power supply has a high proportion of weather-driven resources, which creates challenges for ensuring adequate power supplies are available to meet peak loads. The region's hydroelectric generation resources make up the largest share of our weather-driven supplies, and the share of wind and solar resources has increased considerably in recent years as carbon-emitting resources are retired and replaced by carbon-free resources. This transition to more reliance on wind and solar resources creates challenges for ensuring an adequate power supply because carbon-emitting resources are typically dispatchable whereas wind and solar are not, unless they are augmented with storage technologies (whose costs and limitations are far from trivial). The resulting reduction in operators' ability to control the dispatch of resources has important consequences for how individual utilities and the region as a whole can ensure there is an adequate power supply at whatever moment customers' needs reach their highest levels, and for however long these peak needs last.

To ensure that power supplies are adequate but not overbuilt, the region's utilities are taking efforts to coordinate how they study their generation capacity under different weather conditions, being sure to account for the diversity and correlations across the loads and generation in their service territories. The goal is to strike an appropriate balance between making sure that generation supplies are adequate but also that resources are shared efficiently across the region to minimize the total cost of the system.

NorthWestern is participating in these discussions and supports the development of a program to coordinate and share information and resources. NorthWestern will also join the Western Energy Imbalance Market (EIM) in April of 2021. Participation in the EIM helps make efficient use of resources, but it does not reduce a Balancing Authority's need for capacity. In addition, participation in the EIM will require us to meet certain standards that ensure that NorthWestern does not unduly "lean on" the other participants to meet our needs. In other words, we will need to bring our own fair share of capabilities—that is, sufficient resources to meet our customers' flexibility and peak load needs—to the table. This can be in the form of utility-owned resources or other arrangements, such as contracts with other generation owners. More detailed information about the EIM's requirements and the development of a regional resource adequacy program are provided in Chapter 2 Developments in Regional Markets.

6 Northwest Power Pool, (2019). "Exploring a Resource Adequacy Program for the Pacific Northwest." Page 20. Available at https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf.
The projections in the NWPCC study are from 2018, the BPA Whitebook is from 2018, and the PNUCC Forecast is from 2019.

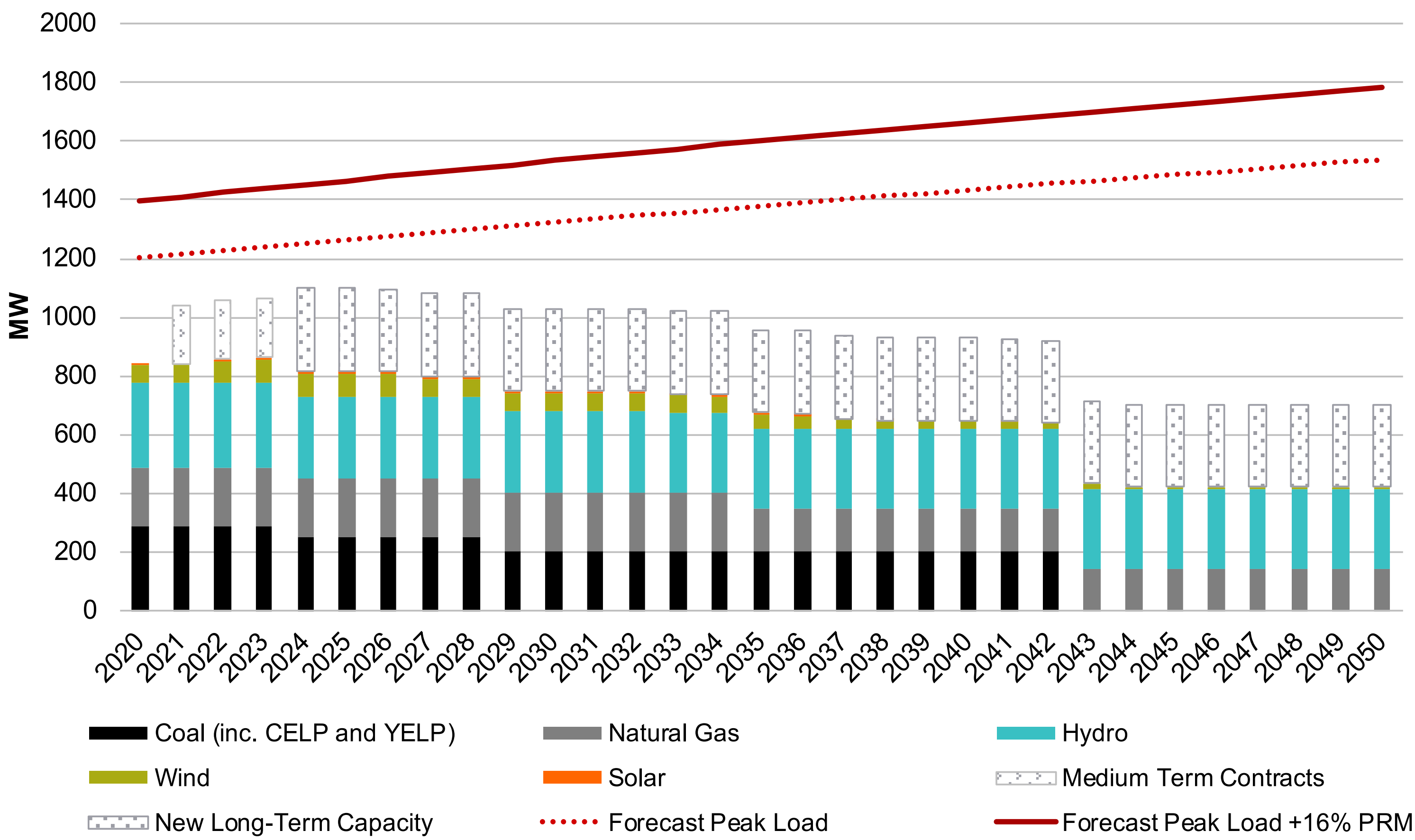
NorthWestern's Capacity Position

NorthWestern's current generation portfolio is too small for meeting our peak loads and thus requires us to rely significantly on imported power from other utilities or independent power producers. Our peak loads are in the range of 1,200 to 1,250 MW and our portfolio currently has an effective load-carrying capability of about 840 MW.[7] This is about 600 MW less than what industry standard utility planning practices would recommend (standard practice is to have capacity equal to peak loads plus a "planning reserve margin" in the neighborhood of 13-18%). As the region now confronts a deficit as a whole, NorthWestern's heavy reliance on purchases from other utilities becomes increasingly risky. If the remaining generation facilities at Colstrip shut down, our deficit will increase by about 238 MW.[8]

The effective load-carrying capability of a generation portfolio is less than the total nameplate capacity. The difference is that the nameplate capacity is the maximum power each resource can provide under *ideal* conditions, and the effective load-carrying capability is the amount of capacity the resource can be expected to provide during *peak load* conditions. A resource's ability to serve peak loads depends on a range of factors that include the weather, fuel supplies, resource operating capabilities, and unexpected outages. Thus, measurements of a generation portfolio's peak-serving capacity use probabilistic assessments based on simulations of loads and generation output under a range of conditions. Refer to Section 3.3.1 Capacity Contributions for more detailed discussion.

The generation resources currently under NorthWestern's control include a diverse range of fuel types and resource ownership arrangements. About 65% of NorthWestern's installed capacity is dependent on the weather. The following table and graphic show NorthWestern's current and projected capacity position if no action were taken to remedy the projected deficits.

Figure 2: NorthWestern's Capacity Position



7 In this Supplement, we use the Effective Load Carrying Capability (ELCC) metric for measuring the capacity contribution from intermittent resources (e.g., wind and solar) and energy-limited technologies (e.g., storage). We previously measured the capacity contribution of intermittent resources using an "exceedance methodology" developed by the Southwest Power Pool. However, the ELCC method improves on the prior method in a number of ways and is increasingly being used for planning purposes by planning entities across the industry. The application of ELCC in this Supplement is described in Section 3.3.1 Capacity Contributions. For a comprehensive description of ELCC, see *Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy,* Schlag et al., 2020. Available at https://www.ethree.com/elcc-resource-adequacy/.

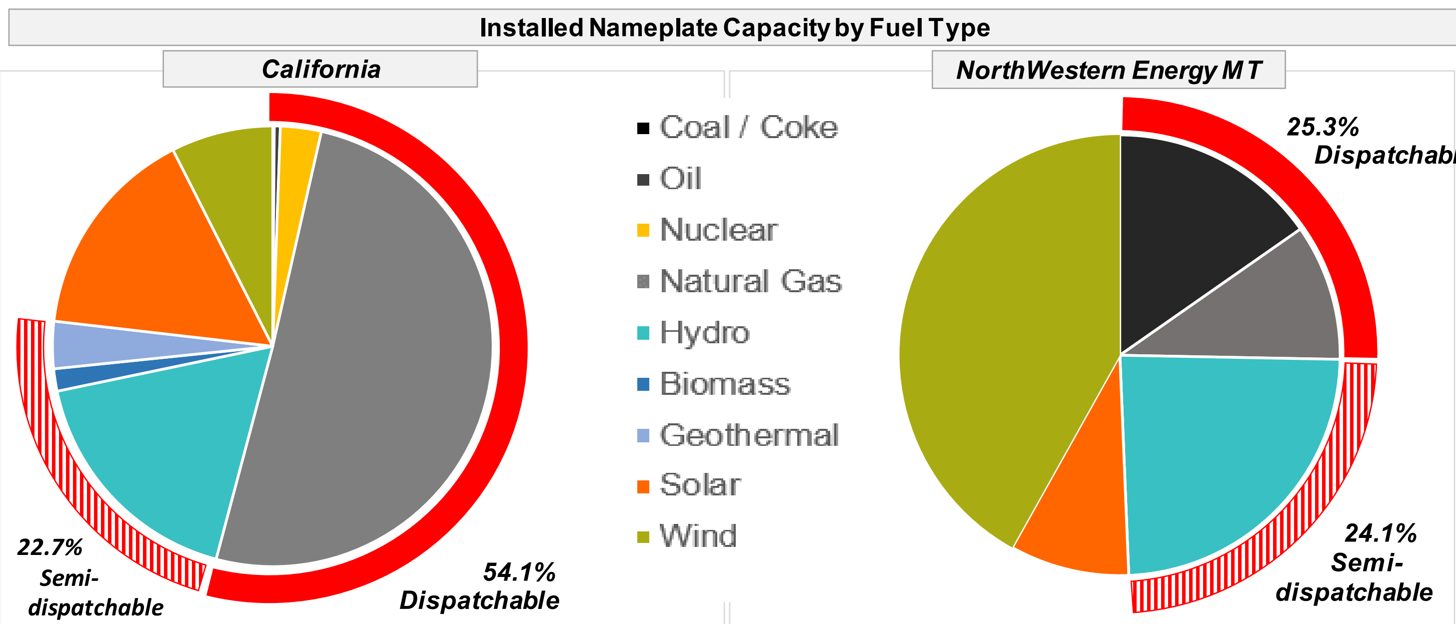
8 NorthWestern's 222 MW share of Colstrip provides 204 MW of effective capacity and CELP provides 34 MW. See Section 3.2 NorthWestern's Resources.

Figure 3: NorthWestern's Existing Generation Capacity, by Fuel Type

Capacity by Fuel Type							
Fuel Type	**Maximum (Nameplate) Capacity**		**2019 Annual Energy**		**Effective Load Carrying Capability**		
	(MW)	**(% of total)**	**(GWh)**	**(% of total)**	**(% of Nameplate)**	**(MW)**	**(% of total)**
Existing Resources							
Hydro	486	33%	2,864	43%	60%	292	35%
Wind	455	31%	1,182	18%	13%	59	7%
Solar	17	1%	30	0%	6%	1	0%
Carbon-free subtotal	958	65%	4,076	61%	37%***	352	42%
Coal	222	15%	1,429	21%	92%**	204	24%
Natural Gas	202	14%	381	6%	98%**	197	24%
Thermal QF*	87	6%	761	11%	97%**	84	10%
Total	**1,469**	**100%**	**6,647**	**100%**	**57%*** **	**837**	**100%**
QFs Eligible for Contract but not yet Online							
Wind	392				5	20	
Solar	160				5	8	

" CELP and YELP
** Based on forced outage rates instead of ELCC calculations
*** Weighted average of capacity contributions across resource types

Figure 4. Comparison of Resource Mix: California and NorthWestern Energy



A Balanced Approach

The combination of the growing shortage of capacity in the region combined with the variability introduced by increasing amounts of weather-driven resources together create a crucial need for generation resources that will reliably be available when loads are high and weather-driven generation is low. Such resources could take the form of dispatchable resources like traditional thermal generators or energy storage technologies, or wind and solar resources located in other weather regimes that may generate when the solar or wind in NorthWestern's balancing area do not (such resources would also require the associated transmission capacity necessary to deliver their power to our load). Demand side management measures like energy efficiency and demand response will also contribute to reducing the shortfall, though they will not be adequate on their own given the magnitude of NorthWestern's capacity deficit.

The growing prevalence of wind and solar generation across the West has had counterintuitive effects on energy prices: prices are lower on average but they have higher volatility. In combination with historically low prices for natural gas, the "free" energy from wind and solar ("free" only because there is no fuel cost) has reduced the cost of energy in wholesale power markets. However, the variability and uncertainty introduced by wind and solar generation can increase the probability of coming up short in periods when loads are high, which can result in rapid spikes in the price of power. As long as there is an adequate supply of power it may be reasonable to be exposed to occasional price spikes. However, if there is not an adequate supply of power these events may cause a "loss of load" which would result in some customers temporarily losing power.[9] Our region in particular is vulnerable to power shortages during a low-water year because we rely so heavily on generation from hydroelectric dams. Given the variability in power prices, there is also economic value in the ability to control dispatchable resources. When prices are lower than a dispatchable resource's variable cost, it can be dispatched down and withheld from generating to take advantage of the cheaper market power. Similarly, when prices are higher than a dispatchable resource's variable costs, it can be dispatched up to generate revenue.

Because of NorthWestern's capacity deficit, and because the region faces a shortage and markets are thus increasingly less reliable as a source of energy, NorthWestern identified a strategy in the 2019 Plan to acquire new capacity by soliciting competitive proposals and considering opportunity resource purchases. The implementation of this strategy includes a request issued in June 2020 for new contracts with existing resources (targeting the medium-term of 1-3 years), and our request issued in January 2020 for proposals of long-term sources of capacity, including the development and construction of new generating resources (targeting the 3- to 30-year timeframe).

The proposals received in response to NorthWestern's RFPs are being evaluated to determine which proposals will ensure a reliable supply of electricity at the lowest long-term total cost. This evaluation will take into account the costs, risks, and benefits associated with different resource types and contract structures. NorthWestern will likely provide its assessment and recommendation for the most cost-effective collection of capacity resources and contracts to the Montana Public Service Commission for approval prior to committing to these new sources of capacity.

Figure 5: Resource Adequacy and Near-Term Resource Actions

NorthWestern's Resource Adequacy Position			
Current Resource Position			
Peak Load	1200	MW	Grows from about 1,200 MW in 2021 to 1,250 in 2030. See Section 3.1.
Planning Reserve Margin	16	%	Approximate. See Section 3.3.2.
Total Peak Need	1392	MW	
Existing Capacity	837	MW	See Section 3.2.1.
Deficit	555	MW	
Pending Resource Actions			
Request for Near-Term Contracts	200	MW	Approximate. See Section 3.3.3.
Request for Long-Term or New Generation	280	MW	See Section 3.3.4.
Long-Term Capacity Deficit (2024 and beyond)			
If RFP for Long-Term Capacity is successful:	275	MW	
Effect on deficit if:			
Colstrip closes	+238	MW	Colstrip provides 204 MW of effective capacity and CELP provides 38 MW.
RFP for Long-Term Capacity is unsuccessful	+280	MW	
Deficit if Colstrip closes and RFP is unsuccessful:	793	MW	

9 A common metric for determining whether a system is reliable is to measure the "loss of load probability" (LOLP). Typically, a system with an expected LOLP of less than one day in ten years is considered reliable.

2. DEVELOPMENTS IN REGIONAL MARKETS

Power markets in the West have historically relied on bilateral trading arrangements rather than the organized markets used in other parts the country. This has been changing recently, driven in part by concerns about capacity shortages, increasing amounts of variable energy supplies, and technological developments. NorthWestern is actively participating in discussion to develop a Resource Adequacy program for the Pacific Northwest, and will soon join the Western Energy Imbalance Market. This section describes the key developments expected in regional markets in the coming future and describes how they will be likely to influence NorthWestern's customers and energy supplies.

2.1. Load-Resource Balance in the Region

A number of recent analyses conclude that the Pacific Northwest faces a near-term shortage of power supplies during peak load conditions. Utilities across the region are projecting capacity shortages in their integrated resource plans, and California experienced challenges meeting its peak loads this August, which resulted in rolling blackouts for the first time since 2001.

The Northwest Power Pool offers a clear summary of the studies of resource adequacy in the Pacific Northwest: "Although each study differs in scope and methods, a common finding across most of these studies is that the Northwest is either capacity-short today or will be within the next two years."[10] Depending on the particular scenarios and assumptions considered, these studies place the probability of near-term supply shortages around 7 percent[11] as soon as 2021 and up to 26 percent in 2026 (NWPCC) with as much as 16,000 MW of new firm capacity—equivalent to about 13 times NorthWestern's peak load needs—required by 2030 if all coal in the region is retired (Energy and Environmental Economics). The entities conducting these studies include a range of organization types, all with considerable expertise in power supply planning and the Pacific Northwest region.

Figure 6. Resource Adequacy Studies of the Pacific Northwest

Studies of Resource Adequacy in the Pacific Northwest		
Entity	**Report**	**Location**
Northwest Power and Conservation Council	Pacific Northwest Power Supply Adequacy Assessment for 2024	https://www.nwcouncil.org/sites/default/files/2024%20RA%20Assessment%20Final-2019-10-31.pdf
Bonneville Power Administration	2018 Pacific Northwest Loads and Resources Study	https://www.bpa.gov/p/Generation/White-Book/Pages/White-Book-2018.aspx
Northwest Power Pool	Exploring a Resource Adequacy Program for the Pacific Northwest	https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf
Energy and Environmental Economics	Resource Adequacy in the Pacific Northwest	https://www.publicgeneratingpool.com/s/E3_NW_RA_Presentation-2018-01-05.pdf
Pacific Northwest Utilities Conference Committee	2020 Northwest Regional Forecast	https://pnucc.org/system-planning/northwest-regional-forecast

NorthWestern has historically relied on importing power from other utilities or independent power producers to meet our peak loads, but the tightening of the regional capacity position makes this increasingly risky. The tight capacity situation is also occurring in the Western US more broadly. In August 2020, California faced rolling blackouts for the first time in 20 years, caused in part by an overly optimistic assessment of the availability of imports. In their planning assessments, the California Independent System Operator (CAISO) assumed they would be able to import over 10 GW of power to meet their peak demand. But when their loads peaked in August, there were several key hours when significantly less was available and imports were as low as 5 GW (50% less than expected).[12] Imports may be restricted due to high demand on neighboring systems, such as happened in the recent case in California when extreme heat covered a large portion of the Western US. Transmission constraints can also limit the ability to use imports to meet peak loads (transmission constraints are discussed further in Section 2.4 and were analyzed in Chapter 6 of the 2019 Plan).

10 Northwest Power Pool, (2019). "Exploring a Resource Adequacy Program for the Pacific Northwest." Page 20. Available at https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf
11 For reference, the Northwest Power and Conservation Council's threshold for measuring resource adequacy is 5%.
12 Manfei Wu, Judah Rose, and Maria Scheller (2020). California's Blackout Signals a Need for Enhanced Reliability Planning. ICF White Paper, available at https://www.icf.com/insights/energy/californias-blackout-signals-reliability-planning.

As coal-fired generation is retired in our region, other utilities are facing capacity deficits. The following table presents the capacity position forecast for other investor-owned utilities in the region, drawing on data from each utility's most recently published integrated resource plan. Investor-owned utilities are more likely to acquire new generation capacity, but there are also independent power producers and publicly owned utilities in the region who may as well, along with the Bonneville Power Administration, which is the largest generation owner in the region. This table thus presents one piece of the regional puzzle, while the studies by the Northwest Power and Conservation Council and others mentioned above provide a comprehensive assessment. The only regional utility not facing a capacity deficit is Idaho Power, which shows a small degree of excess capacity throughout its planning horizon.

Figure 7. Capacity Position of Pacific Northwest Utilities

	NorthWestern	Avista Energy	Portland General	Idaho Power	PacifiCorp	Puget
Target PRM %	16	18	15	14 - 17	13	17.8 - 18.3
IRP Isssued	2020	2019	2019	2020	2019	2019
Capacity Deficit by Year						
2021	569	0	190	0	0	685
2022	567	0	197	0	0	685
2023	575	0	246	0	0	685
2024	633	0	368	0	0	685
2025	647	0	685	0	0	685
2026	662	14		0	0	1767
2027	693	302		0	0	1767
2028	707	302		0	839	1767
2029	771	302		0	1359	1767
2030	785	325	1176	0	1602	1767
2031	799	325		0	1766	2122
2032	812	325		0	2046	
2033	833	325		0	2042	
2034	848	325		0	2048	
2035	923	495	1763	0	2027	
2036	940	495		0	3520	
2037	970	495		0	4217	
2038	988	495		0		
2039	1000	495		0		3218
2040	1013	547	2125	0		

2.2. Resource Adequacy and the Northwest Power Pool

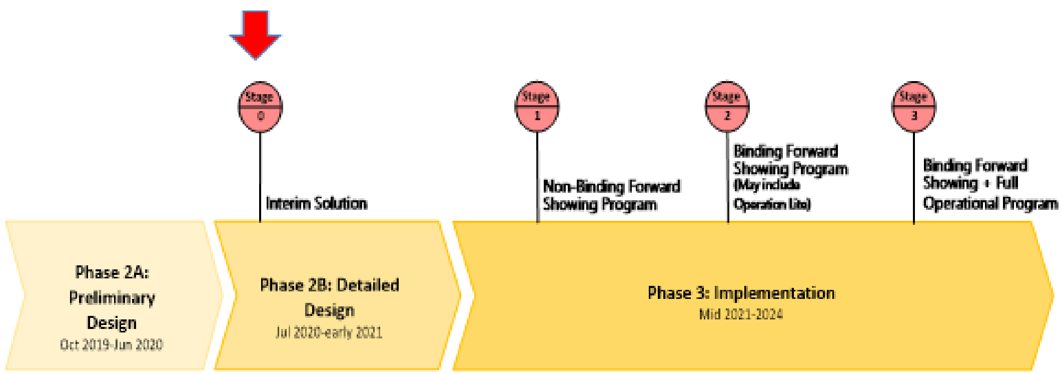
Resource Adequacy (RA) is the term used to describe an electric system's ability to meet demand under a broad range of conditions, subject to an acceptable standard of reliability. Currently, utilities in the Northwest individually plan for resource adequacy, typically through their resource planning processes. In 2019, the Northwest Power Pool began the Resource Adequacy Program Development Project (RAPDP) [13], an initiative to develop a resource adequacy program for the region. This initiative was driven by a recognition that the region could begin to experience capacity shortages as soon as 2020, that by the mid-2020s the capacity deficits could reach thousands of megawatts, and that regional cooperation could provide more efficiency than would be achieved by each utility planning on its own. One of the program objectives is that the resulting RA program deliver investment savings to customers through diversity benefits.

NorthWestern will continue to participate in and monitor regional advancements in regional energy markets and resource adequacy programs since they hold potential to provide operational and economic benefits. The ultimate decision whether to join any one of these programs or markets depends on the unique characteristics of how they are designed. For example, characteristics such as footprint, transmission connectivity, governance, cost structure and cost allocation, potential benefits, and services offered will all be important considerations. Any such decision will also be made in consultation with the MPSC and Montana Consumer Counsel to consider the program's alignment with the state policies of Montana.

NWPP Program Status

RAPDP has been underway since late 2019. The timeline below shows the overall project timeline. The RAPDP Steering Committee and workgroups are currently in the Detailed Design phase of the project. This phase is expected to last into early 2021. Implementation is expected to begin in mid-2021.

Figure 8. Development Timeline - Northwest Power Pool Resource Adequacy Program



In September 2020, the RAPDP Steering Committee released a Conceptual Design document for the program.[14] This document describes the project background as well as the preliminary design elements for the various aspects of the program. Some of the key elements of the proposed design include:

- The program includes a Forward Showing timeframe and an Operational timeframe
- Each entity will be required to demonstrate in advance that it has the physical capacity needed to meet its forecasted peak load plus a reserve margin (the determination of the reserve margin is part of the program).
- The program is technology neutral, meaning that any resources that can help meet the peak load requirement can participate in the program.
- Resources will be accredited based on their contribution to meeting peak load.
- To qualify in the Forward Showing timeframe, resources must be accompanied by firm transmission.
- Contracts that are not linked to a specific resource or portfolio of resources will not qualify for resource adequacy.

13 Detailed information on RAPDP can be found at www.nwpp.org/adequacy
14 The Conceptual Design document is available at https://www.nwpp.org/private-media/documents/2020-07-31_RAPDP_PublicCD_v2.pdf

2.3. Western Energy Imbalance Market

NorthWestern is on track to enter the EIM on April 1, 2021. While this transition will be a significant event for NorthWestern's operations, we continue to expect the effect on resource planning to be relatively small.

As we have noted, the EIM is an energy market, not a capacity market. Further, a requirement of the market is that NorthWestern enter each hour with both (1) sufficient scheduled energy and resources under control needed to meet our load, and (2) the flexible capacity needed to react to changes in load and variable resource output on our system. We cannot acquire either of these things from the EIM. We expect that the amount of flexible capacity we need for the EIM will be similar to what we need to reliably balance our system outside of the EIM. Further, long-term acquisition of capacity that is needed to help meet our peak load requirements will also be useful and valuable in EIM because of its ability to dispatch to the EIM's price signals.

NorthWestern is currently in the Market Simulation phase of EIM integration and testing. This phase will be followed by Parallel Operations, which begins in February of 2021. We expect to have better estimates of our flexible capacity requirements for EIM once we have consistent, accurate load and variable energy resource production data flowing to the EIM market operator that will allow calculation of the requirement. We expect to have data to estimate the requirements by early January, but the actual requirement will not be known until just prior to the go-live date of April 1, 2021.

As we gain actual operating experience in the EIM, we will evaluate the flex ramping requirements and other factors to determine whether any adjustments to our long-term resource planning modeling are warranted. In current operations, we must set aside capacity for INC and DEC. In the EIM, the situation differs slightly. As described above, though we will still need this flexible capacity to meet the market requirements and balance our system, the resources providing this flexible capacity can be dispatched by the market, possibly providing opportunities for further optimization.

2.4. Transmission Access

NorthWestern has considered, and will continue to consider, transmission investments that would enhance reliability for customers. Transmission availability is an important element in helping NorthWestern capture the benefits of both bilateral markets and organized markets on behalf of customers. The ability to both export and import energy unlocks the ability to optimize resources and provides economic benefit to NorthWestern's customers. Transmission capacity allows NorthWestern to sell excess generation in times of low load and to purchase energy from external sources for delivery to NorthWestern's load. In addition, long-term firm transmission rights can be used in conjunction with firm external resources to contribute to resource adequacy.

However, the availability of transmission capacity by itself does not contribute to resource adequacy. Whether it is in a regional program or providing an adequate portfolio on a stand-alone basis, NorthWestern must own or contract with generation resources to meet its peak requirements on a forward-looking basis. For example, having transmission rights from Mid-C to the NorthWestern system would not qualify as a resource in helping meet peak load unless we also had a contract with a resource at Mid-C that meets the program requirements. Put another way, transmission investments would not take the place of resource investments—both firm generation and firm transmission are needed in order to provide reliable supply. The entire cost of delivering a distant resource to our load, including both the development or contract costs and the transmission costs, would need to be compared against alternatives. Because of this, NorthWestern would evaluate additional transmission investment as part of the total incremental investment needed to purchase off-system generation. Transmission service alone offers no guarantee of generation capacity or improvement in the reliability of our energy supply and as such, does not substantiate the need for evaluation on its own.

3. LOAD AND RESOURCE BALANCE

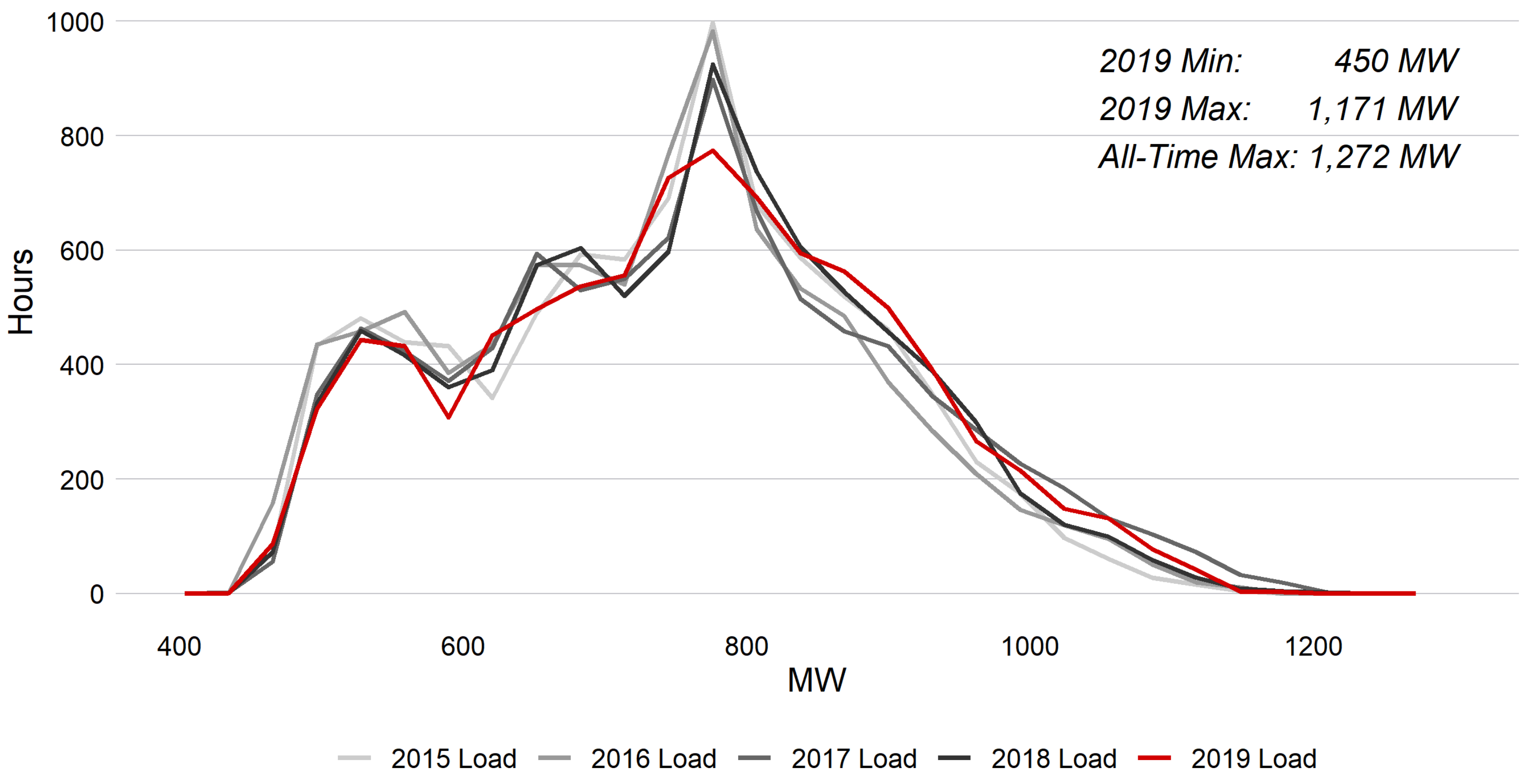
Planning for an adequate power supply requires careful consideration of the relationships between the demand for power and the supply provided by renewable resources, because they are both influenced by the weather. The Pacific Northwest has a long history of considering the seasonal and annual variability in hydro generation, which are driven by variation in the amount and timing of precipitation, snowmelt, and stream flows. Lately, the growth of weather-driven resources like wind and solar has amplified the need to consider how several key factors—primarily temperature-driven demand and weather-driven supply—are correlated with each other. NorthWestern takes into account the historical relationships between weather, loads, and supply when analyzing different mixes of generation resources and determining their collective adequacy, costs, and benefits.

This chapter discusses the historical patterns exhibited by NorthWestern's electric loads, the resources used to meet these loads, and the challenges facing NorthWestern and the Pacific Northwest as a region to ensure an adequate supply of power to meet peak loads.

3.1. NorthWestern's Loads

Over the course of a full year, NorthWestern's loads range from about 450 to 1,200 MW, with our all-time peak exceeding 1,270 MW.[15] In 2019, our load reached its highest point—1,171 MW—during the 9:00 AM hour of March 4. This peak was about 250% higher than the year's minimum load of 450 MW, which occurred during the 4:00 AM hour on May 26. The average load in 2019 was 756 MW.

Figure 9. Distribution of Hourly Loads 2015 – 2019



3.1.1. Peak Loads: When Will They Occur?

The size and timing of our peak loads vary from year to year. Historically, NorthWestern's loads reach their highest peaks in the winter. However, the annual peak has occurred in the summer 4 times in the last decade. In general, our loads have risen near to or above 1150 MW at least once each year, and often exceed that amount considerably, but it is difficult to predict whether loads will rise this high in winter, or summer, or in both seasons. In addition, sometimes loads rise near peak levels and remain there for a sustained period. This is discussed further in the next section.

15 This occurred during the 6:00pm hour on December 6, 2013.

Figure 10. Peak Loads by Season, 2010-2019.

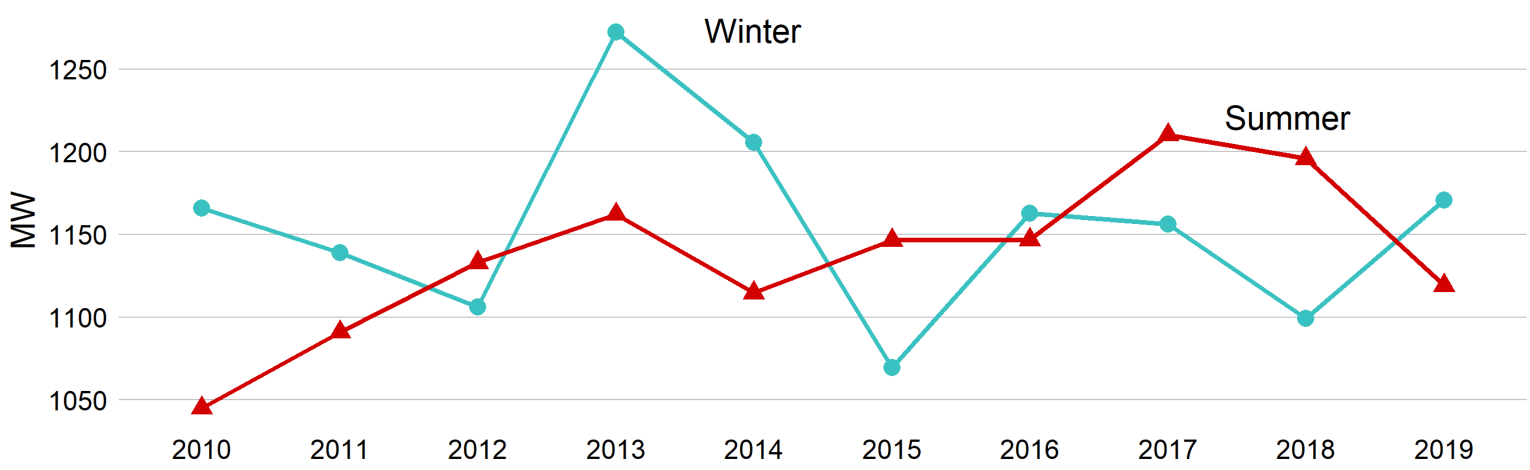
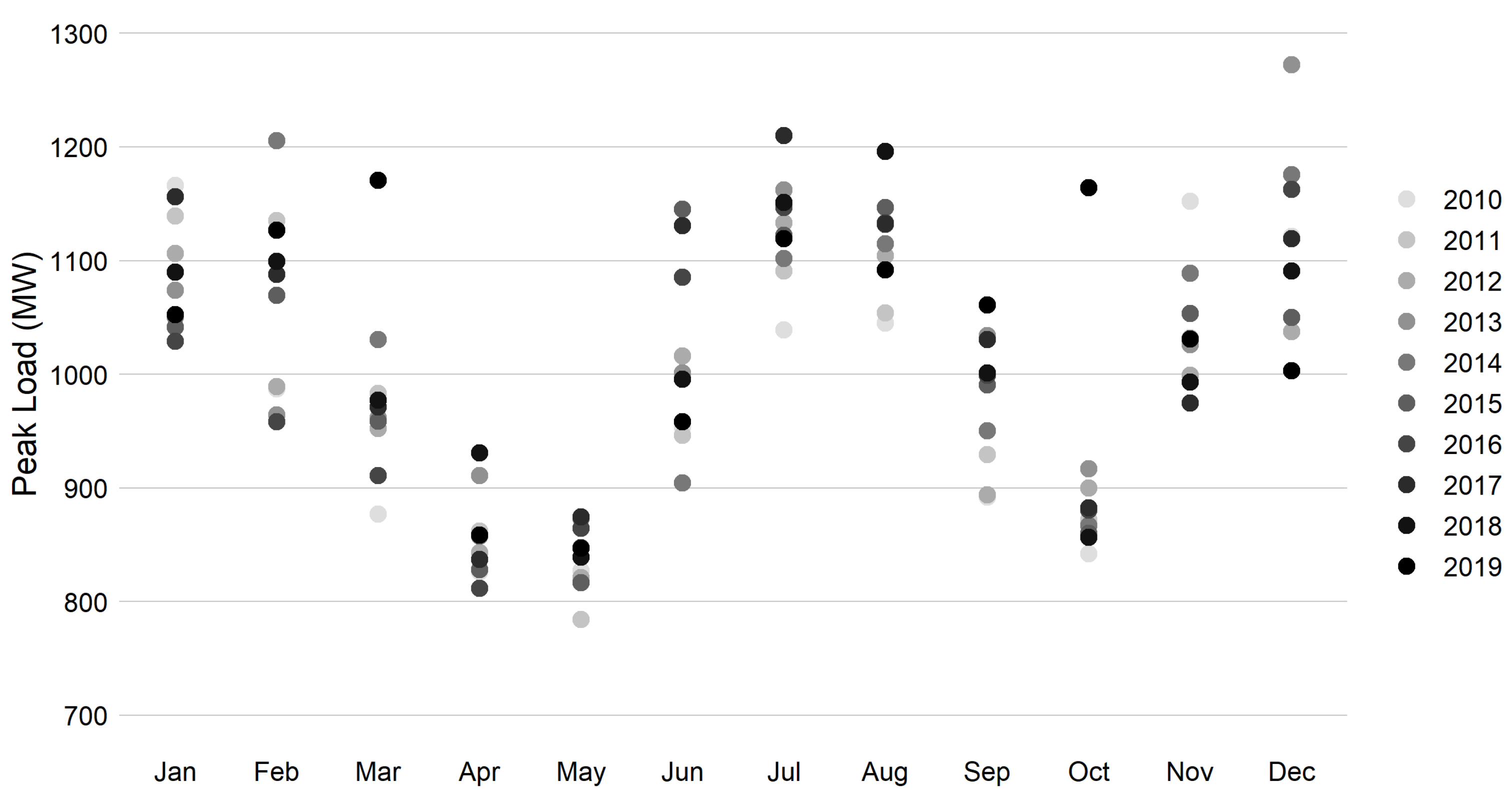
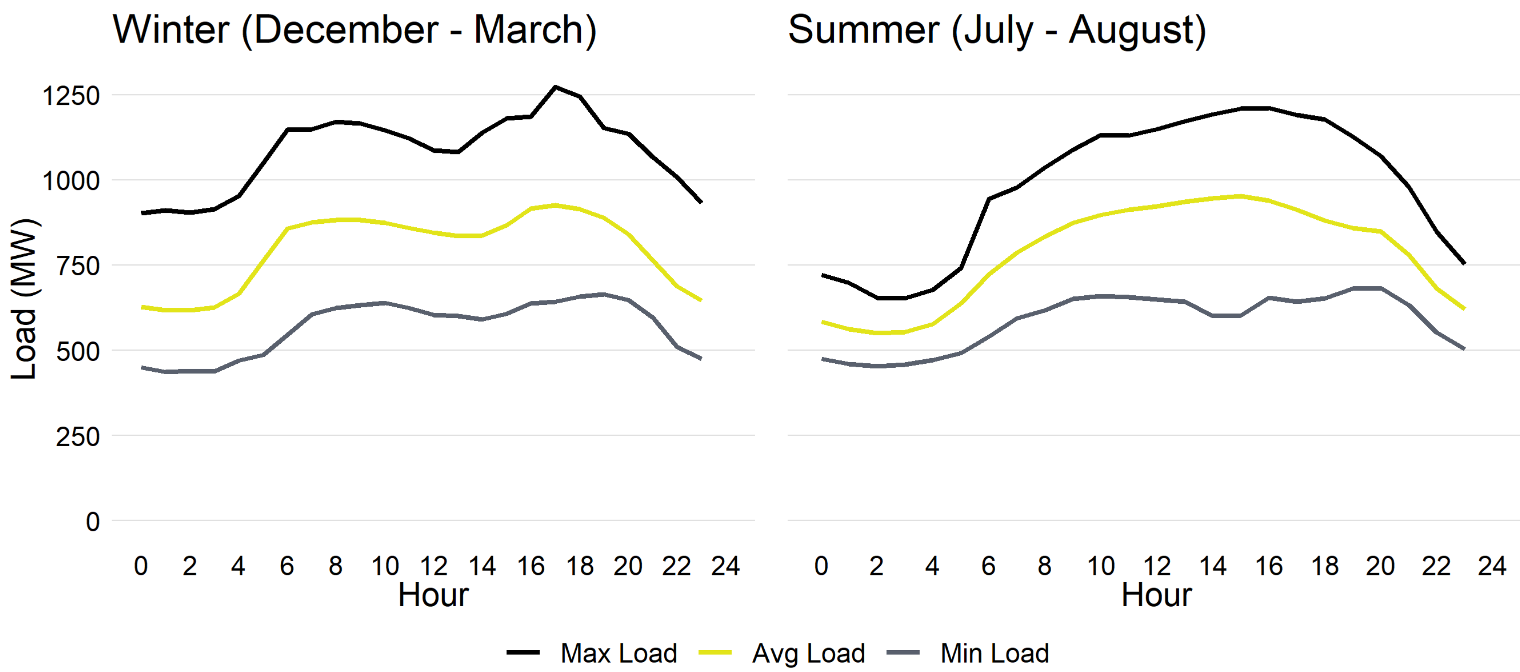


Figure 11. Peak Load by Month, 2010-2019.



The daily shape of loads and the usual timing of the peak load hour differs between summer and winter. In summer, the highest loads typically occur in the late afternoon or early evening. In the winter, loads peak twice throughout the day, with the highest loads usually occurring later in the evening between 5pm and 6pm, and a smaller morning peak occurring around 8am.

Figure 12. Average Daily Load Shape, 2010-2019

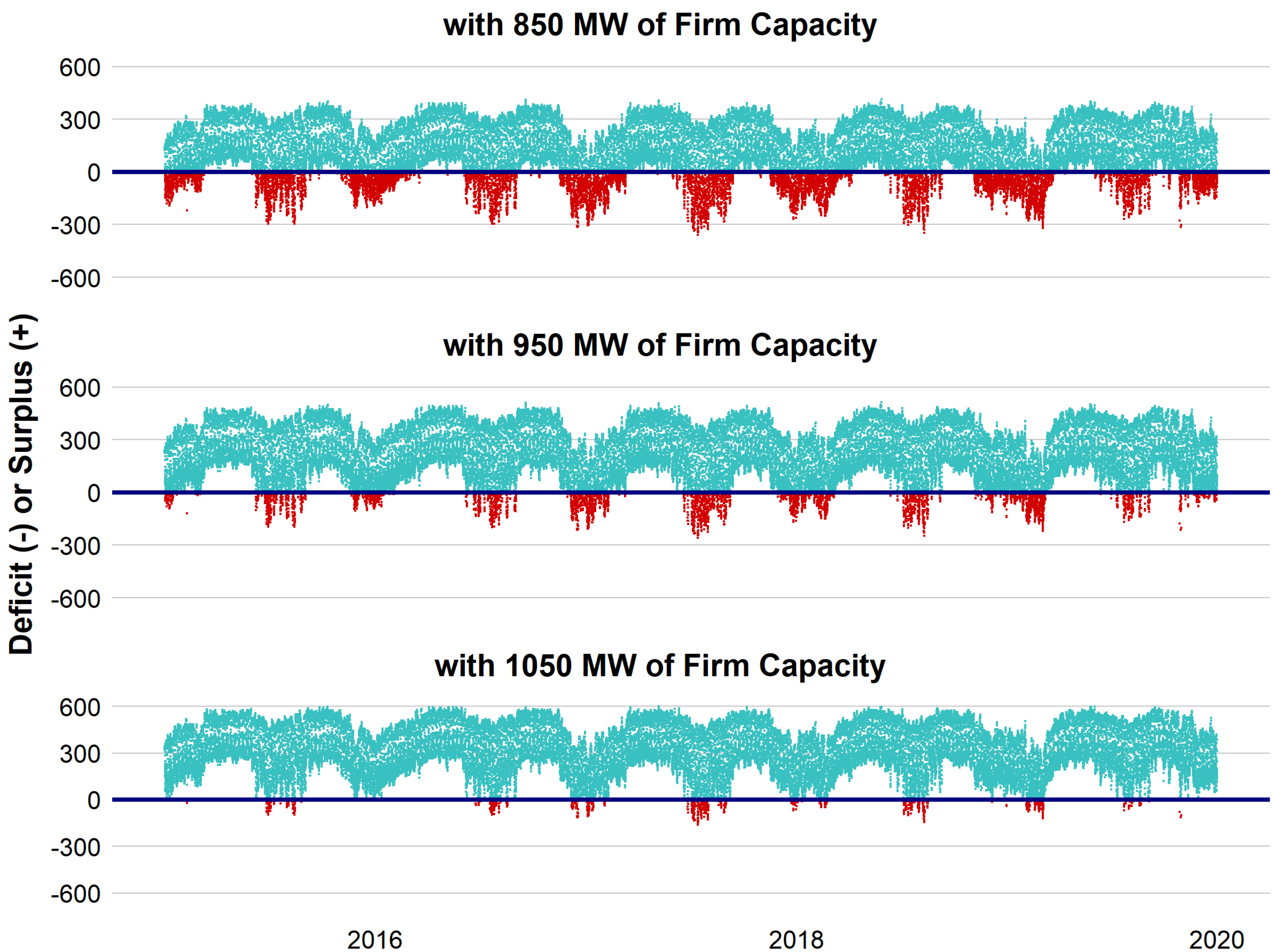


3.1.2. Deficit Events: How Long Do They Last?

The generation available from our resource portfolio is frequently insufficient for meeting our customers' load. Based on a comparison of historic loads with the effective capacity of our current portfolio, we can expect to experience an average of about 264 instances of capacity deficits per year. The deficits occur in all seasons of the year, though they tend to be more numerous and longer lasting in winter.

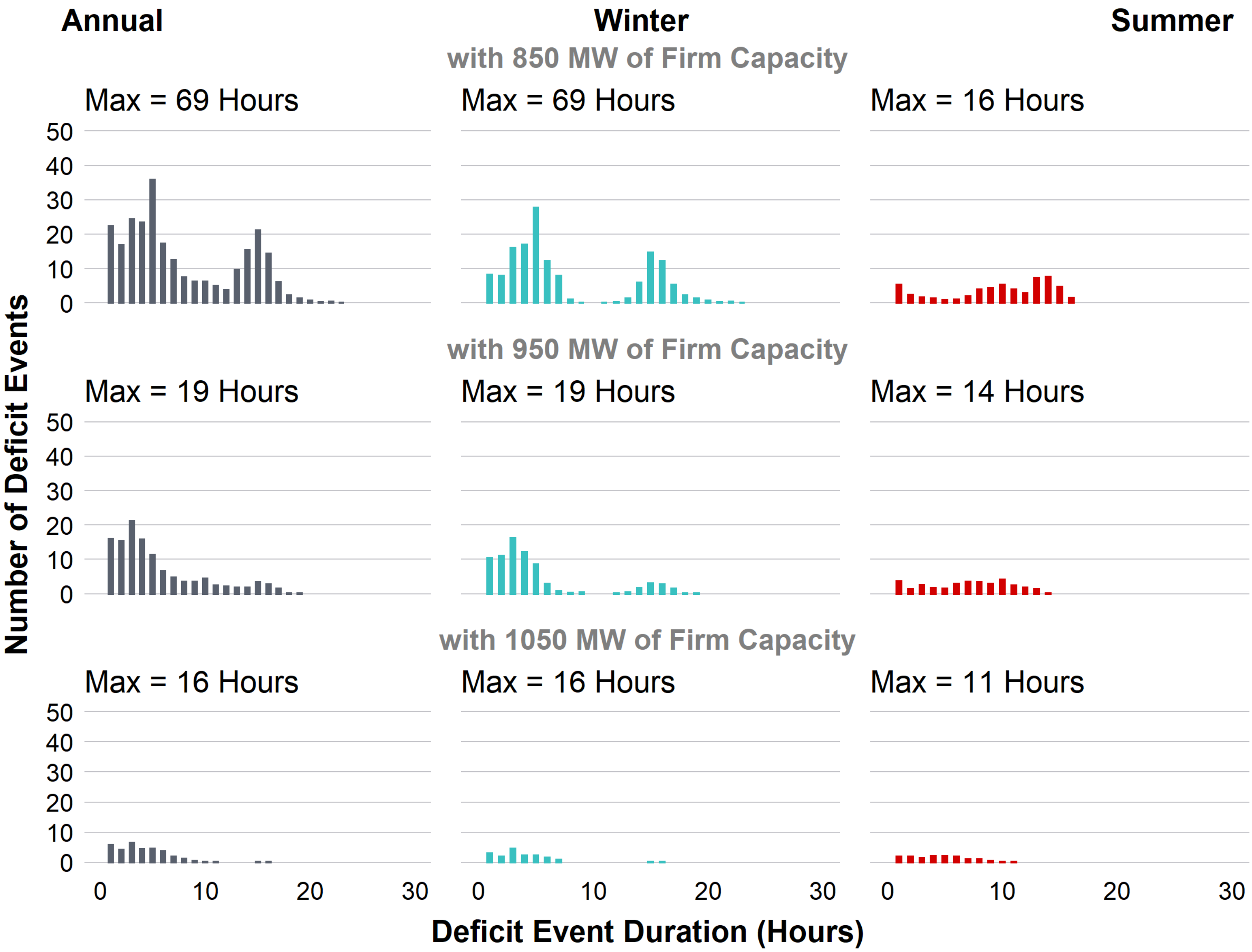
The following figure presents a timeline of when deficit events would have occurred during the last five years with our current portfolio, assuming energy imports from market purchases were not available. This figure illustrates the nature of the deficit events that NorthWestern might experience in a situation with a tightening regional power supply. The figure shows in red each hour in 2015-2019 when load surpassed the indicated amount of firm capacity, which represents when there was a risk that a shortage of supply in energy markets would cause a loss-of-load-event or customers not having power. NorthWestern's current portfolio provides slightly less than 850 MW of effective load-carrying capability during peak load conditions.

Figure 13: Capacity Deficits at Different Levels of Capacity for 2015 - 2019 Loads



The duration of these deficit events can vary considerably, from less than one hour to as long as multiple days. The figure below shows how the frequency and length of deficit events would vary with different levels of 100% reliable firm generation capacity. The top row shows the frequency and length of deficits that a portfolio with 850 MW of firm capacity would experience over the last 10 years of load conditions. This is approximately equal to our current portfolio's effective capacity of 840 MW, however in reality actual resources are not 100% reliable or able to provide energy for unlimited durations (for example, a storage resource will eventually need to recharge and solar generation will subside as the sun sets).

Figure 14: Frequency and Length of Deficits based on Historical Loads (2009 – 2019)



To evaluate the ability of potential new resources to improve the reliability of our power supply in light of the tightening regional capacity position requires an understanding of the frequency, depth, and duration of potential deficits. The duration of potential deficits is particularly important to understand when evaluating energy-limited resources like energy storage (including batteries and pumped hydro storage but also traditional hydro resources and the storage available in their upstream reservoirs). The figure above shows how the number and duration of deficit events decreases as 100% reliable capacity is added. However, if capacity is added in the form of energy-limited resources, these resources may not be able to provide energy for long enough to ride through the longer deficits.

To assess how the composition of a generation portfolio should be balanced between longer-duration capacity resources and shorter-duration resources, NorthWestern has examined how the duration of the longest deficit events would change with larger amounts of firm capacity in the portfolio. These events represent longer-lasting peak load events, such as multi-day periods of particularly cold or hot weather. The analysis is based on the last 10 years of NorthWestern's historical load data and focuses on how the longest events—those in the 99.97th percentile—would change with different amounts (MW) of 100% reliable capacity. This 99.97th percentile threshold corresponds to the commonly used reliability standard of a loss of load expectation of 1 day in 10 years, or 2.4 hours per year.[16]

The deficit events identified in this analysis do not necessarily represent loss of load events because market purchases are not accounted for. However, reliance on short-term purchases of energy is typically not considered for reliability planning purposes because the availability of such energy cannot be guaranteed and because it could easily result in double-counting of the market (by multiple utilities). This is a key reason that the Northwest Power Pool is developing a resource adequacy program for the region and is an issue of particular emphasis in the program's development. This program is discussed in Chapter 2 Developments in Regional Markets.

16 This standard is also identified in NERC standard BAL-592-RF-03. Dividing the 2.4 hour standard by the 8760 hours in a year yields a loss of load expectation of 0.03, which corresponds to the 99.97th percentile.

Developing an adequate portfolio from NorthWestern's currently deficit capacity position is complicated by the long-duration deficit events we sometimes experience. This complication arises because most assessments of the capacity provided by individual resources are calculated under the assumption that the portfolio is adequate to begin with (as discussed in Section 3.3.1 Capacity Contributions). If a resource is added to a portfolio that is adequate (or nearly so), the failure of that resource will have a smaller impact on the ability of that portfolio to serve its load compared to a portfolio that has a large deficit to begin with. If the region experiences a deficit across a wide geographic scale, the ability of short duration (i.e., energy limited) resources to reduce the probability of a loss-of-load on NorthWestern's system will be significantly less, relative to longer duration resources, for loss-of-load events that last more than a few hours.

Using NorthWestern's last 10-years of hourly load data, the following table shows how the 99.97th percentile of the duration of deficits would change with increasing amounts of 100% reliable capacity. Note that this analysis does not identify the number of hours between deficit events. This is an additional factor for assessing the value of energy storage resources, which would need to be recharged between consecutive events in order to provide capacity during the later event. However, the need for such recharging is accounted for when assessing the ELCC of different resources.

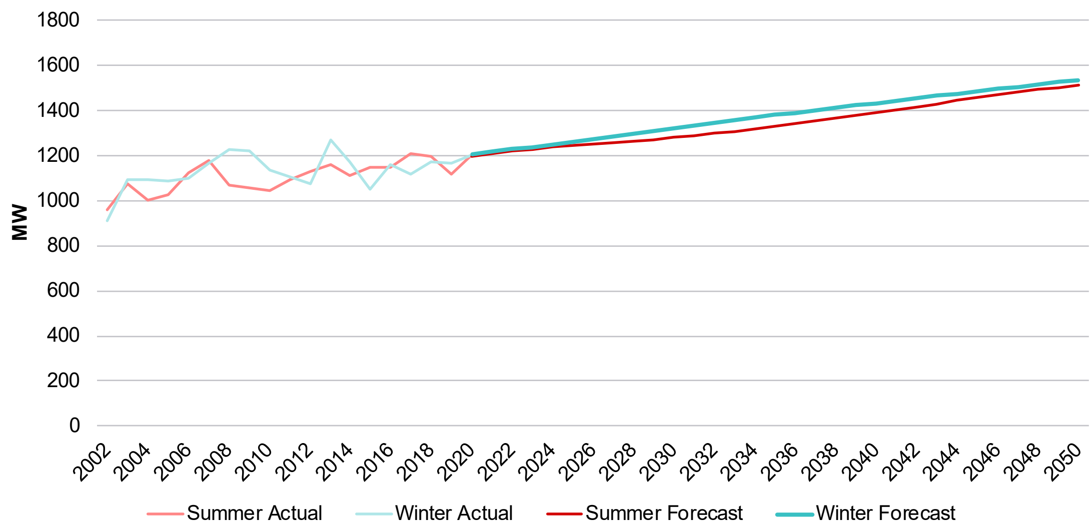
Figure 15. Distribution of Deficit Event Durations based on Historical Loads (2009 – 2019)

Accredited Capacity	Average Number of Deficit Events per Year	Distribution of Event Durations (Hours)		
		P95	P99.97 *	P100 (Max)
Annual				
1250	0.1	1.0	1.0	1.0
1200	0.5	2.0	2.0	2.0
1150	2.9	5.0	5.0	6.0
1100	13.5	7.0	8.0	9.0
1050	33.0	8.0	15.8	16.0
1000	66.3	14.0	17.0	17.0
950	117.9	15.0	17.8	19.0
900	195.2	15.0	19.0	45.0
850	252.0	16.0	43.8	69.0
Winter				
1250	0.1	1.0	1.0	1.0
1200	0.4	2.0	2.0	2.0
1150	1.5	3.5	5.0	5.0
1100	6.5	5.6	6.0	6.0
1050	16.6	7.0	16.0	16.0
1000	37.5	15.0	17.0	17.0
950	71.8	16.0	18.8	19.0
900	123.0	16.0	34.7	45.0
850	142.1	17.0	57.5	69.0
Summer				
1250	0.0	0.0	0.0	0.0
1200	0.1	2.0	2.0	2.0
1150	1.3	5.4	6.0	6.0
1100	6.4	7.0	9.0	9.0
1050	14.2	9.0	11.0	11.0
1000	22.9	11.0	12.9	13.0
950	32.6	12.0	13.9	14.0
900	44.5	14.0	16.0	16.0
850	55.5	15.0	16.0	16.0
* P99.97 corresponds to 1 day in 10 years loss of load expectation.				

3.1.3. Forecast of Future Peak Loads

NorthWestern's most recent forecast projects growth in our peak loads of approximately 0.8% per year. This forecast has been updated since the 2019 Plan with historical load data through the end of 2019. Relative to the prior forecast, the current one projects slightly lower peaks. The forecast includes the expected reduction in peak loads resulting from the benefits of demand side management measures. Based on both historical data and our load forecast, NorthWestern expects to experience similarly high peaks in both the summer and winter seasons, though the forecast still predicts slightly higher winter peaks.

Figure 16. Forecast of Peak Loads



3.2. NorthWestern's Resources

3.2.1. Current Resources

This section summarizes NorthWestern's generation portfolio, including the underlying fuel mix and the timeline over which resources have been added to the portfolio. An itemized table of the resources in the portfolio is included at the end of this section and the 2019 Plan contains additional detail.

NorthWestern's generation portfolio has a diverse mix of resource types with a total nameplate capacity of approximately 1,470 MW. For planning purposes, this total nameplate capacity yields an effective load-carrying capability of 837 MW for our customers' peak load needs. The portfolio's contribution to peak loads is substantially less than the total installed capacity because much of the portfolio includes hydro and wind resources, which depend on the weather and thus cannot be relied upon at 100 percent of their installed capacity. In this Supplement, NorthWestern uses the Effective Load Carrying Capability (ELCC) metric to measure the capacity contribution of intermittent and energy-limited resources. This method has become the industry standard and is discussed in more detail in Section 3.3.1 Capacity Contributions.

Some of our resources have been in operation for decades, such as the Colstrip Generating Station and the hydros, while others are relatively new. More recent additions include the Dave Gates Generating Station, a 150-MW natural gas resource that came online in 2011, and over 300 MW of wind in various locations that have come online since 2008. The newest addition to NorthWestern's portfolio is the 80-MW South Peak Wind Farm, which began operations in early 2020.

Figure 17. Timeline of Resource Additions in NorthWestern's Portfolio

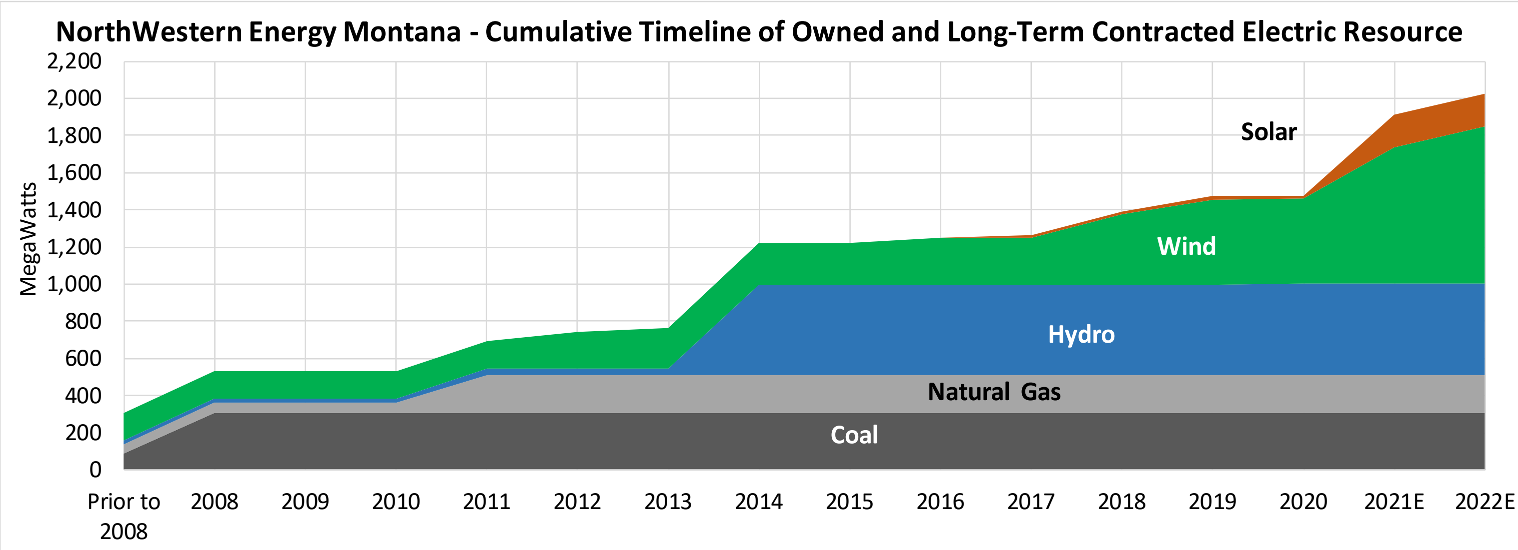


Figure 18. Fuel Mix of NorthWestern's Portfolio: Installed Capacity, Energy, and Capacity Contribution

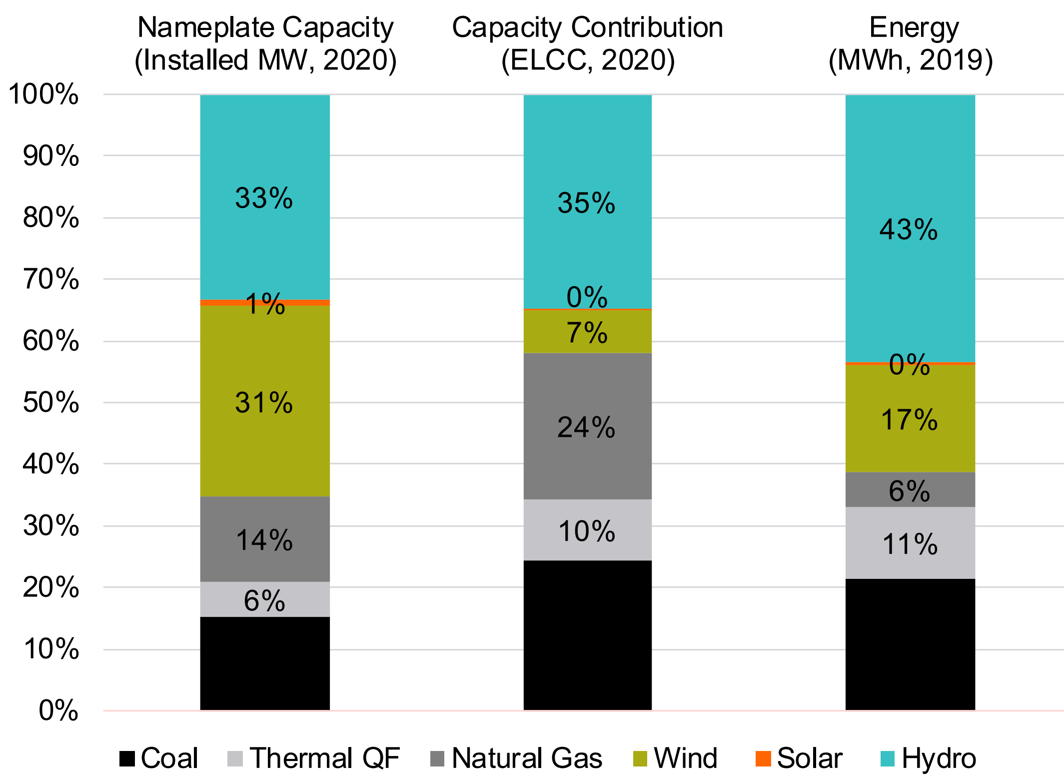


Figure 19. NorthWestern's Generation Portfolio – Detail

Portfolio Resources	Facility Capacity (MW)	Expiration Date	Peak Load Contribution (MW)	Peak Load Measurement Method
Total - Online	**1,469**		**837**	
Total - Online + Expected	**2,021**		**865**	
Hydro				
Thompson Falls	94	Rate Based	56.4	ELCC (E3 Study: 60%)
Cochrane	62	Rate Based	37.2	ELCC (E3 Study: 60%)
Ryan	68	Rate Based	40.8	ELCC (E3 Study: 60%)
Rainbow	64	Rate Based	38.4	ELCC (E3 Study: 60%)
Holter	53	Rate Based	31.8	ELCC (E3 Study: 60%)
Morony	49	Rate Based	29.4	ELCC (E3 Study: 60%)
Black Eagle	21	Rate Based	12.6	ELCC (E3 Study: 60%)
Hauser	18	Rate Based	10.8	ELCC (E3 Study: 60%)
Mystic	12	Rate Based	7.2	ELCC (E3 Study: 60%)
Madison	8	Rate Based	4.8	ELCC (E3 Study: 60%)
Small Hydro	**37**		**22**	
Turnbull Hydro LLC	13	12/31/2032	7.8	ELCC (E3 Study: 60%)
State of MT DNRC (Broadwater Dam)	10	6/30/2024	6	ELCC (E3 Study: 60%)
Tiber Montana LLC	7.5	5/31/2024	4.5	ELCC (E3 Study: 60%)
Flint Creek Hydroelectric LLC	2	1/15/2037	1.2	ELCC (E3 Study: 60%)
Hydrodynamics Inc (South Dry Creek)	1.2	6/30/2021	0.7	ELCC (E3 Study: 60%)
Wisconsin Creek LTD LC	0.6	7/31/2021	0.3	ELCC (E3 Study: 60%)
Boulder Hydro Limited Partnership	0.5	6/30/2022	0.3	ELCC (E3 Study: 60%)
Lower South Fork LLC	0.5	1/15/2037	0.3	ELCC (E3 Study: 60%)
Ross Creek Hydro LC	0.5	6/30/2032	0.3	ELCC (E3 Study: 60%)
Gerald Ohs (Pony Generating Station)	0.4	12/9/2020	0.2	ELCC (E3 Study: 60%)
Allen R. Carter (Pine Creek)	0.3	6/30/2024	0.2	ELCC (E3 Study: 60%)
Donald Fred Jenni (Hanover Hydro)	0.2	6/30/2034	0.1	ELCC (E3 Study: 60%)
Hydrodynamics Inc (Strawberry Creek)	0.2	6/30/2023	0.1	ELCC (E3 Study: 60%)
James Walker Sievers (Cascade Creek)	0.1	2/28/2035	0.0	ELCC (E3 Study: 60%)
James Walker Sievers (Barney Creek)	0.1	2/28/2035	0.0	ELCC (E3 Study: 60%)
Mammoth Hydro	0.2	Owned by YNP	0.1	ELCC (E3 Study: 60%)
Total	**486**		**292**	
Thermal/Natural Gas				
Basin Creek	52	12/31/2034	51.7	Forced Outage (0.64%)
DGGS 1	50	Rate Based		
DGGS 2	50	Rate Based	145.5	Forced Outage (3%)
DGGS 3	50	Rate Based		
Total	**202**		**197**	
Thermal/Coal				
Colstrip	222	Rate Based	203.7	Forced Outage (8.23%)
Yellowstone Energy Limited Partnership (BGI)	52	12/31/2028	50.4	Forced Outage (3%)
Colstrip Energy Limited Partnership	35	6/30/2024	34.0	Forced Outage (3%)
Total	**309**		**288**	
Wind - Online				
Judith Gap Energy LLC	135	12/31/2026	17.6	ELCC (E3 Study: 13%)
Stillwater Wind LLC (WKN)	80	10/31/2043	10.4	ELCC (E3 Study: 13%)
South Peak Wind LLC	80	4/15/2035	10.4	ELCC (E3 Study: 13%)
Spion Kop Wind	40	Rate Based	5.2	ELCC (E3 Study: 13%)
Greenfield Wind LLC	25	10/31/2041	3.3	ELCC (E3 Study: 13%)
Big Timber Wind LLC (Greycliff)	25	3/31/2043	3.3	ELCC (E3 Study: 13%)
Two Dot Wind Farm LLC	11.3	Rate Based	1.5	ELCC (E3 Study: 13%)
Fairfield Wind LLC (Greenbacker)	10	12/31/2033	1.3	ELCC (E3 Study: 13%)
Musselshell Wind Project LLC	10	3/23/2036	1.3	ELCC (E3 Study: 13%)
Musselshell Wind Project Two LLC	10	3/23/2036	1.3	ELCC (E3 Study: 13%)
Gordon Butte Wind LLC	9.6	3/20/2036	1.2	ELCC (E3 Study: 13%)
71 Ranch LP	2.7	12/31/2043	0.4	ELCC (E3 Study: 13%)
DA Wind Investors LLC	2.7	12/31/2043	0.4	ELCC (E3 Study: 13%)
Oversight Resources LLC	2.7	12/31/2043	0.4	ELCC (E3 Study: 13%)
Small Wind	11		1	
Cycle Horseshoe Bend Wind LLC	9	8/31/2025	1.2	ELCC (E3 Study: 13%)
Two Dot Wind LLC (Broadview East Wind)	1.6	10/31/2043	0.2	ELCC (E3 Study: 13%)
Total	**455**		**59**	
Wind - Expected				
Black Bear Wind LLC	79.2	Est 12/31/2036	4	ELCC (E3 Study: 5%)
Grizzly Wind LLC	79.2	Est 12/31/2036	4	ELCC (E3 Study: 5%)
Wheatland Wind LLC	75	Est 12/31/2037	4	ELCC (E3 Study: 5%)
Caithness Beaver Creek 1	60	Est 9/30/2040	3	ELCC (E3 Study: 5%)
Caithness Beaver Creek 2	60	Est 9/30/2040	3	ELCC (E3 Study: 5%)
Pondera Wind LLC	20	Est 12/31/2037	1	ELCC (E3 Study: 5%)
Teton Wind LLC	19	Est 12/31/2037	1	ELCC (E3 Study: 5%)
Total	**392**		**20**	
Solar - Online				
Green Meadow Solar LLC	3	3/31/2042	0.2	ELCC (E3 Study: 5%)
South Mills Solar 1 LLC	3	3/31/2042	0.2	ELCC (E3 Study: 5%)
Black Eagle Solar LLC	3	9/30/2042	0.2	ELCC (E3 Study: 5%)
Great Divide Solar LLC	3	9/30/2042	0.2	ELCC (E3 Study: 5%)
Magpie Solar LLC	3	9/30/2042	0.2	ELCC (E3 Study: 5%)
River Bend Solar LLC	2	3/31/2042	0.1	ELCC (E3 Study: 5%)
Bozeman Solar	0.3	Rate Based	0.0	ELCC (E3 Study: 5%)
Total	**17**		**1**	
Solar - Expected				
MTSun LLC	80	Est 12/31/2036	4	ELCC (E3 Study: 5%)
Clenera Apex I	80	Est 12/31/2036	4	ELCC (E3 Study: 5%)
Total	**160**		**8**	

3.2.2. Short-Term Energy Market

NorthWestern expects that short-term energy market transactions will continue to be an important component of our supply portfolio. However, short-term energy purchases cannot take the place of long-term capacity in the portfolio. Section 5.2 Capacity Products and Energy Products discusses the criteria that market products and contracts must satisfy in order to contribute toward resource adequacy requirements.

Interaction with short-term markets, for both purchases and sales, allows NorthWestern to optimize its portfolio. As more weather-driven resources like wind and solar are added in the region, low-price periods are likely to become more frequent. During these low-price periods, dispatchable resources can be run at low output levels or taken offline, allowing NorthWestern to purchase energy from the market at a lower cost to customers than the variable cost of the dispatchable resources. In higher price periods, NorthWestern will continue to dispatch its owned and long-term contracted resources at higher levels to serve its load, and in cases when it has excess capacity, to make wholesale sales that benefit customers.

3.3. Balance: Solving Our Capacity Shortage

NorthWestern is actively taking steps to address our capacity shortage. This includes requesting proposals for 1- to 3-year contracts for capacity from existing resources and proposals for longer-term capacity, which could be in the form of new generation resources or longer contracts (>3 years) with existing resources.

When evaluating the collective capacity provided by a portfolio of resources, it is essential to understand how the attributes of the resources in the portfolio interact with each other. Weather is a key factor to consider because of the correlations between loads and weather-driven resources. Additional factors include the events or incidents that may force a generator out of service for unexpected reasons, as well as the chance that energy-limited resources such as energy storage technologies may not have sufficient energy stored for use during times of peak need.

3.3.1. Capacity Contributions

The accelerating shift to a system built with a growing proportion of resources powered by the weather has brought a reduction in the ability of system operators to control (“dispatch”) the level of power provided by much of the generation on the system. This increases the complexity of ensuring an adequate supply of power for meeting customers’ demand when it peaks and requires careful assessment of the likely level of generation that will be provided by weather-driven resources during periods of peak demand, which often occur during extreme weather events. Similarly, assessing the capacity available from energy-limited resources like batteries and pumped hydro storage requires taking into account the limits on the amount of energy such resources can store and then comparing this to the duration of the peak demand periods.

In this Supplement, NorthWestern applies the Effective Load Carrying Capability (ELCC) metric to assess the capacity contributed by weather-driven (wind, solar, hydro) and energy-limited (storage) resources.[17] The ELCC of an individual resource represents the amount of “perfect” (100% reliable) capacity the resource could replace in a portfolio without altering the reliability of that portfolio. It is calculated in two steps:

- Step 1: calculate the reliability level of the system including the resource whose capacity contribution is being evaluated.
- Step 2: remove the resource from the system and add increments of perfect (100% reliable) capacity until the system is back to the same level of reliability calculated in Step 1.
- Result: the ELCC of the resource is the amount of firm capacity added in Step 2.

As a high-level example, to determine the ELCC of a hypothetical 100 MW wind plant, first determine the reliability level of the portfolio that contains the wind plant. Then remove the plant from the portfolio and incrementally add perfect capacity back to the portfolio until the original reliability level is met. If, for example, the portfolio requires the addition of 15 MW, then the wind plant has an ELCC of 15 MW or 15% (15 MW divided by the nameplate capacity of 100 MW is 15%).

17 There is not currently a universally accepted standard or unified method for determining resource adequacy, though ELCC is increasingly being used and appears to be emerging as a standard metric.

In actual circumstances, there are several challenges to calculating ELCC values. The calculations required in both Step 1 and Step 2 are computationally intensive because they require simulating loads and resource performance across a large range of weather and operating conditions. This is typically done based on historical data and analyses of the correlations between weather, loads, and renewable generation. Another challenge is that there are interactive effects between resources that greatly increase the complexity of the required simulations and calculations. This is true for resources with similar characteristics (e.g., two wind plants) or different resource types. Some resource combinations are complementary and can have a combined ELCC that is greater than the sum of their individual ELCCs (these are "synergistic" resource combinations). Other resource combinations may have interactions that result in a combined ELCC less than the sum of their individual ELCCs (these are "antagonistic" combinations).[18]

For this Supplement, NorthWestern retained the consulting firm Energy and Environmental Economics (E3) to calculate the ELCC values for the existing intermittent resources on our system and potential types of new resource additions. The calculations were conducted using E3's Renewable Energy Capacity Planning Model (RECAP) and historical weather data since 1970.[19] The generation from wind and solar resources was simulated using historical data as well as shapes E3 derived based on updated technology characteristics and generation data from the National Renewable Energy Lab (NREL). The full report from E3 is available as Appendix 1 to this Supplement.

The first step in the process was to determine how much firm capacity would need to be added to NorthWestern's existing resource portfolio to achieve the standard loss of load expectation of 0.1 days per year (equivalent to 1 day in 10 years). Based on their simulations and analyses, E3 determined that **NorthWestern's existing portfolio would need +678 MW of additional firm capacity to meet the standard reliability measure** (a loss-of-load probability of 1 day in 10 years).[20] This deficit is slightly larger though generally consistent with the deficits discussed in Chapter 1, which were approximated using a planning reserve margin of 16%. E3 based their determination on simulations that represent what NorthWestern's hourly load would have been under 2018 economic conditions for the weather years of 1970-2018. The simulations included forced outages of thermal plants and followed the standard practice of evaluating the system's performance without assuming the availability of imports from other systems.

After determining how much additional firm capacity would need to be added to NorthWestern's existing portfolio, E3 simulated the performance of the system with and without NorthWestern's existing wind, solar, and hydro resources, and a variety of new wind, solar, and storage resources. Using the method described above, this allowed E3 to calculate the ELCC of these resources. The ELCCs that E3 calculated for our existing hydro, wind, and solar resources are 60%, 13%, and 3%, respectively. The following table presents the ELCC results for new wind, solar, storage, and hybrid resources.

18 Schlag et al., (2020). *"Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy,"* Energy and Environmental Economics, Inc.

19 More information about E3's RECAP model is available at https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/.

20 E3's report describing these calculations is contained in Appendix 1 to this Supplement and is available for download at http://www.northwesternenergy.com/our-company/regulatory-environment/2019-electricity-supply-resource-procurement-plan

Figure 20. ELCCs of Incremental Resource Additions to NorthWestern's Resource Portfolio

Incremental ELCC Provided by Different Resources, 2020					**A**	**B**	**C**	**D**	**E**
Additional Nameplate Capacity (MW)		**Charging From**	**25 MW**	**50 MW**	**100MW**	**200MW**	**300MW**	**400MW**	**500MW**
Standalone Storage	3hr	Grid	100%	100%	99%	82%	65%	54%	47%
	4hr	Grid	100%	100%	100%	91%	72%	61%	53%
	6hr	Grid	100%	100%	100%	98%	84%	70%	59%
	8hr	Grid			100%	100%	92%	76%	65%
	10hr	Grid			100%	100%	97%	81%	69%
Solar PV	Simulated			5%	4%	3%	2%		
	Simulated With Snow Losses			4%	3%	3%	2%		
	Historical			2%	2%	1%	1%		
Wind	Historical			6%	5%	5%	5%		
	Simulated			11%	10%	9%	8%		
4-Hr Storage + Solar	25% of Solar PV	Grid			29%				
	50% of Solar PV	Grid			54%				
	100% of Solar PV	Grid			100%				
	100% of Solar PV	Solar			66%				
4-Hr Storage + Wind	50% of Wind	Grid			54%				
	25% of Wind	Grid			30%				
	50% of Wind	Wind			46%				
Note: values in red boxes were used as the basis for modeling new resource additions.									

From the results produced by E3, NorthWestern calculated the incremental ELCC of successive 100 MW additions by resource type. These are the values that, when summed together for multiple 100-MW additions of a particular resource type, will result in the capacity contribution for the larger-than-100-MW additions determined by E3. For example, column B above shows that adding 200 MW of 4-hr battery contributes 91% (or 182 MW), whereas column A below shows the capacity contribution of adding the first 100 MW of 4-hr battery is 100% (100 MW) and the second 100 MW (column B) is 81 MW, which together equal the value above (slight differences are due to rounding in the presentation of results). The use of the marginal values in the table below is necessary to allow for modeling successive 100-MW increments of resource additions.

Figure 21. ELCC of Incremental Resource Additions Modeled in Chapter 5

Effective Capacity Provided by Different Resources, 2020	**A**	**B**	**C**	**D**	**E**
Additional Nameplate Capacity (MW)	**100MW**	**200MW**	**300MW**	**400MW**	**500MW**
Incremental Nameplate Capacity (MW)	**+100MW**	**+100MW**	**+100MW**	**+100MW**	**+100MW**
Carbon-Free Resources					
Standalone Storage - 4hr	100	81	36	26	20
Pumped Hydro Storage - 10hr	100	100	90	32	21
Solar PV (Simulated)	5	5	5	5	5
Wind (Historical)	5	5	5	5	5
Hybrid Solar: 100 MW VER + 100 MW 4-Hr Grid-charged Battery)	100	86	41	31	25
Hybrid Wind: 100 MW VER + 50 MW 4-Hr Grid-charged Battery)	55	55	46	46	23
Thermal (Carbon-emitting) Resources					
Internal Combustion Engine	95	95	95	95	95
Simple Cycle Aeroderivative Turbine	95	95	95	95	95
Calculation Source:	Important Note: These values reflect saturation effects within resource types in the storage and hybrid categories, but they do not reflect interactions between resource types nor saturation within the wind and solar types.				
E3 Calculation or 1 minus forced outage rate for thermals.					
Approximated as flat extension of E3 calculations.					
Approximated as sum of component parts.					

The potential interactive effects from making multiple resource additions are complex and must be kept in mind when evaluating different resource portfolios. The values calculated by E3 reflect saturation effects that occur when adding multiple resources of the same type, but they do not reflect interactive effects that would occur when adding resources of different types. For example, the ELCC of a 100 MW 4-hour battery would be different than reflected in the table if it were made with the addition of 100 MW of 10-hour pumped hydro storage (or any other resource type). Interactive effects are not reflected in these calculations and this is especially important to keep in mind when comparing portfolios of resource additions.

3.3.2. Planning Reserve Margins

Planning to ensure that power supplies are adequate for meeting peak needs has historically been done based on an assessment of the "loss of load probability" (LOLP) of a system. This allows a determination of how much generation above expected peaks is needed to provide an adequate margin in case of unexpectedly high peak demands or unfortunately timed generator outages. This additional amount of generation provides a "planning reserve margin" (PRM) and utilities typically maintain a generation portfolio with enough capacity to meet peak loads plus this planning reserve margin.

In this Supplement, we use a planning reserve margin of 16%. This margin is in line with the North American Electric Reliability Corporation's (NERC) recommendation for the Western Electricity Coordinating Council (WECC) and is within the range of planning reserve margins used by other utilities and system planners in the West. Notably, the California Independent System Operator (CAISO) considers a planning reserve margin as high as 20% in its recent proposal to enhance its resource adequacy program [21]. The 16% margin used in this Supplement is also less than the 678 MW of additional accredited capacity we would need to achieve a loss-of-load probability of 1 day in 10 years (the calculation of this value is discussed in Section 3.3.1 Capacity Contributions). However, the use of a 16% planning reserve margin should not be misunderstood as an inflexible commitment. NorthWestern's near-term resource actions are not designed to immediately achieve a 16% margin. As the Northwest Power Pool develops its Resource Adequacy program, the planning reserve margin required for NorthWestern to participate will be established through rigorous analyses of regional loads and generation and may differ from 16%. The more the region is able to coordinate the sharing of resources and take advantage of diversity in loads and renewable generation, the more each individual utility will be able to reduce its need for additional planning reserve margins and thus reduce costs. This program is discussed more in Section 2.2 Resource Adequacy and the Northwest Power Pool.

The capacity provided by NorthWestern's portfolio is less than our peak loads and less than any measure of resource adequacy established by power system planners. We do not have a planning reserve margin and our ability to meet peak loads is subject to the availability of power from other utilities and generators. While improved regional coordination should result in a reduced need for individual utilities in the region to carry excess capacity, NorthWestern's ability to participate in any such program will almost surely require us to add a considerable amount of capacity to our portfolio, either in the form of contracts with existing generators or the acquisition of new sources of capacity.

3.3.3. Request for Near-Term Capacity Products

As part of our near-term strategy for achieving resource adequacy, on June 26, 2020 NorthWestern issued a request for proposals (RFP) for capacity and energy beginning in the summer or fall of 2020 from resources that are currently in operation. This request was issued both to address our near-term capacity needs and to gain information about the depth of the market for capacity products. As the remainder of this section describes, the responses to the RFP confirm NorthWestern's concern that the capacity market lacks depth, particularly for resource-adequacy supporting products. The total amount offered by all bidders was 398 MW, of which only 350 MW would likely meet the requirements of a future resource adequacy program. The fact that the amount of capacity offered—even for terms of less than three years—is far below the amount that NorthWestern needs in the long term is concerning.

In the request, NorthWestern solicited products for a period spanning between one and three years and identified the products below as being most beneficial to NorthWestern's supply portfolio:

- Fixed- or index-priced on-peak firm energy delivered to NorthWestern's Balancing Authority ("NWMT") using firm transmission on all applicable transmission systems from an identifiable existing resource or resources;
- Fixed- or index-priced on-peak firm energy with buyer's choice of delivery at either Mid-Columbia or NWMT using firm transmission on all applicable transmission systems on a day-ahead basis from an identifiable existing resource or resources;
- Intra-hour firm capacity and energy that is capable of delivering energy to the NWMT system within 10 minutes of being requested;
- Contingency reserves – spinning and non-spinning;
- Physical tolling agreements;
- Other capacity and energy products developed from negotiations between buyer and sellers.

21 CAISO Resource Adequacy Enhancements 5th Revised Straw Proposal, July 7, 2020. Available at http://www.caiso.com/InitiativeDocuments/FifthRevisedStrawProposal-ResourceAdequacyEnhancements.pdf

NorthWestern sent the RFP directly to over 50 entities in the WECC that NorthWestern identified as owning or controlling resources capable of providing these products and services and issued a press release.

Five entities responded to the RFP with conforming offers and one entity offered a product that was non-conforming. One of the five entities that originally offered a capacity and energy product later rescinded its offer due to concerns about the market and its overall portfolio position. Figure 22 below summarizes the offers NorthWestern received in response to the RFP.

Figure 22. Responses to NorthWestern's RFP for 1- to 3-year Capacity Contracts

Summary of Bid Responses to Request for 1- to 3-year Capacity Products						
Entity	**Option**	**Description**	**Term**	**Quantity**	**Defined Source**	**Expected to Meet RA Program Requirement?**
Entity 1	1-1	On Peak Block w/buy back	3 Year	100	No	No
	1-2	On Peak Block w/buy back	3 Year	100	Yes	Yes
	1-3	On Peak Block w/buy back	3 Year	100	Yes	Yes
	1-4	Intra-hour All Hours	3 Year	50	Yes	Yes
	1-5	Dynamic All Hours	3 Year	50	Yes	Yes
Combined Maximum Offer Entity 1				**100**		
Entity 2	2-1	Firm DA energy specified	3 Year	200	Yes	Yes
	2-2	Spinning Reserves	3 Year	200	Yes	No
Combined Maximum Offer Entity 2				**200**		
Entity 3	3-1	Seasonal On Peak	3 or 5 Year	48	No	No
Combined Maximum Offer Entity 3				**48**		
Entity 4	4-1	[Offer withdrawn]				
Entity 5	5-1	On Peak Block	<1 Year	50	Yes	No
	5-2	On Peak Block	<1 Year	50	Yes	Yes
Combined Maximum Offer Entity 5				**50**		
Combined Maximum, All Entities				**398**		
Combined Maximum, All Entities, RA Qualifying				**350**		

3.3.4. Request for Long-Term Capacity Resources

NorthWestern is currently in the process of evaluating new sources of capacity offered in response to our 2020 Capacity Request for Proposals ("Capacity RFP"), which was issued in the first quarter of 2020. The Capacity RFP is an all-source solicitation seeking bids for new sources of capacity totaling up to 280 MW and for terms ranging from 3 years up to the full life of a new resource (this can range from 20 to 30+ years, depending on technologies). Bids submitted into this RFP will be evaluated individually and in combination with other bids. The RFP is structured to seek a combination of resources that will be able to provide energy over sustained periods sufficiently long to collectively contribute to reducing the frequency and duration of our expected deficit events. The amount of longer-duration capacity is based on analyses of the duration of supply deficits our current portfolio would be expected to experience if faced with the historical load shapes of the last 10 years (as discussed in Section 3.1.2).

NorthWestern's recommended selection of the most cost-effective combination of sources of capacity offered in the 2020 Capacity RFP will likely be submitted in a filing for approval by the Montana Public Service Commission (MPSC) prior to final acquisition of any new contracts or resources.

4. PRICE FORECASTS

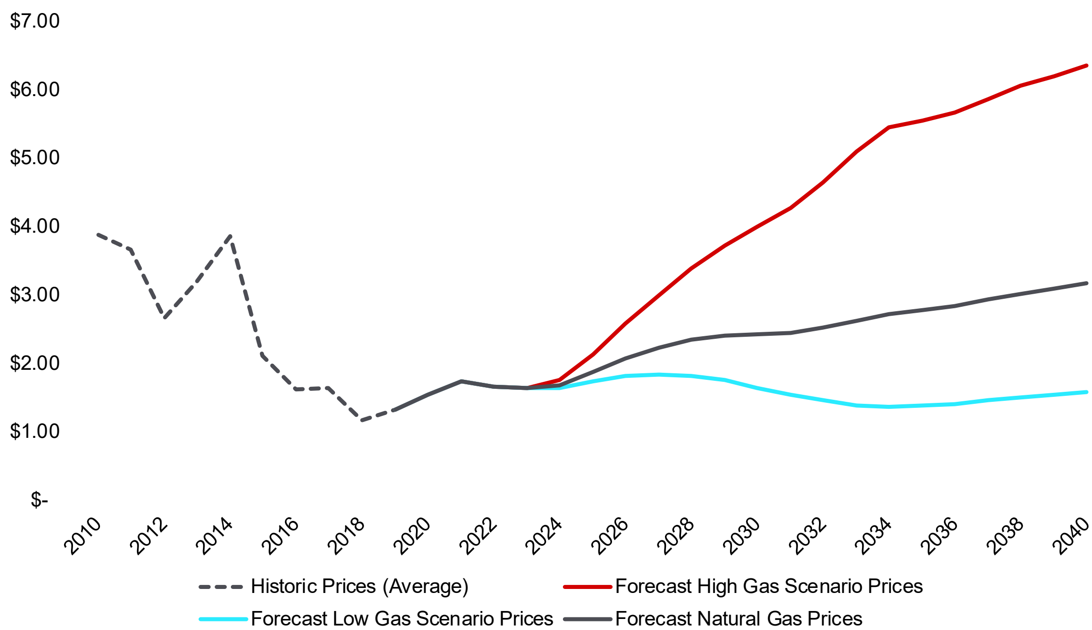
Forecasts of future energy prices play a key role when comparing the costs of different generation portfolios. This chapter describes the price forecasting methods NorthWestern uses.

4.1. Natural Gas Prices

NorthWestern's forecast of natural gas prices is based on 4 years of futures prices for natural gas at the Alberta Energy Company (AECO) hub, which is the most relevant regional location for natural gas consumed on NorthWestern's system. These prices are then escalated for the remainder of the forecast horizon based on the escalation rates most recently published by the US Energy Information Administration (EIA) in their Annual Energy Outlook. The escalation rate published by the EIA is for the Henry Hub, a much larger hub for natural gas than AECO, and represents general trends expected by EIA (they do not provide a similar forecast for the AECO hub). In addition to the price of gas at the AECO hub, there is also a cost for delivery across NorthWestern's natural gas system of $0.53 per MMBtu. This cost is included when evaluating gas generation resources and has an effect on the variable costs of gas generation in the range of $5 per MWh, depending on the specifications and efficiency of the gas resource.

In Chapter 5 Portfolio Modeling we also consider a High Gas Price scenario, in which prices rise to double their base levels. This scenario allows for consideration of how portfolios might perform in a future in which gas prices are higher than expected.

Figure 23. Historic and Forecast Natural Gas Prices, 2010 – 2040



4.2. Power Prices

Power prices are influenced by a range of factors that operate on different time-scales. For example, the demand for power follows daily patterns based on residential and business activity and seasonal patterns driven largely by the weather. Demand can also exhibit long-term trends based on population growth, economic trends, or improvements in energy efficiency. Like the demand for electricity, renewable generation is also subject to daily and seasonal variations. These factors must be considered when forecasting prices.

There are three main inputs into the power price forecast:

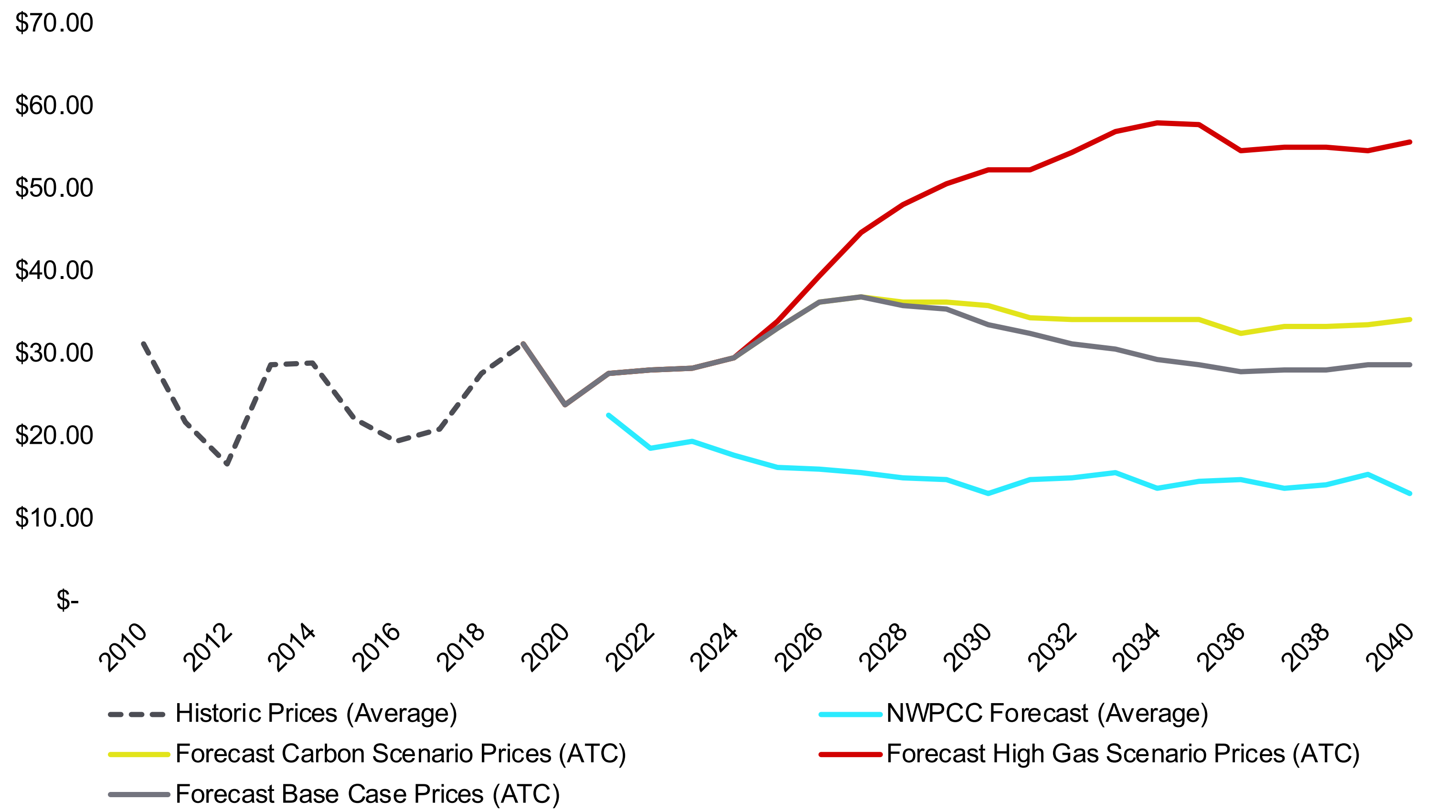
- **Forward prices for power.** NorthWestern's power price forecasts are based on four years of futures prices for power at the Mid-Columbia trading hub. These are drawn from the first 15 trading days of each of the preceding two quarters.[22] These are available in blocks of time for light-load hours (night time and Sundays) and heavy-load hours (weekdays and Saturdays).
- **Forward prices for natural gas.** These are based on four years of futures prices at the AECO hub.
- **A forecast of the market heat rate.**[23] This forecast is constructed by Ascend Analytics. When forecasting market heat rates, Ascend incorporates projections of significantly increased levels of renewable resources in the broader generation portfolio in the Western US. This increase in renewable generation is expected to reduce average power prices because of renewables' $0 cost for fuel, but the intermittency of renewable generation is also expected to increase price volatility.

22 The prices used in this Supplement are from 2020 Q2 and Q3.

23 The heat rate is a measure of power plant efficiency. It is the ratio of thermal energy in to electrical energy out and commonly calculated as MMBtu per MWh. A lower heat rate indicates better efficiency. The market heat rate in this context refers to the marginal heat rate of all generators in the market in any given hour.

The forward curves from futures market for power are combined (via the heat rate forecast) with forecasts of long-term trends in daily price shapes, hourly price volatility, seasonal variation. The forecast of power prices for the period beyond the end of the forward curve is constructed by multiplying the forecast market heat rate by the forecast of natural gas prices. This results in a forecast of power prices at the Mid-Columbia (Mid-C) hub for buying and selling power. NorthWestern's system is not directly connected to the Mid-C hub and purchases or sales of energy on NorthWestern's system often experience a price differential relative to Mid-C prices. This differential is influenced by differences in the supply and demand for power between the two locations, as well as the cost of transmission between the two locations (NorthWestern often requires transmission service to deliver purchased power from the hub to our system, or to deliver power from our system to the hub for sales). An analysis of the difference in prices for energy bought and sold on our system relative to energy bought and sold at Mid-C shows that there is a basis (differential) of about -$8 for energy that NorthWestern sells, and +$2 for energy that NorthWestern purchases. These bases are incorporated into our simulations of the prices at which NorthWestern can purchase or sell energy.

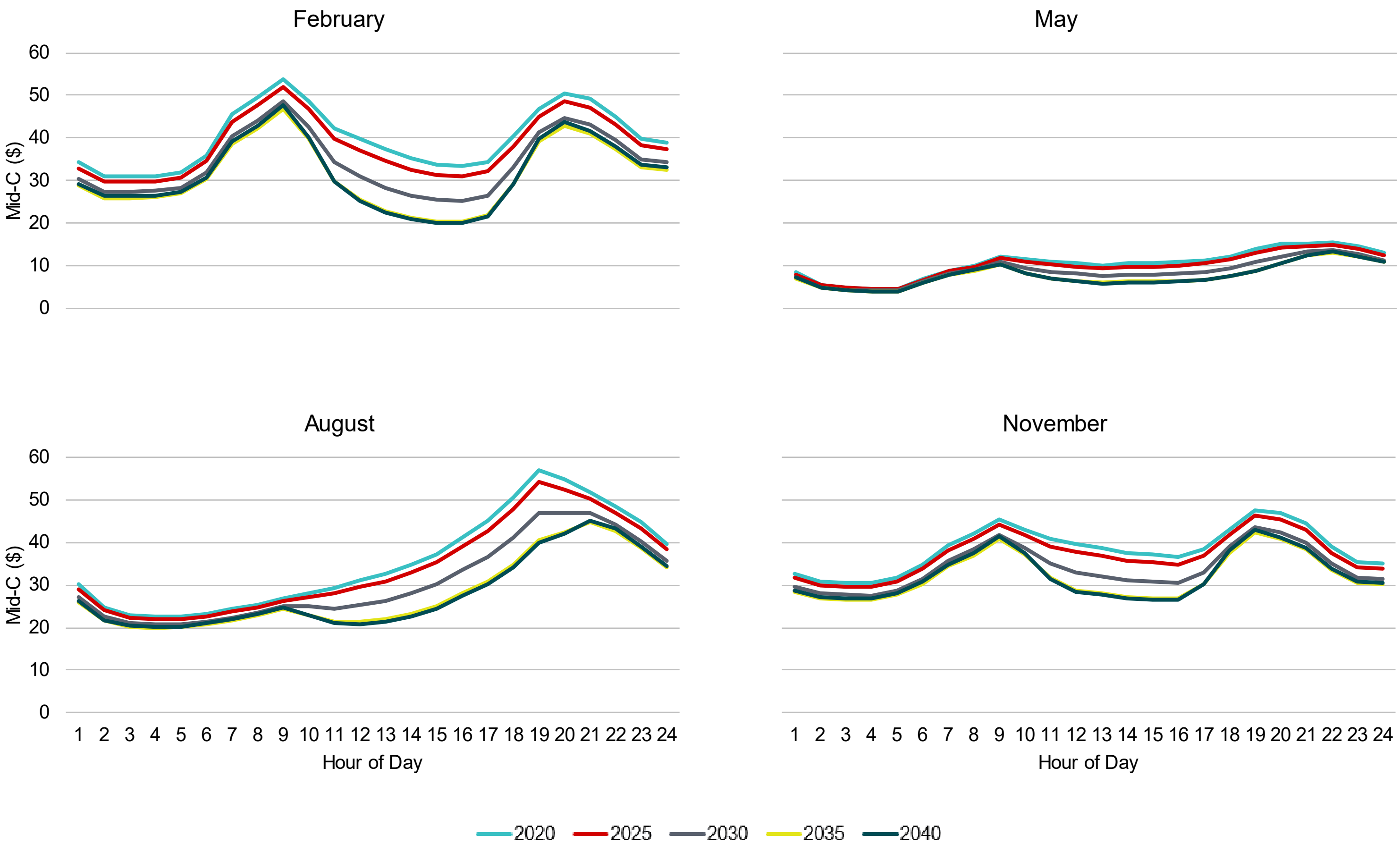
Figure 24. Historic and Forecast Power Prices, 2010 – 2040



A key aspect of future power markets is that the influx of renewable energy is expected to increase the frequency of periods in which supply exceeds demand and power prices become negative. The pattern of renewable energy putting significant downward pressure on average prices has been seen in California as the rapid growth of solar energy has saturated the market with daytime energy and pushed the net peak (load minus renewable generation) into the evening after the sun sets. This phenomenon is not as apparent in the Mid-C market, though the Mid-C and California markets are influenced by each other. The combination of the reduction in average prices with the increase in price volatility represents a shift in the underlying fundamentals of power markets. This shift is driven by the replacement of dispatchable resources with intermittent resources.

The following graphic shows how the daily price shapes are expected to change over time during different seasons of the year.

Figure 25. Forecast Changes in the Daily Shape of Power Prices, by season



The price forecast methods used in this Supplement are the same as those used in the 2019 Plan with one exception—the use of 4 years of futures prices.[24] Previously, NorthWestern's practice was to use futures prices for as far out as the futures market appeared to be liquid, because the use of actual futures prices is less speculative than a forecast when futures prices exist. However, this practice could sometimes result in jumps in the price curves from quarter to quarter if the period through which the futures market was liquid had changed. To avoid these jumps, and to standardize and simplify the process, NorthWestern has switched to using a standard 4-year period of futures prices.

4.3. Carbon Price Scenario

To consider how future power prices could be affected by a carbon price, NorthWestern examines a scenario in which thermal generators are assessed a carbon tax per ton of carbon they emit. This penalty is incorporated into the dispatch algorithm. This scenario also uses a power price forecast based on a calculation of the amount by which average power prices would increase under the carbon tax. This forecast is the product of an assumed carbon price and the carbon intensity of the market-wide marginal unit in each hour (the carbon intensity in each hour is based on an average across many simulations). In this Supplement we run a modeling scenario using the base carbon price from the 2019 Plan.[25] Because of the large prevalence of solar energy during daytime hours, which lowers the carbon intensity of the daytime generation mix, a carbon price is expected to have a larger effect on off-peak prices. Over time, this, combined with the lack of low-cost renewable generation during sundown hours, will cause off-peak prices to approach on-peak prices.

24 This method is consistent with the MPSC's recent orders on calculating avoided costs for Qualifying Facilities (Order Nos. 7699c and 7702b).

25 This is the base carbon price developed in Navigant's 2018 Net Energy Metering Study, which starts at $5.70 per ton of carbon emissions in 2028 and escalates to just under $50 per ton by 2050.

5. POTENTIAL NEW RESOURCES

5.1. Physical Resources

In this Supplement we present analyses that examine portfolios constructed from a more focused set of resources than was considered in the 2019 Plan. We focus here on a smaller set of resources to facilitate the study of a larger and more useful range of resource portfolios (the construction of these portfolios is discussed in Chapter 6 Portfolio Modeling). The focus on these resources does not suggest that other resource types or contracts for capacity from existing resources may not provide value or will not be considered or pursued in a competitive solicitation. NorthWestern's Capacity RFP is an all-source solicitation and all resource types that provide capacity are eligible to participate and will be evaluated on their specific characteristics.

The costs and specifications of resources analyzed here are based on generic engineering representations of these resources' costs and capabilities. With two exceptions, the resource costs used in this Supplement were drawn from the National Renewable Energy Lab's (NREL) Annual Technology Baseline (ATB). The exceptions are pumped hydro storage and Reciprocating Internal Combustion Engine (RICE) units, which were not included in the ATB. The costs used in this analysis for RICE units and pumped hydro storage are updated versions of the cost estimates used in the 2019 Plan.

The resource types analyzed here are:

- Wind
- Solar PV
- Pumped hydro storage
- Lithium-ion battery storage
- Solar-storage hybrids
- Wind-storage hybrids
- Natural gas reciprocating internal combustion engines

These resources were selected because they represent the most commonly-considered generation resources in utility planning processes today. They are resources whose performance characteristics are sufficiently established to allow for straightforward representation in modeling exercises, whose state of technological development is reasonably mature, and whose costs are not expected to be prohibitively high. However, there is a wide range of technologies that may play important roles in Montana's future energy supply and their exclusion here should not be taken to suggest that they would not be considered if available. These technologies include many that hold promise for the future, whether they are still in relatively early stages of development (e.g., hydrogen-based generation), further along (e.g., small modular nuclear reactors), or have been in use for decades (e.g., hydro, nuclear, geothermal, and combined-cycle combustion turbines, among others). Again, the exclusion of certain resource types here was done only to facilitate the analysis of a wide range of portfolio types useful for assessing the relative performance of the major types of resources likely to be available in the coming several years.

As in the 2019 Plan, we have not modeled contracts for capacity with existing resources. This is not because such contracts are not under consideration. Such contracts have been solicited via NorthWestern's near-term RFP (discussed in Section 3.3.3 Request for Near-Term Capacity). These contracts are not modeled here because there is not a standard definition for such contracts in our region and the value of such contracts tends to depend in large part on their contractual specifications and deliverability characteristics.

The resources that were included in the 2019 Plan but which are not considered here are:

- Combined Cycle Combustion Turbines (CCCT): These natural-gas fired resources have historically been viewed as low-cost sources of energy but with limitations on their operations and flexibility, including slower ramp rates and constraints on minimum operating levels and required down-times. In addition, they typically require a large volume of natural gas at high pressures, which can create significant additional costs and strain gas delivery systems (see Section 5.1.3 Additional Infrastructure Costs for more discussion).
- Simple Cycle Combustion Turbines (SCCT): These have better flexibility than CCCTs but also require larger volumes of gas available at higher pressure. Notwithstanding this, to the extent SCCTs might be valuable resources for NorthWestern's portfolio, the RICE units modeled herein may be viewed as a general representation of flexible natural gas technologies.
- Compressed Air Energy Storage and Flow Batteries: The flexibility of energy storage resources is typically viewed as highly valuable in combination with wind and solar generation. However, these energy storage technologies are currently much less common than lithium-ion batteries. They are also typically more expensive. These technologies are also considerably similar to the 4-hour (lithium-ion) and 10-hour (pumped hydro storage) options analyzed in this plan and to that extent the storage resources modeled herein may be viewed as general representations of the wider range of storage technologies.
- Geothermal: This resource was included in the 2019 Plan but was never selected in those analyses by the capacity expansion model. The generally high costs and limited availability of geothermal resources leads it to be an unlikely resource, though potentially it could be a highly valuable source of capacity, depending on the specifics and cost.

Figure 26. New Resource Cost Estimates

Resource	Fixed Cost ($/kW-mo)	Fuel Delivery Cost ($/MMBtu)	Variable Operating and Maintenance Costs ($/MWh)	Fixed Operating Expense (Million $/year)	Capital Cost (Million $)	Capital Cost ($/kW)	Capital Cost per MW Effective Capacity** (ELCC) (Million $)
Li-Ion 4-hr Battery 25MW	$3.03			$0.48	$36.4	$1,455	$1.45
Pumped Hydro 100MW	$1.26		$0.94	$5.14	$286.7	$2,867	$2.87
RICE 18MW	$1.67	$0.53	$4.87	$0.76	$36.5	$2,029	$2.14
RICE 9MW	$2.41	$0.53	$2.75	$0.46	$23.2	$2,573	$2.71
Solar 100MW	$1.32			$2.89	$132.5	$1,325	$26.50
Wind 100MW	$3.54			$1.68	$161.1	$1,611	$32.22
Solar 100MW + Li-Ion 4-hr 100MW***	$4.14			$4.55	$263.2	$1,316	$2.63
Wind 100MW + Li-Ion 4-hr 50MW***	$6.41			$2.57	$228.2	$1,522	$4.15

**Fixed operating expenses include costs associated with insurance and local taxes.*

***Effective Capacity measured by ELCC for the first incremental addition of each resource type (see Section 3.3.1 Capacity Contributions).*

****Respective cost savings of 2.4% and 5.3% are applied for capital cost of hybrid wind + battery and hybrid solar + battery facilities, relative to the sum of the cost of the stand-alone components.*

5.1.1. A Note on NREL's Cost Estimates

The cost estimates in NREL's ATB are generally lower than the cost estimates used in the 2019 Plan. This appears to be driven in large part by NREL's consideration of larger scale resources and the associated economies of scale assumed to drive down the cost per unit of installed capacity as scales increase. For example, NREL's ATB considers simple cycle resources that are 3 to 5 times larger than the units considered in the 2019 Plan, and wind and battery resources that are each 2 times larger. The capacity factors for renewable resources that were assumed in NREL's ATB and in the 2019 Plan are similar.

5.1.2. Sub-Hourly Dispatch Credit

Resources that can change their output level quickly in response to real-time price signals are able to capture value (revenue) via sub-hourly changes in dispatch that less flexible resources cannot capture. NorthWestern estimates this revenue stream by calculating a sub-hourly dispatch credit for these resources. The sub-hourly revenue that these resources can capture can help to offset NorthWestern's purchased power costs, which benefits customers. This source of value is not reflected in an hourly dispatch model even though it represents a potentially valuable source of revenue which should be considered in a comprehensive evaluation of a resource's costs and benefits. NorthWestern conducts a sub-hourly evaluation outside of its hourly dispatch model to calculate this revenue credit for flexible resources. Of the resources analyzed in this Supplement, the resources able to generate a sub-hourly dispatch credit are lithium-ion batteries, pumped hydro storage, and RICE units.

To estimate the value associated with sub-hourly dispatch flexibility requires a sub-hourly calculation of the revenue that flexible resources can generate. The method for achieving this calculation is to simulate the dispatch of the resource twice, once to an hourly price signal and second to both an hourly and 5-minute price signal. In this second dispatch, the simulation algorithm considers whether more revenue can be generated by dispatching to the hourly or sub-hourly prices, and then evaluates the additional revenue generated from dispatching to 5-minute prices when this is more valuable than dispatching to hourly prices. As part of this simulation, imperfect foresight in dispatch decisions is incorporated by adding random noise to the historical time-series of prices used to simulate the dispatch decisions.[26] The difference between the value the resource is able to generate between the first and second methods represents the additional revenue credit attributable to the resource because of its sub-hourly dispatch abilities.

For calculating the sub-hourly credit used in this Supplement, the dispatch to 5-minute prices was based on historical 5-minute prices at the Decker (MT) node. The Decker node is part of the EIM via PacifiCorp, who is an EIM participant, and is the closest EIM node to NorthWestern's service territory. Future volatility in the 5-minute price stream is scaled in accordance with the volatility parameter in

26 The random noise was modeled as a normally distributed error with a zero mean value and standard deviation equal to the standard deviation in the historical prices.

Ascend Analytics' price forecast (described in Chapter 4 Price Forecasts).

Figure 27. Sub-Hourly Dispatch Credits ($/kW-yr)

	Sub-Hourly Credit ($/kW-yr)		
	Li-Ion 4-hr Battery	**Pumped Hydro**	**RICE**
2021	$54	$61	$37
2022	$59	$66	$40
2023	$65	$73	$45
2024	$68	$75	$46
2025	$72	$81	$49
2026	$75	$83	$51
2027	$77	$85	$52
2028	$76	$84	$52
2029	$75	$83	$51
2030	$76	$85	$52
2031	$83	$92	$56
2032	$85	$94	$58
2033	$88	$98	$60
2034	$91	$101	$62
2035	$92	$103	$63
2036	$98	$109	$67
2037	$101	$112	$69
2038	$103	$114	$70
2039	$107	$118	$73

5.1.3. Additional Infrastructure Costs

When modeling the costs of potential new generation resources, NorthWestern includes cost estimates that represent generic engineering specifications of each resource type. These estimates include the costs associated with the underlying technologies from general engineering specifications and estimates of the cost to build the resource, but they do not include costs associated with location-specific additional infrastructure required by the resource or for integration into NorthWestern's system, such as gas pipelines or additional electric transmission infrastructure. The cost of additional infrastructure is not included because the costs for infrastructure that are not standard parts of the underlying generation technology can vary considerably by location, technology, and size of the project. (However, before any actual resource decisions are made, a detailed analysis of all costs is completed that includes site-specific project cost estimates and any additional infrastructure requirements. At this stage of an evaluation, these estimates are much more developed than generic resource costs like those used in modeling analyses presented in resource plans.)

This section discusses the major types of location-specific costs that must be considered when making final resource evaluations but which are not included in general resource cost estimates such as those used in this analysis.

5.1.3.1. Electric Transmission Infrastructure

There are two main types of infrastructure costs to consider when a project interconnects to the transmission system:

Generation Interconnection Costs include all necessary equipment needed to interconnect the generator to the transmission system, including but not limited to: meters, communication equipment, relays, breakers, and in some instances, the project requires construction of an entirely new substation. All substation work undergoes both environmental and permitting reviews, which may add costs to the project. Typically, the cost of an interconnection increases with the complexity of the work needed to add a point of interconnection.

Network Upgrade Costs include any costs that the generator interconnection creates on the bulk electric transmission system beyond those identified for the point of interconnection. Network Upgrade costs are a product of both the generation interconnection and the designation processes which, together, should allow the generation project the opportunity to achieve full output at all times. Network Upgrades may include things such as re-conductoring transmission lines, building new transmission lines, upgrading transformers, upgrading/installing communications equipment, etc.

A project wishing to be designated to serve network load must achieve interconnection rights as well as designation rights. Once a project has both interconnection and designation, then it may be considered as a candidate for a Network Resource as it will have the expectation of being able to generate and move its power onto the transmission system 100% of the time.

There may be costs associated with network resource designation on the transmission system. All costs needed for the success of a generation project to achieve both interconnection and designation as a network resource are identified through their respective processes; interconnection costs are identified in the interconnection process and Network Upgrade costs are identified in either the interconnection process, the designation process, or both.

5.1.3.2. Gas Infrastructure

In addition to electric transmission infrastructure, gas-fired generators require sufficient pipeline infrastructure to meet their fuel needs. These costs include an interconnection into the gas transmission system which may require improvements to the bulk gas transmission system, such as pipeline pressure uprates, laying additional line ("looping"), or installing additional gas compression equipment. These costs, and the incremental pipeline capacity that they secure, are identified through detailed engineering and cost analyses.

Gas projects may be connected into the gas transmission system on an interruptible service level, rather than receiving firm service. Firm service means there is sufficient gas pipeline capacity to meet the operational needs of the unit at all times. Interruptible service means the gas supplied to the generator is subject to interruption based on competing pipeline system needs, including the needs of other firm system users. Most of the large (200+ MW) gas power plants in the West receive firm gas service, and generally pay higher costs than they would for interruptible service. [27]

To overcome some of the costly upgrades required for firm service, and to handle the operational challenges that may be created by relying on interruptible service, gas-fired generators can be designed for dual fuels, which allows them to run on an alternative fuel source stored onsite, such as diesel, heating oil or liquefied natural gas.

5.1.3.3. Available Gas Capacity on NorthWestern's System

Based on preliminary engineering and cost estimates, NorthWestern's existing gas system could support up to approximately 300 MW of additional gas-fired generation, depending on the technologies, locations considered, and time of year. However, this gas service would be interruptible and may require other infrastructure investments to meet the operational parameters of a specific generator, such as increased inlet pressure. Firm service would require additional system investments. Additions of new gas-fired generation in excess of 300 MW would require costly new infrastructure, likely in excess of $100M. Depending on the location and specific size and needs, costs for this new infrastructure would likely include environmental studies, land permitting, pipeline construction, interconnection construction, additional compressor stations, and alternate supply contracts to access the additional gas.

5.1.4. Historical Performance of Wind and Solar

All else equal, resources that provide energy at times corresponding to when customers use energy are more valuable than resources whose generation is not correlated with demand. The following table and graphic show how generation on NorthWestern's system from wind and solar have been correlated with our loads and with wholesale power prices in 2017-2019.

Figure 28: Correlation of Wind and Solar Generation with Loads and Prices[28]

	Annual	Winter	Summer
Correlation with Load			
Wind	0.04	-0.05	-0.04
Solar	0.30	0.18	0.55
Correlation with Mid-C Price			
Wind	0.03	0.02	-0.13
Solar	0.004	-0.03	0.13

Solar: The amount of solar generation on NorthWestern's system is small compared to wind but exhibits a stronger correlation with historic loads, especially in the summer. The higher degree of correlation between solar and load is due to the coincidence of solar's daily generation cycle with daytime activity, and with a portion of the evening peak in summer (in winter the daily peak demand typically occurs after sunset). Solar generation has historically had only a moderate correlation with market prices and is thought to be putting significant downward pressure on daytime prices in California, where solar generation has reached particularly high levels.

27 See https://www.eia.gov/todayinenergy/detail.php?id=35112.

28 For these calculations, summer includes Jul-Aug and winter includes Dec-Mar.

Wind: The generation from wind resources in Montana has almost no correlation with Montana loads. While wind does tend to generate more in the winter, its correlation with loads does not increase relative to summer. Wind generation in Montana has not historically exhibited correlation with market prices.

Figure 29. Wind & Solar Generation vs. Load & Mid-C Prices: Winter (Dec-Mar, 2017-2019)

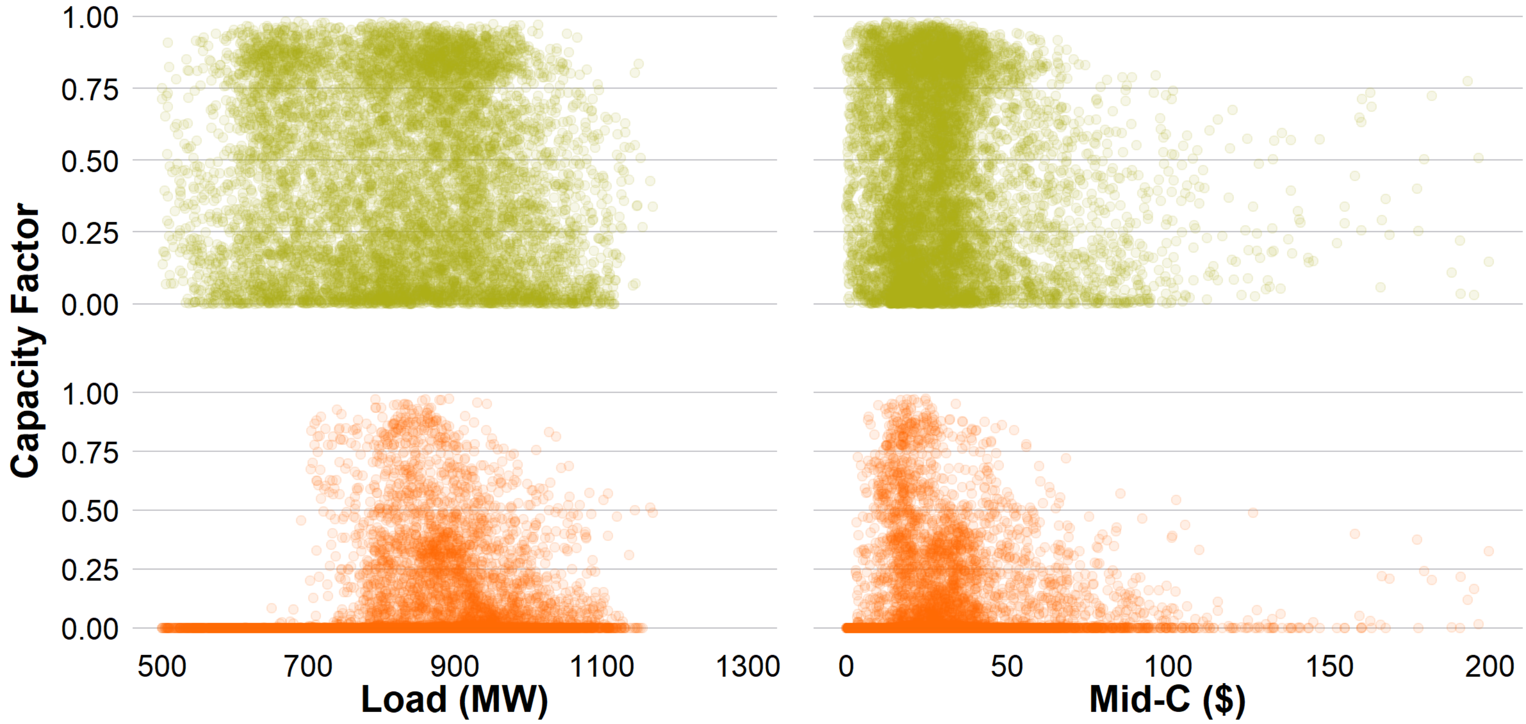
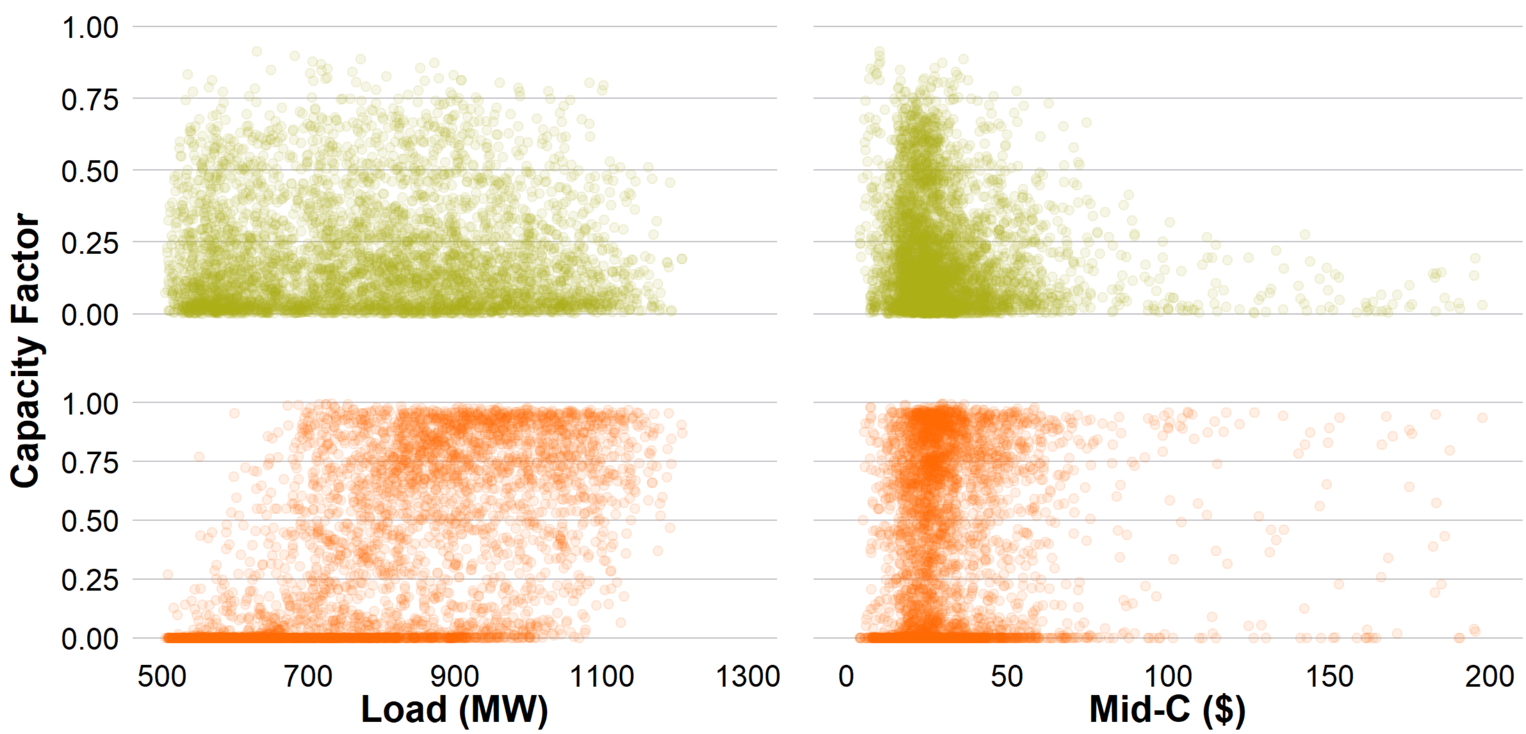


Figure 30. Wind & Solar Generation vs Load & Mid-C Prices: Summer (Jul-Aug, 2017-2019)



5.1.5. Demand Side Management: Energy Efficiency and Demand Response

Demand Side Management (DSM) like investments in energy efficiency (EE) and Demand Response (DR) can reduce loads and thus contribute to reducing NorthWestern's capacity deficit. NorthWestern's acquisition of DSM is determined based on tests of cost effectiveness. In addition, DR was eligible to participate in NorthWestern's capacity RFP. DSM measures and programs are evaluated over the full life in which the measure or program is expected to provide benefits. In this Supplement and the 2019 Plan, NorthWestern models DSM as a reduction in projected loads.

NorthWestern evaluates the cost effectiveness of DSM measures and programs based on the Total Resource Cost (TRC) test. The TRC test is a comparison of the benefits (the net present value of the lifetime avoided energy and capacity costs) to total program costs (NorthWestern's program implementation costs and incremental customer costs). Typically, a TRC benefit-to-cost ratio of 1.0 or greater indicates that a DSM measure or program is cost effective.

In January 2020, Nexant, Inc. completed the Updated Electric Energy Efficiency Market Potential Study for NorthWestern (Updated Electric Potential Study). This study built upon the previous assessment completed in 2017 by incorporating updated calculations of the costs of energy and capacity that DSM measures can allow NorthWestern to avoid, as well as updated end-use load shapes and lighting end-use measure assumptions, which helped to characterize the value of annual energy and peak demand savings. NorthWestern's DSM Acquisition Plan includes an energy savings target of 4.35 average MW (aMW) through 2020-2021 and 3.77 aMW each year for the remaining 15-year time horizon of the plan.

The results of the Updated Electric Potential Study provided NorthWestern with hourly profiles of energy savings for residential, commercial, and industrial programs. These profiles demonstrate how the DSM programs would reduce energy use at an hourly level over the course of a full year. The commercial and residential profiles were paired with historic hourly load data from 2010 – 2019 to determine the capacity contribution of these measures using the methodology set forth in the Southwest Power Pool's (SPP) Planning Criteria. The Planning Criteria states that the capacity contribution is calculated by determining the top 3% of load hours in the peak load month for each year and then identifying the 60th percentile of energy savings (or generation) contributed by the resource being evaluated.

Using this method, the capacity contributions for NorthWestern's DSM measures are 66% for the commercial/industrial and 50% for the residential sectors. These respective capacity contributions were applied to develop annual avoided capacity values measured in dollars per MWh of energy savings, which were then added to the annual avoided energy rates to determine the total avoided costs provided by the DSM measures for each sector.

The updated DSM avoided costs and updated lighting end-use measure assumptions were used to update DSM offerings for the 2020-2021 program year. An overview of NorthWestern's 2020-2021 DSM programs and engagement opportunities are listed and described below.

Efficiency Plus (E+) Lighting Programs: Cost-effective light-emitting diode ("LED") offerings are included in NorthWestern's E+ Commercial and E+ Residential Lighting Programs. NorthWestern offers rebates and contributes to costs through buy down programs in order to distribute and encourage purchase and use of ENERGY STAR® LEDs and fixtures, and other energy-efficient lighting measures. NorthWestern has engaged with DNV GL to implement these lighting programs.

E+ Commercial Programs and Contractors: NorthWestern continues to acquire energy efficiency in the commercial sector by contracting with firms to provide services in support of the E+ Business Partners Program and the E+ Commercial Electric Programs for Existing Facilities and New Construction. The following six firms are currently concentrating on the commercial and small industrial sectors:

- Cushing Terrell (formerly CTA Architects Engineers)
- Energy Resource Management, Inc. (ERM)
- McKinstry Essention
- CLEAResult Consulting, Inc.
- National Center for Appropriate Technology (NCAT)
- Associated Construction Engineers (ACE)

NorthWestern compensates these contractors on a performance basis, with payment based on a percentage of the energy conservation resource value of each individual 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. 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 these programs.

The E+ Commercial Electric Rebate Program for Existing Facilities includes incentives for motor rewinding. Currently, four electric motor service centers in NorthWestern's electric service area perform efficient motor rewinding service.

Northwest Energy Efficiency Alliance: NEEA is a regional non-profit organization supported by electric utilities, public benefits administrators, state governments, public interest groups, and energy efficiency industry representatives. Through regional leveraging, NEEA encourages "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. NEEA also funds some of the infrastructure development of ENERGY STAR Northwest and other above-code new home activities.

Additional Activities: NorthWestern staff and contractors sponsor training seminars during the year to increase awareness of energy conservation and energy efficiency opportunities in buildings and facilities. The objectives of these programs are to educate and inform building operators, designers, builders, and trade allies about using energy-consuming equipment efficiently and to promote the E+ programs, services, information resources, and incentives. Where practical or appropriate, Continuing Education Units (CEUs) are offered. A blend of Universal System Benefits (USB) and DSM funds covers the cost of these activities.

NorthWestern also communicates information about its E+ programs to its customers through media, events, appearances, meetings, speaking engagements, booth sponsorships, trade fairs and shows, conferences, and other special events. NorthWestern maintains networks of retailers, distributors, and other trade allies and provides information about its E+ programs through print, radio, television, distribution literature, and personal contact. As with the training seminars described above, a mix of USB and DSM funding is used.

NorthWestern recently initiated a DSM Stakeholder group through invitations to a diverse set of individuals. The intention of this group is for it to make recommendations to NorthWestern for consideration in development of its 2021-2022 electric DSM program offerings. The "DSM Circle of Life" was presented at a kickoff meeting held on September 2, 2020. NorthWestern plans to hold six or seven meetings of this stakeholder group between the September 2nd kickoff meeting and March 31, 2021. More meetings will be added if necessary to ensure adequate discussion of relevant issues with the goal of receiving valuable input from the stakeholder group on future potential electric DSM program offerings.

A summary of NorthWestern's energy savings targets, acquisitions and expenses is provided in Figure 31.

Figure 31. Historical DSM Targets and Costs

DSM/NEEA/USB Acquisition Target & Acquisition Reported, and DSM/NEEA Expense (excludes USB Expenses*)								
Tracker Year	**DSM NEEA USB Acquisition Target (aMW)**	**DSM Acquisition Reported (aMW)**	**NEEA Acquisition Reported (aMW)**	**USB Acquisition Reported (aMW)**	**Total DSM NEEA USB Acquisition Reported (aMW)**	**DSM Program Expense**	**NEEA Program Expense**	**Total DSM NEEA Expense**
2013-2014	6.00	4.90	1.14	0.59	6.62	$7,526,764	$1,812,813	$9,339,577
2014-2015	6.00	3.99	1.32	0.38	5.69	$4,399,366	$1,015,012	$5,414,378
2015-2016	6.00	3.41	1.14	0.58	5.13	$4,831,958	$1,219,625	$6,051,582
2016-2017	4.35	4.25	1.23	0.35	5.82	$5,303,406	$1,221,149	$6,524,555
2017-2018	4.35	5.26	1.54	0.27	7.07	$6,283,806	$1,523,720	$7,807,527
2018-2019	4.35	7.35	1.98	0.24	9.58	$7,744,933	$916,514	$8,661,446
2019-2020	4.35	7.10	1.72	0.27	9.09	$7,195,779	$1,262,384	$8,458,163
Cumulative	**35.40**	**36.26**	**10.07**	**2.68**	**49.01**	**$43,286,011**	**$8,971,216**	**$52,257,227**
*Although energy savings produced by USB programs are counted toward the overall annual aMW target, USB programs are funded through a separate charge and USB spending is not reported or included here.								

5.2. Market-Based Capacity Products and Energy Products

NorthWestern expects that market transactions will always be a part of its portfolio. These transactions can be categorized in many ways, but at a high level, they can be divided into two categories.

The first category is the set of market transactions that help NorthWestern provide reliable service during peak load periods. These are the transactions that would qualify under the NWPP Resource Adequacy Program and are considered capacity transactions. As currently conceived, the key requirements are that the contract is sourced from an identifiable generator or portfolio of generators; that the capacity from the generator is not counted toward any other entity's resource adequacy requirement; and that it is delivered on firm transmission. For resource adequacy purposes, these contracts must be for a minimum term (likely one to four months) and must be secured in advance (likely about seven months before the peak season).

The challenge of relying on these transactions is that it is not known in advance if they will be available in the market and in what amounts. In order to rely on the transactions for resource adequacy purposes, they need to be contracted with enough lead time so that, if sufficient quantities are not available, NorthWestern can pursue other alternatives such as developing new resources. As discussed in Section 3.3.3. Request for Near-term Capacity Products, the availability of these types of products is limited and they often have unique terms and conditions, which are difficult to predict and evaluate in portfolio simulation models. However, the challenges with modeling these types of products in portfolio simulations does not mean that they cannot play a role in NorthWestern's supply portfolio going forward, only that they must be evaluated on the specifics of their characteristics if and when they are available. The limited response to NorthWestern's RFP for near-term capacity products (discussed in Section 3.3.3) suggests that the current market for these products is small.

The second category of market transactions is those that help optimize the supply portfolio. These transactions are typically short-term (from hour-ahead up to one month) and are considered energy transactions. Examples of these transactions are selling excess generation in the market when it is not needed for customer loads and purchasing energy in the market to serve load when it is cheaper to do so than to run a generator in NorthWestern's portfolio. These types of transactions do not serve resource adequacy purposes.

6. PORTFOLIO MODELING

The modeling framework applied in this Supplement differs from the one used in the 2019 Plan. In the 2019 Plan, each portfolio began with an initial set of resources (such as NorthWestern's existing portfolio, or the existing portfolio plus 100 MW of new solar), which was then augmented in later years with sufficient capacity to meet projected peak loads in every year in the planning horizon. The type of new capacity added in later years was selected by a capacity expansion optimization model. This framework allowed for the calculation of the total projected revenue requirement for a selection of portfolios that had adequate capacity in every year of the planning horizon, but it provided a limited ability to examine a wide range of portfolios.

In this Supplement, we use a modeling framework that allows for an evaluation of a wider range of possible resource combinations. Here, we have constructed 21 unique portfolios that each add about 600 MW of effective load carrying capability (ELCC) to our existing portfolio in 2024 and include no other resource additions thereafter (the capacity expansion optimization model is not used). By leaving the portfolios unchanged over the planning horizon it is straightforward to see how the difference in their compositions translates into differences in their performance. Of course, because no resources are added beyond the initial portfolio, the adequacy of the portfolios diminishes over time (as loads grow, contracts expire, and existing resources retire) and in reality there will need to be future adjustments to ensure adequacy is maintained. Thus, the net present value of the revenue requirement (NPVRR) calculated for each portfolio does not represent the full costs of maintaining an adequate supply over the planning time horizon. Nonetheless, this framework makes for a simple and transparent examination of the costs and performance characteristics of different resource portfolios.

In constructing these portfolios, we include the technologies most commonly considered in utility planning analyses today. These technologies include wind, solar PV, lithium-ion batteries, pumped hydro storage, and reciprocating internal combustion engines (RICE units). As discussed in Section 5.1, the use here of a more focused set of resources is intended to facilitate straightforward comparisons and is not to suggest that other resource types or contracts for capacity from existing resources may not provide value or will not be considered in a competitive solicitation. Indeed, there are many technologies—geothermal, flow batteries, compressed air energy storage, nuclear, combustion turbines, demand side management, and others—that may prove to be important players in NorthWestern's future energy portfolio. However, the resources considered here represent a full range of fuel sources and the major ways generation technologies can differ in cost and energy production characteristics.

The resource costs used in this modeling analysis are described in Section 5.1 Physical Resources. These costs are based off of engineering estimates of the cost to build and operate each resource type. A more specific understanding of the costs of building and operating actual resources of these types on NorthWestern's system, including associated infrastructure costs, are not known without first receiving bids from project developers in response to an RFP.

The three key dimensions across which the portfolios differ are (1) the amount of energy they produce, (2) the degree to which they are dispatchable, and (3) the amount of storage they contain. Every portfolio contains NorthWestern's existing resources and contracts as well as the new wind and solar Qualifying Facilities (QFs) that have signed Power Purchase Agreements (PPAs) or have an MPSC order approving rates. These QFs include 392 MW of wind and 160 MW of solar (see Figure 19 in Section 3.2.1 for a list of these QFs).

6.1. Portfolios

The 21 portfolios analyzed here each add a different combination of new resources to NorthWestern's existing portfolio. Each portfolio contributes approximately 600 MW of new effective capacity, as measured by the effective load carrying capability (ELCC) metric discussed in Section 3.3.1.

The construction of the portfolios was subject to the following constraints and relationships:

- The relationship between the nameplate capacity and accredited (ELCC) capacity was calculated according to the ELCC results in Section 3.3.1.
- The total nameplate capacity required to provide 600 MW of effective capacity varies considerably across each portfolio. This variability is because different resource types have different ELCCs.
- The capacity contribution of each resource addition reflects the declining marginal ELCCs within each resource category, but they do not reflect the interactions that could occur when adding resources of different types, which is an important factor that must be considered when making actual resource decisions.
- The amounts of pumped hydro storage and natural gas additions were limited to reflect expected constraints on their availability:
- Pumped hydro was limited to a maximum of 400 MW nameplate capacity, reflecting the likely availability of that resource in Montana.
- Natural gas additions were limited to 315 MW nameplate capacity, reflecting the likely extent of new gas-fired generation that could be added to NorthWestern's gas system without triggering a need for significant investment in new gas system infrastructure. One exception to this limit on natural gas was included in Portfolio 1, which is modeled for illustrative purposes and includes about 600 MW of new gas capacity.

Using these constraints and relationships, the portfolios were constructed to reflect a range of mixtures of new resources:

- Portfolios 1 – 5 were designed to contain primarily one type of resource. Of these, the portfolios containing primarily storage or hybrid resources were augmented with additional carbon-free resources (wind, solar, and storage) as needed to achieve a capacity addition of about 600 MW ELCC.
- Portfolios 6 – 18 contain various mixtures of capacity (RICE units, batteries, and pumped hydro) and energy resources (wind and solar).
- Portfolio 19 contains a balanced mix of all resource types except natural gas.
- Portfolios 20 and 21 contain all resource types.

We also conducted a sensitivity analysis on portfolios 11-15 and 18 to consider the effect of an ELCC of 15% for wind and solar instead of the 5% calculated by E3 (see Section 3.3.1). For this analysis, we reconstructed these 6 portfolios by reducing the amount of wind and solar by two-thirds (if the capacity credit they receive is 3 times larger, they only need one-third as much wind and solar to achieve the same effective capacity). The results of this analysis are discussed in Section 6.5.

Figure 32. Portfolios of New Resources

Portfolios - New Capacity (MW)											
Portfolio	Capacity Measure	Natural Gas	Battery Storage	Pumped Hydro	Wind Hybrid		Solar Hybrid		Wind	Solar	Total
					Wind	Storage	Solar	Storage			
1	ELCC:	601									601
	Nameplate:	630									630
2	ELCC:		502						50	50	602
	Nameplate:		1700						1000	1000	3700
3	ELCC:			306					150	150	606
	Nameplate:			375					3000	3000	6375
4	ELCC:		201		201				100	100	602
	Nameplate:		250		400	200			2000	2000	4850
5	ELCC:		201				186		100	100	587
	Nameplate:		250				200	200	2000	2000	4650
6	ELCC:	301	303								604
	Nameplate:	315	700								1015
7	ELCC:	301		306							607
	Nameplate:	315		375							690
8	ELCC:	301							150	150	601
	Nameplate:	315							3000	3000	6315
9	ELCC:		303						150	150	603
	Nameplate:		700						3000	3000	6700
10	ELCC:	197	201	200							598
	Nameplate:	207	250	200							657
11	ELCC:	155	201	200					50		606
	Nameplate:	162	250	200					1000		1612
12	ELCC:	155	201	200						50	606
	Nameplate:	162	250	200						1000	1612
13	ELCC:	249	303						25	25	602
	Nameplate:	261	700						500	500	1961
14	ELCC:	301	253						25	25	604
	Nameplate:	315	450						500	500	1765
15	ELCC:		253	245					50	50	598
	Nameplate:		450	250					1000	1000	2700
16	ELCC:	249		245					50	50	594
	Nameplate:	261		250					1000	1000	2511
17	ELCC:	249	253						50	50	602
	Nameplate:	261	450						1000	1000	2711
18	ELCC:	197	201	150					25	25	598
	Nameplate:	207	250	150					500	500	1607
19	ELCC:		140	150	110		100		50	50	600
	Nameplate:		150	150	200	100	100	100	1000	1000	2800
20	ELCC:	155	50	150	110		100		25	25	614
	Nameplate:	162	50	150	200	100	100	100	500	500	1862
21	ELCC:	155	140	50	110		100		25	25	605
	Nameplate:	162	150	50	200	100	100	100	500	500	1862

6.2. Simulating the Performance of Each Portfolio

NorthWestern simulated the performance of the 21 portfolios using the PowerSimm™ modeling platform. The 2019 Plan fully describes the modeling platform. Generally, the model simulates hourly variation in weather, loads, power and natural gas prices, forced outages, and renewable generation. For the studies in this Supplement, we use a 20-year planning horizon and 10 simulations of every hour in that period, resulting in a simulation of every variable 1.75 million times.[29] The portfolios are simulated under 4 different pricing scenarios, and random price variation is simulated within each scenario. The price scenarios are: (1) reference (base-case), (2) carbon, (3) high gas and high power, and (4) high gas and reference-level power. See Chapter 4 for more information on the price forecasts.

For variables that are common to all portfolios (weather, loads, prices, etc.), the same simulated values are applied to every portfolio. Variables that are not common across portfolios are simulated on a portfolio-specific basis (e.g., outages at new RICE units are simulated for the portfolios with new RICE units in them, but not for portfolios that do not contain RICE units).

Based on these simulations, the model then determines the hourly dispatch of resources in the portfolio to achieve the lowest total cost of serving load. Determining the hourly dispatch requires a co-optimization to ensure that in every hour there is both an adequate supply of energy and sufficient capability to provide the ancillary services necessary to maintain loads and generation in balance at short-term time steps (from moment-to-moment regulation to slower (15-minute) load-following and the contingency reserves required in case of outages). The model's economic dispatch algorithm incorporates the use of purchases from the market when it costs less than generating from the dispatchable resources in the portfolio and sales to the market when NorthWestern's portfolio has excess generation that can be sold economically.

6.3. Results – Total Cost of Each Portfolio

The results of the portfolio models allow us to calculate the net present value of the revenue requirement (NPVRR) for each portfolio. The NPVRR is the key measure to evaluate a portfolio's cost. It includes the capital costs of building new resources, variable costs of operations and maintenance and fuel, the net revenue from all energy purchases and sales, and the existing capital costs embedded in the current portfolio. Because these portfolios were simulated 10 times (rather than the 100 simulations used in the 2019 Plan), we have not calculated risk premiums in this analysis.[30]

The results of the simulation models suggest that costs are lower for portfolios that contain mostly resources with larger capacity contributions, while costs are higher for portfolios that contain resources with lower capacity contributions. This can be seen in the following figure. The least-cost portfolio contains a mix of 4-hr batteries and natural gas RICE units and no other new resources. The second lowest-cost portfolio is similar, with pumped hydro storage in addition to 4-hour batteries and RICE units, and no other new resources. The following figure also shows the costs of each portfolio under each pricing scenario. The estimated costs of each portfolio are fairly stable across the 4 pricing scenarios, and the relative ranking of the portfolios within each pricing scenario is stable as well.

Remember…

The portfolios analyzed here do not contain adequate levels of capacity to meet NorthWestern's projected peak loads. The results are useful for understanding the relative differences between the portfolios, but they do not provide a complete estimate of future carbon emissions.

29 20 years times 8,760 hours per year times 10 simulations per hour equals 1,752,000 simulations.

30 The risk premium is a measure of the risk associated with the upper tail of the distribution of cost outcomes. The upper tail represents the most expensive outcomes for each portfolio contained within the simulations. With a reduced number of simulations, the risk premium is subject to high volatility and has considerably less meaning. For a conceptually similar assessment to the risk premium, one can compare how the results presented here change across the 4 price scenarios.

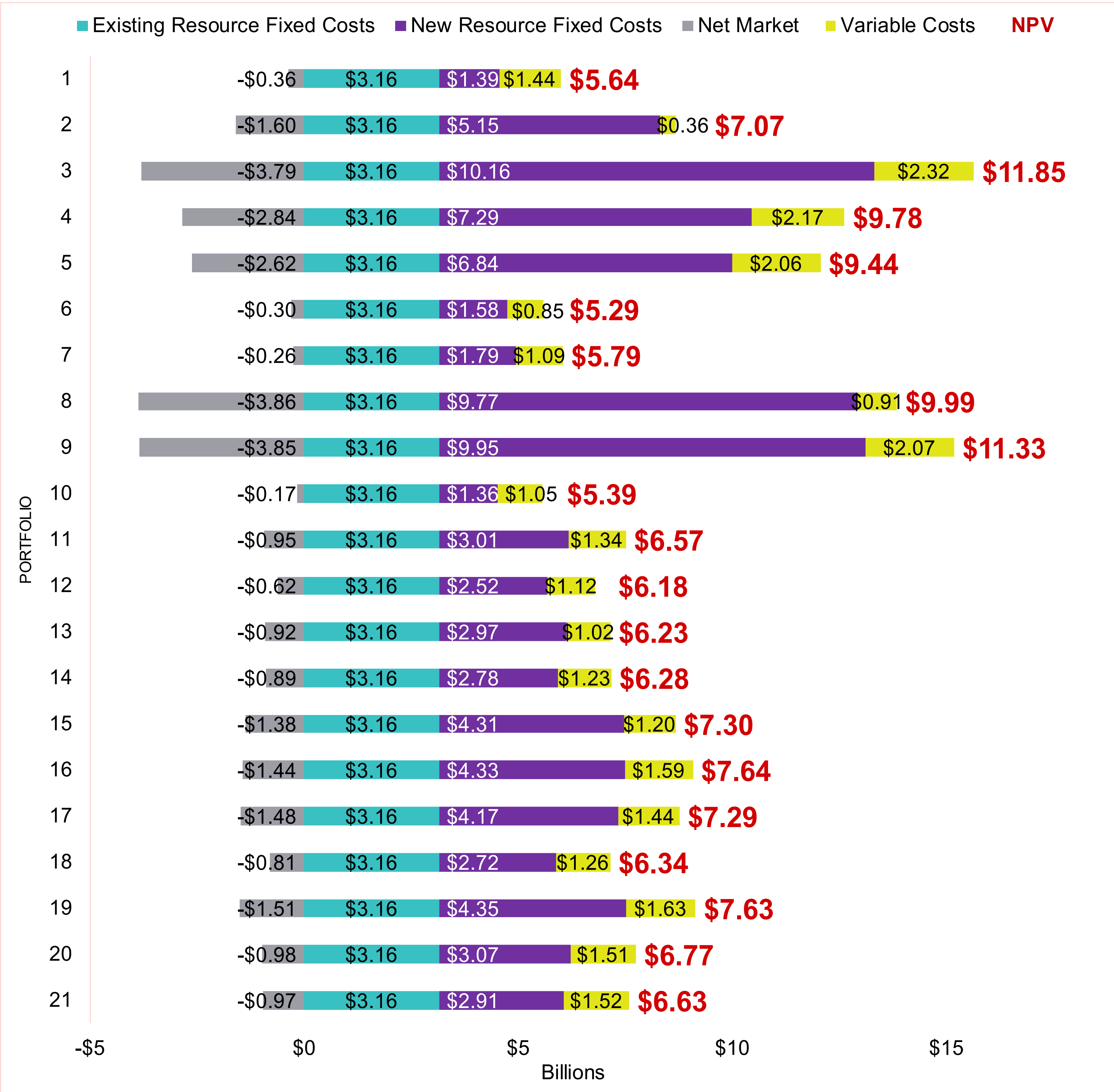
Figure 33. Portfolio Modeling Results - Total Portfolio Costs

Portfolios Ranked by Cost - Base Case Prices													
Cost			New Capacity (Nameplate MW)										
						Wind Hybrid		Solar Hybrid					
Portfolio	NPVRR (Billion)	Rank	Natural Gas	Battery Storage	Pumped Hydro	Wind	Storage	Solar	Storage	Wind	Solar	Total Nameplate	ELCC
6	$5.29	1	315	700								1015	604
10	$5.39	2	207	250	200							657	598
1	$5.64	3	630									630	601
7	$5.79	4	315		375							690	607
12	$6.18	5	162	250	200						1000	1612	606
13	$6.23	6	261	700						500	500	1961	602
14	$6.28	7	315	450						500	500	1765	604
18	$6.34	8	207	250	150					500	500	1607	598
11	$6.57	9	162	250	200					1000		1612	606
21	$6.63	10	162	150	50	200	100	100	100	500	500	1862	605
20	$6.77	11	162	50	150	200	100	100	100	500	500	1862	614
2	$7.07	12		1700						1000	1000	3700	602
17	$7.29	13	261	450						1000	1000	2711	602
15	$7.30	14		450	250					1000	1000	2700	598
19	$7.63	15		150	150	200	100	100	100	1000	1000	2800	600
16	$7.64	16	261		250					1000	1000	2511	594
5	$9.44	17		250				200	200	2000	2000	4650	587
4	$9.78	18		250		400	200			2000	2000	4850	602
8	$9.99	19	315							3000	3000	6315	601
9	$11.33	20		700						3000	3000	6700	603
3	$11.85	21			375					3000	3000	6375	606

Portfolio Costs - All Price Scenarios								
	Base Scenario		Carbon Price		High Gas and High Power Prices		High Gas Price, Base Power Price	
Portfolio	NPVRR (Billion)	Rank	NPVRR (Billion)	Rank	NPVRR (Billion)	Rank	NPVRR (Billion)	Rank
1	$5.64	3	$5.74	3	$5.60	3	$5.72	3
2	$7.07	12	$7.04	12	$6.12	11	$7.08	12
3	$11.85	21	$11.64	21	$9.48	21	$11.86	21
4	$9.78	18	$9.78	19	$8.15	19	$9.93	18
5	$9.44	17	$9.32	17	$7.82	18	$9.45	17
6	$5.29	1	$5.39	1	$5.21	1	$5.34	1
7	$5.79	4	$5.89	4	$5.74	4	$5.83	4
8	$9.99	19	$9.77	18	$7.60	17	$10.04	19
9	$11.33	20	$11.11	20	$8.92	20	$11.34	20
10	$5.39	2	$5.48	2	$5.36	2	$5.43	2
11	$6.57	9	$6.61	9	$6.05	9	$6.59	9
12	$6.18	5	$6.24	5	$5.87	7	$6.20	5
13	$6.23	6	$6.28	6	$5.77	5	$6.27	6
14	$6.28	7	$6.33	7	$5.85	6	$6.32	7
15	$7.30	14	$7.29	13	$6.49	14	$7.31	13
16	$7.64	16	$7.65	16	$6.84	16	$7.68	16
17	$7.29	13	$7.29	14	$6.47	13	$7.33	14
18	$6.34	8	$6.40	8	$5.93	8	$6.37	8
19	$7.63	15	$7.61	15	$6.73	15	$7.65	15
20	$6.77	11	$6.81	11	$6.24	12	$6.80	11
21	$6.63	10	$6.67	10	$6.11	10	$6.65	10

There is large variation across the portfolios in the way that 3 of the 4 cost categories contribute to each portfolio's total costs (the embedded capital cost of the existing resources does not change across portfolios). The portfolios with higher fixed (capital) costs for new resources tend to also generate much higher market sales. Figure 34 shows these patterns in the purple (new resource fixed costs) and grey (net market sales) bars. The largest driver of cost differences between the portfolios is the fixed costs associated with the new resources.

Figure 34. Total Portfolio Costs – Base Case Price Scenario, By Cost Type



6.4. Results – Market Sales and Purchases

The total cost (NPVRR) of each portfolio is influenced by revenue generated by the volume and cost of energy sales made to the market, and the volume and cost of energy purchased from the market. There is considerable variation in the amount of excess energy produced by each portfolio and sold into energy markets, and the portfolios with lower total costs tend to have significantly fewer market sales. Market sales volumes are a key measure for evaluating the economic risk of each portfolio. Having high volumes of market sales brings a much higher degree of market risk because if future prices turn out to be lower than forecast, the revenue of these sales will be much less and this would result in higher costs for portfolios that depend heavily on revenue from market sales to offset the construction cost of the resources in the portfolio. In addition, the timing of energy surpluses can significantly influence the value of the excess energy. For example, if wind generation is high at times of low loads and low prices, the excess energy would not generate much revenue. Additionally, if these excesses occur during periods of constrained transmission, there can be limited ability to convert the excess energy into revenue.

Figure 35. Market Sales and Purchases by Portfolio - Base Case Price Scenario

Figure 36. Portfolio Cost and 2030 Market Sales

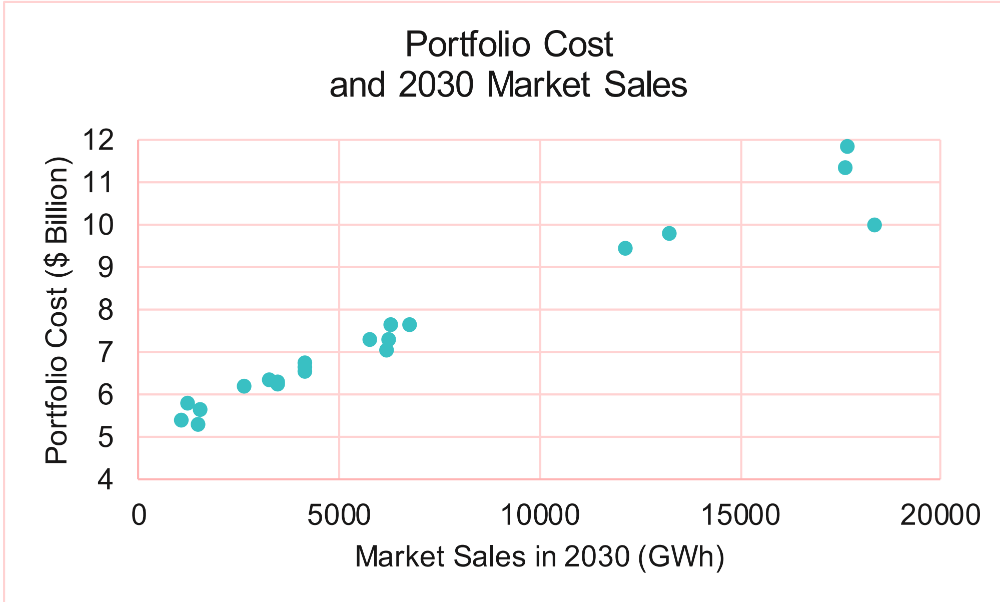


Figure 37. Market Sales by Portfolio and Price Scenario, 2025 and 2030

Market Sales																
	Base Scenario				Carbon Price Scenario				High Gas and High Power Prices				High Gas Price, Base Power Price			
	GWh		$ Millions		GWh		$ Millions		GWh		$ Millions		GWh		$ Millions	
Portfolio	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030
1	2,803	1,525	$101.4	$63.0	2,931	1,319	$103.5	$59.9	2,690	2,490	$100.4	$155.6	2,548	946	$92.6	$37.8
2	6,924	6,209	$242.9	$230.7	6,962	6,061	$244.2	$244.1	6,911	6,938	$249.4	$418.6	6,847	6,083	$239.6	$224.6
3	18,522	17,669	$501.2	$485.1	18,526	17,403	$496.7	$514.1	18,493	18,184	$516.8	$855.4	18,449	17,569	$498.2	$480.0
4	14,152	13,262	$384.6	$366.3	14,160	12,992	$381.5	$385.3	14,124	13,764	$396.1	$650.9	14,080	13,160	$381.5	$361.4
5	13,013	12,138	$357.7	$340.1	13,017	11,870	$356.4	$358.4	12,984	12,639	$368.2	$604.8	12,940	12,037	$354.6	$335.0
6	2,229	1,482	$92.2	$68.6	2,364	1,334	$94.3	$67.3	2,184	2,232	$92.9	$152.8	2,097	1,154	$87.2	$54.1
7	2,057	1,230	$83.4	$56.8	2,188	1,073	$85.5	$54.6	2,012	1,938	$83.8	$131.5	1,924	895	$78.4	$42.1
8	19,485	18,388	$520.1	$494.6	19,651	18,104	$521.5	$525.4	19,434	19,259	$535.6	$892.7	19,341	18,013	$514.8	$478.5
9	18,463	17,614	$509.2	$494.7	18,479	17,359	$505.2	$524.5	18,436	18,151	$524.9	$871.0	18,390	17,518	$506.1	$489.9
10	1,787	1,080	$71.3	$48.8	1,889	936	$74.9	$48.1	1,762	1,665	$72.0	$111.8	1,694	842	$67.5	$38.3
11	5,142	4,164	$158.2	$132.7	5,234	3,919	$158.1	$133.3	5,121	4,851	$162.3	$258.5	5,054	3,928	$154.7	$122.3
12	3,452	2,648	$120.4	$99.5	3,539	2,449	$121.0	$99.1	3,432	3,289	$122.8	$197.6	3,366	2,414	$116.9	$89.2
13	4,497	3,488	$157.8	$131.5	4,653	3,241	$159.4	$131.5	4,458	4,339	$160.9	$261.8	4,372	3,152	$153.1	$117.1
14	4,607	3,484	$154.2	$124.6	4,774	3,233	$156.0	$124.0	4,556	4,364	$156.9	$252.8	4,462	3,097	$148.9	$107.9
15	6,676	5,782	$206.8	$187.2	6,691	5,527	$206.0	$192.4	6,650	6,318	$212.0	$341.1	6,605	5,676	$203.7	$182.1
16	7,396	6,276	$219.6	$191.5	7,548	6,012	$220.3	$196.0	7,356	7,114	$224.9	$366.0	7,271	5,943	$214.9	$177.1
17	7,366	6,262	$223.9	$196.7	7,519	6,002	$224.6	$201.8	7,326	7,107	$229.4	$374.6	7,240	5,927	$219.1	$182.3
18	4,309	3,283	$141.2	$114.6	4,454	3,035	$142.7	$113.7	4,281	4,040	$144.2	$229.9	4,205	2,998	$137.1	$102.3
19	7,660	6,745	$222.2	$201.8	7,678	6,486	$221.3	$208.5	7,633	7,252	$228.1	$366.7	7,589	6,641	$219.1	$196.8
20	5,133	4,130	$160.0	$135.1	5,238	3,877	$160.4	$135.7	5,111	4,836	$163.9	$262.5	5,043	3,884	$156.4	$124.4
21	5,138	4,138	$158.5	$133.8	5,221	3,883	$158.1	$134.0	5,116	4,836	$162.4	$260.0	5,048	3,892	$155.0	$123.1

Figure 38. Market Purchases by Portfolio and Price Scenario, 2025 and 2030

Market Purchases																
	Base Scenario				Carbon Price Scenario				High Gas and High Power Prices				High Gas Price, Base Power Price			
	GWh		$ Millions		GWh		$ Millions		GWh		$ Millions		GWh		$ Millions	
Portfolio	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030
1	175	400	$3.1	$8.5	129	551	$2.1	$14.3	183	255	$3.4	$6.9	193	626	$3.6	$17.8
2	774	1,109	$14.5	$23.2	799	1,312	$14.9	$29.8	798	1,385	$15.5	$43.8	787	1,141	$15.0	$24.5
3	117	212	$2.2	$4.8	119	272	$2.4	$7.2	123	229	$2.5	$7.7	123	225	$2.5	$5.4
4	106	209	$2.1	$5.0	108	274	$2.2	$7.5	112	220	$2.3	$7.7	113	224	$2.3	$5.7
5	111	219	$2.2	$5.2	111	285	$2.2	$7.8	118	230	$2.5	$8.0	118	235	$2.5	$5.9
6	593	1,097	$8.8	$20.2	509	1,323	$7.2	$29.4	614	1,012	$9.6	$26.0	624	1,281	$9.8	$27.5
7	401	802	$5.8	$14.5	325	996	$4.4	$22.1	412	675	$6.3	$16.2	422	966	$6.4	$20.8
8	56	120	$1.1	$2.7	42	161	$0.7	$4.4	58	80	$1.2	$2.4	61	171	$1.2	$4.9
9	150	260	$2.9	$6.0	155	331	$3.1	$8.7	157	298	$3.2	$10.1	157	274	$3.1	$6.6
10	444	864	$6.8	$16.3	391	1,094	$5.6	$24.8	456	744	$7.4	$19.0	464	1,008	$7.5	$21.9
11	199	374	$3.3	$7.2	174	460	$2.9	$10.8	205	355	$3.5	$9.5	207	430	$3.5	$9.4
12	287	544	$4.5	$10.6	255	701	$4.0	$16.7	296	511	$4.9	$14.0	299	624	$4.9	$13.8
13	245	454	$3.6	$8.4	214	557	$3.1	$12.4	254	466	$4.0	$11.9	256	516	$4.0	$10.8
14	138	283	$2.0	$5.1	110	357	$1.4	$8.1	145	265	$2.2	$6.4	146	341	$2.2	$7.4
15	234	384	$4.3	$8.4	238	473	$4.6	$11.8	243	442	$4.7	$14.4	241	399	$4.6	$9.0
16	93	188	$1.4	$3.5	73	239	$1.0	$5.6	97	168	$1.5	$4.2	99	229	$1.6	$5.2
17	108	217	$1.6	$4.1	88	275	$1.2	$6.4	113	207	$1.8	$5.3	115	260	$1.8	$5.8
18	145	285	$2.2	$5.3	119	360	$1.7	$8.3	150	267	$2.4	$6.8	152	332	$2.4	$7.2
19	150	272	$2.8	$6.1	153	347	$3.0	$9.0	158	297	$3.1	$9.9	157	287	$3.1	$6.8
20	132	254	$2.1	$4.9	115	325	$1.8	$7.7	136	243	$2.3	$6.5	138	293	$2.3	$6.5
21	123	244	$2.0	$4.8	107	312	$1.7	$7.6	127	229	$2.1	$6.2	129	284	$2.2	$6.4

Figure 39. Net Market Position by Portfolio and Price Scenario, 2025 and 2030

Net Market Position (sales minus purchases)																
	Base Scenario				Carbon Price Scenario				High Gas and High Power Prices				High Gas Price, Base Power Price			
	GWh		$ Millions		GWh		$ Millions		GWh		$ Millions		GWh		$ Millions	
Portfolio	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030
1	2,627	1,125	$98.3	$54.6	2,802	769	$101.4	$45.6	2,507	2,235	$97.0	$148.7	2,355	320	$89.0	$20.0
2	6,150	5,100	$228.4	$207.5	6,163	4,748	$229.3	$214.3	6,112	5,553	$233.9	$374.8	6,060	4,942	$224.6	$200.1
3	18,406	17,457	$499.0	$480.3	18,407	17,131	$494.2	$506.8	18,370	17,954	$514.3	$847.7	18,327	17,344	$495.7	$474.7
4	14,046	13,053	$382.5	$361.3	14,052	12,718	$379.3	$377.8	14,011	13,544	$393.8	$643.2	13,967	12,936	$379.2	$355.7
5	12,902	11,919	$355.5	$334.8	12,906	11,585	$354.2	$350.6	12,867	12,409	$365.7	$596.7	12,822	11,802	$352.2	$329.1
6	1,636	385	$83.3	$48.3	1,855	12	$87.1	$38.0	1,570	1,220	$83.3	$126.8	1,474	-127	$77.5	$26.6
7	1,657	428	$77.6	$42.4	1,863	78	$81.1	$32.5	1,599	1,264	$77.5	$115.3	1,502	-71	$72.0	$21.3
8	19,430	18,268	$519.0	$491.9	19,608	17,944	$520.8	$521.0	19,376	19,179	$534.4	$890.3	19,280	17,842	$513.5	$473.6
9	18,313	17,354	$506.3	$488.7	18,323	17,028	$502.1	$515.8	18,278	17,853	$521.8	$860.9	18,233	17,243	$503.0	$483.2
10	1,343	215	$64.4	$32.6	1,498	-158	$69.4	$23.3	1,306	922	$64.7	$92.7	1,229	-166	$60.1	$16.5
11	4,943	3,790	$155.0	$125.4	5,059	3,459	$155.2	$122.5	4,916	4,496	$158.8	$249.0	4,847	3,498	$151.2	$112.9
12	3,165	2,104	$115.9	$88.8	3,285	1,747	$117.0	$82.4	3,135	2,778	$117.8	$183.6	3,067	1,789	$112.0	$75.4
13	4,253	3,034	$154.2	$123.2	4,439	2,685	$156.3	$119.1	4,204	3,873	$157.0	$249.8	4,116	2,636	$149.1	$106.2
14	4,469	3,201	$152.3	$119.4	4,664	2,876	$154.6	$115.9	4,412	4,100	$154.8	$246.4	4,316	2,756	$146.7	$100.5
15	6,442	5,398	$202.4	$178.8	6,452	5,054	$201.4	$180.6	6,407	5,876	$207.3	$326.7	6,364	5,277	$199.1	$173.1
16	7,303	6,088	$218.2	$187.9	7,475	5,773	$219.2	$190.4	7,259	6,946	$223.4	$361.9	7,172	5,713	$213.3	$171.9
17	7,259	6,045	$222.3	$192.6	7,431	5,727	$223.3	$195.4	7,213	6,901	$227.6	$369.4	7,126	5,667	$217.4	$176.5
18	4,164	2,999	$139.0	$109.3	4,335	2,675	$141.0	$105.4	4,131	3,773	$141.8	$223.1	4,053	2,666	$134.7	$95.1
19	7,509	6,472	$219.4	$195.6	7,526	6,138	$218.3	$199.5	7,476	6,956	$225.0	$356.8	7,431	6,353	$216.1	$189.9
20	5,001	3,876	$158.0	$130.2	5,124	3,553	$158.6	$127.9	4,975	4,593	$161.7	$256.0	4,906	3,591	$154.1	$117.9
21	5,015	3,894	$156.6	$129.0	5,114	3,571	$156.4	$126.4	4,988	4,608	$160.3	$253.9	4,920	3,608	$152.8	$116.6

6.5. Results – Carbon Emissions

The portfolios examined in this analysis produce total carbon emissions over the 20-year modeling horizon that range from about 13.6 million tons to about 22.9 million tons, or 0.7 million to 1.1 million tons per year.[31] These values include the carbon emissions associated with the total generation in each portfolio, whether that energy is used to serve NorthWestern's customers or sold into wholesale markets, and do not include emissions associated with market purchases.

In general, the portfolios with lower carbon emissions have higher costs. This can be seen in Figure 40. Among the portfolios whose total costs are under $8 billion, the tradeoff between higher costs and lower emissions works out to approximately $230 per ton of carbon avoided.[32] This tradeoff increases considerably when considering the set of portfolios with total emissions under 15 million tons, as can be seen in the near vertical alignment of these portfolios in Figure 40. However, the tradeoff is far less among the least-cost portfolios. Between Portfolios 6 and 10 (the red dots in Figure 40), the cost increase is only about $56 per ton of carbon avoided.

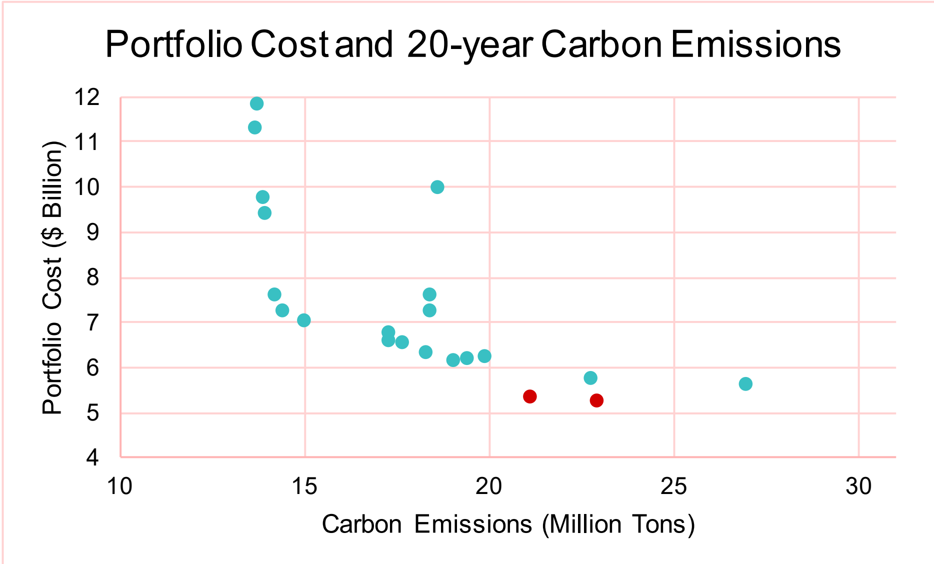
Remember…

The portfolios analyzed here do not contain adequate levels of capacity to meet NorthWestern's projected peak loads. The results are useful for understanding the relative differences between the portfolios, but they do not provide a complete estimate of future carbon emissions.

31 This range does not include Portfolio 1, which contains more new gas-fired RICE units than could be added to NorthWestern's gas system without triggering a need for costly system upgrades. Portfolio 1 has total emissions of about 27 million tons.

32 This value was estimated by fitting an ordinary least squares regression line on the set of portfolios whose total cost is under $8 billion and total emissions under 25 million. The estimated coefficient (slope) is -0.23.

Figure 40. Portfolio Cost and Carbon Emissions

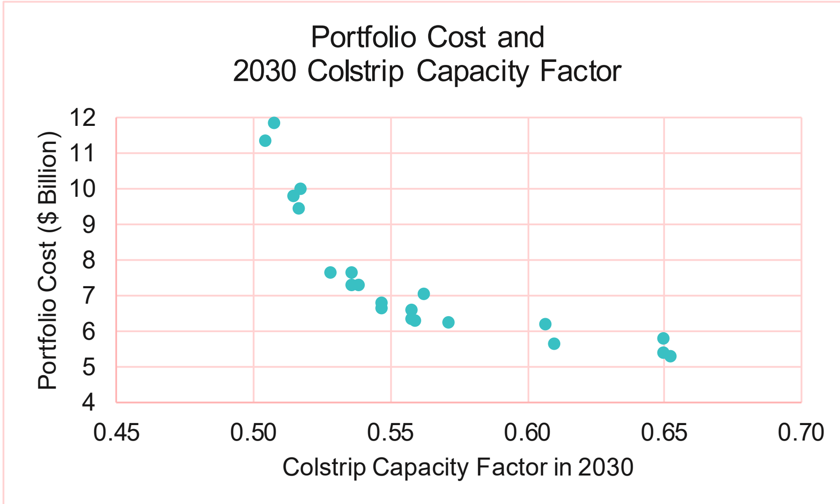


The carbon emissions produced by these portfolios are influenced by the amount of generation produced by NorthWestern's 222-MW share of the Colstrip generating facility. Figure 41 shows the capacity factor of Colstrip for each portfolio and price scenario in the years 2025 and 2030. Figure 42 shows the relationship between each portfolio's total cost and the capacity factor of Colstrip in 2030 for that portfolio under the Base Case price scenario.

Figure 41. Capacity Factor of Colstrip, by Portfolio and Price Scenario

Colstrip Capacity Factor								
	Base Scenario		Carbon Price Scenario		High Gas and High Power Prices		High Gas Price, Base Power Price	
Portfolio	2025	2030	2025	2030	2025	2030	2025	2030
1	0.58	0.61	0.58	0.37	0.61	0.81	0.60	0.59
2	0.58	0.56	0.60	0.33	0.60	0.80	0.58	0.53
3	0.53	0.51	0.54	0.29	0.55	0.76	0.53	0.49
4	0.53	0.51	0.55	0.29	0.56	0.77	0.54	0.50
5	0.53	0.52	0.54	0.29	0.56	0.77	0.54	0.50
6	0.63	0.65	0.63	0.38	0.66	0.84	0.64	0.63
7	0.62	0.65	0.61	0.37	0.65	0.84	0.63	0.63
8	0.53	0.52	0.53	0.29	0.56	0.77	0.54	0.50
9	0.53	0.50	0.54	0.29	0.55	0.76	0.53	0.49
10	0.62	0.65	0.61	0.37	0.65	0.84	0.63	0.63
11	0.56	0.56	0.57	0.32	0.59	0.79	0.57	0.54
12	0.59	0.61	0.60	0.35	0.62	0.81	0.60	0.59
13	0.57	0.57	0.58	0.32	0.60	0.80	0.58	0.55
14	0.56	0.56	0.56	0.31	0.59	0.79	0.57	0.54
15	0.55	0.54	0.57	0.31	0.58	0.78	0.56	0.52
16	0.55	0.54	0.55	0.30	0.58	0.78	0.55	0.51
17	0.55	0.54	0.55	0.30	0.58	0.78	0.56	0.52
18	0.56	0.56	0.57	0.32	0.59	0.79	0.57	0.54
19	0.54	0.53	0.56	0.30	0.57	0.78	0.55	0.51
20	0.55	0.55	0.56	0.31	0.58	0.79	0.56	0.53
21	0.55	0.55	0.56	0.31	0.58	0.79	0.56	0.53

Figure 42. Portfolio Costs and Colstrip Capacity Factor in 2030



6.6. Results – Portfolio Costs If Wind and Solar Receive Higher Capacity Credit

To consider how the results might change if wind and solar were to merit a higher capacity credit than the ELCCs calculated by E3, we reconstructed 5 portfolios using an ELCC for wind and solar of 15%, which is 3 times higher than the actual ELCC. This results in a 67% reduction in the amount of wind and solar in each of these portfolios (if the capacity credit of wind and solar is 3 times larger, they only need one-third as much wind and solar to provide the equivalent amount of capacity). The portfolios analyzed in this scenario are Portfolios 11-14 and 18.[33]

Figure 43. Scenario Analysis – Sample of Portfolios with Higher (3x) ELCC for Wind and Solar

New Capacity - Nameplate (MW)										
Portfolio	Natural Gas	Battery Storage	Pumped Hydro Storage	Wind Hybrid (Wind)	Wind Hybrid (Storage)	Solar Hybrid (Solar)	Solar Hybrid (Storage)	Wind	Solar	Total
11x3	162	250	200	0	0	0	0	300	0	912
12x3	162	250	200	0	0	0	0	0	300	912
13x3	261	700	0	0	0	0	0	200	200	1361
14x3	315	450	0	0	0	0	0	200	200	1165
18x3	207	250	150	0	0	0	0	200	200	1007

The following table shows the total costs of these portfolios and the amount by which the costs changed, relative to their companion portfolios that were constructed using a 5% ELCC for wind and solar.

Figure 44. Scenario Analysis - Total Portfolio Costs With Higher (3x) ELCC for Wind and Solar

Portfolio Costs With VER ELCC=15%, and Change Relative to ELCC=5%								
	Base Scenario		Carbon Price		High Gas and High Power Prices		High Gas Price, Base Power Price	
Portfolio	NPVRR (Billion)	Change in NPVRR	NPVRR (Billion)	Change in NPVRR	NPVRR (Billion)	Change in NPVRR	NPVRR (Billion)	Change in NPVRR
11x3	$5.68	$(0.89)	$5.75	$(0.86)	$5.52	$(0.53)	$5.71	$(0.89)
12x3	$5.57	$(0.60)	$5.65	$(0.59)	$5.47	$(0.40)	$5.60	$(0.60)
13x3	$5.61	$(0.62)	$5.68	$(0.61)	$5.39	$(0.39)	$5.65	$(0.62)
14x3	$5.65	$(0.63)	$5.71	$(0.62)	$5.45	$(0.40)	$5.69	$(0.63)
18x3	$5.71	$(0.63)	$5.78	$(0.62)	$5.54	$(0.40)	$5.74	$(0.63)

33 Portfolios with hybrids were not included in this analysis because including hybrids would add considerable complication to the adjustment from 5 to 15% ELCC. However, these portfolios include stand-alone batteries and renewables together and should therefore be reasonably representative of the general effects that would result from a higher ELCC for wind and solar.

Taking the change in NPVRR associated with each of these portfolios and dividing it by the total MW of renewables in their companion portfolio (the one constructed under the 5% ELCC) allows us to calculate the average cost reduction per MW of renewables that can be expected in general if wind and solar were to merit a 15% ELCC, rather than 5%. These values are shown for each portfolio in Figure 45. If wind and solar were to merit an ELCC of 15%, rather than 5%, this would reduce the total cost of each portfolio by an average of about $675,000 per MW of wind and solar in the initial portfolio (see Figure 45, third column, bottom row). For example, if a portfolio had 1000 MW of wind initially (under a 5% ELCC) the reduction down to the 333 MW of wind that would be needed with a 15% ELCC would have a corresponding reduction in portfolio costs of $675 million ($675,000 times the 1000 MW in the initial portfolio).

Figure 45. Change in Total Cost if Wind and Solar Receive Higher (3x) ELCC ($ per MW of Renewables in Original (ELCC=5%) Portfolio)

Portfolio	Original VER - Total Nameplate (MW)	Change in NPVRR per MW VER (Nameplate)			
		Base	Carbon	High Gas & High Power	High Gas & Base Power
11x3	1000	$(887,125)	$(858,566)	$(534,709)	$(886,775)
12x3	1000	$(603,725)	$(590,639)	$(402,514)	$(602,808)
13x3	1000	$(621,261)	$(605,866)	$(386,063)	$(619,963)
14x3	1000	$(631,035)	$(615,783)	$(396,009)	$(629,436)
18x3	1000	$(631,534)	$(616,394)	$(396,148)	$(630,440)
Average		**$(674,936)**	**$(657,450)**	**$(423,089)**	**$(673,884)**

Figure 46 shows how the cost reductions associated with a 15% ELCC would change the rankings of portfolios under the Base Case price scenario. For the portfolios that were not reconfigured in the 15% ELCC scenario, their total costs with a 15% ELCC for wind and solar are approximated by taking their initial NPVRR and then subtracting $674,936 for every MW of wind and solar in the portfolio.

Figure 46. Effect of Higher (3x) ELCC for Wind and Solar on Portfolio Cost Rankings

Effect of Higher VER ELCC on NPVRR Rankings			
NPVRR with VER ELCC =5%	**Portfolio**		**NPVRR with VER ELCC =15%**
$5.29	6	6	$5.29
$5.39	10	10	$5.39
$5.64	1	12	$5.57
$5.79	7	13	$5.61
$6.18	12	1	$5.64
$6.23	13	14	$5.65
$6.28	14	11	$5.68
$6.34	18	2	$5.69
$6.57	11	18	$5.71
$6.63	21	7	$5.79
$6.77	20	15	$5.95
$7.07	2	8	$5.87
$7.29	17	17	$5.92
$7.30	15	21	$5.94
$7.63	19	20	$6.08
$7.64	16	19	$6.26
$9.44	5	16	$6.27
$9.78	4	5	$6.69
$9.99	8	4	$7.04
$11.33	9	9	$7.20
$11.85	3	3	$7.73
NPVRR with VER ELCC=15% based on reconfigured portfolio.			
NPVRR with VER ELCC=15% based on avg cost savings from reconfigured portfolios.			
Portfolios 1, 6, 7 and 10 contain no new VERs (NPVRR is unchanged)			