NORTHWESTERN ENERGY'S SOUTH DAKOTA 2024 INTEGRATED RESOURCE PLAN

NorthWestern® Energy

Delivering a Bright Future

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1. Executive Summary

1.1. Overview of NorthWestern Energy's 2024 IRP

The energy sector is undergoing transition caused by evolving policy, increasing installations of Variable Energy Resources (VER), and legacy resources approaching their end of life. While coal retirements and growth of VERs have occurred across the region for years, the pace and magnitude of change is intensifying, resulting in increased challenges for utilities to plan for and maintain an adequate and reliable power system while accommodating future uncertainty. Over the next five years within the Southwest Power Pool (SPP) area, an additional 1,985 MW of coal capacity is projected to be retired[1]. NorthWestern Energy Public Service (NorthWestern or NWE) explores the impacts these various factors may have on our portfolio over the next twenty years and what actions could be taken to ensure future energy reliability. This Integrated Resource Plan (IRP or Plan) utilizes modeling to evaluate different generation resource portfolios and their performance across a range of future conditions. The modeling suggests that NorthWestern could fill the near-term capacity shortfall with solar and battery storage resources, the mid-term capacity shortfall with natural gas resources, and the long-term capacity shortfall with carbon free resources such as small modular reactors or battery storage. As is explained further in this IRP, resource retirement and obsolescence also drive the need to secure additional generation resources.

1 Page 7, table 2, https://www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf

2. Introduction

2.1. Purpose of 2024 South Dakota IRP

NorthWestern publishes an updated South Dakota IRP every two years, reflecting an updated view of the utility's assets, load obligation, generation resource options, and portfolio modeling. The IRP evaluates different potential generation resource portfolios that could meet the needs of our South Dakota electric customers reliably, safely, and affordably over a twenty-year time horizon. The IRP can be considered a roadmap to inform the development of an adequate energy supply portfolio for the coming years. All references to NorthWestern's assets and customers are intended to reflect those customers and assets in South Dakota, unless otherwise noted.

2.2. Updates since the 2022 IRP

Resource planning is an on-going process that continues between and after the filing date of an IRP. There have been several updates and investigations related to resource planning since our last IRP was filed in 2022. They include:

- Inflation Reduction Act-related credits are incorporated for renewable resources. Both Production Tax Credits (PTCs) and Investment Tax Credits (ITCs) are considered in candidate resource costs. Despite these IRA credits, the overnight build costs for wind and solar have increased since the 2022 Plan, resulting in similar costs between the 2022 IRP and this current one.
- Evaluation of timelines and repercussions of retiring emitting resources, related to Environmental Protection Agency (EPA) Mercury and Air Toxics Standards (MATS), standards for greenhouse gas emissions, and Regional Haze Rules (RHR).
- Evaluation of replacement of existing resources that have reached their end of life such as Aberdeen 1 and Yankton 1 through 4, Clark, and Faulkton. In the case of Aberdeen 1, a replacement option has been selected and site work is in process; associated details are provided in this IRP.
- Inclusion of new candidate resource types and configurations, such as a flexible fuel generator, a Simple Cycle Combustion Turbine (SCCT) Frame option (frame CT), and a Combined Cycle Combustion Turbine (CCCT) option.
- Updated resource costs, capacity accreditations, and fuel costs.

2.3. Planning Uncertainty

Resource planning requires the consideration of information about the future that is not known with certainty — including forecasts of prices and electric loads — and incorporates assumptions about the costs and characteristics of different factors, such as generating technologies. Further, the regulatory landscape can change quickly, leading to uncertainty in resource operation and viability. This IRP should be considered a snapshot of best available information at the time of filing. Unforeseen events or circumstances that occur after the Plan's filing are outside the scope of this IRP and may result in changes from the content contained herein. Accordingly, the IRP does not result in specific decisions about new resources for addition to NorthWestern's generation portfolio. Instead, the IRP provides information about the system's likely future needs under different conditions and evaluates various resource types based on their generic costs and characteristics. The IRP serves as a useful foundation to evaluate, rather than prescribe, future resource determinations, which would necessarily require more specific information. NorthWestern will remain flexible and responsive as the future unfolds and will update our plans accordingly.

2.4. Planning Process

The IRP process includes updating load forecasts, resource costs, and resource contribution assumptions, and refreshing our production cost and automated resource selection models for a 20-year planning horizon. Each IRP evaluates expected changes to our portfolio, customer needs, and load growth scenarios, as well as impacts imposed by the regulatory change during the planning horizon. Additionally, our IRP evaluates generation resource retirement scenarios that may result from environmental rule changes.

NorthWestern also files a separate Ten-Year Energy Facility Plan pursuant to SDCL § 49-41B-3 and ARSD ch. 20:10:21[2]. The 2024-2033 Ten-Year plan was submitted July 2024 and contains more information on existing transmission facilities, but it does not contain the comprehensive modeling and analysis regarding resource planning that this IRP does.

2.5. Action Items and Progress from the 2022 IRP

The 2022 IRP specified the following action items. This section briefly lists the status of those items and references the location in this IRP for more detail.

Resource Retirements and Replacements

- Both Yankton 1-4 and Aberdeen 1 generators were mentioned for retirement and replacement in the 2022 IRP. These generators accounted for approximately 42.4 MW of nameplate capacity, with Aberdeen 1 having a nameplate capacity of 28.8 MW and Yankton having a nameplate capacity of approximately 13.6 MW. Their current status is:
    - ↳ Yankton's four Reciprocating Internal Combustion Engines ("RICE") remain in a continued outage state and it is not economic to restore the site to operational condition. These units are slated to be fully depreciated December 31, 2025.
    - ↳ NorthWestern issued a request for proposals ("RFP") in January 2024 to replace Aberdeen 1's 28.8 MW of nameplate capacity. The RFP sought a quick-to-market combustion turbine option located at the existing Aberdeen Generating Station site with a 30-year design life minimum. The project will use the existing 34.5 kV electrical interconnection to NorthWestern's system and the existing Northern Border Pipeline (NBPL) natural gas supply. A selection was made from the RFP and more details are provided in the Action Plan section.

Transmission Project Progress

- The Chamberlain Junction Project that was mentioned in the 2022 IRP has been completed and the new switchyard was energized and in-service by the end of 2023. More details on this project are presented in the High Priority Transmission Projects section.

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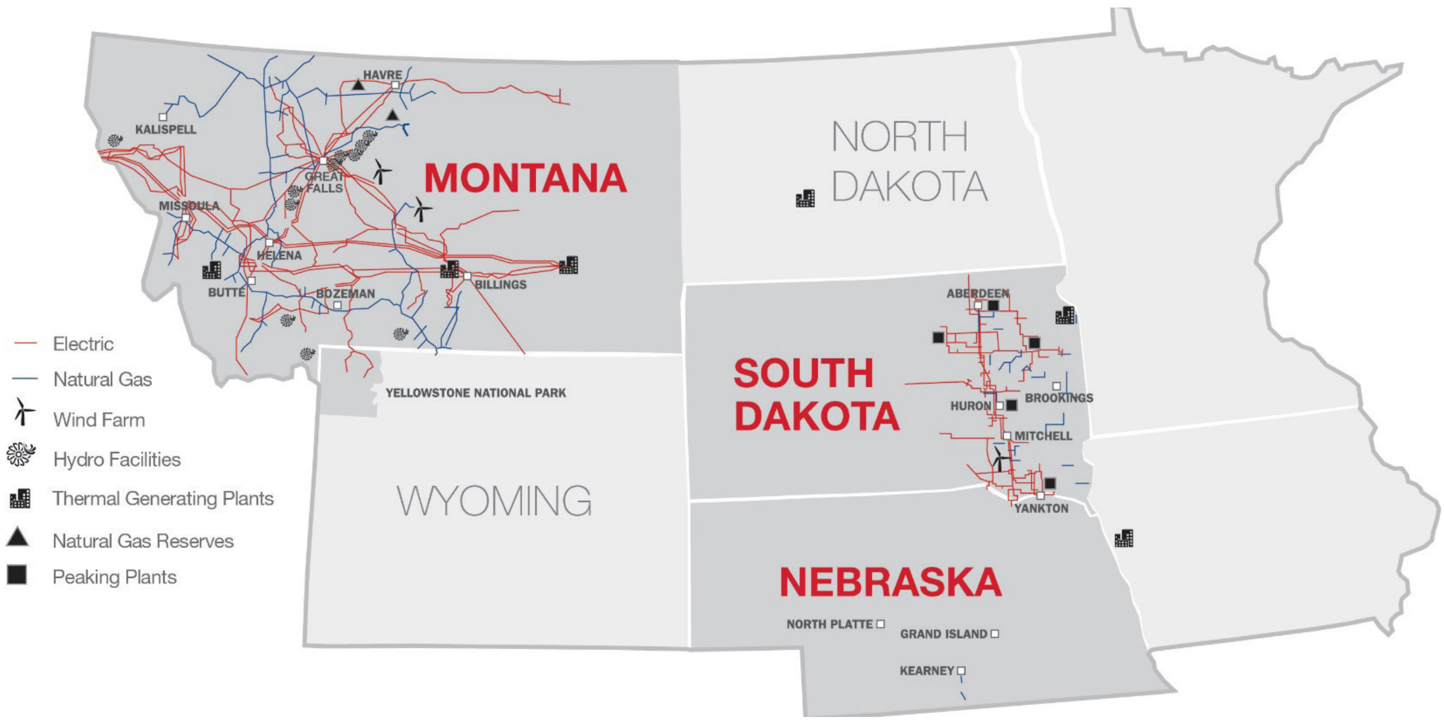
2 10-Year Plan location: https://puc.sd.gov/10utilityyearplan/default.aspx.

3. NorthWestern's Service Territory and Regional Outlook

3.1. NorthWestern's Service Territory

NorthWestern provides power (electric and gas service) to 775,300 customers across Montana, South Dakota, and Nebraska. Of that total, we provide electric service to 64,800 customers in South Dakota. Our service territory in South Dakota is within the jurisdiction of the Southwest Power Pool (SPP), which functions as a balancing authority, reliability coordinator, and market operator. NorthWestern meets its customer requirements from a variety of generation assets located both within South Dakota and outside the state as shown in Figure 1.

FIGURE 1 NORTHWESTERN ENERGY SERVICE TERRITORY



3.2. Organized Markets

3.2.1. Southwest Power Pool – Structure and Requirements

The Southwest Power Pool (SPP) is a regional transmission organization (RTO) that directs operations of the electric grid over a multi-state area. Its Balancing Authority Area covers 552,885 square miles with a population of over 19 million people[3]. SPP is a nonprofit corporation, mandated by the Federal Energy Regulatory Commission (FERC) to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale electricity prices on behalf of its members.

SPP members commit their transmission and generation assets into SPP, and then buy and sell wholesale energy and reserves on a day-ahead and real-time basis to meet their loads. SPP coordinates these wholesale power and transmission activities. NorthWestern is a member of SPP and currently has a number of transmission lines controlled by the SPP Tariff.

SPP's Tariff currently requires utilities to meet an annual Resource Adequacy Requirement (RAR). SPP has proposed a seasonal metric (summer and winter) to FERC. The intent of this requirement is to ensure the SPP system has an adequate supply of energy to meet the peak needs of all member companies. As part of this process, every Load Responsible Entity (LRE) is required to document 5 years of peak load and generation information. SPP uses this information to calculate a Planning Reserve Margin (PRM). The PRM is calculated using probabilistic methods which

3 Page 1, https://www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf.

theoretically set the system reliability to a loss of load event one time every ten years. Each member must have enough capacity to cover their peak load plus this PRM to pass the RAR. NorthWestern's annual PRM under SPP is currently 15%. In August 2024, SPP's board approved higher PRM requirements, which will become effective in 2026. The higher PRMs are 36% for the winter season and 16% for the summer season[4]. The new PRM values mark the first time the SPP has defined a winter PRM separately from the summer requirement. This IRP utilizes the new higher PRM requirements in its modeling and capacity planning; however, the increased PRM requirements have not yet been approved by FERC.

In addition to increasing the PRMs, SPP is seeking tariff revisions from FERC on generation accreditation. These proposed metrics in the tariff include performance, forced outage rates, and fuel assurance. According to SPP, challenges observed during past peak load events require it to adopt methodology for accrediting capacity that better anticipates resource availability based on how they have historically performed[5]. SPP's current accreditation for wind, solar, and storage fails to account for the reduction in reliability value as more is added to the grid. Additionally, SPP's accreditation methodology for conventional resources does not consider historical availability and performance.

In its February 2024 filing with FERC[6], SPP proposed using Effective Load Carrying Capability (ELCC) for wind, solar, and storage resources and Performance Based Accreditation (PBA) for conventional resources to determine resource capacity contributions. The proposed ELCC and PBA methodologies will allow SPP to have a more accurate understanding of resource availability based on their past performance. The PBA for conventional resources would be based on a power plant's "equivalent forced outage rate" during times the resources are needed. SPP utilizes the reliability metric of 1 day in 10 years (or 0.1 day/year), which is also used in its Loss of Load Expectation (LOLE) analysis to determine the planning reserve margin for the SPP BAA. SPP asked FERC to approve its proposal with an effective date of Oct. 1, 2025.

3.3. Regional Power Supply and Demand

The resource stack in SPP continues to change to a higher percentage of renewables. Thermal generation is on the decline, largely driven by retirements, while wind generating assets are expanding in SPP's markets[7]. Renewable resource proliferation has increased planning uncertainty, necessitated actions for system reliability, and increased periods of negative prices. For example, in 2008 wind produced 3% of total energy in SPP[8]. In 2022 wind produced the highest percentage of generation (~38%), exceeding coal for the second time in 3 years. Wind's installed nameplate capacity in SPP in 2022 was over 32,000 MW, which equated to 32% of total nameplate in the SPP market[9] for that year. Figure 2, on the following page, shows SPP's evolving energy mix from 2008 to 2023 and the sharp declines in coal generation coupled with the growth of wind resources. The changing composition of resources in SPP markets and the inherent variability of replacement resources creates uncertainty and challenges for NorthWestern's supply planning.

These challenges manifest as negatively priced intervals when there is abundant wind energy and low demand. For example, in 2022, ~7% of intervals had negative prices in the day-ahead market, and the real-time market[10] saw negative prices in ~15% of intervals. Another challenge is wind underperformance that falls short of the resource's current accreditation. SPP cites a specific instance on June 6, 2023, when the wind fleet provided only 110.6 MW, as compared to 5,073 MW of accredited capacity, 23,838 MW of historical wind max output, and 32,028 MW of

4 https://www.spp.org/news-list/spp-board-approves-new-planning-reserve-margins-to-protect-against-high-winter-summer-use/

5 ELCC Methodology Transmittal Letter 20240224, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240223-5157&optimized=false

6 https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240223-5157&optimized=false

7 Page 83, SPP State of the Market 2022 report https://www.spp.org/documents/69330/2022%20annual%20state%20of%20the%20market%20report.pdf

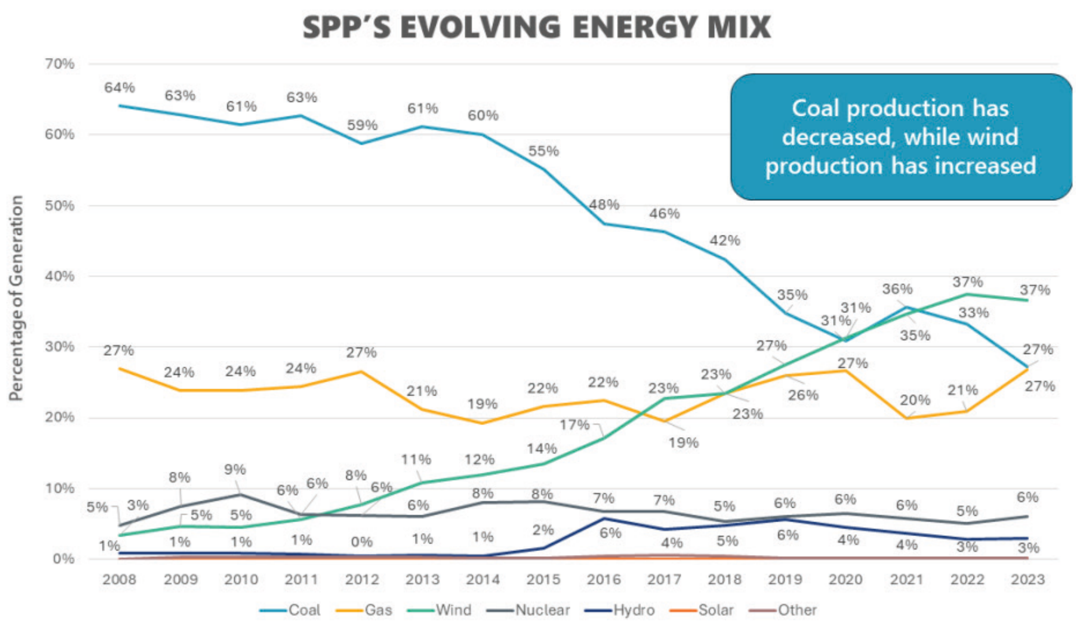
8 ELCC Methodology Transmittal Letter 20240224 https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240223-5157&optimized=false

9 Page 49 and 67, SPP State of the Market 2022 report.

10 Pages 147 and 148, SPP State of the Market 2022 report.

nameplate capacity[11]. The challenges posed by integrating more variable energy resources are likely to continue. SPP reports that its generation queue contains a large amount of wind resources, in addition to increasing amounts of solar and storage resources.

FIGURE 2 - SPP'S EVOLVING ENERGY MIX[12]



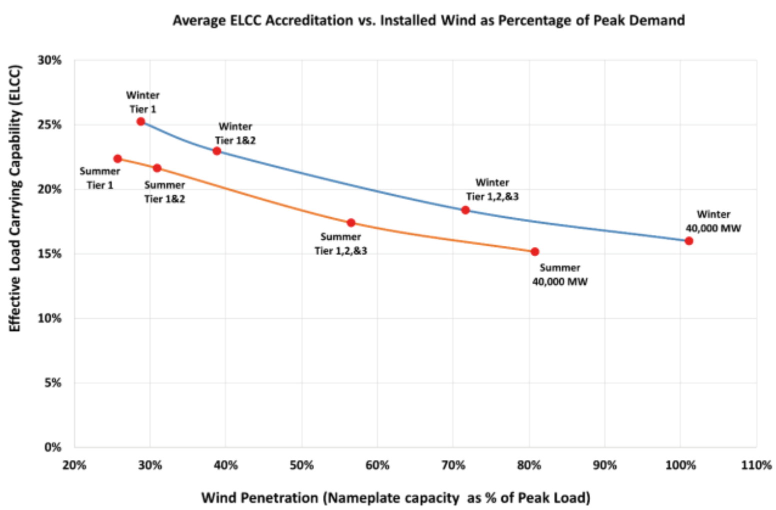
A challenge unique to the proliferation of variable resource types is that they exhibit declines in their ability to provide capacity during critical hours, due to their non-dispatchable nature. This characteristic is referred to as declining ELCCs, and these trends can be seen in SPP's plots from its "2022 ELCC Wind and Solar Study Report"[13], reproduced below for wind. The study looked at different amounts ("tiers") of wind penetration and computed the corresponding ELCC values and percentages. Figure 3 shows the results for wind resources; a similar declining trend was also produced in the solar analysis.

11 Page 8, ELCC Methodology Transmittal Letter 20240224 https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240223-5157&optimized=false

12 Page 8, ELCC Methodology Transmittal Letter 20240224 https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240223-5157&optimized=false

13 https://www.spp.org/documents/68289/2022%20spp%20elcc%20study%20wind%20and%20solar%20report.pdf

FIGURE 3 - SPP'S DECLINING WIND ELCC RESULTS[14]



In its "State of the Market, Winter 2024"[15] report, SPP continues to see an increase in demand year over year, and significant peak load events associated with regional weather events. Wind energy plays a large role in the SPP footprint. At the end of February 2024 SPP had a nameplate wind capacity of 33,725 MW. This is an increase in wind nameplate of 1,700 MW seen in the previous year. At the same time, energy production from coal is trending downwards. However, that trend can be affected by fuel prices. For example when the cost of coal generation is more economic than natural gas-fired generators, then more energy is produced from coal.

14 Page 6, https://www.spp.org/documents/68289/2022%20spp%20elcc%20study%20wind%20and%20solar%20report.pdf

15 https://www.spp.org/documents/71500/spp%20mmu%20qsom%20winter%202024.pdf

4. Load Service Requirement

4.1. Seasonal Load Shape

Our load in South Dakota exhibits a seasonal pattern. Figure 4, below, shows the peak load in every month for the last five years of observed load data. In general, our highest loads occur in the summer, due to agricultural and air-conditioning loads. However, significant loads also occur in the winter months related to heating demands. The summer peaking characteristic is expected to continue over the planning period. The dual peaks in both summer and winter mean that we must plan to have resources that perform reliably in both summer and winter conditions. We must also balance the potential for oversupply in the “shoulder” months (spring and fall) when demand is lower and excess energy may not be marketable.

Figure 4 Max Observed Load (MW) By Month, 2019-2023

4.2. Load Forecast

4.2.1. Methodology

NorthWestern evaluated three load forecast scenarios in this Plan: 1) expected load, 2) high industrial load growth, and 3) a low winter PRM scenario. At the core of each forecast is NorthWestern’s Excel model that relies on 10 years of observed data to forecast seasonal load and peak demand. The expected load scenario is derived from the linear trend of the observed data, a 16% summer PRM, and a 36% winter PRM. These PRMs were approved by the SPP board in August 2024[16], as discussed in section 3.2.

The expected load scenario load forecast is the starting point for the high industrial load growth forecast scenario. However, a yearly industrial load adder is included that is based on average historical industrial growth. This adder is +2.5 MW/yr for peak and 12,642 MWh/yr for load for each year of the forecast. The exception is in 2025, when 11 MW of total industrial load are added to reflect the anticipated start of a new large customer load.

The low winter PRM forecast scenario modifies the expected winter PRM of 36% to match the summer PRM of 16%, in case the higher winter PRM is rejected by FERC.

16 https://www.spp.org/news-list/spp-board-approves-new-planning-reserve-margins-to-protect-against-high-winter-summer-use/

4.2.2. Demand Response

NorthWestern offers a rate schedule for irrigation customers that incentivizes load shifting to night and weekend periods via lower rates during off-peak and shoulder periods. As a condition, customers on this rate agree to be interrupted during the hours from 3pm to 7pm in order to receive the lower off-peak rates. This program constitutes the only demand response program offered at the time of this Plan.

There are about 70 customers on this rate with an annual consumption of ~2,500,000 kWh. The associated demand response from this interruptible irrigation load is ~1 MW. Interruptions are not common and do not occur each year. When necessary, NorthWestern calls the customers and instructs them to eliminate their load for the relevant time period. A penalty would apply if these customers do not remove their load when called upon. NorthWestern has not had difficulty in realizing the load reductions when implemented.

4.2.3. Advanced Metering Infrastructure (AMI)

NorthWestern has installed approximately 65,800 meters as part of a project to convert its South Dakota electric metering system to Advanced Metering Infrastructure (AMI), thereby converting 100% of its electric customers to AMI. The AMI system offers enhanced features such as remote meter reading, remote connect/disconnect capabilities, and outage detection, and it captures high-resolution interval data. Specifically, fifteen-minute interval data is captured on polyphase meters, while hourly data is captured on single-phase meters.

Currently, the interval data is utilized to address customer inquiries, while automated outage alarms are streamed to the advanced distribution management system (ADMS) to swiftly pinpoint potential outages. Moreover, the system has significantly reduced truck rolls associated with meter reading and meter-related services, such as move-ins/move-outs, connections, and disconnections. NorthWestern is in the initial stages of uploading interval data into a platform to manage customer usage concerns, conduct in-depth analysis, and forecasting.

4.2.4. Load Forecast Results

Table 1 shows the annual peak load forecast results for the scenarios considered in this IRP. The Base column represents the peak load forecast as-is, without any additional adders. The subsequent columns show the Base forecast including the expected seasonal PRMs, the high industrial load adder and PRM, and the alternate Base forecast with the same PRM value for both winter and summer. NorthWestern plans its resource needs against the values that include the PRM to comply with SPP requirements, and these are the values used in the PowerSIMM™ modeling scenarios.

Table 1 – Load Forecast Results

	Base		**Base + PRM**		**High - Industrial Load Adder**			**High - Ind Load Adder + PRM**		**Base + Low Winter PRM**	
			36%	16%		Base + Ind Load Adder		36%	16%	16%	16%
	Winter	Summer	Winter + PRM	Summer + PRM	Adder	Winter	Summer	Winter + PRM	Summer + PRM	Winter + PRM	Summer + PRM
2024	324	348	440	404	2.5	326	351	444	407	376	404
2025	327	352	445	408	11	338	363	460	421	379	408
2026	330	355	449	412	13.5	344	369	467	428	383	412
2027	333	359	454	416	16	349	375	475	435	387	416
2028	337	362	458	420	18.5	355	381	483	442	391	420
2029	340	366	462	424	21	361	387	491	449	394	424
2030	343	369	467	428	23.5	367	393	499	456	398	428
2031	346	373	471	433	26	372	399	506	463	402	433
2032	350	376	475	437	28.5	378	405	514	470	405	437
2033	353	380	480	441	31	384	411	522	477	409	441
2034	356	383	484	445	33.5	390	417	530	484	413	445
2035	359	387	489	449	36	395	423	538	491	417	449
2036	362	391	493	453	38.5	401	429	545	498	420	453
2037	366	394	497	457	41	407	435	553	505	424	457
2038	369	398	502	461	43.5	412	441	561	512	428	461
2039	372	401	506	465	46	418	447	569	519	432	465
2040	375	405	510	470	48.5	424	453	576	526	435	470
2041	379	408	515	474	51	430	459	584	533	439	474
2042	382	412	519	478	53.5	435	465	592	540	443	478
2043	385	415	524	482	56	441	471	600	547	447	482
2044	388	419	528	486	58.5	447	477	608	554	450	486

Although including the PRMs is important for resource adequacy modeling to ensure that NorthWestern stays compliant with SPP requirements, comparisons are also made between historical load maxima and the expected peak load forecasts. The PRMs are not included in these views. Figure 5 shows the expected load forecast for both winter and summer seasons as compared to seasonal observations from 2016 to 2023. The average growth rate associated with this forecast is just under 1% per year.

FIGURE 5 – OBSERVED LOAD AND EXPECTED LOAD FORECAST BY SEASON (MW)

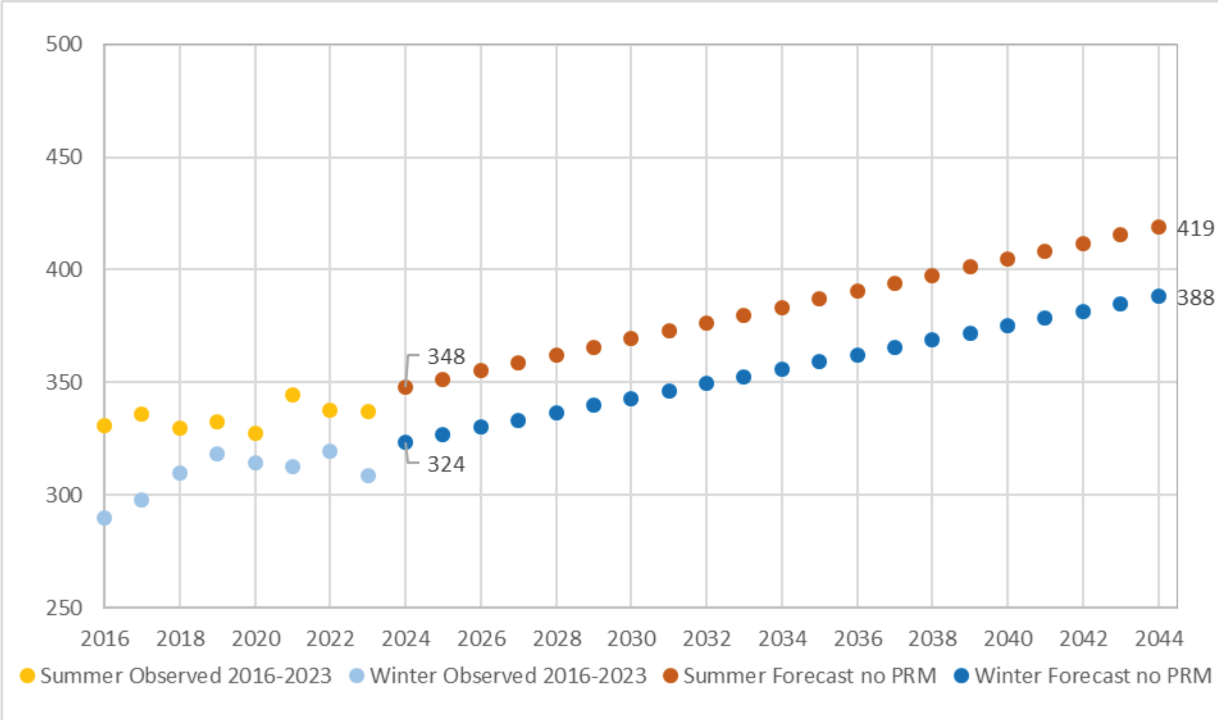
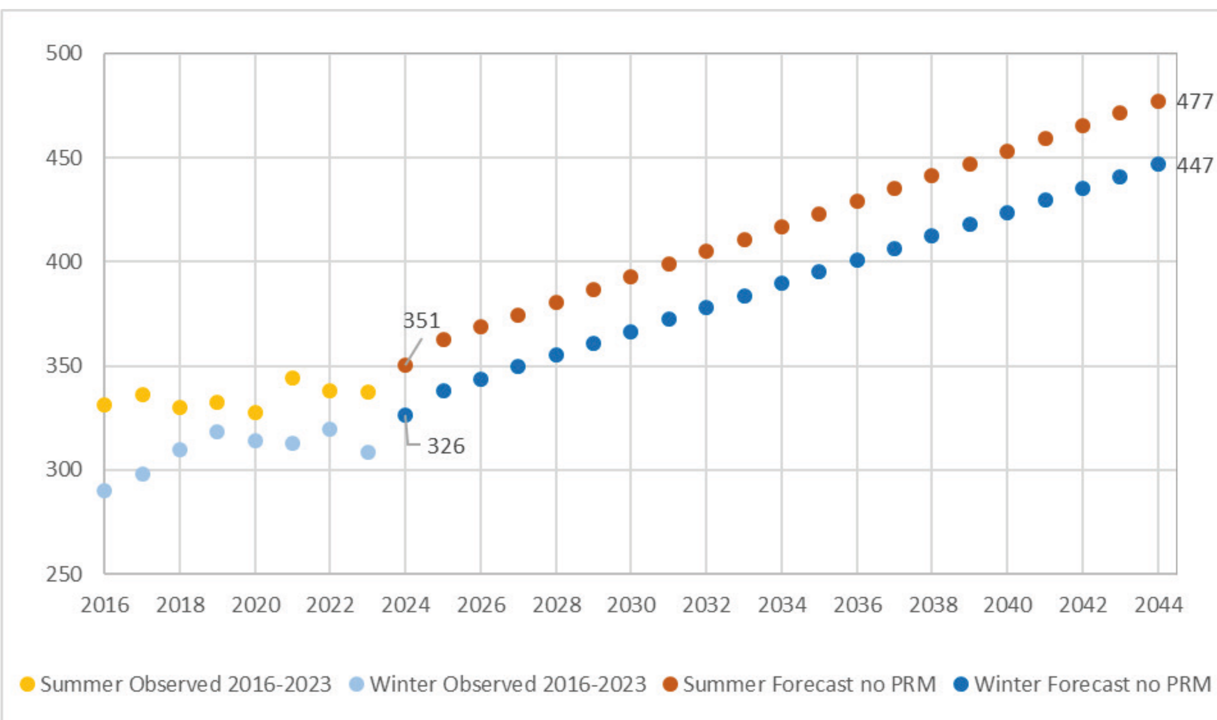


Figure 6 shows the high industrial load forecast scenario for both winter and summer seasons as compared to seasonal observations from 2016 to 2023. The PRM is not included in this view. The average growth rate associated with this scenario is approximately 1.6% per year.

FIGURE 6 – OBSERVED LOAD AND HIGH INDUSTRIAL LOAD FORECAST BY SEASON (MW)



4.3. Capacity Needs

The following figures show NorthWestern's supply portfolio for the next 20 years relative to: 1) the Base peak load forecast, 2) the Base forecast + winter and summer PRMs, 3) the high industrial load forecast scenario + winter and summer PRMs, and 4) a low (16%) winter PRM. The figures are split by winter and summer seasons to capture the seasonal load and resource accreditation differences. In Figure 7, the winter view, the higher seasonal resource accreditation for wind coupled with the lower winter peak loads results in the portfolio being adequate until 2038 with the 16% PRM. However, with the higher 36% winter PRM the portfolio is deficit as early as 2025 and again in years 2029-2044. As expected, the high industrial forecast leads to further deficits.

In Figure 8, the summer peaking characteristic on our service area is evident via the higher load obligation and the earlier and larger deficits that begin in 2025 and persist for the entire period, with both the PRM and high industrial forecasts. Also notable is that while NorthWestern's winter portfolio capacity accreditation is higher, mainly driven by higher wind accreditation, the 36% winter PRM increases the winter planning obligation above the summer planning obligation. This presents challenges in resource planning and marketing strategy, namely that the capacity requirement may be set at the winter level and there may be extra capacity in the summer seasons.

FIGURE 7 - WINTER CAPACITY PLANNING VIEW

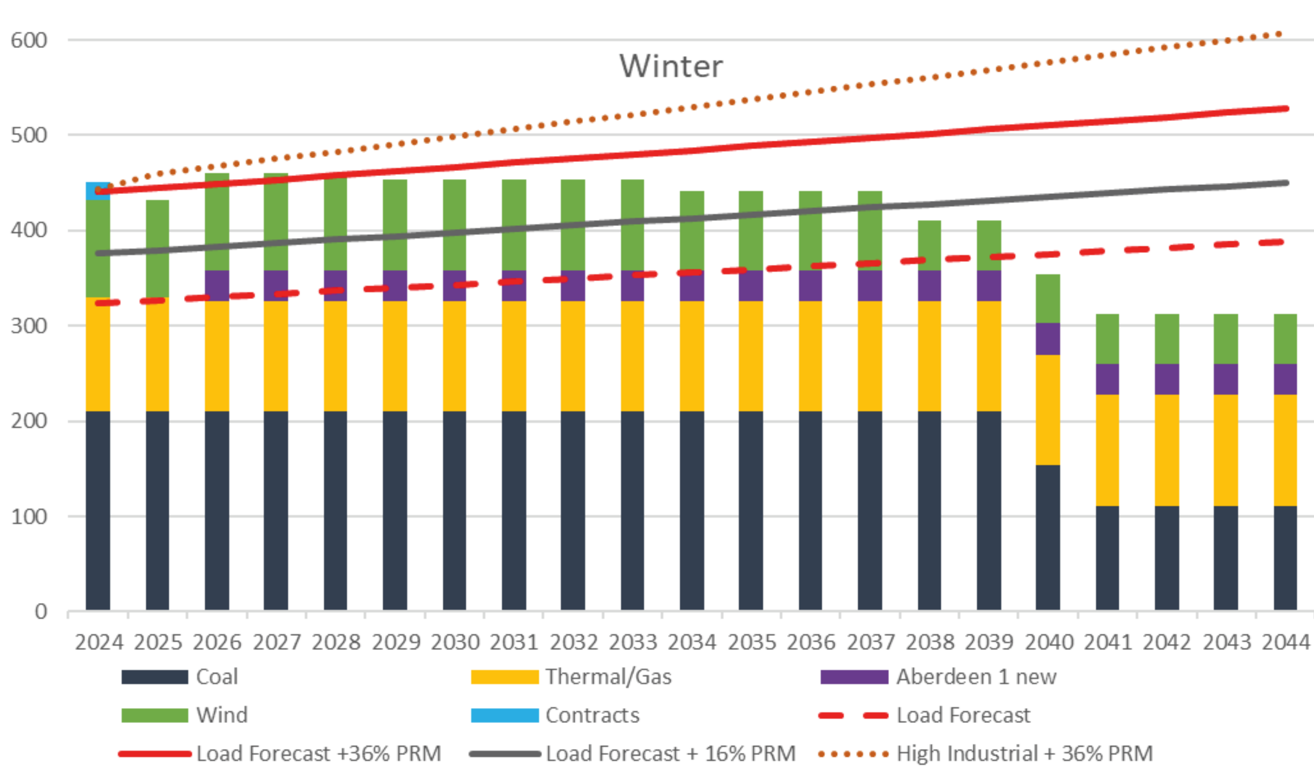
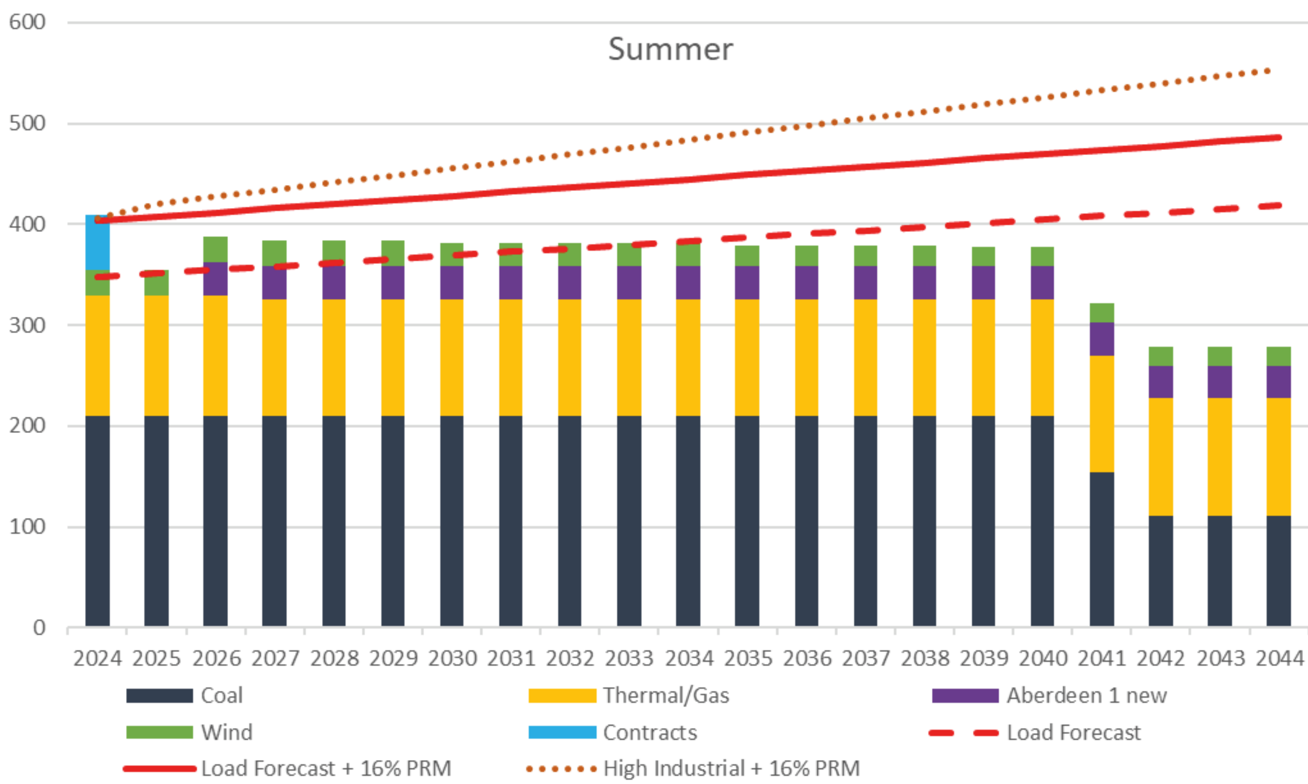


FIGURE 8 - SUMMER CAPACITY PLANNING VIEW



4.4. Duration Analysis

Duration in power planning refers to the elapsed time that generation resources are needed and available to serve load during peak demand periods. An important distinction can be made between long-duration resources versus resources that have a shorter reliable duration, due to generator type, design, or fuel limitations. Long-duration resources are indispensable during extended peak load events such as cold snaps or heatwaves. Therefore, duration is an important factor in supply planning and influences the selection of supply resources.

NorthWestern analyzed duration using observed load for a 6-year period from 2018 to 2023. NorthWestern analyzed four load levels beginning at the 250-MW level and ending at 335 MW (note that max load observed is 344.4 MW in 2021). The number of load hours that met or exceeded each level was quantified, in addition to the percent of total load hours, and the longest duration exceedance. NorthWestern performed this same analysis with load adjusted by subtracting observed wind generation, termed “net load”. The net load more accurately captures the load that NorthWestern had to serve from its long-duration resources. It is important to consider that this analysis is based on observed load values and that forecast load increases will require additional long-duration resources.

The results in Table 2, on the following page, show that the longest continuous period where the full load exceeded 250 MW was 81 hours (over 3 days). At the higher load levels analyzed, the events shorten in duration but still occur frequently. In general, with today’s peak loads, NorthWestern requires traditional long-duration resources up to the 300 MW load level. Beyond 300 MW, it is possible that shorter duration resources, like 8-hour batteries, could provide coverage, provided they have adequate charge ahead of time. It is important to note that as load growth occurs, the level of long-duration resources required will also increase above 300 MW.

Table 2 - Duration Analysis, Full Retail Load

2018 - 2023 Retail Load - Duration Results				
Total Hours at or Above Load Level				
250	275	300	325	335
6151	2014	431	30	8
% of hours exceeding				
11.70%	3.83%	0.82%	0.06%	0.02%
Longest Duration (hours)				
81	41	14	5	3

Table 3 - Duration Analysis, Net Load

2018 - 2023 Net Load - Duration Results				
Total Hours at or Above Load Level				
250	275	300	325	335
1472	330	43	1	0
% of hours exceeding				
2.80%	0.63%	0.08%	0.00%	0.00%
Longest Duration (hours)				
21	11	6	1	0

The duration results using net load in Table 3 show a shortening of total hours at or above each load level. However, there are important considerations in interpreting these results. Specifically, the wind energy contribution primarily only shortens the duration of time above a particular level, but does not appreciably lower the observed peak load. This means that conventional resources are essential to meeting critical load demands during extreme events when life and property are at risk.

In evaluating our load hours that exceed 300 MW, we observe that a large amount of wind nameplate capacity is required to yield a relatively small capacity contribution. For example, NorthWestern's wind fleet current nameplate is 165 MW, but its average contribution is ~5 MW during peak net load events over 300 MW (Table 4). This contribution to peak load equates to 3% of the nameplate on an average basis. However, within these peak hours there are times that the wind is not producing at all, meaning that other dispatchable and long-duration resources must be available and are what carry demand during the peak intervals. During these times additional wind resources will not yield more output, meaning that installing more wind is an exercise in diminishing capacity returns and increasing costs. Put another way, during our peak net hours over 300 MW, wind is not performing, and ~98% of demand is being met by non-wind resources. Table 4 demonstrates these points via 43 peak net load events from 2018 to 2022 where our net load was 300 MW or higher. The month of each peak event is shown, as is the corresponding wind generation for each hour, and the percentage of load that was met by other dispatchable and long-duration resources. These results underscore the important role that traditional generation resources serve during critical hours when variable generation is not producing.

Table 4 - Wind Performance During Peak Net Load Hours

Event	Month Event Occurred	Net Load Calculated MW	Wind Contribution MW (out of 165 MW nameplate)	Total Load MW	% Load Served by Non-Wind Resources
1	Feb	300	**6**	306	98.1%
2	Jul	300	**3**	303	99.2%
3	Aug	301	**7**	307	97.9%
4	Jul	301	**19**	320	94.0%
5	Feb	301	**0**	301	100.0%
6	Jul	301	**0**	301	99.9%
7	Jul	301	**6**	308	97.9%
8	Jul	302	**14**	316	95.7%
9	Jul	302	**9**	311	97.1%
10	Jul	303	**8**	311	97.4%
11	Jan	303	**1**	304	99.7%
12	Jul	303	**19**	322	94.0%
13	Jul	303	**6**	309	98.2%
14	Jul	304	**2**	306	99.3%
15	Feb	305	**1**	305	99.7%
16	Jul	305	**11**	316	96.6%
17	Jul	305	**1**	306	99.8%
18	Feb	306	**1**	307	99.6%
19	Feb	306	**3**	309	99.1%
20	Jul	306	**6**	312	98.2%
21	Jul	307	**0**	307	99.9%
22	Feb	307	**4**	311	98.7%
23	Jul	307	**24**	331	92.8%
24	Jan	308	**0**	308	100.0%
25	Jul	309	**3**	312	98.9%
26	Jul	309	**2**	311	99.4%
27	Jul	310	**1**	311	99.7%
28	Jan	312	**0**	312	100.0%
29	Jan	312	**0**	312	100.0%
30	Jul	313	**10**	323	96.9%
31	Jul	314	**4**	318	98.6%
32	Jul	314	**0**	315	99.9%
33	Aug	315	**5**	320	98.5%
34	Jul	315	**8**	322	97.6%
35	Jan	315	**0**	315	100.0%
36	Jul	316	**4**	319	98.9%
37	Jul	317	**6**	323	98.0%
38	Jul	319	**8**	327	97.7%
39	Jul	319	**0**	320	99.9%
40	Aug	321	**6**	326	98.2%
41	Jul	321	**1**	322	99.6%
42	Jul	322	**11**	333	96.7%
43	Aug	326	**7**	333	97.9%

5. NorthWestern's Existing Supply Resources

5.1. Current Generation Portfolio and Fuel Mix

NorthWestern's South Dakota portfolio consists of owned thermal units (coal[17], natural gas, and fuel oil) and wind resources, several of which are power purchase agreements. Table 5 lists each resource in the portfolio and their key resource attributes for 2024. There are several smaller diesel mobile units that are not listed in Table 5. NorthWestern supplements its owned resources with short-term energy purchase contracts as required (not shown). Figure 9 shows the breakdown of fuel types for the portfolio for the data associated with Table 5.

TABLE 5 – GENERATING ASSETS AND CHARACTERISTICS

Generation Unit	Type	Fuel Type	Owned/ Contracted Nameplate Capacity (MW)	Accredited Capacity - Winter (MW)	Accredited Capacity - Summer (MW)	COD	Contracted/ Owned	Contract Term/ Depreciable Life
Coal								
Big Stone (JOU, 474 MW Total)	Steam	Coal	111	111	111	1975	23.4% Owner	12/31/2046
Neal 4 (JOU, 644 MW Total)	Steam	Coal	57	56	56	1979	8.7% Owner	12/31/2040
Coyote (JOU, 427 MW Total)	Steam	Coal	43	42.6	42.6	1981	10% Owner	12/31/2041
Total			211	210	210			
Natural Gas								
Aberdeen 2 (AGS2)	CT	NG / Diesel	60	56.4	56.4	2013	Owned	12/31/2048[3]
Bob Glanzer Generating Station	RICE	NG	58	56.9	56.9	2022	Owned	6/30/2057
Yankton Generating Station (YGS)[1]	RICE	NG / Diesel	13.6	0	0	1974	Owned	12/31/2025[3]
Total			132	113	113			
Diesel								
Aberdeen 1 (AGS)[2]	CT	Diesel	28.8	0	0	1978	Owned	12/31/2026[3]
Clark	RICE	Diesel	2.8	2.1	2.1	1970	Owned	12/31/2026[3]
Faulkton	RICE	Diesel	2.8	0	0	1969	Owned	12/31/2026[3]
Mobile C	RICE	Diesel	2.5	0	0	2009	Owned	12/31/2044[3]
Mobile B	RICE	Diesel	1.8	1.6	1.6	1991	Owned	12/31/2026[3]
New Mobiles - Units 1-8	RICE	Diesel	8	2.9	2.9	11/1/2019	Owned	10/31/2054[3]
Big Stone	RICE	Diesel	0.3	0	0	1975	23.4% Owner	12/31/2046
Total			47	7	7			
Wind								
Beethoven Wind	VER	Wind	80	52	19	2015	Owned	8/31/2045
Titan I Wind (Rolling Thunder I Power Partners, LLC)	VER	Wind	25	7.4	2.0	1/1/2010	Contracted	12/31/2029
Aurora County Wind CED LLC	VER	Wind	20	15.5	1.4	10/1/2018	Contracted	9/30/2038
Brule County Wind CED LLC	VER	Wind	20	15.3	0.6	10/1/2018	Contracted	9/30/2038
Oak Tree (Oak Tree Energy, LLC)	VER	Wind	19.5	11.5	2.3	1/1/2015	Contracted	12/31/2034
Total			165	102	25			
Total Portfolio			554	431	355			

1YGS is not currently operational. The facility would require extensive upgrades to safely and reliably bring back online.

2Aberdeen 1 is not currently operational but is being replaced with new modular turbines.

3These assets do not have specified estimated retirement dates built into the depreciation rates approved by the Commission. The useful life of these assets is determined on a case by case basis. Therefore, the Depreciable Life end date is an estimate.

17 The coal resources are Jointly Owned Units (JOU)

FIGURE 9 – NORTHWESTERN 2024 PORTFOLIO FUEL TYPE SUMMARY (NAMEPLATE)

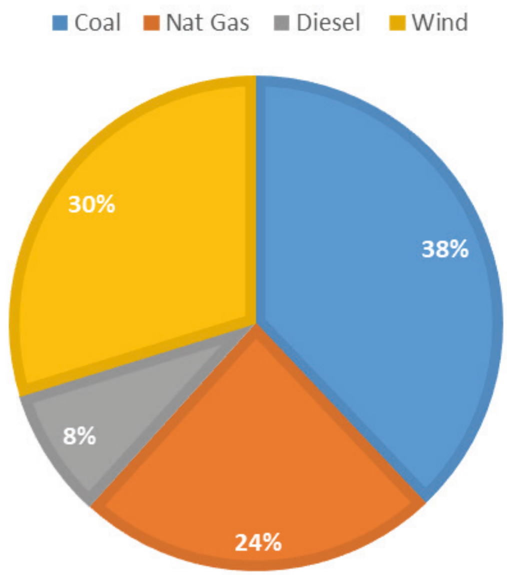
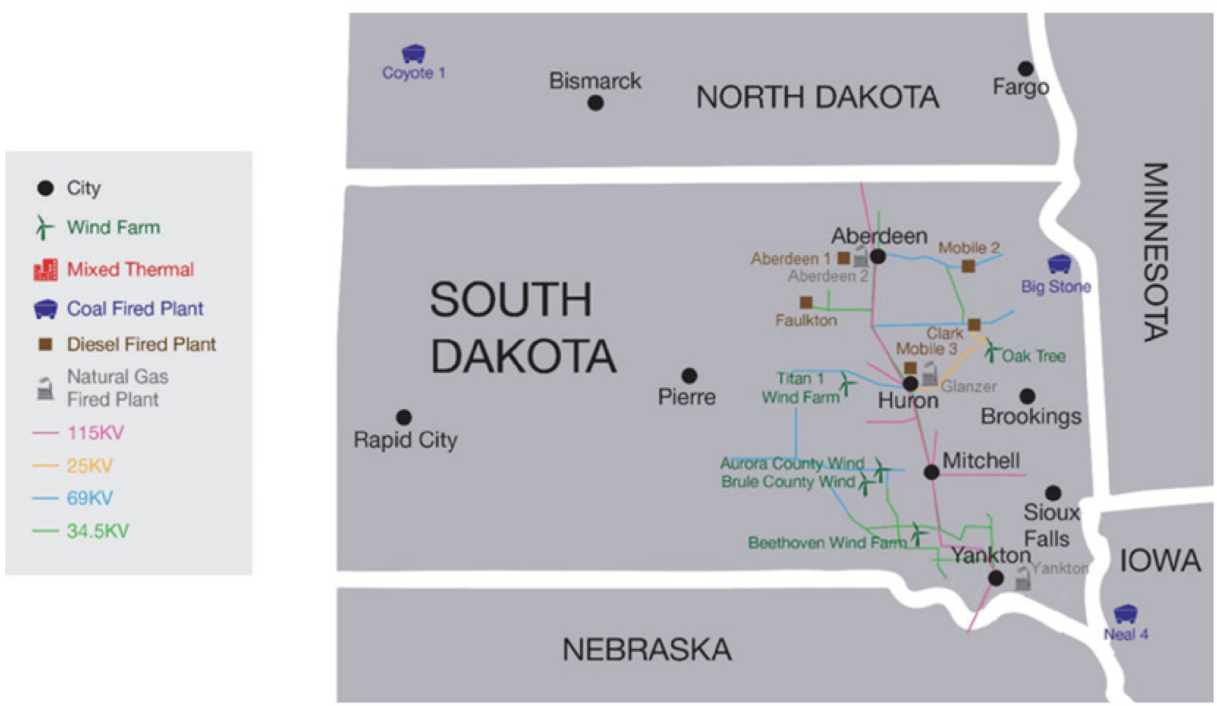


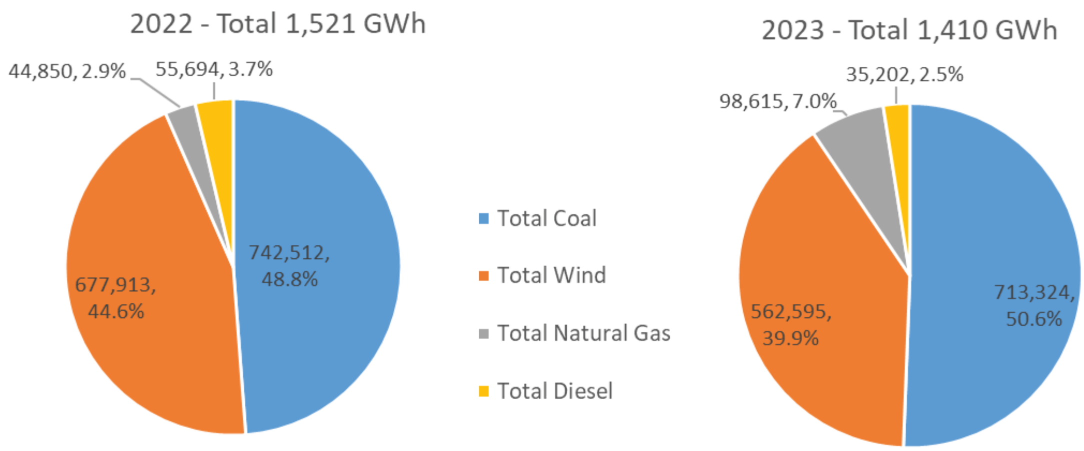
Figure 10 shows the location of each asset in our portfolio across a multi-state area. The three jointly owned coal plants, Coyote, Big Stone, and Neal 4, are located in the service area of the Midcontinent Independent System Operator (MISO); NorthWestern is the only joint owner that operates in SPP.

FIGURE 10 – GENERATING ASSET MAP



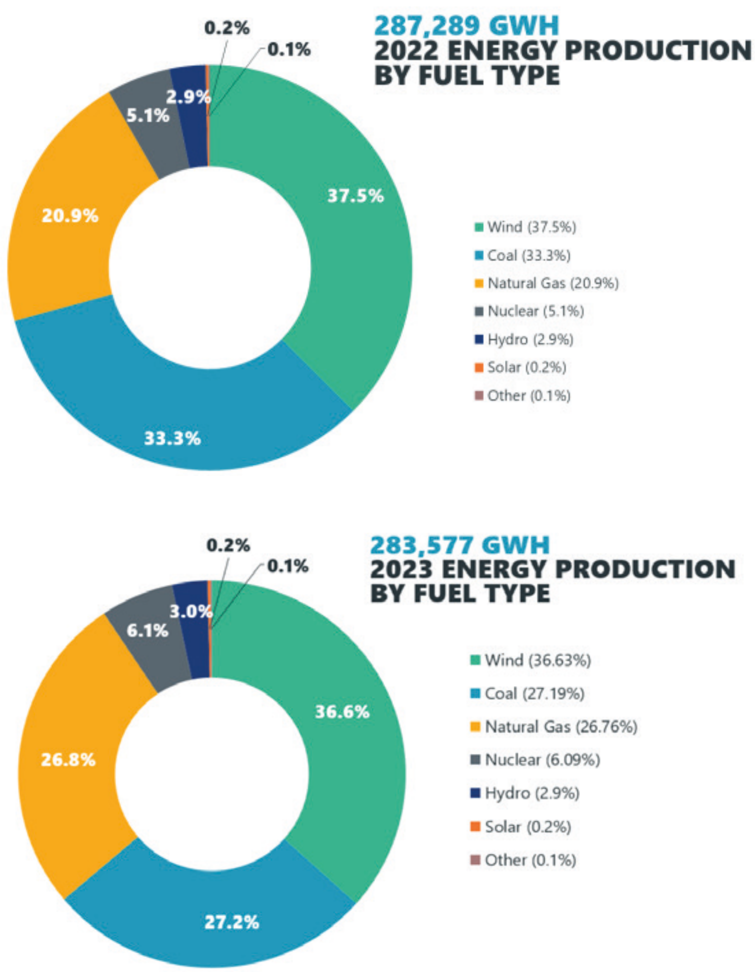
The energy production in MWh for 2022 and 2023 for each resource type in NorthWestern's portfolio is shown in Figure 11, on the following page. The total generation is also shown in GWh. While NorthWestern has a significant proportion of wind energy based on nameplate capacity, our reliable and dispatchable coal and natural gas assets ensure load is met during critical capacity hours.

Figure 11 – NorthWestern Generation Portfolio Production



For comparison to NorthWestern, SPP's 2022 and 2023 energy production figures are shown in Figure 12. The overall SPP footprint has a higher percentage of natural gas generators and a lower percentage of coal. Unlike NorthWestern, the broader SPP footprint also contains nuclear, hydro, and solar assets. NorthWestern's wind generation exceeded SPP's in 2022 (44.6% to 37.5%).

Figure 12 – 2022 and 2023 SPP Energy Production by Type[18][19]



18 Page 5, https://www.spp.org/documents/70194/2022%20annual%20report%20-%209.26.23.pdf

19 https://storymaps.arcgis.com/stories/79884f30428b4b4a9469765f3ecfc652

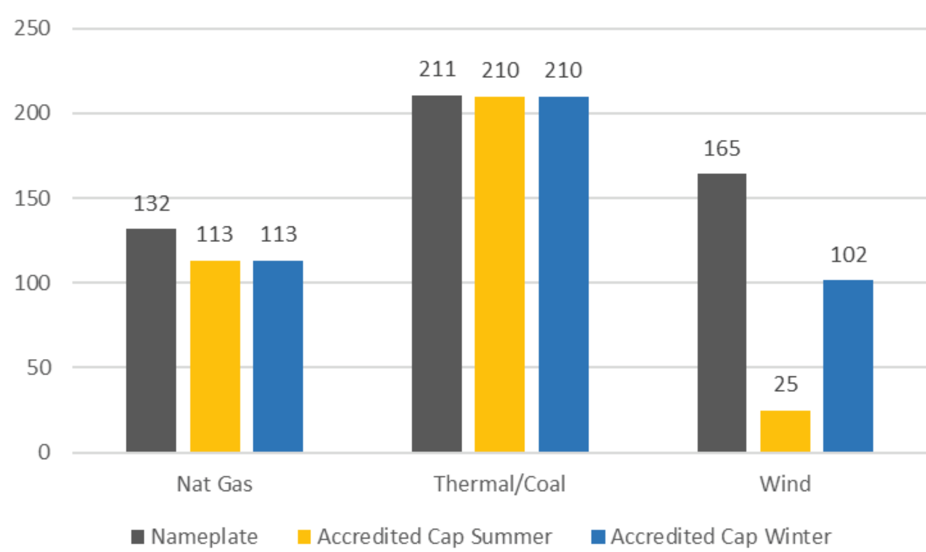
5.2. Nameplate and Accredited Capacity

The nameplate capacity of a generator refers to the maximum generation that it can produce under ideal circumstances, such as with ample fuel, wind, or solar conditions. Most generators do not operate at their full nameplate capacity except in limited circumstances. From a resource planning and adequacy perspective, nameplate capacity does not convey the ability of a resource to serve load during times when critical capacity is needed. Accredited capacity is a better metric to represent the capacity contribution of resources. Accredited capacity reflects the actual ability, informed by historical performance, of each resource to reliably serve load in peak load hours. Thermal generators generally have high accreditations which reflect the ability to maintain or increase their generation during peak times. Wind and solar, in contrast, generally have much lower accreditations on account of wind and solar inputs being variable and unpredictable.

The capacity accreditations of our resources in South Dakota are determined by SPP's Planning Criteria[20]. Each member is required to test and accredit its resources in accordance with the planning criteria procedures. Wind and solar resource capabilities are determined on a monthly basis utilizing multiple years of historical production and load data[21]. To determine capacity accreditation, SPP currently uses a spreadsheet tool that analyzes the production as correlated to the top 3% of load hours and selects the net power output that can be expected from the facility 60% of the time or more.[22] An option is to forego the calculations and accept a flat 5% of nameplate accreditation for wind and 10% of nameplate for solar, but NorthWestern does not use this option. Energy Storage Resources (ESR) with a duration of more than 4 hours are accredited based on testing for their rated duration with no adjustments[23]. ESR under four hours have their rating adjusted proportionally to a four-hour equivalency. NorthWestern does not have any battery resources in our portfolio at this time. Accredited capacity for conventional (includes thermal) generators is defined as the maximum of net generating capability that can be sustained for four continuous hours[24].

Figure 13 shows the difference between nameplate and accredited capacity, by season, for the natural gas, coal, and wind generation types in NorthWestern's portfolio as of 2024. Note the much higher accreditations, and less seasonal difference, for thermal resources as compared to wind.

FIGURE 13 – 2024 NAMEPLATE AND ACCREDITED CAPACITY COMPARISON



20 https://www.spp.org/documents/69546/spp%20planning%20criteria%20v4.1.pdf.

21 Page 42-43, https://www.spp.org/documents/69546/spp%20planning%20criteria%20v4.1.pdf.

22 In its February, 2024 filing with FERC, SPP has proposed using ELCC.

23 Page 39, https://www.spp.org/documents/69546/spp%20planning%20criteria%20v4.1.pdf.

24 Page 37, https://www.spp.org/documents/69546/spp%20planning%20criteria%20v4.1.pdf.

Another factor to consider with increasing penetrations of wind and solar resources is that their ELCC values decline. This relates to the variable nature of their fuel sources, which cannot reliably serve capacity critical hours even if more nameplate capacity is added. Declining ELCC values factor into NorthWestern's capacity planning. Specifically, resource types that do not exhibit declining capacities may be more prudent candidate resources than those that do, and could even cost less than building large amounts of nameplate capacity that does not reliably produce during capacity critical hours.

5.3. Jointly Owned Coal Units

5.3.1. Big Stone Plant

NorthWestern owns a 23.4% interest in the 475-MW Big Stone Plant (111 MW), which is located near Big Stone City, South Dakota. The other owners of this coal-fired plant are Otter Tail Power Company and Montana-Dakota Utilities Co. (MDU). Otter Tail Power Company operates the plant. NorthWestern is the only owner who is a SPP participant; the others operate in Midcontinent Independent System Operator (MISO). Big Stone is a coal-fired, cyclone-burner baseload plant that was placed in service in 1975. The fuel source is Powder River Basin sub-bituminous coal delivered by Burlington Northern Santa Fe Railway Company.

NorthWestern's current contractual commitment for the Big Stone facility requires a 5-year notice prior to termination. In addition to the partial ownership of Unit 1, NorthWestern owns approximately 300 kW of diesel RICE capacity from the station that serves as black start capability of the Big Stone coal plant.

5.3.2. Coyote Station (Coyote)

NorthWestern owns a 10% interest (43 MW) in the 427-MW Coyote Station, which is located near Beulah, North Dakota. NorthWestern is one of four joint owners and the only owner in SPP (the remaining owners operate in MISO). Coyote is a coal-fired, cyclone-burner, dry-scrubbed baseload plant that began commercial operations in 1981. The plant is fueled by North Dakota lignite, which is obtained from an adjacent coal mine owned by a subsidiary of the North American Coal Company. NorthWestern is party to a long-term coal supply contract effective through 2040 for the Coyote Station.

Coyote Station's operations and future plans are currently under review. The Minnesota Public Utility Commission's approval of Otter Tail Power Company's Integrated Resource Plan calls for Otter Tail Power Company's withdrawal by 2031[25]. Further, Coyote operations are likely to be affected by EPA rules, such as the MATS updates for lignite plants, issued July 8, 2024. Facility owners and NorthWestern will review options and will analyze scenarios for future Coyote operations, including running Coyote to full term (through 2041).

5.3.3. George Neal Plant, Unit 4

NorthWestern owns an 8.7% interest (57 MW) in the 646-MW Neal 4 plant, which is located near Sioux City, Iowa. It is jointly owned by 14 entities and NorthWestern is the only owner of a significant plant share who is in SPP while all other major owners operate in MISO. It is fueled with pulverized sub-bituminous coal and is a baseload plant that was placed into service in 1979. MidAmerican Energy Company is the principal owner and operating agent for the plant. The fuel source for George Neal 4 is Powder River Basin sub-bituminous coal delivered by the Union Pacific Railroad.

The operating agreement for George Neal 4 is effective through 2014 "or so long after as Unit 4 shall be used or useful for the generation of electric power." Given that the major owners are in MISO, MidAmerican dispatches the plant based on the MISO market, which can result in dispatch that is not ideal for NorthWestern's needs and that falls short of NorthWestern's ownership share. Neal's capacity factor is the lowest of all of the jointly owned coal facilities that NorthWestern has interest in (Table 6). NorthWestern has attempted to resolve this dispatch issue through discussions with MidAmerican and will continue to pursue resolution.

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25 See Minnesota Public Utilities Commission Docket Number 21-339, Docket Type RP

Table 6 shows the last five years of production for NorthWestern's share for each of the coal plants and the associated capacity factors. The capacity factors were computed by dividing the annual MWh values by the product of the max share quantity and the total hours in each year.

Table 6 – MWh and Capacity Factor For NorthWestern Coal Shares

	Bigstone		Coyote		Neal	
Year	Annual MWh	Cap Factor %	Annual MWh	Cap Factor %	Annual MWh	Cap Factor %
2019	524,761	54%	203,833	54%	123,093	25%
2020	358,386	37%	262,576	70%	61,038	12%
2021	373,950	38%	228,874	61%	122,497	25%
2022	423,119	43%	213,423	57%	105,971	22%
2023	353,714	36%	246,432	66%	113,178	23%

5.4. Natural Gas and Diesel Units

5.4.1. Glanzer Station (BGGS)

The 58.2-MW Bob Glanzer Generating Station (BGGS) is located in Huron, South Dakota and is the newest addition to NorthWestern's South Dakota portfolio. BGGS replaced the former 43-MW "Huron 2" generating station and began commercial operations in 2022. It consists of 6, 9.7-MW RICE and it is a fast-ramping resource that helps with integration of renewables. BGGS is configured to offer ancillary services, including contingency reserves and regulation. Natural gas service is provided by Northern Natural Gas (NNG) pipeline. BGGS is interconnected at 69 kV.

5.4.2. Aberdeen 1

Aberdeen 1 was a 28.8-MW diesel oil-fueled GE Frame 5 Combustion Turbine (CT) that became restricted due to age and the cost of keeping the unit in service. It had a low historical availability, a high heat rate, and was typically only operated for testing or in emergencies. While Aberdeen 1 last generated in 2022, replacement capacity is required on a MW for MW basis to support voltage regulation in the vicinity. NorthWestern issued an RFP in January 2024 for on-site replacement generation and selected two new natural gas combustion turbines as replacement from this RFP. The demolition of Aberdeen 1 began in July 2024, and the new generation is expected to be online in 2026. Aberdeen 1 is interconnected at 34.5 kV.

5.4.3. Aberdeen 2

Aberdeen 2 is a Mitsubishi Power Aero FT8-3 CT Twin-Pac that began operations in 2013. Aberdeen 2 has a capacity of 60 MW with dual fuel capability of natural gas or diesel. Primarily it has been run on natural gas. Aberdeen 2 is reliable and is not considered for retirement at this time. The emission permits for the Aberdeen location are based on both Aberdeen 1 and 2 units; due to the paired nature of the permits, Aberdeen 2 faces constraints as a result of Aberdeen 1. The air permit for Aberdeen 2 is based on the unit heat input and a rolling number of unit starts and stops for each 12-month period. Aberdeen 2 is interconnected at 115 kV.

5.4.4. Mobile Units

NorthWestern has ten small mobile diesel-fired RICE engine units in its portfolio. These units range in size from 1 to 2.5 MW nameplate capacity and provide system redundancy during transmission outages or system maintenance. In addition to supporting system reliability events, capacity from the mobile generators is used to meet the PRM requirement in SPP. These generators can be called upon by SPP during reliability events for load support during the summer season (June 1st through September 30th). As part of the PRM requirement, NorthWestern needs to have these generators connected at a point of interconnection (POI), and ready to support any directive from SPP from June 1st through September 30th. The Aberdeen Siebrecht Substation and the Yankton Northwest Substation are the designated locations to interconnect these units to meet that requirement. Since the SPP Business Practices[26] specify that a 5-MW injection threshold triggers a Generation Interconnection Study, NorthWestern only interconnects four generators at each of these two substations to stay below the 5-MW threshold.

5.4.5. Clark and Faulkton

The Clark and Faulkton units are 2.8-MW Fairbanks Morse diesel RICE units installed in 1970 and 1969, respectively. Initially, their retirements were planned when the mobile units were placed in service. However, due to the fire at Huron and the Yankton 1-4 units' continued outage state, both Clark and Faulkton are still maintained in the portfolio.

Due to the age of the Clark and Faulkton engines, maintenance is becoming more difficult and costly. Replacement parts are not available and must be fabricated, and there are few service personnel with the knowledge to work on the engines and associated equipment. The units are used strictly for back-up service during transmission outages.

While Clark has been generally reliable, the building housing the engine is in poor condition. If the Clark plant were to remain in service on a long-term basis, additional capital would be required for upgrades and repairs.

Clark and Faulkton are being evaluated for retirement in 2026. Once they are retired, some of NorthWestern's mobile units can be moved to fill in the generation need. There are direct connections that the mobiles can use to establish a connection with the transmission system. This means there will be minimal time between removing Clark and Faulkton from service and getting replacement mobiles in place.

5.4.6. Yankton

Yankton's four natural gas/diesel RICE, totaling 13.5 MW, remain in a continued outage state. It is not economic to restore the Yankton facility to operational condition and the facility is slated for retirement. Yankton is interconnected at 34.5 kV.

5.5. Qualifying Facilities

Certain power production facilities may meet the criteria to be a Qualifying Facility (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA requires utilities to purchase power from QFs at avoided cost.[27] A utility may terminate this "must purchase" obligation by demonstrating that QFs have non-discriminatory access to wholesale markets. In December 2016, in Docket No. QM17-1-000, FERC granted NorthWestern's application to terminate the requirement that it enter into new contracts or obligations to purchase electric energy and capacity from QFs with a net capacity greater than 20 MW on a service territory-wide basis in its service territory in South Dakota within SPP.

There are three wind QFs currently in NorthWestern's South Dakota portfolio: Oak Tree, Aurora, and Brule, totaling 59.5 MW of nameplate capacity.

5.6. Renewables

5.6.1. Wind Resources

NorthWestern's current portfolio includes 5 wind generation facilities, listed in Table 7. Beethoven wind is owned by NorthWestern and is located near Tripp, South Dakota. NorthWestern has power purchase agreements for Rolling Thunder/Titan and the other 3 facilities. Table 8 shows the capacity factors for these wind assets for the last five years.

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26 Pg. 6-41, https://opsportal.spp.org/documents/studies/GI%20MANUAL%20BUSINESS%20PRACTICE_7250_20230915.pdf

27 See 18 CFR §§ 292.303 and 292.304

Table 7 – Portfolio Wind Resources, Nameplate MW

Wind Generation – Online	Nameplate Capacity (MW)	Interconnection Voltage
Beethoven Wind	80	115 kV
Rolling Thunder/Titan	25	69 kV
Oak Tree (QF)	19.5	69 kV
CED Aurora (QF)	20	69 kV
CED Brule (QF)	20	69 kV
Total	**165**	NA

Table 8 – Capacity Factors For Wind Assets

Capacity Factor					
	Aurora	Beethoven	Brule	Oak Tree	Titan
2019	45%	41%	44%	41%	37%
2020	46%	44%	43%	43%	38%
2021	47%	40%	47%	42%	41%
2022	51%	47%	49%	46%	42%
2023	42%	39%	38%	40%	36%

5.7. Federal Laws Impacting Coal and Natural Gas Generators

5.7.1. Mercury and Air Toxics Standards (MATS)

The EPA first issued the MATS rule in 2012 to limit mercury and other hazardous air pollutants from coal and oil-fired utility steam generating units. All of the jointly owned coal-fired power plants in our portfolio – Big Stone, Coyote, and Neal 4 – are currently in compliance with the existing MATS rule. However, effective July 8, 2024 EPA implemented new tighter mercury emission standards, requiring lignite facilities to meet the same mercury emission standard as other bituminous and sub-bituminous coal burning plants, which is a 70% decrease (from 4.0 lb/TBtu to 1.2 lb/TBtu). It is expected that flue gas treatments could bring Coyote in compliance with the tightened mercury standard. Big Stone and Neal 4 are not affected by the new rule.

The new rules also impose more stringent limits for all coal units for filterable particulate material (fPM), which is used as a surrogate for hazardous air pollutants. The fPM standard in the final rule drops from 0.030 lb/MMBtu to 0.010 lb/MMBtu for all coal-based generating units. The EPA allows up to four years to comply with the final rule and also requires continuous particulate matter monitoring to demonstrate compliance. Big Stone, Neal, and Coyote are expected to be able to meet the 0.010 lb/MMBtu fPM standard with their existing baghouses and without additional controls.

5.7.2. Performance Standards for Greenhouse Gas (GHG) Emissions

Effective July 8, 2024, EPA adopted regulations for GHG, which are summarized in Table 9, on the following page. These rules require technologies such as carbon capture and sequestration, alternate fuels (natural gas or hydrogen) and/or capacity limits to reduce emissions for facilities that plan to operate beyond 2032. However, if plants plan to retire by 2032 the rules do not require expensive pollution control investments. For plants that plan to operate past 2032, the standards begin to affect operations in 2030. Depending upon the planned retirement date of these plants, different standards are required. For natural gas CC and CT units, the regulations vary based on capacity factor and are tighter for facilities that run with high capacity factors (like baseload units). These rules are currently being challenged by a number of utilities, which may lead to delay or reversal of the performance standards.

Table 9 – EPA Carbon Rules[28]

Final Best System of Emissions Reduction (BSER) and Resulting Performance Standards[1]			
	Through Dec. 31, 2031	Jan. 1, 2032 - Dec. 31, 2038	2039 and beyond
Coal			
111(d) - Existing Steam EGUs[3] (coal-fired)*			
• Retire by 12/31/2031	Excluded from regulation	Unit retired	
• Retire 2032-2038	40% natural gas co-firing, presumed 16 percent emissions reduction: beginning 1/1/2030**		Unit retired
• Retire after 1/1/2039	No applicable standard	CCS[4] at 90% capture rate, presumed 88.4 percent emissions reduction **	
111(d) - Existing Steam EGUs[3] (gas-fired)*			
• ≥ 45% Capacity Factor	Routine efficient operations: 1,400 lb CO_2/MWh beginning 1/1/2030		
• < 45% Capacity Factor	Routine efficient operations: 1,600 lb CO_2/MWh beginning 1/1/2030		
• < 8% Capacity Factor	Uniform fuels: 170 lb CO_2/MMBtu for oil-fired sources and a presumptive standard of 130 lb CO_2/MMBtu for natural gas-fired sources		
Natural Gas			
111(b) - New NGCC*[2]			
• Base Load > 40%	Highly efficient generation/best O&M practices 800 lb CO_2/MWh for > 2,000 MMBtu/h Units 900 lb CO_2/MWh for < 2,000 MMBtu/h Units	CCS[4] at 90% capture rate 100 lb CO_2/MWh for > 2,000 MMBtu/h Units 110 lb CO_2/MWh for < 2,000 MMBtu/h Units	
111(b) - New CT*[2]			
• Intermediate CT > 20% CF to ≤ 40% CF	Efficient Operation 1,170 lb CO_2/MWh		
• Low Utilization (CT)** ≤ 20% CF	Use of clean fuels (NG, Nos. 1 & 2 fuel oil): 20% annual CF restriction 120-160 lb CO_2/MMBtu		

*States set emissions limits for existing units under Clean Air Act § 111(d) that reflect EPA's BSER. Under Clean Air Act § 111(b), EPA sets emissions limits based on its BSER determination for new units.

**Actual emissions limits will be unit specific. States will set these limits using a unit-specific baseline annual emissions rate. For standard setting and compliance purposes, that rate is determined by taking the annual pounds of CO_2 emitted and dividing it by the annual total MWhs produced.

1 A covered EGU is not required to use the technology identified as BSER, but instead to achieve an emissions rate equivalent to using the BSER. For existing units, the regulations would allow states to authorize the use of various compliance flexibility tools to meet the standards (e.g. averaging, trading, mass-based approaches, etc.)

2 New source standards are effective upon proposal, which is the date of Federal Register publication May 23, 2023.

3 EGU: Electric Generating Unit

4 CCS: Carbon Capture and Storage

5.7.3. Regional Haze Rule (RHR)

The EPA originally established the RHR in 1999. It required states to develop and implement plans to improve visibility in certain Class I areas (primarily national park and wilderness areas). On June 15, 2005, the EPA issued final amendments to the rule. The goal of the rule is to reduce certain pollutants to improve visibility in Class I areas to "natural visibility conditions" by 2064. These pollutants include fine particulate matter, nitrogen oxides, sulfur dioxide, certain volatile organic compounds, and ammonia. Facilities built between 1962 and 1977, with emissions in specified quantities that contribute to visibility impairment in Class I areas, are required to install best available retrofit technology (BART) to control emissions. States were given until December 2007 to develop state implementation plans (SIPs) to comply with the rule.

States were similarly expected to submit SIPs for the second planning period (2018-2028) by August 2022.

The three coal plants serving NorthWestern's customers are in three different states (SD, IA, ND). Of these plants, Coyote is the only plant that has the potential to be impacted by the RHR due to its NOX emissions. However, each associated state has submitted SIPs to the EPA concluding that no new reductions are needed to meet the RHR goal year of 2064.

28 Source: Edison Electric Institute (EEI), Appendix A, "Clean Air Act Section 111 Final Rules". https://images.magnetmail.net/documents/clients/EEI_/2024-04/cmysh0zo.qcv/Appendix_A_111_Rules.pdf

5.7.4. Coal Combustion Residuals

The Disposal of Coal Combustion Residuals (CCR) from Electric Utilities final rule was signed December 19, 2014. These regulations set forth requirements for the disposal of CCR under the solid waste provisions in subtitle D of the Resource Conservation and Recovery Act. The rule establishes requirements for new and existing CCR landfills and surface impoundments. The requirements also cover structural integrity of impoundments, groundwater protection, operating criteria, record keeping, and information disclosure.

Effective July 8, 2024, EPA amended CCR rules. The new rules apply to management units of CCRs that are 1,000 tons. For such units that are not supporting critical infrastructure, closure is required within 60 months of the final rule publication. Site monitoring is also required under the rule.

All of the jointly owned coal-fired power plants in the portfolio (Big Stone, Coyote, and Neal) are currently in compliance with the amended CCR rule.

6. Transmission and Distribution

6.1. NorthWestern's Electric Transmission System

NorthWestern owns 1,310 miles of transmission assets that play a vital role in moving the energy to our South Dakota customers. These owned facilities, along with a number of transmission agreements, form a reliable transmission network to serve the energy needs of our South Dakota electric customers.

NorthWestern's transmission system is comprised of several voltage levels. A 115-kV transmission system runs from Ellendale, ND to Yankton, SD and is the backbone of NorthWestern's transmission system. The system has a number of interconnections with Western Area Power Administration (WAPA) and a 115-kV interconnection with Xcel Energy east of Mitchell, SD. A number of 69-kV and 34.5-kV lines tap off of the 115-kV backbone system to distribute energy to NorthWestern customers in over 110 communities.

Outside of the South Dakota service territory, NorthWestern also owns sections of generator lead lines that move energy generated from the jointly-owned coal plants to our transmission system. The line miles, by voltage level, are shown in Table 10. These values are inclusive of the lines we own that move energy from Big Stone, Coyote, and Neal to serve load.

Table 10 – Transmission System Miles

Transmission System (mi)	
345 kV	25
230 kV	18
115 kV and lower	348
69 kV and lower	919
Total	1310
Distribution System (mi)	
Overhead	1633
Underground	659
Total	2292

6.2. SPP Integrated Transmission Planning (ITP) Process

NorthWestern is both a transmission customer and a transmission-owning member of the SPP and is required to follow SPP transmission guidelines. NorthWestern transferred functional control of its South Dakota electric transmission facilities to SPP on October 1, 2015, and updates the qualifying facilities under the SPP Tariff annually. NorthWestern also actively participates in SPP's regional Integrated Transmission Planning process, which analyzes reliability, economic, and policy needs within the region and along the seams of neighboring Regional Transmission Organizations (RTOs).

All of NorthWestern's transmission facilities reside in SPP zone 19, which is also referred to as the Upper Missouri Zone (UMZ), shown in Figure 14. The UMZ is a multi-owner zone consisting of 20 different transmission owning or using members with interconnected facilities located across six states.

Figure 14 – Map of Upper Missouri Zone

As part of an effort to establish consistency in construction, operations and SPP tariff interpretation, the UMZ Coordination Group created a formal charter, developed Zonal Planning Criteria (ZPC), and approved a zonal voting process. These efforts have led to fair treatment of all zonal members while also outlining processes to move needed projects forward. ZPC were developed to identify transmission needs on a more local or zonal level and are incorporated into SPP's annual ITP process. The UMZ submitted revised ZPC for the 2024 – 2025 planning session.

6.3. High Priority Transmission Projects

6.3.1. Chamberlain Junction Switchyard Project

In early 2024, NorthWestern and East River Electric completed construction of the Chamberlain Junction switchyard. The six-terminal switchyard, which sits approximately three miles east of Chamberlain, SD, brings together the radial 69-kV transmission systems of NorthWestern and East River, providing a looped transmission system in the area with two different Western Area Power Administration sources serving the system. The switchyard addresses reliability needs on the radial 69-kV system from Mt. Vernon to Chamberlain, SD.

6.3.2. Yankton-Gavins-Beresford Study

This project studies low-voltage risks in the Sioux Falls area related to Spirit Mound Generation[29] being offline. The study will evaluate options to strengthen the system in conjunction with Upper Missouri Zone transmission system members. It was approved by the UMZ Planning Group back in April, but has not been granted approval by SPP.

For transmission projects not identified or directed by SPP, Transmission Owner members of the SPP RTO may seek to self-sponsor changes to their transmission equipment. However, Transmission Owner-sponsored upgrades without SPP Transmission Provider direction may not be accepted as part of the SPP transmission system and may not be included for recovery of transmission investment costs. As none of the affected Transmission Owner members for this project (WAPA, MRES, EREC, and NWE) want to move it forward as a self-sponsored upgrade and potentially not get cost recovery, the UMZPG will continue to pursue this reliability-based project through the SPP ITP process.

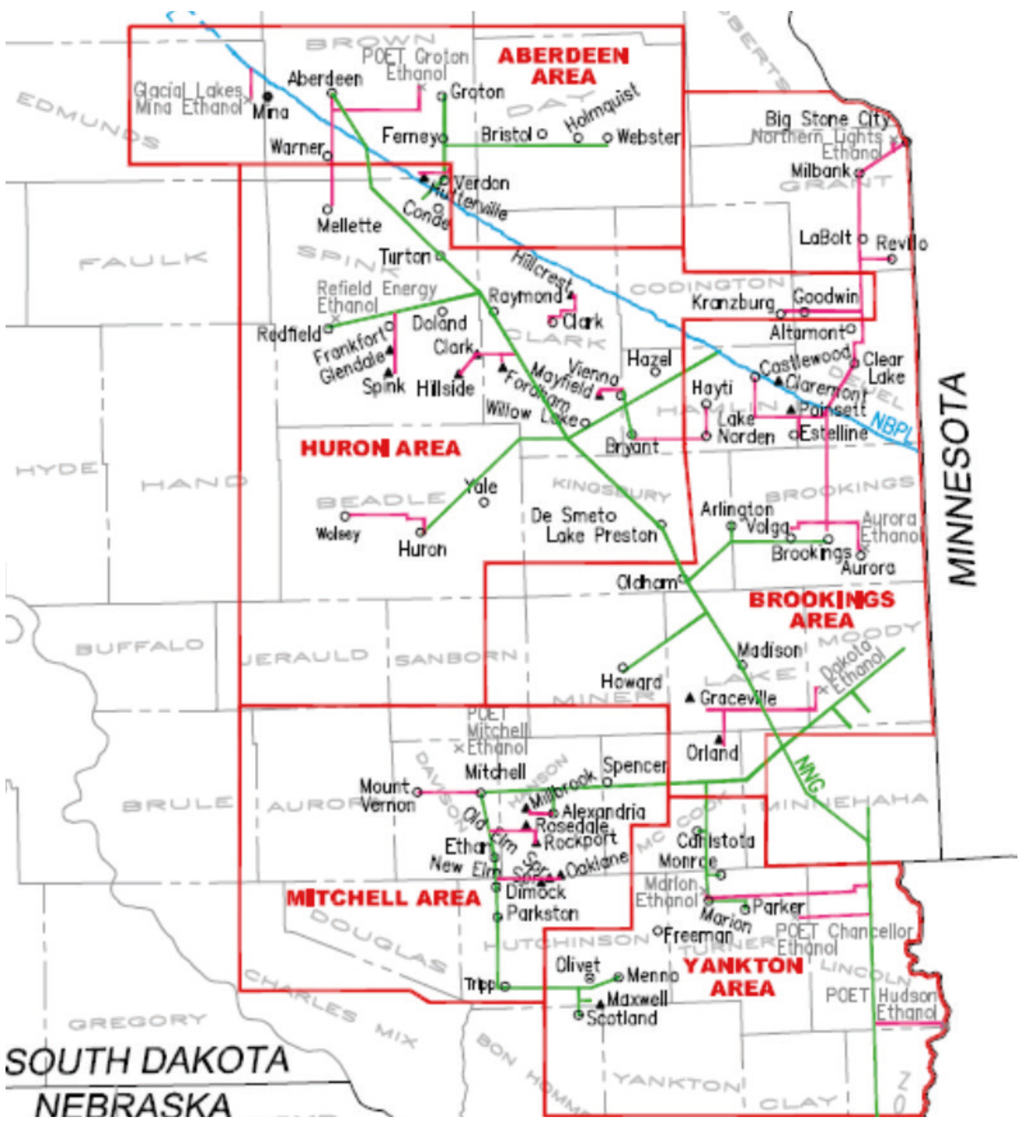
29 Spirit Mound is the fuel oil peaking power plant owned by Basin Electric. https://dakotagas.com/News-Center/basin-today-stories/How-Basin-Electrics-power-plant-professionals-prepared-and-performed-during-the-February-energy-emergency

6.4. Gas Transmission System

NorthWestern's resources are served from two major natural gas pipelines: 1) Northern Natural Gas Pipeline (NNG), and 2) Northern Border Pipeline (NBPL). These are shown green and blue, respectively, in Figure 15. In general, both of these lines are fully subscribed meaning that securing firm gas transmission is not an option without substantial pipeline expansion. However, there is ample input gas supply meaning that future investments in pipeline expansion could support additional gas generation. Both of these lines get supply from Canada and the Bakken shale region, and in the case of the NNG, supply also comes from Texas. NorthWestern has existing firm gas on both pipelines and buys additional capacity as needed on the markets.

Given the pipeline constraints it is possible that new resources could be supplemented with liquefied natural gas (LNG); however, this IRP does not price an LNG option or associated infrastructure in the modeling. It is also possible to purchase additional gas peaking supply on the market from other subscribers on either NNG or NBPL, although the availability is uncertain.

FIGURE 15 – GAS TRANSMISSION SYSTEM



7. Portfolio Modeling and Inputs

7.1. Introduction

In developing this Plan, NorthWestern relied on both capacity expansion and production cost models[30] to analyze system needs and evaluate options to meeting those needs under a variety of future scenarios. This chapter describes the approach, assumptions, results, and implications of the modeling performed by NorthWestern for the Plan. The modeling for this IRP was performed between April 2024 and September 2024.

7.2. Analytical Method

NorthWestern modeled its portfolio and load independently, rather than modeling the entire SPP footprint and resource stack. This NorthWestern-centric modeling approach is useful to ensure that NorthWestern can independently serve its load obligation and the seasonal PRM that SPP requires. The PRM requirement is required by the SPP tariff to participate in SPP markets[31] and ensures that members are not excessively leaning on other SPP resources. The modeling approach is described in Figure 16.

Figure 16 – High level overview of the IRP modeling approach

Define Plan Objectives	• Ensure NorthWestern's resource portfolio can serve load throughout the year • Define base case, early retirement, and resource build options, including sensitivities
Develop Inputs and Assumptions	• Review and update inputs for NorthWestern's load and supply resources in the system model • Create future scenarios • Determine future resource options, cost and characteristics
Modeling	• Capacity expansion - Create least-cost portfolios • Resource adequacy - Ensure system meets RA requirements • Production cost models - Determine operations, costs, and emissions for portfolios
Evaluate Outputs	• Validate model outputs to ensure accurate and reliable results • Summarize outputs for use in the planning process

7.3. Model Framework

NorthWestern conducted both capacity expansion and production cost modeling. The capacity expansion model adds resources to attain resource adequacy. The model utilizes a stochastic approach to capture variability and uncertainty in load, renewables, and prices. Simulations rely on historical data for weather, renewable generation, load, and market prices to create realistic future simulations. Simulations are scaled to future expectations based on monthly forecasts for renewables, load, and prices and incorporating expectations of price volatility and daily price shapes. The result is a set of simulations covering a useful and accurate range of potential future paths.

7.3.1. Capacity Expansion Modeling

The capacity expansion modeling indicates the least-cost resource procurements or retirements which satisfy the model constraints.[32] The models begin with a dispatch of existing and candidate resources to determine variable costs, energy generation, and carbon emissions over the time horizon of the study. The model's price simulations follow a forecast and do not adjust with local increases in energy production. The following constraints are employed in the models:

1. Reserve Margin – Requires portfolio to meet monthly peak demand plus the seasonal PRM. Planning reserve margins are applied in the model as a way to limit the risk of not meeting the peak demand.

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30 The models are part of the PowerSIMM Suite licensed and developed by Ascend Analytics

31 See SPP tariff attachment AA

32 PowerSIMM's capacity expansion module is Automated Resource Selection (ARS)

2. Fossil Fuel Resources – Does not allow new fossil fuel resource additions after 2035, which is consistent with NorthWestern's Net Zero by 2050 goals.
3. Resource Build Limits – Prohibits early resource builds to reflect lead times for RFP process, construction, and permitting. The first year of build is 2027 for wind, solar, and battery resources; 2028 for gas resources; and 2032 for nuclear resources.

NorthWestern configured the capacity expansion model by providing candidate resource options that could be used to meet NorthWestern's load plus planning reserve margin. Candidate resource configurations require inputs defining the accredited capacity value of the resource, capital cost, annual fixed costs, number of units that can be built annually, and other technical specifications of the resource. In addition to the candidate resources, NorthWestern configured model constraints that defined system needs such as seasonal capacity requirements.

Outputs from the model provide the timing and quantity of resources to procure through the time horizon which satisfy the above constraints at the lowest cost. The model considers full resource costs including capital costs, fixed costs, variable costs (fuel, variable O&M, startup costs), and the Inflation Reduction Act (IRA) tax credits (discussed below). Market sales revenue is treated as a negative cost in the model.

The next stage of the planning process is to evaluate model output portfolios in resource adequacy models. If a portfolio is capacity deficient, the capacity acquisition model is rerun with adjusted inputs to the portfolio to meet resource adequacy requirements.

7.3.2. Production Cost Modeling

Finally, the portfolios are evaluated with production cost modeling (PCM) to calculate generation costs of the specific candidate resources chosen by the capacity acquisition model. In the early coal retirement scenarios, any undepreciated book value in the retirement year is divided evenly over the next 10 years. Aside from generation costs, PCM also provides outputs for carbon emissions, market purchases and sales of power, and operational characteristics of the dispatchable resources like capacity factors.

The PCM results include cost information from both the study over the planning period as well as post processing calculations. The study results, referred to as Total Generation Costs, include variable O&M costs, fuel and fuel delivery costs, startup and shutdown costs, storage charging costs for batteries, and renewable resource variable costs. Market purchases and market sales from the entire portfolio are also outputs from the study. The post-processing calculations include fixed-cost calculations, such as revenue requirements of both existing resources as well as candidate resources added to the portfolio by ARS.

For candidate resource revenue requirements that extend beyond the planning period, NorthWestern has included the remaining book value (RBV) in 2045, the first year outside of the planning window, discounted back to 2025 as an indication of the book value that is unaccounted for in the total portfolio costs. The RBV is not included in the total portfolio costs because RBV can be an indication of additional costs (revenue requirements, fixed and variable costs, etc.) as well as an indication of potential market sales revenue to offset the total portfolio costs. Portfolios that have relatively high RBV are an indication that the expansion model had added resources later in the planning period.

7.3.3. Sub-hourly Credits

Analysis was conducted for this IRP using a one-hour step size in the model and assets dispatch to hourly day-ahead prices. This approach is referred to as hourly analysis. To capture additional revenue opportunities, especially during real-time price fluctuations, a sub-hourly analysis was performed. The analysis focuses on the potential candidate resources considered for the IRP, such as CT, ICE[33], 4-hour and 8-hour batteries.

The production cost model can forecast real-time (5 min) price changes in the future based on real-time historical

33 Internal Combustion Engine

data. The model optimizes the asset operation by dispatching them to the real-time prices, allowing the fast-ramping resources to capitalize on the price fluctuations. This method is called sub-hourly modeling.

By comparing the revenues from the sub-hourly model to the hourly model, the extra revenue earned by responding to real-time prices is quantified. This additional revenue earned by the assets is called sub-hourly credit and can be expressed as the revenue earned per kW of capacity. In SPP, generally the day-ahead revenues are lower than the real-time revenues. The following charts (Figure 17, Figure 18, Figure 19, and Figure 20) illustrate the revenue earned by the asset in both the day-ahead and real-time markets.

Figure 17 – Day-Ahead and Real-Time Revenues Earned by CT

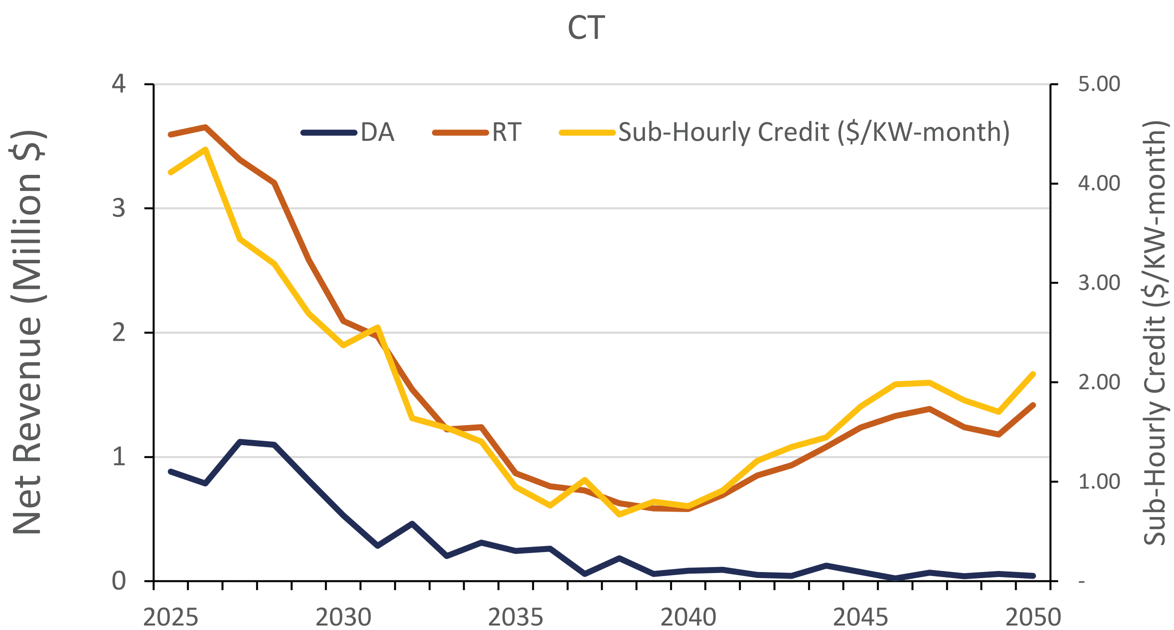


Figure 18 – Day-Ahead and Real-Time Revenues Earned by ICE

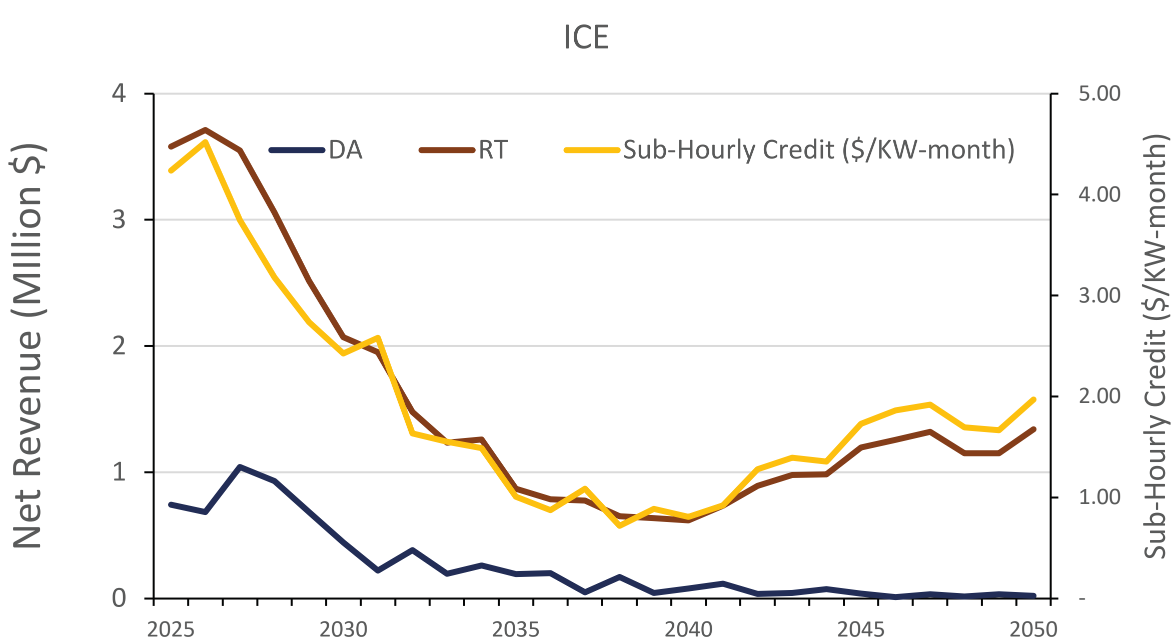


FIGURE 19 – DAY-AHEAD AND REAL-TIME REVENUES EARNED BY 4-HOUR BESS

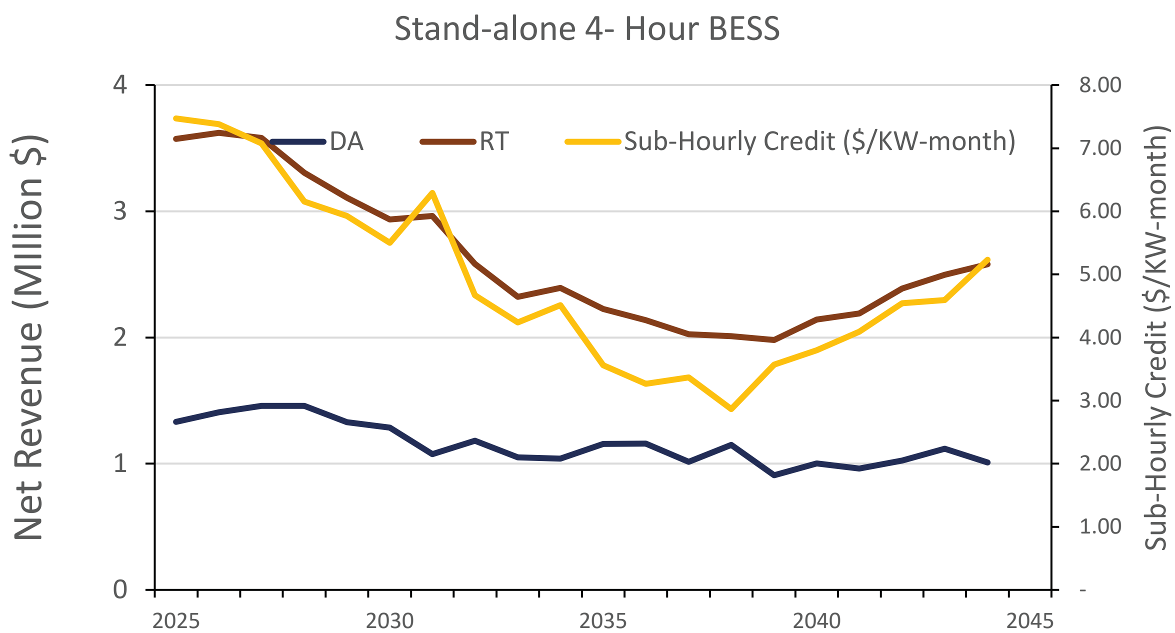


FIGURE 20 – DAY-AHEAD AND REAL-TIME REVENUES EARNED BY 8-HOUR BESS

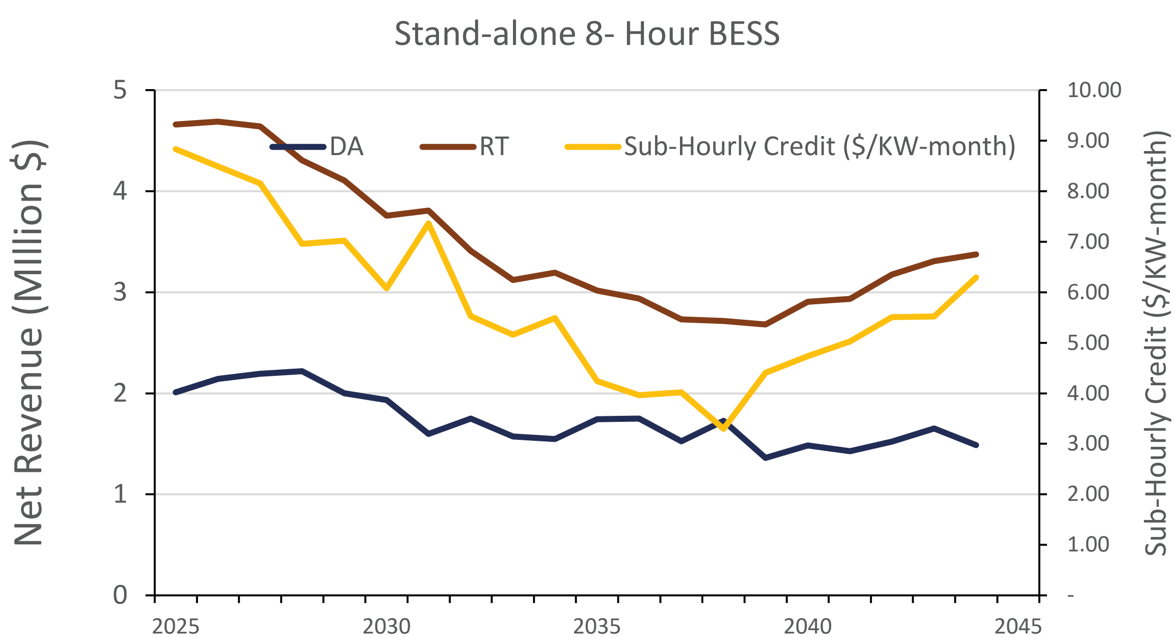
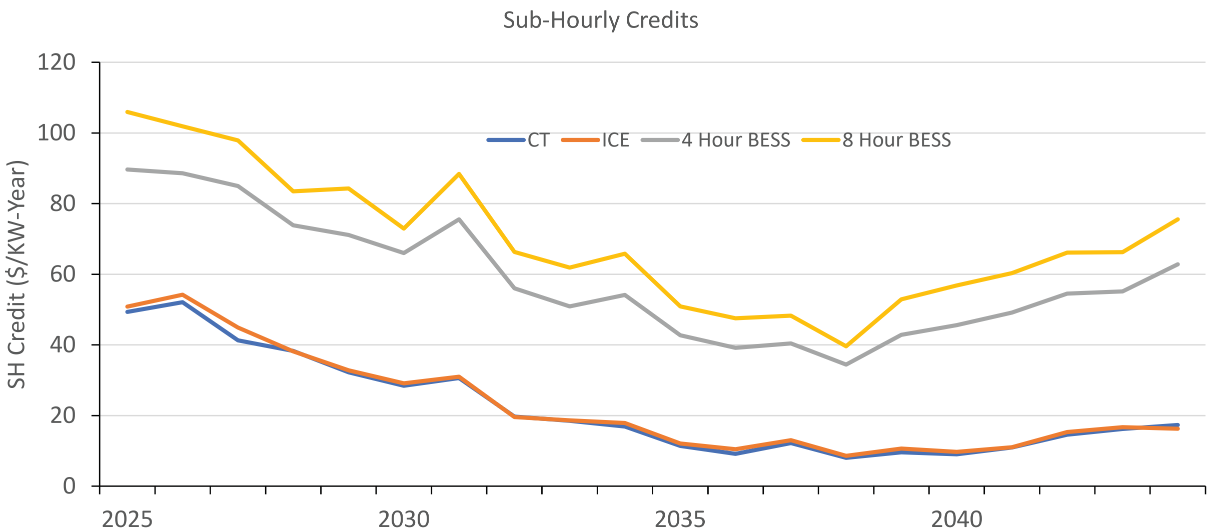


Figure 21 shows the sub-hourly credit of a CT, ICE, 4-hour and 8-hour batteries in $/kW-year. ICE and CTs have nearly equal sub-hourly credits. Batteries, on the other hand, can earn higher revenues when operated in real time as they can capture the sub-zero prices, initiate charging, and respond instantly to the higher price spikes and discharge energy. This figure is based on modeling and may not represent the actual value or magnitude of sub-hourly credits in the future. Consequently, these values may need to be re-evaluated when comparing costs of candidate resources.

FIGURE 21 – SUB-HOURLY CREDIT OF CT, ICE AND BESS



If NorthWestern were to evaluate an Opportunity Resource or conduct an RFP in the future, it may be appropriate to conduct a sub-hourly analysis for that resource. To accommodate the sub-hourly analysis, resources that are able to ramp up and ramp down within the hour may have to be simulated using an hourly analysis as well as a sub-hourly analysis to get a complete understanding of a resource's ability to provide value to the portfolio. Examples of resources that have the ability to fast ramp within the hour could include batteries, aeroderivative units, or RICE.

7.4. Model Inputs

7.4.1. Base Portfolio

The base portfolio is comprised of the resources described in Table 5. The Base Portfolio models all resources through either their depreciable or contracted life.

7.4.2. Inflation Reduction Act (IRA) Credits

The Inflation Reduction Act (IRA) took effect in 2022 and it, among other things, extended and expanded tax credits for carbon-free generation and energy storage. The IRA extended the Production Tax Credits (PTC) until 2032 for wind. Solar and nuclear now can receive the PTC. Energy storage can receive the Investment Tax Credit (ITC) without the requirement to charge from a renewable resource. As discussed below, the IRA tax credits were incorporated into the financial modeling for the SD IRP.

7.4.2.1. Investment Tax Credits ("ITC")

Internal Revenue Code ("IRC") Section 48E, as created by the Inflation Reduction Act (IRA), provides for a base credit of 6% on the basis of any qualified facility and any energy storage technology. A qualified facility means a facility used for the generation of electricity, which is placed into service after December 31, 2024, and for which the greenhouse gas emissions rate is no greater than zero. This would include, but not be limited to, facilities that generate electricity via solar energy, wind, and nuclear. Energy storage technology means property (other than property primarily used in the transportation of goods or individuals and not for the production of electricity) which receives, stores, and delivers energy for the conversion to electricity and has a nameplate capacity of not less than 5 kilowatt-hours, and thermal energy storage property. If prevailing wage and apprenticeship requirements are met, that percentage increase to 30% of the basis of energy property.

Battery storage property and nuclear energy property have all been computed using the ITC under the assumption they would be qualified facilities. Further, NorthWestern assumed meeting the prevailing wage and apprenticeship requirements and therefore has used the 30% rate in qualified ITC credit computations. Due to income tax considerations, NorthWestern may transfer the credits to unrelated third parties, and has factored a discount of 10% into the computations.

7.4.2.2. Production Tax Credits ("PTC")

Qualified facilities, as defined by the IRA, can qualify for the clean electricity production tax credit (IRC 45Y). The base rate for the production tax credit for the 2024 tax year is 0.6 cents per kilowatt-hour. This base rate increases to 3 cents per kilowatt-hour if prevailing wage and apprenticeship requirements are met. Wind energy property and solar energy property have been computed using the PTC as a negative variable cost under the assumption they would be qualified facilities. Further, NorthWestern assumed that it will meet the prevailing wage and apprenticeship requirements and thus would be eligible for the production tax credit of 3 cents per kilowatt-hour. Due to income tax considerations, NorthWestern may transfer the credits to unrelated third parties and has factored a discount of 10% into the computations.

Solar resources were simulated separately with the ITC and the PTC to understand which tax credit provided a lower overall cost. The net present value was compared between the two different tax credit assumptions over the planning period. The analysis showed that the PTC provided more value than the ITC for candidate solar resources. Therefore, the IRA PTC was also applied to solar candidate resources as a negative variable cost. The IRA's tax credits are currently expected to fully roll off in 2036.

7.4.3. Candidate Resources

Candidate resources are resources that could be used over the 20-year planning horizon to meet the needs defined in the IRP. The candidate resources NorthWestern modeled are described below.

7.4.3.1. Aeroderivative Combustion Turbine

A 55-MW simple cycle aeroderivative combustion turbine (Aero CT) is a candidate resource. The first year that an Aero CT is allowed in the model is 2028. Aero CTs are adopted from aviation use and are lighter, smaller, and more advanced when compared to frame installations that are generally designed for a specific site. Aero CTs can handle a greater number of starts and stops compared to frame installations. They can operate with natural gas or be dual fuel with diesel backup. The expected depreciable life of an Aero CT is 32 years.

Aero CTs require a higher gas pressure than RICE units, which adds construction and operations cost. The effective heat rate of Aero CT units increases significantly as the unit is dispatched at lower output levels below maximum capability and may not be able to run effectively below 50% capacity.

7.4.3.2. Modular Combustion Turbine

A 30-MW simple cycle modular combustion turbine (modular CT) is a candidate resource. The first year that a modular CT is allowed in the model is 2028. Modular combustion turbines can be simpler and quicker to assemble and build relative to site built options. They can operate with natural gas or be dual fuel with diesel backup. The expected depreciable life of an Aero CT is 32 years.

7.4.3.3. Simple Cycle Frame Combustion Turbine (Frame CT)

A 55-MW simple cycle frame combustion turbine (frame CT) is a candidate resource. The first year that a frame CT is allowed in the model is 2028. Frame industrial gas turbines are somewhat slower in startup and have narrower operating ranges than aero-derivative options. However, they can be less expensive than other turbine options and still provide peaking attributes. The expected depreciable life of a frame CT is 32 years.

7.4.3.4. Combined Cycle Combustion Turbine

A 150-MW combined cycle combustion turbine (CCCT) is a candidate resource. The first year that a CCCT is allowed in the model is 2028. Combined cycle turbines generally have higher efficiency due the extraction of more energy in the second process -- for example a steam turbine run from a gas turbine. The expected depreciable life of a CCCT is 32 years.

7.4.3.5. Reciprocating Internal Combustion Engine

A 55.8-MW reciprocating internal combustion engine (RICE) is a candidate resource. The first year that a RICE unit is allowed in the model is 2028. RICE units are internal combustion engines, similar to vehicle engines. They can operate with natural gas or be dual fuel with diesel backup. Similar to CT plants, RICE installations supply peaking power and operate in load following scenarios. Due to their wide range of operability and rapid response capability, RICE technology compares favorably for peaking applications. Generally, in utility power generation applications, RICE technology is smaller in scale and has better efficiency as compared to simple cycle CT technology. The expected depreciable life of a RICE unit is 32 years.

7.4.3.6. Modular RICE

A 34.4-MW modular RICE is a candidate resource in this IRP. Modular RICE plants can be simpler and quicker to assemble and build relative to site built options.

7.4.3.7. Flex Fuel Generator

A 50-MW flex fuel generator, fueled by natural gas, is a candidate resource. A flex fuel generator allows the ability to utilize other gaseous fuels, such as hydrogen mixes. The expected depreciable life of the flex fuel generating unit is 32 years.

7.4.3.8. Nuclear – Small Modular Reactors (SMRs)

A SMR is a reactor of 300 MW or less in size. NorthWestern received an $800,000 deferred accounting order from the South Dakota Public Utilities Commission that allows NorthWestern to investigate the potential for development of a SMR in South Dakota[34]. SMRs in increments of 80 MW are included as candidate resources in this IRP. The first year that a SMR is allowed in the model is 2032, reflecting the long licensing, permitting, and construction time for these resources. SMRs have the ability to provide reliable, safe, and carbon-free power. Further, due to their smaller footprint and modular design, SMRs can be sited on locations not suitable for larger power plants. SMR designs generally are simpler than large nuclear plants and rely on passive safety systems, rather than operator action, to keep the public safe. Nuclear waste from SMRs will need to be managed, much like the waste from existing nuclear power sources. NorthWestern tracks the continued advancement of SMR designs from numerous companies. In the U.S., companies developing SMR technologies include X-Energy, TerraPower, and NuScale. The expected depreciable life of a SMR unit is 60 years.

The Nuclear Regulatory Commission (NRC) regulates SMRs and requires an extensive licensing process. Under the NRC's regulations, there are 16 planning phases. The NRC provides flexibility with developers when developing their plans in order to help guide developers through compliance with evolving regulations. With respect to meeting safety and design requirements the various SMR developers have been given an opportunity to present how their inherently safe designs still meet the minimum safety requirements of the existing regulations. Updates to these regulations are expected in 2025.

7.4.3.9. Battery Energy Storage System (BESS)

Lithium ion ("Li-ion") batteries provide a high energy storage density that has resulted in adoption across the transportation, technology, and power generation markets. Due to its characteristics, Li-ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term spinning reserve.

An important consideration of battery energy storage system (BESS) is round trip energy efficiency. Losses experienced in the charge/discharge cycle include those from plant inverters, heating and ventilation, and associated control systems. Li-ion technology experiences degradation both in terms of capacity and round-trip

34 Docket EL23-002 (March 1, 2023)

efficiency with time due to a variety of factors including number of full charge/discharge cycles and environmental exposure.

In addition to stand-alone storage options, batteries can also be paired with wind or solar resources to create a hybrid project. In general, the battery is connected to the VER resource that is used to charge the battery. The battery is then dispatched to market and load signals. Some configurations allow for the battery to be charged from both a VER and the grid while others only allow charging from the VER.

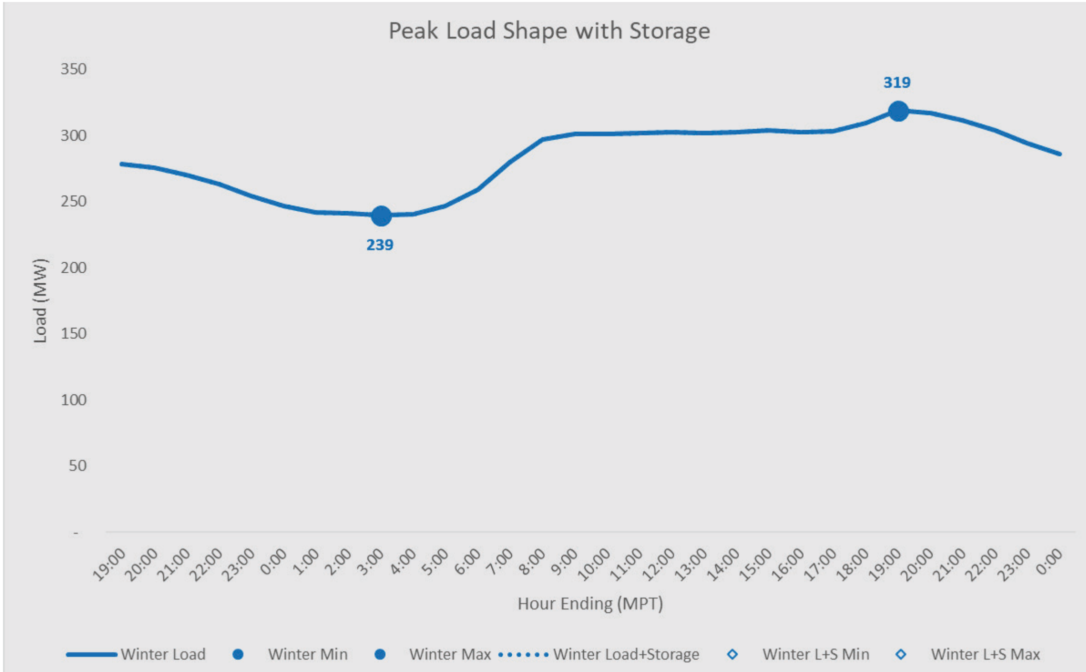
The configuration and sizing of hybrids vary widely making it difficult to model a representative hybrid resource. In addition, evaluating these as stand-alone resources allows for more flexibility in the battery's dispatch under SPP price signals, and potentially more value to NorthWestern from an energy arbitrage perspective, than being constrained to charging from a VER. In this IRP, NorthWestern chose to model a number of portfolios that include both stand-alone battery and stand-alone VER resources. The intent is to evaluate how these resources could provide capacity value to meet our needs in the South Dakota service territory.

Utility-scale battery disposal is an ongoing question that is still being explored at the time of this IRP's publication. Li-ion batteries are expected to have a service life of 20 years.

It is assumed that stand-alone BESS can be charged and discharged once per day, including days when the load experiences a seasonal peak. BESS act like a load when they are charged from the grid. The number of stand-alone BESS that can be used to meet resource adequacy is limited based on the amount of charging demand that is added to the system. Figure 22 below shows NorthWestern's winter peak that occurred on January 1, 2019, and the summer peak that occurred on July 28, 2021. Notice that the winter peak shape is much more flat and shallow than the summer peak shape. These seasonal load shapes dictate how much BESS charging load can be added to the system. Ideally, BESS are charged across the lowest 4-hour period and discharged across the highest 4-hour period of the load shape. These same load shapes were applied to the highest winter and summer peaks over the 20-year planning horizon of 388 MW and 419 MW, respectively. Figure 23 and 24 show a charging analysis[35] of how the peak load shape changes with the addition of 75 MW and 100 MW of BESS, respectively, for these 20-year summer and winter peaks. Notice that 100 MW of BESS creates a new winter peak load during the charging period of the BESS while the 75 MW of BESS is sufficiently decreasing the overall peak load for both the winter and summer peaks. Therefore, one unit of 50-MW 4-hour BESS and one unit of 25-MW 4-hour BESS was determined to be the maximum amount of 4-hour storage that is considered in the IRP.

35 This charging analysis assumes 10% of energy losses during charging.

Figure 22 – Winter and Summer Peak load shape.



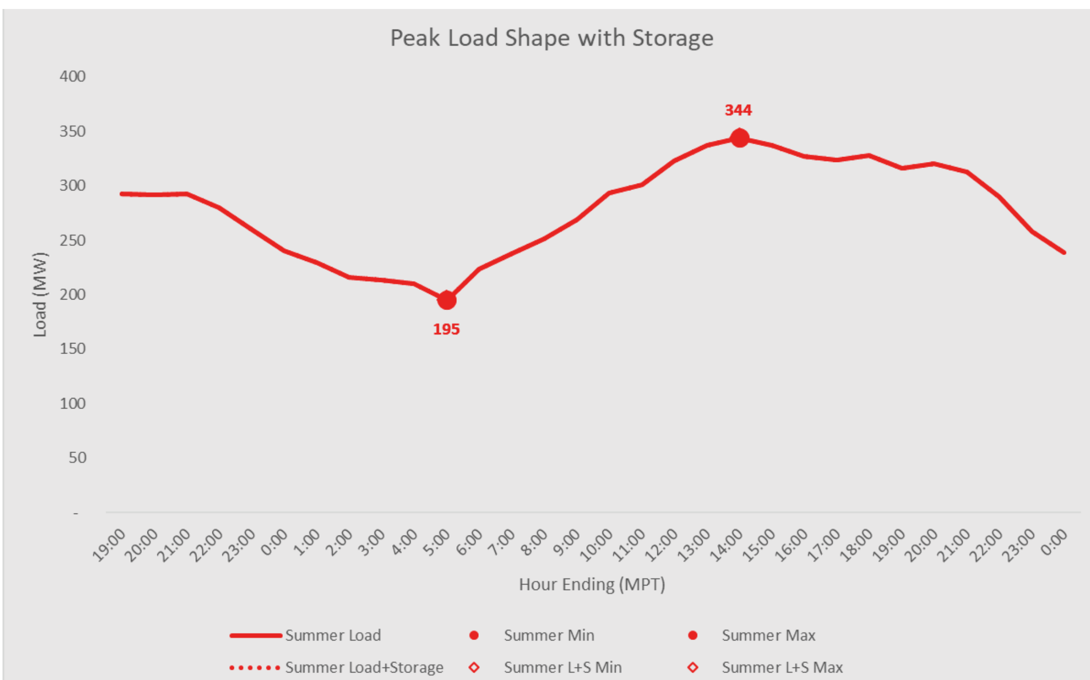
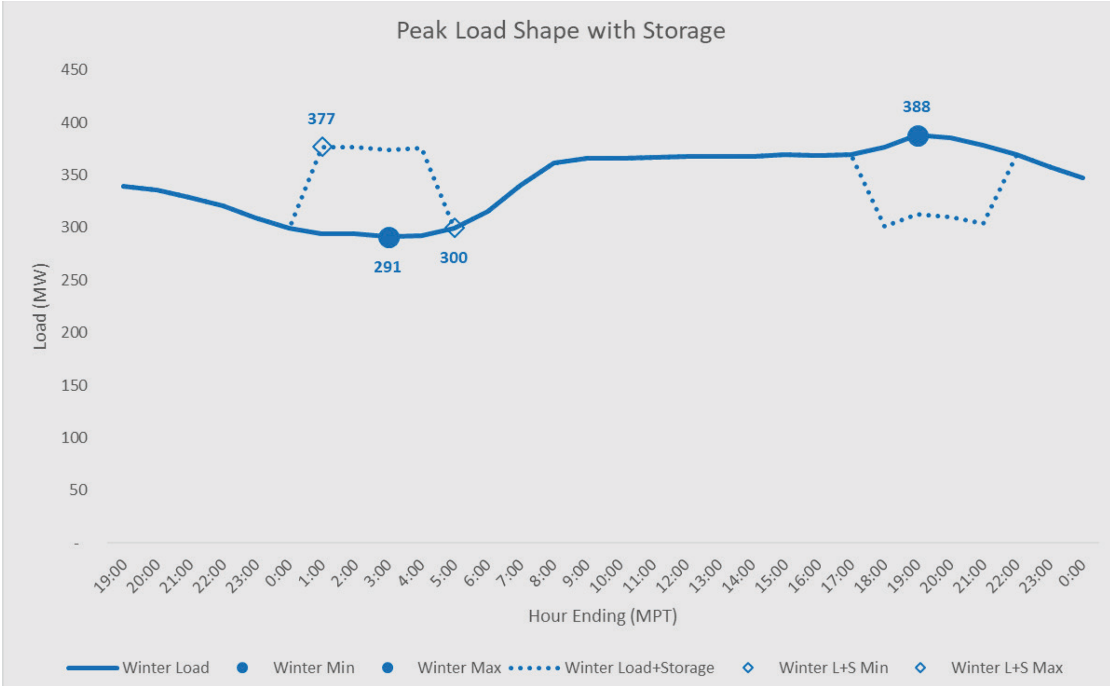


FIGURE 23 – WINTER AND SUMMER PEAK LOAD SHAPE WITH 75 MW OF BESS.



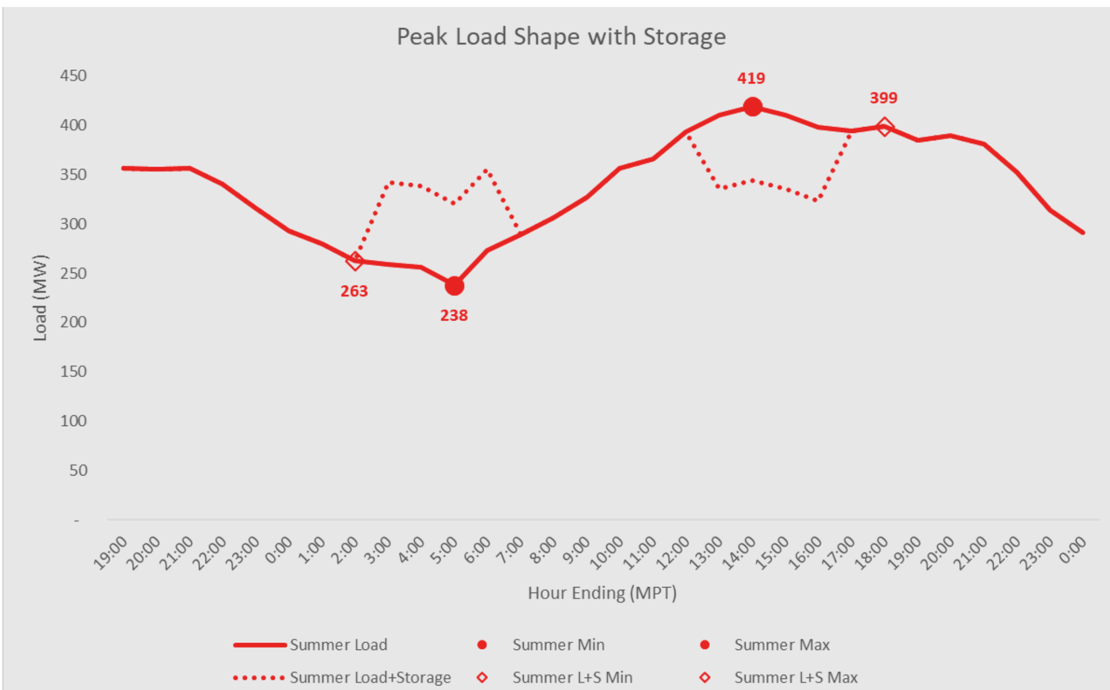
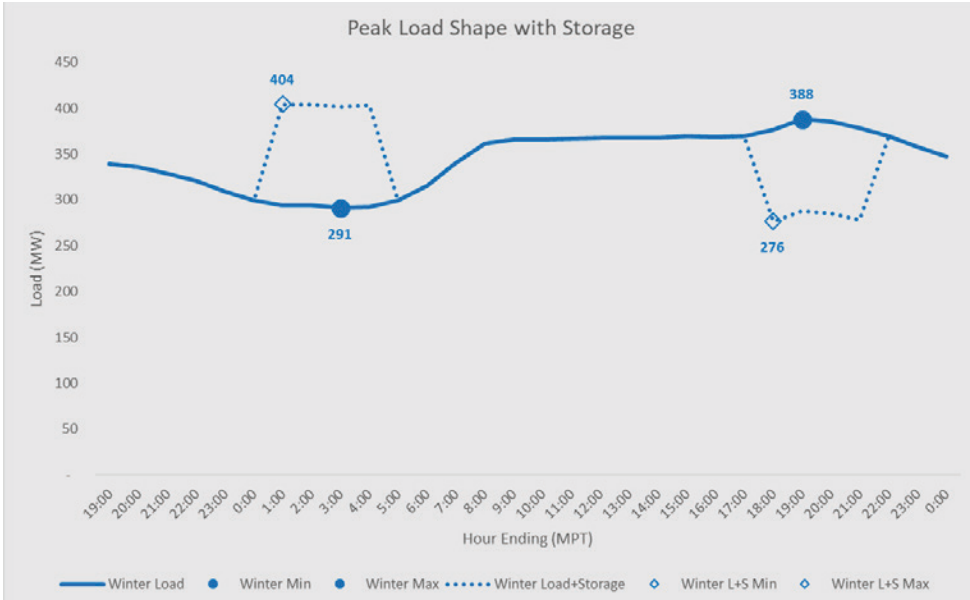
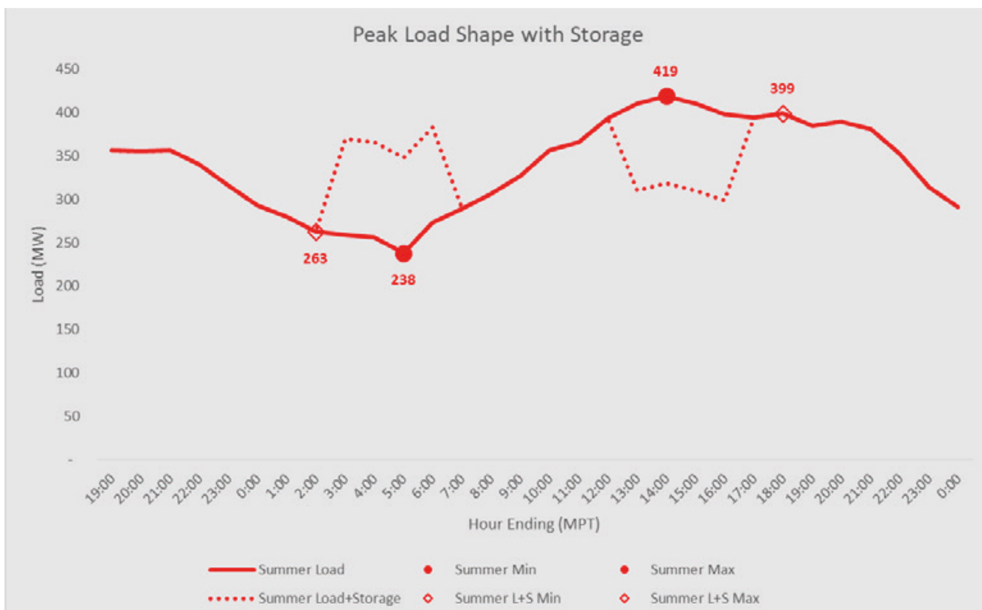


Figure 24 – Winter and Summer peak load shape with 100 MW of BESS.





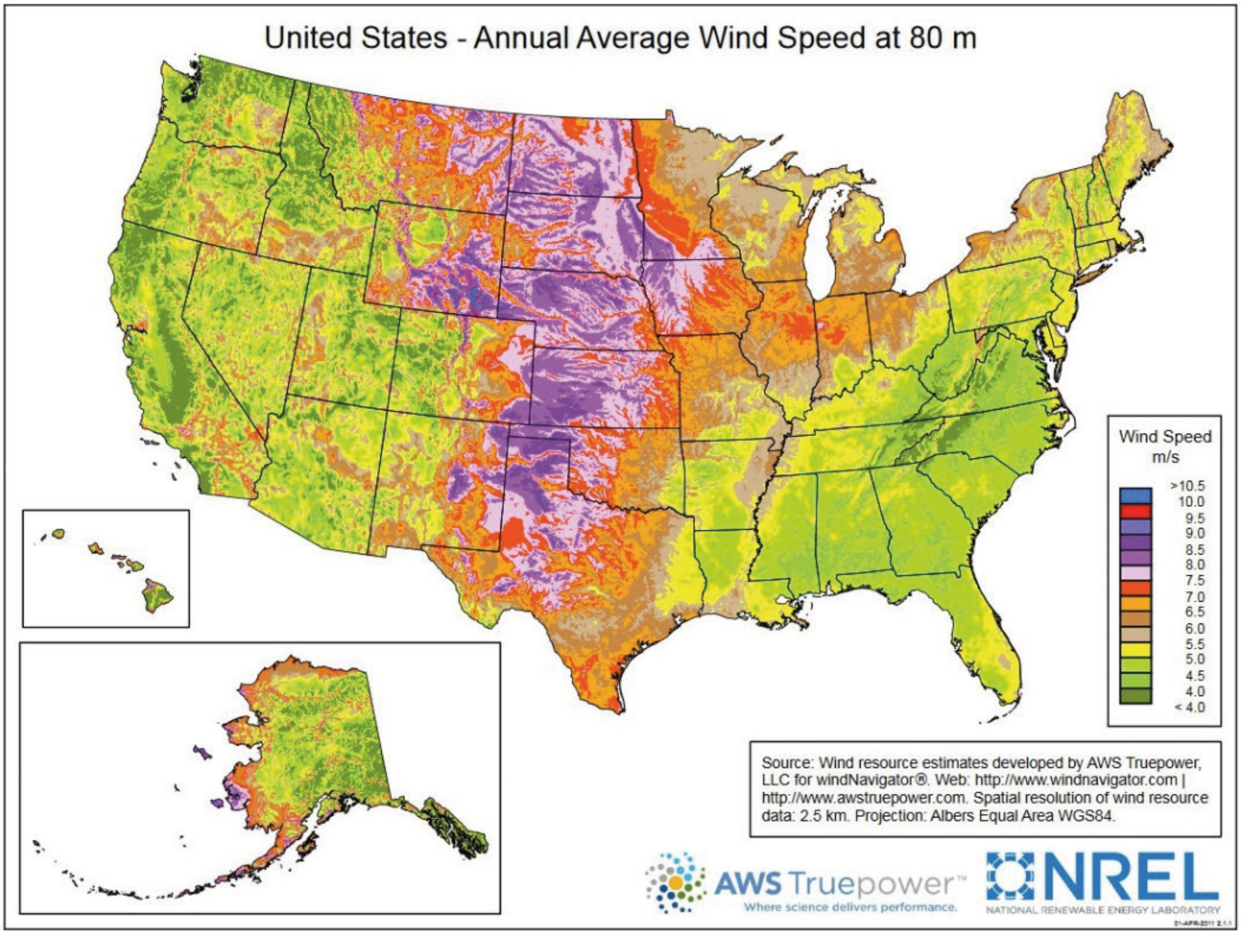
This same charging analysis could be performed for 8-hour BESS as well. However, 8-hour storage will be further limited because of the longer charging durations as well as coordination with 4-hour storage. Therefore, 8-hour BESS applications were not considered.

The 4-hour BESS candidate resources that are modeled are one unit of 50 MW and one unit of 25 MW BESS. The first year that batteries are allowed in the model is 2027. There are several emerging BESS technologies, related to different chemistry types, but the most prevalent type in service today is Li-ion batteries.

7.4.3.10. Wind Generation

Installed wind generation in the U.S. has proliferated in recent years and this trend is expected to continue; therefore, wind is included as a candidate resource in this IRP. Individual wind turbines can be designed for sizes between 1.5 – 5 MW. The first year that wind resources are allowed in the model is 2027. Wind development potential, as based on average wind speed, is favorable in South Dakota as shown in Figure 25.

FIGURE 25 – UNITED STATES AVERAGE WIND SPEEDS[36]



The expected depreciable life of wind turbine and blade units is 30 years. The blades are large, durable pieces of fiberglass that are challenging to cut, bend, or otherwise repurpose. While wind farm growth is expected to continue into the future, it is important to acknowledge that the majority of spent blades are currently disposed of in landfills.

7.4.3.11. Solar Photovoltaic (PV)

Similar to wind projects, the first year that new solar is allowed in the model is 2027. Solar installations use photovoltaic cell (PV) arrays to convert light from the sun into electricity. PV cells are made of semiconductor materials and come in many sizes, shapes, and ratings. Solar cells produce direct current (DC) electricity and require inverters to convert the direct current output to alternating current for grid-connected installations. Solar PV arrays are mounted on structures that can either tilt the PV array at a fixed angle or incorporate tracking mechanisms that automatically move the panels to follow the sun across the sky. The fixed angle is determined by local latitude, orientation of the structure, and electrical load requirements. Tracking systems provide more energy production. Single-axis trackers are designed to track the sun from east to west, and dual axis trackers allow for modules to remain pointed directly at the sun throughout the day. The expected depreciable life of solar units is 25 years. Solar panels that reach end of life are difficult to recycle; most of them end up in landfills, despite containing valuable materials.

Unlike wind, NorthWestern's current South Dakota portfolio does not include any utility-scale solar photovoltaic resources. Capacity accreditation values for solar were estimated using SPP's existing tariff methodology for wind and solar resources, discussed in the Net Planning Capability ("NPC") section 7.1.8 of the latest SPP Planning Criteria version 4.4A. This NPC methodology was applied to five years of calculated solar generation data created using the National Renewable Energy Laboratory's ("NREL") System Advisor Model ("SAM") v.2023.12.17. To create this data,

36 https://windexchange.energy.gov/maps-data/319

weather data was downloaded from the National Solar Radiation Database ("NSRDB") for a proxy location in Huron, SD for the years 2018-2022. This weather data was used in SAM to create corresponding generation data for a theoretical 50-MW (AC-rated) nameplate solar resource. The NPC calculation was performed for the 5-year period using the resulting SAM hourly generation and NorthWestern's actual hourly load. The results show that the NPC capacity accreditation values for solar are 73.5% (36.8 MW) for summer and 0.0% (0.0 MW) for winter seasons.

These values were assumed to represent initial solar resource additions to NorthWestern's portfolio, referred to as "Tier 1". Tier 1 capacity limits were determined based on SPP's "2022 ELCC Wind and Solar Study Report[37]" criteria of 20% of average seasonal system peak load for the previous three years for solar. The resulting Tier 1 limits for solar were calculated as 68 MW for summer and 63 MW for winter. Any solar resources exceeding Tier 1 limits were assumed to fall into Tier 2, which has capacity accreditation reductions similar to SPP's Tier accreditation percentage differential (-15% between solar tiers) in that same report. Therefore, any Tier 2 solar additions would have accredited capacity values of 58.5% for summer and 0.0% for winter seasons. The Tier 2 accreditations were assumed for any solar candidate resources.

7.5. Candidate Resource Costs

Candidate resource cost modeling includes both capital and variable costs. The capital costs are represented by a levelized revenue requirement derived from an overnight capital cost ($/kW) and a fixed operating and maintenance (O&M) cost ($/kW-year). Variable cost modeling for candidate resources includes variable O&M ($/MWh) and hourly runtime cost ($/hour). These capital and variable cost estimates were provided by Aion Energy LLC (Aion) and are shown in Table 11. Aion's full report is provided in the electronic files. The cost for small modular reactors was derived from the Idaho National Laboratory's Gateway for Accelerated Innovation in Nuclear (GAIN) report, "Meta-Analysis of Advanced Nuclear Reactor Cost Estimations"[38]. The cost estimates from the GAIN report are shown below in Table 12. The cost of the Flex Fuel generator was provided by the manufacturer with an overnight capital cost of $2,350/kW, a fixed O&M cost of $5/kW-year, and $8.75/MWh of variable O&M for 2024 for a 50-MW build.

Using Aion's estimates, the GAIN report estimates, and the Flex Fuel generation information along with assumed inflation rates and technology advancement rates, NorthWestern was able to develop capital costs for each candidate resource considered in the Plan. The overnight capital cost curves assumed in the IRP are provided in Figure 26, on the following page. These cost curves were used, along with fixed O&M costs, to develop revenue requirements for candidate resources that were used as inputs to the overall portfolio costs described in Section 8.4. The net present value of the candidate resource capital and fixed costs that were used as inputs to the PowerSIMM model as well as levelized revenue requirements that were used for the post processing of the total portfolio costs are provided as electronic files. As with all candidate resources, the fixed costs of the Flex Fuel generator were escalated by inflation every year. However, there was no offsetting technology advancement factor provided so the Flex Fuel cost curve in Figure 26 has a positive slope.

37 https://www.spp.org/documents/68289/2022%20spp%20elcc%20study%20wind%20and%20solar%20report.pdf

38 https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_107010.pdf

Table 11 – Capital and O&M Cost estimates for candidate Resources.

		Generation		Storage			2024$						
No.	South Dakota	Scale (MWac)	Heat Rate (Btu/ kWh-HHV)	Scale (MWac)	Duration (hours)	Capability (MWh)	Installed Over-night[1] ($/ kW)	Installed Over-night[1] ($/ kWh)	Fixed O&M ($/ kW-yr)	Fixed Hourly Fee ($/ hour)	Start Fee ($/start)	Variable O&M ($/ MWh)	Total Non-Fuel Variable Costs ($/ MWh)
1	Wind	50		-		-	$ 2,331	n/a	$ 51.87	$ -	$ -	$ -	$ -
2	Wind	100	-	-		-	$ 2,029	n/a	$ 43.62	$ -	$ -	$ -	$ -
3	Wind	300	-	-		-	$ 1,817	n/a	$ 35.63	$ -	$ -	$ -	$ -
4	Solar PV - SAT	50		-		-	$ 1,968	n/a	$ 25.59	$ -			
5	Solar PV - SAT	100	-	-	-	-	$ 1,900	n/a	$ 24.72	$ -	$ -	$ -	$ -
6	Solar PV - SAT	300	-	-	-	-	$ 1,694	n/a	$ 22.15	$ -	$ -	$ -	$ -
7	BESS - Li-Ion[2]			25	4	100	$ 2,265	$ 566	$ 29.70	$ -	$ -	$ -	$ -
8	BESS - Li-Ion[2]	-	-	50	4	200	$ 2,043	$ 511	$ 29.33	$ -	$ -	$ -	$ -
9	BESS - Li-Ion[2]			25	8	200	$ 4,087	$ 511	$ 58.66	$ -	$ -	$ -	$ -
10	BESS - Li-Ion[2]	-	-	50	8	400	$ 3,683	$ 460	$ 57.86	$ -	$ -	$ -	$ -
11	SC Modular CT[3]	30	9,800	-	-	-	$ 1,854	n/a	$ 27.51	$ 200	$ -	$ 0.58	$ 7.24
12	SC CT - Aero[3]	30	9,500	-	-	-	$ 2,448	n/a	$ 27.51	$ 200	$ -	$ 0.58	$ 7.24
13	SC CT - Aero[3]	55	9,260	-	-	-	$ 1,963	n/a	$ 20.61	$ 263	$ -	$ 0.47	$ 5.25
14	SC CT - Aero[3]	110	9,260	-	-	-	$ 1,831	n/a	$ 16.71	$ 525	$ -	$ 0.47	$ 5.25
15	SC CT - Frame[3]	55	9,520	-	-	-	$ 1,683	n/a	$ 19.81	$ -	$ 3,200	$ 0.40	$ 6.22
16	SC CT - Frame[3]	110	9,520	-	-	-	$ 1,570	n/a	$ 16.06	$ -	$ 6,400	$ 0.40	$ 6.22
17	SC Modular RICE (8 x 4.25 MW)[3]	34	9,010	-	-	-	$ 2,135	n/a	$ 34.24	$ 440	$ -	$ 2.26	$ 15.20
18	SC RICE[3]	50	8,750	-	-	-	$ 2,228	n/a	$ 28.80	$ 403	$ -	$ 2.26	$ 10.31
19	SC RICE[3]	100	8,750	-	-	-	$ 1,899	n/a	$ 20.8	$ 805	$ -	$ 2.26	$ 10.31
20	SC RICE[3]	150	8,700	-	-	-	$ 1,789	n/a	$ 18.13	$ 1,208	$ -	$ 2.26	$ 10.31
21	CCCT[4]	150	6,700	-	-	-	$ 1,632	n/a	$ 22.11	$ 666	$ -	$ 1.37	$ 5.81
22	CCCT[4]	265	6,700	-	-	-	$ 1,457	n/a	$ 19.73	$ 1,051	$ -	$ 1.31	$ 5.28

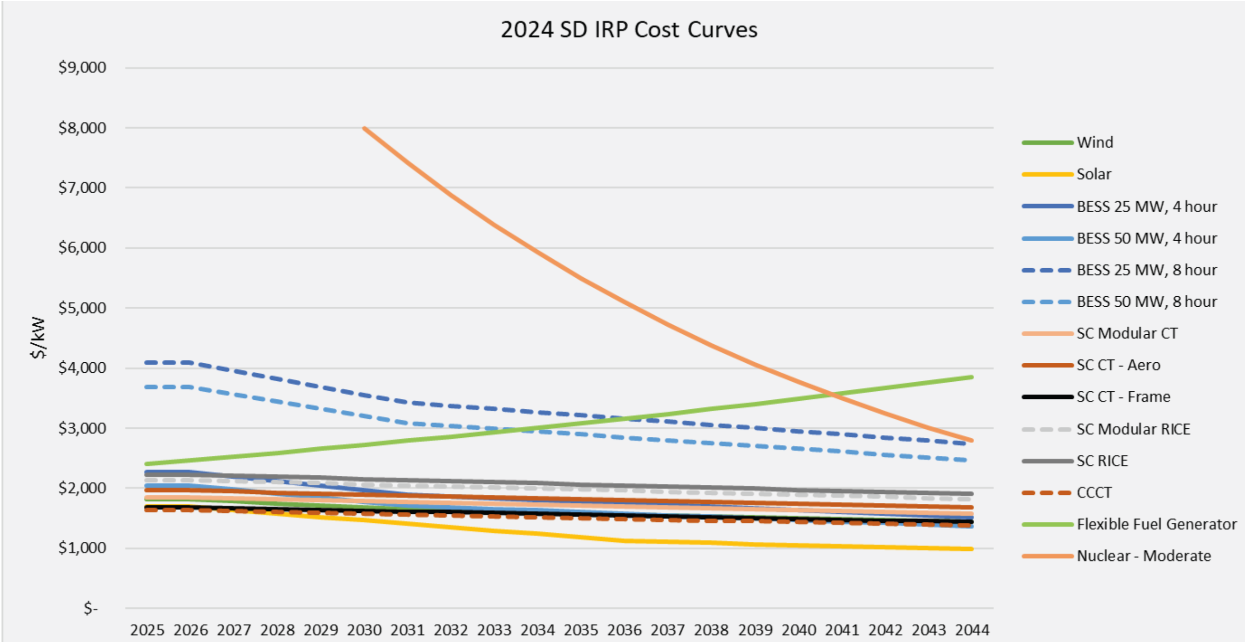
Notes
1. Overnight installed costs include direct and indirect EPC project costs and owner's cost but exclude AFUDC, electric transmission network upgrades, and bulk gas system upgrades, as applicable.
2. BESS resources based on lithium ion technology, 365 equivalent cycles per year, and capacity augmentation throughout the study period.
3. O&M costs for simple cycle configurations assume a dispatch profile of 100 starts per year and 1,000 hours of operation per year.
4. O&M costs for combined cycle configurations assume a dispatch profile of 150 starts per year and 4,000 hours of operation per year.

Table 12 – GAIN nuclear estimates

Table A-1. Summary of key data outputs from this report. For National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) consideration.

		Advanced	Moderate	Conservative
Large Reactor	BOAK OCC ($/kWe)	5,250	5,750	7,750
	OCC 2050 ($/kWe)	2,250	3,750	6,000
	Fuel Costs ($/MWh)	9.1	10.3	11.3
	Fixed O&M ($/kW-yr)	126	175	204
	Variable O&M ($MWh)	1.9	2.8	3.4
	Power output (MWe)	1,000		
	Capacity Factor	0.93		
	Construction time (months)	60	82	125
	Ramp rate (%power/min)	5%		
	Learning Rate	8%		
SMR	BOAK OCC ($/kWe)	5,500	8,000	10,000
	OCC 2050 ($/kWe)	2,000	4,000	6,250
	Fuel Costs ($/MWh)	10.0	11.0	12.1
	Fixed O&M ($/kW-yr)	118	136	216
	Variable O&M ($MWh)	2.2	2.6	2.8
	Power output (MWe)	300		
	Capacity Factor	0.93		
	Construction time (months)	43	55	71
	Ramp rate (%power/min)	10%		
	Learning Rate	9.5%		

Figure 26 – Overnight Capital Cost Curves of Candidate Resources



7.6. Capacity Accreditations of Candidate Resources

NorthWestern modeled an accredited capacity for each candidate resource considered in the IRP. The accredited capacity or, more specifically, the effective load carrying capability (ELCC), is defined as the amount of incremental load a resource can reliably serve, while also considering probabilistic parameters of unserved load. The ELCCs on a percentage basis for each candidate resource considered in the IRP are described in Table 13.

For candidate Combustion Turbines (CT aero, modular, frame, combined cycle) and RICE resources, NorthWestern assumed the same ELCC percentages as the Aberdeen 2 and BGGS, respectively. The flex fuel resource ELCC was provided by that company's data. For nuclear SMR resources NorthWestern assumed an ELCC percentage of 97%. Wind and solar accreditation is explained above in their respective sections. NorthWestern assumed seasonal ELCC percentages based on SPP's 2022 ELCC Wind and Solar Study report[39] and the SPP's 2024 ELCC Wind, Solar, and ESR Study Report[40] for candidate wind resources. Note that the SPP's 2024 ELCC report was preliminary at the time that the modeling was completed. For candidate solar resources, NorthWestern performed a NREL SAM study to calculate a more representative ELCC value for solar at the latitude of NorthWestern's service territory. For battery storage resources NorthWestern assumed a seasonal Tier 3 ELCC percentage described in SPP's 2022 ELCC ESR Study report[41]

39 https://www.spp.org/documents/68289/2022%20spp%20elcc%20study%20wind%20and%20solar%20report.pdf

40 https://www.spp.org/documents/72346/2024%20spp%20elcc%20wind%20solar%20&%20esr%20report.pdf

41 https://www.spp.org/documents/68930/2022%20elcc%20esr%20report.pdf

Table 13 – Candidate Resource ELCC assumptions.

Resource	Nameplate (MW)	Summer ELCC	Winter ELCC
4h Battery Storage	25	84.0%	51.0%
4h Battery Storage	50	84.0%	51.0%
Solar	50	58.5%	0.0%
Wind	50	14.5%	27.2%
CCCT	150	94.0%	94.0%
CT Aero	55	94.0%	94.0%
CT Frame	55	94.0%	94.0%
CT Modular	30	94.0%	94.0%
RICE	55.8	98.0%	98.0%
RICE Modular	34.4	98.0%	98.0%
Flex Fuel	50	98.0%	98.0%
Nuclear SMR	80	97.0%	97.0%

7.7. Price Forecasts

7.7.1. Power and Natural Gas Forecast

NorthWestern purchased the Base price forecasts for power and natural gas from Ascend Analytics and used the forecasts to define the expected (average) value of power and fuel prices over an extended time period. Ascend also provided NorthWestern with elevated price forecasts that are used in sensitivities to the effect of increased costs on resource selection.

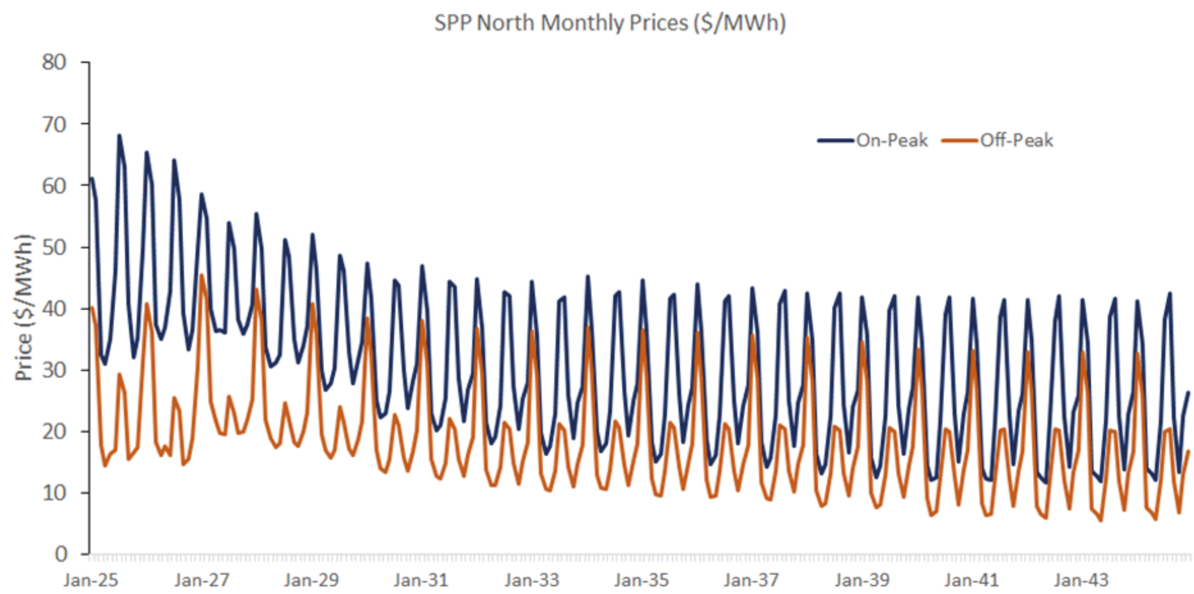
NorthWestern evaluates candidate resources and potential retirements by simulating a range of values around these averages to reflect the inherent uncertainty in future conditions. NorthWestern uses the PowerSIMM modeling software to conduct these simulations.

Ascend forecasts begin with market forward prices for fuel and power prices over the duration for which they are liquid, ensuring that Ascend's models are calibrated to observed market conditions. Ascend then blends the end of the liquidity period with a long-run forecasting approach that explicitly accounts for the new market dynamics that are caused by increasing deployment of storage and intermittent (non-dispatchable) renewable resources with zero/near-zero marginal costs.

Ascend releases long-term price forecasts for all the ISOs every year. For the IRP, NorthWestern used Ascend's SPP forecasts as of March 2023. Ascend uses forward prices from the Intercontinental Exchange (ICE) for the first four years followed by a fundamentals-based projection of market prices thereafter. Ascend used the SPP North hub for the electricity price and Ventura for gas prices.

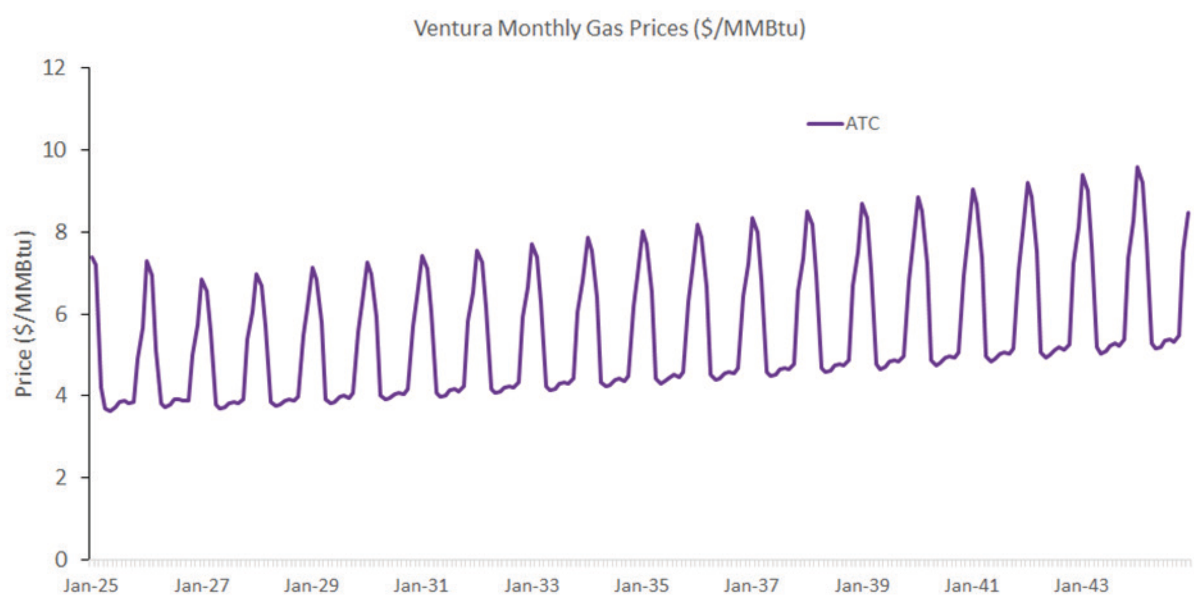
Ascend forecasts prices for on-peak (Monday – Friday HE07-22) and off peak (all other) hours. The on-peak prices in SPP are currently around $70/MWh, and NorthWestern expects these prices to decline gradually by the 2030s due to significant growth in wind and solar generation, after which they stabilize (Figure 27). Peak prices are observed in summer, particularly July. The high renewables penetration in SPP is contributing to the decline in electricity prices. This trend is expected to continue as renewables penetration increases.

FIGURE 27 – SPP FORECASTED POWER PRICES



The Ventura gas price starts at $7/MMBtu and slowly increases over time, eventually reaching around $10/MMBtu (Figure 28).

FIGURE 28 – VENTURA GAS PRICE FORECAST



7.7.2. Coal Price Forecast

NorthWestern derived the coal price forecasts using existing supply contracts for Big Stone through 2028, Coyote through 2028, and Neal through 2034 as a starting point for projections. An annual escalation rate of 2.35% is applied to extend the forecast for the remainder of the planning period. The escalation rate is calculated using a 20-year average of historical annual escalation rates for Implicit Price Deflators for Gross Domestic Product (GDP) published by the U.S. Bureau of Economic Analysis.

8. Modeling Scenarios & Results

8.1. Primary Scenarios

The Primary Scenarios included the Base Case as well as early retirement scenarios of NorthWestern's coal resources. The early retirement scenarios were modeled to gauge how the uncertainty in environmental regulations affects our future resource portfolio and capacity needs. The early coal retirement scenarios are listed below. All retirement dates are assumed to occur at the end of the calendar year. All early coal retirement scenarios assume the base power, natural gas, and coal price forecasts. In all scenarios no carbon-emitting resources are allowed after 2035 to be consistent with NorthWestern's Net Zero by 2050 goal.

- 2032 Coal Retirement – all coal resources including Big Stone, Coyote, and Neal retire at the end of 2032.
- 2035 Coal Retirement – all coal resources including Big Stone, Coyote, and Neal retire at the end of 2035.
- 2032-2035 Coal Retirement – Coyote retires at the end of 2032 and Big Stone and Neal retire at the end of 2035.

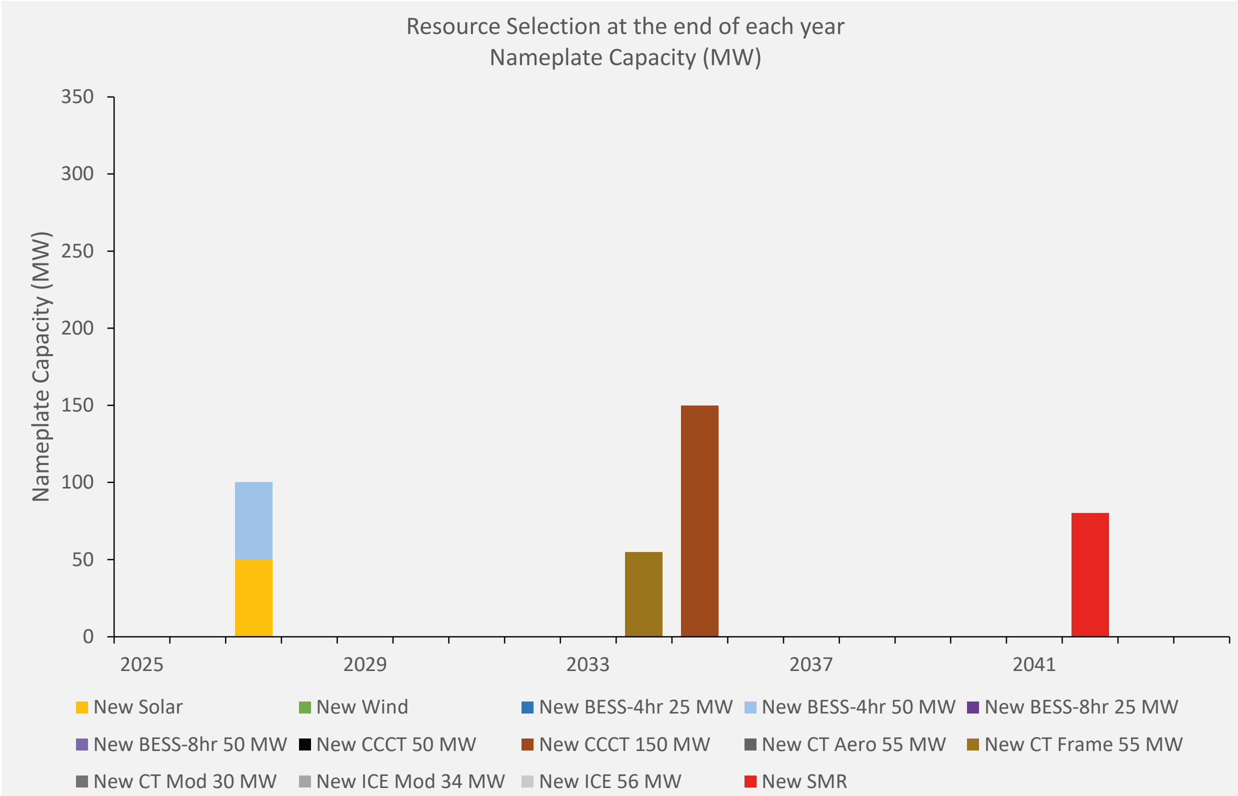
8.1.1. Base Case

The Base Case assumes the base power, natural gas, and coal price forecasts. All resources in NorthWestern's portfolio are assumed to retire at the end of their depreciable life or expire at the end of their contract term as described in Table 5.

As shown in Figure 29, the ARS results for the Base Case adds a mix of resources. The Base Case shows an addition of a 50-MW solar and a 50-MW 4-hour BESS in the 2027 time frame to mitigate a capacity shortfall in the summer season. The portfolio is then adequate up to 2034 when another addition occurs with a 55-MW CT Frame unit to mitigate a capacity shortfall in the winter season. A 150-MW CCCT unit is added at the end of 2035 as this is the last year in which NorthWestern can build a carbon-emitting resource to adhere to the Net Zero Goal. Even though this resource is added in 2035, the capacity is not needed until the early 2040s when Neal and Coyote reach their planned retirement dates. Finally, an 80-MW SMR is added in 2042 to lower the overall portfolio cost, not specifically for capacity.

As described in Section 4.3, the near-term resource additions of solar and BESS are driven by a summer capacity shortfall in 2027. This near-term capacity deficiency for the summer season that causes an early resource addition is consistent throughout many of the scenarios modeled.

Figure 29 – ARS results for the Base Case.

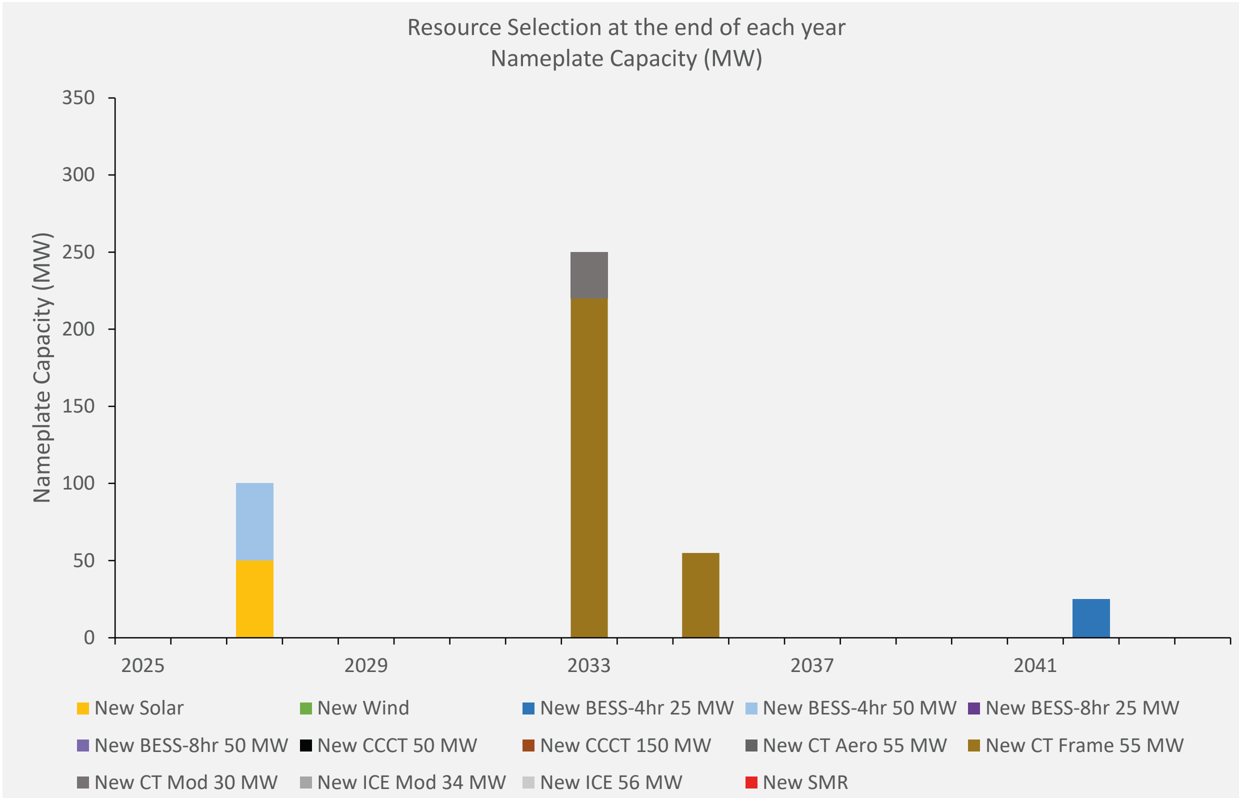


8.1.2. 2032 Coal Retirement

The 2032 Coal Retirement scenario was chosen to simulate the enforcement of the EPA's GHG regulations discussed in Chapter 5.

The ARS results for the 2032 Coal Retirement scenario are shown in Figure 30. There are early resource additions to mitigate a capacity shortfall in the summer season. The largest year of resource additions is in 2033 with four 55-MW CT Frame units and a single 30-MW modular CT as a response to the early coal retirements. Another 55-MW CT Frame unit is added in 2035 to add low-cost capacity before the Net Zero Goal goes into effect in 2036. Finally, a 25-MW BESS is added in 2042 to meet a capacity shortfall in the winter season.

FIGURE 30 – 2032 COAL RETIREMENT ARS RESULTS

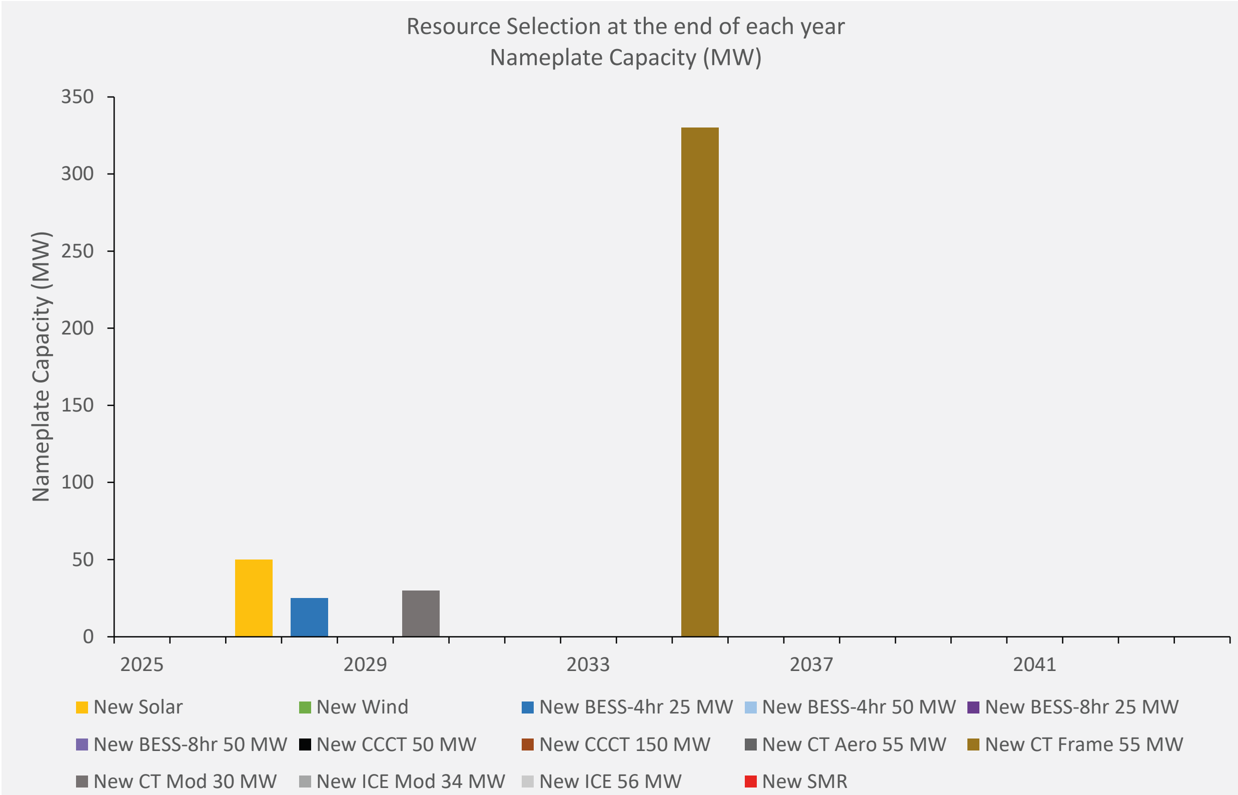


8.1.3. 2035 Coal Retirement

The 2035 Coal Retirement scenario was chosen to simulate an early retirement year in which SMRs could be installed as “Nth of kind” projects rather than “First of kind” projects that typically have higher costs.

The ARS results for the 2035 Coal Retirement scenario are shown in Figure 31. There are early resource additions to mitigate a capacity shortfall in the summer season. A 30-MW modular CT unit was added in 2030 to mitigate a capacity shortfall in the winter season. The largest year of resource additions is in 2035 with six 55-MW CT Frame units. After these additions to replace the lost capacity of the coal units, there are no more resources added as the 2035 additions are sufficient for the planning horizon.

FIGURE 31 – 2035 COAL RETIREMENT ARS RESULTS

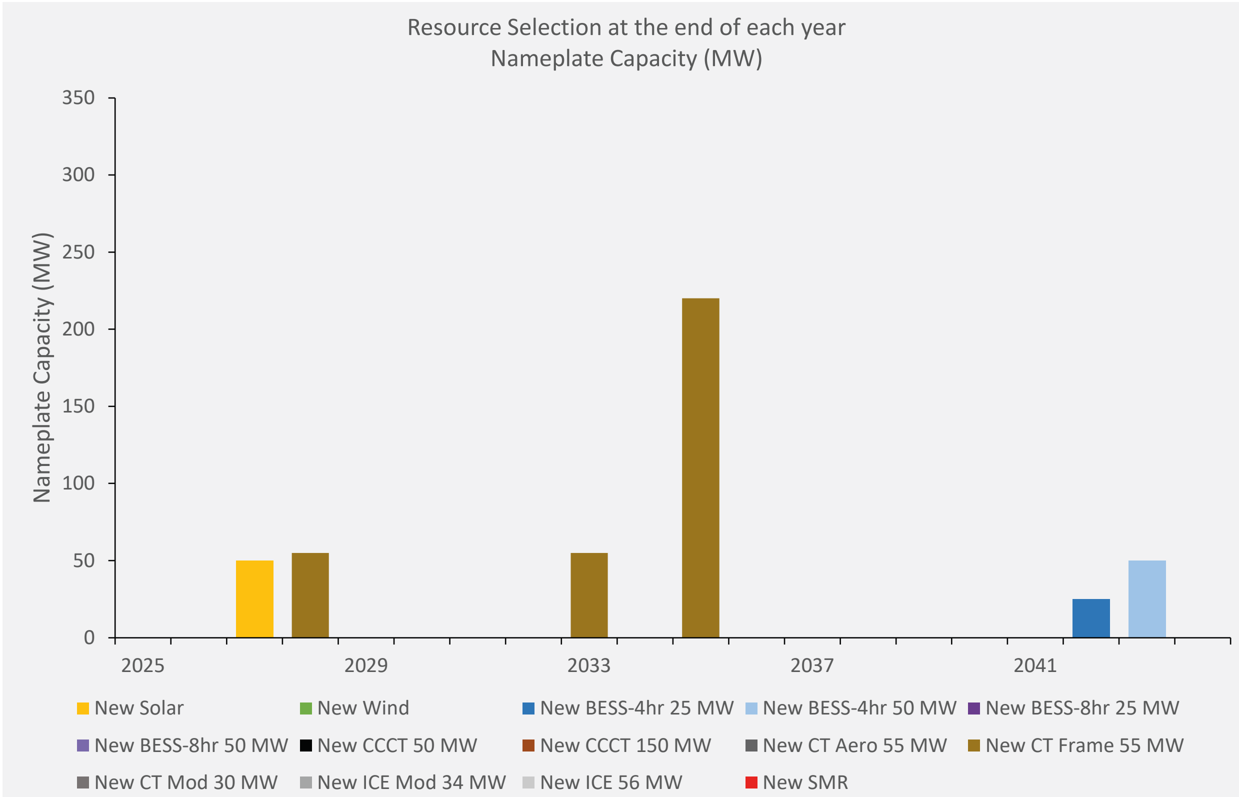


8.1.4. 2032-2035 Coal Retirement

The 2032-2035 Coal Retirement scenario was chosen to simulate an early retirement of the coal resources with Coyote being likely to retire earlier than Neal or Big Stone given Ottertail's announcement of its intent to exit Coyote sooner than NorthWestern.

The ARS results for the 2032-2035 Coal Retirement scenario are shown in Figure 32. The results are very similar to the resource additions in the 2032 Coal Retirement and the 2035 Coal Retirement scenarios. There are early resource additions to mitigate a capacity shortfall in the summer season. Then, more CT Frame units are added in 2033 and 2035 after the coal units retire. Then, BESS are added in 2042 and 2043 to mitigate a capacity shortfall in the winter seasons.

FIGURE 32 – 2032-2035 COAL RETIREMENT ARS RESULTS

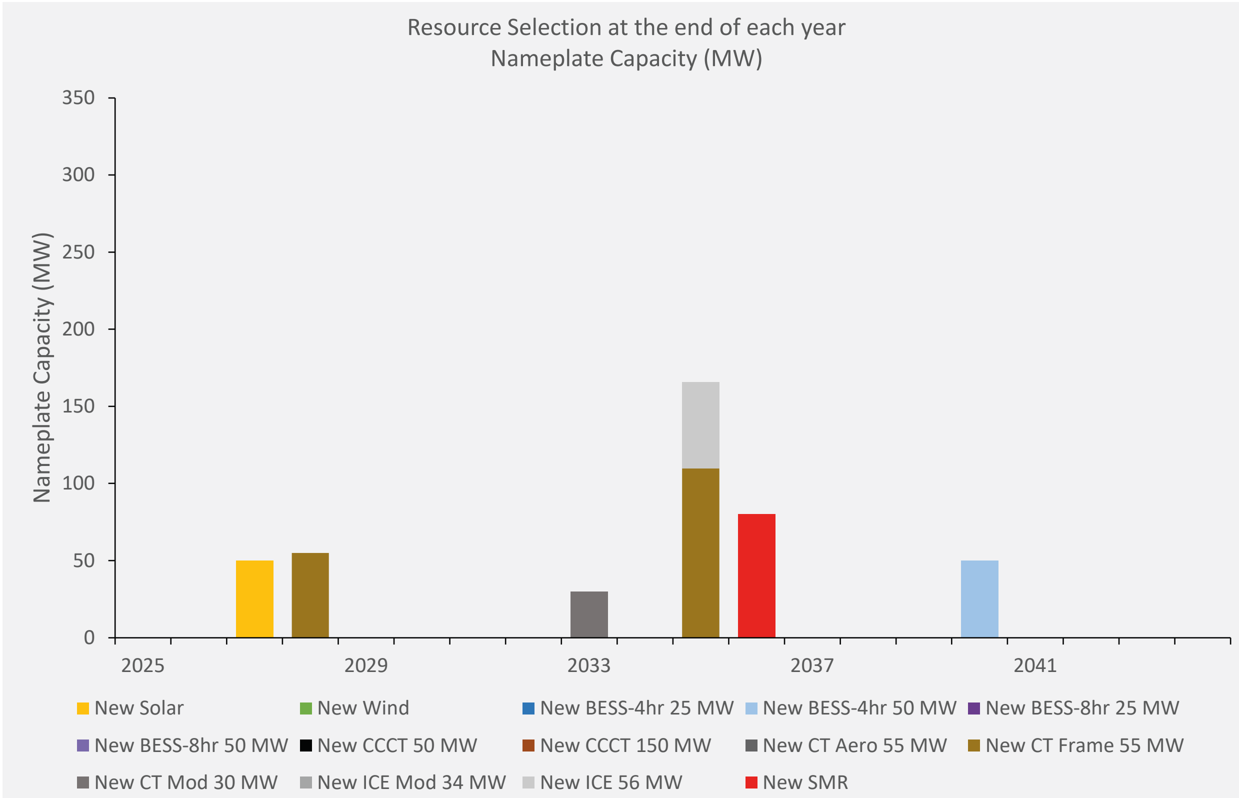


8.1.5. Nuclear Replacement Scenario

This Nuclear Replacement scenario modifies the 2035 Coal Retirement scenario by implementing an 80-MW SMR nuclear resource starting in 2036. The Nuclear Replacement scenario assumes the base power, natural gas, and coal price forecasts.

The ARS results for the Nuclear Replacement scenario are shown in Figure 33. The model has the foresight of the 80-MW SMR addition in 2036 and has added resources with that consideration. Even though the SMR is added at the beginning of 2036, there is still a capacity shortfall. To mitigate the capacity shortfall, there are two 55-MW CT Frames and a 56-MW RICE added at the end of 2035. The combination of natural gas resources and the 80-MW SMR mitigates the capacity shortfall for the midterm. A 50-MW BESS is added in 2040 to fill the capacity shortfall in the winter season.

FIGURE 33 – NUCLEAR REPLACEMENT ARS RESULTS



8.2. Carbon Free Replacement Scenarios

The Carbon Free Replacement scenario assumes an accelerated carbon free goal by modifying the 2032 and 2035 Coal Retirement scenarios to only allow carbon free resources to be selected. There are no natural gas resources modeled in the Carbon Free Replacement scenarios. The Carbon Free Replacement scenarios assume the base power, natural gas, and coal price forecasts.

The ARS results for the 2032 Coal Retirement, Carbon Free and the 2035 Coal Retirement, Carbon Free scenarios are shown in Figure 34 and Figure 35, respectively. The resources added to each portfolio are the same with SMRs making up the bulk of the lost capacity. BESS are also added to manage the high energy production of the SMRs.

FIGURE 34 – 2032 COAL RETIREMENT, CARBON FREE ARS RESULTS

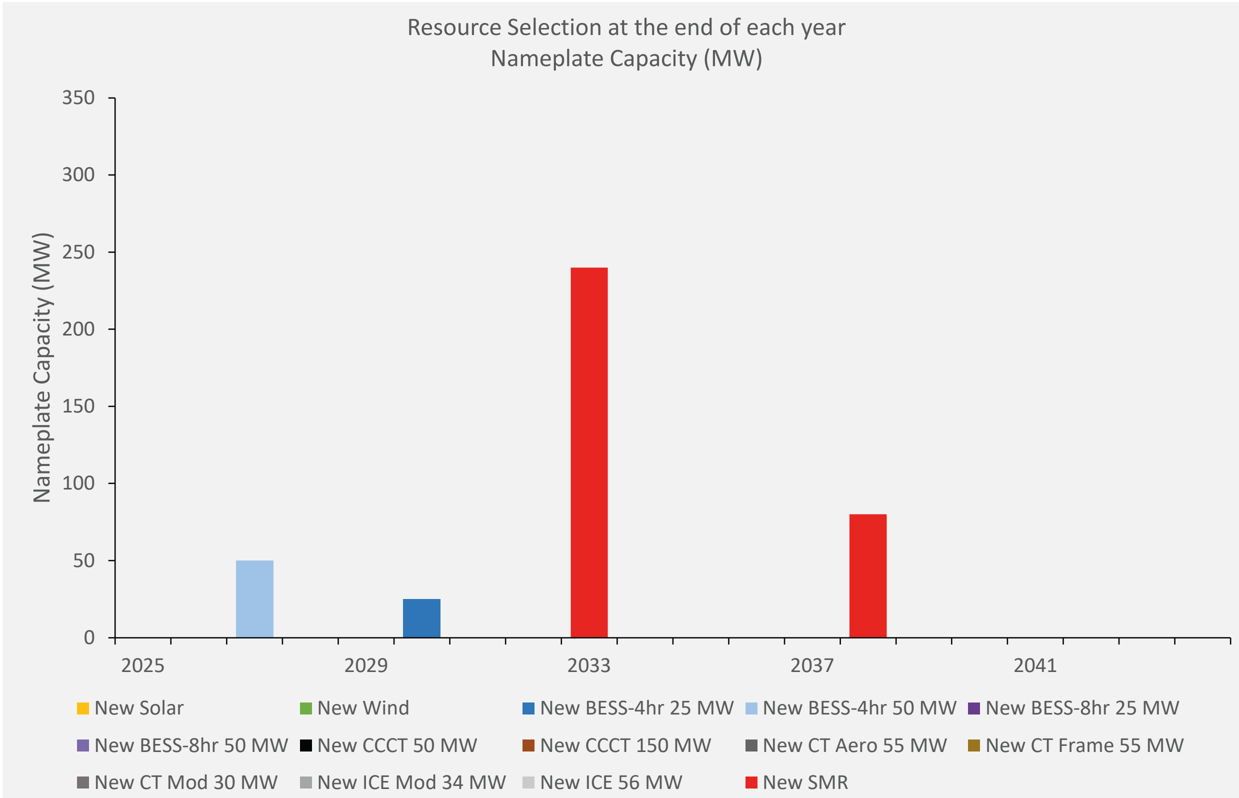
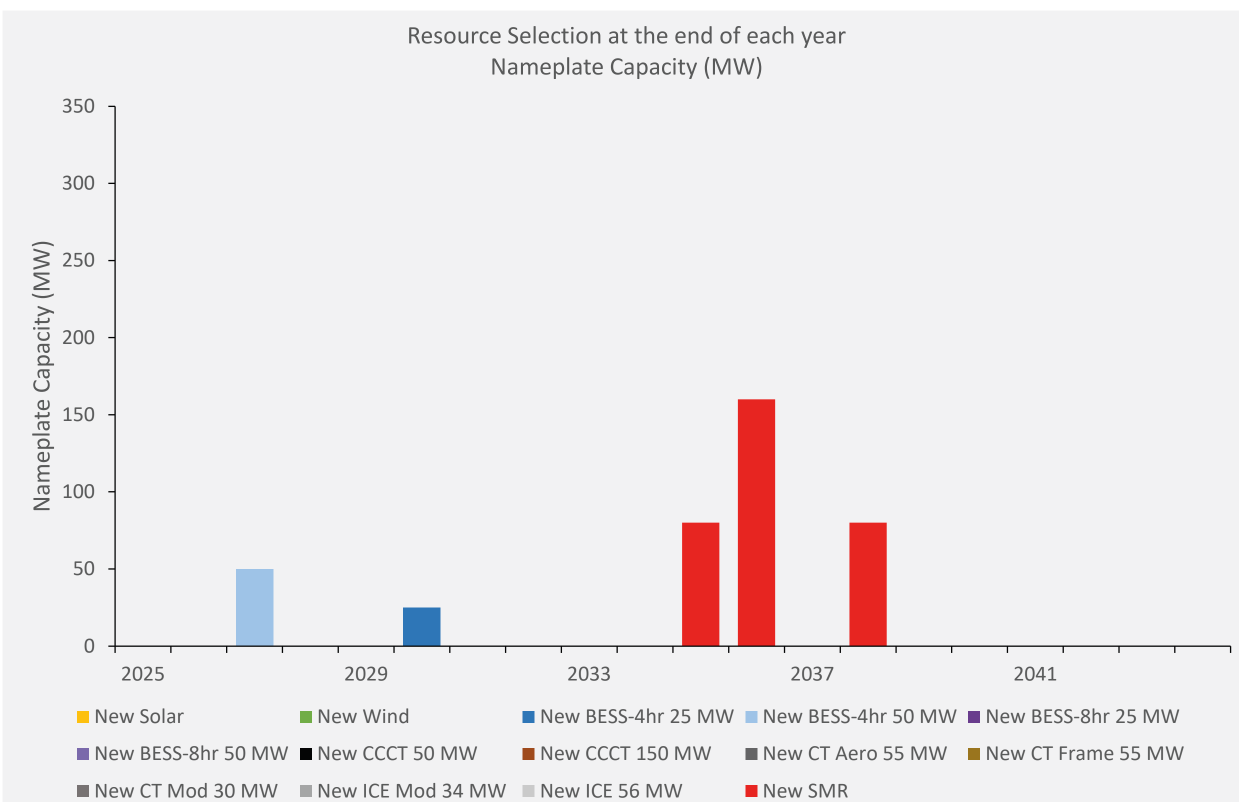


FIGURE 35: 2035 COAL RETIREMENT, CARBON FREE ARS RESULTS



8.3. Sensitivities

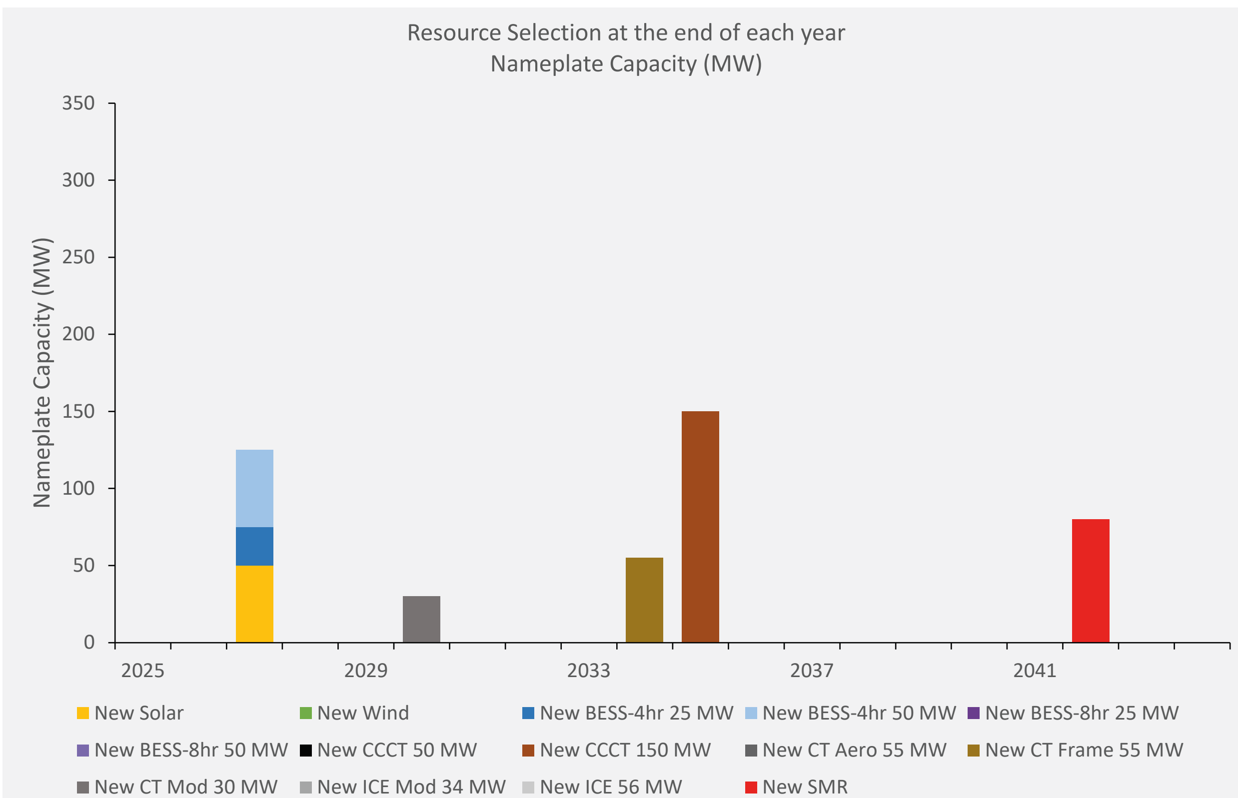
In addition to the scenarios listed above, NorthWestern considered several sensitivities to evaluate how changing model input assumptions for future conditions affects the model results. The sensitivities include

- Base Case portfolio with higher load (High Load)
- Base Case portfolio with a doubling of the power price forecast (2x Power)
- Base Case portfolio with a doubling of the gas price forecast (2x Gas)
- Base Case portfolio with a low winter PRM of 16% (Low Winter PRM)

8.3.1. High Load

The High Load sensitivity was chosen to understand how the ARS and PCM results would change with an increase in load. The ARS results for the High Load sensitivity are shown below in Figure 36. There are early resource additions to mitigate a capacity shortfall in the summer season. The large resource additions throughout the mid- and long-term planning period are required to meet the higher load plus PRM requirement for the winter seasons. Low-cost capacity is added before the Net Zero Goal goes into effect in 2036.

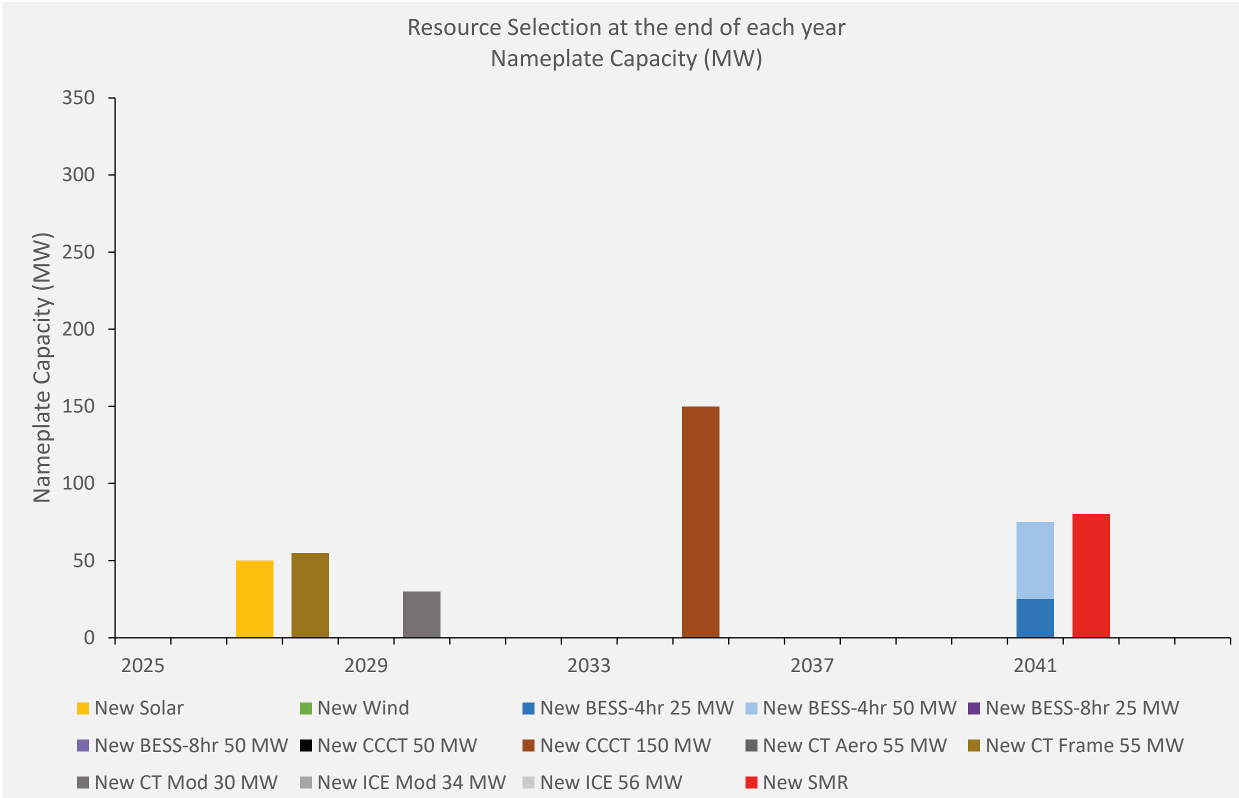
FIGURE 36 – HIGH LOAD SENSITIVITY ARS RESULTS



8.3.2. 2x Power

The 2x Power sensitivity was chosen to understand how the ARS and PCM results would change with an increase in power prices. The ARS results for the 2x Power sensitivity are shown in Figure 37. The resource additions for the 2x Power sensitivity are very similar to Base Case and the High Load resource additions. The major difference is that the 2x Power Portfolio has higher capacity factors of dispatchable resources because these dispatchable resources are responding to the large spread between the variable cost of running the unit to the market revenue generated by selling the output. This phenomenon is evident as a large increase in Market Sales as shown in Figure 44, the PCM Results for Sensitivity Scenarios.

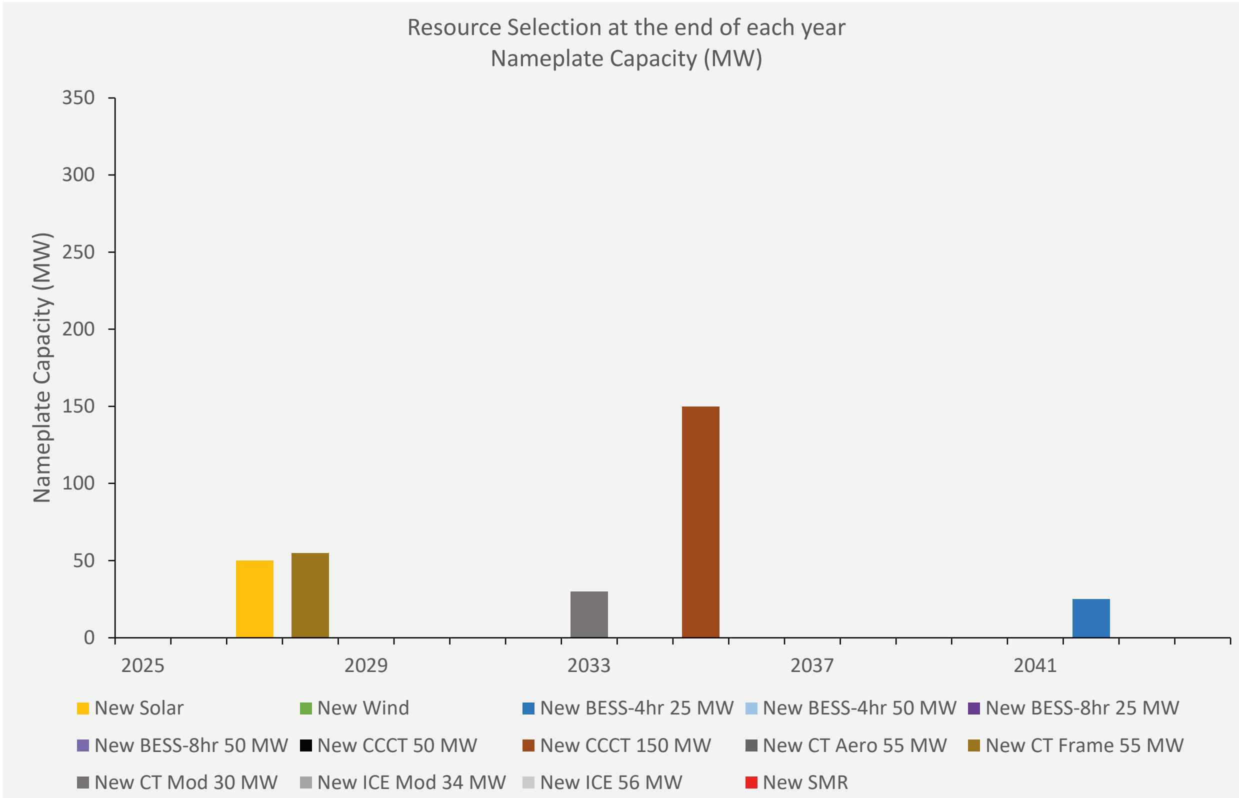
FIGURE 37 – 2X POWER SENSITIVITY ARS RESULTS



8.3.3. 2x Gas

The 2x Gas sensitivity was chosen to understand how the ARS and PCM results would change with an increase in natural gas prices. The ARS results for the 2x Gas sensitivity are shown below in Figure 38. The resource additions are not significantly different than other scenarios. The major difference is that the 2x Gas Portfolio has low capacity factors for natural gas resources due to the higher fuel cost. This phenomenon is evident as a large reduction in Market Sales as shown in Figure 44, the PCM Results for Sensitivity Scenarios.

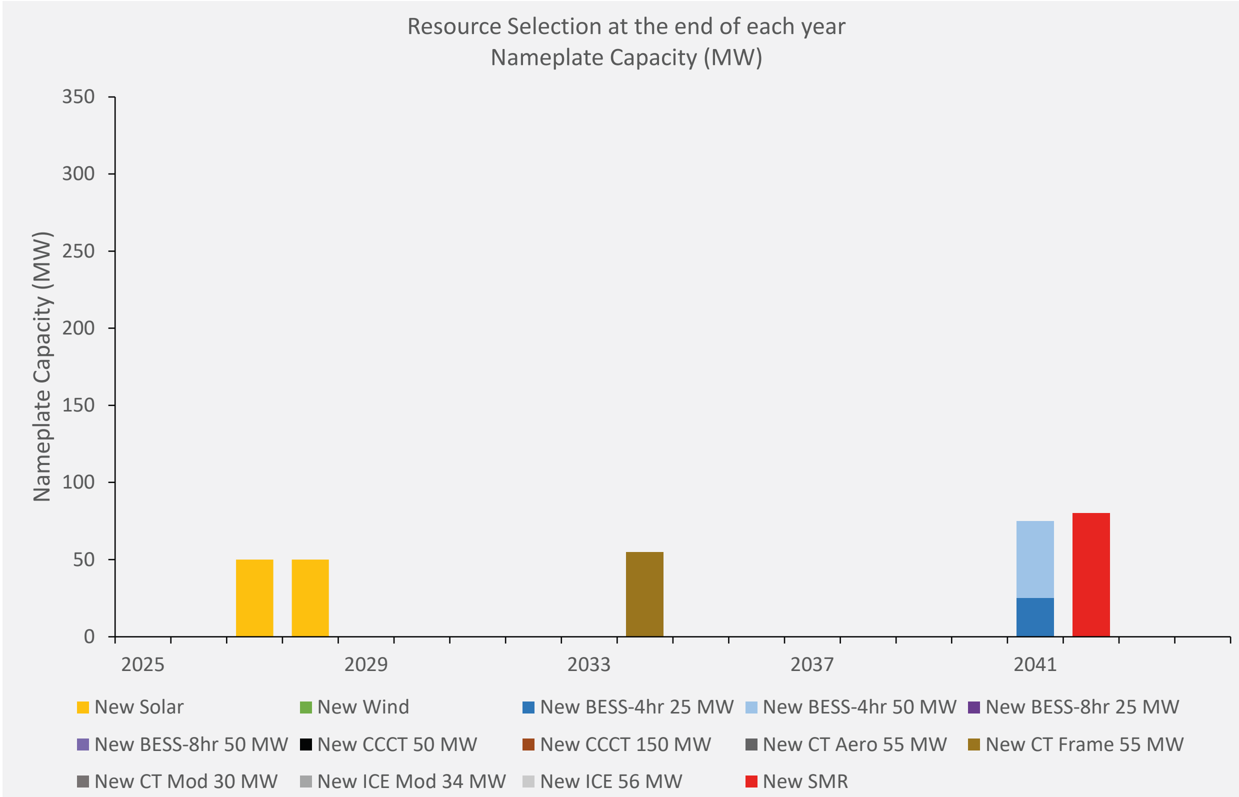
FIGURE 38 – 2X GAS SENSITIVITY ARS RESULTS



8.3.4. Low Winter PRM

The Low Winter PRM sensitivity was chosen to understand how the ARS and PCM results would change if SPP had assigned the winter PRM to 16%, consistent with the summer season PRM, rather than 36% PRM. The ARS results for the Low Winter PRM are shown in Figure 39. Because the summer load forecast is higher than the winter forecast and the summer and winter PRMs are equal in this sensitivity, all resource additions are driven by the summer capacity requirement. In this sensitivity, more solar is added in the near term to take advantage of the high summer ELCC. The mid- and long-term resource additions are needed to mitigate the capacity shortfall of the summer season.

FIGURE 39 – LOW WINTER PRM ARS RESULTS



8.4. Production Cost Results

Production Cost Modeling results represent a snapshot in time based on model inputs at the time of IRP preparation. The PCM results for each portfolio are made up of costs including Total Generation Costs, which are described above in Section 7.3.2, Existing Resource Revenue Requirements, New Resource Revenue Requirements, Market Purchases, and Market Sales as a negative cost, or offsetting revenue. The revenue requirements for Existing Resources were provided by NorthWestern's Regulatory and Finance group. The revenue requirements for New Resources were also developed by NorthWestern's Regulatory and Finance group using inputs of fixed-cost estimates of candidate resources shown in Table 11. Market Purchases are energy purchases made from the market when the cost of energy is lower than the variable cost of the Portfolio's dispatchable resources or when the Portfolio is short on energy. Market Sales are recorded as a negative cost or a positive revenue that offsets the entire portfolio cost. Market Sales are made from the market when the cost of energy is higher than the variable cost of the Portfolio's dispatchable resources or when the Portfolio is long on energy.

The total costs of each Portfolio are provided in terms of net present value (NPV) of the cost described above over the 20-year planning horizon discounted back to 2025 using a rate of 6.81%, which is the most recently approved weighted average cost of capital (WACC) for NorthWestern's SD customers. The total costs are given in terms of dollars as well as a relative percentage difference between each Portfolio and the Base Case Portfolio.

8.4.1. Primary Scenarios

The PCM results of the Base Case and Early Coal Retirement scenarios, including the SMR replacement, are shown in Figure 40. The PCM results show that an early retirement of NorthWestern's coal resources will cause an overall increase in total costs. Market purchases increase and market sales decrease in the Early Coal Retirement scenarios relative to the Base Case because the relatively low variable cost coal resources are being replaced with higher variable cost natural gas resources. This creates a condition in which energy can be purchased cheaper on the market compared to running the natural gas resources. While natural gas resources may have a higher variable cost relative to NorthWestern's coal assets, the natural gas resources are still low fixed cost resources used to mitigate capacity shortfalls. The increased total portfolio costs for the Early Coal Retirement scenarios are also due to adding new resources earlier in the planning period which causes an increase in the total revenue requirement. The Nuclear Replacement scenario results in a higher portfolio cost compared to the 2035 Coal Retirement scenario (without a specified SMR addition) due to the higher cost of SMRs compared to the CT Frame units that were the largest resource additions in the 2035 Coal Retirement scenario. The RBV of the Base Case and Early Coal Retirement scenarios, including the SMR replacement, are shown in Figure 41.

FIGURE 40 – PCM RESULTS FOR PRIMARY SCENARIOS

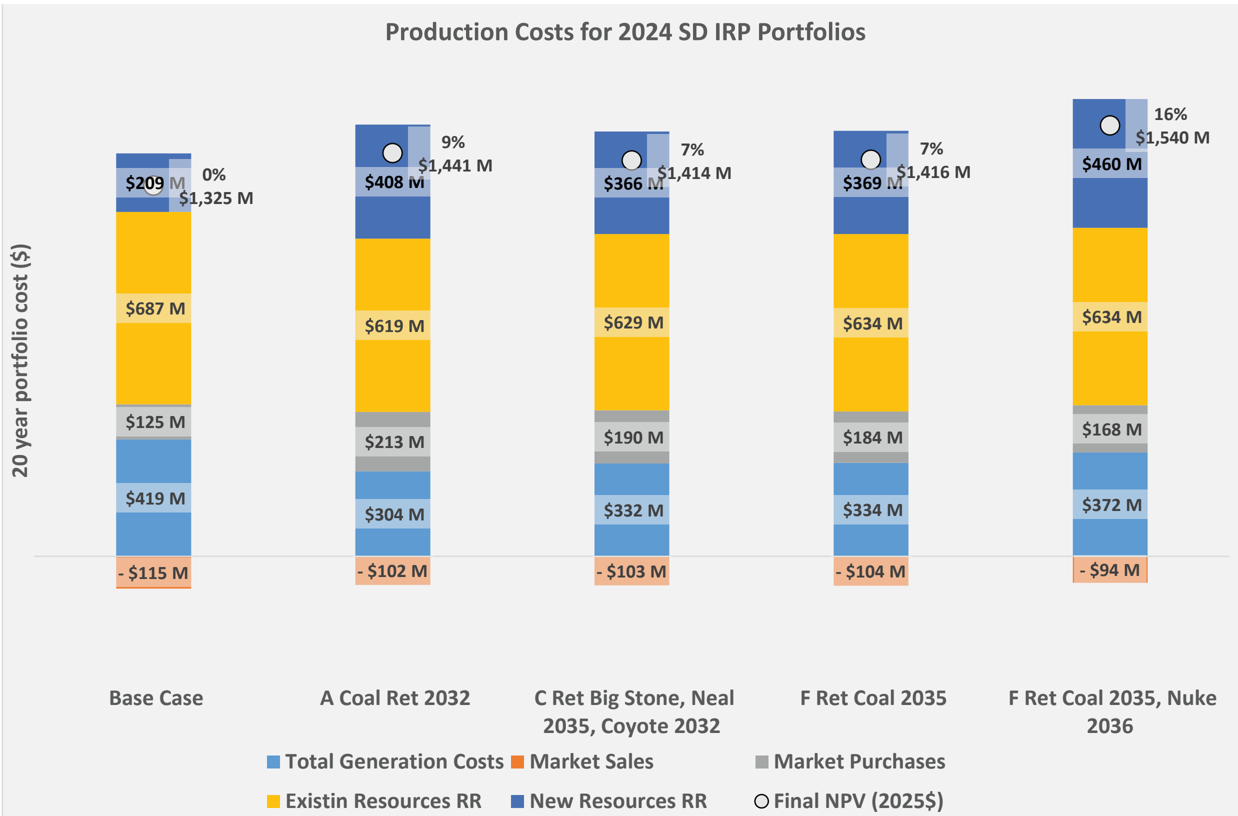
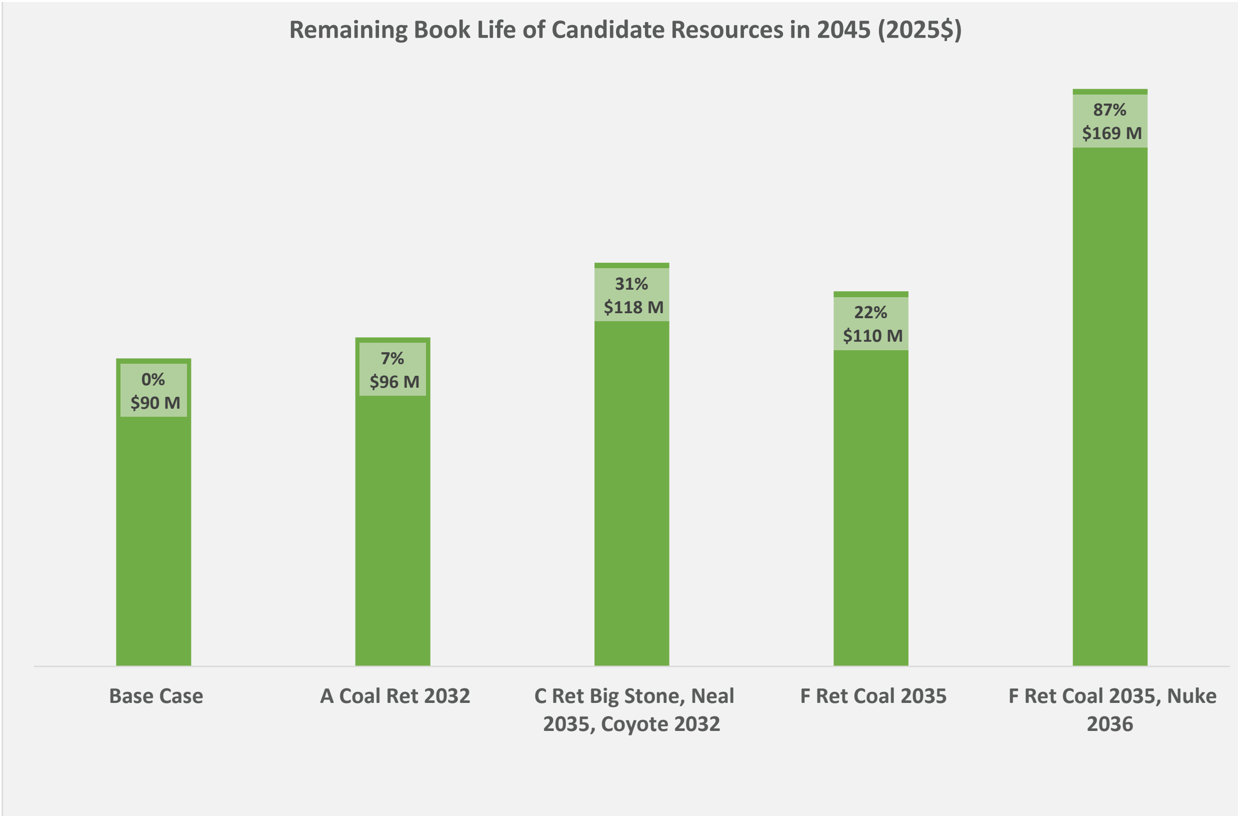


Figure 41 – Remaining Book Value for Primary Scenarios



8.4.2. Carbon Free Scenarios

The PCM results of the Base Case and Carbon Free scenarios are shown in Figure 42. The PCM results show that replacing the coal resources with only Carbon Free resources show a relatively large increase in total costs. The increased costs are due to the higher overall cost of SMRs compared to traditional natural gas resources as well as the limited amount of BESS resources that can be added to the Portfolio. The relationship of market purchases and market sales of the Carbon Free scenarios behave opposite from the Early Coal Retirement scenarios relative to the Base Case. Market purchases decrease and market sales increase in the Carbon Free scenarios relative to the Base Case because the low variable cost SMR resources are dispatched more often to take advantage of the spread between the SMR variable costs and market prices. This creates a condition in which more energy is produced from the SMR resources and less energy is purchased from the relatively more expensive market. While SMR resources may have a low variable cost relative to other dispatchable resources, the fixed costs of SMR resources are higher which causes an increase in the overall revenue requirement. The RBV of the Carbon Free scenarios is shown in Figure 43. The RBV results of the Carbon Free scenarios is different than the Primary scenarios in that the RBV of the 2035 Carbon Free scenario is lower than the RBV of the 2032 Carbon Free scenario due to the capacity cost of SMR declining at a faster rate than the discount rate used in the RBV NPV calculation.

FIGURE 42 – PCM RESULTS FOR CARBON FREE SCENARIOS

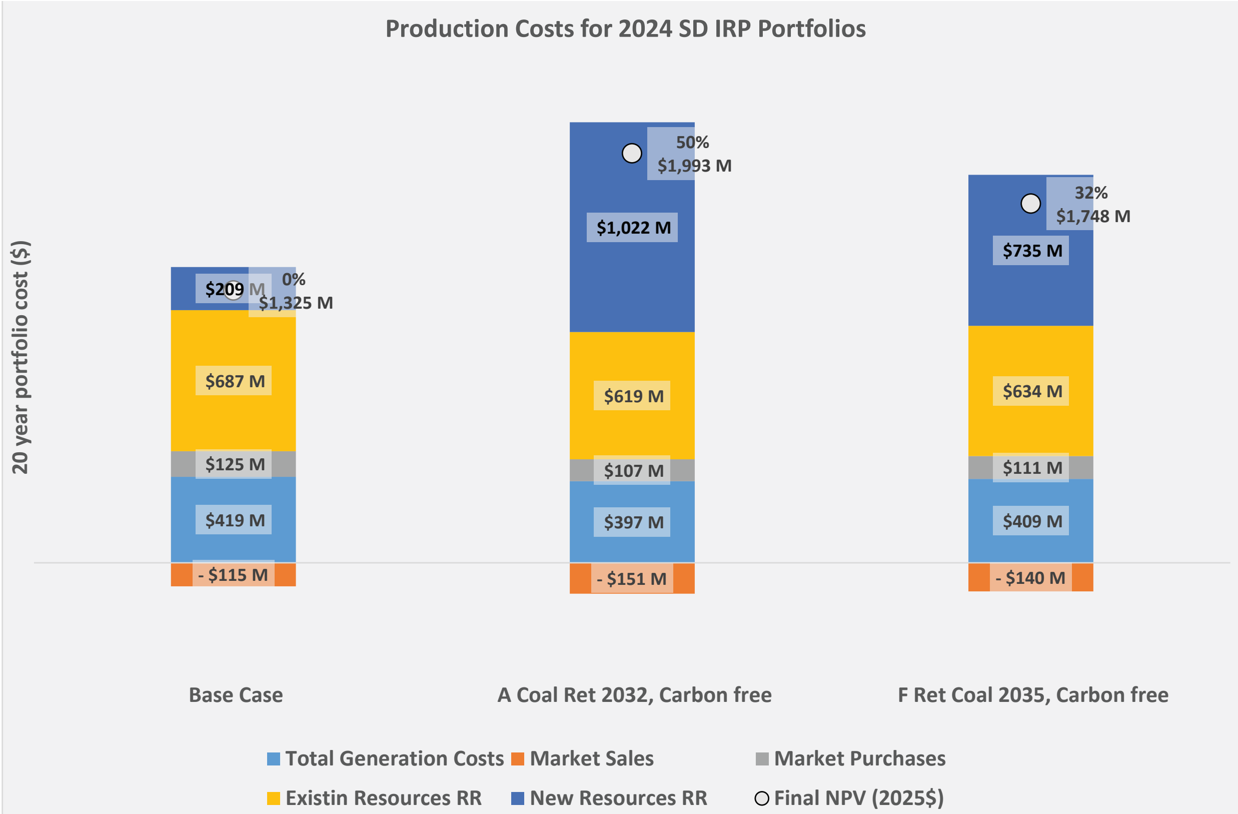
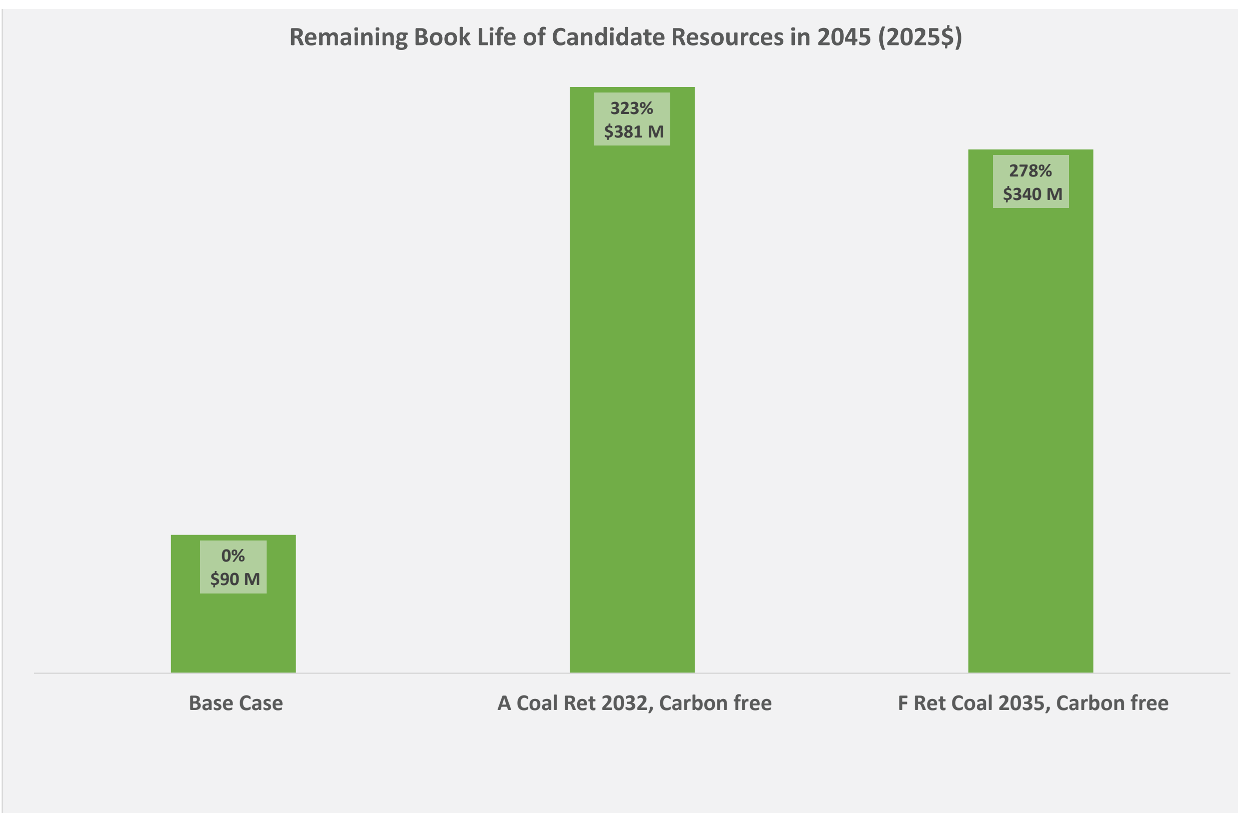


FIGURE 43 – REMAINING BOOK VALUE FOR CARBON FREE SCENARIOS



8.4.3. Sensitivities

The PCM results of the Base Case and Sensitivities are shown in Figure 44. The PCM results show that increased load growth will result in higher total costs primarily due to more resource additions. The 2x Gas sensitivity shows nearly the same total costs as the Base Case due to higher natural gas fuel costs, which results in more market purchases and less market sales relative to the Base Case. The 2x Power sensitivity shows an overall reduction in total costs due to the large amount of market sales enabled by low variable costs of the natural gas and SMR resources. The Low Winter PRM also shows an overall reduction in total costs due to fewer resource additions as a result of the smaller winter PRM. The RBV of the sensitivities are shown in Figure 45. The major standout is the relatively small RMV of the 2x Gas sensitivity. This is due to the fact that a majority of the fixed costs of newly added resources are added earlier in the planning window compared to the Base Case.

FIGURE 44 – PCM RESULTS FOR SENSITIVITY SCENARIOS

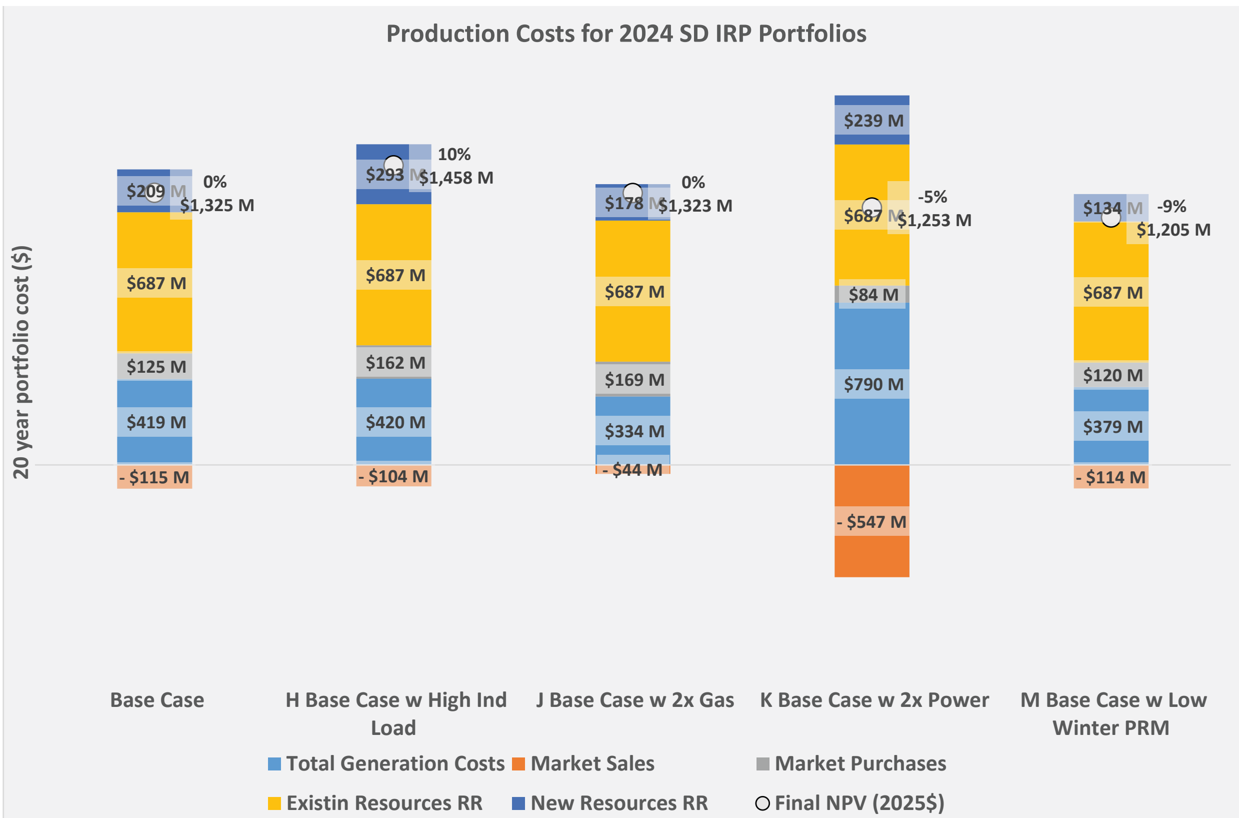
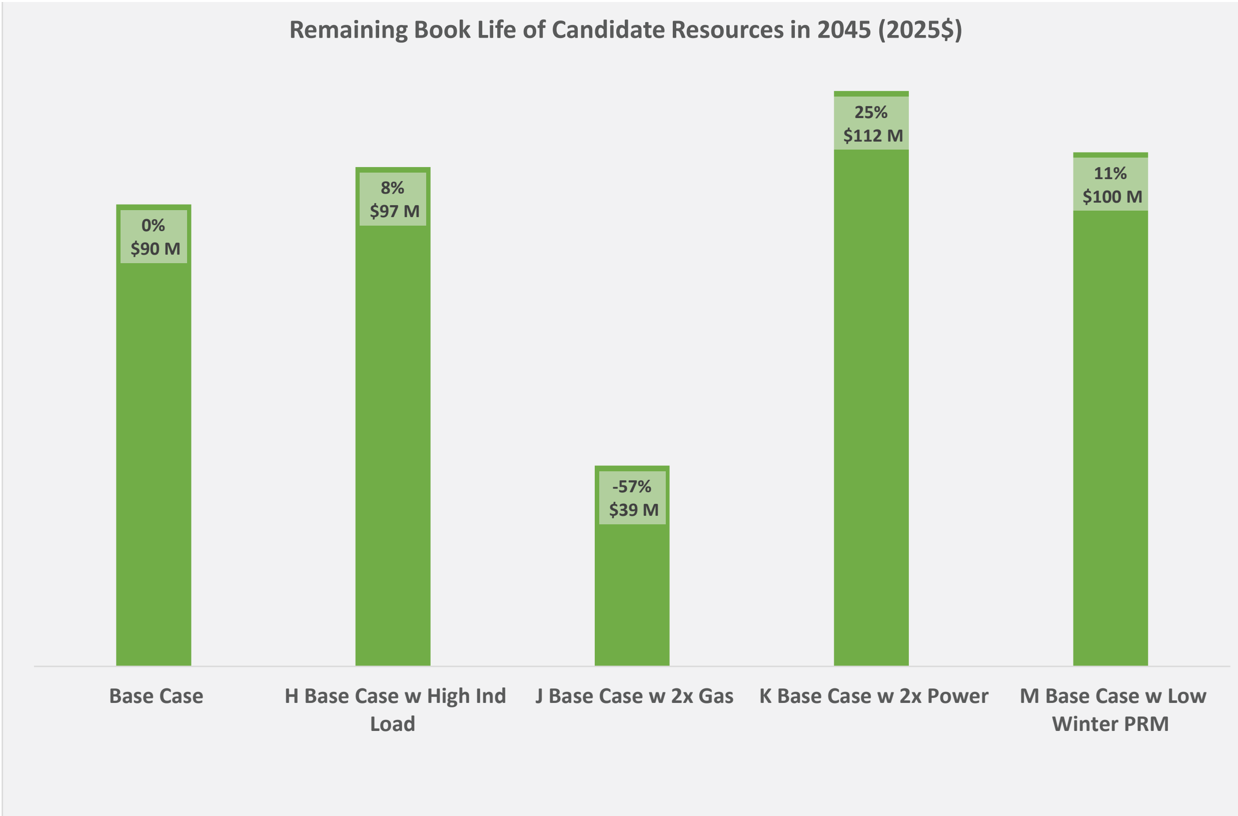


Figure 45 – Remaining Book Value for Sensitivity Scenarios



9. Action Plan

9.1. Generation Projects

9.1.1. Aberdeen 1 Replacement

NorthWestern has initiated development of 30 MW of nominal capacity at its Aberdeen Generating Station near Aberdeen, South Dakota. The Aberdeen 1 replacement is two simple cycle, single fuel natural gas combustion turbines. This new generation will replace Aberdeen 1, which is beyond its useful life, and supplements the existing Aberdeen 2. The replacement utilizes the existing Aberdeen 1 interconnection at 34.5 kV to NorthWestern's system and the existing on-site Northern Border Pipeline ("NBPL") natural gas supply. The Aberdeen 1 replacement resulted from the 2022 SD IRP and is included as an assumption in the modeling for this IRP.

The turbines will be two Solar Titan 130 gas generation sets, each rated at 13.9 MW output. With evaporative cooling the total combined output is 28.8 to 30 MW. Commercial operations are expected to commence in 2026.

9.1.2. Yankton Replacement

The Yankton facility cannot be economically restored, and it continues to be a likely candidate for retirement and replacement. NorthWestern will continue to monitor our resource adequacy position and consider alternate generation resources to replace Yankton's capacity via a potential RFP.

9.2. Transmission Projects

NorthWestern listed the following three proposed transmission projects in its 10-year plan[42] that it submitted in July 2024:

9.2.1. Faulkton Tie

NorthWestern's Faulkton load is currently served from a radial 34.5-kV line. In order to increase reliability to the area, NorthWestern is looking to interconnect with East River Electric's 69-kV line approximately 8 miles to the north.

9.2.2. Redfield Transmission Substation Rebuild

NorthWestern is currently in the process of rebuilding the Redfield Transmission substation. The existing substation currently sits in a floodplain and has experienced past flooding issues. The substation will be rebuilt out of the floodplain. In addition, there are asset life concerns with the existing substation equipment.

9.2.3. Huron West Park Rebuild

NorthWestern is planning on rebuilding the Huron West Park substation. The existing substation has several asset life and reliability concerns. Due to the configuration of the substation, a new greenfield substation will be built to address these concerns.

9.3. Long-Term Supply Action Plan

NorthWestern will continue to monitor our resource adequacy obligation for the summer and winter seasons. For any capacity shortfall that may occur, NorthWestern may fill that need through an RFP, power purchase contract, or Opportunity Resource. NorthWestern will also continue to monitor and evaluate options resulting from evolving federal rules for emitting resources.

42 https://puc.sd.gov/commission/commissionaction/10yearplan/NWE2024.pdf

10. Appendices

10.1. Appendix 1 – Acronyms

A

AERO .... Aeroderivative

Aion .... Aion Energy LLC

AMI .... Advanced Metering Infrastructure

Ascend .... Ascend Analytics

B

BART .... Best Available Retrofit Technology

BESS .... Battery Energy Storage System

Big Stone .... Big Stone Plant

C

CCR .... Coal Combustion Residuals

Coyote .... Coyote Station

CT .... Combustion Turbine

D

DEQ .... Department of Environmental Quality

E

ELCC .... Effective Load Carrying Capability

EPA .... Environmental Protection Agency

F

FERC .... Federal Energy Regulatory Commission

G

GHG .... Greenhouse Gas

BGGS .... Bob Glanzer Generating Station

H

I

IRP .... Integrated Resource Plan

ITC .... Investment Tax Credit

ITP .... Integrated Transmission Planning

J

K

L

Li-Ion .... Lithium-Ion

LOLE .... Loss of Load Expectation

LRE .... Load Responsible Entities

M

MATS .... Mercury and Air Toxics Standards

MISO .... Midcontinent Independent System Operator

MWh .... Megawatt Hours

N

Neal .... Neal Unit 4

NERC .... North American Electric Reliability Corporation

NNG .... Northern Natural Gas

NorthWestern .... NorthWestern Energy

NOX .... Nitrogen Oxides

NPC .... Net Planning Criteria

NPV .... Net Present Value

NRC .... Nuclear Regulatory Commission

NREL .... National Renewable Energy Laboratory

O

O&M .... Operation and Maintenance

P

POI .... Point of Interconnection

PPA .... Power Purchase Agreements

PRM .... Planning Reserve Margin

PTC .... Production Tax Credit

PV .... Photovoltaic

Q

QF .... Qualifying Facility

R

RECS .... Renewable Energy Credits

RFP .... Request for Proposal

RICE .... Reciprocating Internal Combustion Engine

RT .... Real Time

RTO .... Regional Transmission Organization

S

SC .... Simple Cycle

SIP .... State Implementation Plan

SMR .... Small Modular Reactor

SPP .... Southwest Power Pool

T

TU .... Transmission Using Member

TO .... Transmission Owning Member

U

UMZ .... Upper Missouri Zone

V

VER .... Variable Energy Resource

W

WAPA .... Western Area Power Administration

X

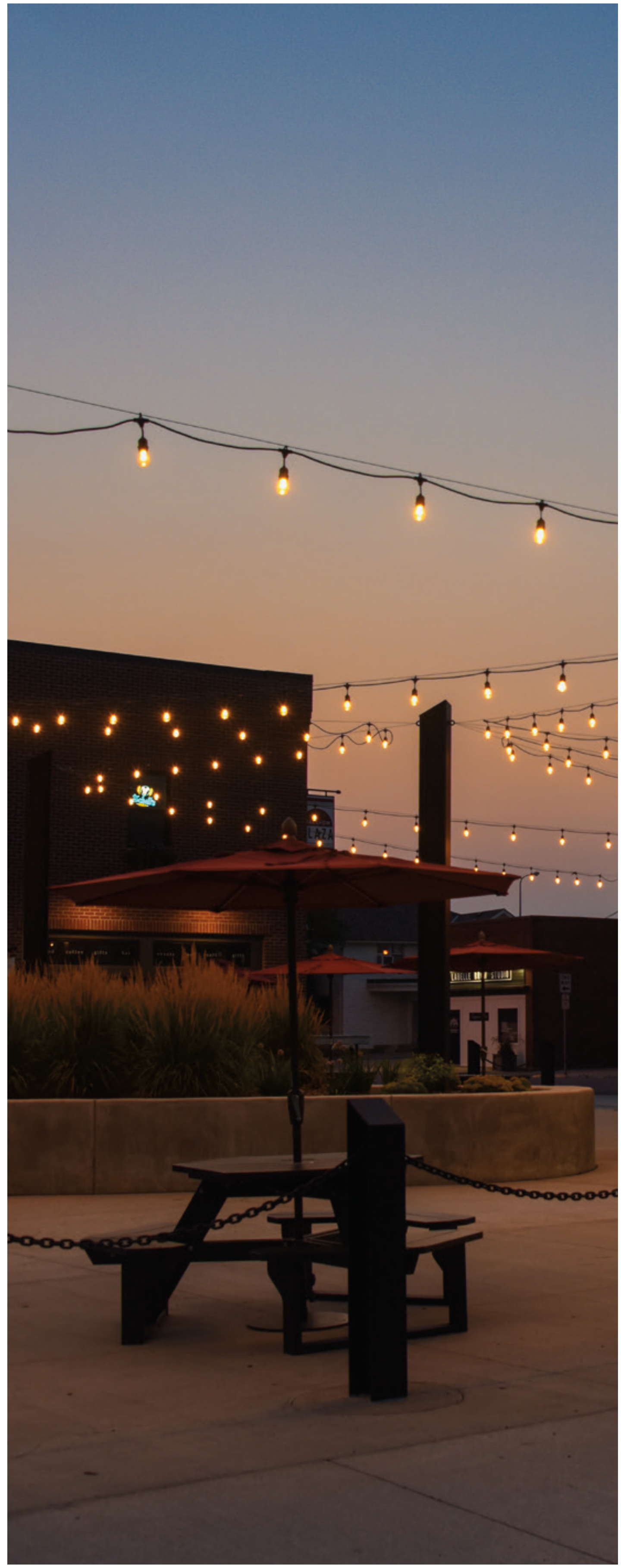
Y

YGS .... Yankton Generating Station

Z

Zone 19 .... Upper Missouri Zone

ZPC .... Zonal Planning Criteria



10.2. Appendix 2 – Glossary

A

Ancillary Services Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice. These services include, among others, Regulation and Frequency Response, Reactive Power, Contingency Reserve, incremental and decremental

Average Annual Energy The total amount of energy, measured in kWh or MWh, delivered over a period of one year divided by 8,760 hours per year.

Avoided Costs Incremental cost for energy generated or acquired from another source.

B

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

Balancing Authority Area The collection of generation, transmission, distribution infrastructure, and load-resource balance within the metered boundaries of the Balancing Authority.

C

Capacity (Nameplate capacity) The maximum power output potential a machine or system can produce or carry under specified conditions generally expressed in kW or MW; (current capacity) instantaneous measurement of power delivery; (capacity resource) expression of capability to serve load.

Capacity Factor The ratio of actual output to potential output over a period of time. Normally calculated by actual output in MWh divided by the product of nameplate capacity times 8,760 hours.

CapEx Capital expenditure reflecting the cost of a resource, a project, or the expense to repair an asset.

Contingency Reserves As defined by NERC Standard BAL-002-WECC-2a, capacity held for deployment in the event of a contingency such as a generator or transmission trip. Contingency Reserve is comprised of Spinning and Non-spinning Reserves.

D

Demand The rate of electrical use during a period of time.

Demand Response Programs used by utilities as resource options for balancing supply and demand with methods such as time-based rates, peak pricing rates, and direct load control.

Dispatchability The ability of a generating resource to deliver or adjust its output on demand.

E

F

Flexible Resource A generating plant that has the capability to handle fast start-up, bi-directional ramping, and shut-down demands.

G

H

Heat Rate The amount of thermal energy (Btus) required by a generating unit to produce 1 kWh of electrical energy, expressed in this Plan as the higher heating value heat rate.

I

Independent System Operator An independent federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and to ensure the safety and reliability of the electric system. ISOs typically include day-ahead and real-time markets for energy and ancillary services, with some including capacity markets.

Intercontinental Exchange A trading platform that helps to define markets through an electronic exchange including energy commodities and other products.

Integration (Resource use) The process of adding new generation resources and rebalancing the operations of existing resources in a portfolio to continue to meet load and other balancing authority requirements, including regulation reserves, imbalance service, and scheduling.

Interconnected (Transmission Grid use) The condition of being electrically connected and in synchronous operation with the electric transmission system operated by a BA.

Intermittent (Resource use) Not continuously available, random, or varying in output.

Inverter An electronic device that converts direct current (DC) to alternating current (AC), i.e., solar PV generation to grid-compatible power.

J

Jointly-Owned Coal Units (JOU) A coal facility owned by multiple parties. These parties may be in different states and markets.

K

L

Load The net use of electric power from the transmission and distribution system for customers or devices.

Load Following The use of on-line generation, storage, or load equipment to track the intra- and inter-hour changes in retail loads, similar to regulation, but over longer periods of time.

Loss of Load Expectation (as defined by NERC) The expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand (load). The LOLE is usually measured in days/year or hours/year. The convention is that when given in days/year, it represents a comparison between daily peak values and available generation. When given in hours/year, it represents a comparison of hourly load to available generation. LOLE is sometimes referred to as loss of load probability (LOLP). Also see LOLP.

Loss of Load Probability (as defined by NERC) The proportion (probability) of days per year, hours per year, or events per season that available generating capacity/energy is insufficient to serve the daily peak or hourly demand. This analysis is generally performed for several years into the future and the typical standard metric is the loss of load probability of one day in ten years or 0.1 day/year. Also see LOLE.

M

Must-take (Resource use) A plant that requires, by physical design or contractual agreement, that the owner or purchasing customer accept all power production as it is generated.

N

Nameplate Capacity The maximum rated generating output of a facility under specific conditions defined by the manufacturer.

NERC North American Electric Reliability Corporation is a nonprofit corporation formed by the electric utility industry to promote the reliability and adequacy of bulk power transmission in the electric utility systems of North America.

Net Present Value The present value of future cash flows at a determined rate of return, used to discount future values back to today's dollars for a cost comparison of multiple projects, for example, alternative energy supply portfolios.

Non-Spinning Reserves Also known as "Operating Reserve – Supplemental." Reserves that are not online but are capable of coming online to serve demand within 10 minutes or interruptible loads that can be removed from the system within a similar timeframe.

NREL SAM National Renewable Energy Laboratory's system advisor model for systems-based analysis of solar technology improvement.

NREL Wind Toolkit A national dataset of meteorological conditions and turbine power for over 126,000 sites across the U.S. provided by the National Renewable Energy Laboratory.

O

Off-Peak Hours Those hours defined by NAESB business practices, contracts, agreements, or guides as periods of lower electric demand.

On-Peak Hours Those hours defined by NAESB business practices, contracts, agreements, or guides as periods of higher electric demand.

Open Access Federal Energy Regulatory Commission (FERC) Order 890: provides for non-discriminatory access to jurisdictional transmission systems to all eligible customers. NorthWestern has an Open Access Transmission Tariff.

Opportunity Resource Those generation resources, either existing or new-build, which remain unknown as to their availability until an opportunity to purchase arises. Opportunity resources cannot be known or modeled ahead of time in an IRP.

Optimization Process of determining the lowest NPV utilization of resources to reliably meet energy, capacity, and ancillary needs.

P

Peak Demand The highest hourly net energy consumption for load.

Photovoltaic An electricity generation system that converts sunlight (photons) into electric current (voltage) within a semiconductor panel.

Point of Interconnection (POI) A location where two or more networks connect with one and other.

Portfolio A specified mix of actual resources or various combinations of actual and potential resources used to meet electric load demand.

Power Purchase Agreement (PPA) A contract between the utility and generation facility owner that defines the terms of the purchase and sale of energy production.

Q

Qualifying Facility A small-scale renewable power producer that meets the capacity, fuel source, and operational criteria set forth by PURPA, including all pertinent requirements of Code of Federal Regulations Title 18 Conservation of Power and Water Resources and state law corollaries.

R

Ramp Rate Speed at which a generator can increase or decrease generation, typically measured in units of MW/minute during the ramp period.

Rate-based (Resource use) A utility-owned generation resource in which the costs to purchase or build the resource are paid by the utility's customers through billed electric rates.

Real-time The balancing and marketing of electric energy in the present-time as opposed to any future time. Also referred to as 24 hours a day, seven days a week.

Regulation An ancillary service consisting of reserves that are responsive to automatic generation control and are sufficient to provide normal regulating margin..

Reliability Adequacy and security of the transmission system to operate properly under stressed conditions.

Renewable A type of energy, or resource that generates the energy, that is produced from essentially sustainable fuel, such as falling water, wind, geothermal, or solar radiation.

Reserve margin Excess generating capacity above expected peak demand normally used in recovering from contingencies (unexpected events) within the BA.

S

Spinning Reserves On-line generation that is synchronized and ready to serve additional demand within ten minutes and can sustain that change in output for a minimum of sixty minutes, and can meet other WECC requirements.

Stochastic A process in which there is inherent randomness; where the same inputs will produce a distribution of outcomes through iterative sampling of variables.

Sub-bituminous An intermediate coal with properties between lignite and bituminous coal.

T

Turbine A rotary mechanical device that converts fluid or air energy into work, such as turning a rotor to produce power.

U

Utility System The interconnected grid consisting of generation, transmission, and distribution equipment.

V

Variable Energy Resource A renewable energy source that is non-dispatchable either due to its fluctuating nature or must-take contract requirements.

Volatility The degree of variation of a market price over a period of time. High volatility indicates large price swings (either positive or negative) while low volatility indicates more stable market conditions.

W

Weighted Average Cost of Capital The rate that a company is expected to pay on average to all its security holders to finance assets. It is used to discount all costs back to present value in order to compare portfolio cash flows in the future.

X

Y

Z