


Electricity Supply Resource **Procurement Plan**

South Dakota 2018

NorthWestern Energy

Delivering a Bright Future

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CHAPTER 1
EXECUTIVE SUMMARY

Electricity Resource Procurement Plan Overview

The 2018 South Dakota Electricity Supply Resource Procurement Plan ("2018 Plan" or "Plan") evaluates NorthWestern Energy's ("NorthWestern") electric load-serving obligation and guides NorthWestern's resource procurement process in South Dakota for the next 10 years. In this Plan, NorthWestern addresses the aging South Dakota generation fleet and proposes retiring existing units and replacing them with new, modern, efficient and reliable units for the benefit of NorthWestern's customers. With the HDR Fleet Assessment completed, NorthWestern will move forward with identifying specific generation assets for retirement and replacement.

The Plan's conclusions are intended to provide guidance regarding NorthWestern's resource investments within a changing resource planning landscape. NorthWestern will maintain flexibility when implementing this Plan, and reassess its options when carrying out the actionable items identified in this Plan.

South Dakota Generation Fleet Assessment

The 2018 Plan draws from the results of a comprehensive Fleet Assessment conducted by HDR Engineering ("HDR") and is based on the latest load forecast for the South Dakota system, capacity planning reserve margin (PRM) requirements for the Southwest Power Pool (SPP), and the latest industry rules and regulations.

Maintainability was a critical factor in assessing each of the scenarios under consideration. Overall, the South Dakota fleet experiences significant durations of unavailability/forced outages based on spare parts obsolescence and lack of OEM support, primarily due to the age of the units. New unit additions would significantly improve maintainability, whether from NorthWestern staff and/or through long term service agreements.

The HDR assessment examinee a number of scenarios in which older resources are retired and replaced with new resources. Scenarios in which existing resources are retired and replaced with a large, centrally-located generation station are lower cost, but also reduce local area reliability. Scenarios involving the retirement and replacement of all existing resources at one time are less costly than scenarios that take the same actions over a longer period of time, but have greater short-term rate impacts. NorthWestern intends to pursue a staged retirement and replacement strategy that occurs over time. As a first step, NorthWestern plans to acquire and deploy four, 2 megawatt ("MW") mobile generation units in 2019. The mobile units will alleviate generation supply reliability concerns for the towns of Clark, Faulkton and other strategic locations across the SD service territory.

Generation Fleet Assessment Conclusion

The South Dakota Generation Fleet Assessment study presents a comprehensive assessment of NorthWestern's existing South Dakota fleet of generation resources. The study examines a number of scenarios in which older generation fleet assets are retired and replaced with new generation assets.

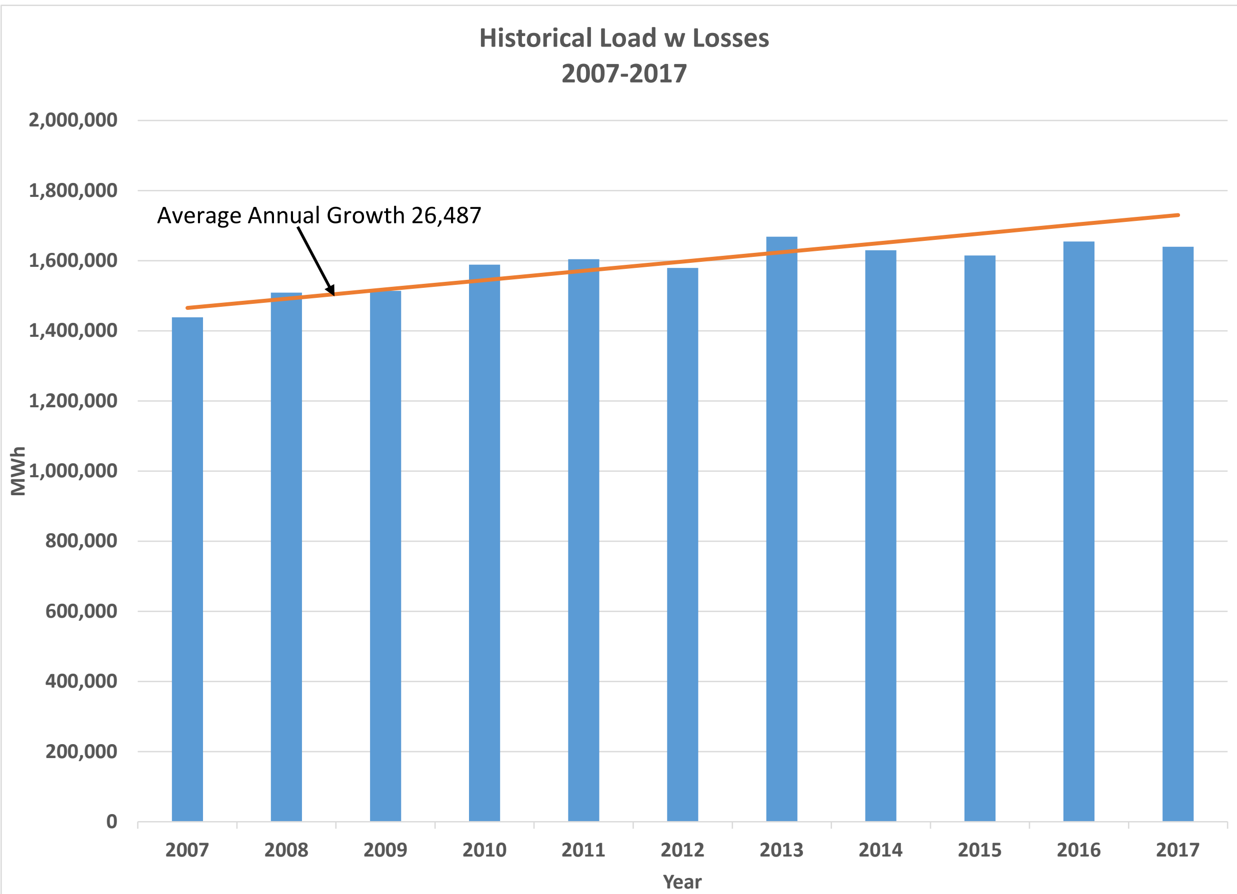
Scenarios in which existing assets are retired and replaced with large, central generation station equipment are lower cost, but NorthWestern believes maintaining and enhancing the local reliability attributes of the existing, dispersed, South Dakota fleet is of paramount importance.

Load Service Requirements

Energy

NorthWestern's system energy requirements for a 12-month period ending December 31, 2017, were around 1.639 million MWh as shown in the figure shown below. Total system energy need has grown over the last 10 years at an average rate of approximately 1.84 percent per year (or 26,487 MWh per year).

Figure 1-1. Historical Load – Retail Sales 2007 – 2017



Capacity

NorthWestern is required to maintain SPP's PRM requirement, which is a minimum generation reserve margin of 12 percent. NorthWestern satisfies the requirement using its existing generating fleet and with market purchases and/or power purchase agreements ("PPAs").

NorthWestern's average annual peak capacity needs have increased by an average of 2.6 MW since 2003. Based on its latest forecast, NorthWestern anticipates a system peak of approximately 336 MW in 2018. Since SPP's PRM requirement is currently 12 percent, NorthWestern's SPP requirement is approximately 377 MW. Currently, NorthWestern's owned and contracted resources have a combined summer peaking capacity of approximately 411 MW.

Figure 1-2 below illustrates NorthWestern's current capacity surplus and forecasted future capacity deficits. Beginning in 2019, NorthWestern anticipates needing to obtain additional capacity through market purchases or economic additions of physical generation resources in order to satisfy SPP's PRM requirement. Need for capacity is expected to increase from 5 MW in 2019 to around 9 MW in 2028. Industrial load growth is difficult to predict and can affect NorthWestern's overall load growth. The Industrial Load Growth Sensitivity in Figure 1-2 shows the need for capacity could increase from 10 MW in 2019 to around 40 MW in 2028, if industrial load growth occurs.

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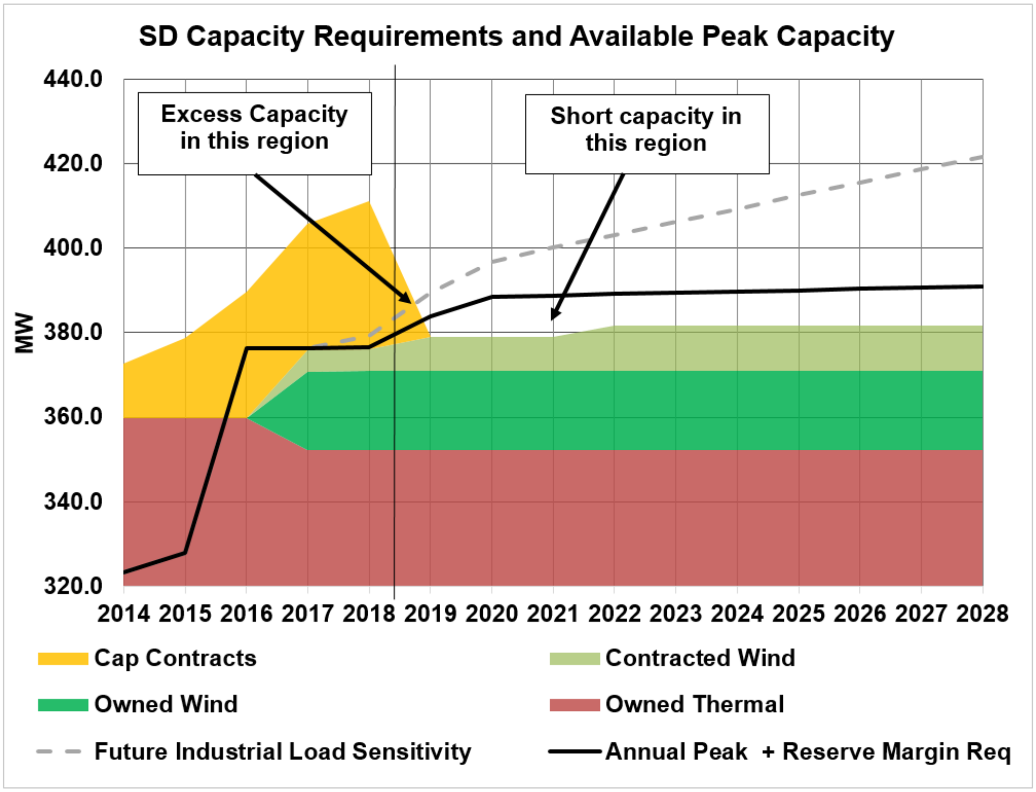
Figure 1-2. Capacity Requirements and Available Peak Capacity



Portfolio Modeling Results

Figure 1-3 shows the 10-year NPV of costs for the Base, Solar, Wind, and Li-Ion portfolios. The Base portfolio represents “business as usual” with a capacity addition in 2020 to meet Southwest Power Pool (SPP) planning reserve margin (PRM) requirements. All other portfolios are derived from the Base Portfolio.

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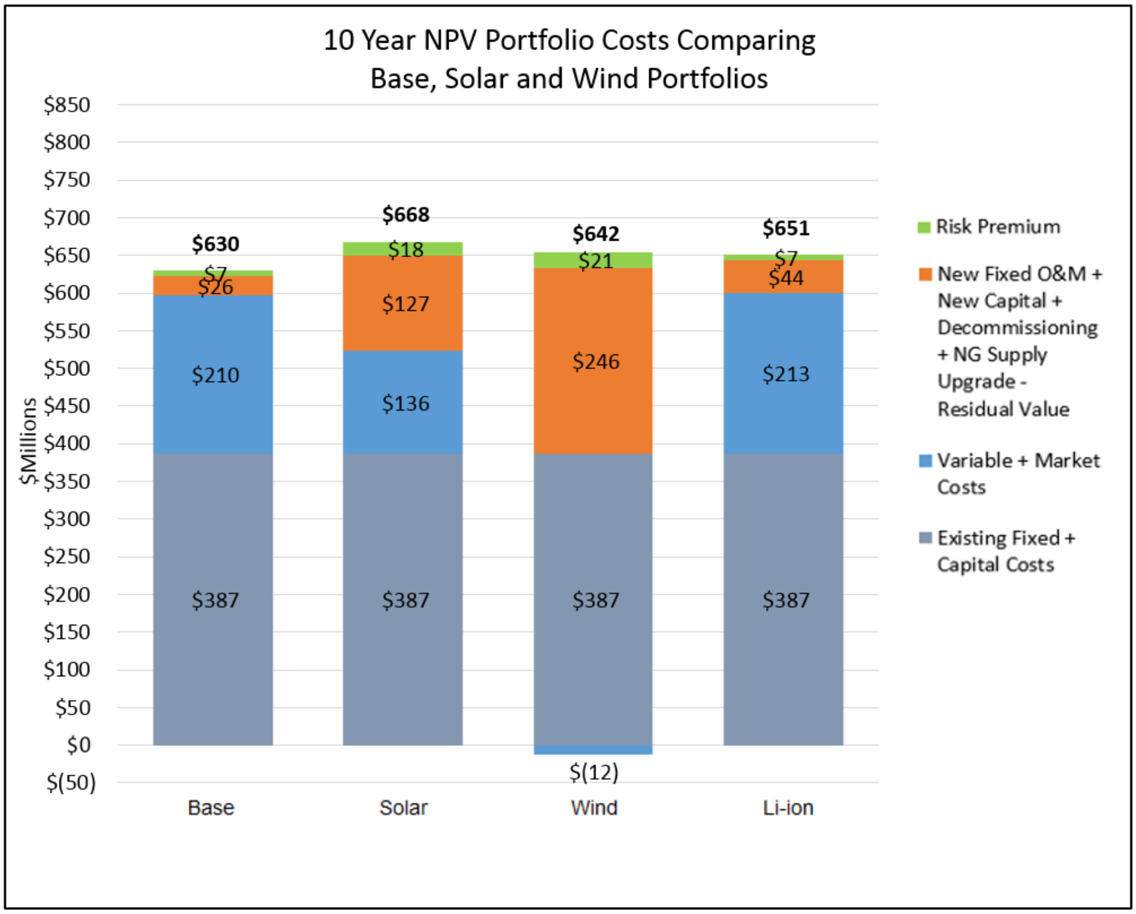
Figure 1-3. Net Present Value of Portfolio Costs
Base, Solar, Wind, and Li-Ion Portfolios



The cost category titled "Existing Fixed + Capital Costs" includes the revenue requirement of NorthWestern's existing portfolio of generation. The cost categories "Variable + Market Costs" and "Risk Premium" are calculated using PowerSimm™. The category "New Fixed O&M + New Capital + Decommissioning + NG Supply Upgrade – Residual Value" reflects the revenue requirement impacts of adding new generation to the resource portfolio and also reflects the residual value of the remaining life of the new assets beyond the 10-year planning period.

The Base portfolio has the lowest NPV costs. The resource additions in the Wind, Solar, and Li-ion portfolios match the Base and provide equivalent SPP PRM requirements, but are not viable alternatives to replace the assets considered for retirement in the Fleet Assessment. Li-Ion portfolio costs are higher than Base, but the analysis does not value the ancillary services a Li-Ion facility could provide; nor does it include the extra costs associated with providing those services.

Figure 1-4. Net Present Value of Portfolio Costs Base, Growth, and Growth & Retire Portfolios

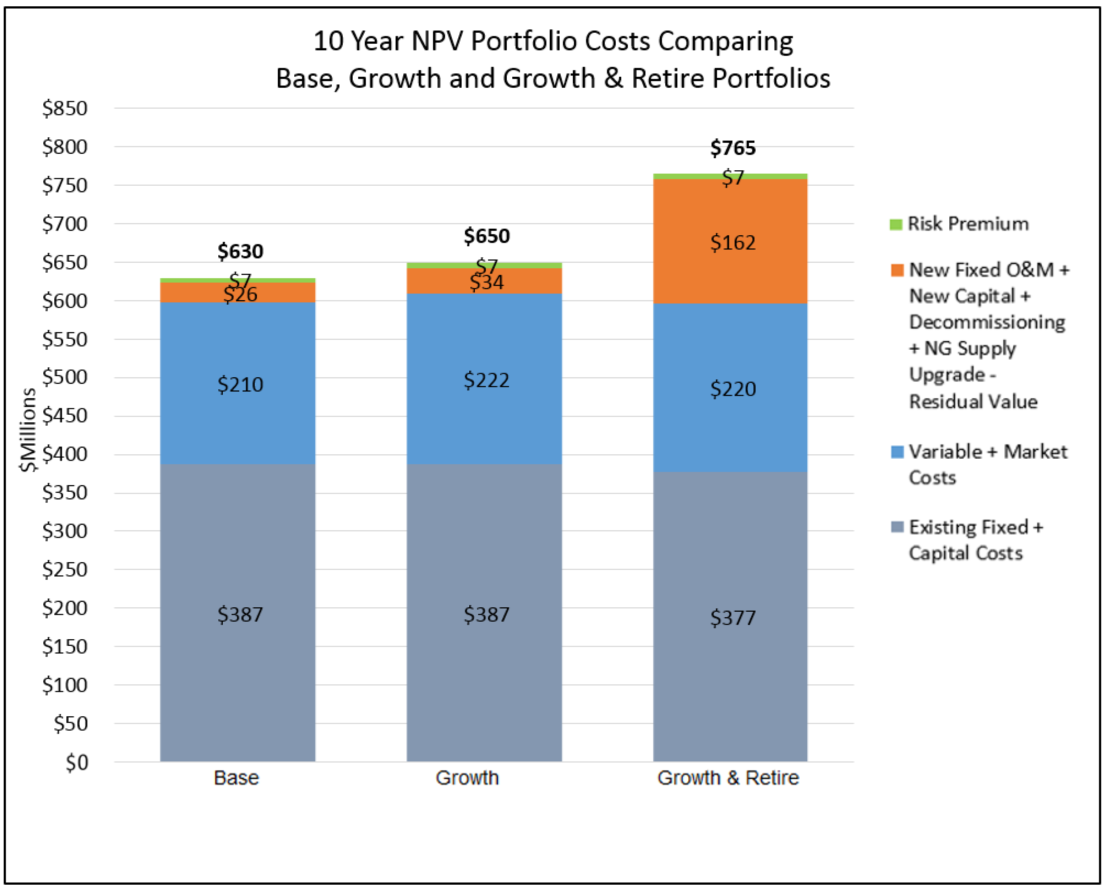


Figure 1-4 compares the 10-year NPV of costs for the Base, Growth, and Growth & Retire portfolios. The Growth portfolio includes an additional 2.5 MW/year growth in peak load, which results in a need for additional capacity. As with the Base portfolio, the Growth portfolio adds Recip units to satisfy SPP PRM requirements. The Growth portfolio serves as the “base case” for the Growth & Retire portfolio. The Growth & Retire portfolio includes additional investment to replace Aberdeen Unit 1, Huron Unit 1 and Huron Unit 2 generation facilities, and includes new assets to meet SPP PRM requirements.

Figure 1-5. Net Present Value of Portfolio Costs
Base, Retire #7 and Alt. Retire Portfolios

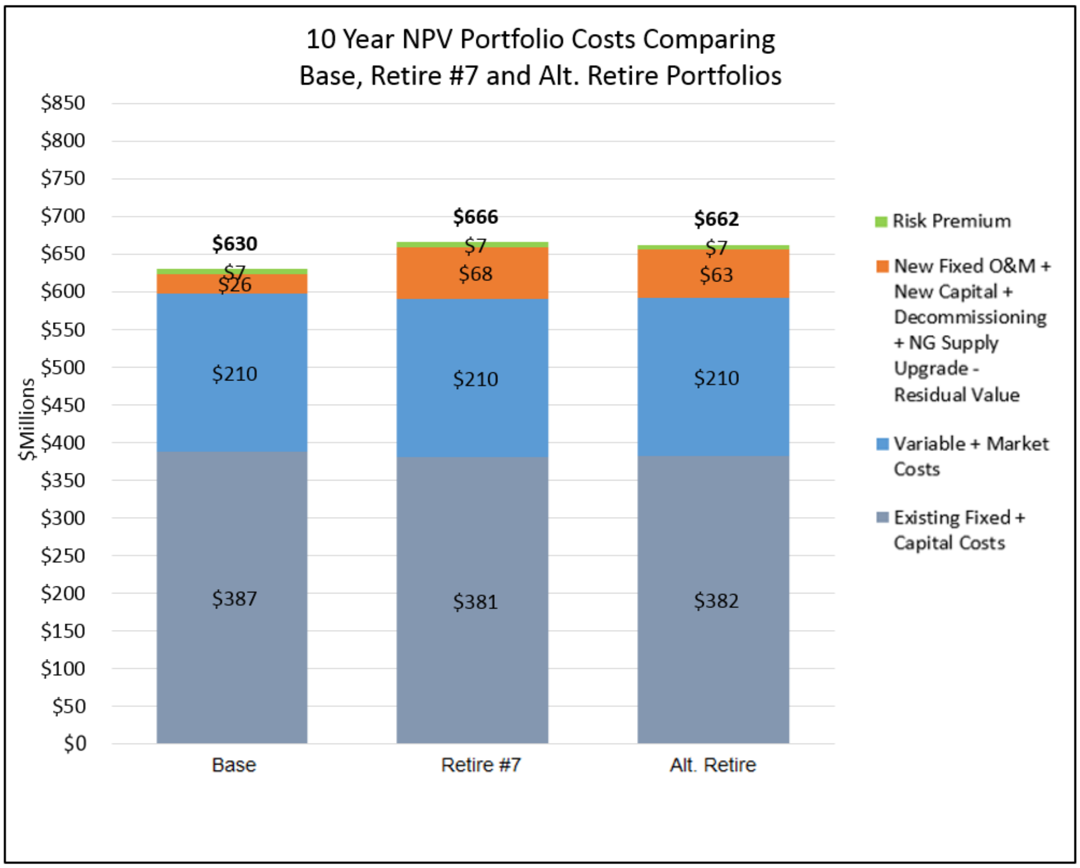
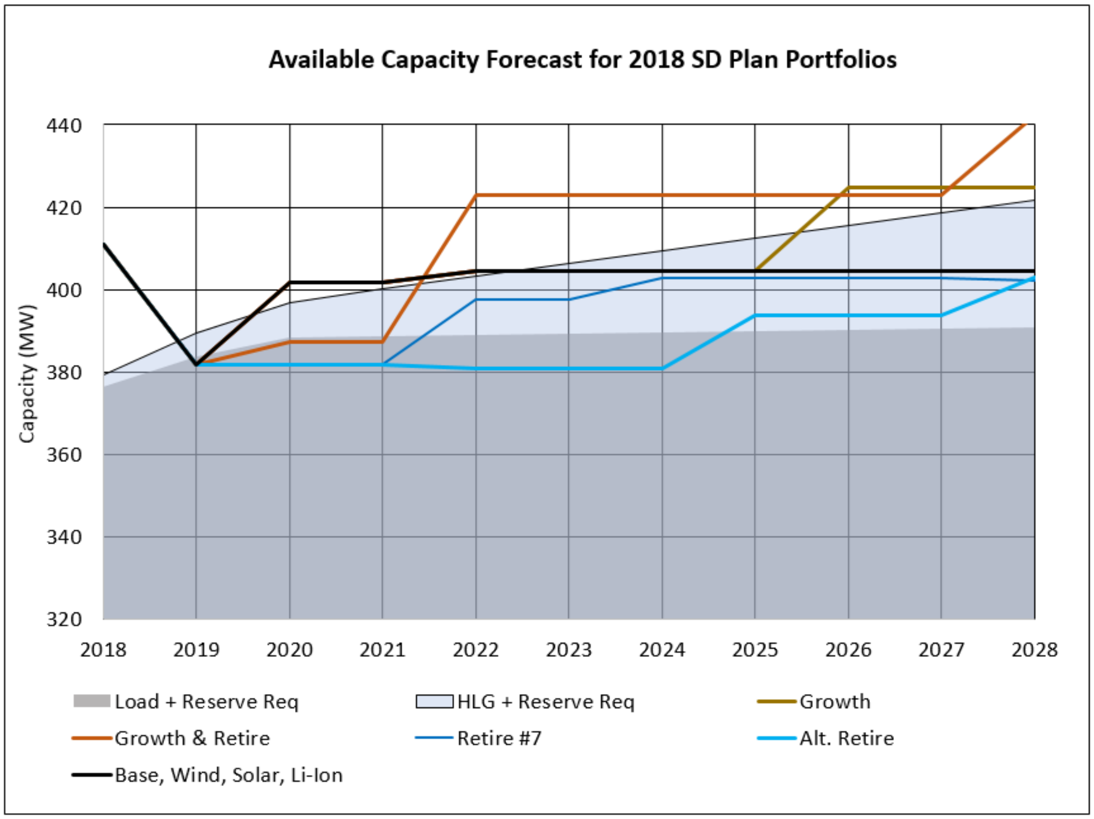


Figure 1-5 shows the results of the Base, Retire #7, and the Alt. Retire portfolios. In both retirement portfolios, rate base for existing resources is reduced to reflect the retirement of existing resources, and additional new capital costs are included to reflect additional investment. The Retire #7 and Alt. Retire portfolios are $20 million and $36 million higher than Base portfolio respectively. The retirement portfolios are higher cost, but provide NorthWestern's customers with a continued legacy of reliable local energy supply and enhance system reliability.

Figure 1-6. Available Capacity Forecast by Portfolio



The shaded areas in the Figure 1-6 represent forecasted capacity needs in the Base and Growth scenarios. Capacity positions for each of the eight portfolios modeled are illustrated by the colored lines. As discussed above, the capacity additions in the Base, Wind, Solar and Li-Ion portfolios align perfectly, as each portfolio adds 20 MW of capacity to the portfolio in 2020.

Conclusion

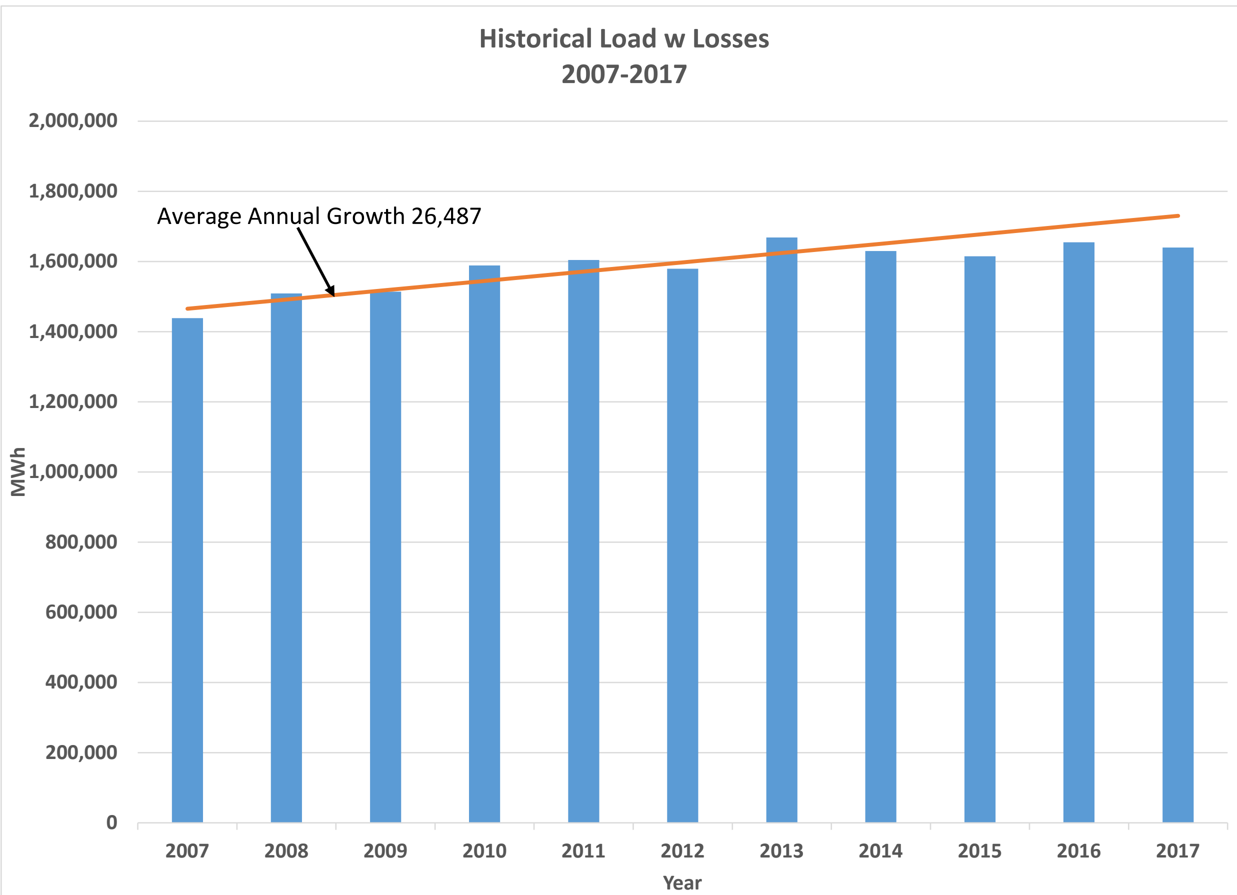
Maintaining and enhancing local reliability and grid support remains a high priority for NorthWestern. Additionally, capacity continues to be of concern and NorthWestern will continue to evaluate its capacity needs and the best means to meet those needs. With those goals in mind, NorthWestern will pursue courses of action which maintain or improve local area reliability, maintain or improve grid reliability, provide opportunities for economic growth in South Dakota, and provide economic value for NorthWestern's customers.

CHAPTER 2
FORECASTS

Historic Growth of Energy

NorthWestern's total system load has grown over the last 10 years at an average rate of 26,487 MWh per year. System energy requirements for calendar year 2017 were around 1.64 million MWh, as shown in Figure 2-1 below.

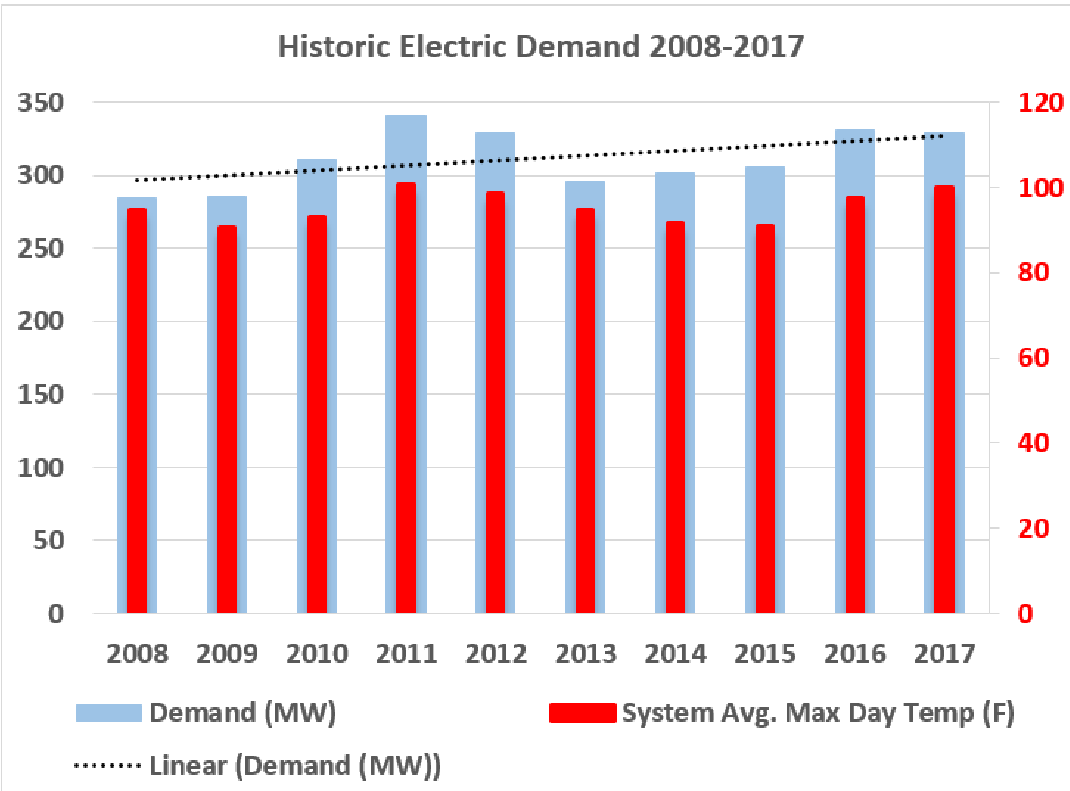
Figure 2-1. Historical Load – Retail Sales 2007 – 2017



Historic Growth of Capacity Demand

NorthWestern has also experienced continued growth in capacity demand, or peak loads, over the past 10 years as shown in Figure 2-2 below. During this period, summer peak loads have grown about 4.5 MW per year. Although year-to-year weather-dependent peaks vary, the overall growth has been fairly consistent as illustrated in Figure 2-2 below. Figure 2-2 also shows the system average maximum temperature on the peak load day.

Figure 2-2. Historical Electric Demand (Capacity) 2008-2017



NorthWestern's electric service territory is characterized by predominantly residential and small commercial customers with a small number of light-industrial and large-industrial customers. This type of retail customer class has a high demand for space heating and cooling relative to their base load requirements. As a result, the system annual load profile has significant seasonal variation, with maximum demands occurring during winter and summer extreme temperature periods. Average annual load factors are typically in the 50% to 60% range.

During the last 10 years, the highest summer peak load occurred on August 1, 2011. This system peak load of 341 MW occurred during a period of extreme high ambient temperatures, with a system-averaged maximum daily temperature of 100.5 degrees Fahrenheit ("°F"). The normal average temperature for NorthWestern's peak loads is typically under 100°F. As the NorthWestern load continues to grow, the peak usage will also continue to grow and be affected by sustained extreme warm temperatures. Winter peak loads shown in Table 2-1 below remain below summer peak loads, but in recent years winter peak loads have been growing faster than summer peak loads.

Table 2-1. Historical Yearly Winter Peak Load

Year	Peak MW	Day
2017	298	Wednesday, December 27, 2017
2016	290	Thursday, December 15, 2016
2015	301	Tuesday, January 13, 2015
2014	286	Monday, January 06, 2014
2013	265	Monday, December 23, 2013

Load Forecasting

NorthWestern has been able to meet much of the energy and capacity needs of its customers over the last several years with owned resources. NorthWestern supplements energy with spot market purchases from SPP and capacity with short-term capacity agreements. Continued growth in energy and capacity demand and the aging fleet of capacity resources led NorthWestern to propose the changes to its portfolio to meet customer needs.

Energy

The historical energy load average annual growth remains relatively steady at approximately 26,487 MWh per year. Growth continues to be observed in new residential construction with a steady interest from the commercial sector as with the Dakota Access Pipeline and Ag Processing Inc. within NorthWestern's service region. Forecast system energy requirements for 2027 are expected to be near 1.8 million MWh as shown in Figure 2-3 below. However, unforeseen increases in industrial activity or energy conservation within NorthWestern's service territory could significantly affect future energy requirements.

Figure 2-3. Historical and Forecast System Load

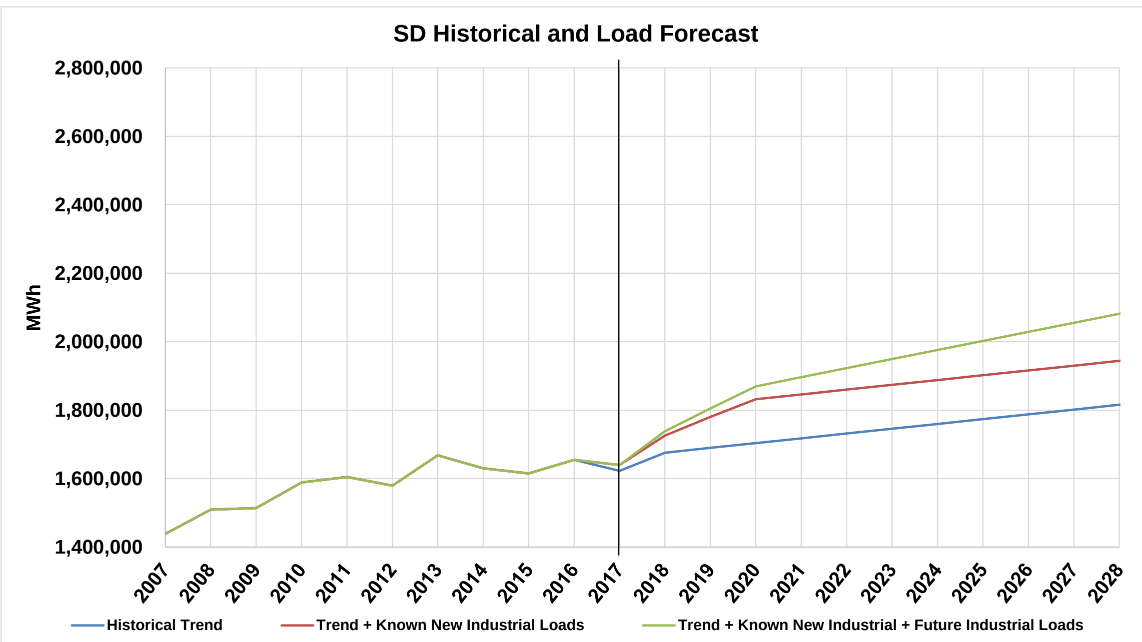


Figure 2-4 shows the type of resources that provided energy for NorthWestern's load during 2017. Intermittent wind provided 29% of the supply for the portfolio in 2017, reducing coal-fired generation and market purchases. SPP economically dispatches all of NorthWestern's registered resources.

Figure 2-4. 2017 Actual Energy Resource Mix

Figure 2-5 below details the resources that are used to serve NorthWestern's load requirements in around-the-clock ("ATC") hours as modeled in the PowerSimm™ software. The combination of economically dispatched thermal units and Company-owned and contracted for renewable resources leaves NorthWestern in a long position for most hours in the near term.

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Figure 2-5. NorthWestern Supply Portfolio Monthly
ATC Resource Stack Base Case

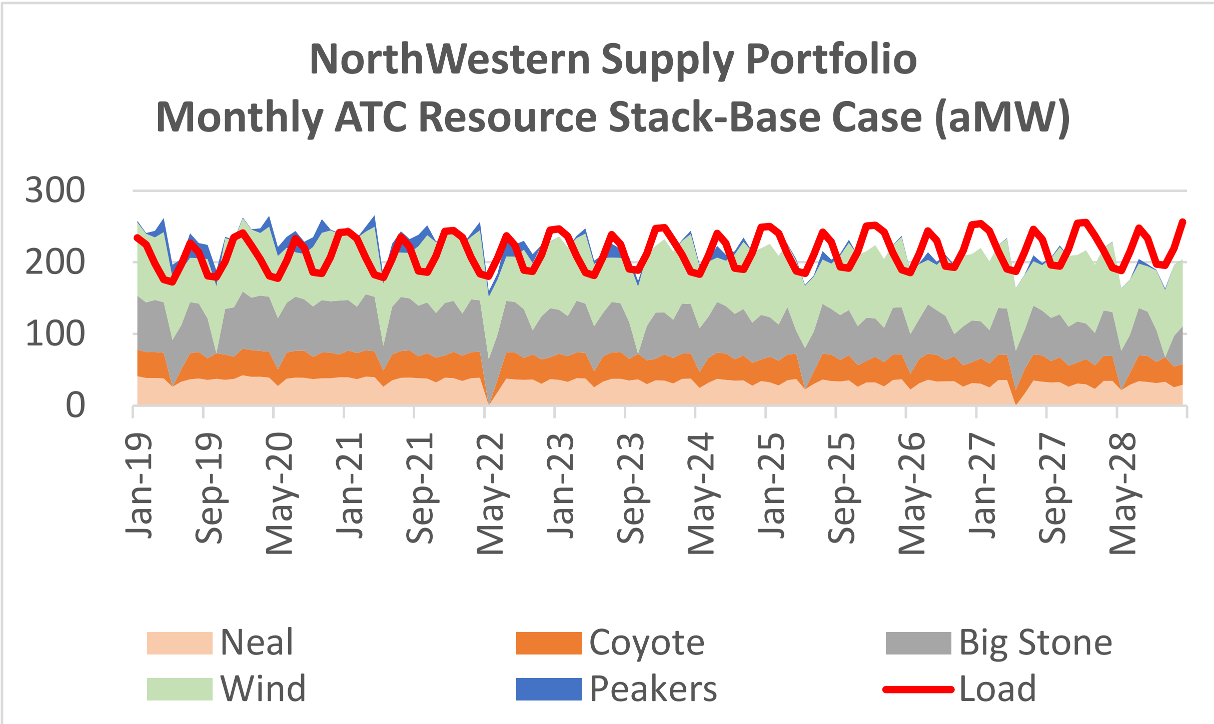

Figure 2-6 portrays the forecasted market sales and purchases over the next 10 years. The effects of increased NorthWestern load with renewables and lower economic dispatch of thermal units due to depressed market prices, leave NorthWestern with a declining levels of market purchases and sales through 2029.

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Figure 2-6. Monthly ATC Market Purchases & Sales (MWh)

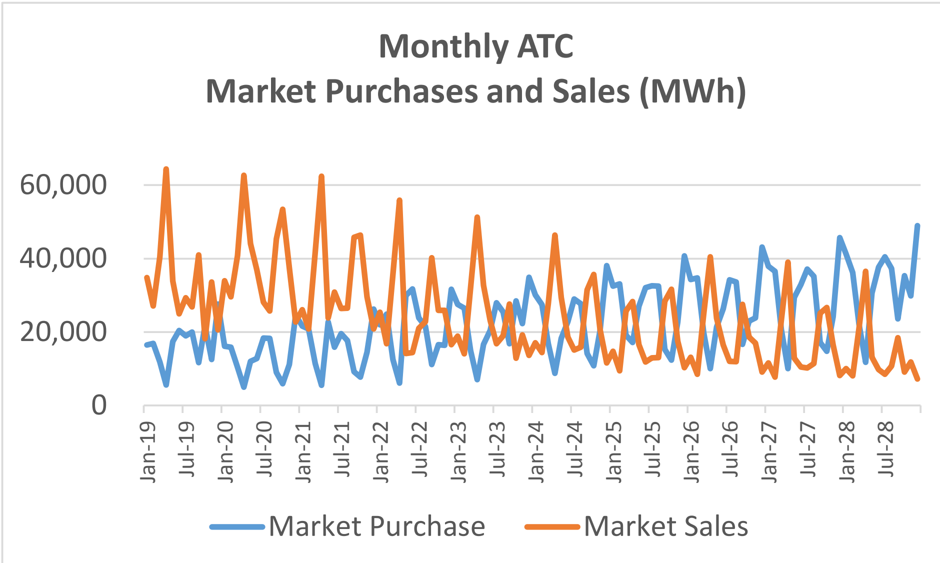
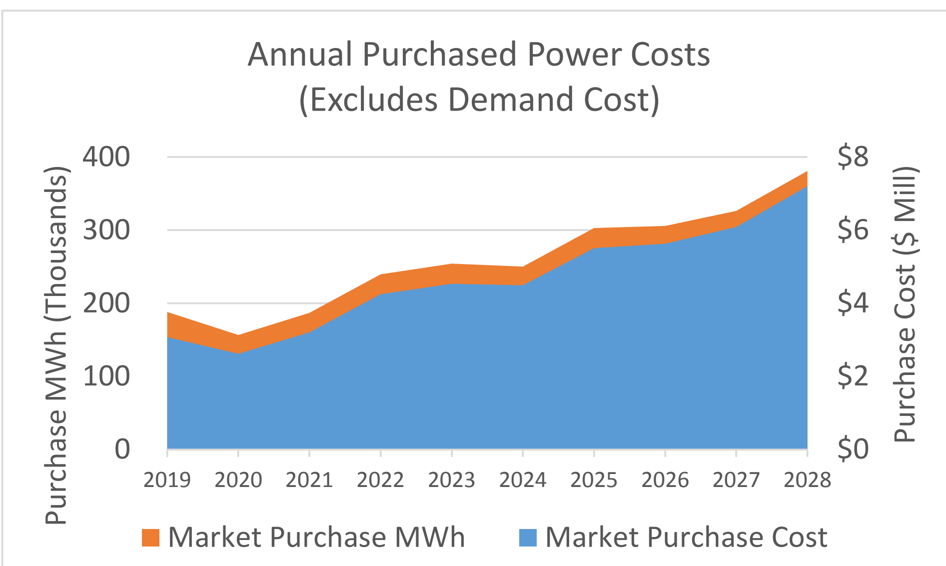


Figure 2-7 represents the forecast for total purchased power costs and the amount of forecasted MWh to be purchased. In 2029, estimated purchase power costs are expected to rise to about $7.2 million in the base case.

Figure 2-7. Annual Purchased Power Cost and Associated MWh



Capacity

Effective 2017, SPP will require a 12% PRM. Historic peak loads show an average growth rate of approximately 1% per year over the last 10 years. The peak load forecast is based on a 10-year historical correlation of peak loads including two factors: system-averaged maximum ambient temperature on peak load days and annual load. A regression analysis was used to determine the dependence of peak loads on each of these two variables. Using a nominal "design" peak load temperature of 100ºF and a 10-year historical trend-based load forecast, the results were used to generate a peak load trend from 2019 through 2028. The two new large industrial loads discussed in the energy section above, were added to these forecasted peak loads, and the resulting values were used to determine the SPP PRM. The 2019-2028 peak load forecast is shown in Table 2-2 along with the total capacity obligation including the 12% PRM[1].

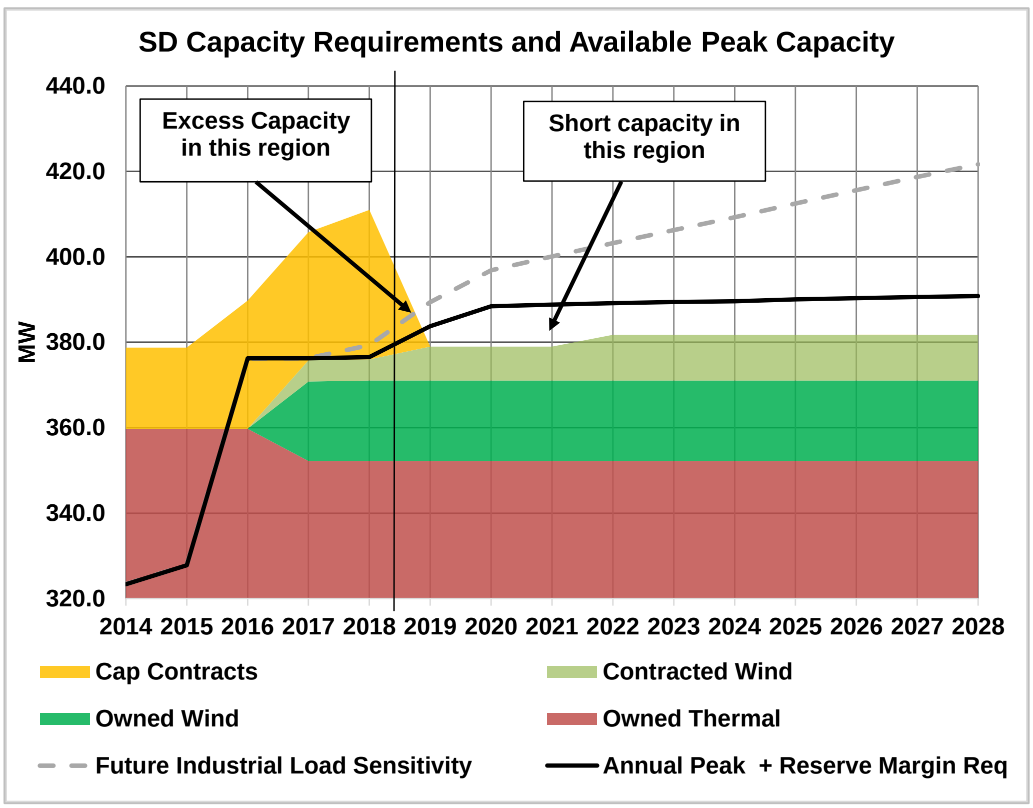
Table 2-2. Summer Peak Load 10-Year Forecast

Year	Summer Peak (MW)	Summer Peak with 12% Reserve Margin (MW)
2014	302	323
2015	306	328
2016	331	376
2017	336	376
2018	336	377
2019	343	384
2020	347	388
2021	347	389
2022	347	389
2023	348	389
2024	348	390
2025	348	390
2026	348	390
2027	349	391
2028	349	391

[1] This is the SPP-prescribed level.

Figure 2-8 illustrates NorthWestern's current capacity surplus and forecasted future capacity deficits. Beginning in 2019, NorthWestern anticipates that it will need to obtain additional capacity through market purchases of capacity or economic additions of physical generation resources to satisfy SPP capacity requirements. Need for capacity is expected to increase from 5 MW in 2019 to around 9 MW in 2028. Industrial load growth is difficult to predict and can affect NorthWestern's overall load growth. The Industrial Load Growth Sensitivity in Figure 2-8 shows that the need for capacity could increase from 10 MW in 2019 to around 40 MW in 2028, if industrial load growth occurs.

Figure 2-8. Capacity Requirements and Available Peak Capacity



As discussed in Chapter 4 on the HDR assessment, this Plan evaluates comparisons of different types of capacity facilities that may provide additional benefits to NorthWestern customers.

Commodity Forward Prices

NorthWestern relies on current expectations of forward/forecast prices, market expectations of price-implied volatility, fundamental market relationships, rate of mean reversion, and correlations of simulated prices through time in order to capture variability in the simulation of commodity prices. The simulated forward/forecast commodity prices include power at the SPP North trading hub, natural gas at Ventura, Iowa, and coal used for generation at Big Stone, Coyote, and Neal. The forecasted commodity prices provide the expected values from the average of simulation results. These forecasts are used in the evaluation of potential future resources.

Electricity Price Forecast

NorthWestern uses the Ascend Analytics forward market curve for its electricity price forecast, which is discussed in detail in Chapter 6. Table 2-3 shows the mean heavy load, light load, and around the clock electric and natural gas price forecasts that are modeled in PowerSimm™.

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Table 2-3. Base Case Electricity and Natural Gas Price Forecasts

Mean Electricity and Natural Gas Price Forecasts				
Year	HL - On Peak ($/MWh - Nominal)	LL - Off Peak ($/MWh - Nominal)	Around the Clock ($/MWh - Nominal)	Natural Gas ($/MMBtu - Nominal)
2019	$27.85	$18.46	$22.83	$2.49
2020	$24.71	$18.57	$21.43	$2.78
2021	$26.26	$18.89	$22.32	$2.82
2022	$26.36	$18.16	$21.98	$2.92
2023	$26.46	$17.82	$21.84	$3.10
2024	$25.96	$17.43	$21.40	$3.27
2025	$25.73	$17.03	$21.08	$3.46
2026	$25.48	$16.61	$20.74	$3.57
2027	$25.48	$16.43	$20.64	$3.70
2028	$25.45	$16.22	$20.51	$3.80
10 Year Lev.	$26.05	$17.73	$21.60	$3.11

Natural Gas Price Forecast

NorthWestern's long-term natural gas forecast is a combination of current forward market prices and the application of long-term price escalation factors. The near-term Ventura forward prices are obtained from the Intercontinental Exchange ("ICE") through October 2019. The forward curve is then escalated from November 2019 through the remainder of the planning horizon at the escalation rate from the Energy Information Administration ("EIA") 2018 Annual Energy Outlook nominal Henry Hub gas price projection for SPP North in the reference case.

Coal Price Forecast

The coal price forecasts for Big Stone, Coyote, and Neal are used to fuel each of the plants. Estimated prices are used for Coyote through 2022, Big Stone through 2024, and Neal through 2027. After the estimated prices, the coal prices are escalated throughout the remainder of the planning horizon using the 20-year average inflation escalation for Gross Domestic Product as provided by the U.S. Bureau of Economic Analysis, approximately 2% annually. Table 2-4 below shows projected coal forecasts.

Table 2-4. Coal Price Forecasts

Coal Price Forecasts			
Year	Coyote ($/ton - Nominal)	Big Stone ($/ton - Nominal)	Neal ($/ton - Nominal)
2019	$31.22	$36.89	$32.17
2020	$26.74	$38.00	$30.31
2021	$27.86	$39.14	$30.56
2022	$30.94	$40.31	$31.30
2023	$31.56	$41.52	$31.87
2024	$32.19	$42.76	$32.58
2025	$32.83	$43.62	$33.23
2026	$33.49	$44.49	$34.02
2027	$34.16	$45.38	$34.78
2028	$34.84	$46.29	$35.47
10-Year Lev.	$33.34	$44.10	$34.58

Conclusions

Energy load growth has remained relatively stable over the last 10 years. NorthWestern is also in the process of planning for one new large industrial load coming online in 2019 and another recent industrial load increasing in 2020. Beginning in 2019, NorthWestern is forecasting that it will need to obtain additional capacity either through adding internal generation or third-party contracts, in order to meet its system capacity requirement. Based on the current forecast, this need will increase from 5 MW in 2019 to around 9 MW in 2028.

CHAPTER 3
EXISTING PORTFOLIO RESOURCES

Generation Asset Summary

NorthWestern uses a portfolio of resources to meet the existing energy and capacity needs of its South Dakota customers and SPP requirements. As described in this section, the South Dakota portfolio includes base load coal generation, natural gas and diesel peaking generation, owned wind generation, wind PPAs, capacity, and energy purchase agreements. NorthWestern's portfolio of resources is distributed throughout and surrounding its South Dakota service territory, as shown in Figure 3-1. A summary of NorthWestern's current South Dakota portfolio is provided in Table 3-1.

Figure 3-1. Map of NorthWestern's Electric Generation Resources

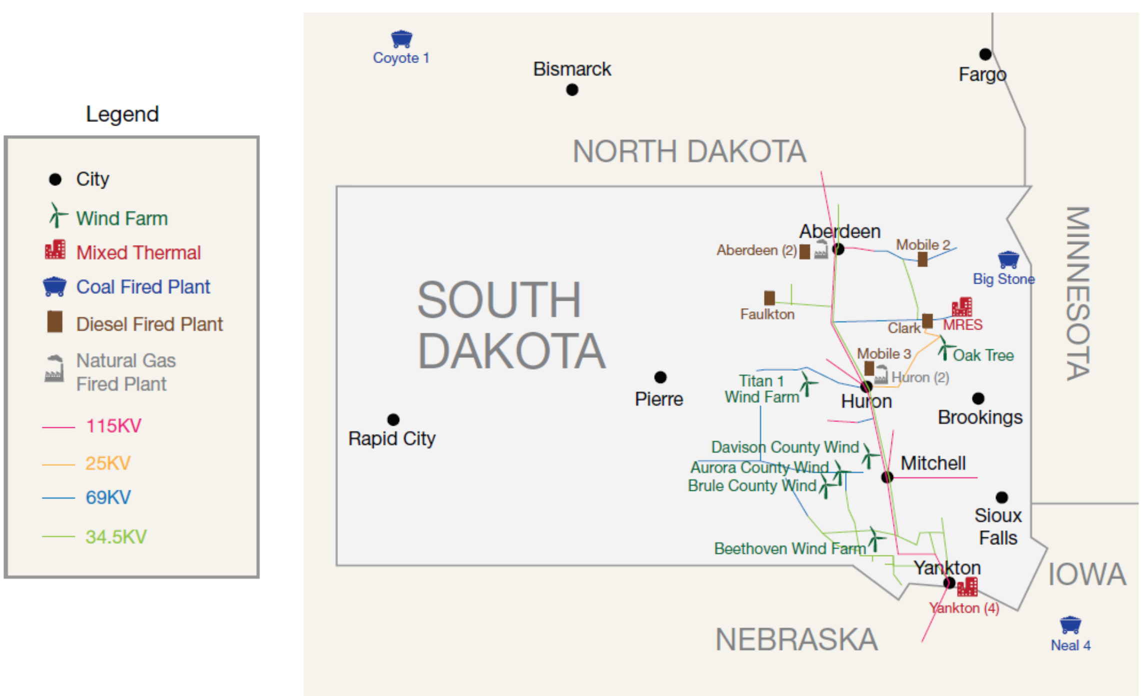


Table 3-1. NorthWestern's Current South Dakota Portfolio

Generation Unit	Type	Capacity (MW)	SPP Summer (MW)	SPP Winter (MW)	Fuel	Heat Rate (Btu/kWh-HHV)	COD
Aberdeen Generating Station Unit (AGS) 1	CT	22.6	20.5	28.0	Diesel	13,560	1978
AGS2	CT	82.2	52.0	60.0	NG / Diesel	10,000	2013
Huron Generating Station Unit (HGS) 1	CT	17.6	11.0	14.5	NG	15,850	1961
HGS2***	CT	43.7	43.7	49.0	NG / Diesel	12,784	1992
Clark	RICE	2.8	2.6	2.7	Diesel	10,700	1970
Faulkton	RICE	2.8	2.5	2.5	Diesel	10,200	1969
Yankton Generating Station Unit (YGS) 1	RICE	2.3	2.2	2.2	NG / Diesel	11,100	1974
YGS2	RICE	2.8	2.8	2.8	Diesel	11,600	1974
YGS3	RICE	6.5	6.5	6.5	NG / Diesel	10,800	1975
YGS4	RICE	2.0	2.0	2.0	Diesel	9,400	1963
Mobile B	RICE	1.8	1.8	1.8	Diesel	15,000	1991
Mobile C	RICE	2.0	2.0	2.0	Diesel	15,000	2009
Big Stone*	Steam	500.0	110.4	111.2	Coal	10,739	1975
Coyote*	Steam	500.0	42.7	42.7	Coal	11,077	1981
Neal 4*	Steam	696.0	55.9	55.9	Coal	9,949	1979
Beethoven	Wind	80.0	18.6	44.4	Wind	NA	2015
Rolling Thunder I Power Partners LLC (Titan)	Wind	25.0	3.9	0.8	Wind	NA	2010
Oak Tree Energy LLC	Wind	19.5	1.1	6.9	Wind	NA	2015
CED Aurora County Wind LLC **	Wind	20.0	1.0	1.0	Wind	NA	est 2018
CED Brule County Wind LLC **	Wind	20.0	1.0	1.0	Wind	NA	est 2018
CED Davison County Wind LLC **	Wind	20.0	1.0	1.0	Wind	NA	est 2019
Missouri River Energy Services	Contract	35.0	35.0		Contract		

Note: Capacity from 2018 SPP Resource Adequacy Workbook filing.
Commercial Operation Date is (COD)
* Capacity Sum/Wint is owned share.
** Capacity is Net Planning Capability default.
*** Installed date shown units are 1970's vintage.

Peaking Units

NorthWestern's thermal peaking units, shown in Table 3-2 below (sorted by age), consist of nine reciprocating internal combustion engine ("Recip") units and four simple cycle combustion turbine ("CT") units. With a combined summer peaking capacity of 149.6 MW[1], these facilities are situated in seven different locations across NorthWestern's service territory. The age of these units ranges from 57 years old to 5 years old, with several more than 40 years old. The smaller Recip peaking units (Clark, Faulkton, Yankton, Mobile

[1] All capacity values listed in the Peaking Units section refer to SPP RAW summer peaking capacities.

B, and Mobile C) use diesel fuel or are dual-fueled with natural gas and diesel fuel. These Recip units provide a total combined capacity of 23 MW. The four larger CT units are Aberdeen 1 and 2 and Huron 1 and 2. Aberdeen 1 is a 22.6 MW diesel-fueled CT in operation since 1978. Aberdeen 2 is an 82.2MW dual-fueled (natural gas/fuel oil) CT in operation since 2013. Huron 1 is a 17.6 MW dual-fueled CT in operation since 1961. Huron 2 is a 43.7 MW dual-fueled CT in operation since 1992.

Table 3-2. Thermal Peaking Units

Generation Peaking Unit	Type	Capacity (MW)	SPP Summer (MW)	Heat Rate (Btu/kWh-HHV)	COD
Aberdeen Generating Station Unit (AGS) 1	CT	22.6	20.5	13,560	1978
AGS2	CT	82.2	52	10,000	2013
Huron Generating Station Unit (HGS) 1	CT	17.6	11	15,850	1961
HGS2***	CT	43.7	43.7	12,784	1992
Clark	RICE	2.8	2.6	10,700	1970
Faulkton	RICE	2.8	2.5	10,200	1969
Yankton Generating Station Unit (YGS) 1	RICE	2.3	2.2	11,100	1974
YGS2	RICE	2.8	2.8	11,600	1974
YGS3	RICE	6.5	6.5	10,800	1975
YGS4	RICE	2	2	9,400	1963
Mobile B	RICE	1.8	1.8	15,000	1991
Mobile C	RICE	2	2	15,000	2009
Big Stone	RICE	0.3		15,000	1975

Aberdeen Generating Station

The Aberdeen Generating Station ("AGS") is located south of the city of Aberdeen, South Dakota, and consists of two units totaling approximately 104.8 MW in capacity. Characteristics for AGS Unit 1 ("AGS1") and AGS Unit 2 ("AGS2") are summarized in Table 3-3.

Table 3-3. Aberdeen Generating Station Unit Overview

Aberdeen Generating Station		AGS1	AGS2
Type	-	CTG	CTG
Make	-	GE	Pratt & Whitney
Model	-	MS5001	FT8-3
COD	Year	1978	2013
Fuel	-	Fuel Oil	Dual Fuel
Capacity (Nameplate)	MW	28.8	82.2
Heat Rate	Btu/kWh - HHV	13,560	10,000

The Aberdeen site is normally staffed during the day by three employees. Additional staffing is applied if the units are dispatched outside of these day shift hours. The units share a single 990,000 gallon fuel oil tank. Natural gas fuel is delivered to the site via a six inch pipeline off of the Northern Border Pipeline Company ("NBPL") system. A demineralized water system for AGS2, utilized mainly for water injection for emissions control, includes indoor hook-ups for two demineralized water trailers to operate at a time. The indoor space contains sufficient space such that a future, permanent water treatment plant could be installed.

Aberdeen Generating Station Unit 1

AGS1 has the lowest historical availability of NorthWestern's South Dakota combustion turbine/generator ("CTG") fleet. This is due in large part to the age of the machine and the difficulty of finding and acquiring replacement parts. Frequently, replacement parts must be reverse-engineered and custom-manufactured. Availability of AGS1 is also influenced by the fact that original equipment manufacturer ("OEM") support is limited. While some support from GE may be available, and aftermarket suppliers may exist, NorthWestern has noted increased challenges associated with parts availability/obsolescence.

AGS1 has one of the highest heat rates in the NorthWestern CTG fleet. AGS1 does bid into the SPP integrated marketplace; however, it rarely operates based on economic dispatch. Historically, AGS1 has had a cost to generate of nominally $278/MWh, which is the highest in the NorthWestern South Dakota fleet by a significant margin and typically results in AGS1 only being operated for testing or in an emergency. As an indication of historical dispatch, AGS1 has averaged only 14 operating hours per year between 2012 and 2016, with hours decreasing since the addition of AGS2.

AGS1 operates on diesel fuel and is permitted for a significant amount of operation on an annual basis. As a result, AGS2 has an annual dispatch limitation given that all assets on the site are considered in the air permitting process. Ideally, NorthWestern would not have any dispatch limitations on AGS2 given that it is currently the most cost-effective thermal unit in the South Dakota fleet. Therefore, NorthWestern intends to investigate a potential update to the AGS1 air permit to reduce the impacts on AGS2. The AGS air permit is currently set to expire and will need to be renewed in 2020, which could present an opportunity for adjustment/optimization. Retirement of AGS1 would also assist in facilitating increased dispatch of AGS2.

AGS1 is needed to support voltage regulation of the grid in the Aberdeen area. While this does not preclude AGS1 from being retired, the retirement of AGS1 would require a MW-for-MW replacement at the Aberdeen site. Additionally, based on the historical availability of AGS1, the unit’s current capability to respond to such an event could prove to be challenging.

Based upon the vintage of the unit, challenges experienced with making repairs, and high cost of generation (as evidenced by the very limited dispatch and operation of the unit), AGS1 is a prime candidate for retirement. However, if AGS1 were retired, replacement capacity would be required to support voltage regulation in the immediate vicinity. Pending further review, this could be an opportunity for NorthWestern to investigate storage technologies given their suitability for supporting voltage on the electric grid (e.g., fast start times). A storage installation option would likely require additional land at the site.

<u>Aberdeen Generating Station Unit 2</u>

AGS2 is NorthWestern's largest and newest unit within the fully-owned South Dakota thermal fleet and has been dispatched the most with 220 operating hours on average between 2013 and 2016. Since AGS2 was placed into service, most of the operating hours for the dual fuel unit have been on natural gas fuel, with only a single gas curtailment event occurring necessitating operation on diesel. Since going into operation, the average cost of generation at AGS2 has been $41/MWh, which is the lowest in the NorthWestern-owned thermal fleet. Recent studies completed by NorthWestern show that the installation of a demineralized water treatment plant on site could improve the AGS2 cost of generation by up to approximately $5/MWh, given the high cost of producing demineralized water via the current rental trailer systems. However, further investigation and study would be required to confirm this. Additionally, AGS2 has had some challenges with freeze protection systems and has had to make temporary improvements to keep the units available.

Based upon the vintage of the unit, historical reliability, and relatively low cost to generate power, AGS2 would not be suitable for retirement at this time. However, there are opportunities to optimize operating capability and cost-effectiveness going forward (e.g., addition of an on-site water treatment facility, removal of air operating permit dispatch limitations, etc.) that could facilitate increased economic dispatch in both the energy and ancillary services markets.

Mobile Unit Fleet

NorthWestern is expanding its fleet of mobile generators by adding nominally 8 MWs of new mobile generation capacity. Considering the findings of the HDR assessment described in Chapter 4, NorthWestern determined retiring the Clark and Faulkton generation facilities and expanding our mobile generator fleet would have the following benefits:

- Continues the legacy of providing local reliability for the Clark and Faulkton communities.
- Negates the need for planned capital improvement projects and ongoing O & M expenses.
- Increases reliability in other smaller communities where new mobile generator pads and associated electrical connections will be added.
- Increases NorthWestern's operational flexibility and system restoration capabilities, particularly in emergency situations.
- Provides additional accredited capacity to satisfy SPP's planning reserve margin (PRM) requirements.

The Clark and Faulkton units are small 2.8 MW Fairbanks-Morse RICE units; installed in 1970 and 1969 respectively. The units are fueled by diesel, used strictly for back-up service during transmission outages, and are not currently offered to the SPP market. Due to the age of the Clark and Faulkton engines, maintenance is becoming more difficult and costly. Many replacement parts are not available and must be fabricated. In addition, there are only a few people available with the technical/mechanical knowledge to work on the engines and associated equipment.

Clark has been generally reliable with a historical availability in excess of 96%. However, a recent pump failure caused a month-long outage since a replacement pump could not be found and the old one had to be rebuilt. The building housing the engine is also in poor condition. If the Clark plant were to remain in-service on a long term basis, additional capital would have been required for upgrades and repairs. The five-year plan included $1M in total capital improvements and $162,000 for total O&M costs. Planned capital improvements included upgrades to controls, the generator breaker and protective relaying.

Faulkton has had reliability issues in the past resulting in low historical availability of 69% and required overhauls of both the engine and generator. As with Clark, if the Faulkton plant were to remain in-service, additional funds would have been used for improvements. The five-year plan for Faulkton included $315,000 in total capital improvements for upgrading the engine control panel and $180,000 for total O&M costs.

Huron Generating Station

Huron Generating Station ("HGS") is located east of the city of Huron and consists of two units totaling approximately 60 MW in capacity (nameplate). Characteristics for HGS Unit 1 ("HGS1") and HGS Unit 2 ("HGS2") are summarized in Table 3-4.

Table 3-4. Huron Generating Station Unit Overview

Huron Generating Station		HGS1	HGS2A	HGS2B
Type	-	CTG	CTG	
Make	-	Westinghouse	Pratt & Whitney	
Model	-	W121-171	GG4A-9	GG4CF3
NorthWestern COD	Year	1961	1992	
Unit Vintage	Year		1973	1978
Fuel	-	Natural Gas	Dual Fuel	Dual Fuel
Capacity (Nameplate)	MW	15.0	15.0	30.0
Heat Rate	Btu/kWh - HHV	15,850	12,784	

The HGS site is staffed during the day shift by two people. Additional staffing is applied if the units are dispatched outside of these day-shift hours. HGS2 utilizes a single 50,000 gallon fuel oil tank installed in 2016. Natural gas fuel is delivered to the site from the south by a radial line from the Northern Natural Gas ("NNG") system. The HGS site has had some historical natural gas curtailment challenges; however, this has improved with a more recent tap from the NBPL line near Watertown.

Recent capital improvements common to the entire facility include a new workshop addition in 2016, storage building addition in 2015, new fuel oil heater in 2014, and improved parking lot in 2014. The facility presents manageable maintenance challenges. As a result, HGS2 is the second in line in terms of NorthWestern's owned thermal assets in South Dakota to dispatch into SPP and HGS1 is third, both following AGS2.

Huron Generating Station Unit 1

HGS1 is the oldest unit in NorthWestern's South Dakota fleet, has the highest heat rate at 15,850 Btu/kWh ("HHV"), and operates on average only 40 hours per year. The age of the unit has made obtaining replacement parts difficult and, similar to other old machines, the single OEM representative available to NorthWestern is nearing retirement age. The controls on HGS1 are manual push buttons with no automation, which makes them unique compared to the other fleet units and not representative of current industry standards. Hence, additional training for operations staff is required.

HGS1 lacks both functional fire suppression and vibration monitoring systems, which puts the machine at greater risk for catastrophic failure compared to newer units. The addition of fire protection for the main building and turbine floor is tentatively planned for 2018.

While significant capital upgrades are anticipated to keep HGS1 operational, plant staff believe the machine is fairly robust, and it does operate reliably on the rare occasions when it is brought online. Regardless, based on the vintage of the unit, the difficulty of making repairs, and the high cost of maintenance and operation as evidenced by the very limited dispatch and operation of the unit, HGS1 is a prime candidate for retirement.

Huron Generating Station Unit 2

HGS2 is a Pratt & Whitney TwinPac with two mismatched combustion turbine units driving a single generator. Unit 2A operates on average 67 hours per year, and Unit 2B operates on average 42 hours per year. The installation of different turbine generator units has created maintenance issues because there is no commonality of parts between the units. This has worsened as the machines have aged and parts, as well as OEM support, have become more difficult to obtain.

Due to the location of the combustion turbine exhaust stacks, HGS2 has historically had issues with the generator overheating as a result of turbine exhaust air being pulled into the generator cooling system under certain wind conditions. In addition, the existing HGS2 lube oil system requires external cooling on hot operating days to prevent overheating. The HGS2 fire suppression system has experienced multiple unexpected discharges for unknown reasons, resulting in the unit being forced out of service until the bottles can be refilled. HGS2 has also had challenges with the freeze protection system which has caused reduced unit availability.

Based upon the age of this unit, the difficulty of making repairs, and the high cost of maintenance and operation as evidenced by the limited dispatch and operation of the unit, HGS2 is a prime candidate for retirement in order to improve the fleet operability, reliability, and cost-effectiveness.

Yankton Generating Station

The Yankton Generating Station ("YGS") contains four reciprocating internal combustion engine ("RICE") units. This 13.6 MW facility does not bid into the SPP integrated marketplace but does count towards NorthWestern's accredited capacity to satisfy SPP's PRM requirements. The four units average a total of 40 operating hours per year with the majority of these hours required for bimonthly maintenance starts. The plant is located east of Yankton in the midst of farmland with a single residence across the road from the plant. Three of the units (YGS1, YGS2, and YGS3) began operation in 1974/5. YGS Unit 4 ("YGS4") was relocated to Yankton in 1983 but is a 1963 vintage unit. YGS is fed natural gas fuel from a radial tap off of the NNG system. The Yankton area has historically been constrained from a natural gas supply perspective based on current infrastructure in place and location on the system. Characteristics of the four units are summarized in Table 3-5.

Table 3-5. Yankton Generating Station Unit Overview

Yankton Generating Station		YGS1	YGS2	YGS3	YGS4
Type	-	RICE	RICE	RICE	RICE
Make	-	Fairbanks Morse Engine			
Model	-	38TD8-1/8	38TD8-1/8	PC-2	38TD8-1/8
COD	Year	1974	1974	1975	1963
Fuel	-	Dual Fuel	Fuel Oil	Dual Fuel	Fuel Oil
Capacity (Nameplate)	MW	2.3	2.8	6.5	2.0
Heat Rate	Btu/kWh - HHV	11,100	11,600	10,800	9,400

Currently, YGS is an unmanned facility inspected weekly by staff from the HGS site. Historically, the units could not be started reliably, which has resulted in unplanned maintenance and associated expenditures to bring YGS1, YGS2, and YGS4 to a condition such that they can be started and operated on a consistent basis. Funding to bring YGS3 to the same condition is not currently planned and will continue to be evaluated.

NorthWestern recently installed a system-wide water strainer to improve water quality to the units, but it has been a consistent maintenance challenge. The cooling water system utilizes an open, evaporative system with a cooling tower, which is rare for this type of plant. The open cooling system results in poor water quality and significant engine heat exchanger corrosion due to infrequent operation of the units. While the units are off, the water does not circulate and becomes stagnant in the cooling tower basin. YGS3's heat exchanger was open during HDR's site visit, and significant corrosion was visible throughout the heat exchanger and piping.

Based upon the age of the units, the cost to bring YGS3 back into reliable operation, and the cost to maintain and operate the units as compared to the quantity of generated power, YGS is a prime candidate for retirement. It is also noted that locational marginal pricing ("LMP") is highest at Yankton compared to the other sites in NorthWestern's South Dakota service territory, which offers greater opportunity over other sites given that the existing units do not operate.

Thermal Asset Vintage

To compare the age and size of NorthWestern's fully-owned South Dakota fleet to other in-service generating units, HDR reviewed data from the SPP and MISO markets regarding participating CTG and RICE units. While the comparison did not provide an indication as to a specific unit's likelihood to be dispatched, it did provide general insights into the comparative effectiveness and vintage to other units in the market. While NorthWestern is an SPP market participant, MISO is directly adjacent to SPP and provides another comparative reference point in the central United States.

Unit characteristics and vintage rankings in the SPP and MISO markets for NorthWestern's thermal fleet are summarized in Table 3-6. The rankings identify the percentage of comparable units that are newer than the identified NorthWestern asset. It is important to note that the percentile rankings are reviewed and identified separately for comparative CTG installations or RICE installations.

Table 3-6. Fleet Characteristics and Vintage Summary

Plant	Unit	Technology Type	Size (MW)	Date	Age on 5/1/18	SPP % of Capacity Newer	Miso % of Capacity Newer
Aberdeen	GT1	CTG	28.0	May-1978	40.0	77.9%	79.3%
Aberdeen	2	CTG	60.0	Apr-2013	5.1	17.9%	3.9%
Huron	1	CTG	14.5	Jan-1961	57.3	100.0%	100.0%
Huron	2A	CTG	49.0	Jun-1991	26.9	67.4%	70.9%
Clark	1	RICE	2.0	Jan-1970	48.3	72.5%	88.2%
Faulkton	1	RICE	2.5	Mar-1969	49.2	74.0%	89.4%
Mobile	2	RICE	2.7	Mar-1991	27.2	54.2%	77.4%
Mobile	3	RICE	2.2	Nov-2008	9.5	20.2%	22.6%
Yankton	1	RICE	2.8	Aug-1974	43.8	65.8%	84.4%
Yankton	2	RICE	6.5	Aug-1974	43.8	65.7%	84.4%
Yankton	3	RICE	1.8	Mar-1975	43.2	64.7%	84.1%
Yankton	4	RICE	2.0	Feb-1963	55.3	82.6%	93.8%
CTG-Average			37.9	Dec-85	32.3	65.8%	63.5%
RICE-Average			2.8	Apr-78	40.0	62.4%	78.0%

As can be noted from the data, HGS1 represents the oldest operating CTG in both the SPP and MISO markets. AGS2, compares favorably, with 17% of the SPP market capacity newer; however, the next newest unit, HGS2, is only newer than 33% of the SPP market capacity. On a total average basis, approximately 65% of both the SPP and MISO market CTG units are newer than the NorthWestern units. Similar metrics are apparent for the NorthWestern RICE units with approximately 60% of SPP units being newer than the average NorthWestern unit. The newest non-mobile RICE unit in NorthWestern's fleet is YGS3, which is only newer than 35% of the SPP market capacity.

This data indicates that the NorthWestern combustion turbine and RICE units are all on the older side of the SPP market with all but AGS2 and Mobile Unit 3 falling below the average age based both on capacity and number of generating units.

The data presented in Table 4-6 is also summarized graphically in Figures 3-2 and 3-3 for CTGs and RICE units, respectively.

Figure 3-2. Combustion Turbine Capacity Vintage

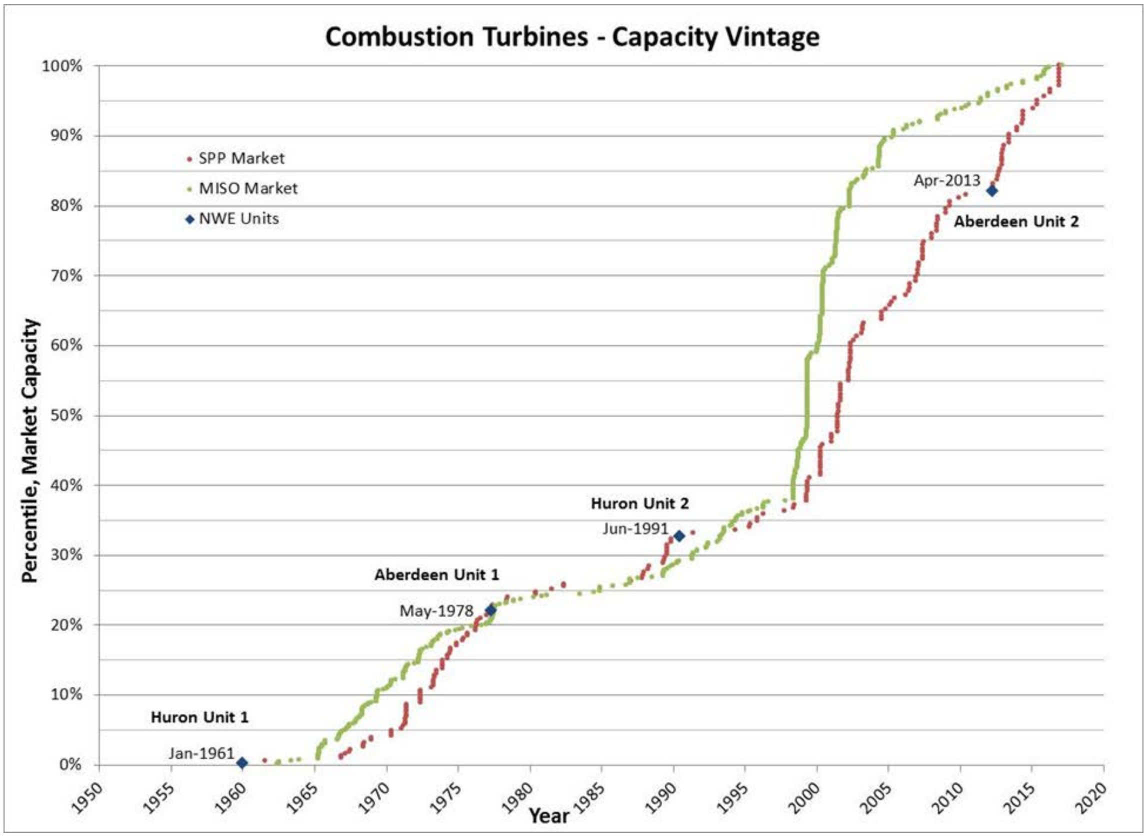
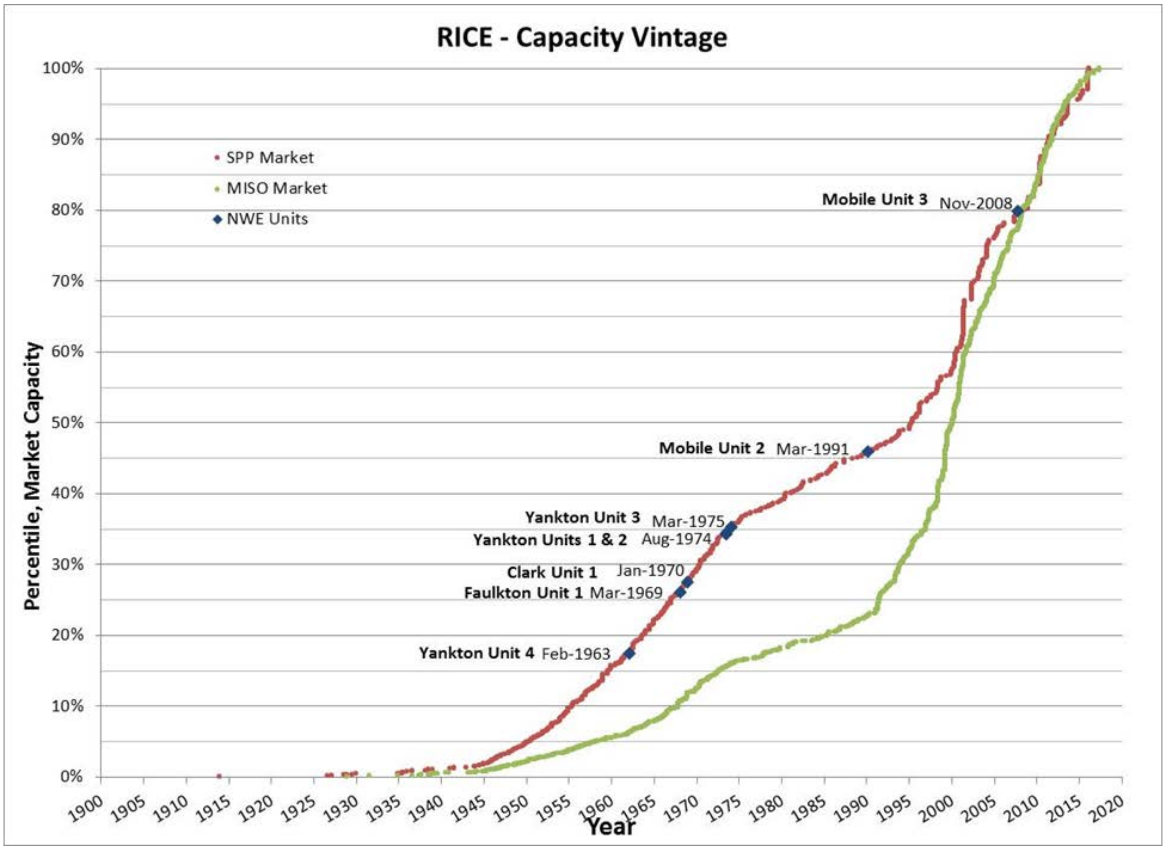


Figure 3-3. RICE Capacity Vintage



Joint-Owned Units

NorthWestern is currently party to three joint-owned unit ("JOU") agreements for partial ownership of Big Stone Unit 1 near Big Stone City, South Dakota; Coyote Station Unit 1 in Mercer County, North Dakota; and George Neal Generating Station Unit 4 near Sioux City, Iowa. All of these are coal-fired units. Table 3-7 provides an overview of the applicable unit in-service dates, thermal type, and NorthWestern's ownership commitment.

Table 3-7. Joint-Owned Unit Overview

Joint-Owned Units		Big Stone	Coyote	Neal 4
Type	-	Cyclone	Cyclone	Pulverized
COD	Year	1975	1981	1979
Fuel	-	Coal	Coal	Coal
Capacity (Nameplate)	MW	474.0	427.0	644.0
Heat Rate	Btu/kWh - HHV	10,739	11,077	9,949
NorthWestern Ownership	MW	111.0	42.7	56.0
	%	23.4%	10.0%	8.7%

Big Stone Plant

The Big Stone Plant ("Big Stone") is a joint venture between NorthWestern Energy, Otter Tail Power Company ("OTP"), and Montana-Dakota Utilities Company ("MDU"), with OTP being the operating agent. NorthWestern's ownership and share of the output of the plant is 23.4% or 106.7 MW under the SPP Resource Adequacy Workbook ("RAW") measure.

Big Stone is a coal-fired, cyclone burner, non-scrubbed base load plant that was placed in service in 1975. The unit is rated at 475 MW. The fuel source is Powder River Basin sub-bituminous coal delivered by Burlington Northern Santa Fe Railway Company.

NorthWestern's contractual commitment for the Big Stone facility runs through December 31, 2015, or any time thereafter. With the contract now operating in the "any time thereafter" period, a five-year notice is required prior to terminating the contract. In addition to the partial ownership of Unit 1, NorthWestern owns approximately 300 kW of diesel RICE capacity from the station.

Neal Energy Center Unit 4

Neal Energy Center Unit 4 ("Neal 4") is a pulverized coal, non-scrubbed base load plant located near Sioux City, Iowa. It is a joint venture among 14 power suppliers and was placed in service in 1979. MidAmerican Energy Company is the principal owner and operating agent for the plant. With a total plant rating of 646 MW in 2013, NorthWestern's ownership share is approximately 60.4 MW under the SPP RAW measure, or 8.68%. The fuel source for Neal 4 is Powder River Basin sub-bituminous coal delivered by the Union Pacific Railroad.

The JOU agreement for Neal Unit 4 is effective through 2014 "or so long after as Unit 4 shall be used or useful for the generation of electric power." NorthWestern currently experiences some challenges with the Neal 4 unit given that this unit resides in the Midcontinent Independent System Operator (MISO) region.

Coyote Station

Coyote Station ("Coyote") is located near Beulah, North Dakota, and began commercial operations in 1981. The owners of the plant are OTP (35%), Minnkota Power Cooperative (30%), MDU (25%), and NorthWestern (10%). OTP is the managing partner. Coyote is a coal-fired, cyclone burner, dry-scrubbed base load plant. The total plant rating is 427 MW (transmission limited). NorthWestern's ownership share of Coyote is 45 MW under the SPP RAW measure, or 10%. The fuel source is North Dakota lignite from an adjacent coal mine that is owned by Dakota Westmoreland.

The contractual commitment for the Coyote facility runs through December 31, 2021. NorthWestern is also subject to a long-term coal supply contract for the Coyote facility, which carries significant penalties for early termination.

Wind Units

NorthWestern relies on wind generating assets both through direct ownership as well as purchasing power through PPAs. NorthWestern currently has two PPAs for wind power in South Dakota: one with the Titan I Wind Farm and one with the Oak Tree Wind Farm.

Beethoven

Beethoven is a new, reliable unit with a high historical capacity factor (approximately 47.6%) located near Tripp, South Dakota. The Beethoven wind farm is a NorthWestern-owned facility and consists of 43 GE wind turbines generating approximately 1.8 MW each. Beethoven is maintained from an O&M facility in nearby Avon, South Dakota. The wind turbines have been extremely reliable since commencing operation, and there have been no major outages nor future outages planned for the units. NorthWestern currently maintains a full-service agreement ("FSA") with GE for the maintenance of the wind farm. Characteristics for the Beethoven wind farm are summarized in Table 3-8.

Table 3-8. Beethoven Wind Farm Overview

Beethoven		
Type	-	Wind Farm
Make	-	GE
Model	-	1.85-87 80m
COD	Year	2015
Capacity (Nameplate)	MW	80.0

Titan I

Rolling Thunder I Power Partners, LLC entered into a PPA with NorthWestern for the generation of its 25 MW Titan I ("Titan") wind project, which began commercial operation in January 2010. The Titan I PPA was executed in 2008 and is in effect at least through 2028.

Oak Tree

Oak Tree Energy, LLC ("Oak Tree") entered into a PPA for the generation of its 19.5 MW wind project. Commercial operations began in January 2015. The Oak Tree PPA was executed in 2013 and is in effect at least through 2034. The contract is for 75,527 MWh of energy annually, with all power sold to NorthWestern.

Capacity Evaluation of Wind

Under the current SPP Planning Criteria[2] ("Criteria"), the capacity contribution of a renewable resource towards the SPP capacity requirement is determined by a Net Planning Capability ("NPC") calculation as discussed in more detail later in this chapter. The results of these NPC calculations for existing wind projects are reflected in Table 3-1 above.

For Titan, eight calendar years of actual generation data were used (2010 – 2017). Oak Tree was modeled using three calendar years of actual generation data (2015-2017). For the two wind projects Aurora and Brule generation information was not available so the SPP default wind NPC value of 5% was assigned.

For Beethoven, generation data for 2013 to 2017 and met-data was used for the NPC.

The significance of changing to the SPP methodology is that the accredited summer capacity contribution of the wind fleet, previously valued at 0 MW, will become 26.6 MW.

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[2] SPP currently defines net planning capability of renewable resources and the recommended calculation methodology in the SPP Planning Criteria, Version 1.4, published October 9, 2017. https://www.spp.org/spp-documents-filings/?id=18162 "SPP Current Effective Planning Criteria."

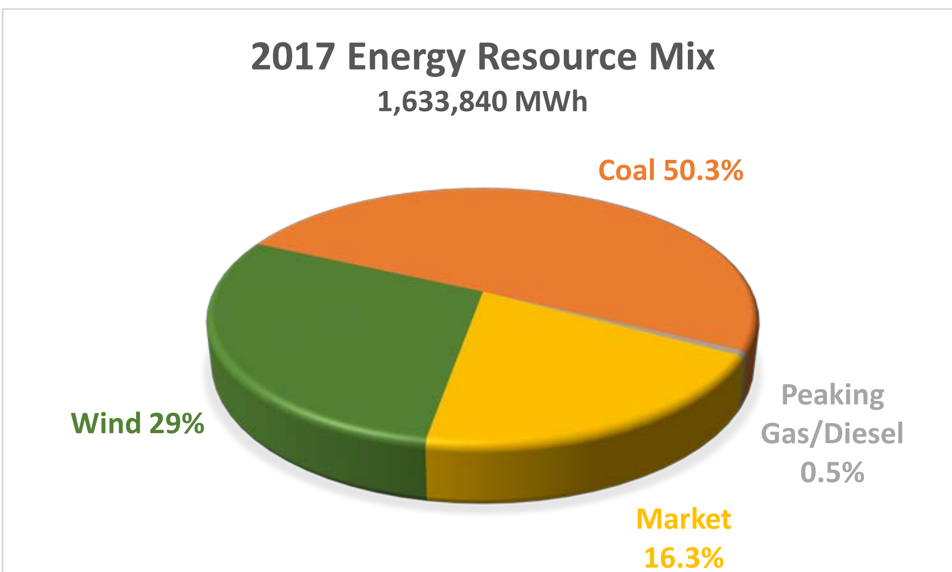
Capacity and Energy Agreements

NorthWestern entered into a capacity agreement with Missouri River Energy Services ("MRES") in 2014. The capacity agreement will provide 35 MW in 2018. The power is provided by the Watertown Peaking Plant. Capacity price is a fixed contract rate, while any energy produced is priced at the incremental cost of this unit.

Energy Resource Mix

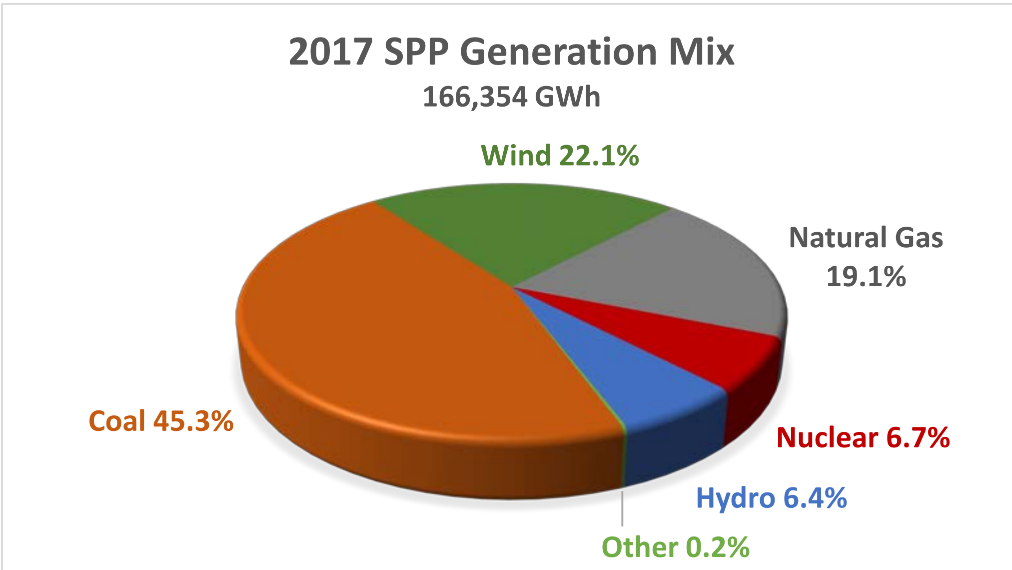
Generation from the facilities described above is delivered to the SPP market to help meet NorthWestern's capacity and energy needs. In 2017, the energy resource mix, shown in Figure 3-4, provided approximately 1,633,840 MWh of net generation in the following percentages: 50.3% base load coal, 29.0% owned and contracted wind, 16.3% net market purchases, and 0.5% peaking natural gas and diesel.

Figure 3-4. 2017 NorthWestern SD Energy Resource Mix



As an SPP member, all of NorthWestern's generation to meet load is sold to SPP and all the energy required to meet load is purchased from SPP. The 2017 SPP generation mix is shown in Figure 3-5 below.

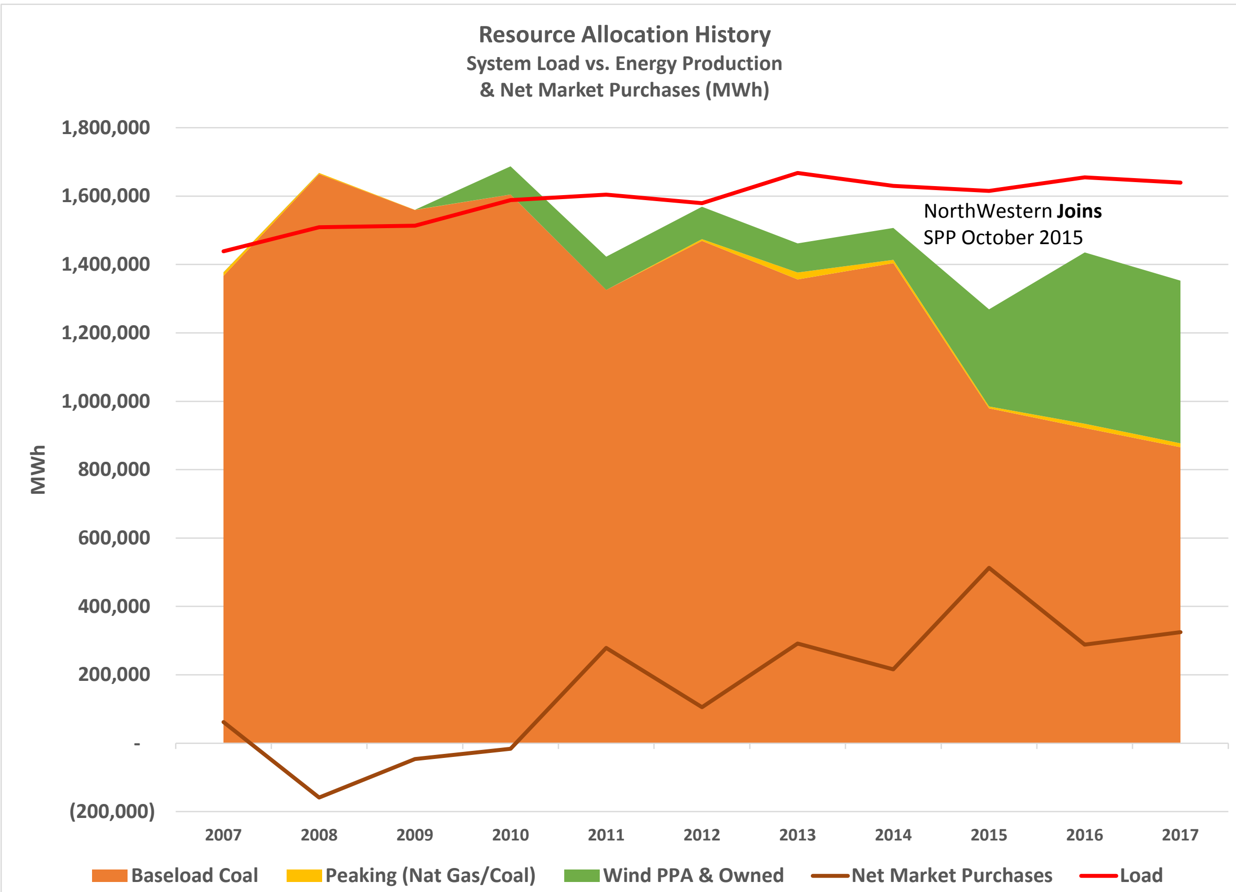
Figure 3-5. 2017 SPP Generation Mix



Coal-fired plants generated 45.3% of the total in 2017, while natural gas plants generated around 19.1%, wind about 22.1%, hydro about 6.4%, and nuclear about 6.7%. DSM and other resources (fuel oil, solar and biomass) make up only a small portion of the total.

Figure 3-6 below shows the historical relationship of NorthWestern's system load to energy production and energy purchases. The transition to SPP has not had a significant impact on this relationship. Recent increases in net market purchases are a response to low market prices, as thermal units continue to be dispatched economically. Wind generation has increased significantly due to Oak Tree and Beethoven entering the portfolio in 2015, which has also offset some thermal generation. Low natural gas prices and the availability of energy in the wholesale market has enabled NorthWestern to make economy purchases rather than generating with some of its higher cost units.

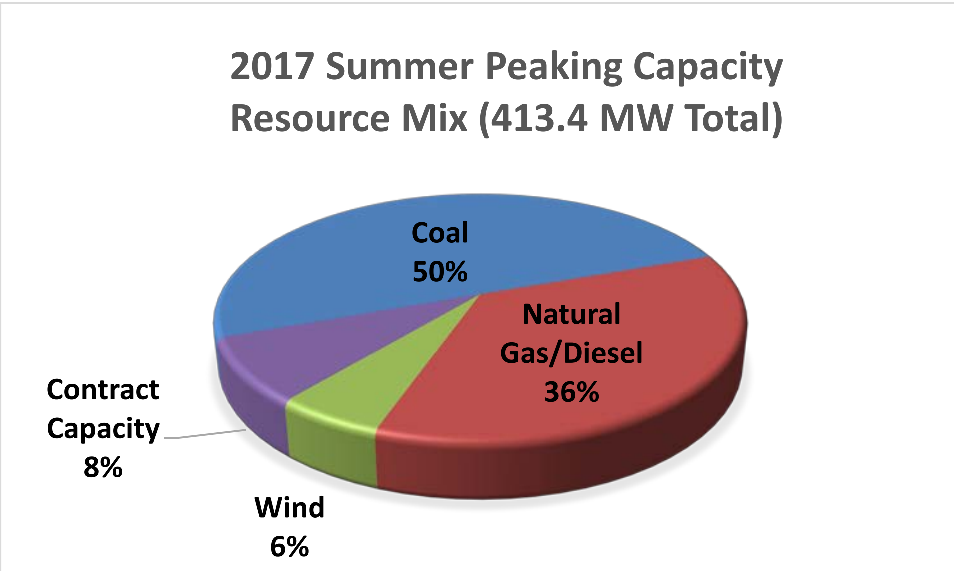
Figure 3-6. Resource Allocation History – System Load vs. Energy Production & Net Market Purchases



Capacity Resource Mix

NorthWestern is subject to capacity requirements set by SPP. SPP members are required to maintain adequate generation to meet their peak load, plus a PRM of 12.0%. SPP provides guidelines for its recommended methodology of evaluating the available peak capacity or NPC of wind and solar resources. In the Criteria, the recommended method is a specific monthly NPC calculation for all operating years of a facility (up to 10 years), utilizing the top 3% of peak load hours for each month, and the generation value met or exceeded 60% of these hours. Under this method, the existing fleet of wind resources are capable of providing 23.6 MW of NPC capacity. Figure 3-7 below shows that NorthWestern meets its SPP capacity requirement primarily with owned coal and natural gas peaking plants.

Figure 3-7. Summer Peaking Capacity Resource Mix



SPP rules require that units larger than 10 MW be registered in the Integrated Marketplace. Smaller units located behind the meter may be dispatched when needed and can be counted toward the Member's capacity requirements. Figure 3-8, below, shows the historical capacity portfolio and annual reserve requirement.

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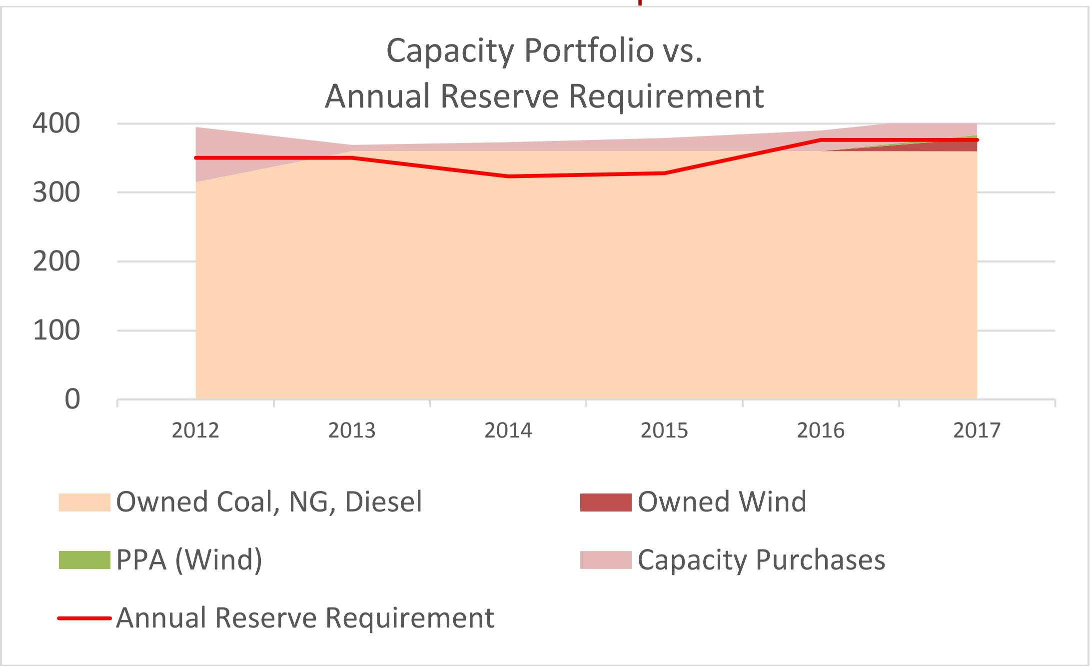
Figure 3-8. 2012 – 2017 Capacity Portfolio vs. Annual Reserve Requirement



The annual reserve requirement amount dipped in 2014 and 2015 due to a lower peak demand in both years but it is currently set at 12% by SPP

CHAPTER 4
HDR FLEET ASSESSMENT

HDR Assessment Overview

Introduction

NorthWestern retained HDR Engineering, Inc. (“HDR”) to assist in assessing its existing South Dakota generating fleet for opportunities to improve overall system reliability and operational flexibility. The assessment was a comprehensive, qualitative and quantitative analysis of NorthWestern’s existing fleet and considered the retirement of existing generating assets as well as the associated replacement of retired capacity with capacity from new generating resources**.** Various NorthWestern departments provided input for the evaluation including: Resource Planning; Energy Supply; Finance; Transmission Planning; Distribution; Environmental; Lands and Permitting; and others.

Assessment Guidelines

NorthWestern established the following assessment guidelines:

- Ensure safety is a main focus during all activities, particularly during site visits.
- Investigate the ten year outlook for the South Dakota fleet considering existing assets and potential resource additions.
  - Provide value for NorthWestern customers.
  - Enhance the energy landscape in South Dakota.
- Investigate how fleet modernization may improve reliability, efficiency, and operational flexibility.
  - Improve starting/operating reliability and capability.
  - Mitigate maintenance challenges from parts obsolescence and associated generator downtime.

  - Improve fleet efficiency to reduce fuel usage.
  - Realize benefits of flexible resources in the current marketplace.
- Drive customer value through increased dispatch and participation in the ancillary marketplace.
- Maintain and plan for future SPP capacity requirements for South Dakota.
- Establish a landscape for attracting additional industrial customers to locate in South Dakota.

Assessment Activities

The activities performed during the assessment included:

- Obtaining data and information regarding NorthWestern's existing assets and sites.
- Inspecting existing NorthWestern sites and interviewing operations staff.
- Reviewing and evaluating NorthWestern's existing assets and prioritizing assets for retirement considering vintage, performance attributes, historical availability and reliability, projected maintainability and associated costs going forward, and suitability to provide reliability and economic value for customers.
- Evaluating NorthWestern sites for potential generation additions.
- Developing fleet retirement/replacement scenarios considering various combinations of existing unit retirements and site generation additions.
- Developing technical and economic attributes of the various scenarios considering performance, capital costs, and operating costs.
- Comparing fleet retirement/replacement scenarios against the "business-as-usual" (or "do nothing") case considering reliability, maintainability, load proximity, operational flexibility, ancillary benefit, and community implications.
- Developing a comprehensive economic model to compare lifecycle costs against the "business-as-usual" case considering existing asset net book value ("NBV"), new unit capital costs, ratemaking principles consistent with previous regulatory

filings/rate cases, taxes, operations and maintenance (O&M) expenses, and energy and capacity revenues.

Key Assumptions

The following represent key assumptions used for the generating fleet assessment:

- Nominal one-for-one capacity replacements in terms of MW retired/added (or as close to one-for-one as possible given existing unit sizes and new generation configurations considered).
- Exclude future anticipated load growth in the development of retirement/replacement fleet scenarios.
- Retirement occurs "back-to-back" to new generation additions (i.e., there was assumed to be no gap in accredited capacity for SPP PRM requirements).
- Base scenarios in the comparative analysis on general "themes" rather than being definitive and/or all inclusive.
- Retirements and new unit additions occur in calendar year 2022, except the scenario that investigated spreading out the retirements/replacements over an extended duration of time.

HDR Fleet Assessment

Retirement Analysis Prioritization

HDR prioritized NorthWestern's generating assets in terms of suitability for potential retirement. Prioritization was generally based on historical reliability concerns, O&M challenges (e.g., parts obsolescence and maintainability), and contractual obligations.

The following assets were determined to be the most suitable for potential retirement. In general, these assets represent some of the oldest thermal units in NorthWestern's South Dakota service territory. Reliability of these units has been and will continue to be a concern and significant financial expenditures will be required to keep them operational.

- Aberdeen Generating Station Unit 1 (AGS1) – nominal 20 MW combustion turbine
- Huron Generating Station Unit 1 (HGS1) – nominal 10 MW combustion turbine
- Huron Generating Station Unit 2 (HGS2) – nominal 50 MW combustion turbine
- Yankton Generating Station (YGS) – nominal 13 MW RICE facility

The basis for categorizing the SD assets into primary and secondary candidates for potential retirement is summarized below:

Primary Candidates for Retirement

- AGS1 is an older vintage unit with high operating costs and reliability concerns; however, a retirement of AGS1 must also consider voltage regulation implications to the local electric grid.
- HGS1 is the oldest combustion turbine generator (CTG) in SPP, is controlled manually, and is the least efficient thermal unit in NorthWestern's fleet, making it a prime candidate for potential retirement.
- HGS2 has mismatched combustion turbine units coupled to a common generator, causing parts sourcing and operational challenges. Historical O&M challenges as well as the vintage of the units justifies them for potential retirement.
- YGS requires significant financial investment before the units can be reliably operated. With limited to no dispatch expected even if the condition of the units was improved, all of the YGS units are candidates for potential retirement.

Secondary Candidates for Retirement

- Clark and Faulkton are smaller units not currently offered to the SPP market; they are used for back-up service during transmission outages and to support outages due to severe storm events. However, based on their age, historical reliability and large expected upcoming capital expenditures, they are considered secondary candidates for retirement. Retirement of Clark and Faulkton is being considered as part of a potential expansion of NorthWestern's mobile generator fleet.

Assets to Remain in Service

- AGS2 was installed in 2013 and is NorthWestern's newest and most flexible unit. While NorthWestern will continue to investigate ways to optimize this asset to benefit its system and customers, AGS2 is not being considered for retirement.
- While continued investigation is likely, the JOUs (Big Stone, Coyote, and Neal 4) are not considered for retirement in this plan given contractual obligations and for other reasons. All JOU agreements will continue to be evaluated in subsequent planning activities.
- NorthWestern's Beethoven wind farm was installed in 2015 and has operated reliably since commercial operation. The Titan 1 and Oak Tree wind PPAs are long-term contracts with few reliability concerns. The wind resources are not candidates for retirement at this time.

Potential Generation Additions

After prioritizing the assets to consider for potential retirement, HDR characterized and assessed potential "replacement" generation additions. The results of the South Dakota Siting Study and Generation Technology Assessment, completed by HDR in 2016, were incorporated into HDR's analysis. The replacement analysis considered multiple sizes of reciprocating internal combustion engine (RICE) configurations as "proxy" (i.e., placeholder) additions across NorthWestern's system at Aberdeen, Redfield, Huron, Mitchell, and Yankton. The use of RICE configurations as "proxy" resources does not preclude other technologies as well as other sites from being considered going forward.

RICE Technology

HDR assumed RICE technology of nominal 18 MW capacity (each) would be used as replacement generation. This assumption was consistent with the results of the 2016 Technology Assessment. While RICE technology was assumed for the replacement assessment, selection of the actual technology will result from ongoing planning and analysis.

The characteristics of reciprocating engines align well with the results of NorthWestern's previous IRP activities, which identified a need for flexible, dispatchable resources to operate at peak times and contribute to SPP reserve margin requirements at all times. RICE units can provide firm and reliable capacity to NorthWestern's system, with the ability to dispatch quickly, participate in the energy and ancillary services marketplace, and provide a cost-effective solution for customers.

Retirement/Replacement Scenarios

HDR identified retirement/replacement scenarios by initially identifying overarching "themes", with the themes intended to capture general trends that would be representative across a variety of scenarios. Based on the assets prioritized for potential retirement, the RICE technology considered, and the five sites considered for generation replacements/additions, seven scenarios were developed for consideration. Qualitative and quantitative attributes were then established for each scenario.

Scenario Descriptions

The various retirement/replacement fleet scenarios considered in the analysis are described below. The following general assumptions/notes apply to all of the scenarios:

- The scenarios were limited to the assets that were prioritized in terms of suitability for potential retirement (AGS1, HGS1, HGS2, and YGS).
- The scenarios considered replacement of capacity assumed to be retired; however, future resource needs, such as those due to customer load growth, were not contemplated.
- If AGS1 were to be retired, the same amount of capacity would need to be added to the AGS site to support voltage regulation in the immediate vicinity.
- HGS was assumed to serve as the central O&M "hub" for the South Dakota fleet.
- The four units at YGS were not considered individually (i.e., YGS was considered as one nominal 13 MW facility).
- Except for the scenario in which retirements/replacements were spread out across multiple years, all retirements and additions were assumed to occur in 2022.

Scenario 1: 115 kV Electric Transmission Modernization

The intent of this scenario was to evaluate modernization of the 115 kV electric transmission "backbone" that runs from north to south across NorthWestern's South Dakota service territory:

- Retire HGS1, HGS2, and YGS in 2022 (~73 MW total)
- Add 40 MW at HGS, 20 MW at Mitchell, and 20 MW at YGS in 2022

Scenario 2: Mitchell LMP Basis

The intent of this scenario was to have something to compare against Scenario 3 and evaluate the influence of the LMP basis difference between Mitchell and YGS:

- Retire HGS1, HGS2, and YGS in 2022 (~73 MW total)

- Add 40 MW at HGS and 40 MW at Mitchell in 2022

Scenario 3: YGS LMP Basis

The intent of this scenario was to compare a retire/replace scenario at HGS and an addition at YGS against Scenario 2:

- Retire HGS1, HGS2, and YGS in 2022 (~73 MW total)
- Add 40 MW at HGS and 40 MW at YGS in 2022

Scenario 4: Large Centrally-Located Plant

The intent of this scenario was to understand the influence of a centrally-located plant versus a more distributed fleet in terms of dispatch frequency, capital and operating costs, staffing, fleet reliability, etc.:

- Retire HGS1, HGS2, and YGS in 2022 (~73 MW total)
- Add 80 MW at HGS in 2022

Scenario 5: Distributed Fleet

The intent of this scenario was to investigate a modernized, distributed fleet with generation hubs along the 115 kV transmission backbone:

- Retire AGS1, HGS1, HGS2, and YGS in 2022 (~93 MW total)
- Add 20 MW each at AGS, HGS, Redfield, Mitchell, and YGS

Scenario 6: Smaller Replacement-In-Kind

The intent of this scenario was to investigate a subset of Scenario 1 to understand attributes associated with smaller capacity replacement/addition:

- Retire YGS in 2022 (13 MW total)
- Add 20 MW at YGS in 2022

Scenario 7: 10 Year Fleet Modernization

This scenario was similar to Scenario 5 but with retirements/additions spread out over a number of years rather than all retirements occurring in 2022:

- Retire YGS in 2022, HGS in 2024, and AGS1 in 2028 (~93 MW total)
- Add 20 MW at YGS in 2022, add 20 MW each at Redfield, HGS, and Mitchell in 2024, and add 20 MW at AGS in 2028

Each of the scenarios were evaluated to determine qualitative and quantitative attributes for comparison, with the two major areas of focus being fuel supply and electric transmission capability. However, other factors were also considered. The basis for developing qualitative and quantitative attributes are discussed in the following sections.

Major Considerations

Location

HDR completed a Siting Study in 2016 to assess existing and greenfield sites for potential generation additions. In that study, seven existing sites were identified where there was either current or previous generation along with transmission substations. Two greenfield siting areas were identified through a comprehensive screening process, considering siting “corridors” where natural gas and electric transmission system facilities are located close together.

As evaluated in the 2016 Siting Study, the Aberdeen site had the highest qualitative rating and the lowest first year cost of generation of any site considered, benefitting from attractive natural gas fuel costs and attractive overall siting attributes. Huron followed in terms of relative attractiveness, just behind Aberdeen in both technical rating and first year cost of generation. Yankton also evaluated favorably with respect to the technical rating and was determined to be the most attractive site from a land availability perspective, with significant flat land within existing property boundaries available for development. Due to the comparatively less attractive rankings of the Clark, Webster, and Raymond sites, they were removed from further consideration, resulting in the following sites being considered most viable for some form of generation replacement/addition:

- Aberdeen
- Redfield
- Huron
- Mitchell
- Yankton

Natural Gas Fuel Supply

Natural gas infrastructure upgrade costs for varying levels of fuel supply to each of the sites under consideration were applied accordingly for each scenario. Those costs are summarized in the table below. Further investigation into natural gas supply tariff implications and allocation capabilities will be required.

Table 4-1. Conceptual Natural Gas Supply Upgrade Costs ($1,000; 2022$)

NG Upgrade Costs	Δ20MW	Δ40MW	Δ60MW
AGS	$2,700	$3,000	$3,700
HGS	$100	$17,400	$17,500
Mitchell	$300	$36,500	$36,600
Redfield	$11,800	$15,900	$21,500
YGS	$1,800	$27,900	$28,100

Electric Interconnection/Transmission

HDR performed a power flow analysis to assess electric transmission capability using NorthWestern planning models and the Siemens PSS/E power system simulation and analysis software. The analysis considered standalone retirements, standalone generation additions, and the scenarios mentioned above. For generation additions, the analysis considered incremental site additions of up to 100 MW to provide a bookend for potential system constraints. For each scenario, overloads were identified for the applicable generation addition amount. Generation was dispatched consistent with SPP planning methodology. Additionally, wind generation currently in the SPP and MISO interconnection queues was investigated.

For the summer peak case, no overloads were identified for any of the scenarios. For the summer shoulder case, significant upgrades were identified due in large part to the amount of projected wind included in the model. However, given that the generation additions considered would be "peaking" units, only the summer peak case would apply. As such, the evaluation did not include any transmission network upgrade costs for any of the scenarios under consideration.

This evaluation was completed consistent with SPP interconnection processes; however, implications associated with the retirement and/or replacement of generation assets will not be fully understood until the generator interconnection process is completed. Additionally, where possible, it was assumed that existing generator interconnection agreements ("GIAs") would be utilized to facilitate new generation additions (at sites where assets would be retired). It was further assumed that, as long as the amount of generation added did not exceed the GIA limit, the interconnection process could be avoided. This would likely require a material modification study to confirm that generator parameters of the new unit(s) would not have a negative impact on nearby facilities.

Land Rights and Environmental Considerations

Land Rights

In order to assess the amount of land required, site-specific layouts were developed for three RICE power plant configurations: a one unit RICE power plant; a two RICE unit power plant; and, a three RICE unit power plant. In general, the evaluation assumed that each of the sites under consideration could support new generation additions without incurring significant land acquisition costs. Land availability, local permitting, and other land rights considerations were investigated in more detail as part of the 2016 Siting Study and would need to be investigated further for any specific development going forward.

Environmental Permitting Considerations

Environmental permitting requirements, including those associated with air quality as well as other considerations (wetlands, threatened and endangered ["T&E"] species, cultural resources) were investigated in detail as part of the 2016 Siting Study. In general, HDR's retirement/replacement analysis assumed that retirements and/or replacements at the various sites under consideration could occur without significant environmental permitting challenges. Specific environmental permitting requirements will need to be investigated in subsequent development activities, as applicable.

Capital and Operating Costs

Conceptual capital and operating costs were developed for each of the scenarios considered. Cost estimating began with "inside-the-fence" estimates for each of the proxy RICE configurations, considering main power generation equipment, auxiliary systems, and facilities that would be the same regardless of the site of installation. Subsequently, "outside-the-fence" costs were estimated based on site-specific attributes, such as natural gas fuel supply capability. Additionally, the site-specific decommissioning costs mentioned above were included.

New Unit ("Inside-the-Fence") Capital Costs

American Association of Cost Engineering International ("AACE") Class 4 project cost estimates (i.e., feasibility study level accuracy) were developed for the new generation assets using NorthWestern's existing Huron site as a basis. Inside-the-fence conceptual cost estimates were developed based on an Engineer, Procure and Construct ("EPC") with Owner-furnished equipment ("OFE") contracting strategy. The cost estimates were based upon major equipment pricing from OEMs, labor rates specific to South Dakota, equipment quantities, and reference data from previous similar projects. Outside-the-fence or site-specific costs such as decommissioning of existing units, fuel supply infrastructure, electric transmission infrastructure, were estimated separately for each retire/replace scenario (see below for further discussion).

Table 4-2 summarizes the conceptual project capital costs for each RICE configuration. The total project cost represents estimated installed cost for a 2022 COD and include Owner's costs. All project $/kW values were computed based upon dividing the project costs by the net plant capacity at full plant load at summer day ambient conditions.

Table 4-2. Conceptual Project Cost Estimates (2022$)

Project Costs (2022 US$)	1x0 18MW RICE	2x0 18MW RICE	4x0 18MW RICE
Net Output	18.3	36.7	73.4
EPC Cost ($1,000)	$36,649	$56,499	$94,418
Construction Schedule (months)	18	19	20
Owner's Costs	$10,785	$16,812	$28,407
Total Project Cost ($1,000)	$47,434	$73,310	$122,825
Total Project Cost ($/kW)	$2,585	$1,998	$1,674

Site Upgrade Costs

Results from the siting evaluations identified natural gas upgrade costs for adding incremental generation capacity at each site. These costs are summarized in Table 5-1. As discussed, no electric transmission network upgrade costs were included in this analysis based upon the power flow analysis that yielded zero constraints for the summer peak case.

Decommissioning Costs

Demolition costs for each existing site were determined in conjunction with a demolition contractor familiar with similar units and based upon site drawings, photos, and input from the site visits. Costs included the removal of all equipment, equipment salvage value, and basic restoration of the site. Demolition costs did not account for any environmental remediation which would require an environmental survey to adequately scope and price. Total estimated costs as well as high level decommissioning timelines are summarized in Table 4-3.

Table 4-3. Conceptual Decommissioning Costs (2022$)

Retire Costs (2022 US$)	Aberdeen CTG-1	Huron CTG-1	Huron CTG-2	Yankton RICE-All
Net Output	20.0	10.0	50.0	13.0
Decomissioning Cost ($1,000)	$750	$900	$600	$2,400
Decomissioning Cost ($/kW)	$38	$90	$12	$185
Demo Schedule (Months)	6	9	6	12

While the HDR report identified costs for decommissioning of the identified facilities, it is important to note there are three main cost drivers impacting the demolition of a power plant. These include the scrap metals market, the quantity of hazardous materials and the extent of any required environmental remediation.

Scenario Cost Summary

Costs for new generating units, site upgrades, and decommissioning were itemized for each site/unit under each retire/replace scenario and are summarized in Table 4-4. Total costs shown are for comparative purposes between scenarios; refer to economic model results for capital investment and financing breakdown.

Table 4-4. Conceptual Fleet Assessment Scenario Costs (2022$)

Scenarios Costs	(2022 US$)	#1	#2	#3	#4	#5	#6	#7
New Capital Costs	($1000)							
Aberdeen		$ -	$ -	$ -	$ -	$ 47,434	$ -	$ 55,009
Huron		$ 73,310	$ 73,310	$ 73,310	$122,825	$ 47,434	$ -	$ 49,835
Mitchell		$ 47,434	$ 73,310	$ -	$ -	$ 47,434	$ -	$ 49,835
Redfield		$ -	$ -	$ -	$ -	$ 47,434	$ -	$ 49,835
Yankton		$ 47,434	$ -	$ 73,310	$ -	$ 47,434	$47,434	$ 47,434
Site Upgrade Costs	($1000)							
Aberdeen		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Huron		$ -	$ -	$ -	$ 100	$ -	$ -	$ -
Mitchell		$ 300	$ 36,500	$ -	$ -	$ 300	$ -	$ 315
Redfield		$ -	$ -	$ -	$ -	$ 11,800	$ -	$ 12,397
Yankton		$ 1,800	$ -	$ 27,900	$ -	$ 1,800	$ 1,800	$ 1,800
Decomissioning Costs	($1000)							
Aberdeen CTG-1		$ -	$ -	$ -	$ -	$ 750	$ -	$ 870
Huron CTG-1		$ 900	$ 900	$ 900	$ 900	$ 900	$ -	$ 946
Huron CTG-2		$ 600	$ 600	$ 600	$ 600	$ 600	$ -	$ 630
Yankton RICE-All		$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400
Total Costs	($1000)	$174,178	$187,021	$178,421	$126,825	$255,720	$51,634	$271,307

Implementation Schedules

Conceptual, site-generic project implementation schedules were developed from initial project development to project COD, which was assumed to be January 1, 2022, for the RICE configurations. Project durations for both construction and decommissioning activities were also incorporated into the economic model annual cash flow calculations discussed below.

HDR developed the implementation schedules based upon a review of key project milestones, construction activities, OEM-provided primary equipment lead times, and experience on previous/similar applications. Environmental permitting and regulatory approvals were not investigated in detail when developing these schedules.

Qualitative Assessment

Once the fleet retirement/replacement scenarios were developed by HDR, they were then comparatively assessed in a detailed qualitative analysis. The "business-as-usual" case (or current fleet) was also included in this assessment. This section describes the basis and results of the qualitative analysis. Each of the main qualitative criteria are discussed below, followed by the results of the comparative assessment.

Fleet Reliability

Overall fleet reliability in terms of both starting and operating reliability was assessed for each of the scenarios. The existing NorthWestern assets identified for retirement have been challenged historically with overall reliability and availability. As such, scenarios in which historic operations are maintained, either for a finite duration or until the end of the asset's useful life, were viewed to be less attractive in this qualitative category.

Maintainability

Maintainability was a critical factor in assessing each of the scenarios under consideration. Overall, the South Dakota fleet experiences significant durations of unavailability/forced outages based on spare parts obsolescence and lack of OEM support, primarily due to the age of the units. New unit additions would significantly improve maintainability, whether from NorthWestern staff and/or through a Long Term Service Agreement ("LTSA") with the OEM. As a result, scenarios which included more capacity replacement fared better in this category. Additionally, this criterion considered when the replacements would occur, with scenarios contemplating earlier replacements benefitting over scenarios that consider few or later replacements.

Load Proximity

There are significant load centers in NorthWestern's South Dakota service territory that do not have any generation located nearby. Historically, NorthWestern has benefitted from having generation located in close proximity to load centers, particularly during extreme weather/outage events. Typically, generation located in close proximity to load centers also benefits from less transmission-related congestion. Redfield, Mitchell, and Yankton are all locations where peak loads exceed the amount of generation in the immediate vicinity. Thus, scenarios that included generation additions at those locations as well as those that maintained generation at other major load centers benefited in this qualitative category.

Flexibility

This category mainly focused on operational flexibility, with scenarios considering an increased amount of flexible generation benefitting over those that did not. Newer vintage units would be able to follow load, respond to market signals, and provide increased ancillary benefit as compared to the units in NorthWestern's existing South Dakota fleet. Given their age, many of NorthWestern's existing assets do not possess the operational flexibility that newer units possess.

Ancillary Services

Ancillary services can include plant capabilities such as start-up times and ramp rates. NorthWestern's existing South Dakota fleet is generally less competitive in these areas as compared to newer generation technologies. With increasing renewables penetrating the grid as well as market trends, generating assets that are more responsive and have lower startup costs are advantaged and dispatched first.

Community

NorthWestern has received feedback from various communities regarding their desire to have generation resources located nearby. In particular, the communities of Mitchell and Yankton have expressed a desire to add and maintain/increase capacity, respectively. Additionally, generation at Huron has been viewed favorably given the large NorthWestern presence in the community. In general, communities across NorthWestern's service territory desire generation resources to be located nearby in case of extreme outage/weather-related events (such as the ice storm in the early 2000's). Additionally, local generation resources often provide a revenue stream to municipalities, counties, and/or the state in the form of tax revenues. All this said, scenarios that considered adding and/or maintaining assets in Mitchell and Yankton fared favorably in this category.

Comparative Qualitative Assessment

Based on the characterization of NorthWestern's generating assets and the attributes associated with each retirement/replacement scenario considered, the results of the comparative qualitative assessment are summarized in Table 4-5.

Table 4-5. Comparative Qualitative Summary

Scenarios	Modernized Capacity (MW)	Fleet Reliability	Maintainability	Load Proximity	Flexibility	Ancillary Benefit	Community
#1 (115kV)	72.5	~	+	+	+	+	+
#2 (Mtch-LMP)	72.5	~	+	~	+	+	+
#3 (Yktn-LMP)	72.5	~	+	~	+	+	X
#4 (HGS Hub)	72.5	~	+	X	+	+	X
#5 (Distr.)	90.6	+	+	+	+	+	+
#6 (1-for-1)	18.1	X	X	X	X	X	~
#7 (#5-10yr)	90.6	~	~	+	~	~	+
Existing	0	X	X	~	X	X	~
Legend: + = Positive, ~ = Neutral, X = Negative							

As evaluated, Scenario 5 was the most attractive scenario from a qualitative perspective. The following were observations and findings from the qualitative assessment:

- The attractiveness of Scenario 5 was mainly driven by all of the prioritized assets (AGS1, HGS1, HGS2, and YGS) being replaced with new, flexible, and reliable capacity all at once in 2022.
- Scenario 1 also evaluated favorably but was slightly less attractive than Scenario 5 based on AGS1 remaining in the fleet.
- Scenario 7 was similar to Scenario 5 but considered later retirement/replacement, and thus would not modernize the fleet as soon. However, Scenario 7 would spread out the required capital investment associated with the fleet modernization initiative and therefore potentially would spread out customer costs.
- Scenario 2 evaluated favorably, but was slightly less attractive, given that this scenario would locate new generation at two locations and would not locate generation in close proximity to the load at Yankton.
- Scenarios 3, 4, and 6 were less attractive on a qualitative basis than the other scenarios. However, they were more attractive than the "existing fleet" scenario.
- Scenario 3 was less attractive due to not locating generation at Mitchell.
- Scenario 4 did not provide for a distributed, modernized solution, which NorthWestern's customers have indicated is a priority for improving overall fleet reliability (a distributed fleet versus a central station is discussed further below).
- Scenario 6 did consider improved reliability at Yankton but was viewed to be less attractive given that only a small portion of the existing fleet would be modernized.

Overall, the results of HDR's qualitative assessment suggested that increased fleet modernization would benefit NorthWestern's system, with the addition of distributed, flexible resources appearing more attractive than maintaining the existing, older resources. Of course, fleet modernization at any level must consider cost. Financial implications of the different scenarios, as compared to maintaining and operating the existing fleet, are discussed in the following section.

Economic Assessment

In addition to the qualitative analysis discussed above, the fleet scenarios were further evaluated in a quantitative model to identify their relative economic benefits. HDR developed the economic model and incorporated NorthWestern's specific financial structure as well as inputs related to O&M costs (e.g., staffing).

The evaluation was structured as an incremental cost benefit analysis in that only the effects associated with units assumed to be retired as well as the new units added were evaluated. The performance and operations of the existing units remaining in operation were not assumed to be impacted or adjusted for any of the scenarios evaluated. The scenarios investigated the replacement of retired assets with a comparable amount of new, flexible capacity; these scenarios and, therefore, the overall retire/replace assessment did not contemplate potential future resource needs (for example, the need for generation additions associated with future load growth). Additional assumptions used in the economic analysis as well as the results from this comparison are presented in the following sections.

Existing Assets

Economic assumptions associated with the existing assets were developed based upon data provided to HDR by NorthWestern. This information was only used for the assets assumed to be retired in the various scenarios identified.

Net Book Value and Depreciation Costs

The net book value (NBV) for existing units was derived directly from accounting data as of August 2017. Depreciation costs were estimated using the net asset book values, in-service dates, and the remaining book value of each asset. Non-depreciable assets such as land and recent investments in assets that would continue to be used were not included in these calculations. The value of each asset was depreciated until the value reached zero (assuming no residual values). It was assumed that most existing units are fully depreciated from a tax perspective and carry a deferred taxes liability. No asset retirement obligations were assumed.

Future Capital Improvement Costs

Future capital improvement plan ("CIP") costs for existing units were estimated based on the allocated values in the 5-year capital plan for each unit. CIP costs occurring prior to unit retirements in each scenario included a 50% discount from the original 5-year plan to represent only performing critical improvements to maintain capacity accreditation. For scenarios with unit additions after 2022, credits for future CIP costs were only applied for 3 years prior to retirement. Future CIP costs were estimated to be the annual average of 2017 – 2022 forecast and escalated by 2% per year for 2023 and later years. CIP costs for the 5-year plan and future years are summarized below in Table 4-6.

Table 4-6. Existing Units Capital Improvement Costs

Capital Improvement Plan ($1,000)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Aberdeen CTG-1	$0.0	$0.0	$100.0	$500.0	$0.0	$0.0	$102.0	$104.0	$106.1	$108.2	$110.4	$112.6
Huron CTG-1	$0.0	$118.9	$0.0	$0.0	$150.0	$600.0	$147.7	$150.7	$153.7	$156.8	$159.9	$163.1
Huron CTG-2	$0.0	$156.9	$0.0	$0.0	$0.0	$0.0	$26.7	$27.2	$27.8	$28.3	$28.9	$29.5
Yankton RICE-All	$262.0	$0.0	$1,055.1	$700.0	$0.0	$500.0	$427.9	$436.5	$445.2	$454.1	$463.2	$472.4

Future Operational Costs: Fuel

Historical annual natural gas and fuel oil consumption for each generating unit were estimated to be the annual average of their 2012 – 2016 consumptions and escalated by 1% per year for 2017 and later years. Fuel consumption was estimated to increase year-to-year due to unit performance degradation. Increased fuel consumption was assumed to not be associated with increased utilization/dispatch. Historical consumptions and forecasted 2017 (and beyond) consumptions are summarized below in Table 4-7.

Table 4-7. Existing Units Fuel Consumption Summary

Fuel - Gas (MMBTU)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Aberdeen CTG-1	0	0	0	0	0	0	0	0	0	0	0
Huron CTG-1	612	23,562	2,262	1,790	1,912	6,088	6,149	6,210	6,272	6,335	6,399
Huron CTG-2	13,186	41,004	1,526	3,258	23,809	16,722	16,889	17,058	17,229	17,401	17,575
Yankton RICE-ALL	495	3,902	0	279	0	945	954	963	973	983	993
Fuel - Oil (Gallons)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Aberdeen CTG-1	37,079	55,437	20,082	2,894	7,058	24,755	25,003	25,253	25,505	25,760	26,018
Huron CTG-1	0	0	0	0	0	0	0	0	0	0	0
Huron CTG-2	0	846	380	4,855	0	1,228	1,241	1,253	1,266	1,278	1,291
Yankton RICE-ALL	13,436	8,807	6,515	441	100	5,918	5,978	6,037	6,098	6,159	6,220

Future Operation and Maintenance Costs: O&M

Future O&M costs for existing units were estimated based on the 5-year historical O&M values and escalated by 2% every 5 years for 2017 and later years. O&M costs were expected to increase year-to-year due to a variety of factors including unit performance degradation, parts obsolescence, and escalation in labor rates. Forecasted O&M costs are summarized in Table 4-8.

Table 4-8. Existing Units O&M Costs Summary

O&M ($1,000)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Aberdeen CTG-1	$ 80.3	$ 80.3	$ 80.3	$ 80.3	$ 80.3	$ 81.9	$ 81.9	$ 81.9	$ 81.9	$ 81.9	$ 83.5
Huron CTG-1	$ 240.3	$ 240.3	$ 240.3	$ 240.3	$ 240.3	$ 245.1	$ 245.1	$ 245.1	$ 245.1	$ 245.1	$ 250.0
Huron CTG-2	$ 386.0	$ 386.0	$ 386.0	$ 386.0	$ 386.0	$ 393.7	$ 393.7	$ 393.7	$ 393.7	$ 393.7	$ 401.5
Yankton RICE-ALL	$ 300.0	$ 300.0	$ 300.0	$ 300.0	$ 300.0	$ 306.0	$ 306.0	$ 306.0	$ 306.0	$ 306.0	$ 312.1

Electrical Generation

Future electrical generation was estimated to be the annual average of 2014 – 2016 historical electrical generation (MWh) for each unit and reduced by 1% per year for 2017 and later years. Electrical generation was estimated to decrease year-to-year due to unit performance degradation. Historical generation and forecasted 2017 generation are summarized below in Table 4-9.

Table 4-9. Existing Units Electrical Generation

Generation (MWh)	2014	2015	2016	2017	2018	2019	2020	2021	2022
Aberdeen CTG-1	28	28	28	28	28	27	27	27	27
Huron CTG-1	109	109	109	110	109	108	106	105	104
Huron CTG-2	1,523	1,523	1,523	1,538	1,523	1,508	1,493	1,478	1,463
Yankton RICE-ALL	35	35	35	35	35	35	34	34	34

New Generation Assets

Unit Performance and Dispatch

Overall performance was assumed to be the same for all potential new generation sites, and annual performance degradation based upon historical industry and OEM data was accounted for in the modeling. Levelized performance, assumed dispatch, and annual totals are provided below in Table 4-10 for the combinations of reciprocating engines assumed in the analysis.

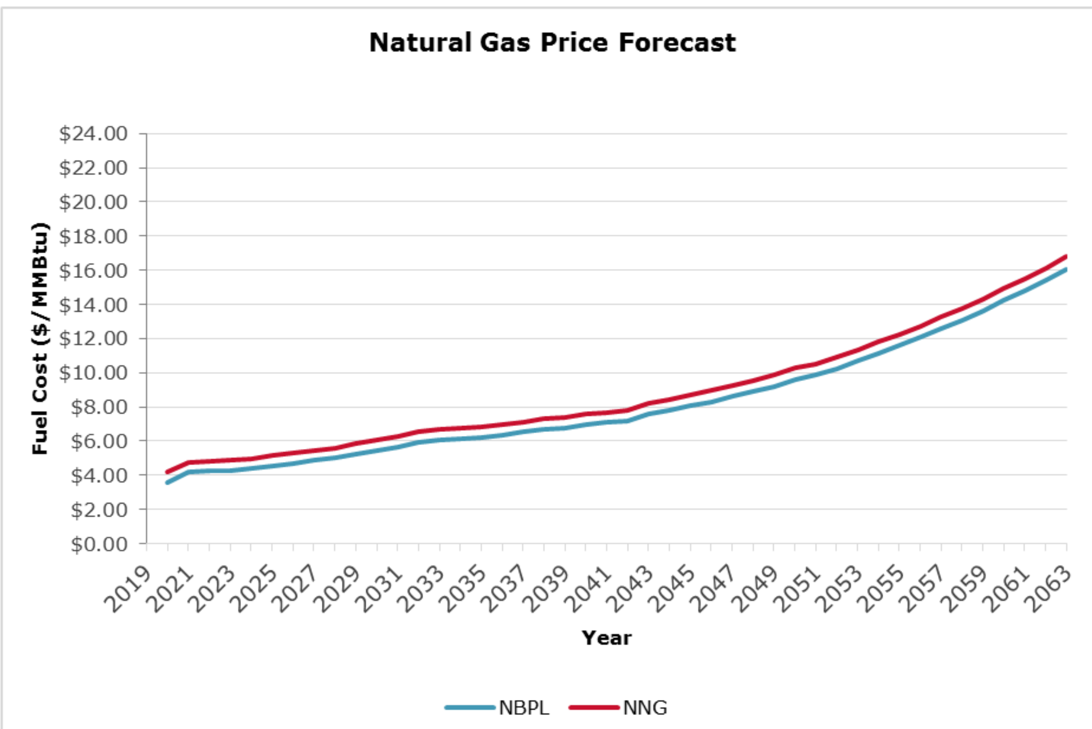
Table 4-10. New Generation Asset Performance and Dispatch Summary

		1x0 18MW RICE	2x0 18MW RICE	4x0 18MW RICE
Gross Plant Output	(MW)	18.8	37.6	75.3
Auxiliary Power	(MW)	0.5	0.9	1.9
Net Output	(MW)	18.3	36.7	73.4
Net Cycle Heat Rate, HHV	(Btu/kWh)	8,347	8,347	8,347
Net Cycle Efficiency	(% HHV)	41%	41%	41%
First Year Dispatch				
Total Net Generation	(MWh)	23,711	47,422	94,845
Capacity Factor	(%)	14.75%	14.75%	14.75%
Levelized Dispatch				
Total Net Generation	(MWh)	23,390	46,696	92,767
Capacity Factor	(%)	14.55%	14.53%	14.43%

Fuel Costs

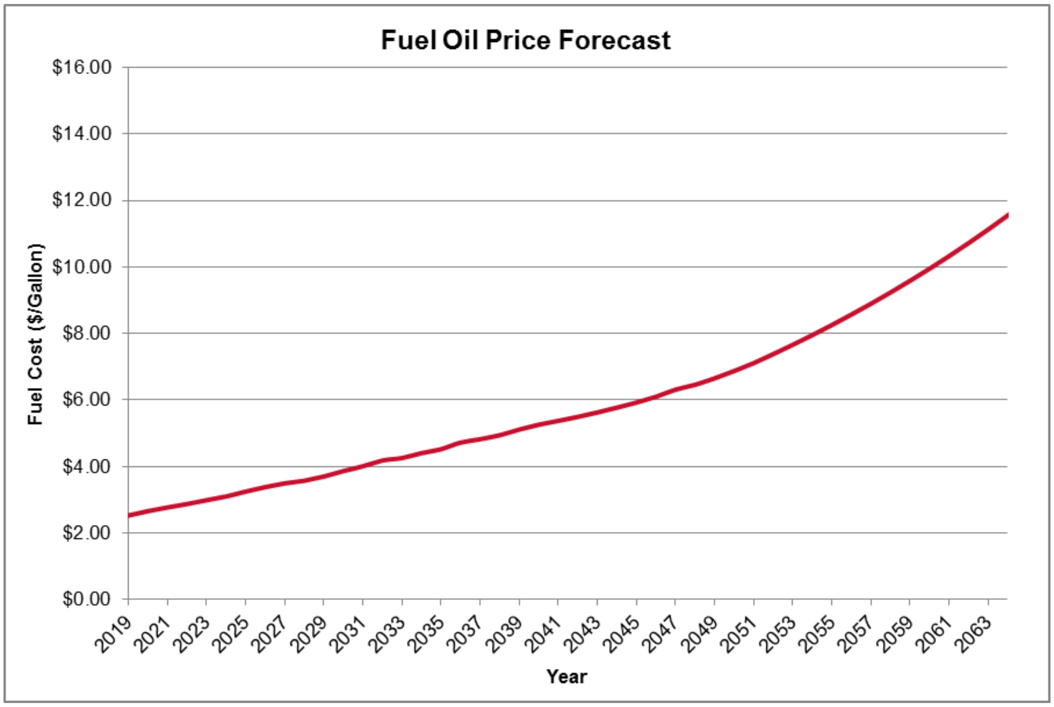
Natural gas and distillate fuel oil price forecasts were used to develop projected fuel costs for each of the scenarios considered and used for both new and existing units in the analysis. The natural gas pricing forecast was obtained from future curves at the NNG Ventura hub for years 2018 – 2040. For 2041 and on, the future curve was extrapolated using the average annual price escalation rate. The natural gas price forecasts for this analysis are displayed below in Figure 4-1.

Figure 4-1. Assumed Natural Gas Price Forecast



The distillate fuel oil pricing forecast was obtained from the 2017 Energy Information Administration ("EIA") energy sector price forecasts for years 2019 – 2050. The average of 2019 – 2050 annual escalation was used as a fixed escalation for 2051 and later years. This forecast was only used in the economic model to estimate future fuel savings associated with the potential retirement of existing fuel oil fired units. The distillate fuel oil price forecast for this analysis is displayed below in Figure 4-2.

Figure 4-2. Assumed Distillate Fuel Oil Price Forecast



<u>O&M Costs</u>

O&M costs in the economic model included traditional fixed, variable, and consumable O&M costs. Fixed O&M costs included estimated staffing costs, reoccurring equipment maintenance costs, on-site spare parts inventory, insurances, and miscellaneous site/building maintenance. All fixed costs for new generation options at existing sites were computed as the incremental change to existing fixed O&M costs.

Variable O&M costs included parts and maintenance dependent upon hours of operation and associated maintenance intervals. These costs include engine oil costs for the RICE engines, replacement parts and outsourced labor to perform maintenance on the major equipment, and other balance of plant (“BOP”) equipment. RICE maintenance costs were based on the assumption of pursuing a long term service agreement (“LTSA”) directly with the OEM.

Consumable costs included costs for material delivery and disposal for all materials used within the power generation process, except for fuel and O&M related consumables such as spare parts. Assumptions for fixed O&M and consumable costs are outlined in Tables 4-11 and 4-12.

Table 4-11. Fixed Cost Assumptions

Fixed Cost	First Year Price (2022$)
Fixed Cost Escalation	2.50%
Spare Parts Inventory	0.05% of EPC Project Cost
Annual Cost for Salaried Staff	$140,000
Annual Cost for Hourly Staff	$100,000
Insurance	0.05% of EPC Project Cost
Annual Site / Building Maintenance Cost	$100,000

Table 4-12. Consumable Cost Assumptions

Consumable	First Year Unit Price (2022$)
Consumable Escalation Rate	2.50%
Ammonia, aqueous	$192.34 / Ton (as 19% NH3)
Makeup Water	$1.50 / kgal
Demin Water	$3.50 / kgal
Waste Water Treatment	$1.00 / kgal

Cost of Generation

Incorporating the estimated operating costs and overall thermal cycle performance, total cost of generation (“COG”) values for the new reciprocating engine installations were estimated and are summarized in Table 4-13. Capital recovery costs were excluded from the COG values below and instead calculated within each retire/replace scenario’s economic model. Costs are presented on both a first-year basis and a 45-year levelized basis for each option at summer day ambient conditions and full load performance. The capacity factors for each option are based on an assumed nominal 15% annual capacity factor for reference. The thermal performance shown for each option is representative of "new and clean" performance; however, both permanent and recoverable equipment degradation was accounted for in the cost of generation analysis.

Table 4-13. Cost of Generation Summary

		1x0 18MW RICE	2x0 18MW RICE	4x0 18MW RICE
Net Output	(MW)	18.3	36.7	73.4
Net Cycle Heat Rate, HHV	(Btu/kWh)	8,347	8,347	8,347
First Year Dispatch				
Total Net Generation	(MWh)	23,711	47,422	94,845
Capacity Factor	(%)	14.75%	14.75%	14.75%
Levelized Dispatch				
Total Net Generation	(MWh)	23,390	46,696	92,767
Capacity Factor	(%)	14.55%	14.53%	14.43%
First Year Cost of Generation				
Fixed O&M	($/MWh)	$25.23	$15.36	$10.73
Variable O&M	($/MWh)	$5.49	$5.40	$5.32
Consumables	($/MWh)	$1.25	$1.08	$0.98
Fuel Costs	($/MWh)	$35.79	$35.79	$35.79
First Year COG	($/MWh)	$67.77	$57.63	$52.82
Levelized Cost of Generation				
Fixed O&M	($/MWh)	$37.64	$22.86	$15.93
Variable O&M	($/MWh)	$8.26	$8.13	$8.01
Consumables	($/MWh)	$1.88	$1.61	$1.46
Fuel Costs	($/MWh)	$59.03	$58.95	$58.61
Total Levelized COG	**($/MWh)**	**$106.81**	**$91.55**	**$84.01**

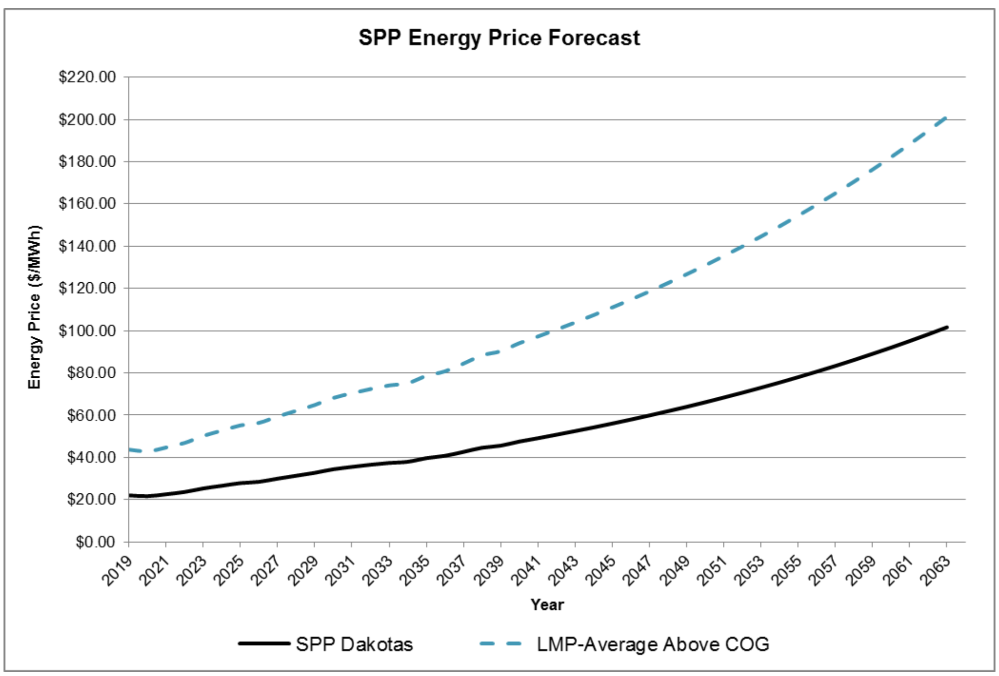
Scenario Revenue Breakdown

Results from the cost of generation analysis discussed above were used to estimate future revenue streams for each scenario considered. The basis for price forecasts, future escalation, and volume formulations of each revenue stream is identified below.

Energy Sales

Cost of generation results for each new generation technology option were compared to historical day-ahead hourly LMP data for each NorthWestern generating site to estimate the average LMP and number of hours per year when the LMP exceeded the total COG excluding fixed costs. The resultant average LMP was scaled with year-to-year percent changes in the Wood McKenzie energy price forecast trend for SPP Dakotas in 2017 – 2040. The average of 2017 – 2040 annual escalation was used as a fixed escalation for 2041 and later years. Results for the energy pricing and future forecasts are summarized in Figure 4-3. The resultant dispatch volume (hours per year) where the LMPs exceeded the COG is consistent with the capacity factor assumptions and resultant generating hours per year summarized above in the new technology dispatch summary (an annual capacity factor of nominally 15% was utilized for all new RICE generation resources considered in this assessment).

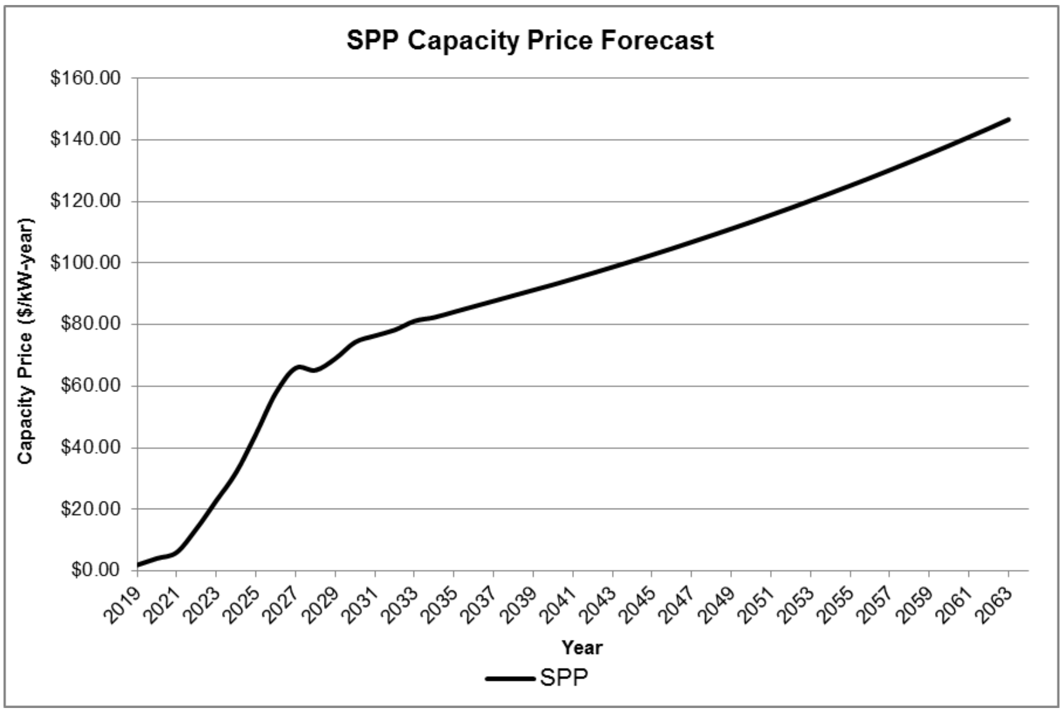
Figure 4-3. SPP Energy Pricing Forecast



Capacity Revenue

The resultant net capacity (MW) for each new generation option, including annual degradation, was used with the Wood McKenzie capacity price forecast for SPP in 2017 – 2040. A fixed 2% annual escalation was used for 2041 and later years. Results for the capacity pricing forecasts are summarized in Figure 4-4. Estimated capacity value was treated as a revenue stream in the economic model.

Figure 4-4. SPP Capacity Pricing Forecast



Ancillary Services Revenue

Cost of generation results for each new generation technology option were compared to historical day-ahead hourly ancillary services pricing to estimate average bid pricing and expected hours per year each technology could provide each ancillary service. While ancillary services revenues were estimated as part of this evaluation, this revenue stream was toggled "off" in the economic model. Further coordination is required with SPP and

Rainbow (NorthWestern's energy marketer for South Dakota) to fully understand ancillary services revenue potential. New, flexible resources would be expected to realize some amount of ancillary services revenue in the SPP integrated marketplace. As such, toggling this revenue "stream" off represented a conservative approach. Given that ancillary services revenues were not included in the economic model, potential ancillary benefit was included in the qualitative assessment.

Overall Economic Modeling Assumptions

In addition to the capital and operating costs, technology thermal cycle performance, and revenue breakdown assumptions identified herein, the following overall financial modeling assumptions were used as a basis to compare each retirement/replacement scenario against the existing fleet/status quo:

- For the scenarios with retired units, the forecasted future costs for those retired units (CIP, fuel, O&M) were entered as a cost savings credit in their overall scenario total costs.
- For existing units maintained in operation, their forecasted future costs were represented as a zero net change (no incremental change from existing fleet operation).
- Future CIP costs for new generation options was assumed to be 0.5% of total construction costs, starting 2 years after COD with a 5-year saw-tooth profile (increasing with time until improvement with major overhauls), and escalated at 2.0% per year thereafter.
- A reference system load volume of 190 GWh was considered across all scenarios to levelize the generation/purchase volumes, and bring each scenario to an equal reference; the value of this reference was determined by subtracting the annual generation (MWh) from the JOUs and wind assets from the total annual load.

- It follows that, based on the nominal 15% capacity factor considered for new generating assets, all scenarios, regardless of capacity modernized, required some quantity of energy purchases from the market.
- Fixed capacity payments, or capital recovery costs, were developed for each scenario on a fleet-wide incremental change basis.
- Tax depreciation was based on a 15-year modified accelerated cost recovery system ("MACRS") schedule with book depreciation as a straight line over the life of the project.

Factors used to determine the capital recovery costs and other economic parameters considered in this analysis are summarized in Table 4-14.

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Table 4-14. Economic Model Assumptions

Common Proforma Parameters	
Regulatory Rate of Return	7.36%
Study Period	30 years
Capital Escalation	2.50%
Base year for NPV Calculations	2018
Corporate Income Tax Rate	
State Tax Rate	0.00%
Federal Tax Rate	21.00%
Effective Tax Rate	21.00%
PP&E Financing Assumptions	
Capital Structure	
Debt	49.0%
Equity	51.0%
Cost of Capital	
LT Bond Interest Rate	5.14%
Equity	9.50%
WACC (After Tax)	7.36%
Bond Financing	
Amortization Schedule	Interest-only
Payment Schedule	Monthly
Term	30 years
Annual Interest Rate	5.14%
Monthly Interest Rate	0.43%
Dividend Distributions	Yes
AFUDC Included?	Yes
Loss on Retirement and Disposal of Assets Included in Regulatory COS?	Yes

Based on these assumptions, the economic modeling results for each scenario are summarized with key outputs and financial metrics described below.

<u>Key Outputs</u>

- Average Generation (MWh) – Average incremental generation per year from new units, less expected generation from retired units over the 30 year study period.
- Modernized Capacity (kW) – Average capacity of new units over the 30 year study period. Delays in unit installation reduce the overall average capacity over the study period.

- Levelized Free Cash Flow to Equity (FCFE) ($/kW) – Net present value (NPV) of FCFE divided by the average modernized capacity.
- Levelized Free Cash Flow for the Firm (FCFF) ($/kW) – NPV of FCFF divided by the average modernized capacity.
- In order to "normalize" the results of the economic model, scenario NPVs are presented on an NPV basis ($) as well as an NPV per amount of modernized capacity basis ($/kW).
- The $/kW of modernized capacity metric is estimated by individually discounting the free cash flows in the numerator and dividing this by the anticipated average annual capacity value.
- Comparative Rank – Ranking of the levelized capacity output metrics from best (1) to worst (7).

Financial Metrics

- Capital Cost (YOE$) – Total capital costs of installing new units in year of expenditure (YOE) dollars (costs adjusted for future inflation). These costs do not include costs of retiring units or future capital improvements.
- Levered Discounted Cash Flows (PV) – The present value of various metrics relevant to estimating cash flows to equity.
    - Equity Investment – The total equity issued to fund new units.
    - Levered Free Cash Flow – Free cash flow after debt service available to equity holders.
    - Levered NPV (FCFE) – NPV of all future cash flows to equity. This metric assesses results taking into account impacts from leverage (or debt financing).
- Unlevered Discounted Cash Flows (PV) – The present value of various metrics relevant to estimating cash flows to the firm.

  - Capital Investment – The total capital investment required to fund new units. This includes both debt and equity issuance.
  - Unlevered Free Cash Flow – Free cash flow available to the firm before any debt service.
  - Unlevered NPV (FCFF) – Net present value of all future cash flows to the firm, before any debt service. This metric assesses results without taking into account impacts from financing.
- Average Regulatory Return on Equity (ROE) – Average ROE over the 30 year study period in line with regulatory requirements for calculation ROE. This metric relies on the regulatory allowable return rather than actual financing cash flows such as interest payments, principal repayment, or dividend payments.
- Average Investor ROE – Average ROE over the 30 year study period from the standpoint of investors. This metric takes into account the actual financing structure and associated payments of each scenario.

Scenario Quantitative Comparison

Incorporating all of the identified economic model inputs and assumptions, key outputs and financial metrics were arranged in a side-by-side comparison for each scenario. The scenarios are presented as shown in Table 4-15.

Table 4-15. Scenario Descriptions (Brief)

Scenario #1	Scenario #2	Scenario #3	Scenario #4	Scenario #5	Scenario #6	Scenario #7
Modernize 115kV	Mitchell-LMP	Yankton-LMP	HGS Hub	Distributed Fleet	Replace-in-Kind	10 Yr Modernization

The resultant side-by-side comparison is shown below in Tables 4-16 and 4-17 on a levered basis and Tables 4-18 and 4-19 on an unlevered basis.

Table 4-16. Scenario Quantitative Comparison Results (Levered)

Key Outputs	#1	#2	#3	#4	#5	#6	#7
Avg. Generation (MWh)	92,087	92,004	92,004	91,378	115,536	23,360	106,192
Modernized Capacity (kW)	72,452	72,452	72,452	72,452	90,565	18,113	83,251
Levelized FCFE ($/kW)	($1,448)	($1,487)	($1,400)	($1,020)	($1,423)	($5,936)	($1,495)
Comparative Rank	4	5	2	1	3	7	6

Table 4-17. Scenario Financial Metrics (Levered)

Financial Metrics	#1	#2	#3	#4	#5	#6	#7
Capital Cost (YOE$)	$165 M	$177 M	$169 M	$119 M	$243 M	$48 M	$258 M
Levered Discounted Cash Flows (PV)							
Equity Investment	$70 M	$75 M	$71 M	$50 M	$103 M	$20 M	$92 M
Levered Free Cash Flow	-$35 M	-$33 M	-$30 M	-$24 M	-$26 M	-$87 M	-$32 M
Levered NPV (FCFE)	-$105 M	-$108 M	-$101 M	-$74 M	-$129 M	-$108 M	-$124 M
Avg. Regulatory ROE	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
Avg. Investor ROE	9.38%	8.00%	9.38%	8.43%	8.69%	8.56%	1.59%

Table 4-18. Scenario Quantitative Comparison Results (Unlevered)

Key Outputs	#1	#2	#3	#4	#5	#6	#7
Avg. Generation (MWh)	92,087	92,004	92,004	91,378	115,536	23,360	106,192
Modernized Capacity (kW)	72,452	72,452	72,452	72,452	90,565	18,113	83,251
Levelized FCFF ($/kW)	($1,817)	($1,885)	($1,780)	($1,289)	($1,857)	($6,362)	($1,936)
Comparative Rank	3	5	2	1	4	7	6

Table 4-19. Scenario Financial Metrics (Unlevered)

Financial Metrics	#1	#2	#3	#4	#5	#6	#7
Capital Cost (YOE$)	$165 M	$177 M	$169 M	$119 M	$243 M	$48 M	$258 M
Unlevered Discounted Cash Flows (PV)							
Capital Investment	$136 M	$147 M	$140 M	$99 M	$201 M	$39 M	$181 M
Unlevered Free Cash Flow	$5 M	$10 M	$11 M	$5 M	$33 M	-$76 M	$20 M
Unlevered NPV (FCFF)	-$132 M	-$137 M	-$129 M	-$93 M	-$168 M	-$115 M	-$161 M
Avg. Regulatory ROE	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
Avg. Investor ROE	9.38%	8.00%	9.38%	8.43%	8.69%	8.56%	1.59%

The following are key observations from the quantitative analysis:

- Scenario 4, which considered a larger, centralized generation addition at HGS, resulted in the lowest $/kW of modernized capacity, benefitting from economies of scale realized from a single installation versus multiple installations across multiple sites.

- As compared to the other scenarios considering nominally 73 MW of modernized capacity, Scenario 4 resulted in a nominal $20 to $25 million NPV improvement. This was largely driven by installed costs being nominally $500/kW lower for a centralized plant versus multiple distributed units.
- Scenario 7, which was a duplicate of Scenario 5 but with sequential retirements and replacements, offered a slight improvement of NPV of costs due to spreading capital costs over multiple years. However, the resultant NPV of unit costs ($/kW) was worse because the overall modernized capacity was delayed and operating costs for existing units were incurred until retirement.
- Scenarios 5 and 7 considered nominally 93 MW of modernized capacity and, accordingly, the NPV of costs were greater than for the other scenarios.
- Scenarios 1, 3, 5, and 7 all resulted in very similar $/kW of modernized capacity metrics, with each carrying various cost/benefits primarily due to the capabilities of the generation addition sites under consideration. For example, Scenario 2 incurred higher initial capital costs based on the natural gas fuel supply capability at the Mitchell site. Mitchell would incur significant natural gas infrastructure costs for generation additions greater than 20 MW.
- Scenario 6 resulted in the highest $/kW of modernized capacity, primarily due to less capacity modernized as well as high costs associated with keeping the existing units in operation.

Summary of Qualitative and Quantitative Analysis

Table 4-20 provides a summary of the comparative qualitative and quantitative retirement/replacement analysis.

Table 4-20. Retirement/Replacement Assessment Comparative Results

Scenarios	Modernized Capacity (MW)	Fleet Reliability	Maintainability	Load Proximity	Flexibility	Ancillary Benefit	Community	Levered FCFE ($/kW cost)
#1 (115kV)	72.5	~	+	+	+	+	+	$1,448
#2 (Mtch-LMP)	72.5	~	+	~	+	+	+	$1,487
#3 (Yktn-LMP)	72.5	~	+	~	+	+	X	$1,400
#4 (HGS Hub)	72.5	~	+	X	+	+	X	$1,020
#5 (Distr.)	90.6	+	+	+	+	+	+	$1,423
#6 (1-for-1)	18.1	X	X	X	X	X	~	$5,936
#7 (#5-10yr)	90.6	~	~	+	~	~	+	$1,495
Existing	0	X	X	~	X	X	~	-
Legend: + = Positive, ~ = Neutral, X = Negative								

The following represent general observations from the retirement/replacement assessment:

- Scenarios considering more modernization earlier in the study period fared more favorably in the qualitative assessment. As a result, Scenario 5 evaluated positively in the qualitative assessment, considering retirement of AGS1, HGS1, HGS2, and YGS and replacement capacity resources being distributed across the NorthWestern South Dakota service territory by 2022 (20 MW at each of AGS, Redfield, HGS, Mitchell, and YGS).
- Scenario 5 also fared reasonably well in the quantitative assessment, grouped with four other scenarios (1, 2, 3, and 7). For the economic analysis, this grouping possessed slightly higher $/kW modernized costs as compared to Scenario 4, which considered a larger, centralized generation addition at HGS, with the associated benefits from economies of scale realized from a larger, single installation versus multiple smaller installations.
- Scenario 4, however, did not evaluate favorably in the qualitative assessment as this scenario would not provide a distributed, modernized solution, which is a top priority for improving overall fleet reliability.
- Scenario 6, which considered replacement-in-kind of generation at YGS only, did not evaluate favorably in either the qualitative or the quantitative analysis.

- Scenario 7 is similar to Scenario 5, but with a build-out completed over a ten year span of time. Capital costs are slightly higher in a delayed build out case. Several positive qualitative benefits in Scenario 5 change to neutral in Scenario 7, when the build occurs over time. This occurs because Fleet Reliability and Maintainability suffer under an extended buildout. Similarly, Flexibility and Ancillary benefits also suffer from a delayed buildout. On the positive side, short term rate impacts are mitigated in Scenario 7. Additionally, Scenario 7 allows NorthWestern the opportunity revisit this study and reassess; the timing of retirements, technology costs, ancillary benefits, and customers' needs at that time.
- Across all scenarios, the NPV of costs ranged from approximately $60 million to $100 million (on a levered basis), generally with the lower cost scenarios presenting less qualitative benefits (larger, centralized plant) as compared to the higher cost options (multiple, smaller resources distributed strategically across NorthWestern's 115 kV electric transmission backbone).

As compared to a larger, centralized generating station, a distributed fleet is viewed to be superior based on:

- Improved transmission reliability, considering multiple transmission outlets to the grid versus a single outlet supporting the majority of generating capability.
- Lower transmission system losses, with assets located throughout the South Dakota service territory nearer to load centers. Based on closer proximity to load centers, this would result in more "real" power delivered to end users (i.e., a more efficient system).
- Improved capability to provide electric service/system restoration (e.g., black start) across the service territory due to, for example, an extreme weather event or transmission system failure.

- Increased natural gas fuel supply diversity, with distinct radial lines off of the interstate pipeline(s) feeding the distributed assets versus a single line supplying a larger, central facility (similar benefit to greater number of transmission outlets). There could also be benefit from natural gas fuel being sourced from multiple interstate pipeline systems (e.g., if generation is sourced from both Northern Border Pipeline and Northern Natural Gas).
- Ability to supply ancillary services/grid support (e.g., voltage support) on a more localized basis, which benefits the remote/rural portions of NorthWestern's system.
- Providing locational marginal pricing (LMP)/market pricing diversity and not being subject to market conditions at a single node. While this is not anticipated to significantly influence financial benefits near term, this could result in significant benefits long term as markets evolve and NorthWestern participates more in the integrated marketplace.
- Assuming a staged generation addition approach, the ability to evolve and adapt with the marketplace and broader industry (review asset technology/consider emerging technologies, optimize generation location, etc.). A phased, distributed approach could also allow for more responsiveness to specific, localized shifts in load centers/load growth.
- While the ability to adapt with the marketplace facilitates more efficient use of capital expenditures, a phased, distributed approach would also spread out potential rate impacts to customers (versus a larger expense all at once associated with a large, centralized facility). This approach would provide the optionality of spreading out rate adjustments over multiple rate cases versus including in a single rate case.
- Broadening and maintaining the tax base and economic development attributes across multiple communities throughout the state.

While a larger, central plant would likely result in lower capital and operating expenditures (based on current market conditions and on an NPV basis), a distributed solution possesses significant qualitative attributes that are viewed to provide more benefit to NorthWestern's South Dakota system overall.

Conclusion

The South Dakota Generation Fleet Assessment study presents a comprehensive assessment of NorthWestern's existing South Dakota fleet of generation resources. The study examines a number of scenarios in which older generation fleet assets are retired and replaced with new generation assets.

Scenarios in which existing assets are retired and replaced with large, central generation station equipment are lower cost, NorthWestern believes maintaining and enhancing the local reliability attributes of the existing, dispersed, South Dakota fleet is of paramount importance.

CHAPTER 5
NEW RESOURCES

New Resources Overview

In addition to the multiple configurations of reciprocating internal combustion engines (RICE) considered as "proxy" configurations in HDR's South Dakota Fleet Assessment (discussed elsewhere in this document), the 2018 Plan also considers wind, solar PV, and battery energy storage resources as possible additions to the portfolio. The planning process involved analysis and contributions from outside consultants Ascend Analytics, HDR, and other sources.

Wind Resources

Overview

Wind power is a widely adopted generation technology. Improvements in efficiencies and the availability of Federal Production Tax Credits ("PTCs") have been instrumental in the growth of wind energy. The current PTC is $0.014/kWh over a 10-year time period for wind facilities commencing construction in 2018. PTCs are being phased out and this tax credit value represents a 40% reduction from the $0.024/kWh base credit originally available under this program. For wind facilities commencing construction in 2019, the tax credit amount is reduced by 60% from the base credit. The tax credit is not available for projects commencing construction after 2019. The phase out of the PTC is summarized in the Table below.

Table 5-1. Federal Wind PTC Phase-Out

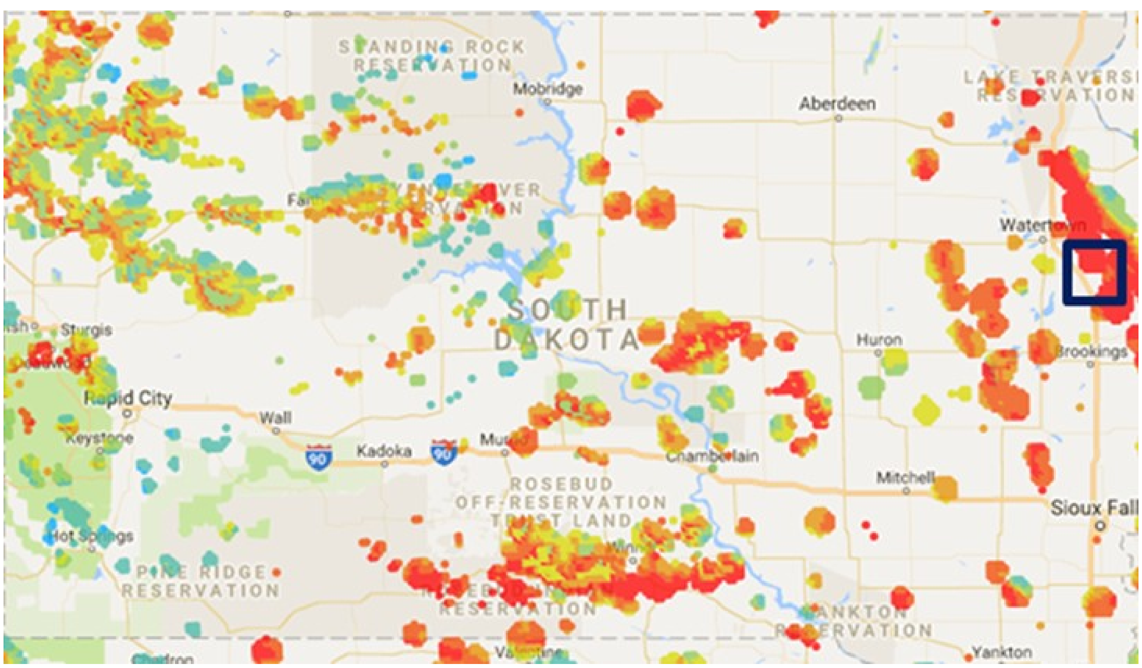
Federal PTC Phase Out					
Year Construction Begins	2016	2017	2018	2019	Future
Wind PTC ($/kWh)	$0.024	$0.019	$0.014	$0.010	$0.000

Performance

Wind farms are typically designed for a 20 year life, but well maintained turbines can last up to 25 years depending on the service conditions at the site and historical maintenance practices. Typical wind turbine sizes range from nominally 1.5 MW to 5 MW. For the 2018 Plan, the turbine design has a rated power of approximately 2.5 MW and a hub height of 100 meters ("m").

Wind turbine capacity is based largely on the length of the propeller blades. Taller turbines are not only able to use longer blades for higher output capacity, but are also able to take advantage of the better wind speeds available at greater heights (while also considering related aviation regulations and requirements). An average net capacity factor ("NCF") range for a wind power facility is typically in the range of 25 to 50 percent depending on available wind energy within the region. The estimated NCF for the South Dakota locations shown in Figure 5.1 below, is 44.42%.

Figure 5-1. Wind Location for South Dakota Analysis



National Renewable Energy Laboratory WIND Toolkit application was used to provide wind resource production data. The WIND Toolkit application includes meteorological conditions and turbine power for over 120,000 sites in the United States. The power data was developed using wind data at a 100 m hub height and site-appropriate turbine power curves to estimate the power produced at each of the turbine sites.

Cost Estimates

The project cost for a 100 MW, 40 turbine wind farm project located in South Dakota was estimated by HDR to be $1,650/kW. This conceptual engineering, procurement, and construction ("EPC") cost includes the wind turbines, foundations, electrical systems up to the high side of the facility, GSU transformers, and instrumentation and controls. It was assumed that the turbines would be installed on land not owned by NorthWestern resulting in an assumed land lease cost, which is not included in the capital costs (typically included in O&M costs).

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

Currently, wind power plants have a timeline of nominally two years from contractor notice-to-proceed ("NTP") through commercial operation date ("COD"). The 2018 Plan assumes a COD of 2020 for the 100 MW utility-scale wind project being modeled.

Turbine

Consolidated Edison Development Projects

In 2018, NorthWestern Energy entered into power purchase agreements with three qualifying facilities ("QFs") developed by Consolidated Edison Development, Inc. ("CED") known as CED Aurora County Wind, LLC; CED Brule County Wind, LLC; and CED Davison County Wind, LLC.

Aurora County Wind is a 20 MW wind farm located in Aurora County, South Dakota. It has an anticipated online date of December 2018. It will consist of nine Model 2.3-116 General Electric wind turbines. It will have a control system installed for the purposes of limiting the maximum output of the facility to 20 MW at all times.

Brule County Wind is a 20 MW wind farm located in Brule County, South Dakota. It has an anticipated online date of December 2018. It will consist of nine Model 2.3-116 General Electric wind turbines. It will have a control system installed for the purposes of limiting the maximum output of the facility to 20 MW at all times.

Utility Scale Solar PV

Overview

Solar PV technology uses solar cells or photovoltaic ("PV") arrays to convert light from the sun directly into electricity. PV cells are made of different semiconductor materials and come in many sizes, shapes, and ratings. Solar cells produce direct current ("DC") electricity and therefore require a DC to alternating current ("AC") converter to allow for grid connected installations.

Solar PV arrays are mounted on structures that can either tilt the PV array at a fixed angle or incorporate tracking mechanisms that automatically move the panels to follow the sun across the sky. The fixed angle is determined by the local latitude, orientation of the structure, and electrical load requirements. Tracking systems provide more energy production. Single-axis trackers are designed to track the sun from east to west and dual-axis trackers allow for modules to remain pointed directly at the sun throughout the day. For the purposes of modeling solar PV in the 2018 Plan, NorthWestern assumes a 100 MW Solar PV facility with single-axis tracking configuration.

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

Table 5-2. Federal ITC Phase-Down

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

In January 2018, the U.S. imposed a 30% tariff on imported crystalline-silicon solar cells and modules that went into effect February 7, 2018. The tariffs start at 30% of the cell price in 2018 and then gradually drop to 15% by February 7, 2021. Per Solar Energy Industries

Association ("SEIA"), the 30% tariff can be expected to increase year 1 PV module prices by roughly $0.10/W or $100/kW.

Cost Estimates

A 100 MW solar PV installation would include approximately 40, 2.5 MW arrays each consisting of about 8,764 modules of 370 watt-peak-capacity (Wp). The land area required for this application could require about 400 to 700 acres to support the capacity. The major components of a PV system include the PV modules/arrays, DC to AC converters/inverters, and mounting structures. An average capacity factor range for a solar power facility is typically in the range of 10 to 30 percent, with annual averages around 25 percent depending upon solar resources within the region. The estimated average annual capacity factor for the South Dakota site was estimated using NREL's PVSyst program, and determined by HDR to be 24.10%.

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

First year fixed O&M costs for a 100 MW solar power plant are estimated to be $21.60/kW-yr. There are typically no variable O&M costs associated with solar power generation. Typical staffing requirements are minimal and, for the purpose of this analysis, include one salaried and two hourly staff. The 2018 Plan assumes a COD of 2020 for the 100 MW utility-scale solar PV project being modeled.

Battery Energy Storage

Overview

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

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

Li-ion battery technology is a relatively mature technology, having been first proposed in 1970 and released commercially in 1991. The market for utility-scale energy storage systems is relatively early in development, but it is growing and evolving quickly. The increasing demand for battery storage is driving advances in the technology and manufacturing capacity for Li-ion. This is also aiding the trend of declining initial capital cost for this technology.

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

While the first successful demonstration project for a vanadium redox flow battery system was in the 1980's, today, there are only a few systems in operation worldwide. The vanadium redox flow industry is moving toward pre-packaged systems in containers to better compete with Li-ion systems. There is significant interest in these vanadium redox flow systems as they have a high cycle life, have a large allowable temperature range, and longer storage durations.

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

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

The FERC Order essentially removes the barriers for market entry and levels the playing field for BESS with other resources. However, how SPP implements Order 841 will affect storage system market value for NorthWestern and other utilities operating in SPP.

For the 2018 Plan, HDR evaluated a proxy 25 MW, 100 MWh BESS with one discharge cycle per day. The basis of capacity sizing was to provide NorthWestern with about 4 hours of dispatch capability enabling demand management/load shifting as well as provide temporary local service restoration in an outage.

Performance

HDR contacted numerous BESS companies[1] (aka "integrators") for technical and commercial data. Technical information as well as experience, scope of supply, schedule of delivery, pricing and O&M details were solicited from the integrators that responded. Information received was specific to Li-ion technology, largely due to its prevalence in the industry. Some information was also gathered from vanadium redox flow battery integrators.

Major components of a BESS station include the battery containers, battery management system ("BMS"), power conversion system ("PCS") enclosures, plant control systems, and balance of plant systems including the cooling system, station load transformers, pad

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

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

Table 5-3. Battery Energy Storage System Performance Data

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

Table 5.3 summarizes estimated performance data for a typical 25 MW, 100 MWh BESS. An important consideration of BESS is round trip energy efficiency, which is the amount of AC energy the system can deliver relative to the amount of AC energy used by the system during the preceding charge. Losses experienced in the charge/discharge cycle include those from the PCS (inverters), heating and ventilation, control system losses, and auxiliary losses. Li-ion technology experiences degradation both in terms of capacity and round-trip efficiency with time due to a variety of factors including number of full charge/discharge cycles and environmental exposure. Typically, integrators employ augmentation strategies such as oversizing and/or periodic replacement, to ensure the grid connected BESS is supplying the necessary MW, MWh and expected cycle life during the performance period. To meet electric utility customer needs, BESS integrators are willing to provide a guaranteed equipment life of about 20 years with an appropriate augmentation

strategy. Each battery OEM and integrator strategy can be different and there are no set industry standards.

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

Cost Estimates

The capital cost for an installed BESS includes the costs of the energy storage equipment, power conversion equipment, power control system, balance of system including site utilities, electric scope to the high side of the GSU transformer, and installation costs.
For Li-ion systems, battery cells are arranged and connected into strings, modules, and packs which are then packaged into a DC system meeting the required power and energy specifications of the project. The DC system includes internal wiring, temperature and voltage monitoring equipment, and an associated battery management system responsible for managing low-level safety and performance of the DC battery system. For vanadium redox flow batteries, the DC system costs include electrolyte storage tanks, membrane power stacks, and container costs for the system along with associated cycling pumps and battery management controls. Each system would involve a PCS to convert the produced DC power to AC power for ultimate grid utilization. The high level capital costs for a 25 MW/100 MWh Li-ion and vanadium redox flow BESS are estimated by HDR to be \$2,070/kW and \$1,700/kW, respectively.

The major component of the O&M cost for a Li-ion BESS system is related to energy and capacity augmentation. Augmentation maintains the BESS capability to serve the Owner's requirement for the term of the agreement. These costs are typically covered in the fixed O&M costs. Additional fixed O&M costs typically include:

- 24x7 remote monitoring
- Remote troubleshooting
- Performing scheduled maintenance activities, inverter replacements, emergency and unscheduled maintenance support
- Periodic reporting, training and continuous improvement
- Software licensing and updates
- HVAC maintenance
- Auxiliary electrical loads
- Landscaping
- Mechanical/electrical inspections and updates.

For flow battery systems, maintenance services typically include:

- Power stack and pump inspection and replacement
- Inverter replacements
- Sensor calibration
- Cooling systems service
- Tightening of plumbing fixtures and mechanical and electrical connections
- Periodic chemistry refresh and full discharge cycles to refresh capacity

For Li-ion BESS, the variable O&M costs include a discharging or cycling charge which is the variable component of the augmentation service agreement[2]. The total annual augmentation costs are estimated based on one full cycle/day discharge rate. No staffing costs are included. For the Li-ion BESS, conceptual first year fixed and variable O&M costs are estimated at $39.61/kW-yr and $7.00/MWh, respectively.

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

For the vanadium redox flow BESS, conceptual first year fixed O&M costs are estimated at \$34.01/kW-yr[3]. There are typically no variable O&M costs associated with this technology.

The variable O&M costs do not include electric purchases made to charge the batteries. The charging cost can vary and is a function of energy costs at the time of charging.

The BESS integrator's scope of supply typically includes most of the systems up to the inverter terminal where AC power is available to the GSU transformer. Accordingly, the BESS integrator can deliver the major systems within nine months from NTP. Additional site engineering, foundation and substructure work, permitting, site utilities and utility interconnection work is generally completed by a general/EPC contractor. A typical 25 MW BESS project can be commissioned and in commercial operation within 14 months from NTP. The 2018 Plan assumes a COD of 2020 for the BESS project being modeled.

Thermal Resources

Thermal generation options considered in the 2018 Plan include combustion turbine ("CT") and RICE technologies. Both are commonly implemented technologies for utility scale power generation applications using pipeline natural gas as the primary fuel source.

Two of the options considered in the Plan include the option to switch to a backup fuel in the event that the natural gas supply to the power generation facility is curtailed. Both the 50 MW aeroderivative simple cycle CT and the 18 MW simple cycle RICE were evaluated with backup fuel capabilities. Two different backup fuels were considered for these

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

options: diesel fuel oil ("FO") and liquefied natural gas ("LNG"). All other thermal options consider natural gas fuel only.

CT and RICE generation units are commercially proven and widely available technologies for power generation. The major CT and RICE manufacturers have significant experience throughout the world. RICE units generally range in size from 100 kW to 20 MW and current CT offerings range in size from 1.5 MW to 370 MW.

Simple Cycle Frame Combustion Turbine

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

Simple Cycle Aeroderivative CT

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

The nominal 25 MW aeroderivative CT option is assumed to operate in simple cycle, include an inlet air evaporative cooler, and an SCR system/oxidation catalyst for emissions control. The 50 MW aeroderivative CT option consists of a larger nominal 50 MW aeroderivative CT. The base option is a single simple cycle aeroderivative CT operating on natural gas fuel only. Both an inlet air evaporative cooler and exhaust SCR system/oxidation catalyst are assumed. Two additional derivatives of this option were also reviewed considering the use of a secondary backup fuel. Both diesel fuel oil and LNG were considered as backup fuels for this technology.

The option to add diesel fuel backup capability involves the inclusion of a diesel storage tank, additional fuel forwarding pumps, and a modification of the CT to allow operation on both gaseous and liquid fuels. When operating on diesel fuel oil, the CT will experience derated output and efficiency.

Adding the option for LNG involves the addition of a cryogenic tank for storing the LNG, a re-gasifier which converts the LNG back to its original gaseous state, and a system for disposing of the LNG boil off during storage of the fuel. This configuration does not include a natural gas liquefaction plant (LNG assumed to be trucked in). When operating on LNG supply, the turbine output and efficiency are similar to that when the CT is operating on natural gas. This is because the fuel is supplied in its gaseous state. Equipping a facility with LNG storage tends to be more complicated and, as a result, has higher capital cost than when utilizing diesel fuel oil as a back-up fuel supply.

Reciprocating Engines

This resource option consists of a single nominal 18 MW RICE burning natural gas as a primary fuel. The engine is assumed to have an SCR system/oxidation catalysts for emissions reduction and engine cooling is achieved with fin-fan radiators. Like the 50 MW aeroderivative CT described above, this technology is also reviewed with secondary back-up fuel. Both diesel fuel oil and LNG are assumed as backup fuels. Because of the inherent differences in the dual fuel machine relative to the single fuel engines, the dual fuel engines have a lower output and efficiency compared to the gas-only models. Where the gas-only option considers spark ignition (with either natural gas or LNG), the dual fuel (NG/diesel) configuration considers compression ignition. As a result, the dual fuel (NG/diesel) configuration requires a liquid oil pilot system, even when operating on natural gas fuel. The scope of supply for both the diesel fuel train and storage tank and the LNG fuel train and cryogenic storage tank are similar to what is described in the 50 MW aeroderivative CT discussion above. A second RICE option was included for evaluation and consists of a single 9 MW RICE operating on natural gas as the only fuel source. This engine is also assumed to be equipped with an SCR system/oxidation catalyst for emissions control and engine cooling is achieved with fin-fan radiators.

Characteristics of Production and Summary of Costs

Table 5-4 below summarizes the costs of the generation and storage technologies presented in this chapter. These technologies are considered for inclusion in NorthWestern's resource portfolio and modeled using PowerSimm™. The results of portfolio modeling results are presented in Chapter 6.

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Table 5-4. New Resources - Cost Summary

New Resource Characteristics	Fuel	Nameplate Capacity (Nominal)	Design Life	Net Heat Rate - Summer (HHV)[1]	Capital Cost[2]	Fixed O&M (Yr 1)	Variable O&M (Yr 1)
Technology	Type	(MW)	(Years)	(Btu/kWH)	$/kW	($/kW-yr)	($/MWH)
Combustion Turbine - Dry Cooling							
Simple Cycle 1x0 CT - 50 MW Frame	NG	49.3	30	10,087	$1,398	$11.93	$7.62
Simple Cycle 1x0 CT - 25 MW Aeroderivative	NG	27.4	30	10,350	$1,702	$18.43	$4.91
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	50.6	30	9,615	$1,252	$11.54	$3.72
Simple Cycle 1x0 CT - 50 MW Aeroderivative (NG / Fuel Oil)[4]	NG / Fuel Oil	50.4	30	9,654	$1,397	$11.92	$4.39
Simple Cycle 1x0 CT - 50 MW Aeroderivative (LNG)[4]	NG / LNG	50.6	30	9,645	$1,692	$11.98	$4.04
Reciprocating Internal Combustion Engine							
Simple Cycle 1x0 RICE - 18 MW Class NG Only	NG	19.4	30	8,409	$1,833	$23.07	$4.65
Simple Cycle 1x0 RICE - 18 MW Class NG Only (NG / LNG)[4]	NG / LNG	19.4	30	8,438	$2,149	$23.43	$5.00
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel	NG	17.9	30	8,553	$2,017	$25.10	$5.73
Simple Cycle 1x0 RICE - 18 MW Dual Fuel (NG / Fuel Oil)[4]	NG / Fuel Oil	17.4	30	8,593	$2,075	$29.45	$7.38
Simple Cycle 1x0 RICE - 9 MW Class NG Only	NG	9.6	30	8,119	$2,306	$54.20	$4.57
Solar Photovoltaic (PV)							
Solar PV - Single Axis Tracking	N/A	105.0	20	N/A	$1,330	$21.60	N/A
Wind Energy							
Wind Energy	N/A	105.0	25	N/A	$1,650	$37.00	N/A
Battery Energy Storage System (BESS)							
BESS - Lithium Ion (4 Hour)	N/A	26.3	20	N/A	$2,070	$39.61	$7.00
BESS - Vanadium Flow (4 Hour)	N/A	26.3	20	N/A	$1,700	$34.01	N/A

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

CHAPTER 6
PORTFOLIO MODELING AND ANALYSIS

Modeling Overview

NorthWestern uses the PowerSimm™ suite of products from Ascend Analytics to model costs and risks of alternative portfolios. PowerSimm™ uses a stochastic simulation approach to consider uncertainty over the planning horizon. The stochastic simulations allow NorthWestern to quantify the effects of variation of load, renewable generation, thermal generation, and commodity prices on a simulated portfolio. PowerSimm™ is utilized to establish total system production costs, and capital cost expenditures are subsequently accounted for by NorthWestern and are modeled to reflect the regulated utility model as governed by the South Dakota Public Utilities Commission ("PUC").

Implied Market Heat Rate and Volatility

Overview

- Power price projections are a product of forecasted gas prices and implied heat rates, where implied heat rates are projected to decline due to increased renewable penetration.
- As additional zero marginal cost renewables enter the market, average market heat rates decline as thermal resources with higher heat rates become increasingly uneconomic.
- Based on the amount of new renewables expected to enter the market, Ascend's analysis indicates that implied heat rates will decline from 9.7 MMBtu/MWh today to 5.5 MMBtu/MWh in 2040.
- Increased renewables are also expected to increase Day-Ahead ("DA") spot price volatility through 2021, and then hold constant.

- Price projections are uploaded to PowerSimm™ and used for dispatch optimization. Lower prices and higher volatility will result in the economic dispatch of flexible resources instead of traditional inflexible assets.

Implied Market Heat Rate

Historically, competitive electricity markets like SPP exhibited high correlation between gas costs and electricity prices. While this is still largely the case today, some periods are now showing divergence, and this divergence is expected to increase with a shift in generation resources towards renewable energy.

The implied market heat rate is defined as the power price divided by the natural gas price. Typically, the implied market heat rate is compared with the heat rate of generation units to determine what type of unit (e.g. mid-merit combined cycle or peaking combustion turbine) is "in-the-money" and economic to dispatch. While natural gas prices are expected to remain relatively stable for the foreseeable future, the influx of renewable generation in SPP with zero marginal cost portends a reduction in average power costs moving forward. Declining power prices divided by stable gas prices means that market implied heat rates will decline over time. The expected decline in implied market heat rates is illustrated in Figure 6-1.

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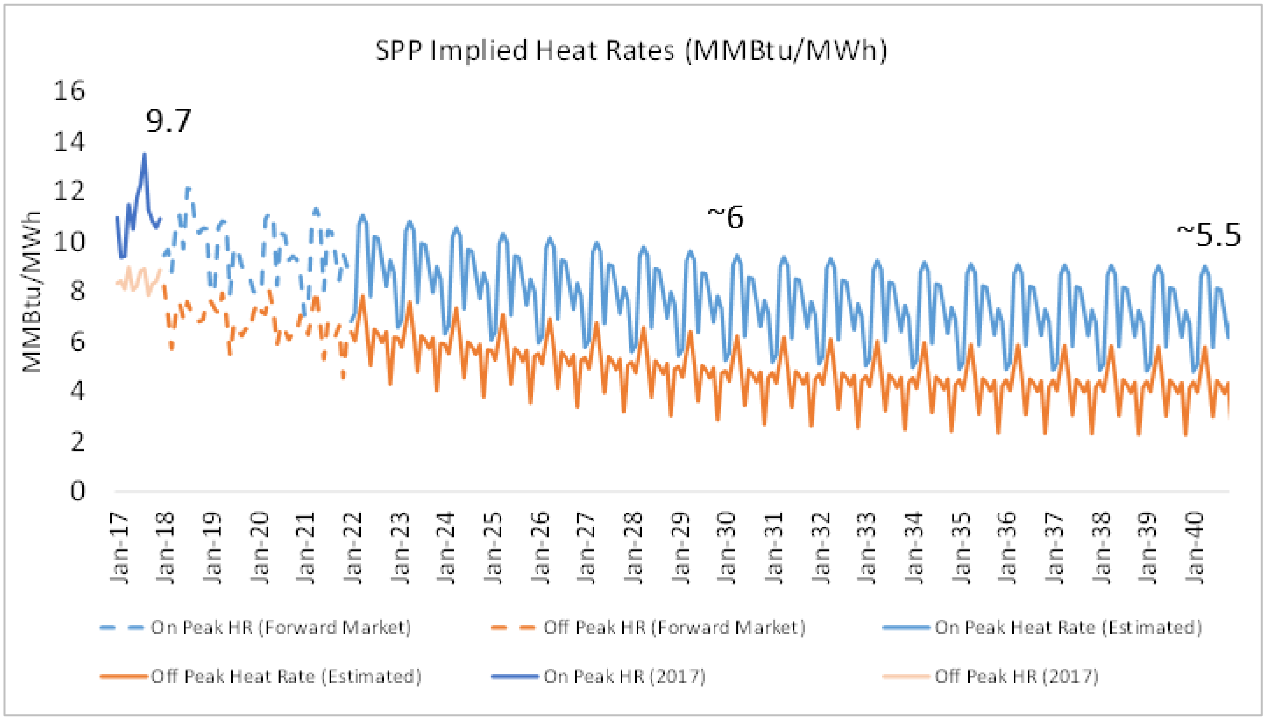
Figure 6-1. Forecast of Implied Market Heat Rates in SPP through 2040



To forecast power and gas prices in the short term, Ascend utilized forward price curves for power at SPP North and gas prices at Ventura through 2021. The forward curves show that future contract power prices are rising at a slower rate than gas prices, showing that the market also expects a decline in implied heat rate. Past 2021, natural gas prices are escalated by the CPI of 2%. Natural gas price projections are shown in Figure 6-2.

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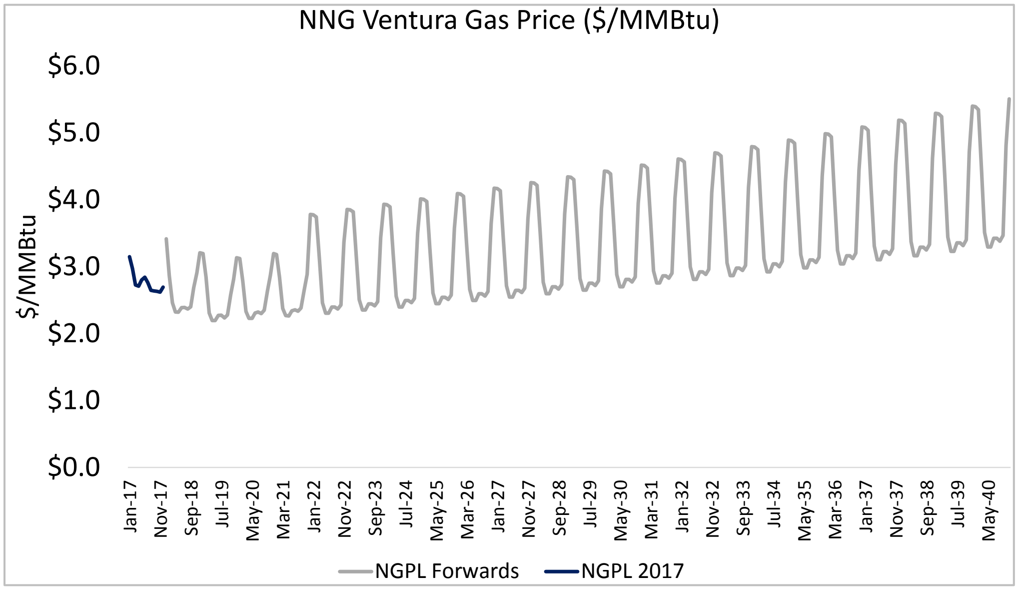
Figure 6-2. Projected Ventura Gas Prices



Past 2021, Ascend projects electricity prices to be the product of projected gas prices and implied heat rates. To forecast implied heat rates, Ascend conducts the fundamentals analysis described below.

The current average implied heat rate in SPP North is ~9.7, which is typical of a coal-heavy system. However, we expect that on average the marginal unit will shift from coal to gas and increasingly wind and solar. Eventually by 2040, the marginal unit will be primarily renewables, setting the implied heat rate lower than that of an efficient gas plant. Table 6-1 shows the percentage each generation type has been the marginal unit over time, historically and projected.

Table 6-1. Frequency of Marginal Unit by Asset Type, Historical and Projected

Year	Coal	Natural Gas	Wind *
2015	52%	19%	6%
2016	37%	27%	9%
2017	37%	27%	14%
2020	30%	25%	20%
2025	23%	20%	30%
2030	10%	15%	45%

Traditionally, market heat rates have been a metric of what type of generation has been competitive. As shown in Table 6-1, renewables are anticipated to be the marginal generation much of the time. As a result, implied heat rates are expected to decline and electricity market prices are expected to follow; driving Ascend's conclusion that implied market heat rates will decline to about 5.5 by 2040.

SPP has seen significant wind additions with the decline of capital costs associated with renewables, a trend that is expected to continue into the future. Table 6-2 shows the minimum, average, and maximum percent of renewable generation serving load in any given hour within the month. In 2017, while the average wind penetration as a percentage of load in SPP in any given hour was approximately 20-25%, the region experienced renewable (wind) penetration rates as high as about 55%.

Table 6-2. Minimum, Average, Maximum % Renewables Serving Load

	Min % Renewables serving load	Average % Renewables serving load	Max % Renewables serving load
January	1.60%	22.30%	45.40%
February	2.10%	28.20%	51.50%
March	3.60%	30.30%	52.90%
April	6.10%	30.70%	53.30%
May	2.90%	25.60%	51.50%
June	1.40%	19.90%	46.80%
July	1.90%	14.40%	36.60%
August	1.20%	12.30%	41.10%
September	2.00%	22.60%	48.50%
October	4.20%	31.30%	53.30%
November	5.10%	27.30%	51.70%
December	2.80%	26.20%	54.60%

Renewable generation in SPP is becoming “the new baseload” generation. Typically wind assets have an incentive to run even at negative prices due to the PTC. This has caused an increase in the frequency of negative prices. The relationship between wind share of load and DA prices over the past three years is shown below.

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Figure 6-3. DA Prices vs. Renewable Penetration in SPP

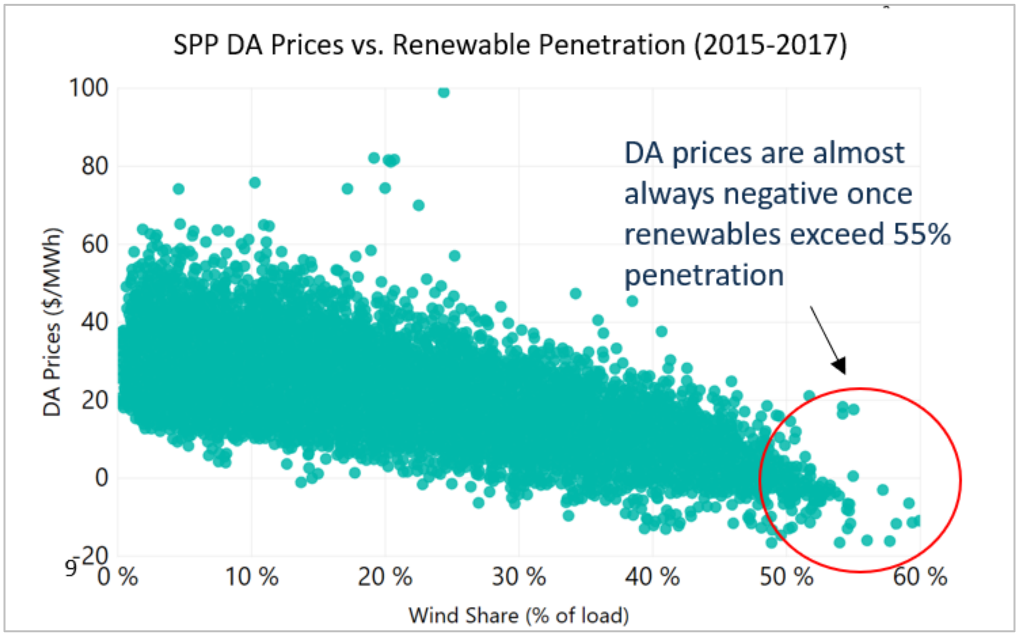

Figure 6-3 shows the relationship between wind generation and the decline in DA prices. Interestingly, it also shows that after about 50% wind penetration, prices are almost always negative. With more wind additions, and increasingly more solar in the interconnection queue, the observed trend of low or negative prices should increase. Figure 6-4shows the shifting generation mix from 2015-2017, as well as Ascend's projection of the generation mix in 2040.

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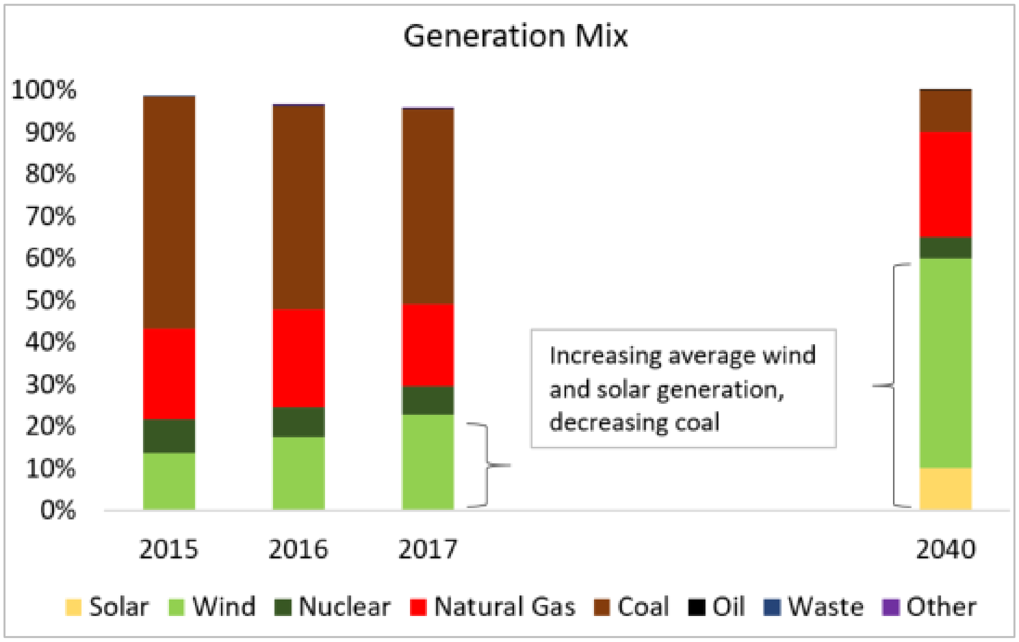
Figure 6-4. Historical and Projected SPP Generation Mix



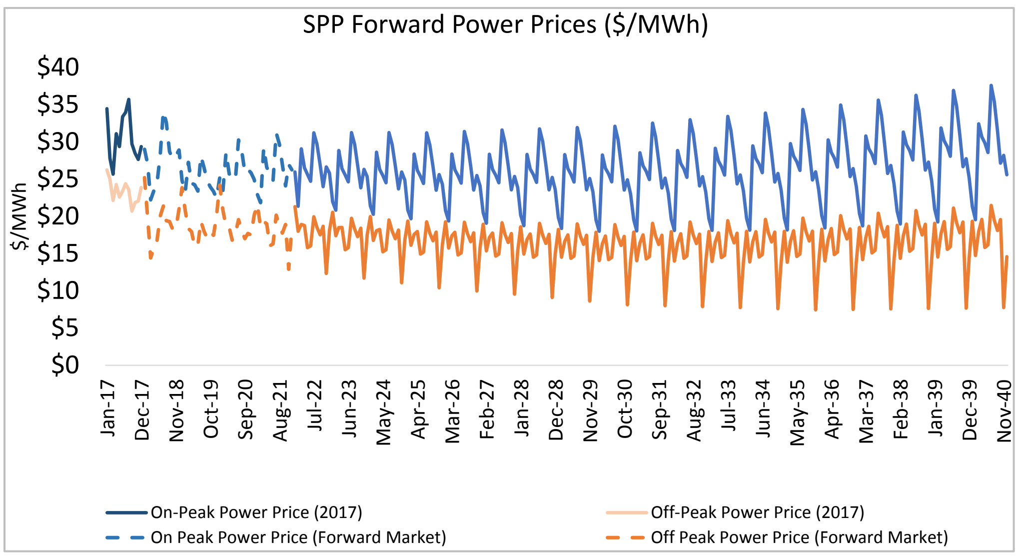
Ascend based projections of renewable energy on projected installations from the SPP interconnection queue. Table 6-3 shows future projects with at least an approved interconnection agreement in place through 2021. Ascend conservatively assumes only about 20% of the projects below will be developed. After 2021, Ascend forecasts the growth of renewable installations at a slightly slower rate of increase based on projections of over generation and curtailment of intermittent wind and solar.

Table 6-3. Projected Installation from SPP Interconnection Queue

In-Service Date	Wind (GW)	Solar (GW)	Battery (GW)
2018	8.9	1.3	
2019	10.8	3.9	
2020	24.8	10.7	2.4
2021	7.3	3.4	0.4

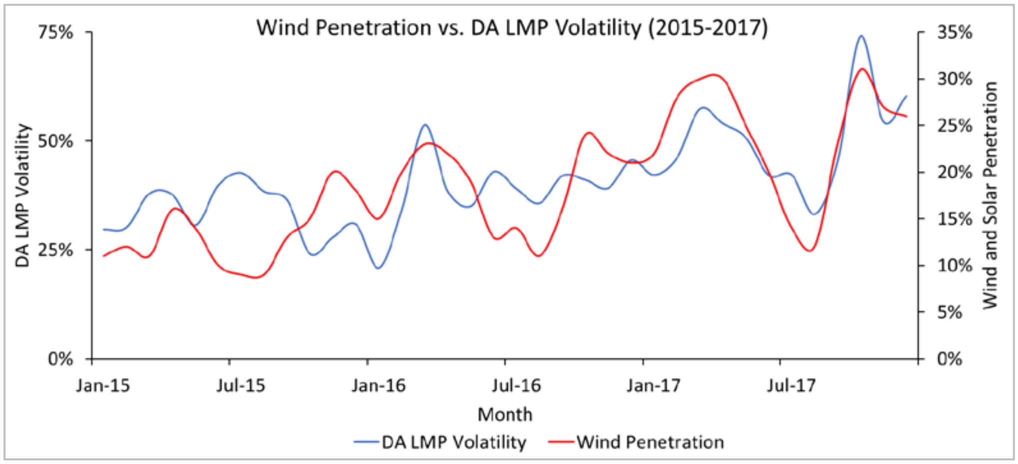
Growth in CTs is expected to remain constant over time, but as volatility in price increases due to rise in intermittent generation, flexible generation with immediate ramp rates will provide greater reliability to the grid and will be dispatched more. In addition, with rapidly falling battery module prices, installations of battery projects will increase to help mitigate increasing price volatility. Ultimately, Ascend determined power price as a function of projected gas price and implied market heat rate. As shown in Figure 6-5, power prices are expected to decline slightly over time before leveling off and then begin increasing slightly past 2030.

Figure 6-5. Projected Power Prices at SPP North



Along with annual declining power price projections dependent on implied heat rates, volatility in prices is projected to increase dramatically with increases in intermittent renewable generation availability. Figure 6-6 below shows the monthly wind penetration levels in SPP from 2015 through 2017, along with the monthly volatility of hourly DA LMP prices. At about 20% renewable penetration, the relationship between DA spot price volatility and renewable penetration becomes increasingly correlated.

Figure 6-6. Wind Penetration vs. DA Spot Price Volatility



DA LMP volatility becomes increasingly correlated with greater growth in renewable penetration. This is demonstrated as the hourly price shapes over the course of a day shift with more solar online mid-day and greater wind online at night. Figure 6-7 shows how the hourly implied heat rate shape is projected to change over time (from 2018 to 2021 to 2024) given projections in solar and wind growth. Mid-day implied heat rates are greatly reduced (the "duck curve" effect) and night time hours also exhibit lower implied heat rates as well. Shoulder hours are anticipated to see greater implied heat rates over time as inflexible generation is required to come online as the sun sets. The daily profile for market prices will follow market heat rates, while natural gas prices are expected to remain relatively constant within the day.

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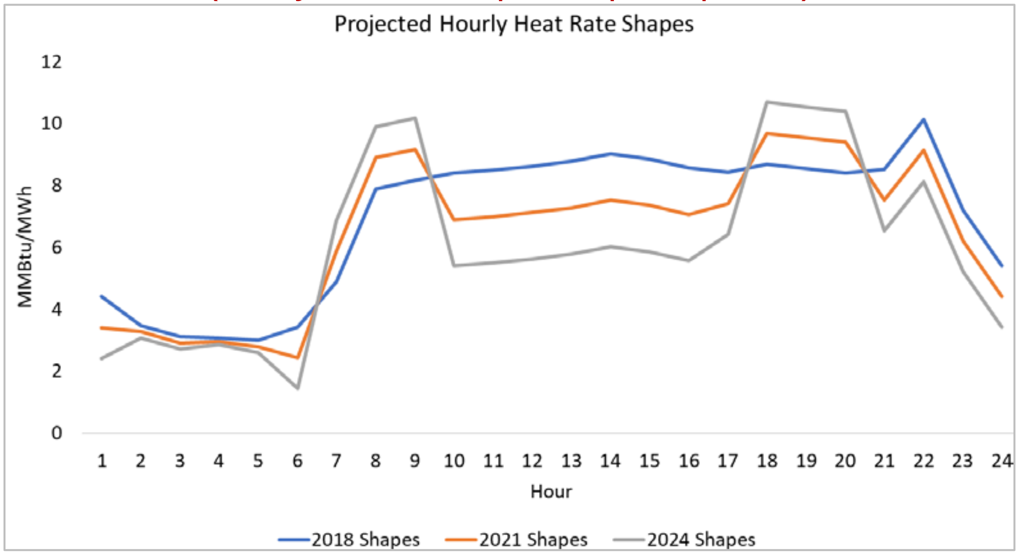
Figure 6-7. Projected Shift in Hourly Heat Rate Profiles
(Proxy for shift in power price profile)



Average wind penetration levels in 2017 were about 20-25%, with total renewable generation reaching over 50% in some hours (Table 6-2). Figure 6-8 below shows projected volatility growing at a slightly faster rate than the past few years due to the strong projections of solar and wind project development (Table 6-3). After 2021, Ascend takes a conservative approach and maintains the volatility projected in 2021 throughout the remainder of the forecast. Ascend's approach reflects the difficulty of forecasting future volatility in prices given many variables, including the potential for batteries to enter the market that will help to mitigate price volatility.

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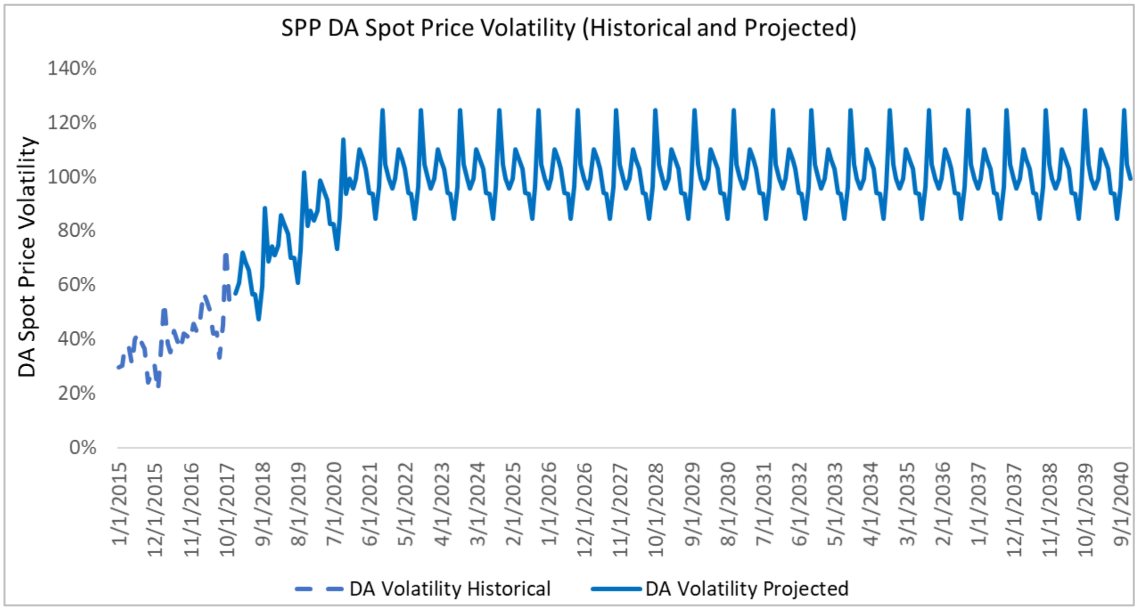
Figure 6-8. Historical and Projected Day-ahead Spot Price Volatility



The above inputs (projections of power price and DA spot volatility) are used in PowerSimm™ modeling of NorthWestern's portfolios. SPP North prices are projected based on gas prices and declining implied heat rates, as well as increasing spot price volatility. These price projections are uploaded to NorthWestern's PowerSimm™ portfolio and NorthWestern's assets are optimally dispatched at this price. The dispatch of existing and future assets will be impacted by this new market outlook.

Increasing hourly spot volatility will impact traditional inflexible assets in PowerSimm™. Generation assets, such as coal plants and combined cycle gas plants, will not be able to ramp quickly enough to react to market volatility. In addition, generation assets with long start-up times and high start-up costs may miss the high price periods in a more volatile market. These economic considerations are included in PowerSimm's™ optimization logic and the effects are shown in the dispatch results.

Portfolio Analysis

Defining Potential Resources

The resource technologies considered for inclusion in NorthWestern's resource portfolio are shown in Table 6-4, (a larger version of this table is included in Chapter 5 as Table 5-4). HDR analyzed two battery technologies in the 2018 Resource Planning Generation and Storage Resource Characteristics study; Li-Ion and Vanadium flow technologies. Additionally, HDR analyzed the costs of utility-scale wind and solar PV facilities.

Table 6-4. Resource Definition and Cost Summary

New Resource Characteristics	Fuel	Nameplate Capacity (Nominal)	Design Life	Net Heat Rate - Summer (HHV)[1]	Capital Cost[2]	Fixed O&M (Yr 1)	Variable O&M (Yr 1)
Technology	Type	(MW)	(Years)	(Btu/kWH)	$/kW	($/kW-yr)	($/MWH)
Combustion Turbine - Dry Cooling							
Simple Cycle 1x0 CT - 50 MW Frame	NG	49.3	30	10,087	$1,398	$11.93	$7.62
Simple Cycle 1x0 CT - 25 MW Aeroderivative	NG	27.4	30	10,350	$1,702	$18.43	$4.91
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	50.6	30	9,615	$1,252	$11.54	$3.72
Simple Cycle 1x0 CT - 50 MW Aeroderivative (NG / Fuel Oil)[4]	NG / Fuel Oil	50.4	30	9,654	$1,397	$11.92	$4.39
Simple Cycle 1x0 CT - 50 MW Aeroderivative (LNG)[4]	NG / LNG	50.6	30	9,645	$1,692	$11.98	$4.04
Reciprocating Internal Combustion Engine							
Simple Cycle 1x0 RICE - 18 MW Class NG Only	NG	19.4	30	8,409	$1,833	$23.07	$4.65
Simple Cycle 1x0 RICE - 18 MW Class NG Only (NG / LNG)[4]	NG / LNG	19.4	30	8,438	$2,149	$23.43	$5.00
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel	NG	17.9	30	8,553	$2,017	$25.10	$5.73
Simple Cycle 1x0 RICE - 18 MW Dual Fuel (NG / Fuel Oil)[4]	NG / Fuel Oil	17.4	30	8,593	$2,075	$29.45	$7.38
Simple Cycle 1x0 RICE - 9 MW Class NG Only	NG	9.6	30	8,119	$2,306	$54.20	$4.57
Solar Photovoltaic (PV)							
Solar PV - Single Axis Tracking	N/A	105.0	20	N/A	$1,330	$21.60	N/A
Wind Energy							
Wind Energy	N/A	105.0	25	N/A	$1,650	$37.00	N/A
Battery Energy Storage System (BESS)							
BESS - Lithium Ion (4 Hour)	N/A	26.3	20	N/A	$2,070	$39.61	$7.00
BESS - Vanadium Flow (4 Hour)	N/A	26.3	20	N/A	$1,700	$34.01	N/A

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

Defining Potential Portfolios

Table 6-5 lists the modeling assumptions for the portfolios that NorthWestern modeled using PowerSimm™. NorthWestern's base case resource portfolio ("Base") includes existing resources and one new 20 MW Recip added in 2020 in order to maintain SPP PRM requirements. Base portfolio natural gas forward prices are based on EIA's forecast of natural gas prices at SPP interconnects in its 2018 Annual Energy Outlook reference case. Electric forward market prices reflect Ascend's projection of declining market heat rates and increased price volatility as discussed earlier in this chapter. The Base portfolio also provides the "base" on which all other resource portfolios are modeled.

Two portfolios, "Wind" and "Solar," analyze the effects of additional utility-scale renewables on NorthWestern's resource portfolio. The "Li-Ion portfolio analyzes the effects of adding a Li-ion battery facility to the portfolio. To provide comparable levels of capacity, which is necessary for and "apples-to-apples" comparison, the Wind, Solar and Li-Ion add enough of their respective resources in 2020 to replace the 20 MW Rice in the Base portfolio.

The Wind portfolio replaces the 20 MW Rice in the Base with 400 MW of wind added in 2020. PTCs were included in the evaluation of the Wind portfolio at $24/MWh (or 100 percent). Similarly, the Solar portfolio replaces the 20 MW Rice in the Base, with 200 MW of solar PV added in 2020. The Solar portfolio included an Investment Tax Credit (ITC) of 26 percent. Except for the replacement of 2020 Rice generation unit, all other input assumptions for Wind and Solar align with the Base portfolio.

HDR analyzed two battery technologies for the 2018 Plan, Li-Ion and Flow batteries; NorthWestern modeled the Li-Ion technology. The "Li-Ion" portfolio replaces the 20 MW Rice in the Base with a 20 MW/80 MWh Li-Ion battery installation added in 2020. PowerSimm™ analysis is limited to hourly energy effects and did not model any additional value for ancillary services. A discussion on ancillary services occurs later in this chapter. The Base, Wind, Solar PV, and LI-Ion portfolios all add 20 MW of capacity in 2020, and all four portfolios are directly comparable on an resource adequacy basis.

The Fleet Assessment performed by HDR is presented in Chapter 4. The "Retire #7" portfolio evaluates the portfolio created by Scenario #7 from the Fleet Assessment study. Retire #7 models the retirement and replacement of generation resources at Yankton, Huron, and Aberdeen. In 2022, 13.6 MW of generation at Yankton is replaced with a 20 MW Recip unit. In 2024, 61.3 MW of generation at Huron is replaced with three 20 MW Recip units to be located at Redfield, Huron, and Mitchell. In 2028, 22.6 MW of generation from Aberdeen Unit 1 is replaced with a 20 MW Recip at Aberdeen.

NorthWestern has continued to assess various retire and replace scenarios since the completion of the fleet assessment. The "Alt. Retire" portfolio analyzes NorthWestern's current thinking regarding the logical staging for retirement and replacement. The Alt. Retire portfolio examines the retirement of the same generation assets as the Retire #7 portfolio, but with different timing. In 2022, 43.7 MW at Huron (Unit 2) is replaced with two 20 MW Recips. In 2025, 13.6 MW of generation at Yankton is replaced with a 20 MW Recip. In 2028, 11 MW of generation at Huron (Unit 1) is replaced with a 20 MW Recip located in Mitchell. In 2031, 22.6 MW of generation at Aberdeen (Unit 1) is replaced with a 20 MW Recip.

NorthWestern also analyzed two high load growth portfolios. The "Growth" portfolio contains all of the same modeling assumptions as the Base portfolio, except for higher load growth (2.5 additional MW/year), and the inclusion of additional resources to maintain SPP PRM requirements. In the Growth portfolio, a 20 MW Recip is added to the resource portfolio in 2020 and another in 2026.

The "Growth & Retire" portfolio combines high load growth with the retirement of generation at Yankton, Huron, and Aberdeen. In 2020, 61.3 MW at Huron is replaced with

60 MW of Recip generation. In 2024, 13.6 MW of generation at Yankton in replaced with 40 MW of Recip generation. In 2028, Aberdeen Unit 1 (22.6 MW) generation is replaced with 40 MW of Recip generation added at Mitchell. In 2037, 40 MW of Recip generation is added at Aberdeen.

Table 6-5. Resource Plan Portfolio Assumptions

Portfolio	Assets	Natural Gas/Power/Load Forecast
Base	Big Stone, Neal, Yankton, Titan, Beethoven, OakTree, Aberdeen, Coyote, Mobile Units, Huron, Aurora County, Brule County, Davison County, Retire Clark in 2019, Retire Faulkton in 2019, Add 20 MW Rice in 2020	– Base case load forecast – Electricity monthly forward price curves from Ascend – Natural gas prices use ICE through October 2019, and then escalated using EIA's 2018 AEO escalation for Henry Hub
Wind	Base - 20 MW Rice in 2020 + 400 MW Wind in 2020	– Same as Base
Solar	Base -20 MW Rice in 2020 + 200 MW Solar PV in 2020	– Same as Base
Li-Ion	Base - 20 MW Rice in 2020 + 20 MW/80 MWh Li-Ion Battery in 2020	– Same as Base
Retire #7	Base - Base addition - 13.6 MW at Yankton in 2022 + 20 MW at Yankton in 2022 - 61.3 MW at Huron in 2024 + 20 MW at Redfield, 20 MW at Huron, and 20 MW in Mitchell in 2024 - 22.6 MW at Aberdeen 1 in 2028 + 20 MW in Aberdeen in 2028	– Same as Base
Alt. Retire	Base -Base Addition - 43.7 MW at Huron in 2022 + 40 MW at Huron in 2022 -13.6 MW at Yankton in 2025 + 20 MW in Yankton in 2025 - 17.6 MW at Huron in 2028 + 20 MW in Mitchell in 2028 - 22.6 MW at Aberdeen in 2031 +20 MW in Aberdeen in 2031	– Same as Base
Growth	Base - Base Addition + 20 MW at Huron in 2020 + 20 MW at Huron in 2026 + 20 MW at Huron in 2033 + 20 MW at Aberdeen in 2039	– Base with higher load growth of 2.5 MW/yr
Growth & Retire	Base - Base Addition - 61.3 MW at Huron in 2020 + 60 MW in Huron in 2020 - 13.6 MW at Yankton in 2022 + 40 at Yankton in 2022 - 22.6 MW at Aberdeen in 2028 + 40 MW at Mitchell in 2028 + 40 MW at Aberdeen in 2037	– Same as Growth

Summary of Results

Portfolio modeling with PowerSimm™ produces a total NPV of term costs for each portfolio. The total NPV costs are segregated into components of existing resource fixed and capital costs, variable costs, new resource fixed and capital costs less the residual value of new resources, and risk premium. The NPVs in Figures 6-9 through 6-11 do not reflect any additional value that could be gained from the sale of ancillary services to the SPP markets. SPP includes markets for Regulation Up, Regulation Down, Spinning Reserve, and Supplemental Reserve. Table 6-6 shows the average prices for these products during 2017 in the Real-time ("RT") market.

Table 6-6. Average Prices for Ancillaries in 2017

	RT Reg Up $/MWh	RT Reg Down $/MWh	RT Spin $/MWh	RT Supp $/MWh
2017 Average Price	$9.97	$9.78	$5.29	$0.97

Both Recips and batteries are capable of providing ancillary services. The value that could be realized through the sale of ancillary services would depend on the specific characteristics and operating costs of the resources. For example, the amount of Regulation Up and Regulation Down that could be provided would depend on the resource's ability to ramp up or down in a 5-minute period.

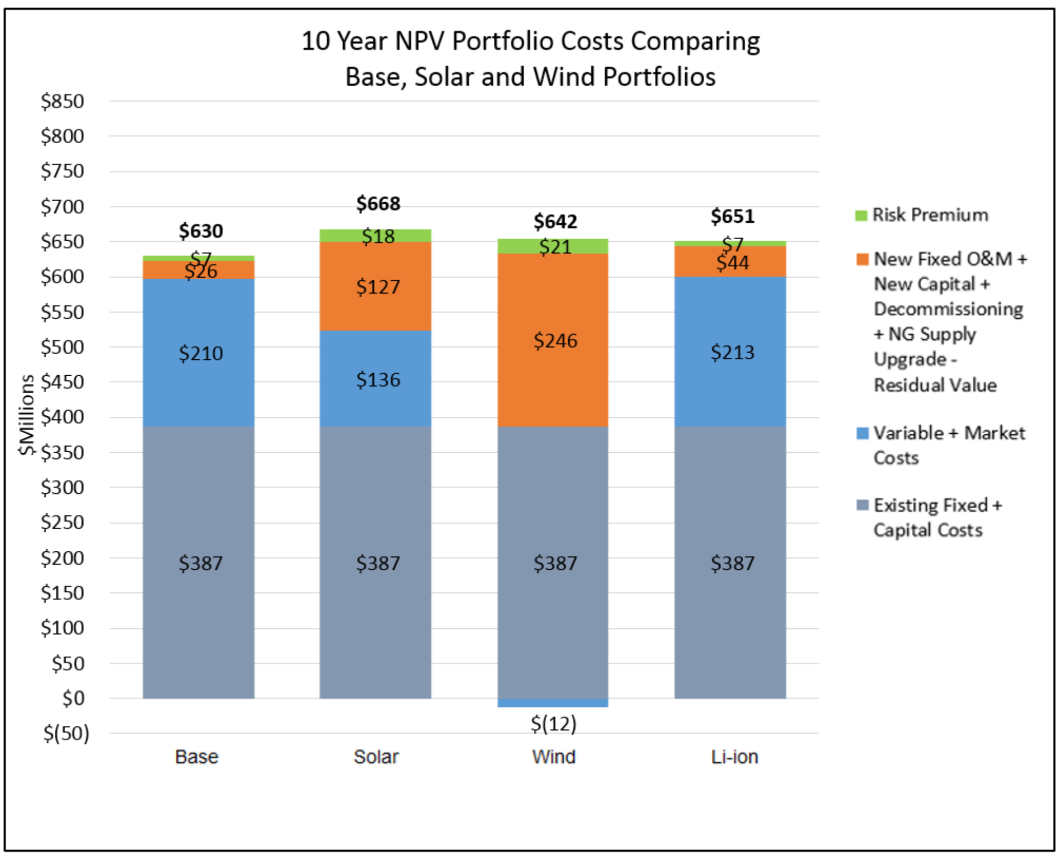
For a Recip, the cost of providing those services would depend on the cost of fuel and other variable costs to operate at a set point that would allow a resource to dispatch up or down from that level. The provision of ancillary services using battery installations would likely increase the number of charge and draw-down cycles that a battery would experience, therefore degradation would likely occur sooner than would otherwise be the case.

Similarly, providing ancillary services would likely increase the ramping of Recips and could potentially lead to higher maintenance costs. The resource costs provided by HDR in Table 6-4 do not reflect operations for ancillary services.

Portfolio Modeling Results

Figure 6-9 shows the 10-year NPV of costs for the Base, Solar, Wind, and Li-Ion portfolios. The Base portfolio represents "business as usual" with a capacity addition in 2020 to meet Southwest Power Pool (SPP) planning reserve margin (PRM) requirements. All other portfolios are derived from the Base Portfolio.

Figure 6-9. Net Present Value of Portfolio Costs
Base, Solar, Wind, and Li-Ion Portfolios



The cost category titled “Existing Fixed + Capital Costs” includes the revenue requirement of NorthWestern’s existing portfolio of generation. The cost categories “Variable + Market Costs” and “Risk Premium” are calculated using PowerSimm™. The category “New Fixed O&M + New Capital + Decommissioning + NG Supply Upgrade – Residual Value” reflects the revenue requirement impacts of adding new generation to the resource portfolio and also reflects the residual value of the remaining life of the new assets beyond the 10-year planning period.

The Base portfolio has the lowest NPV costs. The resource additions in the Wind, Solar, and Li-ion portfolios match the Base and provide equivalent SPP PRM requirements, but are not viable alternatives to replace the assets considered for retirement in the Fleet Assessment. Li-Ion portfolio costs are higher than Base, but the analysis does not value the ancillary services a Li-Ion facility could provide; nor does it include the extra costs associated with providing those services.

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Figure 6-10. Net Present Value of Portfolio Costs
Base, Growth, and Growth & Retire Portfolios

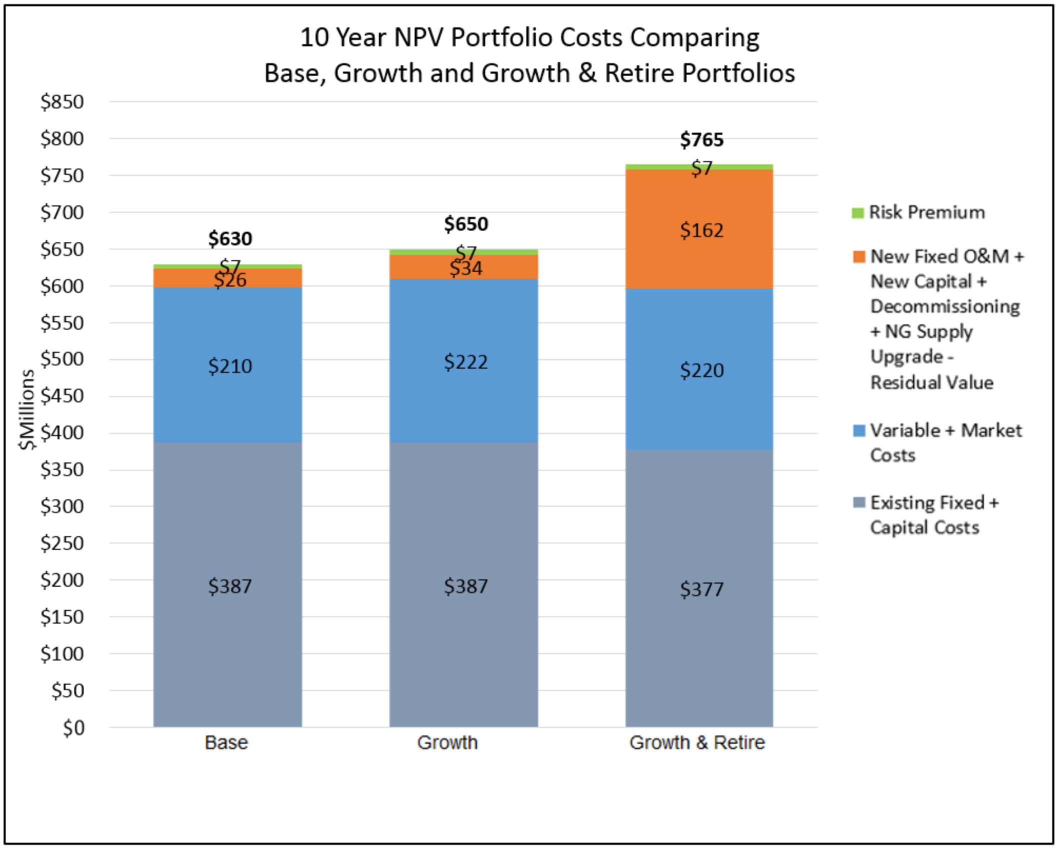


Figure 6-10 compares the 10-year NPV of costs for the Base, Growth, and Growth & Retire portfolios. The Growth portfolio includes an additional 2.5 MW/year growth in peak load, which results in a need for additional capacity. As with the Base portfolio, the Growth portfolio adds Recip units to satisfy SPP PRM requirements. The Growth portfolio serves as the "base case" for the Growth & Retire portfolio. The Growth & Retire portfolio includes additional investment to replace Aberdeen Unit 1, Huron Unit 1 and Huron Unit 2 generation facilities, and includes new assets to meet SPP PRM requirements.

Figure 6-11. Net Present Value of Portfolio Costs
Base, Retire #7 and Alt. Retire Portfolios

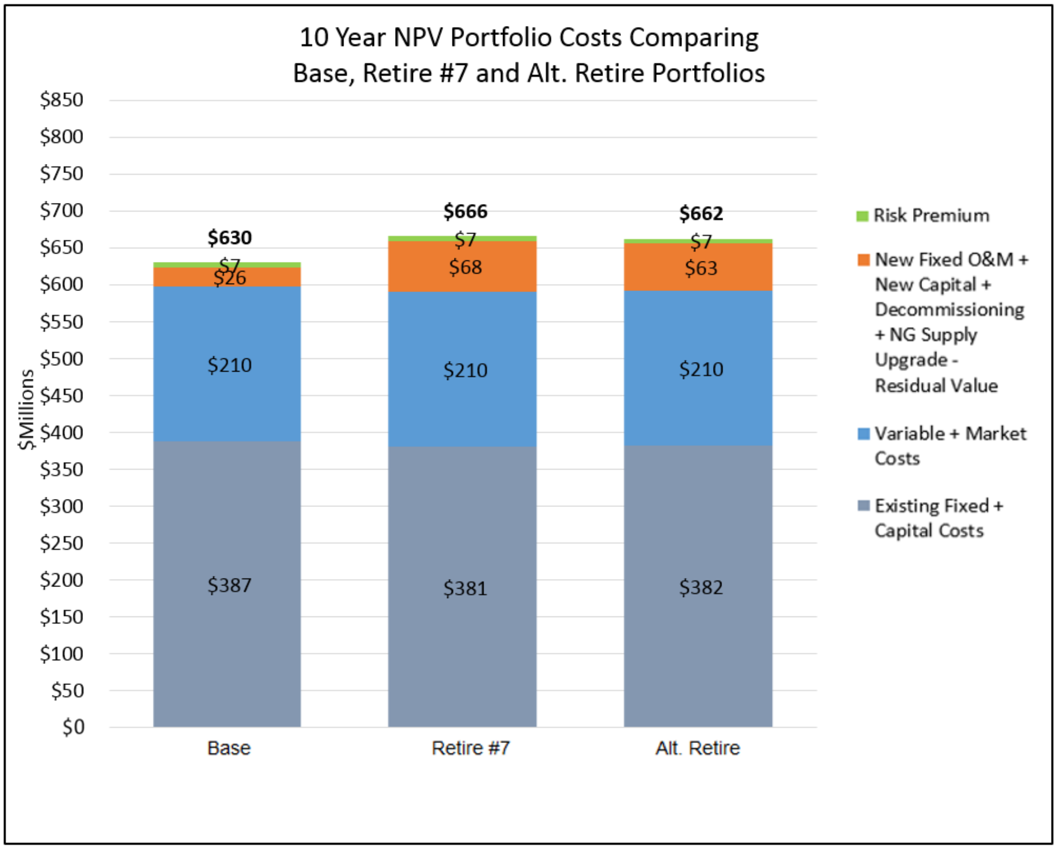
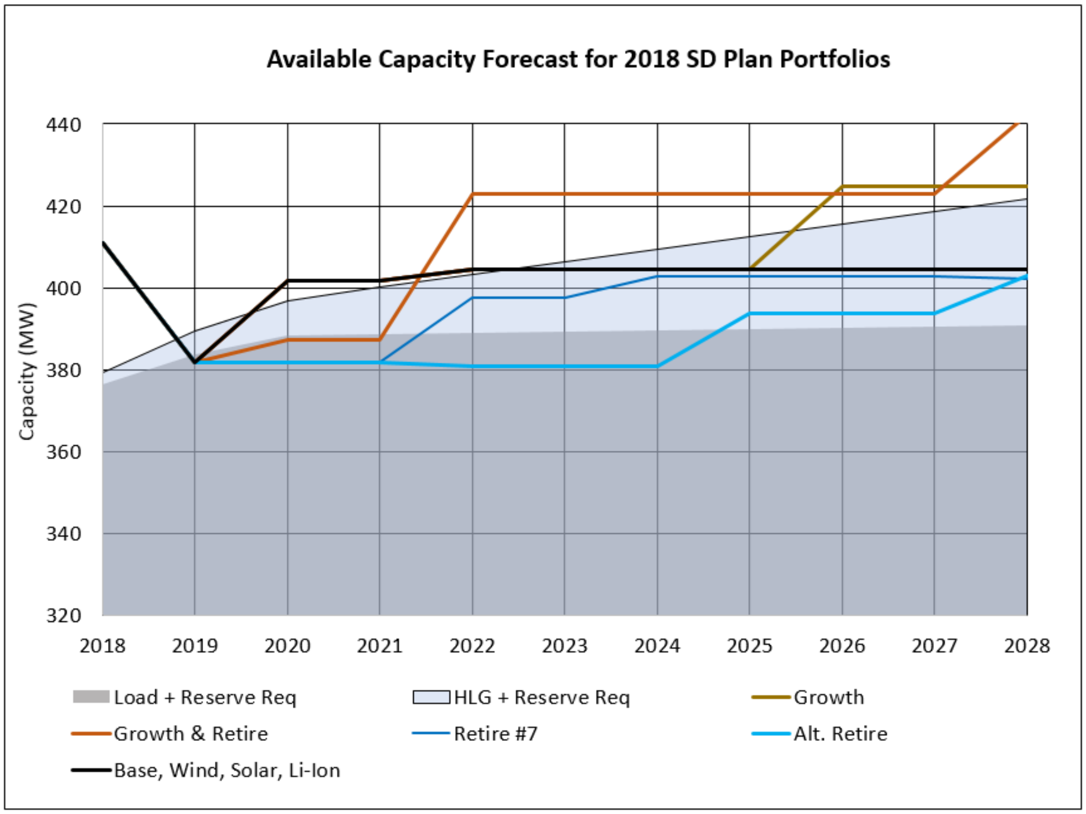


Figure 6-11 shows the results of the Base, Retire #7, and the Alt. Retire portfolios. In both retirement portfolios, rate base for existing resources is reduced to reflect the retirement of existing resources, and additional new capital costs are included to reflect additional investment. The Retire #7 and Alt. Retire portfolios are $20 million and $36 million higher than Base portfolio respectively. The retirement portfolios are higher cost, but provide NorthWestern's customers with a continued legacy of reliable local energy supply and enhance system reliability.

The shaded areas in the Figure 6-12 represent forecasted capacity needs in the Base and Growth scenarios. Capacity positions for each of the eight portfolios modeled are illustrated by the colored lines. As discussed above, the capacity additions in the Base, Wind, Solar and Li-Ion portfolios align perfectly, as each portfolio adds 20 MW of capacity to the portfolio in 2020.

Figure 6-12. Available Capacity Forecast by Portfolio



Conclusions

NorthWestern modeled renewables, battery technology, and retire and replace portfolios against the current Base portfolio. The Wind, Solar and Li-ion portfolios are all higher cost than the Base portfolio, which is the least-cost NPV portfolio. Additionally, those portfolios do not address the issues raised in HDR's Fleet Assessment.

Maintaining and enhancing local reliability and grid support remains a high priority for NorthWestern. Additionally, capacity continues to be of concern and NorthWestern will continue to evaluate its capacity needs and the best means to meet those needs.

With these goals in mind, NorthWestern will pursue courses of action which maintain or improve local area reliability, maintain or improve grid reliability, and provide opportunities for economic growth. NorthWestern intends to pursue a staged retirement and replacement strategy that occurs over time. Replacing generation assets in stages allows for continual reassessment of technologies and their costs, and current market conditions prior to each separate stage of the retirement and replacement strategy.

CHAPTER 7
ENVIRONMENTAL

Environmental Trends that Influence the 2018 Plan

Introductory Statement

Environmental considerations continue to be a critical aspect of NorthWestern's resource planning process. We are committed to providing utility services that reliably and cost-effectively meet our customers' needs, while protecting the quality of the environment. We are vigilant in monitoring the impacts of our operations on the environment, in complying with the spirit, as well as the letter, of environmental laws and regulations, and in responsibly managing the natural resources under our stewardship.

NorthWestern's Statement of Environmental Policy

NorthWestern Energy's policy is to provide cost-effective, reliable and stably-priced energy while being good stewards of the natural resources and complying with environmental regulations. We apply the following environmental principles in our day to day business:

1. Our business practices reflect a respect for, and a commitment to, sustainability and the long term quality of the environment.
2. One of our priorities is being good stewards of natural and cultural resources at our hydroelectric projects.
3. We comply with the spirit as well as the letter of environmental laws and regulations.
4. Environmental issues and impacts are an integral part of our planning, operating and maintenance decisions.
5. We promote our customers' efforts to conserve energy.

6. We support providing energy through non-carbon emitting and renewable resources when consistent with our statutory requirement to provide cost-effective energy.
7. We strive to minimize the generation of wastes and promote the reuse and/or recycling of materials.
8. We seek to continuously improve our environmental compliance and stewardship.
9. We embrace a team culture where positive environmental stewardship and compliance are encouraged, mentored and rewarded.
10. Our contractors and consultants must comply with this policy when working for or representing NorthWestern Energy.

The electric utility sector is heavily regulated by state and federal environmental laws such as the Clean Air Act, the Clean Water Act, the Endangered Species Act, the Migratory Bird Treaty Act, the Bald and Golden Eagle Protection Act, and laws regulating waste generation and disposal. High-level considerations of environmental regulations are discussed below.

Clean Air Act

No single law or public policy issue has had as great an influence on resource planning as the Clean Air Act. Below we provide high-level considerations of the Clean Power Plan, Regional Haze, and the Mercury and Air Toxics Rule (MATS).

Greenhouse Gas ("GHG") Emissions

Regulations covering GHG emissions from new and existing electric generating units vividly demonstrate the potential impacts of the Act and have injected substantial uncertainty into the planning process. Coal-fired generation plants are under particular scrutiny due to their level of GHG emissions. As discussed in Chapter 3 and depicted in Figure 3-2, our South Dakota energy supply resource mix includes 56% of base load coal-fired energy generation provided by jointly owned coal plants located in three states – the Big Stone Plant in South Dakota, the Coyote Station in North Dakota, and the Neal 4 Plant in Iowa.

New Source Performance Standards ("NSPS")

On October 23, 2015, the final standards of performance to limit GHG emissions from new, modified, and reconstructed fossil fuel generating units and from newly constructed and reconstructed stationary combustion turbines were published in the Federal Register ("FR"). The standards reflect the degree of emission limitations that the U.S. Environmental Protection Agency ("EPA") believes are achievable through the application of its designated "best systems of emission reduction" ("BSER"). Parties are currently challenging this regulation. EPA's carbon dioxide ("CO_2") emissions limit for fossil fuel-fired electric utility steam generating units precludes the construction of any new base load coal-fired plants because the BSER includes carbon capture and storage systems which are not yet ready for commercial use. New base load natural gas combined cycle and simple cycle combustion turbines are also required to meet a CO_2 emissions standard. Non-base load simple cycle combustion turbines are required to meet a heat input-based standard. New reciprocating engines would not be affected by the NSPS. NorthWestern's analyses in this plan factored in consideration of the NSPS for combustion turbines.

Existing Source Performance Standards

The final rule titled, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units" was also published in the FR on October 23, 2015. This rule establishes guidelines for states to follow in developing plans to reduce GHG emissions from existing electric generating units under Section 111(d) of the Clean Air

Act. EPA refers to this rule as the Clean Power Plan ("CPP").

The CPP specifically establishes CO_2 emission performance rates for existing fossil fuel-fired electric utility steam generating units and stationary combustion turbines. The CPP established dates by which states were required to submit plans. Initial plans were due to EPA by September 2016, although states had the option to seek a two-year extension to finalize their plans. On February 9, 2016, the U.S. Supreme Court issued a stay of the implementation of the final CPP pending resolution of challenges by several states (including South Dakota), utilities, trade groups and other companies.

On March 28, 2017, President Trump issued an Executive Order instructing all federal agencies to review all regulations and other policies (specifically including the Clean Power Plan) that burden the development or use of domestically produced energy resources and suspend, revise or rescind those that pose an undue burden beyond that required to protect the public interest. As a result of the Executive Order review, the EPA proposed to repeal the CPP on October 10, 2017. Subsequently, the EPA issued an Advance Notice of Proposed Rulemaking on December 28, 2017, soliciting information on systems of emission reduction that comply with EPA's interpretation of the Clean Air Act for a possible replacement of the CPP. In its repeal and replace proposal, EPA indicated that it had not yet determined whether it will promulgate a new rule to replace the CPP and the form, if any, such a replacement would take.

Due to the actions described above, there remains significant risk regarding the uncertainty of the ultimate disposition of carbon emissions reductions in the states where NorthWestern's jointly owned affected power plants are located.

Carbon Costs

Estimated potential future costs associated with the regulation of CO_2 emissions from thermal power plants represent one of the risks that NorthWestern considered in its modeling analysis. In the 2014 Plan, NorthWestern accounted for the potential costs resulting from CO_2 reduction regulation by including a cost for carbon. The 2016 Plan did not assign a cost to carbon emissions, but noted that carbon is included in the market prices produced by the EIA in its Annual Energy Outlook for the SPP North Reference case. These prices are included in the escalation to the natural gas and electric prices in the modeling under the Clean Power Plan portfolio. The 2018 Plan treats carbon costs in the same manner as the 2016 Plan.

Summary of Key Environmental Risks: Jointly Owned Facilities

Regional Haze Rule

The Regional Haze Rule addresses visibility impairment in Class I areas. Class I areas include national parks and wilderness areas. 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.

Big Stone Plant ("Big Stone")

Big Stone has been online since 1975 and therefore, was BART-eligible. Air dispersion modeling for Big Stone indicated the plant contributed to visibility impairment at Class 1 areas in South Dakota, North Dakota, Michigan and Minnesota. Therefore, Big Stone was required to install and operate BART that was determined by the South Dakota Department of Environment and Natural Resources ("DENR") to be selective catalytic reduction in conjunction with separated over-fire air for control of nitrogen oxides ("NO_X"), a scrubber for reducing sulfur dioxide ("SO_2"), and a bag-house to control particulate matter. The air quality control system comprised of this equipment was commissioned on December 29, 2015 and is fully operational. Since Big Stone was required to install and operate BART, it is not anticipated that further requirements relative to Regional Haze compliance will be required in the future.

Coyote Station ("Coyote")

Coyote has been online since 1981 and therefore, was not BART-eligible. Although the unit was not BART-eligible, the North Dakota Regional Haze State Implementation Plan ("SIP") required Coyote to reduce NO_X emissions by July 2018. To satisfy the SIP, separated over-fire air equipment was installed during a spring 2016 planned maintenance outage. We anticipate Coyote will be required to participate in future reasonable progress evaluations. In fact the operator, Otter Tail Power, has been notified by the State of North Dakota that it needs to conduct a "four factor" analysis for submittal by the end of 2019. This analysis is to be used by the state to identify possible 2028 control strategies.

Neal Unit 4 ("Neal 4")

In Iowa, no source specific or unit specific emissions limits or compliance schedules were developed for the regional haze SIP. Iowa relied on the Cross-State Air Pollution Rule to enact BART. Future impacts to Neal 4 resulting from the Regional Haze Rule are not anticipated at this time.

Regional Haze SIP Revisions

States are required to revise their regional haze implementation plans and submit them to EPA by July 31, 2018 and every 10 years thereafter. However, on April 25, 2016, EPA signed a proposed rule to delay the July 31, 2018 revision date until July 31, 2021.

Mercury and Air Toxics Rule ("MATS")

MATS became effective April 16, 2012, requiring new and existing coal-fired facilities to achieve emissions standards for mercury, acid gases, and other hazardous pollutants. Existing sources were required to comply with the new standards by April 16, 2015.

All of the jointly owned coal-fired power plants in our portfolio –Big Stone, Coyote, and Neal 4 – are currently in compliance with the MATS rule. Therefore, we assume subsequent SIPs will contain no additional requirements for material upgrades to any of the plants.

Coal Combustion Residuals ("CCR")

"The Disposal of Coal Combustion Residuals from Electric Generating Utilities" was published in the FR on April 17, 2015. These regulations set forth requirements for the disposal of CCR as non-hazardous waste 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 groundwater protection, operating criteria, record keeping and notification, and public information posting. Several new requirements will apply to the Big Stone and Coyote. The CCR disposal area at Neal 4 is undergoing a compliant closure. MidAmerican Energy, the Neal 4 operator, anticipates utilizing a nearby compliant CCR disposal facility for future wastes.

Big Stone

Big Stone operates a dry disposal site that is already regulated, permitted, and inspected by DENR. Big Stone also has a surface impoundment used to temporarily handle boiler slag sluiced to the impoundment before it is disposed in the dry disposal site or beneficially reused. Big Stone conducted the required background groundwater monitoring program for the impoundment but is currently planning on converting to a new boiler slag handling system in the fall of 2018, eliminating the need to sluice boiler slag to this surface impoundment. After the new boiler slag handling system is operational, all CCR will be removed from the impoundment and the area will be closed.

Coyote

Coyote operates a dry disposal site that is already regulated, permitted and inspected by the North Dakota Department of Health. Coyote also operates three surface impoundments used to temporarily handle and dewater boiler slag sluiced to the impoundments before it is disposed of in the dry disposal site or beneficially reused. Similar to Big Stone, Coyote is conducting the required background groundwater monitoring programs for the impoundments.

Summary of Key Environmental Risks: Owned Facilities

Each of NorthWestern's owned generation facilities in South Dakota operates under air quality operating permits issued by DENR. The permits typically set visibility limits and emissions limits for total suspended particulate matter, SO_2, NO_X, carbon monoxide, and volatile organic carbons. In accordance with these permits, NorthWestern maintains control equipment, conducts sampling, testing, measurement, recordkeeping, compliance certification, and reporting and pays an annual air fee.

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Table 7-1. Environmental and Natural Resource Permits

Station	Title V Operating Permit #	Expiration Date
Aberdeen	28.0801-03	43,878
Huron	28.0801-04	43,994
Yankton	28.0801-07	43,896
Clark	28.0801-18	43,755
Faulkton	28.0801-28	44,328

Other Environmental Considerations

Wind Generation

In siting the 80 MW Beethoven Wind Farm, the developer and now NorthWestern as the owner/operator, follow the U.S. Fish and Wildlife Service's ("USFWS") Land-Based Wind Energy Guidelines, which are voluntary guidelines for addressing wildlife conservation concerns. The Bird and Bat Conservation Strategy for the project is being implemented. Post-construction monitoring to determine impacts of operations on birds and bats has been completed. Results of the monitoring indicate that additional material mitigation at our wholly owned wind facility is not needed.

The USFWS has regulatory authority to administer the following regulations that could affect siting or operating a wind farm in South Dakota: the Migratory Bird Treaty Act, the Bald and Golden Eagle Protection Act, the Endangered Species Act as amended, the National Wildlife Refuge System Improvement Act of 1997, and the National Environmental Policy Act. New wind generation in South Dakota will be subject to the aforementioned regulations.

Summary

NorthWestern's planning process will continue to be impacted by environmental and wildlife regulations, as well as legislation that will affect current and future thermal and renewable generation resources. Providing reliable, cost-effective energy in an environmentally safe manner remains one of NorthWestern's commitments. We will continue to comply with environmental statutes and guidelines while fulfilling our responsibility to our customers.

CHAPTER 8
CONCLUSIONS AND ACTION PLAN

Summary Discussion

NorthWestern investigated various retirement/replacement scenarios as part of this 2018 Plan in order to assess the potential for modernizing its fleet while improving reliability and operational flexibility.

NorthWestern retained HDR to support completion of the retirement/replacement fleet assessment, the results of which are incorporated throughout the 2018 Plan. HDR and NorthWestern conducted detailed site visits and collected key operational and maintenance data for all of NorthWestern's South Dakota service territory assets. HDR assimilated and analyzed all of the data and then prioritized the assets for further evaluation based on general suitability for retirement considering vintage, operational capabilities, contractual obligations, and other factors. HDR's assessment identified AGS1, HGS1, HGS2, and YGS as the assets most suitable for further investigation as potential candidates for retirement.

Multiple retirement/replacement scenarios were developed by considering overarching "themes" involving various levels of fleet modernization. HDR developed technical, financial, and qualitative attributes for each of the scenarios in order to complete a detailed qualitative and quantitative comparative assessment which included the existing fleet ("business-as-usual") case. The qualitative assessment considered factors difficult to monetize such as reliability, maintainability, proximity to load centers, operational flexibility, and surrounding community implications.

The assessment indicates a larger centrally-located generation station would likely result in lower capital and operating expenditures (based on current market conditions and on an NPV basis) when compared to a distributed generation solution. However, a distributed generation solution possesses significant qualitative attributes and provides more benefit to NorthWestern's overall South Dakota system. NorthWestern believes maintaining a distributed fleet of generation resources in South Dakota is better than developing a larger centrally-located generation station for the following reasons:

- Improved transmission reliability, considering multiple transmission outlets to the grid versus a single outlet supporting the majority of generating capability.
- Lower transmission system losses, with assets located throughout the South Dakota service territory nearer to load centers. Placing assets in closer proximity to load centers results in more "real" power delivered to end users (i.e., a more efficient system).
- Improved capability to provide electric service/system restoration (e.g., black start) across the service territory due to, for example, an extreme weather event or transmission system failure.
- Increased natural gas fuel supply diversity, with distinct radial lines off of the interstate pipeline(s) feeding the distributed assets versus a single line supplying a larger, central facility (similar benefit to greater number of transmission outlets). There could also be benefit from natural gas fuel being sourced from multiple locations on alternate interstate pipeline systems (e.g., if generation is sourced from both Northern Border Pipeline and Northern Natural Gas).
- Ability to supply ancillary services/grid support (e.g., voltage support) on a more localized basis, which benefits the remote/rural portions of NorthWestern's system.
- Providing locational marginal pricing /market pricing diversity and not being subject to market conditions at a single node. While this is not anticipated to significantly influence financial benefits near term, this could result in significant

benefits long term as markets evolve and NorthWestern participates more in the integrated marketplace.

- Assuming a staged generation addition approach, the ability to evolve and adapt with the marketplace and broader industry (review asset technology/consider emerging technologies, optimize generation location, etc.). A phased, distributed approach could also allow for more responsiveness to specific, localized shifts in load centers/load growth.
- While the ability to adapt with the marketplace facilitates more efficient use of capital expenditures, a phased, distributed approach would also spread out potential rate impacts to customers (versus a larger expense all at once associated with a large, centralized facility). This approach would provide the optionality of spreading out rate adjustments over multiple rate cases versus a larger adjustment in a single rate case.
- Broadening and maintaining the tax base and economic development opportunities across multiple communities throughout the state.

As a first step, NorthWestern plans to acquire and deploy four 2 MW mobile generation units in 2019. The mobile units will alleviate generation supply reliability concerns for the towns of Clark, Faulkton and other strategic locations across the SD service territory.

Next Steps

SPP requirements drive NorthWestern's planning process. NorthWestern remains committed to full participation in SPP and full compliance with all SPP requirements. Capacity continues to be of concern and NorthWestern will continue to evaluate capacity needs and the best means to meet those needs. Given the economic dispatch regime of SPP, NorthWestern will examine how best to serve customer needs in a manner consistent with its current fleet of generation resources.

NorthWestern will move forward with identifying specific generation assets for retirement and replacement using the following action plan.

Action Plan

1. *Retirement/Replacement.* Using the HDR Fleet Assessment as a basis, NorthWestern will prepare for the retirement and replacement of aging resources throughout its service territory. Specifically, NorthWestern will continue investigating the retirement of Huron Generating Station 2 in 2022, followed by the addition of about 40 MW in Huron in 2024.
2. *Mobile units.* NorthWestern will acquire and deploy four 2 MW mobile generation units in 2019. The mobile units will alleviate generation supply reliability concerns for the towns of Clark, Faulkton and other strategic locations across the SD service territory.
3. *Capacity.* Expiration of the current capacity agreement with Missouri River Energy Services after the 2018 summer season will create a capacity shortfall beginning in 2019. NorthWestern's current capacity forecast shows need for capacity of 5 MW in 2019 and around 9 MW in 2028 (more if industrial growth occurs). Mobile generating resources, will meet 9 MW of this short-term capacity need.
4. *Grid Reliability.* Beyond the mobile unit additions, NorthWestern will continue to study the added value of locating future resource additions at sites strategically located throughout NorthWestern's South Dakota service territory in order to help increase electricity supply and transmission grid reliability.

5. *Generation Technologies.* NorthWestern will continue to monitor and evaluate generation technologies with the potential to help NorthWestern meet its load-serving obligation at the lowest total cost to its customers. This could include re-evaluating CTG technology as well as considering a pilot project(s) using technologies NorthWestern does not currently employ (e.g., battery storage, especially where electric grid support is needed).

6. *Environmental.* NorthWestern's current planning efforts continue to prioritize compliance with environmental regulations. NorthWestern will continue to monitor proposed rules and will incorporate any additional environmental regulations/requirements into its planning processes as necessary.

7. *SPP Operations*. NorthWestern will continue to coordinate with SPP regarding the ancillary services market, generation interconnection process, and other pertinent ISO topics. SPP requirements for resource capacity contribution and peak load forecasting will be adhered to as those standards continue to develop. Resource planning will necessarily reflect those changes.

8. *SPP Transmission Planning.* NorthWestern will continue to monitor and participate in SPP working groups dedicated to the transmission planning process. NorthWestern will also continue to evaluate the results of SPP studies, along with system needs identified in the studies.

9. *Ancillary Services Market.* NorthWestern will further investigate the ancillary services market and associated potential revenues by coordinating with Rainbow (NorthWestern's energy marketer for South Dakota) and discussing with other market participants.

10. *Aberdeen Generating Station 1 Air Permit.* NorthWestern intends to investigate a potential update to the AGS1 air permit to reduce the impacts on AGS2. The AGS air permit is currently set to expire and will need to be renewed in 2020, which could

present an opportunity for adjustment/optimization. The retirement of AGS1 would also assist in facilitating increased dispatch capability of AGS2.

11. *Fuel Requirements.* NorthWestern will further investigate natural gas fuel supply capability, dual fuel/no fuel generation technologies, and/or liquefied natural gas configurations.

12. *Economic Development Opportunities.* NorthWestern will continue to investigate potential economic development opportunities in South Dakota in order to identify potential synergies with large commercial & industrial customers, municipalities, and others.

13. *Joint-Owned Units.* The Big Stone, Coyote, and Neal 4 agreements will continue to be evaluated.

14. *Natural Gas Supply.* NorthWestern will investigate additional natural gas supply capabilities at the different generation sites throughout its system. Specifically, allocation capabilities need to be discussed with Northern Natural Gas.

15. *Land Rights.* Land availability, local permitting, and other land rights considerations to support new generation additions must be investigated further.

16. *Environmental Permitting Requirements.* Specific environmental permits will need to be investigated for the sites under consideration for retirement/replacement.