Exhibit 19

No. 2

4-24) In response to Staff's discovery request 1-17, the Company indicated that it was in the process of evaluating need and negotiating a PPA with a respondent regarding a PPA for 35 MW starting in 2019. The Company also indicated that it was attempting to resolve confidentiality restrictions. Please provide an update regarding this matter including the length of term being contemplated. Please also explain if the Company will be needing additional capacity in addition to the 35 MW and if so, please provide the capacity need, timing and MW on a year by year basis.

Response: NorthWestern is still in negotiations with the counter party. Based on the most recent analysis that is included in the 2016 Procurement Plan, NorthWestern's need will be less than 35 MW and the company is evaluating a 3 year agreement. Attached is NorthWestern Energy's 2016 plan.

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CHAPTER 1
EXECUTIVE SUMMARY

The 2016 SD Electricity Supply Resource Procurement Plan

The 2016 South Dakota Electricity Supply Resource Procurement Plan ("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. The Plan sets forth resource options that maintain cost-effective electric service for our customers in South Dakota and meet Southwest Power Pool ("SPP") requirements. This document sets forth a plan to at least study the older generation units in NorthWestern's fleet of generation resources and explore opportunities to enhance grid reliability. The Plan also analyzes a range of environmental and market uncertainties that have the greatest potential to impact customer needs and long-term procurement options.

NorthWestern's resource plan is updated biennially and evolves with any significant changes in legislation, regional operational or planning needs, and environmental requirements. The Plan's conclusions are intended to provide guidance regarding NorthWestern's resource investments on behalf of its South Dakota customers. Within this changing resource planning landscape, NorthWestern will maintain flexibility when implementing this Plan.

Southwest Power Pool

NorthWestern joined the SPP in October 2015. NorthWestern participates in several aspects of the SPP Integrated Marketplace including the Day-Ahead Market, Real-Time Balancing Market, and the Auction Revenue Rights / Transmission Congestion Rights Market. As a participant in SPP, NorthWestern must abide by market rules and requirements including the requirement to maintain a specified level of Planning Reserve Margin ("PRM").

Load Requirements

Energy

NorthWestern's assets are located in the newly developed Upper Missouri Zone ("UMZ") of SPP. This zone was created by SPP to designate the addition of the Integrated System ("IS") with regional participants and NorthWestern. Both the UMZ and SPP are very long in electric energy supply and renewable resources. As a result, the need for additional base load energy-producing resources will be limited for a period of time unless the existing resources or loads change significantly. As a member of SPP, NorthWestern will tailor supply resource planning activities for energy, capacity and ancillary services to fit within the definition and characteristics of the SPP market and operational protocols.

NorthWestern's total system energy need has grown over the last 10 years at an average rate of approximately 29,000 megawatt-hours ("MWh") per year. System energy requirements for a 12-month period ending July 31, 2016 were around 1.65 million MWh as shown in Figure 1-1 below.

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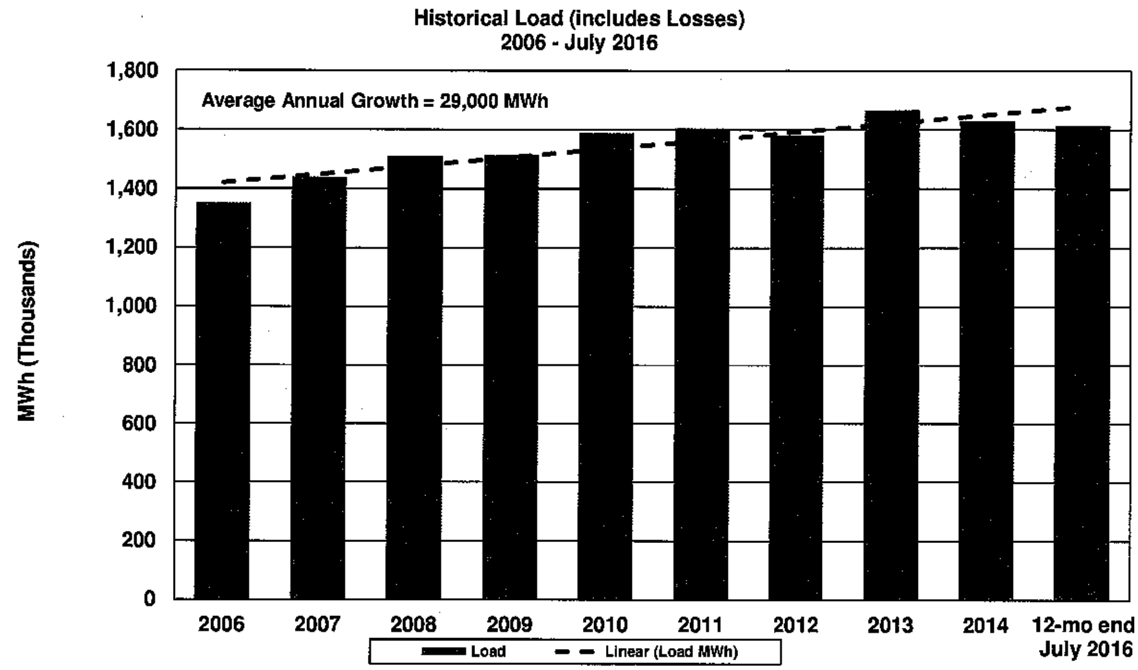
Figure 1-1 Historical Load – Retail Sales 2006 – July 2016

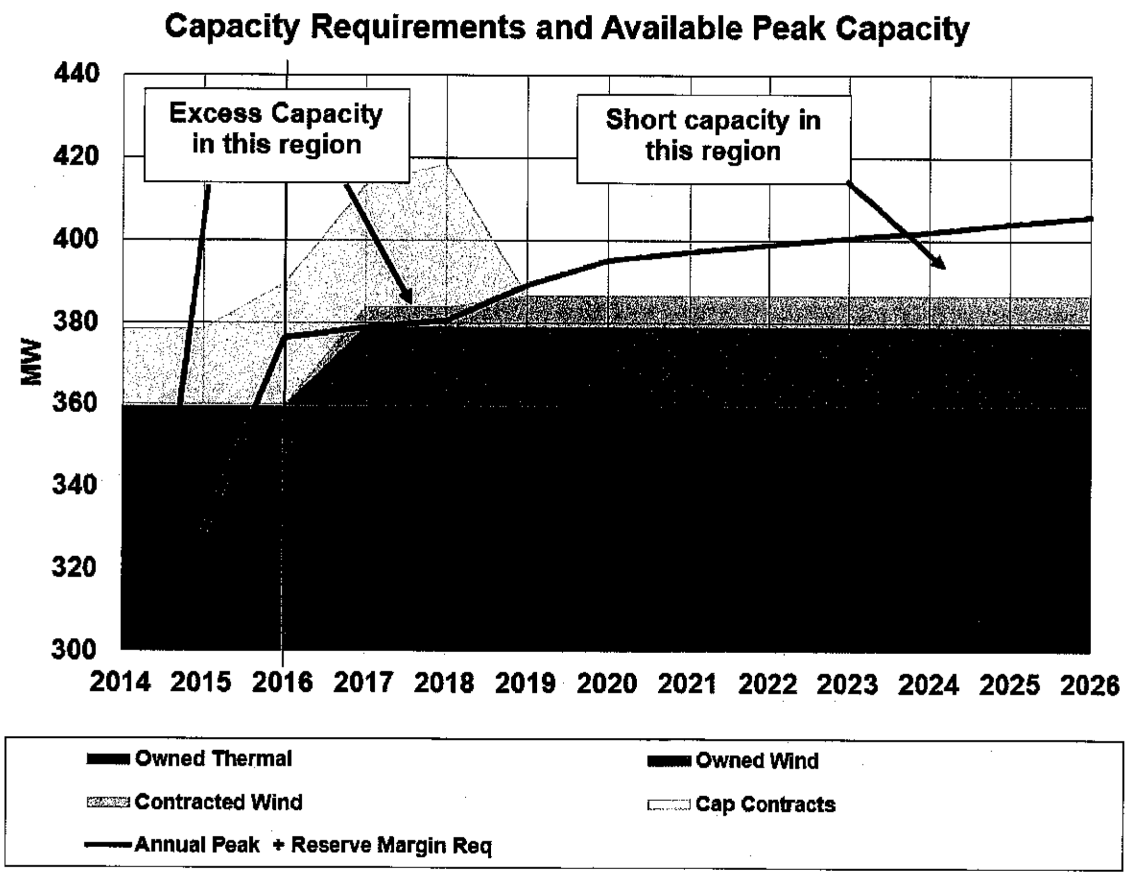


Capacity

NorthWestern's peak capacity needs have increased by an average annual amount of 2.6 megawatts ("MW") per year since 2003, with a peak load of 341 MW in 2012. Peak load in 2016 was 331 MW. Currently, NorthWestern's owned and contracted resources have a combined summer peaking capacity of approximately 390 MW. Going forward, NorthWestern's capacity planning will have the added requirement of meeting SPP's PRM. The PRM is defined as the difference between an entity's firm capacity and its peak demand, divided by its peak demand. Starting in 2017, SPP will require a minimum PRM of 12% which, based on a forecasted peak, results in a capacity requirement of approximately 379 MW in 2017.

Figure 1-2 below illustrates NorthWestern's current capacity surplus and forecasted future capacity deficits. Beginning in 2019, NorthWestern is forecasting 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. NorthWestern's need for capacity is expected to increase from 3 MW in 2019 to around 19 MW in 2026.

Figure 1-2 Capacity Requirements and Available Peak Capacity



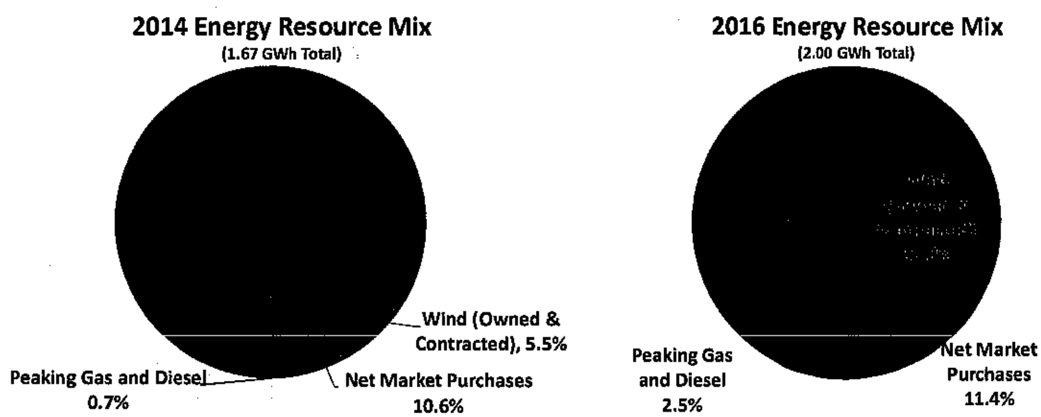
* MISO Loss of Load Expectation study planning reserve requirement of 7.1% in 2014 and 2015
** Beethoven was purchased by NWE in September of 2015
*** SPP Planning Reserve Margin (PRM) Requirement of 13.6% in 2016 changes to 12% in 2017

SPP capacity requirements and available transmission may significantly influence the timing for any additional capacity that NorthWestern might add. NorthWestern will evaluate its capacity options as 2019 approaches to determine the most cost-effective capacity additions and will examine economic opportunities to replace aging generation infrastructure and enhance grid reliability.

Existing Resources

In 2015, NorthWestern's energy supply portfolio added 99.5 MW of intermittent wind resources. This increase in wind shifts the resource mix that provides energy for NorthWestern's load. Figure 1-3 (duplicated from figure 5-4) shows the shift in resources that provide energy for NorthWestern's load comparing 2014 actuals to 2016 forecast. Intermittent wind will make up 25% of the supply for the portfolio reducing the amount of coal generation needed. Annual net market purchase figures remain stable as any reductions due to increased wind generation are balanced by increased economic purchases due to lower market prices. The forecast for 2016 also will see additional natural gas generation due to the dispatch requirements of SPP. SPP will continue to economically dispatch NorthWestern's registered resources.

Figure 1-3 2014 Actual vs. 2016 Forecast Energy Resource Mix



Continued low market prices allow NorthWestern to make economical purchases in lieu of operating higher-priced internal resources, resulting in lower costs to customers. The 13 peaking units, with a combined 193 MW nameplate capacity, are available to supply capacity but do not generate a significant amount of energy annually.

Retirement Study

With the economic dispatch regime of SPP, NorthWestern must re-examine how best to serve its customers' needs. NorthWestern's entry into SPP has lowered customers' rates, and has changed NorthWestern's dispatch of resources. An evaluation of NorthWestern's older generation assets for possible retirement and replacement is needed to determine how to best serve the long-term needs of our customers.

NorthWestern is working with an engineering consulting firm to develop a Retire and Replacement Study for the natural gas-fired and oil-fired generating units. The study will examine heat rates, parts availability, and book value and will provide a cost benefit analysis for replacement of those assets with proxy technology selections. The economic contributions of each asset to the overall resource portfolio will also be evaluated. NorthWestern expects that the study will be completed in July 2017, and the results will be used to inform its resource development plans for South Dakota.

Grid Reliability

Historically, NorthWestern operated generating plants throughout its South Dakota service territory, including Webster, Aberdeen, Faulkton, Redfield, Clark, Huron, Woonsocket, Highmore, Chamberlain, and Yankton. These plants were originally built for base load generation, supplying power around-the-clock for the communities served. As the transmission system was expanded, these same units continued to provide peaking energy, as well as contingency reserves and reliability support, to those same communities.

Resource development plans for South Dakota will be undertaken with the goal of increasing grid reliability when addressing resource portfolio requirements. Strategically locating generation assets across the system, while meeting the overall system capacity requirement, adds an additional level of reliability. It also provides additional capability for integrating current and future renewable generating resources, which can be widely distributed within NorthWestern's system. Table 1-1 compares current generating capability of existing generation assets to 2015 peak loads at select locations within South Dakota.

Table 1-1 Locational Generation and Loads

Location	Generating Capability MW	Number of Units	2015 Peak MW Demand
Aberdeen	72.5	2	76.1
Webster	0	0	2.55
Redfield	0	0	12.1
Clark	2.6	1	2.5
Huron	54.4	2	47.8
Highmore	0	0	3.8
Mitchell	0	0	54.2
Chamberlain	0	0	4.9
Yankton	13.42	4	54.3

The table shows that generation in Huron exceeded peak demand in 2015, while Aberdeen generation nearly matches peak demand. In comparison, Mitchell had a peak demand of about 54 MW in 2015 and currently has no generation capability. Yankton's existing generation can only support about 25% of its 2015 peak demand. The other communities listed in Table 1-1 either represent larger population centers that previously had generation or remote locations with limited/partial contingency back-up capability. Locating economic generation capacity at these locations could provide economic system capacity while increasing reliability.

Resource Options

The Plan examines natural gas, wind, solar photovoltaics ("PV"), Demand Side Management ("DSM"), and energy storage resources as possible additions to the portfolio. DSM programs were implemented in late 2014 and have expanded to include prescriptive rebates for residential and commercial electric new construction customers. Utility-scale energy storage technologies were also evaluated to update estimates of costs and capabilities and to identify potential value in the context of the SPP Market. Lithium-ion, vanadium flow, and sodium sulfur batteries, as well as pumped-storage hydro and compressed air storage systems, were considered as potential future additions though not modeled in this Plan.

Portfolio Modeling and Analysis

NorthWestern modeled a number of resource options using the PowerSimm™ suite from Ascend Analytics ("Ascend"). The eight portfolios examined are described in greater detail in Chapter 6:

- Base – Existing assets plus market purchases.
- 50 MW Wind – Base plus 50 MW wind.
- 100 MW Wind – Base plus 100 MW wind.
- 50 MW Solar – Base plus 50 MW solar.
- 100 MW Solar – Base plus 100 MW solar.
- Recip – Base plus two reciprocating engines in 2022 and one reciprocating engine in 2024.
- Combustion Turbine – Base plus one combustion turbine in 2022.
- Clean Power Plan – Base case plan under Clean Power Plan compliance.

The Base portfolio is the least cost net present value ("NPV") portfolio, but with slightly higher risk than thermal or wind portfolios. NorthWestern is in a position where it must make market purchases in order to fulfill its load-serving obligation in all portfolios other than the 100 MW Wind portfolio. Possible future environmental regulations as measured in the Clean Power Plan portfolio increase costs only slightly over the Base portfolio.

The Recip portfolio has a lower NPV cost than the renewable portfolios or the Combustion Turbine portfolio. Peaking generation that can rapidly and efficiently respond to the SPP market price signals has additional value over less flexible or less efficient generation. Reciprocating engines provide capacity, deliver dispatchable economic energy, and provide ancillary services.

Conclusions

This Plan sets forth the criteria by which NorthWestern will evaluate future resource decisions, including addressing its future capacity requirements, potential plant retirements, and enhancements to grid reliability. Existing uncertainties discussed in the Plan, such as the regulation of carbon emissions and other regulatory considerations, will have a significant influence on the type and timing of future resource choices. SPP requirements will also greatly influence resource decisions, as will transmission availability, or the lack thereof.

CHAPTER 2
SOUTHWEST POWER POOL MARKET

Regional Transmission Organization

Transition to SPP

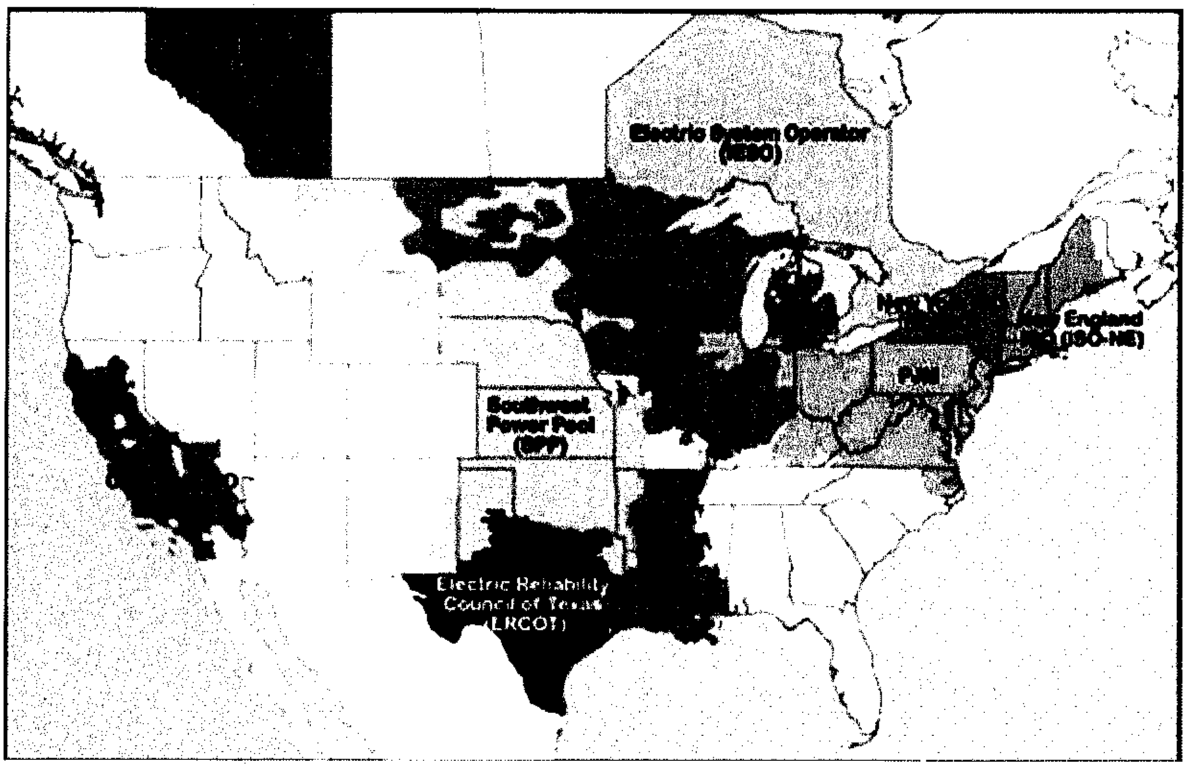
NorthWestern's transmission, load, and generating resources in the state of South Dakota are located within what was formerly the Balancing Authority ("BA") of the Western Area Power Administration Upper Great Plains Region ("Western-UGP"). The Western-UGP region was comprised of approximately 10,000 miles of transmission owned by Western, Basin Electric Power Cooperative ("Basin"), and Heartland Consumers Power District ("Heartland") and collectively known as the Integrated Transmission System ("IS"). On October 1, 2015, NorthWestern along with Western-UGP, Basin, and Heartland, joined the SPP.

SPP Overview

SPP is one of the seven Regional Transmission Organizations ("RTOs") / Independent System Operators ("ISOs") in the United States. Figure 2-1 below shows a map of the latest RTOs in North America. RTOs independently administer the transmission grids within their foot prints and host markets where their members and other participants transact.[1] The key characteristic of an RTO market is that the RTO is responsible for committing the units of the Market Participants within the footprint. The SPP Integrated Marketplace offers a Day-Ahead Market and Real Time Balancing Markets. The Integrated Marketplace offers 5-Minute Settlements.

[1] The terms RTO and ISO are used synonymously for ease of reference in this document.

Figure 2-1 Regional Transmission Organizations / Independent System Operators



SPP was founded in 1941 and now operates as an RTO in 14 states (AR, IA, KA, LA, MN, MO, MT, NE, NM, ND, OK, SD, TX, and WY) with 94 members including investor-owned, municipal systems, generation and transmission cooperatives, and other entities. In additional to the Integrated Marketplace founded in 2014, which encompasses the Day-Ahead, Real-Time, Operating Reserve, and Transmission Congestion Rights Markets, SPP is a centralized Balancing Authority, Reliability Coordinator, and Regional Entity.

The SPP Integrated Marketplace offers five products, which are grouped into two categories: Energy and Operating Reserve. The products under the Operating Reserve category are classified as: Regulation Reserve, which includes Regulation-Up Reserve and

Regulation-Down Reserve; and Contingency Reserve, which includes Spinning Reserve and Supplemental Reserve.

The SPP Integrated Marketplace encompasses different processes: Day Ahead Market ("DA Market"), Reliability Unit Commitment ("RUC"), Real-Time Balancing Market ("RTBM"), Reserve Market, Auction Revenue Rights ("ARR")/Transmission Congestion Rights ("TCRs").

Day Ahead Market

The key objective of the DA Market is to enable Market Participants to offer and bid for Energy and Operating Reserve products. The DA Market uses specialized systems and algorithms to co-optimize the availability of Energy and Operating Reserves, to ensure that the available resources are able to meet the load demand and operating reserve obligations for the next Operating Day. The DA Market is financially binding. Market Participants submit Resource Offers for generation into the DA Marketplace. Each Market Participant that serves load must offer enough capacity to cover the bid-in load and Operating Reserve requirements for the next Operating Day.

A Demand Bid in the DA Market is a proposal made by a Market Participant to purchase Energy at a specified location and period of time in the Day-Ahead Market. Only a Market Participant with a registered load may submit demand bids for the registered load Settlement Location. Market Participants are required to submit their Day-Ahead Demand bids, Resource Offers, and outage notifications, along with certain other information to SPP by 9:30 a.m. each day. Once the Market runs its processes, SPP publishes the results of the DA Market which include hourly information for each Market product award and the Locational Marginal Price ("LMP") for each Settlement Location for each hour. The LMP is the cost to serve the next increment of load at the specified Settlement Location.

In addition, SPP also publishes the Marginal Clearing Price ("MCP") for each Operating Reserve product for each Reserve Zone. The MCP for an Operating Reserve product is the cost to provide the next capacity increment for the Operating Reserve product at the specific Reserve Zone.

A key activity in the DA Market is the RUC process. The RUC is a mechanism used by SPP to create a reliable operating plan for the next Operating Day to ensure that there is enough capacity available and committed to cover the system load and Operating Reserved requirements forecasted for that day. The key objective of the DA and RUC processes is to create an operating schedule that will minimize the total commitment costs based on availability of generation resource offers, system load, and Operating Reserve requirements forecast for the next Operating Day. SPP requires that each Market Participant submit offers for both DA and RT for any registered resource that is not on planned, forced, or other approved outage. Any Resource committed by the RUC process or the Reliability Assessment processes for the next Operating Day are subject to Make-Whole Payment if they meet the eligibility criteria.

The MWP is a unique feature in the DA Market, with the objective to make any Resource committed in the DA financially whole. The MWP guarantees that the Market Participant receive enough revenues to cover certain costs (e.g., Startup cost, No-load cost, etc.) for the Energy and Operating Reserve offers for a given Operating Day as long as the Resource meets the required criteria. In Summary, the DA uses DA offer data to optimize the operating plan for the next Operating Day. The Market Participant is required to offer enough capacity to cover the load. The DA Market clearing involves matching Resource Offers to the Load Bids. The Market Participant is required to submit offers for all Resources that are not on an outage. The RUC uses the load forecasts projected by SPP to optimize the committed resources.

Real Time Balancing Market

In the RTBM, SPP optimizes the real-time load and generation committed by the DA and RUC processes. The purpose of the RTBM is to minimize the total production costs by evaluating online Resources' Real-Time Offers and statuses and the short-term load forecasts and their Operating Reserve requirements. The execution of the RTBM takes place on 5-minute intervals. Resources committed in the RTBM receive dispatch instructions for Energy and Operating Reserve every 5 minutes with the designated amount. SPP issues setpoint instructions on 4-second intervals indicating the required Energy and Operating Reserve deployment for each committed Resource. If there is a Reliability event taking place during the given Operating Day, SPP may issue a manual directive in addition to the setpoint instructions to alleviate the emergency condition. The dispatched amounts cleared in the RTBM are settled on RTBM LMPs, which are calculated and posted for each 5-minute interval.

Auction Revenue Rights and Transmission Congestion Rights

The SPP Integrated Marketplace offers Market Participants the opportunity to participate in the ARR and TCR processes. These tools can be used to hedge against congestion risk between, for example, the generation LMP and the load LMP. Market Participants are allocated ARRs based on firm transmission reservations. The ARRs can be self-converted to TCRs or sold in the ARR Auction. TCR holders are paid (or charged) the difference between the DA LMPs at the source and sink on the TCR path.

NorthWestern Participation in the SPP Integrated Marketplace

As indicated earlier, there are five different products that a Market Participant can offer in the SPP Integrated Marketplace. NorthWestern owns facilities located in the SPP Footprint that are used to supply Energy into the Market. In order for a Market Participant to do business with SPP, it must register its Assets (including load and generation), with the exception of Behind the Meter generation that is less than 10 MW. NorthWestern participates in the DA Market, the RTBM, and in the ARR/TCR processes.

Capacity Requirement

As a load-serving member of SPP, NorthWestern is obligated to meet the capacity requirements outlined in Attachment AA of the SPP Open Access Transmission Tariff ("OATT"). PRM is defined as the difference between an entity's firm capacity and its net peak demand, divided by its net peak demand. SPP requires that each load responsible entity have a minimum PRM of 12%. Note that NorthWestern's smaller, Behind-the-Meter generation resources (Faulkton, Clark, and the mobile units) may be counted toward the Required Capacity Margin calculation. See Chapters 3 and 5 for information on NorthWestern's compliance with this requirement.

SPP Transmission Planning Process

SPP's Integrated Transmission Planning (ITP) process is a three-year process that focuses on obtaining a reasonable balance between long-term transmission investments and congestion costs to customers. The three-year planning cycle includes a 20-year assessment (ITP20), a 10-year assessment (ITP10), and annual Near-Term assessments (ITPNT) of the region. ITP20 identifies potential projects that are generally 300kV and above, while ITP10 focuses on facilities that are 100kV and above. ITPNT looks out over the next 5-7 years and includes at all applicable voltage levels. For each of these ITP assessments, SPP runs multiple scenarios through their model to identify potential needs. Along with economic and reliability studies, SPP also considers different carbon reduction scenarios within the planning process. See Attachment O within the SPP OATT for additional details on SPP's planning process.

Opportunities for NorthWestern within SPP's ITP Process

SPP's ITP process is an open process that allows proposed transmission facilities to come from several different areas of the Tariff. These areas are: transmission service requests, generation interconnection service requests, ITP upgrades, the balanced portfolio process, the high priority study process, requests for sponsored upgrades, and interregional projects. Each of these potential upgrades has its own evaluation and approval process, along with its own method of cost allocation on how the project will be funded

Upgrades that are studied and approved in the SPP planning process qualify for regional and zonal cost allocation. Upgrades that do not achieve SPP approval also do not qualify for cost allocation. If the requestor still chooses to construct the upgrade without SPP approval, the cost of the project is directly assigned to the requestor. SPP refers to these projects as a Sponsored Upgrades. Directly assigning costs to the requestor is also common in transmission service and generation interconnection requests, if upgrades are needed to grant the request for service or interconnection. See Attachment J in the SPP OATT for more information on cost allocation.

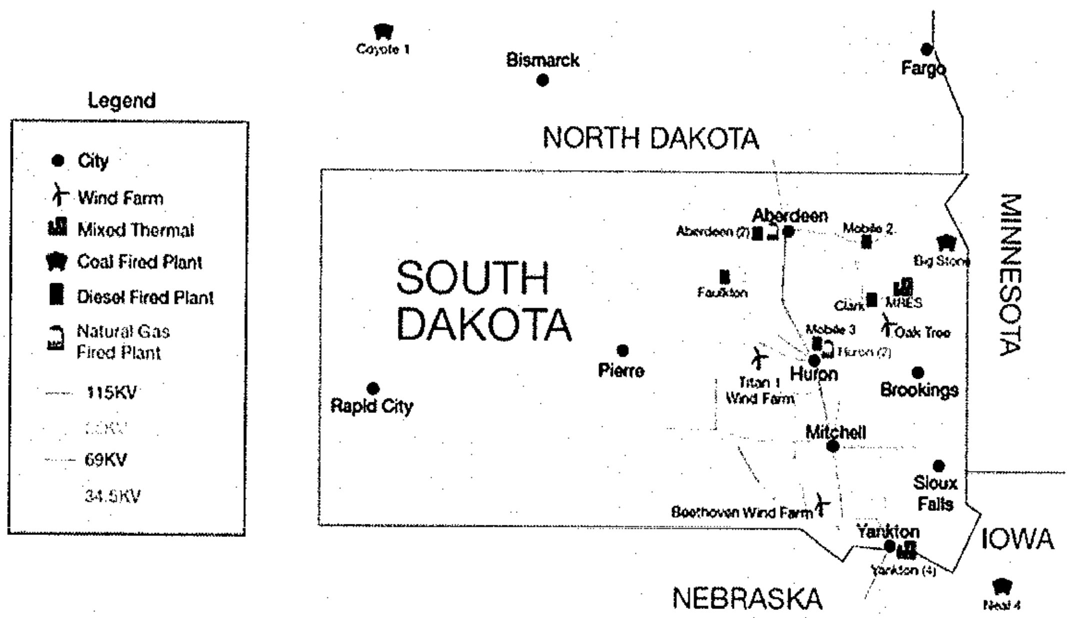
All projects within the SPP have the potential to impact NorthWestern from reliability and economic standpoints. Projects that are approved to address system needs also present possible construction opportunities for interested stakeholders. For these reasons NorthWestern actively monitors and participates in SPP working group meetings, to understand system needs and the solutions being proposed. Attachment Y in the SPP OATT outlines the criteria that qualifies certain upgrades to be Competitive Upgrades, where qualified applicants have the opportunity to submit project proposals to construct, own, and maintain the Competitive Upgrade. Proposals submitted for Competitive Upgrades enter into SPP's Transmission Owner Selection Process (TOSP). The proposals that meet all TOSP criteria are then evaluated by an Industry Expert Panel (IEP) which makes a recommendation of project selection to the SPP Board of Directors. Upgrades that do not meet the criteria of a Competitive Upgrade default to the incumbent transmission owner for construction and ownership.

CHAPTER 3
EXISTING PORTFOLIO RESOURCES

Existing Portfolio Resources Discussion

NorthWestern uses a mixture of resources to meet the existing energy and capacity needs of its South Dakota customers and requirements of SPP. As described in this section, the South Dakota portfolio includes base load coal generation, natural gas and diesel peaking generation, owned wind generation, wind Power Purchase Agreements ("PPAs"), capacity and energy purchase agreements, and DSM programs. NorthWestern's portfolio of resources are distributed throughout and surrounding its South Dakota service territory, as shown in Figure 3-1.

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



NorthWestern's owned and contracted resources supplying energy and capacity used to serve is South Dakota service territory is shown in Table 3-1.

Table 3-1 Generation Asset Summary

Source	Facility	Nameplate Capacity (MW)	Summer Peaking Capacity (MW)	Type	Fuel	First Year in Service	2014 Energy (MWh)	2015 Energy (MWh)
Owned Baseload (208.6 MW)	Big Stone	122.9	111.2	Cyclone Burner	Coal	1975	696,000	377,000
	Neal 4	55.6	56.1	Pulverized	Coal	1979	380,000	439,000
	Coyote	45.6	42.7	Cyclone Burner	Coal	1981	313,000	193,000
Owned Peaking and Local Area Backup Service (151.4 MW)	Aberdeen Unit 2	69.9	52.0	CT	Nat Gas/Fuel Oil	2013		
	Huron Unit 2	42.9	43.7	CT	Nat Gas/Fuel Oil	1992		
	Aberdeen Unit 1	28.8	20.5	CT	Diesel	1978		
	Huron Unit 1	15.0	11.0	CT	Nat Gas/Fuel Oil	1961		
	Yankton Unit 3	6.5	6.5	Recip	Nat Gas/Fuel Oil	1975		
	Yankton Unit 2	2.8	2.8	Recip	Diesel	1974		
	Clark	2.8	2.6	Recip	Diesel	1970		
	Faulkton	2.8	2.5	Recip	Diesel	1969		
	Mobile 3 (currently in Huron)	2.5	2.0	Recip	Diesel	2009		
	Yankton Unit 1	2.3	2.2	Recip	Nat Gas/Fuel Oil	1974		
	Yankton Unit 4	2.0	2.0	Recip	Diesel	1963		
	Mobile 2 (currently in Webster)	1.8	1.8	Recip	Diesel	1991	(Total)	(Total)
	Big Stone	0.3	0.3	Recip	Diesel	1975	12,000	7,000
Owned Renewable (78.0 MW)	Beethoven (Including PPA)	80.0	19.1 *	Wind	Wind	2015	0	226,000
Capacity and Energy Contracts (up to 35.0 MW)	Missouri River Energy Services (supplied by Watertown Peaking Plant)	30 in 2016-2017, 35 in 2018	30 in 2016-2017, 35 in 2018	Mixed	Mixed	2016	0	0
Renewable Energy Contracts (44.5 MW)	Titan I	25.0	4.0 *	Wind	Wind	2010	91,000	93,000
	Oak Tree	19.5	1.0 *	Wind	Wind	2015	0	67,000
WAPA Net Purchases				Mixed	Mixed		177,000	226,000
SPP Net Purchases				Mixed	Mixed			30,000
Efficiency (up to 0.5 MW)	Demand-Side Management	0.4	0.4	Mixed	Mixed	2014		4,000
	Totals (Not including DSM)	571.4	414.2				1,669,000	1,658,000

* Wind Resource SPP Net Planning Capability effective in 2017

Big Stone Plant

The Big Stone Plant ("Big Stone") is located near Big Stone City, South Dakota. The plant is a joint venture between NorthWestern Energy, Otter Tail Power Company ("OTP"), and Montana-Dakota Utilities Company ("MDU"), with OTP as the operating agent. NorthWestern's ownership and share of the output of the plant is 23.4% or 111.2 MW.

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.

To meet new emission reduction requirements of the Regional Haze Rule, an Air Quality Control System ("AQCS") retrofit was installed at Big Stone and put into service in December 2015. The project consists of the addition of a Flue Gas Desulfurization ("FGD") system (scrubber and baghouse), a Selective Catalytic Reduction ("SCR") system, Separated Over Fire Air ("SOFA") system, and an Activated Carbon Injection ("ACI") system for the control of mercury emissions. NorthWestern's share of the capital cost was approximately $98 million with Allowance for Funds Used During Construction ("AFUDC").

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 56.1 MW, or 8.68%. The fuel source for Neal 4 is Powder River Basin sub-bituminous coal delivered by the Union Pacific Railroad. Environmental compliance projects to control sulfur oxide, nitrogen oxide, and mercury emissions from Neal 4 were completed in 2013 and 2014 at a cost of approximately $24 million for NorthWestern's share.

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 42.7 MW, or 10%. The fuel source is North Dakota lignite from an adjacent coal mine that is owned by Dakota Westmoreland.

An ACI system was installed in 2015 to bring Coyote into compliance with the final Mercury and Air Toxics Standards ("MATS") rule. An Advanced Overfire Air ("AOA") system for nitrous oxide control was installed in the spring of 2016. These retrofits were part of a larger boiler project to replace the lower boiler wall and redesign the cyclone entry to accommodate the AOA. Testing for other toxic emissions revealed that Coyote was well within compliance. NorthWestern's share of capital costs for this project was $2.2 million. Based on current compliance test results, NorthWestern anticipates that Coyote will be able to qualify as a Low Emitting Electrical Generating Unit ("LEE").

Peaking Units

NorthWestern's 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 149.8 MW[1], these facilities are situated in seven different locations across NorthWestern's service territory. The age of these units ranges from 65 years old to three years old with several older than 35 years. The higher heating value ("HHV") heat rates are also given for each unit. The most recent addition, Aberdeen Unit 2, benefits from significant improvements in technology and is much more efficient than the others. This lower heat rate increases the economic opportunities for this resource to be offered into the SPP market.

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

Table 3-2 Thermal Peaking Units

Facility	SPP Qualified Summer Peaking Capacity (MW)	Type	Fuel	HHV Heat Rate at Maximum Capacity (BTU/kWh)	First Year in Service
Huron Unit 1	11.030	CT	Nat Gas/Fuel Oil	17,000	1961
Yankton Unit 4	2.000	Recip	Diesel	15,000	1963
Faulkton	2.500	Recip	Diesel	15,000	1969
Clark	2.600	Recip	Diesel	15,000	1970
Yankton Unit 2	2.750	Recip	Diesel	15,000	1974
Yankton Unit 1	2.170	Recip	Nat Gas/Fuel Oil	15,000	1974
Yankton Unit 3	6.500	Recip	Nat Gas/Fuel Oil	15,000	1975
Big Stone	0.269	Recip	Diesel	15,000	1975
Aberdeen Unit 1	20.520	CT	Diesel	13,500	1978
Mobile 2 (currently in Webster)	1.750	Recip	Diesel	15,000	1991
Huron Unit 2	43.700	CT	Nat Gas/Fuel Oil	14,000	1992
Mobile 3 (currently in Huron)	2.000	Recip	Diesel	15,000	2009
Aberdeen Unit 2	52.000	CT	Nat Gas/Fuel Oil	9,419	2013

The smaller Recip units use diesel or are dual-fueled with natural gas and fuel oil and combine to provide a total capacity of 22.5 MW. SPP is currently evaluating its process for determining qualifications of thermal plants with nameplate capacity under 10 MW that are not entered into the SPP market to be registered as capacity-contributing resources. The smallest three Recips, Big Stone, Mobile 2, and Mobile 3, have not been entered into the SPP Market by NorthWestern and therefore their summer peaking capacity, totaling 4.1 MW, may not qualify under SPP capacity requirements. The four larger CT units are Aberdeen 1 & 2 and Huron 1& 2. Aberdeen 1 is a 20.5 MW diesel-fueled CT in operation since 1978. Aberdeen 2 is 52.0 MW dual-fueled (natural gas/fuel oil) CT in operation since 2013. Huron 1 is 11.0 MW dual-fueled CT in operation since 1961. Huron 2 is a 43.7 MW dual-fueled CT in operation since 1992.

Demand Side Management

NorthWestern received final approval from the PUC to begin implementation of a two year pilot DSM Plan in June 2014. The approved DSM Plan included a tracker mechanism in which electric DSM program costs and an Electric Lost Margin adder of 30% be recovered. An electric Energy Efficiency Program rate was developed to track and recover the electric DSM program costs and Electric Lost Margin adder. The Programs, offered under the Efficiency Plus ("E+") sub-brand, were officially rolled out to customers on October 1, 2014. NorthWestern contracted with DNV▪GL ("DNV") to implement the South Dakota E+ Programs and perform the residential in-home energy audits.

The Year 1 E+ program offerings were focused solutions targeting existing residential and commercial customers. The electric E+ program offerings included:

- E+ Audit for the Home – Free onsite energy audit for residential electric space and/or water heat customers.
- E+ Residential Lighting – Rebates available to residential customers for ENERGY STAR® hard-wired compact fluorescent lamp ("CFL") fixtures in existing or new construction homes. A one-time in-store CFL coupon was also offered through participating retailers.
- E+ Commercial Lighting – Prescriptive and custom rebates offered in existing and new construction for the replacement of less efficient lighting products with high efficiency technologies.
- E+ Commercial Existing Construction Electric Rebate Program – Rebates available for qualifying measures including insulation, programmable thermostats, variable frequency drives, and refrigeration and ENERGY STAR measures.
- E+ Residential Existing Construction Electric Rebate Program – Rebates available for qualifying measures including insulation, programmable thermostats, and air conditioning measures.

Through customer participation in Year 1, E+ programs resulted in electric savings of about 1.34 million kilowatt hours ("kWh") or 0.15 average megawatts ("aMW"). These savings were primarily driven through commercial lighting rebates.

During Year 1, partnerships with retailers and relationships with area trade allies were developed. In early March, trade allies (i.e. distributors, electrical contractors, engineers, architects, heating, ventilation, and cooling ("HVAC") contractors, insulation contractors, building contractors) were invited to attend any of four E+ program workshops in Aberdeen and Mitchell. The workshops provided information about the E+ program offerings so that trade allies may successfully market the programs to their customers.

Year 2 program offerings were expanded from the list above to include:

- E+ Residential Lighting – Expanded to not only include ENERGY STAR hard-wired CFL fixtures in existing or new construction homes, but also included an occupancy sensor rebate.
- E+ Commercial New Construction Electric Rebate Program – Rebates available to electric customers for qualifying refrigeration, air conditioning, and ENERGY STAR measures that exceed code.
- E+ Residential New Construction Electric Rebate Program – Rebates available to electric customers for qualifying insulation, programmable thermostat, weatherizing, and ENERGY STAR measures that exceed code.
- E+ Business Partners Program – Customized incentives available to commercial and industrial customers for electric conservation in both new and existing facilities. Examples of custom projects include improvements to HVAC systems, refrigeration, air handling, and pumping systems.

Additional recruitment of trade allies continued through Year 2, as did interactions with individual commercial customers to identify and develop commercial rebate projects.

South Dakota rebate programs for Year 2 were granted extension from the PUC through December 31, 2016. Between July 1, 2016 and September 30, 2016, E+ programs have saved 2.94 million kWh or 0.34 aMW with a majority of savings coming from commercial customers installing variable frequency drives in existing facilities.

Wind Units

Beethoven

In May 2015, BayWa r.e. Wind LLC completed the construction of the 80 MW Beethoven wind project near Tripp, South Dakota, and NorthWestern began receiving generation under a PPA. In September 2015, NorthWestern completed the purchase of Beethoven. Beethoven consists of 43 GE-1.85/87 turbines, each capable of generating 1.85 MW, and an adjacent expansion site capable of supporting an additional 50 MW of wind generation. The SPP qualified peaking capacity of this facility for 2016 is 19.1 MW.

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 that began commercial operation in January 2010. The SPP-qualified peaking capacity of this facility for 2016 is 4.0 MW. The Titan PPA extends 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 SPP-qualified peaking capacity of this facility for 2016 is 0.975 MW.

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

[2] SPP currently defines net planning capability of renewable resources and the recommended calculation methodology in the SPP Planning Criteria, Version 1.0, released in November 20, 2015.

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, all six full calendar years of actual generation data were used (2010 – 2015). Oak Tree had only one full calendar year of actual generation data available (2015). Since this doesn't meet the Criteria requirements of using the three most recent calendar years, 2013 - 2015, the SPP default wind NPC value of 5% was assigned.

For Beethoven, generation data for 2013 – 2015 were not immediately available since Beethoven had only been in operation since March 2015. The Criteria allows for the use of calculated generation data correlated with a reference tower within 50 miles if measured data is not available for facilities in operation 3 years or less. Based on this rule, wind data supplied as part of a DNV due diligence assessment completed prior to NorthWestern's acquisition of Beethoven was used to complete the period for January, 2013 – March 2015. Hourly simulated generation values were calculated from this wind speed data using the National Renewable Energy Laboratory ("NREL") System Advisor Model tool. The SPP 2016 NPC calculation was performed using both actual and simulated generation values for Beethoven.

The Criteria establish that NPC calculations shall be updated at least once every three years. In addition, the NPC for Oak Tree will be calculated when the facility has accumulated three years of generation data, in early 2018.

The significance of changing to the SPP methodology is that the accredited capacity contribution of the wind fleet, previously valued at 0 MW, will become 24.1 MW in 2017. The resulting increase of approximately 24 MW of available capacity reduces NorthWestern's expected need of up to 65 MW down to 41 MW.

Capacity and Energy Agreements

NorthWestern entered into a capacity agreement with MRES in 2014. The capacity agreement provides 30 MW from summer 2016 through 2017, and 35 MW in 2018. The power is provided by the Watertown Peaking Plant. The capacity price is a fixed contract rate, while any energy produced is priced at the incremental cost of this unit. This MRES contract addressed capacity needs previously secured under a contract with Basin for up to 19 MW through 2015.

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 2015, the energy resource mix, shown in Figure 3-2, provided approximately 1,658,000 MWh of net generation in the following percentages: 60.9% base load coal, 23.3% owned and contracted wind, 15.4% net market purchases from Western Area Power Administration ("WAPA") and SPP, and 0.4% peaking natural gas and diesel.

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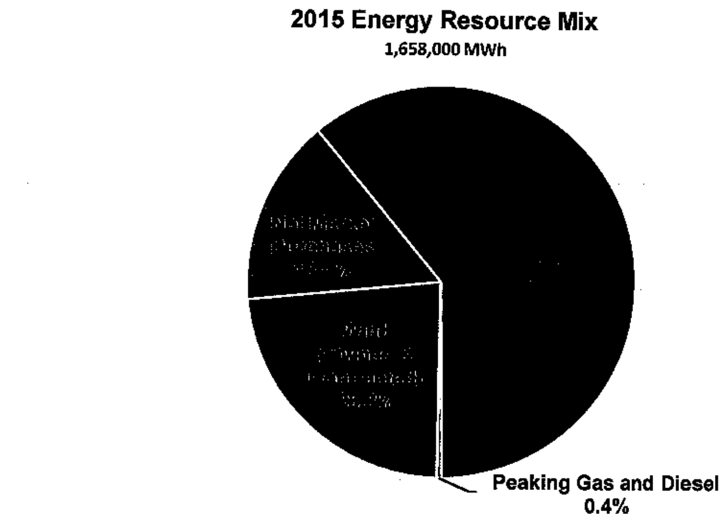
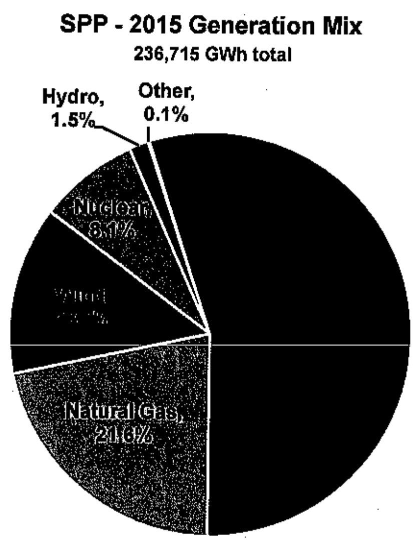
Figure 3-2 2015 NorthWestern SD Energy Supply Mix



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 2015 SPP generation mix is shown in Figure 3-3 below.

Figure 3-3 2015 SPP Generation Mix



Coal-fired plants generated 55% of the total in 2015, while natural gas plants generated around 22%, wind about 13.5%, and nuclear about 8.1%. DSM and other resources (fuel oil, solar and biomass) make up only a small portion of the total.

Figure 3-4 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.

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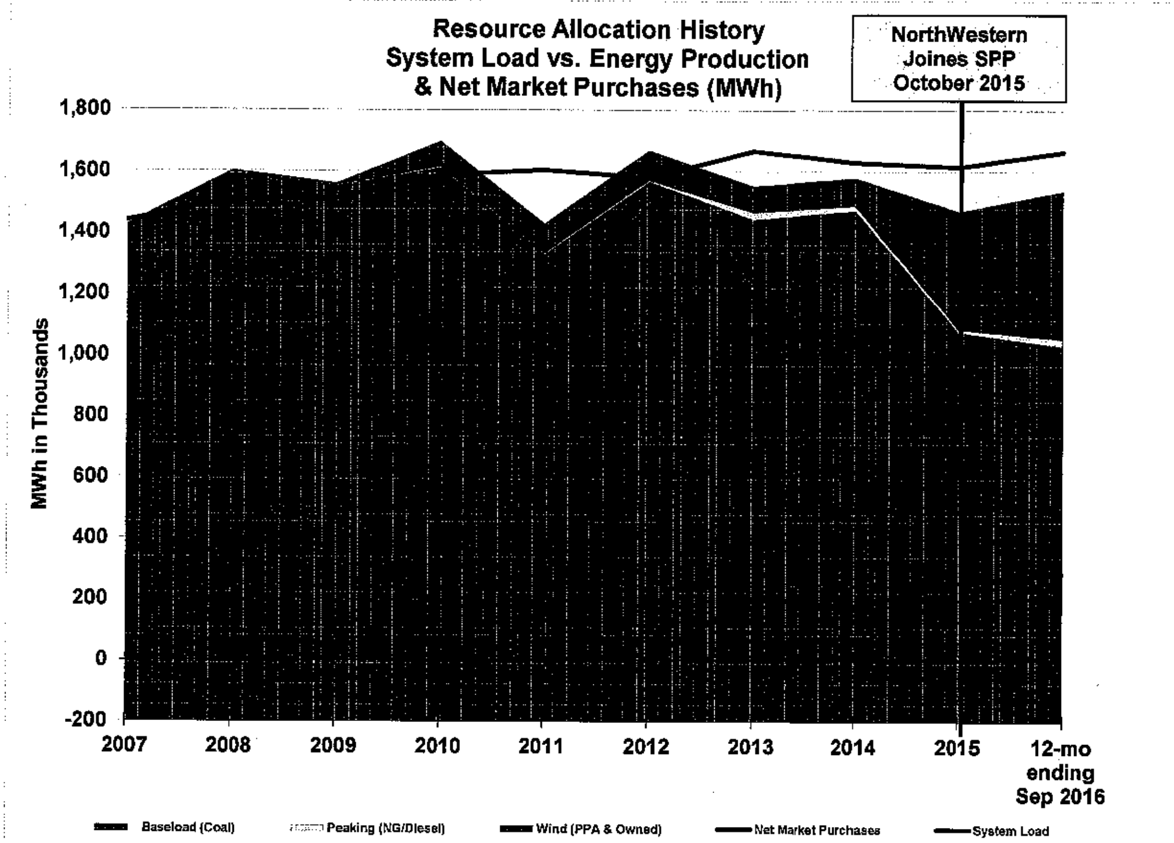
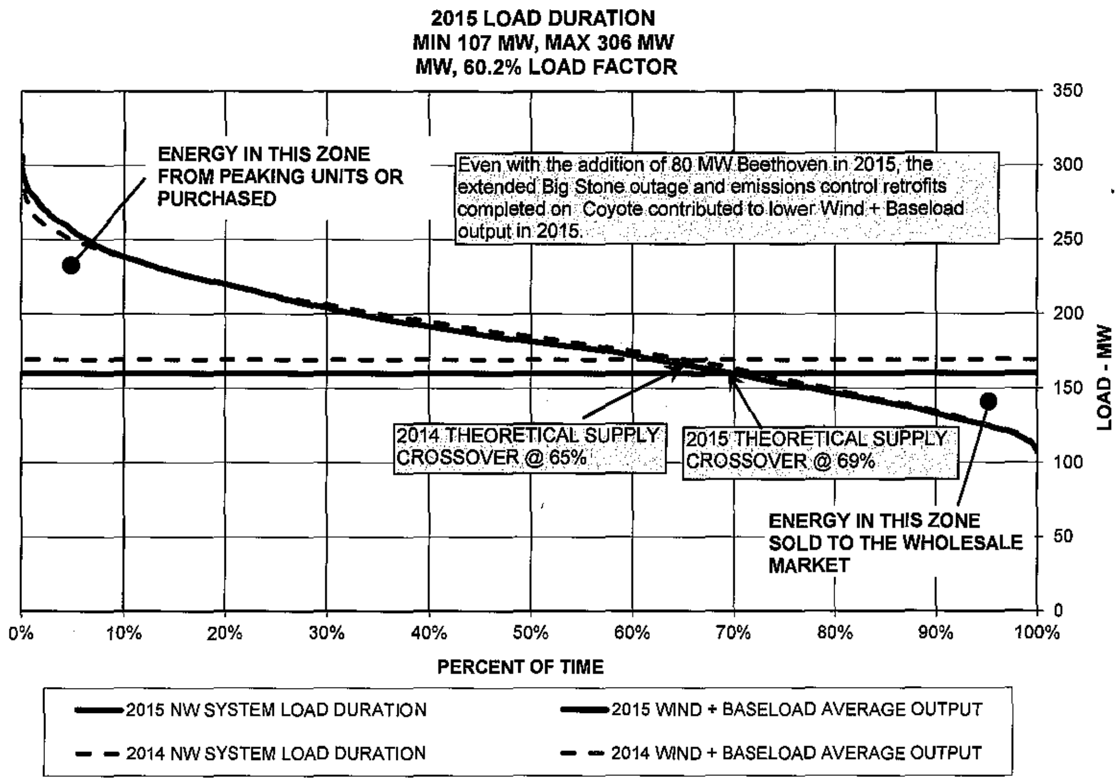
Figure 3-4 Resource Allocation History – System Load vs. Energy Production & Net Market Purchases



As depicted in Figure 3-5 below, NorthWestern made economy energy purchases in 69% of the hours during 2015. After adjusting for unusually extended base load unit outages during the year, the outage-adjusted level would have been about 40% or approximately 3,500 hours per year where NorthWestern would be purchasing from the market to meet the load. That level reflects the slow increase in the market purchases (in the range of 20-30% over the last ten years (outage-adjusted)). NorthWestern made economy energy purchases in 65% of the hours during 2014.

Figure 3-5 2015 Load Duration Curve



In recent years, customers have benefited from lower energy prices even as NorthWestern's market purchases have increased.

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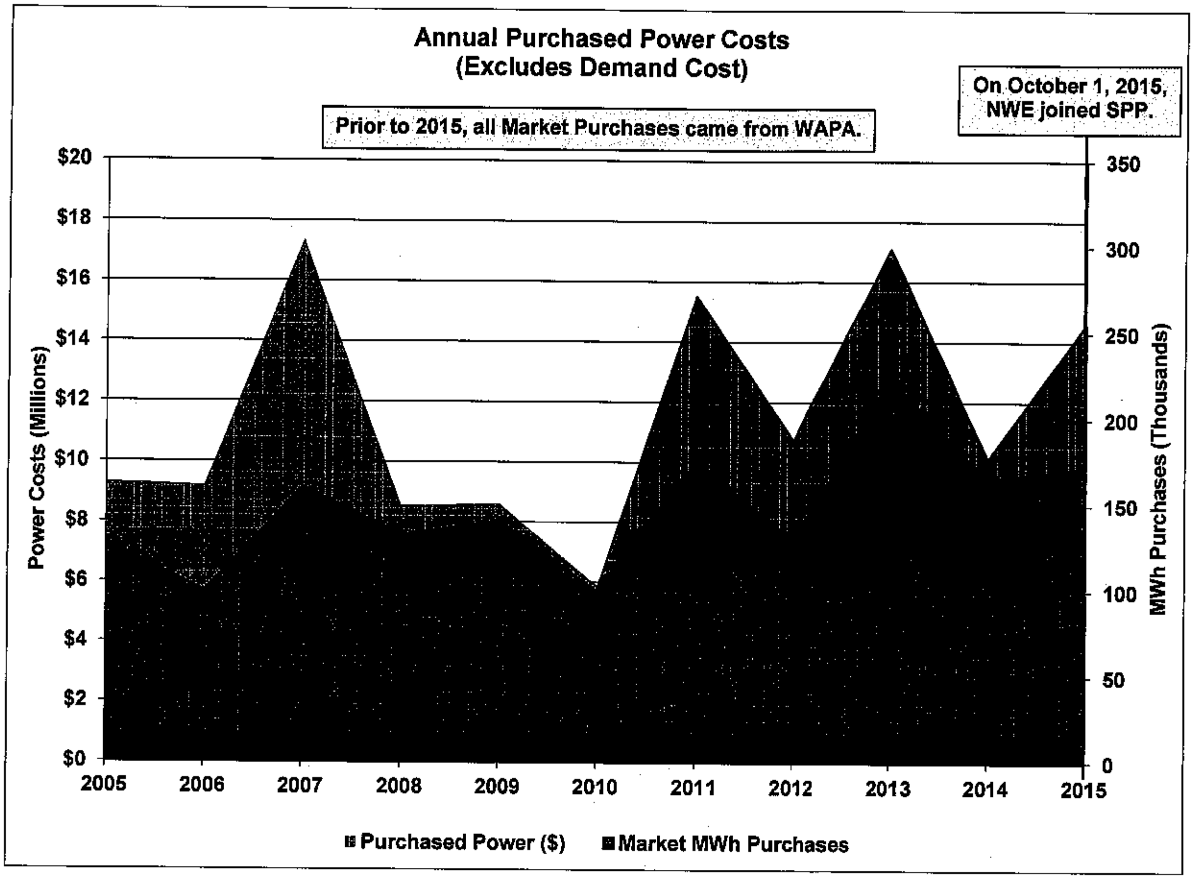
Figure 3-6 2005 – 2015 Annual Purchased Power Costs

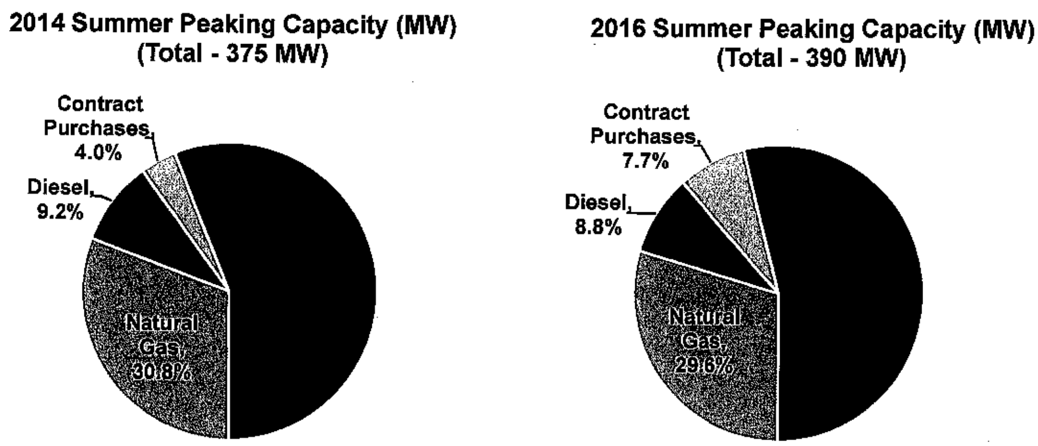


Capacity Resource Mix

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 24.1 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, 2014 & 2016



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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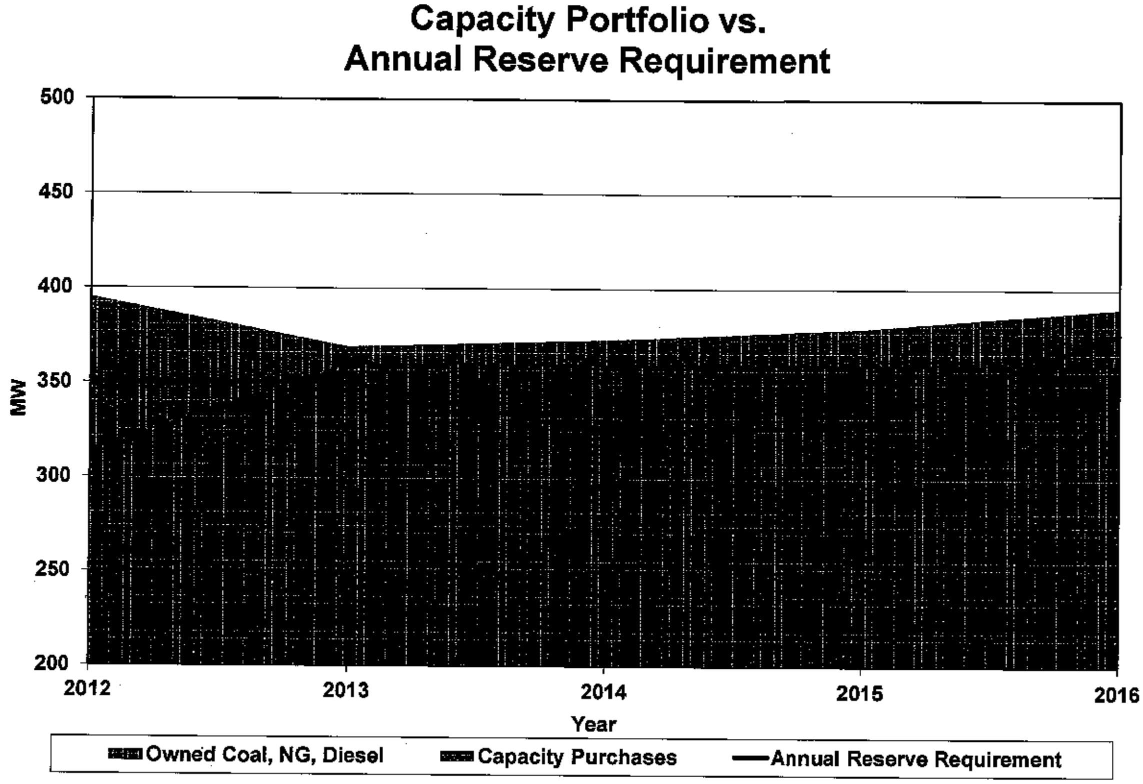
Figure 3-8 2012 – 2016 Capacity Portfolio vs. Annual Reserve Requirement



Although the annual reserve requirement amount dipped in 2014 and 2015 due to a lower peak demand in both years, NorthWestern's reserve requirement percentage remained at 7.1% until 2016, when it became 13.6% under SPP.

Retirement Study

Table 3-1 shows NorthWestern's existing resources and the year they entered service. A number of NorthWestern's generation units in that list were placed into service in the 1960s and 1970s and may have exceeded their useful life. NorthWestern's Thermal & Wind Generation Department is working with HDR to develop a Retire and Replacement Study for the natural gas-fired and oil-fired generating units. The study will examine efficiency, reliability, parts availability, book value, and provide a cost benefit analysis for replacement of those assets with proxy technology selections. The economic contributions of each asset to the overall resource portfolio will also be evaluated. NorthWestern expects that the study will be completed in July 2017 and the results will be used to inform resource development in South Dakota.

CHAPTER 4
NEW RESOURCES

New Resources Overview

The 2016 Plan addresses capacity, wind, solar PV, DSM, and energy storage resources as possible additions to the portfolio. The planning process involved analysis and contributions from outside consultants Ascend, HDR, DNV GL, and other sources. NorthWestern issued an RFP for capacity resources in early 2016. In parallel with the RFP effort, HDR worked with the NorthWestern Generation Department to provide a siting and technology study. This technology study identifies favorable sites to build a generation asset and the technology best suited for the operating profile and site.

Thermal Resources

Technology Study

NorthWestern selected HDR, in a selection process that included 12 energy engineering consulting firms, to provide both a Technology Assessment and a Siting Study to be used in evaluating proposals submitted in response to an RFP for capacity. The Technology Assessment, evaluated six different simple cycle configurations of CT and Recip technology from various manufacturers capable of meeting the specified requirements and other objectives. These six proxy units, shown in Table 4-1, were chosen as a representative sampling of currently available technology types.

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Table 4-1 Technology Assessment Configurations

Number of Units	Manufacturer	Model	Type	Total Gross Output (MW)
1	GE	LMS100PB	Aeroderivative CT	102.9
4	Wartsila	18V50SG	Recip	75.0
8	GE Jenbacher	J920	Recip	68.6
2	GE	LM6000PF	Aeroderivative CT	86.4
1	PW Power Systems	FT8 Swiftpac 60	Aeroderivative CT	60.4
2	Siemens	SGT-800-47	Frame / Industrial CT	90.9

NorthWestern and HDR met with the manufacturers of these units to learn more about technical performance criteria, costs, available engineering, procurement, and construction ("EPC"), and maintenance options. NorthWestern modeled each of these configurations independently as an addition to the existing South Dakota supply portfolio/SPP system using PowerSimm to determine their respective 45-year levelized cost of generation. The potential benefits derived from their ability to serve the SPP ancillary services market and increase reliability due to having multiple shafts were not included in this analysis. Results of this study suggest that Recip technology would offer the most favorable economics to NorthWestern and its customers over a 45-year project life based primarily on efficiencies, fuel costs, and frequency of economic dispatch to the SPP market.

Defining New Gas-Fired Resources

NorthWestern modeled two specific natural gas-fired units from the technology study as additions to the portfolio: Wartsila 18V50SG Recip (18 MW), and PW Power Systems FT8 SWIFTPAC 60 aero-derivative CT (60 MW). The costs and operating characteristics for these units are shown in Table 4.2 below.

Table 4-2 Resource Definition and Cost Summary

Technology		Operating Characteristics					Costs			Emissions (Tons/MMBtu)		
Resource Description	Manufacturer and Unit	Net Capacity (MW)	HHV Heat Rate (Btu/kWh)	Min Stable Load (MW)	Min Stable Load Eff. (Btu/kWh)	Start-Up Time (min)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	NO_X	SO_2	CO_2
Recip	Wartsila 18V50SG	18.56	8,215	3.5	11,462	1	$1,436	$9.13	$7.71	0.19	0.0014	118
Aero-derivative CT	PW Power Systems FT8 SWIFTPAC 60	59.50	9,266	28.3	12,012	2	$1,400	$13.03	$6.16	0.19	0.0014	118
Wind	Generic Wind *	50					$1,788	$40.12				
Wind	Generic Wind *	100					$1,788	$40.12				
Solar	Generic Solar **	50					$1,999	$36.00				
Solar	Generic Solar **	100					$1,929	$36.00				

* The Generic Wind resource is based on a weighted average production profile of three existing wind resources. Costs are based on Beethoven.
** The Generic Solar resource is based on the DNV-GL indicative design and costs (Appendix C), and NREL SAM simulated production.

Resource Siting

In 2016, HDR performed a siting study which evaluated seven existing NorthWestern sites and two new greenfield siting areas. Each site was ranked on a technical basis considering several weighted factors including fuel supply, electric transmission, air quality, and ability to enhance system reliability. In addition, sites were also ranked economically based on their projected first year cost of generation ("COG"). These locations and their respective technical and first year COG rankings are shown in Table 4-3. The results suggest that NorthWestern's existing Aberdeen location is the most favorable site to support a nominal 60-MW generation addition to the NorthWestern system.

Table 4-3 Siting Study Locations and Rankings

Site	Technical Rank	First Year COG Rank
Aberdeen	1	1
Huron	2	3
Aberdeen South (greenfield)	4	2
Yankton	3	6
Redfield (north of town at 115kV Substation)	6	5
Mitchell	5	7
Clark	8	4
Raymond (greenfield)	7	9
Webster	9	8

At the time of HDR's siting study, NorthWestern learned that the natural gas infrastructure would not be able to support any addition generation without upgrades at the Yankton site. The study found that 1,000 to 2,000 dekatherms per day ("dkt/day") of gas supply capacity available at Mitchell, and an additional 2,000 dkt/day at Huron, would translate into additions of nominal generation capacities of 9 MW at Mitchell (based on an average of the range), and 11 MW at Huron, respectively. With the proximity of the Northern Border Pipeline to the Aberdeen Generating Station, it was assumed that large quantities of natural gas could be utilized in this area.

In September 2016, NorthWestern learned that additional gas supplies may become available on Northern Natural Gas ("NNG"), the existing natural gas pipeline in Yankton, Mitchell, and Huron. Having an available fuel supply increases the favorability of adding generation at these three locations. The new information indicates an incremental 5,500 million cubic feet per day ("Mcf/day") at Yankton. If NorthWestern secured that capacity in Yankton, it could support up to 30 MW of additional generation. Electrical interconnection and transmission system upgrades associated with this quantity of generation would be minimal, consisting of just interconnection facilities.

At Mitchell, the new information indicates an incremental 4,000 Mcf/day, which could potentially support additional generation up to 22.2 MW. At Huron, the incremental opportunity is 13,000 Mcf/day. NorthWestern anticipates that amount of additional natural gas supply at Huron could support up to 70 MW of new generation. No additional gas capacity was identified in Aberdeen. However, with the proximity of the Northern Border Pipeline to the Aberdeen Generating Station, it is assumed that large quantities of natural gas could be utilized in this area. Upon further investigation of the Air Quality permit for the Aberdeen Generation Station, it was discovered that emissions from Aberdeen's Unit 1 could reduce the starts and operating hours of a new unit(s).

RFP for Capacity

Due to expiring contracts, support of known and future load growth, and the need to maintain a PRM of 12%, NorthWestern's 2014 Plan identified the need for up to 65 MW of additional capacity within the planning horizon. In February 2016, NorthWestern issued an RFP for capacity products that also meet the requirements for accreditation and dispatch as defined by the SPP OATT. The goal was to identify cost-effective technology to supply at minimum a nominal 60 MW of capacity by early 2019. The operating profile for the self-build option was planned to provide real-time dispatch, ancillary services, and be economically dispatched within the SPP market.

NorthWestern received bids from seven companies in response to the RFP. NorthWestern is still evaluating the need for additional resources and is in discussions with the most economical resource identified in the RFP. As discussed in Chapter 3 of the 2016 Plan, changes in SPP methodology are anticipated to increase the accredited capacity contribution of the wind fleet, previously valued at 0 MW, to 24.1 MW for 2017.

SPP Screening Studies for Long Term Service Requests

NorthWestern issued LTSR to SPP for transmission from the proposed locations from several of the RFP bids. In addition, NorthWestern requested that SPP perform screening studies to determine the impacts on the SPP system and provide an approximation of transmission remediation costs resulting from the addition of 55 MW of generation at these sites. The screening studies modeled transmission service from each site to NorthWestern's load. The result of all three studies indicated that limiting constraints exist within the SPP regional transmission system for the requested transfer of capacity. Two of the sites would require transmission upgrades that had completion date estimates as early as the end of 2019, well beyond NorthWestern's capacity addition planning goal of COD in early 2019. One proposal would not require transmission upgrades.

Grid Reliability

NorthWestern's delivery system is comprised of 3,550 miles of transmission and distribution assets, along with 124 substations. This system has interconnections with transmission facilities of OTP, MDU, Xcel Energy Inc., and WAPA. It also has emergency interconnections with the transmission facilities of East River Electric Cooperative Inc. ("EREC") and West Central Electric Cooperative. Effective October 1, 2015, NorthWestern is now a transmission-owning member of SPP for South Dakota transmission operations.

Historically, NorthWestern Energy operated generating plants throughout its South Dakota service territory, including Webster, Aberdeen, Faulkton, Redfield, Clark, Huron, Woonsocket, Highmore, Chamberlain, and Yankton. These plants were originally built for base load generation, operating 24/7 supplying power for the communities served. As the transmission system has expanded, these same units have continued to provide peaking power and energy as well as contingency and reliability to those same communities.

However, a number of these units have exceeded their expected life, and some have been retired.

From a distribution/transmission operations perspective, distributing generation assets across the system, to meet the overall system capacity requirement, adds an additional level of reliability. It also provides additional capability for integrating current and future renewable generating resources, which can be widely distributed within NorthWestern's system. For example, if 25 MW of wind generation falls offline, it would be more efficient to start up three smaller 9-MW units compared to a 50 MW plant. Installing smaller units, distributed throughout NorthWestern's service territory has the potential to provide scalability and flexibility in meeting the system needs, while also providing additional system reliability. Table 4-4 compares current generating capability of existing generation assets to 2015 peak loads.

Table 4-4 Locational Generation and Loads

Location	Generating Capability MW	Number of Units	2015 Peak MW Demand
Aberdeen	72.5	2	76.1
Webster	0	0	2.55
Redfield	0	0	12.1
Clark	2.6	1	2.5
Huron	54.4	2	47.8
Highmore	0	0	3.8
Mitchell	0	0	54.2
Chamberlain	0	0	4.9
Yankton	13.42	4	54.3

The table shows that generation in Huron exceeded peak demand, while Aberdeen generation nearly matches peak demand. In comparison, Mitchell had a peak demand of about 54 MW and currently has no generation capability. Yankton's existing generation can only support about 25% of the peak demand. The other communities listed in the table either represent larger population centers that previously had generation or remote locations with limited/partial contingency back-up capability. For example, Webster has a radial 69-kilovolt ("kV") feed with an emergency tie to EREC. Clark is on a radial 69-kV line, with an emergency tie to WAPA via Watertown Municipal. Chamberlain and Highmore both have extended 69-kV line exposure (50 miles +/-) and are located at or near the ends of our system although both have emergency ties to EREC.

During the 2005 ice storm, all of the distributed generating assets, as well as a host of rented assets, were utilized for an extended period of time to provide service throughout the event. In comparison, some of EREC's customers were without power, in some cases for 3 to 5 weeks, until miles of line could be rebuilt. With its customers being able to receive continuous service, NorthWestern was able to focus all of its available resources reconstructing downed transmission and distribution assets. Tornados, blizzards, and equipment failures are among the many reasons that support locating new generation, where possible, throughout NorthWestern's service territory.

Demand Side Management

NorthWestern's ended its electric E+ programs for South Dakota in October 2016, with the exception of the Energy Audit for the Home, as the budget was met. For more information on those programs, see the Existing Resources Chapter[1]. Using the knowledge gained from the two year pilot DSM Plan and updated avoided costs and energy efficient measure information, NorthWestern designed and filed a proposed 2017 DSM Plan on November 18, 2016.

[1] For more information on those programs, see Chapter 3.

Wind Resources

Wind is an intermittent generation resource, meaning that generation levels fluctuate greatly in a short time period. It is not uncommon for actual generation to deviate considerably from forecasted generation within the hour. NorthWestern used a weighted average production profile from the three wind resources in the energy supply portfolio when developing the generation expectations for the generic wind resources. The resource characteristics and costs of the 50-MW and 100-MW wind resources modeled in PowerSimm are shown in Table 4-2. NorthWestern used the capital and operating costs from Beethoven when developing the costs for the generic wind resources.

Utility Scale Solar PV

Solar resources are intermittent in nature. The movement of clouds can change solar production from maximum output to zero production in a matter of seconds. Solar resources, however, do provide capacity during NorthWestern's summer peak. To develop a greater understanding of solar PV resources, NorthWestern contracted with DNV to provide a solar resource design.

In 2015, DNV supplied NorthWestern with a generic scalable solar PV resource designed to be suitable for Montana locations[2]. Other than specifying that the proxy resource be sized somewhere around 3 MW, DNV was left to determine the appropriate size, components, etc. DNV's indicative design is a 3.02 MW_{DC} (2.5 MW_{AC}) solar PV project using Canadian Solar polycrystalline silicone-based modules and SMA Sunny Central inverters. The design uses single-axis tracking with conventional backtracking. DNV also applied estimates for soiling losses (which includes snow cover), shading losses, and

[2] NorthWestern believes that this generic Solar PV design would also be suitable for solar resources located in South Dakota.

energy losses associated with equipment failures, unplanned outages, planned downtime, and solar PV degradation over time.

DNV provided NorthWestern with capital cost estimates for the indicative design. The cost of solar facilities has continued to decline, so NorthWestern contracted with DNV to update the capital costs contained in the original study. DNV provided NorthWestern with an updated study, "Indicative Design, Energy, and Cost Estimation for 2.5 MW_{AC} Photovoltaic Project," on October 1, 2016. To model larger solar PV resources, DNV also advised NorthWestern that it would be reasonable to scale the indicative design up to 50 MW and 100 MW using the NREL Technical Report, "NREL/TP-6A20-64746[3]." Solar PV production was modeled using the DNV supplied indicative design and typical meteorological year weather data ("TMY3") for Huron, South Dakota using the NREL SAM. The modeled cost of utility scale solar PV is shown in Table 4-2.

Energy Storage

Utility-scale battery storage, particularly lithium-ion technology, is still evolving but on the edge of being a cost-effective alternative to fossil-fueled plants for some of the needed services described above. Many demo projects under 3 MWh have been in existence, but only a few 10+ MWh systems have been deployed in the U.S. Used for years in electric vehicles and consumer products, lithium-ion technology developments and increased manufacturing continue to drive costs down. Other technologies, such as flow and molten salt batteries, have some beneficial properties but their consideration has been limited due to higher relative costs and fewer utility-scale demonstration projects.

[3] This report is available at: www.nrel.gov/publications.

Pumped storage hydro ("PSH") uses off-peak or renewable power to pump water upstream to a storage reservoir, so that it is available to flow downstream through a turbine to generate electricity when needed. This relatively mature technology has benefitted recently from enhanced control capabilities. With the ability to quickly adjust speed and switch from pumping to generation, new PSH technology can be used to provide ancillary services including frequency regulation. These plants require appropriate geology and reservoirs which limit site selection and can lead to permitting and environmental concerns. Compressed Air Energy Storage ("CAES") utilizes the release of compressed air to spin a turbine/generator. CAES requires large geological features, such as a mined salt dome or a previously used natural gas reservoir capable of storing the air. This limits potential site locations.

Recent capital cost estimates for lithium -ion systems are around $3,330/kW. Projections estimate a 6-12%/year decrease in costs over the next 5 years, with these rates slowing in subsequent years. PSH had an average capital cost estimated at around $2,920/kW. Proposed PSH projects in NorthWestern's Montana and South Dakota service areas had rough estimated costs of approximately $2,250/kW[4] and $1,800/kW[5] (in $2016), respectively. Table 4-5 lists various energy storage technologies and estimates of their related costs.

[4] Gordon Butte Pumped Storage Hydro states that its 400-MW project will cost approximately $900M ($2016). http://gordonbuttepumpedstorage.com/news/

[5] A feasibility study was conducted on the proposed Gregory County PHS, wind farm, and transmission line project to connect the South Dakota wind energy with MISO. The projected capital costs were estimated to be $4 - $5 billion in 2011 for the entire project. PSH costs were estimated at $2B for 1,200 MW. ($2012)

Table 4-5 Storage Technologies and Cost

Storage Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Roundtrip Efficiency (%)	Design Life (Years)
Compressed Air Energy Storage	$2,030	$18.90	$0.80	70%	25
Pumped Storage Hydro	$2,920	$15.30	$0.10	80%	50
Li-ion Batteries	$3,330	$22.50	$0.00	82%	20
Flow Batteries (Vanadium Redox)	$4,570	$30.00	$43.00	74%	20
Sodium Sulfur (NaS) Molten Batteries	$5,410	$26.90	$29.50	78%	20

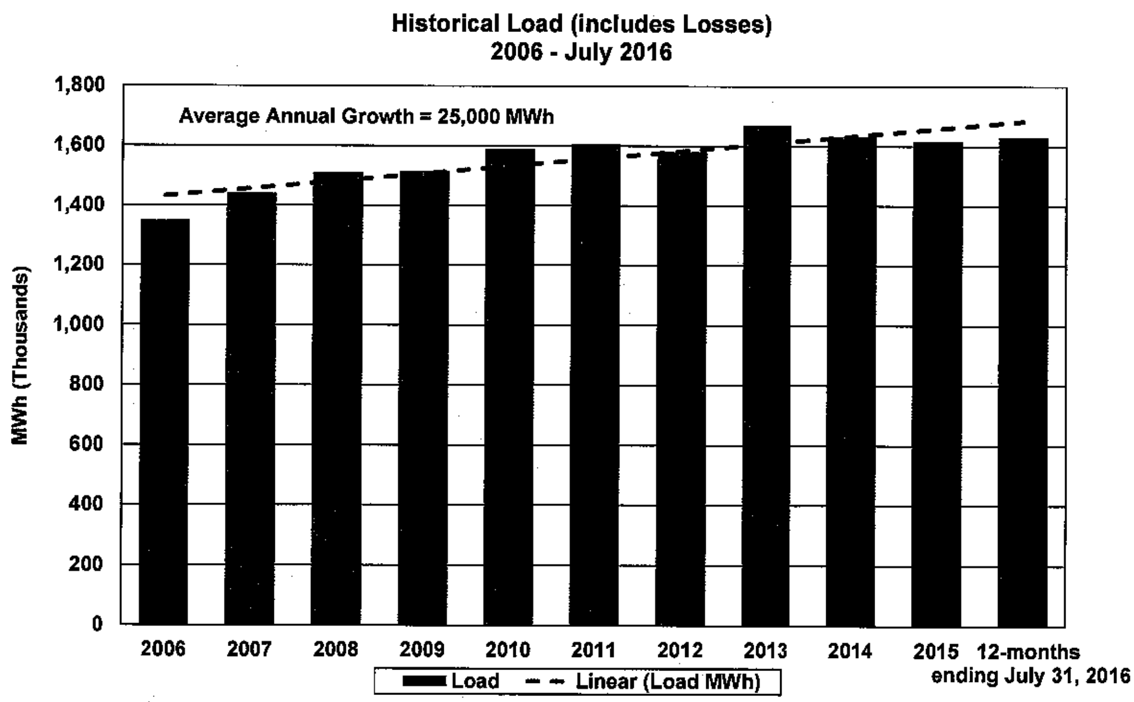
Energy storage has the potential to provide multiple grid services including transmission upgrade deferral, integration of renewable energy, distribution system reliability, peaker replacement, and frequency regulation. As a new member of SPP, NorthWestern will continue to evaluate internal needs as they apply to the regional SPP balancing footprint. The relative importance of each service that storage can provide will influence the choice of location and technology. Understanding the multiple value streams and defining cost-benefit analysis methodologies that aggregate these values will be key to justifying the economics in the near term. These methodologies are not well-established in the industry and thus determining an accurate levelized cost of storage poses new challenges.

CHAPTER 5
FORECASTS

Historic Growth of Energy

NorthWestern's total system load has grown over the last 10 years at an average rate of 25,000 MWh per year. System energy requirements for the 12-month period ending July 31, 2016 were around 1.65 million MWh, as shown in Figure 5-1 below.

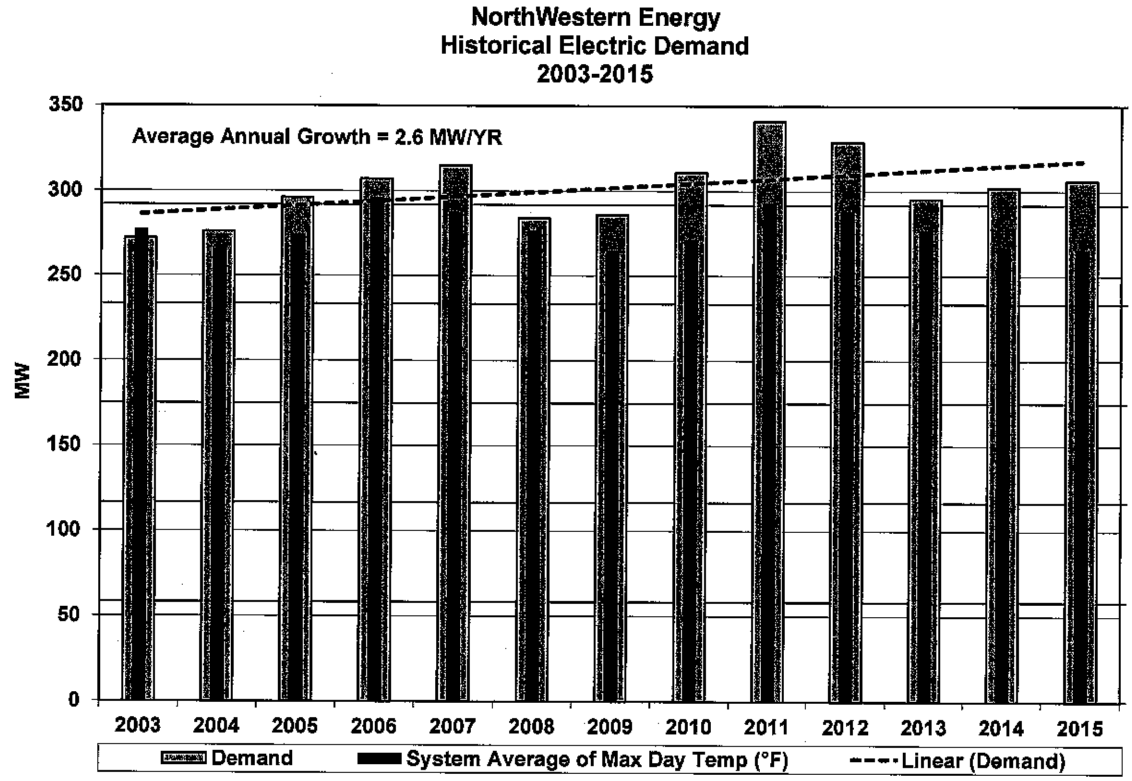
Figure 5-1 Historical Load – Retail Sales 2006 – July 2016



Historic Growth of Capacity Demand

NorthWestern has also experienced continued growth in capacity demand, or peak loads, over the past 13 years as shown in Figure 5-2 below. During this period, summer peak loads have grown about 2.6 MW per year. Although year-to-year weather-dependent peaks vary, the overall growth has been fairly consistent as illustrated in Figure 5-2 below. Figure 5-2 also shows the system average maximum temperature on the peak load day.

Figure 5-2 Historical Electric Demand (Capacity) 2003-2015



NorthWestern's electric service territory is characterized by predominantly residential and small commercial customers with a small number of light-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. The normal average temperature for NorthWestern's peak loads is typically under 100 degrees. 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 5-1 below remain below summer peak loads, but in recent years winter peak loads have been growing faster than summer peak loads.

Table 5-1 Historical Yearly Winter Peak Load

Annual Year Winter Peak Load		
Year	Peak MW	Day
2015	301	January 13, 2015
2014	286	January 6, 2014
2013	265	December 23, 2013
2012	274	January 19, 2012
2011	278	January 7, 2011

Load Forecasting

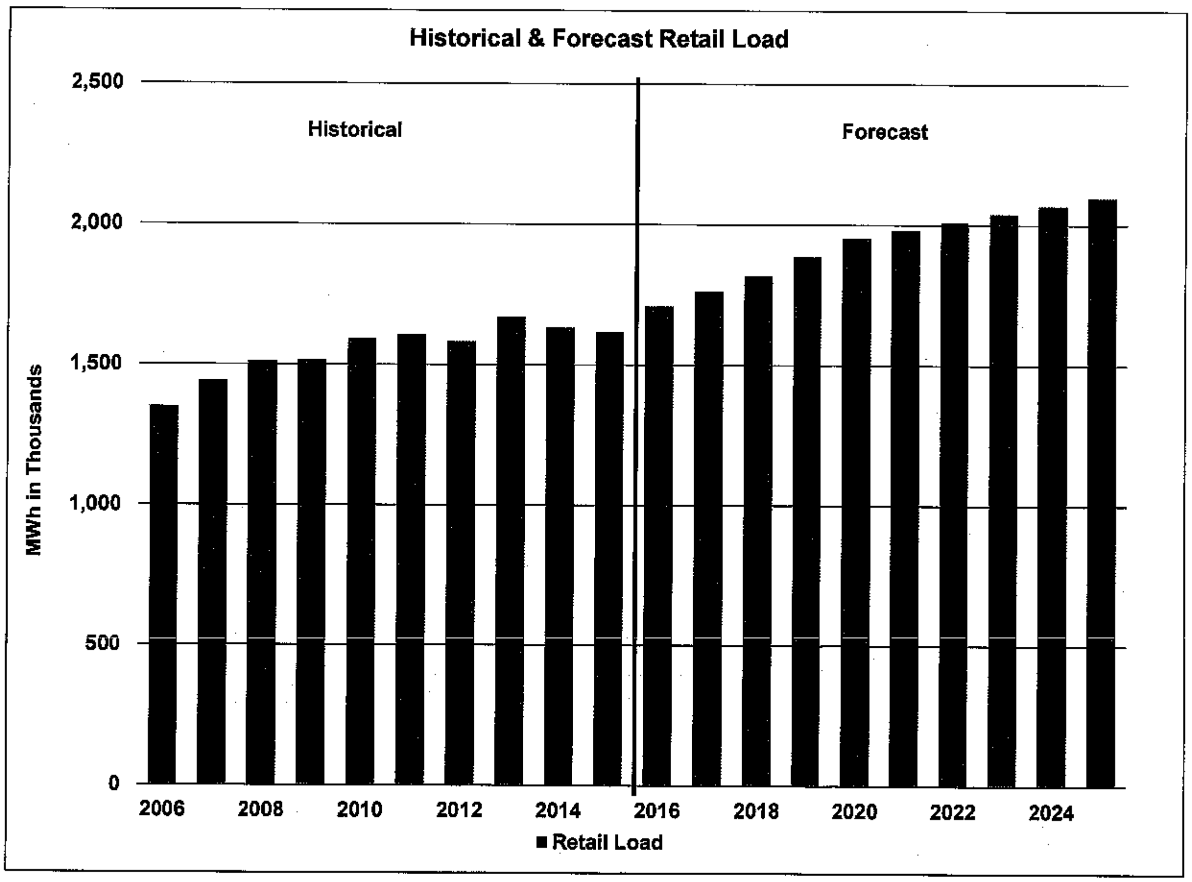
NorthWestern has been able to meet much of the energy and capacity needs of its customers over the last several years with owned resources. NorthWestern supplements the energy demand with spot market purchases from SPP and capacity with short-term capacity agreements. Continued growth in energy and capacity demand will require the expansion of NorthWestern's portfolio to meet customer needs.

Energy

The historical energy load annual growth remains relatively steady at approximately 25,000 MWh per year. Growth continues to be observed in new residential construction with a steady interest from the commercial sector within NorthWestern's service region.

NorthWestern is also in the process of negotiating supply contracts for two new large industrial loads that may come online in the next few years. One of these loads would be near Redfield and is projected to have an annual consumption of 50-80 million kWh. This project does not have a firm completion date but could start commercial operation in 2017. The other, located in Aberdeen, is projecting an estimated annual energy use of 48.4 million kWh with a commercial operation date in March 2019. Considering a continuation of the historical growth rate with these new large industrial loads, the forecasted system energy requirements for 2025 are expected to be near 2.1 million MWh as shown in Figure 5-3 below. However, unforeseen increases in industrial activity or energy conservation within NorthWestern's service territory could significantly affect the forecasted usage.

Figure 5-3 Historical and Forecast System Load



In 2015, NorthWestern's energy supply portfolio added 99.5 MW of intermittent wind resources. This increase in wind shifts the resource mix that provides energy for NorthWestern's load. Figure 5-4 shows the shift in resources that provide energy for NorthWestern's load comparing 2014 actuals to 2016 forecast. Intermittent wind will make up 25% of the supply for the portfolio reducing the amount of coal and market purchases. Annual net market purchase figures remain stable as any reductions due to increased wind generation are balanced by increased economic purchases due to lower market prices. The forecast for 2016 also will see additional natural gas generation due to the dispatch requirements of SPP. SPP will economically dispatch all of NorthWestern's registered resources.

Figure 5-4 2014 Actual vs. 2016 Forecast Energy Resource Mix

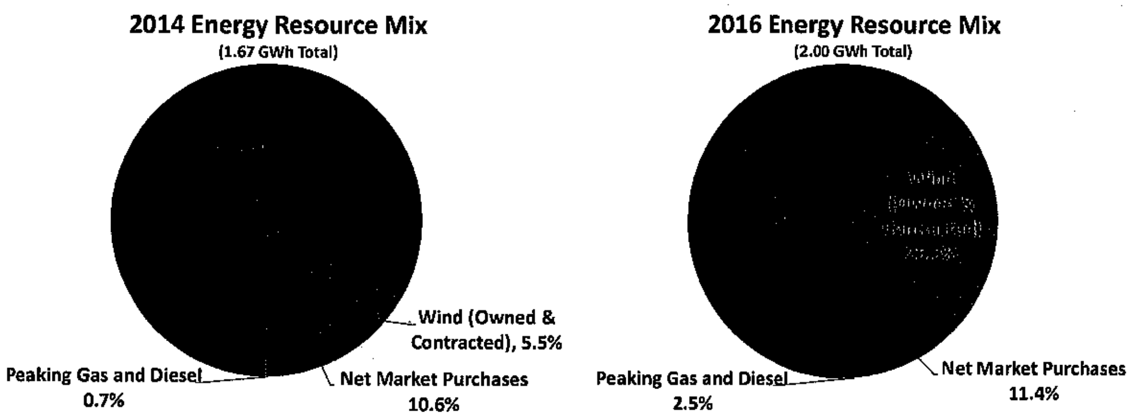
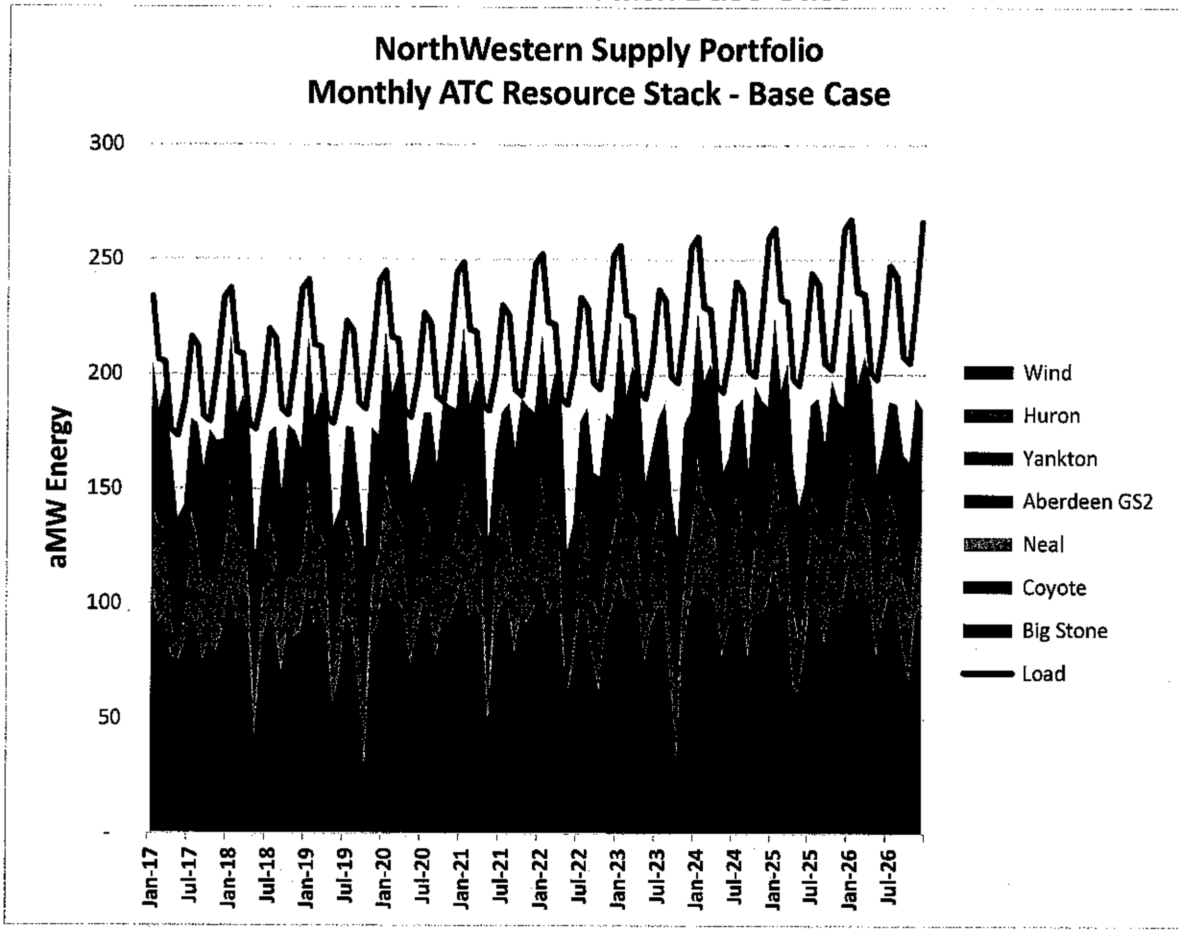


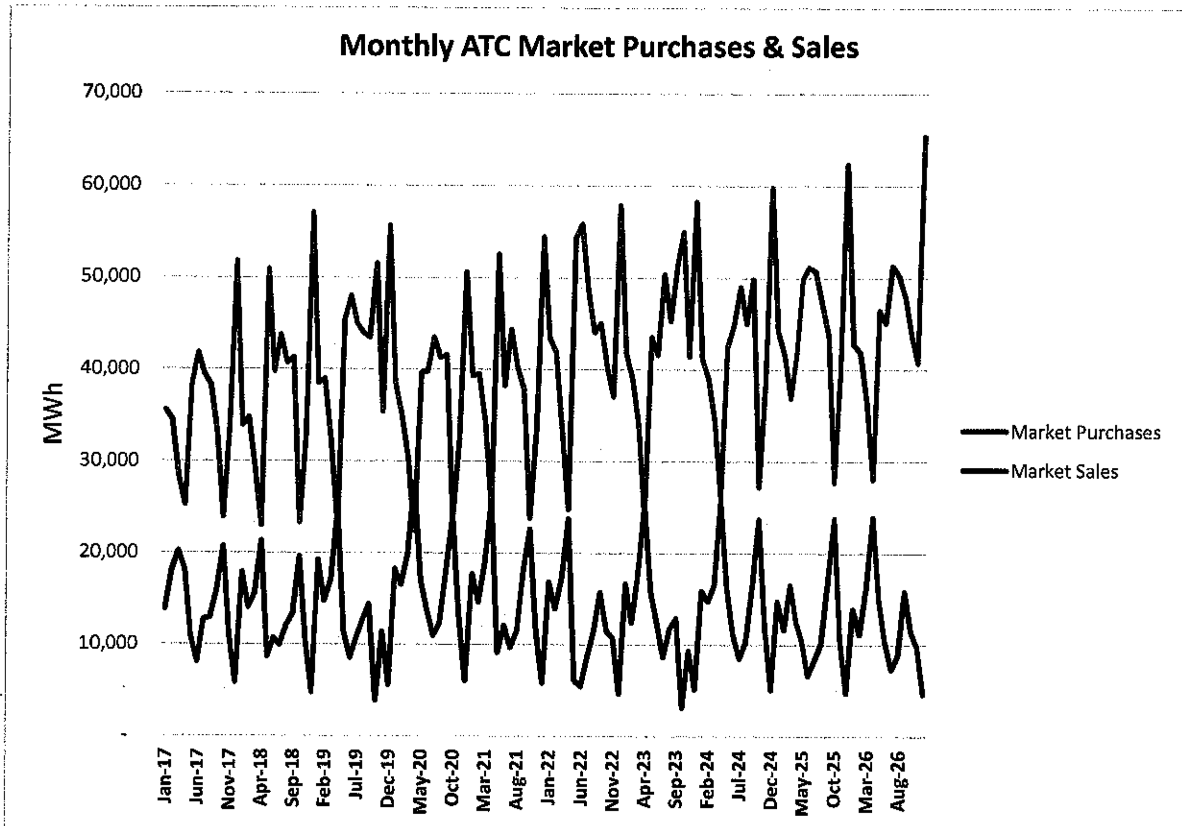
Figure 5-5 below details the resources that are used to serve NorthWestern's load requirements in around-the-clock ("ATC") hours as modeled in the PowerSimm software. The combination of economically dispatched thermal units and Company-owned and contracted for renewable resources leaves NorthWestern slightly short of fulfilling its load-serving obligations during most hours.

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



The expected load growth through 2026 may increase the need for NorthWestern to provide a market flexible resource to serve this obligation. A minimal level of market purchases are expected to be needed over the planning horizon. Figure 5-6 portrays the forecasted market sales and purchases over the next 10 years. The effects of increased NorthWestern load and lower economic dispatch of thermal units due to depressed market prices leave NorthWestern with a higher level of market purchases than market sales through 2026.

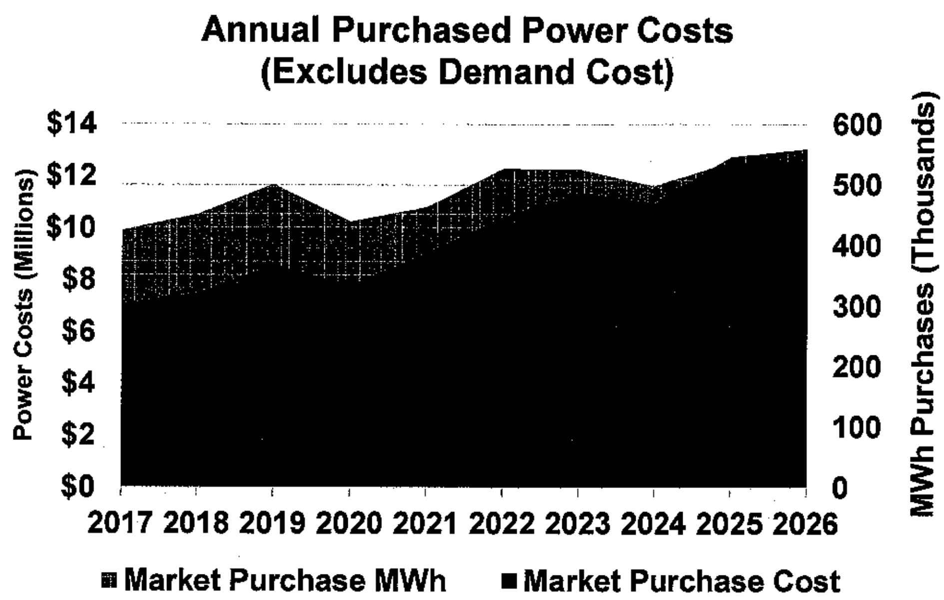
Figure 5-6 Monthly ATC Market Purchases & Sales



NorthWestern will continue to evaluate, also keeping in mind availability of transmission, if and when the addition of a base load or load-following resource is most cost effective or needed for reliability.

Figure 5-7 represents the forecast for total purchased power costs and the amount of forecasted MWh to be purchased. In 2026 estimated purchase power costs are expected to be almost $12 million for the base case.

Figure 5-7 Annual Purchased Power Cost and Associated MWh



Capacity

As a member of SPP, NorthWestern is currently required to carry 13.6% of capacity in excess of its peak load to meet the PRM requirement. Effective 2017, SPP will require a 12% PRM. Historic peak loads show an average growth rate of around 1% per year over the last 10 years. The peak load forecast is based on a 10-year historical correlation of peak loads with 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 100° F and a 10-year historical trend-based load forecast, the results were used to generate a peak load trend from 2017 through 2026. The two new large industrial loads discussed above were added to these forecasted peak loads, and the resulting values were used to determine the SPP PRM. The 2017-2026 peak load forecast is shown in Table 5-2 along with the total capacity obligation including the 12% PRM[1].

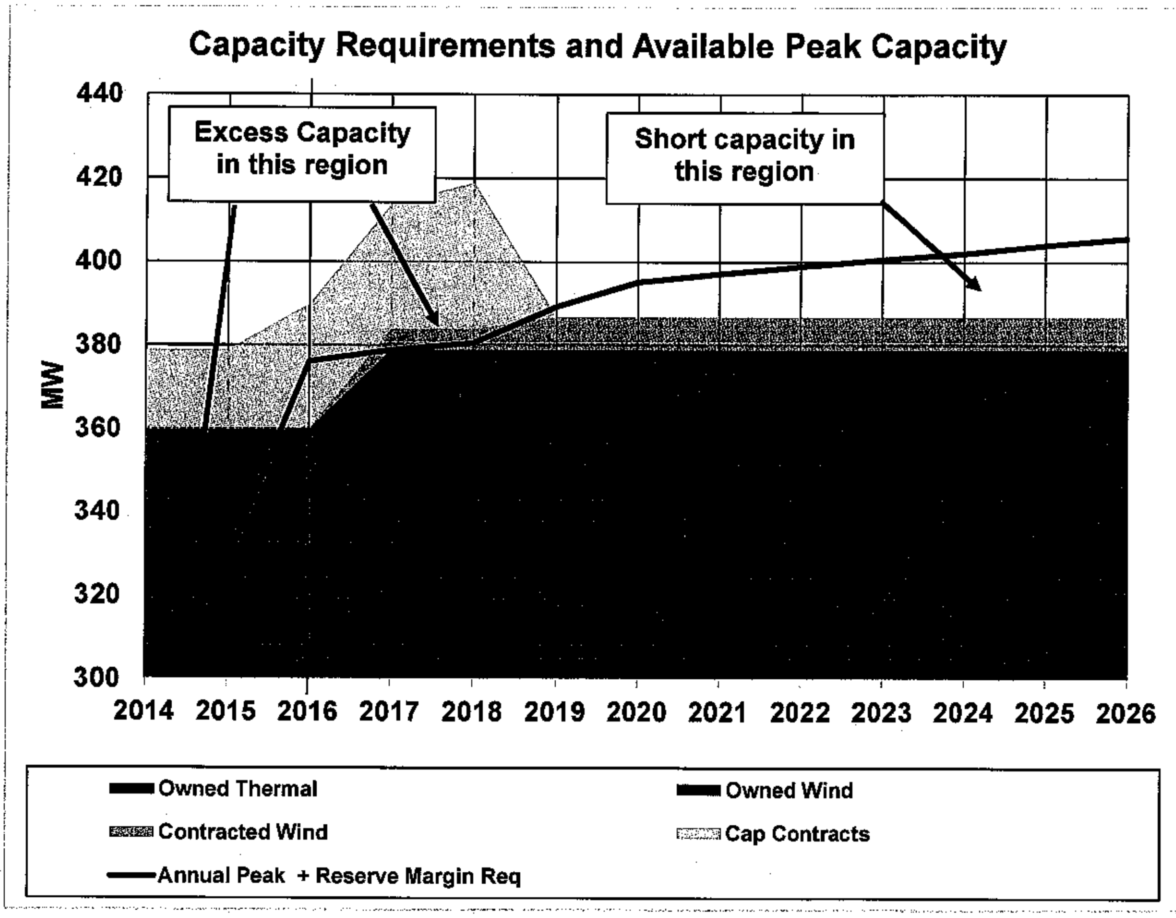
Table 5-2: Summer Peak Load 10-Year Forecast

Year	Summer Peak (MW)	Summer Peak with 12% Reserve Margin (MW)
2017	338	379
2018	340	381
2019	348	389
2020	353	395
2021	355	397
2022	356	399
2023	358	401
2024	359	402
2025	361	404
2026	362	406

Figure 5-8 below displays NorthWestern's forecasted future capacity deficits and surpluses, based on predicted future capacity obligations compared to existing capacity commitments (existing generation plus third-party capacity contracts). Beginning in 2019, NorthWestern is forecasting that it will need to obtain additional capacity either through adding internal generation or securing third-party contracts, in order to meet its system capacity requirement. In the current forecast, this need will increase annually from 3 MW in 2019 to around 19 MW in 2026.

[1] This is the SPP-prescribed level.

Figure 5-8 Capacity Requirements and Available Peak Capacity



* MISO Loss of Load Expectation study planning reserve requirement of 7.1% in 2014 and 2015
** Beethoven was purchased by NWE in September of 2015
*** SPP Planning Reserve Margin (PRM) Requirement of 13.6% in 2016 changes to 12% in 2017

NorthWestern will evaluate capacity options as 2019 approaches to determine the most cost-effective capacity additions. Along with projected growth, changes to the planning reserve requirement and available transmission may significantly influence the timing for any additional capacity. As discussed in Chapter 4, 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 the Ventura, 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. The forecasts that are used in this plan will be utilized in evaluation of other potential future resources.

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") until October 2017. The forward curve is then escalated after October 2017 through the remainder of the planning horizon at the escalation rate from the Energy Information Administration ("EIA") 2016 Annual Energy Outlook nominal Henry Hub gas price projection for SPP North in the No Clean Power Plan reference case.

Electricity Price Forecast

NorthWestern uses the same methodology for its electricity price forecast as is used for its natural gas forecast. Forward market electricity prices are provided by ICE through December 2018. The electricity price is then escalated using the same escalation rate as the natural gas forecast.

Table 5-3 details the mean heavy load, light load, and around the clock electric and natural gas price forecasts that are modeled in PowerSimm.

Table 5-3 Base Case Electricity and Natural Gas Price Forecasts

Mean Electricity & Natural gas Price forecasts

Year	HL - On Peak ($/MWh - Nominal)	LL - Off Peak ($/MWh - Nominal)	Around the Clock ($/MWh - Nominal)	Natural Gas ($/MMBtu - Nominal)
2017	$24.77	$18.56	$21.45	$3.30
2018	$28.70	$17.88	$22.91	$3.91
2019	$32.36	$20.16	$25.84	$4.41
2020	$36.48	$22.73	$29.13	$4.97
2021	$37.16	$23.15	$29.67	$5.06
2022	$37.91	$23.62	$30.27	$5.17
2023	$41.48	$25.84	$33.12	$5.65
2024	$44.01	$27.42	$35.14	$6.00
2025	$46.09	$28.71	$36.80	$6.28
2026	$46.36	$28.89	$37.02	$6.32
10-Year Lev.	$36.16	$22.95	$29.10	$4.92

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 from 2017 through 2021, Big Stone from 2017 through 2024, and Neal from 2017-2025. 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. Table 5-4 details the projected coal forecasts.

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Table 5-4 Coal Price Forecasts

Coal Price Forecasts			
Year	Coyote ($/ton - Nominal)	Big Stone ($/ton - Nominal)	Neal ($/ton - Nominal)
2017	$26.20	$39.14	$34.70
2018	$25.19	$40.31	$39.05
2019	$29.36	$41.52	$39.83
2020	$26.29	$42.77	$41.34
2021	$28.72	$44.05	$43.10
2022	$29.29	$45.37	$44.91
2023	$29.88	$46.74	$46.74
2024	$30.48	$48.14	$48.47
2025	$31.09	$49.10	$50.45
2026	$31.71	$50.08	$51.46
10-Year Lev.	$28.45	$44.01	$42.99

Conclusions

Energy load growth has remained relatively stable over the last 10 years. NorthWestern is also in the process of planning for two large industrial loads coming online in the next few years. 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 annually from 3 MW in 2019 to around 19 MW in 2026.

CHAPTER 6
PORTFOLIO MODELING AND ANALYSIS

Modeling Overview

For the 2016 Plan, NorthWestern used the PowerSimm™ suite of products from Ascend. PowerSimm™ is a modeling software that NorthWestern uses to model costs and risks to its portfolio. 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.

Portfolio Analysis

NorthWestern modeled a range of potential conditions with varying levels of renewables, thermal capacity additions, and the effect of environmental policies. NorthWestern's base case resource portfolio ("Base") includes existing resources with no planned additions. The Base portfolio depends on market purchases to meet current and future portfolio needs. The Base escalates the natural gas and electric prices based on EIA's forecast of natural gas prices at SPP interconnects in the Annual Energy Outlook "No Clean Power Plan" reference case. The Base portfolio also provide the "base" upon which all other resource portfolios are modeled.

Table 6-1 below lists the portfolios that NorthWestern modeled and the modeling assumptions for those portfolios. Additional renewable resources, wind and solar, were modeled to analyze the effect of varying levels of renewable resources on NorthWestern's resource portfolio. These portfolios are: the "50 MW Wind" case, the "100 MW Wind" case, the "50 MW Solar" case, and the "100 MW Solar" case.

Two portfolios analyze the addition of thermal resources to the Base portfolio. The "Recip" portfolio includes two 18 MW Wartsila internal combustion engines located in Yankton entering the portfolio in 2022 and one 18 MW Wartsila located in Mitchell in 2024. The "Combustion Turbine" portfolio adds one 60 MW Pratt and Whitney combustion turbine located in Huron to the portfolio in 2022.

NorthWestern also analyzed the effect of prospective future environmental regulations in the "Clean Power Plan" portfolio. This portfolio uses the reference case from the EIA's Annual Energy Outlook for the escalation of natural gas and electric prices, which assumes Clean Power Plan compliance.

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Table 6-1 Resource Plan Portfolio Assumptions

	Assets	Natural Gas/Power Forecast
Base Portfolio	Big Stone Coyote Neal Aberdeen 1 Aberdeen 2 Huron 1 Huron 2 Peaking Plants Titan Beethoven OakTree	Simulated monthly forwards from current Intercontinental Exchange market prices. Natural gas and electric prices use ICE through October 2017 while electricity uses ICE through December 2018 respectively. Extended through the 2026 by using nominal natural gas escalation from EIA Southwest Power Pool / North No Clean Power Plan Reference case.
50 MW Wind	Base +50MW wind in 2018	Same as base
100 MW Wind	Base +100MW wind in 2018	Same as base
50 MW Solar	Base +50MW solar in 2018	Same as base
100 MW Solar	Base +100MW solar in 2018	Same as base
Recip	Base + 2 recip in 2022 + 1 recip in 2024	Same as base
Combustion Turbine	Base +1 ct in 2022	Same as base
Clean Power Plan	Base	Same as base for current prices. Escalation uses the EIA Southwest Power Pool / North Clean Power Plan Reference case.

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 fixed and capital costs, variable costs, fixed and capital costs less the residual value of new resources, and risk premium.

Figure 6-1 below shows the ten-year NPV of costs for the Base, 50 MW Wind, 100 MW Wind, 50 MW Solar, and 100 MW Solar cases. The NPV of all four renewable portfolios is higher than the NPV of the Base. The addition of renewables helps to offset purchases, but includes a greater cost than relying on market purchases.

Figure 6-1
10-Year Net Present Value of Portfolio Costs, 2017-2026 (2017 $)
Base, 50 MW wind, 100 MW wind, 50 MW solar, and 100 MW solar cases

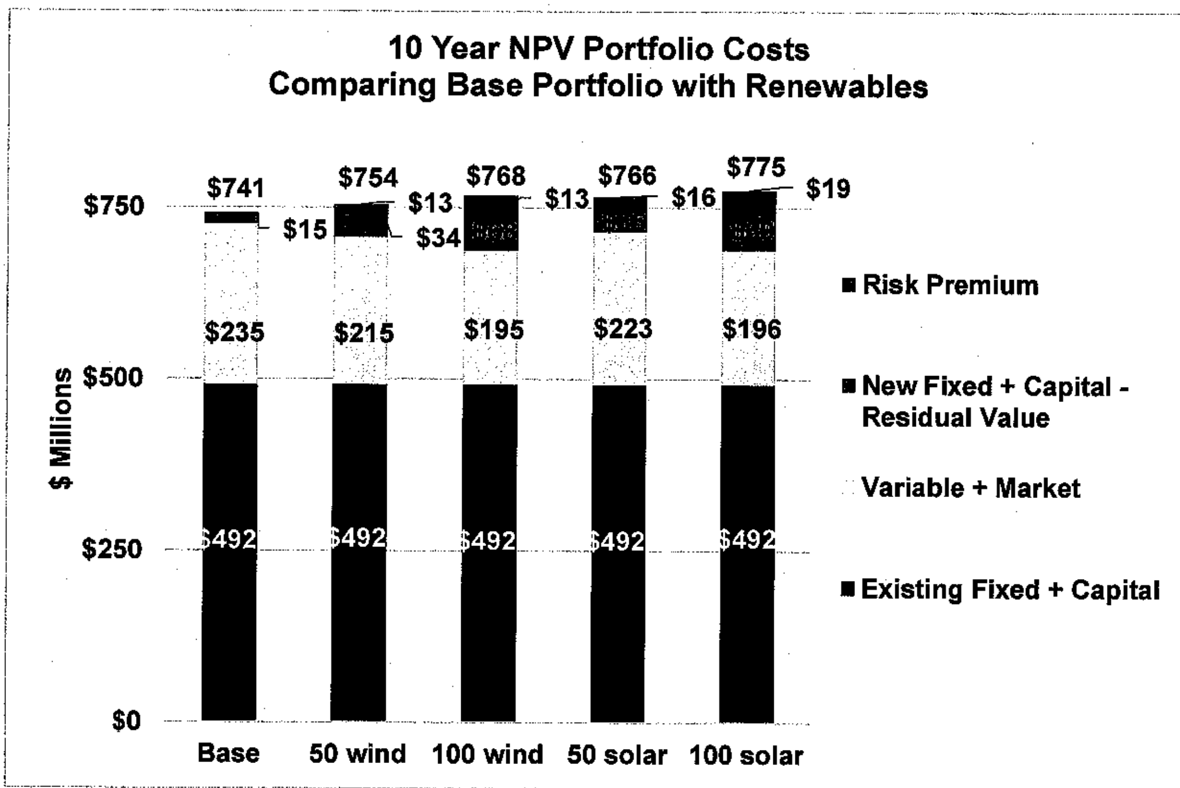
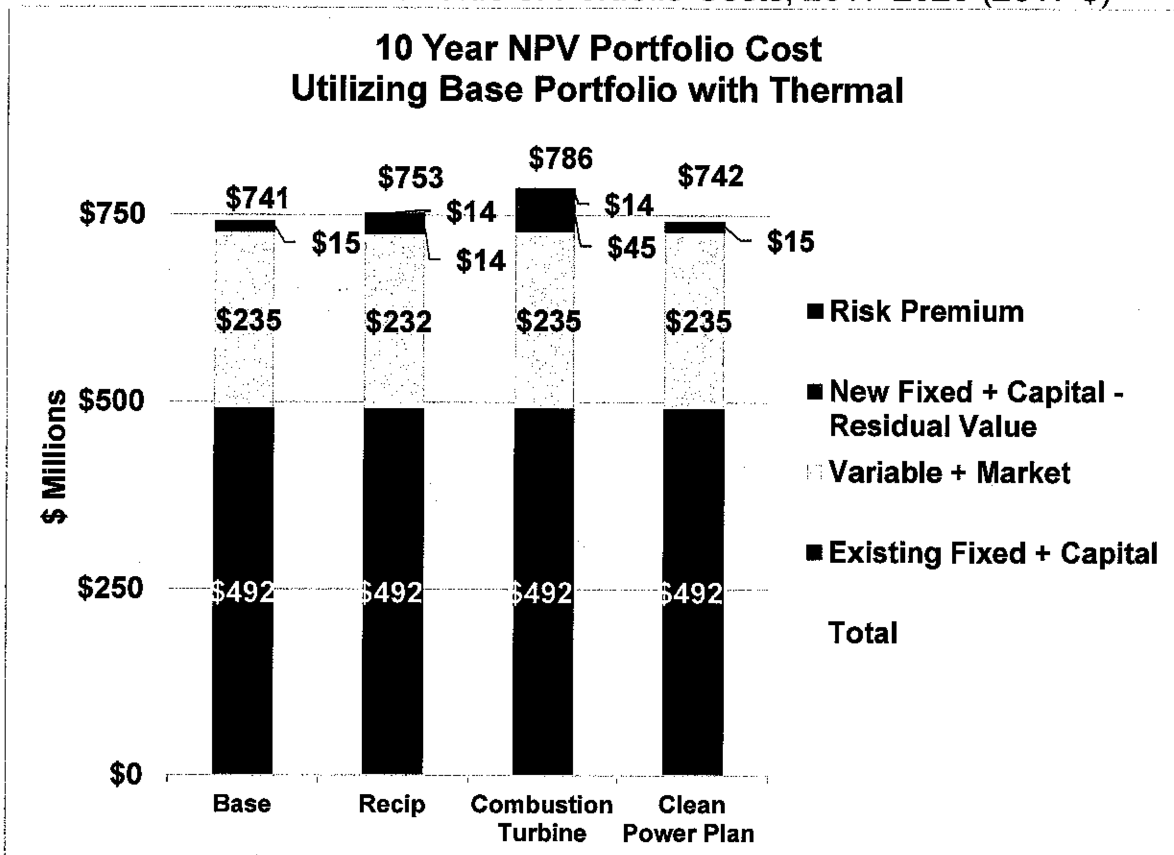


Figure 6-2 shows the ten-year NPV of costs for the Base, Recip, Combustion Turbine, and Clean Power Plan cases. As shown below, the Recip portfolio with additional reciprocating engines is more economical than the Combustion Turbine portfolio. The lower heat rate and increased flexibility of reciprocating engines more than offsets their higher capital costs. The Clean Power Plan portfolio shows slightly increased costs over the Base portfolio.

Figure 6-2
10-Year Net Present Value of Portfolio Costs, 2017-2026 (2017 $)



The annual portfolio costs for the Base and renewable portfolios are displayed below in Figure 6-3, and the annual portfolio costs of the Base, thermals, and Clean Power Plan portfolios are shown in Figure 6-4. Portfolio costs have decreased from the 2014 Plan.

Figure 6-3 Annual Portfolio Costs – Base and Renewables

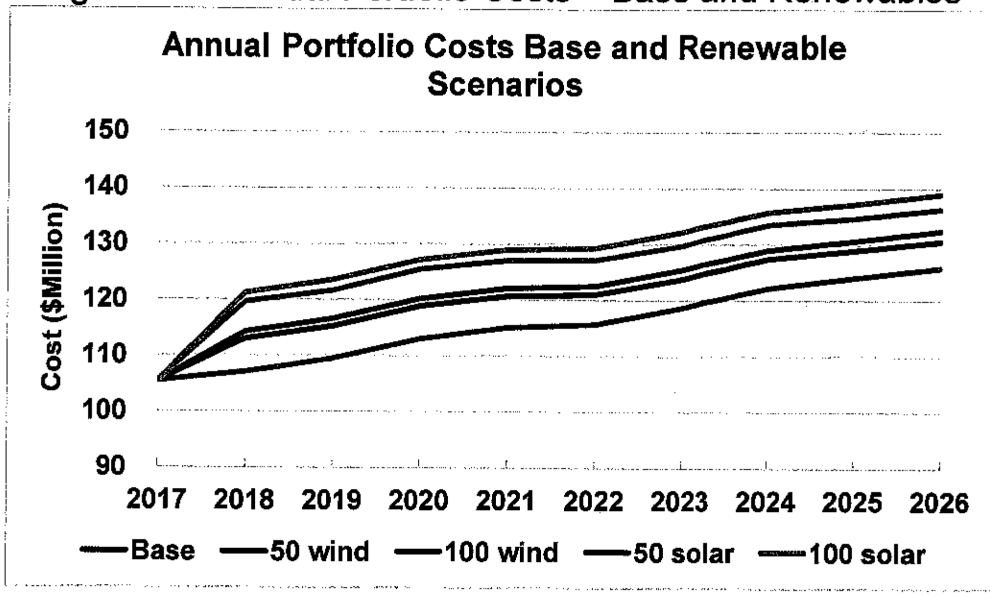
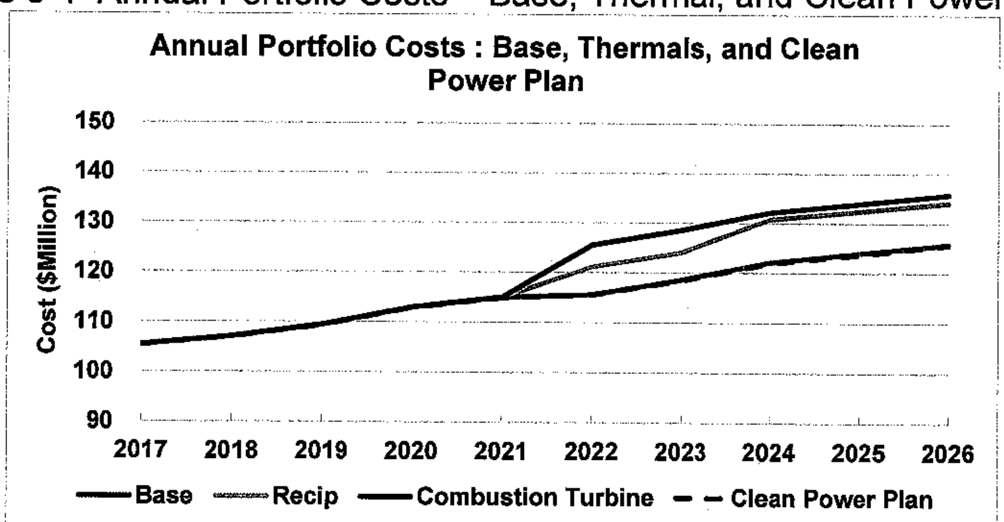


Figure 6-4 Annual Portfolio Costs – Base, Thermal, and Clean Power Plan



Figures 6-1 through 6-4, above, exhibit the economics of the NorthWestern supply portfolio in terms of cost and risk. In contrast, the net positions of each supply portfolio are shown below in Figure 6-5 and Figure 6-6. The net position charts show the amount of energy purchased or sold in each portfolio in the SPP market based on utilizing the most economic resources to meet NorthWestern's load obligations and using NorthWestern's resources to supply energy to the SPP market when it makes economic sense to do so. Renewable resources are modeled as must-run, must-take resources. The Net Position figures show that NorthWestern must rely on market purchases to fulfill its load serving obligation in every scenario other than the 100 MW Wind portfolio, as shown by the negative net position values of all portfolios except the 100 MW Wind.

Figure 6-5 Net Position Base and Renewable Portfolios

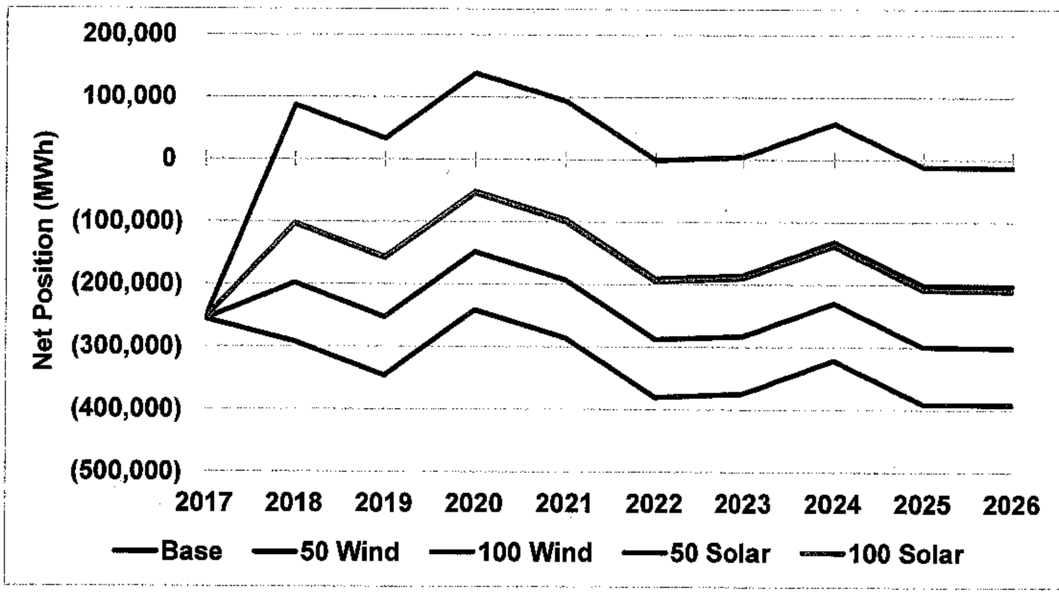
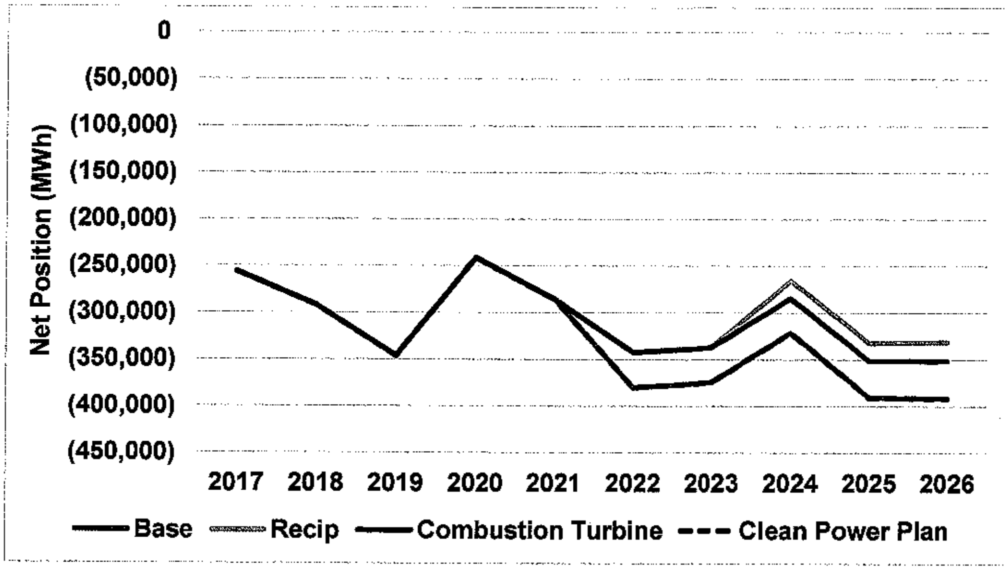


Figure 6-6 below details the physical net position of the base portfolio compared to the thermal portfolios and the Clean Power Plan scenario. The addition of thermal resources helps to reduce the amount of market purchases through the study horizon, but market purchases are still required to fulfill NorthWestern's load-serving obligation.

Figure 6-6 Net Position for Base, Thermal, and Clean Power Plan Portfolios



Evaluation of Capacity Resource Additions

NorthWestern evaluated various thermal generation technologies because of the capacity deficiency that arrives in 2022. An 18 MW Wartsila 50SG reciprocating engine and a 60 MW Pratt and Whitney ("P&W Swiftpac 60") combustion turbine were assessed to determine the potential economic value of each asset under observed market conditions of SPP. While both assets are gas-fired generators, the differentiating factors reside in their efficiency and flexibility.

The SPP market provides market prices on 5-minute increments and places an economic premium on resources that can provide the flexibility to react in an ever-changing market. Flexible resources that can economically deliver regulation energy and 10-minute spinning reserves carry additional value in SPP. The combined effect of a volatile 5-minute energy market and an attractive ancillary service market delivers a clear price signal to generators that have the ability to:

- Startup and shutdown within 5 minutes;
- Have negligible start-up costs; and
- Run at minimum load efficiently to provide regulation services.

A comparison of the economic performance of the Wartsila 50 SG engine versus the P&W Swiftpac 60 reinforces the value of flexible generation and efficiency. Peaking generation that can rapidly and efficiently respond to the SPP market price signals has additional value over less flexible or less efficient generation.

Figure 6-7 Annualized Gross Margin Profit by Market Product for Wartsila 50SG and P&W Swiftpac 60 Generation

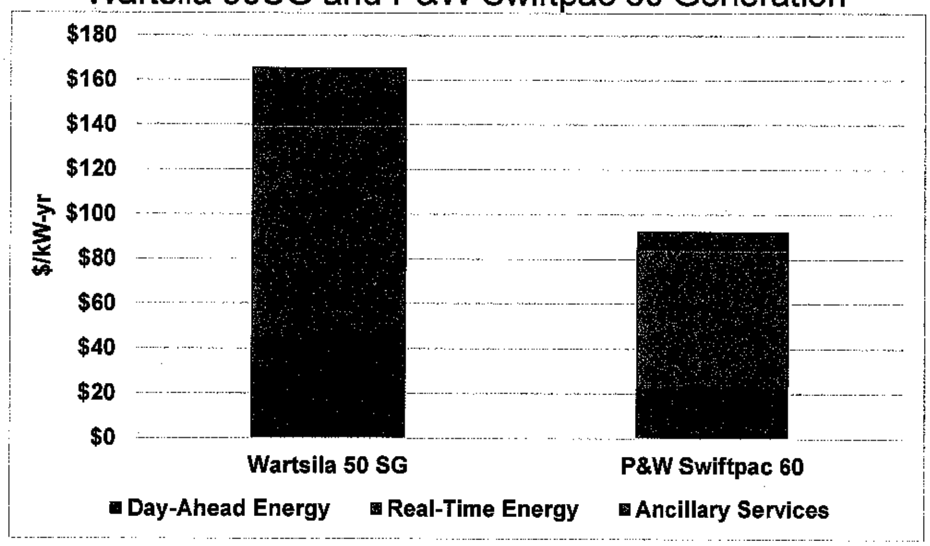


Figure 6-7 quantifies the additional value that the Wartsila 50SG provides over the P&W Swiftpac 60 combustion turbine. These generators realize revenue from three principal SPP markets: 1) Day-ahead energy, 2) Real-time energy, and 3) Ancillary services. Because the Wartsila 50SG engines have a lower heat rate and greater operating flexibility, the Wartsila provides more value than the P&W Swiftpac 60 combustion turbine. The

Wartsila engines have an annual gross margin profit of $166/kW-yr versus $92/kW-yr for the P&W Swiftpac 60.

Input Assumptions for Capacity Resource Additions

The input assumptions and modeling results captured the physical and economic attributes of each generator relative to market prices. The operating characteristics of each generator operating in South Dakota are shown in Table 6-2.

Table 6-2 Generation Asset Input Assumptions

Asset Characteristic	Wartsila 18V50SG	Pratt and Whitney Swiftpac 60
Output (ISO)	18.56 MW	59.5 MW
Efficiency - HHV (ISO)	8,215 Btu/kWh	9,266 Btu/kWh
Minimum stable load	3.5 MW	28.3 MW
Efficiency at minimum stable load	11,462 Btu/kWh	12,012 Btu/kWh
Start-up time	1 min	2 min
Start-up cost (maintenance)	0 $/start	200 $/start
Start-up fuel cost	5.50 $/MW/start	53.02 $/MW/start
VOM	$7.71/MWh	$6.16/MWh
Nox	0.19 T/MMbtu	0.19 T/MMbtu
SO_2	.0014 T/MMbtu	.0014 T/MMbtu
CO_2	118 T/MMbtu	118 T/MMbtu

The market prices for each commodity are summarized in Tables 6-3 and 6-4.

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Table 6-3 Summary of Energy Market Price Inputs for South Dakota

Commodity	Price Interval (Units)	Average Price		Price Volatility	
		Peak	Off-Peak	Peak	Off-Peak
Gas Price (DA)	Daily	$2.95/MBtu		29%	
Power (DA)	Hourly	$20.16/MWh	$22.29/MWh	39%	44%
Power (RT)	5 Minutes	$21.24/MWh	$19.53/MWh	181%	168%

Table 6-4 Summary of Ancillary Market Price Inputs for South Dakota

Commodity	Price Interval (Units)	Average Price		Price Volatility	
		Peak	Off-Peak	Peak	Off-Peak
10 minute Spin (DA)	Hourly	$7.87/MW	$5.68/MW	552%	563%
10 minute Non-Spin (DA)	Hourly	$3.0/MW	$2.07/MW	1438%	1531%
Regulation Up (DA)	Hourly	$13.20/MW	$10.34/MW	330%	312%
Regulation Down (DA)	Hourly	$6.31/MW	$7.01/MW	132%	50%
10 minute Spin (RT)	5 Minutes	$3.84/MW	$3.38/MW	550%	571%
10 minute Non-Spin (RT)	5 Minutes	$1.48/MW	$1.39/MW	1305%	1205%
Regulation Up (RT)	5 Minutes	$11.22/MW	$10.07/MW	289%	287%
Regulation Down (RT)	5 Minutes	$9.30/MW	$9.50/MW	%135	138%

Conclusions

NorthWestern modeled varying levels of renewables, thermals, and environmental compliance against the current Base portfolio. The Base portfolio was the least-cost NPV portfolio, but has slightly higher risk than the thermal or wind portfolios. NorthWestern is in a position where it must make market purchases in order to fulfill its load-serving obligation in all portfolios other than the 100 MW Wind portfolio. Possible future environmental regulations, as indicated in the Clean Power Plan portfolio, increase costs only slightly over the Base portfolio.

The Recip portfolio has a lower NPV cost than the renewable portfolios or the Combustion Turbine portfolios. Peaking generation that can rapidly and efficiently respond to the SPP market price signals has additional value over less flexible or less efficient generation. Reciprocating engines provide capacity, deliver economic energy, and provide ancillary services. NorthWestern will continue to analyze the appropriate generation technologies that provide capacity and additional value in the SPP market.

CHAPTER 7
ENVIRONMENTAL

Environmental Trends that Influence the 2016 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.

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, and laws regulating waste generation and disposal. High-level considerations of environmental regulations are discussed below.

Greenhouse Gas Emissions

No single law or public policy issue has had as great an influence on resource planning as the Clean Air Act. The new regulations covering greenhouse gas ("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 60.9% 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 include 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

In a separate action that dramatically affects existing power plants, 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. States have the option to develop their own implementation plans or adopt a federal implementation plan. The EPA gave states the option to develop compliance plans based on CO_2 emission rates (pounds ("lbs.") of CO_2 per MWh) or CO_2 mass (tons) emissions. 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.

These deadlines are now on hold since the legality of the CPP is being challenged by several states (including South Dakota), utilities, trade groups and other companies. On February 9, 2016, the U.S. Supreme Court issued a stay of the implementation of the final CPP. The stay does not, however, alleviate uncertainty from a planning perspective. The stay will remain in effect until the U.S. Court of Appeals enters a decision on the substantive challenges to the CPP and the Supreme Court either denies a petition for a writ of certiorari following that decision or enters a judgment following grant of a petition for a writ of certiorari. The U.S. Court of Appeals heard oral arguments on September 27, 2016. Timing of the final resolution of the legal challenges to the CPP is difficult to predict, but a decision could be made by late 2017 or early 2018.

Despite the Supreme Court's decision to stay the CPP, 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. In this 2016 Plan analysis a cost is not assigned directly to carbon emissions, but 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.

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 Plant 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 Plant was required to install and operate BART which the South Dakota Department of Environment and Natural Resources determined 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.

Coyote Station

Coyote Station 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 Station 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.

Neal Unit 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 equal BART.

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. Currently, Neal Unit 4 does not anticipate any compliance issues with the Regional Haze Rule in the near future. For Big Stone Plant and Coyote Station, it is as yet uncertain how future regional haze SIP revisions may affect them. However, NorthWestern, along with the other joint owners, believes Coyote Station could be faced with additional NO_x and SO_2 reductions.

Mercury and Air Toxics Rule

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 – the Big Stone Plant in South Dakota, the Coyote Station in North Dakota and the Neal 4 Plant in Iowa – are currently in compliance with the MATS rule. Therefore, we assume in the Plan there will be no additional material upgrades required for additional MATS compliance obligations for any of the plants.

Coal Combustion Residuals

"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 coal combustion residuals ("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 cover groundwater protection, operating criteria, record keeping and notification, and public information posting. Several new requirements will apply to the Big Stone Plant and the Coyote Station. Neal 4 is already in compliance since all ash is dry disposed.

Big Stone Plant

Big Stone Plant operates a dry disposal site that is already regulated, permitted, and inspected by the South Dakota Department of Environment and Natural Resources. Big Stone Plant 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. Currently Big Stone Plant is conducting the required background groundwater monitoring program for the impoundment. Background groundwater monitoring must completed by October 19, 2017, and a location restriction determination must be made by October 19, 2018.

Coyote Station

The Coyote Station operates a dry disposal site that is already regulated, permitted and inspected by the North Dakota Department of Health. The Coyote Station also operates three surface impoundments used to temporarily handle and dewater boiler slag sluiced to the impoundments before it is disposed in the dry disposal site or beneficially reused. Similar to Big Stone Plant, Coyote Station 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 operates under air quality operating permits issued by the South Dakota Department of Environmental and Natural Resources. 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.

Table 7-1 Environmental and Natural Resource Permits

Station	Title V Operating Permit #	Expiration Date
Aberdeen	28.0801-03	February 17, 2020
Huron	28.0801-04	June 12, 2020
Yankton	28.0801-07	March 6, 2020
Clark	28.0801-18	October 17, 2019
Faulkton	28.0801-28	May 12, 2021

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 Plan for the project is being implemented, and post-construction monitoring is underway to determine impacts of operations on birds and bats. Results of the monitoring will help inform NorthWestern of any operational or other mitigation that may be necessary. At this time we do not foresee additional material mitigation at our wholly owned wind facility.

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 and 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.

NorthWestern modeled a portfolio that included CPP compliance. The CPP portfolio included escalation in the natural gas and electric prices that were provided by the EIA Annual Energy Outlook Reference case for CPP Compliance. See Chapter 6 for the modeling results of the CPP portfolio.

CHAPTER 8
CONCLUSIONS AND ACTION PLAN

Conclusion

This Plan evaluates NorthWestern's electric load-serving obligation and guides NorthWestern's resource procurement process in South Dakota for the next 10 years. The Plan is updated biennially and evolves with any significant changes in legislation, regional operational or planning needs, and environmental requirements. The Plan's conclusions are intended to provide guidance regarding NorthWestern's resource investments on behalf of its South Dakota customers.

Portfolio Management

SPP requirements will also guide NorthWestern's planning process, and NorthWestern remains committed to full participation in SPP and full implementation of all SPP requirements. Given the economic dispatch regime of SPP, NorthWestern will examine how best to serve its customers' needs in a manner consistent with its current fleet of generation resources.

Capacity continues to be of concern and NorthWestern will continue to evaluate its capacity needs, and the best means to meet those needs. An evaluation of NorthWestern's older generation assets for possible retirement and replacement will be undertaken in 2017. Additionally, opportunities to enhance grid reliability in a cost effective manner will also be studied. These evaluations, along with the other analysis contained in the Plan, will be used to determine how to best serve the long-term needs of our customers.

Additionally, NorthWestern expects that the action plan items listed below will significantly influence NorthWestern's actions between resource plans. To facilitate the implementation of this Plan, NorthWestern set forth the following action plan.

Action Plan

1. *Presentation to the South Dakota Public Utilities Commission ("PUC").* The 2016 Electric Integrated Resource Plan will be presented to the PUC in December of 2016.

2. *Retirements.* NorthWestern will work with an engineering consulting firm to develop a Retire and Replacement Plan for the natural gas-fired and oil-fired generating units. The study will examine efficiency, reliability, parts availability, and book value, and it will provide a cost benefit analysis for replacement of those assets with proxy technology selections. The economic contributions of each asset to the overall resource portfolio will also be evaluated. NorthWestern expects that the study will be completed in July 2017 and the results will be used to inform its resource development plans for South Dakota.

3. *Capacity.* Expiration of the current capacity agreement with MRES after the 2018 summer season will create a capacity shortfall beginning in 2019. NorthWestern's current capacity forecast shows that it will be 3 MW short in 2019, increasing to around 19 MW short in 2026. NorthWestern will evaluate market purchases of capacity and economic additions of physical generation resources to satisfy capacity requirements.

4. *Grid Reliability.* NorthWestern will continue to study the value that can be attained by locating future resource additions at sites that are strategically located throughout NorthWestern's South Dakota Service territory, to help increase grid reliability.

5. *Generation Technologies.* NorthWestern will continue to monitor and evaluate generation technologies that have the potential to help NorthWestern meet its load-serving obligation at lowest total cost to its customers.

6. *Environmental.* NorthWestern's current planning efforts continue to center on technologies that comply with proposed environmental regulations. NorthWestern will continue to monitor CPP proposed rules and will incorporate any additional environmental regulations/requirements into its planning processes as necessary.

7. *SPP Operations.* NorthWestern will continue the integration of its planning to meet SPP planning criteria. 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 the system needs that are realized from the studies.