Exhibit 19

No. 4

1-4) Please provide the most recent IRP prepared for NorthWestern's South Dakota jurisdiction.

Response No. 1-4) See Attached marked for Response to 1-4. NorthWestern will be completing a new resource procurement plan for South Dakota prior to the end of 2016.

2014 South Dakota Electric Integrated Resource Plan

NorthWestern™ Energy

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CHAPTER 1

EXECUTIVE SUMMARY

The 2014 South Dakota Integrated Resource Plan

This Plan provides the outline of a disciplined economic evaluation of supply (energy and capacity) for addressing the next 10 years of NorthWestern's electric load-serving obligation in South Dakota. The Plan analyzes a range of potential environmental and market uncertainties that have the greatest potential to impact customer needs and long-term procurement options. The Plan's conclusions are intended to provide guidance regarding NorthWestern's investments on behalf of its South Dakota customers. The reader is cautioned not to extrapolate conclusions from this Plan to other service territories served by NorthWestern and vice versa. For example, regulatory environments, markets, and portfolios in many instances significantly differ, and therefore such extrapolations are likely erroneous and are irrelevant.

This Plan is based on currently available information, and it will be updated biennually to reflect significant future events, such as new legislation, regional operational/planning needs, or environmental requirements. Within this changing landscape for utility resource planning, NorthWestern will not blindly adhere to this plan but will maintain the flexibility to adjust to legislative, market, and other variables that impact the services it provides to its customers.

Regional Transmission Organizations ("RTO")

NorthWestern will continue its transition to SPP. This is expected to be completed in October 2015. As NorthWestern gains experience in the newly formed market and learns as this market establishes itself, NorthWestern will continue to evaluate the best use of NorthWestern's portfolio and apply that information to its modeling, planning, and execution of its asset optimization plan.

Load Requirements

Energy

NorthWestern is located in the newly developed Upper Midwest Zone ("UMZ"). This is the zone created by the Southwest Power Pool ("SPP") to designate the addition of the Integrated System ("IS") with regional participants and NorthWestern. Characteristics of the UMZ and SPP footprints include: very long in electric energy supply and additional renewable resources scheduled to enter service during 2015. As a result, the need for more energy-producing resources will be limited for a period of time unless the existing resources or loads change significantly. NorthWestern will continue to evaluate the load-serving requirements (energy, capacity and ancillary services) for its retail customers during and after the transition to SPP. As a participant of SPP, NorthWestern will tailor supply resource planning activities to fit within the definition and characteristics of the SPP market and operational protocols.

Capacity

With continued upward pressure on the levels of capacity needed to serve load, NorthWestern will evaluate market availability and physical resources that would best fit NorthWestern's portfolio. Both the UMZ and SPP indicate being long capacity, however, NorthWestern's 2013 capacity RFP only yielded one offer that had a limit of 42 MW available. Once NorthWestern is a member of SPP, addition capacity may be available within the larger footprint. However, while the SPP footprint may be long capacity, transmission services to guarantee delivery of the SPP capacity to NorthWestern's customers may not be available. Due to the lead time of constructing a facility by the beginning of 2019, NorthWestern will need to determine capacity availability shortly after transitioning to SPP.

As discussed in Chapter 4, the Portfolio Analysis and Modeling section of this Plan, identifying opportunities to add resources that create revenue through transmission services while fulfilling NorthWestern's revenue requirement may determine the types of resources that should be developed. NorthWestern currently does not have assets that provide ancillary services for its generation and load service. NorthWestern may also need to add assets that can produce ancillary services for its portfolio in order to support these requirements.

Conclusions

This Plan sets the backdrop against which any future resource decisions will be considered. Existing uncertainties discussed in the Plan, such as the regulation of carbon emissions and new uncertainties, such as other regulatory considerations, will have a significant influence on the type and timing of future resource choices. Transmission availability, or the lack thereof, could also influence resource decisions. Furthermore, historic market changes have demonstrated the limited predictive value of natural gas price forecasts, as actual market prices have varied greatly, both in higher and lower costs than what the best-informed analysts predicted. Other inputs have similar limitations.

Nevertheless, NorthWestern expects future electricity supply costs to increase in the long term. Current low energy prices will be pressured upward by baseload facility retirements, regulatory emission requirements, transmission infrastructure additions, and energy reliability upgrades. As a result, customers should take higher future costs into account when they make decisions about home construction, insulation, appliance purchases, and their consumption behaviors.

NorthWestern's expected need to acquire incremental energy and capacity is likely to increase the portfolio's exposure by an incremental 25 MW to 39 MW by 2019. This capacity need will likely be addressed through natural gas powered generation units, market purchases, or some combination. The estimate does not include any capacity that would be required for new large customers. Current forecasted market conditions indicate that NorthWestern should utilize the market for the short term while evaluating the financial and reliability conditions that could influence the decision to add generation resources. This use of the market in combination with existing resources is the preferred alternative that has been determined from modeling conducted in this planning cycle.

Action Plan

NorthWestern's Action Plan provides specific steps to implement the conclusions as set forth in this Plan:

1. *Presentation to the South Dakota Public Utilities Commission ("PUC").* The outline of the Plan was presented to the PUC during December 2014. NorthWestern welcomes questions and comments from the PUC.

2. *Future Capacity Contracts.* Termination of the current capacity agreement with Missouri River Energy Services ("MRES") after the summer season of 2018 will create a capacity shortfall from our portfolio. NorthWestern will evaluate options to fulfill its capacity requirements. NorthWestern is forecasted to be 25 MW to 39 MW short in 2019 based on normal growth not including large customer additions. If the market is unable to economically or physically support the capacity requirements, NorthWestern will construct additional generation resources to satisfy the requirements.

3. *Baseload Energy.* NorthWestern will continue to evaluate market opportunities for the addition of energy supply resources.

4. *Renewable Energy Resources.* To diversify the renewable resource portfolio and to achieve the renewable energy objective, renewable supply sources and energy-saving Demand-Side Management ("DSM") opportunities will be identified and, where appropriate, solicited.

5. *Periodic Review.* NorthWestern will continue to monitor conditions and update this Plan accordingly. One known variable is the June 2, 2014 release by the U. S. Environmental Protection Agency ("EPA") of its Clean Power Plan ("CPP") Proposed Rules. NorthWestern has filed comments on the CPP (see Appendix A) expressing numerous concerns regarding the draft rules fundamental structure as well as concerns specifically related to South Dakota and Montana. As currently proposed, the CPP could result in significant impacts to South Dakota customers and result in significant changes to this Plan. EPA is currently planning to release a final version of the CPP in June of 2015. NorthWestern cannot predict what changes, if any, will be made to the proposed CPP or what impacts the final version of the CPP will have on this Plan and its resource portfolio. NorthWestern will continue to participate in opportunities to work with EPA, the South Dakota Department of Environment and Natural Resources, the PUC, Edison Electric Institute, and other stakeholders as EPA is finalizing the CPP in order to keep current and to provide meaningful input and technical expertise. After the CPP is finalized, NorthWestern will evaluate and update this Plan as necessary.

CHAPTER 2

EXISTING PORTFOLIO

Existing Portfolio Resources

NorthWestern uses a mixture of resources to meet the existing energy and capacity needs of its South Dakota customers. As described in this section, the South Dakota portfolio includes baseload coal generation, natural gas and diesel peaking generation, wind power purchase agreements ("PPAs"), capacity and energy purchase agreements, and efficiency programs.

Energy Resource Mix

NorthWestern's energy requirements have historically been met with its coal resources and market purchases. In late 2009, a wind PPA was added to the portfolio which provides additional energy as shown in Figure 2-1.

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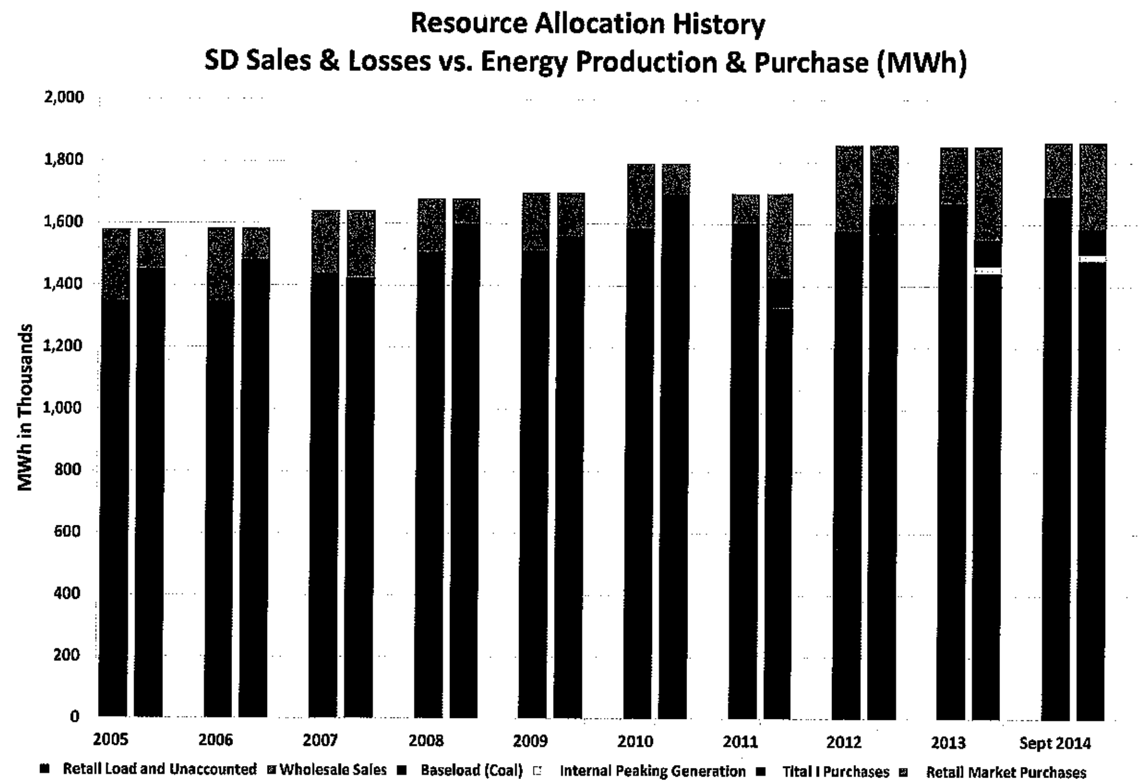
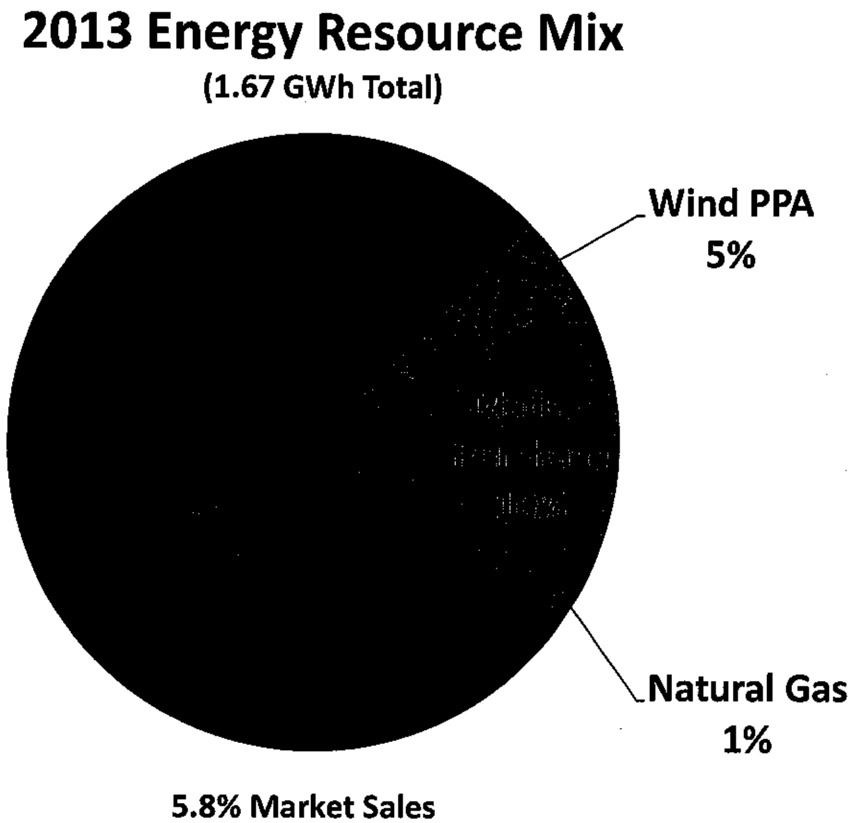
Figure 2-1: Resource Allocation - SD Sales & Losses vs. Energy Production & Purchase



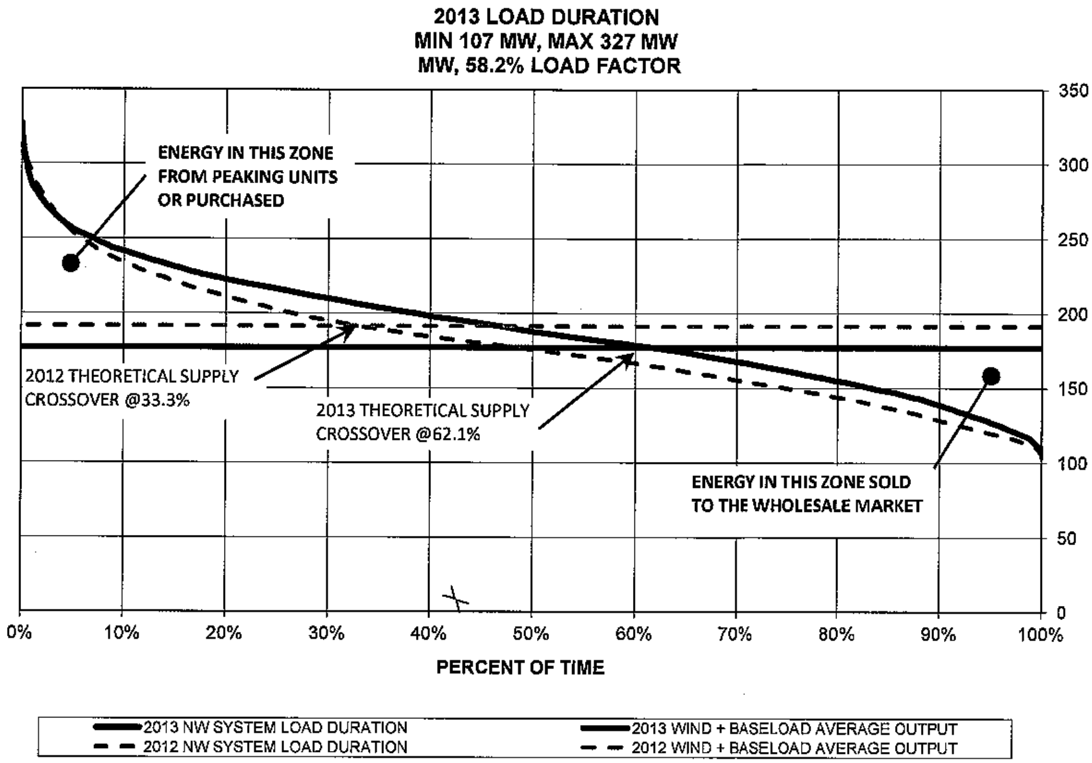
The existing portfolio is comprised of; 78% of the energy resource needs are provided by the baseload coal resources, 5% from a wind PPA, and 1% from natural gas generation [as shown in Figure 2-2 below]. The balance of the energy needs has been provided through market purchases from the Western Area Power Administration ("WAPA") balancing pool.

Figure 2-2: 2013 Energy Resource Mix



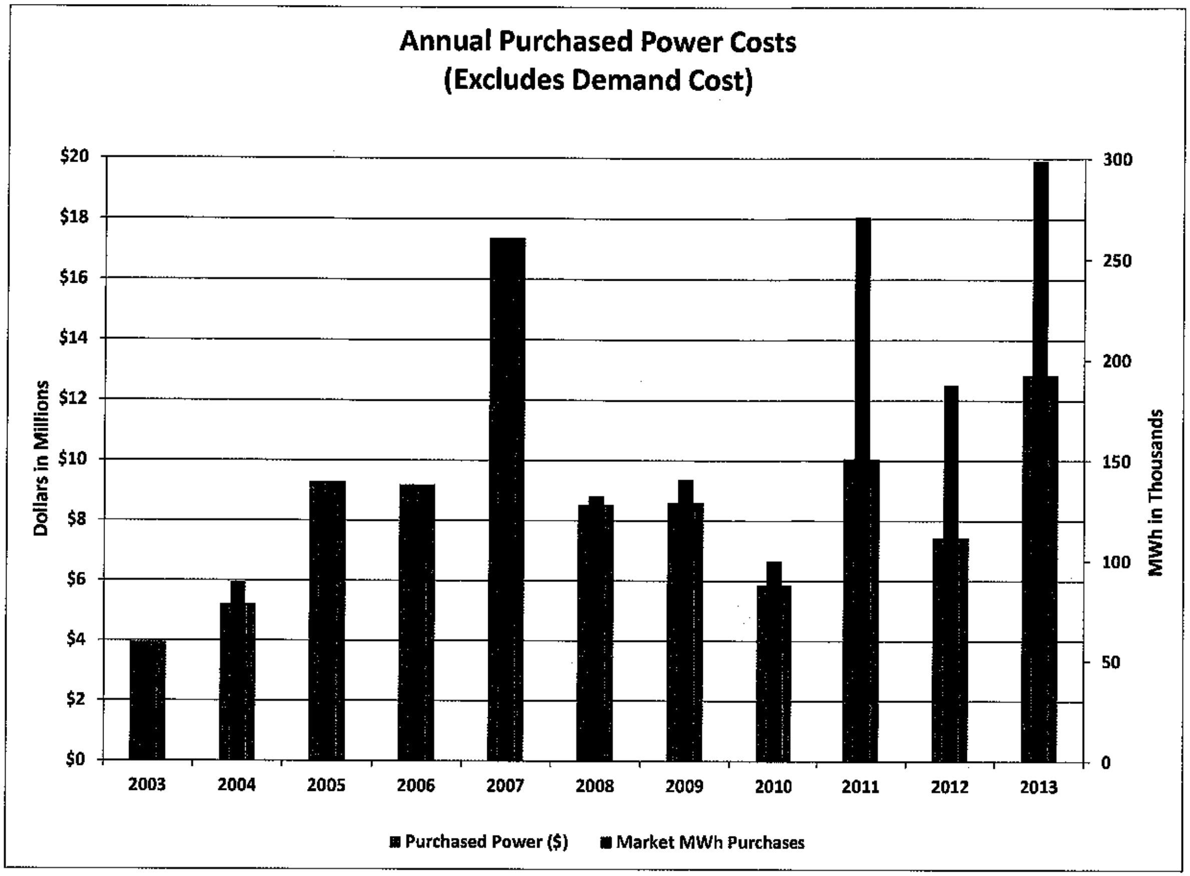
As NorthWestern's load has grown, the ability of its existing owned generation to supply its entire load has been reduced, resulting in an increased dependence on the economy energy market. As depicted in Figure 2-3 below, NorthWestern was dependent upon economy energy purchases 62% of the hours during 2013. After adjusting for unusually extended baseload 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 was dependent upon economy energy purchases for 33% of the hours during 2012.

Figure 2-3: 2013 Load Duration Curve



Increased dependence upon market energy purchases to meet the load service obligation brings with it the risks of price uncertainty due to market volatility, deliverability due to congestion, and reliability due to weather. The effects of market volatility and the resulting cost uncertainty are depicted in Figure 2-4 below. For example, during 2007, extended maintenance outages of baseload units coincided with a period of unusually high market prices, nearly doubling the cost per megawatt hour ("MWh") compared to several years before and after that event. In recent years, total portfolio costs have benefited from lower energy prices even as its dependence on the market has increased.

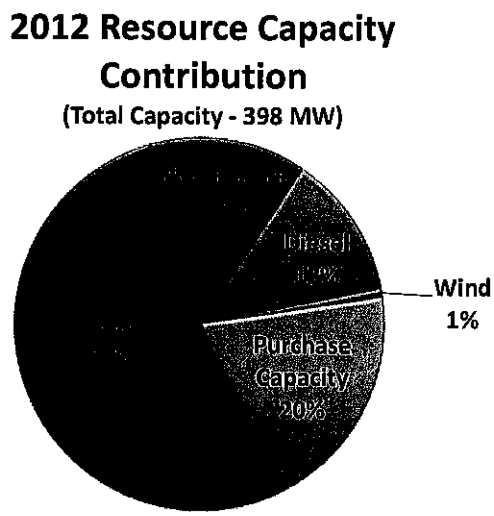
Figure 2-4: 2003 – 2013 Annual Purchased Power Costs



Capacity Resource Mix

NorthWestern's capacity resource portfolio has been dominated by coal since the mid-1970s. In 2012, NorthWestern's resources for meeting capacity demand requirements were 53% coal, 20% off-system capacity purchases, 14% natural gas, 12% diesel, and 1% wind. With relatively high exposure to off-system capacity purchases and market indications of reduced capacity and transmission availability in the future, NorthWestern became concerned about the ability to obtain and deliver purchased capacity to NorthWestern's system. As a result, NorthWestern started constructing a 50 MW combustion turbine peaking unit in Aberdeen, South Dakota in 2011. This additional owned resource was declared commercial in 2013, replacing a large part of an expiring short-term capacity purchase agreement. The Aberdeen peaking unit allowed for a smaller capacity purchase agreement to be executed in early 2014 to help provide a bridge to the next capacity resource acquisition. A comparison between the 2012 and 2014 capacity resource mixes in the portfolio is shown in Figure 2-5.

Figure 2-5: Capacity Resource Mix, 2012 & 2014



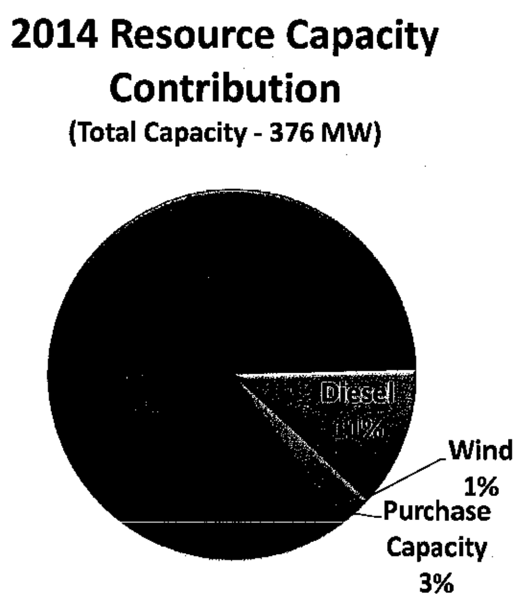


Table 2-1: Generation Asset Summary

Generation Asset Summary

Baseload (Summer Ratings, 2013)	Big Stone 111.2 MW Neal 4 56.1 MW Coyote 42.7 MW **Total 210.0 MW**
Peaking Provides peaking and local area back-up service	Existing mixture of 13 diesel engine and combustion turbines at seven locations providing 149.8 MW.
Capacity and Energy Contracts	Basin Electric (BEPC) for up to 19 MW through 2015 Missouri River Energy Services (MRES) for up to 45 MW for 2016 through 2020
Renewable Capacity and Energy Contracts	Titan I Wind near Ree Heights, SD for 25 MW (nameplate) has been in service since late 2009. In late 2014 and early 2015, two additional wind farms totaling 100 MW (nameplate) will be placed in service.
Efficiency	DSM – estimated 0.50 MW per year

Baseload Generation Assets

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"). NorthWestern's ownership and share of the output of the plant is 23.4% or 111.2 MW. OTP is the operating agent for the three partners.

Big Stone is a coal-fired, cyclone burner, non-scrubbed baseload 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 ("BNSF"). A 2013-2014 emerging issue regarding BNSF coal delivery to Big Stone is a trend in increased time between coal deliveries to Big Stone reportedly caused by increased rail system congestion in the region. As a result, during part of 2013 and much of 2014, the plant was forced to reduce output during off-peak periods in order to maintain a minimum level emergency coal stockpile. This reduced output has caused a large increase in energy market purchases at prices significantly higher than plant production costs in 2013, partially depicted in Figure 2-4 above.

Construction of the Air Quality Control System ("AQCS") for Big Stone began in 2013 to allow the plant to meet new emission reduction requirements. 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 upgrade cost will be approximately $103 million with Allowance for Funds Used During Construction ("AFUDC"). The project will be completed in 2015. Because the AQCS will increase station service requirements, the net output to NorthWestern will be decreased by approximately 2 MW, from 111.2 MW to 109.2 MW.

Neal Energy Center Unit 4 ("Neal 4")

Neal 4 is a pulverized coal, non-scrubbed baseload 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 8.68% ownership share is approximately 56.1 MW. The fuel source is Powder River Basin sub-bituminous coal delivered by the Union Pacific Railroad.

The Neal 4 environmental compliance project for the control of sulfur and nitrogen oxide emissions included a scrubber, baghouse, and Selective Non-Catalytic Reduction ("SNCR") system and was completed in 2013. The installation of an ACI system for the control of mercury emissions was completed during 2014.

Coyote Station

Coyote Station ("Coyote"), located near Beulah, North Dakota, was declared commercial 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 baseload plant. The total plant rating is 427 MW (transmission limited) with NorthWestern's ownership share of 10% or 42.7 MW. The fuel source is North Dakota lignite from an adjacent mine owned by Dakota Westmoreland.

Under the final Mercury and Air Toxics Standards ("MATS") Rule, Coyote will need to install ACI for mercury emissions control plus perform supplementary testing to determine if additional controls for "other toxic emissions" are needed. The ACI system and supplementary testing are budgeted and scheduled to be accomplished in 2015. In addition, Coyote has budgeted to install an Advanced Overfire Air system for nitrous oxide control in 2016 (required by 2018).

Peaking Units

NorthWestern's peaking units are a mix of diesel engine and natural gas combustion turbine peaking generators located at various points within NorthWestern's South Dakota service territory. The commercial operation dates of these units range from 1961 to 2013. The largest unit is a 52 MW combustion turbine at Aberdeen, South Dakota. Regulated emissions for these plants are negligible due to the very low number of annual operating hours. The unit mix is identified in Appendix B: Electric Plant Capacities.

In 2013, NorthWestern completed the construction of the 52 MW combustion turbine at Aberdeen. This addition increased total available peaking generation capability and improved local area reliability. NorthWestern identified the need for additional internal generating capacity to satisfy continuing load growth and to offset the anticipated lack of purchased future capacity availability. This capacity scarcity was brought about by several factors. First, a number of conventional generating projects throughout the region have been delayed or cancelled for a variety of reasons, including environmental regulations. In addition, even though a large amount of investment in mandated renewable energy generation projects has been made, these projects typically provide very little dispatchable capacity. Furthermore, requests for firm transmission service for the delivery of generating capacity purchased from outside NorthWestern's system were denied due to a lack of available transmission capacity to its system.

Capacity and Energy Agreements

NorthWestern has entered into six energy and/or capacity agreements to meet its load service obligation. They are: (1) an energy balancing agreement with WAPA; (2) a capacity and energy agreement with Basin Electric Power Cooperative ("BEPC"); (3) a capacity and energy agreement with MRES; (4) a PPA for energy from the Titan 1 Wind Project; (5) a PPA for energy from the Oak Tree Energy Wind project; and (6) a PPA for energy from the Beethoven Wind project.

1) WAPA energy balancing agreement is used to provide for hour-to-hour energy shortage or surplus on NorthWestern's South Dakota system.
    a. Term: Renewed annually for one-year terms.
    b. Energy: Non-firm market pricing.

2) BEPC capacity and energy agreement.
    a. Term: Summer seasons for 2012, 2013, 2014, and 2015.
    b. Capacity: Summer season of April 1 through September 30.
        i. 2012 - 5 MW
        ii. 2013 - 11 MW
        iii. 2014 - 15 MW
        iv. 2015 - 19 MW
    c. Energy: Price is negotiated with BEPC.

3) MRES capacity and energy agreement.
    a. Term: Summer season for 2016 through 2018.
    b. Capacity:
        i. 2016 - 30 MW
        ii. 2017 - 30 MW
        iii. 2018 - 35 MW
    c. Energy: Incremental cost of designated peaking unit.

4) Titan 1 Wind Project agreement.
    a. Term: 20 years, starting in 2010.
    b. Capacity: Up to 25 MW.
    c. Energy: Price is fixed by contract.

5) Oak Tree Energy wind project agreement.
   a. Term: 20 years, starting in late 2014.
   b. Capacity: Up to 19 MW.
   c. Energy: Price is fixed by contract.

6) Beethoven I & II wind project agreements
   a. Term: 20 years, starting in late 2014.
   b. Capacity: Up to 80 MW.
   c. Energy: Price is fixed by contract.

Capacity contracts assist NorthWestern in managing the reserve requirements. When available, these contracts are short term market solutions that allow for the appropriate planning of additional resources. Due to the long lead times in the construction of these facilities and the short term nature of capacity agreements and available transmission, the use of contract capacity needs limited for customer reliability. NorthWestern's capacity resources and needs are illustrated and summarized in Figure 2-6.

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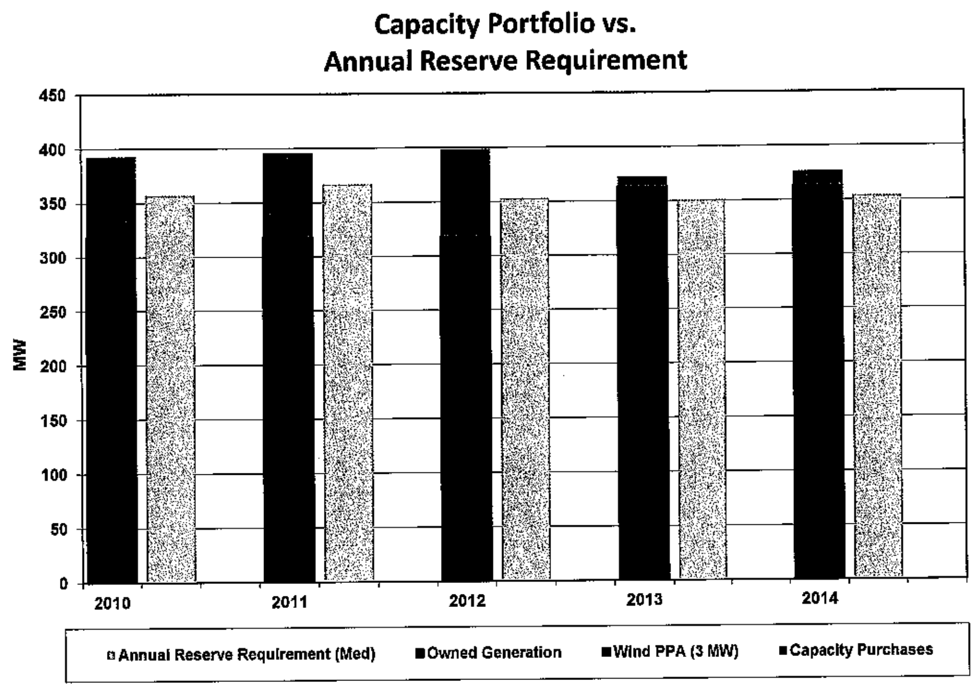
Figure 2-6: 2010 – 2014 Capacity Portfolio vs. Annual Reserve Requirement



Demand-Side Management

NorthWestern received final approval from the PUC to begin implementation of a DSM program in June 2014. The DSM program was officially rolled out to customers on October 1, 2014. NorthWestern estimates that DSM will reduce the current load by approximately 0.25 to 0.50 MW per year beginning in late 2014. The DSM program includes:

- Residential and small commercial energy audits
- Inspection, education, and direct installation of specific measures
- Trained personnel for audits and installations
- Equipment rebates
- Residential and commercial lighting rebate programs
- Multiple methods to deliver prescriptive rebates
- Partnerships with retailers and area HVAC contractors

The early stages of the DSM program are focused solutions targeting existing residential and commercial customers. In late 2015, plans are to begin offering DSM programs to new residential and commercial construction.

Existing Residential

- Energy-efficient fluorescent lighting (CFLs) & insulation (ceiling, wall, floor, tank, & pipe)
- Programmable thermostat
- Low-flow faucets, showerheads, and aerators
- High-efficiency heat pump
- Energy management system
- Energy-efficient fluorescent lighting (T8 and T5)

Existing Commercial

- HVAC
- Variable air volume
- Variable speed drives
- Controls, sensors, sweep controls & photocells
- LED exit signs
- Motors and much more
- Demand Response; many variants

CHAPTER 3

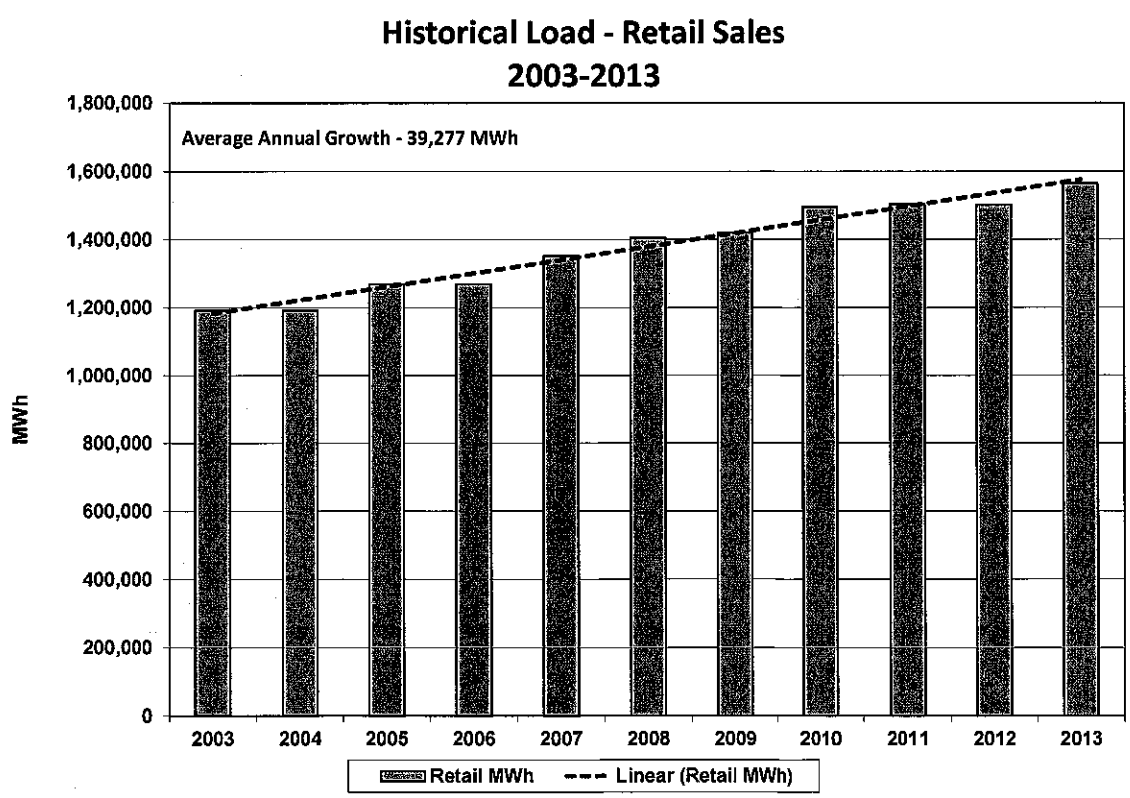
FORECASTS

Historical Energy and Capacity

Historic Growth of Energy

NorthWestern's total system energy demand has grown at a steady rate. Year-over-year adjustments due to economic reasons have had short-term effects, but average steady annual growth at about 39,300 MWh has continued over the long term as illustrated in Figure 3-1. System energy requirements for 2014 are expected to be around 1.6 million MWh.

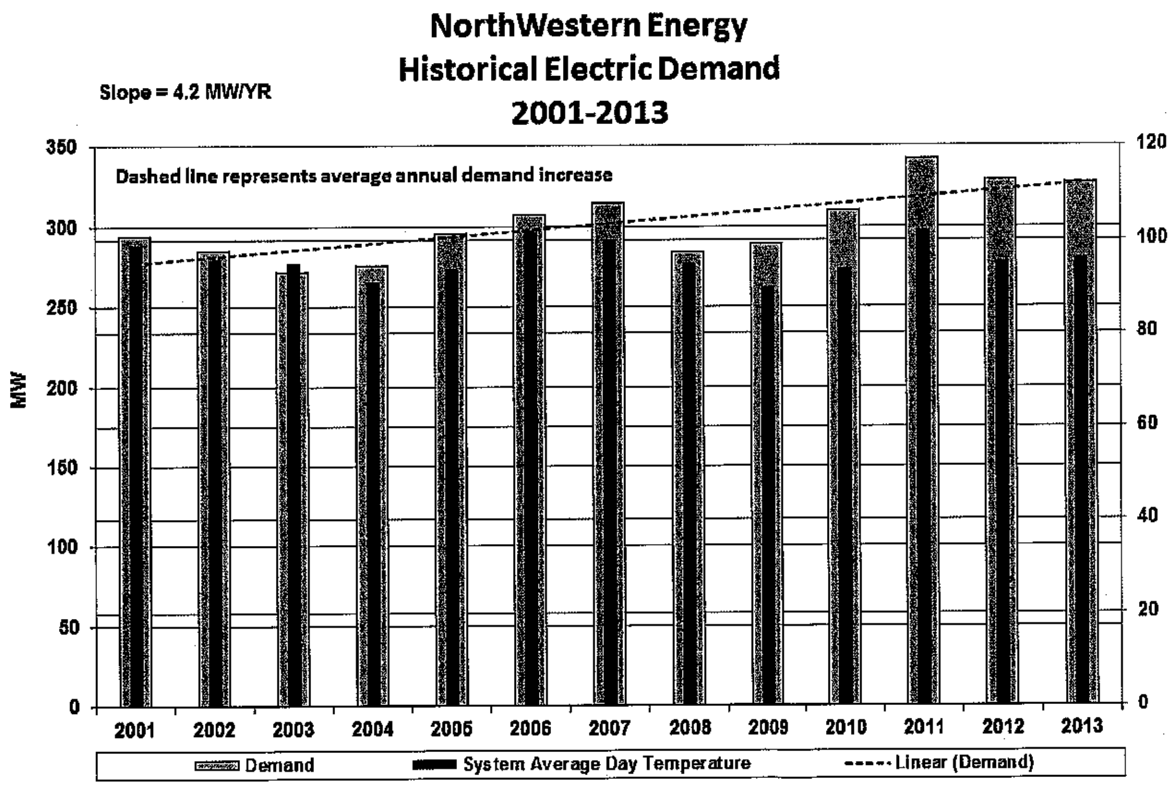
Figure 3-1: Historical Load – Retail Sales 2003-2013



Historic Growth of Capacity Demand

Similar to energy usage growth, NorthWestern has experienced continued capacity demand growth over the past 10 years, as represented by Figure 3-2. During this period, the summer peak load records indicate annual growth of about 4 MW. Although the year-over-year weather-dependent peaks vary, the overall growth has been fairly consistent as illustrated in Figure 3-2 below.

Figure 3-2: Historical Electric Demand (Capacity) 2001-2013



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 base 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. Annual load factors are typically in the 50% to 60% range.

Winter space heating is supplied predominantly by natural gas or other non-electric sources; whereas summer space cooling is electricity-based. In recent years, however, winter peak loads have been growing faster than summer peaks. During the winter of 2013-2014, NorthWestern established a record winter demand of 304 MW. The addition of the Aberdeen peaking unit will satisfy the need for winter capacity for several years going forward. For the near term, summer peaks are the driver for determining required electric generating capacity. This last winter season was the first time in at least the last four decades that the winter peak exceeded the following summer peak of 302 MW, which was lower, mostly due to cooler average summer temperatures.

During the last 10 years, new record summer peak loads have been established on four occasions. These are shown in Table 3-1 with the respective system average ambient outside air temperature during the peak load measurement period.

Table 3-1: Historical Summer Peak Loads

Year	Peak MW	Temperature ° Fahrenheit	Day
2005	297.8	98.0	August 2
2006	309.4	100.8	July 31
2007	315.1	99.9	July 23
2011	341.0	101.5	August 1

The most recent system peak load of 341 MW was established in the summer of 2011 during a period of extreme high ambient temperatures. During that period, the weighted average temperature was an unprecedented 101.5 degrees Fahrenheit. However, for the purposes of peak annual load forecasting for future periods, a "system design" temperature of 100 degrees Fahrenheit will continue to be used, as it more closely reflects the historic average temperature experienced at the times of new peak load records.

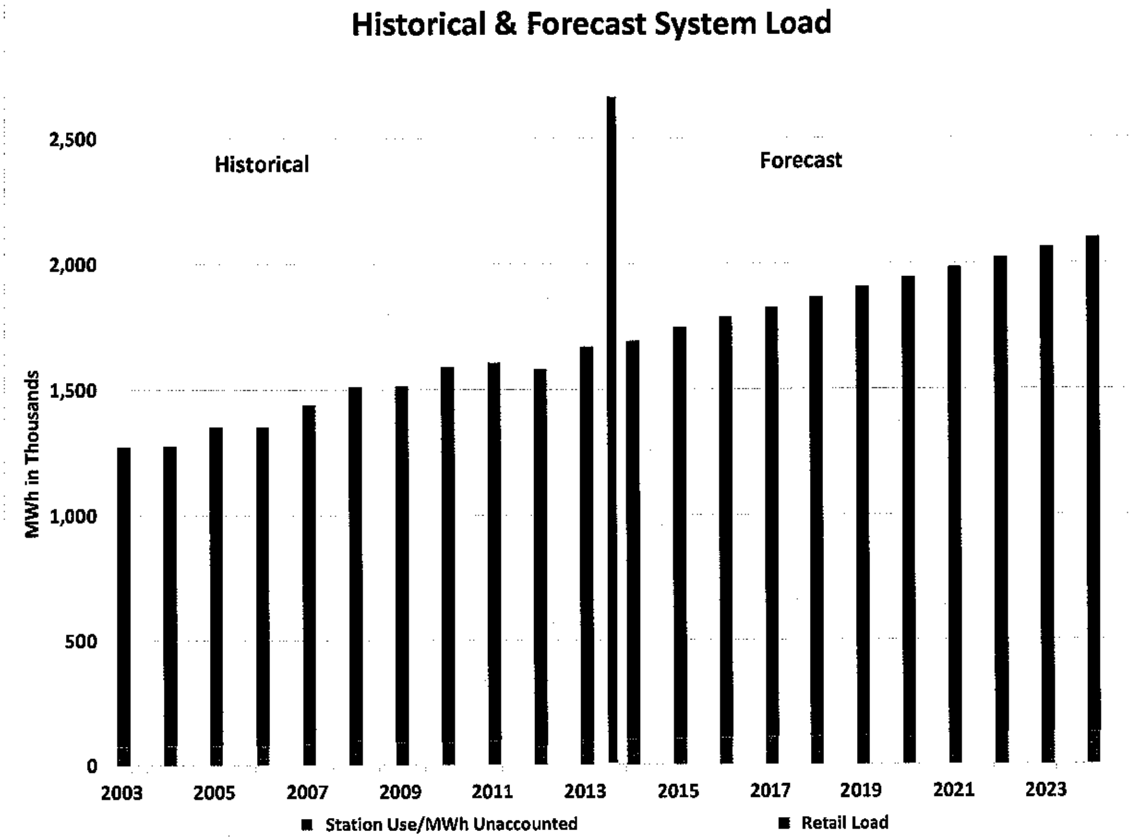
Load Forecasting

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 has supplemented the energy demand with spot market purchases from WAPA 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

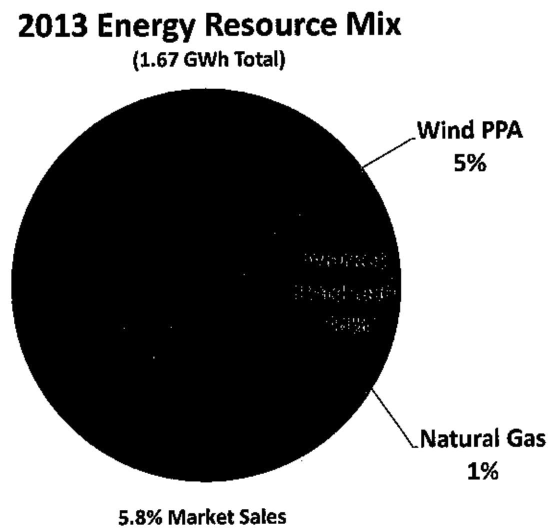
The historical energy annual growth remains relatively steady at approximately 39,300 MWh per year. Growth continues to be observed in new residential construction with a steady interest from the commercial sector within NorthWestern's service region. Considering a continuation of the historical steady growth rate, the forecasted system energy requirements for 2024 are expected to be near 2.1 million MWh as shown in Figure 3-3 below. However, an increase in industrial activity or increased energy conservation within NorthWestern's service territory can significantly affect the forecasted usage.

Figure 3-3: Historical and Forecast System Load



In 2015, NorthWestern's energy supply portfolio will add 100 MW of intermittent wind resources. This increase will shift the resource mix that provides energy for NorthWestern's load. Figure 3-4 shows the shift in resources that provide energy for NorthWestern's load comparing 2013 actuals to 2016 forecast. Intermittent wind will make up 25% of the supply for the portfolio reducing the amount of coal and market purchases. Due to timing differences between NorthWestern's hour-to-hour load and the intermittent generation output characteristics of wind, there is only a small forecast reduction in market purchases and an increase in sales forecast for 2016.

Figure 3-4: NorthWestern's 2013 Actual vs. 2016 Forecast Energy Resource Mix



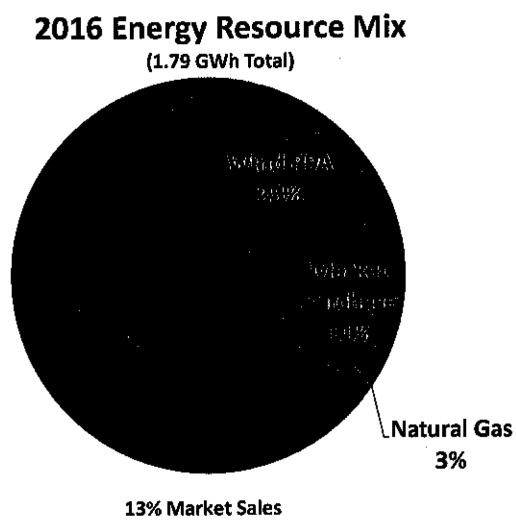
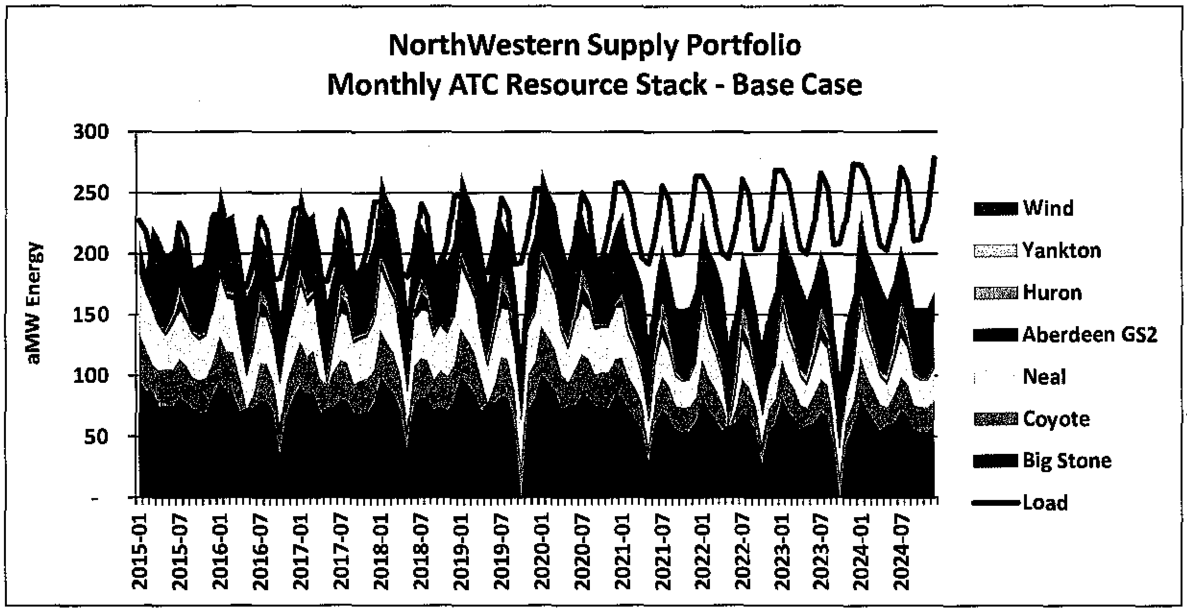


Figure 3-5 below compares NorthWestern's load requirements with available resources around-the-clock ("ATC"). Utilizing the PowerSimm model, NorthWestern's production is economically dispatched against the market. The "must take" intermittent wind resources are also added to the supply portfolio. Through 2020, NorthWestern's supply is able to provide most of the required energy for the portfolio.

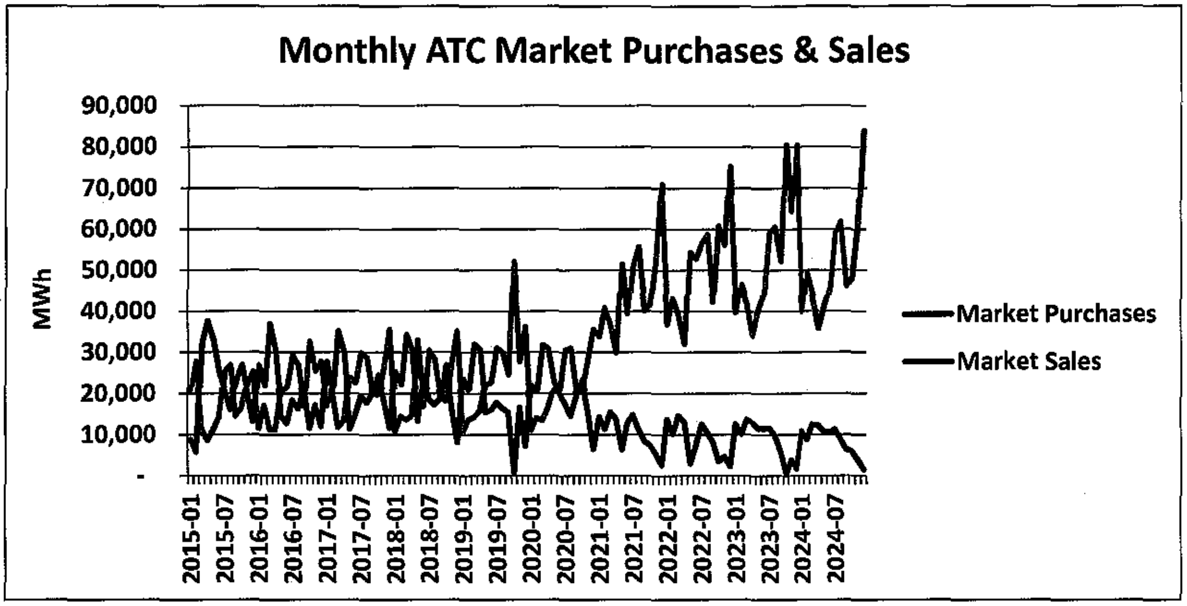
As described in Chapter 4, the Portfolio Modeling and Analysis section of this Plan, a carbon price is reflected in the cost of all carbon-emitting electric production resources starting in 2021. Under economic dispatch, the effect of this carbon price addition will result in an increased reliance on market purchases and a decreased reliance on carbon-emitting assets. As the actual effect of carbon on market electricity prices and the effect on carbon-emitting production are clarified over the next few years, the impact will be more clearly defined as it relates to NorthWestern's portfolio.

Figure 3-5: NorthWestern Supply Portfolio Monthly ATC Resource Stack Base Case



Depending on the ability of NorthWestern to modulate the output of its coal, natural gas, and fuel oil resources, NorthWestern should be able to limit the volume of market purchases and sales required to meet the load requirements and utilize intermittent wind resources. Figure 3-6 portrays the forecasted market sales and purchases over the next 10 years. The effects of increased NorthWestern load and, as identified above, the additional carbon costs increases the economic dispatch of market purchases after 2021.

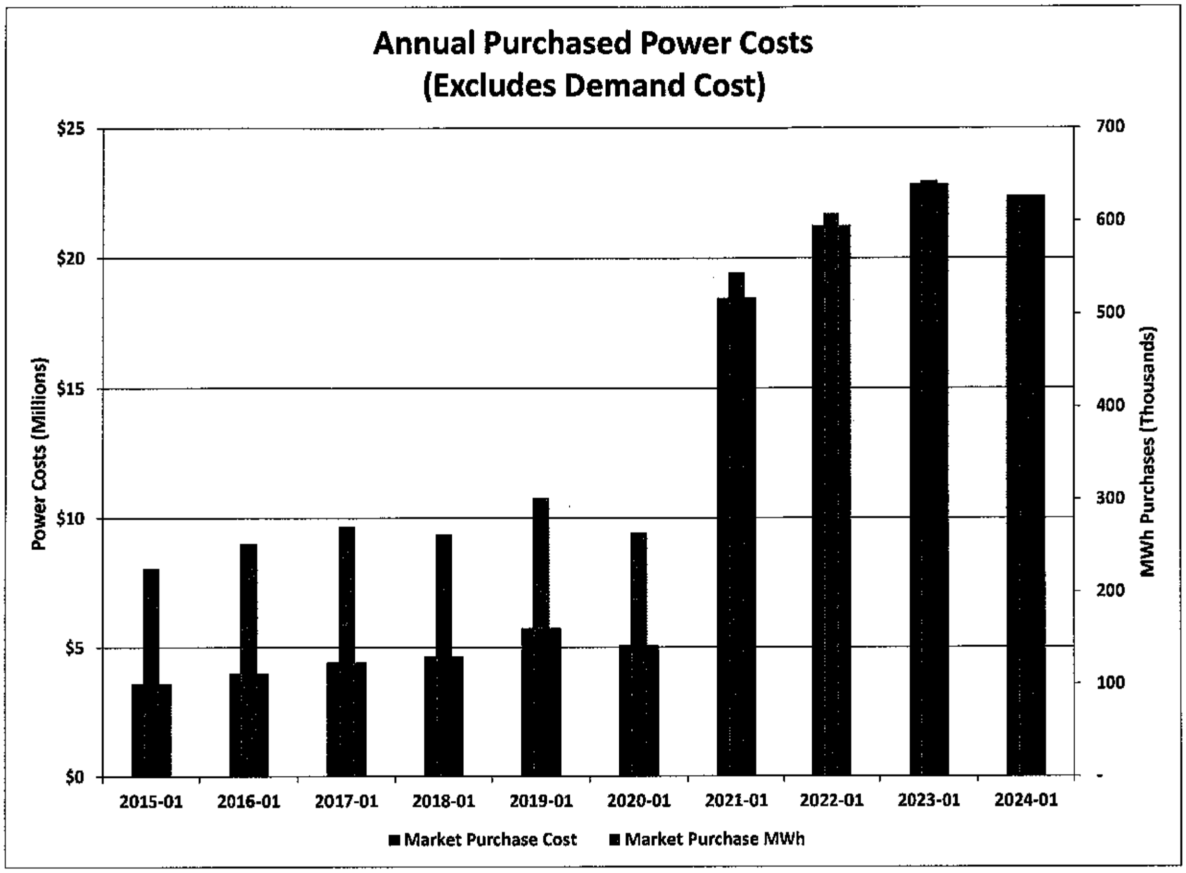
Figure 3-6: Monthly ATC Market Purchases & Sales



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

Figure 3-7 represents the forecast for total purchased power costs and the amount of forecasted MWh purchased. The estimated purchase power costs are forecasted to be over $22 million in market energy by 2024. The same assumed increase in carbon costs increases the amount of energy purchased by NorthWestern and the resulting cost of energy supply.

Figure 3-7 Annual Purchased Power Cost and Associated MWh



Capacity

NorthWestern is currently required to carry 7.1% of capacity in excess of its peak load under the Midcontinent Independent System Operator, Inc. ("MISO") Legally Enforceable Obligation ("LEO") study. In 2015, when NorthWestern migrates to the SPP, the reserve capacity requirement is estimated to be approximately 13.64%. Historic peak load patterns indicate fairly close correlation to a 1.0 to 1.1% per year average growth rate at the 100 degrees Fahrenheit system design temperature. For the purposes of this forecast, a growth rate of 1% per year has been chosen. In summary, the 2015-2024 peak load forecast is shown in Table 3-

2 along with the total obligation, including a 13.64% planning reserve requirement[1] starting in 2016.

Table 3-2: Summer Peak Load 10-Year Forecast

Year	Summer Peak MW	Summer Peak with 13.6% Reserves MW
2015**	334	358
2016	338	384
2017	342	388
2018	346	393
2019	350	398
2020	354	402
2021	358	407
2022	362	411
2023	366	416
2024	370	420
Note:** In 2015 MISO Reserve Obligation is 7.1%.		

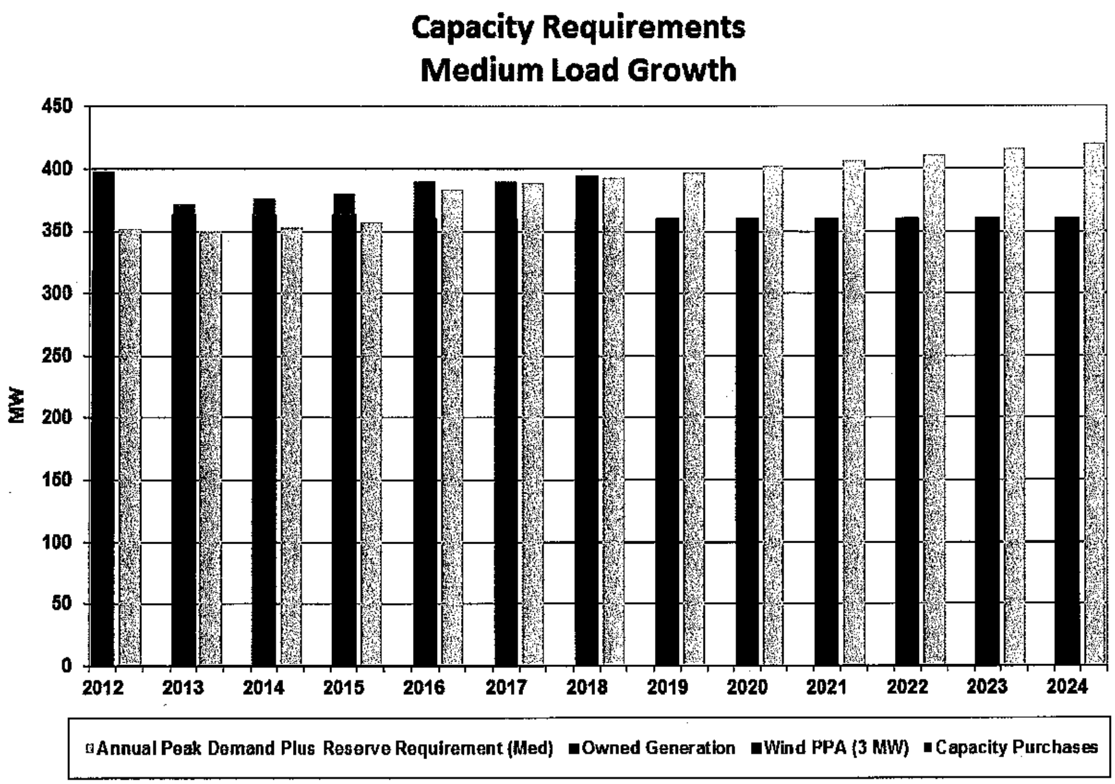
Figure 3-8 below displays NorthWestern's forecasted future capacity deficits and surpluses, based on predicted future capacity obligations compared to existing capacity commitments (existing generation plus third party capacity contracts).

The figure also compares NorthWestern's capacity obligation and available resources to meet those needs. The planning reserves required for the MISO Loss Of Load Expectation ("LOLE") study is 7.1% above system peak demand and that will change to an estimated 13.64% in 2016 when NorthWestern joins SPP. Beginning in 2019, NorthWestern is forecasting that it will need to obtain

[1] This is the SPP-prescribed level for this region.

additional capacity either through adding internal generation or third-party contracts, in order to meet its system capacity requirement.

Figure 3-8: Capacity and Obligation, 2012–2024



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

Conclusions

Despite the considerable value of the planning process, modeling inputs have inherent limitations, and, in many instances, conclusions regarding portfolio performance must be tested and validated under market conditions. For example, key inputs to the model, such as price forecasts, are simply an informed estimate of what may happen in the future. Historic market changes have diminished the predictive value of natural gas price forecasts, as actual market prices have fluctuated from what best-informed analysts predicted. Other inputs have similar limitations.

Thus, the conclusions of this Plan should not be viewed as definitive regarding which resource types will be added, but rather the Plan sets the backdrop against which resource options will be considered, based on what we know at the time. Uncertainties discussed in the Plan, such as the status of federal treatment of carbon emissions or other regulatory requirements, will likely have a significant influence on future resource choices.

Future electricity supply costs are likely to continue to increase. Customers should take higher future costs into account when they make decisions about home construction, insulation, appliance purchases, and their consumption behaviors.

NorthWestern's continued growth in demand for energy and capacity will either increase the portfolio's exposure to market purchases or increase the overall generation portfolio. Current forecasted market conditions indicate that NorthWestern should utilize the market for the short term while evaluating the financial and reliability conditions that would drive the addition of new resources.

CHAPTER 4

PORTFOLIO MODELING AND ANALYSIS

Background

For its 2014 Plan, NorthWestern selected Ascend Analytics ("Ascend") of Boulder, Colorado, to perform modeling analysis on the South Dakota electricity supply portfolio using its PowerSimm™ suite of products. PowerSimm is a complete analytics platform used in the analysis of energy portfolios and risk management in both short- and long-term planning. Previous analysis conducted by Ascend using PowerSimm was used in NorthWestern's application to purchase hydroelectric facilities in Montana, and it was deemed by an independent third party, Evergreen Economics, in the contested hydropower purchase case, to have met industry best practices for long-term planning and resource valuation.[1] This chapter describes the results from utilizing PowerSimm to model the various South Dakota portfolios, the approach used to value and monetize risk, and the underlying assumptions and inputs that drive the modeling results.

A major component of best practices resource planning is accounting for and quantifying risk facing an electricity supply portfolio. The PowerSimm software platform uses the effect of weather variability on load, wind generation, and spot gas prices, and then simulates spot electricity prices as a function of these parameters. Using these inputs, the portfolio optimization program has two main objectives: 1) to meet NorthWestern's load-serving obligation using the most

[1] Evergreen Economics, "Review of NWE's Application to Purchase Hydroelectric Facilities", A Report to the Montana Public Service Commission; March 27, 2014.

economic resources and 2) to optimally dispatch NorthWestern's generation resources to meet either its own load or, when it is optimal to do so, supply energy and/or capacity to the market.

The introduction of meaningful uncertainty is inherent in this modeling framework as the uncertainty in these inputs is captured through probability distributions that maintain the relationships between the various parameters outlined above. This method of considering a range of future states and the likelihood of these states occurring, also known as stochastic optimization, provides a more robust approximation of the value of the portfolio being considered.

This methodology determines the most likely value for each portfolio, but also captures the uncertainty in that value by providing the likely range of the values through a confidence interval. The wider the confidence interval, the less certainty there is in the actual value, and the narrower the confidence interval, the more certainty there is in the true value of the portfolio. This methodology is in contrast to deterministic optimization, which provides a single estimate of portfolio value under a static set of conditions and does not provide any information as to the uncertainty in that value. Table 4-1 below outlines the input variables that were modeled with uncertainty.

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Table 4-1: Input Variables Utilized in South Dakota

Input Variables Utilized in South Dakota PowerSimm Modeling		
Uncertainty Factor	**Traditional Tools**	**PowerSimm Simulation Model**
Load growth	Fixed	Simulated uncertainty
Load patterns	"Typical" profile	Uncertainty in profile and usage pattern
Weather	Fixed	Weather drives demand and causes renewable generation
Wind	Fixed	Simulated with weather
CO_2 emissions	Fixed	Simulated based on uncertainty in costs
Gas & power prices	Fixed	Simulated monthly, daily & hourly prices
Forward/Forecast prices	N/A	Simulated forward curves

Our analysis looks at a need for energy and capacity. The first analysis is focused on the economic merits of resource additions to provide reliable, economic energy and the second is on capacity.

Because NorthWestern will be entering the SPP market within the next year, the new unit additions were evaluated with respect to the market dynamics for the UMZ area within SPP. The SPP market conditions support some of the lowest wholesale costs of supply in the country.

These low prices are a result of excess baseload resources and rapidly increasing quantities of wind generation that amount to over 10% of the energy supply. From a market fundamentals perspective, the opportunity to realize value through producing economic energy is very limited, as shown in the next section. However, this excess amount of baseload energy has led to a relatively inflexible resource supply stack to meet the volatile supply dynamics of wind generation. This inflexibility of supply resources coupled with NorthWestern's need for capacity has also created economic opportunities for highly flexible capacity that is adaptive to the highly volatile real-time market conditions.

Economic Energy Analysis

Two cases were modeled with respect to the make-up of NorthWestern's energy supply portfolio:

1. The "Base" case includes the existing resources in the portfolio with no planned additions or retirements assumed during the planning horizon.
2. The "CCCT" case assumes the 2021 retirement of Big Stone and the conversion of the Aberdeen Generating Station 2 peaker resource into a 146 MW nameplate capacity combined-cycle combustion turbine ("CCCT") with 140 MW of operating capacity.

The next section summarizes the results for the two planning cases.

Summary of Results

The net present value ("NPV") of the costs from 2015 to 2024 to serve the NorthWestern electric load is presented below in Figure 4-1. Costs are presented categorically by Existing Capital, which includes the current fixed cost revenue requirement of all non-load-serving assets, generation fixed operating costs, variable operating costs including market purchases and sales, new fixed and capital costs, and the risk premium associated with the portfolio. For the conversion of Aberdeen to a CCCT, capital costs are levelized and an economic salvage value is credited against costs in 2024. For the retirement of Big Stone in 2021, there is a $22 million cost for decommissioning and stranded costs. The risk premium represents the cost of risk related to the supply portfolio. The risk premium is an aggregated cost of risk reflecting the combined volatility impact subjected on the supply portfolio of all the input variables listed in Table 4-1 above. See the discussion under the Modeling Framework section of this chapter for more detail on the calculation of risk premium.

Figure 4-1. 10-Year Net Present Value of Portfolio Costs, 2015-2024 (2015 $)

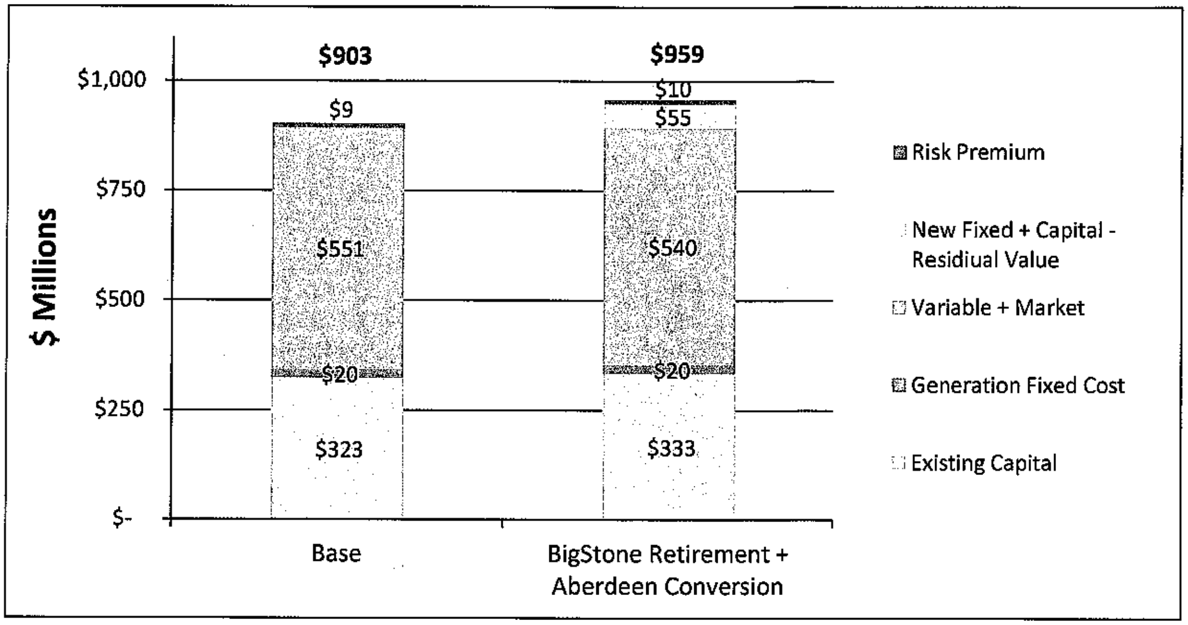
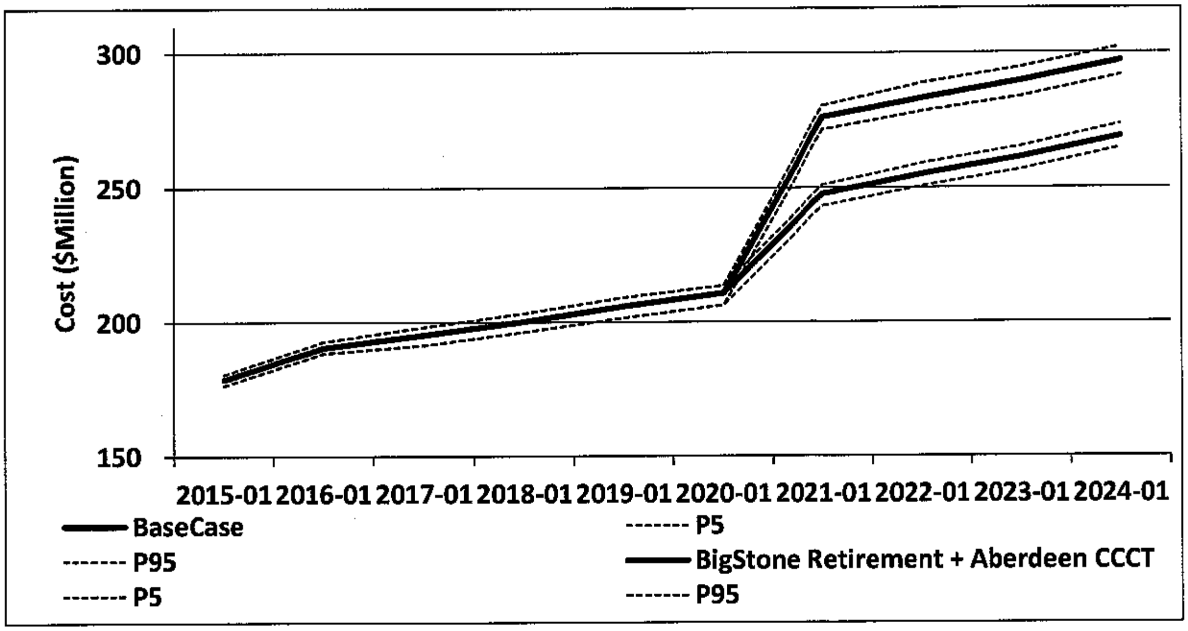


Figure 4-1 shows that the Base Case portfolio subjects customers to the lowest amount of risk-adjusted cost. The CCCT case maintains a similar level of risk as the Base case, but the capital cost associated with the conversion increases total risk-adjusted costs to well above the Base case.

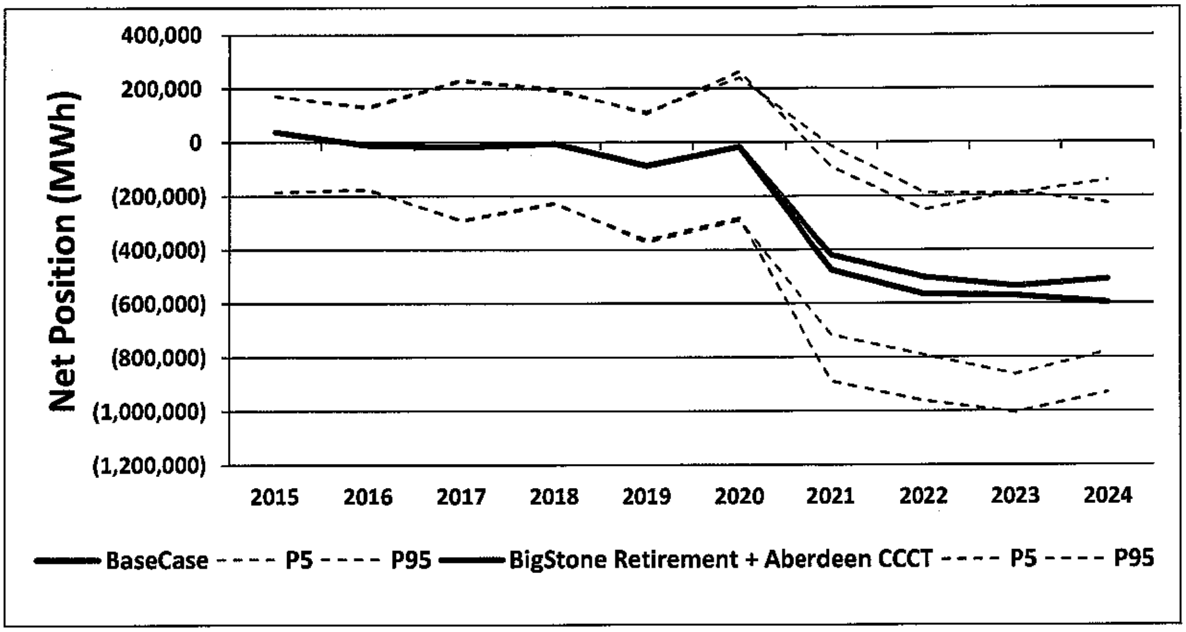
The modeled portfolio costs for each year of the planning horizon are displayed below in Figure 4-2. By inclusion of the 5th and 95th percentile cost values ("P5" and "P95" respectively), this figure illustrates the range of potential portfolio costs in any given year. The P5 and P95 values represent the lower and upper tails of the distribution of simulated portfolio costs produced by PowerSimm, while the mean represents the average portfolio cost of all the simulations. The greater the spread between the P5 and P95 values, the greater the volatility, and therefore risk, that the portfolio is exposed to. As a result of the relatively low energy prices in SPP, the CCCT upgrade would not be economic often enough to justify the cost of the conversion.

Figure 4-2 Annual Portfolio Cost Confidence Intervals (2015 $)



Figures 4-1 and 4-2 above, exhibit the economics of the NorthWestern supply portfolio in terms of cost and risk. In contrast, the net position of each supply portfolio considered is shown in Figure 4-3, which shows the physical position of each portfolio across the study horizon. The net position chart indicates the competitiveness of NorthWestern's current and planned generation resources in the SPP markets by utilizing the most economic resources to meet NorthWestern's load obligations and using NorthWestern's resources to supply energy to the SPP market when they are economic. NorthWestern's resources are utilized to meet nearly its entire load-serving obligation until 2020, when a carbon cost is assumed to be incurred. The implementation of a cost on carbon emissions reduces the cost-effectiveness of NorthWestern's resources, and the least-cost solution is to use energy from the market to meet load. This increases the exposure of NorthWestern's load to market risk, but this risk is outweighed by the cost savings from using relatively lower-cost energy from the marketplace.

Figure 4-3. Net Position 5th, mean, 95th



Need for Capacity

While it may be less costly for NorthWestern to meet load through market purchases, there exists a need to examine its ability to furnish enough capacity to meet load. To examine capacity needs, the same simulations were utilized that generated costs and risk to determine capacity requirements. The capacity analysis utilizes the simulation of load, wind generation, and unit outages. A complete validation of these simulations has been performed and key benchmark results are presented later in this report.

For this analysis, a capacity deficit exists when available NorthWestern generation resources are not sufficient to meet load in a given hour. Simulations indicate that the current portfolio is expected not to be able to serve load on average 2.65 hours/year beginning in 2015, increasing to 16.11 hours/year in 2024 (see Figure 4-4 below). The P95 confidence bound is the value that should be considered when determining capacity needs and shows the number of hours could be as high as 16 hours/year and 49.5 hours/year in 2015 and 2024, respectively. The confidence interval specified by the P5 and P95 endpoints indicate the range of possible hours the portfolio could be short in a given year with a 90% confidence that the true value is within this range. In other words, it is unlikely that the number of hours short in a given year would exceed this value. Additionally, Figure 4-5 indicates that while the portfolio is short of capacity during the year, it is not short by a large number of MW, with expected values ranging from 16.5 MW in 2015 to 43.8 MW by 2024. The P95 confidence interval indicates these values could be upwards of 60.9 MW and 100.5 MW in years 2015 and 2024, respectively.

Figure 4-4. Hours Short by Year mean and 95th

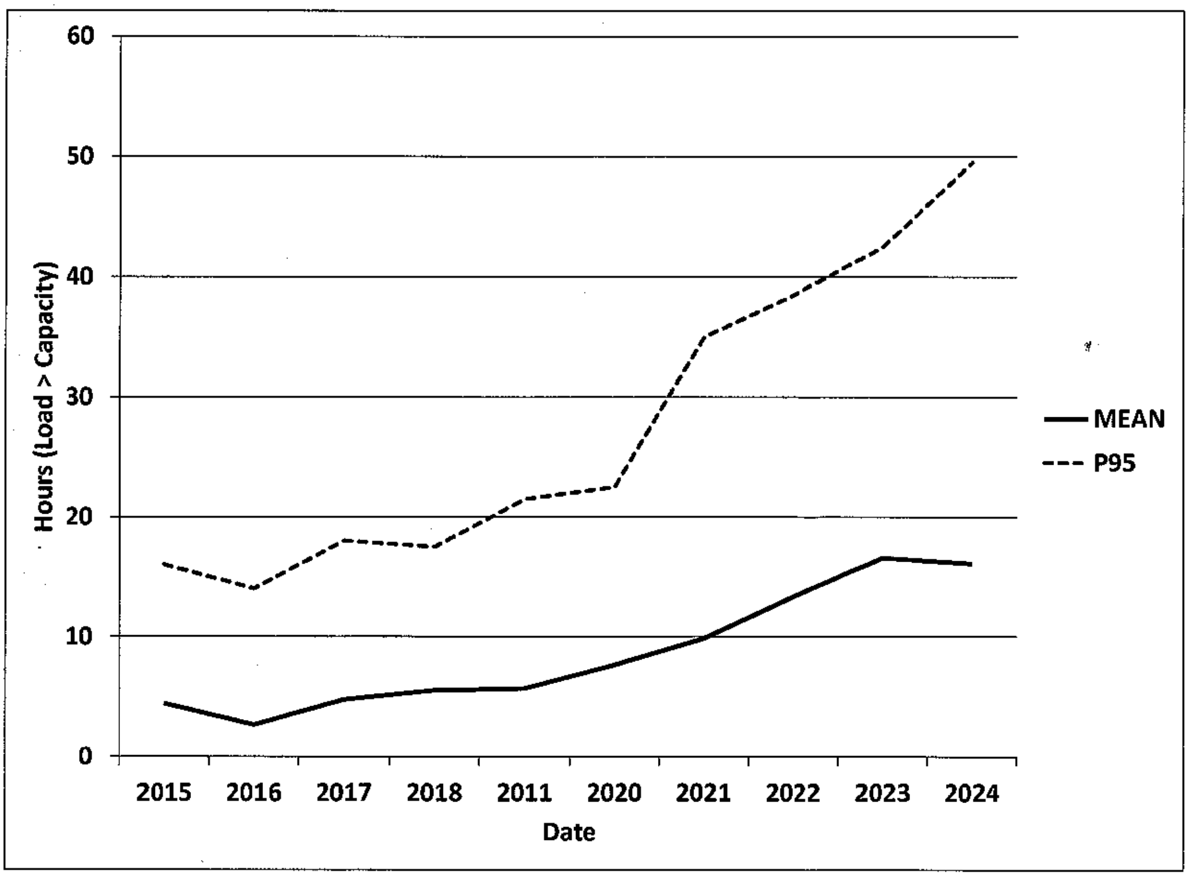
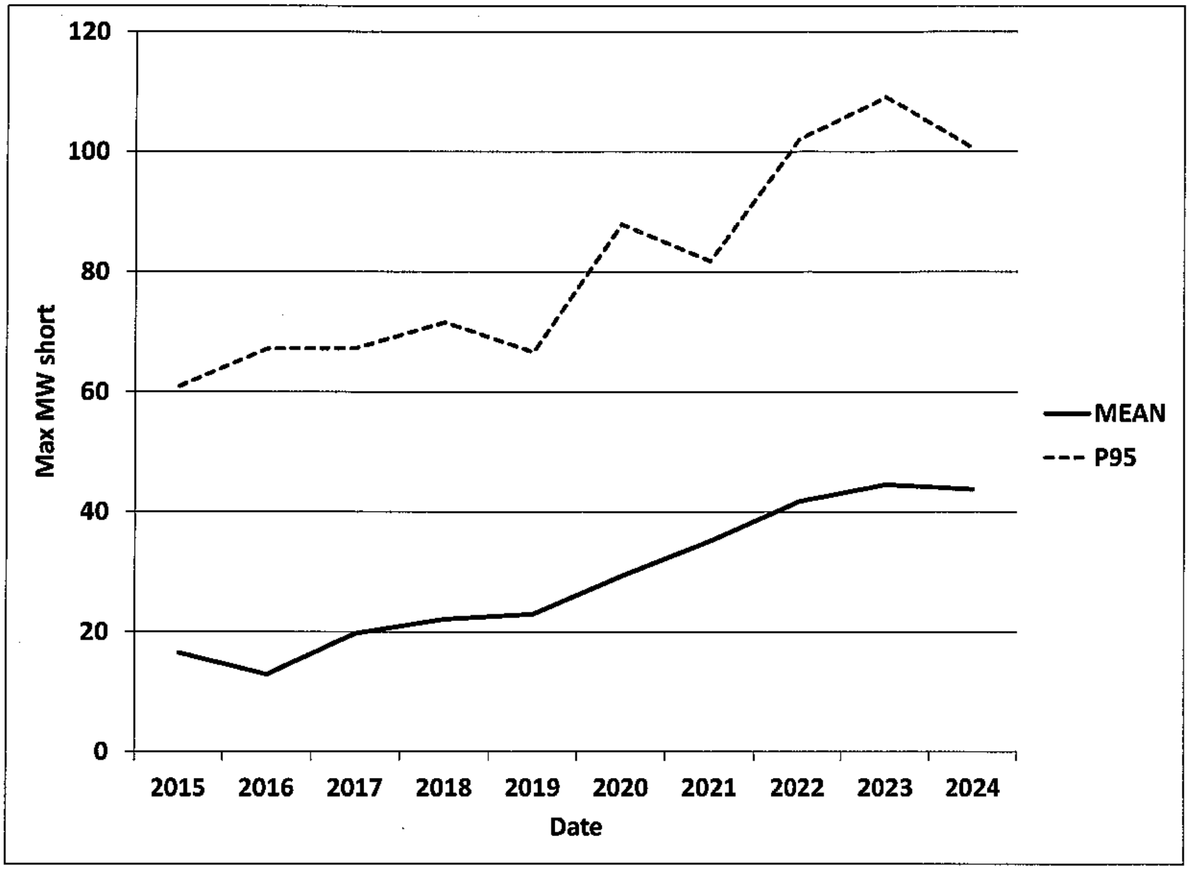


Figure 4-5. Max Capacity Short by Year mean and 95th



The supply side of the SPP market has an abundance of inexpensive generation, creating large reserve margins. While NorthWestern can capitalize on these market conditions to meet energy needs, capacity requirements have to be met as economically as possible. Finding resources that are capable of meeting NorthWestern's capacity requirements and at the same time providing the most economic value to its customers is considered in the next section.

Evaluation of Capacity Resource Additions

In response to the increased likelihood of Northwestern becoming short of capacity during the summer months, the need arose to evaluate the relative merits of various generation technologies. A market assessment was performed to value a 200 MW equivalent of Wartsila 50SG engines and GE 7FA turbines for a proxy South Dakota location, calculated as the average of five Nebraska pricing points in SPP[2] from March 1 to September 1, 2014. The purpose of this analysis was to assess the economic value of each asset under observed market conditions of SPP. While both assets are considered peaking generators, the differentiating factors reside with their efficiency and responsiveness.

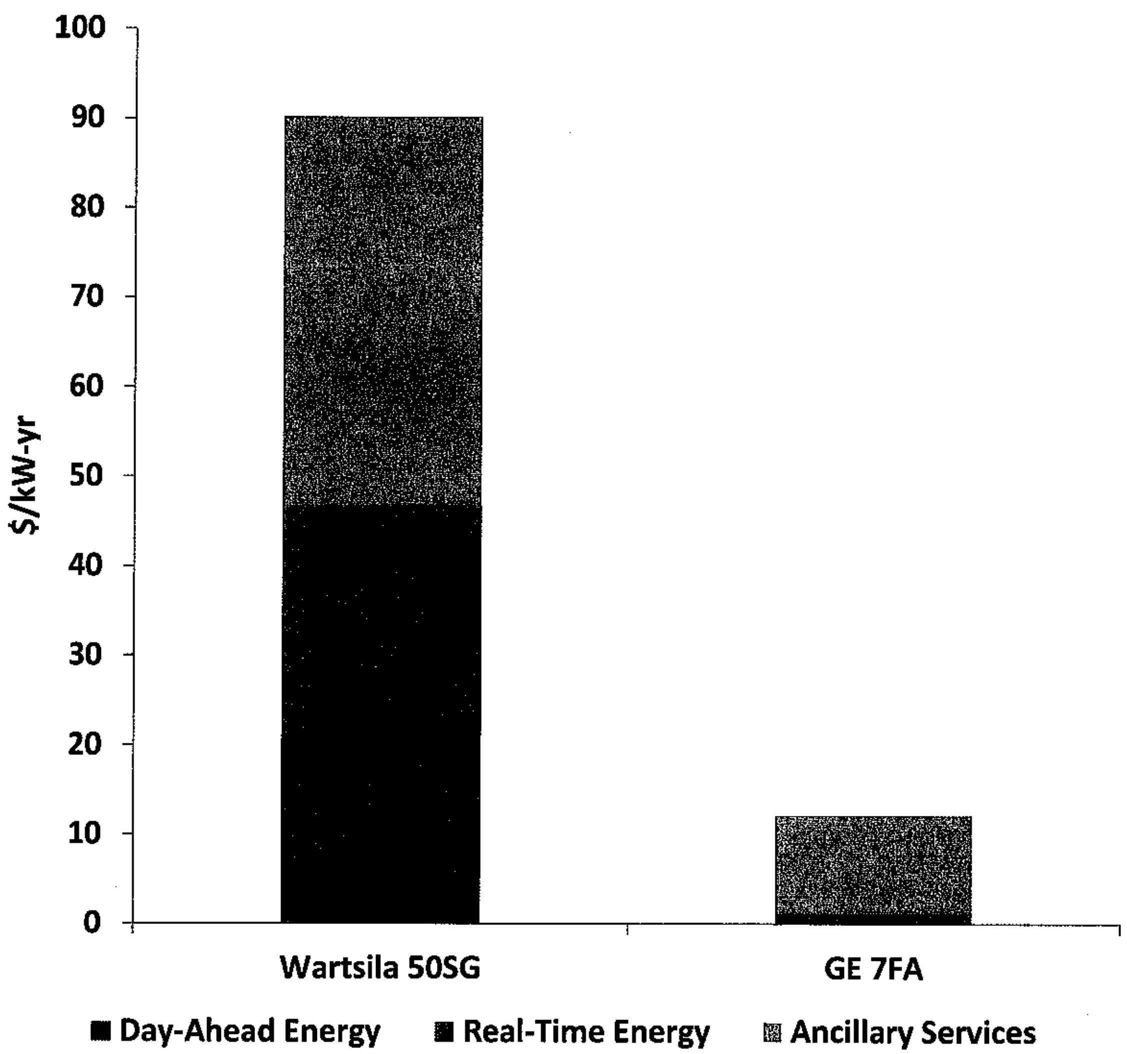
The SPP market places a substantial economic premium on flexibility to react to the 5-minute real-time market. In addition, flexible resources that can economically deliver regulation energy and 10-minute spinning reserves carry additional value. The combined effect of a highly volatile 5-minute energy market and an attractive ancillary service market deliver a clear price signal to generators:

1) Startup and shutdown within 5 minutes;
2) Perform generator cycles from off to on at a negligible cost; and
3) Run at minimum load efficiently to provide regulation services.

A comparison of the economic performance of the Wartsila 50SG engines versus the GE 7FA turbines reinforces the value of flexible generation. Peaking generation that can rapidly and efficiently respond to the SPP market price signals has substantial value over less flexible generation. The results shown in Figure 4-6 confer the economic value of generation flexibility inherent in the Wartsila 50SG relative to the GE 7FA.

[2] SPS.Jones1

Figure 4-6. Annualized Gross Margin Profit by Market Product for 200 MW of Wartsila and GE 7FA Generation



For 200 MW of equivalent Wartsila and GE generation capacity, the Wartsila engines realize 740% more value. The Wartsila engines have an annual gross margin profit of $90.2/kW-yr versus the GE 7FA of $12.2/kW-yr. These generators realize revenue from three principal SPP markets: 1) Day-ahead

energy, 2) Real-time energy, and 3) Ancillary services. Because the Wartsila engines have substantial operating flexibility, gross margin profits are almost equally proportioned between the three power market components. In contrast, the GE 7FA generators realize the preponderance of gross margin profit from ancillary services.

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 4-2.

Table 4-2. Generation Asset Input Assumptions

Asset Characteristic	Wartsila	GE 7FA.05
Output (ISO)	18.4 MW	227 MW
Output (Site, ISO temp)	18.4 MW	195.6 MW
Efficiency (ISO)	8,266 Btu/KWh	9,838 Btu/KWh
Overnight EPC cost	920 $/KW	667 $/KW
Minimum stable load	40%	40%
Efficiency at minimum stable	9,711 Btu/KWh	13,899 Btu/KWh
Start-up time	5 min	10 min
Start-up cost (maintenance)	0 $/start	12,000 $/start
Start-up fuel cost	0.58 $/MW/start	3.3 $/MW/start
VOM	5.5 $/MWh	3.85 $/MWh
Mark-up (Costless adder)	6 $/MWh	6 $/MWh

The market prices for each commodity over the six-month period from March 1 to September 1 are summarized in Tables 4-3 and 4-4. The analysis used the market data under the transactional time intervals of the second column: Gas prices change daily, while day-ahead power and ancillary services (10-minute spin, 10-minute non-spin, and regulation) operate under a one-hour time step, and real-time power operates on 5-minute increments. The third and fourth columns provide the average price and price volatility measured as standard deviation of price as a percent of the average price.

Table 4-3. Summary of Energy Market Price Inputs for South Dakota Proxy 3/1/2014 to 9/1/2014

Commodity	Price Interval (Units)	Average Price		Price Volatility	
		Peak	Off-Peak	Peak	Off-Peak
Gas Price (DA)	Daily	$5.14/MBtu		78%	
Power (DA)	Hourly	$37.90/MWh	$24.30/MWh	42%	47%
Power (RT)	5 Minutes	$33.45/MWh	$21.64/MWh	169%	300%

Table 4-4. Summary of Ancillary Market Price Inputs for South Dakota Proxy 3/1/2014 to 9/1/2014

Commodity	Price Interval (Units)	Average Price		Price Volatility	
		Peak	Off-Peak	Peak	Off-Peak
10 minute Spin (DA)	Hourly	$10.76/MW	$5.30/MW	71%	114%
10 minute Non-Spin (DA)	Hourly	$2.56/MW	$1.75/MW	138%	64%

Regulation Up (DA)	Hourly	$19.60/MW	$11.84/MW	43%	67%
Regulation Down (DA)	Hourly	$7.04/MW	$8.02/MW	132%	50%
10 minute Spin (RT)	5 Minutes	$6.38/MW	$4.92/MW	605%	686%
10 minute Non-Spin (RT)	5 Minutes	$3.58/MW	$2.94/MW	983%	1049%
Regulation Up (RT)	5 Minutes	$17.99/MW	$13.78/MW	291%	322%
Regulation Down (RT)	5 Minutes	$13.54/MW	$12.73/MW	127%	108%

The SPP market has 75,000 MW of installed generation capacity with a reserve margin of 47%.[3] Compared against standard planning reserves of 15%, SPP has the largest reserve margin in the United States. In terms of market dynamics, generators are in an extremely weak position to exercise market power and collect scarcity rents during high demand periods. The substantial amount of excess capacity usually creates poor fundamental conditions for peaking units to realize adequate returns to justify their entry on a merchant basis. For example, the GE 7FA turbines scaled to 200 MW only earn approximately $0.55 million per year when dispatched on day-ahead and real-time energy. However, SPP also has a rapidly growing fleet of wind generators that constitute over 10% of energy production, with expectations of wind providing 15% of energy by 2015. The combination of variable wind in conjunction with 25,000 MW of relatively inflexible coal generation creates conditions of high variability in real-time prices.

[3] Wind resource capacity in SPP contributes 5% of capacity toward reserve margins.

How can a market so long economic energy and capacity provide opportunities for new generation? The answer resides with flexibility of supply resources in SPP to respond to changes in load and address congestion problems. Generation responds dynamically to the changes in load to maintain a proper balance between demand and supply. If ramp rates are too low, the market cannot respond quickly enough to manage system changes and ramp deficiencies occur. Deficiencies result in price spikes and increase overall price volatility.

From 2012 to 2013, ramp deficiencies increased by about 10% to approximately 100 events per year because of the added variability of increased wind generation and a decrease in ramp capabilities from online capacity. The deficiency in ramp capabilities manifests itself through higher and more volatile market prices for regulation services and energy. While these events are short-lived, they can create extreme changes in real-time prices. For example, real-time power prices are 300% more volatile than day-ahead prices. With additional renewable resources expected to become a larger fraction of SPP energy supply, the market price signals and need for highly flexible generation resources is expected to grow.

Modeling Framework for Evaluation of Capacity Resources

The modeling framework maximized the value of generation across energy and ancillary service markets. By optimizing the generation dispatch to the asset attributes of Table 4-2 and the historic market prices summarized in Tables 4-3 and 4-4, Ascend maximized gross margin profits for each generator. In this analysis, the joint optimization to energy and ancillary services can be best understood by outlining the components of value and operational dynamics of the peaking plants. There are four principal sources of revenue:

1) Day-ahead energy;
2) Day-ahead ancillary services;
3) Real-time energy; and
4) Real-time ancillary services.

Each component provides a critical potential source of revenue. The joint optimization provides a basis for maximizing revenue across all four components. While the analysis in this section provides valuable insight into the relative merits of the two generation technologies, it is limited in scope. Data from the first six months of market operations were used to determine the economic value of the two resource types. To obtain a more robust estimate of economic value and further substantiate this analysis, forecasted simulations of future value and additional market history are necessary.

Flexibility in operations and efficiency in cycling generation on and off becomes paramount for peaking plants to realize additional value beyond day-ahead energy. The realization of value in the day-ahead market provides emphasis on plant efficiency (heat rate) and to a lesser extent on start-up costs. A generator operating in the day-ahead market simply offers its variable cost of generation and start-up costs. For both the GE and Wartsila peaking plants, we added $6/MWh to the variable cost of generation to guarantee a profit for operations. Revenue for 10-minute non-spin ancillary services requires a generator to have a start-up time of less than 10 minutes. With 5- and 10-minute start-up times, respectively, the Wartsila and GE units earn non-spin revenue when not running. Both generators have rapid ramp-up and down capabilities once on-line.

The joint optimization between energy and ancillary services will typically reduce generation to minimum load in the day-ahead market and permit the units to garner the remaining 60% of operating capacity as either regulation-up or 10-minute spinning reserves. With ancillary services for regulation-up and 10-minute spin at an average price of $15.49/MWh and $7.87/MWh, respectively, reducing energy output to supply ancillary services can enhance profits. A day-ahead combined energy and ancillary service strategy may be to offer generation at a minimum load (40% of max capacity) and have the balance of the unit collect regulation-up or 10-minute spinning reserves. This strategy will enable the generator to realize the value of flexibility.

The optimization framework continues to realize additional value for highly flexible generators in the real-time energy market. The real-time energy market produces additional value as prices change from the day-ahead market and generators have the opportunity to react to these changing prices. For example, a generator selected to provide energy at $45/MWh from the day-ahead market has the opportunity to increase profits by shutting down and completing energy deliveries through purchases from the real-time market. The generator would exercise this right to shut down whenever the real-time price is less than the combination of the variable cost of production and start-up costs. When the generator is down, market purchases are made to fulfill the commitment of the day-ahead market. However, if the real-time price of energy or ancillaries exceeds the day-ahead price, the generator receives the price commitment of the day-ahead market. If the generator has not committed the capacity in the day-ahead market due to low prices, the capacity is available for the real-time market, and the fast starting units could be started in real time if the price in the real-time market exceeds the variable operating costs.

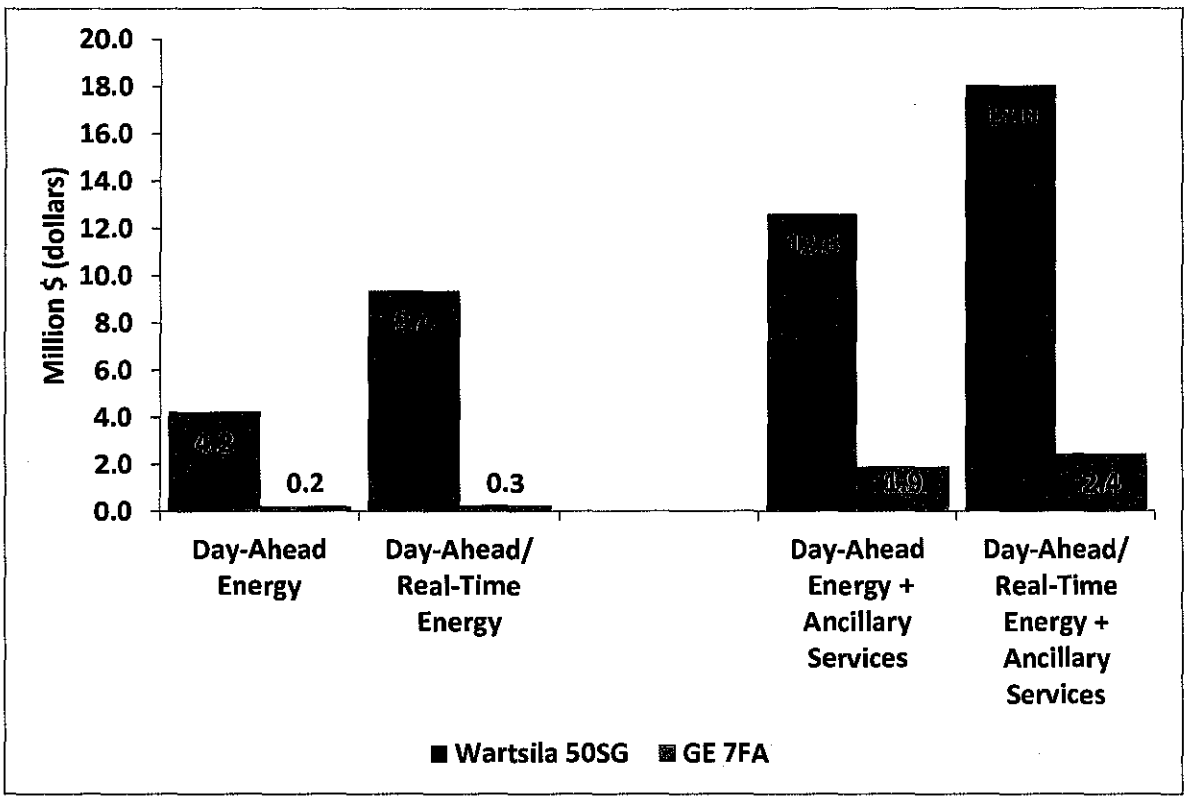
The modeling framework consisted of Ascend's PowerSimm™ software to perform the asset optimization with additional validation and summarization of results conducted in a spreadsheet. PowerSimm™ applies dynamic optimization to maximize the value of energy production across the day-ahead and real-time markets for energy and ancillary services. The optimization routine first operates against day-ahead prices for energy and ancillary services. After the day-ahead unit commitment has been performed, the model then looks to further optimize value in the real-time market. This modeling logic would presumably apply to an operating protocol designed to maximize portfolio value when NorthWestern operates within SPP.

Results of Capacity Resource Additions

The results reflect the full operating value for 200 MW Wartsila and GE 7FA peaking plants as they would have been realized in SPP over the first six months of operation and then annualized. The composition of gross margin profits across day-ahead and real-time markets for energy and ancillary services is shown in Figure 4-7 for both generators. With the SPP market signals valuing extremely efficient flexible resources, the Wartsila engines substantially outperform the GE 7FA turbines.

The left side of Figure 4-7 shows both day-ahead and then day-ahead plus real-time profits. Because of high start-up costs and higher heat rate, the GE 7FA realizes $0.3 million profit in both the day-ahead and real-time markets. Whereas, the Wartsila engines see annual profits more than double from $4.2 million to $9.4 million with the addition of the real-time market. The right side of Figure 4-7 first presents day-ahead energy and ancillary services and then includes on the far right the capability to release additional profits through real-time energy and ancillary services. The GE 7FA realizes $1.7 million in additional profit through the inclusion of ancillary services – evenly split between regulation-up, down, and non-spinning reserves. Whereas, the Wartsila engines realize $3.2 million increase in profits (compared to the day-ahead energy only case) – primarily from regulation services. The introduction of real-time energy and ancillary service markets continues to create substantial additional opportunity for the highly flexible Wartsila engines. Profits from the introduction of real-time energy and ancillary markets for the Wartsila engine rise by $5.4 million to $18.0 million versus a $0.5 million increase to $2.4 million for the GE 7FA.

Figure 4-7. Wartsila 50SG and GE 7FA Annualized Gross Margin Profit by Energy Market Component



Realizing opportunities in the real-time market requires extremely flexible generation with negligible start-up costs. For the production of ancillary services, the Wartsila engines gain additional value over the GE 7FA turbines through 35%

higher efficiency at minimum generation.[4] The higher efficiency at minimum load positions the Wartsila engines to realize premium ancillary services of either regulation-up or spinning reserve. With no maintenance start-up cost (compared to $12,000 for the GE 7FA) and a $0.58/MW start-up fuel cost, the Wartsila engines are both economically and physically capable of responding to the substantial volatility in real-time prices. The Wartsila engines' highly flexible start-up and shut-down capabilities position the engines to rapidly respond and realize profits from the volatility in market prices. The Wartsila engines' relatively high operating efficiency at minimum load further enables the plant to realize additional profits from ancillary services. The stark contrast in gross margin revenue between the two peaking plants enables the Wartsila engines to earn back the added capital cost of $253/KW in 3.2 years.[5]

SPP Market Fundamentals

As an Independent System Operator, the SPP spans nine states (AR, KS, LA, MS, MO, NE, NM, OK, and TX) with a 2013 coincident peak load of 45.3 GW.[6] SPP has 75,000 MW of installed generating capacity with a reserve margin of 47%.[7][8] Compared against standard planning reserves of 15%, SPP has the largest reserve margin in the United States. Figure 4-8 shows the SPP system load and the system supply curve. The system load is on average approximately 26.3 GW, substantially less than available SPP capacity, and that has the effect

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[4] The Wartsila units have a minimum operating plant heat rate of 9,838 Btu/KWh versus 13,899 Btu/KWh for the GE 7FA. Both units have minimum operating levels at 40% of maximum capacity.

[5] This analysis is intended to compare and contrast the profitability of various technologies participating in the SPP markets and is not an endorsement for either technology.

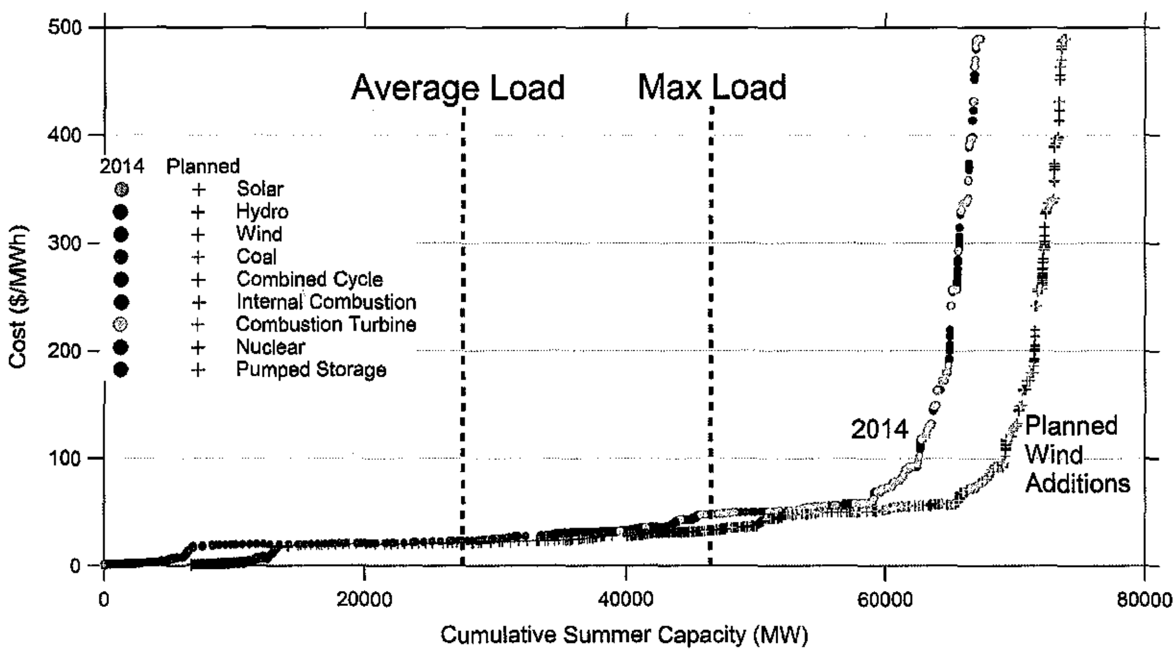
[6] http://www.spp.org/publications/Intro_to_SPP_OCTOBER%202014.pdf.

[7] 2013 SPP State of the Market Report, http://www.spp.org/publications/2013%20SPP%20State%20of%20the%20Market%20Report.pdf.

[8] Wind resource capacity in SPP contributes 5% of capacity toward reserve margins.

of keeping energy prices relatively low. Additionally, SPP also has a rapidly growing fleet of wind generators totaling 9,000 MW of installed capacity and accounting for over 10% of energy production, and wind's contribution will substantially increase to 22,228 MW with the completion of over 13,228 MW under development shown in Figure 4-9.[9] Energy generated from wind is expected to meet 15% of SPP load by 2015, further shifting the existing SPP system supply curve to the right, as variable costs of wind generation are near zero (Figure 4-8).

Figure 4-8. SPP 2014 Peak and Planned Generation Supply Curves and 2013 Average and Peak Load



The substantial amount of excess capacity would be expected to create poor fundamental conditions for peaking units to realize adequate returns to justify their entry on a merchant basis. However, the conditions created by intermittent and highly variable wind generation in conjunction with 25,000 MW of relatively

[9] http://www.spp.org/publications/Intro_to_SPP_OCTOBER%202014.pdf.

inflexible coal leads to increased variability in real-time prices. Figures 4-10 through 4-12 below summarize energy and ancillary prices for SPP Zone 1, which comprises the state of Nebraska, and they are the most relevant prices for South Dakota. While day-ahead locational marginal prices (LMPs) in Zone 1 are on average 15.9% higher than in the real-time market, the variability of real-time prices as a percent of the average LMP is approximately 200% higher than the day-ahead market (Figures 4-10 and 4-11). Similarly, variability of upward regulation and 10-minute spin is markedly higher in real time, particularly during the off-peak period when wind generation is at its highest levels of the day (Figures 4-12 and 4-13). This increased variability of real-time energy prices relative to day-ahead prices can be substantially attributed to the intermittency of wind generation combined with a highly inflexible supply stack comprised primarily of coal generation.

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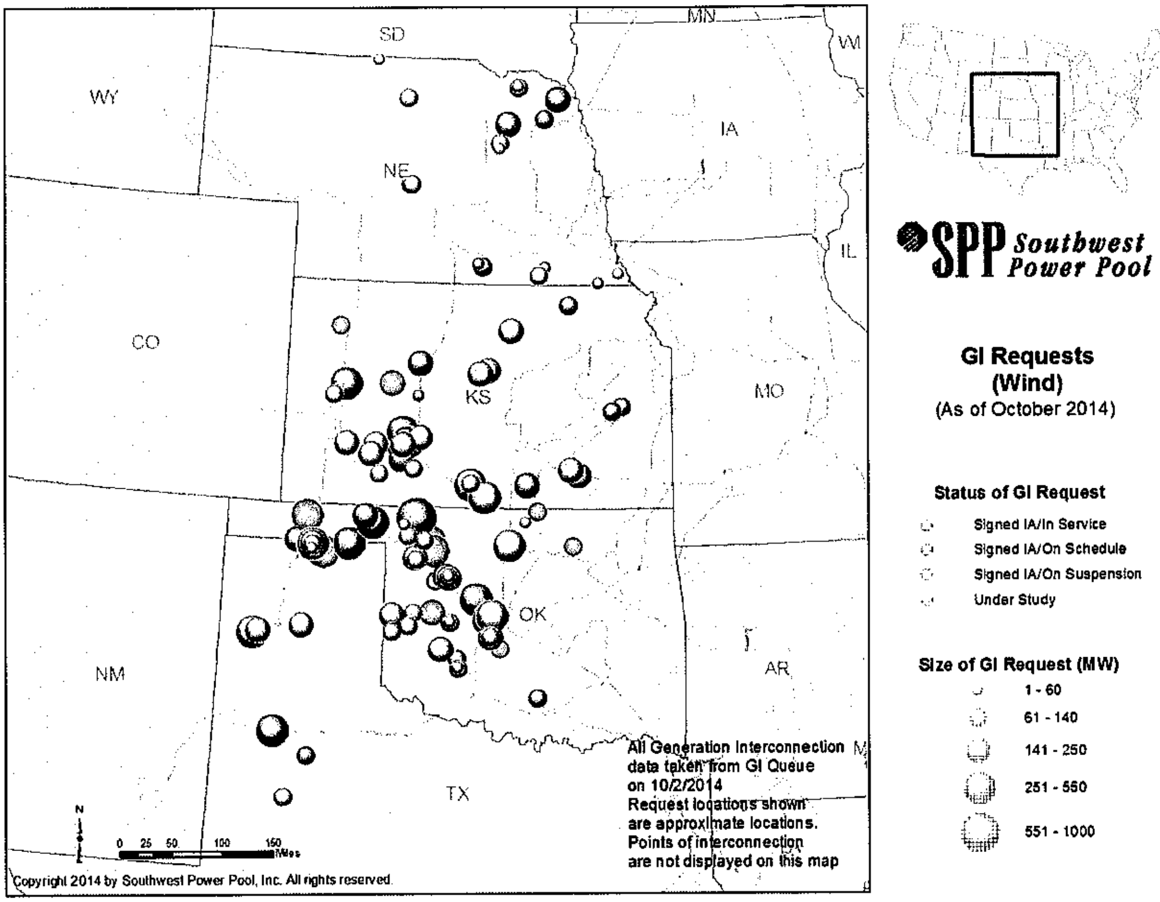
Figure 4-9. Sites and capacities of existing and planned wind sites in SPP. 10



[10] http://www.spp.org/publications/Intro_to_SPP_OCTOBER%202014.pdf.

Figure 4-10. Summary of SPP Zone 1 day-ahead and real-time average zonal market price inputs over the period 3/1/14 to 9/1/14.

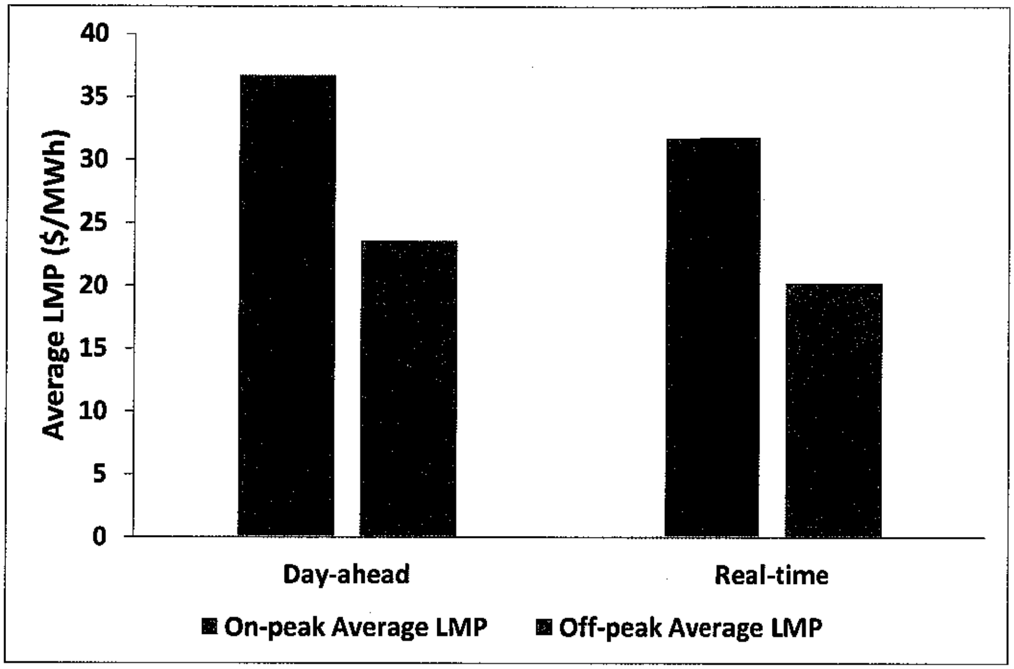


Figure 4-11. Summary of standard deviation of SPP Zone 1 day-ahead and real-time zonal market price inputs over the period 3/1/14 to 9/1/14.

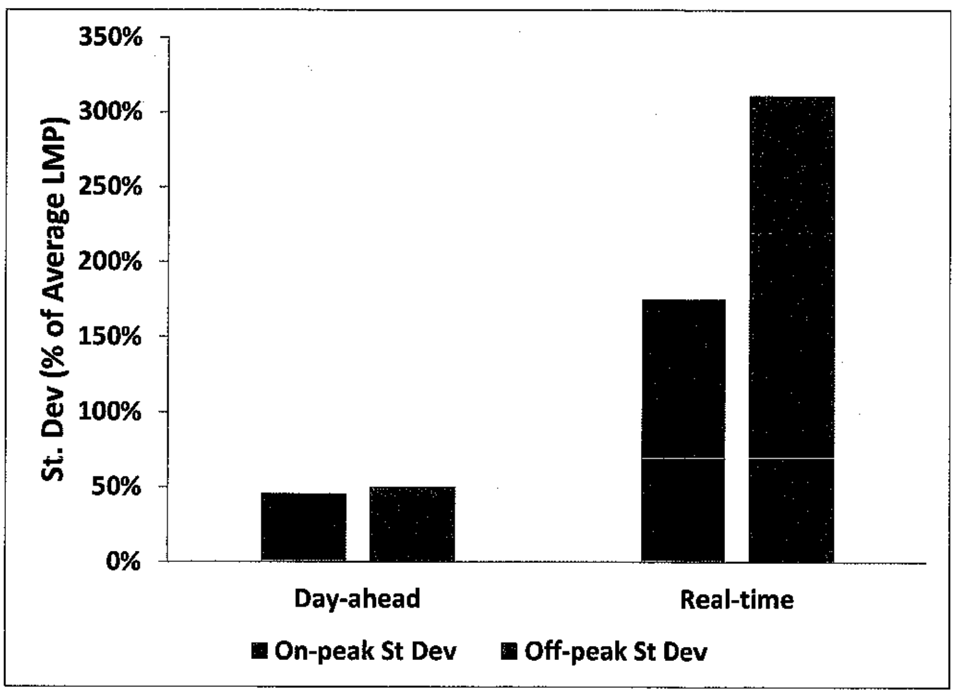


Figure 4-12. Summary of Average SPP Zone 1 day-ahead and real-time ancillary services prices over the period 3/1/14 to 9/1/14.

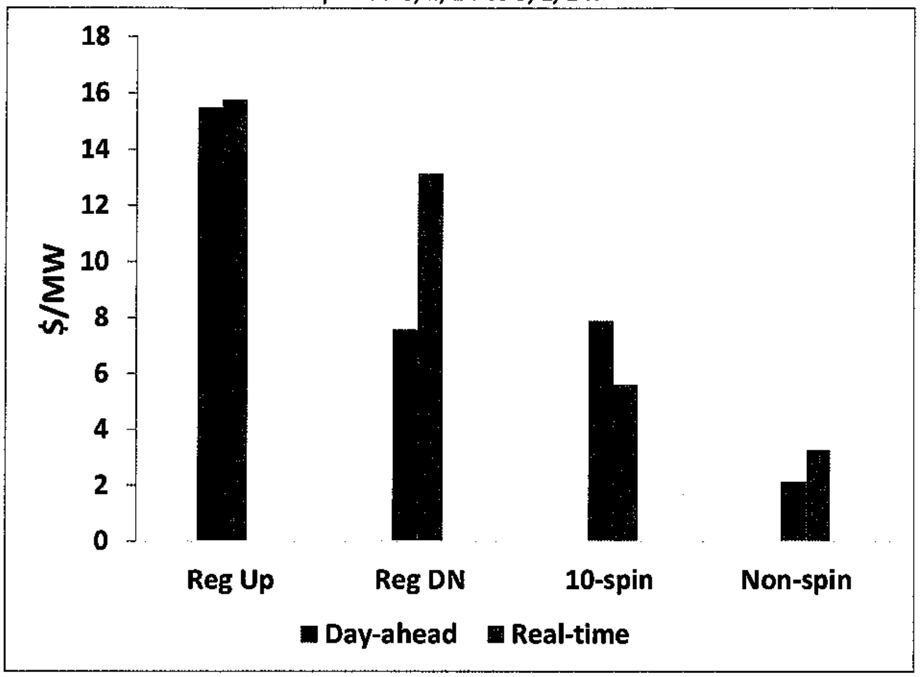
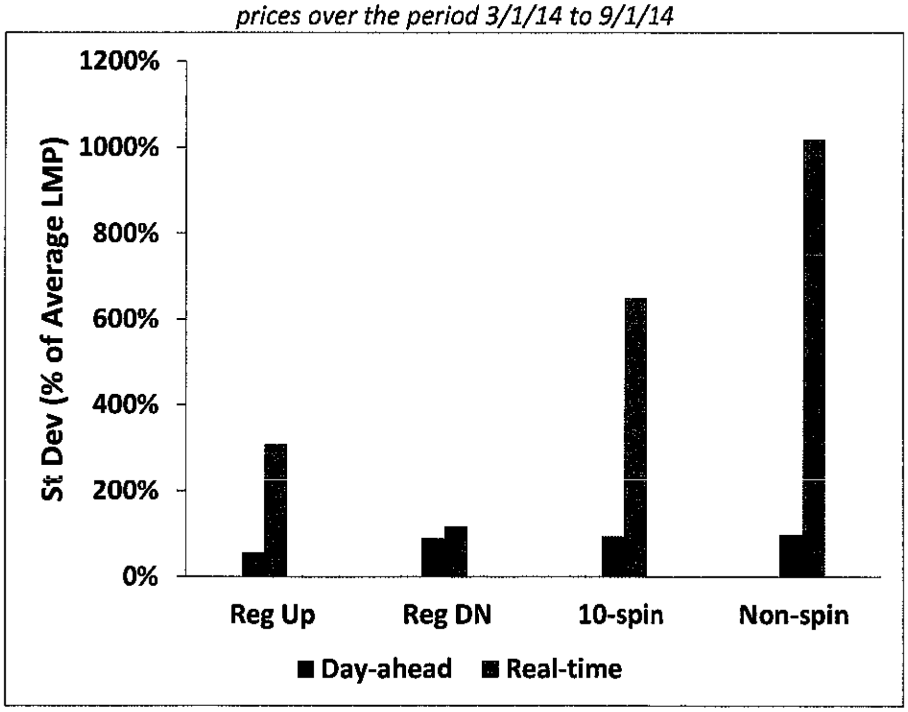


Figure 4-13. Summary of Standard Deviations of SPP Zone 1 day-ahead and real-time ancillary services prices over the period 3/1/14 to 9/1/14



With the system long intermittent resources and going longer due to wind resource additions, there is relatively little value for new resources to compete directly in the energy market. The real value lies in resources that add dispatch flexibility to the system and can quickly respond to short-term changes in load and intermittent wind generation. Fast-ramping resources are well positioned in the SPP markets to capture the value created by highly variable real-time energy and ancillary service prices.

Modeling Framework

Ascend's modeling process for economic energy discussed at the beginning of this report has two principal components. First, the PowerSimm simulation engine uses historical input data to preserve fundamental structural relationships between weather, load, wind generation, and electric and natural gas prices in its projections of these variables throughout the planning period. Second, PowerSimm simulates the operation of all generating units for the two modeling cases using the same realizations of future values in order to calculate the range of portfolio costs for each case.

Commodity Forward Prices

In order to capture meaningful uncertainty in its simulation of future states, PowerSimm relies on current expectations of forward/forecast prices which are provided for in the most recent forward market curve, and that is input into the model. Market expectations of price volatility, fundamental market relationships, rate of mean reversion, and correlations of simulated prices through time are reliant on historical forward market curves that are input into the model. The simulated forward/forecast commodity prices include power at the Indiana hub with a discount basis value applied to reflect South Dakota pricing, natural gas at

Ventura, and Powder River Basin ("PRB") coal. For each commodity, current monthly forward prices establish the mean forward price curve through 2020 with prices escalating at inflation thereafter.

Uncertainty in forward price simulations is examined in Figure 4-14 and Figure 4-15, which show the confidence intervals, presented as the P5 and P95 trajectories, as well as the current market expectation of prices, the mean, for South Dakota-priced heavy-load electricity and Ventura natural gas.

Figure 4-14 South Dakota Heavy Load Price Confidence Intervals (nominal dollars)

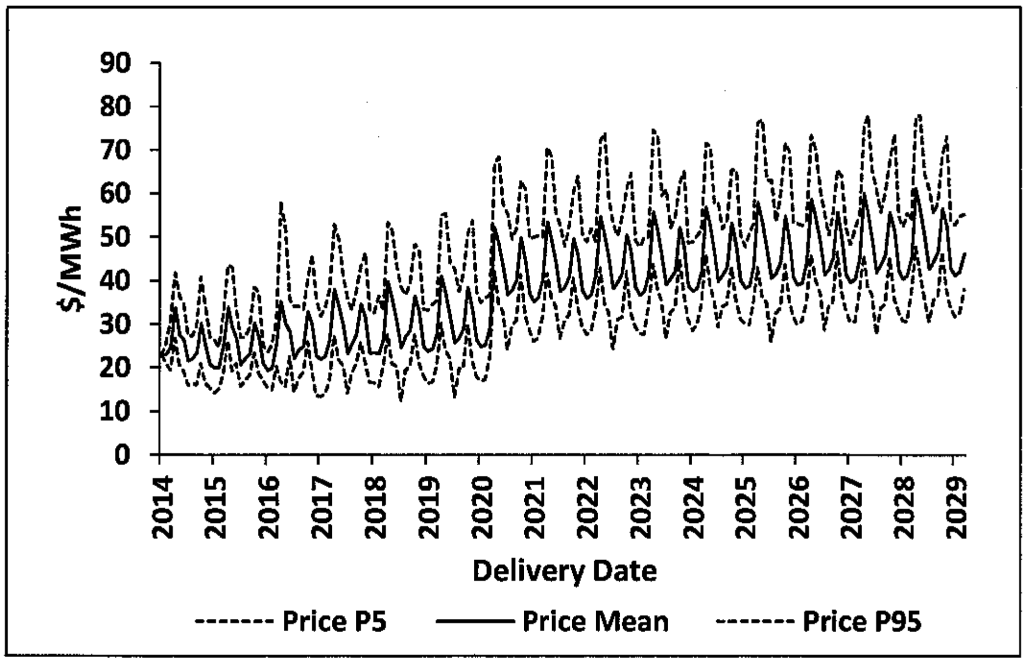
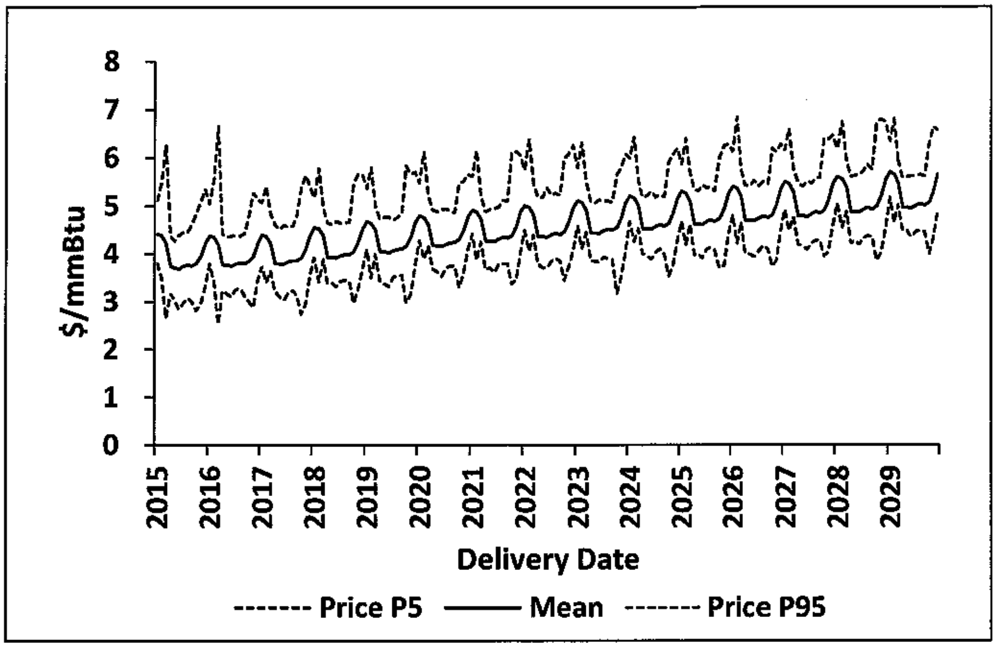


Figure 4-15 Ventura Price Confidence Intervals



Finally, the structural relationship of forward/forecasted prices for power and gas is investigated via plots of the market implied heat rates.[11] Figure 4-16 and Figure 4-17 show the simulated mean and the 5th and 95th percentiles for the forward market implied heat rates for South Dakota heavy load and light load, respectively. These heat rates are computed by dividing the modeled forward market price of South Dakota electricity, excluding the impact of any carbon dioxide ("CO_2") price, by the modeled forward price of Ventura gas. The simulations show that the implied heat rates for South Dakota heavy load are greater than those for South Dakota light load, which is consistent with market expectations.

[11] The market implied heat rate is the ratio of power prices ($/MWh) to gas prices ($/MBtu) and yields units of generation heat rates of MBtu/MWh.

Figure 4-16 Heavy Load Implied Market Heat Rate Confidence Intervals

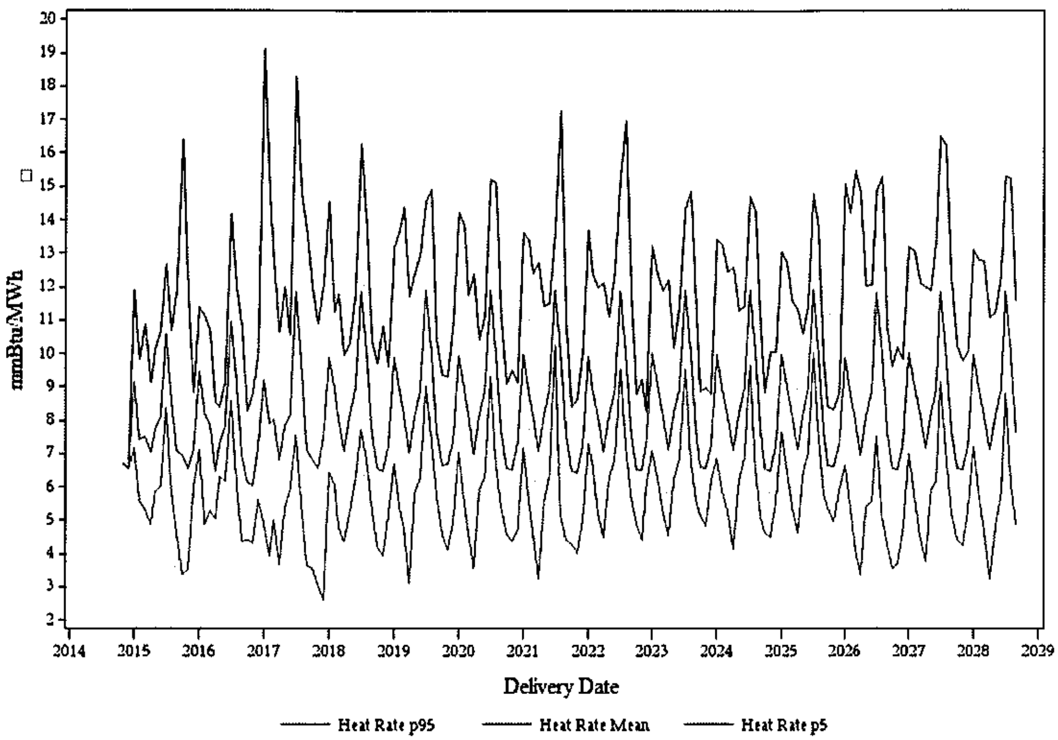
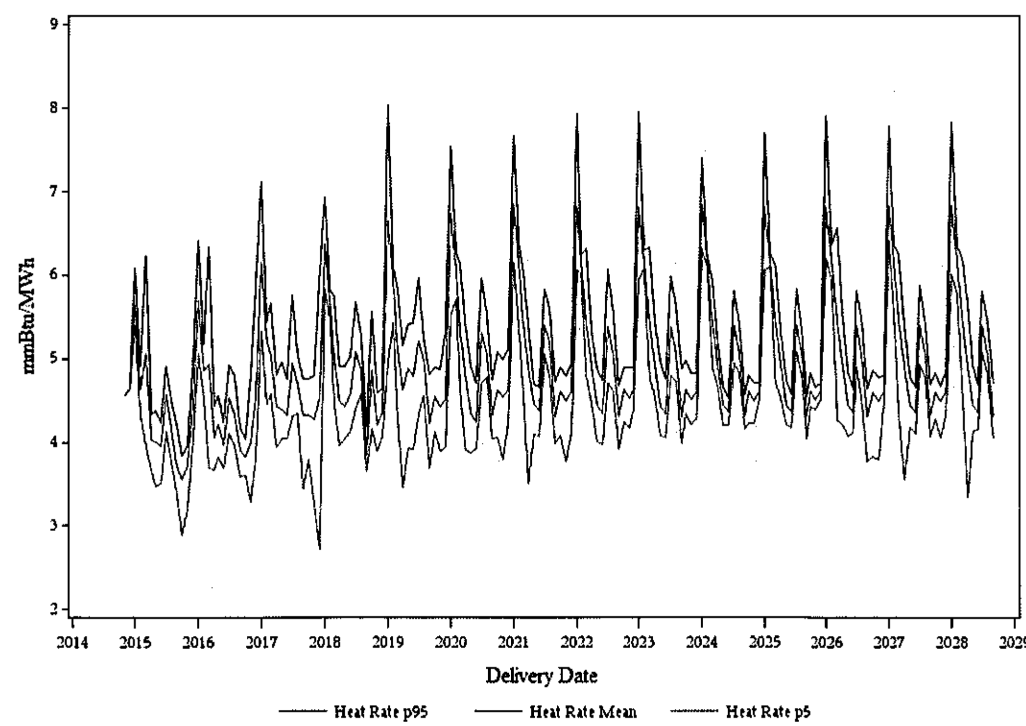


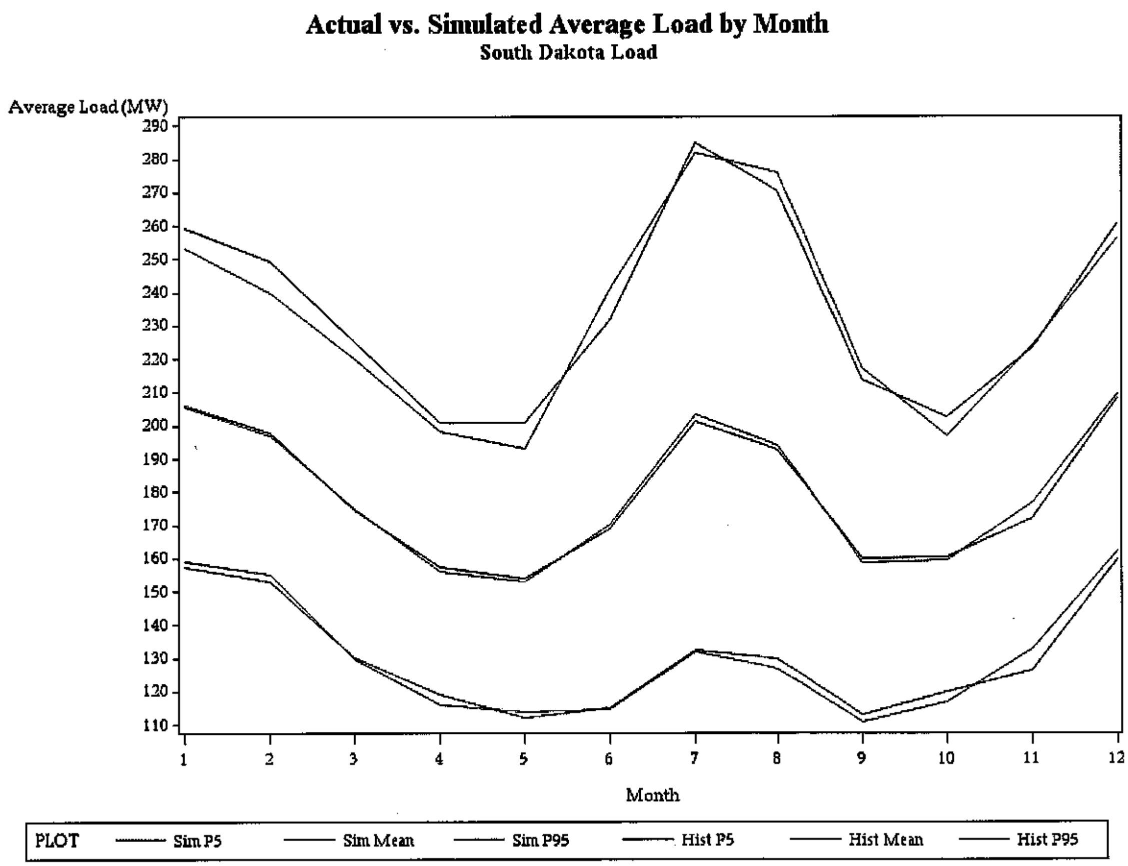
Figure 4-17 Light Load Implied Market Heat Rate Confidence Intervals



Load Projections

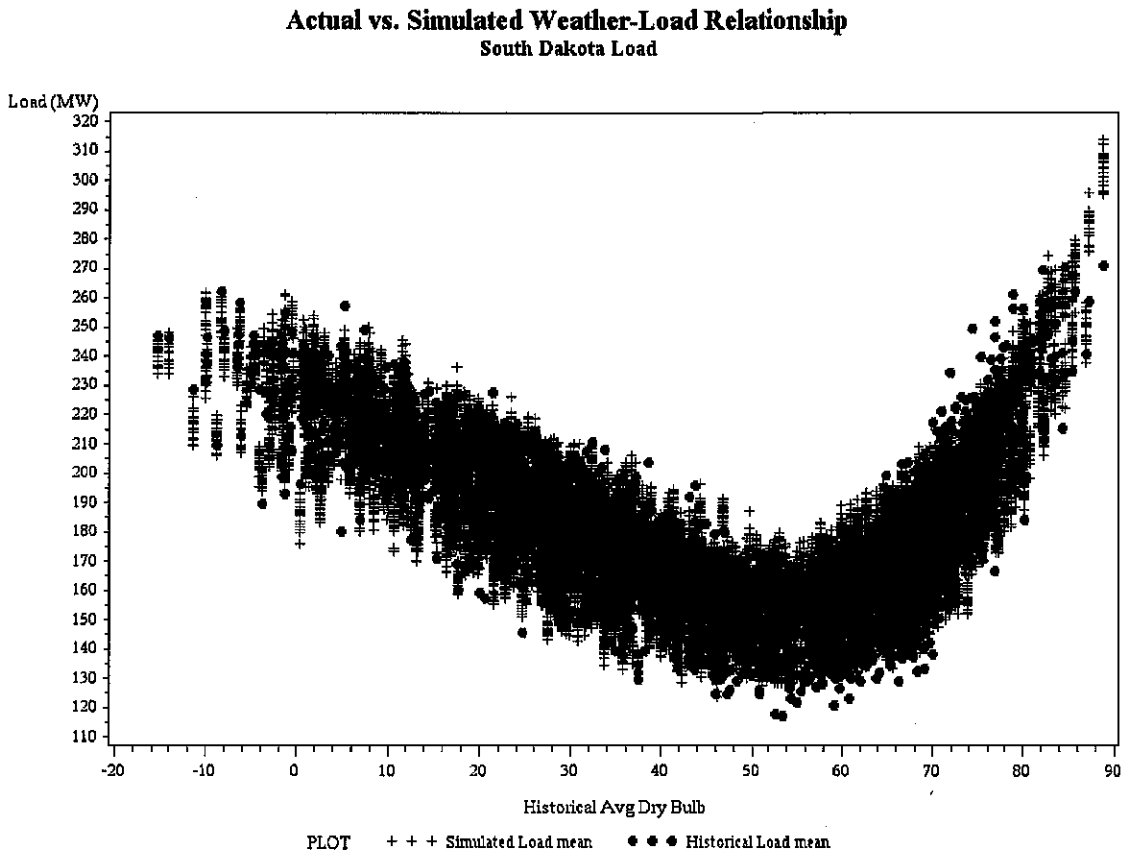
Developing accurate electricity load simulations is critical for determining cost of service, associated risks, and appropriate hedging strategies. In addition, load simulation has significant bearing on electricity prices because of the strong non-linear relationship between electricity load and prices. Figure 4-19 shows the simulated mean and the 5th and 95th percentiles for NorthWestern's load-serving obligation.

Figure 4-19 NorthWestern Actual vs. Simulated Average Load by Month



Additionally, the nonlinear relationship between load and temperature is maintained in the simulation output; electric load typically becomes elevated when the temperature is either low or high. This relationship is readily observed in both the historical data and the simulated output for load and weather, as shown in Figure 4-20. Historical data points are shown in red and simulations are shown in blue. The plot shows that the observed historical relationship is accurately captured by the simulation output.

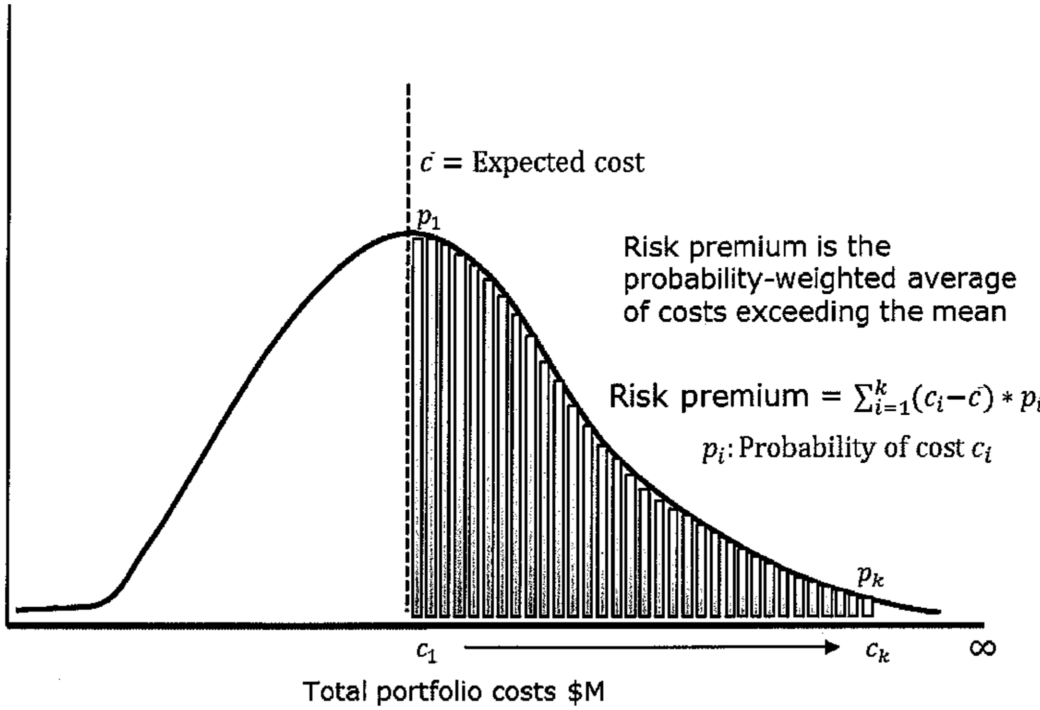
Figure 4-20 Actual vs Simulated Weather-Load Relationship



Risk Premium Definition

PowerSimm monetizes the risk that a particular portfolio is subject to by use of the risk premium, defined as the integral of the cost distribution above the mean. This is similar to the approach taken by traders to evaluate the value of an option, or by insurance companies in valuing a policy. The derivation of the risk premium is illustrated graphically in Figure 4-21.

Figure 4-21 Illustration of Risk Premium Concept



The risk premium can be added to the expected value to better approximate the full distribution of costs, and portfolios can be directly compared based on the sum of expected cost plus the risk premium. This risk metric improves upon traditional planning approaches such as cost-at-risk or efficient frontier analysis by providing a single number by which to compare portfolios, rather than requiring a planner to decide on a weighting between cost and risk.

CHAPTER 5

ENVIRONMENTAL

The Environmental Protection Agency ("EPA") has issued Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; in Proposed Rule- EPA Docket ID No. EPA- EPA-HQ-OAR-2013-0602. NorthWestern has serious concerns concerning potential impacts associated with the implementation of the proposed guidelines as drafted by EPA. On December 1, 2014 NorthWestern submitted comments to EPA to convey its concerns and to identify and explain why it opposes EPA moving forward with its proposed rule until needed modifications can be made.

The following paragraphs are taken directly from the cover letter that accompanied NorthWestern's formal written comments to EPA.

This rulemaking will fundamentally affect what the U.S. Department of Homeland Security (DHS) identifies as the one unique critical infrastructure platform upon which the fifteen other critical infrastructures all depend. According to DHS, the energy sector is unique because, "Without a stable energy supply, health and welfare are threatened, and the U.S. economy cannot function." Energy is "uniquely critical because it provides an enabling function across all critical infrastructure sectors."[1] *As the EPA carries out its important mission and addresses significant environmental concerns, it should be mindful of the utility sector's essential infrastructure stewardship obligation.*[2]

[1] Other critical infrastructures include areas such as communications, education, health care, agriculture, transportation, and emergency services. U.S. Department of Homeland Security website, Energy Sector Overview, http://www.dhs.gov/energy-sector.

[2] Please include this letter with our comments.

NorthWestern Energy is an investor-owned utility and one of the largest providers of electricity and natural gas in the northwest quadrant of the United States. We serve approximately 673,200 customers (403,600 electric and 269,600 natural gas) in Montana, South Dakota and Nebraska. Although a "mid-sized" corporation, our service territory is one of the largest in the country.

Our electric system includes 27,750 miles of electric transmission and distribution lines and serves 297 communities and surrounding rural areas covering two-thirds of Montana, eastern South Dakota, and Yellowstone National Park in Wyoming. Our natural gas system includes over 9,400 miles of natural gas transmission and distribution lines and serves 174 communities and surrounding rural areas in Montana, South Dakota and central Nebraska.

NorthWestern is honored to be the electric provider for over 344,000 Montana electric customers (roughly 75% of all Montana electric customers), and over 62,000 South Dakota electric customers. We are dedicated to our mission of "delivering safe, reliable innovative energy solutions that create value for customers, communities, employees and investors." These comments are offered in that spirit.

Although NorthWestern serves the great majority of Montana customers, we control only 8.8% of the coal generation capacity in Montana, as most of that generation is owned by non-jurisdictional utilities, a merchant operator, or a Qualifying Facility.

NorthWestern Energy has a long history of leadership in reducing greenhouse gases. More broadly, NorthWestern practices a stewardship approach to its environmental and other responsibilities. Twenty-four years ago, in 1990, NorthWestern's predecessor company in Montana, the Montana Power Company, began a voluntary greenhouse gas reduction plan to reduce carbon dioxide emissions by using demand side management programs, improving hydroelectric generation at existing hydro plants, promoting renewable energy, reducing electrical losses from generation and transmission, and implementing a forest carbon management plan.

NorthWestern Energy is proud of the energy supply mix it has assembled over the past seven years. Because of a $900 million investment in purchasing run-of-the-river dams and hydroelectric facilities, which just closed on November 18, 2014, over 50% of our Montana electricity generation portfolio consists of renewable hydroelectric and wind energy resources. That is, over 50% of our electricity generation to serve our Montana customers comes from wind and *water. As a result of that investment, our Montana carbon emissions will be reduced by 41%.*

At the Big Stone Plant in South Dakota, NorthWestern Energy, Otter Tail Power Company and Montana-Dakota Utilities Company have nearly completed installation of a $400 million dollar air quality control system which will reduce nitrogen oxide, sulfur dioxide, particulate matter, and mercury, by about 90%. This project will help all of the owners balance cost-effective base load service and environmental responsibilities (NorthWestern's Montana and South Dakota systems are not electrically interconnected).

In Montana, NorthWestern Energy has invested approximately $2.2 billion in renewable resources and cost-effective demand side management. This includes the hydro acquisition, which will provide our Montana customers long-term price stability for a significant portion of the portfolio that serves them, from a clean, renewable and carbon-free resource. It also includes $46 million in efficiency; indeed, NorthWestern is responsible for nearly 80% of all the efficiency that has been achieved in Montana. NorthWestern also participates in organizations such as the Northwest Energy Efficiency Alliance (NEEA), of which it was a co-founder, to develop and implement the next generation of efficiency investments. NorthWestern has also made significant investments in facilities to integrate intermittent resources such as wind. For example, we constructed the Dave Gates Generating Station, a supply resource which is operated to provide transmission products, to provide reliability and integration services.[3]

Unfortunately, the proposed rule inadequately credits our customers for sound past and current resource decisions. Our investments in wind, wind integration, efficiency, and now hydro result in a Montana portfolio that in 2016 will be about 40% better than the EPA goal for all of Montana in 2030, with additional opportunities for improvement over the next decade. This portfolio serves the

[3] As a result of a September 2012 Federal Energy Regulatory Commission (FERC) ALJ decision, which is now pending on rehearing, NorthWestern has reserved and potentially under-recovered approximately $27 million on the FERC-jurisdictional side of regulation service. From where we sit, the FERC, by denying NorthWestern approximately $27 million in costs associated with building and operating the Dave Gates Generating Station, which had to be constructed to meet the system's needs, including the increased wind generation in our service territory, is undermining the EPA's environmental initiatives. This highlights a key challenge under the proposed rule: The EPA must work with other federal and state agencies to ensure that policies are aligned and that parties subject to their jurisdiction are not whipsawed by inconsistent policies and decisions.

great majority of all Montanans, but with less than 9% of the coal generation. Despite NorthWestern's investments that reduce greenhouse gas emissions, and its leadership in promoting energy efficiency, the rule ignores these achievements by, for example, failing to recognize early actions before 2012 to reduce emissions, failing to include existing hydroelectric power in state compliance plans, and by assuming that the existing coal-based fleet can improve its heat rate by an average of 6 percent. NorthWestern and its customers should be rewarded, not penalized, for its leadership in generating energy from non-carbon emitting resources.

Since the proposed rule was published in the Federal Register, NorthWestern Energy has been actively engaged with EPA, state agencies, state governments, utility regulatory commissions, utilities, business groups, the Edison Electric Institute, the Coalition for Innovative Climate Solutions and others, analyzing the proposed rule. We, along with others, have worked hard to understand the proposed rule, to identify opportunities and to identify areas where more work and analysis is required before states can draft implementable compliance plans. There are challenges, some of them very significant, and the EPA has a tremendous responsibility to ensure the final rule addresses the economical, technical and physical realities as well as the environmental factors associated with delivering electricity safely, reliably and securely.

Holistic solutions to the challenges associated with the proposed Clean Power Plan will involve careful analysis and the combined efforts of states, utilities, utility regulatory commissions, institutional consumer advocates, FERC, NERC, WECC and the other regional reliability entities, RTOs, the National Security Agency and other stakeholders. NorthWestern Energy looks forward to working with EPA and other stakeholders to form representative groups of experts so the cumulative impacts associated with the proposed rule for each state and region can be properly analyzed and modeled to ensure that the emission rate goals can be achieved without compromising the reliability and affordability of electricity. The Western States Comments (October 30, 2014) were a notable contribution by eleven disparate states cooperating to raise practical questions and address them pragmatically.

These comments do not address legal questions that have been raised. We do note that there are significant authority gaps and even conflicts between multiple federal and state entities that have differing jurisdiction, divergent mandates and even disparate philosophies. Economic regulators are guided by, for example *the Hope and Bluefield[4] cases and the opportunity to earn a reasonable return, the just and reasonable rate standard, and the utility obligation to serve. Economic regulators also review utility supply portfolios and implement various portfolio requirements, along with reliability requirements, service quality requirements, and infrastructure investment and operational requirements.[5] State economic regulators generally do not have authority over public and cooperative electric providers or merchant generators, among other relevant actors. Environmental regulators, in this case, are concerned with a Best System of Emissions Reduction, and consider, for example, cost and feasibility. They do not regulate utilities qua utilities; however, decisions they make do affect utility operations, customer service and price. For an eventual version of the EPA proposal to work without significant service and price dislocations, Mars and Venus, and all of their siblings and progeny, need to talk.*

In that spirit, NorthWestern Energy submits the attached constructive comments which are focused on some of the significant practical problems and challenges associated with the proposed rule, along with recommendations/requests numbered 1 through 9.

We appreciate the opportunity to provide our comments. We greatly appreciate the time EPA has taken to meet with stakeholders during the comment period. We are available at your convenience to answer any questions you may have.

NorthWestern's formal comments to EPA are included as Appendix A.

[4] *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)

[5] On behalf of state economic regulators, the National Association of Regulatory Utility Commissioners (NARUC) has adopted several resolutions concerning framework issues for coordinating environmental and economic regulation, most notably including *Resolution on Increased Flexibility with Regard to the EPA's Regulation of Greenhouse Gas Emissions from Existing Power Plants* (NARUC, November 20, 2013).

CHAPTER 6

CONCLUSIONS AND ACTION PLAN

Conclusion

NorthWestern is faced with significant challenges associated with a changing utility and market environment driven in part by a growing fleet of intermittent renewable resources composed primarily of wind power. To address these challenges, state-of-the-art modeling techniques have been employed to analyze and answer questions about how to best meet future capacity and load growth needs under conditions of uncertainty. Moving forward, NorthWestern will use these methods to inform resource optimization and decision making.

RTO

NorthWestern will continue its transition to SPP. This is expected to be completed in October 2015. As NorthWestern gains experience in the newly formed market, it will continue to evaluate the best use of portfolio resources and apply that information to its modeling, planning, and execution of its asset optimization plan.

Energy

NorthWestern is located in the newly developed UMZ. This is the zone created by SPP to designate the addition of the Integrated System and NorthWestern into SPP. Characteristics of the UMZ and SPP footprints include: very long electric energy supply resource assets and additional renewable resources scheduled for 2015. As a result, the need for more energy-producing resources will be limited for a period of time unless current generation resources or energy demand change significantly. NorthWestern will continue to evaluate its load-serving requirements (energy, capacity and ancillary services) for its retail customers during and after the transition to SPP. As a participant of SPP, NorthWestern will tailor supply resource planning activities to fit within the definition and characteristics of the SPP market and operational protocols.

Capacity

With continued upward pressure on the levels of capacity needed to serve NorthWestern's load, NorthWestern will evaluate market availability and physical resources that would best fit NorthWestern's portfolio. Both the UMZ and SPP indicate being long capacity, however, NorthWestern's 2013 capacity RFP only yielded one offer that had a limit of 42 MW available. Once NorthWestern is a member of SPP, addition capacity may be available within the larger footprint. However, while the SPP footprint may be long capacity, transmission services to guaranteed delivery of the SPP capacity to NorthWestern's customers may not be available. Due to the lead time of constructing a facility by the beginning of 2019, NorthWestern will need to determine capacity availability shortly after transitioning to SPP.

As discussed in Chapter 4, opportunities to add resources that create additional revenues by providing ancillary services while fulfilling NorthWestern's revenue requirement may help us to identify the types of resources that should be developed. NorthWestern currently does not have assets that provide ancillary services for its generation and load service. NorthWestern may also need to add assets that can produce ancillary services to its portfolio in order to support these requirements.

Carbon

NorthWestern filed comments on EPA's proposed Clean Power Plan ("CPP") on December 1, 2014 and expressed several concerns regarding the fundamental structure of the plan as well as concerns specifically related to South Dakota and Montana. As currently proposed, the CPP could result in significant impacts to South Dakota customers and result in significant changes to this Plan. EPA is currently planning to release a final version of the CPP in June of 2015. NorthWestern cannot predict with any degree of certainty what changes, if any, will be made to the proposed CPP or what impacts the final version of the CPP will have on this Plan. NorthWestern plans to continue to take advantage of opportunities to work with EPA, SD DENR, SD PUC, EEI and other stakeholders as EPA is finalizing the CPP in order to keep current and to provide meaningful input and technical expertise. After the CPP is finalized NorthWestern will evaluate and update this Plan as necessary.

Summary Conclusions

This Plan sets the backdrop against which any future resource decisions will be considered. Existing uncertainties discussed in the Plan, such as the regulation of carbon emissions and new uncertainties, such as other regulatory considerations, will have a significant influence on future resource choices. Transmission availability, or the lack thereof, will also influence resource decisions. Furthermore, historic market changes have demonstrated the limited predictive value of natural gas price forecasts, as actual market prices have fluctuated from what best-informed analysts predicted. Other inputs have similar limitations.

Nevertheless, we expect future electricity supply costs to increase in the long term. Current low energy prices will be pressured upward by baseload facility retirements, regulatory emission requirements, transmission infrastructure additions, and energy reliability upgrades. As a result, customers should take higher future costs into account when they make decisions about home construction, insulation, appliance purchases, and their consumption behaviors.

NorthWestern's expected need to acquire incremental energy and capacity is likely to increase the portfolio's exposure by an incremental 25 MW to 39 MW by 2019. This capacity need will likely be addressed through natural gas powered generation units, market purchases, or some combination. The estimate does not include any capacity that would be required for new large customers. Current forecasted market conditions indicate that NorthWestern should utilize the market for the short term while evaluating the economic and reliability conditions that could influence the decision to add additional generation resources.

Action Plan

NorthWestern's Action Plan provides specific steps to implement the conclusions as set forth in this Plan:

1. *Presentation to the South Dakota Public Utilities Commission ("PUC").* The outline of the Plan was presented to the PUC during December 2014. NorthWestern welcomes questions and comments from the PUC.

2. *Future Capacity Contracts.* Termination of the current capacity agreement with Missouri River Energy Services ("MRES") after the summer season of 2018 will create a capacity shortfall from our portfolio beginning in 2019. NorthWestern will evaluate options to fulfill its capacity requirements. NorthWestern currently forecasts it will be 25 MW to 39 MW short in 2019 based on normal growth not including large customer additions. If the market is unable to economically or physically support, because of

transmission constraints, the capacity requirements, NorthWestern will construct additional generation resources to satisfy the requirements.

3. *Baseload Energy.* NorthWestern will continue to evaluate market opportunities for the addition of energy supply resources.

4. *Renewable Energy Resources.* To diversify the renewable resource portfolio and to achieve the renewable energy objective, renewable supply sources and energy-saving Demand-Side Management ("DSM") opportunities will be identified, and where appropriate, solicited and implemented.

5. *Carbon Emissions.* The most important issue facing the utility industry is the regulation of CO_2 emissions by EPA. NorthWestern will continue to participate in the regulatory and legislative processes to protect the interests of customers and seek acceptable environmental policies for its thermal generation facilities.

6. *Periodic Review.* NorthWestern will continue to monitor conditions and update this Plan accordingly. One known variable is the June 2, 2014 release by the United States Environmental Protection Agency ("EPA") of its Clean Power Plan Proposed Rules. NorthWestern has filed comments (Appendix A) expressing numerous concerns regarding the draft rules fundamental structure as well as concerns specifically related to South Dakota and Montana. As currently proposed, the CPP could result in significant impacts to South Dakota customers and result in significant changes to this Plan. EPA is currently planning to release a final version of the CPP in June of 2015. NorthWestern cannot predict what changes, if

any, will be made to the proposed CPP or the impacts the final version of the CPP will have on this Plan. NorthWestern plans to continue to participate in opportunities to work with EPA, SD DENR, SD PUC, EEI and other stakeholders as EPA is finalizing the CPP in order to keep current and to provide meaningful input and technical expertise. After the CPP is finalized NorthWestern will evaluate and update this Plan as necessary.

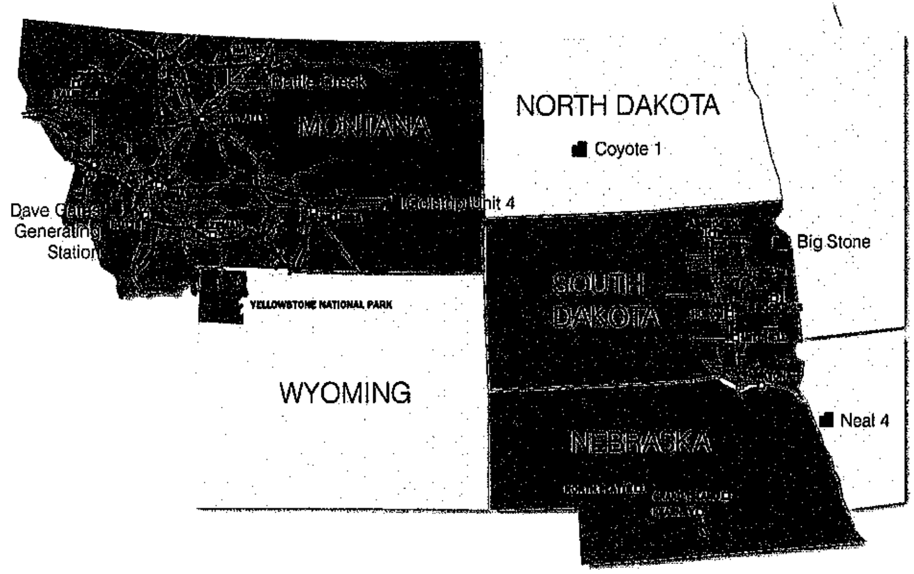
APPENDIX A

NorthWestern® Energy

Delivering a Bright Future

Comments on the Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

Docket ID Number: EPA-HQ-OAR-2013-0602
Submitted Electronically
December 1, 2014



A. Hydropower

Northwestern Energy has reduced the carbon intensity of its Montana generation fleet by 41% as a result of an approximately $900 million investment in hydroelectric generation which closed in November, 2014. An important attribute of these hydro assets and one of the key reasons this acquisition made sense, is that they are carbon-free baseload resources. Indeed, hydropower is the only cost-effective, large-scale, carbon-free baseload renewable energy source available.

EPA must recognize the real and significant carbon benefits of hydropower and the critical role of this renewable, carbon-free resource in the nation's diverse energy supply mix. In an effort to create a one size fits all paradigm, EPA's proposal fails to adequately recognize the actual carbon intensity of states, utilities and, most importantly, customers, like those of NorthWestern Energy, using this carbon-free source of electricity. In fact, EPA's methodology appears to penalize states with existing hydropower by increasing renewable energy targets and has the potential to perversely create excess generation for a utility and therefore unnecessary higher costs for customers.

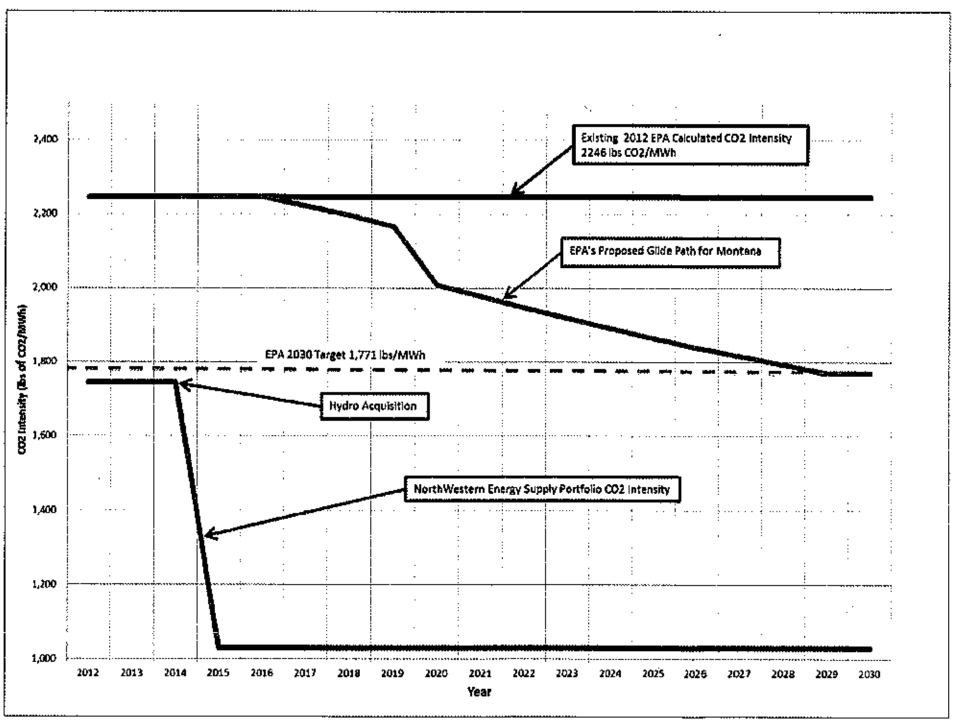
1. ***Recommendation/Request: NorthWestern Energy requests EPA recognize the importance of existing hydropower by: 1) supporting policies that recognize the many benefits of hydropower and promote its continued use, enhancement and expansion; 2) encouraging the relicensing of existing hydro facilities by allowing the carbon-free emissions from relicensed hydro plants to be used for compliance; 3) allowing states to use existing hydropower for compliance; and, 4) not penalizing states by using existing hydropower to increase renewable energy targets.***

In November 2014, NorthWestern Energy purchased 11 hydroelectric facilities from PPL Montana, including 633 megawatts of generation capacity, a storage reservoir and related assets. These existing hydroelectric facilities offer NorthWestern's Montana customers, a great majority of whom are served by NorthWestern Energy, long-term rate stability from a clean, carbon-free generation resource. Our customers are paying approximately $900 million to acquire these facilities which resulted in a 41% reduction to the carbon intensity of their portfolio. We project our customers' bills will increase approximately 5 % initially from the purchase. But in the long-term, the Montana hydro facilities will produce electricity at a predictable, stable price below the cost of buying electricity in a volatile regional market particularly as states and regions implement measures to comply with the proposed Clean Power Plan.

Our customers have already invested an estimated $1.25 billion in renewable energy since 1983 and $100 million in energy efficiency since 2004, not including the hydro acquisition. As a result of this acquisition, our Montana customers will benefit from an electric energy portfolio comprised of over 50% wind and water generation. The carbon intensity of our Montana customer's portfolio will be around 1,030 pounds of CO_2 per MWh. This intensity is less than the proposed performance standard for a new natural gas combined cycle plant.

If we simply ignore the hydropower that actually serves our customers and for which they are paying, the denominator decreases and the carbon intensity of the remaining portfolio increases to about 1,870 lbs/MWh. The following figure compares EPA's calculated baseline carbon intensity for Montana, EPA's interim and final goal and the carbon intensity of NorthWestern Energy's supply portfolio before and after the hydro purchase. Clearly, ignoring the newly acquired hydropower does not fairly or accurately represent the carbon intensity of our customer's energy supply portfolio.

NorthWestern Energy Supply Portfolio Carbon Intensity



This information illustrates actual customer impacts resulting from ignoring existing hydropower in the proposed Clean Power Pan methodology of calculating and reducing carbon intensity. Asking our customers to acquire other forms of renewables or additional energy efficiency that is not cost effective to further decrease the already low carbon intensity of their energy supply will result in additional rate increases and will likely increase the overall mass of carbon dioxide associated with our portfolio. This is due to the regulation service, typically provided by natural gas units, required for the additional energy imbalance and frequency response associated with other forms of renewable energy.

NorthWestern Energy also provides electric service for about 61,000 customers in South Dakota. Nearly 75% of the energy production in South Dakota comes from renewable sources; 50% is hydropower and about 25% is wind power. However, EPA's methodology for calculating the baseline and interim carbon intensity target also penalizes South Dakota by not recognizing hydropower for compliance purposes as part of the fleet of generating sources. Additional comments regarding the treatment of hydropower in South Dakota can be found in Section B - Renewable Energy.

As we discuss in Section B - Renewable Energy, because EPA included existing hydropower production in determining renewable energy and energy efficiency goals, EPA must not penalize states by using hydropower to increase their renewable energy and energy efficiency goals while at the same time not allowing existing hydropower to be used for compliance. If states cannot use hydropower to calculate a fair and accurate representation of their carbon intensity, EPA must develop alternatives allowing some credit for existing hydropower. One alternative NorthWestern Energy supports is the approach recommended by the state of South Dakota. South Dakota recommends following the procedure in EPA's Prevention of Significant Deterioration program where baseline emissions are established by the facility owner using a 24-month average over the previous 5 or 10 years depending on the source type. South Dakota recommends EPA allow states to use the previous 10 years to determine a baseline level of hydropower production. Hydroelectric production above the baseline would be eligible to use for compliance with the state's goals. If hydroelectric production falls below the baseline, there would be no credit for that particular year and a state would not be penalized for a low hydro year since any hydroelectric production decreases carbon intensity.

Similar to increasing power output at existing hydro facilities, EPA's final guidelines should recognize the considerable commitment associated with the FERC relicensing process and the significant contribution existing hydropower facilities make toward reducing total U.S. carbon emissions. As currently proposed, the guidelines may negatively affect an electric utility's decision on whether or not to embark on the complicated, lengthy and resource-intensive commitment required to relicense an existing hydro plant. The final guidelines should recognize the value of hydropower relicensing by allowing generation from relicensed facilities to be used by states as a compliance tool.

EPA proposed an alternative that includes existing hydropower in establishing state goals and demonstrating compliance. However, EPA's alternative approach begins with a state's 2012 hydropower production percentage then adds in the renewable goal percentage. This alternative approach presumes a state's hydropower production remains constant at 2012 levels which is not a realistic presumption and we do not support this alternative as currently proposed.
NorthWestern Energy believes EPA should emphasize the importance of existing hydropower. Hydropower is the nation's largest source of renewable electricity and EPA should support policies that recognize the many benefits of hydropower

and promote hydropower's continued use, enhancement and expansion. By ignoring the contribution from hydropower in reducing the nation's carbon intensity, EPA falsely inflates the United States' contribution to global carbon emissions

NorthWestern submits the following list as examples of the many benefits of hydropower:

- Hydropower is the only renewable energy resource capable of providing base load and required ancillary services such as load balancing and grid frequency regulation. Other forms of renewable generation are intermittent and non-dispatchable and require another associated source of generation, such as simple or combined cycle natural gas plants, to regulate grid frequency, increasing their carbon footprints. Regulation service will become increasingly important as states work to achieve the proposed renewable energy targets.

- Hydropower is used across the country, providing carbon-free renewable electricity to every state; its use is not limited to a handful of states. This is demonstrated by simply looking at the top ten hydropower producing states which include Washington, Alabama, California, South Dakota, Montana, Oregon, New York, Idaho, Tennessee and Arizona.

- Hydropower has no air emissions and does not require a large auxiliary load to operate air quality control equipment.

- Hydropower reduces carbon emissions by displacing other emitting forms of energy production more effectively than other forms of renewable energy because it can serve base loads.

- Hydropower is the only renewable energy resource that enhances and maintains the reliability, stability and security of the electric grid. Reliability, stability and security will become increasingly important as the nation's energy supply mix is changed and possibly more narrowly focused on natural gas.

- Maximizing the potential at existing hydropower facilities by adding capacity or improving efficiency will increase carbon-free generation while reducing the need for new electric and gas transmission lines, substations, compressor stations, etc.

- Maximizing the potential at existing hydropower facilities will also reduce or prevent facility siting issues associated with endangered species or species of special concern.

B. Renewable Energy

As noted previously, NorthWestern Energy has already made substantial investments in renewable energy including hydro and wind, integration of intermittent renewables, and transmission to enable renewable development. Much of this investment is not recognized in EPA's methodology.

EPA's methodology for developing renewable energy goals is not consistent and, as currently drafted, penalizes states with existing hydroelectric generation and states that have already taken actions to develop other renewable energy resources.

2. ***Recommendation/Request: EPA should recognize and not penalize states that have taken early action to develop renewable energy and recognize the many benefits hydroelectric generation. EPA should re-evaluate each state independently or allow the states to determine their own realistic renewable energy potential.***

NorthWestern Energy and our customers have already made substantial investments both in acquiring and in attempting to expand renewable energy. In 2006, NorthWestern Energy had approximately 5000 MW of new generation projects in its transmission interconnection queue in Montana, the vast majority of which were new wind generation projects seeking access to the transmission system to reach electricity markets outside Montana. In direct response to this demand for transmission service that would enable development of renewable energy projects in Montana, NorthWestern Energy, at its own risk, began development of the Mountain States Transmission Intertie (MSTI) project, a new 500kV transmission path from Montana to southeast Idaho. MSTI was intended to address the need for new electric transmission service to transmit electricity from generating sources like wind farms to loads and customers. NorthWestern halted the project in 2012, after investing $24 million and six years in the project, due to a lack of firm commitments for transmission capacity to reach markets and due to state and federal permitting processes that were daunting, expensive and without clear timelines. This example highlights a significant issue related to the Clean Power Plan renewable energy goal assumptions. Given our experience with MSTI, it is unclear to NorthWestern Energy who will finance and construct many of the new transmission lines that would be required to allow expansion of renewables, particularly on a timeline and scale contemplated in the Clean Power Plan, or who will be willing to purchase large amounts of renewable energy originating in Montana.[1]

Concerning its own supply needs, NorthWestern Energy's supply portfolio is already comprised of a substantial percentage of renewables – greater than 50 % – and has no need at this time for additional generation that cannot provide capacity, something intermittent resources are currently unable to provide.

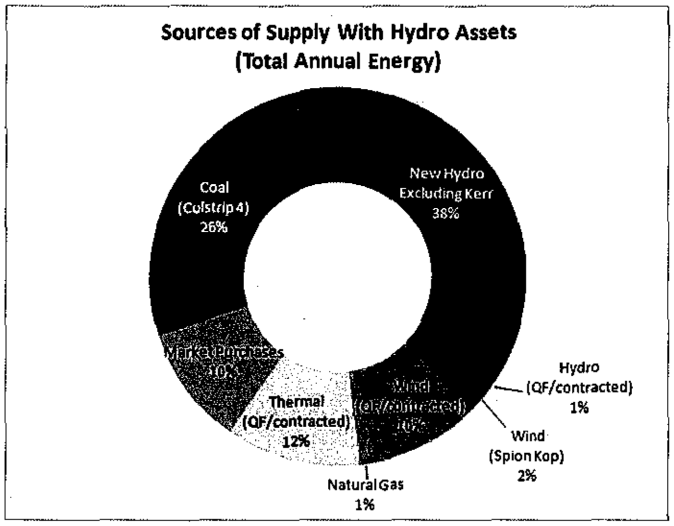
[1] To date, most western transmission projects that have moved beyond the initial development phase are enabled by connecting regulated supply to regulated load.

NorthWestern Energy and its customers have invested approximately $1.25 billion in renewable energy (this does not include the recent investment in the hydroelectric facilities discussed in our Cover Letter and Section A - Hydropower) and should receive credit for these investments. EPA's use of 2012 as a base line for establishing state goals fails to recognize CO2 reductions achieved before 2012 and results in significant inequality among states. Customers should be credited, not penalized, for already building a progressive generation portfolio. EPA must consider investments made prior to 2012 and state-by-state assessments when determining renewable energy targets and allow states, companies and customers who have taken early action to use both new and existing renewable energy to comply with the proposed goals. EPA could use an earlier baseline year or allow states to accumulate a bank between 2012 and 2020 to use for compliance in subsequent years.

In Montana, about 95% of our normal retail load is currently served with existing resources, which includes 50% combined from hydroelectric and wind generation as is depicted in the NorthWestern Energy Montana Supply Portfolio figure below. We have limited need for additional power and only for specific types of power, peak and super peak which intermittent renewables cannot currently provide. This portfolio status will be the situation until the mid to late 2020s when some power purchase contracts expire, resulting in the potential for adding some combination of additional renewables or combined cycle natural gas generation.

In South Dakota, which is second in the country for percentage generation from wind, our portfolio includes approximately 30% wind generation. South Dakota legislation establishes a voluntary goal of 10% electrical generation from renewable energy sources by 2015 and NorthWestern Energy is pleased to have already exceeded that target. Requiring our customers to pay for additional renewables integration at this point will increase rates and not result in a significant reduction in carbon dioxide emissions, particularly since integrating additional intermittent generation requires significant investment in carbon-emitting ancillary equipment (e.g., simple cycle gas plants) for grid frequency and imbalance regulation.

NorthWestern Energy Montana Supply Portfolio



EPA's methodology is not consistent and is unintentionally punitive to states where existing hydropower is used to quantify renewable energy targets but cannot be used as a method of compliance. EPA states in the proposed rule, "Hydropower generation is excluded from this existing 2012 generation for purposes of quantifying BSER related RE generation potential." However, EPA's methodology actually uses net generation, <u>including existing hydropower</u>, to calculate (i.e. quantify) RE generation potential, thereby increasing goals for renewable energy.

In South Dakota, where 50% of energy production is from hydropower, EPA calculated an annual RE target of 1,818,150 MWh, twice what the target would have been by excluding hydropower to quantify BSER related RE generation potential. Due to the way EPA determined the RE targets, South Dakota's 2020 RE goal is the same as its 2029 RE goal, and South Dakota must meet its 2029 RE goal beginning in 2020 with no ramp up period. In Montana, where 41% of energy production is from hydropower, EPA calculated an annual RE target of 2,722,706 MWh. If hydropower were excluded in order to quantify BSER related RE, the annual RE target would have been 1,652,132 MWh.

For South Dakota, EPA's proposed methodology results in a 35% reduction in CO2 emission levels in a state that contributes just .15% of the total U.S. power sector carbon dioxide emissions. This equates to about a .05% reduction in U.S. power sector carbon dioxide emissions.[2]

EPA should either evaluate each state independently or allow the states to determine their own realistic RE potential. Of course, many states are already doing this valuable work, absent federal regulation and without the threat of enforcement action. Because EPA accounted for hydropower production by including it in setting renewable energy and energy efficiency goals, EPA should not penalize states with hydropower by not allowing them to use hydropower for compliance. Instead, EPA should give states the flexibility to use existing hydropower to demonstrate compliance with the state goal. An example of a method to use hydropower for compliance is discussed in Section A - Hydropower.

Assigning renewable goals informed by regional averages and 2012 generation does not ensure realistic goals based on transmission constraints and grid reliability. EPA should conduct rigorous state-specific renewable energy

[2] http://www.eia.gov/electricity/annual/html/epa_09_05.html 2012 data

integration analyses, factoring in existing transmission capacity and reliability issues, environmental siting requirements, land use requirements and restrictions, endangered and species of special concern habitat and other factors to inform the renewable goals set for states. EPA should also consider the impact of neighboring states and regions attempting to significantly increase renewables integration within the same timeframe, which will also compound reliability and constructability related challenges.

Montana and South Dakota have great potential for wind energy, and NorthWestern has invested millions of dollars to support its development. However, planning and developing new wind projects is a complicated, time intensive process involving multiple integrated steps in order to ensure compliance with federal and state environmental regulations and land use restrictions; obtain transmission service agreements; plan and construct transmission facilities; and negotiate and finalize power purchase agreements.[3] EPA should allow states to determine their own renewable potential, including transmission availability, and integration schedules based on thorough state specific and regional analyses and interest from renewable developers. As previously mentioned, NorthWestern Energy's very costly experience attempting to expand transmission in Montana to allow additional generation, much of it wind generation, ended in a $24 million write-off and failure. It did provide valuable lessons which we will apply when considering future projects.

[3] In the non-organized western market, there is the classic chicken and egg scenario: power purchase agreements with load servers are needed by project developers in order for them to commit to transmission service agreements, thereby allowing transmission developers to proceed with their investments. Lenders require developers to show that they have firm transmission service to deliver the product to consumers. One is dependent on the other.

C. Energy Efficiency

With the recent hydro acquisition, NorthWestern Energy has invested approximately $2.2 billion in renewable resources and cost-effective demand side management which includes $46 million in energy efficiency. NorthWestern is responsible for nearly 80% of all the energy efficiency that has been achieved in Montana. NorthWestern also participates in organizations such as the Northwest Energy Efficiency Alliance (NEEA), of which it was a co-founder, to develop and implement the next generation of efficiency investments.

EPA's methodology for developing energy efficiency (EE) goals is not consistent and penalizes states, companies and customers that have already made significant investments to develop and implement demand side management (DSM) energy efficiency programs

EPA should recognize that the pool of achievable, cost-effective EE is not infinite and that utilities that have been operating aggressive programs have much fewer opportunities. Continuation and expansion of DSM energy efficiency programs must be carefully evaluated because the value of the savings is measured primarily by avoided electricity costs, and determined by state economic regulators. Available cost-effective EE savings will change as cost effectiveness changes.

3. ***Recommendation/Request: EPA should recognize and not penalize states, companies and customers that have taken early action by allowing use of past and present programs for compliance purposes. The EPA should use state-specific information to establish realistic, cost-effective, state-specific energy efficiency savings rates taking into consideration past and existing efficiency programs as well expectations for future***

programs. As the following section explains, NorthWestern Energy customers in Montana have already made significant investments in EE and NorthWestern believes maintaining the current level of cost effective EE savings for its customers into the future is unlikely.

NorthWestern Energy offers by far the largest suite of DSM energy efficiency programs in Montana and does not believe that its' efficiency programs can achieve and sustain the EPA proposed annual goal of 1.5% of retail sales. NorthWestern Energy and our customers have already made substantial investments in demand side management programs, investing over $100 million over the past several years.

NorthWestern Energy is a co-founder of the Northwest Energy Efficiency Alliance (NEEA) and is currently working to develop and implement the next generation of efficiency investments. NEEA is a voluntary alliance of all 142 utilities, consumer- and investor-owned, in the four Northwest states of Idaho, Montana, Oregon and Washington. In collaboration with its partners, NEEA leads regional market transformation efforts to accelerate adoption by 13 million residential, commercial and industrial electricity consumers of energy efficiency products, systems and practices. In the last 18 years, savings of 1,155 average megawatts - about 20 percent of energy savings in the four Northwest states, the equivalent of the output of two coal-fired plants - are attributable to the market transformation work of NEEA and its partners. [4]

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[4] In their comments to EPA regarding this docket dated November 26, 2014, NEEA explains how a market transformation program has gained solid acceptance in the Pacific Northwest. NEEA supports EPA's recognition of the important contributions that market transformation measures and codes and standards can make to energy efficiency and the use of such measures in compliance plans.

NorthWestern, and its predecessor, the Montana Power Company (MPC), have a long history of implementing broad-based, successful DSM programs for the benefit of their customers, and have been the leaders in that regard among utilities in Montana, and across the country. Over the past 10 years alone, NorthWestern's programs have, on average, produced approximately 6 aMW (approximately equal to 1% of retail sales) of savings per year.

MPC commenced its DSM efforts in 1978 in response to the 1978 National Energy Conservation Policy Act with an on-site residential energy audit. A commercial program and additional residential programs were added in 1987. From 1990 through 1998, MPC's DSM activities were driven by least cost planning efforts in which the cost effectiveness of DSM savings was judged against MPC's avoided electric costs. MPC's suite of DSM programs was expanded and promoted to all MPC customers during that time.

During the mid to late 1990s the movement toward competitive electricity supply markets created uncertainty regarding the value of DSM from the utility perspective. In response, in 1997, Montana established funding for Universal System Benefits ("USB") programs, which included on-going financial support for the energy conservation programs that exist today.

So for NorthWestern, and its pursuit of energy efficiency savings from and for its customers, these types of programs have been actively in place for 36 years.

NorthWestern is required to operate cost effective DSM programs. That is, the value of the savings produced by the energy efficiency measures that are included in the programs, and the programs themselves, must be greater than their costs. The value of the savings is determined primarily by NorthWestern's avoided electricity costs which are established in the context of NorthWestern's electric procurement planning process. It is critical that this cost effectiveness criteria be met. Otherwise, customers would pay more for DSM savings than the alternative electricity supply option, resulting in electricity supply costs that are greater than they would otherwise be.

DSM program costs are paid for by customers as part of their overall electricity supply costs. Programs and costs receive a high-level of review and scrutiny before the Montana Public Service Commission ("MPSC") each year.

NorthWestern submitted its first electric Default Supply Resource Procurement Plan in 2004 ("2004 Plan") in accordance with governing statutes and MPSC administrative rules. The 2004 Plan identified approximately 100 aMW of achievable cost effective DSM and established annual DSM savings targets of 5 aMW starting in 2007 after providing for a three year ramp-up period to grow from the 2 aMW produced annually by the USB programs at the time. From the 2006-2007 tracker year through the 2009-2010 tracker year NorthWestern's USB and DSM programs produced almost 6 aMW of savings per year on average.

More recently, NorthWestern's 2009 Electricity Supply Resource Procurement Plan identified 84.3 aMW as the amount of remaining achievable, cost effective electric DSM and established NorthWestern's annual DSM acquisition goal at 6.0 aMW per year – approximately 1% of retail sales. NorthWestern has acquired approximately 32 aMW of cumulative DSM savings since the 2009 DSM plan was implemented beginning in 2010. Assuming it could all be acquired by 2030, the remaining 52.3 aMW of cumulative DSM savings (84.3 aMW – 32 aMW) represents about 7.6% of NorthWestern's current retail electricity supply sales.

NorthWestern has exceeded 6.0 aMW of savings for each of the past six tracker years, peaking in the 2011-2012 tracker period at more than 9 aMW. Since the 2011-2012 tracker year, however, year-over-year program savings have decreased markedly to approximately 7.5 aMW and 6.8 aMW in the 2012- 13 and 2013-14 tracker years respectively. Three reasons for this trend and why NorthWestern does not believe its DSM programs could achieve EPA's energy efficiency goals include: 1) the past successes of NorthWestern and MPC's long-standing DSM programs; 2) decreasing avoided costs; and, 3) federal legislative developments that continue to reduce the future contribution that energy efficiency lighting can make to annual DSM results.

The pool of achievable, cost effective DSM is finite (reference the 84.3 aMW of DSM identified in the 2009 Plan, for example). As customers implement EE measures due to our programs, the pool of remaining opportunities for efficiency improvements shrinks, making it increasingly difficult to continue to achieve constant year-over-year savings goals of 6 aMW.

Eligible DSM measures, achievable cost-effective DSM potential, proper DSM program rebate/incentive levels, and expenditure levels for various other DSM program activities such as marketing and outreach must be evaluated against electricity supply avoided costs. In short, lower avoided costs translate to reduced achievable cost effective DSM potential and put downward pressure on DSM program savings results. The DSM plan developed in 2009 was based on the then current 20-year levelized avoided cost of approximately $70 per MWh. The 2013 Electric Resource Procurement planning cycle produced a 20-year levelized avoided cost of approximately $44 per MWh.

New federal regulations relating to compact fluorescent lamps (CFLs) and other lighting technologies began phasing in over a three-year period starting January 1, 2012. In certain applications CFLs will continue as a cost-effective efficient replacement lighting technology for certain applications (e.g. for halogen lamps), but the amount of CFLs rebated through the DSM lighting programs will diminish significantly.

Because of the lack of additional cost-effective programs, NorthWestern has not forecast increasing its annual DSM savings goal. In fact, because of the issues just discussed, we are concerned that achieving 6 aMW per year of cost-effective DSM savings into the future is unlikely. In any event, we expect the recent trend of decreasing program savings to continue, at least in the near term, absent stabilized or increased avoided costs and/or the appearance of a "new" cost-effective energy efficiency technology or technologies.

In the broader context for the state of Montana, NorthWestern has no way of projecting the energy savings potential or pace of savings for large electric customers who are deemed "Choice customers". Most industrial customers on NorthWestern's delivery system purchase their electricity in the wholesale market and are not part of NorthWestern's annual retail sales. Additionally, NorthWestern has no way of projecting the energy savings of the other regulated utilities or the rural electric co-ops that serve large portions of the state. These two points are added because much of the remaining energy efficiency potential in Montana is beyond NorthWestern Energy's scope or control.

The Clean Power Plan should recognize and not penalize states, companies and customers that have taken early action by allowing use of past and present programs for compliance purposes. The EPA should use state-specific information from utility regulatory commissions and companies with significant experience like NorthWestern Energy, to establish realistic, cost-effective, state-specific energy efficiency savings rates taking into consideration past and existing efficiency programs.

Developing cost-effective energy efficiency is an area where coordination among the environmental regulator, the economic regulator and the institutional consumer advocate are essential. Utility programs are the largest provider of cost-effective energy efficiency. Too often, these efforts are not adequately supported by state policy, and the consumer advocate may even be hostile to necessary policies that support these essential programs.

D. Building Block 1 - Heat Rate Improvements

EPA's assumption that the existing coal-based EGU fleet can improve its heat rate by an average of 6 %, through a combination of improved operation and maintenance (O&M) and equipment upgrades is based on unreliable, inconsistent data and is not realistic.

4. ***Recommendation/Request: EPA must re-evaluate the methodology used to determine the target heat rate improvement (HRI) of 6%, specifically the proposed method of using historic heat rate data computed from continuous emissions monitoring systems (CEMS). EPA should use site-specific data to determine a particular unit's ability to further improve heat rate, including recognition of efficiency improvements already undertaken and the loss of efficiency gains from implementation of other environmental upgrades, rather than assumptions based on an analysis of heat rates calculated using stack flow data from CEMS.***

EPA must address the following issues and provide more situational specific heat rate improvements:

- Decreases in heat rates translate to decreases in cost of operation. It is common practice for owners and operators of coal-fired power plants to analyze and employ cost-effective measures to improve efficiency through both capital and O&M projects. Many power plants may already be operating at peak efficiency and may have already implemented many or all of the equipment upgrades, operations and maintenance procedures included in the 2009 Sargent & Lundy report.

- Each state should require coal-fired power plants to submit a HRI report to identify measures that have already been implemented and those that may still be accomplished and adjust their interim carbon intensity targets accordingly.

- Future technological advances may make additional HRI improvement possible and EPA should consider this while developing interim state carbon intensity targets and not assume that all HRIs will be implemented within the next few years.

- Implementing measures to ensure that New Source Review (NSR) concerns do not discourage heat rate improvements at existing coal-fired power plants. Capital projects designed to assist with unit efficiency improvements have historically been the subject of litigation filed by EPA and third party environmental groups against coal-fired electric utilities. In the Proposed Rule, EPA explains that a state could "develop conditions for a source expected to trigger NSR that would limit the unit's ability to move up in the dispatch enough to result in a significant net emissions increase that would trigger NSR (effectively establishing a synthetic minor limit)." In other words, EPA suggests that fossil fuel-fired units can avoid triggering NSR by limiting their utilization such that there is no increase in annual emissions. EPA's proposal that some sources could avoid NSR through synthetic minor limits is not a viable option.

- Increases in heat rate due to air quality control equipment installed due to other federal regulations. For example, it appears EPA did not consider the decrease in heat rate efficiency resulting from power plants complying with the federal Regional Haze Program.

- The effect of shifting generation from coal-fired EGUs to NGCCs and to renewables will have on the heat rates. As coal fired EGUs are utilized less, heat rates will degrade, negating HRIs and possibly stranding the investments made to implement HRIs.

- Heat rate improvements do not remain constant, but degrade over time, ultimately increasing the rate and mass of CO_2 emissions. EPA has falsely assumed heat rate improvements will remain constant.

- EPA should allow for recent efficiency projects at coal plants to be used for compliance.

The Association of Mechanical Engineers has specific Performance Test Codes (PTC) for steam turbine-generators which include test procedures that result in the highest level of accuracy consistent with the best engineering knowledge and practice in the steam turbine industry. A performance test conducted in accordance with the appropriate ASME PTC is the most accurate method of determining turbine-generator performance. Initial thermal acceptance tests can be performed using PTC – 6 "Steam Turbines" while periodic tests can be performed using PTC – 6S "Simplified Procedures for Routine Tests of Steam Turbines." PTC – 6 requires the use of calibrated instrumentation and controlled measurement procedures and PTC -6S aids in developing procedures to monitor performance. The Utility Air Regulatory Group (UARG) concluded in their report entitled "*CRITIQUE OF EPA's USE OF REFERENCE UNITS TO SELECT HEAT RATE REDUCTION TARGETS*" prepared by J. Edward Cichanowicz and Michael C. Hein:

> *"The takeaway from this experience is that CEMS-derived gross heat rate data are an inadequate basis from which to judge modest changes in heat rate. As noted, year-to-year changes can be highly variable. The numerous observations regarding the role of stack gas flow monitor calibration in what might appear to be heat rate changes – where major reductions in*

gross heat rate are reported co-incident with routine annual recalibration or a change in test methods used for calibration – support the conclusion that CEMS-derived heat rate data are significantly influenced by factors unrelated to actual changes in heat rate. ***The most reliable way to gauge the payoff of heat rate improving investments is through thermal performance monitoring*** *[Emphasis added]."*

NorthWestern Energy concurs with UARG. Using CEMS-derived heat rate data is not an appropriate method to use to determine a fleet wide HRI average. Each coal-fired power plant is unique and each plant should be analyzed on a case-by-case basis to identify the measures that have already been implemented and realistic heat rate improvement goals.

Many power plants may already be operating at peak efficiency and may have already implemented the equipment upgrades and operations and maintenance procedures included in the 2009 study by Sargent & Lundy. Otter Tail Power Company submitted detailed comments regarding the 475-megawatt Big Stone Plant in South Dakota which NorthWestern Energy co-owns with Otter Tail and Montana-Dakota Utilities Company.

NorthWestern Energy supports the comments filed by the Otter Tail Power Company regarding the Big Stone Plant, a portion of which are summarized and highlighted in the following bulleted paragraphs.

- EPA asserts that it is possible under Building Block 1 to achieve overall HRIs of 6% (or 4% under the alternate goals) **on average** at existing coal-fired EGUs. Big Stone Plant is the only coal-fired EGU operating in South Dakota. Therefore, South Dakota's ability to attain the 6% (or alternate 4%) HRI required by the proposed rule depends entirely on the Big Stone Plant.

- Given EPA's building block 2, increasing output from natural gas fired combined cycle plants while correspondingly decreasing the output from coal plants, and the fact that Big Stone is South Dakota's only coal plant, obtaining heat rate improvements while decreasing plant efficiency through decreased generation output, is entirely unrealistic.

- Big Stone Plant has already made, or plans to make in 2015, all applicable HRIs identified in the Sargent & Lundy report and it should not now be penalized for early, proactive measures to improve plant efficiency and reduce emissions prior to EPA's announcement of the Clean Power Plan. The table on the following page compares the HRIs Big Stone Plant has already implemented, or plans to implement within the next year, to the HRIs identified in the Sargent & Lundy report.

- Big Stone Plant is currently installing a $384 million state-of-the-art air quality control system (AQCS) to comply with EPA's Regional Haze and MATS rules. The AQCS system is energy intensive using an estimated 8 or 9 MW of the energy produced by Big Stone Plant, increasing the plant's net heat rate by approximately 1.7%. In the best case scenario, the two remaining planned HRI projects at Big Stone Plant will merely offset this degradation and return Big Stone Plant to its baseline heat rate.

- By applying this 6% average HRI to all EGUs in a state without consideration of unit-specific limitations, EPA violates its statutory obligation to allow states to conduct unit-specific assessments in establishing standards of performance for existing sources.

HRI Measures Identified in Table 2-13 of EPA's GHG Abatement Measures TSD

Practice/Project	Available at Big Stone Plant?	Comments
Condenser Cleaning	No	Big Stone Plant uses a cooling pond and also
Intelligent Soot Blowers	No	Installed in 2011

Electrostatic Precipitator (ESP) Modification	No	N/A to Big Stone Plant
Boiler Feed Pump	No	Already overhauled as needed
Air Heater and Duct Leakage Control	No	Already routinely addressed
DCS Replacement	No	Already upgraded twice, most recently in 2011
SCR and FGD System Modification	No	N/A to Big Stone Plant
Cooling Tower Advanced Packing	No	N/A to Big Stone Plant
Economizer	Yes	Will be accomplished in 2015
Acid Dew Point Control	No	N/A to Big Stone Plant
Combined VFD and Fan	Yes	Will be accomplished in 2015
Turbine Overhaul	No	Already accomplished

Clearly, it is neither practical nor feasible to expect Big Stone Plant to attain the additional 6% HRI contemplated by the proposed rule. The lack of a site-specific evaluation of feasible HRI at this plant demonstrates that the EPA's across-the-board 6% HRI target is arbitrary and capricious.

E. <u>Building Block 2 –Re-dispatch to NGCC</u>

EPA assumes that, on average, each state's existing natural gas combined cycle (NGCC) fleet, including NGCC units under construction as of January 8, 2014, can increase utilization to 70 percent in order to reduce carbon dioxide mass emissions from higher-emitting EGUs by shifting generation to existing NGCC units.

The assumptions underlying building block 2 perhaps most clearly illustrate the problems associated with creating carbon reduction approaches based upon generic assumptions supposedly applicable to all states. For South Dakota the assumptions that existing NGCC units can increase generation to achieve a 70% capacity factor and that the increase in NGCC generation will displace generation from in-state steam units are not practical or reasonable or based on sound analyses. EPA did not analyze several critical unit, state and interstate specific information including but not limited to: grid stability and reliability, NERC critical infrastructure protection, long term power supply contracts, contractual relationships between NGCC units and steam units including units owned by multiple parties, gas and electric transmission capacity, electric transmission rights, gas and electric transmission equipment upgrades and/or changes, natural gas availability, natural gas supply contracts, dependable unit capacity, and units dispatched by different RTOs.

5. ***Recommendation/Request: EPA should re-analyze Building Block 2 by involving plant owners, RTOs, Balancing Authorities, FERC, NERC, WECC, states and other stakeholders to determine the feasibility and limitations of Building Block 2 for each state including consideration of the interstate relationships between generation and loads.***

The basis of EPA's analysis regarding the feasibility of implementing Building Block 2 is not detailed, accurate or reasonable. As an example, NWE suggests considering the application of Building Block 2 in the state of South Dakota.

Otter Tail Power Company submitted detailed comments regarding the application of Building Block 2 in South Dakota and the Big Stone Plant. NorthWestern Energy co-owns the 475 MW Big Stone Plant with Otter Tail Power Company and Montana-Dakota Utilities Company. NorthWestern Energy supports the comments filed by the Otter Tail Power Company regarding Building Block 2 and the Big Stone Plant, a portion of which are summarized and highlighted in the following bulleted paragraphs.

- South Dakota has only one coal-fired unit, the Big Stone Plant, and one NGCC unit, the Deer Creek Station. Big Stone Plant generates a significant portion of the energy the co-owners use to serve customers in four states: Minnesota, North Dakota, South Dakota, and Montana. The 324 MW Deer Creek Station is owned by Basin Electric Power Cooperative who serves customers in nine states: Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming.

- Big Stone Plant and Deer Creek Station were built for unique reasons by different owners and there is no contractual relationship between the owners of the two plants. Each plant is operated for the purpose of meeting each owner's own electric loads. EPA mistakenly assumes the energy generated by Deer Creek Station is available for use by the customers of Big Stone Plant.

- Big Stone Plant and Deer Creek Station are dispatched by different RTOs making redispatch of Deer Creek Station in place of Big Stone Plant infeasible. Big Stone Plant is interconnected to the Midcontinent Independent System Operator (MISO). Big Stone Plant co-owners offer or schedule the energy through the MISO market, giving MISO operational control of Big Stone Plant. Deer Creek Station is currently located within the Integrated System (IS) of the Western Area Power Administration, Basin Electric, and Heartland Consumers Power District. The Integrated System is expected to join the Southwest Power Pool (SPP) in 2015, at which time SPP will assume operational control over Deer Creek Station. RTOs commit and dispatch generation within their footprints to ensure reliable operations by balancing supply and demand and there is no current method that allows an RTO to dispatch a unit located in a different RTO. EPA falsely assumes Deer Creek Station will be dispatched to meet the needs of the Big Stone Plant co-owners' loads.

- The transmission infrastructure was not designed to support the transmission of energy from Deer Creek Station to customers of the Big Stone Plant co-owners. Currently there is adequate transmission capability and infrastructure to support delivery of Big Stone Plant generation to its retail customers and Deer Creek Station generation to its customers. Detailed engineering studies and modeling would be necessary to determine transmission paths, adequacy of the transmission system, and any necessary additions and/or upgrades. Furthermore, Deer Creek Station would need to acquire transmission service to serve the retail customers of the Big Stone Plant located in Montana, South Dakota, Minnesota and North Dakota.

The complex nature of the bulk electric system and interaction between and among electric generation, load centers, wholesale electricity markets, and gas and electric transmission systems warrants a careful holistic analysis. EPA must re-analyze Building Block 2 involving plant owners, RTOs, Balancing Authorities, FERC, NERC, WECC, states and other stakeholders to determine the feasibility and limitations of Building Block 2 for each state including consideration of the interstate relationships between gas and electric transmission, electric generation and load centers.

F. Reliability and Security

NorthWestern Energy operates a transmission system and balancing authority area (BAA) in Montana under the mandatory reliability requirements of the North American Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("WECC"). These mandatory reliability criteria require NorthWestern to operate within tight tolerances and operating levels regarding the transfer of power within its BAA and to other BAA's that are interconnected to our system. We are also required to balance, on a moment to moment basis, the available resources to meet the electrical demand within the BAA. These criteria are dependent upon and driven by, not only the transmission configuration and characteristics, but also on the type, size and variability of generation sources interconnected to the transmission system. The electrical reliability and security of transmission systems and BAAs can be greatly impacted by significant changes in the mix of generation facilities interconnected to the system. It is with these responsibilities and obligations in mind that we present the following comments.

Reliable and secure electric generation and transmission are essential to national security and the economy. EPA is proposing sweeping unprecedented changes to the interconnected power system, including the natural gas transmission system, yet has not conducted a baseline study of the cumulative interstate and intrastate effects of the proposed building blocks on stability, reliability and security.

6. ***Recommendation/Request: It is essential, prior to issuing a final rule, for EPA to undertake reliability analyses to assure that there is no disruption in the reliability and security of the interconnected power system. The proposed guidelines and compliance period do not adequately account for the complexity of the interconnected power system nor do they sufficiently address how the need to maintain reliability affects the timing of implementing such changes. Working with states, FERC, NERC, WECC, RTOs, the National Security Agency and other stakeholders, EPA must analyze and model proposed implementation plans and the cumulative effects of the building blocks and/or other proposed state compliance mechanisms, both interstate and intrastate, to ensure, to the extent possible, there will be no detrimental effects to the reliability and security of the interconnected power system. The electric and gas industry should be invited to provide electric and gas system modeling and expertise regarding the impact to reliability of proposed implementation. Without such modeling, stakeholders cannot appropriately evaluate the proposal and the complex interactions between states and regions.***

   Additional flexibility for states in implementing compliance plans is necessary. As plans are implemented, there will be unexpected

and unintended consequences and EPA must allow states to address these by revising their compliance plans as necessary. States should not be locked in to a particular approach as there are simply too many variables associated with the interconnected power system and the proposed Clean Power Plan.

Under the Federal Power Act, FERC has jurisdiction to promulgate and enforce mandatory reliability standards for the bulk-power system, a power that FERC has delegated to the North American Reliability Council (NERC). Reliability standards are designed to ensure reliable operation of the bulk-power system. For example, in regions with RTOs, if a generation facility proposes to retire (or will close due to redispatch), the relevant RTO must determine whether the retirement of that facility will result in the violation of a NERC reliability standard or otherwise jeopardize the reliable operation of the bulk-power system. If a System Operator determines that retirement of a facility will jeopardize the reliable operation of the bulk-power system, the System Operator may require that the facility continue to operate.

In the western U.S. there are few RTOs. Instead there are 38 interconnected balancing areas (BAs), one of which is NorthWestern Energy, and each BA is responsible for continually balancing supply and demand (i.e., generation and load) in their respective areas. The Western Electricity Coordinating Council (WECC) is responsible for coordinating grid reliability of the Western Interconnection. Each BA in the Western Interconnection is responsible for matching net actual interchange and scheduled interchange for its interconnections with other BAs on a 4-second basis and complying with mandatory NERC performance standards. BAs are not distinct geographical areas, which adds additional complexity to the process used to continually match supply and demand. For example, the Colstrip Plant in Montana is in 5 separate

BAs because the generation from Colstrip is used for serving load centers in several states. As this example illustrates, Clean Power Plan compliance plans in one state can and will impact several states, highlighting the need for the EPA to work with WECC and all stakeholders to analyze and model the complex interaction of proposed state compliance plans.

In its Initial Reliability Review of the proposed guidelines, NERC affirms that the proposed guidelines will require major changes to the way the interconnected power system is planned and operated in order to ensure reliability while achieving emission reductions. NERC states that the proposed guidelines "introduce potential reliability concerns that are more impactful than prior environmental compliance programs due to the extensive impact to fossil-fired generation." In particular, NERC notes that the proposed guidelines do not recognize the need to expand and enhance the transmission grid and that the guidelines do not address grid reliability issues associated with increased variable resources and retirement of fossil-based generation:

> *Conventional generation (e.g., steam and hydro), with large rotating mass, has inherent operating characteristics, or ERS, needed to reliably operate the BPS. These services include providing frequency and voltage support, operating reserves, ramping capability, and disturbance performance. Conventional generators are able to respond automatically to frequency changes and historically have provided most of the power system's essential support services. As variable resources increase, system planners must ensure the future generation and transmission system can maintain essential services that are needed for reliability.*

It is important to note and as described above, replacement of thermal (coal) fired conventional plants with variable renewable resources does not, by itself, result in maintaining reliability in the interconnected transmission system. This is the case generally and holds true for NorthWestern Energy's system.

EPA is proposing sweeping unprecedented changes to the interconnected power system, which received a D+ from the American Society of Civil Engineers (ASCE) in its 2013 Assessment of America's Infrastructure report, without conducting a comprehensive reliability and system security assessment.

The ASCE states:

> *"Energy: America relies on an aging electrical grid and pipeline distribution systems, some of which originated in the 1880s. Investment in power transmission has increased since 2005, but ongoing permitting issues, weather events, and limited maintenance have contributed to an increasing number of failures and power interruptions. While demand for electricity has remained level, the availability of energy in the form of electricity, natural gas, and oil will become a greater challenge after 2020 as the population increases. Although about 17,000 miles of additional high-voltage transmission lines and significant oil and gas pipelines are planned over the next five years, permitting and siting issues threaten their completion. Thus, the grade for energy remained a D+."*
>
> *"Conclusion: Infrastructure is the foundation that connects the nation's businesses, communities, and people, driving our economy and improving our quality of life. For the U.S. economy to be the most competitive in the world, we need a first class infrastructure system – transport systems that move people and goods efficiently and at reasonable cost by land, water, and air; transmission systems that deliver reliable, low-cost power from a wide range of energy sources; and water systems that drive industrial processes as well as the daily functions in our homes. Yet today, our*

infrastructure systems are failing to keep pace with the current and expanding needs, and investment in infrastructure is faltering."

It's also important to note that the U.S. power sector already faces serious cyber security threats. Recently, Admiral Michael Rogers, director of the National Security Agency and head of U.S. Cyber Command, testified before a House Intelligence Committee hearing on cybersecurity threats that other countries are currently capable of launching cyber-attacks that would shut down the electric grid. EPA must work with the NSA, Homeland Security and all stakeholders to ensure implementation of the Clean Power Plan, with its heavy reliance on natural gas, does not exacerbate this situation.

G. Remaining Useful Life

EPA proposes that the remaining useful life of affected EGUs should not be considered as a basis for adjusting state goals or the timelines to achieve the proposed goals. EPA proposes to prescribe how electric generating units are dispatched irrespective of remaining useful life or stranded costs and financial impacts. EPA's assessment "that the issue of remaining useful life will arise infrequently in the development of state plans to limit CO2 emissions from affected existing EGUs" is inaccurate. EPA has not adequately considered the impacts of forced closures of fossil-fired units with substantial remaining useful life, and the associated impacts on consumers and the economy related to stranded asset costs.

7. ***Recommendation/Request: EPA must recognize the remaining useful life of EGUs, including the effect on remaining useful life of recent upgrades and major pollution control installations, when setting standards of performance in order to avoid stranded asset problems. EPA must defer to state authority to determine the***

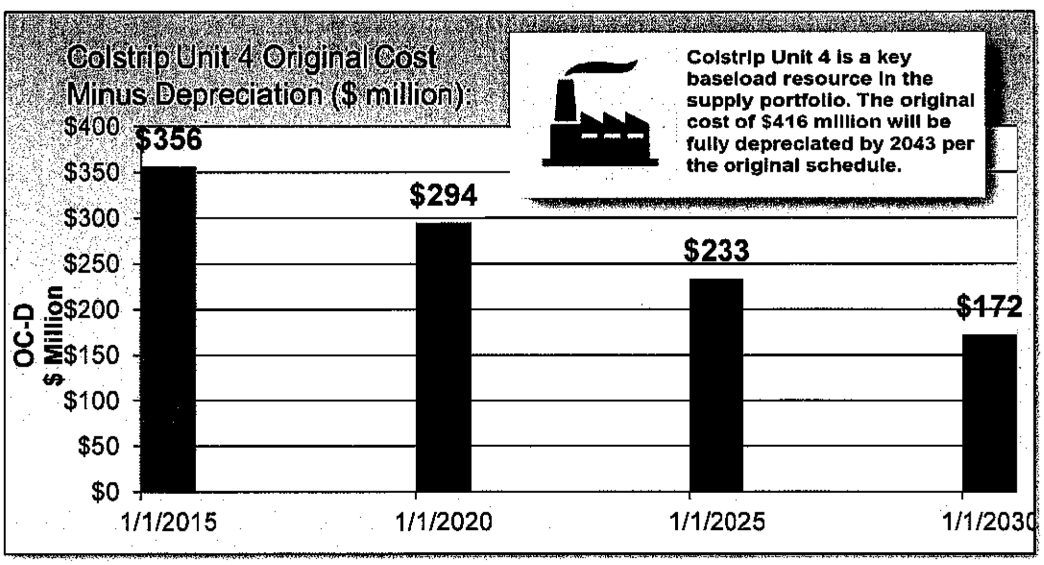
feasibility and timing of redispatch (Building Block 2) and integration of new generation considering, among other things, remaining useful life of existing EGUs.

NOTE: EPA issued a Notice of Data Availability (NODA) that was published in the Federal Register on October 30, 2014. In the NODA, EPA seeks comment on considering the book life of existing generation assets including any major upgrades to the assets like pollution control retrofits. Since EPA published the NODA just one month before the deadline for submission of comments on the proposed rule, stakeholders have not had adequate time to fully understand the implications of the NODA in relation to the proposed rule. Issuing a NODA that late, particularly since the proposed rule is likely the most complex rulemaking ever undertaken by the EPA, does not appear to comply with EPA's obligation under the Administrative Procedures Act and Clean Air Act. EPA should allow additional time for stakeholders to fully assess the NODA.

EPA is required by statute to permit states to consider remaining useful life in setting and modifying standards of performance for individual units. EPA has no discretion to deviate from these clear statutory terms and eliminate or restrict state authority to consider remaining useful life. EPA takes an unprecedented approach in the proposed rule. Rather than preserving the state authority to consider remaining useful life, EPA "proposes that the remaining useful life of the affected EGUs, and the other facility-specific factors identified in the existing implementation regulations, should not be considered as a basis for adjusting a state emission performance goal or for relieving a state of its obligation to develop and submit an approvable plan that achieves that goal on time."

NorthWestern Energy has an ownership interest in Unit 4 at the 2100 MW Colstrip generating facility located in Colstrip, Montana. This resource is a key foundational baseload resource in our Montana Energy Supply portfolio. The original cost of our ownership interest in Colstrip Unit 4 was $416 million and will not be fully depreciated until 2043 per the original depreciation schedule (see Colstrip Unit 4 Depreciation Schedule figure on following page). Any scenario resulting in the need to replace our Colstrip generation with, for example, a combination of renewables and associated balancing/regulation requirement (i.e. simple cycle gas plant generation), would mean our customers would be paying for the remaining investment in Colstrip Unit 4 *and* the replacement generation. This would impose a substantial financial burden and is therefore unfair and unreasonable to our customers.

NorthWestern Energy Share of Colstrip Unit 4 Depreciation Schedule



As an additional example of the need for states to consider remaining useful life, consider the Big Stone Plant in South Dakota. By the end of 2015, NorthWestern Energy, Otter Tail Power Company and Montana-Dakota Utilities Company will have completed installation of an approximately $400 million air quality control system - in order to comply with a different set of EPA regulations - which will reduce nitrogen oxide, sulfur dioxide, particulate matter and mercury by about 90%. The assumptions in the proposed Clean Power Plan reduce the capacity factor of the Big Stone Plant to 23%, a level which would obviously result in stranding the $400 million air quality control system as well as the remaining unrecovered costs of each owner in the plant. Not only would customers be paying for an inoperable state-of-the art air quality control system, they would be paying for additional power for either market power purchases or the construction of a new gas-fired power plant. This, too, is unfair and unreasonable to customers.

EPA fails to consider the very real issue of stranded costs arising from the forced shutdown of coal-fired EGUs well before the end of their useful lives. EPA contends it is exercising discretion to interpret Section 111 to limit states' consideration of remaining useful life. However, the plain language in Section 111(d) precludes EPA from exercising any discretion with respect to restricting the states' ability to incorporate remaining useful life and other factors into standards of performance as guaranteed by Congress.

This outcome is especially perverse because under original cost minus depreciation ratemaking, as plants are depreciated on the books the cost to customers goes down. All other things equal, they should become more valuable to customers. This is another situation where economic and environmental regulators need to communicate better.

H. Timeline

EPA's proposed timeline for submittal and finalization of state and regional plans and the proposed timeline for compliance with proposed goals are completely unrealistic. EPA has not appropriately considered the time required to develop and coordinate state and regional compliance plans, draft and finalize necessary changes to state laws and policies, conduct transmission siting and reliability studies, conduct environmental impact assessments, coordinate development with other federal regulations such as the Endangered Species Act, and several other factors.

> ***8. Recommendation/Request: EPA must allow states significantly more time to develop draft compliance plans and should eliminate the interim compliance targets.***

The importance of a reliable, stable secure interconnected power system to deliver affordable electricity is unquestionable. This rulemaking will fundamentally affect what the U.S. Department of Homeland Security (DHS) identifies as the one unique critical infrastructure platform upon which the fifteen other critical infrastructures all depend. According to DHS, the energy sector is unique because, "Without a stable energy supply, health and welfare are threatened, and the U.S. economy cannot function." Energy is "uniquely critical because it provides an enabling function across all critical infrastructure sectors."[5]

[5] Other critical infrastructures include areas such as communications, education, health care, agriculture, transportation, and emergency services. U.S. Department of Homeland Security website, Energy Sector Overview, http://www.dhs.gov/energy-sector.

EPA's proposed compliance timeline does not allow adequate time for the needed reliability assessments and system changes to be accomplished before 2020, by which time many states would need to have accomplished significant emission reductions. NERC, the entity responsible for ensuring the reliable operation of the Bulk Power System in North America, has concluded that "[t]he proposed timeline does not provide enough time to develop sufficient resources to ensure continued reliable operation of the electric grid by 2020. To attempt to do so would increase the use of controlled load shedding and potential for wide-scale, uncontrolled outages."

To the extent states desire to engage in multi-state emissions trading programs, the emission implementation timeline is simply inadequate. There is far too little time to allow states to engage neighboring states on the myriad, complex issues required for such plans. For example, states will need to coordinate receiving credit for renewable generation when renewable energy credits have been sold out-of-state, incorporating new generation sources and siting interstate gas and electric transmission facilities. States will also need to determine the effects of redispatch decisions between power plants in different states and generators that export their generation under existing agreements with out-of-state distribution utilities.

Numerous factors support the need to eliminate the interim compliance period. EPA has not demonstrated that every state can increase utilization of existing natural gas combined cycle (NGCC) units to 70 % by 2020. EPA incorrectly assumes that current natural gas and electric transmission infrastructure is sufficient to support this dramatic increase, and EPA does not account for the fact that many natural gas units must back-up renewable generation. Increasing generation from existing NGCC units will likely require electric and gas transmission upgrades and expansions. As NERC recently has noted, these projects can take ten to fifteen years to plan, design, site, permit and construct. Further, the proposed interim compliance period does not allow sufficient time for regional transmission organizations (RTOs) and independent system operators (ISOs) to evaluate and potentially alter market rules to accommodate changes in dispatch.

In the West, the federal government owns vast portions of many states. The use of these lands will be paramount to increasing renewable generation and siting gas and electric transmission structures and EPA must allow ample time for states to work with other federal agencies.

EPA must also consider the impacts of other federal regulations involving listed and threatened species, species of special concern, migratory birds, eagles and other similar regulations and requirements when making assumptions about timelines, redispatch and particularly expansion of renewable energy generation. For example, Montana and ten other western states have significant core sage grouse habitat. Montana's Governor signed an executive order creating a habitat conservation plan for sage grouse. Montana is interested in managing sage grouse and their habitat rather than relinquishing control to the U.S. Fish and Wildlife Service (USFWS) under the Endangered Species Act. The USFWS is to decide next year whether states' efforts to conserve sage grouse and their habitat will ensure survival or if the sage grouse must be added to the federal endangered and threatened species list. State and federal conservation plans will impact development and siting of wind farms, electric generating stations, gas and electric transmission lines, and all associated permanent and temporary infrastructure required to construct these facilities. Indeed, the Clean Power Plan, and the associated assumptions involving redispatch and renewables integration may affect whether or not sage grouse are listed as endangered.

For states to be able to create plans that can be successfully implemented, the rule will require unprecedented coordination of all aspects of government, the utility industry, utility regulatory commissions, institutional consumer advocates, FERC, NERC, WECC and the other regional reliability entities, RTOs, the National Security Agency, the U.S. Fish and Wildlife Service and other stakeholders. It is important to provide a realistic timeframe in order to work with all stakeholders and develop compliance and implementation plans based on sound policy and necessary engineering and economic analyses than it is to meet an arbitrary deadline.

I. <u>Baseline Year</u>

EPA established state emission rate goals using 2012 as a single baseline year which results in disparity among states and additional error in the calculation of baseline carbon dioxide emissions intensity. Using 2012 as the baseline year penalizing states and companies that have taken early action to reduce GHG emissions and address climate change.

9. ***Recommendation/Request: EPA should change the methodology for calculating carbon intensity in the proposed rule and expand the baseline period (e.g. from one year to five years) in order to minimize the impact and disparities associated with basing emissions targets on a single year.***

   EPA should also start with an earlier year (e.g., 2005) to address the punitive impact of the proposed rule on states and companies that have taken early action to reduce GHG emissions and address climate change.

   NOTE: EPA issued a Notice of Data Availability (NODA) that was published in the Federal Register on October 30, 2014. Since EPA published the NODA just one month before the deadline for

> ***submission of comments on the proposed rule, stakeholders have not had adequate time to fully understand the implications of the NODA in relation to the proposed rule. Issuing a NODA that late, particularly since the proposed rule is likely the most complex rulemaking ever undertaken by the EPA, does not appear to comply with EPA's obligation under the Administrative Procedures Act and Clean Air Act. EPA should allow additional time for stakeholders to fully assess the NODA. Notwithstanding the late issuance of the NODA, EPA should not modify the way it calculates state goals by imposing a minimum level of re-dispatch or redefine Building Block 2 by calculating it on a regional basis. Every state and region has unique generation portfolios that reflect specific energy demand requirements and resource availability.***

Numerous anomalous events can occur during any one-year period as was the case in 2012. These anomalies include increased utilization of affected units due to extreme weather events, atypically low GHG emissions rates from coal-fired generation due to historically low natural gas prices, a changing portfolio (additions and retirements) of available units for dispatch, unit outages, and above normal levels of hydropower generation. Following are some examples:

- The unusually high hydropower production experienced in the Pacific Northwest during 2012 resulted in unusually low fossil power generation. Across the region, hydropower generation was 110 % of average in 2012. By mandating emission reductions from the 2012 baseline, EPA has proposed goals for states in the Pacific Northwest that are artificially skewed relative to states that rely more on thermal generation.

- South Dakota's total energy production in 2012 was one of the highest on record. Therefore, the mandate to increase renewable energy generation and decrease usage through energy efficiency mechanisms (goals that are tied to the state's total generation in 2012) is more onerous than it otherwise would be had a multiyear approach been used or had another year been selected as the baseline.

- South Dakota's one natural gas combined cycle plant was undergoing test firing in 2012. EPA considered it an existing unit under its proposal. Using data from an earlier year would reduce its impact on South Dakota's state goal or eliminate it from being considered as an operational unit depending on what year is selected
- Wind generation in South Dakota increased significantly between 2008 and 2012 and, by EPA using 2012 as the baseline, is receiving no credit for this increase.
- The Colstrip Plant in Montana ran 23% less than what would be expected during a representative normal year.

In order to set realistic and equitable state goals, EPA must start with a baseline period that is statistically representative of generation and GHG emission levels. EPA must address certain anomalies that arose in 2012 to avoid the unfair and arbitrary impacts that penalize some states and/or companies. We note that EPA uses multiple years for baselines in other programs and for compliance purposes because of the variability issues associated with use of a single year. At a minimum, EPA must address corrections related to other data anomalies, such as affected units that were off-line for most or all of the baseline year.

NORTHWESTERN ENERGY - SD/NE
ELECTRIC PLANT CAPACITIES
AS OF DECEMBER 31, 2013

LOCATION	SAP LOCATION	TYPE	FUEL	GENERATOR NAME PLATE RATING (KW)	2013 CAPABILITY SUMMER (5/13-10/13)	WINTER (11/12 - 4/13)	AT TIME OF PEAK	COMMERCIAL DATE
Aberdeen, SD*								
Unit #1	2ABABN0040	Combustion Turbine	FO	28,800	20,520	28,000	20,520	1978
Unit #2	2ABABN0042	Combustion Turbine	NG/FO	82,235	52,000	60,000	52,000	2013
Clark, SD**								
Unit #1	2HUCLK0060	Diesel	FO	2,750	2,600	2,720	2,600	1970
Faulkton, SD**								
Unit #1	2HUFLK0061	Diesel	FO	2,750	2,500	2,500	2,500	1969
Huron, SD*								
Unit #1	2HUHUR0064	Combustion Turbine	NG/FO	15,000	11,030	14,500	11,030	1961
Unit #2	2HUHUR0062	Combustion Turbine	NG/FO	42,925	43,700	49,000	43,700	1991/92
Yankton, SD*								
New Plt. #1	2YKYNK0080	Diesel	NG/FO	2,276	2,170	2,170	2,170	1974
New Plt. #2	2YKYNK0080	Diesel	FO	2,750	2,750	2,750	2,750	1974
New Plt. #3	2YKYNK0080	Diesel	NG/FO	6,500	6,500	6,500	6,500	1975
New Plt. #4	2YKYNK0080	Diesel	FO	2,000	2,000	2,000	2,000	1963
Mobile Unit**								
Unit #2		Diesel	FO	1,750	1,750	1,750	1,750	1991
Unit #3		Diesel	FO	2,500	2,000	2,000	2,000	2009

* Manned less than 24 hours
** Unmanned

LOCATION	SAP LOCATION	TYPE		GENERATOR NAME PLATE RATING (KW)	SUMMER	WINTER	AT TIME OF PEAK	COMMERCIAL DATE
Big Stone, SD								
Unit #1	1BSBSP0600	Steam		122,850 *	111,150	111,150	111,150	1975
*Name Plate			525,000	NWPS Share 23.4% = 122,850				
Summer Capacity			475,000	NWPS Share 23.4% = 111,150				
Big Stone, SD								
Diesel		Diesel		269 *	269	269 #	269	1975
*Name Plate			1,149	NWPS Share 23.4% = 269				
Summer Capacity			1,149	NWPS Share 23.4% = 269				
Sioux City, IA								
Neal #4	1NLNLP0630	Steam		55,558 *	56,110	56,110	56,110	1979
*Name Plate			639,996	NWPS Share 8.681% = 55,558				
Summer Capacity			646,354	NWPS Share 8.681% = 56,110				
Beulah, ND								
Coyote I	1CYCYP0620	Steam		45,578 *	42,700	42,700	42,700	1981
*Name Plate			455,780	NWPS Share 10% = 45,578				
Summer Capacity			427,000	NWPS Share 10% = 42,700				
TOTAL CAPACITY (kw)		Steam		223,986	209,960	209,960	209,960	
		Other		192,505	149,789	174,159	149,789	
				416,491	359,749	384,119	359,749	

2013 Summer Peak was 326,960 on August 27,2013.
2013 Winter Peak was 292,978 on December 11, 2013

2013 Capability: Summer (5/1/13-10/31/13)
Winter (11/1/12-4/30/13)

Emergency Use Only Engines - As of May 1, 2013, these engines were not retrofitted to meet the RICE/NESHAP compliance standards. Redfield is scheduled to be retired in 2014 and Highmore in 2015.

LOCATION	SAP LOCATION	TYPE	FUEL	GENERATOR NAME PLATE RATING (KW)	SUMMER	WINTER	AT TIME OF PEAK	COMMERCIAL DATE
Highmore, SD**								
Unit #1	2HUHMR0063	Diesel	FO	675	560	600	560	1948
Unit #2	2HUHMR0063	Diesel	FO	1,360	1,250	1,330	1,250	1960
Unit #3	2HUHMR0063	Diesel	FO	2,750	2,630	2,750	2,630	1970
Redfield, SD**								
Unit #1	2HURED0065	Diesel	FO	1,360	1,300	1,320	1,300	1962
Unit #2	2HURED0065	Diesel	FO	1,360	1,300	1,320	1,300	1962
Unit #3	2HURED0065	Diesel	FO	1,360	1,300	1,320	1,300	1962