Integrated Resource Plan

2015

Submitted to the
North Dakota Public Service Commission
July 1, 2015

Volume I: Main Report

Montana-Dakota Utilities Co.

2015 Integrated Resource Plan

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MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

INTEGRATED RESOURCE PLAN

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EXECUTIVE SUMMARY

Montana-Dakota Utilities Co.'s (Montana-Dakota) 2015 Integrated Resource Plan (IRP) conducted for the integrated electric system comprised of its service territories in the states of Montana, North Dakota and South Dakota continues a 28-year practice of documenting efforts used to determine the best value resource plan for its customers. The purpose of integrated resource planning is to consider all resource options reasonably available to meet the end-use customer's demand for reliable and cost-effective energy, and provide a road map for Montana-Dakota's future resources. Considered resources include a combination of traditional generating stations, distributed generation, renewable resources, demand-side management programs, and new and emerging technologies.

Montana-Dakota's IRP process encompasses four main areas: load forecasting, demand-side analysis, supply-side analysis, and integration and risk analysis. A summary of the IRP study results for each of these areas is provided.

The **load forecasting** activities, as discussed in Chapter 2, employ an econometric forecasting method along with other forecasting methods and analyses resulting in a combined analysis approach to predict the integrated system customers' future demand for electricity. The long-term forecast is an estimate of energy requirements and peak demand for twenty years into the future. The results for the base forecast show that, during the 2015-2034 timeframe, the projected average annual growth rate for summer peak demand is 1.7 percent prior to any reductions due to demand response programs, while annual energy requirements are expected to increase at a rate of 2.1 percent.

The **demand-side analysis** is an evaluation process to identify the feasible demand-side management (DSM) programs for Montana-Dakota's system. As discussed in Chapter 3, Montana-Dakota evaluated a number of energy efficiency and demand response programs, hereinafter referred to collectively as DSM programs, for its customers in Montana, North Dakota, and South Dakota. Montana-Dakota's expected DSM program plans over the 2016-2018 period for each state are discussed at the end of Chapter 3.

The **supply-side analysis** is an evaluation process to determine the feasible generation options available to serve Montana-Dakota's system. The future resources to which Montana-Dakota has committed, based on prior IRP processes, include new simple-cycle reciprocating internal combustion engines (RICE) at Lewis & Clark (Lewis & Clark 2), Mercury and Air Toxic Standard (MATS) project at Lewis & Clark, and an air quality control system (AQCS) at the existing Big Stone plant. The potential resource options studied included simple-cycle combustion turbines, combined cycle combustion turbines, simple-cycle reciprocating internal combustion engines, coal-fired generation, wind generation, solar, geothermal, biomass, landfill gas, short term capacity purchases, and Thunder Spirit Wind. Along with the potential resource options, MISO energy purchases are available to meet energy needs.

The **integration and risk** process considers the feasible supply-side and demand-side options to determine a least-cost resource expansion plan to economically and reliably meet customer requirements into the future. A number of scenarios were investigated to determine the sensitivity of the least-cost plan to several factors that may impact the expansion plan. These sensitivity scenarios ranged from; high and low natural gas prices, high and low load growth, high and low energy market prices, high capital costs on natural gas units, diminishing energy markets, and applying a carbon tax to fossil fired units. The analytical tool used for the integration process was the Electric Generation Expansion Analysis System (EGEAS), a resource expansion program developed by the Electric Power Research Institute. The results of the integration and risk process are then considered as part of the overall decision in determining the best resource plan for Montana-Dakota and its customers.

The **results** of the integration analysis indicate that Montana-Dakota's current base case resource plan includes the continued construction of the following to be in service by the end of 2015: Big Stone AQCS, the addition of the MATS project at the Lewis & Clark Station, Thunder Spirit Wind at 107.5 MW, 19 MW of RICE units at Lewis & Clark and adding 200 MW of a combined cycle unit in 2020. As previously noted, the results of the least-cost model and sensitivity analyses are used to inform the process of selecting the best plan to meet the future needs of Montana-Dakota's customers.

Concerning DSM, a 15 MW demand response program developed under a third party contract by 2017, Montana-Dakota will continue to promote existing interruptible rates to reach a total of 16 MW by 2017. Montana-Dakota will look to implement a residential AC Cycling program by 2017 that will have a total of 10 MW in the program by 2021.

Figure E-1 provides an overview of the identified need for capacity for the period 2015-2034. In this figure, "PRMR UCAP" represents Montana-Dakota's planning reserve margin requirements (PRMR) prescribed by the Midcontinent Independent System Operator, Inc. (MISO) based upon Montana-Dakota's current 50/50 demand forecast and a 80.3 percent coincident factor, while "Existing ZRC" represents the amount of zonal resource credits (ZRC) that Montana-Dakota has secured to meet its PRMR. For resource adequacy purposes, Montana-Dakota must have an amount of ZRC equal to or greater than PRMR; otherwise deficiency charges are assessable under the MISO tariff.

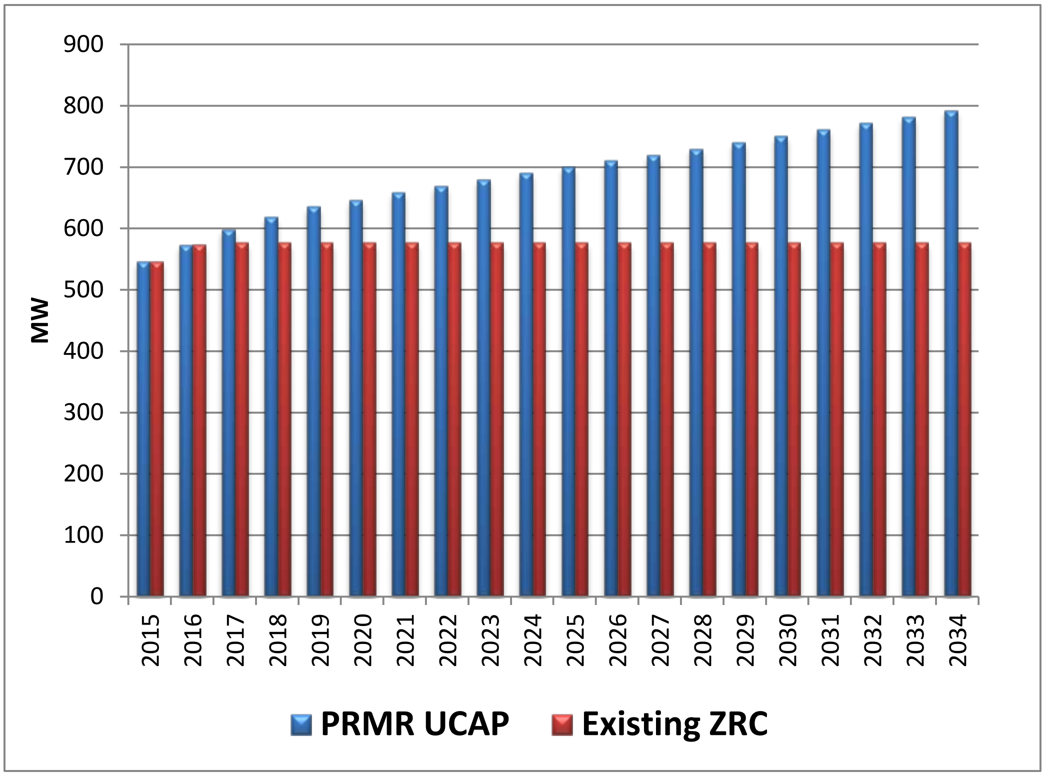

Figure E-1: Zonal Resource Credit and Planning Reserve Margin Requirement

Based on the analysis of the resource expansion models and the consideration of customer impacts, market availability of capacity and energy, and other factors such as environmental regulations and the balance of its generation mix, Montana-Dakota's recommended resource plan is to pursue the following resources to meet the requirements identified for the 2015-2019 period:

- Continue the implementation of the commercial demand response program and the interruptible rate to obtain a total of 31 MW by 2017,
- Implement the residential AC Cycling program by 2017 and obtain a total of 10 MW in the program by 2021,
- Plan for the installation and/or partnering of 200 MW of combined cycle generation to be online in 2020,

- Meet short-term capacity deficits via the MISO Capacity Auction or through bi-lateral capacity purchase agreements, and
- Monitor the development of final rules and implementation strategies for EPA Clean Power Plan for existing sources.

The recommended resource plan is considered to be the best plan to economically and reliably meet customers' requirements over the five-year planning horizon. Montana-Dakota also plans to issue a new request for proposal for capacity and energy resources in 2016 to start the process for the next planning cycle.

The 2015 IRP process and product (report and attachments) were enhanced by the participation of Montana-Dakota's IRP Public Advisory Group (PAG). The PAG has been a valuable tool within the IRP process since 1994. The 2015 advisory group was established at the beginning of the 2015 planning cycle and provided Montana-Dakota with input throughout the 2015 IRP process.

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For ease of handling, this IRP report is printed and bound in four separate volumes:

Volume I – Main Report (the current document)

Volume II – Attachment A: Load Forecast Documentation

Volume III – Attachment B: Demand-Side Analysis Documentation

Volume IV – Attachment C: Supply-Side and Integration Analysis Documentation
Attachment D: Public Advisory Group Documentation
Attachment E: Supply Side Resources Study
Attachment F: Future Transmission Service Charge Impacts

CHAPTER 1

ENVIRONMENTAL CONSIDERATIONS

MDU Resources Group, Inc.'s Corporate Environmental Statement states:

> *"Our Company will operate efficiently to meet the needs of the present without compromising the ability of future generations to meet their own needs. Our environmental goals are:*
>
> - *To minimize waste and maximize resources;*
> - *To support environmental laws and regulations that are based on sound science and cost-effective technology; and*
> - *To comply with or exceed all applicable environmental laws, regulations and permit requirements".*

Montana-Dakota strives to maintain compliance and operate in an environmentally proactive manner, while taking into consideration the cost to customers. Montana-Dakota actively monitors federal and state legislative and regulatory activity related to environmental issues, including air emissions, greenhouse gases (GHG), waste disposal and water discharges. The Company has also established memberships in relevant trade organizations to assist in monitoring the potential impact of proposed legislation and regulation to the Company's operations.

The U.S. Environmental Protection Agency (EPA) has finalized significant air emissions regulations for coal-fired electric generating facilities and has proposed significant new regulations that aim to reduce air emissions, including GHGs, at fossil-fired electric generating facilities and pollutants in wastewater discharges. The EPA also published a final rule in the Federal Register on April 17, 2015 for management of coal ash at coal-fired electric generating facilities. The culmination of all various pending environmental requirements, in particular the EPA's proposed rule regulating carbon dioxide emissions from existing fossil fuel fired electric generating units, may result in the retirement of existing coal-fired baseload units earlier than otherwise would occur. Montana-Dakota will continue to monitor the proposed regulations and take the final, as well as proposed, regulations into consideration when planning for future resource needs.

<u>Renewable Energy</u>

Montana-Dakota has been involved with renewable energy analysis and development for many years, and has several renewable energy installations.

Montana-Dakota has 50 MW of installed wind generation capacity at two locations, providing approximately seven percent of its customers' electric energy requirements, and will be installing an additional 107.5 MW of wind at the Thunder Spirit Wind project near Hettinger, North Dakota by the end of 2015. The Company also owns a 7.5 MW heat recovery facility on the Northern Border Pipeline Compressor Station in central North Dakota, which uses high-temperature exhaust gas as the primary heat source. Given that waste heat is utilized as the "fuel" for this generating facility, no additional fossil fuel is required and therefore incremental emissions to generate electricity are negligible.

Commitment to Reducing Air Emissions

In 2003, Montana-Dakota joined other utilities, through a memorandum of understanding from the Edison Electric Institute to the Department of Energy, to commit to reduce the utility industry's carbon dioxide (CO_2) emission intensity by three to five percent by 2010. Montana-Dakota has shown its commitment by reducing the Company's CO_2 emissions intensity in 2008 by approximately seven percent as compared to 2003. In 2010, Montana-Dakota updated its CO2 emissions intensity goal, committing to a 10 percent reduction of the Company's average CO_2 emissions intensity from its electric generating facilities by 2012 compared to 2003 levels. As of January 1, 2012, Montana-Dakota achieved greater than 10 percent reduction from the Company's 2003 electric generating facility CO_2 emissions intensity, surpassing the Company's goal. The Company met these goals through customer energy efficiency, renewable energy projects and through implementing heat rate improvement projects at the Company's coal-fired generation facilities over time.

Montana-Dakota has been active in researching options for CO_2 capture, sequestration, and beneficial uses. The Company has been a member of the Plains CO_2 Reduction Partnership (PCOR) since its inception in 2003. The partnership is led by the Energy and Environmental Research Center (EERC) at the University of North Dakota and is one of seven regional partnerships across the United States. The Company has also been a member of the Partnership for CO_2 Capture (PCOC) project since 2014, which is also led by the EERC. PCOC provides support of pilot-scale demonstrations and researches and evaluates promising CO_2 capture technologies that can enhance the cost and performance of CO_2 capture systems.

Montana-Dakota has also actively participated in the environmental workgroups of the North Dakota Lignite Energy Council such as the Lignite Technology Development Workgroup and the Environmental Workgroup. In the last few years, these workgroups have focused on CO_2-related issues such as lignite gasification, oxyfuel combustion, pre- and post-combustion CO_2 capture technologies, and beneficial uses of CO_2.

Environmental Regulation Pollution Control Project Impacts

The air emissions regulations that have had the most immediate impact on operations at Montana-Dakota's electric generating facilities are the federal Regional Haze (RH) Rule and the Mercury and Air Toxics Standard (MATS) Rule. The most significant projects that are being implemented to comply with these rules include a filterable particulate matter pollution control project for MATS Rule compliance at the Lewis & Clark Station being installed in 2015, as well as the air quality control system (AQCS) project at the Big Stone Plant for the RH Rule compliance that is under construction and is to be completed in 2015. Montana-Dakota's ownership share in Big Stone Plant is 22.7 percent. Details regarding the Big Stone Plant AQCS project were included in Montana-Dakota's 2011 IRP. Additional air emissions regulations that will impact the utilization of fossil-fired generation resources are the GHG regulations EPA has proposed. These rules are expected to be finalized in the summer of 2015. High level impacts from these air emissions regulations are discussed below.

Mercury and Air Toxics Standard Rule

The MATS Rule, published as a final rule in the Federal Register on February 16, 2012, requires existing coal-fired electric generating units (EGUs) to meet hazardous air pollutant (HAP) emission standards reflecting the application of maximum achievable control technology (MACT). The deadline to demonstrate compliance with the MATS Rule emission limits and operating requirements is April 16, 2015, with a potential additional year extension for installation of pollution control projects approved through the state air permitting authority. With the exception of Lewis & Clark Station (L&C), the majority of MATS air pollution control projects being implemented at Montana-Dakota's electric generating facilities do not result in significant cost. Since Lewis & Clark Station's MATS compliance has changed substantially in the past 12 months, discussion is provided below to provide an update on the compliance project.

In 2012, Montana-Dakota determined through stack emissions testing conducted at L&C that filterable particulate matter emissions reductions were required to comply with the MATS non-mercury emissions limit. Initially, Montana-Dakota contracted with Sargent & Lundy, LLC

(S&L) in November 2012 to develop an emission control strategy for reducing filterable particulate matter to control non-mercury metals per the MATS Rule, identifying a fabric filter bag house design combined with mist eliminator vessel modifications as the recommended compliance option. In the spring of 2014, Montana-Dakota was forced to re-evaluate its compliance plan due to the increasing cost of the bag house installation from roughly $27 million to $40 million and determined that the proposed bag house project was no longer an economically feasible compliance option and began exploring other compliance options.

Montana-Dakota began investigating a minimal natural gas co-fire as a potential compliance option, as well as potential modifications to the existing scrubber. In March 2014, Montana-Dakota conducted initial co-fire testing at 50, 30 and 10 percent natural gas blends with lignite. The test results indicated that co-firing, even at 50 percent, did not significantly alter particulate matter emissions at L&C. Based on these results, and further testing to determine optimum scrubber efficiencies from April to July, Montana-Dakota determined that, co-firing was not an effective MATS compliance option.

During the summer of 2014, Montana-Dakota investigated whether sufficient reductions could be achieved through the optimization of the existing pollution control equipment and good combustion practices, as well as potential changes that could be made to the scrubber to achieve compliance with a minimal co-fire of natural gas. Montana-Dakota made changes to maximize the effectiveness of the existing scrubber at L&C. However, the changes did not produce a sufficient reduction in particulate emissions to achieve compliance.

Later in the summer of 2014, Montana-Dakota began work with URS Corporation (URS), now AECOM, to evaluate retrofitting the existing scrubber for improved particulate matter capture, since URS has extensive experience in making custom/niche improvements to existing wet scrubbers across the industry. After studying L&C's scrubber, URS proposed installing enhanced mist elimination, a sieve tray and spray header, and forced oxidation within the confines of the existing scrubber vessel and mist eliminator section of the stack. URS guaranteed that these retrofits would meet the MATS limit and could be completed by December, 2015 at a cost of approximately $16 million.

Due to the time needed for installation of the updated pollution control project, and as allowed under the MATS Rule, Montana-Dakota submitted a supplemental request for approval of a one-year compliance extension to the MT DEQ on November 24, 2014 for installation of the proposed controls. A one-year extension was granted by the MT DEQ on January 30, 2015, requiring controls to be in place by April 16, 2016. Equipment design for the scrubber retrofit was completed in early 2015 and equipment is being procured for the installation to be completed during L&C's fall 2015 outage.

Effluent Limitations Guidelines (ELG) Rule

On June 7, 2013, the EPA published the proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG Rule) in the Federal Register. This rule requires reductions in pollutants discharged to surface waters from wastewater associated with steam electric generating units through imposing stringent discharge limits and treatment technology requirements, projected to be applicable to several of Montana-Dakota's coal-fired electric generating facilities. Montana-Dakota has completed preliminary review of the proposed ELG Rule and has not identified any significant pollution control projects that would be required to be implemented at the Company's electric generating facilities for compliance. EPA is expected to finalize the ELG Rule in 2015, at which time Montana-Dakota will conduct additional review of any potentially required pollution controls.

Coal Combustion Residual (CCR) Rule

The EPA's Coal Combustion Residual (CCR) Rule establishes federal requirements for management and disposal of coal ash, as well as potential closure requirements for ash impoundments. On April 17, 2015, the EPA published a final CCR Rule that requires management of coal ash through solid waste regulations. The regulation was finalized in a way that provides enforcement mainly by citizens through citizen law suits and does not require states to adopt the rule requirements or issue permits for coal combustion residual operations, including the management of coal ash in surface impoundments or landfills. The rule requires closure of impoundments and landfills of existing units that do not meet specific criteria and replacement with new impoundments and, new landfill retrofits in a very stringent timeframe for compliance. The rule also requires new groundwater monitoring programs. The construction of landfills or impoundments may be required depending on site and criteria evaluations that must be completed over the next one to two years. Montana-Dakota is currently evaluating the final rule to determine whether any significant surface impoundment or landfill closures, replacements or retrofits will be required at Montana-Dakota's coal-fired electric generating.

316(b) Rule – Aquatic Species Protection

On August 15, 2014 the EPA published a final rule under section 316(b) of the Clean Water Act, establishing requirements for water intake structures at existing steam electric generating power plants. The purpose of the rule is to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures. The majority of the Company's electric steam generating units are either not subject to the rule requirements or have completed studies that indicate compliance costs not are expected to be significant. Any required controls will be determined in the next National Pollutant Discharge Elimination System permit reviews which are projected to occur between 2018 and 2019. Lewis & Clark Station had not been required to complete a 316(b) study and is now required to complete a study by 2018. The study results will be used to determine any required controls. The installation schedule for any required controls would be established with the permitting agency after the study is completed. Discussion of required controls and cost impacts from these controls will be included in future IRPs.

Greenhouse Gas (GHG) Rules for Fossil-fired Electric Generating Units

New Source Rule

New source performance standards (NSPS) for emissions of carbon dioxide (CO_2) for new fossil fuel-fired electric utility generating units (EGUs) were proposed by the EPA under section 111(b) of the Clean Air Act with the proposed rule published in the Federal Register on April 13, 2012. This rule proposed standards for new coal-fired generating units, natural gas-fired combined cycle units and integrated gasification combined cycle units, and did not include standards for new natural gas-fired simple cycle combustion turbines. The EPA had planned to finalize the rule by April 2013. However, the EPA released a re-proposed GHG NSPS rule for new electric generating units on January 8, 2014. This re-proposed rule applies to new fossil fuel-fired electric generation units, including coal-fired units, natural gas-fired combined cycle units, and integrated gasification combined cycle units and now includes natural gas-fired simple-cycle peaking units that supply more than one-third of a unit's potential electric output and more than 219,000 MWh net electric output to the grid per year. The EPA's 1,100 pounds of carbon dioxide per MW hour emissions standard for coal-fired units does not allow any new coal-fired electric generation to be constructed unless carbon dioxide is captured and sequestered. Even though this rule is in a proposed status and is not yet final, the Clean Air Act new source NSPS section establishes EPA's ability to apply the requirements to any new units permitted after the date that the rule is proposed

As the new source NSPS GHG rule becomes final, Montana-Dakota will incorporate any additional changes in consideration of new coal- and natural gas-fired electric generating facilities into the supply-side resource analysis.

Existing Sources

On June 18, 2014, the EPA published in the Federal Register a proposed rule under 111(d) of the Clean Air Act limiting carbon dioxide emissions from existing fossil fuel-fired electric generating units. The proposed rule would require each state to meet an “interim goal” emission rate based on average emissions from 2020 to 2029 and a “final goal” emission rate in 2030 and beyond. The emission rates vary widely among states, and are lower than the emission rate standards for new coal-fired generation in all instances and the emission rate standards for new gas-fired units in most instances.

The basis for the state-specific emission rate goals are four “Building Blocks” identified as the best system of emission reductions by EPA. The four building blocks are: (1) heat rate improvements at existing coal-fired EGUs, (2) redispatch of existing generation to reduce output from existing coal-fired EGUs and to increase output from existing natural gas combined cycle units (NGCC), (3) increased renewable energy resources and new or retained “at risk” nuclear generation, and (4) increased energy efficiency deployment. The starting point for the calculation is the average 2012 emissions rate of all fossil-fired EGUs, expressed as their aggregate carbon dioxide (CO2) output divided by their aggregate generation in MWh. The final emission rate goals are expressed in pounds per megawatt hour (lb/MWh). EPA’s reliance on emission reductions beyond reductions achievable at the affected source and well beyond its jurisdiction is arbitrary and capricious and ultra vires regulation. However, litigation is expected to be required to ultimately determine this outcome and some believe this may not be known until possibly 2018.

Each state would be required to submit a plan by June 30, 2016, or if part of a multi-state plan by June 30, 2017, that contains certain required components. If a state needs additional time to submit a complete plan, then the state would be required to submit an initial plan by June 30, 2016, that documents the reasons the state needs more time and includes commitments to concrete steps that would ensure that the state would submit a complete plan by June 30, 2017 or a complete multi-state plan by June 30, 2018, as appropriate. Theoretically, EPA would review and approve proposed plans within a year. The state plans could include performance standards, emissions reductions or limits on generation for each existing fossil fuel-fired generating unit. It is unknown at this time what each state will require for emissions reductions from each Montana-Dakota owned and jointly owned fossil fuel-fired electric generating unit. The EPA was instructed by President Obama to develop this rule by June 1, 2014, and finalize the rule by June 1, 2015. The EPA has since indicated that a final rule for existing units would be delayed and published in August 2015.

Montana-Dakota does not expect to have certainty in the Company's compliance obligations until possibly later in 2017 or 2018, after EPA begins approving or disapproving state plans. With compliance required starting in as early as 2020, there are concerns about impacts from stranded assets such as the Montana-Dakota's co-owned Big Stone Plant (Big Stone). In its analysis, the EPA anticipated a significant re-dispatch of generation from Big Stone to Basin Electric Power Cooperative's Deer Creek Station, which is the only natural gas combined cycle unit in South Dakota. Deer Creek and Big Stone are separately owned, serve different territories, and participate in different markets (Big Stone is in MISO, while Deer Creek will join the Southwest Power Pool in 2015). Because Deer Creek was under construction during most of 2012, it operated very little and was assigned a one percent annual capacity factor when EPA calculated the emission rate goal for South Dakota. Based in large part on this misapplication of Deer Creek's 2012 capacity factor, the Proposed Rule inappropriately anticipates that 1,965,000 MWh of generation would shift from Big Stone to Deer Creek`. If this shift occurred, Big Stone would operate at just 23 percent of its capacity. Because Big Stone's minimum operating load is approximately 40 percent of maximum load, running the plant at 23 percent of its capacity would require the plant to be off-line for at least half of the year. Under these conditions, it is likely that the plant would be retired. Considering that Big Stone will complete the installation of the $384 million dollar Air Quality Control System (AQCS) in 2015 required by an EPA rule establishing Regional Haze Program requirements for South Dakota, of which Montana-Dakota's share is approximately $87 million, there is a concern that a larger asset would be stranded if retirement of Big Stone was required to meet EPA's interim targets in 2020. Montana-Dakota completed modeling of this scenario with the 2013 IRP model considering a four year life for the Big Stone AQCS project, and Big Stone AQCS was still chosen as a least cost supply-side resource even with a four year life. Montana-Dakota, as well as Big Stone Plant operator Otter Tail Power, the SD PUC and others, have made numerous and forceful comments to EPA indicating that the SD target was calculated based on faulty assumptions and that these assumptions need to be corrected in the final rule. The EPA has indicated that it understands the nature of these comments. However, the level of correction that EPA would potentially make to the SD target is unknown.

For EPA's block 1 proposed heat rate improvement projects at coal-fired generating units, Montana-Dakota disagrees with EPA's assumption under block 1 that existing coal-fired electric generating units can achieve a six percent heat rate improvement. Most of Montana-Dakota's coal-fired electric generating units have already implemented the types of equipment upgrades and best practices identified by EPA as the basis for its six percent heat rate improvement estimate, therefore, Montana-Dakota's units are not expected to be able to achieve an additional six percent heat rate improvement cost effectively. In addition, some heat rate improvements would not be sustainable since heat rate improvements decline over time due to natural degradation, installation of emission control technologies, and the need to cycle load (such as the increased cycling that EPA predicts will occur in order to implement re-dispatching of coal- to gas-fired units).

Additionally, the operation of controls installed to comply with other environmental regulations, such as Regional Haze and MATS, results in heat rate increases that can be so significant that they overwhelm heat rate improvements achieved through the types of equipment upgrades and best practices on which EPA bases its six percent assumption. For example, Big Stone may require up to eight megawatts (MWs) of station power to operate Regional Haze pollution controls that currently are under construction at the unit. The additional load will negatively affect the units' current heat rate and make it technically infeasible for Big Stone to comply with a six percent heat rate improvement from its 2012 baseline heat rate.

Montana-Dakota has projected compliance costs for some significant requirements based on the proposed rule. However, the costs are expected to change when the rule becomes final, and may increase depending on the targets assigned to the state in which Montana-Dakota operates fossil-fired generating units. As explained above and in Montana-Dakota's comments submitted to the EPA on December 1, 2014, Big Stone Plant could be required to shut down for compliance with this rule. Montana-Dakota estimates that it would require a $43.6 million revenue increase in 2020 for Montana-Dakota's share of the cost to replace the approximate 475 MW Big Stone Plant with a comparable size natural gas combined cycle unit. The replacement of this supply-side resource alone would result in a 10 percent rate increase for Montana-Dakota's ratepayers, in addition to the cost increase associated with the Regional Haze AQCS project.

Also included in our December 1, 2014 comments to EPA was an estimated cost to comply with the EPA's proposed 1.5 percent annual incremental energy efficiency savings on the customer side that the EPA determined was feasible for all states. The implementation of these programs would require Montana-Dakota to make significant and escalating investments in energy efficiency savings programs. Using costs developed by the American Council for an Energy Efficient Economy (ACEEE) in their March 26, 2014 Research Report U1402 titled "The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs", Montana-Dakota estimates that by 2029 it would have to invest $14 million annually in energy efficiency programs to achieve the EPA's goal. Furthermore, the Nexant study commissioned by Montana-Dakota identified a lower percent achievability of energy efficiency program savings for Montana than the EPA's proposed 1.5 percent. The study identified an average annual percent achievability of about 0.3% over the study period from 2015 to 2034. Energy efficiency program savings achievability is further discussed in Chapter 3 and in Attachment B.

Montana-Dakota's current Integrated Resource Planning process shows that more wind resources are being added to the Company's generation mix which would assist Montana-Dakota in complying with the rule as proposed. The retirement of coal-fired units also is a potential mechanism for achieving compliance with the Rule. If the proposed state targets for the states in which Montana-Dakota operates are made more stringent in the final rule, Montana-Dakota expects that more renewable generation and energy efficiency programs would be needed to achieve compliance, as well as coal-fired generation resource retirements.

At this time, Montana-Dakota believes a company fleet-wide compliance plan would be most cost effective, especially if the EPA is successful in requiring compliance utilizing the electric system beyond the boundary of an affected source itself, and Montana-Dakota has emphasized this need to the EPA and to the state environmental agencies that regulate the Company's facilities for their consideration in developing their state plans. As this rule is finalized and states begin compiling state plans which contain compliance requirements, Montana-Dakota will be able to provide further discussion of the costs and consider the impacts in the supply-side resource analysis of the IRP process. It should be noted that the four building blocks are not the only methods to comply with the final emissions limits and that the industry is currently assessing additional methods of compliance.

<u>Modified or Reconstructed Sources</u>

The EPA also published a separate proposed rule under 111(b) of the Clean Air Act on June 18, 2014 that limits carbon dioxide emissions from existing units that are modified or reconstructed. In this proposed rule, the EPA proposes emissions limits that could potentially be unachievable if a unit is modified or reconstructed. Similar to the new source NSPS GHG rule discussed further above, even though the modified or reconstructed source rule is in a proposed status and is not yet final, the Clean Air Act 111(b) new source NSPS section establishes EPA's ability to apply the requirements to any existing units that are modified or reconstructed after the date that the rule is proposed. Therefore, Montana-Dakota incorporates these proposed rule requirements into the supply-side resource analysis of the IRP process and Montana-Dakota may be limited in considering modification or reconstruction of existing units for supply-side resource options.

Regional Haze Rule (RH Rule)

The EPA promulgated the Regional Haze Rule (RH) in 1999 to address visibility impairment in Class I areas in the United States, constituting 156 national parks and wilderness areas. This rule was developed in accordance with the Clean Air Act's (CAA) national goal of remedying existing and preventing future visibility impairment of Class I areas due to man-made air pollution. In 2005, the EPA published a revised rule that included guidelines for control technology determinations under the RH Rule for Best Available Retrofit Technology (BART) sources and for sources addressed for reasonable progress.

State environmental agencies like the South Dakota Department of Environment and Natural Resources (DENR) and North Dakota Department of Health (NDDH) are required to submit State Implementation Plans (SIPs) to EPA that develop and implement their strategy to reduce emissions that may contribute to regional haze, and to set reasonable progress goals toward meeting the goal of no man-made visibility impairment in Class I areas by 2064. The first round of RH SIPs were finalized in 2012 and considered emission reductions from BART sources, as well as other emissions sources in consideration of reasonable progress toward improving visibility in Class I areas. Periodic reviews, every five to ten years, will continue to be completed by States and the EPA to continue progress toward the 2064 goal with the next round of emissions reductions to be determined in approximately 2018 with pollution control projects expected to be installed by approximately 2023. Emission reduction projects that may be required in the next review period will be included in future IRPs.

CHAPTER 2

LOAD FORECASTING

Montana-Dakota uses econometric modeling as the starting point for its forecasts. The econometric models for the 2015-2034 forecast were developed using the statistical software package called SAS®. In order to capture the extraordinary growth currently being experienced and expected as a result of the Bakken oil field activity, other forecasting methods and analyses also enter into the forecasting process for the Integrated System resulting in a combined analysis approach to the forecast.

An econometric model is a set of equations that expresses electricity use as a function of underlying factors such as customer income, price of electricity and alternate fuels, and weather. The strengths of econometric forecasting models include:

- Econometric models explicitly measure the effects of underlying causes of trends and patterns.
- Econometric models provide statistical evaluation of forecast uncertainty.
- Econometric models utilize economic and demographic information that is easily understood.
- Econometric models can be readily re-estimated.

The load forecasting process develops a forecast for annual energy sales and a forecast for peak demand. The energy forecast is developed for each sales sector on a state by state basis – Montana, North Dakota, and South Dakota – and the forecasts by state are combined to arrive at the Integrated System forecast in total. The Integrated System peak demand forecast is developed on a total system basis. Detail regarding the specific econometric factors used in the energy sales forecast and peak demand forecast is given in the detailed description of the load forecast provided as Attachment A.

Energy Sales Forecast

The energy sales forecast is disaggregated into five sales sectors:

- Residential sector.

- Small Commercial & Industrial (SC&I) sector. This sector consists of those commercial and industrial customers whose peak demand averages less than 50 kilowatts a month over a year's time.

- Large Commercial & Industrial (LC&I) sector. This sector consists of those commercial and industrial customers whose peak demand averages more than 50 kilowatts a month over a year's time.

- Street Lighting. This sector consists of energy for public street and highway lighting.

- Miscellaneous. This sector includes energy for sales to other public authorities, interdepartmental sales, and Company use.

The LC&I sector was disaggregated into seven end-use categories which were then forecasted separately. Six large customers were forecasted individually and all other LC&I energy sales were categorized as General LC&I energy sales (energy sales to all other LC&I customers) and forecasted as a group.

Econometric equations were tried initially in the development of the forecasted sales for the three primary customer categories by state – residential, SC&I, and General LC&I – while sales forecasts for the street lighting and miscellaneous sectors were developed primarily using linear regression. The final models used for each of the primary customer categories were a combination of econometrics and judgment. The sales forecasts for the six LC&I end-use customers were developed using a combination of regressions and information available from Montana-Dakota's field personnel regarding these large customers. More detail regarding the specific econometric factors used in the sales forecast is included in the load forecast in Attachment A.

Peak Demand Forecast

The peak demand forecast is developed for the summer peaking season on a total integrated system basis; it is not disaggregated by state or by sector. The peak demand forecast was developed through the use of an econometric analysis where weighted average temperatures for Bismarck, North Dakota (70%), Miles City, Montana (15%) and Williston, North Dakota (15%) were used as part of the equation in order to capture weather diversity across the integrated system.

Any known interruptions (Interruptible Demand Response Rate 38 and/or customer outages) that occurred at the time of the summer peak were added to the historical actual summer peak used in the peak demand econometric model. The summer peak value thus represents the peak as it would have occurred had there not been any interruptions. More detail regarding the specific factors used in the peak demand forecast is described in Attachment A.

Forecast Adjustments

The forecast methodology for both energy sales and peak demand results in an initial energy sale forecast by sales sector for each state and an initial peak demand forecast. Reductions to the energy sales forecasts by sector and by state and to the peak demand forecast are made to reflect demand-side management programs. Once these reductions are reflected in the energy sales forecasts, the total of the energy sales forecasts by class are adjusted by the loss factor to arrive at the final forecast of total energy requirements.

Demand-Side Management (DSM) Reductions

The load forecast presented in this IRP was prepared in 2014 (*Electric Load Forecast 2015-2034*, published December 31, 2014). The DSM programs that were selected for the 2013 IRPs were incorporated in the forecast so that it reflects reductions resulting from the DSM programs planned at that time.

Losses

The energy sales forecast reflects the energy delivered to Montana-Dakota's customers' meters. The total amount of electricity provided by generating resources to meet Montana-Dakota's customers' energy needs is greater than what is delivered to the meters and is called the total energy requirements. The difference between the energy sales and total energy requirements reflects the losses that occur within the transmission and distribution system.

The percentage of the annual energy losses has varied from year to year. The average value for the past ten years is 8.434 percent. Using this value for all future years, the total system hourly loads are calculated for each year during the study period.

Final Energy Requirements and Peak Demand Forecast

The forecasted energy sales and system peak demand are first adjusted to reflect the effects of the DSM programs planned in the 2013 IRP and then adjusted for losses to calculate the total energy requirements and demand forecast. This is the amount of energy and capacity that must be acquired to meet Montana-Dakota's customers' energy needs.

The final forecast results are presented in Table 2-1 summarizing the total energy requirements and seasonal peak demand.

Table 2-1

Montana-Dakota Utilities Co.
Historical and Forecasted Energy and Demand
Integrated System
Reflecting Demand-Side Management Programs from 2013 IRP
Calendar Month Basis

	Total Energy Requirements (net of DSM and EE)		Summer Peak - MW				Winter Peak 2/				Demand Response	
Year	MWh	% Change	Total Demand Before any DSM or EE	Energy Efficiency (EE)	Demand Net of EE 1/	% Change	Total Demand Before any DSM or EE	Energy Efficiency (EE)	Demand Net of EE 1/	% Change	Rate 38/39 Interrupt Loads	Commercial Demand Response
2004	2,204,012				458.4				383.9			
2005	2,327,117	5.59%			459.1	0.15%			387.2	0.86%		
2006	2,397,793	3.04%			485.5	5.75%			397.2	2.58%		
2007	2,510,540	4.70%			525.6	8.26%			407.3	2.54%		
2008	2,596,990	3.44%			476.6	-9.32%			455.0	11.71%		
2009	2,593,368	-0.14%			473.8	-0.59%			459.6	1.01%		
2010	2,718,192	4.81%			502.5	6.06%			457.8	-0.39%		
2011	2,776,082	2.13%			535.8	6.63%			510.8	11.58%		
2012	2,919,752	5.18%			573.6	7.05%			516.2	1.06%		
2013	3,115,064	6.69%			546.9	-4.65%			582.1	12.77%		
2014	3,250,683	4.35%			533.0	-2.54%			not yet available			
2015	3,563,732	9.63%	626.0	1.5	624.5	17.17%	605.2	1.5	603.7		13.4	10.0
2016	3,809,892	6.91%	656.2	1.5	654.7	4.84%	634.3	1.5	632.8	4.82%	15.4	12.5
2017	4,044,774	6.17%	685.2	1.5	683.7	4.43%	652.4	1.5	650.9	2.86%	15.4	15.0
2018	4,220,333	4.34%	707.4	1.5	705.9	3.25%	664.5	1.5	663.0	1.86%	15.4	15.0
2019	4,366,313	3.46%	726.3	1.5	724.8	2.68%	676.6	1.5	675.1	1.83%	15.4	15.0
2020	4,464,924	2.26%	739.8	1.5	738.3	1.86%	688.0	1.5	686.5	1.69%	15.4	15.0
2021	4,565,434	2.25%	753.5	1.5	752.0	1.86%	699.2	1.5	697.7	1.63%	15.4	15.0
2022	4,659,237	2.05%	766.4	1.5	764.9	1.72%	709.3	1.5	707.8	1.45%	15.4	15.0
2023	4,738,979	1.71%	777.8	1.5	776.3	1.49%	719.2	1.5	717.7	1.40%	15.4	15.0
2024	4,818,606	1.68%	789.1	1.5	787.6	1.46%	728.6	1.5	727.1	1.31%	15.4	15.0
2025	4,898,425	1.66%	800.5	1.5	799.0	1.45%	738.2	1.5	736.7	1.32%	15.4	15.0
2026	4,978,277	1.63%	811.9	1.5	810.4	1.43%	747.4	1.5	745.9	1.25%	15.4	15.0
2027	5,059,454	1.63%	823.4	1.5	821.9	1.42%	756.6	1.5	755.1	1.23%	15.4	15.0
2028	5,139,170	1.58%	834.8	1.5	833.3	1.39%	765.3	1.5	763.8	1.15%	15.4	15.0
2029	5,220,318	1.58%	846.3	1.5	844.8	1.38%	774.0	1.5	772.5	1.14%	15.4	15.0
2030	5,302,866	1.58%	858.0	1.5	856.5	1.38%	782.8	1.5	781.3	1.14%	15.4	15.0
2031	5,386,977	1.59%	869.8	1.5	868.3	1.38%	791.8	1.5	790.3	1.15%	15.4	15.0
2032	5,472,577	1.59%	881.9	1.5	880.4	1.39%	800.6	1.5	799.1	1.11%	15.4	15.0
2033	5,558,146	1.56%	893.9	1.5	892.4	1.36%	809.8	1.5	808.3	1.15%	15.4	15.0
2034	5,645,254	1.57%	906.1	1.5	904.6	1.37%	819.1	1.5	817.6	1.15%	15.4	15.0

1/ Historical demand reported is system actual demand.
2/ Winter Peak is for Nov-Dec of current year and Jan-Apr of following year.

Forecast Uncertainty

Forecasting is a process permeated with uncertainty. The demand and energy projections produced by the combined analysis forecasting process results in a forecast based solely on the information used as inputs to the equations. For purposes of integrated resource planning, a single forecast does not allow the analysis of risk and uncertainty associated with the input assumptions. Robust resource decisions cannot be made unless uncertainty is considered. This uncertainty can be expressed by peak demand forecasts that reflect temperatures which correspond to higher confidence levels as well as high-growth and low-growth scenarios in energy forecasts.

Effect of Temperature on Peak Demand

The final forecast results were developed assuming average temperatures at the time of the system peak. However, with an average temperature forecast, by definition actual peak demand would have a 50 percent probability of being lower than the forecast values and a 50 percent probability of exceeding forecast values (50/50 forecast). It can appear that peak demand is under-forecasted when the actual temperature at the time of system peak exceeds average temperatures.

Montana-Dakota conducts a study periodically to establish the relationship between summer peak demand and temperature at the time of system peak. As part of the study, the Company's historical July and August demands and corresponding temperatures at times when the temperatures equaled or exceeded 85°F on Mondays through Thursdays are analyzed. The 2013 study results indicated each one degree increase in temperature at the time of summer peak would result in an increase of approximately 6.0 MW in summer peak demand.

Further statistical analysis of temperatures at the time of system peak for the years 1984 through 2014 (prior to 1984 Montana-Dakota was a winter peaking utility) provided the results shown in Table 2-2.

Table 2-2
Temperature Probability at Peak and Effect on Peak Demand

Probability	Weighted Average Temperature	Approximate Increase in Peak Demand (MW)
50.0%	96.5	0.0
75.0%	99.5	18.0
80.0%	100.2	22.2
85.0%	101.1	27.6
90.0%	102.1	33.6
95.0%	103.7	43.2
97.0%	104.8	49.8

As Table 2-2 shows, with a weighted average temperature of 96.5°F at the time of peak, there is a 50 percent probability the temperature at peak would be lower than 96.5°F and a 50 percent probability the temperature at peak would be higher than 96.5°F. This forecast is referred to as the 50/50 demand forecast.

Also from Table 2-2, there is a 90 percent probability actual temperatures at the time of the system peak will not exceed 102.1°F. However, at this temperature (102.1°F), the system peak demand would be 33.6 MW higher than the demand in the base, or 50/50, forecast. This forecast is called the 90/10 forecast and provides a peak demand forecast that represents a 90 percent probability the actual peak demand will not exceed the forecast value and a 10 percent probability the actual peak demand will be higher than the forecast value. Table 2-3 summarizes the results of the 50/50 probability and 90/10 probability demand forecasts.

Table 2-3
Alternate Summer Peak Demand Forecast Comparison

Year	Base Forecast (96.5 degrees F) 50/50 Forecast (MW)	Growth Rate	Alternate Forecast (102.1 degrees F) 90/10 Forecast (MW) */
2015	624.5		658.1
2016	654.7	4.84%	689.9
2017	683.7	4.43%	720.5
2018	705.9	3.25%	743.9
2019	724.8	2.68%	763.8
2020	738.3	1.86%	778.0
2021	752.0	1.86%	792.4
2022	764.9	1.72%	806.0
2023	776.3	1.49%	818.0
2024	787.6	1.46%	829.9
2025	799.0	1.45%	841.9
2026	810.4	1.43%	853.9
2027	821.9	1.42%	866.0
2028	833.3	1.39%	878.0
2029	844.8	1.38%	890.1
2030	856.5	1.38%	902.4
2031	868.3	1.38%	914.8
2032	880.4	1.39%	927.5
2033	892.4	1.36%	940.1
2034	904.6	1.37%	953.0

*/ The growth rate for the 90/10 Forecast scenario is assumed to be the same as that of the 50/50 Forecast scenario.

High-Growth and Low-Growth Scenario Forecasts

Another approach taken to express forecast uncertainty in this study was to simulate high-growth and low-growth scenarios which represent the corresponding economic conditions that may occur. These high-growth and low-growth scenario forecasts were developed as follows.

Historical total energy was analyzed in order to find a period of time during which unusually high growth was experienced and a period of time during which unusually low growth was experienced. Based on the historical sales data, the average growth rate that occurred from 1977 to 1985 was used as the high-growth rate, and the average growth rate that occurred from 1985 to 1993 was used as the low-growth rate. Both of these periods consist of eight years of history.

However, as shown on Table 2-1, the growth now projected for the Integrated System in 2015, 2016, and 2017 is greater than 4.4 percent. Montana-Dakota decided that the high-growth scenario would be set to the growth projected for 2015, 2016, and 2017 and growth would then fall to 4.4 percent per year for 2018 to 2034. Forecasted growth for 2015, 2016, and 2017 is fairly well defined through work with Montana-Dakota's field personnel who have contact with and closely monitor the addition and connection of customers on the system. It is unlikely that additional growth opportunities will develop in the near term which will increase the forecasted growth above these levels. For the low-growth scenario, an average growth rate of 0.5 percent per year was assumed to occur during the 20-year forecast horizon.

Demand for each scenario was derived by applying the load factors calculated from the base forecast to the high-growth and low-growth scenario forecasted energy. The results of the high- and low-growth scenarios for energy and demand are shown on Table 2-4. The following page presents the graphs of the numeric results.

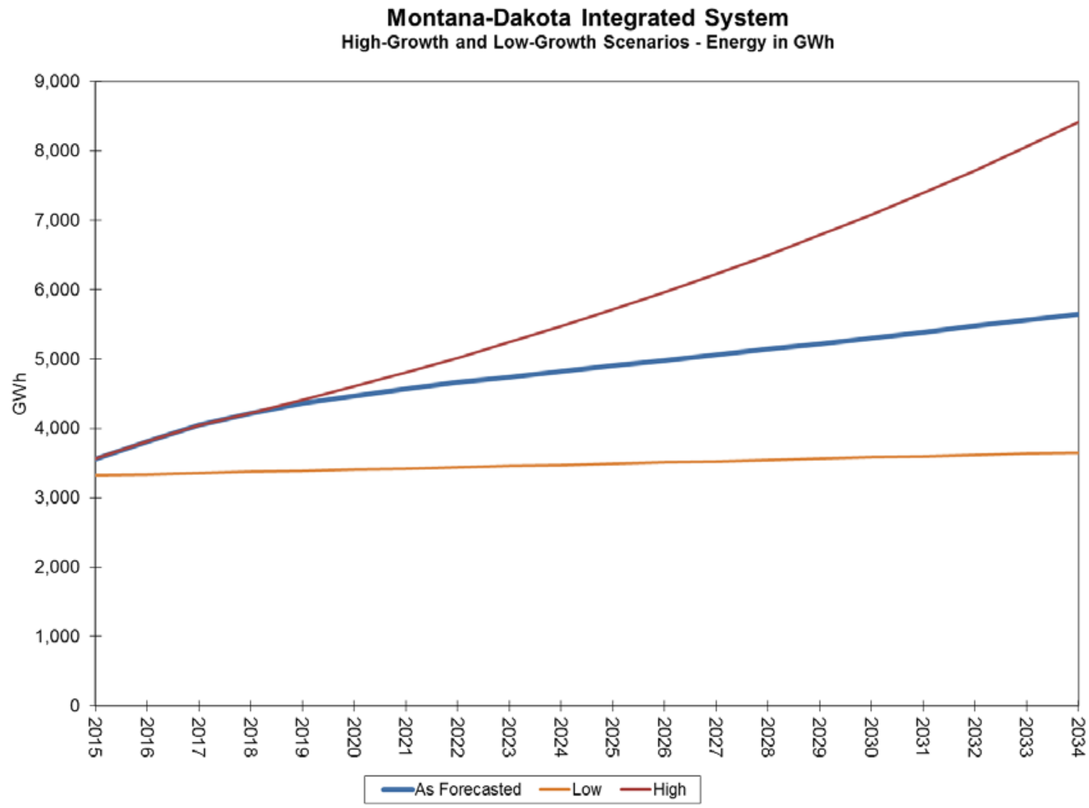
Table 2-4

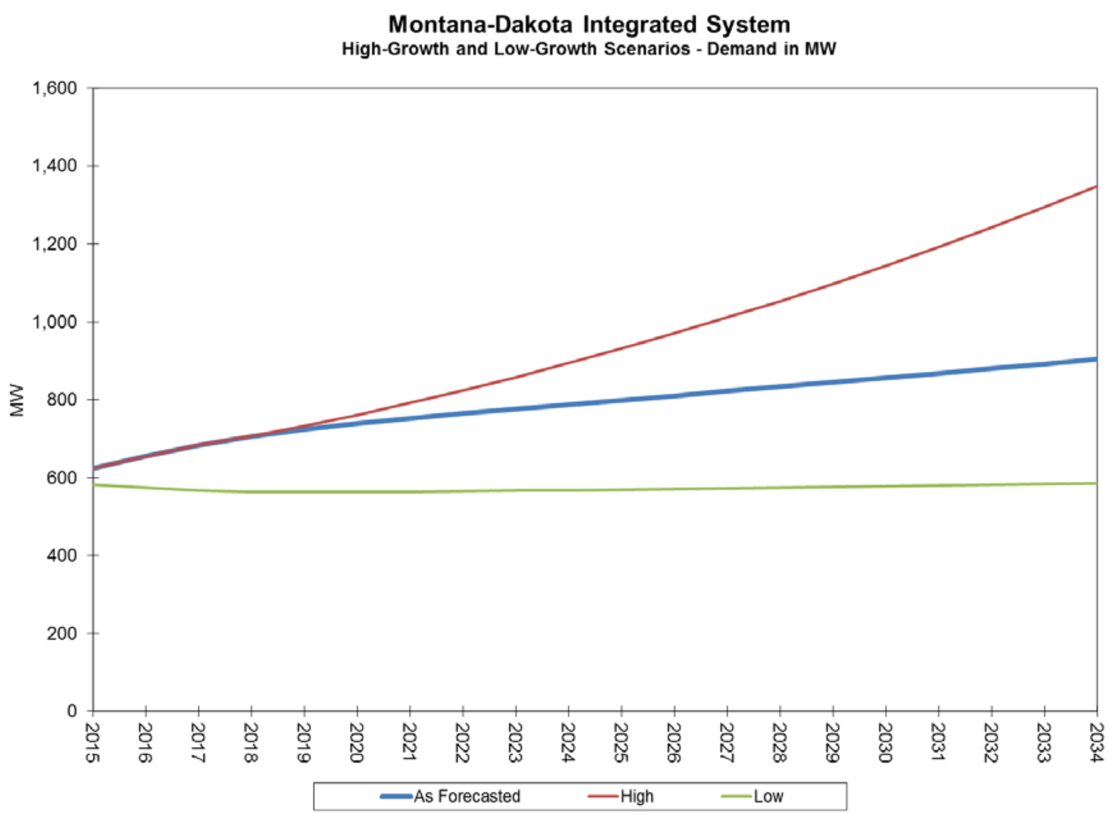
High-Growth and Low-Growth Scenarios
Total Annual Energy (GWh) and
Summer Peak Demand (MW)

	ENERGY			DEMAND		
	Forecast	HIGH 1/	LOW 2/	Forecast	HIGH	LOW
2015	3563.7	3563.7	3321.6	624.5	624.5	582.1
2016	3809.9	3809.9	3338.2	654.7	654.7	573.6
2017	4044.8	4044.8	3354.9	683.7	683.7	567.1
2018	4220.3	4222.8	3371.7	705.9	706.3	564.0
2019	4366.3	4408.6	3388.6	724.8	731.8	562.5
2020	4464.9	4602.6	3405.5	738.3	761.1	563.1
2021	4565.4	4805.1	3422.5	752.0	791.5	563.7
2022	4659.2	5016.5	3439.6	764.9	823.6	564.7
2023	4739.0	5237.2	3456.8	776.3	857.9	566.3
2024	4818.6	5467.6	3474.1	787.6	893.7	567.8
2025	4898.4	5708.2	3491.5	799.0	931.1	569.5
2026	4978.3	5959.4	3509.0	810.4	970.1	571.2
2027	5059.5	6221.6	3526.5	821.9	1010.7	572.9
2028	5139.2	6495.4	3544.1	833.3	1053.2	574.7
2029	5220.3	6781.2	3561.8	844.8	1097.4	576.4
2030	5302.9	7079.6	3579.6	856.5	1143.5	578.2
2031	5387.0	7391.1	3597.5	868.3	1191.3	579.9
2032	5472.6	7716.3	3615.5	880.4	1241.4	581.6
2033	5558.1	8055.8	3633.6	892.4	1293.4	583.4
2034	5645.3	8410.3	3651.8	904.6	1347.7	585.2

1/ High forecast assumes no growth greater than that already forecasted for 2015, 2016, and 2017
4.4% growth per year (actual 77-85 growth) for the remainder of the forecast horizon 2018-2034

2/ Low forecast assumes 0.5% growth per year (actual 85-93 growth).


Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Energy in GWh
GWh
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
As Forecasted
Low
High


Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Demand in MW
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
As Forecasted
High
Low

Bakken and Sanish-Three Forks Update[1]

The Bakken Shale Formation ranks as one of the largest oil developments in the United States in the past 40 years. The Bakken has single-handedly driven North Dakota's oil production to levels four times higher than previous peaks in the 1980s. North Dakota is now second only to Texas in terms of oil production in the United States.

The Bakken Shale Formation is located in Eastern Montana and Western North Dakota, as well as parts of Saskatchewan and Manitoba in the Williston Basin. Oil was initially discovered in the Bakken play in 1951, but was not commercial on a large scale until the past ten years. The advent of modern horizontal drilling and hydraulic fracturing helps make Bakken oil production economic. The U.S. Geological Survey has estimated the Bakken Shale Formation could yield 4.3 billion barrels of oil and estimates from Continental Resources stretch as high as 40 billion barrels.

The Three Forks Formation underlies the Bakken Shale. The formation is sourced by the Bakken and produces across parts of North Dakota and Montana. The play is a secondary target in some areas and has proven even more prolific than the Bakken in some other areas.

The Bakken rig count dropped to below 100, down from a peak rig count of 220 in May of 2012[2], for the first time in five years in March 2015, primarily due to low crude oil prices. While Montana-Dakota does not typically serve drilling rigs, the reduction in rigs actively exploring for or producing oil and natural gas may have an indirect effect on Montana-Dakota's sales and demand through a slowdown in the growth of indirect oil serving loads including residential; and small and large commercial and industrial customers like retail customers, schools, water treatment facilities, and oil pumping loads.

When the electric load forecast that is reflected in this IRP was developed in mid- to late-2014, oil field activity was very strong and oil production records were almost continually being set. As of early 2015, it is still unknown the long-term impact on Montana-Dakota's electricity sales and demand forecast associated with the recent drop in oil prices across the world. Montana-Dakota has seen reduced customer sales through 2015 to date but a majority of this decline in sales can be attributed to milder weather the past winter and a delay in several new large commercial and industrial customers coming online as they originally had planned.

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[1] http://bakkenshale.com/
[2] http://bakkenshale.com/drilling-rig-count/bakken-rig-count-down/

At this time it would be premature to adjust the sales and/or demand forecasts for Montana-Dakota's Integrated System due to the recent change in the Bakken. It is unknown if the decrease in Bakken activity will be a permanent or long-lasting change or if it is just a short-term reaction to the current price of oil. Montana-Dakota goes through a lengthy and detailed process to produce its electric load forecasts annually and there will be an opportunity to reflect current and established market conditions in the forecast developed later in 2015. Similarly, the IRP process is a fluid process and the models are updated when necessary between IRP filings to reflect important changes. Forecast uncertainties in the IRP process are also accounted for in various sensitivities to test the robustness of any future resource planning and construction activities.

CHAPTER 3

DEMAND-SIDE ANALYSIS

Overview

Demand-Side Management (DSM) is a resource planning tool a utility can use to meet two objectives: (1) to potentially offset future generation resource costs through load management and/or conservation measures and (2) to enhance customer service through the offering of programs to customers that will help reduce their overall demand and/or energy requirements.

With the demand for electricity and the need for additional resources growing, Montana-Dakota recognizes the value that DSM can play in meeting our customer's future energy requirements. However, the implementation of DSM programs cannot be done without cost consideration to the utility's customers and shareholders. Interests need to be balanced to achieve results at an affordable cost to both the utility and its customers.

Montana-Dakota's DSM analysis is completed on a state by state approach (Montana, North Dakota, and South Dakota) versus an Integrated System approach, due to the complexities of offering DSM programs across multiple jurisdictions and then in total for the Integrated System. The DSM benefit/cost analysis is contained in Attachment B of this IRP.

Provided in this Chapter is a discussion of the DSM program planning activities, a summary of the DSM program benefit/cost analysis, a summary of current DSM Programs and activities, and Montana-Dakota's future DSM implementation plan for 2016-2018.

DSM Program Planning

In the 2013 IRP Montana-Dakota provided the results of the Nexant Energy Efficiency Potential Study that was completed for the Montana service territory, which also included an energy efficiency attitudes survey of customers. In addition, Nexant also performed a Program Planning Study for the Montana Service territory, which was completed in December of 2013.

The following are a summary of the key findings of the Nexant studies and customer survey.

Key findings of the Energy Efficiency Potential Study:

- Montana-Dakota's Montana service territory has opportunities to achieve savings through energy efficiency programs. Ramp rate is very slow and total achievable annual potential for the study period is approximately 0.3% of energy consumption.

- Higher incentive levels will likely cause proportionally greater market adoption in all sectors. Low incentive levels will likely have less of an effect in Montana-Dakota's Montana service territory as compared to the average utility service territory.

- Lighting, appliance, and space heating end uses make up approximately 80 percent of the residential sector's achievable potential.

- Commercial end-uses such as lighting, plug loads, and refrigeration should be given priority since together they account for over 75 percent of the sector's savings potential.

Key findings of the Program Planning Study:

- Fixed costs have a substantial impact on program cost effectiveness and participation rates will have a major impact on overall cost-effectiveness.

- Adjusting program delivery mechanisms and marketing efforts should increase participation, leading to higher program effectiveness.

- Commercial and Industrial focus on lighting, motors and drives, and high efficiency equipment and controls. A direct install program may work due to the limited contractor network in the Montana service territory.

- Residential focus on lighting, home weatherization, and appliances.

Key findings from the results of the customer survey:

- Reduction of residential customers' energy bill is a strong market driver.

- Only the least expensive measures are likely to be considered with an incentive level of 25 percent of the incremental cost. In many cases, customers would be more likely to take action at the 50 percent or greater incentive level.

- Residential & commercial customers expressed two major reasons for not taking immediate action to adopt energy efficiency: the desire to wait until current equipment fails and the fact the upfront cost of the measures is too high.

- Residential and commercial customers expressed limited awareness of Montana-Dakota's energy efficiency programs.

Montana-Dakota used the key findings discussed above to review the existing DSM program offerings and delivery mechanisms. The portfolio of DSM programs included in this IRP are not significantly different from the currently offered programs, however different program delivery and outreach efforts are being considered for implementation in 2016. A summary of the program delivery and increased outreach efforts being considered are:

- Point of sale options for residential CFL and LED Lighting
- Additional prescriptive measure added to commercial lighting program
- Direct install program for commercial lighting
- Contractor network development and training
- Development of additional energy education and outreach material

Montana-Dakota also used the study ramp rates and achievable potential to estimate the achievable potential for the integrated system. The Montana service territory ramp rates and achievable potential are projected for the South Dakota due to similar market characteristics. The North Dakota service territory ramp rates and achievable potential have been increased over what is projected for the Montana service territory due to larger communities served and a stronger contractor network.

Based on the results of the Montana study and Montana-Dakota's market knowledge of the service territory Montana-Dakota estimates the achievable annual energy reduction of 0.35 percent of annual energy sales (MWh) and 1.78% of demand (MW) over the IRP planning period. A summary of the MWh and MW results are shown below in Tables 3-1 and 3-2, respectively. The complete state by state analysis and discussion are contained in Attachment B.

Table 3-1: Montana-Dakota's System-Wide Potential MWh Savings Summary

YEAR	Total Sales Sales (MWh)	Achievable EE %	Achievable MWh
2015	3,276,295	0.08%	2,700
2016	3,506,186	0.13%	4,614
2017	3,724,612	0.13%	4,899
2018	3,886,364	0.18%	6,911
2019	4,022,388	0.20%	7,867
2020	4,113,217	0.26%	10,838
2021	4,206,229	0.27%	11,401
2022	4,293,415	0.36%	15,540
2023	4,366,963	0.36%	15,814
2024	4,440,395	0.43%	19,126
2025	4,514,021	0.43%	19,455
2026	4,587,595	0.43%	19,786
2027	4,662,533	0.43%	20,124
2028	4,735,995	0.43%	20,460
2029	4,810,770	0.43%	20,801
2030	4,886,834	0.43%	21,149
2031	4,964,341	0.43%	21,504
2032	5,043,285	0.43%	21,866
2033	5,122,142	0.43%	22,229
2034	5,202,418	0.43%	22,600
Cumulative	**88,366,005**	**0.35%**	**309,686**

Table 3-2: Montana-Dakota's System-Wide Potential MW Savings Summary

Year	Summer Peak (MW)	Achievable EE %	Achievable MW	Winter Peak (MW)	Achievable EE %	Achievable MW
2015	626.0	0.10%	0.63	605.1	0.10%	0.61
2016	656.3	0.10%	0.66	634.4	0.10%	0.63
2017	685.2	0.10%	0.69	652.4	0.10%	0.65
2018	707.4	0.10%	0.71	664.5	0.10%	0.66
2019	726.2	0.10%	0.73	676.7	0.10%	0.68
2020	739.7	0.10%	0.74	687.9	0.10%	0.69
2021	753.4	0.10%	0.75	699.2	0.10%	0.70
2022	766.4	0.10%	0.77	709.4	0.10%	0.71
2023	777.8	0.10%	0.78	719.2	0.10%	0.72
2024	789.1	0.10%	0.79	728.6	0.10%	0.73
2025	800.5	0.10%	0.80	738.3	0.10%	0.74
2026	811.9	0.10%	0.81	747.4	0.10%	0.75
2027	823.4	0.10%	0.82	756.6	0.10%	0.76
2028	834.8	0.10%	0.83	765.2	0.10%	0.77
2029	846.4	0.10%	0.85	774.0	0.10%	0.77
2030	858.0	0.10%	0.86	782.8	0.10%	0.78
2031	869.9	0.10%	0.87	791.9	0.10%	0.79
2032	881.8	0.10%	0.88	800.6	0.10%	0.80
2033	893.9	0.10%	0.89	809.8	0.10%	0.81
2034	906.1	0.10%	0.91	819.1	0.10%	0.82
Cumulative					**1.78%**	**14.56**

Benefit/Cost Analysis

To determine which programs are cost effective, and therefore should be included as resource options in the integration analysis, a benefit/cost analysis by state was performed for each of the potential DSM programs. The basic function of the analysis was to calculate each DSM program's benefits and costs to determine the cost effectiveness of each respective program on a stand-alone basis. The programs were evaluated using five different cost-effectiveness tests: the Participant Test, the Utility Test, the Ratepayer Test, Societal Cost Test and the Total Resource Cost (TRC) Test. The *Participant Test* considers the economic impact of a program on the participating customers, the *Utility Test* considers the impact on the utility, the *Ratepayer Test* includes all quantifiable benefits and costs of a given program and considers its impact on all ratepayers, and the *Societal Cost Test* includes environmental externalities and considers the impact on the "society" (both the participants and non-participants).

The *Total Resource Cost Test* reflects the total benefits and costs to all customers (both the participants and non-participants). In determining whether a program is cost effective, Montana-Dakota relied on the resulting benefit/cost ratio of the TRC Test as well as the practicality of implementation and the ongoing administration of that program.

A summary of the benefit/cost ratios by state are contained below in Table 3-3. A discussion of the results and the complete DSM program analysis by state and in total for Montana-Dakota Integrated System is contained in Attachment B and Appendix A of Attachment B of this report.

DSM Benefit/Cost Summary
Table 3-3

Montana

DSM Program	Customer Class	RIM	Utility	Societal	Participant	Total Resource Cost
Total Portfolio		2.01	2.41	3.07	3.62	2.06
Residential Programs						
Central Air Conditioning Tier 1 (14.5 SEER)	Residential	1.02	1.23	1.68	0.85	0.75
Central Air Conditioning Tier 2 (16 SEER) - Replacement	Residential	0.98	1.16	1.57	0.82	0.70
Central Air Conditioning Tier 2 - New	Residential	0.93	1.09	1.51	0.82	0.67
Window AC Units	Residential	0.64	0.71	1.39	1.50	0.80
Thermal Storage with ASHP	Residential	4.55	7.83	8.76	1.35	4.39
Residential Lighting	Residential	1.35	7.95	17.03	18.14	9.85
Demand Response						
Residential AC Cycling	Residential	1.87	1.70	2.53	2.94	1.61
Commercial Programs						
Commerical Lighting	Commerical	1.45	4.86	6.85	4.33	3.03
Commercial Motors - Replacement	Commerical	1.45	4.03	0.88	0.50	0.38
Commerical Motors - New / on Failure	Commerical	1.69	6.74	1.27	0.69	0.55
Variable Speed Drives - VFD'S	Commerical	1.21	9.95	4.07	3.13	1.95
Commercial Partnership Program (Custom)	Commerical	1.68	4.96	4.86	3.68	2.73
Demand Response						
Commercial Demand Response Program	Commercial	2.13	2.13	2.95	73.25	2.13
Interruptible Rate DR Program	Commercial	2.84	2.88	3.76	16.82	2.71

North Dakota

DSM Program	Customer Class	RIM	Utility	Societal	Participant	Total Resource Cost
Total Portfolio		2.03	2.47	3.14	4.33	2.12
Residential Programs						
Central Air Conditioning Tier 1 (14.5 SEER)	Residential	1.09	1.27	1.69	0.76	0.76
Central Air Conditioning Tier 2 (16 SEER) - Replacement	Residential	1.00	1.15	1.53	0.74	0.68
Central Air Conditioning Tier 2 - New	Residential	1.01	1.54	1.54	0.74	0.69
Window AC Units	Residential	0.63	0.68	1.34	1.39	0.78
Thermal Storage with ASHP	Residential	4.71	8.20	8.97	1.30	4.50
Residential Lighting	Residential	1.44	11.35	19.57	16.60	11.35
Demand Response						
Residential AC Cycling	Residential	1.69	1.69	2.46	2.24	1.59
Commercial Programs						
Commerical Lighting	Commerical	1.68	7.05	9.65	6.18	4.28
Commercial Motors - Replacement	Commerical	1.27	4.30	0.89	0.61	0.39
Commerical Motors - New / on Failure	Commerical	1.41	7.07	1.27	0.82	0.55
Variable Speed Drives - VFD'S	Commerical	0.99	10.70	4.12	4.01	1.98
Commercial Partnership Program (Custom)	Commerical	1.46	5.27	5.01	4.46	2.82
Demand Response						
Commercial Demand Response Program	Commercial	2.12	2.12	2.92	23.00	2.11
Interruptible Rate DR Program	Commercial	2.84	2.88	3.76	16.82	2.71

South Dakota

DSM Program	Customer Class	RIM	Utility	Societal	Participant	Total Resource Cost
Total Portfolio		1.92	2.52	3.13	3.48	1.98
Residential Programs						
Central Air Conditioning Tier 1 (14.5 SEER)	Residential	1.08	1.26	1.76	0.84	0.78
Central Air Conditioning Tier 2 (16 SEER)	Residential	0.92	1.07	1.49	0.81	0.66
Central Air Conditioning Tier 2 - New	Residential	0.93	1.07	1.52	0.81	0.68
Window AC Units	Residential	0.54	0.59	1.12	1.50	0.66
Thermal Storage with ASHP	Residential					
Residential Lighting	Residential	1.49	9.59	16.60	19.19	9.59
Demand Response						
Residential AC Cycling	Residential	1.68	1.68	2.45	2.86	1.59
Commercial Programs						
Commerical Lighting	Commerical	2.26	6.21	8.95	5.62	3.96
Commercial Motors - Replacement	Commerical	1.69	3.88	0.90	0.58	0.39
Commerical Motors - New / on Failure	Commerical	2.11	6.70	1.36	0.80	0.58
Variable Speed Drives - VFD'S	Commerical	1.49	9.32	4.01	4.01	1.93
Commercial Partnership Program (Custom)	Commerical	1.88	4.40	4.52	4.02	2.54
Demand Response						
Commercial Demand Response Program	Commercial	2.19	2.19	2.96	4.73	2.11
Interruptible Rate DR Program	Commercial					

Program Portfolio Overview

Montana-Dakota currently offers Energy Efficiency DSM Programs only in Montana which are funded through the Universal Systems Benefit Charge. Demand Response DSM Programs are available to commercial customers in Montana, North Dakota, and South Dakota. The following is an overview of program details associated with each residential and commercial DSM measure that is currently being offered. The overview provides a description of the program, jurisdictions where the program is or will be offered, DSM measures included in the program, incentive levels, and the marketing and promotion plan. A summary of all programs is presented in Table 3-4.

Summary of Portfolio of Programs
Table 3-4

	Montana	North Dakota	South Dakota
Residential Programs			
Central Air Conditioner Tier 1 (14.5 SEER) - Replacement	$100/ton		
Central Air Conditioner Tier 2 (16 SEER) - Replacement	$200/ton		
Central Air Conditioner Tier 2 - New	$200/ton		
Window Air Conditioner Units	$50		
Thermal Storage with Air-Source Heat Pump	$60/kW		
Residential Lighting	$2/bulb		
Commercial Programs			
Commercial Lighting	$0.40/watt		
Commercial Motors - Replacement	$15/HP		
Commercial Motors - New/On Failure of Exist. Equip.	$4/HP		
Variable Speed Drives - VFD	$30/HP		
Commercial Central Air Conditioner Tier 1 (14.5 SEER)	$100/ton		
Commercial Central Air Conditioner Tier 1 (16 SEER)	$200/ton		
Commercial Air Conditioner - Split Systems	$100/ton		
Commercial Air Conditioner - Packaged Systems	$100/ton		
Commercial Partnership Program (Custom)	Project-Specific		
Commercial Demand Response Program	Customer-Specific	Customer-Specific	Customer-Specific
Interruptible Rate Demand Response Program	$5.00/kW	$3.00/kW	

DSM Activity Summary

Montana-Dakota currently offers Energy Efficiency DSM Programs in Montana and Demand Response DSM Programs in Montana, North Dakota, and South Dakota. The following is a discussion of the activity in the currently offered programs.

Montana Energy Efficiency (EE) DSM Programs

The Montana EE Programs are funded through the Universal Systems Benefit Charge and have been offered for the last several years.

Participation in the Montana EE portfolio of programs continues to be limited in both the residential and commercial programs. In 2014 there were a total of five participants in the residential programs and a total of seven participants in the commercial programs.

Demand Response Programs

Montana-Dakota currently offers two demand response programs for commercial and industrial customers. The Commercial Demand Response Program and Interruptible Demand Response Rate which together provide demand response options to customers starting at 50 kW of demand billing.

Commercial Demand Response Program

The Commercial Demand Response Program was launched in June of 2012 and is available to commercial and industrial electric customers in all states, with a priority focused on customers with loads of 150 kW or higher. The total program goal remains 25 MW, however for the integration analysis a conservative approach was taken assuming 15 MW for the summer of 2017.

The Commercial Demand Response program had increased activity in 2014, with 7.6 MW enrolled and participating in the program by year end.

Currently, the enrollment of one large participant is pending enrollment/nomination in the program. This will account for an additional 2.5 MW in the program and it is expected that the total program with have approximately 10 MW by summer of 2015.

Interest in the program continues, however Montana-Dakota and the third party administrator continue to experience a longer than expected sales cycle time. This can be attributed to the education process involved in obtaining new participants and the ability to contact the appropriate decision maker.

Interruptible Demand Response Rate

The Interruptible Demand Response Rate has been available for several years and is available to commercial and industrial electric customers with loads of 500 kW or higher. This program currently has 13.4 MW enrolled and Montana-Dakota's goal is to increase participation by 2.6 MW or to a total enrollment of 16 MW by the summer of 2017.

Montana-Dakota continues to work with customers and engineering companies to promote the use of the Interruptible Demand Response Rate and expects that the goal of 16 MW will be achieved by the summer of 2017.

DSM Implementation Plan

The following is a discussion by state of the expected DSM activity for program years 2016-2018. Also included is a discussion on Montana-Dakota's continued research into distributed generation as a possible fit for future system supply.

<u>Montana</u>

Montana-Dakota will only continue with the existing energy efficiency programs offered in Montana that are cost effective for the remainder of 2015 and implement cost effective program changes in residential and commercial lighting in 2016. Increase marketing and outreach to customers, contractor network, and energy service companies.

In addition, Montana-Dakota will continue to implement the Commercial Demand Response Program and promote the Interruptible Demand Response Rate in an effort to attain total program goals of 15 MW and 16 MW respectively. Montana-Dakota will also continue to review the residential air conditioning cycling program for possible implementation in 2016 or 2017.

<u>North Dakota</u>

Montana-Dakota will continue to implement the Commercial Demand Response Program and promote the Interruptible Demand Response Rate in an effort to attain total program goals of 15 MW and 16 MW respectively. In addition, Montana-Dakota will continue to review the residential air conditioning cycling program for possible implementation in 2016 or 2017.

South Dakota

Montana-Dakota will continue to implement the Commercial Demand Response Program in an effort to attain total program goals of 15 MW and 16 MW respectively. In addition, Montana-Dakota will continue to review the residential air conditioning cycling program for possible implementation in 2016 or 2017.

Distributed Generation

Distributed Generation (DG) refers to decentralized energy production that takes place on, or near the site being served. DG operates independently of traditional, centralized utility-scale electric generation facilities and can be paired with energy storage devices to run independently of the grid, or can *supplement* grid tied resources to provide peaking and resiliency benefits.

Examples of DG resources include cogeneration (fired by fossil or bio fuels), small wind, rooftop or community solar photovoltaic (PVE), and solar thermal. Decentralized projects can be as simple as placing a single solar panel on a residential rooftop, or can entail combining multiple resources together with storage for micro grids which provide power at a "campus" or small community level.

While traditional fuel sources such as coal, gas, and large wind remain best cost resources for electric generation, on-site energy production is becoming increasingly cost competitive. And with the price of many distributed technologies declining, and the continued advancement of storage, distributed generation has tremendous potential to impact the grid and shape the way customers use energy—although the extent of these impacts will vary greatly region by region.

Regardless of the form Distributed Generation takes, it will be essential to continue monitoring technologies as they emerge and to determine what resources and adaptations (storage, smart grid upgrades, policy changes, new programs, etc.) may be needed to effectively adjust to an evolving energy economy.

The core technologies that are likely to have the greatest impacts in MDU's electric service area have been explored below:

Distributed Solar

Solar photovoltaic energy (PVE) is a prolific but intermittent resource which is collected through panels and converted into electricity that can be used immediately or fed back to the electric grid. Although this technology has been around for decades, in recent years its presence has grown significantly on a national scale. This is because of marked increased in enabling regulations and tax credits across the country, as well as the maturation of solar technology itself, increasing electric rates, and the emergence of viable battery technologies.

In Montana-Dakota’s electric service area, low electric rates have kept the presence of solar to a minimum. However, as the costs of solar technologies continue to decline and average electric rates gradually increase over time, our regions will begin to see an increased solar presence.

Montana-Dakota will monitor opportunities for the prudent integration of distributed solar energy, as well as consider optimal metering and interconnection policies. These are necessary first steps to effectively manage an emerging solar presence. A proactive, coordinated approach to the eventuality of solar will ensure greater benefit and stability for the nascent solar market in our region and help avoid the duck curve, and associated reliability concerns experienced in areas where solar planning was not approached holistically.

Distributed Natural Gas-Fired Combined Heat and Power (CHP)

Cogeneration, otherwise known as Combined Heat and Power (CHP) captures and utilizes excess heat generated during the production of electric power. Natural gas fired CHP is often valued from a source efficiency standpoint since line losses from traditional electric generation are mitigated by the use of natural gas. Likewise, CHP powered by waste heat or biogas has additional environmental benefits and can be relatively low cost if the fuel derives from an existing waste process.

CHP technologies include fuel cells, combustion/micro turbines and combined cycle plants. Waste heat can be used for hot water and steam for electrical generation. These technologies lead to savings for electric customers, reduced load benefits from a demand side management standpoint (DSM), and greater resiliency.

Montana-Dakota will continue examine the viability of cogeneration where existing gas capacity and/or availability of appropriate fuel sources allow for cost-effective application of this technology for DSM. From a holistic distributed generation standpoint, this technology would be of particular value within the context of a micro-grid in which intermittent resources are operating that could benefit from the smoothing effect of a more stable fuel source.

Storage

Storage technologies such as lithium ion batteries have continued to become increasingly prolific due in part to the electric vehicle industry. Further development of storage has taken place due to the proliferation of the rooftop solar industry, and to major investments in the technology by the States of New Jersey, California, Washington and New York.

Although not yet at a viable price point within Montana-Dakota's electric service area, the significant ramp-up of large scale investments in lithium ion and flow battery technologies across the country will continue to drive costs downward. At the same time, storage will become increasingly essential to manage the emerging presence of solar, to manage peak, and otherwise optimize customer usage.

Montana-Dakota will continue to monitor energy storage technologies such as lithium ion, and vanadium flow batteries as technology costs continue to decline and will consider if limited testing of this technology, paired with an intermittent resource such as wind or solar might be prudent.

Future Policy Considerations

As suggested above, there is a great deal of developing activity on the horizon when it comes to DG technologies. Much of what takes place in Montana-Dakota's service area will depend on the price of electricity, the rate at which the costs of distributed technologies decline, the market appetite for these technologies, and the value they serve from a system reliability standpoint.

In addition to these factors, it is likely that emerging national policy outcomes, such as the EPA's Clean Power Plan, will also have a strong influence on the role of distributed generation— in particular the role of renewable DG. The outcomes of this and other policy will also have significant impacts on the future of DG, as will any state or regulation driven mandates that emerge in the future.

CHAPTER 4

SUPPLY-SIDE RESOURCE ANALYSIS

The objective of the supply side analysis is to identify the available and most cost-effective supply-side capacity resources to be added to Montana-Dakota's generating portfolio. Capacity resources must be proven technology and be able to maintain the system reliability that Montana-Dakota's customers have come to expect. Selected supply-side resources, together with the feasible Demand-Side Management (DSM) programs are used as inputs to the integration analysis, the final process to determine the least-cost integrated resource plan.

The supply-side analysis considers supply-side alternatives currently available to Montana-Dakota as well as those resources to which Montana-Dakota has made a commitment to install or purchase. A detailed discussion of the supply-side model assumptions, characteristics of the existing generation, the committed resources, and the proposed resources is included in Attachment C.

Committed Supply-Side Options

Current Resources

Montana-Dakota's existing generation serving the Integrated System is comprised of baseload coal-fired generation at the Heskett Station (Units I and II), the Lewis & Clark Station, Montana-Dakota's shares of the Coyote and Big Stone Stations, and natural gas- fired peaking generation at Glendive (Units I and II), Miles City, and Heskett 3. Montana-Dakota also owns and operates the Diamond Willow and Cedar Hills wind farms, three 2 MW portable diesel units, and the Glen Ullin Station 6 waste heat generating unit serving the Integrated System. Total zonal resource credits (ZRC) available from the existing units in 2015 are 513 ZRC.

Future Capacity Resources

In the 2013 IRP analysis, the Big Stone Air Quality Control Systems (AQCS) project at the existing Big Stone plant, of which Montana-Dakota is a 22.7 percent owner, has become a committed project for Montana-Dakota. To comply with the EPA regional haze rules, the Big Stone plant is required to install the AQCS using Best Available Retrofit Technology (BART), which was committed in the model in 2015. The analysis assumed the retirement of the Big Stone plant (with 98.8 ZRCs) in 2015 with a new resource option available to the EGEAS model in 2015 that includes the AQCS retrofit project and associated future operating costs for the Big

Stone plant. The new resource option was assumed to be accredited with a lower ZRC value (97.2 ZRCs), as the AQCS will slightly reduce the capacity output of the Big Stone plant.

As noted in the 2013 IRP analysis, Montana-Dakota looked at the addition of a bag-house at the existing Lewis & Clark Station with an end of year 2015 in-service date. The bag-house addition was to comply with EPA's Mercury Air and Toxic Standard (MATS). The original cost of the project was modeled at $27.5 million, but the costs were updated after the IRP filing and increased to over $40 million. With this increase Montana-Dakota began exploring other compliance options and has found a lower cost method as described in Chapter 1 to comply with MATS, and these costs have been reflected in the 2015 IRP as this project is committed in the model for 2016.

As noted in the 2013 IRP analysis, the model selected simple-cycle reciprocating internal combustion engines (RICE) units to be selected in 2015 to meet the resource adequacy requirement in 2015. The location of another generating resource at near Lewis & Clark provides synergies in operations and siting with the existing Lewis & Clark Station and provides system reliability benefits of having additional generation in the transmission constrained Bakken Region of eastern Montana and northwestern North Dakota. Montana-Dakota has since gone forward to add 19 MW of RICE units at the current site of Lewis & Clark Station in the fall of 2015. This project was modeled as a committed resource to be available at the start of 2016.

As also noted in the 2013 IRP analysis, the model selected 50 MW of wind, the maximum purchase wind option available to the model. Montana-Dakota has since entered in to contract to purchase the project or purchase the energy from Thunder Spirit Wind. This is a 107.5 MW wind farm located near Hettinger, ND, which came out of Montana-Dakota's 2013 request for proposal. The larger 107.5 MW project size allows for greater economies of scale than the 50 MW project size and is a better fit for Montana-Dakota's customers load serving requirements than a larger 150 MW project. The Thunder Spirit Wind project is scheduled to be completed and online by the end of 2015.

Considered Supply-Side Resource Alternatives (Described in greater detail in Attachment C)

Coal

Coal-fired baseload generation is a stable capacity and energy source characterized as having a high capital cost with low operating and fuel costs. With low operating and fuel costs, baseload units produce large amounts of energy at a relatively low cost. The high capital costs are spread over the life of the project. However, as significant new federal air quality, water discharge, and waste management regulations are proposed, new coal-fired baseload generation is unlikely to be feasible in the foreseeable future.

Simple Cycle Reciprocating Internal Combustion Engine

Simple-cycle reciprocating internal combustion engines (RICE) are primarily built to serve peaking capacity needs. Because they are fueled by natural gas or fuel oil, which have higher fuel costs than coal, they are usually limited in the amount of energy they supply. The RICE units are, however, can be installed within a relatively short lead time (two years).

Simple Cycle Combustion Turbines

Simple-cycle combustion turbines (SCCT) are primarily used to supply low-cost capacity, but a limited amount of energy, since they are fueled by either natural gas or fuel oil, which are more costly than coal. Combustion turbines have a relatively low capital cost, but the energy produced is more expensive than that produced from coal because of the higher fuel cost. Combustion turbines can be installed with a relatively short lead time (two to three years) and serve peaking capacity needs for the Company.

Combined Cycle Combustion Turbines

A conventional combined cycle combustion turbine (CCCT) burns natural gas or fuel oil in a SCCT. The hot exhaust gases from the SCCT pass through a heat recovery steam generator that produces steam for a steam turbine. Because CCCTs use natural gas or fuel oil, CCCTs have higher fuel costs than coal-fired baseload units. The advantage of a CCCT is that it is more efficient to operate than a SCCT, but its hours of operation could be limited because of its high fuel costs.

Wind (Self-Built)

A wind energy resource is characterized as a renewable resource with low energy costs associated with its operation and maintenance. The main disadvantage of wind generation is that, because of the variability of wind, it cannot be relied on as a firm capacity resource. Unlike the thermal resources such as coal-fired units and combustion turbines, wind energy resources are allowed limited zonal resource credits (ZRC) by MISO. Therefore, the installation of additional wind generation on Montana-Dakota's system requires adding other capacity resources to meet the MISO planning reserve margin requirements. This option represents Montana-Dakota's self-built wind generation.

Solar

Another renewable resource alternative is solar, which has a higher capital cost than wind generation. Like wind, solar is a variable output energy resource and must rely on other capacity resources to meet Montana-Dakota's MISO zonal reserve margin requirements. Three different types of solar options were included in the model: thermal, concentrated, and photovoltaic solar.

Landfill Gas

Methane gas produced from landfill sites can be captured and used as an alternative fuel to produce electricity. The landfill gas option modeled by Montana-Dakota was of a relatively large size, and would require a large and mature landfill, which may not be representative of a unit capable of being built within Montana-Dakota's service territory.

Biomass

There are several types of fuels that can be used for biomass generation including but not limited to: agriculture wastes, forestry by-products, and municipal waste. The biomass option is considered a renewable resource with high capital and fuel costs as compared to coal and natural gas fired options.

Solid Waste

Operating similar to a biomass-fired power plant, a solid waste power plant burns municipal solid waste as its fuel. A performance and cost analysis was completed for this unit for inclusion as a supply-side resource alternative. However, after a considerable amount of research, an accurate estimate for fuel costs could not be obtained. Therefore, the solid waste option was not included as an alternative for the supply-side resource options.

Geothermal

Geothermal power uses the earth's temperature to heat water or another working fluid which in turn is used to turn a turbine and a generator. The hot fluid is then cooled and returned to depth for reheating. The geothermal option is considered a renewable resource with high capital and operating and maintenance costs as compared to coal and natural gas fired options. A geothermal plant is dispatchable and would receive ZRCs for resource adequacy purposes similar to a coal or gas-fired facility.

Existing and Committed Resources

The need for any type of new planning resource, whether it is a supply-side resource or the implementation of demand-side programs, is primarily driven by the forecast of the peak demand and energy needs of customers. In addition, the retirement of existing facilities due to aging, high maintenance, and high environmental compliance costs will also trigger the need for new resources.

For an understanding of Montana-Dakota's capability to serve projected loads, a comparison of ZRCs and planning reserve margin requirement (PRMR) is shown in Tables 4-1 through 4-3. ZRCs are defined as the total resources within MISO available to meet Montana-Dakota's own PRMR. MISO requires each generator to determine its summer capability through a Generator Verification Test Capability (GVTC) process that establishes the generator's Installed Capacity (ICAP) value. The ICAP value and each individual generator's equivalent forced outage rate ($XEFOR_d$) are then used to establish an unforced capacity (UCAP) value for the generator:

$$UCAP = ICAP - (1\text{-}XEFOR_d).$$

UCAP values are then directly converted to ZRCs, which are used to verify the ability to meet Montana-Dakota's peak load obligation, as required by MISO.

As a member of MISO, Montana-Dakota is required to maintain a total number of ZRCs equal to or greater than the Company's projected yearly MISO non-coincident summer peak demand with a 1.9 percent adder for MISO losses, plus a 7.1 percent planning reserve margin (PRM).

Montana-Dakota is required to meet an 80.3 percent coincident factor for the 2015-16 planning year in MISO based on the fact Montana-Dakota does not peak at the time of the MISO system-wide peaks.

Table 4-1 shows that, under the current system load forecast and with the current capacity purchase contracts, Montana-Dakota has adequate capacity to meet its PRMR through 2016. However, to meet growing customer demand, an additional 22.3 ZRC will be needed in 2017. This capacity deficit will increase to 70.1 ZRC in 2020 and grow to 123.3 ZRC in 2025. With the high-growth scenario forecast, as shown in Table 4-2, a capacity deficit will occur in 2017 (22.3 ZRC) and grow to 90.1 ZRC in 2020. Under the low-growth scenario forecast, as shown in Table 4-3, a capacity deficit never occurs.

To address future capacity deficits, Montana-Dakota will need additional demand-side and/or supply-side resources. The analyses in this IRP will help provide direction for the best selection of new resources to economically and reliably meet customers' requirements.

Table 4-1

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison

BASE FORECAST

Year	Zonal Resource Credits	MISO Capacity Purchase	Total Zonal Resource Credits	50/50 Coincident Summer Peak Demand w/MISO Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (+)/(-)
2015	530.7	16.6	547.3	511.0	547.3	0.0
2016	574.4		574.4	535.7	573.7	0.7
2017	576.9		576.9	559.4	599.2	-22.3
2018	576.9		576.9	577.6	618.6	-41.7
2019	576.9		576.9	593.1	635.2	-58.3
2020	576.9		576.9	604.1	647.0	-70.1
2021	576.9		576.9	615.3	659.0	-82.1
2022	576.9		576.9	625.9	670.3	-93.4
2023	576.9		576.9	635.2	680.3	-103.4
2024	576.9		576.9	644.5	690.2	-113.3
2025	576.9		576.9	653.8	700.2	-123.3
2026	576.9		576.9	663.1	710.2	-133.3
2027	576.9		576.9	672.5	720.3	-143.4
2028	576.9		576.9	681.9	730.3	-153.4

Table 4-2

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison

HIGH-GROWTH FORECAST

Year	Zonal Resource Credits	MISO Capacity Purchase	Total Zonal Resource Credits	Coincident Summer Peak Demand w/Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (+)/(-)
2015	530.7	16.6	547.3	511.0	547.3	0.0
2016	574.4		574.4	535.7	573.7	0.7
2017	576.9		576.9	559.4	599.2	-22.3
2018	576.9		576.9	577.9	619.0	-42.1
2019	576.9		576.9	598.8	641.3	-64.4
2020	576.9		576.9	622.8	667.0	-90.1
2021	576.9		576.9	647.7	693.6	-116.7
2022	576.9		576.9	673.9	721.8	-144.9
2023	576.9		576.9	702.0	751.8	-174.9
2024	576.9		576.9	731.3	783.2	-206.3
2025	576.9		576.9	761.9	816.0	-239.1
2026	576.9		576.9	793.8	850.2	-273.3
2027	576.9		576.9	827.0	885.7	-308.8
2028	576.9		576.9	861.8	923.0	-346.1

Table 4-3

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison

LOW-GROWTH FORECAST

Year	Zonal Resource Credits	MISO Capacity Purchase	Total Zonal Resource Credits	Coincident Summer Peak Demand w/Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (+)/(-)
2015	530.7	16.6	547.3	476.3	510.1	37.2
2016	574.4		574.4	469.4	502.7	71.7
2017	576.9		576.9	464.0	497.0	79.9
2018	576.9		576.9	461.5	494.3	82.6
2019	576.9		576.9	460.3	492.9	84.0
2020	576.9		576.9	460.8	493.5	83.4
2021	576.9		576.9	461.3	494.0	82.9
2022	576.9		576.9	462.1	494.9	82.0
2023	576.9		576.9	463.4	496.3	80.6
2024	576.9		576.9	464.6	497.6	79.3
2025	576.9		576.9	466.0	499.1	77.8
2026	576.9		576.9	467.4	500.6	76.3
2027	576.9		576.9	468.8	502.1	74.8
2028	576.9		576.9	470.3	503.6	73.3

CHAPTER 5

INTEGRATION AND RISK ANALYSIS

The integration process considers all the demand-side programs discussed in Chapter 3 as well as the supply-side options discussed in Chapter 4 and integrates both resource types into a single least-cost plan. The Electric Generation Expansion Analysis System version 9.02 (EGEAS), a computer program developed by the Electric Power Research Institute (EPRI), is used to perform the resource expansion analysis and develop the least-cost integrated resource plan. From this analysis, Montana-Dakota will determine the least-cost integrated resource plan to guide its future resource selections.

Integration of Demand-Side and Supply-Side Resources

As indicated in Chapter 3, the DSM programs identified in the 2013 IRP have been or are expected to be implemented, and the reduction in energy and peak demand for energy efficiency is reflected in Montana-Dakota's load forecast as the existing demand response programs are modeled in EGEAS as resources. Therefore, these programs have been integrated with the supply-side options in all resource expansion analysis.

As a result of the demand-side analysis described in Chapter 3, the AC cycling program was included as a resource option in the Base Case with "New DSM" starting in 2017 at 2 MW and growing the program to 10 MW by 2021. All models did include a committed amount of 14.4 MW from the interruptible rate and 10 MW of the commercial demand response program in 2015 and increasing to 16 MW and 15 MW respectively by 2017.

Sensitivity Analysis

A sensitivity analysis was performed to see how the resource expansion plans would be affected by variations of certain key parameters that may change in the future from modeled assumptions.

Carbon Tax

Montana-Dakota analyzes new environmental requirements as information becomes available. Pending rules impacting carbon-dioxide emissions, solid waste, other air emissions and water quality management at the existing plants have been evaluated, although no engineering analysis has been conducted on compliance with these proposed regulations. With the potential of a future carbon penalty applied to all fossil fuel units and MISO energy purchases, a carbon tax was modeled to assess the impact on the resource expansion plan. The assumed carbon tax was applied to all carbon emissions from Montana-Dakota's existing coal-fired units and natural gas-fired SCCTs, energy purchases from the MISO market, and new generating units added to the resource plan starting in 2020. While no carbon tax was modeled in the base case, Montana-Dakota modeled a carbon tax of $30 per ton for a sensitivity analysis.

The modeling was preformed differently in the 2015 IRP as the cost of the carbon tax was included in the dispatch cost of the units as opposed to previous IRPs where the cost of the carbon tax was added in after the units were dispatched. This new methodology in the model and the low natural gas prices caused the coal fleet to have very low capacity factors compared to the Base Case. Therefore, additional sensitivities were modeled around the $30 carbon tax to see what the cost of natural gas would have to increase to with a $30 carbon tax and what the carbon tax would have to decrease with the base gas prices for the coal fleet to have capacity factors similar to a zero carbon tax scenario. This caused the natural gas to increase by $1.50/MBTU with the $30 carbon tax, and using the base gas prices the carbon tax was reduced to $15/ton. An additional sensitivity was completed combining both of the $1.50/MBTU gas adder and using the $15 carbon tax.

Natural Gas Price Sensitivity

Prices for natural gas supplies as delivered to Montana-Dakota's existing turbines, future combustion turbines, and future combined cycle plants were developed in-house for use in the resource expansion analysis based on Montana-Dakota's view of the long-term outlook of natural gas pricing. For the base case, natural gas was priced for delivery at $2.96/MBTU for 2015, and increasing to $3.95/MBTU in 2019. After 2019, natural gas prices were escalated by three percent annually. Considering the historical fluctuations of natural gas prices, there is a need to consider what impact both higher and lower gas prices would have on the least-cost plan. Therefore, high and low gas price scenarios were also developed, whereby the gas price used in the base case was increased by $3/MBTU and decreased by $1/MBTU from the Base Case, respectively.

High- and Low-Growth Scenario Forecasts

The base forecast in Chapter 2 projected that summer peak demand would increase at an average rate of 3.4 percent per year for the next five years and at an average rate of 1.7 percent per year through 2034. Energy requirements would increase at an average rate of 4.6 percent per year for the next five years, and at an average rate of 2.1 percent per year through 2034. The forecast also established high-growth and low-growth scenarios in which energy requirements were assumed to grow at 4.4 percent beginning in 2018 and 0.5 percent per year respectively over the twenty year period. EGEAS runs were made using both the high- and low-growth load forecasts to determine the least-cost resource plan under those scenarios.

High Combustion Turbine and Internal Combustion Engines Costs

Historically the costs of materials associated with the construction of generation have generally increased at a rate higher than general inflation both in the United States and the rest of the world. The base case costs for all generation options reflect the present price forecasts, but for purposes of risk analysis, Montana-Dakota considered the impact of higher installed and O&M costs of new generation (i.e., combustion turbines) on the resource plan. Therefore, to determine the sensitivity of the base case to increases in combustion turbine costs, a sensitivity scenario was developed that increased the installed cost and O&M costs of combustion turbines by 20 percent over the Base Case. The higher combustion turbine and internal combustion engine cost scenario also accounts for differences in site constructability through Montana-Dakota's service territory, , as some areas like the Bakken Region tend to have higher construction costs due to higher labor, housing, and material costs. These higher cost areas may have additional benefits, like system reliability or access to trapped natural gas, associated with their developments which are considered when selecting a new generation site.

MISO energy purchases

Currently and in the past Montana-Dakota has been able to purchase energy from the MISO market to meet our needs at lower costs than running our own gas fired SCCT units on non-peak hours and majority of the peak hours. With the potential for coal retirements in MISO due to EPA rules, the cost of energy will probably increase and the availability of purchasing energy from the MISO market could also be limited. With these scenarios, Montana-Dakota modeled sensitivities of a $10/MWh adder to the base case on energy prices for on and off peak and a $5/MWh reduction in energy prices for both on and off peak. For the availability of the market, Montana-Dakota reduced the modeled amount of energy purchases available from 50 MW on and off peak to zero by 2020 and 2025.

Ninety percent coincident factor for MISO Resource Adequacy (RA)

The ninety percent coincident factor sensitivity scenario reflects a higher capacity need for MISO RA, however the energy needs do not change. This scenario was done in part to show the change in capacity need if there was a change to Montana-Dakota's current 80.3 percent coincident factor within MISO.

CHAPTER 6

RESULTS

This section presents the results of the 2015 Integrated Resource Plan, taking into consideration the results of the resource expansion analysis as well as other factors Montana-Dakota deemed critical in evaluating future resources. The additional factors not modeled in EGEAS but considered when determining the final resource plan are as follows.

Economic, Societal, and Customer Issues

Montana-Dakota is committed to providing its customers with competitively priced, highly reliable electricity. The integrated resource planning process must not rely solely on the results of a computer model analysis, but must also consider risks and other factors that are essential to provide the overall best choices for meeting the requirements of customers. The factors considered in the analysis are:

- Fuel price stability,
- Benefits resulting from participation in the MISO market,
- The possibility of unexpected new large load developing in Montana-Dakota's service territory,
- The integration of renewable generation resources and the economic and social benefits that they provide, and
- Public interest programs.

Midcontinent Independent System Operator, Inc. (MISO) Market

Since the beginning of the MISO energy market in 2005 and with the Ancillary Service Market (ASM) and Capacity Market startup in 2009, the ability of Montana-Dakota to use its existing resources within these markets has expanded. Therefore, when considering which resources to consider as benefiting retail customers, the presence of the markets available in MISO is a factor.

Montana-Dakota continues to perform integrated resource planning based on the obligation to serve its customers with a stable and reliable power supply. The MISO energy market provides opportunities and benefits to Montana-Dakota, but Montana-Dakota does not rely totally on the market for its power supply requirements.

The MISO market provides a source for energy when prices are lower than Montana-Dakota's generating costs, or when, due to planned maintenance or forced outages, Montana-Dakota needs to purchase energy to maintain reliability. The market also provides a means whereby Montana-Dakota can sell energy into the market from its generating facilities that is not needed by Montana-Dakota customers, with the margins benefiting the customers. Figure 6-1 shows the forecasted MISO market energy prices used within the model. The model included a 50 MW block of energy for off-peak and on-peak periods.

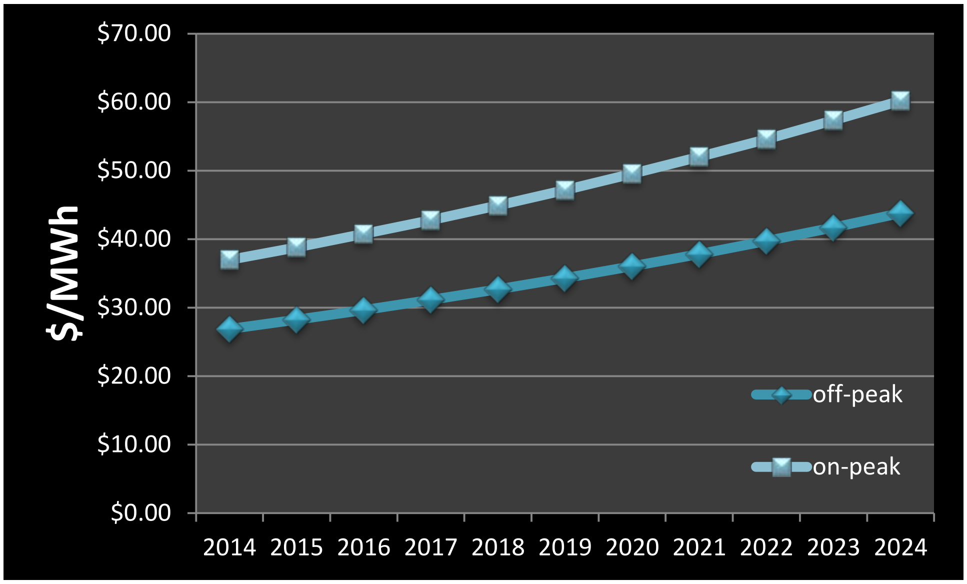

Figure 6-1: Forecasted On-Peak and Off-Peak MISO Market Prices developed by Montana-Dakota

MISO implemented an annual capacity auction starting with the 2013-14 planning year. Montana-Dakota purchased 16.6 MW of capacity from the MISO Capacity Auction for the 2015-2016 MISO Planning Year. Montana-Dakota will continue to monitor and utilize the MISO Capacity Auction as a short-term economical option for needed capacity or look to enter into economic long-term capacity purchases through bi-lateral agreements if available.

<u>Reliance on Natural Gas</u>

About 31 percent of Montana-Dakota's owned generating nameplate capacity is natural gas-fired as of 2015. As shown on Figure 6-2, natural gas prices have been historically volatile. Unlike coal, long-term supply contracts for natural gas are generally not available at competitive prices.

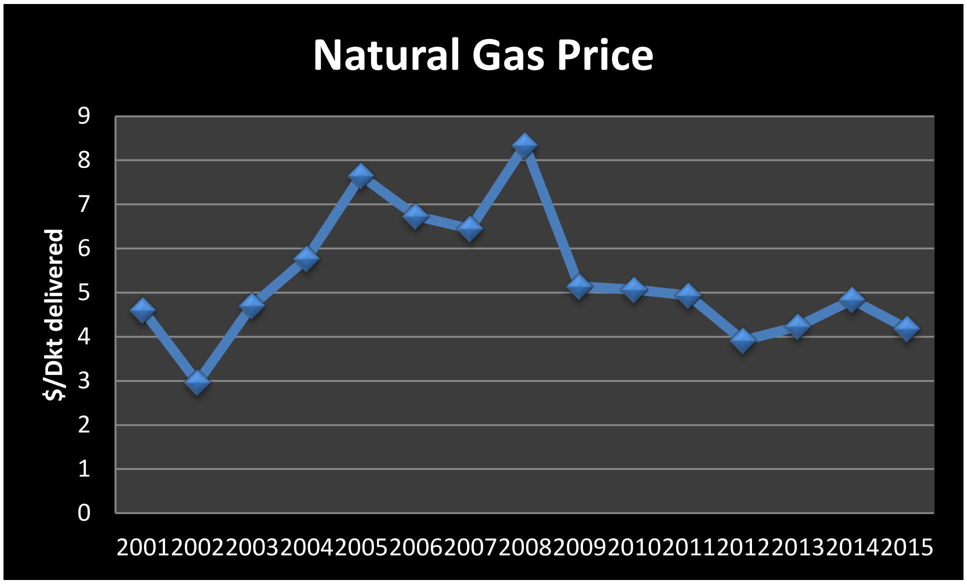

Figure 6-2: Historical Natural Gas Prices of Montana-Dakota's existing combustion turbines (Based on 12-Month Average)

Resource Expansion Analysis Results

The most probable load forecast, fuel prices, and resource installed costs were modeled in the EGEAS Base Case with the "New DSM". The Base Case with "New DSM" least-cost plan consists of the following resource additions for the 2015-2020 period:

- Purchase 10 MW of capacity in 2015
- Install 107.5 MW of Thunder Spirit Wind in 2015;
- Install 37.3 MW Simple Cycle Combustion Turbine in 2017;
- Continue the commercial demand response program to achieve 15 MW by 2017 and achieve 16 MW from Montana-Dakota's interruptible rate;
- Implement the residential AC Cycling program by 2017 to reach a total of 10 MW in the program by 2021; and
- Install 200 MW from a large Combined Cycle unit in 2020.

In the later years an additional 200 MW of a larger combined cycle unit was selected in 2030. The net present value of the Base Case least-cost plan over the 50-year study period equates to $4,452.60 million in 2014 dollars, as shown in Attachment C Table 3-1.

Sensitivity scenarios indicate that the Base Case plan is very robust under all assumptions. However, load growth has a significant impact on the resource selection. As expected, the low-growth scenario indicates the need for less peaking capacity and energy, while the high-growth scenario shows much more peaking capacity and energy is needed than is shown in the Base Case. The high and low gas price scenarios also support the Base Case selections for capacity, except that the high gas price case also selected an additional 230 MW of self-built wind throughout the 20 years.

The cost of materials and labor as well as potential environmental costs put upward pressure on the cost estimates for both baseload coal-fired units and combustion turbines. The scenario in which the installed cost of combustion turbines increased by 20 percent also selected the same capacity additions as in the Optimal Resource Case.

Montana-Dakota has historically relied on, and is currently relying on, the MISO market for energy to serve its customer load instead of using existing higher priced energy resources. On a low or high change in market prices, the resource plan never changed and had a slight decrease and increase in NPV respectively. The scenario of Montana-Dakota being self-sufficient and not relying on the market in the future added in an additional combined cycle and a slight increase in the NPV.

The carbon tax sensitivity scenarios show the economic impact of a tax on carbon on Montana-Dakota's generating system and customers. The total production costs increase significantly, and with low natural gas prices causing existing coal units to run less at $30/ton of CO_2. Additional sensitivities were done with increasing natural gas prices and lowering the carbon tax to get a better idea on how a carbon tax would affect Montana-Dakota's existing units and units selected in the future.

As shown in Figures 6-3 and 6-4, in 2015 approximately 31 percent of Montana-Dakota's ZRC comes from natural gas- and oil-fired combustion turbines while in 2020, based on the Base Case plan, approximately 51 percent of the Company's ZRC would be made up of natural gas and oil-fired combustion turbines or engines.

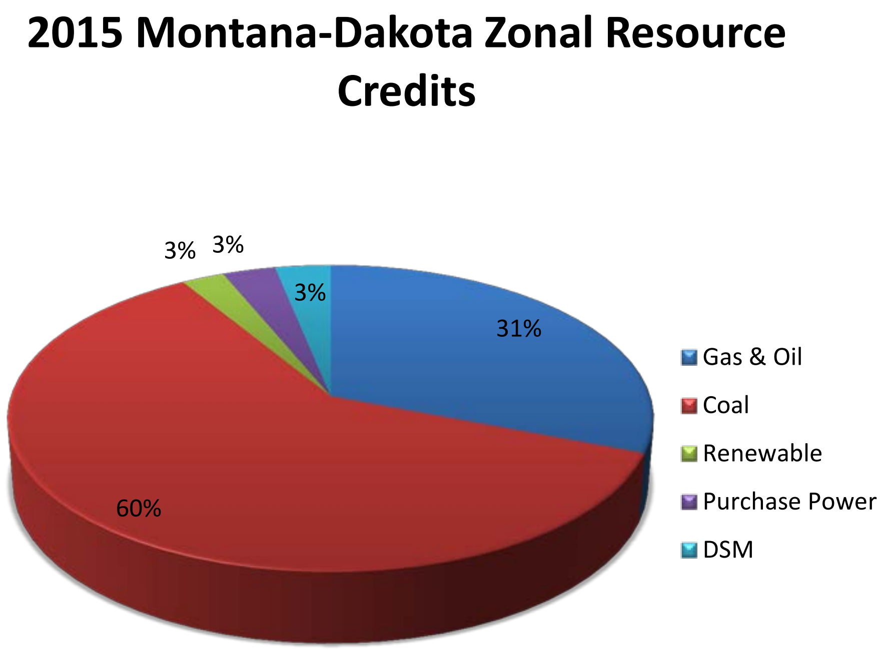

Figure 6-3: 2015 Montana-Dakota Zonal Resource Credits

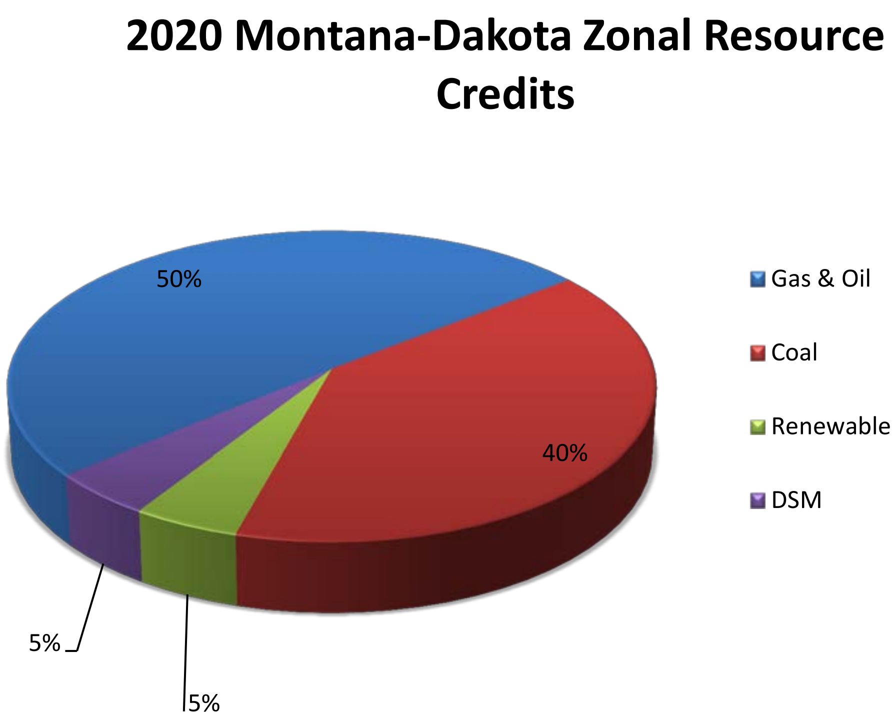

Figure 6-4: 2020 Montana-Dakota Zonal Resource Credits

Future Resource Plan

Based on the analysis of the resource expansion models and the consideration of customer impacts, market availability of capacity and energy, and other factors such as environmental regulations and the balance of its generation mix, Montana-Dakota's recommended resource plan is to pursue the following resources to meet the requirements identified for the 2015-2019 period:

- Continue with the construction of Thunder Spirit Wind to be completed by the end of 2015;Continue with the installation of the Big Stone Plant AQCS equipment to be completed in 2015;

- Continue with the installation of the MATS project at Lewis & Clark Station to be completed by the end of 2015;

- Continue with the installation of the 19 MW Lewis & Clark II simple-cycle reciprocating internal combustion engine project to be completed by the end of 2015;

- Continue the commercial demand response program to achieve 15 MW by 2017 and achieve 16 MW from Montana-Dakota's interruptible rates.

- Implement residential AC Cycling program in 2017 and grow the program to 10 MW by 2021

- Meet short-term capacity deficits via the MISO Capacity Auction or through bi-lateral capacity purchase agreements; and

- Begin work on the potential partnership in a large combined cycle resource to be online in or after 2020. Potential ownership share in this new resource would be 200 MW.

The recommended resource plan is considered to be the best plan to economically and reliably meet customers' requirements over the five-year planning horizon, as explained below.

Montana-Dakota's recommended resource plan satisfies future customer requirements through a balance of a new peaking capacity resource addition, the additional wind, and pollution control investments in the Big Stone and Lewis & Clark low-cost energy resources.

Additional factors that are considered in confirming the best cost new supply-side resource option include, but are not limited to: site location issues, susceptibility to inclement weather and sustained cold temperature operation, fuel delivery requirements and limitations, transmission interconnection options, transmission upgrade requirements identified through a generator interconnect study, facility maintenance requirements and ability to perform, best fit with Company expertise, and overall operation and maintenance costs.

CHAPTER 7

TWO-YEAR ACTION PLAN

This section of the report provides the two-year action plan resulting from this IRP analysis. The plan describes the specific activities that Montana-Dakota intends to implement for its long-range integrated resource plan.

Load Forecasting

- Montana-Dakota will continue to review its load forecasting assumptions and inputs as part of its routine process.
- Montana-Dakota will continue to evaluate ways to improve its seasonal peak demand forecast in order to better respond to the MISO market requirements.
- Montana-Dakota will continue to evaluate the accuracy of its forecasts to determine the areas that need improvements.

Demand-Side Resources

- Montana-Dakota expects to continue to expand the number of interruptible rate customers to achieve a total of 16 MW by 2017.
- Montana-Dakota expects to achieve 15 MW of commercial demand response by the summer of 2017.
- Montana-Dakota expects to implement a residential AC Cycling program by 2017 to achieve a total of 10 MW in the program by 2021.

Supply-Side Activities

- Montana-Dakota will continue with the installation of the Big Stone AQCS project to be online by the end of 2015.
- Montana-Dakota will continue with its purchase of the 107.5 MW Thunder Spirit Wind project to be online by the end of 2015.
- Montana-Dakota will continue with the installation of the Lewis & Clark MATS project to be online by the end of 2015.

- Montana-Dakota will continue with the installation of the 19 MW Lewis & Clark II simple-cycle reciprocating internal combustion engine project to be online the fall of 2015.

- Montana-Dakota will continue to study the need to install local generation projects throughout its service area to support load growth and mitigate transmission constraints.

- Montana-Dakota will explore the opportunity of partnering with others on the design and construction of a large combined cycle combustion turbine facility with an in-service date in or after 2020.

- Montana-Dakota will continue to monitor the availability and price of energy and short-term capacity in the MISO market or through bi-lateral arrangements and will purchase additional capacity as needed to meet customer demand when economic to do so.

- Montana-Dakota will continue to monitor the development of final rules and implementation strategies for EPA 111d greenhouse gas emitting rules for existing sources, and influence the outcomes where possible.

<u>Other Activities</u>

Montana-Dakota will maintain the IRP Public Advisory Group to provide input to and review the Company's future IRPs.

CHAPTER 8

PUBLIC ADVISORY GROUP

This chapter describes the role and the workings of Montana-Dakota's IRP Public Advisory Group (PAG), a broad base advisory board for review and evaluation of the Company's IRP process. The first PAG was established for the 1995 IRP, and the PAGs have assisted with all IRPs since then. The 2015 IRP advisory group was established at the beginning of the 2015 planning cycle and held its first meeting in October 2014.

Objective

The objective of the PAG is to provide Montana-Dakota with input to its integrated resource planning process from a non-utility perspective. This advisory group reviews, evaluates, and recommends modifications to Montana-Dakota's planning process, resource plans, resource acquisition processes, and efficiency programs from the perspective of customers, government agencies, and public interest organizations.

Montana-Dakota considers the PAG's role to be one of providing advice and counsel on the planning process. The Company took input from the PAG under advisement in making planning decisions.

Participants

Participants in the PAG are non-utility personnel from the three states served by Montana-Dakota's integrated system: Montana, North Dakota, and South Dakota. The advisory group is structured to approximately reflect the proportions of Montana-Dakota's load in each state: Montana – 30 percent, North Dakota – 60 percent and South Dakota – 10 percent. The PAG members are also selected to balance representation from consumer advocacy groups, government agencies (including regulatory bodies), business concerns, and academia.

As a result, the PAG consists of two members from Montana, five members from North Dakota, and one member from South Dakota. In addition, the North Dakota Public Service Commission appointed a representative to participate as an observer. The names and affiliations of the 2015 PAG participants are shown in Table 8-1.

Table 8-1
The 2015 IRP Public Advisory Group

Montana

Barbara Roberts
Action for Eastern Montana
Glendive, Montana

Garrett Martin
Department of Environmental Quality
Helena, Montana

North Dakota

Mike Fladeland
North Dakota Department of Commerce
Bismarck, North Dakota

Dr. Patrick O' Neill
Department of Economics
University of North Dakota
Grand Forks, North Dakota

John Klein PE LEED®AP
Apex Engineering Group
Bismarck, North Dakota

Bruce Conway
OptCTS, Inc
Williston, North Dakota

Rich Wardner
North Dakota State Senate
Dickinson, North Dakota

Victor Schock
North Dakota Public Service Commission
Bismarck, North Dakota
(Invited as an observer)

South Dakota

Patrick Steffensen
South Dakota Public Utilities Commission
Pierre, South Dakota

Meetings

Input from the PAG to the IRP process occurred through the PAG meetings and communications between the PAG members and Montana-Dakota personnel. The Company funded travel and out-of-pocket expenses for the PAG members to attend the meetings. Their time was absorbed by themselves or by their employers.

At each meeting, the Company presented methods, analysis, and findings to the group. The meetings provided an opportunity for the participants to contribute their comments and concerns about work in progress. In this way, the group could raise issues and discuss them, and the Company could consider incorporation of the group's input into the IRP. The meeting dates and the items discussed at each meeting are contained in Attachment D.

The 2015 IRP public advisory process was designed to make efficient use of the PAG members' time and expertise and provide the members with updated information on the rapidly changing electric utility industry. The Company's presentations at the meetings were more result and policy-oriented, rather than focusing on the technical data. Efforts were made to provide the members discussion of recent changes within the Company and in the electric utility industry. The group's discussions, therefore, tended to concentrate on issues, policies, and overall results. The public advisory process enhances Montana-Dakota's IRP analysis and reports through the information and suggestions provided by the group.

There were three 2015 IRP PAG meetings held in Bismarck, North Dakota. In addition to presenting the topics for discussion and taking feedback from the PAG members, Montana-Dakota served as a facilitator in setting agendas, taking care of meeting logistics such as meeting notices and expense reimbursements, and documenting the presentations at the meetings.

Since the PAG functions in an advisory role, no formal voting procedures were instituted. Montana-Dakota usually strove, however, for a consensus opinion of the PAG on the issues brought before it. The Company was willing to discuss any IRP-related topics that were of interest to PAG members. It also invited participants to provide written comments to document their opinions or concerns.

Conclusions

Montana-Dakota is pleased with its public advisory process. The public involvement resulted in better study assumptions and provided useful information to both the Company and the PAG participants and their constituents.