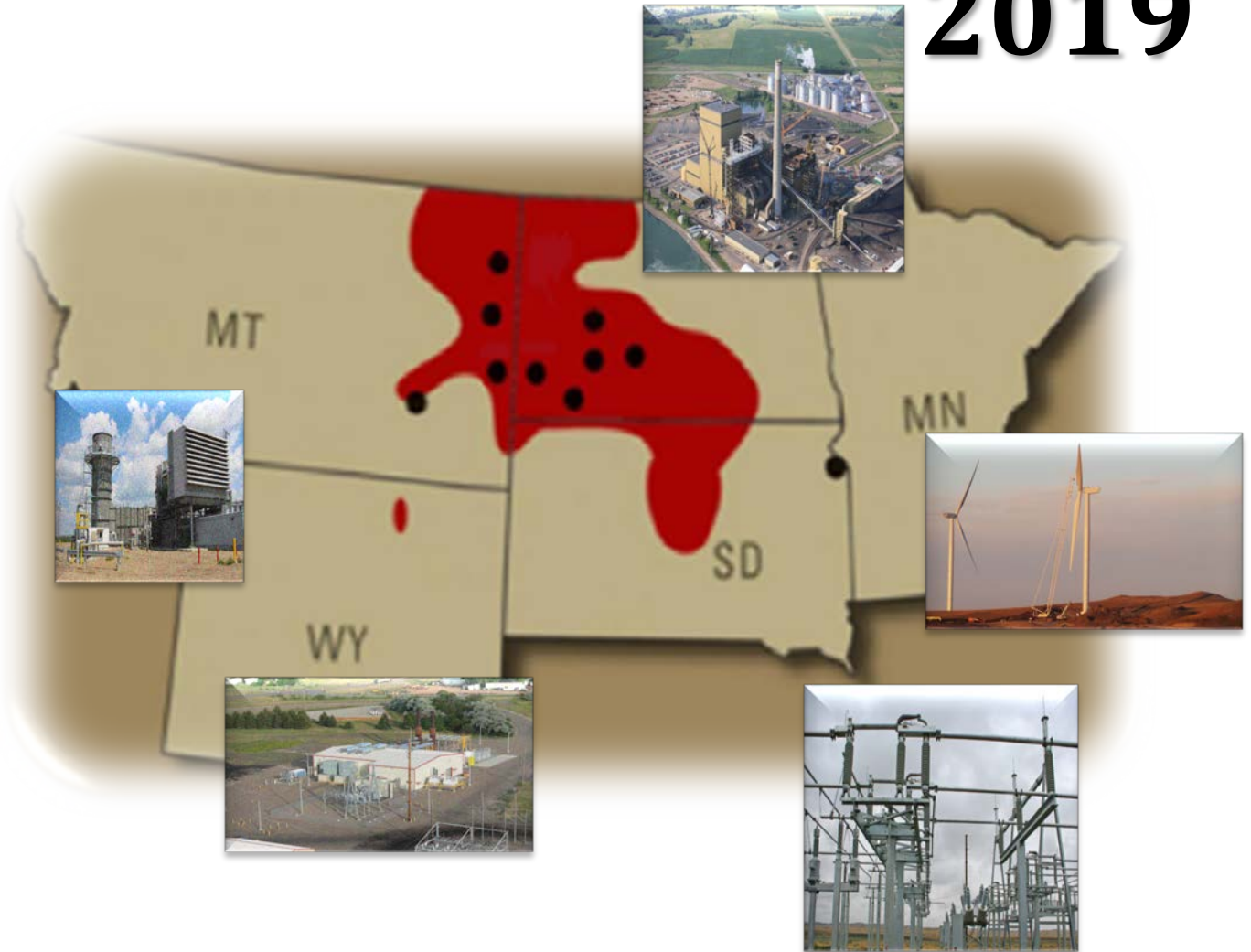




Integrated Resource Plan 2019



**Submitted to the
North Dakota Public Service
Commission July 1, 2019**

Volume I: Main Report

Montana-Dakota Utilities Co.
2019 Integrated Resource Plan

Submitted to the North Dakota Public Service Commission

July 1, 2019

Volume I
Main Report



**MONTANA-DAKOTA
UTILITIES CO.**

A Subsidiary of MDU Resources Group, Inc.

INTEGRATED RESOURCE PLAN

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EXECUTIVE SUMMARY

Montana-Dakota Utilities Co.'s (Montana-Dakota) 2019 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 30-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. Resources considered include a combination of traditional generating stations, distributed generation, renewable resources, and demand-side management programs.

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 20 years into the future. The results for the base forecast show that, during the 2019-2038 timeframe, the projected average annual growth rate for summer peak demand is 1.2 percent prior to any reductions due to demand response programs, while annual energy requirements are expected to increase at a rate of 1.3 percent.

The **demand-side analysis** is an evaluation process to identify the feasible demand-side management (DSM) programs, including energy efficiency programs for Montana-Dakota's system. As discussed in Chapter 3, Montana-Dakota updated the evaluation of several 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 2019-2021 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 including unit retirements. 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, biomass, short term capacity purchases, and results from a 2018 Request for Proposal (2018

RFP). Along with the potential resource options, Midcontinent Independent System Operator (MISO) energy purchases are available to meet energy needs.

The **integration and risk** process consider 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. Several scenarios were investigated to determine the sensitivity of the least-cost plan to several factors that may impact the resource plan. These sensitivity scenarios included; high and low natural gas prices, high and low load growth, high and low energy market prices, high capital costs on natural gas units, a combination of high natural gas and energy market prices 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: retiring the Lewis & Clark 1 coal-fired unit the end of 2020 and the Heskett 1 and Heskett 2 coal-fired generating units by the end of 2021, and adding a natural gas-fired simple cycle combustion turbine at the Heskett Station site along with the increased reliance of MISO market purchases. The Lewis & Clark 1 unit is a 52 MW generator that was originally placed into service in 1958, the Heskett 1 unit is a 25 MW generator that was originally placed into service in 1954 and the Heskett 2 unit is a 73 MW generator originally placed into service in 1963. The IRP model also selected future wind, solar, and natural gas-fired generation from the 2018 RFP which the Company did not pursue due to project size, uncertainties in final costs associated with network upgrades, and location of resources. 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.

Figure E-1 provides an overview of the identified need for capacity for the period 2019-2038 assuming the retirement of the Lewis & Clark 1, Heskett 1 and Heskett 2 units by the end of 2021. In this figure, "PRMR UCAP" represents Montana-Dakota's customer load obligation or planning reserve margin requirements (PRMR) prescribed by MISO based upon Montana-Dakota's current 50/50 demand forecast with an 81.5 percent coincident factor. "Existing ZRC" represents the amount the amount of capacity supply resources or zonal resource credits (ZRC) that Montana-Dakota has secured to meet its capacity requirements or PRMR. For resource adequacy purposes, Montana-Dakota must have an amount of ZRC (capacity supply resources) equal to or greater than PRMR (customer load obligations); otherwise deficiency charges are assessable under the MISO

tariff.

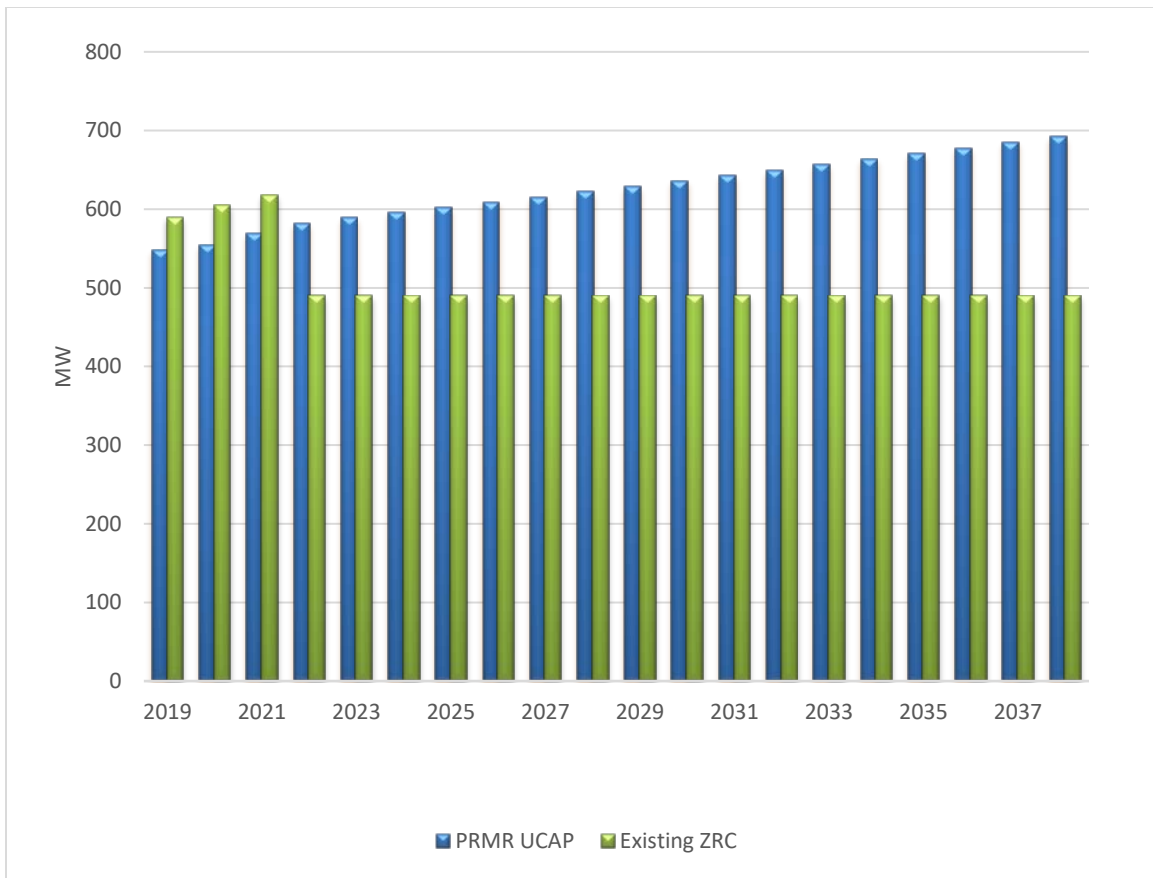


Figure E-1: 2019-2020 MISO Planning Year Zonal Resource Credit and Planning Reserve Margin Requirement

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 plan to meet the requirements identified for the 2019-2024 period is as follows:

- Move forward with the retirement of Lewis & Clark 1 at the end of 2020 and Heskett 1 and Heskett 2 at the end of 2021.
- Continue with the design and development and file an Advanced Determination of Prudency with the ND Public Service Commission (PSC) the fall of 2019 for a new 88 MW simple cycle combustion turbine at Heskett Station to be online in 2022 or early 2023.
- Submit regulatory filings in each jurisdiction to address the retirements of Heskett 1, Heskett 2, and Lewis & Clark 1.

- Issue a new request for proposal for supply side and demand side resources prior to the next IRP.
- Monitor the development of and impacts to Coyote Station associated with the next round of regional haze reductions.
- Meet short-term capacity deficits via the MISO Capacity Auction or through bi-lateral capacity purchase agreements.
- Increase energy purchases from MISO, as necessary.

The recommended resource plan is considered to be the best plan to economically and reliably meet customers' requirements over the planning horizon.

The 2019 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 2019 advisory group was established at the beginning of the 2019 planning cycle and provided Montana-Dakota with input throughout the 2019 IRP process.

*

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: 2018 Capacity and Energy RFP
 - Attachment G: Transmission Impacts
 - Attachment H: MISO RTO Overview
 - Attachment I: Retirement Analysis

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 provides comments to federal and state legislative and regulatory activities related to environmental issues including proposed regulation, 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, and amendments to the rule on July 30, 2018, for management of coal ash at coal-fired electric generating facilities. The culmination of all various pending environmental requirements, including any new EPA rulemaking to reduce 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 regulation changes and will take both proposed and final regulations into consideration when planning for future resource needs.

Renewable Energy

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

Montana-Dakota has 205 MW of installed wind generation capacity at three locations, providing over 25 percent of its customers' electric energy requirements. Montana-Dakota also owns a 7.5 MW heat recovery facility on the Northern Border Pipeline Compressor Station in south-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 Greenhouse Gas 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 (CO₂) emission intensity by three to five percent by 2010. Montana-Dakota has shown its commitment by reducing the Company's CO₂ 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 CO₂ emissions intensity from its electric generating facilities by 2012 compared to 2003 levels. Montana-Dakota continues to see reductions in its CO₂ emission intensity with the additions of renewable and gas-fired generation since 2010. Since 2003, Montana-Dakota's electric generation resource fleet CO₂ emission intensity has been reduced by approximately 24 percent. It is expected to continue to decline in future years. In 2017, a new target was developed to reduce the Company's electric generation resource fleet CO₂ emission intensity by 45 percent in 2030 from the Company's fleet emission intensity in 2005.

Montana-Dakota has been active in researching options for CO₂ capture, sequestration, and beneficial uses. The Company has been a member of the Plains CO₂ 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 CO₂ Capture (PCOC) project since 2014, which is also led by the EERC. PCOC provides support of pilot-scale demonstrations and researches and evaluates promising CO₂ capture technologies that can enhance the cost and performance of CO₂ 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. These workgroups have focused on CO₂-related issues such as lignite gasification, oxyfuel combustion, pre- and post-combustion CO₂ capture technologies, exploration of Allam Cycle utilization of lignite fuel, and beneficial uses of CO₂.

Montana-Dakota started a LED conversion program in 2018 for Company owned street lighting to reduce energy usage and thus help with reducing emissions. More information on this program can be seen in Chapter 3.

Environmental Regulation Pollution Control Project Impacts

The Regional Haze (RH), Mercury and Air Toxics Standard (MATS) and Coal Combustion Residuals (CCR) rules have had the most immediate impact on operations at Montana-Dakota's electric generating facilities. Significant projects have been implemented to comply with these rules at the Lewis & Clark 1, Big Stone Plant, Heskett 2, and Coyote Station. Most recently, additional projects have been implemented for CCR rule compliance at Lewis & Clark 1, Big Stone Plant, and Coyote Station. These projects are discussed under the Coal Combustion Residuals Rule section below.

Additional air emissions regulations that will impact the utilization of fossil fuel-fired generation resources are GHG regulations and RH rule emissions reductions under the next periodic review (round two). Discussion on the GHG rulemaking status for fossil-fired electric generation units and potential emissions reductions that may result under RH round two is provided further below.

Coal Combustion Residuals (CCR) Rule

On April 17, 2015, the EPA published a final Coal Combustion Residual (CCR) rule that requires management of coal ash through solid waste regulations. The rule requires ground water and location restriction evaluations to be conducted at ash impoundments and landfills not located at coal mines. The outcome of these evaluations may require closure of impoundments and landfills that do not meet specific criteria, resulting in the need to replace ash management systems.

On December 16, 2016, the Water Infrastructure Improvements for the Nation (WIIN) Act was signed into law, providing the EPA and states the authority to administer and enforce CCR rule requirements through permitting programs. Administration of the CCR rule by the EPA and states may potentially result in availability of alternative compliance options.

In 2018 and 2019, a few projects were completed at Montana-Dakota's owned and co-owned coal-fired electric generation resources for compliance with CCR rule requirements. Lewis & Clark 1

Station completed a retrofit to the scrubber ponds in 2018 at a cost of \$5.4 million to comply with certain CCR surface impoundment requirements. The project included removal of CCR materials, deconstruction of berms, re-establishment of base and berms, construction of a new composite liner system composed of geosynthetic clay liner and geomembrane, application of liner cover materials, modification of the existing pump house, and construction of a haul road and access ramps. The project costs also included closure and reconstruction of a related temporary storage pad for dewatering flue gas desulfurization solids prior to transport that was needed due to the pond retrofit. Surface impoundments that do not retrofit or otherwise meet all applicable CCR regulatory requirements by October 17, 2018 must close by October 31, 2020. EPA extended the latter deadline, but not the former, via a CCR rule amendment published on July 30, 2018. Under the CCR Rule as originally enacted, the scrubber ponds would have had to close no later than April 17, 2019, without completion of the retrofit project.

In 2018, Big Stone Plant completed a retrofit of its bottom ash handling system equipment which included installing a submerged flight conveyor and closed a surface impoundment and temporary storage area by removing all CCR material. Montana-Dakota's ownership share of the Big Stone Plant project cost was approximately \$2 million. Coyote Station completed the same retrofit of its bottom ash handling system equipment during its 2019 spring outage and will close three surface impoundments by removing all CCR material. Closure of Coyote Station's surface impoundments is anticipated to be completed by about the end of 2020. Montana-Dakota's ownership share of the Coyote Station project cost is expected to be approximately \$2.5 million.

316(b) Rule – Aquatic Species Protection

On August 15, 2014, the EPA published a rule under Section 316(b) of the Clean Water Act, establishing requirements for water intake structures at existing steam electric generating facilities. 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 generating facilities are either not subject to the rule or have completed studies that indicate compliance costs are not expected to be significant. In consideration of the planned retirement dates for Lewis & Clark 1 by the end of 2020 and Heskett 1 and Heskett 2 by the end of 2021, no impingement or entrainment reduction controls are expected to be required.

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

On March 28, 2017, President Trump issued an Executive Order (EO) titled "Promoting Energy Independence and Economic Growth" directing the administrator of the EPA to review the New

Source Performance Standards (NSPS) Greenhouse Gas (GHG) rule, referred to as the 111(b) rule, which established carbon dioxide limits for new, modified, and reconstructed fossil-fired electric generation units and the Clean Power Plan (CPP) rule, referred to as the 111(d) rule, which established carbon dioxide limits for existing fossil-fired electric generation units. These rules became final on October 23, 2015. The administrator of the EPA is directed to review the rules for consistency with the policy set forth in the EO and if appropriate to publish for notice and comment proposed rules suspending, revising or rescinding the rules.

In addition, the EPA also filed a motion with the D.C. Circuit Court on March 28, 2017, requesting the CPP rule case, as well as the current case involving the NSPS GHG rule, be held in abeyance while the agency conducts its review of the rules, and that the abeyance remain in place until 30 days after the conclusion of review and any resulting forthcoming rulemaking. The EPA also published a proposed rule on April 4, 2017, initiating review of the CPP rule and NSPS GHG rule. In parallel, the EPA published a proposal on October 16, 2017, to repeal the Clean Power Plan in its entirety and published the proposed Affordable Clean Energy (ACE) rulemaking to revise the Clean Power Plan. The proposed revised rule would require states to conduct a review of heat rate improvement projects that could be implemented at each individual coal-fired electric generating facility and determine, using a multi-factor analysis, which projects a facility would need to implement. The state would establish a standard of performance for carbon dioxide emissions for each facility based on the heat rate improvement projects required to be implemented. Compliance requirements and costs for existing and new fossil-fired electric generation resources, if any, will become clearer as the EPA completes its review of state standards. We are currently reviewing a pre-publication of the ACE rule that was released on June 19, 2019. From our preliminary reading, the final rule does not appear to have significantly changed from the proposal and EPA has repealed the CPP in the final rulemaking. Montana-Dakota will evaluate this rulemaking and incorporate changes as needed into the evaluation of supply-side resources.

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 are required to submit State Implementation Plans (SIPs) to the EPA which present the implementation strategy for reducing emissions from man-made sources 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. Round one of regional haze was finalized in about 2012 and considered emission reductions from BART sources, as well as other emissions sources in consideration of reasonable progress toward improving visibility. During round one, three of Montana-Dakota's owned and co-owned coal-fired electric generation units were required to install pollution controls. The air quality control system (AQCS) project at the Big Stone Plant was completed in 2015, limestone addition at the Heskett 2 fluidized bed for sulfur dioxide emissions reductions was completed in 2016, and advanced separated over-fire air installation at Coyote Station for nitrogen oxides control was completed in 2016. Periodic reviews, every ten years, will continue to be completed by States and the EPA in order to continue progress toward the 2064 goal.

On January 10, 2017, EPA finalized amendments to the RH rule that included additional requirements for states as they complete their periodic reviews and extended the next periodic review (round two) by three years. States are now to submit regional haze round two SIPs to EPA by July 31, 2021. However, EPA has made it known that additional guidance or rulemaking may still be completed in 2019 that could result in the changes to states' evaluation of sources. Presently, regional haze emissions reduction projects, if required, for round two are to be completed by July 31, 2028.

On April 19, 2019, Montana Department of Environmental Quality (MT DEQ) requested Montana-Dakota submit information to support the agency's reasonable progress analysis for Lewis & Clark 1 by September 30, 2019. On February 19, 2019, Montana-Dakota released a planned retirement date for Lewis & Clark 1 of approximately the end of 2020 and since this planned retirement date will occur prior to the end date of round two, the Company would not install pollution controls. Montana-Dakota will review and submit any additional supporting information to MT DEQ for the agency's reasonable progress analysis as requested by September 30, 2019.

North Dakota Department of Health (NDDH), now North Dakota Department of Environmental Quality (ND DEQ), sent requests to sources, including Heskett Station and Coyote Station, to submit a four-factor analysis for consideration of round two emissions controls to the ND DEQ by January 31, 2019. The analyses were prepared and submitted to the ND DEQ. The four-factor analysis is a review of technically feasible SO₂ and NO_x pollution controls that could be applied to a source to reduce emissions that can contribute to regional haze. The analysis includes

evaluation of cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and remaining useful life of the unit.

Although pollution controls for Heskett 1 and Heskett 2 were submitted to ND DEQ for evaluation in the four-factor analysis, a planned retirement date of about the end of 2021 was released by Montana-Dakota on February 19, 2019, for Heskett 1 and Heskett 2. As this retirement date will occur prior to the end date of round two, no pollution controls would be installed for Heskett 1 and Heskett 2.

Coyote Station's four-factor analysis identified feasible NO_x and SO₂ pollution controls that will be evaluated by the ND DEQ for possible installation. If the ND DEQ would require additional controls, those controls would be memorialized in North Dakota's SIP and submitted to EPA by July 31, 2021. As mentioned above, any required controls would have to be installed and operating by July 31, 2028, the end of Regional Haze round two. The next steps include ND DEQ completing review of Coyote Station's four-factor analysis and any supplemental information requested.

The capital cost estimates included in Coyote Station's four-factor analysis are wide ranging, largely depending on whether Coyote Station would be able to continue using its existing flue gas desulfurization (FGD) equipment. For example, and as a point of reference, the capital cost of installation of a dry sorbent injection (DSI) combined with other operational improvements to the existing FGD is projected to be in the \$24 million range with annual operating costs projected at \$12.5 million. However, replacing existing controls by installing a new FGD, similar to controls at several other North Dakota plants, would have a capital cost of approximately \$243 million with annual operating costs projected at \$20.6 million. One of the factors used in selecting the pollution control option is cost-effectiveness, and lower cost control options that achieve substantial emissions reductions may have an advantage depending on what ND DEQ considers as a final cost-effectiveness threshold.

It is unknown at this time what controls ND DEQ will require for Coyote Station in round two. By the end of 2019 or in early 2020, it is expected that the ND DEQ would indicate the possible pollution controls for Coyote Station. As RH guidance or rulemaking changes are made known by EPA and any additional future emissions reduction requirements are made known by ND DEQ, Montana-Dakota will incorporate the requirements into future IRP supply-side resource evaluations.

CHAPTER 2

LOAD FORECASTING

Montana-Dakota typically conducts a 20-year load forecast study annually with the last such study conducted in 2017. The actual load in 2018 was comparatively close to the forecast, with the year ending under one percent from plan. Therefore, a full study was not conducted in 2018. Instead, the 2017 study results were adjusted in the years and sectors where growth is confidently anticipated.

Montana-Dakota uses econometric modeling as the starting point for its forecasts. The econometric models for the 2018-2037 Integrated System forecast conducted in 2017 were developed using the statistical software package called SAS[®] with adjustments to account for recent growth and slowdown periods associated with the Bakken oil field activity 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:

- Econometrics explicitly measure the effects of underlying causes of trends and patterns.
- Econometrics provide statistical evaluation of forecast uncertainty.
- Econometrics 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 customers whose peak demand averages less than 50 kilowatts per month over a year's time.
- Large Commercial & Industrial (LC&I) sector. This sector consists of those customers whose peak demand averages more than 50 kilowatts per 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 end-use categories which were then forecasted separately. Four 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 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 using 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 sales 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 2017 (*Electric Load Forecast 2018-2037*, published December 31, 2017). The DSM programs that were selected for the 2017 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 10 years calculated in the 2017 study was 8.173 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 2017 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 from the 2017 study, along with anticipated updates, are presented in Table 2-1 summarizing the total energy requirements and seasonal peak demand. Notice the forecast values for 2038 were held constant from 2037 values.

Table 2-1
**** 2017 UPDATED ****
Montana-Dakota Utilities Co.
Historical and Forecasted Energy and Demand
Integrated System
Reflecting Demand-Side Management Programs from 2017 IRP
Calendar Month Basis

Year	Total Energy Requirements (net of DSM and EE)		Summer Peak - MW				Winter Peak 2/			
	MWh	% Change	Total Demand	Energy	Demand	% Change	Total Demand	Energy	Demand	% Change
			Before any DSM or EE	Efficiency (EE)	Net of EE 1/		Before any DSM or EE	Efficiency (EE)	Net of EE 1/	
2008	2,596,990				476.6			455.0		
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%		557.2	-4.28%	
2015	3,263,271	0.39%			611.5	14.73%		514.9	-7.59%	
2016	3,206,737	-1.73%			596.8	-2.40%		564.9	9.71%	
2017	3,251,539	1.40%			579.1	-2.97%		565.1	0.03%	
2018	3,313,387	1.90%			572.4	-1.16%				
2019	3,371,540	1.76%	611.9	0.7	611.2	6.79%	556.6	0.7	555.9	
2020	3,406,504	1.04%	619.1	0.7	618.4	1.18%	564.0	0.7	563.3	1.33%
2021	3,498,444	2.70%	634.7	0.7	634.0	2.52%	579.8	0.7	579.1	2.80%
2022	3,631,116	3.79%	649.3	0.7	648.6	2.30%	594.8	0.7	594.1	2.59%
2023	3,714,673	2.30%	658.2	0.7	657.5	1.37%	603.6	0.7	602.9	1.48%
2024	3,756,568	1.13%	665.4	0.7	664.7	1.09%	611.0	0.7	610.3	1.23%
2025	3,797,247	1.08%	672.5	0.7	671.8	1.07%	618.2	0.7	617.5	1.18%
2026	3,840,320	1.13%	679.8	0.7	679.1	1.09%	625.8	0.7	625.1	1.23%
2027	3,884,011	1.14%	687.2	0.7	686.5	1.09%	633.5	0.8	632.7	1.23%
2028	3,928,323	1.14%	694.6	0.8	693.8	1.08%	641.3	0.8	640.5	1.23%
2029	3,973,283	1.14%	702.1	0.8	701.3	1.08%	649.2	0.8	648.4	1.23%
2030	4,018,879	1.15%	709.7	0.8	708.9	1.08%	657.2	0.8	656.4	1.23%
2031	4,065,122	1.15%	717.4	0.8	716.6	1.08%	665.4	0.8	664.6	1.25%
2032	4,112,016	1.15%	725.1	0.8	724.3	1.07%	673.6	0.8	672.8	1.23%
2033	4,159,613	1.16%	732.8	0.8	732.0	1.06%	682.0	0.8	681.2	1.25%
2034	4,207,909	1.16%	740.7	0.8	739.9	1.08%	690.5	0.8	689.7	1.25%
2035	4,256,904	1.16%	748.6	0.8	747.8	1.07%	699.2	0.8	698.4	1.26%
2036	4,306,885	1.17%	756.6	0.8	755.8	1.07%	708.0	0.8	707.2	1.26%
2037	4,357,582	1.18%	764.7	0.8	763.9	1.07%	716.9	0.8	716.1	1.27%
2038	4,357,582	0.00%	764.7	0.8	763.9	0.00%	716.9	0.8	716.1	0.00%

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, 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 2017 study results indicated each one degree increase in temperature at the time of summer peak would result in an increase of approximately 6.9 MW in summer peak demand.

Further statistical analysis of temperatures at the time of system peak for the years 1984 through 2016 (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**

<u>Probability</u>	<u>Weighted Average Temperature</u>	<u>Approximate Increase in Peak Demand (MW)</u>
50%	96.8	0.0
75%	99.8	20.7
80%	100.6	26.2
85%	101.4	31.7
90%	102.5	39.3
95%	104.1	50.4
97%	105.2	58.0

As Table 2-2 shows, with a weighted average temperature of 96.8°F at the time of peak, there is a 50 percent probability the temperature at peak would be lower than 96.8°F and a 50 percent probability the temperature at peak would be higher than 96.8°F. This forecast is referred to as the 50/50 demand forecast.

Also, from Table 2-2, there is a 90 percent probability that actual temperatures at the time of the system peak will not exceed 102.5°F. However, at this temperature (102.5°F), the system peak demand would be 39.3 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 2017 study's 50/50 probability and 90/10 probability impact on the updated summer demand forecast to yield an Alternate Summer Peak Demand Forecast Comparison.

Montana-Dakota is a member of MISO and for resource adequacy requirements is only required to maintain enough capacity resources to meet its 50/50 forecast demand with adjustments per MISO's rules for resource adequacy.

Table 2-3
**** 2017 UPDATED ****
Alternate Summer Peak Demand Forecast Comparison

<u>Year</u>	<u>Base</u> <u>Forecast</u> <u>(96.8 degrees F)</u>	<u>Growth</u> <u>Rate</u>	<u>Alternate</u> <u>Forecast</u> <u>(102.5 degrees F)</u>
	<u>50/50 Forecast</u> <u>(MW)</u>		<u>90/10 Forecast</u> <u>(MW) */</u>
2019	611.2		650.5
2020	618.4	1.18%	658.2
2021	634.0	2.52%	674.8
2022	648.6	2.30%	690.3
2023	657.5	1.37%	699.8
2024	664.7	1.09%	707.5
2025	671.8	1.07%	715.0
2026	679.1	1.09%	722.8
2027	686.5	1.09%	730.7
2028	693.8	1.08%	738.6
2029	701.3	1.08%	746.6
2030	708.9	1.08%	754.7
2031	716.6	1.08%	762.9
2032	724.3	1.07%	771.1
2033	732.0	1.06%	779.3
2034	739.9	1.08%	787.7
2035	747.8	1.07%	796.1
2036	755.8	1.07%	804.6
2037	763.9	1.07%	813.2
2038	763.9	0.00%	813.2

*/ 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 periods consist of eight years of history.

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 high- and low-growth scenarios for energy and demand from the 2017 study, along with anticipated updates to the peak, are shown on Table 2-4. The following page presents the graphs of the numeric results. Notice the forecast values for 2038 were held constant from 2037 values with low and high growth rates applied.

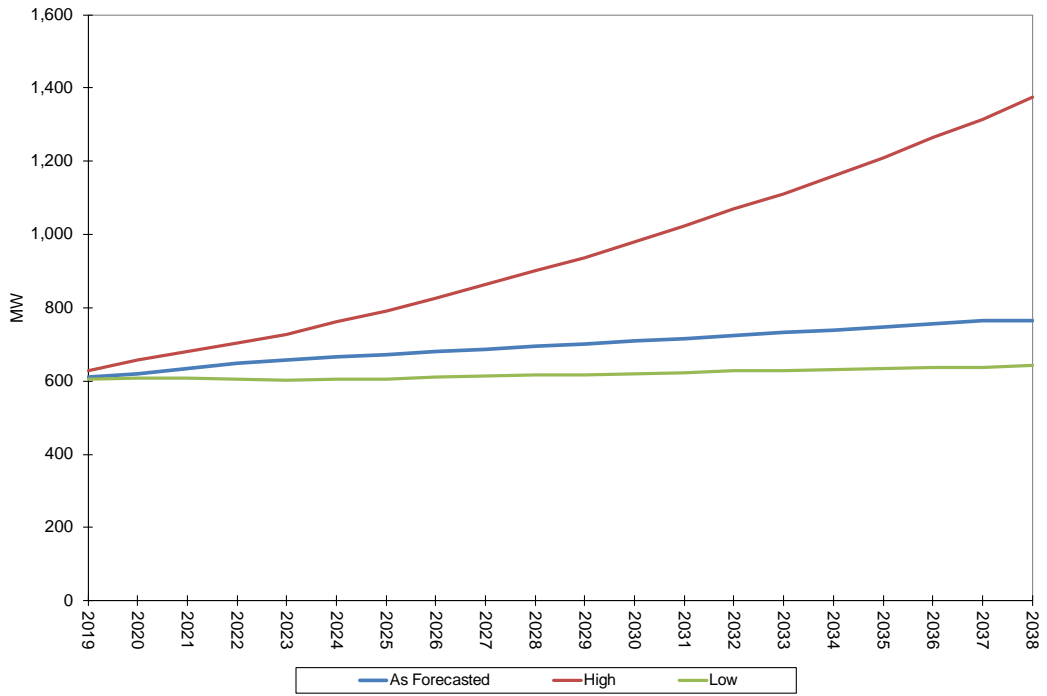
Table 2-4
**** 2017 UPDATED ****
High-Growth and Low-Growth Scenarios
Total Annual Energy (GWh) and
Summer Peak Demand (MW)

	<u>ENERGY</u>			<u>DEMAND</u>		
	<u>Forecast</u>	<u>HIGH 1/</u>	<u>LOW 2/</u>	<u>Forecast</u>	<u>HIGH</u>	<u>LOW</u>
2019	3,371.5	3,459.2	3,330.0	611.2	627.1	603.7
2020	3,406.5	3,611.4	3,346.7	618.4	657.4	609.2
2021	3,498.4	3,770.3	3,363.4	634.0	681.4	607.9
2022	3,631.1	3,936.2	3,380.2	648.6	703.1	603.8
2023	3,714.7	4,109.4	3,397.1	657.5	727.4	601.3
2024	3,756.6	4,290.2	3,414.1	664.7	761.2	605.7
2025	3,797.2	4,479.0	3,431.2	671.8	790.2	605.4
2026	3,840.3	4,676.1	3,448.4	679.1	826.9	609.8
2027	3,884.0	4,881.8	3,465.6	686.5	862.8	612.5
2028	3,928.3	5,096.6	3,482.9	693.8	902.7	616.9
2029	3,973.3	5,320.9	3,500.3	701.3	936.6	616.2
2030	4,018.9	5,555.0	3,517.8	708.9	979.9	620.5
2031	4,065.1	5,799.4	3,535.4	716.6	1022.4	623.2
2032	4,112.0	6,054.6	3,553.1	724.3	1069.4	627.6
2033	4,159.6	6,321.0	3,570.9	732.0	1109.3	626.7
2034	4,207.9	6,599.1	3,588.8	739.9	1160.4	631.0
2035	4,256.9	6,889.5	3,606.7	747.8	1210.2	633.6
2036	4,306.9	7,192.6	3,624.7	755.8	1265.6	637.8
2037	4,357.6	7,509.1	3,642.8	763.9	1312.8	636.8
2038	4,357.6	7,839.5	3,661.0	763.9	1374.2	641.8

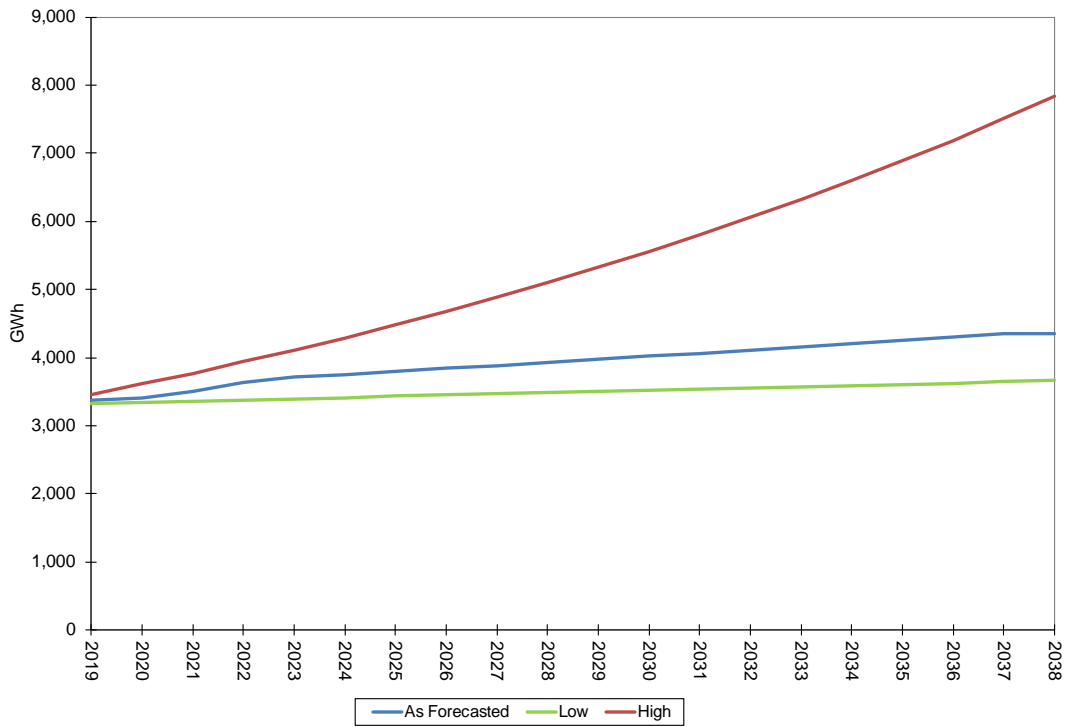
1/ High forecast assumes 4.4% growth per year (actual 77-85 growth).

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

Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Demand in MW



Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Energy in GWh



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 electric 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 summary of current DSM Programs and activities, a discussion of the DSM program planning activities, a summary of the DSM program benefit/cost analysis, and Montana-Dakota's future DSM implementation plan for 2019-2021.

Current Program Portfolio Summary

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. Montana-Dakota has also implemented (or plans to implement) LED conversion street lighting projects throughout Montana, North Dakota and South Dakota for its company-owned street lighting. 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 the programs is presented in Table 3-1.

Summary of Portfolio of Programs			
Table 3-1			
	Montana	North Dakota	South Dakota
Residential Programs			
Residential LED Lighting (A-line, 40W, 60W, 75W & 100W equivalent)	50% of the package price of the bulb – maximum \$5/bulb		
Residential LED Lighting (Globe, Indoor Flood & Outdoor Flood)	50% of the package price of the bulb – maximum \$7/bulb		
Commercial Programs			
Commercial Lighting	Prescriptive program based on measure		
Commercial Partnership Program (Custom)	Project-Specific		
Commercial Demand Response Resources (DRR) 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 current 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 on the residential side. In 2018 there was one participant (15 bulbs) in the residential LED lighting program and a total of 35 participants in the commercial lighting program. The redesign of the commercial lighting program significantly increased participation in the program. Montana-Dakota closed the program in July of 2018 as pre-approvals of lighting projects already met the annual allocated budget for this program. The commercial lighting program was available again on January 1, 2019.

Commercial 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. Combined, these programs are currently providing 40.4 MW of demand response at year end 2018, with an overall goal of providing 45 MW of demand response by 2021.

Commercial Demand Response Resources (DRR) Program

The DRR 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 and is currently fully subscribed and closed to new customers.

On January 30, 2019, Montana-Dakota called the first event for the DRR program. The MISO Reliability Coordinator declared a maximum generation event starting at 7 AM CST. Montana-Dakota called a DRR event beginning at 7:45 AM CST and ending at 11:45 AM CST. Overall customers enrolled in the DRR program performed well during the event as the 4-hour average performance achieved 23.9 MW.

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 15.4 MW enrolled and Montana-Dakota's goal is to increase participation by 2.1 MW or to a total enrollment of 20 MW by the summer of 2021.

Company-Owned Street Lighting – LED Conversion

In 2018, Montana-Dakota implemented the beginning of an LED conversion program for Company-owned street lighting. The first phase of the project consisted of a LED conversion Company-owned streetlight in its Montana service territory. In 2018, Montana-Dakota completed the conversion of approximately 5,600 streetlights in the state of Montana. The estimated energy savings associated with the Montana conversion project is approximately 3,984,000 kWh per year or the equivalent of serving approximately 410 homes for a year. In February 2019, Montana-Dakota began the LED street lighting conversion of approximately 7,900 streetlights in the state of North Dakota. The North Dakota project has been completed with an estimated energy savings

of 5,356,000 kWh per year. The LED street light conversion project in South Dakota is scheduled for 2020.

Additional LED conversion lighting projects will include Company-owned flood light replacements (company-wide in 2019) and Company-owned yard light replacements (company-wide in 2020-2021).

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, Montana-Dakota provided the results of the Nexant Program Planning Study for the Montana service territory in the 2015 IRP. Montana-Dakota continues to use the key findings of both studies in our DSM planning process for the 2019 IRP.

Montana-Dakota 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 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 1.70% of demand (MW) over the IRP planning period. A summary of the MWh and MW results are shown below in Tables 3-2 and 3-3, respectively. The complete state by state analysis and discussion are contained in Attachment B.

Table 3-2: Montana-Dakota’s System-Wide Potential MWh Savings Summary

<u>YEAR</u>	<u>Total Sales Sales (MWh)</u>	<u>Achievable EE %</u>	<u>Achievable MWh</u>
2019	3,116,804	0.13%	4,080
2020	3,149,126	0.13%	4,134
2021	3,234,120	0.18%	5,770
2022	3,356,767	0.20%	6,569
2023	3,434,011	0.26%	8,970
2024	3,472,741	0.27%	9,337
2025	3,510,346	0.36%	12,617
2026	3,550,165	0.36%	12,766
2027	3,590,555	0.43%	15,289
2028	3,631,519	0.43%	15,475
2029	3,673,082	0.43%	15,664
2030	3,715,233	0.43%	15,856
2031	3,757,982	0.43%	16,051
2032	3,801,333	0.43%	16,248
2033	3,845,334	0.43%	16,448
2034	3,889,981	0.43%	16,651
2035	3,935,274	0.43%	16,858
2036	3,981,478	0.43%	17,068
2037	4,028,345	0.43%	17,275
Cumulative	68,674,196	0.35%	243,128

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

<u>Year</u>	<u>Summer Peak (MW)</u>	<u>Achievable EE %</u>	<u>Achievable MW</u>	<u>Winter Peak (MW)</u>	<u>Achievable EE %</u>	<u>Achievable MW</u>
2019	611.9	0.10%	0.61	556.6	0.10%	0.56
2020	619.1	0.10%	0.62	564.1	0.10%	0.56
2021	634.7	0.10%	0.63	579.8	0.10%	0.58
2022	649.3	0.10%	0.65	594.9	0.10%	0.59
2023	658.2	0.10%	0.66	603.6	0.10%	0.60
2024	665.3	0.10%	0.67	611.0	0.10%	0.61
2025	672.5	0.10%	0.67	618.2	0.10%	0.62
2026	679.8	0.10%	0.68	625.8	0.10%	0.63
2027	687.3	0.10%	0.69	633.6	0.10%	0.63
2028	694.6	0.10%	0.69	641.2	0.10%	0.64
2029	702.1	0.10%	0.70	649.2	0.10%	0.65
2030	709.7	0.10%	0.71	657.2	0.10%	0.66
2031	717.4	0.10%	0.72	665.4	0.10%	0.67
2032	725.2	0.10%	0.73	673.7	0.10%	0.67
2033	732.8	0.10%	0.73	682.0	0.10%	0.68
2034	740.7	0.10%	0.74	690.5	0.10%	0.69
2035	748.5	0.10%	0.75	699.0	0.10%	0.70
2036	756.6	0.10%	0.76	708.0	0.10%	0.71
2037	764.8	0.10%	0.76	716.9	0.10%	0.72
Cummulative					1.70%	12.17

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 3-4. A discussion of the results and the complete DSM program analysis by state and in total for Montana-Dakota's Integrated System is contained in Attachment B and Appendix A of Attachment B of this report.

Table 3-4: DSM Benefit/Cost Summary

**Montana-Dakota Utilities Co.
Montana Electric DSM Program Summary
Table B-5**

Benefit/Cost Ratios						
DSM Program	Customer Class	RIM	Utility	Societal	Participant	Total Resource Cost
Total Portfolio		1.87	2.27	3.40	5.64	2.38
Residential Programs						
Residential Lighting	Residential	0.70	2.55	2.28	3.04	1.43
Demand Response						
Residential AC Cycling	Residential	1.33	1.38	2.91	3.38	1.93
Commercial Programs						
Commercial Lighting	Commercial	0.81	5.07	6.22	6.09	3.18
Commercial Partnership Program (Custom)	Commercial	1.00	5.07	4.61	5.11	2.82
Demand Response						
Commercial Demand Response Program	Commercial	2.41	2.41	3.31	80.19	2.41
Interruptible Rate DR Program	Commercial	3.21	3.29	4.28	17.06	3.10

**Montana-Dakota Utilities Co.
North Dakota Electric DSM Program Summary
Table B-6**

Benefit/Cost Ratios						
DSM Program	Customer Class	RIM	Utility	Societal	Participant	Total Resource Cost
Total Portfolio		1.69	1.98	3.10	6.47	2.16
Residential Programs						
Residential Lighting	Residential	0.65	2.35	2.05	2.92	1.28
Demand Response						
Residential AC Cycling	Residential	1.16	1.20	2.53	3.35	1.68
Commercial Programs						
Commercial Lighting	Commercial	1.18	6.68	8.04	6.82	4.11
Commercial Partnership Program (Custom)	Commercial	1.01	4.62	4.10	4.85	2.51
Demand Response						
Commercial Demand Response Program	Commercial	2.11	2.11	2.88	23.16	2.09
Interruptible Rate DR Program	Commercial	3.21	3.29	4.28	17.06	3.10

**Montana-Dakota Utilities Co.
South Dakota Electric DSM Program Summary
Table B-7**

Benefit/Cost Ratios						
DSM Program	Customer Class	RIM	Utility	Societal	Participant	Total Resource Cost
Total Portfolio		1.59	1.92	3.08	4.74	2.05
Residential Programs						
Residential Lighting	Residential	0.57	2.03	1.88	3.18	1.17
Demand Response						
Residential AC Cycling	Residential	1.16	1.20	2.54	3.39	1.68
Commercial Programs						
Commercial Lighting	Commercial	2.14	6.02	7.58	6.88	3.86
Commercial Partnership Program (Custom)	Commercial	1.72	3.98	3.76	4.88	2.30
Demand Response						
Commercial Demand Response Program	Commercial	2.18	2.18	2.94	4.95	2.11

DSM Implementation Plan

The following is a discussion by state of the expected DSM activity for program years 2019-2021. Also included is a discussion on Montana-Dakota's continued research into distributed energy resources as a possible fit for future system supply.

Montana

Montana-Dakota is proposing to continue with the existing energy efficiency programs offered in Montana through 2021. The portfolio will continue to include the residential LED lighting program, commercial lighting program, and commercial partnership program.

In addition, Montana-Dakota will continue to implement the Commercial Demand Response Program and promote the Interruptible Demand Response Rate.

North Dakota

Montana-Dakota will continue to implement the Commercial Demand Response Program and promote the Interruptible Demand Response Rate.

South Dakota

Montana-Dakota will continue to implement the Commercial Demand Response Program and LED street light conversion in 2020.

Distributed Energy Resources

Distributed Energy Resources (DER) refers to decentralized energy production that takes place on, or near the site being served. DER 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 DER resources include cogeneration (fired by fossil or biofuels), small wind, rooftop or community solar photovoltaic (PV), 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 energy resources 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 DERs take, 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 Montana-Dakota’s electric service area are described below.

Distributed Solar

Solar photovoltaic energy (PV) is an intermittent resource which is collected through panels and converted into electricity that can be used on site 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 price decreases due to 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 region will likely 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.

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 using 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 to 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 energy resource standpoint, this technology would be of 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 major investments in the technology by the states of New Jersey, California, Washington and New York.

Approaching 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 down costs. 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 DER 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 national policy outcomes will also have a strong influence on the role of distributed energy resources. The outcomes of this and other policy will also have significant impacts on the future of DER, 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 which could be added to Montana-Dakota's generating portfolio. This analysis also discusses the timing of existing unit retirements. 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, which is the final process to determine the least-cost integrated resource plan.

The supply-side analysis considers generation resource alternatives currently available to Montana-Dakota as well as those resources to which Montana-Dakota has made a commitment to install, purchase, or retire. 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 1 and 2), the Lewis & Clark Station 1, Montana-Dakota's shares of the Coyote and Big Stone Stations, and natural gas-fired peaking generation at Glendive (Units 1 and 2), Miles City, Heskett 3, and Lewis & Clark Station 2. Montana-Dakota also owns and operates the Diamond Willow, Cedar Hills, and Thunder Spirit wind farms, two 2 MW portable diesel units, Glen Ullin Station 6 waste heat generating unit, and the Commercial Demand Response Program and Interruptible Demand Response Rate serving the Integrated System. Total zonal resource credits (ZRC) available from the existing units in 2019 are 590.1 ZRC.

Future Capacity and Energy Resources

As part of the development of the 2019 IRP, Montana-Dakota issued a request for proposals of capacity and energy resources in August of 2018 (2018 RFP). Screening of the responses to the 2018 RFP did not identify any projects that were shortlisted as part of the RFP process. The IRP model did select future wind, solar, and natural gas-fired generation from the 2018 RFP which the

Company did not pursue due to project size, uncertainties in final costs associated with network upgrades, and location of resources. Some of the projects from the 2018 RFP were included in the IRP modeling to show the potential need to reevaluate projects in the future. Additional information on the 2018 RFP can be seen in Attachment F to the 2019 IRP Report.

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

Coal

Coal-fired baseload generation is a capacity and energy source characterized as having a high capital cost with low operating and fuel costs historically. With low operating and fuel costs, baseload units can 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 have been implemented, new coal-fired baseload generation has become more capital intensive and operating and fuel costs have increased, and thus is unlikely to be feasible in the foreseeable future.

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 have been historically more expensive than coal. Combustion turbines have a relatively low capital cost, but the energy produced has been more expensive than that produced from coal because of the historically higher fuel costs. As natural gas prices have dropped with the development of shale gas formations in the U.S., new natural gas-fired resources have become cost competitive with other traditional forms of generation like coal-fired plants. Combustion turbines can be installed with a relatively short lead time (two to three years) and serve peaking capacity needs for the Company.

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 been historically more expensive than coal, they are usually limited in the amount of energy they supply. The RICE units, however, can be installed within a relatively short lead time (two to three years) and are normally more thermally efficient and require lower fuel pressure compared to SCCT's of similar power output.

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. CCCT's have one of the highest efficiencies of any new power plant, at more than 60 percent in many instances. These units are usually used as an intermediate unit today but is increasingly being used as more of a baseload unit to replace retired coal 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 depending on fuel costs compared to other alternatives.

Wind

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 self-building a wind generation project.

Solar

Another renewable resource alternative is solar, which has traditionally had a higher capital cost than other types of renewable generation. The installed cost of solar has come down in recent years with technology improvements and higher levels of manufacturing. 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.

Storage

A storage resource is used to store energy mainly on off-peak times to later be used when needed for peak conditions. These units are often paired with renewable resources or can be used to increase reliability and reduce loading on a transmission or distribution system. Like solar, the installed cost of storage has come down in recent years with technology improvements and higher levels of manufacturing.

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.

2018 RFP Options

Although none of the proposals from the 2018 RFP were selected because of uncertainties with final costs associated with to be determined network upgrades, projects sizes, and locations as described in Volume IV Attachment F – 2018 RFP Analysis, several of the responses were included as options for the EGEAS model to select for future considerations. The options included: wind, solar, solar/storage, storage only, and combined cycle partnership.

Existing 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, high environmental compliance costs, and economic competitiveness will also trigger the need for new resources. Montana-Dakota assumes the retirement of the Heskett 1, Heskett 2, and Lewis & Clark 1 coal-fired generating plants by the end of 2021 in the model as supported by the analysis in Volume IV Attachment I – Retirement Analysis. The units are modeled for retirement at the same time to allow the EGEAS model to more efficiently replace the units retiring capacity and energy rather than staggered unit retirement dates as is expected to occur.

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:

$$UCAP = ICAP - (1 - XEFOR_d).$$

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 2 percent adder for MISO losses, plus a 7.9 percent planning reserve margin (PRM).

Montana-Dakota is required to meet an 81.5 percent coincident factor for the 2019-20 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, Montana-Dakota has adequate capacity to meet its PRMR through 2021. The capacity deficit in 2022 will be 92.0 ZRC and is expected to grow to 146.1 ZRC in 2030. Under the high-growth scenario forecast, as shown in Table 4-2, a capacity deficit will occur in 2022 (140.9 ZRC) and grow to 389.1 ZRC in 2030. Under the low-growth scenario forecast, as shown in Table 4-3, a capacity deficit occurs in 2022 at 51.8 ZRC and grows to 66.8 ZRC in 2030.

To address future long-term 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

<u>Year</u>	<u>Zonal Resource Credits¹</u>	<u>50/50 Coincident Summer Peak Demand w/MISO Losses</u>	<u>Planning Reserve Margin Requirement</u>	<u>Surplus/ Deficit(-)</u>
2019	590.1	508.1	548.2	41.9
2020	605.1	514.1	554.7	50.4
2021	618.1	527.0	568.7	49.4
2022	489.8	539.2	581.8	-92.0
2023	489.8	546.6	589.8	-100.0
2024	489.8	552.6	596.2	-106.4
2025	489.8	558.5	602.6	-112.8
2026	489.8	564.5	609.1	-119.3
2027	489.8	570.7	615.8	-126.0
2028	489.8	576.8	622.3	-132.5
2029	489.8	583.0	629.0	-139.5
2030	489.8	589.3	635.9	-146.1
2031	489.8	595.7	642.8	-153.0
2032	489.8	602.1	649.7	-159.9

1 – Total based on 2019-20 MISO Planning Year Zonal Resource Credits

Table 4-2

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

HIGH-GROWTH FORECAST

<u>Year</u>	<u>Zonal Resource Credits¹</u>	<u>50/50 Coincident Summer Peak Demand w/MISO Losses</u>	<u>Planning Reserve Margin Requirement</u>	<u>Surplus/ Deficit(-)</u>
2019	590.1	521.3	562.5	27.6
2020	605.1	546.5	589.7	15.4
2021	618.1	566.4	611.2	6.9
2022	489.8	584.5	630.7	-140.9
2023	489.8	604.7	652.5	-162.7
2024	489.8	632.8	682.8	-193.0
2025	489.8	656.9	708.8	-219.0
2026	489.8	687.4	741.7	-251.9
2027	489.8	717.2	773.9	-284.1
2028	489.8	750.4	809.7	-319.9
2029	489.8	778.6	840.1	-350.3
2030	489.8	814.6	878.9	-389.1
2031	489.8	849.9	917.1	-427.3
2032	489.8	889.0	959.2	-469.4

1 – Total based on 2019-20 MISO Planning Year Zonal Resource Credits

Table 4-3

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

LOW-GROWTH FORECAST

<u>Year</u>	<u>Zonal Resource Credits¹</u>	<u>50/50 Coincident Summer Peak Demand w/MISO Losses</u>	<u>Planning Reserve Margin Requirement</u>	<u>Surplus/ Deficit(-)</u>
2019	590.1	501.9	541.5	48.6
2020	605.1	506.4	546.4	58.7
2021	618.1	505.3	545.3	72.8
2022	489.8	501.9	541.6	-51.8
2023	489.8	499.9	539.3	-49.5
2024	489.8	503.5	543.3	-53.5
2025	489.8	503.3	543.0	-53.2
2026	489.8	506.9	547.0	-57.2
2027	489.8	509.2	549.4	-59.6
2028	489.8	512.8	553.3	-63.5
2029	489.8	512.2	552.7	-62.9
2030	489.8	515.8	556.6	-66.8
2031	489.8	518.1	559.0	-69.2
2032	489.8	521.7	562.9	-73.1

1 – Total based on 2019-20 MISO Planning Year Zonal Resource Credits

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 13 (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 least-cost analysis, Montana-Dakota will determine the best integrated resource plan to meet customer needs.

Integration of Demand-Side and Supply-Side Resources

The reduction in energy and peak demand for previously implemented DSM programs has been reflected as a reduction in Montana-Dakota's load forecast or as supply side DSM resources in the EGEAS model. Energy efficiency programs reduce Montana-Dakota's load forecast while supply side DSM resources are reflected as a resource and are not used to reduce the load forecast amounts.

As a result of the demand-side analysis described in Chapter 3, all models did include a committed amount of 15.4 MW from the interruptible rate and 25 MW of the commercial demand response program in 2019 and increasing to a total of 45 MW by 2021.

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. Potential future 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 2025. While no carbon tax was modeled in the base case, Montana-Dakota modeled a carbon tax of \$30 per ton for a sensitivity analysis.

Natural Gas Price Sensitivity

Prices for natural gas supplies as delivered to Montana-Dakota's existing turbines, potential future combustion turbines, and potential future combined cycle plants were developed in-house using historic pricing and forward gas indexes for use in the resource expansion analysis based on Montana-Dakota's view of the long-term outlook of natural gas pricing. For new resources in the base case, natural gas was priced for delivery at \$3.04/MMBtu for 2019 and decreasing to \$2.67/MMBtu in 2023. After 2023, 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 \$2/MMBtu and \$5/MMBtu and decreased by \$1/MMBtu 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 1.8 percent per year for the next five years and at an average rate of 1.2 percent per year through 2038. Energy requirements would increase at an average rate of 2.42 percent per year for the next five years, and at an average rate of 1.3 percent per year through 2038. The forecast also established high-growth and low-growth scenarios in which energy requirements were assumed to grow at 4.4 percent 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 Reciprocating Internal Combustion Engines Costs

The costs of materials associated with the construction of generation can fluctuate over time with changes in commodity costs, availability of skilled craft labor, import tariffs, and 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 capital costs and O&M costs for 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 reciprocating 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 have seen higher construction costs due to higher labor, housing, and material costs. These higher cost areas may provide 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

Historically, 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 these scenarios, Montana-Dakota modeled sensitivities of a \$5/MWh and \$10/MWh adder for the high energy price scenarios and used a \$3/MWh reduction for a low energy price scenario to the base case on energy prices for both on and off peak.

Natural Gas and MISO Energy Purchases

This sensitivity assumes both natural gas and the energy market prices increased by \$5/MMBtu and \$25/MWh over the Base Case.

Ninety percent coincident factor for MISO Resource Adequacy (RA)

The ninety percent coincident factor sensitivity scenario reflects a higher capacity need for MISO resource adequacy requirements; 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 81.5 percent coincident factor within MISO.

CHAPTER 6

RESULTS

This section presents the results of the 2019 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. 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 safe, stable and reliable power supply and the expectations that it be least cost, sustainable and environmentally friendly. 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 200 MW block of energy for off-peak and on-peak periods.

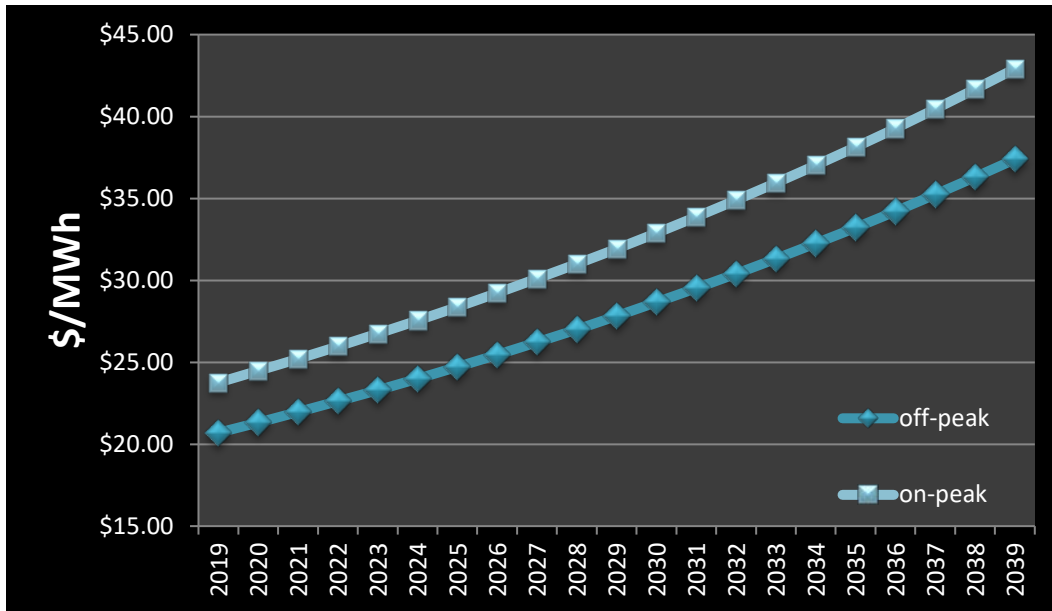


Figure 6-1: Forecasted On-Peak and Off-Peak MISO Market Prices developed by Montana-Dakota

MISO implemented an annual capacity auction starting with the 2013-14 planning year. Montana-Dakota has purchased small amounts of short-term capacity from the MISO Capacity Auction in past years. 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. Figure 6-2 shows the historical MISO Planning Resource Auction for zone 1, in which Montana-Dakota is located. The spike in 2016-2017 pricing on Figure 6-2 is a function of the single annual time period for the MISO capacity auction. The auction clearing price does not necessarily represent a long-term trend but is a function of annual offer prices submitted by generators and the amount of capacity that market participants buy in the market which changes from year-to-year.

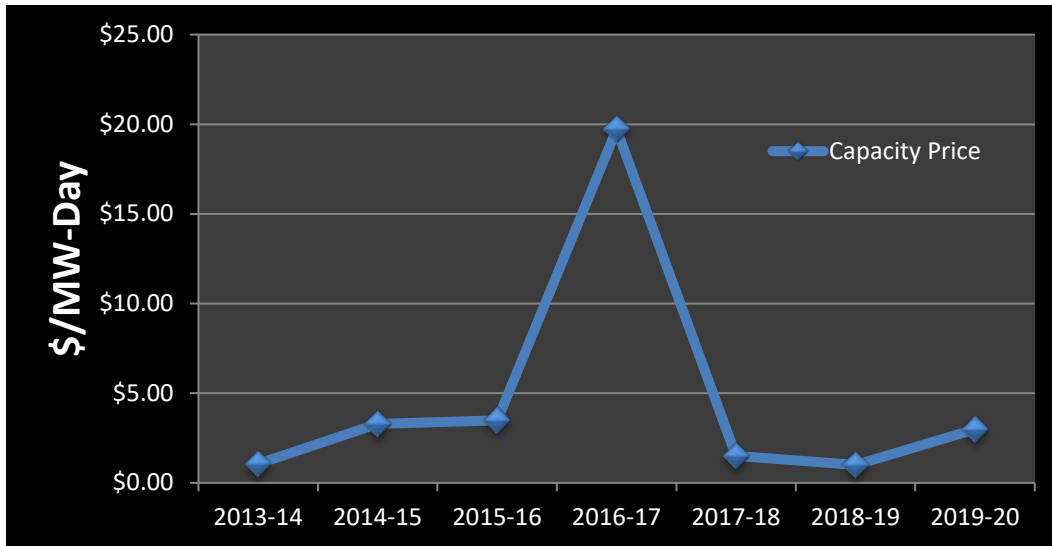


Figure 6-2: Historical MISO Capacity Resource Auction Prices for Zone 1

Reliance on Natural Gas

About 28 percent of Montana-Dakota’s owned generating nameplate capacity is natural gas-fired as of 2019. As shown on Figure 6-3, natural gas prices, though historically volatile, have stabilized with the development of shale gas formations in the U.S. Unlike coal, longer-term supply contracts for natural gas are generally not available and tend to be more seasonal in duration.

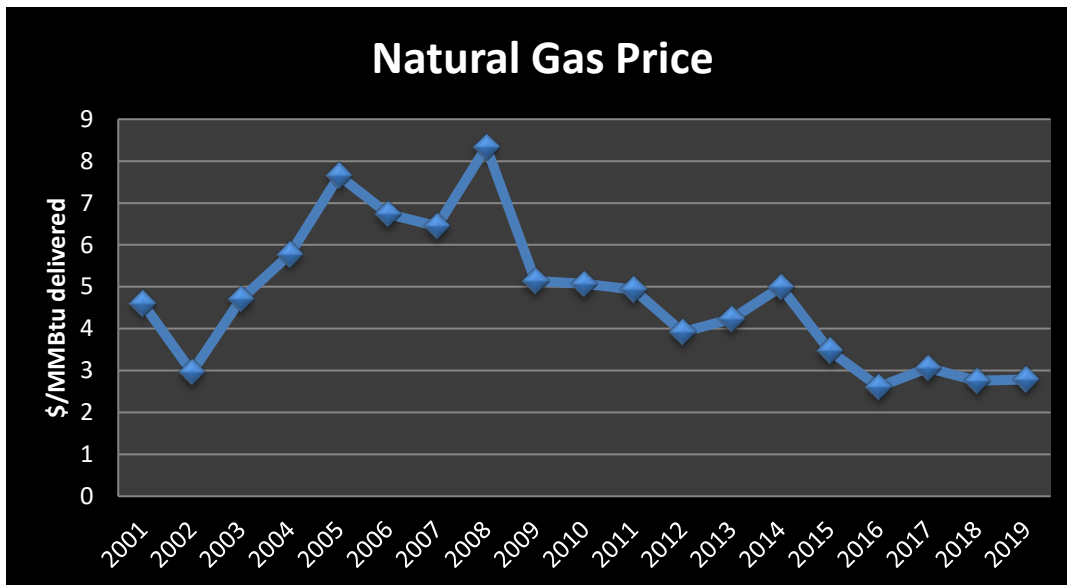


Figure 6-3: Historical Natural Gas Prices of Montana-Dakota’s existing combustion turbines (Based on 12-Month Average)

Resource Expansion Analysis Results

The most probable load forecast, fuel prices, and resource installed costs were modeled in the EGEAS Base Case. The Base Case least-cost plan consists of the following resource changes for the 2019-2024 period:

- Retire Lewis & Clark 1 by the end of 2020; and Heskett 1 and Heskett 2, by the end of 2021; and
- Install an 88 MW natural gas-fired Simple Cycle Combustion Turbine unit to be online in 2022 or early 2023.

The IRP model did select future wind, solar, and natural gas-fired generation from the 2018 RFP which the Company did not pursue due to project size, uncertainties in final costs associated with network upgrades, and location of resources as described in Attachment F – 2018 RFP Analysis. 5 MW of future solar generation was also selected in 2038. The net present value of the Base Case least-cost plan over the 50-year study period equates to \$2,860 million in 2018 dollars, as shown in Attachment C Table 3-1.

Sensitivity scenarios indicate that the Base Case plan is fairly robust under all assumptions in showing the need for a simple cycle gas-fired combustion turbine to meet future capacity and energy needs along with future wind, solar, and natural gas-fired generation. 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 throughout the 5-year action plan.

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 a similar plan to the Base Case.

Montana-Dakota has successfully utilized the MISO market for energy purchases, when available, to serve its customer load instead of using higher priced existing energy resources. In the low energy market price scenario, the resource plan never changed and had a slight decrease in NPV. Under the high energy market price scenario, the model selected the same plan under the \$5/MWh but selected 10 MW of purchase capacity in 2038 instead of the solar. These two scenarios resulted in a higher NPV than the Base Case.

When increasing both the natural gas and MISO energy market prices the resource plan selected is the same as the Base Case but does cause a significant increase in the NPV.

The carbon tax sensitivity scenarios show the economic impact of a tax on CO₂ on Montana-Dakota's generating system and customers. The total production costs increase significantly, and with low natural gas prices, existing coal units run less assuming \$30/ton of CO₂.

As shown in Figures 6-4 and 6-5, in 2019 approximately 30 percent of Montana-Dakota's Zonal Resource Credits are supplied by natural gas- and oil-fired combustion turbines while in 2022, based on the Base Case plan, approximately 43 percent of the Company's Zonal Resource Credits would be made up of natural gas- and oil-fired combustion turbines or engines.

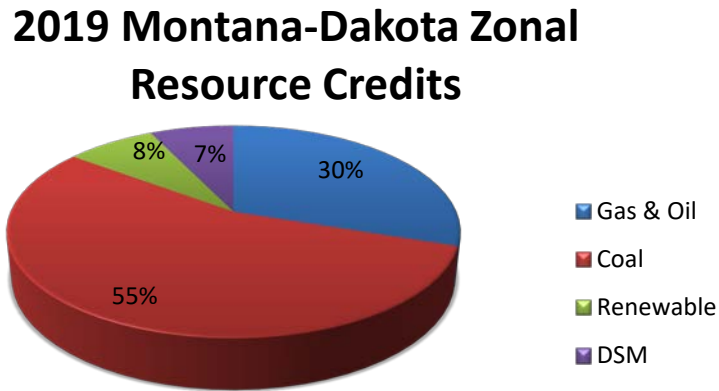


Figure 6-4: 2019 Montana-Dakota Zonal Resource Credits

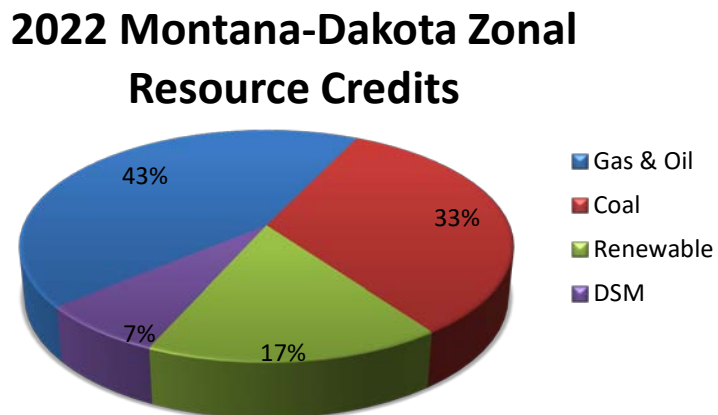


Figure 6-5: 2022 Montana-Dakota Zonal Resource Credits

Figures 6-6 and 6-7 shows the percentage of energy on a yearly basis in 2019 and after the retirements of Heskett 1, Heskett 2, and Lewis & Clark 1 in 2022. In 2019, 49 percent of Montana-Dakota’s energy will come from coal, 17 percent from renewable and 27 percent MISO energy market; while in 2022, 31 percent will come from coal, 23 percent from renewable and 47 percent will come from the MISO energy market based upon forecasted fuel and MISO energy prices. In 2022, Coyote and Big Stone have an annual capacity factor around 60 percent. If MISO energy prices increase higher than forecasted, Big Stone, Coyote, and Montana-Dakota’s natural gas-fired units could be dispatched to offset forecasted MISO energy purchases and provide pricing protection for customers.

2019 Montana-Dakota Energy

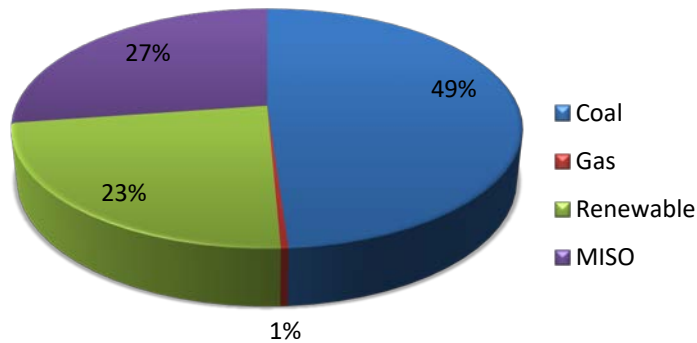


Figure 6-6: 2019 Montana-Dakota Energy by Resource Type

2022 Montana-Dakota Energy

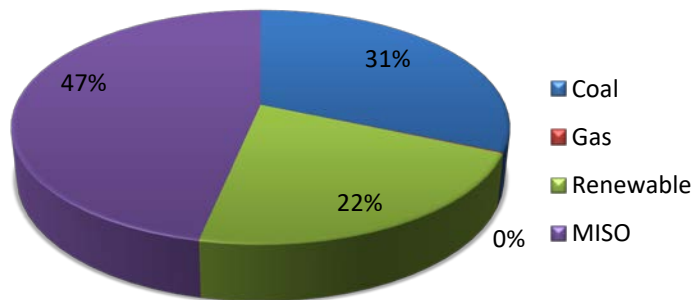


Figure 6-7: 2022 Montana-Dakota Energy by Resource Type

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 2019-2024 period:

- Retire Lewis & Clark 1 by the end of 2020; and Heskett 1 and Heskett 2, by the end of 2021;
- Continue the design and engineering work on a natural gas-fired simple cycle combustion turbine resource to be online in 2022 or early 2023; and
- Issue a new request for proposal prior to the next IRP.

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

Montana-Dakota's recommended resource plan satisfies future customer requirements through the retirement of Heskett 1, Heskett 2, and Lewis & Clark 1 along with the addition of a natural gas-fired simple cycle resource and additional MISO energy market purchases.

CHAPTER 7

TWO-YEAR AND FIVE-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 evaluate the accuracy of its demand and energy forecasts and make improvements where needed.

Demand-Side Resources

- Montana-Dakota will continue to implement existing, and evaluate new, cost-effective energy efficiency and demand response programs to meet the company's future requirements.

Supply-Side Activities

- Montana-Dakota will retire Lewis & Clark 1 at the end of 2020; and Heskett 1 and Heskett 2 at the end of 2021.
- Montana-Dakota will continue with the design and development and file an Advanced Determination of Prudence with the ND PSC the fall of 2019 for a new 88 MW simple cycle combustion turbine at Heskett Station to be online in 2022 or early 2023.
- Montana-Dakota will submit regulatory filings to address the retirements of Heskett 1, Heskett 2, and Lewis & Clark 1.
- Montana-Dakota will issue a new request for proposal of supply side resources prior to the next IRP.
- Montana-Dakota will continue to study the need to install local generation projects, including community solar, throughout its service area to support load growth, mitigate transmission constraints, and provide customer requested programs.
- 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 or necessary to fill short term needs.

- Montana-Dakota will continue to monitor the development of and impacts to Coyote Station associated with the next round of regional haze reductions and other changes of environmental rules for all generation sources and influence the outcomes where possible.
- Montana-Dakota will continue to monitor new RTO resource adequacy requirements associated with changing fleet fuel mix including seasonal variation and reserve margins.
- Montana-Dakota will continue to evaluate solar and battery storage technologies and their potential for implementation within Montana-Dakota's system as generation and transmission devices.

RTO Transmission Arrangements

- Montana-Dakota will continue to monitor the impacts and benefits of its RTO transmission arrangements with MISO and SPP to ensure a safe, reliable, and economic transmission system for its customers.

Other Activities

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

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 2019 IRP advisory group was established at the beginning of the 2019 planning cycle and held its first meeting in November 2018.

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 2019 PAG participants are shown in Table 8-1.

Table 8-1
The 2019 IRP Public Advisory Group

Montana

Kevin Thompson
Action for Eastern Montana
Glendive, Montana

Garrett Martin
Department of Environmental Quality
Helena, Montana

North Dakota

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

Darin Scherr
Bismarck Public Schools
Bismarck, North Dakota

Bruce Conway
OptCTS, Inc
Williston, North Dakota

Senator Rich Wardner
North Dakota State Senate
Dickinson, North Dakota

Martin Fritz
Kadrmas Lee & Jackson
Bismarck, 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 2019 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 2019 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.

CHAPTER 9

RETIREMENT ANALYSIS

Montana-Dakota is retiring the Lewis & Clark 1 coal-fired power plant near Sidney, Montana, at the end of 2020; and the Heskett 1 and Heskett 2 coal-fired power plants near Mandan, North Dakota at the end of 2021. At its retirement date, Heskett 1 will have been in operation for 67 years, Lewis & Clark 1 62 years, and Heskett 2 for 58 years.

The main driver for retirement of Lewis & Clark 1, Heskett 1 and Heskett 2 are the age of the plants, low-cost and availability of natural gas, and low-cost power on the MISO market, as well as rising fuel costs and operating & maintenance expenses at Lewis & Clark 1, Heskett 1, and Heskett 2. The plants have served customers well, providing low-cost energy for many years, operating much longer than expected.

The total cost of a new simple cycle combustion turbine coupled with MISO market purchases is expected to be about half the total cost of continuing to run the Heskett and Lewis & Clark coal-fired units. A 2018 cost per kilowatt hour comparison of fuel and variable operation & maintenance costs shows these older coal units are no longer price competitive resources for our customers as compared to other options:

Heskett	4.30 to 5.55 cents per kWh
Lewis & Clark	3.56 cents per kWh
Other Coal (Coyote and Big Stone)	2.25 to 2.29 cents per kWh
Wind	2.56 cents per kWh
Market	2.59 cents per kWh

The long-range forecast for MISO market and natural gas indicates stable prices.

The Company's 2019 IRP retirement analysis for Heskett 1, Heskett 2 and Lewis & Clark 1 looked at the impacts of various retirement dates, continued viability of the units, and a revenue requirement analysis of customer impacts associated with a retirement and replacement plan.

Varying retirement dates of Heskett 1, Heskett 2 and Lewis & Clark 1 in the IRP model from 2029 to 2024 to 2021 showed a greater magnitude of savings to customers with the earlier retirement date of 2021 which coincides with the expiration of the coal supply agreements at Lewis & Clark 1 at the end of 2020, and Heskett 1 and Heskett 2 at the end of 2021.

The Company also retired Heskett 1, Heskett 2, and Lewis & Clark 1 in the IRP model and allowed the IRP model to re-select the units as a 5-year future resource at zero capital investment with their current fuel and O&M costs. No units were selected.

The Company also developed a revenue requirement model of the costs to continue to operate Heskett 1, Heskett 2 and Lewis & Clark 1 versus the retirement and replacement with a simple cycle combustion turbine coupled with market purchases. The replacement scenario coupled with market purchases is approximately half the cost of continuing to run the older coal-fired units.

There are 70-plus employees total at both coal-plant locations. Once the coal plants are no longer in operation, approximately 10 total employees will operate the two natural gas fired units at Heskett and the two natural gas fired combustion engines at Lewis & Clark. A plan is in place which is intended to maintain staff until the plant retirements and the company will offer training for employees who wish to fill open positions in other areas of the company.

Generation portfolio before and after retirements:

Source	Current	2023
Coal	44%	29%
Natural Gas	28%	41%
Renewable	28%	30%

Post Retirement Decommissioning and Demolition Summary

Lewis & Clark 1

Montana-Dakota intends to retire Lewis & Clark 1 at the end of 2020. After retirement, Montana-Dakota plans to decommission and demolish (D&D) Lewis & Clark 1, and has retained Burns & McDonnell Engineering Company (BMcD) as a first step in this D&D effort. The meeting to kick off the BMcD work was hosted by Montana-Dakota at Lewis & Clark Station on June 4-5, 2019. Lewis & Clark 2, which went commercial in 2015, consists of two natural gas fired Wärtsilä 20V34SG simple cycle reciprocating internal combustion engines (RICE) with a combined nameplate rating of 19 MW. As further discussed below, Lewis & Clark Station has shared systems and facilities that support both Lewis & Clark 1 and Lewis & Clark 2.

The major tasks BMcD will initially be performing for Lewis & Clark Station are a Regulated Materials Assessment (RMA) and D&D cost estimate in support of providing a D&D budget to Montana-Dakota in early July 2019. BMcD will be also be helping Montana-Dakota develop the

D&D scope of work to be competitively bid and tentatively awarded to a D&D contractor by the first quarter of 2020. Major tasks associated with this are: preparing a project schedule, developing a plan for continuity of operations for Lewis & Clark 2, preparing an outage plan for pre-decommissioning of Lewis & Clark 1 using plant staff, preparing a contractor bid specification, performing contractor pre-qualifications, supporting the bidding process, evaluating the bids, and making a recommendation for the best bid.

As eluded to earlier, BMcD will be developing a plan for continuity of operations for Lewis & Clark 2. This is required because some of the systems and facilities at Lewis & Clark Station are shared. BMcD will be helping Montana-Dakota evaluate modifications, replacements, and additions to these systems and facilities to minimize major outage impacts to Lewis & Clark 2 operations during D&D, and to ensure standalone operational capability of Lewis & Clark 2.

Montana-Dakota plans to use Lewis & Clark Station staff to perform pre-decommissioning activities of Lewis & Clark 1. BMcD will be preparing a project schedule and an outage plan that will define the duration of this pre-decommissioning outage. The schedule for the D&D contractor will not be known until the work is awarded, but Montana-Dakota anticipates that the D&D contractor will mobilize and start work shortly after the pre-decommissioning outage efforts are complete.

More details on the Lewis & Clark Station D&D project will be known later in 2019 and early 2020 as the costs, milestones, schedule, scope, and sequence of events are defined and refined by BMcD.

R.M. Heskett Station

Montana-Dakota intends to retire Heskett 1 and Heskett 2 at the end of 2021. Montana-Dakota plans to D&D Heskett 1 and Heskett 2 after retirement and has retained BMcD as a first step in this effort. The meeting to kick off the BMcD work was hosted by Montana-Dakota at Heskett on June 5-6, 2019. Heskett 3, which went commercial in 2014, consists of one natural gas fired General Electric (GE) PG7121EA heavy-duty frame (Frame 7EA) simple cycle combustion turbine generator (SCCT) with a nameplate rating of 88 MW. Heskett 4 is a proposed brownfield project located adjacent to Heskett 3 consisting of one natural gas fired GE Frame 7EA SCCT rated at 88MW (see Attachment E – Heskett 4 Analysis). As further discussed below, Heskett has shared systems and facilities that support the three existing units and are expected to support Heskett 4.

The major tasks BMcD will initially be performing for Heskett are an RMA and D&D cost estimate in support of providing a D&D budget to Montana-Dakota in early August 2019. BMcD will be also be preparing a high-level project milestone schedule and D&D plan.

Montana-Dakota expects to start the procurement process for development of the detailed D&D scope of work for Heskett in late 2019 or early 2020. Major tasks are expected to be: preparing a project schedule, developing a plan for continuity of operations for Heskett 3 and Heskett 4, preparing an outage plan for pre-decommissioning of Heskett 1 and Heskett 2 using plant staff, preparing a contractor bid specification, performing contractor pre-qualifications, supporting the bidding process, evaluating the bids, and making a recommendation for the best bid.

As eluded to earlier, a plan for continuity of operations for Heskett 3 and Heskett 4 will be required because some of the systems and facilities at Heskett are shared. Montana-Dakota expects that modifications, replacements, and additions to these systems and facilities will need to be evaluated to minimize major outage impacts to Heskett 3 operations and construction of Heskett 4 during D&D, and to ensure standalone operational capability of Heskett 3 and Heskett 4.

Montana-Dakota plans to use Heskett staff to perform pre-decommissioning activities of Heskett 1 and Heskett 2, so a project schedule and an outage plan that will define the duration of this pre-decommissioning outage will need to be developed. Montana-Dakota anticipates that the D&D contractor will mobilize and start work shortly after the pre-decommissioning outage efforts are complete.

More details on the Heskett D&D project will be developed over the course of 2019, 2020, and 2021.