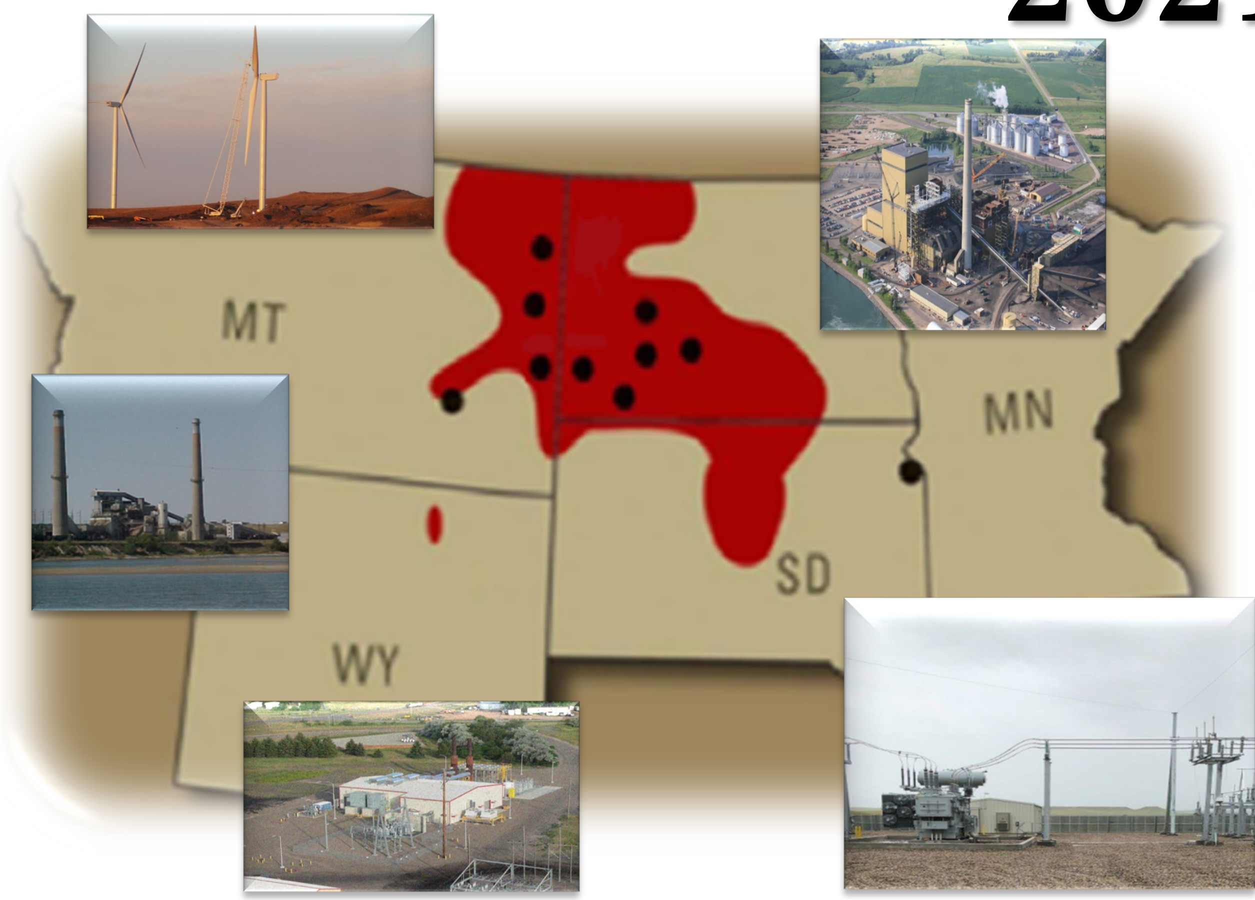
Integrated Resource Plan 2021



Submitted to the
Montana Public Service Commission
September 15, 2021

Volume I: Main Report

Montana-Dakota Utilities Co.

2021 Integrated Resource Plan

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Volume I

Main Report

MONTANA-DAKOTA UTILITIES CO.

A Subsidiary of MDU Resources Group, Inc.

INTEGRATED RESOURCE PLAN

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Montana-Dakota Utilities Co.'s (Montana-Dakota) 2021 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 32-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 2021-2040 timeframe, the projected average annual growth rate for summer peak demand is 0.93 percent prior to any reductions due to demand response programs, while annual energy requirements are expected to increase at a rate of 0.84 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 2021-2023 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, battery storage, biomass, short term capacity purchases, and results from a 2020 Request for

Proposal (2020 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 considers the feasible supply-side and demand-side options to determine a least-cost resource expansion plan to meet customer requirements economically and reliably 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 and low natural gas and energy market prices, limiting energy market, an early Coyote Station retirement scenario, 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 on March 31, 2021, and the Heskett 1 and Heskett 2 coal-fired generating units by March 31, 2022, having a capacity and energy contract through May 31, 2026, and adding a natural gas-fired simple cycle combustion turbine at the Heskett Station site (Heskett 4) in 2023 along with the increased reliance on 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 solar options from a Qualified Facility, a self-built option, and a 2020 RFP option which was not selected as part of the 2020 RFP due to unknown transmission costs in the MISO generator interconnection studies. 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 2021-2040 assuming the retirements of Heskett 1 and Heskett 2 and the already retired Lewis & Clark 1, the addition of the capacity contract and adding Heskett 4. 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 81.1 percent coincident factor. "Existing ZRC" represents 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.

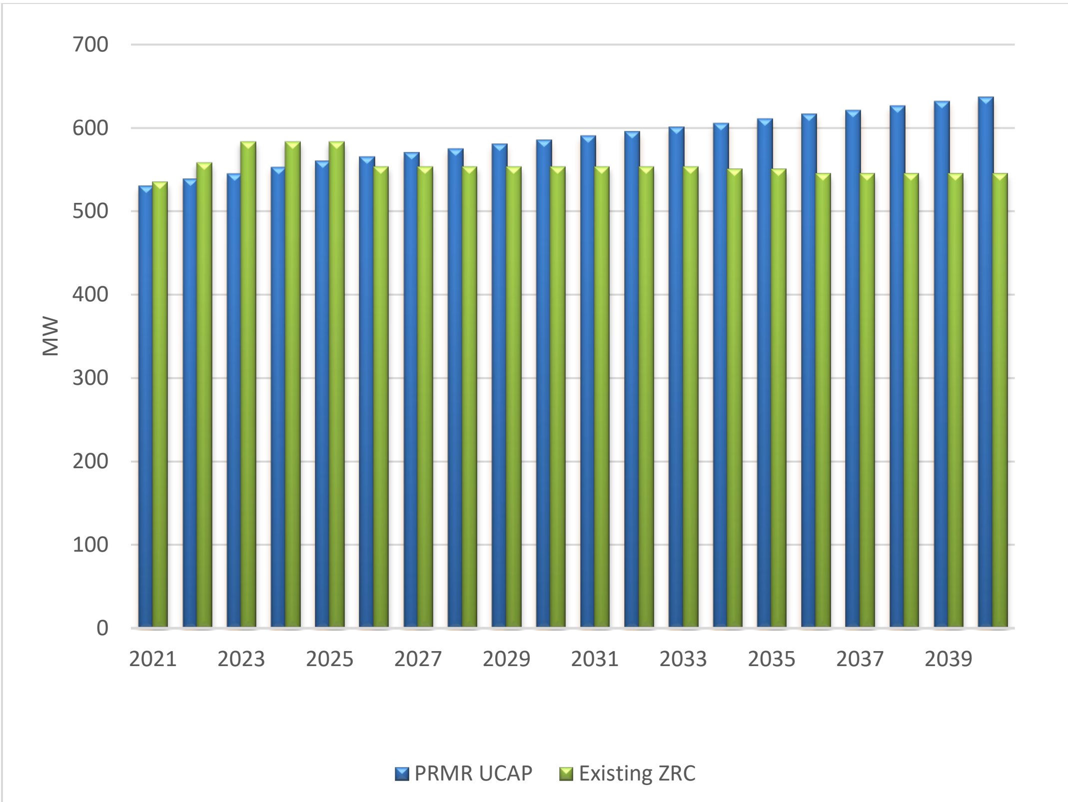

Figure E-1: 2021-2022 MISO Planning Year Zonal Resource Credit and Planning Reserve Margin Requirement

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 2021-2026 period is as follows:

- Continue with the retirements of Heskett 1 and Heskett 2 by March 31, 2022.
- Continue with the design and development for a new 88 MW simple cycle combustion turbine at Heskett Station to be online in early 2023.
- 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.
- Consider new legislation in North Dakota regarding reliability.
- Monitor the impacts associated with the planned generation shifts within MISO including the Long-Range Transmission Plan, multi-season resource adequacy requirements, additional electrification of load associated with carbon reduction future scenarios, and expansion of electric vehicle technologies. Included in the multi-season resource adequacy requirements may be the need to evaluate the conversion of Heskett 3 and 4 to dual fuel combustion.

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

The 2021 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 2021 advisory group was established at the beginning of the 2021 planning cycle and provided Montana-Dakota with input throughout the 2021 IRP process.

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

Volume I – Main Report (the current document)

Volume II – Attachment A: Load Forecast Documentation

Volume III – Attachment B: Demand-Side Analysis Documentation

Volume IV – Attachment C: Supply-Side and Integration Analysis Documentation

Attachment D: Public Advisory Group Documentation

Attachment E: Supply Side Resources Study

Attachment F: 2020 Capacity and Energy RFP

Attachment G: Transmission Impacts

Attachment H: MISO RTO Overview

Attachment I: Responses to Montana Public Service Commission Comments Regarding Montana-Dakota's 2019 IRP

Attachment J: Responses to Montana Department of Environmental Quality Comments Regarding Montana-Dakota's 2019 IRP

CHAPTER 1

ENVIRONMENTAL CONSIDERATIONS

The Company's Environmental Policy states:

> *"The 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 be a good steward of the environment while providing high quality and reasonably priced products and services; and*
> - *To comply with or surpass 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.

Over the past several years, the U.S. Environmental Protection Agency (EPA) has finalized, proposed new and/or reproposed significant regulations for fossil-fired electric generating facilities that aim to reduce air emissions, including GHGs, and pollutants in wastewater discharges. EPA also published a final rule in the Federal Register on April 17, 2015, and amendments from 2018 to 2020, for management of coal ash at coal-fired electric generating facilities. The culmination of these environmental requirements, including any new EPA rulemaking to reduce GHG 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.

Additional emission controls such as carbon capture, utilization, and sequestration (CCUS) could be implemented to avoid retirement of fossil-fired units. However, these controls would increase capital and operational costs and reduce the net output of the units due to the significant energy consumption for operating the emissions controls. We anticipate new zero-carbon resources such as wind or solar electric generation facilities would likely be required in the future considering

President Biden's decarbonization targets for the electric sector. Further, while not an environmental issue, either costly CCUS, over build of renewables, energy storage systems, or other emerging net-zero emissions electric generation technologies would be required to meet reliability requirements along with potential electric transmission buildouts.

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 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 (CO_2) emission intensity by three to five percent by 2010. Montana-Dakota has shown its commitment by reducing the Company's CO_2 emissions intensity in 2008 by approximately seven percent as compared to 2003. In 2010, Montana-Dakota updated its CO_2 emissions intensity goal, committing to a 10 percent reduction of the Company's average CO_2 emissions intensity from its electric generating facilities by 2012 compared to 2003 levels. Montana-Dakota continues to see reductions in its CO_2 emission intensity with the additions of renewable and gas-fired generation since 2010. Since 2005, Montana-Dakota's electric generation resource fleet CO_2 emission intensity has been reduced by approximately 28 percent. In 2017, a new target was developed to reduce the Company's electric generation resource fleet CO_2 emission intensity by 45 percent from 2005 in 2030. We anticipate demonstrating progress toward achieving this target with additional future renewable generation and the past retirement of Lewis & Clark Station Unit 1 and future retirements of R. M. Heskett Stations Units 1 and 2.

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

Montana-Dakota has also actively participated in the environmental workgroups of the North Dakota Lignite Energy Council such as the Lignite Technology Development Workgroup and the Environmental Workgroup. These workgroups have focused on CO_2 related issues such as lignite gasification, oxyfuel combustion, pre- and post-combustion CO_2 capture technologies, exploration of Allam Cycle utilization of lignite fuel, and beneficial uses of CO_2.

Montana-Dakota started a LED conversion program in 2017 for Company owned street lighting and Company owned private lighting rental throughout our service territory to reduce energy usage and thus reducing GHG emissions. The project concluded in early 2021 with over 25,585 energy-saving LED lights installed, resulting in about 16.3 million kWh in annual energy savings which equates to about 12,716 metric tons of CO_2e emissions reduced annually. More information on this program can be seen in Chapter 3.

GHG emissions have also been reduced from Montana-Dakota's energy efficiency and conservation programs for electric residential and commercial customers. For example, the total kilowatt-hour savings from electric energy efficiency and conservation programs completed in 2020 was about 1.42 million kilowatt-hours, equating to a reduction of over 1,000 metric tons of CO_2e.

Environmental Regulation Pollution Control Project Impacts

The Coal Combustion Residuals (CCR) rule has resulted in coal ash management projects completed at Coyote Station, Big Stone Plant and Lewis & Clark Station in 2018 to 2019. In the future, the Regional Haze (RH) rule could result in significant pollution control requirements at Coyote Station. These impacts are discussed below.

Additionally, GHG emissions regulation or congressional legislative action that may be enacted by the Biden Administration would impact the utilization and cost of utilizing fossil fuel-fired generation resources. Discussion on the GHG rulemaking status for fossil-fired electric generation units is provided further below.

Coal Combustion Residuals (CCR) Rule

On April 17, 2015, 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 EPA and states the authority to administer and enforce CCR rule requirements through permitting programs. Administration of the CCR rule by EPA and states may potentially result in availability of alternative compliance options.

In 2018 and 2019, the following projects were completed at Montana-Dakota's owned and co-owned coal-fired electric generation resources for compliance with CCR rule requirements: a scrubber pond retrofit at Lewis & Clark Station completed in 2018, a bottom ash handling system retrofit along with a pond and temporary ash storage area closure at Big Stone Plant was completed in 2018, and a similar retrofit and pond closure project at Coyote Station was completed in 2019.

Regional Haze Rule (RH Rule)

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, EPA published a revised rule that included guidelines for control technology determinations under the RH rule for sources subject to Best Available Retrofit Technology (BART) requirements and for sources addressed for reasonable progress.

State environmental agencies are required to submit State Implementation Plans (SIPs) to 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 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. Any required controls for round two would have to be installed and operating 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. Since Lewis & Clark 1 ceased operation on March 31, 2021, the Company did not install pollution controls.

The 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 ND DEQ by January 31, 2019. The analyses were prepared and submitted to ND DEQ. The four-factor analysis is a review of technically feasible SO_2 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 SO_2 pollution controls for ND DEQ to evaluate. ND DEQ evaluated the four-factor analysis and Coyote Station co-owners submitted supplemental information on pollution controls for ND DEQ review. After review, ND DEQ provided recommendations to the regional modeling contractor for modeling emissions reductions and progress with meeting the glidepath. If ND DEQ would require additional controls, those controls would be memorialized in North Dakota's SIP. The Company expects ND DEQ to draft a SIP and share its controls selection with federal land managers in the summer of 2021. ND DEQ's state implementation plan is anticipated to be submitted to the EPA after July 2021. Any required controls would have to be installed and operating by July 31, 2028 (the end of Regional Haze round two planning period).

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, like 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.

While the North Dakota draft SIP is not yet available for review, it is possible that additional pollution controls could be required for Coyote Station in round two. Additionally, if any potential pollution control requirements are made known by ND DEQ, Montana-Dakota may participate through the SIP public notice and comment process before eventual submittal to EPA for the agency's review and approval. The CAA deadline for EPA action on a SIP is 12 months from the EPA's determination that the SIP is complete. This is anticipated to be the point in time where we would know if the SIP is deemed adequate or if a new federal implementation plan would be proposed by EPA with different controls required. Montana-Dakota will incorporate the requirements into IRP supply-side resource evaluations.

The Coyote Station is co-owned by four utilities. The economics of the plant are different for each owner and are currently under review by the owners, independently. Any actions as a result of the economic analyses by any owner, may have an impact on the economics of the other owners. A scenario was added to the 2021 IRP to study the results of a Coyote Station plant closure in 2028. Detailed modeling of required Coyote Station regional haze controls will be included in the 2023 IRP.

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

On March 28, 2017, former President Trump issued an Executive Order (EO) 13783 titled "Promoting Energy Independence and Economic Growth" directing the EPA administrator 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.

In addition, 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. EPA also published a proposed rule on April 4, 2017, initiating review of the CPP rule and NSPS GHG rule. In parallel, EPA published a proposal on October 16, 2017, to repeal the CPP in its entirety and published the proposed Affordable Clean Energy (ACE) rulemaking to revise the CPP.

Significant legal issues with GHG rule proposals from previous administrations have led to the D.C. Circuit Court to vacate the ACE rule and repeal the CPP. On January 19, 2021 the court remanded the record back to EPA finding that the agency misinterpreted the Clean Air Act (CAA) when the agency determined that the language of CAA Section 111 unambiguously barred consideration of emissions reduction options that were not applied at the source. An EPA memo on February 12, 2021 notes that states do not have to take "any further action" to develop implementation plans and that reinstating the CPP "would not make sense" as a practical matter.

It is expected the Biden administration will propose a new replacement for GHG regulation of existing fossil fuel-fired electric generation units in line with President Biden's Executive Order (EO) 13990 on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis"[1] as EO 13990 revokes former President Trump's EO 13783. Section 1 of the order stipulates one of the policy items of the Administration is to reduce greenhouse gas emissions. To help advance that policy, Section 5 "Accounting for the Benefits of Reducing

[1] Federal Register listing of 2021 Joe Biden Executive Orders. **https://www.federalregister.gov/presidential-documents/executive-orders**

Climate Pollution" provides direction to determine social costs of carbon, nitrous oxide and methane to monetize damages associated with incremental increases in GHG emissions. This social cost of carbon will be used by agencies to determine the social benefits of reducing greenhouse gas emissions when conducting cost-benefit analyses of regulatory and other actions.

On January 7, 2021, before the new administration took office, EPA provided a framework for criteria for making a "significant contribution" finding for greenhouse gas emissions from a source category, for the purpose of regulating new emission sources under section 111(b) of the Clean Air Act. The framework set an emissions threshold of three percent of total gross U.S. GHG emissions (as measured in carbon dioxide equivalent, i.e., CO2e) for conducting rulemaking. On March 17, 2021, EPA asked the D.C. Circuit to vacate and remand the "significant contribution" final rule. The rule was promulgated without public notice or opportunity to comment. On April 5, 2021, the D.C. Circuit vacated and remanded the January 2021 final rule for 111(b). As a result of the ruling, the 2015 EPA regulations to limit GHG emissions from new fossil fuel-fired utility boilers and from natural gas-fired stationary combustion turbines emission limits remain in place.

Congressional action for reducing GHG emissions has also been proposed in 2021. Montana-Dakota includes discussion further below on the proposed Climate Leadership and Environmental Action for our Nation's (CLEAN) Future Act bill.

Montana-Dakota will continue to monitor GHG emission reduction rulemakings and incorporate changes as needed into the evaluation of supply-side resources.

2021 Congressional Proposal - CLEAN Future Act

On March 2, 2021, a discussion draft of the Climate Leadership and Environmental Action for our Nation's (CLEAN) Future Act[2] was released by House Energy and Commerce Committee Democratic leadership, which is intended to achieve the Committee's goal of reaching economy wide net-zero greenhouse gas (GHG) emissions by 2050. The bill provisions reflect President Biden's goals and directives in EO 13990 "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis"[3] and EO 14008 "Tackling the Climate Crisis at

[2] **CLEAN Future Act bill text 2021**. **https://www.congress.gov/bill/117th-congress/house-bill/1512/text**.
[3] **Id-7.**

Home and Abroad"[4] and in the President's revocation of former President Trump's EOs concerning GHG emissions and climate change.

The Committee has been holding hearings and stakeholder meetings in 2021 for refining the bill. Due to varying views of congressional delegates and the very aggressive emission reductions and timeline, many believe the bill would not pass in its present form. However, there could be elements of this bill added to other legislation or included in federal agency regulatory actions, such as through EPA and/or the U.S. Department of Energy (DOE). Although still in draft, there are elements that could be enacted and would impact Montana-Dakota's planning in future IRPs, especially in regard to the CLEAN Future Act bill's proposed aggressive timeline for the electric sector to transition to a low carbon generation resource mix and increasing demand for electricity resulting from transportation electrification and increases in building electrification. Montana-Dakota will continue to monitor these congressional and federal agency actions.

The CLEAN Future Act contains 10 titles addressing national targets for reducing national, economy wide GHG emissions and some of the titles would have direct application to the electric sector. The titles cover the following: national climate targets; the electric power sector; building and appliance efficiency; the transportation sector; the industrial sector; environmental justice; super pollutants (i.e. methane); various "economy-wide" policies (including environmental justice provisions); waste reduction provisions; and worker and community transition. In this IRP, Montana-Dakota provides a high-level summary of some key elements of the bill that would apply to the electric sector.

The bill establishes a national, economy-wide goal of a minimum 50 percent reduction in GHG emissions below 2005 levels by 2030 and a 100 percent clean economy wide goal, defined as economy-wide net zero GHG emissions, no later than 2050. Federal agencies, including EPA, are tasked with developing action plans to achieve these goals. Actions to achieve reductions could include new or modified regulations, incentives, research and development programs, and reductions from federal agency infrastructure. Specific to the electric sector, Title II Subtitle A, proposes a nationwide clean electricity standard (CES) to be administered by EPA which would require all retail electricity suppliers (RES) to obtain 100 percent of their electricity from clean energy sources by 2035. Starting in 2023, all RES would be required to increase the amount of

[4] **Id-7.**

clean electricity provided to consumers annually, with a requirement to reach 80 percent clean electricity by 2030.

Qualifying clean energy up to the year 2030 is defined as electricity generated at any facility with an annual emissions intensity lower than 0.82 metric tons of carbon dioxide equivalent (CO_2e) per megawatt-hour (MWh). Coal-fired electric generation units have emissions intensities higher than 0.82 metric tons CO2e per MWh and many natural gas-fired combined cycle combustion units would be expected to have emissions intensities lower than this. However, beginning in 2030 the bill starts phasing down the emissions intensity, and by 2035, facilities must meet an intensity of 0.4 metric tons of CO_2e per MWh. For an individual fossil fuel-fired electric generation unit to meet that standard, CCUS technology would need to be installed or hydrogen blending would be required.

Owners of electric generation units can be issued zero-emission electricity credits (ZEECs) for the qualified clean energy they generate. The number of ZEECs generated during the year from solar, wind and nuclear generation would be equal to the electricity generated (one ZEEC for one clean energy MWh). Depending on the emissions intensity and the emissions intensity target set for that specific year, only a fraction of generation from natural gas-fired units would generate ZEECs up to the year 2035. A coal-fired unit without CCUS would not generate ZEECs due to the higher emissions intensity and after 2035, a natural gas-fired unit without CCUS would not be expected to generate ZEECs. EPA would establish a trading market for ZEECs to be bought and sold for RES' to demonstrate compliance.

This bill would also set a "fossil fuel adjustment" to account for upstream emissions related to generating units utilizing fossil fuels, such as natural gas-fired combined cycles. This adjustment would be applied to a generating unit's emission intensity, resulting in the electric sector accounting for upstream fuel GHG emissions.

In combination with the emission intensity standards discussed above for generating ZEECs, RESs would need to comply with zero-emission electricity requirements. EPA would establish a baseline zero-emission electricity percentage for each RES as the three-year average percentage of zero-emission electricity that was supplied to the RES' customers in 2017 to 2019. In 2023, an RES's compliance obligation would be equivalent to its baseline zero-emission electricity percentage and would be reduced incrementally from 2024 to 2035, with 100 percent zero-emission electricity required in 2035 and thereafter. ZEECs would be generated and traded to comply with the zero-emission electricity requirements.

Instead of procuring ZEECs to cover its annual compliance obligation, a RES instead can opt to make an alternative compliance payment (ACP). The ACP would be set at $40 in 2023 and increase by three percent annually plus an inflation adjustment. The draft bill allows EPA to extend an RES' deadline to meet the 2035 target for a maximum of five years (until 2040) depending on whether the RES needs to utilize the ACP. The bill would allow for certain units to deduct the quantity of generation from the RES' compliance requirement if they would be designated as a "system support resource" by FERC and required by an ISO/RTO to remain in operation because the units' retirements would "harm the reliability" of the electric grid.

As mentioned at the introduction of this section, Montana-Dakota will continue to monitor congressional and federal agency actions. The Company will incorporate these actions in future IRP analysis as federal agencies promulgate rules and as congressional action is further informed through bill hearings and stakeholder input.

CHAPTER 2

LOAD FORECASTING

Montana-Dakota typically conducts a 20-year load forecast study annually with the last such study conducted in 2020. Montana-Dakota uses econometric modeling as the starting point for its forecasts. The econometric models for the 2021-2040 Integrated System forecast conducted in 2020 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.

<u>Energy Sales Forecast</u>

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 2020 (*Electric Load Forecast 2021-2040,* published December 31, 2020). The DSM programs that were selected for the 2019 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 2020 study was 8.041 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 2019 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 2020 study are presented in Table 2-1 summarizing the total energy requirements and seasonal peak demand.

Table 2-1
Montana-Dakota Utilities Co.
Historical and Forecasted Energy and Demand
Integrated System
Reflecting Demand-Side Management Programs from 2019 IRP
Calendar Month Basis

	Total Energy Requirements (net of DSM and EE)		Summer Peak - MW				Winter Peak 2/			
Year	MWh	% Change	Total Demand Before any DSM or EE	Energy Efficiency (EE)	Demand Net of EE 1/	% Change	Total Demand Before any DSM or EE	Energy Efficiency (EE)	Demand Net of EE 1/	% Change
2010	2,718,192				502.5				457.8	
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%			563.8	-0.22%
2019	3,301,537	-0.36%			536.9	-6.20%			571.1	1.29%
2020	3,169,086	-4.01%			585.6	9.07%				not available
2021	3,350,642	5.73%	586.6	0.6	586.0	0.07%	575.8	0.6	575.2	
2022	3,418,187	2.02%	595.7	0.6	595.1	1.55%	587.3	0.6	586.7	1.99%
2023	3,466,208	1.40%	603.2	0.6	602.5	1.25%	595.4	0.6	594.8	1.38%
2024	3,525,523	1.71%	611.5	0.6	610.8	1.38%	605.4	0.6	604.8	1.69%
2025	3,579,075	1.52%	619.4	0.7	618.8	1.30%	614.4	0.6	613.8	1.48%
2026	3,603,363	0.68%	624.9	0.7	624.2	0.88%	618.6	0.6	617.9	0.68%
2027	3,630,492	0.75%	630.5	0.7	629.8	0.90%	623.1	0.7	622.4	0.73%
2028	3,655,892	0.70%	636.0	0.7	635.3	0.88%	627.4	0.7	626.8	0.70%
2029	3,683,062	0.74%	641.6	0.7	640.9	0.88%	632.1	0.7	631.4	0.74%
2030	3,710,355	0.74%	647.3	0.7	646.6	0.89%	636.6	0.7	635.9	0.72%
2031	3,737,747	0.74%	652.9	0.7	652.3	0.87%	641.3	0.7	640.6	0.73%
2032	3,765,210	0.73%	658.7	0.7	658.0	0.88%	645.9	0.7	645.2	0.72%
2033	3,792,755	0.73%	664.4	0.7	663.7	0.87%	650.6	0.7	649.9	0.73%
2034	3,820,414	0.73%	670.0	0.7	669.3	0.85%	655.3	0.7	654.6	0.71%
2035	3,848,154	0.73%	675.7	0.7	675.0	0.85%	660.0	0.7	659.3	0.72%
2036	3,875,972	0.72%	681.4	0.7	680.7	0.85%	664.6	0.7	663.9	0.70%
2037	3,903,936	0.72%	687.1	0.7	686.4	0.84%	669.4	0.7	668.6	0.71%
2038	3,932,005	0.72%	693.0	0.7	692.2	0.85%	674.2	0.7	673.4	0.72%
2039	3,960,348	0.72%	698.7	0.8	697.9	0.82%	678.9	0.7	678.2	0.70%
2040	3,988,844	0.72%	704.5	0.8	703.7	0.83%	683.7	0.7	683.0	0.71%

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 2020 study results indicated each one degree increase in temperature at the time of summer peak would result in an increase of approximately 7.0 MW in summer peak demand.

Further statistical analysis of temperatures at the time of system peak for the years 1984 through 2019 (prior to 1984 Montana-Dakota was a winter peaking utility) provided the results shown in Table 2-2.

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

Probability	Weighted Average Temperature	Approximate Increase in Summer Peak Demand (MW)
50%	96.0	0.0
75%	100.0	28.0
80%	101.0	35.0
85%	102.1	42.7
90%	103.6	53.2
95%	105.7	67.9
97%	107.1	77.7

*/ Using 7.0 MW/Degree F

As Table 2-2 shows, with a weighted average temperature of 96.0°F at the time of peak, there is a 50 percent probability the temperature at peak would be lower than 96.0°F and a 50 percent probability the temperature at peak would be higher than 96.0°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 103.6°F. However, at this temperature (103.6°F), the system peak demand would be 53.2 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 2020 study's 50/50 probability and 90/10 probability impact on the 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
Alternate Summer Peak Demand Forecast Comparison

Year	Base Forecast (96.0 degrees F) 50/50 Forecast (MW)	Growth Rate	Alternate Forecast (103.6 degrees F) 90/10 Forecast (MW) */
2021	586.0		639.2
2022	595.1	1.55%	649.1
2023	602.5	1.25%	657.2
2024	610.8	1.38%	666.3
2025	618.8	1.30%	675.0
2026	624.2	0.88%	680.9
2027	629.8	0.90%	687.0
2028	635.3	0.88%	693.0
2029	640.9	0.88%	699.1
2030	646.6	0.89%	705.3
2031	652.3	0.87%	711.4
2032	658.0	0.88%	717.6
2033	663.7	0.87%	723.8
2034	669.3	0.85%	729.9
2035	675.0	0.85%	736.1
2036	680.7	0.85%	742.3
2037	686.4	0.84%	748.5
2038	692.2	0.85%	754.8
2039	697.9	0.82%	761.0
2040	703.7	0.83%	767.3

*/ 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.

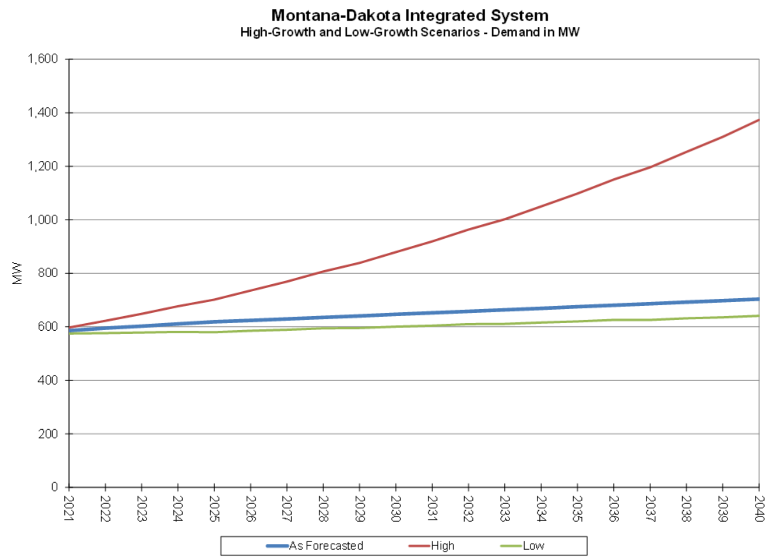
Historical total energy was analyzed in order to find a period during which unusually high growth was experienced and a period during which unusually low growth was experienced. Based on the historical sales data, the average growth rate that occurred from 1977 to 1985 was used as the high-growth rate, 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.

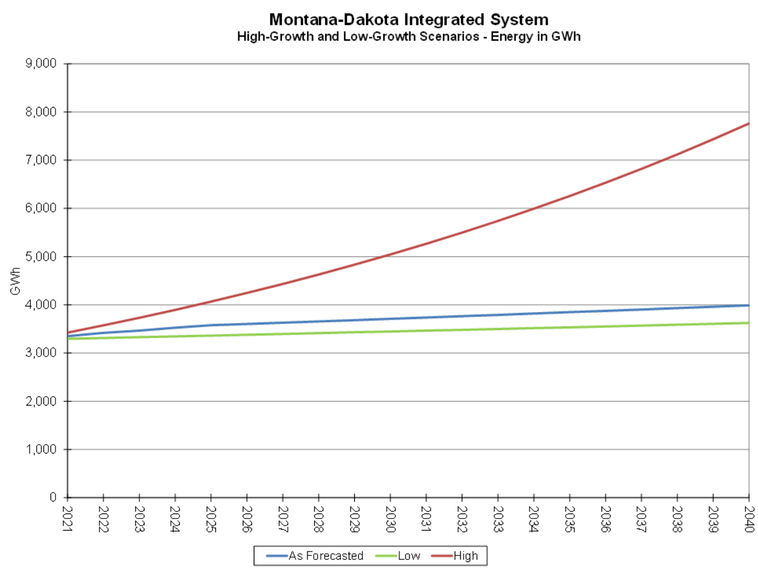
Demand for each scenario was derived by applying the load factors calculated from the base forecast to the high-growth and low-growth scenario forecasted energy. The high- and low-growth scenarios for energy and demand from the 2020 study are shown on Table 2-4. The following page presents the graphs of the numeric results.

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

	ENERGY			DEMAND		
	Forecast	HIGH 1/	LOW 2/	Forecast	HIGH	LOW
2021	3,350.6	3,424.6	3,296.7	586.0	597.3	575.0
2022	3,418.2	3,575.3	3,313.2	595.1	622.4	576.8
2023	3,466.2	3,732.6	3,329.8	602.5	648.8	578.8
2024	3,525.5	3,896.8	3,346.4	610.8	677.0	581.4
2025	3,579.1	4,068.3	3,363.1	618.8	701.4	579.9
2026	3,603.4	4,247.3	3,379.9	624.2	735.7	585.5
2027	3,630.5	4,434.2	3,396.8	629.8	769.2	589.3
2028	3,655.9	4,629.3	3,413.8	635.3	806.7	594.9
2029	3,683.1	4,833.0	3,430.9	640.9	838.8	595.4
2030	3,710.4	5,045.7	3,448.1	646.6	879.4	600.9
2031	3,737.7	5,267.7	3,465.3	652.3	919.2	604.7
2032	3,765.2	5,499.5	3,482.6	658.0	963.7	610.2
2033	3,792.8	5,741.5	3,500.0	663.7	1001.9	610.8
2034	3,820.4	5,994.1	3,517.5	669.3	1050.1	616.2
2035	3,848.2	6,257.8	3,535.1	675.0	1097.7	620.1
2036	3,876.0	6,533.1	3,552.8	680.7	1150.5	625.6
2037	3,903.9	6,820.6	3,570.6	686.4	1195.9	626.1
2038	3,932.0	7,120.7	3,588.5	692.2	1253.6	631.7
2039	3,960.3	7,434.0	3,606.4	697.9	1310.1	635.5
2040	3,988.8	7,761.1	3,624.4	703.7	1373.0	641.2

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
MW
As Forecasted
High
Low


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

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 2021-2023.

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 LED conversion projects throughout Montana, North Dakota and South Dakota for its company-owned street lighting, flood lighting and yard lighting. The following is an overview of program details associated with each residential and commercial DSM measure 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 Commercial Demand Response DSM Programs in Montana, North Dakota, and South Dakota. The following is a discussion of the activity in the programs currently offered.

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 2020 there were four participants (140 bulbs) in the residential LED lighting program and a total of 35 participants in the commercial lighting program. The Commercial Lighting program continues to see strong and steady participation. This is mainly due to an active contractor network in the Montana electric service territory.

Commercial Demand Response Programs

Montana-Dakota currently offers two demand response programs for commercial and industrial customers. The Commercial Demand Response Resources (DRR) 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 2020, with an overall goal of providing up to 60 MW of demand response by 2023.

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 initial total program goal was 25 MW and is currently fully subscribed and closed to new customers. In 2020 Montana-Dakota expanded the DRR program to a target enrollment of 50 MW, with an initial target enrollment of 40 MW by 2023.

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 4.6 MW or to a total enrollment of 20 MW by the summer of 2023.

Company-Owned Street Lighting – LED Conversion

In 2017, Montana-Dakota began the implementation of a LED conversion program for Company-owned lighting (streetlights, flood lights and yard lights). The first phase of the project consisted of a LED conversion of Company-owned streetlighting across the service territory. The estimated Integrated System energy savings associated with the street lighting conversion project is approximately 11,312,000 kWh per year. Additionally, Montana-Dakota has completed LED conversion of Company-owned flood lights and is nearing completion of the LED conversion of Company-owned yard lights. The estimated Integrated System energy savings associated with these conversion projects is approximately 4,947,000 kWh per year.

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 2021 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 0.34 percent of annual energy sales (MWh) and 1.78% of demand (MW) over the IRP planning period. A summary of the MWh and MW results are shown below in Tables 3-2 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

YEAR	Total Sales Sales (MWh)	Achievable EE %	Achievable MWh
2021	3,101,269	0.08%	2,621
2022	3,163,787	0.13%	4,124
2023	3,208,234	0.13%	4,286
2024	3,263,134	0.18%	5,801
2025	3,312,701	0.19%	6,452
2026	3,335,181	0.26%	8,772
2027	3,360,291	0.27%	9,110
2028	3,383,800	0.36%	12,136
2029	3,408,949	0.36%	12,231
2030	3,434,210	0.43%	14,613
2031	3,459,564	0.43%	14,730
2032	3,484,982	0.43%	14,846
2033	3,510,478	0.43%	14,964
2034	3,536,078	0.43%	15,081
2035	3,561,753	0.43%	15,200
2036	3,587,501	0.43%	15,318
2037	3,613,384	0.43%	15,437
2038	3,639,364	0.43%	15,557
2039	3,665,597	0.43%	15,678
2040	3,691,973	0.34%	15,292
Cumulative	**68,722,230**	**0.34%**	**232,250**

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

Year	Summer Peak (MW)	Achievable EE %	Achievable MW	Winter Peak (MW)	Achievable EE %	Achievable MW
2021	586.0	0.10%	0.59	575.2	0.10%	0.58
2022	595.1	0.10%	0.60	586.7	0.10%	0.59
2023	602.6	0.10%	0.60	594.8	0.10%	0.59
2024	610.9	0.10%	0.61	604.8	0.10%	0.60
2025	618.8	0.10%	0.62	613.7	0.10%	0.61
2026	624.2	0.10%	0.62	617.9	0.10%	0.62
2027	629.8	0.10%	0.63	622.5	0.10%	0.62
2028	635.4	0.10%	0.64	626.8	0.10%	0.63
2029	640.9	0.10%	0.64	631.5	0.10%	0.63
2030	646.6	0.10%	0.65	636.0	0.10%	0.64
2031	652.2	0.10%	0.65	640.6	0.10%	0.64
2032	658.0	0.10%	0.66	645.2	0.10%	0.65
2033	663.7	0.10%	0.66	649.9	0.10%	0.65
2034	669.3	0.10%	0.67	654.5	0.10%	0.65
2035	675.0	0.10%	0.68	659.3	0.10%	0.66
2036	680.7	0.10%	0.68	663.9	0.10%	0.66
2037	686.4	0.10%	0.69	668.6	0.10%	0.67
2038	692.1	0.10%	0.69	673.4	0.10%	0.67
2039	697.9	0.10%	0.70	678.2	0.10%	0.68
2040	703.8	0.10%	0.70	683.0	0.10%	0.68
Cummulative					1.78%	12.04

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		1.97	2.58	3.43	7.16	2.39
Residential Programs						
Residential Lighting	Residential	0.64	2.22	2.17	3.04	1.29
Commercial Programs						
Commerical Lighting	Commerical	0.75	4.46	6.35	6.76	2.88
Commercial Partnership Program (Custom)	Commerical	0.93	4.45	4.45	5.43	2.56
Demand Response						
Commercial Demand Response Program	Commercial	2.29	2.29	3.16	81.19	2.28
Interruptible Rate DR Program	Commercial	3.05	3.13	4.08	17.04	2.95

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		1.92	2.46	3.29	8.68	2.28
Residential Programs						
Residential Lighting	Residential	0.60	2.06	1.96	3.00	1.16
Commercial Programs						
Commerical Lighting	Commerical	1.10	5.94	8.28	6.76	3.76
Commercial Partnership Program (Custom)	Commerical	0.94	4.07	3.98	4.72	2.29
Demand Response						
Commercial Demand Response Program	Commercial	1.99	1.99	2.74	23.22	1.98
Interruptible Rate DR Program	Commercial	3.05	3.13	4.08	17.04	2.95

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		1.80	2.50	3.35	5.14	2.12
Residential Programs						
Residential Lighting	Residential	0.52	1.78	1.79	3.05	1.06
Commercial Programs						
Commerical Lighting	Commerical	1.96	5.31	7.73	6.82	3.50
Commercial Partnership Program (Custom)	Commercial	1.56	3.48	3.61	4.74	2.08
Demand Response						
Commercial Demand Response Program	Commercial	2.07	2.07	2.81	4.98	2.00
Interruptible Rate DR Program	Commercial	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

DSM Implementation Plan

The following is a discussion by state of the expected DSM activity for program years 2021-2023. 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 2023. 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.

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. These may or may not feed energy back into the grid.

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 have 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, potentials for reduction in regional transmission organization (RTO) transmission costs, 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 discussions 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) until March 31, 2022, 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. Montana-Dakota has signed a capacity and energy contract that starts on June 1, 2021, and ends on May 31, 2026, which supplies 30 to 90 MWs of capacity and energy depending on the year of the agreement. Total zonal resource credits (ZRC) available from the existing units in the summer of 2021 are 535.2 ZRC.

Future Capacity and Energy Resources

As part of the development of the 2021 IRP, Montana-Dakota issued a request for proposals of capacity and energy resources in January of 2020 (2020 RFP). Screening of the responses to the

2020 RFP did identify three projects that were shortlisted as part of the RFP process. The only project selected from the shortlist was a 25 MW expansion to Montana-Dakota's current Commercial Demand Response Program. The IRP model did select future solar from the 2020 RFP which the Company did not pursue due to uncertainties in final costs associated with network upgrades, and location of resource. Some of the projects from the 2020 RFP were included in the IRP modeling to show the potential need to reevaluate projects in the future. Additional information on the 2020 RFP can be seen in Attachment F to the 2021 IRP Report.

On September 21, 2020, Montana-Dakota entered into a power purchase agreement (PPA) with a 20 MW solar developer located in Fallon County, MT. This project is an eligible FERC Public Utility Regulatory Policies Act (PURPA) Qualified Facility (QF) facility and the PPA for the project has a 20-year term with an expected in-service date the end of 2023.

<u>Considered Supply-Side Resource Alternatives (Described in greater detail in Attachment C)</u>

<u>Coal</u>

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 to the point that it is unlikely to be feasible in the foreseeable future.

<u>Simple Cycle Combustion Turbines</u>

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, however these units are rarely dispatched in the Montana-Dakota system of the MISO energy market. Combustion turbines can be installed with a relatively short lead time (two to three years) and serve as peaking and emergency backup generation 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 are 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.

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. In MISO, solar generation receives a first-year capacity accreditation value of 50 percent while winds first-year capacity accreditation value is closer to 15 percent. The 50 percent first-year capacity accreditation makes solar generation very appealing for meeting peak demand requirements today. This could change significantly on an annual basis when MISO moves to a four-season planning model for resource adequacy, as solar will likely receive zero capacity credit in the winter to meet peak winter demand forecast 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.

2020 RFP Options

Although none of the generation and energy proposals from the 2020 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 – 2020 RFP Analysis, a solar option was included for the EGEAS model to select for future considerations with additional MISO interconnections cost added to the option.

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 and Heskett 2 coal-fired generating plants by the end of March 2022, and the Lewis & Clark 1 coal-fired generating plant was retired on March 31, 2021.

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 2.1 percent adder for MISO losses, plus a 9.4 percent planning reserve margin (PRM).

Montana-Dakota is required to meet an 81.1 percent coincident factor for the 2021-22 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 2025. The capacity deficit in 2026 will be 11.4 ZRC and is expected to grow to 42.0 ZRC in 2032. Under the high-growth scenario forecast, as shown in Table 4-2, a capacity deficit will occur in 2021 (5.9 ZRC) and grow to 318.9 ZRC in 2032. Under the low-growth scenario forecast, as shown in Table 4-3, a capacity deficit doesn’t occur until 2034 at 7.6 ZRC.

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.

MISO is developing new rules which will likely add a four-season resource adequacy requirement beginning in 2023. The impacts of the four-season resource adequacy requirement are not expected to have a large impact on the generation requirements for Montana-Dakota's fleet, but the ultimate impacts are still unknown.

Table 4-1

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

BASE FORECAST

Year	Zonal Resource Credits[1]	50/50 Coincident Summer Peak Demand w/MISO Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (-)
2021	535.2	485.2	530.8	4.4
2022	558.8	492.8	539.1	19.7
2023	584.0	498.9	545.8	38.2
2024	584.0	505.8	553.3	30.7
2025	584.0	512.4	560.5	23.5
2026	554.0	516.9	565.4	-11.4
2027	554.0	521.5	570.5	-16.5
2028	554.0	526.0	575.5	-21.5
2029	554.0	530.7	580.6	-26.6
2030	554.0	535.4	585.7	-31.7
2031	554.0	540.1	590.9	-36.9
2032	554.0	544.8	596.1	-42.1
2033	554.0	549.6	601.2	-47.2
2034	554.0	554.2	606.3	-55.7

1 – Total based on 2021-22 MISO Planning Year Zonal Resource Credits

Table 4-2

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

HIGH-GROWTH FORECAST

Year	Zonal Resource Credits[1]	50/50 Coincident Summer Peak Demand w/MISO Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (-)
2021	535.2	494.6	541.1	-5.9
2022	558.8	515.4	563.8	-5.0
2023	584.0	537.3	587.8	-3.8
2024	584.0	560.6	613.3	-29.3
2025	584.0	580.8	635.4	-51.4
2026	554.0	609.2	666.5	-112.5
2027	554.0	637.0	696.8	-142.8
2028	554.0	668.0	730.8	-176.8
2029	554.0	694.5	759.8	-205.8
2030	554.0	728.1	796.6	-242.6
2031	554.0	761.2	832.7	-278.7
2032	554.0	797.9	872.9	-318.9
2033	554.0	829.6	907.6	-353.6
2034	554.0	869.5	951.2	-400.6

1 – Total based on 2021-22 MISO Planning Year Zonal Resource Credits

Table 4-3

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

LOW-GROWTH FORECAST

Year	Zonal Resource Credits[1]	50/50 Coincident Summer Peak Demand w/MISO Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (-)
2021	535.2	476.1	520.9	14.3
2022	558.8	477.6	522.5	36.3
2023	584.0	479.3	524.3	59.7
2024	584.0	481.4	526.7	57.3
2025	584.0	480.1	525.3	58.7
2026	554.0	484.8	530.4	23.6
2027	554.0	487.9	533.8	20.2
2028	554.0	492.6	538.9	15.1
2029	554.0	493.0	539.4	14.6
2030	554.0	497.6	544.4	9.6
2031	554.0	500.7	547.8	6.2
2032	554.0	505.3	552.8	1.2
2033	554.0	505.7	553.3	0.7
2034	554.0	510.2	558.2	-7.6

1 – Total based on 2021-22 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.

<u>Integration of Demand-Side and Supply-Side Resources</u>

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 2021 and increasing to a total of 60 MW by 2023.

<u>Sensitivity Analysis</u>

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.

<u>*Carbon Tax*</u>

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 2023. While no carbon tax was modeled in the base case, Montana-Dakota modeled a carbon tax of $30 and $50 per ton for 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 $2.68/MMBtu for 2021 and increasing to $2.89/MMBtu in 2025. After 2025, 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 ($2.68/MMBTU in 2021), 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 2040. 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 2040. 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.

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 most of the peak hours. With these scenarios, Montana-Dakota modeled sensitivities of a +25% and +50% adder for the high energy price scenarios and used a -25% reduction for a low energy price scenario to the base case on energy prices for both on and off peak. Montana-Dakota also did a sensitivity using a third-party forecast energy price from Woods & McKenzie.

Montana-Dakota also looked at decreasing the amount of energy that can be purchased from 300 MW on and off peak to 100 MW over five- and ten-year periods.

Natural Gas and MISO Energy Purchases Combination

This sensitivity assumes both natural gas and the energy market prices are increased or decreased 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 81.1 percent coincident factor within MISO.

Coyote Retirement

As the technology requirements for Coyote Stations Regional Haze project are still unknown at this time, a single sensitivity was run to show the impacts on the Company's Resource Plan if Coyote Station was retired by the end of 2027. Additional Coyote Station sensitivities will be included in the 2023 IRP.

CHAPTER 6

RESULTS

This section presents the results of the 2021 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, and highly reliable electric service. 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:

- System reliability and resiliency,
- 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 300 MW block of energy for off-peak and on-peak periods.

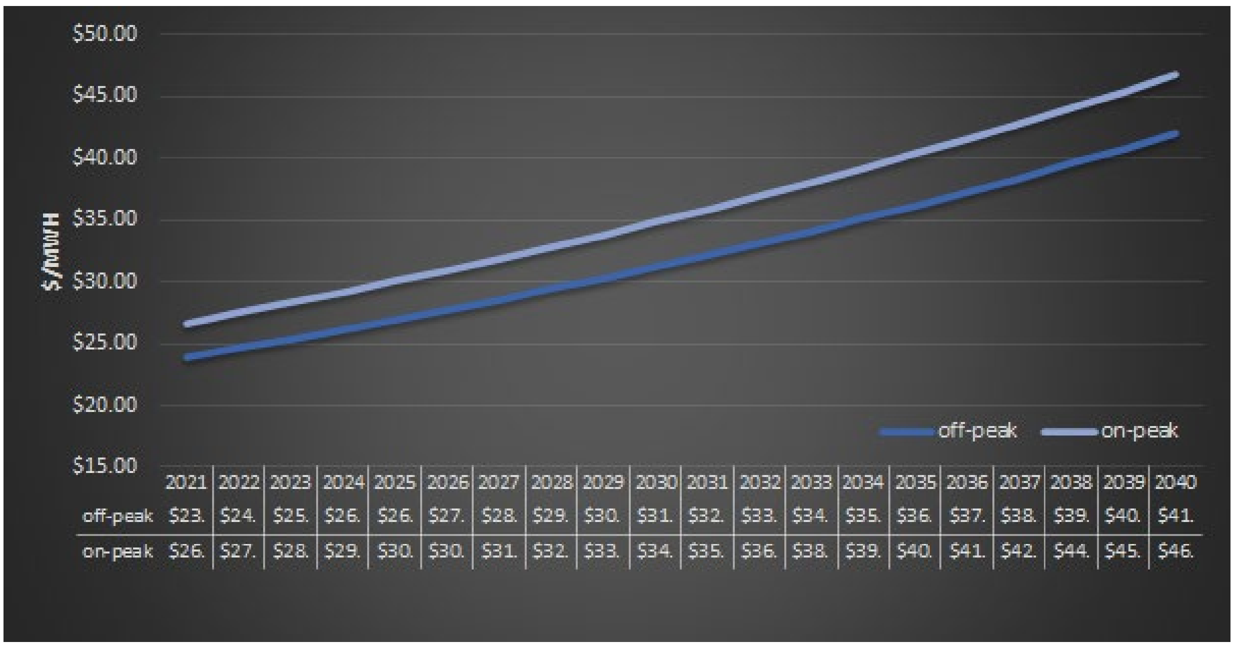


Figure 6-1: Forecasted On-Peak and Off-Peak MISO Market Prices developed by Montana-Dakota

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 but 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

<u>Reliance on Natural Gas</u>

About 28 percent of Montana-Dakota's owned generating nameplate capacity is natural gas-fired as of 2019. This number is expected to increase to 42 percent with the additional of Heskett 4 and the retirements of Lewis & Clark 1, Heskett 1 and Heskett 2. 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. Short term price spikes still occur from time to time but on average natural gas forecast prices have remained low and stable. Figure 6-4 shows the future natural gas price that was used for future resources.

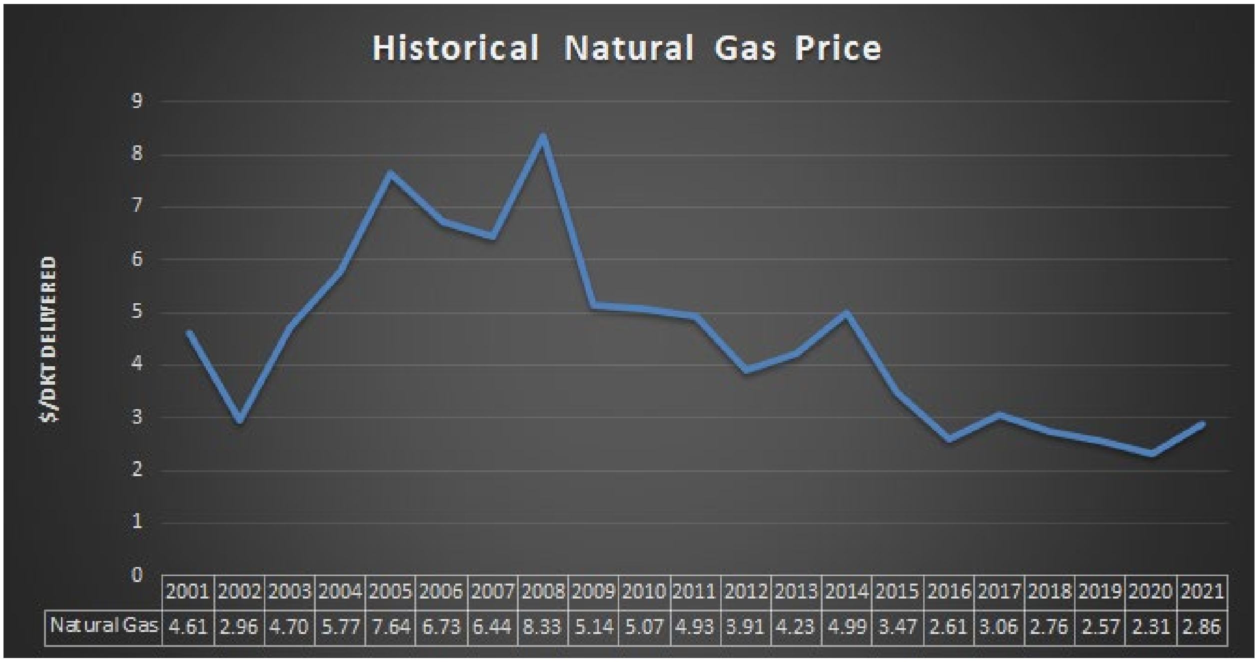


Figure 6-3: Historical Natural Gas Prices of Montana-Dakota's existing combustion turbines (Based on 12-Month Average)

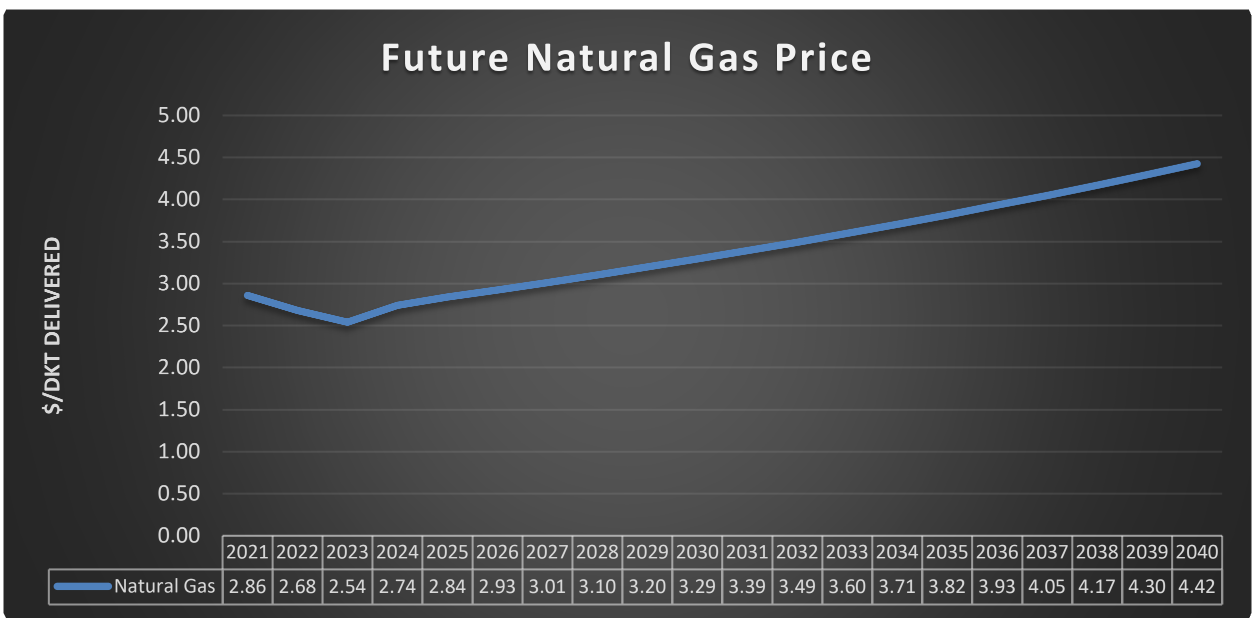


Figure 6-4: Future Natural Gas Prices of Future natural gas alternatives

<u>Resource Expansion Analysis Results</u>

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 2021-2026 period:

- Retired Lewis & Clark 1 on March 31, 2021, and retire Heskett 1 and Heskett 2, by the end of March 2022.
- Install an 88 MW natural gas-fired Simple Cycle Combustion Turbine unit to be online in early 2023.
- Continue to grow the Commercial Demand Response program to a total of 40 MW.
- 20 MW solar QF project located in Fallon County, MT to be online the end of 2023.
- Execution of a Capacity and Energy Purchase Agreement that runs from 2021-2026 and supplies between 30 and 90 MWs of capacity and energy depending on the year of the agreement.

The 20 MW solar QF project was also included as a resource option for the 2021 IRP model and selected as a least cost resource in 2024. The IRP model did select additional future solar from the 2020 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 – 2020 RFP Analysis. Additional 20 MW of storage, 50 MW of solar and capacity was selected in the later years of the study. The net present value of the Base Case least-cost plan over the 50-year study period equates to $2,321 million in 2020 dollars, as shown in Attachment C Table 3-1.

Sensitivity scenarios indicate that the Base Case plan is robust under all assumptions in showing the need for future solar, storage, and capacity to meet capacity and energy needs. However, load growth has a significant impact on the resource selection. As expected, the low-growth scenario indicates the need for less 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.

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 scenarios, the model selected the same plan under the +25% but in the +50% solar was selected over storage. 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 more solar and wind compared to the Base Case and does cause an increase in the NPV. In decreasing both the natural gas and MISO energy market prices the plan stays the same as the Base Case with a lower NPV.

The carbon tax sensitivity scenarios show the economic impact of a tax on CO_2 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 and \$50/ton of CO_2.

As shown in Figures 6-4 and 6-5, in 2021 approximately 34 percent of Montana-Dakota's Zonal Resource Credits are supplied by natural gas- and oil-fired combustion turbines while in 2026, based on the Base Case plan, approximately 47 percent of the Company's Zonal Resource Credits would be made up of natural gas- and oil-fired combustion turbines or engines.

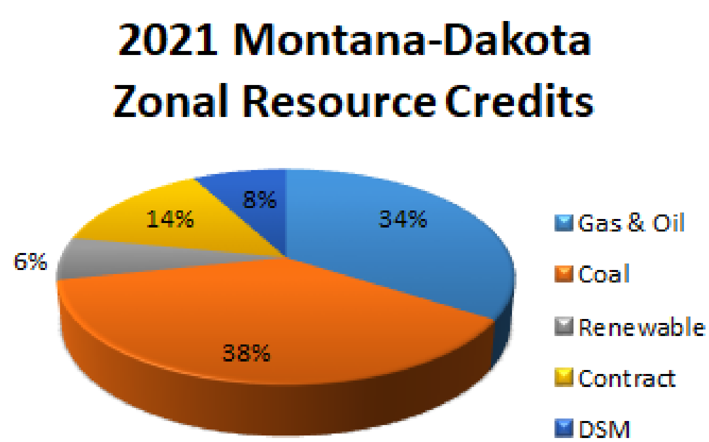


Figure 6-4: 2019 Montana-Dakota Zonal Resource Credits

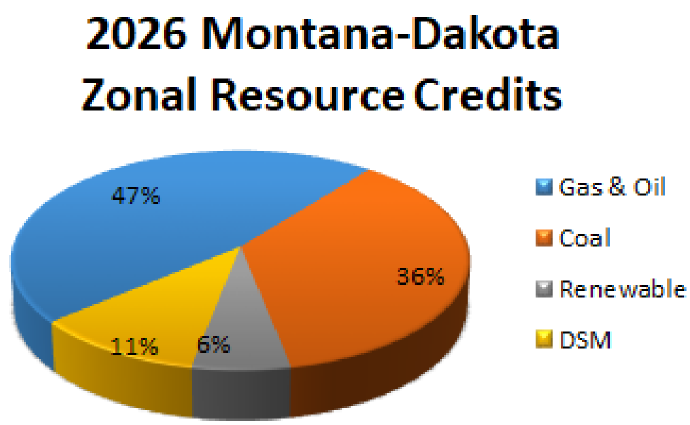


Figure 6-5: 2022 Montana-Dakota Zonal Resource Credits

Figures 6-6 and 6-7 shows the percentage of energy on a yearly basis in 2021 and 2026 after the retirements of Heskett 1, Heskett 2, and Lewis & Clark 1. In 2021, 43 percent of Montana-Dakota's energy will come from coal, 23 percent from renewable, 30 percent MISO energy market, and 4 percent from contract; while in 2026, 45 percent will come from coal, 22 percent from renewable, 25 percent will come from the MISO energy market based upon forecasted fuel and MISO energy prices, and 8 percent from contract. If MISO energy prices increase higher than forecasted, Montana-Dakota's natural gas-fired units could be dispatched to offset forecasted MISO energy purchases and provide pricing protection for customers.

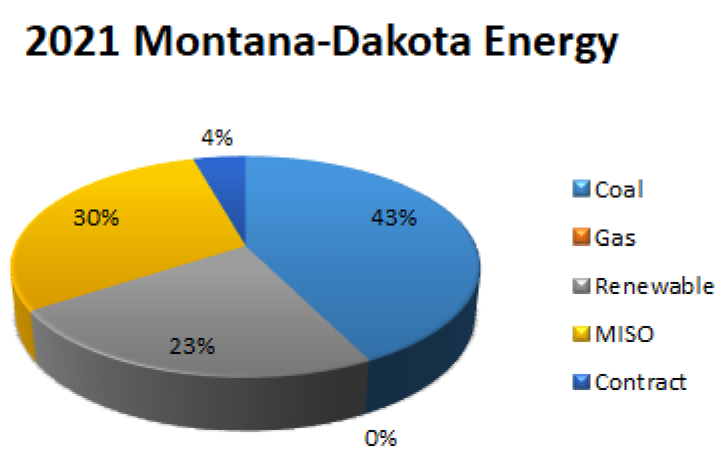


Figure 6-6: 2021 Base Case Montana-Dakota Energy by Resource Type

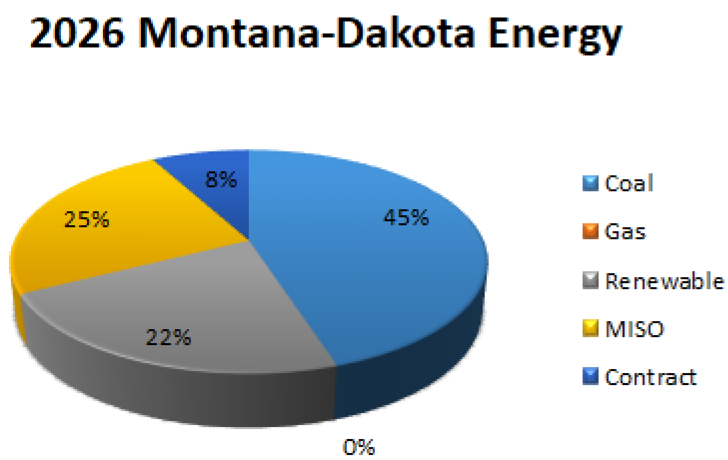


Figure 6-7: 2026 Base Case Montana-Dakota Energy by Resource Type

<u>Future Resource Plan</u>

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 2021-2026 period:

- Retired Lewis & Clark 1 on March 31, 2021; and retire Heskett 1 and Heskett 2 by the end of March 2022.
- Continue to grow the Commercial Demand Response program to a total of 40 MW.
- Continue the design and engineering work on Heskett 4, a natural gas-fired simple cycle combustion turbine resource, to be online in early 2023.
- Issue a new request for proposal prior to the next IRP.

The recommended resource plan is 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 contract for capacity and energy purchases through May 2026 and additional MISO energy market purchases.

CHAPTER 7

TWO-YEAR ACTION PLAN

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

Load Forecasting

- Montana-Dakota will continue to 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 Heskett 1 and Heskett 2 at the end of March 2022.

- Montana-Dakota will continue with the design and development for a new 88 MW simple cycle combustion turbine at Heskett Station to be online in early 2023.

- 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 changing economics in the MISO market and 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. Included in the multi-season resource adequacy requirements may be the need to evaluate the conversion of Heskett 3 and 4 to dual fuel combustion.

- 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.

- Montana-Dakota will continue to monitor the development and impacts of MISO's long transmission plan along with potential future addition of additional electrification from carbon reduction initiatives and the development of electric vehicles.

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 2021 IRP advisory group was established at the beginning of the 2021 planning cycle and held its first meeting in November 2020.

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 2021 PAG participants are shown in Table 8-1.

Table 8-1
The 2021 IRP Public Advisory Group

Montana

Kevin Thompson
Action for Eastern Montana
Glendive, Montana

Kyla Maki
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

Adam Renfandt
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 2021 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 2021 IRP PAG meetings held over conference calls. 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

RESPNONSES TO MONTANA PUBLIC SERVICE COMMISSION COMMENTS REGARDING MONTANA-DAKOTA'S 2019 IRP

This chapter provides responses to the Montana Public Service Commission's (PSC) comments issued on October 28, 2020, in Docket 2019.07.043 regarding Montana-Dakota's 2019 IRP. The PSC comments are included in their entirety in Attachment I to this IRP. The PSC comments (printed in italics) and Montana-Dakota's corresponding responses are presented below:

1. A significant conclusion in the 2019 IRP is that the Lewis & Clark I and Heskett I & II coal-fired generating plants should be retired in 2020 and 2021, respectively. MDU has contemplated an appropriate retirement date for these plants since at least its 2015 IRP. Commission rules dictate that, should an IRP demonstrate that previously rate-based resources should be abandoned and replaced by new resources, the Commission will open separate proceedings to determine recovery of a rate-based asset. Mont. Admin. R. 38.5.2001(5). Therefore, neither the 2019 IRP nor Commission comments in response to the 2019 IRP dictate in itself any decision made by the Commission with regard to cost-recovery of any resource, whether that be a resource that has already been acquired or not.

2. In response to MDU's 2017 IRP, the Commission stated MDU should proactively estimate the amount of capital investment that would likely be required to keep its coal units in service. While the revenue requirement portion of the retirement analysis provided in Volume IV of the 2019 IRP appears to account for at least some of that necessary capital investment, a description of the upgrade-related capital investments MDU expects it would avoid is lacking in that section of the IRP. The main volume of the 2019 IRP assumes the Lewis & Clark and Heskett plants will retire in 2021, and therefore, does not address the cost of potential upgrades at all. MDU should provide a detailed discussion on all costs it expects to avoid by retiring the aforementioned coal plants in 2021 rather than 2024.

With the earlier retirements as stated in the 2019 IRP Volume IV Attachment I all unit overhauls would be avoided with the 2021 retirements. The overhaul for Heskett 2 was delayed to 2020 with the scope of work performed will be limited. The capital costs for each unit to continue to run through 2024 are included below:

Lewis & Clark 1
- **Major Maintenance Outage - $900,000 (2024)**
- **Annual Capital - $600,000 to $700,000 per year**

- **316(b) fish impingement project - $600,000**

Heskett 1 & 2

- **Heskett 1 Major Maintenance Outage- $700,000 (2022)**
- **Heskett 2 Major Maintenance Outage - $1,100,000 (2024)**
- **Annual Capital - $1,200,000 to $1,500,000 per year**
- **316(b) fish impingement project - $1,300,000**

3. MDU should use EGEAS to endogenously model the optimal retirement date(s) of its resources, rather than deterministically selecting retirement dates for the units and testing those dates within the model. Importantly, and related to this analysis, it appears MDU did not include the cost of retiring the coal units (or any other unit) in the EGEAS model within the 2019 IRP. The cost of shutting down a plant can be significant, and the timing and cost of retiring a plant should be considered by MDU. While the Commission recognizes MDU did include the cost of retirement in its revenue requirement analysis for the year 2023, provided in Volume IV of the 2019 IRP, one purpose of the planning exercise is to measure the impact to the NPV of the supply portfolio over the entire planning horizon, rather than a single year. To the extent possible, MDU should forecast both required capital expenditures and retirement costs for its resources, include those costs as an input to the EGEAS model, and allow the model to endogenously select the optimal retirement date for its resources. If it is not possible to conduct this type of analysis within the EGEAS model, MDU should clearly explain why.

The EGEAS model does not allow a unit to be retired on its own as the retirement date has to be picked as an input before the model is run. In past IRPs Montana-Dakota has included capital expenditures for existing resources for the model to retire the unit and then the model would have the option to pick that resource again with the additional capital costs.

In the 2019 IRP Volume IV Attachment I page 16 additional modeling was done to allow the three coal plants to be selected by the model again in 2022 after retiring the end of 2021. The three coal plants assumed zero additional capital cost and current fuel and O&M costs to run for another five years and the model did not select any of three coal plants as a least cost resource.

4. In its most recent electric rate case in front of the Commission, MDU testified that the environmental upgrades made to the Heskett and Lewis & Clark plants would keep the units in service until at least 2025. In re the Application of Montana-Dakota Utilities for Authority to Increase Rates, Dkt. 2018.09.060, Test. Nicole Kivisto 5 (Sept. 28, 2018). Furthermore, in both the 2015 and 2017 IRPs, MDU projected a retirement for those resources at the end of 2024. In *the 2019 IRP, MDU examined various potential retirement dates for the units and found the NPV cost of its portfolio would be less if the units were retired in 2021 rather than 2024. However, the NPV of the portfolio with a 2021 retirement date is $6 million, or a mere 0.21%, less than the NPV cost of the portfolio with a 2024 retirement date. It is not clear that such minimal savings, which are identified in a model that is dependent on uncertain information, justifies the significant change in course of action in moving the retirement date up to 2021. In any future proceeding in which MDU seeks cost recovery for this transition, the Commission will be paying particular attention to this issue.*

5. The Commission appreciates MDU's effort in the 2019 IRP to address the inconsistent escalation factors that had been used in the natural gas and electricity market price forecasts in past IRPs. MDU generally explains how it derived the natural gas and electricity market prices forecasts used in the 2019 IRP, but it does not provide the forecasts in the main report of the 2019 IRP. The electricity market price forecast is provided in graphical form in Volume I of the 2019 IRP, but the actual prices are only located in the EGEAS output files in Volume IV. MDU should provide the year-by-year values for its natural gas and electricity market price forecasts in the main volume of its next IRP, so they can be easily located and understood by any reader of the document. MDU should also compare its own MISO electricity market price forecast with the MISO electricity market price forecast of other utilities in the MISO footprint.

These prices are included in the 2021 IRP Main Report Chapter 6.

6. The MISO capacity market could be an inexpensive source of short-term capacity for MDU. In the next IRP, MDU should more thoroughly discuss to what extent it believes it can rely on the MISO capacity market to meet its annual PRMR.

In Figure 6-2 of the 2021 IRP Main Report Chapter 6, this figure shows the capacity prices over the nine annual capacity auctions and the cost has been at or below $5/MW-day for every auction but one. This shows that Montana-Dakota could rely on the capacity market to purchase short term, but on smaller amounts as going into each auction there is still some unknown on the costs. This could be risky to rely on purchasing large amounts of capacity on the market as the market is based on generator offers to the auction.

7. The Commission agrees with DEQ's assessment that MDU should fully evaluate storage systems as resources that could assist MDU to mitigate transmission constraints, defer grid infrastructure investments, and provide ancillary services. The Commission recognizes that MDU modeled a 50 MW solar project plus a 10 MW battery, as well as a 5 MW solar project plus a 1

MW battery in the 2019 IRP; however, MDU should also model wind plus storage resources, as well as stand-alone storage resources, like a battery, that are not coupled with renewable projects. MDU should analyze what the costs and benefits are of coupling a renewable project with storage compared to a stand-alone storage resource that could be charged when MISO prices are low, in order to see which configuration provides greater benefits to MDU's system. MDU should also model storage resources at a scale larger than 10 MW.

In the 2021 IRP Montana-Dakota continued to model the options of solar plus battery and included storage as a stand-alone option at 10 MW. The model has the option to select multiple options of the 10 MW stand-alone option of the battery storage. The model did not select any battery storage; therefore no option was included to add storage to a wind resource in the 2021 IRP.

8. MDU states in the 2019 IRP that customer participation in Montana in its DSM programs continues to be low. Navigant found in its program planning study in 2013 that program delivery mechanisms and marketing are key to increased participation. In its next IRP, MDU should discuss what program delivery mechanisms and marketing efforts are currently in place to support customer participation in its DSM programs, as well as any potential or recently made changes that have occurred through delivery/marketing in order to encourage increased participation in DSM programs. Furthermore, the 2012 EE potential study and the 2013 program planning study are significantly outdated at this point. MDU should conduct new EE potential and program planning studies and incorporate the results into future IRPs as soon as possible.

Montana-Dakota has increased marketing efforts for the Residential LED Lighting program, specifically through targeted digital display ads directed to homeowners within the zip codes we serve electricity in Montana. In addition to the digital marketing, we continue to also market through billboards and bill inserts.

Montana-Dakota is also planning to commission an Electric Energy Efficiency potential study for the integrated system in 2022 and plans to incorporate the results in the 2023 IRP.

9. MDU conducted an RFP in 2018 but did not short-list any projects. However, MDU states it selected a group of projects that responded to the 2018 RFP to be included in modeling analysis in the 2019 IRP. MDU does not specify what criteria were used to determine which respondents to the 2018 RFP should be analyzed in the 2019 IRP, and which projects should not. In this type of situation, MDU should clearly explain how it selected certain projects from an RFP to be analyzed further in the context of an IRP.

In the 2021 IRP only two RFP projects were included in the modeling which were two of the three bids shortlisted and explained in Volume IV Attachment F, which were the expansion of the existing commercial demand response program and 50 MW of solar. The 50 MW solar that was included in the model has since withdrawn from the MISO Interconnection Queue over the high cost of network upgrades assigned to the project.

CHAPTER 10

RESPNONSES TO MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY COMMENTS REGARDING MONTANA-DAKOTA'S 2019 IRP

This chapter provides responses to the Montana Department of Environmental Quality (DEQ) comments issued on December 20, 2019, in Docket 2019.07.043 regarding Montana-Dakota's 2019 IRP. The DEQ comments are included in their entirety in Attachment J to this IRP. The DEQ comments (printed in italics) and Montana-Dakota's corresponding responses are presented below:

1. DEQ is pleased that MDU continues to increase the discussion and data made available in the utility's biennial IRP submission to the Commission. The additional discussion and data provided improves the transparency of MDU's demand and supply side planning efforts, allowing both regulators and the public to better understand the costs and risks that the utility and its customers will face in the future.

Montana-Dakota again provided input and output modeling files and assumptions to the 2019 IRP to provide transparency with the MT PSC and interested parties. Montana-Dakota also continues to provide additional requested information and content in its IRP development based upon comments that it has received from the MT PSC, MT DEQ, and interested parties from past IRPs.

2. MDU is a member of the Midcontinent Independent System Operator ("MISO"), a regional transmission organization that serves utilities spanning from Manitoba, Canada south to Louisiana. DEQ supports MDU's decision to rely further on MISO purchases for the next several years, taking advantage of MDU's geographic non-coincident peak demand within the ISO footprint while additional resources are developed. MDU states that, "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."

3. DEQ appreciates MDU's analysis showing the economic rationale behind the decision to retire the coal-fired Lewis & Clark Station 1 in Sidney by the end of 2020 and coal-fired Heskett 1 and 2, located in central North Dakota, by the end of 2021. MDU notes that their plan to replace the output of these plants with a combination of a new gas-fired power plant and market purchases is a significantly lower-cost option for customers. The 2019 Plan states, "[t]he 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."3 The modelling *provided in the 2019 Plan showed that the units are uneconomical under various modeling scenarios. Their closure would also reduce the impact of a future price on greenhouse gas emissions by lowering the carbon-intensity of MDU's supply mix.*

While not explicitly required to be addressed in the supply planning process, the closure of Lewis & Clark 1 will impact local jobs, income, and taxes. DEQ encourages MDU to continue working with the local communities affected by the closure. The meeting in Sidney in July of 2019 was a start to this process but DEQ encourages MDU to listen to local concerns and work with the community to mitigate negative impacts to the greatest extent possible.

Montana-Dakota appreciates the comments from the MT DEQ and their engagement with the 2019 IRP development and review. Regarding the comment for the need to engage the local community in Sidney to address impacts of the Lewis & Clark 1 plant closure, the Company has reached out multiple times to several local government leaders to discuss retirement impacts and potential mitigation options.

4. MDU's modelling does not include a future price on greenhouse gas emissions in the 2019 Plan. DEQ acknowledges that MDU includes a carbon cost modelling scenario in the 2019 Plan but finds it concerning that the base case includes no projected cost on greenhouse gas emissions. MDU has chosen to omit carbon costs from their base case analysis at a time when regional peer utilities, including Minnesota Power, Xcel Energy, and other utilities who are members of MISO are taking into account future carbon pricing as a likely factor in their decisions to significantly reduce the carbon intensity of their supply portfolio. DEQ acknowledges that MDU has announced its intent to reduce the carbon intensity of its supply portfolio forty-five percent below 2005 levels by 2030,4 and that the decisions to accelerate the retirement of Lewis & Clark 1 and Heskett 1 & 2 will likely help MDU to reach that target sooner.

The carbon cost portfolio analyzed by MDU falls short of the high-cost scenarios modelled by peer utility Minnesota Power. Its approach to evaluating carbon regulation impacts for the 2015 Plan includes using a $21.50/ton regulation penalty in its base case and comparing the short and long-term action plans with other plausible carbon alternatives, including a delayed carbon regulation penalty to 2025 and a zero carbon regulation penalty. This affected the plan in that additional wind power was selected with the $21.50 penalty modeled.[5] Xcel Minnesota's plan contains carbon emissions cost assumptions starting at around $46/ton in 2020 and moderating in the $20-30 range from 2024 through 2044.

By leaving carbon costs out of its base case and by using a relatively moderate cost for its carbon *modelling scenario, MDU does not adequately plan for and mitigate the risks to its customers of future carbon pricing or regulation.*

Montana-Dakota did not include carbon costs in the 2019 IRP base case for its interconnected customers in Montana, North Dakota, and South Dakota because it is not allowed to include externality costs in its analysis for the State of North Dakota.

Montana-Dakota included a $30 per ton carbon tax in a modeling sensitivity to determine if the future generation resource selection would change from the base case results and they did not change. Therefore, the Company's future resource plan, including plant retirements for Lewis & Clark 1, Heskett 1, and Heskett 2 and the future construction of Heskett 4, is a least cost option for the Company meeting its customers' electric requirements under all modeling scenarios including a future carbon tax sensitivity case.

It should be noted that Montana-Dakota is required to look at externalities, like a future carbon tax, under Montana Code Annotated 69-3-1204(3) and Montana Administrative Rules 38.5.2003 - Environmental Externalities, in the development of its integrated resource plan. Montana-Dakota satisfies this requirement by use of the carbon tax sensitivity. The Company would include additional analysis if the carbon tax sensitivity case results would show different results from the base case analysis.

In the 2021 IRP Montana-Dakota included a $30 and $50 per ton carbon tax as a modeling sensitivity to see what changes would appear from the base case results. An additional Base Case was developed for the 2021 Montana IRP with a $15 per ton carbon tax and all the non-carbon tax 2021 IRP sensitivities were run on this new Base Case. The results can be seen on Table 10-1 and Table 10-2.

Table 10-1: Least-Cost Resource Expansion Plans with $15/ton Carbon Tax for Studied Scenarios

	All Sensitivities with Base Case with $15/ton Carbon Tax										
	Base Case	High Gas $+2	High Gas $+5	Low Gas $-1	High Market +25%	High Market +50%	Low Market -25%	High Gas $+2 & High Market +25%	High Gas $+5 & High Market +50%	Low Gas $-1 & Low Market - 25%	Wood Mckenzie energy pricing
2021											
2022											
2023	Heskett 4	Heskett 4	Heskett 4	Heskett 4	Heskett 4	Heskett 4, Wind (50)	Heskett 4	Heskett 4	Heskett 4, Wind (50)	Heskett 4	Heskett 4
2024	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)
2025											
2026									Solar PPA (50)		
2027						Solar PPA (50)		Solar PPA (50)			
2028											
2029											
2030	Solar PPA (50)	Solar PPA (50)	Solar PPA (50)	PP(10)	Solar PPA (50)		PP(10)			PP(10)	Solar PPA (50)
2031				Solar PPA (50)			PP(10)			PP(10)	
2032							Solar PPA (50)			PP(20)	
2033										PP(20)	
2034	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)		PP(10)	PP(10)	Wind (50)	Solar PPA (50), PP(10)	PP(10)
2035	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)		PP(10)	PP(10)		PP(10)	PP(10)
2036	PP(20)	PP(20)	PP(20)	PP(20)	PP(20)	PP(10)	PP(20)	PP(20)	Wind (50)	PP(20)	PP(20)
2037	Solar (50)	Wind (50), PP(20)	Wind (50), PP(20)	Solar (50)	Solar (50)	PP(20)	Storage (10), PP(20)	Wind (50), PP(20)		Storage (10), PP(20)	Solar (50)
2038	PP(10)	PP(20)	PP(20)	PP(10)	PP(10)	PP(20)	PP(20)	PP(20)	PP(10)	PP(20)	PP(10)
2039	PP(10)	Wind (50), PP(20)	Wind (50), PP(20)	PP(10)	PP(10)	Wind (50), PP(20)	Storage (10), PP(20)	Wind (50), PP(20)	PP(10)	Storage (10), PP(20)	PP(10)
2040	Solar (50), PP(20)	PP(20), Solar(50)	PP(20), Solar(50)	Solar (50), PP(20)	Solar (50), PP(20)	Solar (50), PP(20)	PP(20), Solar(50)	Solar (50), PP(20)	Wind (100), PP(20)	PP(20), Solar(50)	Solar (50), PP(20)
NPV($M)	$2,320.68	$2,339.02	$2,351.50	$2,230.88	$2,516.05	$2,634.00	$2,081.29	$2,542.60	$2,725.37	$2,061.03	$2,335.82
Difference	0.00%	0.79%	1.33%	-3.87%	8.42%	13.50%	-10.32%	9.56%	17.44%	-11.19%	0.65%

Alternative Resources:

PP(XX) - Up Purchase Capacity with number representing MW value
Solar PPA (50) - 2020 RFP (Used $35.45/Mwh and added $16/Mwh for interconnection costs)
Solar QF (20) - Solar Qualified Facility in Montana at 20 MW
Solar (XX) - self-build solar option
Wind (XX) - self-build wind option
Storage (XX) - self-build storage option
Heskett CC Add (163.5) - Combined cycle Heskett 3 & 4
CT (90.7) - GE LMS100PB Simple Cycle Combustion Turbine
CC (329.2) - GE 7FA.05 (1x1) Combined Cycle Combustion Turbine

Table 10-2: Additional Least-Cost Resource Expansion Plans with $15/ton Carbon Tax for Studied Scenarios

	All Sensitivities with Base Case with $15/ton Carbon Tax						
	Base Case	Low Growth	High Growth	MISO 90% Coincident Factor	Limit Energy(100 MW) over 5 years	Limit Energy(100 MW) over 10 years	Coyote retirement
2021							
2022							
2023	Heskett 4	Heskett 4	Heskett 4	PP(10), Heskett 4	Heskett 4	Heskett 4	Heskett 4
2024	Solar QF (20)	Solar QF (20)	PP(10), Solar QF (20)	PP(10), Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)
2025			Solar PPA (50)	PP(10)			
2026			PP(20), Storage (10)	Solar PPA (50)			
2027			Heskett CC Add (163.5)	Solar (50), PP(10)			
2028				PP(10)	Solar PPA (50), Wind (50)		PP(10), CT(90.7)
2029				PP(20)			Solar PPA (50)
2030	Solar PPA (50)			PP(20)		Solar PPA (50)	
2031				CT (90.7)			
2032			Solar (5), PP(20)				
2033		Solar PPA (50)	Solar (50), Wind (50), PP(20)			Wind (50)	PP(10)
2034	PP(10)		CC (329.2)		Wind (50)	Wind (50)	PP(10)
2035	PP(10)						PP(20)
2036	PP(20)				PP(10)	PP(10)	Solar (50), PP(10)
2037	Solar (50)				Wind (50)	Wind (50)	PP(10)
2038	PP(10)				PP(10)	PP(10)	PP(20)
2039	PP(10)				PP(10)	PP(10)	PP(20)
2040	Solar (50), PP(20)	PP(10)	CC (329.2)	PP(20)	Solar (50), Wind (20), Storage(10)	Solar (50), Wind (20), Storage(10)	PP(10), Wind (50), Solar(50)
NPV($M)	$ 2,947.26	$ 2,653.96	$ 5,427.41	$ 3,073.21	$ 3,084.41	$ 3,071.93	$ 3,069.54
Difference	0.00%	-9.95%	84.15%	4.27%	4.65%	4.23%	4.15%

Alternative Resources:
PP(XX) - Up Purchase Capacity with number representing MW value
Solar PPA (50) - 2020 RFP (Used $35.45/Mwh and added $16/Mwh for interconnection costs)
Solar QF (20) - Solar Qualified Facility in Montana at 20 MW
Solar (XX) - self-build solar option
Wind (XX) - self-build wind option
Storage (XX) - self-build storage option
Heskett CC Add (163.5) - Combined cycle Heskett 3 & 4
CT (90.7) - GE LMS100PB Simple Cycle Combustion Turbine
CC (329.2) - GE 7FA.05 (1x1) Combined Cycle Combustion Turbine

5. DEQ commends MDU for analyzing options to integrate storage as a tool to increase grid reliability in certain areas, and to potentially reduce MISO transmission charges. DEQ recommends that MDU continue to evaluate and accurately assign value to energy storage technologies where appropriate for their potential value in mitigating transmission constraints, deferring grid infrastructure investments, and as a potential resource that can provide additional ancillary services. These additional benefits would improve the stability of MDU's service territory as well as providing value to the larger MISO region.

Innovative distributed storage has the potential to be part of the solution to help serve MDU's capacity needs. Improved economies of scale with the production of lithium ion batteries and other storage technologies will create more potential for increased deployment of storage solutions. The 2019 Plan should analyze the costs of customer-owned, grid-connected battery back-up systems that MDU would be able to use as a "distributed power plant." By sharing costs of battery storage systems with customers who also want the reliability of a back-up power supply, the relatively high cost of distributed storage systems may be sufficiently mitigated to provide a cost-competitive, flexible capacity resource, as well as a new service to interested customers. Green Mountain Power, a Vermont investor-owned utility, has successfully piloted this model.

Based on promising recent requests for proposal (RFP) results in other western states, DEQ encourages MDU to continue to explore hybrid renewable energy plus energy storage systems in their future supply-side analyses. As generation and capacity costs for wind and solar energy and energy storage systems continue to drop, the potential to combine renewable energy resources with energy storage has the potential to dramatically change future utility supply plans. Because these technologies are still, in many cases, emerging technologies, they may transition from being less economically optimal resource options to market-leading, least cost resources within the span of one or two IRP biennial periods. As such, DEQ recommends MDU evaluate not only the submissions they receive within their own supply RFP processes, but also the reported public bids that other western and midwestern utilities receive for combined renewable energy and energy storage projects.

Montana-Dakota did include solar and storage options (Volume IV, Attachment C, Table 2-5, Page 12) as future supply side modeling options available to the Company. The Company also received solar and storage bids as part of its 2018 Request for Capacity and Energy Proposals ("2018 RFP") that it included in the 2019 IRP model. Montana-Dakota also included language in its 2020 RFP expressing interest in proposals for energy storage, customer demand side management, and energy efficiency programs.

In the 2021 IRP Volume 4, Attachment E Montana-Dakota did update their pricing for renewables and storage options.

6. DEQ encourages MDU to expand its demand side programs to not rely so heavily on a single interruptible customer for most of its demand side peak reductions.

On page 17, MDU states that "DSM analysis is completed on a state by state approach versus an Integrated System approach." DEQ encourages MDU to treat demand side resources more similarly to supply side resources and conduct a more robust analysis of opportunities to expand and diversify current Energy Efficiency and Demand Response programs. This analysis should include inputting different quantities of energy efficiency and demand response into the model and then comparing those model runs against supply side resources. The assumption that energy efficiency only serves as a "load modifying" resource constrains the analysis, and this can result in undervaluing energy efficiency and demand response. MDU's estimated achievable energy reduction of 0.35% of annual energy sales and 1.70% of demand over the IRP planning period uses estimates from the 2013 Nexant Energy Efficiency Potential Study. These estimates are based on Total Resource Cost test analysis. DEQ recommends that MDU evaluate the achievable energy efficiency potential under additional scenarios; including but not limited to a high-natural gas cost scenario. The IRP should include the ranges of energy efficiency potential under different scenarios.

On page 19 of Volume 1, MDU states: "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." This math does not add up. MDU should clarify if there was another customer missing that was not mentioned for the 20 MW total.

DEQ understands the financial reasons for MDU suspending its Wi-Fi Thermostat Demand Response program; however, it is unfortunate to see MDU relinquish the opportunity presented in the residential program. This new area of demand response has the potential to deliver direct benefits to MDU and to its customers. One benefit of this type of program is that it has the potential to reduce the utility bills of residential customers with air conditioners for four months out of the year. DEQ recommends MDU continue to look closely at expanding its demand response programmatic offerings within the residential and commercial sectors and consider sector diversity as a key benefit when selecting its demand response programs. On its current demand response development trajectory, MDU may become overly dependent on a single market sector *for meeting a majority of MDU's demand response obligations. If that market sector were to experience conditions that diminished its capability to provide demand response capacity to MDU, the utility may find itself in a capacity deficit that could be difficult or expensive to meet.*

DEQ supports MDU's move to create a new Residential LED Lighting Program and the LED conversion project of its company-owned streetlights. In recent years, LED technology has rapidly progressed, in terms of price, lighting quality, and durability. Promoting and incentivizing the increased use of LEDs will assist MDU customers in lowering their overall energy usage and utility bills more quickly and may help dampen peak loads.

The Company's current commercial demand response and interruptible programs have been very successful to date, accounting for 40 MWs of customer load under contract. Montana-Dakota plans to include additional emphasis on potential new customer programs as part of its 2021 IRP. Language was included in the Company's 2020 RFP expressing interest in proposals for energy storage, customer demand side management, and energy efficiency programs.

As part of the Company's 2020 RFP a bid was provided from our current commercial demand response program to expand the program from 25 MW up to 50 MW, which was agreed upon. With this expansion Montana-Dakota is planning to grow its programs to 60 MWs by 2023 from its commercial demand response and interruptible programs.

7. DEQ recommends that MDU include within its future integration and risk analysis a scenario for high growth in distributed generation (e.g., distributed generation growing to meet 3-5% of MDU retail sales 10 years into the future). DEQ believes these results may generate distinctly different results from the low-growth scenario forecast because distributed generation typically does not generate electricity and reduce system load uniformly across the day, month, and year.

To date, the Company has not seen a significant penetration, or customer interest, in distributed generation on its interconnected system. The lack of interest is based upon the geographical viewpoints of our customers as compared to other parts of the country and the economic value of electric services that Montana-Dakota provides today.

The Company will look at potential modeling sensitivities to account for different penetration levels for distributed generation as part of its 2023 IRP. At a high level, high-growth distributed generation scenarios look like a low customer load growth scenario with a shift in hourly energy requirements associated with periods of expected high self-generation by customers.

8. The Base-Case least cost plan consists of a plan to install an 88 MW natural gas-fired Simple Cycle Combustion Turbine unit expected to be online in 2022-2023. DEQ recommends that MDU consider the impact that additional reliance on gas resources in the near term will have on their customers' exposure to longer-term natural gas volatility. The high gas scenario, which increased the gas price by $5/MMBtu from the base case is still less than the $3 to $9 million/ MMBtu spread in EIA's Henry Hub spot price range forecasted for 2030. DEQ suggests running a high gas scenario of $9/MMBtu.

DEQ recommends that MDU also analyze the costs of including carbon capture, utilization, and sequestration (CCUS) capabilities on new gas generation to better understand the potential for using CCUS as a tool to mitigate the risk of carbon pricing or regulation.

Montana-Dakota is in a geographic region of low cost and abundant natural gas supply. Montana-Dakota did run an additional sensitivity in its 2019 IRP which increased both natural gas prices by $5 per MMBtu and market energy prices by $25 per MWh over the base case assumptions. The results of the sensitivity were unchanged regarding future generation resource selections by the model. In short, higher gas and market energy prices were analyzed and do not support continued operation of Montana-Dakota's smaller coal fired plants.

The Company expects market energy prices to remain low in its service area, especially during times of high wind and solar generation, due to the high amount of renewable generation in our area that is built to serve neighboring utility loads. Natural gas-fired generation units provide market price mitigation when renewable sources of generation are unavailable. If natural gas price volatility occurs more frequently during the winter season, the Company may look to add dual fueled combustion technology on Heskett Station Units 3 and 4. Glendive 1, Glendive 2, and the Miles City combustion turbine all have dual fueled capability today.

Montana-Dakota's natural gas-fired units are dispatched very little in the 2019 IRP model and are used mainly to economically meet customer peak demand requirements.

The 2021 IRP model had Montana-Dakota's natural gas-fired units dispatching very little, so a higher natural gas price sensitivity would not have much of an effect on the least cost plan.