



400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

December 17, 2015

Dave Glatt
Section Chief
Environmental Health Section
North Dakota Department of Health
918 E Divide Avenue
Bismarck, ND 58501

Subject: Montana-Dakota Utilities Co. Input on North Dakota's State Plan for Compliance with EPA Clean Power Plan Rule

Dear Mr. Glatt:

Montana-Dakota Utilities Co. (Montana-Dakota) submits the following recommendations to the North Dakota Department of Health (Department) as North Dakota begins work to develop a state plan for managing North Dakota's compliance under the U.S. Environmental Protection Agency's (EPA's) Clean Power Plan (CPP) Rule. Montana-Dakota appreciates the opportunity to provide input to the Department on the development of the state plan. The Department requested answers to some specific questions public noticed on October 12 that may further guide the Department in its development of a state plan. Montana-Dakota provides as much information as possible below to answer those questions and assist in the process of developing a least cost compliance plan for the State of North Dakota.

Montana-Dakota is an investor-owned utility company that generates, transmits and distributes electricity to more than 140,000 customers in 179 communities and adjacent rural areas in North Dakota, South Dakota, Montana and Wyoming, with the majority of our customers (78 percent) located in North Dakota. The total capacity of the company's electric generation resources that serve Montana-Dakota's integrated system is about 740 megawatts (Figure 1), and as of December 31, 2015, we project approximately 50 percent of this capacity to be fueled by coal (Figure 2). However, the majority of the electricity delivered to customers is supplied from our affordable coal-fired electric generating resources. By the end of 2016, Montana-Dakota projects the company's coal-fired generation to provide 80 percent of the energy delivered to customers, with about 19 percent of the energy coming from renewable energy resources (Figure 3).

With the majority of Montana-Dakota's coal-fired generating capacity located in North Dakota (approximately 57 percent as derived from Figures 1 and 2), Montana-Dakota has a very significant interest in the options the Department considers in developing a state plan for CPP Rule compliance. Additionally, as Montana-Dakota is an investor-owned utility, and is therefore

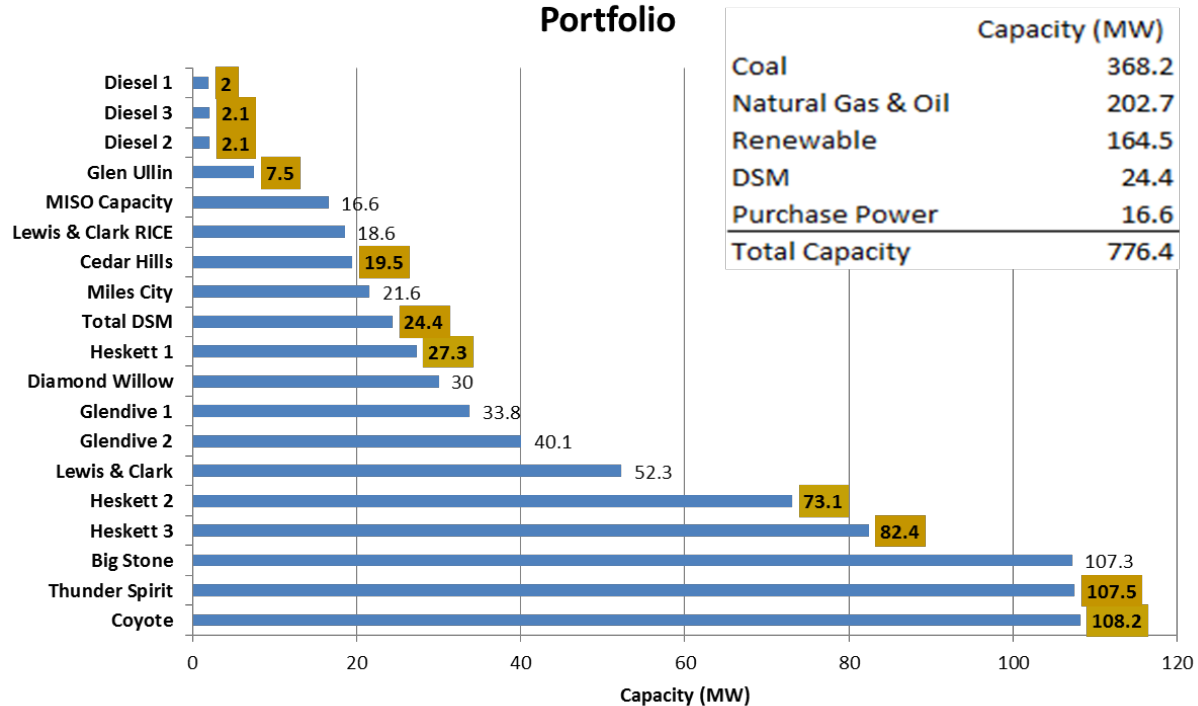
regulated by state utility regulatory commissions, any significant changes in the generation resource mix resulting from compliance will need to be reviewed and approved by the utility commissions for the company to obtain recovery of these investments.

For more than 25 years, Montana-Dakota has used the integrated resources planning (IRP) process to systematically identify reasonably available demand-side and supply-side resources needed to meet its end use customer’s demand for reliable, cost effective, and environmentally responsible electricity. Consumer needs are combined with a least cost analysis to provide a best resource plan which serves as a road map for Montana-Dakota’s future generation resources. The Public Service Commissions (PSCs) of both North Dakota and Montana require this IRP process. Montana-Dakota provided detail about this planning process in Appendix E of the Application for a PSD Permit to Construct a Simple Cycle Combustion Turbine at R.M. Heskett Station that was submitted to the Department on November 28, 2012. A copy of Appendix E is attached to this correspondence.

In North Dakota, there is an Advance Determination of Prudence (ADP) pursuant to N.D.C.C. § 49-05-16 and a Certificate of Public Convenience and Necessity pursuant to N.D.C.C. Chapters 49-03 49.03.1 that also guide the ND PSC and Montana-Dakota in making prudent additions of electric generation assets that are in the best interest of the customer. Montana-Dakota would obtain these approvals from the PSC before incurring significant costs for new generation resources to ensure the company can obtain recovery of these investments.

Figure 1

Montana-Dakota's 2016 Integrated System Generation Portfolio



(Beige shading of value indicates the resource is located in North Dakota)

Figure 2
Projected 2016 Capacity Mix

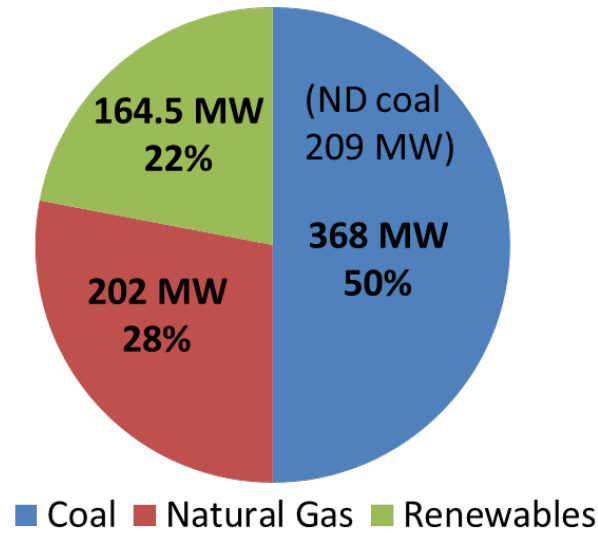
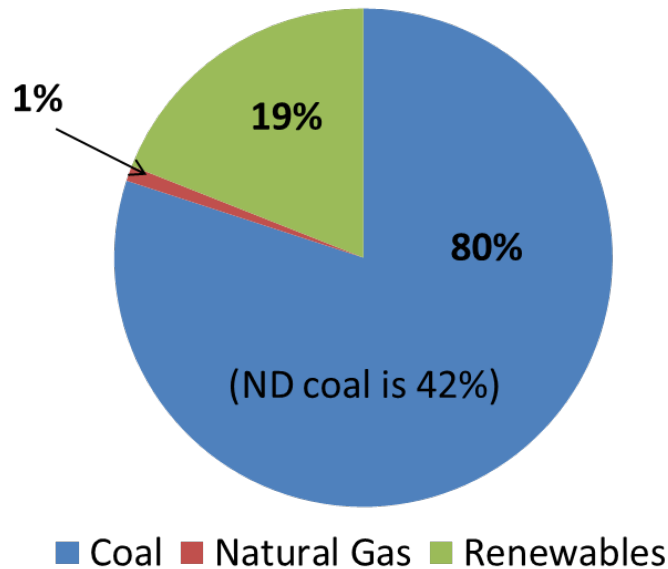


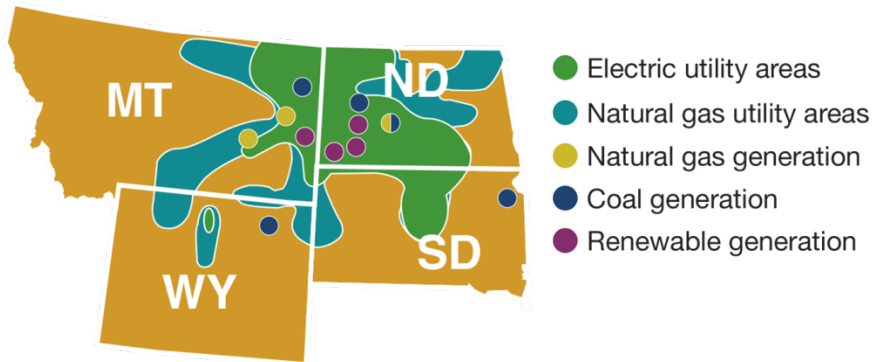
Figure 3
Projected 2016 Energy Delivered



Coal continues to be an economic electric generation resource option in the regions where Montana-Dakota operates, despite low natural gas prices. The company's coal-fired electric generating units (EGUs) provide cost effective and reliable base load electricity to customers.

Figure 4

Montana-Dakota Utilities Co. Generation Locations and Service Territory



There is significant concern with meeting the 2030 final emission target, as well as meeting the stringent targets that would apply as early as 2022. Montana-Dakota anticipates that additional electric and natural gas transmission infrastructure are needed in order to implement the new resources required for compliance with either a mass- or rate-based program. It will take at least five to seven years to install such infrastructure depending on what the state plan requires and where a resource can be sited, permitted and constructed (see Figure 5). If the infrastructure is not in place by the time a new resource is needed, either reliability of the electric system will be at risk or compliance with the CPP Rule may be at risk as the generation required for compliance would not be available and existing units must continue to operate.

Figure 5

ANTICIPATED IMPLEMENTATION TIMELINE
<ul style="list-style-type: none"> • October 23, 2015 - Final GHG Rule in Federal Register • September 6, 2016 – Project Department’s initial submittal to EPA, with allowed two year extension for proposed State Plan • September 6, 2018 – State Plan Submitted to EPA • September 2019 - EPA approves State Plan • 2017 to 2018 - North Dakota Public Service Commission (ND PSC) 2-yr Integrated Resource Plan completed and submitted to commission for proposed generation resources • 2019 – ND PSC issuance of Advanced Determination of Prudence order of new resource implementation and retirement of existing resource if determined a prudent decision by the commission via certification of public convenience and necessity filing • 2019 to 2021 – MISO interconnect and network upgrade study completed for existing resource retirement and new resource – re-evaluate resources and

resource locations depending on network upgrades identified or if major reliability concern identified

- 2020 to 2021 - Obtain major permits and public service commission siting approval
- 2020 to 2025 – Obtain major permits for electric and/or natural gas transmission infrastructure, depending on location, project length and environmental concerns
- 2020 to 2025 – Obtain NEPA Record of Decision, if required
- 2019 to 2022 - Design, engineer, develop bid specifications, award bids and procure resource equipment and receive delivery
- 2022 – Begin resource construction
- 2022 to 2025 – Begin infrastructure construction
- 2025 – Begin resource construction if NEPA review required
- 2025 to 2026 – Commission resource and bring online, depending on infrastructure construction schedule
- 2028 – Commission resource and bring online if NEPA review required

Montana-Dakota has been a member of the Midcontinent Independent System Operator (MISO) since 2003. MISO is an independent system operator and regional transmission operator that provides open-access transmission service and monitors the transmission system across all or parts of 15 states and the Canadian province of Manitoba. MISO's main focus is to maintain transmission system reliability, dispatching generation resources on a least-cost basis throughout the region. MISO's review of CPP compliance options in consideration of reliability and transmission network upgrade needs will be very important.

At the outset, Montana-Dakota stresses that the input provided below is preliminary, and that as more evaluation of compliance options continues, the company's input on some of these topics may change. This is especially true considering the litigation outcome of the rule is unknown, there is presently only a high level understanding of the potential cost of allowances and emission rate credits (ERCs), and we do not know how other states where we have generation resources will develop their state plans. Montana-Dakota will provide supplemental input to the Department as more information becomes available.

Input on the Department's Public Noticed Questions

General Question 1:

- 1) Should the Department develop a plan? If yes, should it be a "State only" plan or a regional plan?

Montana-Dakota recommends the Department develop a state plan and not rely on the EPA to create a plan for the State of North Dakota. Since Montana-Dakota has coal-fired generation in multiple, adjacent states (Montana, South Dakota and Wyoming), we recommend the Department develop

either a “trading-ready” plan or a plan considering adjacent state approaches, incorporating mechanisms to help facilitate interstate emission trading without requiring states to submit joint plans. We believe this approach would be more efficient and result in lower compliance costs.

Montana-Dakota has preliminarily determined that the EPA’s compliance approach as outlined in the agency’s proposed Federal Plan Rulemaking would not be least cost. The higher costs in a Federal Plan are mainly due to EPA’s proposal to limit the period of time allowances are allocated to retired units and requiring a large amount of set-aside allowances be utilized for leakage. Also, in a rate-based compliance approach, the EPA limits what renewable generation or other offsets can qualify to generate an ERC. North Dakota would be able to explore other options for generating ERCs that would be more cost effective for compliance where the EPA may only use what is proposed in the Federal Plan.

General Question 2:

- 2) To what extent should the Department develop a plan?
 - Only improvements at the power plant (inside the fence line)
 - Complete plan as outlined by EPA
 - Something in-between

At the outset, Montana-Dakota believes the rule lacks legal support for incorporating compliance requirements “beyond the fence”. However, in the event that litigation determines compliance with the very stringent emissions reductions must be met, it will be important for utilities to have the ability to reduce emissions across the electric system and not be limited to reductions at the unit itself.

If litigation limits the methodology EPA applied to create the emissions reductions required by North Dakota and only allowed compliance options that could be installed at the unit, there would need to be a focus on evaluating each source and then apply an achievable “inside the fence line” emission standard. Until the courts issue a legal decision on the rule, Montana-Dakota recommends the Department continue on a path to complete a state plan that considers achievable options at each facility, but also meets the intent of the CPP Rule as finalized, allowing as much compliance flexibility for utilities as possible.

General Question 3:

- 3) Should the plan be based on:
 - Mass emission limits (mass) - How should allowances be allocated?
 - Emission rate limits (rate) - Uniform rate or uniform percentage reduction?
 - Block 1 - Plant efficiency improvements only?
 - State measures (e.g. plant limits plus demand-side energy efficiency programs)?

Montana-Dakota is still evaluating whether or not a mass or emission rate compliance option would be least cost. In a mass-based compliance program, Montana-Dakota recommends allowances be freely allocated to affected EGUs based on CO₂ emissions. We believe the CO₂ emissions averaged in the 2010 to 2012 time period may be an acceptable averaging period for determining allowance

allocation for the company's units. Montana-Dakota is reviewing the averaging period in more detail and will provide additional input to the Department at a future time.

Allowances should be allocated to units in perpetuity, including after retirement of units. Continued allocations would be expected to incentivize retirement of higher emitting units and provide lower cost to utilities and electricity customers as those continued allocations would assist with offsetting the investment in lower emitting replacement generation. Units would not need to continue operating to receive allowances as would potentially be considered if allowances to a retired unit would expire. This methodology is also consistent with other CAA trading programs, such as the Acid Rain Program, which provides "permanent" allowances to affected units.

Further, Montana-Dakota believes that benefits of emission reductions from retirements would not be limited to units that retire after the interim compliance period begins in 2022. Any affected units that are considered by the EPA in the agency's 2012 baseline period and that would retire after 2013, should receive allowances. Allowances should not be denied to units that would retire before 2022.

Allocating allowances based on CO₂ emissions ensures that lignite-fired units are not disadvantaged. Lignite coal generally demonstrates a higher carbon content and higher moisture content than other coals, such as a sub-bituminous. The additional moisture penalizes the efficiency of electric generation from lignite and the carbon content increases the CO₂ emission rate. These characteristics contribute to a CO₂ emission rate from lignite-fired units that is approximately 10 percent higher than other coal-fired units.

In addition, Montana-Dakota has implemented heat rate improvement projects at the company's owned and co-owned generating units over time. These projects are implemented when determined to be cost effective and prudent in consideration of cost recovery approval through the utility regulatory commissions. In some cases, efficiency improvements have been either infeasible to implement or cost prohibitive, such as with coal drying. When considering existing plant retrofits, these types of projects can be highly dependent on equipment design margins and physical arrangements. Potential increases in boiler efficiency from implementing a project may be offset by the effects of that project on auxiliary load and negatively impact the heat rate.

In consideration of a rate-based program or applying an emission rate to units, Montana-Dakota interprets that emission rates other than the 1,305 lb CO₂ per MWhr applied to coal-fired generation units could result in more flexibility to comply, but would result in a much more complex program for the Department to manage. Further evaluation of this approach may be appropriate if significant flexibility is achieved and where the ultimate cost of compliance would be lower cost for North Dakota. Montana-Dakota is still evaluating compliance options and does not have any recommended approach at this time. As more information becomes available, we will provide it to the Department.

Montana-Dakota has completed some preliminary evaluation of potential energy efficiency savings that could be realized at the customer endpoint. These opportunities will be further explored and reviewed to determine whether savings can be cost effectively achieved and whether the programs could be approved by utility regulatory commissions. To that end, if the Department considers using the "set aside" allowance allocation methodology for compliance in a mass-based program, we would recommend those allowances be allocated to utilities serving customers in North Dakota who could utilize those allowances to assist in offsetting the cost of the programs or for compliance in operating coal-fired generating units.

As the Department considers both mass- and rate-based plans, allowance allocation for the Clean Energy Incentive Program (CEIP) allowances and energy efficiency project ERC generation should be evaluated. Also, as there are several compliance options available in the rule, each having its own level of complexity and that the target is so much more stringent from the proposed rule, Montana-Dakota recommends that the Department file an initial submittal to the EPA in September 2016 that requests the additional two years to explore which option is least cost for North Dakota.

General Question 4:

- 4) How should the Department incorporate cost and electrical grid reliability concerns into the plan?

Montana-Dakota recommends that the Department engage with a number of entities to incorporate cost and electrical grid reliability concerns with the plan. Some of the entities to include in stakeholder meetings regarding electrical grid reliability are the affected utility companies, Public Service Commission, regional transmission organizations, such as MISO and SPP, and possibly North American Electric Reliability Corporation (NERC) and the Federal Energy Regulatory Commission (FERC) depending on potential impacts expected. Regarding cost concerns, the entities to engage with would be the affected utility companies, coal industry, ND Chamber of Commerce, local coal communities, and the North Dakota Department of Commerce.

Montana-Dakota utilizes an economic dispatch model for planning future resource additions. It is possible that this type of modeling could provide insight into least cost dispatch of units by applying a CO₂ allowance price to the emissions of individual units. As existing unit costs increase, new generation resources would be chosen for dispatch and inform when units may need to be replaced. The cost of replacing an existing unit due to CPP Rule costs should be considered in the cost for compliance that a utility or our customers would incur. However, the model does not predict reliability concerns. As compliance options are developed, modeling can be done through MISO or other impacted regional transmission operators (RTOs) to determine whether reliability concerns exist. Other organizations, such as Electric Power Research Institute (EPRI) and possibly other consulting firms, are developing models that could possibly incorporate reliability with least cost.

Many assumptions must be entered into these models, such as cost of allowances/ERCs, allocations of allowances, availability of allowances and there is much uncertainty with estimating values and availability of compliance mechanisms. As mentioned above, Montana-Dakota recommends that the Department continue to engage with specific reliability-governing and impacted utilities as reliability may be a significant concern with the stringent reductions required as early as 2022, as well as in the interim compliance period and beyond.

General Question 5:

- 5) Should the Department propose any legislation necessary for implementing the plan?

Montana-Dakota does not know if the Department would need to propose any legislation to implement the plan, but believes it is possible that even when implementing the EPA's most straightforward and less complex mass- or rate-based compliance pathways, legislation may be required. For instance in a rate-based program, it would be important for the Department to allow other renewable generation options to qualify for ERCs that the EPA did not identify. In order for

the Department to establish certifications of other types of marketable ERCs, or even the ones directly mentioned by EPA such as wind ERCs, state legislation may be needed to recognize those ERCs as a marketable commodity, especially since these have no direct tie to the affected unit for compliance under the Clean Air Act for rulemaking consideration.

The EPA has indicated the agency is developing the platform in which allowance, and possibly ERCs, would be recorded for trading purposes. State legislation may still be needed to enable the Department to provide utilities with the authority to sell allowances to other utilities. Also, legislation may be required to provide the Department the authority to allocate "set aside" allowances to non-affected entities, as the state may give consideration to using EPA's presumptively approvable way of addressing leakage. Montana-Dakota has not researched the Department's authority on allocating the "set-aside" allowances to non-affected entities as the EPA is proposing in the Federal Plan. We recommend the Department conduct legal review to determine whether legislation is needed for the Department to allocate "set-aside" allowances to non-affected entities, and in administering other requirements of the CPP Rule.

General Question 6:

- 6) Suggestions for cost-effective carbon dioxide reductions.

The Department's first priority in developing the state plan should be to minimize the economic harm to electric customers in North Dakota, which we believe will be high under any scenario. From a mass-based program perspective, allocating allowances freely to utilities for use in compliance will be most cost-effective. This would be most cost-effective for our customers since North Dakota does not have sufficient allowances to distribute to units in 2022 in order for those units to continue operating as in the past. Allowances will already need to be purchased from other states in 2022 for plants to operate, or generation will be curtailed or retirements will occur. As a retirement may occur, allowances allocated to that retired unit should be perpetual, with those allowances used as needed by the utility to maintain operation of a company's other coal-fired generating units. The allowances could also be traded or sold by a utility to other affected units in order to help cover the cost of retiring a unit and having to incur expenses to construct and operate a new generation resource. Montana-Dakota does not recommend that the Department use an allowance auction approach.

For a rate-based program, we recommend the Department explore ERC generation opportunities beyond what EPA has included in the proposed Federal Plan Rule.

General Question 7:

- 7) Comments on EPA's three building blocks and how they apply to North Dakota sources.

Block 1 is not expected to yield significant and economic emissions reductions as explained in Montana-Dakota's comments on the final rule. Even as EPA reduced their assumptions on the percent achievable heat rate improvement from 6 percent to 4.3 percent, Montana-Dakota commented that this was most likely in the range of 1 to 2 percent for the company's units.

Regarding Block 2, re-dispatch of coal-fired generation units to existing natural gas combined cycle (NGCC) generation units, Montana-Dakota believes that since there are no existing NGCCs in North Dakota, the EPA should not have used a region-wide assumption for re-dispatch of coal-fired generation to this type of unit. However, we encourage the Department to continue dialogue with EPA on how further compliance flexibility could be gained from the result of this additional stringency in the North Dakota target, while continuing to develop the state plan according to rule requirements.

Montana-Dakota also believes that the EPA erred in using an abnormally high baseline wind generation installation year of 2012 in making the agency's projections for additional renewables that would be implemented in 2022 and thereafter for North Dakota. The Block 3 estimates for renewable resource additions in North Dakota are significant and the transmission infrastructure is not in place to accommodate the amount of renewables the EPA assumes can be added. Montana-Dakota also has concerns with the ability to obtain permits and potential mitigation costs to implement this large amount of renewable generation considering almost the entire state is located within the 95 percentile corridor for the whooping crane which is a threatened and endangered species.

General Question 8:

- 8) Comments on coordination with the North Dakota Public Service Commission.

Montana-Dakota recommends that the Department consult with the North Dakota Public Service Commission in development of any compliance program that could result in unit retirement and new generation resource requirements as these outcomes overlap with commission jurisdiction. There are significant concerns that stranded assets will result from compliance with the CPP Rule and that additional expenditures will be required for replacement of existing electric generation resources assets. Therefore, it is important for the Department to coordinate with the commission on a regular basis as the plan is developed, especially in consideration of utility company recovery of compliance costs and addressing reliability concerns. We suggest inviting PSC staff to stakeholder meetings on a periodic basis where costs, such as stranded assets costs and replacement generation costs, and reliability are key discussion points.

General Question 9:

- 9) Comments on coordination with other states.

Montana-Dakota recommends the Department maintain communication with the environmental regulatory agencies in the states of South Dakota, Montana and Wyoming, as the company has coal-fired generation resources in each of these other states which also impacts customers in North Dakota. Also, as discussed above under Question 1, interstate emission trading would be more efficient and result in lower compliance costs.

Block 1 Question 10 (Block 1 of EPA's Clean Power Plan refers to efficiency improvements at the existing power plants):

- 10) How should the Department consider "remaining useful life" of each plant in the plan?

In determining the remaining useful life of a unit, there are several things to consider. These include depreciation schedules, terms of contractual agreements, pollution control installations, stranded

asset costs, replacement generation costs, purpose of generation resource, reliability and possibly more factors.

The remaining useful life should be used to determine how emission standard stringency would be applied on a unit-specific basis. As Montana-Dakota provided in comments to the EPA on the proposed rule regarding consideration of remaining useful life of units, “States should have the authority to consider whether (1) modifications to the timing of compliance or (2) the level of the state goal are necessary to avoid unreasonable economic consequences for power generators and their customers.” Montana-Dakota does not agree that remaining useful life should be used to determine such things as allowance allocations. If any unit, no matter what useful life remains, prematurely retires due to the CPP Rule, it would have to be replaced. Any replacement generation a utility installs would be projected to cost more than what it presently costs to operate an existing reliable and affordable coal-fired generation unit.

Block 3 Question 11 (Block 3 refers to renewable generation replacing existing coal-fired generation):

11) How should the Department incorporate accounting of renewable generation emission rate credits or excess mass allowances into the plan?

- North Dakota takes credit for all renewable generation in the state
- North Dakota takes credit for a certain percentage of renewable generation
- Owners of the renewable power can decide how to use the credits as they see fit

Montana-Dakota recommends that owners retain the rights of the renewable generation emission rate credits produced by their renewable generation and utilize those credits for compliance with their own generation resources in North Dakota or other states, or they would be able to market the credits to others to offset compliance costs. Montana-Dakota believes that this approach would avoid conflicts with interstate commerce clause statutes.

Montana-Dakota does not believe there will be any excess allowances available for distribution beyond what is needed to be allocated to affected sources due to the stringency of the target, unless North Dakota is not successful in supporting that leakage is not occurring with the mass compliance approach. If the Department uses a “set aside” approach to address leakage under the mass program, we believe there is support for limiting allowance allocation to renewables and NGCC re-dispatch under any “set-aside” requirement.

North Dakota should not be required to allocate NGCC allowance “set asides” since there are no existing NGCC units in North Dakota that would need an incentive to increase operation. Also, since there has been a history of significant renewable energy development in North Dakota, even continuing after 2012, we believe there could possibly be support that no “set aside” allowance allocations would be needed to incentivize additional renewables in future. The capacity factors achieved in North Dakota would support lower cost wind development continuing in the state, even possibly without a production tax credit for wind.

There would possibly still be CEIP allowances to allocate under the “set aside” approach. Preliminarily, we believe that those allowances should be allocated to entities that provide energy efficiency programs to end-use customers in North Dakota. These allowances could be used to offset

the cost of implementing the energy efficiency programs or for compliance with emissions from coal-fired generation resources.

Block 3 Question 12 (Block 3 refers to renewable generation replacing existing coal-fired generation):

12) Should the Department allow trading of emission rate credits (ERC) or mass allowances (tons of CO₂ emissions)?

- No trading at all
- In-state trading only
- Region wide trading
- Nationwide trading

Montana-Dakota recommends that the Department allow trading at minimum region-wide and believes that the lowest cost compliance would be achieved through nationwide trading. The majority of excess allowances under the CPP Rule appear to be in states on the west and east coasts.

Conclusion:

Without a doubt this is a very complex rule that has created significant challenges. Montana-Dakota believes the first priority should be in developing a state compliance plan that minimizes the economic harm, which we believe will be high under any scenario, to our customers and the state of North Dakota.

While Montana-Dakota fully supports the efforts by North Dakota to challenge the legality of the rule, we believe it's appropriate for the Department to work in parallel to develop and submit a state plan. While creating a state plan, we believe it is important for the Department to continue discussions with the neighboring states of Montana, South Dakota and Wyoming on their respective compliance plan strategies. We also encourage the Department to continue discussions with the PSC on cost impacts to customers.

We do have significant concern with meeting the 2030 final emission target, as well as meeting the stringent targets that would apply as early as 2022. Montana-Dakota anticipates that additional electric and natural gas transmission infrastructure are needed in order to implement the new resources required for compliance with either a mass- or rate-based program. It will take at least five to seven years to install such infrastructure depending on what the state plan requires and where a resource can be sited, permitted and constructed. If the infrastructure is not in place by the time a new resource is needed, either reliability of the electric system will be at risk or compliance with the CPP Rule may be at risk as the generation required for compliance would not be available and existing units must continue to operate.

As previously noted, this is a complex rule and the information provided in this letter is preliminary. As more evaluation of compliance options continues, the company's input on some of these topics may change. This is especially true considering the litigation outcome of the rule is unknown, there is presently only a high level understanding of the potential cost of allowances and emission rate credits, and we do not know how other states where we have generation

Montana-Dakota Input to North Dakota for State Plan to Comply with EPA CPP Rule
December 17, 2015
Page 13 of 13

resources will develop their state plans. Montana-Dakota will provide supplemental input to the Department as more information becomes available.

We appreciate the opportunity to provide this input based on what we know today.

Sincerely,



Abbie Krebsbach
Environmental Director

Enclosure

cc: Nicole Kivisto, President & CEO
Jay Skabo, VP - Electric Supply
Garret Senger, EVP - Regulatory Affairs & CAO
Mike Gardner, EVP - Combined Utility Operations Support
Rick Matteson, Director, Communications & Public Affairs
Pat Darras, VP - Operations
