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

Before the South Dakota Public Utilities Commission

Docket No. EL15-___

Direct Testimony
of
Jay Skabo

Q. Please state your name and business address.

A. My name is Jay Skabo and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the Vice President of Electric Supply for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. My responsibilities include power production and transmission, system operations and planning, and electric dispatch.

Q. Please outline your educational and professional background.

A. I hold Bachelor's Degrees in Chemistry from Dickinson State University and Chemical Engineering from the University of North Dakota. My work experience includes three and half years as the Environmental Manager at Montana-Dakota; and one and a half years as a Region Manager overseeing gas and electric crews, service technicians, and office personnel in constructing and maintaining our gas and electric systems. In 2008, I became Vice President of Operations. In January 2014, I assumed my current position. Prior to joining Montana-Dakota, I was the general manager of an industrial waste processing and disposal facility.

Q. **Have you testified in other proceedings before regulatory bodies?**

A. Yes, I have testified before the North Dakota and Montana Public Service Commissions.

Q. What is the purpose of your testimony?

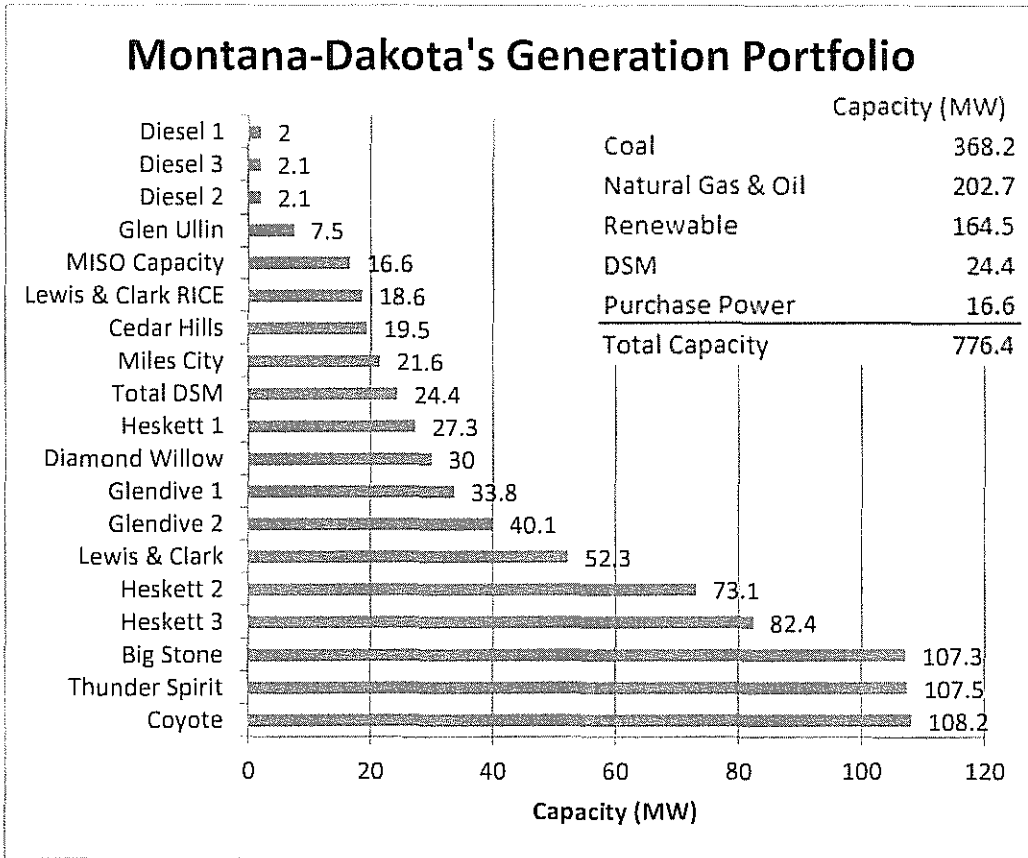
A. The purpose of my testimony is to provide information regarding Montana-Dakota's generation portfolio, recent generation and transmission investments and how these investments will serve customers well into the future.

Q. Please describe Montana-Dakota's current portfolio of generation assets used to serve customers and changes transpiring in 2015.

A. Montana-Dakota's existing generation serving its interconnected electric system is comprised of baseload coal-fired generation at the Heskett Station (Units I and II), the Lewis & Clark Station, Montana-Dakota's shares of the Coyote and Big Stone Stations, and natural gas-fired peaking generation at Glendive (Units I and II), Miles City, and Heskett Unit III. Montana-Dakota also owns the Diamond Willow I, Diamond Willow II and Cedar Hills wind farms, three two (2) MW portable diesel units, and the Glen Ullin Station 6 waste heat generating unit serving our interconnected system. The remainder of the capacity requirements had been provided by a capacity contract with We Energies (which expired in May of 2015) and energy purchases from the MISO energy market. To meet growing needs and increase reliability, to replace the expiring We Energies contract and to reduce reliance on the MISO energy market, Montana-Dakota identified the following resources through the Integrated Resource Planning process as the best options to meet the objectives noted above:

- Heskett III, an 88 MW simple cycle gas fired turbine was placed into service in August 2014. This unit is co-located with the Heskett I and II coal fired units in Mandan, North Dakota. Co-locating at an existing power plant substantially reduces costs. It eliminates the need for purchasing additional land and reduces the amount of additional staff. Heskett III only required two new employees to be added.
- A 18.6 MW natural gas-fired reciprocating engine project comprised of two 9.3 MW Wartsilla generating units is currently under construction and is co-located with the Lewis & Clark Station in Sidney, Montana. This generator is referred to as the Lewis & Clark RICE Project. Siting this unit at an existing plant also takes advantage of the cost savings of co-location.
- A 107.5 wind project known as Thunder Spirit Wind located near Hettinger, North Dakota, is currently under construction.

Following is a graphical presentation of the generation portfolio and associated capacity of each unit.



Mr. Darcy Neigum will provide additional details regarding the selection of each of the new generating units including the justification of need for each project.

Q. What impact have recent EPA regulations had on Montana-Dakota's generation portfolio?

A. The two primary EPA regulations affecting Montana-Dakota's investments included in this rate case are 1) the Mercury and Air Toxics Standards Rule (MATS Rule) and 2) the Regional Haze Rule.

Q. Would you please describe the MATS Rule?

A. The MATS Rule, published as a final rule on February 16, 2012, regulates hazardous air pollutant (HAP) emissions from coal- and oil-fired electric generating units. The rule became effective on April 16, 2012, and compliance with the MATS emission limits was required by April 16, 2015, with the opportunity for a one year extension if required for the installation of the selected air pollution control systems.

The rule includes emissions standards for mercury, non-mercury trace metals, and acid gas emissions from existing coal-fired boilers such as at the Lewis & Clark Station. Work practice standards are also included for control of organic HAP emissions. For the non-mercury metals, the rule includes alternative emission limits for filterable particulate matter (FPM), total non-mercury HAP metals, and individual HAP metals. For the acid gases, the rule includes alternative emission standards for either hydrochloric acid (HCl) or sulfur oxides (SOx) as a surrogate to demonstrate compliance for all acid gas emissions.

Q. What generating units were affected by the MATS Rule?

A. The following units require equipment upgrades in order to comply with the MATS Rule:

- Lewis & Clark Station located near Sidney, Montana,
- Big Stone Plant located near Big Stone City, South Dakota,
- and Coyote Station located near Beulah, North Dakota.

Lewis & Clark, an existing single-unit, 50-MW lignite-fired facility, is a low cost baseload resource critical in meeting Montana-Dakota's customers' energy and capacity requirements. It provides important voltage and reliability support to a transmission-isolated region, and helps mitigate load restrictions during outages of other bulk electric system facilities. Montana-Dakota has gone through several iterations, including natural gas co-firing, in an attempt to find the most economical solution to meeting the MATS Rule.

Ultimately, in September of 2014, Montana-Dakota initiated a study with URS Corporation (URS), a consulting engineer experienced in modifying wet scrubbers similar to the Lewis & Clark Station's scrubber. Montana-Dakota concluded that URS' turnkey solution, with a guarantee to achieve the requirements for MATS non-mercury metals compliance, was an economic solution that could be installed and placed into service in late 2015. Montana-Dakota entered into an agreement with URS to design and install modifications to the existing scrubber. On January 30, 2015, the Montana Department of Environmental Quality issued a one-year compliance deadline extension for meeting the non-mercury hazardous air pollutant metals standard. The Lewis & Clark MATS project is set to be operational in December 2015 at a projected cost of $16.2 million. The Integrated Resource Plan continues to support the capital investment in lieu of shutting down the plant. Mr. Alan Welte will provide additional details regarding the history of the compliance efforts and the Lewis & Clark MATS project.

Activated carbon injection systems are needed to comply with the mercury limit of the MATS Rule at the Coyote Station and Big Stone Plant. At Big Stone Plant this equipment is being installed as part of the Air Quality Control System project, which I will discuss in more detail below.

Q. Were there other generating units affected by the MATS Rule?

A. Yes. Reagent usage will be also be required at the Lewis & Clark Station, the Big Stone Station, the Lewis & Clark RICE units, as well as the Coyote Station and Heskett I. The reagent is required as part of the systems to remove regulated contaminants and will cause an increase in the variable production costs with each of these plants in addition to requiring additional workforce. At Heskett I, the mercury limits are currently being met with the addition of Tire-Derived Fuel to the coal feed.

Q. Would you now describe the upgrades required at the Big Stone Plant in order to meet EPA's Regional Haze Rules?

A. Yes. First, to provide some background information, the Big Stone plant is co-owned by NorthWestern Corporation d/b/a NorthWestern Energy, Montana-Dakota, and Otter Tail Power Company (Otter Tail) hereinafter referred to as the Owners. Otter Tail operates the Big Stone power plant (Big Stone) near Big Stone City, South Dakota. Montana-Dakota's ownership share in the Big Stone Plant is 22.7 percent, and therefore Montana-Dakota is responsible for 22.7 percent of the costs of operating the plant including the investments necessary to comply with the EPA's rules.

The Clean Air Act, 42 U.S.C. §7479, mandates a national goal of remedying and preventing visibility impairment from man-made air pollution in specified areas (referred to as Class I) of the United States which include national parks and wilderness areas. In 1999, EPA promulgated the Regional Haze Rule (40 CFR Part 51), which was revised in 2005, to implement this requirement of the Clean Air Act. The Regional Haze Rule includes the requirement to install the Best Available Retrofit Technology (BART) on major generating sources, including existing electric generating units that were placed into operation between 1962 and 1977. Because the Big Stone Plant began commercial operation on May 1, 1975, it was subject to the requirements of the Regional Haze Rule for the installation of BART. Conversely, Heskett I & II, Lewis & Clark, and Coyote were not included in this phase of the rule due to the dates of their construction.

Q. How was it determined that the Big Stone Plant would be required to install BART?

A. Under the Regional Haze Rule, state environmental agencies are authorized to submit a State Implementation Plan (SIP) to EPA for review and approval, outlining how the state intends to bring affected sources subject to jurisdiction into compliance with the rule. If a state does not propose a SIP, EPA will develop a plan to control emissions from sources located in that state which are shown to contribute to visibility impairment. South Dakota elected to pursue adoption of a SIP through its state agency, in this case the South Dakota Department of Environmental and Natural Resources (DENR).

In response to the Regional Haze Rule, Otter Tail, as the operator of the Big Stone Plant, performed an evaluation of the visibility impact of the plant's operations on seven Class 1 areas in four states. Based on this evaluation, the South Dakota DENR determined the Big Stone Plant's emissions contribute to impairment of visibility in multiple Class I areas and therefore the plant was subject to the BART requirements of the Regional Haze Rule.

Q. How was BART determined for the Big Stone Plant?

A. Otter Tail, as agent for the owners, proposed that separated over-fired air (SOFA) technology be deployed as BART for the Big Stone Plant in its BART analysis. On September 15, 2010, the South Dakota DENR, Board of Minerals and Environment, adopted Administrative Rules of South Dakota chapter 74:36:21 which imposed limits on nitrogen oxides (NOx), sulfur oxides (SOx), and particulate matter that were substantially lower than those in the existing Big Stone Plant permit. The South Dakota Regional Haze SIP included the following as BART technologies applicable to the Big Stone Plant:

- Selective catalytic reduction technology (SCR) with separated over-fired air for control of NOx.
- Semi-dry flue gas desulfurization for control of SOx.
- A baghouse for control of particulate matter.

On January 21, 2011, the South Dakota DENR submitted its SIP to the EPA for review and approval. On March 29, 2012, the EPA approved the South Dakota SIP and the final rule was published on April 26, 2012. Under the South Dakota Regional Haze Rule, the Big Stone Plant must achieve BART compliance expeditiously but no later than five years after EPA's approval of the South Dakota SIP, or April 26, 2017.

Q. Would the Big Stone Plant be forced to close without these environmental upgrades?

A. Yes. The plant could not operate using coal as its fuel source after April 26, 2017, without the environmental upgrades adopted in the South Dakota SIP.

Q. What did the Owners consider when deciding whether to pursue installation of the BART at the Big Stone Plant?

A. The Owners obtained a cost estimate from the engineering firm of Sargent & Lundy for the installation of the BART technology identified in the South Dakota SIP at the Big Stone Plant. The initial estimate of a BART compliant AQCS was $489,397,400 in 2015 dollars, with an accuracy of plus or minus 20 percent. An additional cost to install activated carbon injection for mercury control under the MATS Rule was estimated at $5,012,700 for a total cost estimate of $494,410,100 including engineering, procurement, construction, supervision, and management costs for the project. The Owners then compared the construction and operation costs of Big Stone with the AQCS to several other generation alternatives. In each instance, the assessment concluded that Big Stone with the AQCS was the least cost option. In May of 2012, the North Dakota Public Service Commission issued its Order accepting the AQCS Project as prudent in the Company's joint application with Otter Tail Power Company for an Advance Determination of Prudence.

Q. Did Montana-Dakota conduct any analysis of the Big Stone AQCS and other generation alternatives specific to its generation needs?

A. Yes. Montana-Dakota separately analyzed the cost effectiveness of the Big Stone AQCS project beginning with its 2011 Integrated Resource Plan (IRP). Montana-Dakota modeled sensitivity scenarios surrounding the AQCS and various alternatives. Even when the modeled cost of the AQCS was nearly doubled from its original estimate, it was still selected as part of Montana-Dakota's resource plan recommended in its 2011 IRP.

Q. What is the current status of the Big Stone AQCS project?

A. The project is set to be operational in late 2015 at an estimated cost of $384 million (including the MATS project). Mr. Alan Welte will provide details of the AQCS project.

Q. Did Montana-Dakota consider abandoning the AQCS project based on the proposed Clean Power Plan (CPP) rule?

A. This was considered by Montana-Dakota and the Owners and it was quickly recognized that the plant would have been required to shut down by April 26, 2017, if the emissions controls were not in place. It was also determined that at the time the proposed CPP rule was published, the project was fully under construction and as such, expenses had been committed to the point that the loss of investment would be too significant to curtail construction. For example, as of June 30, 2014, the only major contract left to execute was for demolition services to remove the old baghouse, fans and ash silo. Additional modeling also determined that the investment in the AQCS was still a least cost option, even if the plant was only able to run until December 31, 2019, the effective date of the CPP. Further, the CPP has yet to be finalized, and is expected to undergo significant modifications, and is also highly suspect of being dismantled due to legal challenges. Abandoning the AQCS project when it was well into construction based on the potential of a draft rule with a long implementation timeframe, would have been imprudent.

Q. **Do you believe Montana-Dakota is positioned well for the future given the impending Clear Air Act regulations expected to be released by the EPA in August of this year?**

A. Yes, I do. The investments being made today in new generation will continue to serve Montana-Dakota and its customers under a carbon constrained environment as what I understand is currently contemplated under the Clear Power Plan regarding existing sources. We are adding 107.5 MW of wind resources, which will bring us to 22% carbon free resources in our integrated system generation portfolio, and the Thunder

Spirit wind resource is expandable to 150 MW. By the end of 2015, we will have 200 MW of peaking natural gas generation in our generation portfolio, and we have plans to add approximately 200 MW of natural gas combined cycle generation by 2020. With our current portfolio and the available and planned additions, we should be positioned well to comply with pending Clean Air Act regulations and other EPA mandates.

Q. Turning now to transmission. Would you please provide an overview of transmission investments?

A. Power is delivered over Company-owned transmission lines, as well as lines owned by the Western Area Power Administration (Western) and Basin Electric Power Cooperative (Basin) under long-term agreements. Montana-Dakota is also a member of MISO, which allows access to MISO transmission in the upper Midwest. These transmission arrangements allow Montana-Dakota to efficiently serve customers throughout its service territory with minimal duplication of facilities. Mr. Darcy Neigum will provide information relating to the expiration of the Western Agreement in December 2015 and the impacts associated with Western and Basin's decision to join the Southwest Power Pool.

The Company has built and/or upgraded transmission lines and associated infrastructure, such as substations, to reliably serve customer needs. South Dakota electric customers' share of new transmission investments in the interconnected system over the last five years has been about $2.3 million. Montana-Dakota is planning to invest in over $20 million in transmission area improvements in South Dakota in the next few years which will be cost shared with Montana-Dakota's integrated system customers. The transmission additions include a new 115kV transmission line running from Ellendale to Leola along with substation upgrades at Glenham and Bowdle, South Dakota.

Q. Would you describe the deferred development costs proposed to be recovered as part of this rate case?

A. The costs related to Montana-Dakota's efforts in securing new electric generation generally fall into the following cost categories: engineering, project development, permitting, legal, other expenditures, and Allowance for Funds Used During Construction (AFUDC). Costs were incurred for the development of three baseload projects evaluated by Montana-Dakota, the Big Stone II Project, the Gascoyne Project, and the Milton R. Young III Project. Mr. Jacobson will discuss the development costs that were deferred for recovery until this rate case as authorized by the Commission in Docket No. EL09-025.

The Big Stone II project was a proposed multi-owner coal-fired generating plant to be located at the site of the existing Big Stone Plant near Big Stone City, South Dakota.

In June of 2005, Montana-Dakota entered into project agreements with six other utilities for purposes of pursuing the project. At that time, the participants applied for the necessary permits, and began preliminary engineering and other development work for the project. The North

Dakota Public Service Commission issued an Advance Determination of Prudence for Montana-Dakota's participation in the project in August 2008. This order was based on the cost of a 500 MW to 580 MW facility with an on-line date of mid-2013. This Commission approved the project Site Permit in July 2006 and the Minnesota Public Utilities Commission issued a Certificate of Need (CON) for the Big Stone II transmission lines in March 2009. The project also obtained a water allocation permit, the air quality permit, other necessary permits, and completed a Federal Environmental Impact Statement for the project. The plant was initially permitted as a nominal 600 MW plant, and was expected to be commercial in 2011

On September 11, 2009, Otter Tail Power Company (OTP) withdrew from further participation in the project. At the time, Montana-Dakota had a 26.54 percent share of the project and a corresponding responsibility for shared project costs. Montana-Dakota was one of four participants remaining after OTP withdrew. The remaining participants actively sought new project participants, but were unable to obtain any additional commitments. Lacking new participants to replace OTP, on November 2, 2009, the project participants determined it was no longer feasible to continue the development of the Big Stone II project at the size and cost that was permitted and still remain economically efficient.

Montana-Dakota pursued the Big Stone II project after determining that it was a prudent long-term source of reliable electricity for its customers. When, due to changing circumstances, it became clear that the project was not likely to be constructed, the plant participants abandoned the project. Montana-Dakota seeks recovery of these costs which were prudently incurred in developing the generating resource, although unfortunately, the plant was not built.

Q. Please explain the circumstance surrounding the Gascoyne and Milton R. Young III projects.

A. Montana-Dakota had a long-term power purchase contract for 66 MW that expired in October, 2006. This power purchase contract accounted for nearly 20 percent of Montana-Dakota's base load capacity. Given the magnitude of this resource, and prior to contract expiration, Montana-Dakota sought new resources to replace the contract and to meet Montana-Dakota's retail customers' projected requirements. This included pursuing an extension of the contract, preliminary discussions with OTP regarding the possibility of participating in a second unit at the Big Stone generation station site, and evaluation of construction of gas turbines. At about the same time, the State of North Dakota proposed its Lignite Vision 21 program, and Montana-Dakota began to evaluate the development of a 500 MW coal fired unit in North Dakota, near the town of Gascoyne, in conjunction with that program. The potential to develop a resource within Montana-Dakota's service territory was an attractive option to include in evaluations seeking the best new resource to meet the long term needs of Montana-Dakota's customers.

Having a partner to utilize much of the output of the proposed 500 MW Gascoyne plant was essential, as Montana-Dakota's projected power and energy requirements, even including anticipated load growth, were not this large. When the Company's efforts to locate such a partner were unsuccessful, the plant design was downsized, ultimately to 175 MW. As this size plant was under evaluation, Montana-Dakota was approached about participating in Big Stone II. Preliminary engineering and pricing estimates from the Gascoyne project made it clear that the economies of scale achieved by the larger proposed Big Stone II plant were significant compared to a smaller plant. There were additional economies available from the location of Big Stone II next to the existing Big Stone Plant, as well as cost savings to be recognized at the existing plant. Because of the overwhelmingly favorable economics of the Big Stone II project relative to the Gascoyne plant, Montana-Dakota discontinued further work on this plant design.

Montana-Dakota knew from projected load growth analysis that even with ownership of 116 MW of the Big Stone II plant, additional capacity would be required almost as soon as that plant became commercial. Montana-Dakota approached Minnkota Power Cooperative about ownership in a possible new 250-500 MW multi-owner unit located at the Milton R. Young plant near Center, North Dakota. This unit was expected to become commercial in the 2010-2015 time frame, which fit well for a resource to succeed Big Stone II. Montana-Dakota participated in discussions and preliminary engineering studies including technology, fuel availability and transmission, for about three years- 2005 to 2007. At that time other participants determined to abandon this project for a variety of reasons.

Both Gascoyne and Milton R. Young III were potential regional base load power sources Montana-Dakota evaluated to provide power to its customers, faced with the expiration of a significant contract and steady customer demand growth.

Q. Why should Montana-Dakota's customers pay for plant development costs that did not ultimately result in a resource providing service to customers?

A. Montana-Dakota constantly seeks and evaluates potential new sources of power to serve its customers. Opportunities to develop or partner in multi-owner projects that can achieve economies of scale are rare. All three projects were opportunities to achieve these economies with regional power plants. The plant development costs were a necessary cost associated with the development of Montana-Dakota's next generating facility and should be recovered from customers.

Q. Does this complete your direct testimony?

A. Yes, it does.