STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation **Advance Determination of Prudence Application**	**Case No. PU-06-481**
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. **Advance Determination of Prudence Application**	**Case No. PU-06-482**

ADVOCACY STAFF POST HEARING BRIEF

PRELIMINARY STATEMENT

On November 14, 2006 Otter Tail Corporation d/b/a Otter Tail Power Company ("Otter Tail") or ("OTP") filed an application for advance determination of prudence for Otter Tail's participation and ownership interest in the Big Stone Unit II Generating Plant, Case No. PU-06-481.

On November 15, 2006 Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. ("Montana-Dakota") or ("MDU") filed an application for advance determination of prudence for Montana-Dakota's participation and ownership interest in the Big Stone Unit II Generating Plant, Case No. PU-06-482.

Otter Tail and Montana-Dakota ("Applicants") along with five other utilities are proposing to construct a 630 MW pulverized coal facility located adjacent to the existing Big Stone Plant in Big Stone City, South Dakota. Otter Tail and Montana-Dakota each will own 19.33 percent of Big Stone Unit II.

The companies are requesting that the Public Service Commission

("Commission") determine the construction of Big Stone Unit II generating station to be reasonable and prudent in order to provide the basis for future rate stability proposals the companies will present to the commission.

On December 29, 2006, the Commission issued A Notice of Filing and Notice of Intervention Deadline. In that order the Commission established an intervention deadline of February 15, 2007.

On January 10, 2007, the Commission issued its Notice of Hearing scheduling a public hearing to be held in the Commission Hearing Room at the State Capitol in Bismarck, North Dakota beginning April 17, 2007. The issues identified by the Commission include:

1. Whether the resource addition is reasonable and prudent.
2. Whether the applicants have need for additional generating resources.
3. What alternatives exist for meeting additional generation needs.

On January 24, 2007, the Commission issued a Notice of Public Input Session. Public input sessions were held on February 5, 2007 in Bismarck and on February 12, 2007 in Jamestown.

On February 15, 2007, Mark Trechock, a ratepayer, and the Dakota Resource Council ("DRC") or ("Intervenors") filed a Petition to Intervene. On February 23, 2007, the Commission issued its Order Granting Intervention.

On March 7, 2007, the Commission issued its Notice of Rescheduled Hearing scheduling the public hearing to begin May 29, 2007.

On May 15, 2007, the Commission issued a Notice of Rescheduled Hearings scheduling the public hearing in the proceedings to begin June 26, 2007. The public hearing was held as scheduled.

STATEMENT ON THE LAW OF THE PROCEEDING

I. Prudency.

Otter Tail and Montana-Dakota filed applications for Advance Determination of Prudence in these proceedings under Section 49-05-16 of the North Dakota Century Code. The statute reads as follows:

> **49-05-16. Advance determination of prudence.** A public utility proposing to construct, lease, or make improvements to an energy conversion facility, renewable energy facility, transmission facility, or proposed energy purchase contract from another entity or person for the purpose of ensuring reliable electric service to its customers may file an application with the commission for an advance determination of prudence regarding the proposal. The commission may order that expenses associated with investigating the application made by the public utility or prudence of a resource addition be paid by the public utility in accordance with section 49-02-02.
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> 1. The commission may issue an order approving the prudence of an electric resource addition if:
>   a. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the electric resource addition;
>   b. The commission provides notice and holds a hearing, if appropriate, in accordance with section 49-02-02; and
>   c. The commission determines that the resource addition is reasonable and prudent. For facilities located or to be located in this state the commission, in determining whether the resource addition is reasonable and prudent, shall consider the benefits of having the energy conversion facility, renewable energy facility, transmission facility, or facility generating the energy to be purchased located in this state.
> 2. The commission order must be rendered no later than seven months after the public utility files its application requesting a prudence determination of an electric resource addition.
> 3. A resource addition approved by the commission is subject to annual reporting requirements until commercial operation of the resource addition.
> 4. The commission's order determining prudence of the resource adjustment is binding for ratemaking purposes.
> 5. If at any time following an initial commission order, the commission, following a subsequent hearing, determines that continuation of a project is no longer prudent or that its prior order should be modified,

> the public utility may recover in its rates, and in a timely manner consistent with the public utility's financial obligations, the amounts the public utility already has expensed, incurred, or obligated on a project, including interest expense and a return on equity invested in the project up to the time the new order is entered even though the project may never be fully operational or used by the public utility to serve its customers.
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> 6. There is a rebuttable presumption that an energy conversion facility, renewable energy facility, transmission facility, or facility generating the energy to be purchased which is located in the state is prudent.

The statute provides that the Commission may issue an order approving the prudence of an electric resource addition, but the statute does not define “prudence.” Under the prudent investment or original cost rule, a utility is compensated for all prudent investments at the cost of those investments, when made, regardless of whether they are necessary in hindsight.[1]

The “prudent investment” rule was recognized by the United States Supreme Court a being a valid basis for determining utility rates.[2] The Court stated that “[u]nder the prudent investment rule, the utility is compensated for all prudent investments at their actual cost when made (their ‘historical’ cost), irrespective of whether individual investments are deemed necessary or beneficial in hindsight.”[3]

The Michigan Public Service Commission applied the “prudent investment” test recognized in *Duquesne* to determine the extent of Consumers Power Company’s recovery of its investment in a canceled nuclear plant.[4]

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[1] 73B C.J.S. Public Utilities § 44 (2004).
[2] Duquesne Light Co. v. Barasch, 488 U.S. 299, 109 S.Ct. 609, 102 L.Ed.2d 646 (1989), (*Duquensne*).
[3] Id. at 309.
[4] Association of Business Advocating Tariff Equity v. Public Service Commission, 527 N.W.2d 533,539 (Mich. App. 1994).

The Missouri Public Service Commission ("MPSC"), in considering the prudency of Kansas City Power and Light Company's investment in the Wolf Creek nuclear power plant, determined that a standard of reasonable care requiring due diligence is appropriate for determining whether a regulated utility's actions during the course of the project were prudent.[5] The reasonable care standard used by the MPSC to judge prudency was based on the standard enunciated by the New York Public Service Commission in Re Consolidated Edison Co. of New York, Inc., 45 PUR 4th 325 (N.Y.P.S.C. 1982), which states that a company's conduct "should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problems prospectively rather than reliance on hindsight." In its opinion, the New York Commission stated that its responsibility was to determine how reasonable people would have performed the tasks that confronted the company.

The MPSC, in applying the standard stated that it would not rely on hindsight, and that "[t]he commission will assess management decisions at the time they were made and ask the question, 'given all the surrounding circumstances existing at the time, did management use due diligence to address all relevant factors and information known or available to it when it assessed the situation?'"[6]

The "prudent investment" rule is also addressed in North Dakota law. The State of North Dakota requires that the Board of University and School Lands must apply the

[5] RE Kansas City Power and Light Company, 75 PUR 4th 1, 52 (Mo. 1986).
[6] Id.

prudent investor rule in investing the permanent funds under its control.[7] The statute provides that:

> [t]he 'prudent investor rule' means that in making investments the board shall exercise the same judgment and care, under the circumstances then prevailing and limitations of North Dakota and federal law, that an institutional investor of ordinary prudence, discretion, and intelligence exercises in the management of large investments entrusted to it, not in regard to speculation but in regard to the permanent disposition of funds, considering probable safety of capital as well as probable income.

The prudency requirements that apply to a public utility with regard to the investment of capital for the construction of a generating facility are generally similar to the "prudent investor rule defined in Section 15-03-04. A public utility must exercise the same judgment, discretion and care that a reasonable person would exercise under the circumstances prevailing at the time the decision is made.

II. Environmental Externality Values.

North Dakota Century Code Section 49-02-23 prohibits the Commission Commission from considering environmental externality values in the planning, selection, or acquisition of electric resources. Section 49-02-23 provides:

> The commission may not use, require the use of, or allow electric utilities to use the environmental externality values in the planning, selection, or acquisition of electric resources or the setting of rates for providing electric service. Environmental externality values are numerical costs or quantified values that are assigned to represent either:
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> 1. Environmental costs that are not internalized in the cost of production or the market price of electricity from a particular electric resource; or
> 2. The alleged costs of complying with future environmental laws or regulations that have not yet been enacted.

[7] N.D.C.C. §15-03-04.

North Dakota Century Code Section 49-02-23(1) identifies as environmental externality values environmental costs that are not internalized in the cost of production or market price of electricity from a particular electric resource, and Section 49-02-23(2) identifies as environmental externality values "[t]he alleged costs of complying with future environmental laws or regulations that have not yet been enacted." Section 49-02-23 applies to this proceeding because this proceeding involves the advance determination of prudence of the construction of an electric generation resource.

The prohibition contained in Section 49-02-23 does not preclude consideration of other evidence concerning environmental issues that may be brought before the Commission. The statute only prohibits the consideration of environmental externality values.

The Intervenors' argued in opposition to the Motion *In Limine* filed by OTP and MDU that the costs related to CO_2 regulation are no longer externalities, but a pollutant regulated by the Environmental Protection Agency ("EPA") under the Clean Air Act, subsequent to a decision of the United States Supreme Court issued on April 2, 2007 in *Massachusetts v. Environmental Protection Agency,* No. 05-1120, slip op at 26-30 (2007). That case involved a rulemaking petition to the EPA asking the EPA to regulate greenhouse gas emissions from new motor vehicles under section 202 of the Clean Air Act. Following EPA's denial of the petition, the petitioners appealed to the United States Court of Appeals for the District of Columbia Circuit which affirmed the EPA's decision. The Supreme Court reversed the judgment of the Court of Appeals and remanded the case to the EPA for further proceedings consistent with the Court's opinion.

Whether CO_2 is treated as a pollutant or an externality at the federal level is not controlling on whether or not the North Dakota Public Service Commission should exclude evidence relating to environmental externality values in this proceeding. North Dakota Century Code Section 49-02-23 defines environmental externality values as "numerical costs or quantified values that are assigned to represent *either*: 1. Environmental costs that are not internalized in the cost of production or the market price of electricity from a particular electric resource; or 2. *The alleged costs of complying with future environmental laws or regulations that have not yet been enacted*." (Emphasis added). The Motion filed by OTP and MDU was to exclude evidence related to a monetized CO_2 value based on the prohibition contained in Section 49-02-23(2). The *Massachusetts v. Environmental Protection Agency* case resulted in a remand to the EPA. Presumably, the EPA will initiate a rulemaking which may or may not include CO_2 emissions from power plants, and may or may not establish values on CO_2 emissions. Any action that might be taken by the EPA in its rulemaking relating to CO_2 penalties is a future cost of complying with environmental regulations that have not yet been enacted. The Commission is prohibited from using evidence relating to estimates of such penalties or values under Section 49-02-23(2).

The Administrative Law Judge ("ALJ") issued an Order Granting Motion in Limine ordering "that no party shall offer for the consolidated hearings of these cases any evidence of 'environmental externality values' as defined and prohibited by the provisions of N.D.C.C. §49-02-23." The ALJ subsequently issued an Order Upon Motion to Strike clarifying "that N.D.C.C. §49-02-23 specifically and only prohibits 'environmental externality values' as numerical costs or quantified values that are assigned to represent the alleged costs of complying with future environmental laws or regulations that have not yet been enacted."

North Dakota Century Code Section 49-06-24 provides that "[t]he Commission may not increase electric rates as a result of actions taken by other states requiring higher cost resources to be built, purchased or otherwise acquired as a result of the application of quantified environmental externalities as defined in Section 49-02-23, as part of any resource selection process. The environmental externality values that are at issue in this proceeding involve the potential for CO_2 values being imposed by the EPA. If at some point the EPA does assign values for CO_2 emissions, those costs can be recovered from ratepayers under House Bill No. 1221 passed by the 2007 Legislature.

III. Cost Apportionment Between States.

There were questions posed during the hearing regarding the possible determination of need for the generating facility and costs apportionment between the respective state jurisdictions based upon the projected increased demand for electricity of each individual state.

Historically, the Commission has treated generating plants as part of an integrated system across all state jurisdictions served by a utility. The Commission has allocated costs between state jurisdictions in rate case proceedings based on load characteristics such as 12 coincident peak or peak and average, etc. The jurisdictional allocation factors are developed and used during a rate case to produce future test year revenue requirements to reflect projected load growth for the test year in the jurisdictional allocations and the test year revenue requirement. The Commission then determines jurisdictional allocations in the rate case decision. Advocacy staff believes that is the proper forum for determining appropriate jurisdictional allocations of Big Stone Unit II costs.

The Wyoming Public Service Commission recently addressed apportionment of generating plant costs of a multi-state integrated utility involving peaking plant located in Utah that Intervenors argued should be removed from rates because they were not used and useful for serving Wyoming customers.[8] In its decision, the Wyoming Commission stated:

> We will respect the interjurisdictional allocations process which we and PacifiCorp's other jurisdictions are now actively seeking to reform and improve; and we view the removal of these plants from this case as a step in the wrong direction which would add uncertainty to an already complicated and delicate process. Wyoming does derive benefit from the pooling of resources and the operation of PacifiCorp's generation fleet as part of an integrated system.[9]

Like PacifiCorp, MDU and OPT are integrated utilities operating in multiple jurisdictions. North Dakota derives benefit from the pooling of resources and the operation of generation fleet as part of an integrated system. North Dakota consumers would likely face substantially increased rates for electricity if MDU and OTP were required to have generation facilities to serve only their North Dakota ratepayers.

EVIDENCE AND ARGUMENT ON THE ISSUES

The Notice of Hearing indentified the issues to be considered in these cases as follows:

1. Whether the resource addition is reasonable and prudent.
2. Whether the applicants have need for additional generating resources.
3. What alternatives exist for meeting additional generation needs.

[8] Re PacifiCorp, 224 PUR4th 1 (2003).
[9] Id. at 59

For purposes of briefing, the issues will be addressed in the following order:

1. Whether the applicants have need for additional generating resources.
2. What alternatives exist for meeting additional generation needs.
3. Whether the resource addition is reasonable and prudent.

I. Whether the Applicants have need for Additional Generating Resources.

Bruce Imsdahl, President and CEO of Montana-Dakota Utilities Co., testified that Montana-Dakota and six other utilities, Otter Tail Power Company, Great River Energy, Western Minnesota Municipal Power Agency, Central Minnesota Municipal Power Agency, Southern Minnesota Municipal Power Agency, and Heartland Consumers Power District propose to build the 630 MW Big Stone Unit II generating facility.[10] He stated that MDU chose to participate in the Big Stone Unit II project to acquire energy and capacity to replace the loss of a 66.4 MW contract with Basin Electric Power Cooperative ("Basin") from the Antelope Valley Unit II and to be able to continue to reliably and economically meet the growing energy and capacity needs of MDU's electric customers.[11]

MDU witness, Andrea Stomberg testified that MDU's participation and ownership interest of 19.33% of Big Stone Unit II represents an addition of 116 MWs to MDU's accredited capacity resources.[12] She stated that MDU has contracted with Northern States Power Company for summer capacity of 85 MW in 2007, 90 MW in 2008, 95 MW on 2009, and 100 MW in 2010, with an option to extend to 2011 under the current price and to extend to 2012 under a renegotiated rate.[13] She also testified that until the Big

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[10] Bruce Imsdahl Direct Testimony (DT) at 4.
[11] Id. at 5.
[12] Andrea Stomberg DT at 2.
[13] Id. at 3.

Stone Unit II plant is constructed, energy will be purchased from the Midwest ISO market as needed. She added that based on MDU's experience over a period of time, the Midwest ISO market prices for energy have varied greatly, and did exceed $100/MWh on occasion.[14]

MDU witness, Duane Steen reaffirmed that the primary cause for MDU's need for energy and capacity was the loss of the 66.4 MW baseload power purchase agreement with Basin.[15] He stated that through the Integrated Resource Planning (IRP) process, which encompasses MDU's long-range forecast for the demand for electric power and energy and an analysis of cost effective demand-side resources available to offset the need, MDU determined that an additional baseload power supply was the best option for meeting future power supply and energy requirements.[16] Exhibit MDU 205 attached to Steen's testimony is a load and capability comparison showing a summer peak deficit of 77.5 MW in 2007 and increasing to 107.4 MW in 2012, 113.4 MW in 2013, and 119.4 MW in 2014.

Ward Uggerud, Senior Vice President for OTP, testified that OTP's electrical consumption is growing at approximately 2.4% per year, and that regional consumption is growing at over 2% per year. He stated that OTP and the other Co-owners of Big Stone Unit II predict a capacity deficit in the region by 2011.[17]

OTP witness, Bryan Morlock, testified that OTP's energy requirements are forecast to increase steadily from approximately 4,000,000 MWh in 2005 to approximately 5,100,000 MWh in 2014, and OTP's capacity needs show summer

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[14] Id. at 9.
[15] Duane Steen DT at 2.
[16] Id.
[17] Ward Uggerud DT at 7.

season capacity deficits beginning in 2007 at 15 MW and increasing to 193 MW by 2014.[18]

There are differences of opinion on how to meet the forecasted needs, but no one disagreed with MDU's or OTP's forecasts.

II. What Alternatives exist for meeting Additional Generation Needs.

OTP witness, Ward Uggerud, testified that OTP decided to pursue construction of a supercritical pulverized coal plant at the Big Stone site as a joint project with several other utility providers because of the proposed plant's low busbar cost and high reliability.[19] He said that coal was the most economical form of generation available.[20]

Uggerud testified that before committing to the Big Stone Unit II plant, OTP performed detailed analysis of other ways to generate electricity. OTP looked at renewable energy sources (particularly wind), demand-side management, distributed generation, and integrated gasification combined cycle, and others.[21] He stated that optimum resource expansion usually includes a mix of resources. He emphasized that Big Stone Unit II is not the only resource expansion being contemplated by OTP and that OTP is also planning for additional demand side management ("DSM"), additional wind, renewal of a hydro purchase agreement, and additional peaking capacity.[22]

Uggerud stated that OTP's planning process for the current project concluded that other types of generation, such as natural gas and renewable or some combination

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[18] Bryan Morlock DT at 2-3.
[19] Ward Uggerud DT at 7.
[20] Id. at 9.
[21] Id. at 5.
[22] Id. at 9-10.

thereof, were not appropriate means of producing the amount of baseload power needed.[23]

A natural gas plant was rejected because of gas supply, cost of gas, fluctuation in gas prices, and because there is no natural gas pipeline in the area.[24] He stated that OTP believes that using natural gas to satisfy a baseload need is imprudent energy policy for these utilities and for the country in general.[25]

Uggerud stated that wind currently is a part of OTP's energy portfolio, and will be an increasing part in the future. However, in evaluating wind for the current needs, OTP's analysis showed that a large-scale wind project would need to be backed up by some measure of firm resource, most likely natural gas. The Big Stone Unit II Co-owners respective resource plans and planning efforts did not show that wind was least cost to serve as a baseload facility.[26]

Uggerud stated that integrated gasification combined cycle ("IGCC") holds potential for future development, but presently the capital costs of an IGCC plant are higher than the proposed Big Stone Unit II plant. He said that most of the IGCC plants being proposed are by large electric utility systems. He added that small utilities that do not have government support could not accept the technological risk and higher cost that an IGCC plant would entail.[27]

Uggerud testified that OTP did take into account the possibility of enacting additional DSM efforts to reduce energy demand. He said that while OTP will continue its efforts to promote energy conservation and load management, OTP cannot count on

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[23] Id. at 11.
[24] Id.
[25] Id. at 9.
[26] Id. at 10.
[27] Id. at 11.

DSM reductions beyond what have already been taken into account in OTP's modeling efforts.[28]

Uggerud stated that OTP did not seriously consider building a nuclear plant. He said that no new nuclear plants have been built in the United States for approximately 30 years, and there is ongoing uncertainty over disposal of spent nuclear fuel.[29]

Uggerud testified that OTP and the other Co-owners joined together to benefit from the economies of scale available at Big Stone Unit II, add diversity to their energy mix, and reduce risks of power outages. The Big Stone Unit II plant is a baseload facility that utilizes proven technology with the latest pollution control technology.[30] He said that the Big Stone site was chosen because it takes advantage of existing infrastructure, including railroad lines, coal-handling facilities, and water supply, and it is located within and close to the Co-owners' service areas.[31]

Uggerud testified on rebuttal that Big Stone Unit II will not address all the anticipated needs of the Co-owners, and that OTP is going to need additional generation resources within the near future, as are the other Co-owners. He stated that the Coyote site in North Dakota remains a viable place for future generation expansion.[32] Uggerud stated that Big Stone Unit II will enhance development of generation resources in North Dakota because it will expand the transmission grid to help alleviate the North Dakota export constraint. The Big Stone Unit II plant will also

[28] Id. at 12.
[29] Id. at 12-13.
[30] Id. at 13.
[31] Id. at 14.
[32] Ward Uggerud Rebuttal Testimony (RT) at 6.

assist in the future development in North Dakota because of the air pollution control equipment that will be installed on both Units I and II.[33]

OTP witness, Bryan Morlock, testified that OTP uses the IRP-Manager software tool to develop a series of optimized resource plans. Available supply-side and demand-side alternatives are input into the model and the model is executed to select the optimized resource plan for the given scenario. The IRP-Manager uses an iterative cost-effective module (ICEM) to evaluate each alternative one at a time to determine if implementing the alternative would result in reduced costs, thereby demonstrating cost-effectiveness.[34]

Morlock testified that Big Stone Unit II was selected as part of a least cost resource plan for OTP's customers. He stated that approximately 13% or more of the capacity needs in the resource plan are identified as coming from conservation and DSM efforts.[35] He said that the resource plan also includes the implementation of 67 MW of conservation and DSM, 135 MW of natural gas-fired peaking facilities, 160 MW of additional wind generation, a 50 MW purchase from Manitoba Hydro, and potentially 88 MW or more of a coal-fired integrated gasification combined cycle facility about 2018.[36]

MDU witness, Andrea Stomberg, testified that MDU, through its Integrated Resource Planning process (IRP) identified the need for new baseload generator capacity in 2011 and beyond.[37] She stated that MDU believes the Big Stone Unit II project is the best alternative, both financially and operationally, to meet MDU's need for

[33] Id. at 6.
[34] Brian Morlock DT at 4.
[35] Id. at 10.
[36] Id. at 11-12.
[37] Andrea Stomberg DT at 2.

capacity and energy.[38] As noted previously, the primary driver for MDU's interest in a baseload resource was the expiration of the power purchase agreement with Basin.

Stomberg stated that the capacity expansion model presented in the 2003 IRP suggested that the least cost resource to replace the Basin contract would be gas-fired combustion turbines. Modeling results were rejected by MDU because energy produced by these resources is subject to wide swings in the cost of natural gas. MDU was also concerned about the long term availability of natural gas as a generation fuel.[39]

Stomberg testified that MDU's 2005 IRP reflected the decision to explore coal baseload options. The document also presented several DSM programs.[40] Subsequent to the filing of the 2005 IRP, MDU performed capacity expansion modeling to determine if the Big Stone Unit II addition was the best resource addition for MDU and its customers.[41] Stomberg stated that the addition of Big Stone Unit II for meeting the next resource requirement results in the lowest long-term utility costs among the alternatives of lignite coal fire plants, an IGCC plant, natural gas combined cycle and single cycle plants, wind resources and DSM resources.[42]

Stomberg testified that MDU has launched DSM programs identified in the 2005 IRP including an Energy Star Partnership in May 2006, a program promoting high-efficiency residential air conditioning in May 2006, and the promotion of commercial lighting retrofits in November 2006. These programs are estimated to provide a demand

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[38] Id.
[39] Id. at 6.
[40] Id. at 7.
[41] Id.
[42] Id. at 7-8.

reduction of 6.5 MW.[43] MDU is also investigating the introduction of an air conditioning cycling program for residential and commercial customers. The air conditioning cycling along with 5-10 MW of available conservation were included as resource options in the modeling.[44]

MDU witness, Duane Steen, explained the Request for Proposal ("RFP") process that MDU undertook to investigate new baseload resources and responses to those proposals. MDU issued an RFP in 2004, which resulted in three proposals, only one of which was a qualified bid. MDU rejected the one qualified bid because it offered only a small portion of the needed capacity.[45] In 2006, MDU issued another RFP for baseload coal capacity from which two proposals were received. One proposal was for the a purchase power agreement for the entire output of a Greenfield 254 MW natural gas fired combined cycle plant to be constructed within MDU's service area, and the other proposal was for 120-170 MW from a 750 MW coal-fired plant to be constructed in Iowa.[46] MDU rejected the first proposal because the proposal is for far more capacity than was requested or is needed, and because the resource would result in a resource mix overly dependent on natural gas.[47] MDU is still investigating the second proposal as a possibility for meeting resource needs beyond Big Stone Unit II.

MDU also investigated other generation alternatives under the Lignite Vision 21 Program. MDU studied the feasibility of constructing a 500 MW, a 250 MW or a 175 MW plant at Gascoyne, North Dakota. MDU could not find an entity to take the excess generation for the 500 or 250 MW plants. MDU reviewed its requirements and

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[43] Id. at 8.
[44] Id.
[45] Duane Steen DT at 3.
[46] Id. at 4.
[47] Id.

determined that in order to capture some economies of scale, a 175 MW unit should be investigated.[48]

Steen stated that late in 2004, MDU was invited to participate in the Big Stone Unit II studies. He said the Big Stone Unit II Unit offers advantages over Gascoyne. Big Stone Unit II is an existing power plant site which allows common use of a number of plant systems which include using the existing unit train coal unloading facilities, water treatment, roads, mobile equipment, control room, operators and maintenance employees and a fuel oil system. He stated that all of these items reduce the capital as well as operating cost of Big Stone Unit II compared to a Gascoyne unit. The cost differences led MDU to its decision that Big Stone Unit II is a better option for its customers. [49]

Steen testified that in May 2006, MDU requested PA Consulting Group, Inc. ("PA") to perform a capacity expansion modeling analysis to help evaluate an overall optimal resource plan for MDU. The results of the analysis determined that MDU's participation in the Big Stone Unit II plant would yield the lowest-cost baseload resource expansion option, and it remains the lowest cost option notwithstanding recent cost increases for the project.[50] He said the analysis also confirms MDU's plan to use DSM, renewable energy sources and other resources along with Big Stone Unit II as part of a diverse mix for MDU's customers.[51]

MDU witness, James Heidell, a managing consultant at PA Consulting Group, Inc., testified that the purpose of the base case resource expansion analysis was to

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[48] Id. at 6-7.
[49] Id. at 7-8.
[50] Id. at 8.
[51] Id.

determine the least cost expansion option. The least cost option is based upon the base case load forecast provided by MDU in conjunction with PA's assumptions about resource expansion options and future fuel costs. The study was performed using the Strategist optimization model.[52]

Heidell explained that PA's analysis was based upon a twenty-year time horizon (2006-2025). The analysis considered "end effects." He said that "end effects" account for the value of resources past the end of the study period and are used to ensure that the answer is not biased away from long-lived assets that retain significant value past the end of the study period.[53]

Heidell testified that the study concluded that the lowest-cost system expansion option is to add Big Stone Unit II in 2011 and add combustion turbines in 2014 and 2021.[54] He stated that PA also developed two alternative expansion plans where 1) additional DSM resources are forced in to the utility system in 2011, and 2) additional wind is forced in 2015. He said that both of these alternative plans result in minimal increases in total utility costs over the study period.[55]

Mark Rolfes testified as a witness for both OTP and MDU. He stated that the Big Stone Unit II Co-owners evaluated several different alternative generation technologies before selecting Big Stone Unit II.[56] The Co-owners initially identified 38 potential sites and narrowed the selection to six sites. The six sites included Big Stone located in Grant County, South Dakota, Coyote located in Mercer County, North Dakota, Dickinson located in Wright County, Minnesota, Fargo, located in Cass County, North

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[52] James Heidell DT at 2.
[53] Id. at 3.
[54] Id. at 4.
[55] Id.
[56] Mark Rolfes DT at 2.

Dakota, Glenham located in Walworth County, South Dakota, and Utica Junction located in Yankton County, South Dakota.[57]

Rolfes stated that each of the six sites was evaluated for criteria including water supply, fuel lines, and transmission, which were each given a weight of 20%, environmental issues and air quality were each given 15% and other factors such as highway access were given 10%. He stated that Big Stone received the highest score.[58] Rolfes stated that the advantages of the Big Stone site are numerous, and that most of them are due to existing infrastructure.

Rolfes testified that the Co-owners considered hydro, wind, solar, geothermal and biomass as possible means of generating power. He stated that the Co-owners wanted to make sure that any generation alternative would be able to satisfy three basic objectives for a baseload generation unit: 1) the technology must be applicable; 2) the facility must be available for service when needed; and 3) the facility should enhance the overall reliability of the bulk electric system.[59] The Co-owners determined that several renewable alternatives did not meet the three basic objectives and were not feasible as a source of 600 MW of baseload generation. Included in that category were hydro, solar, geothermal energy, landfill gas, fuel cells, microturbines, and wind.[60]

Rolfes stated that after the Co-owners individually determined that they needed baseload energy, and that Big Stone Unit II was a fit for their needs, they wanted to verify their separate conclusions. The Co-owners hired Burns & McDonnell to evaluate in detail several generation alternatives including a wind plus combined cycle natural

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[57] Id. at 6.
[58] Id. at 7.
[59] Id. at 13.
[60] Id. at 14.

gas combination, an integrated coal gasification combined cycle option, and 100% biomass option. The biomass option was for only 50 MW. Rolfes stated that the analysis showed that a pulverized coal plant was the lowest cost option per unit of the alternatives examined.[61] He said that the Co-owners best estimate, is that a pulverized coal plant like Big Stone Unit II is the most economical technology to address their resource needs.[62]

Advocacy staff witness, Terry Deason, testified that Big Stone Unit II, as proposed, is a 630 MW supercritical pulverized coal unit using state of the art technologies for both its thermal generation and pollution control systems. He said that supercritical technology employs higher operating pressures providing increased efficiencies, which result in greater fuel economy and reduced emissions. He stated that supercritical technology appears to be the technology of choice for large (greater than 500 MWs) baseload generating units.[63]

Deason stated that there are common steps utilized by most utilities to determine there is a need for new generation capacity. The first step is developing an IRP to project future demand. After determining future demand, it is important to evaluate existing generating resources along with future resources (both demand side and supply side) to meet the demand. The goal is to achieve an optimal mix of demand and supply side resources to meet future demand with a reasonable reserve margin.[64] The

[61] Id. at 14-15.
[62] Id. at 17.
[63] Terry Deason DT at 4.
[64] Id. at 5.

last step is the issuance of RFPs for the desired resource.[65] Deason confirmed that both MDU and OTP utilized these common steps in their evaluation process.[66]

Deason stated that the Coyote Station was one of the sites evaluated. He said that it received a score of 339.6, but was eliminated because of serious flaws concerning air quality and transmission issues. He said that Big Stone was selected as the preferred site with a numerical score of 397.7. The preferred alternate site was Utica junction with a score of 383.3.[67]

Deason was critical of the failure of the site evaluation to properly credit Coyote as the only site with the potential for fuel delivery competition.[68]

Deason was also critical of some of the scores and consideration given to the Coyote Station in the site evaluation process. He said that three specific scores merit further consideration. The three scores were for 1) potential airspace restrictions, 2) surface water proximity, and 3) highway access.[69] Deason recalculated the scores because consideration was not given for the fact that Coyote is a brownfield site, located south of the Beulah airport, which has an east-west oriented runway. The site has an existing water pipeline with adequate water supply, and highway access to Interstate 94 is only 25 miles by State Highway 49.[70] With Deason's recalculation, Coyote attained the second highest score of 385.1. He stated that giving equal weight

[65] Id.
[66] Id. at 5-6.
[67] Id. at 6.
[68] Id. at 7-9.
[69] Id. at 9-10.
[70] Id. at 9-10

to rail/mine proximity and fuel delivery competition would reduce Big Stone Unit II's advantage over Coyote to less than 5 points.[71]

Deason stated that his conclusions show that Coyote should remain a viable candidate for future generation plans, but did acknowledge that Coyote has serious issues with proximity to Class I PSD areas as well as serious transmission concerns. He said that the allowable increments are not stagnant and can be affected by changes at other source emitters and changes in pollution control technology. He stated further that if Big Stone Unit II is built along with its transmission infrastructure, the existing transmission constraints for Coyote may be substantially mitigated.[72]

Deason testified that the Revised Burns & McDonnell Report narrowed the focus to three alternatives: 1) 630 MW Supercritical Pulverized Coal (Big Stone II); 2) 500 MW Natural Gas Fired Combined Cycle Gas Turbine ("CCGT"); and 3) 500 MW CCGT plus wind. The report shows Big Stone Unit II is the clear winner on a busbar cost basis.[73]

Deason noted some inconsistencies between analyses prepared for OTP and MDU as well as concerns about coal supply and delivery, and made recommendations concerning those matters. In the end, he stated that he doubted the ambiguities and inconsistencies would change the conclusion of the revised busbar analysis that Big Stone Unit II is the lowest cost alternative.[74]

David Schlissel, a witness for the Intervenors Mark Trechock and Dakota Resource Council ("DRC") or ("Intervenors"), is a Senior Consultant at Synapse Energy Economics, Inc. ("Synapse"). He stated that Synapse was retained by DRC to review

[71] Id. at 10.
[72] Id. at 11.
[73] Id. at 13.
[74] Id. at 47.

the applications and supporting testimony and exhibits submitted by OTP and MDU and to evaluate whether the participation of the companies in Big Stone Unit II is prudent.[75]

Schlissel concluded that: 1) OTP and MDU have not adequately considered the risks associated with building the Big Stone Unit II plant; 2) significant uncertainties and risks associated with the Big Stone Unit II project are the potential for further increases in the project's cost increases in the project's capital cost, the potential for fuel supply disruptions, and future restrictions on CO_2 emissions; 3) it would be imprudent for the companies to continue their participation in the Big Stone Unit II project without taking into consideration expected federal regulation of greenhouse gas emissions or by merely using a single set of very low CO_2 prices in such analyses; 4) OTP and MDU have not shown that the demand for electricity cannot be met more cost effectively through alternatives, including renewable energy resources, energy conservation and load management measures; and 5) the economic and modeling analyses prepared by OPT and MDU are biased in favor of the Big Stone Unit II project.[76]

Some of the issues Schlissel discusses are legitimate concerns that pose risks that the Commission needs to consider in its decision. The potential for further increases in the capital costs of the project are real and have been acknowledged by OTP and MDU. Any delays in the construction of the plant add to the costs. The fuel delivery situation is certainly a concern that needs to be carefully scrutinized by the Commission.

[75] David A. Schlissel DT at 1-2.
[76] Id. at 3.

Schlissel states that greenhouse gas is a big issue in all of the studies he prepared.[77] With regard to CO_2 emissions, Schlissel contends that the companies should use a range of possible CO_2 prices such as the ones in the forecasts presented by Synapse. However, consideration by the Commission of the potential future cost of CO_2 emissions is prohibited under North Dakota Century Code Section 49-02-23. Schlissel did not propose any alternatives to the Big Stone Unit II project.[78]

MDU and OTP did explore the use of renewable resources and DSM in their models. While the results can be questioned, both MDU and OTP have conducted studies which considered various alternatives to the construction of Big Stone Unit II, and their analyses concludes that Big Stone Unit II is the lowest cost alternative.

III. Whether the Resource Addition is Reasonable and Prudent.

As previously noted, prudency requires that a public utility must exercise the same judgment, discretion, and care that a reasonable person would exercise under the circumstances prevailing at the time the decision is made. In order to determine whether the resource addition is reasonable and prudent, the Commission must determine whether MDU and OTP used due diligence in addressing all relevant factors and information known to them or available to them at the time they made their determination that Big Stone Unit II was the best and most cost effective choice for meeting the energy and capacity needs of their customers.

The areas of primary concern include cost and cost escalation, coal delivery, environmental issues, conservation and DSM, and transmission.

[77] TR at 475.
[78] TR at 467-468.

Cost and Cost Escalation.

Mark Rolfes, a witness for both OTP and MDU, testified that the estimated cost for the Big Stone Unit II plant, not including transmission, is 1.442 billion dollars corresponding to a 2012 commercial operation date. He stated that a cost estimate done in 2006, based on a 2011 in-service date, was 1.361 billion dollars. He believes inflation will cause the price to raise approximately six percent per year.[79] Rolfes stated that the actual commercial operation date is dependent on when permitting is complete. If permitting is completed in 2007 as anticipated, the companies expect to have commercial operation in mid 2012.

Kermit Trout, Jr., Vice President-Senior Project Manager for Black & Veach Corporation, testified that factors that impact the estimated costs for Big Stone Unit II will impact all types of generating plants.[80]

Jeffrey Greig, General Manager of Business and Technology Services for Burns & McDonnell, testified on behalf of MDU and OTP. He stated that Burns & McDonnell was hired by the Big Stone Co-owners to evaluate the economies of various baseload generation technologies. Burns & McDonnell determined that a supercritical pulverized coal plant like Big Stone Unit II represented the lowest cost baseload generation technology for all of the Co-owners.[81] In October 2006 a subsequent report was prepared with updated costs to determine the busbar costs for three different baseload generation options which included a 630 MW Big Stone Unit II, a 500 MW combined cycle gas turbine and a 500 MW combination CCGT plus market purchases of wind

[79] TR at 106-107.
[80] Kermit Trout RT at 2.
[81] Jeffrey Greig RT at 3.

energy. The updated analysis demonstrated that the Big Stone Unit II supercritical pulverized coal plant has the lowest busbar costs on a $/MWh basis of the three options.[82]

Advocacy Staff witness, Terry Deason, testified that he reviewed all of the reports prepared by PA Consulting Corporation prepared for MDU and testified to by James Heidell, and the reports prepared by Burns & McDonnell. He stated that all of the reports are quite comprehensive and involve intricate modeling with forecasted assumptions and corresponding economic and engineering inputs. He stated that the Burns & McDonnell reports also contain sensitivity analysis including high and low cases for fuel costs and capital costs. He stated that he placed greater emphasis on the Burns & McDonnell report because it contains more current and more specific information relevant to Big Stone Unit II.[83]

Deason stated that the Burns & McDonnell report comparing the three alternatives shows that Big Stone Unit II is the clear winner on a busbar cost basis with little difference between the busbar costs for CCGT and CCGT plus wind. He said that the cost advantage shrinks substantially as sensitivities are run regarding the Wind Production Tax Credit ("PTC") and a carbon dioxide environmental cost value.[84] Deason stated that the busbar analysis is generally a good tool, but must be tempered with other policy concerns and strategic considerations.[85] He said that different inputs have a meaningful impact of the revised busbar analysis, and he categorized them as

[82] Id.
[83] Terry Deason DT at 12.
[84] Id. at 13.
[85] Id. at 14.

wind inputs, construction inputs, operating inputs, fuel inputs, financial inputs and other assumptions.[86]

For the wind input, Deason noted that new wind farm costs were estimated by Burns & McDonnell at $40/MWh in 2006 including the PTC, and with escalation at 2.5% per year the cost is $46.39/MWh in 2012. He stated that the impact of the PTC should be $20/MWh or higher resulting in the cost of wind at $66/MWh without the PTC. Burns & McDonnell reduced the figure to $60/MWh for use in the busbar analysis.[87] Deason pointed out that there are inconsistencies between the Burns & McDonnell report and the PA report regarding wind costs as well as the capacity factor for wind.[88]

Deason testified that the most significant construction related input is the estimated capital cost expressed in $/KW. In the original busbar cost analysis, the capital cost for Big Stone Unit II was estimated to be $1,800/KW in 2011. The revised busbar analysis is $2,168/KW in 2012.[89] He then stated that Mark Rolfes indicated in conversation that capital costs would need to be increased by 6.5% (13 months at 6% per annum) to reflect a later in service date.[90] In his rebuttal testimony, Mark Rolfes testified that the best estimate for Big Stone Unit II is $1.361 billion if the in service date is 2011. He then stated that the companies expect that the in service date will be delayed at least one year, increasing the cost of the plant by 6%. He added that if the in service date is delayed further, the companies expect the costs to go up approximately $7 million per month.[91] Rolfes then added that if permitting is completed in 2007, the

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[86] Id.
[87] Id.
[88] Id. at 15-16.
[89] Id. at 16.
[90] Id. at 17.
[91] Mark Rolfes RT at 5.

companies expect to have commercial operation in mid-2012.[92] Rolfes testified at the hearing that if the cost analysis had to be updated to reflect a later in service date that the impact would not be material enough to change the conclusion that Big Stone Unit II is the lowest cost alternative because the competing projects would most likely experience the same type and amount of cost escalation.[93] Rolfes stated that a construction timetable of 48 months is achievable, but is slightly optimistic.[94]

Deason stated that the two operating inputs that materially impact busbar analysis are capacity factor and heat rate.[95] He stated that the original busbar cost analysis shows capacity factor to have an extremely large impact on Big Stone Unit II's resulting busbar cost, second only to capital cost. He stated that for purposes of the analysis an overall capacity factor of 88% was assumed. Deason believes the 88% capacity factor is a conservative assumption.[96] Mark Rolfes agreed with Deason and stated that the units should be able to do 90 or 92 percent reliably.[97]

Deason stated that the heat rate is a measure of the thermal efficiency of the plant – the lower the heat rate value, the greater the efficiency. Deason states that the heat rate of 9,095 for the revised busbar analysis is a conservative value in that Rolfes indicated the current projected heat rate for Big Stone Unit II is 8,988 BTU/KWh.[98]

Deason testified that for the fuel inputs, the revised busbar analysis escalates Powder River Basin (PRB) coal deliveries at 2.9% per year whereas Heidell used 2.5%

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[92] Id.
[93] TR at 123-124.
[94] Id. at 124.
[95] Terry Deason DT at 18.
[96] Id. at 18-19.
[97] TR at 125.
[98] Terry Deason DT at 19.

in his analysis. Deason believes the overall adjustment is justified considering the uncertainty of future transportation costs for PRB coal.[99]

Deason stated that it is difficult to predict the price of natural gas, and that it can be the single most important factor in justifying the relatively high capital cost of a solid fuel generating plant like Big Stone Unit II. He noted that Heidell's forecast was consistently lower than Burns & McDonnell.[100] Jeffrey Greig testified that he did not find any serious inconsistencies between Burns & McDonnell's work and Mr. Heidell's work.[101] Greig stressed the fact that both reach the same conclusion under different forecasts for projections of future cost assumptions.[102]

Deason states there are three major categories of financial inputs that materially impact busbar cost analysis: 1) cost of capital; 2) forecasted lives; and 3) tax considerations.[103] The assumptions in the revised busbar analysis are 7.5% interest rate on debt, 12% cost of equity capital, and an overall cost of capital of 9.75%. The analysis is based on a 20 year economic model analysis and assumes a book life of 30 years. Deason agreed with the financial inputs for modeling for busbar cost estimate purposes.[104]

Deason stated that two other assumptions merit discussion. The first is the use of multiple contracts for construction of Big Stone Unit II with Black & Veatch acting as construction manager. Deason states this should allow for more control and more

[99] Id.
[100] Id. at 20.
[101] Jeffrey Greig RT at 3-4.
[102] TR at 180.

[103] Deason DT at 21.
[104] Id. at 22-25.

competition from vendors resulting in lower cost.[105] The second is that the busbar cost analysis assumes no gypsum sales from Big Stone Unit II. He states that in reality there should be some sales resulting in revenue to help offset some of the costs.[106]

Coal Delivery.

Ward Uggerud acknowledged that the Big Stone site has access to only the BNSF Railroad for delivery of coal, and that the existing Big Stone plant had to curtail operations in 2006 because of delivery problems.[107] He stated that with the addition of Big Stone Unit II, coal requirements will more than double.[108] The cost of transportation is more than half the cost of coal.[109]

Robert Brautovich, Assistant Vice President Coal Marketing West for BNSF Railway Company, testified regarding the delivery of coal for the proposed Big Stone Unit II plant. He stated that from 1990 through 2005 PRB coal production increased by over 200 million tons per year, and that BNSF is expecting a 20 million ton increase this year.[110]

Brautovich acknowledged BNSF's coal delivery problems in 2005 and 2006. He said the problems resulted from derailments caused by an early thaw, unusually heavy rainfall in the spring of 2005, and a program to mitigate a track ballast fouling situation in 2005.[111] Brautovich explained the increased expenditures BNSF has been making for equipment and track maintenance and upgrades to handle increased coal shipments.[112]

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[105] Id. at 25.
[106] Id.
[107] Transcript (TR) at 61-62.
[108] TR at 63.
[109] TR at 80.
[110] Robert Brautovich DT at 2-3.
[111] Id. at 4.
[112] Id. at 4-5.

Brautovich stated that he believes BNSF's planning for coal capacity expansion will meet future demand requirements. He said the Co-owners are obligated to supply a sufficient number of railcars necessary to operate the plant. BNSF has committed to provide locomotives to power an additional trainset that the Co-owners have procured.[113] Brautovich testified that BNSF and the Union Pacific are the only railroads that transport coal out of the PRB.[114]

Brautovich testified that BNSF is willing to enter into a performance guarantee that it will provide the service that it says it will provide.[115] He stated that the contracts in the past typically have had financial penalties for non-performance.[116] The penalty typically is a liquidated damage associated with the non-performance for a percentage of the transportation rate, but it would not indemnify the utility for the cost of switching to other sources of fuel or buying power on the open market.[117] Brautovich stated that the railroad could not financially support such a guarantee.[118] He agreed that it is reasonable to assume that the increased expenditures for capital projects will be incorporated into the tariffed rates.[119] Brautovich asserted that past performance by BNSF with regard to the existing Big Stone plant as the most important and primary assurance of BNSF's performance. He stated that Big Stone has been a competitive source of power for the last 30 years, and is in the lower quartile of cost of generators in a five-state area.[120]

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[113] Id. at 5-6.
[114] TR at 212.
[115] TR at 225.
[116] TR at 226.
[117] TR at 227.
[118] TR at 228.
[119] TR at 232.
[120] TR at 234.

Uggerud testified in response to a question from Commissioner Clark regarding the willingness of OTP to share in some of the risk of fuel cost escalation beyond projected levels. He stated that OTP does not want to be in a business where significant costs and the way in which the company recovers those costs are unknown to the company or poses an unacceptable business risk.[121] He stated that in order for that kind of accountability, there would need to be some control regulation over the railroad and also the same kind of control over the coal mine.[122]

Uggerud was asked a series of questions from a statement regarding coal deliveries made to members of NARUC. His responses generally were in agreement with the statements made concerning coal supply problems, operators purchasing more expensive replacement power because of curtailments resulting from the supply problems, and consumers ultimately bearing the higher costs.[123]

Terry Deason testified that the 2.9 % escalation rate for coal is appropriate. While production costs for PRB coal are generally less than for other regions, transportation costs are higher. For western sub-bituminous coal, rail transportation costs represent about 60% of the overall cost.[124] The cost of transportation for Big Stone Unit II is a critical concern because there is no competition for the service.[125]

To address potential coal delivery problems, Deason makes the following recommendations:

[121] TR at 781.
[122] Id.
[123] TR at 783-799.
[124] Deason DT at 33-34.
[125] Id. at 35.

1. Cycle times should be closely monitored. It provides an important measure of equipment utilization and gives an early indication of rail congestion and possible future shipment slowdowns;
2. There should be a forecasted schedule of train loadings for each month for each set of equipment based upon the burn requirements for each plant. The schedule should be communicated to BNSF and should be monitored to be sure it is being met. If the schedule is not met, coordinate with BNSF to rectify the problem;
3. Have a system to manage train deliveries so unloading times can be minimized; and
4. There should be a target number of cars per unit train and enough railcars to meet those targets plus maintenance spares. The actual number of cars per train should be monitored to verify that the targets are being met.[126]

Deason also recommends that light-weight aluminum cars should be utilized, if possible, and that coal inventory level should be increased to provide up to 45 days of inventory on site.[127]

Conservation and DSM.

As noted previously, Morlock testified that the resource plan includes the implementation of 67 MW of conservation and DSM, 135 MW of natural gas-fired peaking facilities, 160 MW of additional wind generation, a 50 MW purchase from

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[126] Id. at 37-38.
[127] Id. at 38-39.

Manitoba Hydro, and potentially 88 MW or more of a coal-fired integrated gasification combined cycle facility about 2018.[128]

Also, Stomberg testified that MDU has launched DSM programs identified in the 2005 IRP including an Energy Star Partnership in May 2006, a program promoting high-efficiency residential air conditioning in May 2006, and the promotion of commercial lighting retrofits in November 2006. These programs are estimated to provide a demand reduction of 6.5 MW.[129] MDU is also investigating the introduction of an air conditioning cycling program for residential and commercial customers. The air conditioning cycling along with 5-10 MW of available conservation were included as resource options in the modeling. Stomberg stated that MDU has a fairly robust DSM program looking at close to 20 MW of DSM in the foreseeable future and will continue to grow the program. She stated that MDU has recently created a position for a person to do nothing but DSM work.[130]

Environmental Issues.

Substantial time was spent discussing the implications and effects of potential CO_2 emissions regulations. As pointed out previously, North Dakota Century Code Section 49-02-23 prohibits the Commission from considering environmental externality values in the planning, selection or acquisition of electric resources.

Big Stone Unit II would provide environmental benefits. First, the Big Stone Unit II Co-owners have committed to installing a joint common wet flue gas desulfurization system that will scrub the gases of both Units I and II. This will result in a significant

[128] Morlock DT at 11-12.
[129] Stomberg DT at 8.
[130] TR at 536-537.

reduction in SO_2 emissions. Second, the Big Stone Unit II selective catalytic reduction system, together with more aggressive operation of the unit I system will result in an additional 630 MW of generation without an increase in NOx emissions. Third, the emissions control system will result in greater mercury removal. The Co-owners have committed to a site cap for mercury that will result in no net increase in mercury with the addition of the 630 MWs to the system. Last, the plant's supercritical design will result in lower CO_2 emissions.[131]

***Transmission*.**

Timothy Rogelstad testified on behalf of OTP and MDU regarding transmission requirements for the Big Stone Unit II project. He stated that the Co-owners have requested that the Minnesota PUC issue a certificate of need to construct a new transmission line between the Big Stone plant and Granite Falls, Minnesota which will be designed capable of operating at 345 kV, but which will likely initially operate at 230 kV. A 230 kV line would also be constructed between the Big Stone plant and Morris, Minnesota. That line will, for the most part, be an upgrade of the existing Big Stone to Morris 115 kV line.[132]

Rogelstad stated that the North Dakota Export (NDEX) transmission constraint is a well known transmission limit in the region.[133] He stated that a significant benefit of locating generation at Big Stone is that it is located midway between the remote generators in western North Dakota and the large load center in Minneapolis – St. Paul. As a result, Big Stone provides a stabilizing effect on the voltage in the region and as a

[131] Ward Uggerud DT at 14-15.
[132] Timothy Rogelstad DT at 11.
[133] Id. at 12.

result can actually improve the NDEX stability problems.[134] Rogelstad stated that sizing the Big Stone to Granite Falls line at 345 kV is prudent because it is part of an efficient transmission regional plan to facilitate the development of new generation resources in the region.[135] The additional cost of the line would be in the range of 25 to 30 million dollars.[136]

Deason stated that transmission upgrades for Big Stone Unit II will have a beneficial effect on the entire transmission system to transmit energy from west to east. Deason stated that with Big Stone Unit II it is estimated that an additional 500 MW of generation could be added to the system.[137]

Advocacy Staff Recommendation.

Advocacy staff recommends granting approval of OTP's and MDU's applications for advance determination of prudence. Advocacy staff witness, Terry Deason, states that if no new generation is pursued, both MDU and OTP would be subject to the prices and availability of power on the market. Reliance on the market is not a good long-term strategy.[138]

Deason states the strategic benefits of Big Stone Unit II as follows:

1. Big Stone Unit II is based on a proven, reliable and efficient technology with low emission rates.
2. It would be built on an existing brownfield site with substantial infrastructure already in place.
3. It would be owned by a group of utilities.

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[134] Id. at 14.
[135] Timothy Rogelstad RT at 6.
[136] TR at 348.
[137] Deason DT at 29-30.
[138] Id. at 45.

4. It would be dispatchable and add to the reliability of MDU's and OTP's systems, and could also act as back-up generation for future wind projects.
5. It would enhance the possibility of off-system sales.
6. It would burn domestic fuel which is in plentiful supply with relatively stable prices.
7. It would enhance the reliability of the transmission grid and increase the potential for export capabilities out of North Dakota.
8. It would have a projected life of 40 plus years which could provide substantial "end effect" benefits.[139]

Deason recommends approval of the applications subject to some potential conditions:

1. Make periodic informational filings on the progress of obtaining all necessary approvals, permits and licenses from other regulatory bodies and an indication when construction commences.
2. At or shortly prior to construction, file a forecasted budget by year for all construction related costs. Information should include the results of RFPs for all major components of the plant. There should be annual updates with an analysis of deviations between actual cost and budget projections and explanations of changes in forecasts for future years. And, if at any time the Co-owners determine that prudence, economic viability or continuation of the project is in jeopardy, there should be an immediate filing indicating the reasons for such determination.

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[139] Id. at 45-46.

3. Implement coal delivery and management measures as discussed at pages 37 and 38 of Deason's testimony. Reports should be available for periodic review by the Commission.
4. Conduct a study of the number of rail cars necessary to serve Big Stone Unit II and whether additional cars should be lightweight aluminum.
5. Require a study which calculates the costs of having a higher coal inventory level, and that cost should be compared to the cost and likelihood of curtailments from inadequate fuel deliveries.[140]

CONCLUSION

Advocacy staff's review of MDU's and OTP's analyses supports MDU's and OTP's conclusion that a baseload generating plant is needed and that Big Stone Unit II is the lowest cost alternative.

There was considerable discussion concerning increased DSM and potential for DSM mandates. Advocacy staff encourages cost effective DSM programs, and believes there may be a place for new and expanded DSM programs to alleviate some of the need for new generation resources going forward. However, Advocacy staff believes that the present need is for a baseload generation resource that will address the capacity and energy needs of OTP and MDU in 2012, and those needs cannot be adequately addressed by DSM or conservation.

Coal delivery is a major issue in these cases. The Commission may want to consider conditioning approval of the applications on approval of a satisfactory long-

[140] Id. at 47-49.

term coal delivery contract that provides performance guarantees with satisfactory penalties for non-performance.

Dated this 3rd day of August, 2007.

Respectfully submitted,

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