MDU EXHIBIT 217

CASE NOS. PU-06-481 & PU-06-482

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER CORPORATION D/B/A

OTTER TAIL POWER COMPANY

AND

MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

PREFILED REBUTTAL TESTIMONY

OF

JAMES HEIDELL

PA CONSULTING GROUP

APRIL 23, 2008

BIG STONE II

PARTNERS IN GENERATION

PREFILED REBUTTAL TESTIMONY OF JAMES HEIDELL

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I. INTRODUCTION

Q: Please state your name and business address.

A: James Heidell, 1700 Lincoln Street, Suite 4600, Denver, CO.

Q: Did you previously submit testimony in this proceeding?

A: Yes, I submitted MDU Exhibits 210-212 and Exhibits 214-215.

II. PURPOSE OF TESTIMONY

Q: What is the purpose of your supplemental testimony?

A: There are two purposes to my testimony; the first is to clarify issues regarding Montana-Dakota's modeling assumptions that were raised by Mr. Terry Deason and Mr. David Schlissel in their supplemental direct testimony in this proceeding. Second, I respond to Mr. Schlissel's characterization that the resource planning modeling conducted by Montana Dakota is flawed.

III. RESPONSE TO TERRY DEASON TESTIMONY

Q: Have you reviewed Staff Witness Mr. Deason's questions regarding some of the assumptions used in Montana-Dakota's resource planning modeling?

A: Yes. I will address the questions raised by Mr. Deason in his Supplemental Direct Testimony regarding the following:

- Assumptions regarding the renewal of the Production Tax Credit (PTC) and fixed costs,
- Cost of wind energy with and without the PTC, and its associated impacts on Montana-Dakota's expansion plan,
- Effects of a PTC extension on operational or reliability considerations,
- Capital cost assumptions for the natural gas-fired combined cycle turbine (CCGT),
- Forecast of natural gas costs,
- Income tax effects on Montana-Dakota's assumed cost of capital, and
- Cost of capital.

Q: Do you agree with Mr. Deason that the PTC can substantially reduce the cost of wind generation?

A: On a levelized cost basis, Montana-Dakota's analysis I presented in my direct testimony shows that wind energy costs approximately 22% less with the benefits of the PTC, compared to without the PTC. Montana-Dakota considered scenarios including and excluding the assumption that the PTC will be extended beyond 2008 because of this differential.

Q: Is it reasonable to assume a scenario where the production tax credit is not extended?

A: Yes. As Mr. Deason notes, the PTC was established in the Energy Policy Act of 1992 to promote the production of renewable energy resources. The PTC has been extended multiple times and there are currently efforts to extend the credit again. Therefore, our resource planning Scenarios I and II that I presented in my direct testimony from March 10, 2008 assume the credit will be extended.

However, there is also the possibility that the PTC will not be extended, which is reflected in Scenarios III and IV. The U.S. House of Representatives implemented a pay-as-you-go policy to address the issue of the growing federal deficit. Given concerns about the federal deficit and rising costs of thermal resources, extension of the PTC is not guaranteed. In any event, it is more prudent to include scenarios in which the PTC is not extended than to assume in every instance that will be extended indefinitely.

Q: Would inclusion of the PTC change the results of the analysis?

A: Scenarios I and II from my March 10 testimony assume that the PTC is extended, and in those scenarios Big Stone II is identified as part of the least-cost mix of new resources. In scenarios III and IV, I have changed multiple assumptions (described in my March 10, 2008 testimony), including the assumption that the PTC is not extended. It is not known whether including the PTC in Scenarios III and IV would change the results without performing more Strategist simulations.

In response to Mr. Deason's request that Montana-Dakota clarify whether extension of the PTC beyond four years would change the company's expansion plans, Montana-Dakota asked me to perform a Strategist simulation similar to Scenarios III and IV but this time including the PTC. The results of that simulation were not complete in time for inclusion with this testimony. However, I will submit supplemental testimony prior to the hearing with those results.

Q: If more wind resources were added to the Montana-Dakota system would that create problems on the Montana-Dakota system?

A: Based upon my review of wind integration issues, it appears that adding more wind resources than currently planned will not necessarily cause operational and reliability issues, depending on the amount of wind generation added. There are a number of issues associated with adding wind generation that need to be considered and the significance of these issues increases with the proportion of the utility's capacity that is based on intermittent wind turbines. These issues include: the cost of transmission necessary to integrate the wind into the electrical grid, the cost of ancillary services to support the wind generation, the potential need for additional quick-start resources, and potential adverse cost impacts associated with a need to back down baseload resources when not needed to provide energy to the system.

Q: Would you please clarify why Montana-Dakota used the same fixed and variable operating cost assumptions for wind generation regardless of the status of the PTC?

A: Montana-Dakota's analysis treats the PTC as an offset to the total costs of wind generation in the calculation of the levelized cost of wind energy. In other words, most of the fixed and variable operating costs do not change as a result of the existence of the tax credit. The credit serves to lower the total levelized cost as a result of the assumption that 100% of the credit can be used and is passed thru to the consumer through the reduction of the total costs.

The one exception to the PTC not impacting the operating costs is that the land use royalty payment (i.e., lease) is assumed to be 3% of revenues. Therefore, when the revenue is decreased based upon the assumption that the tax credit is passed on to the consumer through a lower power price, there is a corresponding decrease in the royalty payment. The Montana-Dakota resource modeling reflects this change in assumed royalties based upon whether the PTC is extended.

Q: Would you address Mr. Deason's observation that Otter Tail uses a cost of $674 / kW for a CCGT while Montana-Dakota uses a cost of $1,795/kW?

A: Yes. Mr. Deason suggests that the disparity between Montana-Dakota's and Otter Tail's assumed cost for a CCGT is based upon a number of factors including:

- economies of scope and scale,
- incorporation of transmission costs, and
- incorporation of Allowance for Funds Used During Construction (AFUDC).

Based upon Mr. Morlock's testimony, it is my understanding that Otter Tail did not use $674/kW for a CCGT. As far as I can tell, the $674/kW number is based upon a 500 MW CCGT in the same study that I relied upon. However, as Mr. Deason notes, there are economies of scope and scale and in the case of Montana-Dakota, I assumed a 120 MW CCGT. Given Montana-Dakota's requirements for new generation, the 120 MW unit is the appropriate size for Montana-Dakota. Furthermore, it is my understanding that Otter Tail analyzed various CCGT sizes ranging from a winter rating of 59.25 MW to 141.3 MW. These units range in costs from $1,571/kW to $2,032/kW, excluding AFUDC. So, the difference in assumptions between Otter Tail's and Montana-Dakota's for this alternative are not as great as Mr. Deason's testimony suggests. In fact, they are very similar. Applicants' witness Bryan Morlock discusses Otter Tail's assumptions in his rebuttal testimony.

The costs for both Otter Tail's and Montana-Dakota's units come from the same study: the *2006 Supply Side Technology Study Update* prepared by Black and Veatch. With regard to Montana-Dakota's analysis, the study identifies the EPC cost for the 120 MW units as $935/kW. The study assumes a 20% owner's cost multiplier for a total cost of $1,122/kW for the 120 MW units.

Montana-Dakota prepared a high-level analysis of the cost of transmission necessary to integrate a new combustion turbine. The estimated cost of transmission is $545/kW. This is a high-level engineering estimate based upon the evaluation of the costs, which included cost of the transmission and the costs of a needed transformer and associated breakers.

The final component of the costs for the CCGT is interest during construction (IDC), which is similar to AFUDC. Otter Tail allows its planning model to calculate AFUDC, while the Montana-Dakota analysis calculated construction financing cost exogenously to the model and added that cost, $128/kW, to the initial capital costs. So, part of the apparent difference between the Otter Tail and Montana-Dakota costs is attributable to differences between the level of costs that are input to the two utilities' capacity expansion planning models.

The result is that based upon a 2006 study, the total estimated costs of a 120 MW CCGT on the Montana-Dakota system is $1,795/kW, which is made up of the turbine costs of $1,122/kW, transmission costs of $545/kW, and construction financing (IDC) costs of $128/kW.

Q: Is it appropriate to use Otter Tail's natural gas cost projections in the Montana-Dakota expansion plan analysis?

A: I don't believe so. Both forecasts start with adjustments to the EIA long-term forecasts, and then further adjustments were made to incorporate delivery costs. The Otter Tail forecast incorporates adjustments for delivery to Minnesota. The Montana-Dakota forecast includes an adjustment for pricing at the Ventura, Iowa hub, a major regional delivery point frequently used for natural gas pricing in this region, and then specific transportation adjustments unique to the Montana-Dakota system for delivery into either the Linton, North Dakota, or Mobridge, South Dakota area.

As Mr. Deason notes in his testimony, the Montana-Dakota commodity gas cost is lower than Otter Tail's forecast in the early years and then higher in later years. I agree with Mr. Deason that "predicting future prices of natural gas is inherently uncertain, particularly over a long-term horizon ...."[1] In fact, despite Mr. Schlissel's assertions that Montana-Dakota has biased its modeling analysis, the starting point for the Montana-Dakota natural gas forecast is actually below the forward prices at the Ventura Hub, and the gas transportation cost assumptions are based upon likely locations of new gas turbines for Montana-Dakota, along with

[1] Supplemental Direct Testimony of Terry Deason, P 15.

information based on Montana-Dakota's long history of actual operating experience and familiarity and knowledge of actual transportation tariffs.

Q: Can you clarify Mr. Deason's questions regarding the delivered cost of natural gas in Montana-Dakota's resource planning modeling?

A: Yes. Mr. Deason correctly notes that Montana-Dakota analyzed two gas transportation cost cases. In Scenarios I and II, the assumption is that the gas turbine would be located in South Dakota and subject to delivery charges under the South Dakota Intrastate Pipeline (SDIP) tariff. Alternatively, in Scenarios III and IV, the SDIP tariff does not apply based on the assumption in these scenarios that the gas turbine would be located near Linton, North Dakota and not on the SDIP system. While it is true that in both scenarios the delivery costs are greater than what is assumed by Otter Tail, but as Mr. Deason correctly notes, the natural gas transportation costs assumed for Scenarios III and IV are actually below the historical transportation costs associated with Montana-Dakota's combustion turbines.

The scenarios that include the SDIP tariff were not designed to bias any results Instead, the scenarios simply reflect a likely location of a new combined cycle unit based Montana-Dakota's prudent consideration of the availability of water and transmission, and on the fact that the high gas transportation rates are projected to decrease in 2019. The potential increase in other costs associated with locating a gas turbine in a location with lower gas transportation costs was not analyzed under Scenarios III and IV.

Q: Does Montana-Dakota's assumed escalation rate used in its natural gas commodity forecast reflect the impacts associated with any potential carbon dioxide emissions regulations?

A: No, as further explained in Ms. Stomberg's April 23, 2008 supplemental rebuttal testimony.

Q: Can you clarify Mr. Deason's question regarding how the Montana-Dakota expansion model accounts for income taxes?

A: The least-cost optimization process used by Montana-Dakota compares resource expansion options based upon the levelized cost of the alternative options. In the expansion modeling analysis, the levelized charge rate is a model input that is specific to the life of the asset. The calculation of year-by-year fixed charges, and hence the levelized fixed charge rate, includes the impact of income taxes. The levelized fixed charge rate used for Big Stone II is 10.14%, and the rate used for the gas-fired turbines is 11.37%.

As noted by Mr. Deason, the total utility cost, including operating expenses, is discounted at the after-tax cost of capital of 7.61%. It is appropriate to use the after-tax cost of capital for the discount rate, since the actual year-by-year fixed charges incorporate the impact of income taxes and hence the costs are after-tax.

Q: Did Montana-Dakota test the impacts of using a higher cost of capital?

A: No, the scenarios developed for the supplemental hearings only assumed the 11% return on equity.

Q: Do you consider the 11% return on equity (ROE) a reasonable assumption for the purposes of the expansion planning modeling?

A: Yes. While the purpose of my work was not to offer an opinion on the appropriate cost of equity for Montana-Dakota, I believe it is appropriate to use a reasonable long-run cost of equity since there are likely to be a number of rate cases to determine the appropriate cost of equity over the life of any generation asset. As a point of reference, the average ROE for electric utilities over the last fifteen years has been 11.07% based upon 295 rate cases across the fifty states.[2] In today's markets, 11% is likely at the upper end of the ROE range given the low benchmark for the risk-free cost of capital based upon current long-term Treasury Notes.

IV. REVIEW OF SYNAPSE MODELING ANALYSIS

Q: Turning now to Mr. Schlissel's testimony regarding Montana-Dakota's modeling assumptions, was the combined cycle turbine costs updated to reflect cost pressures referenced by Mr. Schlissel in his April 9, 2008 testimony?

A: No. The turbine cost is based upon a 2006 study and does not reflect potential cost increases that Mr. Schlissel describes in his testimony and refers to in his Exhibit DAS-S2, the Standard & Poor's discussion of construction cost pressures, and his Exhibit DAS-S3, the Edison Foundation report on rising utility construction costs.

Q: Do you agree with Mr. Schlissel that Montana-Dakota has assumed extremely high capital costs for the gas-fired alternatives?

A: Not at all. Mr. Schlissel is incorrect in his assertion that "MDU already assumed extremely high capital costs for the combined cycle and combustion turbine alternatives."[3] Montana-Dakota has used the estimate of the EPC costs for the CCGT and CT from the 2006 Black & Veatch report discussed earlier and referenced by Mr. Schlissel on page 72 of his April 9, 2008 supplemental testimony.

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[2] SNL Analytics.
[3] Supplemental Direct Testimony of David A. Schlissel, p 76.

Furthermore, the implication of Mr. Schlissel's statement "Even if these EPC costs are increased by 20% to reflect additional owners' cost" is unclear.[4] As I described earlier, Montana-Dakota actually did include the 20% adjustment because adding owners' costs is appropriate, common in the industry, and is part of the total busbar cost estimate as assembled by Black & Veatch.

As I explain earlier in this testimony, the Montana-Dakota capital cost estimates include the estimated cost of transmission required to integrate the new generation. The alternative of not including transmission costs would be inappropriate for two obvious reasons. First, the total capital cost of new resources, including the transmission necessary to get the energy to consumers, needs to be considered. While Mr. Schlissel may be able to ignore transmission costs for purposes his analysis, Montana-Dakota cannot. Second, transmission costs are included in the analysis of the total capital cost of the Big Stone II alternatives and thus it is important to compare apples to apples.

Q: Do you agree with Mr. Schlissel's conclusion that it is appropriate to increase the capital cost of the Big Stone II unit, but not the capital costs of the alternatives?

A: No. If one wants to develop a high capital cost scenario, then the impact of cost increases on all the generation technologies should be evaluated. As I just explained, the capital costs for the gas turbine alternatives are based upon 2006 estimates and use the Black and Veatch projections. Therefore, there is no basis for Mr. Schlissel's assertion that the costs are "extremely high." The costs of the combustion turbines are not unreasonably high when the cost of transmission is included in the estimate. A high cost scenario should also include increasing

[4] Supplemental Direct Testimony of David A. Schlissel, p 72.

the gas turbine costs, and that is what Montana-Dakota did in its 2007 Montana-Dakota Integrated Resource Plan.

Q: What is your response to Mr. Schlissel's assertion that the Montana-Dakota analysis contains significant flaws?

A: Montana-Dakota has continued to use reasonable cost assumptions for all alternative resources. Its natural gas cost assumptions are based on considerable experience in the industry and are reasonable. I disagree that it is somehow a flaw to test the impact of scenarios in which the single largest driver to wind energy economics, the federal production tax credit, is not extended indefinitely, particularly given the history of that particular subsidy and its original intent.

The Montana-Dakota analysis uses consistent information regarding the costs of the alternative fossil fuel resources. The capital cost estimates were developed in similar time-frames. The fossil fuel options are consistently compared so that, with the exception of the wind generation, they all include the estimated cost of transmission upgrades necessary to support the projects.

The costs of the gas turbine options are based upon a 2006 study of supply-side options and include estimates for transmission costs based upon analysis by Montana-Dakota staff. The turbine cost estimates were not adjusted upward to reflect the cost pressures that Mr. Schlissel discusses. Montana-Dakota's analysis rightly included the cost of transmission for both Big Stone II and natural gas alternatives, while Mr. Schlissel does not appear to have done any analysis of the cost of transmission associated with adding new gas turbines. Meanwhile, he does not appear to have any issue with including the transmission costs associated with Big Stone II.

Furthermore, the Montana-Dakota analysis used reasonable gas cost assumptions. Last, there is no basis to Mr. Schlissel's assertion that Montana-Dakota used "very high capital costs" for the wind alternative.[5] The costs are based upon the recently completed Montana-Dakota Diamond Willow project, and are consistent with a 2007 analysis completed by Lawrence Berkeley National Laboratory.[6]

In short, I strongly disagree with his assertions that Montana-Dakota's analysis flawed or biased.

Q: Did you constrain the Strategist modeling to not allow the model to select a combined cycle unit after 2013?

A: No. Mr. Schlissel incorrectly suggests that Montana-Dakota's modeling restricts the ability of the model to select the combined cycle gas turbine.[7] The final model runs allow the combined cycle plant to be selected in 2009 – 2020. As was the case in the Minnesota PUC Certificate of Need (CON) Docket, restrictions on the combined cycle plant were only put into place after testing that the model did not select the combined cycle plant. The purpose of the constraints is to remove non-economic options (after testing) to address some of the limitations related to the model's ability to analyze every possible permutation of resource additions.

Q: Is it a concern that Big Stone II is more expensive than some of the wind / gas options in the period prior to and through 2025?

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[5] Supplemental Direct Testimony of David A. Schlissel, April 9, 2008, p 70.
[6] Wind Project Financing Structures: A Review & Comparative Analysis, September 2007, LBNL-63434.
[7] Supplemental Direct Testimony of David A. Schlissel, April 9, 2008, p 71 lines 6-9.

A: No. Mr. Schlissel implies that it is a flaw to incorporate the "more speculative future" in identifying the lowest cost expansion option.[8] I am aware of no experienced resource planner that would ignore the impact of end-effects. The purpose of looking at end-effects is to compare capital investments of competing alternatives with different life-times so that we can accurately assess the alternatives' true cost-effectiveness throughout its intended use. The economic life of the coal plant is longer than the gas turbine and the coal plant creates a tradeoff between high initial capital costs and longer lower cost fuel. Therefore, if one were to base the lower-cost resource decision on a truncation of the study results in 2025, then the capital cost trade-off associated with the coal plant would not be fully recognized over more than half its useful life. I believe that such a truncation would create a bias in the study results.

Q: Do Mr. Schlissel's scenarios demonstrate that Big Stone II is not part of the least-cost expansion plan?

A: No. While Mr. Schlissel has identified that there are a set of assumptions where it is possible that Big Stone II would not be part of the lowest cost expansion plan, I would not characterize his scenarios as reasonable base cases. The carbon scenarios are based upon assumptions regarding carbon regulation in the absence of any currently-approved regulation and rules.

Furthermore, his assumptions regarding carbon do not consider likely collateral impacts, including an associated rising demand for natural gas turbines and for natural gas. The increased demand for natural gas is likely to lead to increased costs for the natural gas options, and these costs are not reflected in Mr. Schlissel's scenarios. In addition, Mr. Schlissel increases the

[8] Supplemental Direct Testimony of David A. Schlissel, p 74.

capital cost of Big Stone II but ignores cost pressures for other generation resources that would result from the same market forces affecting Big Stone II. This is inconsistent with unbiased least cost planning.

Q: Does this conclude your testimony?

A: Yes.