OTP/MDU Exhibit 326

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

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL 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

# SUPPLEMENTAL PREFILED DIRECT TESTIMONY

OF


JEFFREY J. GREIG

General Manager, Business & Technology Services

BURNS & MCDONNELL ENGINEERING COMPANY


MARCH 10, 2008

BIG STONE II
PARTNERS IN GENERATION

## SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF JEFFREY J. GREIG

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## I. INTRODUCTION

**Q: Please state your name and business address.**

A: My name is Jeffrey (Jeff) J. Greig. My business address is Burns & McDonnell Engineering Co., 9400 Ward Parkway, Kansas City, MO, 64114.

**Q: By whom are you employed, and in what capacity?**

A: I am employed by Burns & McDonnell Engineering Company. I am the General Manager of the Business & Technology Services Division of the company.

**Q: Did you previously provide any prefiled written testimony in this matter?**

A: Yes, I did. I prepared Rebuttal Testimony dated June 21, 2007, that was entered into the record as OTP/MDU Exhibit 309.

**Q: Did you testify at the previous hearing held in June 2007?**

A: Yes, I did. I testified before the Commission on June 26, 2007.

## II. PURPOSE AND SUMMARY

**Q: What is the purpose of your testimony?**

A: The purpose of my testimony is to report on the work that Burns & McDonnell recently completed to compare the economics of various baseload generation technologies, using a number of updated assumptions from the earlier analysis that I reported on during the last round of hearings in 2007. In particular, we provided revised cost estimates for a downsized Big Stone Unit II from a nominal 630 MW facility to either a 580 MW nominal or a 500 MW nominal facility, based on the fact that two partners withdrew from the project last fall.

**Q: Please summarize your testimony.**

A: Burns & McDonnell evaluated several sizes for a supercritical pulverized coal (PC) plant (630 MW, 580 MW, and 500 MW) and compared the busbar costs of energy from those facilities with the busbar cost of a 500 MW combined cycle natural gas (CCGT) facility. Burns & McDonnell also evaluated the busbar costs of a combination 500 MW CCGT facility with market purchases of wind, both with and without the extension of a Production Tax Credit (PTC) for wind. We determined that the Big Stone Unit II supercritical PC plant still has the lowest busbar costs on a $/MWh basis of all the baseload alternatives considered, for both Otter Tail Power and Montana-Dakota Utilities, at all threes plant sizes that were considered, namely 630 MW, 580 MW, and 500 MW.

## III. UPDATED ANALYSIS

**Q: Please describe the analysis that Burns & McDonnell recently completed.**

A: In the fall of 2007 we were requested by the Big Stone participants to update the economic evaluation we performed in 2006 to reflect the fact that two of the utilities had withdrawn from the Big Stone Project and that the remaining five utilities were considering the possibility of downsizing Big Stone Unit II. We estimated the relative busbar costs of energy from the different types of facilities under consideration, relying on the most recent and pertinent assumptions available.

**Q: What assumptions did you update from your 2006 analysis?**

A: One assumption that we updated was the current cost estimates of the various options under review compared to earlier planning estimates. Another assumption was that the size of the proposed Big Stone Unit II project was decreased to either 580 MW or 500 MW. We also updated the fuel cost forecasts based on recent information.

**Q: Did you make any assumptions regarding potential costs for carbon dioxide regulation?**

A: Yes, we included a carbon dioxide cost evaluation required by Minnesota Public Utilities Commission for filings before that state's commission. We analyzed the effect of a $9/ton carbon dioxide cost on the busbar costs of energy from the various technologies considered. This $9/ton assumption was applied to all tons of carbon that would be emitted by Big Stone II, which is conservative. According to leading climate change bills in Congress, new efficient units like Big Stone II could be allocated a large quantity of no-cost carbon allowances. This issue was also addressed in detail in the Minnesota proceeding. This means that $9/ton applied to all tons of carbon is equivalent in annual costs to a much higher allowance cost per ton as it would be applied to only a portion of Big Stone II's carbon emissions.

Further, after Burns & McDonnell completed this analysis in November 2007, we went back again and re-examined some additional higher carbon dioxide costs that the Minnesota PUC adopted in December 2007 and presented those results in the Minnesota proceeding.

**Q: Are you including carbon dioxide costs in your North Dakota testimony?**

A: No, I am not because North Dakota law precludes a utility from incorporating possible future environmental costs into consideration and because the Commission has already ruled that evidence related to this matter is irrelevant. However, I do want to point out that I have not drafted a separate report specifically for North Dakota, so there is discussion of the impact of carbon dioxide costs on Big Stone in the November 2007 Report.

**Q: Did you compare the busbar costs for both investor-owned utilities and publicly-owned utilities?**

A: Yes, because in the overall project there are three publicly-owned utilities involved. We prepared two different economic models – one to reflect public power entities and a second to apply to investor-owned utilities (IOU). Investor-owned and publicly-owned utilities have different financing and capital structures, and have different revenue requirements. For the investor-owned model, a 50 percent debt / 50 percent equity financing structure was assumed, and an income tax liability component was estimated. The revenue requirements of each ownership structure were also determined differently. The public power model was intended to capture economic results that would be expected for a cooperative, municipal utility, or joint action agency. The public power model assumed tax-exempt debt financing through bond issuance for 100 percent of the project capital costs. Also, no income tax liability was estimated.

**Q: Are you including testimony about publicly-owned utilities in your testimony?**

A: No, because the three publicly-owned utilities involved in the Big Stone II project have no customers in North Dakota and are not involved in this advance prudence determination proceeding. However, my November 2007 Report does include the results of my analysis for the publicly-owned utilities.

**Q: Did Burns & McDonnell prepare a written report of its updated economic evaluation of different generation alternatives?**

A: Yes, we did. Burns & McDonnell presented its results in a written report entitled "Updated Economic Evaluation of Baseload Generation Alternatives" dated November 2007. This updated summary is included as OTP/MDU Exhibit 327.

**Q: What was your role in preparing the update?**

A: As with the prior "Updated Economic Evaluation of Baseload Generation Alternatives" prepared in September 2006, I was the overall project manager for the 2007 study update.

## IV. METHODOLOGY

**Q: What methodology did Burns & McDonnell follow in performing its economic analysis?**

A: First, the capital cost, performance, and operations & maintenance (O&M) costs for the different baseload generation alternatives were estimated. These estimates were used as the key inputs into a pro forma economic model that determined the annual busbar cost of power for each alternative on a revenue requirements basis over a 20-year planning period. The technical inputs were combined with economic, financing, and fuel cost assumptions to develop the overall busbar power costs. Two different economic models were prepared to reflect the different potential ownership structures.

**Q: What is meant by the busbar cost?**

A: Busbar refers to the cost of power without transmission, distribution, and ancillary service charges. Effectively the busbar cost is the cost of the power at the plant substation.

**Q: Explain the term revenue requirements.**

A: Revenue requirements are the total costs that need to be recovered on an annual basis, both operating costs and capital costs. For the investor-owned utility model, the revenue requirements are defined as fuel costs, fixed and variable O&M costs, interest on debt, depreciation expense, return on invested equity, and a tax liability component.

**Q: What were the specific financing assumptions used in the economic analysis for the IOUs?**

A: For the investor-owned model, a 50 percent debt / 50 percent equity financing structure was assumed for capital cost financing. The debt component was assumed as 20 years with a 7.5

percent interest rate. The return on equity was assumed to be 12.0 percent. These financing assumptions were used for each of the baseload generation alternatives.

**Q: Explain the term levelized.**

A: Generally, costs increase over time due to inflation impacts on operating costs and fuel costs. Over a long-term planning period, a levelized busbar cost represents a single, all-in power cost that captures measures of both cost escalation and the time value of money. For the selected discount rate, the utility would be indifferent to the levelized busbar cost throughout the planning period or a power cost that started lower but escalated annually. A levelized busbar cost is a useful summary measure for comparing alternatives.

**Q: What specific alternatives were considered in your latest analysis?**

A: We evaluated six different generation options that are capable of providing reliable, dispatchable capacity and energy to meet baseload requirements. These included the following:

- 630 MW Big Stone Unit II supercritical PC plant
- 580 MW Big Stone Unit II supercritical PC plant
- 500 MW Big Stone Unit II supercritical PC plant
- 500 MW combined cycle gas turbine (CCGT) plant
- 500 MW CCGT plant plus market purchases of wind energy with an extension of the Production Tax Credit
- 500 MW CCGT plant plus market purchases of wind energy without an extension of the Production Tax Credit.

## V. COST ESTIMATES

**Q: What were the current cost assumptions provided to Burns & McDonnell for the Big Stone Unit II project?**

A: The current capital cost estimate provided to Burns & McDonnell by Otter Tail for a 630 MW alternative is $1.496 billion excluding transmission construction for the 630 MW project size. This reflects a deferred on-line date of 2013 and is approximately 9.5 percent higher than the cost estimate used in the September 2006 analysis. The cost estimates for the 580 MW alternative and 500 MW alternative were scaled by Otter Tail Power Company and were $1.412 billion (580 MW alternative) and $1.272 billion (500 MW alternative). The cost estimates reflect an appropriate increase in $/kW based on a decline in the economy of scale that the 630 MW unit provides.

**Q: What were the current cost and performance assumptions provided to Burns & McDonnell for the CCGT project?**

A: The Applicants' construction and engineering firm Black & Veatch prepared a report entitled, "Supply-Side Technology Study" dated August 2006. The capital cost estimate for a generic 2 x 1 GE 7FA CCGT project was estimated in 2006$ at $281 million ($562/kW) plus $56.2 million of Owner's costs ($674.4/kW total). This cost was used again and escalated 5.0 percent annually until the proposed commercial operation date.

**Q: What was the basis for the cost of wind resources used in the Updated Economic Evaluation?**

A: For the CCGT plus market purchase of wind energy alternative, it was assumed that non-firm wind energy would be purchased. These wind energy purchases would displace an equivalent amount of energy and would offset the need for a portion of the higher cost gas-fired energy generation by the CCGT. Burns & McDonnell estimated in the earlier study that new wind farm development in the Midwest region costs $40/MWh in 2006$ with the federal production tax credit (PTC) in place. The price of wind turbines has subsequently increased significantly within the last two years due to market factors and material costs such as steel and copper, and many Burns & McDonnell clients are currently pricing new wind farm developments at $50/MWh or higher; however the $40/MWh cost assumption was maintained as a conservative assumption. The 2006$ cost estimate was escalated 5.0 percent annually until the proposed commercial operation date.

The current PTC expires at the end of 2008 and may not be available in 2013 as a subsidy to lower the cost of wind energy. A second scenario was prepared using a cost of purchased wind that is $20/MWh higher under the assumption that the PTC is not available at that time.

## VI. WIND ASSUMPTIONS

**Q: What was the purpose of including the wind resource with the CCGT alternative?**

A: For the CCGT project plus wind case, the 500 MW CCGT plant is the baseload alternative being compared to the supercritical PC plant alternatives. Both are reliable, dispatchable generation resources that can be operated to meet baseload capacity and energy requirements. Wind is not a baseload resource because it does not produce dependable generation year-round at high capacity factors. Hence, our analysis did not assume construction of a wind resource, but market purchases of non-firm wind energy. The wind component was added to the CCGT project alternative to enhance its economic performance by displacing higher cost gas-fired energy production with non-firm wind energy when available. The evaluation was focused on comparing baseload project alternatives, not developing combinations of resources on a system basis as a substitute for utility resource planning efforts.

**Q: What was the assumption regarding the capacity factor of the wind resource?**

A: The evaluation assumed that non-firm wind energy would be available to displace the equivalent of a 40 percent capacity factor for the CCGT plant. In this regard, the assumption was optimistic for typical wind farm production. Nevertheless, we utilized the 40 percent estimate to be conservative in testing Big Stone Unit II economics against alternatives.

**Q: Did you make any assumptions with regard to transmission that might be required for new wind projects?**

A: No, since we are only calculating a busbar cost, we excluded transmission costs for all of the alternatives. In reality, however, new wind farms in the hundreds of megawatts that are being considered here would require substantial new transmission infrastructure. This is another conservative assumption that favors wind.

## VII. OTHER ASSUMPTIONS

**Q: Were the financing assumptions the same as used in the prior studies?**

A: Yes.

**Q: Were the other key operating and economic assumptions the same?**

A: Yes, with the exception that the fuel cost forecasts were updated based on 2007 information.

**Q: What was the basis for the fuel cost forecasts used in the Updated Economic Evaluation?**

A. The Powder River Basin (PRB) fuel cost forecast was provided by Otter Tail Power Company. In the September 2006 analysis, we used a cost of $1.71/MMBtu in 2010 and an overall escalation rate of approximately 2.9 percent. In this round of examination, we used a cost of $1.74/MMBtu in 2010 for the overall delivered cost for PRB coal and an escalation rate of approximately 3.5 percent.

For natural gas, in September 2006, the New York Mercantile Exchange (NYMEX) futures price for Henry Hub natural gas commodity supply in 2011 was $7.20/MMBtu. A conservative transportation cost of $0.40/MMBtu was added to this supply cost for a delivered cost of $7.60/MMBtu in 2011 in the prior analysis. In October 2007, the NYMEX futures price for Henry Hub natural gas commodity supply in 2012 was $7.91/MMBtu. The same conservative transportation cost of $0.40/MMBtu was added to this supply cost for a delivered cost of $8.31/MMBtu in 2012 in the updated analysis. Note that the U.S. Energy Information Administration published that the average differential in wellhead and delivered natural gas fuel costs for electric utilities was $0.67/MMBtu in 2006. The use of $0.40/MMBtu for gas transportation and balancing services for an upper Midwest generic location is conservative, and gives the benefit of the doubt in favor of the CCGT alternative.

**Q: Were any additional sensitivity analyses prepared in the Updated Economic Evaluation with regard to future costs of natural gas?**

A: Yes. As noted before, the assumption for gas transportation costs of $0.40/MMBtu is conservative. In addition, if a federal carbon tax or $CO_2$ allowance structure is implemented in the US, basic economics indicate that the demand for natural gas used in power generation will increase, further exacerbating the current natural gas supply situation and increasing costs further. To evaluate the potential that delivered natural gas costs are understated in the analysis due to these factors, a sensitivity assuming a $0.50/MMBtu and a $1.00/MMBtu increase were evaluated.

**Q: What were the results of this sensitivity analysis?**

A: Under an investor-owned utility ownership structure, if the price of natural gas increased by $0.50/MMBtu, the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $91.04/MWh. If the price of natural gas increased by $1.00/MMBtu the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $93.55/MWh.

## VIII. CONCLUSIONS

**Q: What was the conclusion of your 2007 updated analysis?**

A: This 2007 update confirmed that the Big Stone Unit II project represents the lowest cost baseload generation alternative of those evaluated on a life-cycle basis considering capital and operating costs for Otter Tail Power and Montana-Dakota Utilities. This conclusion was reaffirmed for the 630 MW project size and remained for the smaller 580 MW or 500 MW plant sizes considered. The proposed Big Stone Unit II has been consistently verified as a least-cost baseload generation alternative on a life-cycle basis, with or without the extension of the PTC for wind under capital, operation, performance, and fuel cost estimates that have been periodically updated over time.

**Q: What were the specific results reported in your updated analysis?**

A: For the investor-owned utility ownership model, the lowest cost generation alternative was the 630 MW supercritical Big Stone Unit II project with an estimated levelized busbar cost of $73.98/MWh over the 2013 to 2032 planning period. The 580 MW and 500 MW Big Stone Unit II project alternatives followed at $75.26/MWh and $77.65/MWh, respectively. The CCGT plus market purchases of wind energy alternative was $86.55/MWh (with PTC), which is 17 percent higher than the 630 MW Big Stone Unit II project and 11 percent higher than the 500 MW Big Stone Unit II project.

**Q: Did the results changes from your earlier analysis?**

A: No, they didn't. Some economies of scale are lost when the plant is downsized but supercritical PC remains the lowest cost option. A comparison of the results from the September 2006 study with the 2007 update is shown in the table below.

**TABLE 1. ESTIMATED LEVELIZED BUSBAR COSTS ($/MWH)**

| | **Alternatives Study 2006** | **Updated Evaluation 2007** |
|---|---|---|
| | Investor Owned | Investor Owned |
| 630 MW Supercritical | $69.62 | $73.98 |
| 580 MW Supercritical | N/A | $75.26 |
| 500 MW Supercritical | N/A | $77.65 |
| 500 MW CCGT | $81.89 | $92.68 |
| CCGT plus wind energy purchases | $80.78 | $86.55 |

**Q: Would you advocate that a utility should rely on the kind of economic analysis Burns & McDonnell performed as the primary basis for deciding on which type of generation facility to construct?**

A: No. The purpose of our work was to compare alternative baseload generation technologies capable of providing reliable, dispatchable capacity and energy to meet baseload requirements. Burns & McDonnell has never portrayed the evaluations as an assessment of need or an integrated evaluation of supply and demand-side alternatives. The evaluation compares baseload generation alternatives only and demonstrates that the supercritical Big Stone Unit II pulverized coal plant is a least-cost baseload generation alternative on a life-cycle basis considering capital and operating costs compared to numerous other baseload generation alternatives. A prudent utility would rely on detailed resource planning analyses to make a final conclusion, and that is what I understand the Applicants have completed.

**Q: Does this conclude your testimony?**

A: Yes, it does.