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March 10, 2008

VIA FEDERAL EXPRESS & EMAIL

Illona Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol
Bismarck, ND 58505

Re: Montana Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station
Case Nos. PU-06-481 and PU-06-482

Dear Ms. Jeffcoat-Sacco:

On behalf of Applicants Otter Tail Corporation and Montana-Dakota Utilities Co., enclosed for filing in the above matter please find the following supplemental direct testimony and attached exhibits of Applicants:

Ward Uggerud (OTP Exhibit 112);
Bryan Morlock (OTP Exhibit 117);
Andrea Stomberg (MDU Exhibit 213);
James Heidell (MDU Exhibit 214);
Mark Rolfes (OTP/MDU Exhibit 324);
Tim Rogelstad (OTP/MDU Exhibit 325);
Jeffrey Grieg (OTP/MDU Exhibit 326); and
Thomas Crowley (OTP/MDU Exhibit 328).

Please direct any questions to Montana-Dakota's Mr. Daniel Kuntz (701-530-1016), Otter Tail's Mr. Mark Bring (218-998-7152), or to the undersigned.

Thank you for your consideration.

Very truly yours,

/s/ Todd J. Guerrero

TJG/kas
cc: Attached Service List (w/encl.)

Doc# 2570973\1

282 PU-06-482 Filed 03/10/2008 Pages: 167
Supplemental Direct Testimony & Attached Exhibits of Applicants
Lindquist & Vennum
Todd Guerrero

MDU Exhibit 213

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

ANDREA L. STOMBERG

VICE PRESIDENT OF ELECTRIC SUPPLY

MONTANA-DAKOTA UTILITIES CO.

MARCH 10, 2008

SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF ANDREA L. STOMBERG

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BEFORE THE NORTH DAKOTA SERVICE COMMISSION

SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF ANDREA L. STOMBERG

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Andrea L. Stomberg. My business address is 400 North Fourth Street, Bismarck, ND 58501.

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

A: I am the Vice President of Electric Supply for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. My responsibilities include power production and planning, transmission and system operations, and electric sales and dispatch.

Q: Did you previously submit testimony in this matter?

A: Yes. I provided prefiled testimony admitted as Exhibit MDU-203.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: Describe the purpose of your testimony.

A: My testimony provides an update to the Commission on Montana-Dakota's continued participation in the Big Stone Unit II power plant following departure of two of the original project participants. I am also presenting an overview of the results of Montana-Dakota's updated resource planning modeling, which continues to support the selection of Big Stone Unit II as the most cost effective electric supply-side resource addition for Montana-Dakota's customers.

Q: Please summarize your testimony.

A: After last fall's withdrawal of Great River Energy and Southern Minnesota Municipal Power Agency as participants in the Big Stone Unit II project, the remaining project owners considered the possibility of downsizing the plant to either 500 MW or 580 MW. The resizing of the plant caused the remaining participants to reevaluate the costs. Montana-Dakota also used this opportunity to amend and refine its generation expansion modeling to include various parameters as a sensitivity analysis. Montana-Dakota's pro-rata share of a 500 MW Big Stone Unit II would be 133 MW. Montana-Dakota's resource planning models continue to select Big Stone Unit II as the best new resource for meeting our customers' future electric needs. Our expert resource planning witness Jim Heidell provides further testimony on this issue.

III. RESOURCE PLANNING UPDATES

Q: What inputs changed in Montana-Dakota's resource planning model?

A: In my previous testimony, I discussed Montana-Dakota's need for baseload capacity and energy to: (1) replace a power supply contract between Montana-Dakota and Basin Electric Power Cooperative (Basin) that expired in October, 2006, and (2) support steadily increasing load in the area we serve. The existing and forecasted requirement for a baseload resource has not changed materially in the last year. Indeed, 2007 provided an affirmation of the Company's continued load growth. As a Big Stone Unit II development participant, the cost of the plant is an important component in our power supply planning and resource selection. When the two partners withdrew and the remaining partners decided to examine a smaller unit, we believed it necessary and prudent to re-run our planning models with more current cost estimates to test the selection of the Big Stone Unit II plant. We also used this opportunity to reevaluate and refine other model inputs, as discussed in more detail by Jim Heidell.

Each of Montana-Dakota's Integrated Resource Plans has been the product of a strategic planning exercise that is based on a snapshot of conditions that exist at the time the plan is prepared. The model inputs are therefore subject to change as critical assumptions such as economic and business conditions change. To update or refine the models presented in our earlier testimony, we modified some model inputs including plant costs, alternative generation resource costs, including wind and combined and simple cycle turbines, natural gas pricing, the availability or unavailability of the wind energy production tax credit, sale of energy in excess of our customers' needs to the MISO market, full implementation of conservation and demand-side management programs, and reductions in existing generation capability that may be caused by regulation or obsolescence.

Q: Why did Montana-Dakota make changes in its resource planning model input data?

A: Resource planning models are just that - models of the system at a particular point in time. Given that all the project participants were updating their models to include new project price information, we felt it appropriate to update other input data and assumptions that had changed since our last round of testimony, to confirm for ourselves and the Commission the accuracy of our assumptions, and to assess the sensitivity of prior results to changes from more current input parameters.

Q: What were the results of the new resource planning model analyses?

A: Given reasonable model inputs, our resource planning modeling selects the 500 MW Big Stone Unit II plant as the best new resource to serve our customers.

Q: Would consideration of a 580 MW Big Stone Unit II change the result of the analyses?

A: No. Our results show that even at the higher 500 MW price, the Big Stone II Unit is still cost–effective. Thus a lower cost 580 MW unit (on a per kW basis) will do nothing but enhance the selection of the Big Stone II Unit as the best resource.

Q: Why is Montana-Dakota estimating it will own 133 MW of Big Stone Unit II?

A: Ownership of the 500 MW plant was assumed to be on a pro-rata basis, based on the ownership percentage of the original design with the original seven participants. There may be some further small adjustments in plant ownership once the plant size is finally determined. At this time, Montana-Dakota is asking for an advance prudence decision based on ownership of up to 133 MW of either a 500 or 580 MW plant.

Q: Why did the updated modeling include a scenario with the sale of excess energy into the MISO market?

A. Most baseload expansion results in "lumpy" investment, i.e., it is rarely possible or reasonable to build exactly the amount of baseload capacity that forecasts or resource plan models predict are needed at any particular moment. Often, a resource that is acquired and that will provide for needs over a long period will have energy excess to the customers needs in the early years, leaving energy available for off-system sales from time to time. The Commission is aware of how our customers benefited when we had significant off-system sales during the term of the Basin contract. Owning 133 MW of Big Stone Unit II will work in much the same manner, and should allow Montana-Dakota the opportunity to make off-system sales, particularly in the first years after it comes on line, and share the benefit of those sales with our retail customers through the Commission-approved margin sharing adjustment. As a result, we believed it important in the updated modeling to include a scenario where we had approximately the same volume of pool sales as we did in 2006, as well as a scenario showing no pool sales. As Mr. Heidell explains, the pool sales do not provide a basis for Montana-Dakota's participation in the project, but do provide the company with a more realistic picture of the way in which we operate our utility system within the MISO market, and how our customers may benefit from participation in the plant.

Q: What were the results of the models that demonstrated that Big Stone Unit II continues to be the best resource for your customers?

A: With or without pool sales our customers are better off with Big Stone Unit II than they would be with what the models show to be the next best resource, which includes wind plus natural gas resources based upon assumptions of a high capacity factor for wind resources and continuation of production tax credits for wind resources. Without the high capacity factor and production tax credit assumptions, no wind was selected as an economic resource, and the next most economic option after Big Stone Unit II is primarily natural gas generation. The model of course is dependent upon its inputs and changing any of the assumptions can result in the selection of an entirely different resource. I believe the selection of Big Stone Unit II over the next selected resource boils down to an assessment of risks, including the risk of the affordability of natural gas to generate electricity versus the known long-term availability and affordability of domestic coal, which has historically had far less price volatility than natural gas. Given what Montana-Dakota views as probable increases in the use of natural gas as a fuel source for electric power generation regionally and nationwide going forward, we are very concerned about what that increased reliance on natural gas for electric generation might mean for our electric customers, as well as for our customers that use natural gas to heat their homes and for commercial and industrial uses in their businesses.

Q: What is the status of wind generation in Montana-Dakota's models?

A: Mr. Heidell modeled wind with and without the production tax credit (PTC), as currently the credit will expire at the end of 2008. While it is possible the PTC will be extended for another short period of time, we do not believe that it will be extended indefinitely. And given its considerable impact on the economic competitiveness of wind energy, we believed it prudent to model a scenario on the assumption the PTC will not be available. It is important to note that no transmission upgrade costs were attached to wind in the models, as these costs are very difficult to estimate with reasonable precision. Without transmission upgrade costs, the PTC, and based on a capacity factor of 38 percent, the model selected no wind in addition to the Diamond Willow project.

Montana-Dakota recognizes that wind energy can be part of our overall resource plan. Montana-Dakota intends to expand the Diamond Willow wind farm from its current size of 20 MW by at least another 10 MW, and continue to evaluate other wind projects both within and outside of North Dakota as a supplement to our other resources.

Q: Did you consider future environmental regulations that could drive up the cost of energy from Big Stone Unit II?

A: Montana-Dakota has closely followed the developments in Congress and some of the states relative to carbon dioxide regulation, as well as the recent change in mercury regulations.

A substantial direct tax on carbon dioxide emissions, or a high allowance price in a "cap and trade" system – particularly one that singles out coal instead of applying equally to coal and other carbon dioxide containing fossil fuels -- would change the results of our modeling. As the Commission is aware, Montana-Dakota is prohibited by state law from considering environmental cost regulation in its resource selection process, so we did not perform a quantitative analysis of a range of CO_2 costs, for instance. But based on the considerable amount of information that I have reviewed, I firmly believe that any penalty attached to coal as part of climate change regulation will most certainly increase the cost of natural gas going forward, and that too will change the model results. This is where judgments considering risk must be applied: what is likely and how does that affect the business decision of selecting the generation alternative that is the best long-term resource to customers?

Q: What is Montana-Dakota's current resource mix?

Montana-Dakota's current mix of installed generation capacity resources is 77 percent coal, 23 percent dual fuel turbines, which can burn either gas or oil, and under one percent wind. The 50 MW Lewis & Clark Station can be fired on coal or natural gas alone. Once Big Stone Unit II is constructed, and retaining all of our current generation, the percentage of coal generation in our mix would increase to 82 percent. Replacing the generation from Big Stone Unit II primarily with natural gas, which the model suggests is the next best alternative to Big Stone Unit II in the absence of PTCs, would double our natural gas generation capacity to about 40 percent. This would significantly increase Montana-Dakota's customers' exposure to natural gas price risk. And it is important to point out that many of our customers - over 80 percent - also use natural gas for home heating. If Montana-Dakota increases the use of natural gas for electric generation, these customers are exposed to additional natural gas price risk on their electric bills. We are very concerned about this.

Big Stone Unit II is a highly efficient plant that will burn a domestic fuel that Montana-Dakota is confident will be available for the long term at a price we believe will be relatively stable even with the likelihood of carbon dioxide regulation. In contrast, Montana-Dakota believes that natural gas supply and pricing is far less certain.

Q: What benefits do you see Big Stone Unit II affording Montana-Dakota's customers?

A: As discussed in my previous testimony in this case, Big Stone Unit II is intended in part to replace the 66.4 MW of baseload power supplied under the now expired power purchase agreement between Montana-Dakota and Basin. Until the Big Stone Unit II plant is in commercial operation, Montana-Dakota will continue to need to purchase energy from the MISO market. The cost of this energy cannot accurately be predicted and, as the Commission is aware, can fluctuate widely. Once Big Stone Unit II is available, Montana-Dakota's customers will be more insulated from the uncertainty and variability of the price of power from the market.

In addition, when the Company has available energy from Big Stone Unit II, Montana-Dakota will also be able to sell surplus power into the MISO market and therefore benefit our customers under the Commission-approved margin sharing adjustment.

Q: Describe why you believe Big Stone Unit II is the best resource option for Montana-Dakota's electric customers.

A: There continue to be several reasons why Big Stone Unit II is the best new resource for Montana-Dakota's customers. Montana-Dakota's customers will benefit from economies of scale in the ownership of a large, efficient baseload coal plant. Additional efficiencies will be achieved from having Big Stone II built adjacent to the existing plant. Also, this highly efficient unit will reduce Montana-Dakota's overall carbon-intensity, and the dual scrubber will be an efficient way to reduce emissions of both units. Last, Montana-Dakota takes comfort in having the considerable experience and talent of the other participants available to assist in the design and operation of this plant.

Montana-Dakota focuses on providing our customers with the best overall resource. Montana-Dakota believes the Big Stone Unit II is the best resource to provide customers with reliable power for a predictable and affordable price well into the future. Using the most efficient commercially-proven technology allows us to continue to reduce our net company emissions per MWh for a reasonable cost. Considering all this, plus finding a way to leverage this new resource to clean the emissions of the existing Big Stone Unit I plant, Big Stone Unit II remains Montana-Dakota's clear first and prudent choice.

Q: Does this conclude your testimony?

A: Yes.

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

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AND

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FOR AN ADVANCED DETERMINATION OF PRUDENCE

For the Big Stone Unit II Generating Plant

SUPPLEMENTAL PREFILED DIRECT TESTIMONY

OF

JAMES HEIDELL

PA CONSULTING GROUP

MARCH 10, 2008

BIG STONE II

PARTNERS IN GENERATION

SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF JAMES HEIDELL

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF JAMES HEIDELL

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.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your supplemental testimony?

A: There are two purposes to my testimony. First, the testimony updates the previous analysis I presented to the Commission in June 2007. The updated analysis reflects both the proposed reconfiguration of the Big Stone Unit II power plant and other assumption modifications as a result of over a year of change in the dynamic power industry. Second, the testimony introduces two additional scenarios that evaluate the economics of both the wind and natural gas generation alternatives assuming key assumptions impacting the economics of wind made in the first two scenarios are incorrect and also quantifies the potential benefits of off-system sales.

Q: Is Big Stone Unit II identified as part of the least cost solution in your resource planning modeling for Montana-Dakota?

A: Yes, based upon my updated analysis using the Strategist® Resource Planning expansion software, the reconfigured Big Stone Unit II coal plant remains part of the lowest cost mix of resources for Montana-Dakota's resource expansion plan. The mix of new resources continues to include demand side resources, renewable resources, gas-fired peaking generation, and baseload coal generation. This conclusion is based upon a review of four scenarios that tested a number of key assumptions including the continuation of the federal renewable energy production tax credit (PTC), the cost of natural gas, and the benefits of off-system, wholesale power sales. In all four scenarios the Big Stone Unit II resource is part of the least cost resource mix as a result of Montana-Dakota's need for new generation capacity and energy; a need in-part driven by the expiration of a long-term Basin Electric Power Cooperative power contract. A summary of the least cost resource expansion plan for each of the four scenarios is shown below:

EXPANSION PLAN SUMMARY

Scenario[1]	**I**	**II**	**III**	**IV**
KEY INPUTS				
BSPII Increment[2]	116 MW	116 MW with option for four additional five MW increments	25 MW with maximum of 125 MW	25 MW with maximum of 125 MW
PTC's	Expiration 1/1/2013	Expiration 1/1/2013	Expiration 1/1/2009	Expiration 1/1/2009
Wind Capacity Factor[3]	52%	52%	38%	38%
Off-System Sales	No	No	No	Yes
LEAST COST RESOURCE MIX (In addition to Diamond Willow and conservation)				
Year/MW/Resource	2010 / 31.5 MW / **Wind**		2012 / 43.5 MW / **CT**	
	2011 / 31.5 MW / **Wind**		2013 / 75 MW / **BSPII**	2013 / 125 MW / **BSPII**
	2013 / 116 MW / **BSPII**	2013 / 131 MW / **BSPII**	2016 / 50 MW / **BSPII**	2016 / 43.5 MW / **CT**
	2020 / 43.5 MW / **CT**	2020 / 43.5 MW / **CT**	2020 / 43.5 MW / **CT**	2020 / 43.5 MW / **CT**
Net Present Value - 2007 $(000)	2,203,347	2,183,038	2,124,493	2,051,745

NEXT COST RESOURCE MIX WITHOUT BSII (In addition to Diamond Willow and conservation)				
Year/MW/Resource	2010 / 31.5 MW / **Wind**	2010 / 31.5 MW / **Wind**	2013 / 130.5 MW / **CT**	2013 / 130.5 MW / **CT**
	2011 / 63 MW / **Wind**	2011 / 63 MW / **Wind**		
	2011 / 87 MW / **CT**	2011 / 87 MW / **CT**		
	2012 / 31.5 MW / **Wind**	2012 / 31.5 MW / **Wind**		
	2017 / 43.5 MW / **CT**	2017 / 43.5 MW / **CT**	2016 / 116 MW / **IGCC**	2016 / 116 MW / **IGCC**
	2024 / 43.5 MW / **CT**	2024 / 43.5 MW / **CT**		
Net Present Value - 2007 $(000)	2,215,660	2,215,660	2,363,530	2,312,366

1. Scenarios I & II were developed in Q3 of 2007. Scenarios III & IV were developed in the Q1 of 2008.
2. Big Stone Unit II modeled as a 500 MW unit in all scenarios.
3. There was no binding constraint on the amount of wind that Strategist® could add to the resource plan.

Q: Please summarize what the top two sections of the preceding table illustrate?

A: The top half of the table shows the least cost expansion plan identified by Strategist® in four scenarios prepared for this proceeding. The new resources added are detailed for each of the expansion plans where the year added is indicated and followed by the MW of nameplate capacity added and the type of resource. In all scenarios, the model selected all the available conservation resources and all the plans included Montana-Dakota's Diamond Willow wind project near Baker, Montana.

Q: Please describe what the last section of the preceding table illustrates?

A: The bottom half of the table shows the first resource plan for each scenario that did not include Big Stone Unit II. The model provides a summary of plans considered that have a higher cost than the least cost plan. For each scenario the incremental cost of not including Big Stone Unit II in Montana-Dakota's resource expansion plan is the difference between the net present value (NPV) for each scenario shown on the bottom and middle of the table.

Q: In summary, what was the result of your test of key assumptions regarding the economics of wind?

A: My analysis of the alternative plans evaluated by the Strategist® model indicates that without a production tax credit and with a realistic capacity factor for wind generators, the cost of a wind generation alternative is more than 10% higher than the optimal plan involving Big Stone Unit II.

Q: In summary, what was the result of your analysis of off-system sales?

A: My analysis indicates that on a net present value basis there are an additional approximate $72m of benefits from off-system sales with Big Stone Unit II in Montana-Dakota's resource mix.

Q: What risks do you see with a wind/combustion turbine alternative?

A: No. While Mr. Schlissel, on behalf of Mark Trechock and the Dakota Resource Council, has previously presented testimony in this proceeding regarding the risk of greenhouse gas regulation, there are also significant risks associated with the alternative wind/natural gas expansion plan. Even though the alternative plan has a net present value total cost within two percent of the Big Stone Unit II plan (comparing the top and bottom half of the preceding table under the column labeled "Scenario II"), there are risks associated with this alternative including: performance risk of the wind based upon the assumed capacity factor, fuel price risk associated with natural gas, the potential for significant capital costs associated with transmission and integration costs associated with large amounts of wind generation, and higher operating costs associated with the fossil fuel plants operating in a system with a large amount of wind generation.

As I will discuss later in this supplemental testimony, the previous assumptions used for wind included continuation of the PTC and high annual capacity factors. Both of those assumptions underlie the conclusion that the cost comparison is within two percent. If we were to use more realistic assumptions regarding the capacity factor of wind, the resulting costs of the scenarios will be further apart.

Q: Why was it necessary to update the input assumptions?

A: Resource planning is a dynamic process and a number of updates in assumptions were appropriate because a number of factors had changed since the analysis was completed and presented to this Commission almost one year ago. A key update was to modify the inputs to reflect material changes related to the down-sizing of the proposed Big Stone Unit II coal plant. Given the attention that wind generation has received in this proceeding, it was also critical that the analysis reflect the recent capital cost pressures on the construction of wind turbines. The updates also include changes made in conjunction with the development of Montana-Dakota's 2007 Integrated Resource Plan.

Q: Please summarize the organization of your supplemental testimony?

A: The first section of my testimony summarizes the key assumption updates to my previously filed analysis in this proceeding. The second part describes the sensitivities analysis I conducted. The final section summarizes the results.

Q: Please summarize the information contained in MDU Exhibit 215?

A: My exhibit summarizes the key input assumptions and results from the Strategist® analysis that I completed to support my supplemental testimony.

- Table 1: Fuel cost assumptions for Scenarios I & II
- Table 2: Natural gas cost assumptions (used for Scenarios III & IV)

- Table 3: Load Forecast used for all four scenarios (including a comparison with the load forecast previously used in this proceeding)
- Table 4: Assumptions for Resource Options
- Table 5: Demand Side Resource Options modeled
- Table 6: Scenario I Results Summary
- Table 7: Scenario II Results Summary
- Table 8: Scenario III Results Summary
- Table 9: Scenario IV Results Summary
- Table 10: Montana-Dakota's Least Cost Expansion Plan Summary

III. UPDATE OF ASSUMPTIONS

Q: What assumption updates were incorporated in your updated resource modeling results?

A: I will briefly list the key assumption updates and then provide additional detail on each of the updates. The updates include:

- Reflecting the proposed reconfiguration of the Big Stone Unit II coal plant as a 500 MW project;
- Allowing the Strategist® model to select up to 131 MW of Big Stone Unit II;
- Incorporating Montana-Dakota's revised energy and demand forecast;
- Incorporating Montana-Dakota's recent natural gas cost price forecast;
- Updating the cost of wind projects and testing scenarios with and without extension of the production tax credit (PTC);

- Updating the list of committed projects and contracts in the model to include the Diamond Willow wind project and removal of the South Dakota wind project;
- Incorporating additional demand-side management projects;
- Modeling the option to extend for an additional year Montana-Dakota's existing contract with Northern States Power for approximately 100 MW of capacity; and
- Analyzing constraints on how much wind is allowed to enter the model.

Q: What parameters for Big Stone Unit II did you adjust in your analysis?

A: The base case analysis reflects a resource option for a 116 MW share of the proposed Big Stone Unit II plant for Montana-Dakota. However, certain parameters relating to this resource were changed including extending the commercial on-line date one year to the summer of 2013, updating the capital cost of the project, updating the fuel and non-fuel operating cost assumptions, correcting a heat rate assumption, and incorporating interest during construction (IDC) into the capital cost assumption. The updated capital and O&M cost estimates incorporate the information provided by the Applicant's witness Mr. Mark Rolfes in the fall of 2007.

A second scenario, Scenario II, was also developed to determine whether it would be cost-effective for Montana-Dakota to increase its share of Big Stone Unit II from 116 to 131 MW. This scenario allowed the Strategist® model to select up to four incremental 5 MW shares of Big Stone Unit II if 116 MW share is cost effective.

Q: What capital costs for Big Stone Unit II did you assume in your analysis?

A: The capital cost for the 500 MW configuration of Big Stone Unit II power plant is $1.272B. My analysis in Strategist® involved converting the nominal construction costs in 2006 constant dollars and also incorporates the transmission line capital costs and interest during construction.

Q: Would you please summarize the load forecast update?

A: Yes. Montana-Dakota routinely updates its load forecast. In the process of preparing its 2007 Integrated Resource Plan, Montana-Dakota updated both its long-term forecast and its forecast methodology. Montana-Dakota recently decided to change its end-use forecasting methodology, which it used during the period 1988 – 2005, to an econometric approach. The end-use approach to developing load forecasts is based upon a process that characterizes electricity use by major users with fundamental equations that calculate electricity use as the product of electricity used per unit times the number of units. For example, electricity used per multi-family household times the forecast of the number of multifamily households. The econometric approach to forecast relies on statistical analysis of historical consumption to develop equations that are used to forecast future consumption. For example, residential sales are based upon changes in key explanatory variables such as population, income, and weather. Both approaches are valid load forecasting techniques. In the spring of 2007, Montana-Dakota prepared an econometric forecast of annual energy and peak demand in conjunction with the new Integrated Resource Plan.

Q: How did the long term energy and demand forecast change between the end-use and the econometric forecasts?

A: The new econometric forecast has slightly higher long-term demand and energy growth rates. The long-term average annual demand growth rate increased from 0.99 percent to 1.07 percent while the long-term average annual energy growth rate increased from 0.92 percent to 1.23 percent. Thus, Montana-Dakota is showing slightly more growth than previously forecast.

Q: Please summarize the update to the natural gas forecast.

A: The natural gas forecast consists of two components. The first part is a projection of natural gas prices at the CIG hub, and the second component incorporates the pipeline transportation delivery costs to the Ventura Hub and then through the South Dakota Intrastate Pipeline Company (SDIP) to a location near Mobridge, South Dakota.

The natural gas commodity forecast that I used in my capacity expansion modeling was prepared by Montana-Dakota and is based on the long-term DOE Energy Information Administration (EIA) natural gas forecast which was then adjusted based on Montana-Dakota's extensive in-house experience in procuring natural gas.

The natural gas transportation cost forecast is based upon the firm delivery of natural gas to a site at Mobridge, SD for a new gas turbine project. Delivery of gas to the site is relatively expensive until 2019 as a result of the SDIP tariff. The transportation cost to Mobridge is expected to decline commencing in 2019. Despite the near term high cost of transporting gas to South Dakota, this is nonetheless considered the preferred site for a new Montana-Dakota natural gas resource as a result of pipeline capacity and water constraints related to other potential sites.

Q: What updates were made regarding the assumed cost of wind projects?

A: The cost of wind was updated based upon a spreadsheet model used to calculate the levelized cost of wind over a twenty year period. This model incorporates the assumption that the capital cost of wind is $2,000 / kW (2006 $) rather than the $1,200 / kW that I used in previous modeling. This estimate better reflects the increased cost of wind projects and is also consistent with Montana-Dakota's experience with its 20 MW Diamond Willow project. This estimate also includes an assumed cost to connect the wind project to the transmission grid. However, it does not include the costs for any required transmission system upgrades.

The wind cost assumes two levels of integration costs. The first 156 MW of wind assumes a system integration cost of $4.6 / MWH (2006 $) and incremental wind beyond 156 MW has an integration costs of $6.6 / MWH (2006 $). As described further in my discussion of scenarios, wind was modeled under two assumptions regarding the PTC: first, assuming that the PTC would be extended thru 2012; and second, assuming the PTC is not extended beyond the end of 2008.

Q: What updates were made regarding Montana-Dakota's committed wind projects?

A: The analysis reflects the inclusion of Montana-Dakota's Diamond Willow wind project located near Baker, Montana. The updated analysis no longer includes capacity and energy associated with the 31.5 MW wind project that was slated to be installed near Java, South Dakota. That project was removed from the resource plan since the supplier defaulted on the contract in November, 2006.

Q: What updates in DSM assumptions were made?

A: As in the prior analysis, the impacts of conservation programs that Montana-Dakota is already implementing continue to be embedded in Montana-Dakota's long-term forecast. These programs include a residential high efficiency air conditioning program, a commercial high efficiency lighting program, and an interruptible load program. The least cost planning analysis in Strategist® is also allowed to select four proposed packages of conservation and DSM measures. All of these measures, outlined in MDU Exhibit 215 Table 5, are incorporated into the resource expansion plan developed in Strategist® and are based on Montana-Dakota's 2007 Integrated Resource Plan.

Q: Why was the option to extend the existing capacity contract between Montana-Dakota and NSP added to the resource plan?

A: The NSP contract, a four year contract for capacity starting in the summer of 2007, includes two options for renewal. The first option for renewal in 2011 is at a defined price and that option was incorporated into the Strategist® analysis previously presented to the Commission. In addition, the contract contains an option for a second annual extension, through the summer of 2012, at a price to be negotiated. While an extension of the contract requires that I make an assumption regarding the future contract price, I determined that it is better to include this option to provide a larger number of choices for the Montana-Dakota resource expansion plan. Extending the contract for modeling purposes creates more resource expansion options. Without the contract extension, the model is forced to select a long-term resource in 2012 due to the capacity deficit. The contract extension allows the model to select from long-term resources in 2012 and 2013 and thus creates more options.

Q: How did you determine the price for the contract extension in 2012?

A: I developed a proxy for a negotiated contract price based upon the levelized cost of a new General Electric 7FA combustion turbine. I also used Montana-Dakota's forecasted cost of natural gas.

Q: How much wind generation was incorporated into the resource optimization process?

A. In the case of wind generation, I limited the amount of wind to 219 MW of capacity which translates into approximately 40 percent of the utility's peak demand for 2015 and 25 percent to 35 percent of energy sales in 2015 (based upon a 38 percent or 52 percent capacity factor for the wind generation). These percentages are considered in excess of what could realistically be absorbed on the utility's system without incurring other costs, such as additional regulation up and down services, the need for more quick start capacity, potential loss of efficiencies associated with backing down base-load coal plants, and potential increased maintenance costs associated with more cycling of fossil fuel generation units.

Q: Did your modeling of resource options create a bias against natural gas and wind options as a result of limiting choices associated with the wind / gas options?

A: No. The model could identify whether there was a lower cost combination of wind and natural-gas fired generation subject to the constraint of a realistic maximum amount of wind that Montana-Dakota could absorb on its system.

Q: Can you elaborate on why you chose to limit Strategist® to selecting an additional 189 MW of wind beyond Diamond Willow?

A: The amount of wind that can be assumed as part of the Montana-Dakota expansion plan cannot be completely divorced from the reality and context of its actual system and the limitations of that system. I limited wind in the model to 219 MW (the existing and planned 30 MW Diamond Willow project plus the potential of an additional 189 MW) based upon my review of a number of transmission integration and related studies, including the 2006 Minnesota Wind Integration Study and the Bonneville Power Administration (BPA) 2007 Northwest Wind Integration Plan. The Northwest study analyzed wind penetration on the order of 20 – 30 percent of system capacity. The Minnesota study stops at 25 percent penetration of energy. While neither study identifies a maximum amount of wind that can be absorbed by a utility system, both studies find that the cost of integrating wind into the system increases as more wind is added to the system.

The integration costs increase as a result of increased need for other resources (hydro or thermal) to maintain system reliability and stability. While the Northwest study estimated an integration cost of $4.60 / MWH at a 30 percent penetration of wind, the federal Bonneville

Power system has a large amount of hydropower to support wind integration. Alternatively, Idaho Power and Avista estimate that wind integration costs are respectively \$8.84 and \$16.16 / MWH at a 30 percent penetration.

The impact of more than 219 MW of wind energy on the Montana-Dakota system would depend, in part, on the ability of the MISO system to absorb some of that wind. On a stand-alone basis, this would inevitably require Montana-Dakota coal plants to reduce generation in some hours that would have negative cost implications. For example, 219 MW of assumed wind on the Montana-Dakota system creates the potential for wind production to exceed 75 percent of the Montana-Dakota's hourly demand in over 25 percent of the hours in 2015. This high level of wind penetration could lead to additional costs not modeled in Strategist® due to the complexity of the issue and the difficulty of capturing those complexities in Strategist®. These costs, including the cost of backing down coal plants to uneconomic levels of operation and the need for spinning reserves and regulation-up and regulation-down services, are not fully captured in the assumption regarding wind integration costs. The need for sufficient responsive thermal resources to maintain system reliability with large amounts of wind was recently demonstrated in Texas where emergency curtailments of interruptible load were required as a result of wind variations. In the February 27, 2008 event, wind output in Western Texas dropped from 1,700 MW to 300 MW during a time that load increased from 31,200 MW to 35,612 MW.

Q: Have there been any studies performed on wind integration for the Montana-Dakota system?

A: I am not aware of any studies related to Montana-Dakota's system with regard to the amount of wind capacity the system can absorb without incurring costs for additional generation resources to support the wind. However, based on the Minnesota and Pacific Northwest studies, in order to be conservative (i.e., making an assumption in favor of wind energy), I increased the wind integration costs by only $2/MWH for capacity over 30 percent of the peak demand. Actual costs could be, if not likely will be, considerably greater.

In addition, it is important to also keep in mind that the total cost of adding a significant amount of wind is still understated since unlike the thermal resources analyzed in the expansion model, the costs for transmission that would actually be required to integrate significant additions of wind capacity into the grid were not included in the model.

Q: What was the result of the Strategist® modeling using the updated assumptions?

A: The results of my updated modeling continue to pick the Big Stone Unit II project as part of a least cost resource expansion plan. That plan also includes a new 43.5 MW gas peaking resource, a combination of energy-efficiency programs, and the Diamond Willow wind project.

Q: Did the Strategist® model identify a wind / CT alternative to the Big Stone Unit II alternative?

A: Yes, as shown on the Expansion Plan Summary, when the Big Stone Unit II resource is removed from the preferred resource mix, the next best resource mix under Scenarios I and II consists of four combustion turbines (174 MW) and four wind projects (126 MW in addition to the Diamond Willow project). However, there are some significant uncertainties associated with that plan. The plan assumes a wind capacity factor of over 50 percent which is a very questionable assumption. The cost of wind also assumes that Montana-Dakota would receive the benefit of the federal production tax credit for renewable resources and that no new transmission lines will be required. The assumption with the lack of transmission for wind resources is in contrast to the costs for new transmission facilities that were added to all the thermal options.

Q: Why were new transmission facility costs added to the thermal resources but not to the wind resources?

A: I did not have any studies regarding the costs to build transmission to the wind sites. The exclusion of the transmission cost is not meant to imply that a large penetration of wind energy will not require an associated transmission investment. However, leaving such costs out of the analysis favors the wind alternative.

IV. ADDITIONAL SCENARIOS

Q: Please summarize the additional scenarios that you analyzed?

A: I developed two additional scenarios that update the assumptions used in the third quarter of 2007 analysis. One scenario, Scenario III, is primarily designed to test some of the key assumptions regarding wind that resulted in wind / natural gas resources having a net present value cost within two percent of the least-cost scenario. The other scenario, Scenario IV, examines the potential benefits from off-system sales created by short-term excess capacity available to make such sales if Big Stone Unit II is built. The assumption updates in the additional scenarios include:

1. Testing the impact of the federal PTC not being extended;
2. Adjusting the capacity factor of the wind units to a more reasonable level;
3. Examining the impact of lower natural gas costs;
4. Allowing the resource expansion optimization to select Big Stone Unit II in 25 MW increments instead of as a single 116 MW unit;
5. Allowing the reduction of existing generation capacity that may be caused by regulation or obsolescence; and
6. Updating the cost-of-capital.

The first two assumptions in the list test the impact of two uncertain assumptions that I consider to be key drivers in the levelized cost of the wind. The third and fourth assumption updates were made to address concerns raised by others regarding the Montana-Dakota modeling.

Q: Why did you choose to analyze the impact of off-system sales?

A: The premise that the resource expansion plan should be based primarily on the retail load requirements of Montana-Dakota remains intact. However, a review of the model results indicates the Big Stone Unit II unit is not required to run at full capacity to meet Montana-Dakota's load requirements. In my testimony from last year, I pointed out there are potential benefits to off-system sales from the Big Stone Unit II unit, but those benefits were not included in the analysis. The purpose of the updated analysis is to identify the magnitude of those additional benefits.

Q: What is the impact of incorporating off-system sales into the resource planning optimization process?

A: The analysis identified an estimated additional $72m of benefits on a NPV basis. Importantly, the analysis also shows the selection of the resource expansion plan is not changed by the incorporation of off-system sales. In other words, the model does not rely on off-system sales as a basis for its selection of Big Stone Unit II for Montana-Dakota. Instead, it simply points to the fact that off-system sale opportunities provided by the plant provide additional benefits to Montana-Dakota's customers. These additional benefits diminish over time, however, as Montana-Dakota's retail load growth takes more and more of Montana-Dakota's participation in the project.

Q: Why did you test the impact of the expiration of the production tax credit?

A: The Energy Independence and Security Act of 2007, the major piece of federal energy legislation coming out of Congress last year, did not include an extension of the PTC. I anticipated extension of the PTC when I did my prior Strategist® modeling for Montana-Dakota. While the House of Representatives recently passed a bill to extend the PTC to the end of 2011 and it appears that some extension is likely, permanent extension remains uncertain. As a result, I simply wanted to test how important the federal PTC is to the selection of additional wind generation in any resource expansion modeling that we prepared for Montana-Dakota.

Q: What happens to the wind resource when the PTC is not extended in the model?

A: First, it is important to point out that Montana-Dakota's participation in Big Stone Unit II is identified as part of a least-cost resource plan even in scenarios which included the federal PTC. Even with the PTC extended (Scenarios I and II), the model did not select additional wind (i.e., beyond the 30 MW Diamond Willow) in the optimal expansion plan. The exclusion of the PTC obviously makes wind more expensive so it does not change the results of the model including Big Stone Unit II in the preferred plan. However, as I noted above, assuming no extension of the PTC causes the next best alternative resource plans – plans that substitute significant amounts of wind and natural gas generation in lieu of Big Stone Unit II – to become even more uneconomic, and in fact pushes these plans outside of 10 percent of the cost of the preferred plan.

Q: Why did you revise the assumption regarding the capacity factor of new wind units?

A: In the course of our review of certain of the modeling assumptions, we noted the model is still using a capacity factor for wind energy that is based on a single wind project that Montana-Dakota was considering in South Dakota. That project was cancelled after the developer defaulted. The capacity factor for the wind energy in that project was high, almost 52 percent, based solely on the developer's representations. Thus, to model a more reasonable assumption, we reduced the capacity factor from 52 to 38 percent based on the statistics reported for wind projects recently undertaken by Minnkota Power Cooperative.

Q: Did you adjust the accredited capacity of the wind units in conjunction with reducing the capacity factor?

A: No. The accredited capacity for wind remains at 23 percent of nameplate capacity.

Q: What assumptions did you make to test the impact of lower gas costs?

A: I tested the impact of reducing the gas transportation costs. A natural gas plant located near Mobridge is likely the best location for Montana-Dakota because of the availability of water and gas pipeline capacity, even given the short-term high gas transportation costs. Therefore, the purpose of the analysis was to investigate whether a hypothetical reduction in gas transportation costs makes natural gas-fired generation significantly more attractive. The lower gas price does not change the results, the model still selected Big Stone Unit II as part of the least cost expansion option.

Q: Why did you test selection of Big Stone Unit II in increments of 25 MW?

A: In prior hearings, particularly in the recent Minnesota proceedings, Montana-Dakota has been criticized because it elected not to model increments of Big Stone Unit II to which it has no contractual opportunity to participate. In other words, Mr. Schlissel has argued that Montana-Dakota should allow the model to select the optimal amount of Big Stone Unit II, regardless of whether this amount was available to Montana-Dakota in the real world.

Our recent modeling simply was intended to test the theoretical question of whether a smaller increment of baseload coal would result in a lower cost expansion plan to Montana-Dakota. The Strategist® model still selected 125 MW of Big Stone Unit II as part of the least cost expansion option. However, the model did identify higher cost expansion plans that incorporated smaller amounts of Big Stone Unit II in conjunction with building more combustion turbines.

Q: Why did you adjust the existing unit retirement assumptions?

A: Big Stone Unit II was already identified as part of the resource expansion plan assuming no other generating units are retired during the study period. The sensitivity was designed to identify whether there are additional savings associated with retiring smaller generating units that are relatively inefficient or have potentially high environmental retrofit costs.

Q: Why did you update the cost of capital?

A: The cost of capital was updated to make the analysis consistent with current utility financial assumptions.

Q: What other changes did you make to the modeling assumptions?

A: I corrected an error in modeling the energy profile associated with the possible NSP contract extension. The correction does not change the selection of new resources, but it corrected a problem with more energy being purchased under the short-term contract than what was needed given the availability of the existing coal plants.

V. UPDATED MODELING RESULTS SUMMARY

Q: What do the scenarios presented in your supplemental testimony conclude regarding the incorporation of Big Stone Unit II in Montana-Dakota's resource expansion plan?

A: The scenarios summarized below, and set forth in MDU Exhibit 215 , all indicate that the least cost expansion plan includes 116 to 131 MW of the proposed 500 MW Big Stone Unit II unit. The analysis also demonstrates that, while not a justification for its selection, there are additional benefits to Montana-Dakota customers from off-system sales resulting from the short-term capacity that is available to Montana-Dakota from Big Stone Unit II, which benefits decrease over time as Montana-Dakota's load grows.

Cost / Resource	Scenario I: Update of 2006 Study (Q3 2007)	Scenario II: Update of 2006 Study with Potential for 131 MW of BSII (Q3 2007)	Scenario III: PTC not Extended (Q1 2008)	Scenario IV: PTC not Extended and Off-System Sales (Q1 2008)
Study Period NPV 2007 $(000)	$2,203,347	$2,183,038	$2,124,493	$2,051,745
Big Stone Unit II	116 MW	131 MW	125 MW (five 25 MW increments selected)	125 MW (five 25 MW increments selected)
Wind	93 MW (Diamond Willow and two additional projects)	30 MW (Diamond Willow)	30 MW (Diamond Willow)	30 MW (Diamond Willow)
Combustion Turbines: Natural Gas	43.5 MW (one project)	43.5 MW (one project)	87 MW (two projects)	87 MW (two projects)
Combined Cycle Turbine: Natural Gas	None selected	None selected	None selected	None selected
Conservation	All programs included	All programs included	All programs included	All programs included

Q: What does the Strategist® modeling conclude regarding the Big Stone Unit II alternative versus a hypothetical wind/gas alternative?

A: The modeling continues to show that Montana-Dakota's participation in Big Stone Unit II remains the lowest cost option. In scenarios where the federal PTC is extended, the comparative costs between Big Stone Unit II and a natural gas/wind option becomes very close, with the wind/gas option within two percent of the Big Stone Unit II scenario. These scenarios, however, include use of a questionably high capacity factor for wind and wind would comprise nearly 30 percent of Montana-Dakota's total generating capacity. In cases assuming no PTC extension, a wind-gas option (that also excludes any portion of Big Stone Unit II) does not appear in plans that have a NPV within 10 percent of the least cost plan which includes Big Stone Unit II.

Q: Are there scenarios where the wind-gas option would displace Big Stone Unit II in the expansion plan?

A: Yes. One can change the input assumptions to construct scenarios where Big Stone Unit II would not be identified in the Strategist® model as a least cost expansion plan. Of course, scenarios can be constructed to achieve almost any result so the critical issue is the reasonableness of the collection of input assumptions that constitute the scenario. Those instances where a wind plus natural gas option is shown to be a lower cost option than is Montana-Dakota's participation in Big Stone Unit II would include a number of assumptions that, in my opinion, are unrealistic or undesirable or both. Montana-Dakota has stated, and with which I agree, the results of a particular model is an important consideration in the overall resource selection process. Modeling results, relying entirely on the assumptions upon which they are built, were never intended to be a substitute for experienced business judgment.

Q: Does this conclude your testimony?

A: Yes.

UPDATED STRATEGIST® ASSUMPTIONS AND RESULTS

Table 1: Fuel Cost Assumptions for Scenarios I & II

			Natural Gas		
Year	Big Stone Unit II (nominal)	Lignite - LV-21 (nominal)	Ventura Hub (nominal)	Transportation (NOMINAL)	Delivered (nominal)
2007			**$7.67**	**$2.88**	**$10.55**
2008			**$7.59**	**$2.97**	**$10.56**
2009			**$7.64**	**$3.06**	**$10.69**
2010	**$1.76**	**$1.44**	**$7.70**	**$3.15**	**$10.85**
2011	**$1.81**	**$1.48**	**$7.88**	**$3.24**	**$11.12**
2012	**$1.86**	**$1.53**	**$8.00**	**$3.34**	**$11.34**
2013	**$1.92**	**$1.57**	**$8.18**	**$3.44**	**$11.62**
2014	**$1.98**	**$1.62**	**$8.49**	**$3.54**	**$12.03**
2015	**$2.04**	**$1.67**	**$8.80**	**$3.65**	**$12.45**
2016	**$2.10**	**$1.72**	**$9.20**	**$3.76**	**$12.96**
2017	**$2.16**	**$1.77**	**$9.56**	**$3.87**	**$13.43**
2018	**$2.22**	**$1.82**	**$9.94**	**$3.99**	**$13.92**
2019	**$2.29**	**$1.88**	**$10.33**	**$1.64**	**$11.97**
2020	**$2.36**	**$1.94**	**$10.73**	**$1.69**	**$12.42**
2021	**$2.43**	**$1.99**	**$11.15**	**$1.74**	**$12.89**
2022	**$2.50**	**$2.05**	**$11.59**	**$1.79**	**$13.38**
2023	**$2.58**	**$2.12**	**$12.05**	**$1.85**	**$13.89**
2024	**$2.66**	**$2.18**	**$12.52**	**$1.90**	**$14.42**
2025	**$2.74**	**$2.24**	**$13.01**	**$1.96**	**$14.97**
2026	**$2.82**	**$2.31**	**$13.53**	**$2.02**	**$15.54**

Table 2: Natural Cost Assumptions for Scenarios III & IV

	Natural Gas Alternative (Scenarios III & IV)		
Year	Ventura Hub (nominal)	Transportation (NOMINAL)	Delivered (nominal)
2007	**$7.67**	$ 0.65	$ 8.32
2008	**$7.59**	$ 0.67	$ 8.26
2009	**$7.64**	$ 0.69	$ 8.33
2010	**$7.70**	$ 0.71	$ 8.41
2011	**$7.88**	$ 0.73	$ 8.61
2012	**$8.00**	$ 0.75	$ 8.75
2013	**$8.18**	$ 0.78	$ 8.96
2014	**$8.49**	$ 0.80	$ 9.29
2015	**$8.80**	$ 0.83	$ 9.63
2016	**$9.20**	$ 0.85	$ 10.05
2017	**$9.56**	$ 0.87	$ 10.43
2018	**$9.94**	$ 0.90	$ 10.84
2019	**$10.33**	$ 0.92	$ 11.25
2020	**$10.73**	$ 0.96	$ 11.69
2021	**$11.15**	$ 0.99	$ 12.14
2022	**$11.59**	$ 1.01	$ 12.60
2023	**$12.05**	$ 1.04	$ 13.09
2024	**$12.52**	$ 1.08	$ 13.60
2025	**$13.01**	$ 1.11	$ 14.12
2026	**$13.53**	$ 1.14	$ 14.67

Table 3: Load Forecast Assumptions

	October 2006		Supplemental Filing 03/08	
Year	Peak Demand (MW)	Energy Sales (GWH)	Peak Demand (MW)	Energy Sales (GWH)
2006	481.8	2,441		
2007	487.8	2,496	475.3	2,509
2008	492.4	2,540	481.9	2,562
2009	497.0	2,581	487.9	2,603
2010	502.4	2,624	493.7	2,653
2011	507.7	2,647	499.2	2,688
2012	512.9	2,669	504.7	2,722
2013	518.1	2,689	510.1	2,755
2014	523.3	2,706	515.6	2,789
2015	528.6	2,723	521.1	2,822
2016	533.6	2,740	526.6	2,853
2017	538.9	2,758	532.1	2,884
2018	544.1	2,775	537.5	2,914
2019	549.3	2,793	543.0	2,945
2020	554.5	2,811	548.4	2,976
2021	559.8	2,829	554.0	3,006
2022	564.8	2,847	559.4	3,037
2023	570.1	2,866	564.9	3,069
2024	575.3	2,884	570.4	3,100
2025	580.5	2,903	575.9	3,131
2026			581.4	3163
Avg Annual Growth	0.99%	0.92%	1.07%	1.23%

Table 4: Assumptions for Alternative Resource Options

New Generation Resource Options

Unit	Fuel	Capacity (MW)	Full Load Heat Rate (Btu/kWh)	Capital Cost $/kW (2006)2	First Year Available	Fixed Cost $/kW (2006)	Variable Cost $/MWh (2006)
Combustion Turbine	**Natural Gas**	**43.5**	**9,000**	**975**	**2009**	**32.22**	**3.67**
Combined Cycle	**Natural Gas**	**120**	**7,548**	**1,795**	**2010**	**18.85**	**3.73**
Big Stone Unit II [3]	**Coal**	**116**	**8,988**	**2,853**	**2013**	**31.27**	**1.58**
Wind (2010 - 2012)[1]	**Wind**	**31.5**		**2,000**	**2010**	**56.54**	**4.60**
Wind 2012[2]	**Wind**	**31.5**		**2035**	**2012**	**56.54**	**6.60**
Wind no PTC	**Wind**	**31.5**		**2,000**	**2013**	**56.54**	**4.60**
IGCC	**Coal**	**116**	**9,612**	**3,006**	**2013**	**24.15**	**6.06**
LV -21	**Coal**	**175**	**10,440**	**3,050**	**2013**	**46.72**	**2.75**

1. First 126 MW of wind in addition to the 30 MW of Diamond Willow
2. Next 62.5 MW of wind.
3. Scenarios III & IV modeled Big Stone Unit II in 25 MW increments

Table 5: Demand Side Management Options

Program	Demand (MW)	Program Cost (2007 Dollars)	Total Energy Reduction kWh	Average Cost per kWh
Residential Refrigerators and Freezers (DSM 1)	**0.949**	**$517,491**	**20,750,835**	**$0.03**
Residential and Commercial AC Cycling (DSM 2)	**8.024**	**$3,366,852**	**26,793,912**	**$0.13**
High Efficiency Commercial AC and Motors (DSM 3)	**0.337**	**$309,978**	**11,561,276**	**$0.0268**
Interruptible Rate (DSM 4)	**4.5**	**$553,255**	**3,400,252**	**$0.16**

Table 6: Summary Results For Scenario I

Scenario I: Q3 2007

CON 11-07 Base 500
PA CONSULTING

GENERATION AND FUEL MODULE
SYSTEM REPORT

MDU SYSTEM		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
ENERGY REQUIRED	GWH	2,509	2,561	2,600	2,648	2,683	2,716	2,750	2,784	2,817	2,847	2,878	2,908	2,939	2,970	3,001	3,032	3,063	3,094	3,125	3,157
THERM GENERATION	GWH	2,180	2,122	2,142	2,032	1,943	1,975	2,360	2,394	2,382	2,411	2,443	2,473	2,504	2,534	2,566	2,597	2,628	2,658	2,690	2,722
EMERGENCY ENERGY	GWH	3	3	3	2	1	1	1	-	-	-	1	1	1	-	-	-	-	-	-	1
NET TRANSACTIONS	GWH	326	436	455	615	739	740	389	389	435	436	435	435	435	436	435	435	435	436	435	435
PEAK LOAD	MW	475	477	480	483	486	492	497	503	508	514	519	524	530	535	541	546	552	557	563	568
LOAD FACTOR	PCT	60.27	61.09	61.79	62.55	63	62.9	63.15	63.23	63.29	63.12	63.29	63.31	63.31	63.16	63.33	63.35	63.36	63.2	63.39	63.41
INSTALLED CAPACITY	MW	568	578	583	595	607	607	608	608	611	611	611	611	611	654	654	654	654	654	654	654
RESERVE MARGIN	MW	93	101	102	112	121	116	111	106	103	97	92	86	81	119	113	108	102	97	91	86
RESERVE MARGIN	PCT	19.54	21.07	21.31	23.1	24.91	23.52	22.38	21.04	20.18	18.89	17.63	16.42	15.21	22.18	20.91	19.72	18.52	17.35	16.21	15.08
CAPACITY MARGIN	PCT	16.35	17.4	17.57	18.77	19.94	19.04	18.29	17.38	16.79	15.89	14.99	14.11	13.2	18.15	17.3	16.47	15.63	14.79	13.95	13.11
ENERGY RESV MARGIN	PCT	-86.99	-82.96	-82.51	-80.91	-80.58	-80.82	-93.78	-93.86	-92.3	-92.39	-92.47	-92.55	-92.62	-92.7	-92.77	-92.85	-92.92	-92.99	-93.06	-93.13
FUEL BURNED	MMBTU	24,128	23,467	23,704	22,433	21,392	21,765	24,888	24,462	24,337	24,648	24,972	25,289	25,608	25,896	26,232	26,558	26,887	27,201	26,810	27,080
TOTAL FUEL COST	$(000)	35,312	34,803	36,804	34,448	32,538	34,217	40,760	39,981	40,912	42,845	44,933	47,070	48,937	51,039	53,507	56,030	58,686	61,382	63,230	66,178
VAR. O&M COST	$(000)	5,018	4,972	5,220	4,953	4,736	4,949	5,053	4,554	4,645	4,832	5,023	5,219	5,425	5,616	5,846	6,080	6,325	6,572	6,852	7,136
FIXED O&M COST	$(000)	10,618	10,883	11,156	11,434	11,720	12,013	14,841	17,040	17,466	17,903	18,351	18,809	19,280	22,868	23,439	24,025	24,626	25,242	25,873	26,520
TOTAL THERM COST	$(000)	50,947	50,659	53,179	50,836	48,994	51,179	60,654	61,575	63,024	65,580	68,306	71,098	73,641	79,523	82,792	86,136	89,637	93,196	95,955	99,833
THERMAL COST	$/MWH	23.37	23.87	24.82	25.02	25.22	25.91	25.71	25.72	26.46	27.2	27.96	28.75	29.41	31.38	32.27	33.17	34.11	35.06	35.67	36.68
NET TRANS COST	$(000)	24,107	30,093	32,453	41,146	47,605	56,324	18,198	18,652	22,029	22,622	23,145	23,723	24,316	24,970	25,547	26,186	26,841	27,562	28,200	28,905
EMER ENERGY COST	$(000)	202	189	224	145	93	103	86	26	25	30	36	41	48	14	17	20	23	27	32	38
TOTAL SYS. COST	$(000)	75,256	80,941	85,856	92,127	96,693	107,606	78,937	80,253	85,078	88,232	91,486	94,863	98,006	104,507	108,356	112,342	116,502	120,786	124,187	128,776
SYSTEM COST	$/MWH	29.99	31.61	33.02	34.79	36.04	39.62	28.71	28.83	30.2	30.99	31.79	32.62	33.35	35.19	36.11	37.05	38.04	39.04	39.73	40.79
AVG. MARG. COST	$/MWH	40.48	39.5	42.55	38.41	34.81	36.48	31.61	24.01	24.58	26.04	27.55	29.01	29.28	29.33	30.92	32.5	34.41	36.14	38.53	40.75
TRANS PURCH	GWH	326	436	455	615	739	740	389	389	435	436	435	435	435	436	435	435	435	436	435	435
TRANS PURCH COST	$(000)	24107	30093	32453	41146	47605	56324	18198	18652	22029	22622	23145	23723	24316	24970	25547	26186	26841	27562	28200	28905
TOTAL PURCH	GWH	326	436	455	615	739	740	389	389	435	436	435	435	435	436	435	435	435	436	435	435
TOTAL PURCH	$(000)	24107	30093	32453	41146	47605	56324	18198	18652	22029	22622	23145	23723	24316	24970	25547	26186	26841	27562	28200	28905
TOTAL SALES	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL SALES	$(000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 7: Summary Results For Scenario II

Scenario II: Q3 2007 Allowing for up to Four 5 MW Increments of Big Stone Unit II

MDU SYSTEM		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
ENERGY REQUIRED	GWH	2509	2561	2600	2648	2683	2716	2750	2784	2817	2847	2878	2908	2939	2970	3001	3032	3063	3094	3125	3157
THERM GENERATION	GWH	2180	2122	2142	2172	2223	2256	2641	2677	2665	2695	2725	2756	2786	2818	2849	2880	2911	2942	2973	3004
EMERGENCY ENERGY	GWH	3	3	3	4	4	4	3	1	1	1	1	1	1	0	0	1	1	1	1	1
NET TRANSACTIONS	GWH	326	436	455	473	456	456	106	106	152	152	152	152	152	152	152	152	152	152	152	152
PEAK LOAD	MW	475	477	480	483	486	492	497	503	508	514	519	524	530	535	541	546	552	557	563	568
LOAD FACTOR	PCT	60.27	61.09	61.79	62.55	63	62.9	63.15	63.23	63.29	63.12	63.29	63.31	63.31	63.16	63.33	63.35	63.36	63.2	63.39	63.41
INSTALLED CAPACITY	MW	568	578	583	588	593	593	609	609	611	611	611	611	611	655	655	655	655	655	655	655
RESERVE MARGIN	MW	93	101	102	104	107	101	112	106	103	98	92	87	81	119	114	108	103	97	92	86
RESERVE MARGIN	PCT	19.54	21.07	21.31	21.6	21.93	20.57	22.48	21.14	20.28	18.99	17.73	16.52	15.31	22.27	21.01	19.81	18.62	17.45	16.3	15.17
CAPACITY MARGIN	PCT	16.35	17.4	17.57	17.77	17.99	17.06	18.35	17.45	16.86	15.96	15.06	14.18	13.28	18.22	17.36	16.53	15.69	14.85	14.01	13.17
ENERGY RESV MARGIN	PCT	-86.99	-82.96	-82.51	-82.14	-83.01	-83.22	-96.15	-96.2	-94.62	-94.67	-94.73	-94.79	-94.84	-94.89	-94.95	-95	-95.05	-95.1	-95.15	-95.2
LOSS LOAD	HOURS	96	92	106	120	132	142	105	21	20	24	28	32	36	12	14	16	18	21	24	28
RENEWABLE ENERGY	PCT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FUEL BURNED 000	MBTU	24128	23467	23704	24059	24637	25012	27900	27201	27072	27400	27730	28057	28387	28679	29025	29361	29701	30027	29644	29923
FIXED FUEL COST	$0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUEL COST	$0	35312	34803	36804	38979	41472	43672	48946	45551	46645	48837	51170	53572	55543	57853	60613	63442	66426	69459	71688	75033
VAR. O&M COST	$0	5018	4972	5220	5487	5785	6041	5865	4963	5062	5270	5485	5704	5934	6141	6401	6664	6939	7213	7531	7850
FIXED O&M COST	$0	10618	10883	11156	11434	11720	12013	15168	17612	18052	18503	18966	19440	19926	23530	24119	24722	25340	25973	26623	27288
TOTAL THERM COST	$0	50947	50659	53179	55901	58977	61726	69979	68126	69759	72610	75621	78716	81403	87525	91133	94827	98705	102645	105841	110170
THERMAL COST	$/MWH	23.37	23.87	24.82	25.74	26.53	27.36	26.5	25.45	26.18	26.94	27.75	28.56	29.22	31.06	31.99	32.93	33.91	34.89	35.6	36.67
NET TRANS COST	$0	24107	30093	32453	34927	34682	43040	4620	4735	7764	7958	8157	8361	8570	8785	9004	9229	9460	9697	9939	10188
EMER ENERGY COST	$0	202	189	224	256	287	312	231	45	44	53	62	71	82	25	30	35	41	47	55	64
TOTAL SYS. COST	$0	75256	80941	85856	91084	93946	105077	74831	72906	77567	80621	83840	87149	90056	96335	100167	104092	108206	112389	115836	120422
SYSTEM COST	$/MWH	29.99	31.61	33.02	34.39	35.02	38.68	27.21	26.19	27.54	28.31	29.13	29.96	30.64	32.44	33.38	34.33	35.33	36.32	37.06	38.14
AVG. MARG. COST	$/MWH	40.48	39.5	42.55	45.48	48.37	51.28	40.69	26.15	26.76	28.42	30.25	32.05	32.06	31.9	33.93	35.86	37.97	40.02	42.89	45.61
TRANS PURCH	GWH	326	436	455	473	456	456	106	106	152	152	152	152	152	152	152	152	152	152	152	152
TRANS PURCH COST	$0	24107	30093	32453	34927	34682	43040	4620	4735	7764	7958	8157	8361	8570	8785	9004	9229	9460	9697	9939	10188
TRANS SALES	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRANS SALES REV.	$0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL PURCH	GWH	326	436	455	473	456	456	106	106	152	152	152	152	152	152	152	152	152	152	152	152
TOTAL PURCH	$0	24107	30093	32453	34927	34682	43040	4620	4735	7764	7958	8157	8361	8570	8785	9004	9229	9460	9697	9939	10188
TOTAL SALES	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL SALES	$0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EXTERNAL COSTS	$0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CUST. IMPACT COSTS	$0	0	0	0	0	0	0	0	0									0	0	0	0

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Table 8: Summary Results For Scenario III

Scenario III: Q1 2008 with no Off-System Sales

MDU SYSTEM		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ENERGY REQUIRED	GWH	2,509	2,561	2,600	2,648	2,683	2,716	2,750	2,784	2,817	2,847	2,878	2,908	2,939	2,970	3,001	3,032	3,063	3,094	3,125
THERM GENERATION	GWH	2,449	2,408	2,444	2,485	2,514	2,579	2,643	2,677	2,664	2,695	2,726	2,756	2,787	2,818	2,849	2,880	2,911	2,942	2,973
EMERGENCY ENERGY	GWH	3	3	3	4	4	1	1	1	1	1	1	1	1	-	-	-	-	1	1
NET TRANSACTIONS	GWH	57	151	153	160	165	136	106	106	152	152	152	152	152	152	152	152	152	152	152
PEAK LOAD	MW	475	477	480	483	486	492	497	503	508	514	519	524	530	535	541	546	552	557	563
LOAD FACTOR	PCT	60.27	61.09	61.79	62.55	63	62.9	63.15	63.23	63.29	63.12	63.29	63.31	63.31	63.16	63.33	63.35	63.36	63.2	63.39
INSTALLED CAPACITY	MW	568	578	583	588	593	636	596	587	589	610	610	610	610	653	653	653	653	653	653
RESERVE MARGIN	MW	93	101	102	104	107	145	99	84	81	96	91	85	80	118	112	107	101	96	90
RESERVE MARGIN	PCT	19.54	21.07	21.31	21.6	21.93	29.42	19.96	16.74	15.93	18.71	17.45	16.24	15.03	22	20.73	19.54	18.35	17.18	16.04
CAPACITY MARGIN	PCT	16.35	17.4	17.57	17.77	17.99	22.73	16.64	14.34	13.74	15.76	14.86	13.97	13.07	18.03	17.17	16.35	15.5	14.66	13.82
ENERGY RESV MARGIN	PCT	-99.43	-95.87	-95.93	-96	-96.05	-96.1	-96.15	-96.2	-94.62	-94.67	-94.73	-94.79	-94.84	-94.89	-94.95	-95	-95.05	-95.1	-95.15
LOSS LOAD	HOURS	95	89	104	118	129	40	46	33	32	27	22	25	29	9	11	13	15	17	20
RENEWABLE ENERGY	PCT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FUEL BURNED 000	MBTU	27,076	26,607	27,028	27,508	27,847	28,423	28,325	28,078	27,953	27,806	27,888	28,202	28,519	28,824	29,154	29,478	29,803	30,119	29,718
FIXED FUEL COST	$0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL FUEL COST	$0	39,060	38,908	41,266	43,797	46,110	49,432	48,761	47,621	48,732	51,342	52,326	54,866	57,226	59,815	62,845	65,958	69,245	72,569	75,242
VAR. O&M COST	$0	5,769	5,778	6,102	6,450	6,750	7,084	6,739	6,441	6,557	6,455	6,565	6,821	7,089	7,345	7,642	7,943	8,258	8,577	8,929
FIXED O&M COST	$0	10,618	10,883	11,156	11,434	11,720	14,563	16,561	18,140	18,593	18,599	19,916	20,413	20,924	24,553	25,167	25,796	26,441	27,102	27,779
TOTAL THERM COST	$0	55,448	55,569	58,523	61,682	64,581	71,078	72,061	72,202	73,883	76,396	78,807	82,100	85,239	91,714	95,653	99,697	103,945	108,248	111,951
THERMAL COST	$/MWH	22.64	23.08	23.95	24.82	25.69	27.56	27.27	26.97	27.73	28.35	28.91	29.79	30.59	32.55	33.58	34.62	35.71	36.79	37.65
NET TRANS COST	$0	5,424	10,724	11,379	11,692	13,860	11,462	4,620	4,735	7,764	7,958	8,157	8,361	8,570	8,785	9,004	9,229	9,460	9,697	9,939
EMER ENERGY COST	$0	200	183	219	252	279	72	88	72	70	54	47	55	64	19	23	27	31	36	43
TOTAL SYS. COST	$0	61,072	66,477	70,121	73,626	78,719	82,612	76,769	77,009	81,717	84,409	87,012	90,517	93,873	100,518	104,680	108,953	113,436	117,981	121,933
SYSTEM COST	$/MWH	24.34	25.96	26.97	27.8	29.34	30.41	27.92	27.66	29.01	29.65	30.24	31.12	31.94	33.85	34.88	35.94	37.04	38.13	39.01
AVG. MARG. COST	$/MWH	42.3	41.84	44.68	48.24	53.46	49.76	39.98	32.63	33.32	33.26	31.61	33.5	34.44	35.18	37.57	39.81	42.29	44.53	47.72
TRANS PURCH	GWH	14	106	106	106	106	106	106	106	152	152	152	152	152	152	152	152	152	152	152
TRANS PURCH COST	$0	423	4,264	4,370	4,480	4,592	4,706	4,620	4,735	7,764	7,958	8,157	8,361	8,570	8,785	9,004	9,229	9,460	9,697	9,939
TRANS SALES	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS SALES REV.	$0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UNIT PURCH	GWH	43	45	47	54	59	30	-	-	-	-	-	-	-	-	-	-	-	-	152
UNIT PURCH COST	$0	5,001	6,461	7,009	7,212	9,268	6,756	-	-	-	-	-	-	-	-	-	-	-	-	9,939
UNIT SALES	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UNIT SALES REV.	$0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PURCH	GWH	57	151	153	160	165	136	106	106	152	152	152	152	152	152	152	152	152	152	-
TOTAL PURCH	$0	5,424	10,724	11,379	11,692	13,860	11,462	4,620	4,735	7,764	7,958	8,157	8,361	8,570	8,785	9,004	9,229	9,460	9,697	-
TOTAL SALES	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 9: Summary Results For Scenario IV

Scenario IV: Q1 2008 with no Off-System Sales

MDU SYSTEM		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ENERGY REQUIRED	GWH	2,509	2,561	2,600	2,648	2,683	2,716	2,750	2,784	2,817	2,847	2,878	2,908	2,939	2,970	3,001	3,032	3,063	3,094	3,125
THERM GENERATION	GWH	2,569	2,580	2,583	2,585	2,583	2,636	3,185	3,619	3,612	3,516	3,515	3,474	3,544	3,649	3,600	3,610	3,600	3,557	3,532
EMERGENCY ENERGY	GWH	3	3	3	4	4	4	3	1	1	1	1	1	1	-	-	-	-	1	1
NET TRANSACTIONS	GWH	(62)	(22)	14	60	96	76	(438)	(836)	(796)	(669)	(638)	(567)	(606)	(679)	(600)	(579)	(537)	(463)	(407)
PEAK LOAD	MW	475	477	480	483	486	492	497	503	508	514	519	524	530	535	541	546	552	557	563
LOAD FACTOR	PCT	60.27	61.09	61.79	62.55	63	62.9	63.15	63.23	63.29	63.12	63.29	63.31	63.31	63.16	63.33	63.35	63.36	63.2	63.39
INSTALLED CAPACITY	MW	568	578	583	588	593	593	603	593	595	610	610	610	610	653	653	653	653	653	653
RESERVE MARGIN	MW	93	101	102	104	107	101	106	91	87	96	91	85	80	118	112	107	101	96	90
RESERVE MARGIN	PCT	19.54	21.07	21.31	21.6	21.93	20.57	21.27	18.04	17.21	18.71	17.45	16.24	15.03	22	20.73	19.54	18.35	17.18	16.04
CAPACITY MARGIN	PCT	16.35	17.4	17.57	17.77	17.99	17.06	17.54	15.28	14.68	15.76	14.86	13.97	13.07	18.03	17.17	16.35	15.5	14.66	13.82
ENERGY RESV MARGIN	PCT	-99.43	-95.87	-95.93	-96	-96.05	-96.1	-96.15	-96.2	-94.62	-94.67	-94.73	-94.79	-94.84	-94.89	-94.95	-95	-95.05	-95.1	-95.15
LOSS LOAD	HOURS	95	89	104	118	129	137	104	27	26	19	22	25	29	9	11	13	15	17	20
RENEWABLE ENERGY	PCT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FUEL BURNED 000	MBTU	28,492	28,646	28,679	28,707	28,671	29,256	33,977	37,872	37,789	36,350	36,347	35,875	36,645	37,700	37,175	37,280	37,173	36,705	35,709
FIXED FUEL COST	$0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL FUEL COST	$0	42,078	43,907	45,162	46,256	47,754	52,280	65,977	75,911	78,176	79,887	82,785	83,432	89,009	98,239	97,672	101,588	104,208	103,762	103,632
VAR. O&M COST	$0	6,233	6,486	6,677	6,859	7,030	7,488	8,560	9,604	9,834	9,249	9,502	9,555	10,200	10,886	10,895	11,230	11,438	11,476	11,622
FIXED O&M COST	$0	10,618	10,883	11,156	11,434	11,720	12,013	15,037	17,366	17,800	19,430	19,916	20,413	20,924	24,553	25,167	25,796	26,441	27,102	27,779
TOTAL THERM COST	$0	58,929	61,276	62,995	64,550	66,504	71,782	89,575	102,881	105,810	108,566	112,202	113,401	120,133	133,678	133,733	138,614	142,087	142,340	143,033
THERMAL COST	$/MWH	22.94	23.75	24.39	24.97	25.75	27.24	28.13	28.43	29.29	30.88	31.92	32.64	33.89	36.64	37.15	38.4	39.47	40.02	40.5
NET TRANS COST	$0	1,173	3,750	5,979	8,224	11,572	8,808	(25,131)	(47,588)	(46,776)	(40,485)	(40,285)	(36,600)	(40,982)	(50,892)	(44,024)	(44,598)	(43,019)	(36,773)	(33,646)
EMER ENERGY COST	$0	200	183	219	252	279	300	228	58	56	40	47	55	64	19	23	27	31	36	43
TOTAL SYS. COST	$0	60,302	65,209	69,193	73,026	78,355	80,889	64,672	55,350	59,090	68,121	71,965	76,856	79,215	82,805	89,732	94,043	99,099	105,604	109,430
SYSTEM COST	$/MWH	24.03	25.46	26.61	27.57	29.2	29.78	23.52	19.88	20.98	23.92	25.01	26.43	26.95	27.88	29.9	31.02	32.35	34.13	35.01
AVG. MARG. COST	$/MWH	46.12	48.38	49.87	51.21	55.27	65.39	61.54	61.53	63.67	65.17	67.98	68.52	70.71	76.26	75.94	79.16	81.67	81.34	85.75
TRANS PURCH	GWH	14	106	106	106	106	106	106	106	152	152	152	152	152	152	152	152	152	152	152
TRANS PURCH COST	$0	423	4,264	4,370	4,480	4,592	4,706	4,620	4,735	7,764	7,958	8,157	8,361	8,570	8,785	9,004	9,229	9,460	9,697	9,939
TRANS SALES	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS SALES REV.	$0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UNIT PURCH	GWH	54	56	60	65	68	95	-	-	-	-	-	-	-	-	-	-	-	-	-
UNIT PURCH COST	$0	5,748	7,290	7,913	8,056	10,123	12,922	-	-	-	-	-	-	-	-	-	-	-	-	-
UNIT SALES	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UNIT SALES REV.	$0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
ECON ENERGY PURCH	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
PURCH COST	$0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
AVE. PURCH COST	$/MWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECON ENERGY SALES	GWH	130	184	151	111	78	125	544	942	948	820	789	718	758	831	751	730	689	615	558
SALES REV.	0	4998	7804	6305	4311	3143	8821	29750	52324	54541	48443	48443	44961	49552	59677	53028	53827	52480	46470	43585
AVE. SALES REV.	$/MWH	38.39	42.37	41.64	38.74	40.55	70.72	54.67	55.57	57.53	59.04	61.37	62.6	65.39	71.82	70.58	73.71	76.16	75.58	78.05
NET ECON ENERGY	GWH	-130	-184	-151	-111	-78	-125	-544	-942	-948	-820	-789	-718	-758	-831	-751	-730	-689	-615	-558
NET ECON COST	0	-4998	-7804	-6305	-4311	-3143	-8821	-29750	-52324	-54541	-48443	-48443	-44961	-49552	-59677	-53028	-53827	-52480	-46470	-43585
TOTAL PURCH	GWH	68	162	166	171	174	201	106	106	152	152	152	152	152	152	152	152	152	152	152
TOTAL PURCH	0	6,171	11,554	12,284	12,535	14,715	17,629	4,620	4,735	7,764	7,958	8,157	8,361	8,570	8,785	9,004	9,229	9,460	9,697	9,939
TOTAL SALES	GWH	130	184	151	111	78	125	544	942	948	820	789	718	758	831	751	730	689	615	558
TOTAL SALES	0	4,998	7,804	6,305	4,311	3,143	8,821	29,750	52,324	54,541	48,443	48,443	44,961	49,552	59,677	53,028	53,827	52,480	46,470	43,585

Table 10: Montana-Dakota's Least Cost Expansion Plan Summary

	October 2006	Scenario I Q3 2007	Scenario II Q3 2007	Scenario III Q1 2008	Scenario IV Q1 2008 with Off-System Sales
NPV ($000)	1,780,543	2,203,347	2,183,038	2,124,493	2,051,745
2007	NSP Peaking	NSP Peaking	NSP Peaking	NSP Peaking	NSP Peaking
2008	S.D. Wind & Montana Wind	Montana Wind, DSM	Montana Wind, DSM	Montana Wind, DSM	Montana Wind, DSM
2009		DSM	DSM	DSM	DSM
2010		Wind			
2011	NSP Peaking contract extension	Wind, NSP Peaking contract extension	NSP Peaking contract extension	NSP Peaking contract extension	NSP Peaking contract extension
2012	Big Stone Unit II (116 MW)	NSP Peaking contract extension	NSP Peaking contract extension	NSP Peaking contract extension, CT	NSP Peaking contract extension
2013		Big Stone Unit II (116 MW)	Big Stone Unit II (131 MW)	Big Stone Unit II (75 MW)	Big Stone Unit II (125 MW)
2014	DSM				
2015	Montana Wind, CT & DSM	Montana Wind	Montana Wind	Montana Wind	Montana Wind
2016				Big Stone Unit II (25 MW)	CT
2017					
2018					
2019					
2020		CT	CT	CT	CT
2021					
2022					
2023	Wind				
2024	Wind				
2025					

Scenario I: Big Stone Unit II option modeled as 116 MW share of a 500 MW plant
Scenario II: Big Stone Unit II option modeled as a 116 MW share of a 500 MW plant with an option for up to four additional 5 MW increments
Scenario III: Big Stone Unit II modeled with 25 MW increments
Scenario IV: Big Stone Unit II modeled with 25 MW increments with pool sales.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation, Advance Determination of Prudence Application	**AFFIDAVIT OF SERVICE**
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., Advance Determination of Prudence Application	Case Nos. PU-06-481, PU 06-482

Kristen A. Swenson, of the City of Minneapolis, County of Hennepin, in the State of North Dakota, being duly sworn on oath says: that on the 10th day of March, 2008, she served the following:

Ward Uggerud (OTP Exhibit 112);
Bryan Morlock (OTP Exhibit 117);
Andrea Stomberg (MDU Exhibit 213);
James Heidell (MDU Exhibit 214);
Mark Rolfes (OTP/MDU Exhibit 324);
Tim Rogelstad (OTP/MDU Exhibit 325);
Jeffrey Grieg (OTP/MDU Exhibit 326);
Thomas Crowley (OTP/MDU Exhibit 328); and
An Affidavit of Service.

A copy has also been served upon the attached service list via electronic mail and U.S. Mail.

Kristen A. Swenson

Subscribed and sworn to before me
this 10th day of March, 2008.

Donna A LeClair

Notary Public

DONNA A LECLAIR
Notary Public-Minnesota
My Commission Expires Jan 31, 2010

Doc# 2487093\1

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation, Advance Determination of Prudence Application

SERVICE LIST

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., Advance Determination of Prudence Application

Case Nos. PU-06-481, PU 06-482

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