Joint Intervenors
Exhibit 4

BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application by Otter Tail Power Company on behalf of the Big Stone II Co-owners for an Energy Conversion Facility Siting Permit for the Construction of the Big Stone II Project	))))	Case No EL05-022

Direct Testimony of
David A. Schlissel and Anna Sommer
Synapse Energy Economics, Inc.

On Behalf of
Minnesotans for an Energy-Efficient Economy
Izaak Walton League of America – Midwest Office
Union of Concerned Scientists
Minnesota Center for Environmental Advocacy

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Q. Mr. Schlissel, please state your name, position and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. Ms. Sommer, please state your name position and business address.

A. My name is Anna Sommer. I am a Research Associate at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. We are testifying on behalf of Minnesotans for an Energy-Efficient Economy, Izaak Walton League of America – Midwest Office, Union of Concerned Scientists, and Minnesota Center for Environmental Advocacy ("Joint Intervenors").

Q. Have you previously filed testimony in this proceeding?

A. Yes. We filed testimony on May 19, 2006 on the issue of whether the Big Stone II Co-owners have appropriately reflected the potential for the regulation of greenhouse gases in the design of the proposed facility and in their analyses of the alternatives.

Q. What is the purpose of this testimony?

A. This testimony reports on the results of our investigations of the other three issues that Synapse was asked to examine by Joint Intervenors:

A. The need and timing for new supply options in the utilities' service territories.

B. Whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

C. Whether the applicants have included appropriate emissions control technologies in the design of the proposed facility.

This testimony presents the results of our investigations of these issues.

Q. Please summarize the conclusions of this testimony.

A. Our conclusions are as follows:

1. The Co-owners have not demonstrated that there is a regional need for new baseload generating capacity in 2011.

2. The Co-owners have not demonstrated that they each need new baseload generating capacity beginning in 2011.

3. The Co-owners have not shown that the addition of Big Stone II is the lowest cost option as compared to portfolios of renewable and demand-side alternatives, either in the three jointly sponsored analyses submitted as part of their testimony in this proceeding or in the analyses carried out by the individual project participants.

4. The Co-owners *Phase I Report Big Stone II* summarily dismisses renewable alternatives (that is, wind) in a single paragraph.

5. Although the Co-owners' September 2005 *Generation Alternatives Study* evaluated the economics of a wind alternative to Big Stone II, the results of that study were flawed and biased against wind and in favor of the 600 MW supercritical coal-fired option. Moreover, that Study did not examine the economics of undertaking a combination of renewable and demand-side resources to meet the projected needs of the Co-owners.

6. The assumption in the September 2005 *Generation Alternatives Study* that wind will have a zero capacity value is unreasonable and is contrary to (a) the testimony of Co-owner witnesses in this proceeding, (b) the assumptions made in the Integrated Resource Plans filed by Big Stone II Co-owners in 2005, and (c) the results of the recent *Wind Integration Study* prepared for Xcel Energy and the Minnesota Department of Commerce and other studies.

7. If the Co-owners' *Generation Alternatives Study* is revised to reflect the fact that wind conservatively has a 15 percent to 25 percent capacity value, the installation 800 MW or 1200 MW of wind would have a lower levelized cost than Big Stone II under Synapse's most likely Mid CO_2 price forecast

8. There is no credible evidence that the non-Big Stone II resource plan examined in Co-owners' February 2006 Supplemental Filing in the Minnesota PUC Certificate of Need proceeding actually reflects the individual Co-owners' "next best" resource scenarios.

9. Instead, the alternative resource plan examined in the Co-owners' February 2006 Supplemental Filing can be characterized as a highly risky plan that, other than Otter Tail Power Company, depends exclusively, or, at best, almost exclusively, on coal-fired and natural gas-fired generation and on purchases of power that probably also would be generated at fossil-fired facilities.

10. The Co-owners have not adequately reflected the potential for demand-side management ("DSM") either in their projections of need for new generating capacity or in their analyses of alternatives to the Big Stone II Project.

11. For the reasons discussed in this testimony, the testimony we filed on May 19, 2006 and the testimony filed on May 19th by our colleague, Dr. Ezra Hausman, the South Dakota Public Utilities Commission should reject the Co-owners' Application for An Energy Conversion Facility Siting Permit for the Big Stone II Project.

The Need for Capacity

Q. Have the Big Stone II Co-owners demonstrated in their Application and Testimony that there will be a region-wide need for another 600 MW of baseload generating capacity in 2011?

A. No. At most, the Co-owners have shown a regional need for some additional capacity in MAPP-US during the peak summer hours. They have not shown that there is any regional need for 600 MW of new baseload capacity in 2011 or anytime soon thereafter.

In fact, the September MRO *2005 Ten-Year Reliability Assessment* projects that during winter peak periods the MAPP-US region will have very substantial capacity reserves **above** the 15 percent required levels of reserves. Indeed, the Midwest Reliability Organization ("MRO") September 2005 Assessment projects that MAPP-US will have approximately 4,000 MW of capacity reserves above the regional reserve capacity obligation ("RCO") during the winter of 2011-2012, approximately 3,600 MW of capacity reserves above the RCO during the winter of 2012-13, and approximately 3,300 MW of capacity reserves above the RCO during the winter of 2012-2013.[1] These capacity reserves show that the MAPP-US region will not require any new increments of capacity to ensure adequate reliability during the winter periods for years after 2013.

Consequently, it may be that instead of requiring baseload capacity, the need for capacity during peak summer periods starting in 2011 can be met by the installation of peaking capacity, the implementation of more aggressive demand side management programs, or through the import of additional capacity from MAPP-Canada or other regions surrounding MAPP-US.

Q. How much excess generating capacity does MRO currently project for the MAPP-Canada subregion?

A. MRO currently projects that the MAPP-Canada subregion will have between 1,384 MW of surplus capacity in the summer of 2011, decreasing to about 1,350 MW by the summer of 2014.

Q. Does the Co-owners' assessment of regional capacity need reflect this projected excess capacity in MAPP-Canada?

A. No.

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[1] MRO *2005 Ten-Year Reliability Assessment*, Table 5, at page 10 of 42.

Q. If this projected excess capacity in MAPP-Canada is considered, does the total MAPP system (MAPP-US and MAPP-Canada) show a need for new baseload capacity during the summer of 2011?

A. No. The total MAPP system (both MAPP-US and MAPP-Canada) does not need any new capacity until the summer of 2013.

Q. Have the Big Stone II Co-owners identified or quantified the amounts by which proposed transmission system upgrades and improvements will increase the amount of capacity that can be imported into the geographic areas included in the MAPP system?

A. No. Interrogatory 71(l) in Joint Intervenors' Sixth Set of Interrogatories in this Docket asked the Big Stone II Co-owners to list the new transmission interconnections with the regions around MAPP that Co-owner witness Koegel believes are likely to be in service by the summer of 2011, and to specify the amount by which such additional interconnections will increase the capability to import power into MAPP during peak summer and peak winter conditions. Unfortunately, the Big Stone II Co-owners refused to provide this information.

Q. Have the Big Stone II Co-owners presented evidence that demonstrates the need for capacity in 2011?

A. If we accept their load forecasts as a given, CMPPA is projecting that it will have sufficient capacity through 2012.[2] With its new demand-side management ("DSM"), MRES will have sufficient capacity through 2012.[3] The other Co-owners project some capacity deficits in the summer of 2011.

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[2] Response to our Information Request 38 in Minnesota Docket No. CN-05-619, incorporated by reference in Co-owners' response to Intervenors' Fourth Set of Requests for Production of Documents.

[3] Response to Interrogatory 44 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

Q. Have the Big Stone II owners presented evidence that demonstrates that all of the utilities actually need their MW shares of the proposed plant in 2011?

A. No. The seven Big Stone II Co-owners have repeatedly claimed that they "share a common need for baseload resources in the 2011 timeframe."[4] However, assuming for the sake of argument that the Co-owners' demand forecasts are reasonable, the most that the Co-owners have shown in their Application and Testimony in this proceeding is that almost all of them are currently projecting some levels of capacity deficits during summer peak hours starting in 2011. The Co-owners have not shown that they individually or as a group have any need beginning in 2011 for 600 MW of new baseload capacity that would operate at an 88 percent capacity factor.

Q. Please summarize the evidence that forms the basis for this conclusion.

A. First, none of the Co-owners has presented any analysis that goes beyond looking at system loads and capacity during the summer, or in some cases summer and winter, peak demands. Second, the data provided by certain Co-owners shows that they do not need very much of their MW shares of Big Stone II capacity even during peak hours in 2011. For example, CMMPA is forecasting that it will have sufficient capacity without Big Stone II to meet projected peak demands in 2011 and 2012 and that it will only have deficits of 2 MW in 2013 and 9 MW in 2014.[5] Despite this, CMMPA wants to acquire 30 MW of Big Stone Unit II in 2011.

Similarly, based on its April 2006 forecasts, which assume extreme weather instead of normalized weather,[6] MRES projects an 11 MW capacity surplus (including new DSM) in the peak summer hours of 2011 without Big Stone II. This summer capacity surplus declines to a 35 MW deficit in the peak summer

4 For example, see the South Dakota Siting Permit Application, at pages 39 and 41.

5 South Dakota Siting Permit Application, Exhibit 3-4.

6 The assumption of extreme weather biases MRES' demand forecast to the high side by a significant amount.

hours of 2015.[7] MRES' forecasts do not suggest a need for its entire 110 MW of Big Stone II until 2016 when it will assume the load of Marshall, Minnesota from Heartland. Despite this, MRES contends that it needs its share of Big Stone II starting in 2011.

Q. Do you have any comment on the claim by several of the Co-owners that there is inadequate transmission capacity to allow them to enter into firm contracts to purchase power from third parties?

A. Yes. Beyond simply making this claim, the Co-owners have not presented any evidence showing that the planned transmission system upgrades (including 807 miles of new 345 kV and 230 kV transmission lines, as noted by Co-owner witness Koegel[8]) cannot relieve the constraints that have prevented any of the Co-owners from entering into firm contracts to purchase power from third parties.

Moreover, the Co-owners have not presented any evidence that the creation of MISO and the expansion of MAPP into the Midwest Reliability Organization will not improve their ability to buy firm power from third parties. Finally, the Co-owners have not presented any evidence that building a $1 billion coal plant is a more economic option than undertaking grid system enhancements to relieve any existing transmission constraints.

The Co-owners Economic Analyses Concerning Their Participation in Big Stone II and Evaluation of Alternatives

Q. Is it possible that the addition of a new baseload generating facility can be the lowest cost option even if all of the capacity is not immediately needed to ensure that an owner has adequate capacity to serve loads or for system reliability?

A. Yes.

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7 Response to Interrogatory 44 of Joint Intervenors' Sixth Set of Interrogatories and Combined Set of Request for Production of Documents.

8 Applicants' Exhibit 9, at page 7, lines 10-13.

Q. Have the Co-owners demonstrated that the addition of Big Stone II is the lowest cost baseload option?

A. No. The Co-owners have not shown that the addition of Big Stone II is the lowest cost option as compared to portfolios of renewable and demand-side alternatives either in the three jointly sponsored analyses submitted as part of their testimony or in the analyses carried out by individual project participants.

Q. What are the three jointly sponsored analyses were submitted as part of the Co-owners' testimony in this proceeding?

A. The three jointly sponsored analyses include Applicants' Exhibit 24-A which is the July 2005 *Phase I Report Big Stone Unit II* that was prepared for Otter Tail Power Company by Burns & McDonnell.

Applicants' Exhibit 23-A is the September 2005 *Analysis of Baseload Generation Alternatives*, also prepared by Burns & McDonnell.

Finally, Applicants' Exhibit 25-B presents an economic analysis that was submitted to the Minnesota Public Utilities Commission in the February 28, 2006 *Applicants' Supplemental Information Required by Commission's Order of December 19, 2005*.

None of these analyses compared Big Stone II to renewable alternatives in a complete and unbiased manner. Consequently, their results are not credible.

Q. Were renewable alternatives considered in the July 2005 Burns & McDonnell *Phase I Report Big Stone II*?

A. No. As Co-owner witness Grieg has testified, seven generation alternatives were considered in the economic evaluation of the *Phase I Report*.[9] Six of the seven generation alternatives were coal-fired. One was a natural gas-fired combined cycle facility.

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9 Applicants' Exhibit 23, at page 13, lines 13-18.

Q. Does the *Phase I Report* explain why no renewable alternatives were evaluated?

A. Yes. The Report dismisses the potential use of wind turbines in a single paragraph:

> The most common and economically viable renewable resource technology employed in the region, wind turbines, is not appropriate for this project, primarily because it cannot reliably provide base load capacity. According to the American Wind Energy Association (www.awea.org), North Dakota, South Dakota and Minnesota rank 1, 3 and 9, respectively, among the states with the best wind resource. But even in this relatively windy region, wind turbines typically generate electricity only 30 to 40 percent of the time. Additionally, it is not possible to schedule the dispatch of wind turbines, as their operation is as unpredictable as the wind. Base load capacity must be reliable and able to provide virtually continuous output (with only scheduled short-term outages). In conclusion, wind turbines are not recommended.[10]

Q. Do you agree that wind turbines cannot be relied upon as a viable alternative to a new fossil-fired baseload facility because they cannot reliably provide base load power, are a variable resource and cannot be scheduled for dispatch?

A. No. The arguments raised against wind power in the *Phase I Report* and the data responses from individual Co-owners merely rehash the same tired old arguments against reliance on wind power.[11] As the 2004 *Wind Integration Study – Final Report* prepared for Xcel Energy and the Minnesota Department of Commerce has noted:

> Many of the earlier concerns and issues related to the possible impacts of large wind generation facilities on the transmission grid have been shown to be exaggerated or unfounded by a growing body of research studies and empirical understanding gained from

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[10] Applicants' Exhibit 24-A, at page 2-2.

[11] For example, see the Co-owners' responses to Interrogatories Nos. 17, 33 and 34 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

> the installation and operation of over 6000 MW of wind generation in the United States.[12]

Contrary to what the Co-owners are claiming, wind power can reduce the need for other capacity and provide low cost energy. GRE agrees, stating in discovery in the Minnesota Certificate of Need proceeding for the transmission line that "GRE believes that renewables and conservation could serve at least a portion of future baseload power needs."[13] In fact, when combined with other energy resources, wind can produce energy in patterns comparable to a baseload generation facility. At the same time, the effects of short term wind variability can be mitigated by building a larger number of wind turbines and by siting the wind turbines in different geographic locations.

Moreover, studies and actual operating experience has shown that fairly high penetrations of wind generation can be integrated into the electricity system (up to 20% of system peak demand[14] or more) without having adverse impacts on the reliability or stability of the electric grid. Some additional regulation or load-following support may be needed if large amounts of wind are added to the grid, but that can be provided by existing facilities.[15] Co-owner witness Mark Rolfes has admitted the same, saying "The [Balancing Area Authority] simply must have enough generation available to handle variations between expected and actual generating level of wind on a second-by-second basis. Presuming some type of

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12 *Wind Integration Study-Final Report*, prepared for Xcel Energy and the Minnesota Department of Commerce by EnerNex Corporation and Wind Logics, Inc., dated September 28, 2004, the Project Summary portion of which is included as Exhibit JI-4-A, at page 19.

13 Response to MCEA IR No. 73 in MNPUC Docket No. CN-05-619. Joint Intervenors' have requested that this response be incorporated by reference into this docket.

14 Exhibit JL-4-B, the "Utility Wind Integration State of the Art" report prepared by Utility Wind Integration Group in cooperation with American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association, dated May 2006.

15 Exhibit JI-4-C, "Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States," Parson, Mulligan, et al., presented at the 2006 European Wind Energy Conference.

pre-scheduling was performed based upon wind forecasts, this amount can be a relatively small fraction of the nameplate capacity of the wind."[16]

We also would make two comments regarding the claim that the Co-owners need a fully dispatchable facility. First, the electric grid and, indeed, many of the Co-owners, already have fully dispatchable facilities. They have not shown any evidence why new generation also must be fully dispatchable. Second, none of the Co-owners' economic studies that we have seen reflected any dispatching of the proposed Big Stone II facility, in response to changes in demand or any other factor(s). Instead, these studies have assumed that Big Stone II will operate "flat-out" at an 88 percent average annual capacity.

Q. Did the September 2005 *Generation Alternatives Study* (Exhibit 23-A) evaluate the economics of a wind alternative to Big Stone II?

A. Yes. Among the six alternatives considered, the *Generation Alternatives Study* did examine a wind-gas alternative. However, the evaluation of the wind alternative in the *Generation Alternatives Study* had two flaws which substantially biased its results in favor of the 600 MW supercritical PC alternative that was essentially Big Stone II.

Q. What were the two flaws which critically biased the economic analyses presented in the *Generation Alternatives Study* against the wind-gas alternative?

A. First, the *Generation Alternatives Study* assumed that the wind resources had no capacity value and, therefore, required a 600 MW backup natural gas-fired combined cycle facility. Second, the *Study* limited the amount of wind in the alternative to 600 MW which meant that substantially more than half of the energy provided by the alternative would be produced by the more expensive

[16] Response to Interrogatory 33 of the Joint Intervenors' Sixth Set of Interrogatories and Combined Set of Request for Production of Documents.

combined cycle facility. Together, these assumptions significantly increased the cost of the wind-gas alternative in the *Generation Alternatives Study*.

Q. Is the assumption that wind facilities have no capacity value, and therefore require 100 percent backup, consistent with the testimony sponsored by the Big Stone II Co-owners in this proceeding?

A. No. The testimony of Heartland witness McDowell notes that wind generation is accredited to be available 20 percent of the time for MAPP load and capability planning purposes.[17] Similarly, SMMPA witness Geschwind suggests a 20 percent capacity value for wind when he testifies that "SMMPA would have to install approximately 5 MW of nameplate wind capacity for every 1 MW of nameplate capacity from Big Stone Unit II to arrive at the same level of MAPP-accredited capacity."[18]

Q. Is the assumption that wind facilities have no capacity value, and therefore require a 100 percent backup, consistent with the assumptions made in the most recent Integrated Resource Plans filed by the Big Stone II Co-owners?

A. No. The MRES' recent Supplement to its 2006-2020 Resource Plan filing in Minnesota assigns wind a 15 percent capacity value.[19] Similarly, the capacity tables in Otter Tail Power's 2006-2020 Resource Plan credit wind with a capacity value of approximately 15 percent in the summer and approximately 20 percent in the winter.[20]

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[17] Applicants' Exhibit 4, at page 8, lines 7-8.

[18] Applicants' Exhibit 5, at page 10, line 22, to page 11, line 2.

[19] MRES Supplement to 2006-2020 Resource Plan, dated May 8, 2006, at page 69.

[20] Otter Tail Power Company's 2006-2020 Resource Plan, dated June 28, 2005, Table 4-B, at page 4-9.

Q. Is the assumption that wind facilities have zero capacity value, and therefore require 100 percent backup, consistent with the results of the recent study by Xcel Energy and the Minnesota Department of Commerce?

A. No. The detailed modeling study sponsored by Xcel Energy and the Minnesota Department of Commerce concluded in September 2004 that wind resources in the same general geographic area as South Dakota have capacity values of between 27 percent and 34 percent.[21]

Q. Please explain how limiting the amount of wind resources to 600 MW biases the *Generation Alternatives Study.*

A. Each of the alternatives considered in the *Generation Alternatives Study* were designed to provide the same amounts of capacity for reliability (600 MW) and energy (approximately 4,625 GWh). Because it assumes that the wind resources have zero capacity value, in the wind alternative examined, the *Study* added 600 MW of natural-gas fired combined cycle capacity to "back up" the 600 MW of wind it assumed would be built. By limiting the amount of wind resources to 600 MW, the Study limits the energy that would be produced by that wind capacity to 2,102 GWh (assuming a 40 percent capacity factor for wind). This means that 2,523 GWh, or more than half of the required energy, would be generated by the far more expensive natural gas-fired combined cycle facility. This increases the overall cost of the wind-gas alternative.

Instead of assuming that only 600 MW of wind would be built, the *Generation Alternatives Study* could have assumed that the wind-gas alternative included 800 MW of wind resources. In this scenario, wind would be expected to provide 2,803 GWh of energy, or approximately 61 percent of the total required 4,625 GWh. The remaining 1,822 GWh, or 39 percent, of the required energy would be generated by the significantly more expensive natural gas-fired facility.

[21] Exhibit JI-4-A, at page 27.

Or, the *Generation Alternatives Study* could have assumed that the wind-gas alternative included 1200 MW of wind resources. In this scenario, wind would be expected to provide 4,205 GWh, or approximately 91 percent, of the total required 4,625 GWh. Only 420 MWh, or less than ten percent of the total, would have to be generated at the more expensive natural gas-fired facility.

Q. Are there any circumstances under which a utility would undertake a wind project with a dedicated gas backup constrained to run when wind is not generating energy, as the Co-owners have assumed in the *Generation Alternatives Study*?

A. For the Co-owners, it is difficult to imagine that such a situation would ever occur. First, it is illogical and contrary to customary practice to build one generating unit to "back up" a second unit. Usual practice is to back up the entire pool of generation, not just an individual unit.

Second, to have, but not to bid a gas unit, could be a violation of the current MISO rules since the Co-owners could be accused of withholding capacity from the market. This example also violates the principles of economic dispatch since a unit will run when it is economic to do so, not simply in cases where it would be supplying energy not generated by a wind turbine. So, in practice, the gas "backup" would not be constrained.

Q. Have you corrected the economic analyses presented in the *Generation Alternatives Study* for these flaws?

A. To the extent possible. However, the combination of wind and gas in any proportion would conservatively bias a levelized cost comparison against wind since, for the reasons we just discussed, it is not representative of the manner in which the plants would likely be operated.

We have examined several wind-gas alternative plans which include 800 MW or 1200 MW of wind. We also have very conservatively assumed that the wind resources have a capacity value of 15 percent or 25 percent. This reduces the amounts of natural gas-fired combined cycle capacity that would be added.

In particular, we have examined the following four wind-gas plans:

Alternative One:	800 MW of wind and 480 MW of Combined Cycle Gas Turbine (CCGT) (assumes 15 percent capacity value for the wind).
Alternative Two:	800 MW of wind and 400 MW of CCGT (assumes 25 percent capacity value for the wind)
Alternative Three:	1200 MW of wind and 420 MW of CCGT (assumes 15 percent capacity value for the wind)
Alternative Four:	1200 MW of wind and 300 MW of CCGT (assumes 25 percent capacity value for the wind)

Q. Please explain why you have assumed that the wind resources would have a capacity value of between 15 percent and 25 percent.

A. We have used this range in this analysis to be extremely conservative. The 15 percent low end of the range is based on the Big Stone II Co-owner Integrated Resource Plan filings we noted earlier. The 25 percent high end of the range is, again, very conservatively based on the results of the 2004 *Wind Integration Study* prepared for Xcel Energy and the Minnesota Department of Commerce. We easily could have used a low end wind capacity value above 15 percent and/or a high end wind capacity value above 25 percent based on the results of the *Wind Integration Study* and other studies.

Q. Are the results of your analyses conservative?

A. Yes. The results of our cost analyses are very conservative, i.e. high on the wind/gas side. For the purpose of these analyses, we have accepted all of the Co-owners' assumptions except for the amounts of wind and gas capacity in each alternative scenario. These assumptions include assuming Burns & McDonnell's $50/MWh cost of wind which does not appear to vary with the ownership structure of the wind plant. That is, as with the coal plant a wind facility (without the PTC) owned by a public power utility would have a lower cost because of the lower cost of financing than a wind facility owned by a taxable entity. In addition, we have not reflected any increases in the cost of operating Big Stone II, any potential increases in coal costs, and have accepted the Co-owners' claimed 88 percent annual capacity factor. Clearly, the levelized cost of the coal option could be higher if the costs of building and/or operating the coal facility are assumed to be higher and/or the plant is assumed to operate at less than an average 88 percent capacity factor.

Finally, we have adopted Burns & McDonnell's assumed levelized value of $12/MWh for the Production Tax Credit ("PTC") for wind facilities, which may understate the value of the PTC by not counting the additional tax benefit of the PTC because it is a credit on tax liability rather than a dollar of taxable income. Unfortunately, because there are no spreadsheets or workpapers to support the wind cost, despite our having asked for these in discovery, or to support the PTC calculation we cannot verify whether this tax effect was accounted for or not.

For example, a 2005 study by the Energy Information Administration ("EIA") shows that the PTC is worth approximately $28/MWh levelized over a 10-year period or $21/MWh levelized over a 20-year period, assuming a 38% marginal tax rate. Another study by the National Renewable Energy Laboratory found that the PTC could be worth as much as $23/MWh levelized over a 15-year period, assuming a 40% tax rate.

Q. Please summarize the results of your revisions to the analyses in the *Generation Alternatives Study*.

A. The results of our revisions to the analyses in the *Generation Alternatives Study* are presented in Table 1 and Table 2 below:

Table 1 Levelized Cost Comparison Coal vs. Wind-Gas Combination – for Investor Owned Utilities

Resource Option	Low CO2	Mid CO2	High CO2
Coal 600 MW	$65.60	$81.20	$97.23
Wind 800 MW + CCGT - No PTC			
Alternative One - 800 MW wind + 480 MW CCGT	$68.53	$71.22	$73.98
Alternative Two - 800 MW wind + 400 MW CCGT	$67.32	$69.82	$72.57
Wind 800 MW + CCGT with PTC			
Alternative One - 800 MW wind + 480 MW CCGT	$61.26	$63.95	$66.70
Alternative Two - 800 MW wind + 400 MW CCGT	$60.05	$62.55	$65.30
Wind 1200 MW + CCGT - No PTC			
Alternative Three - 1200 MW wind + 420 MW CCGT	$59.68	$60.32	$60.95
Alternative Four - 1200 MW wind + 300 MW CCGT	$57.58	$58.21	$58.85
Wind 1200 MW + CCGT & PTC with PTC			
Alternative Three - 1200 MW wind + 420 MW CCGT	$48.77	$49.41	$50.04
Alternative Four - 1200 MW wind + 300 MW CCGT	$46.67	$47.30	$47.94

The Low CO2, Mid CO2 and High CO2 figures reflect the Synapse carbon price forecasts presented in Exhibit JI-1-F to our May 19, 2006 testimony.

Table 2 Levelized Cost Comparison Coal vs. Wind-Gas Combination – for Public Power Utilities

Resource Option	Low CO2	Mid CO2	High CO2
Coal 600 MW	$57.54	$74.81	$92.08
Wind 800 MW + CCGT - No PTC			
Alternative One - 800 MW wind + 480 MW CCGT	$67.19	$70.16	$73.12
Alternative Two - 800 MW wind + 400 MW CCGT	$66.16	$69.13	$72.10
Wind 800 MW + CCGT with PTC			
Alternative One - 800 MW wind + 480 MW CCGT	$59.91	$62.88	$65.85
Alternative Two - 800 MW wind + 400 MW CCGT	$58.89	$61.86	$64.82
Wind 1200 MW + CCGT - No PTC			
Alternative Three - 1200 MW wind + 420 MW CCGT	$57.87	$58.55	$59.24
Alternative Four - 1200 MW wind + 300 MW CCGT	$56.32	$57.01	$57.69
Wind 1200 MW + CCGT & PTC with PTC			
Alternative Three - 1200 MW wind + 420 MW CCGT	$46.96	$47.64	$48.33
Alternative Four - 1200 MW wind + 300 MW CCGT	$45.41	$46.10	$46.78

The results in these Tables show the following:

- Under our Mid CO_2 price forecast, which we believe is the most likely, and our High CO_2 price forecast, all of the wind and CCGT alternatives we have examined would have lower levelized costs than the 600 MW coal plant (Big Stone II).

- For the investor owned utilities, under our Low CO_2 price forecast, the 800 MW wind and CCGT alternatives would have lower levelized costs than the coal plant if the PTC is renewed. Both of the 1200 MW wind and CCGT alternatives have lower levelized costs than the coal plant whether or not the PTC is renewed.

- For the public power utilities, under our Low CO_2 price forecast, the coal plant would have a lower levelized cost than the 800 MW wind and CCGT alternatives whether or not the PTC is assumed to be renewed.[22] Under our Low CO_2 price forecast, the coal plant and the 1200 MW wind and CCGT alternative would have about the same levelized costs if the PTC is assumed to be not renewed. If the PTC is renewed, the 1200 MW wind and CCGT alternatives would have lower levelized costs than the coal plant.

- Under all scenarios, the 1200 MW wind and CCGT combination is approximately the same or cheaper than Big Stone Unit II.

Q. Is it reasonable to assume that the Production Tax Credit will be renewed before it expires at the end of 2007?

A. Yes. We believe it is reasonable to assume that the Production Tax Credit will be renewed given (1) its history, (2) increasing concern over U.S. dependence on foreign sources of energy and (3) mounting concern over global warming and climate change and a resulting interest in providing subsidies to non-carbon emitting technologies.

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[22] This conclusion accepts the modeling of the effects of the PTC in the *Generation Alternatives Study*. However, if EIA's levelized PTC value of $21/MWh were used in this analysis, the 800 MW wind and CCGT combination would be more economic for the public power utilities than the coal plant.

Q. Is it possible that there are wind with hydro and/or demand-side management measures that would have lower costs than the wind-gas combinations you have looked at in your revisions to the Co-owners' *Generation Alternatives Study*?

A. Yes. For example, as we discuss later in this testimony, there is evidence of additional, very low cost demand-side management measures available to the Co-owners.

Q. Did the *Generation Alternatives Study* examine a combination of renewable resources, other than the 600 MW wind–600 MW gas mix, to meet the projected needs of the Co-owners?

A. No. The *Generation Alternatives Study* did not examine, with the exception of gas and wind, any combinations of resources, such as a portfolio of wind, demand-side measures, and hydro, to meet the projected needs of the Co-owners.

Q. Do you have any comments about the usefulness of this type of levelized cost comparison, particularly regarding the following claim by the Co-owners:

> **It must be noted that simply comparing $/MWh busbar costs of dissimilar projects is misleading and violates the most basic principles of integrated resource planning. Such a comparison completely ignores the impact of the costs and benefits a single resource can have on other resources, and provides only limited information on how any particular resource matches up with a utility's existing resource mix, the existing load requirements, or the electrical system in total.**[23]

A. Yes. Our first comment is that we believe that the use of levelized costs is a useful tool in the screening of possible alternatives to be studied in greater detail to capture the various factors noted by the Co-owners. We have merely revised the levelized cost analysis presented in the *Generation Alternatives Study* to show that under more reasonable, but still extremely conservative assumptions,

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[23] Response to Interrogatory 17 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

different amounts of wind and CCGT capacity can be more economic than Big Stone Unit II. Our revisions show that there are wind-gas alternatives that would have lower levelized costs than the 600 MW coal option (that is, Big Stone II) and that wind, in general, deserved to be studied in greater detail by the Co-owners.

Secondly, it is important to note that if the Co-owners believed this way about the limits of levelized cost analyses it begs the question of why did the Co-owners prepare and submit the September 2005 *Generation Alternatives Study* to justify their selection of Big Stone II. Their comments, noted above, appear to undercut the validity of their own justification for choosing to build a 600 MW coal-fired facility.

Q. The third joint economic analysis presented by the Co-owners is included in Applicants' Exhibit 25-B and sponsored by Co-owner witness Harris. Is there any credible evidence that the non-Big Stone II resource plans considered in this economic analysis are really the Applicants' individual next best resource scenarios, as Mr. Harris claims?

A. No. There is no evidence to support the claim that the individual utility alternatives to Big Stone II reflected in this economic analysis represent what would be the Co-owners' "next best" resource scenarios. Indeed, there is no evidence that in their development of their purported "next best" resource scenarios, any of the Co-owners, perhaps other than Otter Tail Power, examined additional wind projects in place of Big Stone II. In addition, other than Otter Tail Power, none of the other Co-owners appears to have considered any hydro purchases. None of the Co-owners considered additional demand-side management efforts in place of Big Stone II.

Consequently, there is no evidence that what the individual Co-owners are calling their "next best" resource plans actually would be. That is, there is no evidence that these "next best" plans have lower costs than alternative plans that would include more wind, more aggressive implementation of cost-effective demand side measures and increased purchases of hydro capacity and energy.

In fact, the alternative non-Big Stone II "plan" studied by Mr. Harris really can be characterized as, other than for Otter Tail Power, a highly risky plan that depends almost exclusively on coal-fired and natural gas-fired generation and on purchases of power that probably also would be generated at coal-fired or natural-gas fired facilities.

Q. Why do you consider the alternative to Big Stone II plan studied by Mr. Harris to be "highly risky?"

A. The alternative plan is highly risky because it depends to a very substantial extent on coal-fired generation which almost certainly will be subject to greenhouse gas regulations, as we have explained in our May 19, 2006 Testimony, and on natural gas-fired generation which is likely to be subject to high fuel price levels and volatility. Wind, at a minimum, significantly reduces fuel price and environmental risks.

In addition, new coal-fired facilities, like Big Stone II, may be subject to some of the same production and coal deliverability problems that have recently plagued the existing coal-fired units throughout the Midwest that depend upon coal from the Powder River Basin. Such problems could adversely affect the reliability of Big Stone II and its ability to operate at a consistent 88 percent average annual capacity factor.

Remarkably, the Big Stone II Co-owners refused to acknowledge that future coal shortage issues (caused by rail and production issues) *may* diminish Big Stone II's reliability.[24] The Big Stone II Co-owners similarly refused to acknowledge that recent coal shortage issues *may* increase the risk associated with developing the Big Stone II power plant.[25]

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24 Responses to Questions Nos. 5 and 39 of South Dakota Staff's Third Data Request.

25 Response to Question No. 38 of South Dakota Staff's Third Data Request.

Q. Please comment on the claim by Co-owner witness Harris that if Big Stone II is not constructed, there is no single best resource alternative that the Co-owners would collectively pursue. Instead, each Co-owner would pursue a variety of strategies to meet their obligations.[26]

A. It is true that we have seen no evidence that the Co-owners have studied a joint supply and demand-side plan that they would implement if they were denied permission to build Big Stone II. However, we still believe that if Big Stone II were not built, it would be prudent for the Co-owners to cooperate to develop an optimal alternatives plan that minimized rate impacts on their ratepayers and impacts on the environment. Instead, Mr. Harris has studied an extreme and imprudent situation where there appears to be absolutely no cooperation among the Co-owners to find the most cost-effective alternative plan(s) to Big Stone II.

Q. Please summarize the alternatives that the individual Co-owners considered in developing their "next best" alternatives to Big Stone II.

A. Later in this testimony we will discuss in some more detail the economic analyses that each individual Co-owner has presented as the justification for their participation in Big Stone II and as evidence of their consideration of alternatives to that Project. However, to summarize:

- Montana-Dakota has said that it only considered three possible alternatives to Big Stone II – two of these were coal-fired and the third was to purchase power from the market. Moreover, Montana-Dakota did not perform any economic analyses to quantitatively compare the revenue requirements of these alternatives or to examine any other possible alternatives to Big Stone II.
- Otter Tail Power developed an alternative that assumed it would purchase 120 MW of hydro capacity from Manitoba Hydro.
- Great River Energy's July 2005 *Alternatives Evaluation for the Construction of Big Stone II* only quantitatively considered three resource types, all of which were coal or natural gas-based resources.[27] GRE's

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[26] Applicants' Exhibit 25, at page 2, lines 16-19.

[27] Great River Energy *Alternatives Evaluation for the Construction of Big Stone II*, dated July 2005, at pages 54, 90 and 91.

2005 Integrated Resource Plan similarly modeled only three supply side options: a coal plant, a natural gas-fired combined cycle plant and a gas-fired combustion turbine.[28] Although some scenarios included some wind resources, neither the timing nor the size of the proposed fossil additions were modified.[29]

- MRES' 2006-2020 Resource Plan filing examined a number of scenarios. However, all but two of these scenarios assumed some participation in Big Stone II.[30] Of these two non-Big Stone II scenarios, one modeled participation in a coal-fired facility and a combustion turbine as alternatives. The other substituted an IGCC plant for Big Stone II without re-optimizing the resources. No non-coal or natural gas alternatives were evaluated.
- CMMPA only **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]**
- Heartland has said that it will purchase energy from the market to replace the energy that would have been provided by Big Stone II. Heartland says that it will continue to rely on the market until it can participate in another lower cost resource option, most likely another pulverized coal baseload unit.[31]
- SMMPA's alternative plan to Big Stone II appears to include a 50 MW combustion turbine but no additional wind or other renewable resources or demand-side management.[32]

Because their analyses focused so exclusively on fossil-fired alternatives and/or power purchases from a market that is heavily dominated by fossil-fired generation, the Co-owners collectively failed to consider whether portfolios of wind, hydro and demand-side options would be lower cost alternatives than Big Stone II or the "next best" resource scenarios they posit for the economic analysis presented in Applicants' Exhibit 25-B. This collective failure is particularly egregious given that the Co-owners are located in an area of the nation with

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28 Great River Energy, Integrated Resource Plan, dated July 1, 2005, at page 80.

29 Ibid, at page 108.

30 MRES 2006-2020 Resource Plan, dated June 30, 2005, at page 14.

31 Applicants' Exhibit 25-B, at page 13.

32 See Applicants' Exhibit 25-B, at pages 17 and 18.

significant wind potential and near Manitoba Hydro with its substantial hydro resources.

Q. What impact does Montana-Dakota's failure to seriously consider non-fossil-fired alternatives have on the results of the economic analysis presented in Applicants' Exhibit 25-B?

A. Even though it is proposing to own only 116 MW, or about 19 percent, of Big Stone II, Montana-Dakota's alternate resource plan, involving participation in a lignite plant, inordinately **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]** the economic analysis presented in Applicants' Exhibit 25-B. In fact, Montana-Dakota's alternate plan with the lignite-fired facility would be **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]** than its participation in Big Stone II. This means that Montana-Dakota on its own would be responsible for approximately **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]** percent of the $669 million net present value benefit to Big Stone II shown in Table 8 of Applicants' Exhibit 25-B. This result lacks any credibility given that Montana-Dakota only considered coal-fired options, including power purchases from the market, and failed to perform any quantitative analyses to investigate what would be its lowest cost alternative.

Montana-Dakota's lignite alternative **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]**the NO_x, CO_2, CO and mercury emissions in the non-Big Stone II case. Using the year 2016 as an example, Montana-Dakota's alternative would be responsible for approximately **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]** percent of the NO_x emissions, approximately **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]** percent of the CO_2 and CO emissions, and [**CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL**

MATERIAL ENDS] percent of the mercury emissions in the non-Big Stone II case.

Q. Does the economic analysis presented in Applicants' Exhibit 25-B consider the potential for any greenhouse gas regulations?

A. No. The failure to consider the potential for greenhouse has regulations is another substantial flaw in the analysis.

Q. Turning now to the analyses cited by the individual Co-owners as justification for their participation in Big Stone II. Has Otter Tail Power shown that Big StoneII is a lower cost option than a portfolio of renewable and demand-side alternatives?

A. No.

Q. What analyses does Otter Tail Power rely on for the decision to participate in the Big Stone II Project?

A. Otter Tail Power relies on its recent IRP analyses.[33]

Q. Have you had a full opportunity to review the modeling conducted by Otter Tail Power as part of its July IRP filing?

A. No. Back in January we initially asked Otter Tail Power for the input and output computer files for each of the scenarios discussed in its July 2005 IRP filing. In response, the company provided the requested input files but only gave us the output files for its base case scenario.

Despite repeated requests, Otter Tail Power insisted for several months (including as late as May 3, 2006) that there were no additional output files for any other scenarios. Then, on May 5, 2006, counsel for Otter Tail Power revealed that, in fact, there were output files for other scenarios but they couldn't give all of them to us because they contained confidential information that had been obtained from

[33] Response to Interrogatory No. 4 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

Manitoba Hydro. After about a week of negotiations, we subsequently received portions of those output files. However, we have had only a partial opportunity to review and evaluate the approximately 80 additional files provided by Otter Tail Power in the very short time since we received them on May 12th and 16th.

Q. Does Otter Tail Power's July 2005 IRP compare the cost of participating in Big Stone II with the cost of obtaining an equivalent amount of capacity and energy from renewable and demand side alternatives?

A. No. The Company's 2005 IRP filing does examine two scenarios that are designated as the 50% and 75% Renewable and Conservation scenarios.[34] These scenarios apparently were designed to address the Minnesota planning requirement that it obtain 50 percent and 75 percent of future growth from a combination of renewable sources and conservation. In the 50% Renewable and Conservation scenario, 85 MW of Big Stone II was replaced by a hydro capacity and energy purchase. In the 75% Renewable and Conservation scenario, Otter Tail Power's share of Big Stone II was replaced by 130 MW of hydro capacity from Manitoba Hydro.

Otter Tail Power's filing did show that the PVRR cost of each of these two Renewable and Conservation cases was higher than the cost of the Base Case including Big Stone II.[35] However, this comparison was misleading because, in the 75% scenario, more renewable capacity is purchased than would be necessary merely to replace Otter Tail Power's share of Big Stone II. Moreover, and probably more significantly, the comparison between Big Stone II and the 50% and 75% Renewable and Conservation cases in the 2005 IRP filing did not reflect any environmental externality costs. Nor did it reflect future greenhouse gas regulations. Therefore, the comparison undoubtedly understated, and perhaps by

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34 Otter Tail Power Company 2006-2020 Resource Plan, June 28, 2005, at pages 9-9 to 9-11.

35 Table 4-E in Otter Tail Power's 2006-2020 Resource Plan filing, dated June 28, 2005, notes that the 50% Renewable & Conservation scenario is $56.02 million (or 1.6%) more expensive, in 2004 dollars, than the Base Case. The 75% Renewable & Conservation scenario is reported to be $120.01 million (or 3.5%) more expensive, in 2004 dollars, than the Base Case.

a very significant margin, the relative cost of Big Stone II for Otter Tail Power and its customers as compared to renewables and demand-side alternatives.

Q. Had Otter Tail Power examined the total cost, including environmental externalities, of similar 50% and 75% Renewable and Conservation cases in its earlier IRP Filings?

A. Yes. The Company's 2002 IRP filing evaluated the total cost of the base case and the 50% and 75% conservation and renewable cases including environmental externalities. Thus, the 2005 filing represented a departure from Otter Tail Power's prior practice.[36]

Q. Has Great River Energy shown that participation in Big Stone II is a lower cost option than a portfolio of renewables and demand-side alternatives?

A. No. In its *Alternatives Evaluation for the Construction of Big Stone Unit II*, Great River Energy only examined the economics of three capacity alternatives, two of which were coal-based and one was natural gas-fired.[37] Other alternatives, such as demand side management, renewables including wind, biomass, hydro, solar, landfill gas, and IGCC were eliminated after a qualitative screening.[38] Unfortunately, no economic analyses were prepared for these eliminated alternatives. Consequently, the only economic analyses in GRE's *Alternatives Evaluation* compare Big Stone II to coal and natural gas-fired options.

Q. Do the scenarios examined by GRE in its 2005 Integrated Resource Plan filing in Minnesota offer any insights into whether Big Stone II is a lower cost option than a portfolio of renewable and demand-side alternatives?

A. No. Most of GRE's 2005 Integrated Resource Plan filing focused on an examination of thirteen scenarios, all of which included Big Stone II beginning in

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36 Otter Tail Power 2003-2017 Resource Plan, dated June 28, 2002, at page 4-14.

37 *Great River Energy Alternatives Evaluation for the Construction of Big Stone II*, dated July 2005, at page 54.

38 Ibid, at pages 32-39 and 54

2011.[39] These scenarios clearly provide no information as to the relative economics of participation in Big Stone II as compared to renewable and demand-side alternatives.

GRE did examine two renewable resource plans required by Minnesota's planning statute in its 2005 Integrated Resource Plan filing that it found to have higher PVRR costs than its lowest cost base cases with Big Stone II. However, it is clear from reading GRE's 2005 Integrated Resource Plan that the comparison between these 50% and 75% renewables cases and the cases with Big Stone II probably offer few, if any, insights into the relative economics of GRE's participation in the Big Stone II Project because they do not reflect (1) any environmental externalities or (2) any greenhouse gas regulations. Therefore, the comparison gives a biased and incomplete view of the relative economics of Big Stone II.

Q. Have you had a reasonable opportunity to review the computer modeling performed by GRE in the preparation of its 2005 Integrated Resource Plan filing?

A. No. Despite repeated requests for the output data files for each of the scenarios examined in its 2005 Integrated Resource Plan filing, beginning as far back as January of this year, by May 8th, GRE had only provided the actual model output files for its base case scenario. In response to GRE's continued refusal to provide the actual output files for the other scenarios it had examined in its 2005 IRP filing and under the pressure of having to file this testimony without a significant delay, we revised our request to cover certain summary information. GRE has provided that summary information but not the actual model output files for any scenarios other than their base case scenario.

[39] Great River Energy, Integrated Resource Plan, dated July 1, 2005, at pages 99-101.

Q. Do you have any comments on the recent RFP that GRE issued for 120 MW of power?

A. Yes. GRE issued an RFP for renewable resources last fall. GRE has publicly stated that thirty-one developers responded with more than 50 proposals.[40] According to GRE, wind energy projects were the most competitively priced and, with such a strong response, GRE may accept more bids than planned and delay adding baseload resources.[41] Unfortunately, GRE, to date, has refused to provide us copies of the proposals it has received in response to that RFP.

Q. Did Montana-Dakota Utilities prepare any economic analyses showing that Big Stone II is the lowest cost option?

A. No. Montana-Dakota's 2003 Integrated Resource Plan selected 120 MW of new combustion turbines and some improvements to existing CTs to meet the company's demand through 2021.[42] However, in its 2005 Integrated Resource Plan, where it does not appear to use any model or to perform any quantitative analysis, the company concludes that "subsequent to the filing of the 2004 IRP, Montana-Dakota determined that the plan's heavy reliance on gas-fired generation exposed our customers to considerable price and reliability risk associated with fuel cost and availability. The company believes that coal-fired generation, which has lower and less volatile fuel prices and a more stable fuel supply than natural gas, provides a better value for our customers."[43]

Indeed, Montana-Dakota apparently did not prepare any economic analyses when considering whether to participate in Big Stone II. Instead, it qualitatively evaluated four options, three of which were coal-fired with the fourth being

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[40] *U.S. Utility Could Defer Baseload After Strong Renewables Showing*, Platt's Renewable Energy Report, dated March 6, 2006, at page 22.

[41] *Great River May Delay Adding to Baseload*, Electric Power Daily, February 22, 2006, at page 8.

[42] Montana-Dakota Utilities 2003 Integrated Resource Plan, at page iv.

[43] Montana-Dakota Utilities 2003 Integrated Resource Plan, at page 4-2.

reliance on purchased power.[44] As Montana-Dakota explained in its response to Interrogatories 28 and 58 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents:

- The reference [in the testimony of MDU witness Stomberg] to a "model" was generic, and was intended to convey the concept of a hypothetical, purely quantitative model.[45]
- Montana-Dakota did not perform a purely quantitative model. The statement refers to the fact the expert judgment is required in resource planning; not just quantitative modeling.[46]
- For its 2005 IRP, Montana-Dakota did not use a computer model to compare supply-side and demand-side resources.[47]

We agree with Montana-Dakota that expert judgment is required in resource planning but that is **in addition to** quantitative modeling. Thus, we find that the Company's decision to commit to a more than One Billion Dollar coal-plant without having examined the economics of the various supply-side (let alone both supply- and demand-side) options to have been imprudent. As a result of this imprudence, Montana-Dakota has absolutely no economic studies that can show that participation in Big Stone II is the lowest cost option against any renewable and demand-side alternatives.

Q. What is the expected impact of Big Stone II on Montana-Dakota's residential customer rates?

A. Montana-Dakota has estimated that the addition of Big Stone II will increase its residential customer rates by approximately 20 percent, or about 1.9 cents/kWh[48] excluding the potential impact of greenhouse gas regulation.

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44 Response to Interrogatory 27 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

45 Interrogatory 28 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

46 Ibid.

47 Response to Interrogatory 58 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

Q. What alternatives to Big Stone II were examined in MRES's 2006-2020 Resource Plan filing?

A. MRES's 2006-2020 Resource Plan filing examined a number of scenarios. However, all but two of these scenarios assumed some participation in Big Stone II.[49] Of these two non-Big Stone II scenarios, one modeled participation in a coal-fired facility and a combustion turbine as alternatives. The other substituted an IGCC plant for Big Stone II without re-optimizing the resources. No non-coal or natural gas alternatives were evaluated.

Q. Have you had a full opportunity to review the modeling performed in the analysis of the generation alternatives discussed in MRES' 2006-2020 Resource Plan?

A. No. Despite repeated requests for the output data files for each of the scenarios examined in its 2005 Integrated Resource Plan filing, beginning as far back as January of this year, by May 8th, MRES had only provided several summary files but not any actual model output files. In response to MRES's failure to provide the actual output files for the scenarios it had examined in its 2005 IRP filing and under the pressure of having to file this testimony without a significant delay, we revised our request to cover certain summary information. MRES has provided that summary information but not the actual model output files for any scenarios that it examined in its 2005 IRP filing.

Q. Have you had a reasonable opportunity to review MRES' Supplemental Filing for its 2006-2020 Resource Plan?

A. No. This Supplemental Filing was made just two weeks ago. Due to the limited time available and our need to focus on completing this testimony and the testimony we filed on May 19, 2006, we have not had any opportunity to review the MRES Supplemental Filing in any significant detail.

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[48] Response to MCEA Information Request 44 in MPUC Docket No. CN-05-619.

Q. What economic analyses does CMMPA cite in support of its decision to participate in Big Stone II?

A. CMMPA has cited two studies by R.W. Beck as forming the basis for its decision to participate as a Big Stone II Co-owner: An April 2002, *Generation Resources Planning Study* and a December 2004 *Power Supply Analysis*.[50]

Q. Do the results of these analyses provide any insights as to whether CMMPA's participation in Big Stone II is a lower cost option than a portfolio of renewable and demand-side alternatives?

A. **[CONFIDENTIAL MATERIAL BEGINS**

CONFIDENTIAL MATERIAL ENDS]

Q. What alternatives has SMMPA considered as alternatives to Big Stone II?

A. SMMPA's testimony in this proceeding and the summary of its planning provided in Applicants' Exhibit 25-B suggest that SMMPA considered natural gas-fired resources as alternatives to Big Stone II.[53] It is unclear whether SMMPA evaluated wind, demand-side management and landfill gas as alternatives to Big Stone II or only as complementary resources.

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49 MRES 2006-2020 Resource Plan, dated June 30, 2005, at page 14.

50 Applicants Exhibit 6, at page 5, lines 12-18.

51 At page 9.

52 At pages 1 and 2.

53 Applicants' Exhibit 5, at page 10, lines 10-14, and Applicants' Exhibit 25-B, at pages 17 and 18.

Q. What alternatives did Heartland consider when evaluating whether to participate in Big Stone II?

A. **[CONFIDENTIAL MATERIAL BEGINS**

CONFIDENTIAL MATERIAL ENDS].

However, as we have demonstrated earlier in this testimony, even with overly conservative and the Co-owners' unrealistic operating assumptions, a combination of wind and gas can be cheaper on a cost basis than Big Stone Unit II.

Demand-Side Management

Q. Have the Co-owners adequately considered demand-side management alternatives in their evaluations of the need for new baseload generating capacity and their analyses of the economics of alternatives to Big Stone II?

A. No.

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54 *Power Supply Study*, dated February 17, 2003, at pages 47 and 53.

55 Ibid, at pages 41-46.

56 Ibid, at page 41.

Q. Please explain how the Co-owners have evaluated demand-side management alternatives?

A. CMMPA did not compare DSM against any supply-side resource including Big Stone Unit II. In fact, CMMPA does not perform integrated resource planning,[57] has not evaluated the potential for DSM on its system and does not offer DSM programs. CMMPA states that "DSM programs are approved and funded by the individual city within CMMPA."[58]

Similarly, HCPD did not compare DSM against any supply-side resource such as Big Stone Unit II. Neither does HCPD do integrated resource planning.[59] Nor has it has not evaluated the potential for DSM on its system. HCPD also does not offer DSM programs although its customers offer some energy efficiency and conservation programs.

MRES does not offer DSM programs, its members do. To our knowledge, it had not undertaken any analysis of DSM programs until **[CONFIDENTIAL MATERIAL BEGINS**

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57 Response to Interrogatory 3 of Joint Intervenors' First Set and First Amended Set of Interrogatories.

58 Response to Interrogatory 15 of Joint Intervenors' First Set and First Amended Set of Interrogatories.

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Indeed, as explained in the May 2006 Supplement to MRES' 2006-2020 Resource Plan, MRES' capacity expansion model picked the full level of DSM available to it as part of its least-cost, base case plan.[61]

Montana-Dakota performed a combination of qualitative and quantitative screening to arrive at a set of four DSM programs in its 2005 IRP: 1) ENERGY STAR® Partnership, 2) Promote electric heat (North Dakota only), 3) Promote high efficiency residential central air conditioning, and 4) Promote commercial lighting T-8 retrofit.[62] Montana-Dakota has not evaluated the potential for DSM on its system,[63] the programs it evaluated in its 2005 IRP were limited to a set of 19 and even the programs it found to be cost-effective were not all chosen for implementation.

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[59] Response to Interrogatory 3 of Joint Intervenors' First Set and First Amended Set of Interrogatories.

[60] Supplement to Missouri River Energy Services 2006-2020 Resource Plan, May 8, 2006 at page 53.

[61] Ibid.

[62] Page iii of Montana-Dakota Utilities Co. 2005 Integrated Resource Plan, September 15, 2005.

[63] Based on lack of MDU response to Joint Intervenors' Third Set of Request for Production of Documents, Request No. 4.

According to SMMPA's 2003-2018 IRP, it evaluated DSM measures using the EGEAS model which compares those measures to supply-side resources. It screened the measures evaluated in EGEAS using a methodology that appears to have been based upon a DSM potential study done in 1993.[64] While we have not reviewed the 1993 study (and have not been supplied with a copy of it), we find it very difficult to believe that a 13-year old study could yield reliable and credible DSM potential results given the changing characteristics of SMMPA's load, resources and particularly DSM measures themselves. The cost of DSM measures, their impacts and even the DSM measures that one would implement are very likely to have changed between 1993 and 2006.

Otter Tail Power most recently analyzed the potential for DSM in 2002 but only for its commercial and industrial customers in its Minnesota service territory. In modeling DSM programs for other sectors of customers, it appears to rely upon a 1994 DSM potential study, *Draft Report: DSM Potential Study and Commercial Survey*. While we have not reviewed the study, as with SMMPA's 1993 study, it is very difficult to believe that a 12-year old study could yield reliable and credible DSM potential results for integrated resource planning in 2006.

Most recently, GRE **[CONFIDENTIAL MATERIAL**

CONFIDENTIAL MATERIAL ENDS] DSM should be implemented if it is cost-effective regardless of the budget a utility would prefer to allocate to such activities; to do otherwise, that is, acquire more expensive resources, is an imprudent use of ratepayer money.

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[64] SMMPA Integrated Resource Plan 2003-2018 at pages VI-15 and VIII-8.

Q. What does it mean to "evaluate the potential for DSM" on a Co-owner's system?

A. A study of "DSM potential" would quantify the level of DSM which could be achieved under different scenarios and assumptions. For example, the study might quantify the potential for DSM under different levels of incentives to adopt DSM measures, different customer penetration levels and other factors. The primary goal is to identify the level of cost-effective DSM that could be achieved, and how.

Q. Does the Co-owners' claimed need for Big Stone Unit II account for all cost-effective DSM that could be done on their systems?

A. No. In addition to the lack of any recent DSM potential studies on the part of the Co-owners (with the exception of GRE), there is other evidence that the Co-owners are not leveraging all cost-effective DSM on their systems. One metric to assess the aggressiveness of a utility's DSM portfolio is the "cost of saved energy." The cost of saved energy is the cost of the measure compared to the MWh it saves over the measure's life. Like electricity prices, this cost is represented in $/MWh. If a utility were to maximize cost-effective DSM, one would expect to see a cost of saved energy roughly equal to the cost of the supply-side resource it is adding. In this case, one would expect to see a cost of saved energy roughly equivalent to the levelized cost of Big Stone Unit II.

Another metric to assess DSM performance is the ratio of annual energy savings from DSM activities to customer energy requirements. The lower the ratio, the less likely the utility is to be maximizing its available cost-effective DSM.

Q. Is the Co-owners' cost of saved energy roughly equivalent to the cost of Big Stone Unit II?

A. No. We do not have complete information on the cost of saved energy from the DSM activities of all Co-owners because, in many cases, the Co-owners themselves do not have this information. For those which have provided this information the cost of saved energy is a fraction of the cost of Big Stone Unit II.

With such a large gap between the cost of saved energy and the cost of Big Stone II there are likely to be many cost-effective energy efficiency resources available at a cost within that gap.

In response to Staff's Third Data Request, Interrogatory 31, GRE responded that from 2002 – 2007 its lifetime cost of saved energy ranges from $14.10/MWh to $21.10/MWh.[65] GRE did not provide cost of saved energy data for future years beyond 2007.

However, according to Applicants' Exhibit 23-A, *Analysis of Baseload Generation Alternatives*, the twenty-year levelized busbar cost of Big Stone II to GRE will be $40.85/MWh (2005$), excluding the cost of greenhouse gas regulation. This $19.75/MWh to $26.75/MWh gap in costs between the busbar cost of Big Stone II and GRE's cost of saved energy is a strong indication that additional cost-effective DSM is available to GRE.

As an investor-owned utility, Otter Tail Power's twenty-year levelized busbar cost of Big Stone Unit II is $50.71/MWh. Otter Tail Power's cost of saved energy through 2011 ranges from a low of $8.79/MWh[66] to a high of $27.28/MWh.[67] Like GRE, it is reasonable to expect that there would be many cost-effective energy efficiency measures in the range between Otter Tail Power's highest cost of saved energy, $27.28/MWh, and the cost of Big Stone Unit II without greenhouse gas regulation, $50.71/MWh, a difference of $23.42/MWh!

Similarly, we have calculated Montana-Dakota's cost of saved energy from the two DSM programs selected in its 2005 IRP for which the information necessary to make this calculation was available. The cost of saved energy from Montana-Dakota's programs is $14.31/MWh which is $36.4/MWh less than the levelized

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65 GRE did not state in which year's dollars its cost of saved energy is reported, but we assume 2005$ is likely.

66 We assume an average ten-year measure life in making this calculation.

67 OTP did not state in which year's dollars its incremental cost of energy is reported, but we assume 2005$ is likely.

cost it proposes to pay for Big Stone Unit II, excluding greenhouse gas regulation costs.

Q. You stated that another metric indicating whether a utility is achieving a cost-effective level of DSM is to compare energy savings from DSM to energy sales to customers. Do you have any comments on the Co-owners' DSM programs in that regard?

A. Yes, we do. It is particularly useful in this regard to compare the Co-owners to each other since the characteristics of the customers they serve are not so radically different that the energy savings from DSM that one achieves would not be indicative of the DSM savings that another could achieve. If we use 2007 as a snapshot year, for example, Table 3 shows the energy savings achieved from four of the Co-owners' DSM programs versus the energy requirements in that year.

Table 3. 2007 Energy Savings per MWh of Energy Sales to Customers[68]

Montana-Dakota	GRE	OTP	SMMPA
0.016%	0.276%	0.172%	0.837%

The Co-owner with the smallest cost of saved energy, Montana-Dakota, also achieves the lowest ratio of energy savings to energy sales, less than a tenth of one percent of energy sales to customers. Montana-Dakota, GRE and OTP do not even come close to achieving energy savings in proportion to states with more aggressive portfolios of DSM like California, Connecticut, Rhode Island, Oregon and Wisconsin as illustrated in Table 4, and under-perform compared to SMMPA. After 2007, SMMPA's percentage savings drop off to 0.685% in 2011 and 0.117% in 2020.

[68] Based on response to Interrogatory 30 of Staff's Third Data Request and response to Interrogatory 17 of Joint Intevenors' First Set and First Amended Set of Interrogatories.

Table 4. Energy Efficiency Savings by State[69]

State	Savings (MWh)	Savings (% of sales)	Savings Year
California	933,365	0.8	2003
Connecticut	24,600	0.8	2002
RhodeIsland	50,568	0.8	2002
Vermont	38,400	0.8	2002
Massachusetts	241,000	0.7	2002
Oregon	112,100	0.4	2002
Wisconsin	214,800	0.4	FY2003
Maine	25,500	0.3	2003
New York	290,000	0.3	2002
New Jersey	171,692	0.2	2002
Texas	455,700	0.2	2002
New Hampshire	12,039	0.1	2002-2003

Rate Impact of Big Stone II

Q. Have the Co-owners estimated the rate impact to South Dakota customers from Big Stone II?

A. No, the response to Interrogatory 41 of Staff's Third Data Request was "There exists no projected rate impact information for the Applicants' South Dakota customers based on Big Stone Unit II alone."

We asked the Co-owners a similar rate impact question, "Quantify the expected average rate impact to residential customers from the BSII project for each of the seven Co-owners."[70] With the exception of Montana-Dakota, none of the Co-owners could say what the impact to residential customers will be. Many said that this was due to the fact that they do not serve end-use customers. Montana-Dakota did say that Big Stone Unit II would cause a 20% rate increase.

Q. Have the Co-owners estimated the rate impacts from any portion of Big Stone Unit II?

A. Apparently not from Big Stone Unit II itself, but they did estimate the rate impacts to customers from the associated transmission line. Every single one of

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69 ACEEE 2004. *Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies*, Martin Kushler, Dan York and Patti White, Report No. U041, April 2004.

70 Response to Information Request 44 in Minnesota PUC Docket No. CN-05-619.

the Co-owners estimated this rate impact in Appendix K of the Co-owners application for a Certificate of Need from the Minnesota PUC for the transmission line in support of Big Stone Unit II.

Q. Those rate impact estimates were required as part of the Co-owners' application. Is it possible that the Co-owners are simply not concerned about the rate impact of Big Stone Unit II?

A. It seems unlikely. For example, OTP witness Ward Uggerud states in his testimony "I know first hand [customers'] concern about the price of all their inputs and I understand the relationship between each component of the cost and reliability of the electricity our company provides to customers."[71]

In response to a question about what general factors Otter Tail considered in determining that it needed to add new base load capacity in 2011, Mr. Uggerud further states that

> The first and paramount factor was the fact that Otter Tail's customers live and operate businesses in rural areas and in small towns and cities. The company's residential customers live on relatively modest incomes and, by and large, do not have the economic means to absorb unnecessary rate increases. Thus, the first factor considered was the necessity of maintaining affordable rates.[72]

Q. Do you see any explanation as to why the Co-owners, with the exception of Montana-Dakota, seem not to have quantified the rate impact from Big Stone Unit II?

A. No.

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71 Applicants' Exhibit 1, at page 3, lines 11-13.

72 Applicants' Exhibit 1, at page 7, lines 6-10.

Emission Control Technologies

Q. Have the Applicants' included appropriate emissions control technologies in the proposed design of Big Stone Unit II?

A. The answer is "yes, in part." We examined this issue purely from the perspective of whether the Co-owners can meet applicable, existing rules governing emissions of SO_2, NOx and Hg. We did not, for example, consider whether Big Stone Unit II will meet opacity limits, if applicable, or whether it will meet any future regulations further limiting SO_2, NOx or Hg. Neither did we examine whether the "netting" of increased emissions at Big Stone II is legally supportable. While we do believe that CO_2 will be regulated in the future, we are not aware of any currently economic or commercial method to capture and sequester CO_2 emissions from Big Stone Unit II, and so this issue cannot be reasonably addressed in response to the question.

We expect that with the proposed design of Big Stone Unit II, the Co-owners could meet the SO_2 and NOx requirements based on existing regulations. The Co-owners, however, seem to doubt their ability to achieve mercury reductions necessary to meet the requirements of the Clean Air Mercury Rule (CAMR). While CAMR does allow for the trading of mercury allowances, purchasing allowances instead of making those reductions at the Big Stone site would result in local environmental and public health impacts from mercury deposition.

Witness Terry Graumann states on page 12, lines 7-9 of his testimony, that South Dakota has been allocated an annual mercury budget of 144 pounds beginning in 2010 and dropping to 58 pounds in 2018 and beyond. We presume that South Dakota will ultimately decide to allocate these allowances to Big Stone Unit I and to Big Stone Unit II, should it come online.

At present, the Co-owners project that the design of Big Stone Unit II, in combination with Big Stone Unit I, would result in the emission of 399 pounds of mercury per year.[73] Since the commercial operation date of Big Stone Unit II post-dates the requirement to limit mercury emissions to 144 pounds, this represents a compliance issue for the Co-owners. Even if the Co-owners adopt activated carbon injection (ACI) to further control mercury emissions (in addition to the scrubber/SCR co-benefit reduction), the combined mercury emissions from both Big Stone units may very well exceed the 144 pound cap. If Big Stone Unit I's mercury emissions remain static at their 2004 level of 189.6[74] pounds and Big Stone Unit II achieves a mercury emission rate of .00002lb/MWh,[75] annual mercury emissions would be 92.5 + 189.6 = 282 lbs, exceeding the cap by 138 pounds. Assuming that Big Stone Unit I could also achieve a mercury emissions rate of .00002/MWh, it would have to operate at a capacity factor of no more than 64% in order to achieve annual net emissions of 144 lbs.

The Co-owners have not discussed their strategy for meeting the limits of CAMR nor have they discussed the potential environmental impact of the increased emissions, should they purchase mercury allowances to meet the CAMR limit. Given the costs associated with mercury emissions, such as prenatal intellectual impairment, increased morbidity and mortality from myocardial disease, and economic damage to impaired fisheries, we recommend that these issues be addressed in this proceeding prior to a decision regarding the siting permit.

Q. What is your overall recommendation to the South Dakota Public Utilities Commission?

A. We recommend that the Commission deny the application for an energy conversion facility siting permit for Big Stone II because:

- The facility will represent a significant threat to the environment.

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[73] From the chart bates stamped chart JCO0002254 and clarified in response to Joint Intervenors' Fourth Set of Request for Production of Documents, which incorporated the Co-owners' response to Information Request No. 26 in MN PUC Docket No. CN-05-619.

[74] Ibid.

[75] From Applicants' Exhibit 24-A, page 2-4.

- The Co-owners have not demonstrated that they need 600 MW of additional baseload generating capacity beginning in 2011.

- The Co-owners have not demonstrated that Big Stone is the lowest cost option as compared to a portfolio of wind, other renewable and demand-side alternatives.

Q. Does this complete your testimony?

A. Yes.