

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) Case No EL05-022
Construction of the Big Stone II Project)

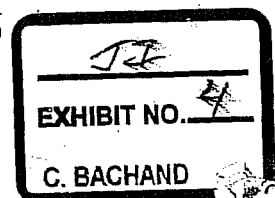
Direct Testimony of
David A. Schlissel and Anna Sommer
Synapse Energy Economics, Inc.

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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May 26, 2006

CORRECTED VERSION June 23, 2006



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

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

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

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

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

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

12 **Q. Have you previously filed testimony in this proceeding?**

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

17 **Q. What is the purpose of this testimony?**

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

20 A. The need and timing for new supply options in the utilities’ service
21 territories.

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

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

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

27 **Q. Please summarize the conclusions of this testimony.**

28 A. Our conclusions are as follows:

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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 CO₂ price forecast

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

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

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

15 11. For the reasons discussed in this testimony, the testimony we filed on May
16 19, 2006 and the testimony filed on May 19th by our colleague, Dr. Ezra
17 Hausman, the South Dakota Public Utilities Commission should reject the
18 Co-owners' Application for An Energy Conversion Facility Siting Permit
19 for the Big Stone II Project.

20 The Need for Capacity

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

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

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1 In fact, the September MRO 2005 *Ten-Year Reliability Assessment* projects that
2 during winter peak periods the MAPP-US region will have very substantial
3 capacity reserves **above** the 15 percent required levels of reserves. Indeed, the
4 Midwest Reliability Organization (“MRO”) September 2005 Assessment projects
5 that MAPP-US will have approximately 4,000 MW of capacity reserves above the
6 regional reserve capacity obligation (“RCO”) during the winter of 2011-2012,
7 approximately 3,600 MW of capacity reserves above the RCO during the winter
8 of 2012-13, and approximately 3,300 MW of capacity reserves above the RCO
9 during the winter of 2012-2013.¹ These capacity reserves show that the MAPP-
10 US region will not require any new increments of capacity to ensure adequate
11 reliability during the winter periods for years after 2013.

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

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

19 A. MRO currently projects that the MAPP-Canada subregion will have between
20 1,384 MW of surplus capacity in the summer of 2011, decreasing to about 1,350
21 MW by the summer of 2014.

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

24 A. No.

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

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

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

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

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

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

19 A. If we accept their load forecasts as a given, CMPPA is projecting that it will have
20 sufficient capacity through 2012.² With its new demand-side management
21 ("DSM"), MRES will have sufficient capacity through 2012.³ The other Co-
22 owners project some capacity deficits in the summer of 2011.

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

³ Response to Interrogatory 44 of Joint Intervenor's Sixth Set of Interrogatories and Combined Request for Production of Documents.

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

3 A. No. The seven Big Stone II Co-owners have repeatedly claimed that they “share
4 a common need for baseload resources in the 2011 timeframe.”⁴ However,
5 assuming for the sake of argument that the Co-owners’ demand forecasts are
6 reasonable, the most that the Co-owners have shown in their Application and
7 Testimony in this proceeding is that almost all of them are currently projecting
8 some levels of capacity deficits during summer peak hours starting in 2011. The
9 Co-owners have not shown that they individually or as a group have any need
10 beginning in 2011 for 600 MW of new baseload capacity that would operate at an
11 88 percent capacity factor.

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

13 A. First, none of the Co-owners has presented any analysis that goes beyond looking
14 at system loads and capacity during the summer, or in some cases summer and
15 winter, peak demands. Second, the data provided by certain Co-owners shows
16 that they do not need very much of their MW shares of Big Stone II capacity even
17 during peak hours in 2011. For example, CMMPA is forecasting that it will have
18 sufficient capacity without Big Stone II to meet projected peak demands in 2011
19 and 2012 and that it will only have deficits of 2 MW in 2013 and 9 MW in 2014.⁵
20 Despite this, CMMPA wants to acquire 30 MW of Big Stone Unit II in 2011.

21 Similarly, based on its April 2006 forecasts, which assume extreme weather
22 instead of normalized weather,⁶ MRES projects an 11 MW capacity surplus
23 (including new DSM) in the peak summer hours of 2011 without Big Stone II.
24 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.

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1 hours of 2015.⁷ MRES' forecasts do not suggest a need for its entire 110 MW of
2 Big Stone II until 2016 when it will assume the load of Marshall, Minnesota from
3 Heartland. Despite this, MRES contends that it needs its share of Big Stone II
4 starting in 2011.

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

8 A. Yes. Beyond simply making this claim, the Co-owners have not presented any
9 evidence showing that the planned transmission system upgrades (including 807
10 miles of new 345 kV and 230 kV transmission lines, as noted by Co-owner
11 witness Koegel⁸) cannot relieve the constraints that have prevented any of the Co-
12 owners from entering into firm contracts to purchase power from third parties.

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

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

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

25 A. Yes.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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 Intervenor's Sixth Set of Interrogatories and Combined Request for Production of Documents.

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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 demand¹⁴ 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

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 JL-4-A, at page 19.

¹³ Response to MCEA IR No. 73 in MNPUC Docket No. CN-05-619. Joint Intervenor's 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 JL-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.

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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.

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

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

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

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

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

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.

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

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

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

10 A. Each of the alternatives considered in the *Generation Alternatives Study* were
11 designed to provide the same amounts of capacity for reliability (600 MW) and
12 energy (approximately 4,625 GWh). Because it assumes that the wind resources
13 have zero capacity value, in the wind alternative examined, the *Study* added 600
14 MW of natural-gas fired combined cycle capacity to "back up" the 600 MW of
15 wind it assumed would be built. By limiting the amount of wind resources to 600
16 MW, the *Study* limits the energy that would be produced by that wind capacity to
17 2,102 GWh (assuming a 40 percent capacity factor for wind). This means that
18 2,523 GWh, or more than half of the required energy, would be generated by the
19 far more expensive natural gas-fired combined cycle facility. This increases the
20 overall cost of the wind-gas alternative.

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

²¹ Exhibit JI-4-A, at page 27.

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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 or operate 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.

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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

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1 percent annual capacity factor. Clearly, the levelized cost of the coal option could
2 be higher if the costs of building and/or operating the coal facility are assumed to
3 be higher and/or the plant is assumed to operate at less than an average 88 percent
4 capacity factor.

5 Finally, we have adopted Burns & McDonnell's assumed levelized value of
6 \$12/MWh for the Production Tax Credit ("PTC") for wind facilities, which may
7 understate the value of the PTC by not counting the additional tax benefit of the
8 PTC because it is a credit on tax liability rather than a dollar of taxable income.
9 Unfortunately, because there are no spreadsheets or workpapers to support the
10 wind cost, despite our having asked for these in discovery, or to support the PTC
11 calculation we cannot verify whether this tax effect was accounted for or not.

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

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

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

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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 CO₂ 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 CO₂ 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 CO₂ 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.

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.

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

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

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

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

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

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

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

²³ Response to Interrogatory 17 of Joint Intervenor's Sixth Set of Interrogatories and Combined Request for Production of Documents.

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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.

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

6 **Q. Why do you consider the alternative to Big Stone II plan studied by Mr.**
7 **Harris to be “highly risky?”**

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

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

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

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.

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

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

13 **Q. Please summarize the alternatives that the individual Co-owners considered**
14 **in developing their “next best” alternatives to Big Stone II.**

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

- 19 ▪ Montana-Dakota has said that it only considered three possible
20 alternatives to Big Stone II – two of these were coal-fired and the third
21 was to purchase power from the market. Moreover, Montana-Dakota did
22 not perform any economic analyses to quantitatively compare the revenue
23 requirements of these alternatives or to examine any other possible
24 alternatives to Big Stone II.
- 25 ▪ Otter Tail Power developed an alternative that assumed it would purchase
26 120 MW of hydro capacity from Manitoba Hydro.
- 27 ▪ Great River Energy’s July 2005 *Alternatives Evaluation for the*
28 *Construction of Big Stone II* only quantitatively considered three resource
29 types, all of which were coal or natural gas-based resources.²⁷ GRE’s

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.

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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

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- 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

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.

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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, CO₂, 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 CO₂ and CO emissions, and **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]**

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

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

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

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

11 A. No.

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

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

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

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

21 Despite repeated requests, Otter Tail Power insisted for several months (including
22 as late as May 3, 2006) that there were no additional output files for any other
23 scenarios. Then, on May 5, 2006, counsel for Otter Tail Power revealed that, in
24 fact, there were output files for other scenarios but they couldn't give all of them
25 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.

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

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

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

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

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.

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

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

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

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

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

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

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

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

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1 2011.³⁹ These scenarios clearly provide no information as to the relative
2 economics of participation in Big Stone II as compared to renewable and demand-
3 side alternatives.

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

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

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

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

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

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

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

11 A. No. Montana-Dakota's 2003 Integrated Resource Plan selected 120 MW of new
12 combustion turbines and some improvements to existing CTs to meet the
13 company's demand through 2021.⁴² However, in its 2005 Integrated Resource
14 Plan, where it does not appear to use any model or to perform any quantitative
15 analysis, the company concludes that "subsequent to the filing of the 2004 IRP,
16 Montana-Dakota determined that the plan's heavy reliance on gas-fired
17 generation exposed our customers to considerable price and reliability risk
18 associated with fuel cost and availability. The company believes that coal-fired
19 generation, which has lower and less volatile fuel prices and a more stable fuel
20 supply than natural gas, provides a better value for our customers."⁴³

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

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.

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1 reliance on purchased power.⁴⁴ As Montana-Dakota explained in its response to
2 Interrogatories 28 and 58 of Joint Intervenor's Sixth Set of Interrogatories and
3 Combined Request for Production of Documents:

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

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

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

22 **A.** Montana-Dakota has estimated that the addition of Big Stone II will increase its
23 residential customer rates by approximately 20 percent, or about 1.9 cents/kWh⁴⁸
24 excluding the potential impact of greenhouse gas regulation.

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

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

46 Ibid.

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

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

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

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

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

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

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

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

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

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

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

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14 **CONFIDENTIAL MATERIAL ENDS]**

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

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

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.

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

3 **A. [CONFIDENTIAL MATERIAL BEGINS**
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12 However, as we have demonstrated earlier in this testimony, even with overly
13 conservative and the Co-owners' unrealistic operating assumptions, a
14 combination of wind and gas can be cheaper on a cost basis than Big Stone Unit
15 II.

16 Demand-Side Management

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

20 **A. No.**

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

⁵⁵ *Ibid*, at pages 41-46.

⁵⁶ *Ibid*, at page 41.

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

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

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

13 MRES does not offer DSM programs, its members do. To our knowledge, it had
14 not undertaken any analysis of DSM programs until [CONFIDENTIAL
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⁵⁷ Response to Interrogatory 3 of Joint Intervenor's First Set and First Amended Set of Interrogatories.

⁵⁸ Response to Interrogatory 15 of Joint Intervenor's 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.

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.

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1 According to SMMPA's 2003-2018 IRP, it evaluated DSM measures using the
2 EGEAS model which compares those measures to supply-side resources. It
3 screened the measures evaluated in EGEAS using a methodology that appears to
4 have been based upon a DSM potential study done in 1993.⁶⁴ While we have not
5 reviewed the 1993 study (and have not been supplied with a copy of it), we find it
6 very difficult to believe that a 13-year old study could yield reliable and credible
7 DSM potential results given the changing characteristics of SMMPA's load,
8 resources and particularly DSM measures themselves. The cost of DSM
9 measures, their impacts and even the DSM measures that one would implement
10 are very likely to have changed between 1993 and 2006.

11 Otter Tail Power most recently analyzed the potential for DSM in 2002 but only
12 for its commercial and industrial customers in its Minnesota service territory. In
13 modeling DSM programs for other sectors of customers, it appears to rely upon a
14 1994 DSM potential study, *Draft Report: DSM Potential Study and Commercial*
15 *Survey*. While we have not reviewed the study, as with SMMPA's 1993 study, it
16 is very difficult to believe that a 12-year old study could yield reliable and
17 credible DSM potential results for integrated resource planning in 2006.

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

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

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1 **Q. What does it mean to “evaluate the potential for DSM” on a Co-owner’s**
2 **system?**

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

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

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

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

24 **Q. Is the Co-owners’ cost of saved energy roughly equivalent to the cost of Big**
25 **Stone Unit II?**

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

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

4 In response to Staff's Third Data Request, Interrogatory 31, GRE responded that
5 from 2002 – 2007 its lifetime cost of saved energy ranges from \$14.10/MWh to
6 \$21.10/MWh.⁶⁵ GRE did not provide cost of saved energy data for future years
7 beyond 2007.

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

14 As an investor-owned utility, Otter Tail Power's twenty-year levelized busbar
15 cost of Big Stone Unit II is \$50.71/MWh. Otter Tail Power's cost of saved
16 energy through 2011 ranges from a low of \$8.79/MWh⁶⁶ to a high of
17 \$27.28/MWh.⁶⁷ Like GRE, it is reasonable to expect that there would be many
18 cost-effective energy efficiency measures in the range between Otter Tail Power's
19 highest cost of saved energy, \$27.28/MWh, and the cost of Big Stone Unit II
20 without greenhouse gas regulation, \$50.71/MWh, a difference of \$23.42/MWh!

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

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.

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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 Customers⁶⁸

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 Intervenor's First Set and First Amended Set of Interrogatories.

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Table 4. Energy Efficiency Savings by State⁶⁹

State	Savings (MWh)	Savings (% of sales)	Savings Year
California	933,365	0.8	2003
Connecticut	24,600	0.8	2002
Rhodelsland	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

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.

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

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

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

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

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

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

23 **A.** No.

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

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

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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 SO₂, NO_x 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 SO₂, NO_x or Hg. Neither did we examine whether the "netting" of increased emissions at Big Stone II is legally supportable. While we do believe that CO₂ will be regulated in the future, we are not aware of any currently economic or commercial method to capture and sequester CO₂ 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 SO₂ and NO_x 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

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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 189.6⁷⁴ 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.

⁷³ From the chart bates stamped chart JCO0002254 and clarified in response to Joint Intervenor's 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.

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- 1 ▪ The Co-owners have not demonstrated that they need 600 MW of
2 additional baseload generating capacity beginning in 2011.
- 3 ▪ The Co-owners have not demonstrated that Big Stone is the lowest cost
4 option as compared to a portfolio of wind, other renewable and demand-
5 side alternatives.

6 **Q. Does this complete your testimony?**

7 **A. Yes.**

8

9

EDUCATION:

Master of Community and Regional Planning, University of Oregon, Eugene, OR. June 1992.

Bachelor of Arts - Political Science, California State University, Chico, CA. May 1990.

PROFESSIONAL EXPERIENCE:

Principal Consultant - MRG & Associates, 1991 to present.

Marshall Goldberg is a resource planner with a broad background in resource and land use policy and impact analysis. He has considerable experience designing, coordinating, and completing research and assessment projects, working with government agencies, managing projects, coordinating team efforts and conducting workshops.

Since 1991, Marshall has been involved in analyzing utility, government, and industry programs and policies as well as evaluating energy and marine resources, land use impacts, and the socio-economic impacts associated with them. These projects cover a broad spectrum, ranging from reviewing and analyzing the economic impacts associated with energy efficiency policies throughout the United States, to analyzing the socio-economic impacts of the US Virgin Islands Marine Protected Areas, to evaluating land use and economic issues associated with power plant development in the Midwest.

Marshall has completed projects for numerous clients, including the U.S.D.A. Forest Service, the Virgin Islands Department of Planning and Natural Resources, the U.S. Department of Energy, the Illinois Department of Commerce and Community Affairs, the National Renewable Energy Laboratory, the Virgin Islands Anti-Litter and Beautification Commission, the American Public Power Association, the American Council for an Energy-Efficient Economy (ACEEE), the Union of Concerned Scientists, the Tellus Institute, the Michigan Public Services Commission, and the Nevada Department of Business and Industry, among others.

During the last fifteen years Marshall has completed numerous resource policy studies, has evaluated the impacts of investments in energy efficiency and renewable resources throughout the U.S. and completed studies assessing the economic impacts of national transportation policies. He has provided testimony before several regulatory commissions; most recently providing testimony before the Indiana Utility Regulatory Commission on developing a framework for siting merchant power plants in Indiana. He has assisted the U.S. Virgin Islands Government in analyzing energy conservation and resource management strategies, provided public policy and community outreach support, and facilitated numerous

workshops, including a strategic planning initiative. Complementing this work, he helped develop the Virgin Islands Energy and Economic Management Information System (EEMIS); a series of electronic databases and analytical tools to support more comprehensive understanding and assessment of the economy, energy, environmental, and land use policies and impacts.

Prior to forming MRG & Associates Marshall worked as a Research Planner at the University of Oregon, Community Planning Workshop, specializing in resource and environmental research, developing and conducting surveys, and land use and transportation planning and analysis. He has taught Environmental Studies and Environmental Health Planning classes for undergraduate and graduate students. His background also includes providing litigation support services, director at a community legal information center, working with farmers, and coordinating research and public education efforts to assist policy makers in land use policy development and planning efforts. Marshall has also done extensive work in the solid and hazardous waste management field, helping develop and coordinate countywide management plans and public information and outreach efforts.

PROFESSIONAL and COMMUNITY ACTIVITIES:

Planning Commissioner, County of Nevada, California, January 2001 to December 2002.

Board of Directors, Willow Wood Waldorf School, Sebastopol, California, 1996 and 1997.

Committee Member, Lane County Resource Recovery Advisory Committee, Eugene, Oregon, 1991 through 1994.

Board of Directors, Grower's Market, Eugene, Oregon, 1993 and 1994

Committee Member, Butte County Solid/Hazardous Waste Advisory Committee, Oroville, California, 1987 through 1990, Vice-chair 1987 through 1989.

Supervisor, Butte County Hazardous Materials Education Program, Butte County Planning Department, Oroville, California, 1989.

Co-Director, Environmental Program, Community Legal Information Center, California State University, Chico, Chico, California, 1988 and 1989.

Marshall has authored or co-authored more than 30 papers and studies on energy, resource policy, land use issues and associated economic and environmental impacts. A listing of his publications and testimony is available upon request.

Jobs and Economic Development Impact (JEDI) Coal Model. An economic development impact model developed for the National Renewable Energy Laboratory (NREL) to assess impacts from constructing and operating coal power plants. January 2006.

Jobs and Economic Development Impact (JEDI) Natural Gas Model. An economic development impact model developed for the National Renewable Energy Laboratory (NREL) to assess impacts from constructing and operating natural gas power plants. January 2006.

A Study of Wind Energy Development in Wisconsin. A collaborative report co-authored with Seventh Generation Energy Systems, Inc., Northwest SEED, Wind Utility Consulting, and the Energy Center of Wisconsin. The report was prepared for the Wisconsin Division of Energy. July 2004.

Jobs and Economic Development Impact (JEDI) Wind Model. An economic development impact model developed for the National Renewable Energy Laboratory (NREL) to assess impacts from constructing and operating wind power plants. January 2003.

Socio-Economic Assessment of Marine Resource Utilization in the U.S. Virgin Islands. A report co-authored with Claudette Hinds (Hinds Unltd.). Prepared for the U.S. Virgin Islands Department of Planning and Natural Resources as part of the V.I. Marine Park Project, an initiative of the Government of the Virgin Islands, implemented as part of the U.S. National Action Plan to Conserve Coral Reefs. January 2003.

The New Motherlode: The Potential for More Efficient Electricity Use in the Southwest. A report co-authored with members of the Southwest Energy-Efficiency Project (SWEET), the American Council for an Energy Efficient Economy (ACEEE), the Tellus Institute and Robert Mowris (Robert Mowris & Associates). Prepared for the Southwest Energy Efficiency Project. November 2002.

The Bottom Line on Kyoto: Economic Benefits of Canadian Action. A report co-authored with Bailie, A., Bernow, S., Dougherty, W., Runkle, B., A report prepared by the Tellus Institute for the David Suzuki Foundation. April 2002.

Clean Energy: Jobs For America's Future. A report co-authored with Bailie, A., Bernow, S., Dougherty, W., Lazarus, M., Kartha, members of the Tellus Institute for the World Wildlife Foundation. October 2001.

Macroeconomic Impacts for the UCS Utopia Transportation Scenario. A report prepared for the Union of Concerned Scientists providing background data and analysis for *Drilling in Detroit: Tapping Automaker Ingenuity to Build Safe and Efficient Automobiles*. June 2001.

Assessing the Impacts of Electric Retail Competition on Mississippi's Residents and Businesses. A report co-authored with Skip Laitner. Prepared for the Mississippi Department of Economic and Community Development Energy Division. November 2000.

Federal Energy Subsidies: Not All Technologies Are Created Equal. A report prepared for the Renewable Energy Policy Project, Washington, DC, for the U.S. Department of Energy. July 2000.

Prefiled and Direct Testimony of Marshall R. Goldberg in the Matter of the Petition by State Line Energy, LLC., for Certain Determinations by the Commission with Respect to its Jurisdiction over Petitioner's Activities as an Exempt Wholesale Generator Under Federal Law, State of Indiana, Indian Utility Regulatory Commission, Cause No. 41590. Prepared for the Citizens Action Coalition of Indiana, Inc. July 2000.

Texas' Global Warming Solutions. A study co-authored with Steve Bernow, William Dougherty, and Jane Dunbar of the Tellus Institute. The study was prepared for the World Wildlife Fund under the direction of the Tellus Institute, Cambridge, MA. February 2000.

Prefiled and Direct Testimony of Marshall R. Goldberg on behalf of the Arizona Corporation Commission. State of Arizona, Arizona Corporation Commission, Cause No. 41590. Prepared for the Citizens Action Coalition of Indiana, Inc. July 2000.

Energy Efficiency and Renewable Energy Technologies as an Economic Development Strategy for Texas. Co-authored with Skip Laitner for the State of Texas Department of Economic Development. December 1998.

Energy Efficiency and Economic Development in Illinois. A report co-authored with Martin Kushler, Steven Nadel, Skip Laitner, Neal Elliott, Martin Thomas of ACEEE. Prepared for the Illinois Department of Commerce and Community Affairs. December 1998.

Arizona Energy Outlook 2010: Energy Efficiency and Renewable Energy Technologies as an Economic Development Strategy. A report co-authored with Skip Laitner for the National Renewable Energy Laboratory, the Land and Water Fund of the Rockies, and the Arizona State Energy Office, a Division of the Arizona Department of Commerce. July 1998.

Quantifying Benefits of U.S. Department of Energy Programs, Study Area: Albuquerque/Bernalillo County, New Mexico. A report co-authored with Skip Laitner for the U.S. Department of Energy, Denver Regional Support Office. Golden, CO. August 1997.

Energy: A Major Economic Development Strategy for Nevada, The Case for Aggressively Pursuing Energy Efficiency and Development of Renewable Energy Industries in Nevada. A report co-authored with Skip Laitner for the Nevada State Energy Office, a Division of the Department of Business and Industry, the Corporation for Solar Technology and Renewable Resources, and the National Renewable Energy Laboratory. June 1997.

Assessing the U.S. Employment Benefits from Increased Production of U.S. Renewable Energy Technologies, Part 1: Review of Renewable Energy Employment Impact Studies and Part 2: Multipliers for Exported Products. Two companion reports co-authored with Skip Laitner and Anne Polansky (Solar Energy Industries Association). Prepared for the Solar Energy Industries Association. Washington, DC. December 1996.

Regional Energy and Economic Self-Sufficiency Indicators in the Southeastern United States. A report co-authored with Skip Laitner for the Southeastern Regional Biomass Energy Program, Tennessee Valley Authority. Muscle Shoals, AL. May 1996.

Planning For Success: An Economic Development Guide for Small Communities. A guidebook for electric utilities, co-authored with Skip Laitner. Prepared for the American Public Power Association. Washington, DC. March 1996.

Environment and Jobs: The Employment Impact of Federal Environmental Investments. A report co-authored with Skip Laitner and Michael Sheehan. Prepared for the National Commission for Employment Policy. Washington, DC. April 1995.

U.S. Virgin Islands Energy Profile. A report co-authored with Skip Laitner and Gregory Holmes. This report represents a compilation of eight individual reports written on energy use, production, policies and economics, for the U.S. Virgin Islands Energy Office. Frederiksted, USVI. December 1994.

Assessment of Small Scale Biomass Cogeneration in the State of Michigan. A report co-authored with Skip Laitner and Gregory Holmes. Prepared for the Michigan Biomass Energy Program, Public Service Commission, Michigan Department of Commerce. Lansing, MI. July 1994.

Energy Choices Revisited: An Examination of the Costs and Benefits of Maine's Energy Policy. A report co-authored with Steve Bernow (Tellus Institute), Skip Laitner (Economic Research Associates), and Jeff Hall and Marc Breslow (Tellus Institute). Prepared for the Mainewatch Institute. Hallowell, ME. February 1994.

Energy and Economic Indicators: A Manual for the U.S. Virgin Islands Energy Office. A guidebook developed for the U.S. Virgin Islands Energy Office staff. Christiansted, USVI. November 1993.

Expanding Energy Savings by Accelerating Market Diffusion of Efficient Technologies: Three Case Studies. A report co-authored with the Center for Applied Research and Economic Research Associates, for the U.S. Department of Energy. Washington, DC. February 1992.

Wind Plant - Project Data Summary

Year of Construction	2007
Project Location	SOUTH DAKOTA
Project Size - Nameplate Capacity (MW)	1320
Turbine Size (KW)	1500
Number of Turbines	880
Construction Cost (\$/KW)	\$1,372
Annual Direct O&M Cost (\$/KW)	\$14.02
Money Value (Dollar Year)	2005
Project Construction Cost	\$1,811,040,000
Local Spending	\$211,758,706
Total Annual Operational Expenses	\$296,476,576
Direct Operating and Maintenance Costs	\$18,506,400
Local Spending	\$11,605,636
Other Annual Costs	\$277,970,176
Local Spending	\$5,589,760
Debt and Equity Payments	\$0
Property Taxes	\$2,069,760
Land Lease	\$3,520,000

Local Economic Impacts - Summary Results

	Jobs	Earnings	Output
During construction period			
Direct Impacts	2,061	\$52.86	\$206.95
Construction Sector Only	1,928	\$49.16	\$194.00
Indirect Impacts	899	\$22.87	\$65.90
Induced Impacts	1,050	\$24.26	\$81.28
Total Impacts (Direct, Indirect, Induced)	4,010	\$100.00	\$354.14
During operating years (annual)			
Direct Impacts	291	\$11.09	\$19.36
Plant Workers Only	172	\$7.96	
Indirect Impacts	73	\$1.92	\$6.30
Induced Impacts	119	\$2.75	\$9.23
Total Impacts (Direct, Indirect, Induced)	483	\$15.76	\$34.88

Notes: Earnings and Output values are millions of dollars in year 2005 dollars. Jobs are full-time equivalent for one year. Plant workers includes field technicians, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement. Totals may not add up due to independent rounding.

Detailed Wind Plant Project Data Costs

SOUTH DAKOTA

	Cost	Local Share
Construction Costs		
Materials	\$95,145,562	90%
Construction (concrete rebar, equip, roads and site prep)	\$24,035,029	0%
Transformer	\$11,271,600	100%
Electrical (drop cable, wire,)	\$20,719,852	100%
HV line extension	\$151,172,042	
Materials Subtotal		
Labor		
Foundation	\$8,287,941	100%
Erection	\$8,287,941	75%
Electrical	\$9,116,735	75%
Management/supervision	\$4,972,765	0%
Labor Subtotal	\$30,665,381	
Construction Subtotal	\$181,837,424	
Equipment Costs		
Turbines	\$994,804,272	0%
Blades	\$331,601,424	0%
Towers	\$208,269,600	0%
Equipment Subtotal	\$1,534,675,296	
Other Costs		
HV Sub/Interconnection	\$66,303,527	100%
Engineering	\$21,732,480	0%
Legal Services	\$1,684,267	100%
Land Easements	\$0	100%
Site Certificate	\$4,807,006	100%
Other Subtotal	\$94,527,280	
Total Project Costs	\$1,811,040,000	

Wind Plant Annual Operating and Maintenance Costs

	Cost	Local Share
Personnel		
Field Salaries	\$6,549,130	100%
Administrative	\$783,363	100%
Manangement	\$2,350,496	100%
Personnel Subtotal	\$9,682,988	
Materials and Services		
Vehicles	\$617,639	100%
Misc. Services	\$1,764,682	80%
Fees, Permits, Licenses	\$617,639	100%
Misc. Materials	\$1,764,682	100%
Insurance	\$2,647,024	0%
Fuel (gals)	\$441,171	100%
Tools and Misc. Supplies	\$705,873	100%
Spare Parts Inventory	\$264,702	2%
Materials and Services Subtotal	\$8,823,412	
Debt Payment (average annual)	\$210,080,640	0%
Equity Payment - Individuals	\$0	100%
Equity Payment - Corporate	\$62,299,776	0%
Property Taxes	\$2,069,760	100%
Land Lease	\$3,520,000	100%
Total Annual Operating and Maintenance Costs	\$296,476,576	

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Other Parameters

Local Share

Financial Parameters

Debt Financing

Percentage financed

Years financed (term)

Interest rate

Equity Financing

Percentage equity

Individual Investors (percent of total equity)

Corporate Investors (percent of total equity)

Return on equity (annual interest rate)

Repayment term (years)

Tax Parameters

Local Property/Other Tax Rate (\$ per MW)

Local Taxes

Land Lease Parameters

Land Lease Cost (per turbine)

Land Lease (total cost)

Lease Payment recipient (F = farmer/household, O = Other)

80% 0%

10

10%

20%

0%

100%

16%

10

\$1,568

\$2,069,760

\$4,000
\$3,520,000

F

100% 100%