BEFORE THE STATE OF MINNESOTA

OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application by Otter Tail Power	)	
Company and Others for Certification of	)	
Transmission Facilities in Western Minnesota	)	**OAH No. 12-2500-17037-2**
And	)	**MPUC Dkt. No. CN-05-619**
In the Matter of the Application to the Minnesota	)	**and**
Public Utilities Commission for a Route Permit for the	)	**OAH No. 12-2500-17038-2**
Big Stone Transmission Project in Western Minnesota	)	**MPUC Dkt. No. TR-05-1275**
	)	

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

On Behalf of
Fresh Energy
Izaak Walton League of America – Midwest Office
Wind on the Wires
Union of Concerned Scientists
Minnesota Center for Environmental Advocacy

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I. INTRODUCTION

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

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

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

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

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

A. We are testifying on behalf of Fresh Energy, Izaak Walton League of America – Midwest Office, Wind on the Wires, Union of Concerned Scientists, and Minnesota Center for Environmental Advocacy ("Joint Intervenors").

Q. Have you previously filed testimony in this proceeding?

A. Yes. We filed Testimony on Greenhouse Gas Regulation issues on November 17, 2006.

II. SUMMARY OF CONCLUSIONS

Q. What is the purpose of your testimony?

A. Synapse was asked to evaluate whether the proposed Big Stone II Project satisfies the following statutory requirements:

> Subd. 3. **Showing required for construction.** No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need.

> Subd. 3a. **Use of renewable resource.** The commission may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, or that transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the commission's satisfaction that it has explored the possibility of

> generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source. For purposes of this subdivision, "renewable energy source" includes hydro, wind, solar, and geothermal energy and the use of trees or other vegetation as fuel.

In addition, we also were asked to assess whether the Applicants' proposal to build the Big Stone II Project adequately limits the adverse risks on them and their customers from financial, social and technological factors that the Applicants cannot control.

Finally, our testimony considered the Minnesota Public Utilities Commission order in this docket which stated that:[1]

> The need for the generating facility and the need for the transmission lines are inextricably linked. As a matter of logic, the transmission lines proposed to be constructed in Minnesota will not be needed where they are proposed if the Applicants have a more reasonable and prudent alternative generation site. And the proposed transmission lines will not be needed at all if the Applicants (due to demand-side management or any combination of other alternatives) do not need the electricity projected to be generated at the Big Stone, South Dakota facility.

This Testimony, our Testimony of November 17, 2006, the Testimonies of our Synapse colleagues Tim Woolf, Robert Fagan and Dr. Ezra Hausman, and the Testimony of Steve Clemmer from the Union of Concerned Scientists present the results of our evaluations and assessments of these issues.

Q. Please summarize your conclusions.

A. Our conclusions are as follows:

1. The Applicants have not adequately considered the risks associated with building a new coal-fired generating unit in their modeling analyses.

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[1] MNPUC Order date December 19, 2005 at page 9.

2. The most significant uncertainties and risks associated with the proposed Big Stone II Project are future restrictions on CO 2 emissions; the potential for further increases in the project's capital cost; and the potential for fuel supply disruptions that could affect plant operating performance and fuel costs.

3. In particular, it is vitally important for each of the Applicants to justify its participation in the Big Stone II Project in light of coming federal regulation of greenhouse gas emissions. It would be imprudent for each Applicant to continue its participation in the Project without doing so or by merely using a single set of very low CO2 prices in such analyses. Instead, each Applicant should use a range of possible CO2 prices such as the forecasts presented by Synapse in this proceeding.

4. The Applicants have not shown that their demand for electricity cannot be met more cost effectively through energy conservation and load-management measures than through the Big Stone II Project.

5. The Applicants have not shown that the Big Stone II Project would be a lower cost option than renewable energy resources.

For these reasons, the Commission should reject the Applicants request for a Certificate of Need for the proposed Big Stone II Project.

Q. Please explain how you conducted your investigations in this proceeding.

A. We have reviewed the testimony and exhibits filed by the Applicants in this proceeding and in South Dakota Public Utilities Commission Case No. EL05-022. We also have reviewed the IRP filings made in Minnesota by Otter Tail Power Company ("Otter Tail" or "OTP"), Missouri River Energy Services ("MRES"), and Great River Energy ("GRE").

In addition, we have participated in discovery in this proceeding, the South Dakota Public Utilities Commission case, and the IRP Dockets. As part of that work, we have prepared information requests that were submitted to the

Applicants by Joint Intervenors and have reviewed the responses to those information requests and to the discovery submitted by the Department of Commerce ("DOC") in Minnesota and the South Dakota Public Utilities Commission Staff in Case No. EL05-022.

Finally, we have rerun the Strategist model for Central Minnesota Municipal Power Agency ("CMMPA"), Montana-Dakota Utilities ("MDU" or "Montana-Dakota") and MRES.

Q. Did you file testimony and testify in South Dakota Public Utilities Commission Case No. EL05-022?

A. Yes. We filed testimony on greenhouse gas regulation issues in Case No. EL05-022 on May 19, 2006 and testimony on other issues related to the proposed Big Stone II Project on May 26, 2006. In addition, we filed surrebuttal testimony on June 9 and June 22, 2006. We each testified before the South Dakota Commission on June 29, 2006

III. THE APPLICANTS HAVE NOT ADEQUATELY CONSIDERED THE RISKS ASSOCIATED WITH BUILDING A NEW COAL-FIRED GENERATING UNIT

Q. Why is it important that the Applicants consider risk when evaluating the economics of building the Big Stone II Project?

A. Risk and uncertainty are inherent in all enterprises. But the risks associated with any options or plans need to be balanced against the expected benefits from each such option or plan.

In particular, parties seeking to build new generating facilities and the associated transmission face of a host of major uncertainties, including, for example, the expected cost of the facility, future restrictions on emissions of carbon dioxide, and future fuel prices. The risks and uncertainties associated with each of these factors needs to be considered as part of the economic evaluation of whether to pursue the proposed facility or other alternatives.

Q. Have you seen any evidence that the Applicants have considered risks and uncertainties in the economic evaluations of the Big Stone II Project discussed in their Supplemental Direct Testimony?

A. No. The Applicant analyses in support of the Certificate of Need application that we have examined do not include any assessment of uncertainty or risks.[2] Instead, the Applicants' models optimize for lowest costs based on a defined, predictable future.

Only the levelized analysis presented by Applicant witness Greig in Applicants Exhibit 47-A even attempts to present a break-even analysis for future CO2 prices, one of the most important of the risks and uncertainties facing owners of proposed fossil-fired generating facilities. However, as we will discuss later in this testimony, that analysis is significantly flawed and its results cannot be relied upon.

Q. Is it reasonable to expect that the Applicants could reflect uncertainty and risk in their economic analyses of whether to pursue the Big Stone II Project or alternatives?

A. Yes. There are a number of ways that the Applicants could have considered uncertainty and risk. The most simple way would have been to perform sensitivity analyses reflecting engineering type bounding in which the key variables would be expected by vary by X% above or below their projected values. However, the Applicants have not conducted such sensitivity analyses as part of their Supplemental Direct Case in support of their application for a certificate of need for the Big Stone II Project.

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2 The only exception to this is Heartland which claims to have run a scenario with market electricity prices reduced by 10%, but did not provide the runs to Joint Intervenors.

Q. Have any of the Applicants previously performed any such sensitivity analyses regarding the proposed Big Stone II Project?

A. Yes. For example, Applicant witness Morlock discussed in his Direct Testimony in this proceeding that under Minnesota law, Otter Tail Power was required to examine a number of alternate resource plan scenarios to satisfy regulatory requirements.[3] Consequently, Otter Tail Power had examined scenarios involving base, low and high load growth with no, low and high externalities.

We believe that prudence also requires that the Applicants look at fossil plant-specific uncertainties and risks associated with their proposal to build and operate the Big Stone II Project. This is especially true in light of the substantial cost increase in the estimated capital cost of the Big Stone II Project that was announced since the Applicants filed their Direct Testimony on June 1st.

Q. What are the most significant fossil plant-specific uncertainties and risks associated with the proposed Big Stone II Project?

A. The most significant uncertainties and risks associated with the proposed Big Stone II Project are future restrictions on CO_2 emissions costs; the potential for further increases in the project's capital cost; and the potential for fuel supply disruptions that could affect plant operating performance and fuel prices.

Q. Is it important to evaluate the uncertainties and risks associated with alternatives to the Big Stone II Project as well?

A. Yes. The risks associated with building natural gas-fired alternatives include potential CO_2 emissions costs, possible capital cost escalation and fuel price uncertainty and volatility.

Renewable alternatives and DSM also have some uncertainties and risks. These include potential capital cost escalation, contract uncertainty and customer participation uncertainty.

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3 Applicants' Exhibit 15, at page 9.

III. A. Mandated Restrictions on Future CO_2 Emissions

Q. Is it reasonable to expect that there will be federally mandated restrictions on power plant CO_2 emissions in the near future?

A. Yes. As we have shown in Joint Intervenors Exhibit-1, we believe that it is reasonable to expect that federally mandated restrictions on CO_2 emissions will be adopted in the near future that will affect the emissions from fossil-fired facilities like Big Stone II and that will affect the facilities' costs of operations.

Q. Have the Applicants' considered the risks associated with the adoption of such restrictions in the Big Stone II Project modeling analyses presented in their October 2, 2006 Supplemental Direct Testimony?

A. No. At most, the Applicants have considered the Minnesota Commission's externality values in their supplemental analyses. However, as we have discussed in Joint Intervenors - Exhibit 1, this is not sufficient because the externality values for carbon dioxide established by the Minnesota Public Utilities Commission and used in resource planning by some of the Applicants are only meant to recognize "external" costs, or in other words, costs that are not directly paid by utilities or their ratepayers. The Minnesota Commission's externality values are not reflective of the costs of complying with future greenhouse gas regulations that will be directly paid by the utilities or ratepayers.

Moreover, the Minnesota Commission's externality values for CO_2 emissions from power plants outside Minnesota are only $0/ton.

Q. Have any of the Applicants acknowledged that the regulation of CO2 emissions is a key uncertainty or risk for the participants in the Big Stone II Project?

A. Yes. A presentation to the SMMPA Board on September 13, 2006 [**PROTECTED MATERIAL BEGINS**

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Unfortunately, SMMPA did not include any CO_2 costs in its modeling of the Big Stone II Project.

Also, GRE witness Lancaster does testify that he believes that future CO2 regulation is likely and that GRE has taken the impact that potential regulation of greenhouse gases may have on the economics of the Big Stone II Project.[5] However, GRE still used a $0/ton price for CO_2 emissions in its modeling.

[4] Bates Page Number SMMPA09646.

[5] Applicants' Exhibit 36, at page 6, lines 9-14.

Q. Is it reasonable to expect that future CO2 regulation will have a significant impact on the results of the Applicants' modeling?

A. Yes. As we will discuss below, it is reasonable to expect that the relative economics of building and operating the proposed Big Stone II Project and, consequently, the results of the Applicants' recent modeling of the Big Stone II Project would be very different if they incorporated a reasonable range of carbon price forecasts.

Q. Are the Big Stone II Applicants already heavily dependent upon coal-fired generation?

A. Yes. The testimony filed by the Applicants in South Dakota in support of the Big Stone II siting permit revealed that each of the Applicants already is heavily dependent upon coal-fired generation. Although some Applicants are making some efforts to add wind, participation in Big Stone II will further increase the Applicants' dependence upon coal-fired generation and, consequently, their exposure to greenhouse gas regulations.

For example, as of 2004, 60.3 percent (winter) to 65.3 percent (summer) of Otter Tail Power Company's generating capacity was coal-fired.[6] When oil and natural gas fired capacity is included, more than 75 percent of Otter Tail's generating capacity is fossil-fired.

GRE's existing generation mix is 55 percent from coal, not including additional coal-fired generation that might be the sources for the other purchased power listed in the Company's testimony.[7] When you consider natural gas-fired and oil-fired facilties, GRE's fuel mix is 94 percent fossil.

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6 Applicants' Exhibits 10-D and 10-E.

7 Applicants' Exhibit 8, at Table 1.

CMMPA's listing of its existing and planned capacity resources includes 43 MW of coal-fired capacity (75 percent of the total) and 13.5 MW of wind.[8]

Seventy-six percent of Montana-Dakota Utilities current owned generation is coal-fired.[9]

Approximately 50 percent of MRES' existing capacity, and all of its baseload capacity, is coal-fired.[10]

Approximately 59 percent of SMMPA's existing generating capacity is coal-fired.[11]

Finally, Heartland's existing resources appear to be a mix of coal-fired generation and purchased power contracts.[12] Heartland has indicated that from 2013 to 2020, i.e., after the end of its purchased power agreement with Nebraska Public Power District, it plans to have the following resources available for its customers: Laramie River Station (50 MW); Customer-owned peaking generation (24 MW); Big Stone Unit II (25 MW); and Whelan Energy Center Unit 2 (80 MW).[13] This means that all of the resources that Heartland plans to have available for its customers during these years will be fossil-fired, and approximately 86 percent will be coal-fired.

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8 Applicants' Exhibit 6 in South Dakota Public Utilities Commission Case No. EL05-022, page 10, lines 1-2.

9 Applicants' Exhibit 11 in South Dakota Public Utilities Commission Case No. EL05-022, page 8, lines 9-17/

10 Applicants' Exhibit 14 in South Dakota Public Utilities Commission Case No. EL05-022, at page 9, line 6, to page 10, line 3.

11 Applicants' Exhibit 13 in South Dakota Public Utilities Commission Case No. EL05-022, page 4, line 14, to page 5, line 8.

12 Applicants' Exhibit 15 in South Dakota Public Utilities Commission Case No. EL05-022, page 16, lines 16-23.

13 Co-owners' Response to Interrogatory 62 of the Intervenors' Sixth Set of Interrogatories in South Dakota Public Utilities Commission Case No. EL05-022.

Q. Even if they add the Big Stone II Project, are the Applicants as a group pursuing resource plans that, overall, will reduce their dependence on coal-fired generation?

A. No. Some of the Applicants may be saying that they are going to be adding a diverse resource mix.[14] However, they will remain heavily dependent on fossil-fired generation even if they actually do pursue the resource plans that they are now discussing. In other words, participating in the Big Stone II Project will limit, not reduce, their future fuel diversity and maintain their dependence on coal.

For example, the results of Otter Tail Power's recent modeling shows that in 2007, **[PROTECTED MATERIALS BEGIN**

[15] **PROTECTED MATERIALS END]**

Q. Is this continued heavy dependence on coal-fired generation prudent?

A. No. The Applicants' continued heavy dependence on coal-fired generation is not prudent. In particular, the Applicants' failure to accept that there will be significant restrictions on future greenhouse gas emissions and to reflect the potential for such restrictions in their resource planning is not prudent. We hope, therefore, that the Commission will hold that the shareholders of any of the Applicants over which it has jurisdiction must bear any costs attributable to such imprudence.

Q. Is it also possible that the Big Stone II Project will face increased costs due to stricter environmental permitting requirements in the future?

A. Yes. The most immediate risk relates to current legal action being brought by the Sierra Club related to the Big Stone I Unit for violations under the Clean Air Act.

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[14] For example, see Applicants' Exhibit 39, at page 2, lines 2-7.

[15] Applicants' response to MCEA IR No. 139.

The Big Stone II Project was allowed to avoid certain permitting requirements under the Clean Air Act because the project would simultaneously reduce emissions on Unit I. However this kind of "netting out" (offsetting a new unit's emissions by reducing emissions at an existing unit) is not legal if Unit I is already obliged under the Clean Air Act to reduce its emissions. Legal action recently launched by the Sierra Club[16] alleges just that, claiming that the owners of Unit I triggered pollution control requirements under the Clean Air Act with earlier modifications to the unit making them already obliged to put pollution controls on Unit I.

If Sierra Club prevails in this challenge, it will have a direct effect on the Big Stone II Project, subjecting it to more stringent requirements under the Clean Air Act, including the requirement to go through an analysis to determine whether it has installed Best Available Control Technologies (BACT). That analysis may require Applicants to add new pollution control equipment, to operate existing control equipment at a higher rate, and to obtain emission limit guarantees from equipment vendors. All these steps – and the loss of efficiency that could result from these new control efforts -- would increase project costs, and this risk is in no way reflected in Applicant's cost estimates.

The Big Stone II Project may also face additional environmental restrictions from forthcoming regulations other than CO_2. The EPA science advisory committee has recommended lowering the 8-hour ozone standard. Already, the Twin Cities is close to noncompliance for ozone, and if the standard is lowered, major sources of NOx upwind of the cities, like Big Stone II, may be required to install additional pollution controls. Similarly, studies now show the need to further tighten standards for small particulate matter (PM 2.5), and litigation is underway seeking a stronger mercury standard than the current federal one, meaning Big

[16] Sierra Club News Release, "Sierra Club: Big Stone Coal Plant is Violating the Clean Air Act; Announces Legal Action Against Plant's Owners," November 20, 2006.

Stone II could face new restrictions and new costs related to these three pollutants.

III. B. The Big Stone II Project Capital Cost

Q. Applicant witnesses Rolfes and Trout have testified that Black & Veatch conducted a "sanity check" in October 2005 to gauge whether the original Burns & McDonnell $1 billion cost estimate for Big Stone II still remained valid.[17] Have you had an opportunity to review the documents related to that "sanity check?"

A. No. At first, the Applicants refused to provide those documents to us.[18] Then when they were ordered on November 21, 2006 to provide the documents to us, the Applicants claimed that the requested data are "not in the care, custody or control of the Applicants and must be sought by the Joint Intervenors from Black & Veatch pursuant to Deposition and/or Subpoena."[19] Then, two days before this Testimony was to be filed, the Applicants have determined that they can give us a single page related to the "sanity check."

Given the extremely late date that this information was being provided, this means that we will be unable to obtain and review any other of the requested "sanity check" documents before this testimony is filed and presented. Therefore, it is impossible for us to verify any of the claims that Mr. Trout makes concerning what Black & Veatch determined in late 2005 concerning the validity of the original Burns & McDonnell Big Stone II Project cost estimate.

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17 Applicants' Exhibit 32, at page 2, line 18, to page 3, line 3, and Applicants' Exhibit 33, at page 25, lines 4-6.

18 Applicants' original responses to MCEA IR No. 153 and IR No. 161.b.

19 Applicants' Supplemental (?)response to MCEA IR No. 153.

Q. Is the Applicants' claim credible that the materials related to the 2005 "sanity check" by Black & Veatch are not within Applicants' custody or control?

A. No. According to Applicants' witness Rolfes, the Big Stone II Applicants asked Black & Veatch to perform the sanity check[20] and, presumably, Black & Veatch was paid for conducting this check. In addition, Mr. Rolfes cites the results of the sanity check review in his testimony so those results must have been communicated to the Applicants. Therefore, the Applicants should have access to the documents prepared as part of the sanity check and should be able to provide them to the Joint Intervenors.

Q. When did the Applicants first learn that the estimated cost of Big Stone II would rise significantly above the original cost of $1 billion?

A. The Applicants' witnesses have claimed that the Big Stone II Project team and Co-owners didn't learn about the approximately 43 percent increase in the project's estimated cost until about July 7, 2006 or after the hearings before the South Dakota Commission had been completed.[21] However, contemporaneous documentation raises serious doubts about the accuracy of that testimony.

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[20] Applicants' Exhibit 32, at page 2, lines 19-20.

[21] For example, see Applicants' Exhibit 32.

[22] Bates Page Number OTP0003738.

.[23]

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Then, on June 23, 2006, which was three days before the start of the hearings on the Big Stone II Project before the South Dakota Public Service Commission, [**PROTECTED MATERIALS BEGIN**

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Q. Does the evidence that you have reviewed support the claim of Applicant witness Rolfes that the June 23, 2006 meeting only addressed "the first preliminary budget estimate that had been put together for the project?"

A. No. [**PROTECTED MATERIALS BEGIN**

.[26] **PROTECTED MATERIALS END]**

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[23] Ibid.

[24] E-mail from Applicants witness Kermit Trout, dated June 23, 2006, at Bates Page Numbers OTP0006537-38.

[25] Bates Page Number OTP0006541.

[26] Bates Page Number OTP0006538.

Q. Was the revised cost estimate that was presented at the June 23rd meeting very different from the estimate that was subsequently presented to the Applicants on July 7, 2006?

A. No. In fact, as shown in Applicants Exhibit 33-H, the project cost estimate that Black & Veatch presented to the Big Stone II Project Team on July 7th was $1.759 billion which was [**PROTECTED MATERIALS BEGIN**

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Q. Applicants' witness Rolfes has testified that Black & Veatch gave "some indication" at the June 23rd meeting "that the cost of the plant would be increasing, i.e., would be more than slightly in excess of $1 billion, which our original feasibility studies showed."[27] Do the meeting notes reflect what Black & Veatch actually told the Big Stone II Project Team at the June 23rd meeting?

A. Yes. [**PROTECTED MATERIALS BEGIN**

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Q. When did Mr. Rolfes communicate the [PROTECTED MATERIALS BEGIN

PROTECTED MATERIALS END] to the Big Stone II Project team and the Applicants?

A. On June 26, 2006, the same day that the hearings on the Big Stone II Project began at the South Dakota Public Utilities Commission, Mr. Rolfes sent a **[PROTECTED MATERIALS BEGIN**

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27 Applicants' Exhibit 32, at page 4, lines 19-21.

[28] **PROTECTED MATERIALS END**]

Q. Applicant witness Rolfes also has testified that Applicants were not surprised about the changes in the commodity prices that were contained in the Black &Veatch July 7, 2006 cost estimate.[29] However, the "information about estimated labor cost increases that Black & Veatch conveyed was not expected."[30] Does the contemporaneous documentation support this claim?

A. No. [**PROTECTED MATERIALS BEGIN**

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[28] Bates Page Number SMMPA09698.

[29] Applicants' Exhibit 32, at page 6, line 6.

[30] Applicants' Exhibit 32, at page 7, lines 4-5.

[31] See Bates Page Number OTP00037.

[32]

[PROTECTED MATERIALS END]

Q. Mr. Rolfes testifies that Black & Veatch delivered the revised cost estimate to the Big Stone II Project Team on Friday night, July 7th.[33] Was July 7th the planned date for the delivery of the revised estimate?

A. **[PROTECTED MATERIALS BEGIN**

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Q. What was the revised project cost estimate issued by Black & Veatch on July 7th?

A. As shown on the last page of Applicants' Exhibit 33-H, the revised project cost estimate was $1.759 billion. **[PROTECTED MATERIALS BEGIN**

[34] **PROTECTED MATERIALS END]**

Q. How did the Applicants react to this revised cost estimate?

A. The Applicants **[PROTECTED MATERIALS BEGIN**

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32 See Bates Page Number OTP0006537 and Applicants' Exhibit 33, at page 21, lines 5-11 and 18-20.

33 Applicants' Exhibit 32, at page 5, lines 3-5.

34 Bates Page Number GRE0005087.

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Q. Did Black & Veatch subsequently reduce that estimated project cost as directed by the Applicants?

A. Yes. **[PROTECTED MATERIALS BEGIN**

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[35] July 10, 2006 e-mail from Ray Howard to SMPPA representatives and staff, provided at Bates Page Number SMMPA09699.

[36] Conference Memorandum of August 2-3, 2006 Cost and Risk Reduction Meeting, at Bates Page Number OTP0003824.

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Q. Did Black & Veatch express any caveats or cautions about the feasibility of actually achieving the cost savings it had identified [PROTECTED MATERIALS BEGIN

? PROTECTED MATERIALS END]

A. Yes. **[PROTECTED MATERIALS BEGIN**

[37] **PROTECTED MATERIALS END]**

Q. Did the Applicants wait to reflect the $165 million in estimated cost savings in their new planning analyses until they had investigated the suggested cost savings in detail and had completed the significant engineering and design efforts that [PROTECTED MATERIALS BEGIN PROTECTED MATERIALS END]?

A. No. **[PROTECTED MATERIALS BEGIN** .[38] **PROTECTED MATERIALS]**

Indeed, each of the Applicants' new modeling and economic analyses of which we are aware, have used the August 2006 revised Big Stone II cost estimate. These analyses were prepared before the Applicants had completed their studies of the $165 million in estimated costs savings in detail and before they had completed the significant engineering and design efforts that **[PROTECTED MATERIALS BEGIN** . **PROTECTED MATERIALS END]**

Q. Have the Applicants provided the cost reduction studies in which they were to investigate the engineering viability of the proposed system design changes which underlay the estimated $165 million in project cost savings?

A. The Applicants have provided some limited documents related to the assessments of the proposed system design changes which underlay the $165 million of cost

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[37] Bates Page Number OTP0003822.

[38] Bates Page Number OTP0006221.

savings. However, the Applicants have refused to provide the cost reduction study that Applicants' witness Trout has testified Black & Veatch was in the process a completing as of the date, i.e., October 2, 2006, his testimony was filed.[39]

At first, the Applicants refused to provide the cost reduction study mentioned by Mr. Trout. Then, when ordered to provide the study, the Applicants decided that it wasn't really a study after all, "as meant in its literal sense. The changes to which Mr. Trout refers in his testimony that are intended to result in cost reductions are ongoing and any new information learned will be produced as it becomes available."[40]

Q. Applicants' witnesses Rolfes and Trout have identified a number of specific market conditions which they believe have led to the dramatic increase in the estimated cost of Big Stone II.[41] Do you agree that with their review of the current market conditions affecting the costs of proposed coal-fired power plants like Big Stone II?

A. Yes. Their review of the factors affecting the estimated costs of new coal-fired generating facilities appears reasonable and is consistent with other information we have seen.

Q. In their new modeling, have any of the Applicants assumed that there will be any further increases in the estimated cost of Big Stone II as a result of the same market conditions identified by Mr. Rolfes and Mr. Trout or other factors?

A. No.

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39 Applicants' Exhibit 33, at page 25, line 21, to page 26, line 2.

40 Applicants' response to MCEA IR No. 168c.

41 Applicants' Exhibit 32, at pages 5 and 6 and Applicants' Exhibit 33, at page 27, line 20, to page 28, line 16,

Q. In your opinion, is that a prudent assumption, that is, that there will not be any further increases in the capital cost of the Big Stone II Project before it is completed?

A. No. Although the current project cost estimate does increase some contingencies, we believe that given past history of large construction projects, it is reasonable to assume that the actual cost of building the Big Stone II Project may be higher than the current cost estimate. This is especially true because all project bids have not been let and construction has not even started.

Indeed, even Mr. Rolfes and Mr. Trout do not foreclose the potential for further increases in the Project's estimated capital cost. For example, Mr. Rolfes has testified that "the [current project] price estimate is a dynamic number and there remains the possibility for design changes."[42] Any significant design changes could have an impact, resulting in capital cost increases or decrease.[43]

Mr. Trout has further noted that future changes in the estimated cost for the Big Stone II Project are "becoming more dependent on outside forces" some of which he describes in his October 2, 2006 Testimony.[44] Mr. Trout has further noted that "the Big Stone II Co-owners have not been in a position realistically or reasonably to "lock in" the prices for a substantial portion of the major cost components of Big Stone Unit II" and that "Until they do so, the project budget will be subject to further refinement."[45]

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42 Applicants' Exhibit 32, at page 4, lines 7-10.

43 Ibid.

44 Applicants' Exhibit 33, at page 24, lines 19-20, and at page 27, line 18, to page 28, line 14.

45 Applicants' Exhibit 33, at page 28, lines 14-17.

Q. Have you seen any specific evidence that shows that the estimated cost of the Big Stone II Project, in fact, already has been increased above the Applicants' current official public estimate?

A. Yes. [**PROTECTED MATERIALS BEGIN**

[48]

PROTECTED MATERIALS END

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[46] *Financial Risk Commitments Prior to Receiving the MN CON,* prepared by Black & Veatch, October 19, 2006, provided in response to MCEA IRs Nos. 214-216, at Bates Page Numbers JCO0012380-JCO00012397.

[47] Ibid, at page no. 1-1, Bates Page Number JCO0012381.

[48] Ibid, at page 4-5, Bates Page Number JCO0012388.

Q. Does it appear that this plan was implemented?

A. Yes. **[PROTECTED MATERIALS BEGIN**

[50] **PROTECTED MATERIALS END]**

Q. What was the estimated impact of the adoption of this revised short-term spending and financial exposure plan on the estimated capital cost of the Big Stone II Project?

A. [**PROTECTED MATERIALS BEGIN**

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49 Ibid, at page 4-6, Bates Page Number JCO—12389.

50 Ibid.

[51] **PROTECTED MATERIALS END]**

But, even this figure does not reflect other factors that could lead to an increase in the ultimate cost of the Big Stone II Project. These factors could include the possibility that [**PROTECTED MATERIALS BEGIN**

. **PROTECTED MATERIALS END]** Other factors that could lead to higher project costs include further project delays, changes in equipment lead times, labor availability, rescheduling or construction inefficiencies due to winter weather, or other market conditions.

Q. [PROTECTED MATERIALS BEGIN

A.

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Q. Did the Applicants discuss any of these developments in their October 2, 2006 Supplemental Testimony?

A. No. The Applicants' Supplemental Testimony was silent on all of these significant developments. They also redacted discussion of these developments from project meeting minutes and correspondence that they provided to the Joint Intervenors. In addition, they opposed the Joint Intervenors' attempts to obtain unredacted versions of those documents. It is clear that the Applicants did not

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[51] *Owners' Alternatives for Financial Risk Commitments Prior to CON and PSD,* prepared by Black & Veatch, August 24, 2006, provided in response to MCEA IRs Nos. 214-216, at page 3-6, Bates Page Number JCO0012332.

want the Joint Intervenors, the Departmentof Commerce, other intervening parties, or the Minnesota Commission to know what was happening.

Q. Have you seen any evidence that any of the Applicants has reflected this [PROTECTED MATERIALS BEGIN

[PROTECTED MATERIALS END] in the revised Big Stone II Project modeling analyses that they have presented in their October 2, 2006 Supplemental Testimony?

A. No.

Q. Have any of the Applicants assumed in their revised modeling analyses that the actual commercial operation date for the Big Stone II Project will be delayed beyond 2011?

A. Some of the Applicants, e.g., Otter Tail Power and CMMPA have continued to assume a commercial date of 2011 for the Big Stone II Project.. However, several other Applicants, i.e., SMMPA and Heartland have modeled later commercial operation dates for the Big Stone II Project.

Q. Has Black & Veatch asked the Big Stone II Co-owners [PROTECTED MATERIALS BEGIN

52 Ibid,, at page 4-2, Bates Page Number JCO0012385.

53 Ibid, at page 4-4, Bates Page Number JCO0012387.

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Q. Have the Applicants already approved this request?

A. No. It appears that the Applicants are going to vote on the [**PROTECTED MATERIALS BEGIN**

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Q. Is it reasonable to expect that there could be further increases in the cost of the Big Stone II Project?

A. Yes. During the remaining six or seven years before the Project is completed, if indeed it is allowed to continue, any number of factors could lead to even higher costs. These factors could include additional delays, additional regulation-related costs, market conditions and weather conditions. Thus, there is no guarantee that the current capital cost estimate for the Big Stone II Project will be the last, even if it is increased by **[PROTECTED MATERIALS BEGIN**

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Q. Have you seen any documents related to any new Big Stone II Project cost estimate that was prepared by or for the Applicants since August of this year?

A. Yes. Just yesterday afternoon, the Applicants delivered to counsel for the Joint Intervenors approximately 100 pages of tables with some narrative explanations that appear to be related to a revised capital cost estimate for the Big Stone II Project that was prepared back in mid-October. However, these materials were not provided before November 28, 2006 even though these sorts of materials had

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54 Ibid, at page 4-4, Bates Page Number JCO0012387.

been sought in a number of information requests that asked for data and documents related to the current status of the Project's cost.

Q. Have you had an opportunity to conduct a full and detailed review and evaluation of these new 100 pages of documents that the Applicants have just made available?

A. No. We have been able to make only the most cursory view of these new materials. For this reason, we believe that they should be given no credibility. The Applicants chose to withhold them from Joint Intervenors until the very last minute. Had we received these documents back when they were prepared in mid-October, we would have spent time reviewing them and would have asked needed follow-up information requests. Obviously, that is not possible now.

Q. Have you found any significant points during your initial cursory review of these new documents that the Applicants have provided?

A. Yes. It appears that [**PROTECTED MATERIALS BEGIN**

[56] **PROTECTED MATERIALS END]**

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55 Applicants' Supplemental responses to MCEA IR No. 110. f. and g., at Bates Page Number OTP0007144,

56 Ibid., at Bates Page Number OTP0007186.

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Q. [PROTECTED MATERIALS BEGIN

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Q. Have any other U.S. utilities recently increased the estimated capital costs of their proposed coal-fired generating facilities as a result of the same market conditions that are discussed by Mr. Rolfes and Mr. Trout?

A. Yes. Duke Energy Carolinas has recently increased the estimated cost of its proposed coal-fired Cliffside Project by roughly 50 percent as a result of the same market factors identified by Mr. Rolfes and Mr. Trout.

Q. Is it your testimony that the Applicants should change their current cost estimate for the Big Stone II Project?

A. Clearly, the Applicants should revise their modeling to reflect the impact of the **[PROTECTED MATERIALS BEGIN** **PROTECTED MATERIALS END]** In addition, given that there is significant uncertainty in the current cost estimate for the Project, the Applicants should perform sensitivity analyses to reflect further increases in the Project's capital cost.

Q. Have you seen any utilities that have prepared such sensitivity analyses to reflect increases in the estimated Project capital costs?

A. Yes. In its modeling of the proposed coal-fired Cliffside Project, Duke Energy Carolinas has considered some scenarios reflecting a 20 percent higher coal capital cost. Unfortunately, Duke combined this 20 percent higher coal capital cost with higher coal and natural gas prices which distorted the analysis and masked the impact of the higher coal capital cost by including the mostly unrelated higher natural gas prices.[57] However, Duke still did consider a 20 percent higher coal capital cost.

Q. Have you seen any such capital cost sensitivity analyses that have been prepared by the Applicants?

A. Yes. The September 2005 *Analysis of Baseload Generation Alternatives* prepared for the Applicants by Burns & McDonnell examined a number of sensitivity analyses including a plus or minus 10 percent of the estimated project capital cost.[58] However, we are not aware or have we seen any similar capital cost sensitivities being performed in subsequent Applicant analyses, particularly, the revised modeling analyses discussed in the Applicants' October 2, 2006 Supplemental Testimony.

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[57] Duke's 2005 Annual Plan filing, at page 49.

[58] Applicants' Exhibit 23-B in South Dakota Public Utilities Commission Case No. EL05-022. Although this study was not been presented as an exhibit in this proceeding, it is discussed in Applicants' Exhibit 25, the Direct Testimony of Jeffrey Geig.

Q. Do you agree with the testimony of Applicants' witnesses Rolfes and Trout that these same market conditions also have led to increases in the estimated costs of other supply-side alternatives such as wind and natural gas-fired facilities?[59]

A. Yes. In general we agree with Mr. Rolfes and Mr. Trout's testimony that these same market conditions also have led to increases in the estimated costs of other supply-side options.

However, we are troubled because Black & Veatch had not investigated what impact any of the market conditions cited by Mr. Trout actually had had on the capital costs of other alternative technologies.[60] Nor had Black & Veatch investigated the number of labor hours that would be required to construct any technologies other than coal.[61]

In addition, there are several factors which suggest that the impact of these factors might be greater on coal-fired facilities than on other alternatives. First, as Mr. Trout testifies, coal-fired plants do require more labor hours during construction than the other technologies – a comparably sized combined cycle project would require substantially fewer labor hours to construct.[62]

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59 Applicants' Exhibit 32, at page 8, line 21, to page 9, line 10, and Applicants' Exhibit 33, at page 28, line 17, to page 29, line 14.

60 Applicants response to MCEA IR No. 169 and 171.

61 Applicants response to MCEA IR No. 170.

62 Applicants' Exhibit 33, at page 29, lines 17-21.

63 August 2006, *Otter Tail Power Company Supply-Side Technology Study Update*, prepared by Black & Veatch, at page 1-2, Bates Page Number OTP0006341, provided in response to MCEA IR No. 174.

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Q. Have all of the Applicants generally increased their estimated costs for other technologies in line with the increase in the estimated capital cost of the Big Stone II Project?

A. No. [**PROTECTED MATERIALS BEGIN**

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64 Ibid.

65 Applicants' Exhibit 35-A.

66 Ibid.

67 Ibid.

Q. The Applicants have assumed that they will achieve approximately $165 million of savings in the Big Stone II Project capital cost as a result of site-specific design changes.[68] Have the Applicants assumed that any similar site-specific savings could be achieved for the other alternatives to Big Stone II that they have examined in their revised modeling?

A. No. Unlike what they have assumed with regard to Big Stone II, it does not appear that any of the Applicants has assumed any such site-specific savings for any other projects. This biases the Applicants' analyses in favor of the Big Stone II Project.

Q. Are there any other assumptions that bias the results of the Applicants' recent modeling in favor of the Big Stone II Project and against wind and other alternatives?

A. Yes. As best as we can tell, most of the Applicants have assumed that each MW of wind capacity that would be added in place of the Big Stone II Project would need an additional MW of new transmission capacity. This may be a reasonable assumption or it may be that some or even most of the alternative wind facilities might be located at sites at which they would not require any new transmission additions beyond those already in service or that are being planned for the electric grid in Minnesota and the Dakotas. We accept that it is quite possible that some new transmission facilities beyond those already in service or already planned may be required to deliver the power from alternate wind facilities to load but we are not sure that every single MW of new wind power will require an additional MW of new transmission capacity.

68 For example, see Applicants' Exhibit 32, at page 4, lines 5-6.

Q. What assumption has Xcel Energy made concerning the delivery of the wind resources that it is proposing in its November 1, 2006 Petition to the Commission to Initiate a Competitive Resource Acquisition Process for 375 MW Base Load Generation?

A. Xcel Energy has said that it:

> will seek to ensure that the delivery of the Wind Resources to load will take place over existing transmission lines, where possible, thus maximizing the efficiency of the transmission system. The region's existing high voltage transmission line system will be enhanced with the addition of the CAPX 2020 transmission lines proposed to strengthen the "backbone" of the region's high voltage system. The CAPX 2020 project includes an assumption of 2,200 MW of new wind generation when determining the need for future facilities.[69]

III.C. The Potential for Supply Disruptions or Higher Fuel Costs

Q. What average annual capacity factors do the Applicants assume the Big Stone II Project will be able to achieve?

A. Generally, the Applicants assume an 88 percent average annual capacity factor for Big Stone II.

Q. Is this a reasonable assumption?

A. It is a very optimistic assumption to assume that a plant that has not yet started commercial operations or, indeed, is not even under construction, will achieve such a high capacity factor in every year, especially during the plant's early immature "breaking-in" years of operation. However, it is not unreasonable to assume that a new base load coal-fired facility, if prudently managed and maintained, ultimately could be able to achieve relatively similar operating performance during its mature operating years.

[69] Xcel Energy's November 1, 2006 Petition to the Commission to Initiate a Competitive Resource Acquisition Process for 375 MW Base Load Generation , at page 1-9.

Q. Are there any factors, besides imprudent management or maintenance, that could result in the plant's failing to achieve the projected 88 percent capacity factor?

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

Q. Could such production and deliverability problems also affect the prices of the coal that would be burned at Big Stone II?

A. Yes.

Q. Have the Applicants performed any sensitivity analyses as part of their recent modeling to determine whether higher than expected coal prices or less than optimal plant performance due to coal deliverability problems would affect the overall economics of the Big Stone II Project?

A. The Applicants have not prepared any such sensitivity analyses that we have seen. Remarkably, the Applicants have refused to even acknowledge that future coal shortage issues (caused by rail and/or production issues) *may* diminish Big Stone II's reliability.[70] The Applicants similarly refused to acknowledge that recent coal shortage issues *may* increase the risk associated with developing the Big Stone II power plant.[71]

Indeed, problems with the delivery of coal have already caused a significant interruption in the operation of Big Stone I this year. For several weeks,

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[70] Responses to Questions Nos. 5 and 39 of the South Dakota Commission Staff's Third Data Request in South Dakota Public Utilities Commission Case No. EL05-022.

[71] Responses to Questions No. 38 of the South Dakota Commission Staff's Third Data Request in South Dakota Public Utilities Commission Case No. EL05-022.

according to media reports,[72] the plant had to scale back operations to 45% of its capacity. Big Stone Plant Manager Jeff Endrizzi said, about the period of reduced production, "It was a very tough 54 days for us but we're here to produce as much power as we can and to not be able to do that is very uncomfortable." He also noted that "I think just raising the general level of awareness of the situation can't hurt. It's hitting us here directly, locally, but it's a very broad based problem."

Q. Is it prudent to not even consider the potential for coal shortages as a risk associated with developing the Big Stone II Project?

A. No. Given the serious problems that have been experienced since May 2005 and the disputes that have arisen between coal shippers, utilities and the railroads that deliver coal from the Powder River Basin, it is not prudent to ignore this risk when evaluating the economics of proposed coal-fired facilities like the Big Stone II Project. Some utilities have been forced to import coal from Columbia in South America or as far away as Indonesia.

Q. Have any of the Applicants' economic analyses contained any sensitivities to reflect the potential for higher fuel prices and/or lower than projected operating performance?

A. The Applicants' September 2005 *Analaysis of Baseload Generation Alternatives,* prepared by Burns & McDonnell, did prepare sensitivity analyses reflecting changes in the assumed fuel prices and capacity factors.[73] However, the Applicants have not prepared similar sensitivity analyses as part of the recent Big

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72 "Coal Supply Still Uncertain at Big Stone," Keloland Television broadcast, 5/25/2006. Online at http://keloland.com/NewsDetail6162.cfm?Id=0,48308. See also, "Big Stone Plant Doesn't Have Enough Coal," Keloland Television broadcast, 03/20/2006, Online at http://keloland.com/NewsDetail6162.cfm?Id=0,46855.

73 The *Analysis of Baseload Generation* Alternatives was included as Applicants' Exhibit 23-B in South Dakota Public Utilities Commission Case No. EL05-022. Although this study was not been presented as an exhibit in this proceeding, it is discussed in Applicants' Exhibit 25, the Direct Testimony of Jeffrey Geig.

Stone II Project Supplemental modeling analyses that reflect the 23 percent increase in the estimated capital cost.

IV. THE APPLICANTS' MODELING ANALYSES DO NOT SHOW THAT THE BIG STONE II PROJECT IS A LOWER COST OPTION THAN DSM AND/OR RENEWABLE ALTERNATIVES.

Q. Are there any flaws or biases that are common to all, or even most, of the Applicants' recent Big Stone II Project modeling analyses?

A. Yes. There are a number of common flaws and biases to the modeling analyses discussed in the Applicants' October 2, 2006 Supplemental Testimony:

1. There is no consideration of CO_2 costs.

2. There are unreasonable constraints on the amounts of cost-effective DSM that are made available.

3. There are unreasonable constraints on the amounts of wind resources that are assumed to be available and/or the assumed capacity factors at which those resources can operate.

4. None of the Applicants reflect the recent **[PROTECTED MATERIALS BEGIN**

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5. The Applicants overstate the need for new baseload capacity.

Q. What impact do these flaws have on the results of the Applicants' recent modeling of the Big Stone II Project?

A. These common flaws and the flaws in each individual Applicant's modeling bias the results of the Applicants' modeling in favor of the Big Stone II Project and against alternatives that include DSM and renewable options.

IV.A. OTTER TAIL POWER

Q. What evidence has Otter Tail provided in support of its claim that the Big Stone II Project remains its least cost option in spite of the recent increase in the facility's projected cost?

A. In his Supplemental Testimony, Bryan Morlock discusses the IRP-Manager analysis which, it believes, show that the Big Stone II Project remains a part of the Otter Tail's least cost resource plan. According to Mr. Morlock this new IRP-Manager modeling analysis is based on a number of revised circumstances, one of which is the new cost estimate for the Big Stone II Project.

Q. Is this evidence persuasive?

A. No. The company's evidence in support of its claim that Big Stone II remains the least cost option is unpersuasive for several reasons.

First, Mr.Morlock's testimony really only says that the IRP-Manager model picked the Big Stone II Project as part of Otter Tail's least cost plan based on minimizing revenue requirements for ratepayers.[74] His testimony provides no information as to how much of an economic advantage Otter Tail's preferred plan with Big Stone II produces over other plans that do not include the Big Stone II Project. Without this information, it is not possible to evaluate the potential economic benefits that might be produced by following the company's preferred plan against the risks associated with that plan or the benefits and costs of pursuing alternatives to Big Stone II. Essentially, Mr Morlock is saying that the Big Stone II Project is a least cost resource because it was picked as such by the IRP-Manager model.

However, Otter Tail has acknowledged that the IRP-Manager model has significant limitations and that the company is in the process of changing to another capacity expansion model.

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[74] Applicants' Exhibit 34, at page 6, lines 1-2.

Second, the IRP-Manager model optimizes for lowest cost based on a defined predictable future without assessment of uncertainty or risks. Otter Tail Power did not conduct any sensitivity analyses based on variations in such critical input assumptions as the cost of Big Stone II, fuel costs, plant performance due to fuel supply disruptions, etc.

Thus, Otter Tail has not prepared any sensitivities as part of its recent modeling to evaluate the significant risks associated with building and operating a new coal-fired generating facility. For example, the company does not present any scenarios that reflect power plant power reductions or outages or increased fuel costs as a result of disruptions of the supply of Powder River Basin coal. Such disruptions have led to substantial amounts of lost plant generation and higher fuel costs at coal plants around the U.S. as a result of the train derailments and track problems experienced in 2005 on the rail lines emanating from Powder River Basin.

Otter Tail also has not prepared any sensitivity analyses to consider the economics of the Big Stone II Project assuming higher project capital costs. Consequently, it has ignored the **[PROTECTED MATERIALS BEGIN**

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Third, the IRP-Manager analysis discussed by Mr. Morlock as evidence that Big Stone II is the least cost option does not reflect the environmental externalities values set by the Minnesota Commission.

Fourth, the IRP-Manager analysis discussed by Mr. Morlock as evidence that Big Stone II is the least cost option also does not reflect any greenhouse gas regulation costs.[75] This advantages any fossil-fired option, such as Big Stone II, that can be expected to emit large amounts of CO_2.

Fifth, Mr. Morlock has told us that he assumed a January 1, 2011 commercial operation date for Big Stone II in the new IRP-Manager run. However, based on the materials presented in Section III.A. of this testimony, we now understand that the plant is not scheduled to achieve an actual commercial operations date before **[PROTECTED MATERIALS BEGIN**

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Q. What limitations has Otter Tail acknowledged in the IRP-Manager model?

A. Otter Tail has identified a number of significant limitations in IRP-Manager that affect its usefulness in capacity planning. For example, the company's response to Joint Intervenors' IR No. 173 notes the following limitations:

- IRP-Manager is not Windows compatible, and has to be run at the DOS level for optimization runs. The manner in which IRP-Manager uses and manages memory is incompatible with newer PC versions. This requires that the model be operated on older PC's with slower CPU times, resulting in single optimization runs taking 5-7 days.
- IRP-Manager is limited to monitoring and calculating six emissions.
- IRP-Manager has some hard-wired limits in the software that are now becoming an issue as regulatory agencies want more options modeled and with greater complexity. Examples of some of these limits are the number of supply options, the number of interchange options, and the number of interchange options with hourly pricing.
- Data input and output capabilities from IRP-Manager are extremely limited and very labor intensive.
- Error checking is extremely cumbersome. There are times when a data input error has occurred and it isn't realized until the end of a 5-7 day run, causing further delay in analysis to complete another long-term run.

[75] Applicants' response to MCEA IR No. 176.

Indeed, Mr. Morlock told us that, unlike some of the other Applicants, Otter Tail had been unable to model any commercial operation date(s) for Big Stone II other than January 1, 2011. We assume that the reason for this is the extremely long time, i.e., 5-7 days, required to complete a new optimization run.

Otter Tail also has acknowledged that IRP-Manager is not well equipped to properly handle all of the federal and state incentives for wind.[76] Therefore, the company has modeled wind as being purchased from developers. However, Otter Tail is considering ownership of wind generation, which might be a more economic option than purchasing it from developers. This limitation in IRP-Manager might bias the analysis against wind alternatives by inflating the cost above what it would be if the wind resources were developed by the company instead of developers.

In addition, due to the limitations in the number of hourly priced transactions allowed within IRP-Manager, Otter Tail was unable to optimize the size of the approximately 50 MW of Manitoba Hydro purchase included in its preferred plan.[77] As result, the company intends to make that determination in its next resource plan filing, using the capabilities of its new planning model, Strategist.[78]

In summary, all of the limitations in the IRP-Manager model render it inadequate for use in determining whether the Big Stone II Project is the most economic option for the company's ratepayers and for assessing the economic benefits of participating in that project against the risks of doing so. In fact, Otter Tail Power appears to be the only utility in the nation that uses this outdated planning model and it is even in the process of changing to a new planning model.[79] The

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76 Otter Tail Power Company's October 25, 2006, Supplemental Information Filing in Docket No. E017/RO-05-968, at page 4.

77 Ibid, at page 9.

78 Ibid, at page 18.

79 Applicants' response to MCEA IR No. 173.

Minnesota Commission should not rely on the results from the IRP-Manager model to find that the building the Big Stone II Project is reasonable.

Q. Would Otter Tail resolve all of the weaknesses you have identified in its economic evidence in this proceeding if it presented the results of an IRP-Manager analysis that considered the Commission's environmental externality values?

A. No. On its own, the results of a single IRP-Manager analysis reflecting the Commission's externalities values would not be persuasive evidence that Big Stone II is the least cost option because it still would suffer from the other limitations and weaknesses we have outlined above. The decision whether to commit to a nearly two billion dollar coal-fired transmission and generation project is far too important to rely on the results of the outdated and very limited IRP-Manager model.

Q. Have you rerun the IRP-Manager to examine alternatives to Big Stone II?

A. No. We did consider attempting to rerun the IRP-Manager model but decided against doing so because of its limitations, the fact that the model is so slow, and because there is no continuing vendor support. We also considered converting Otter Tail's IRP-Manager inputs into Strategist format but could not do so because of time limitations.

Q. Have you seen any analyses prepared by or for Otter Tail Power since the new official plant cost estimate was released in early August that have compared the Big Stone II Project against any renewable alternatives?

A. Yes. The information that Otter Tail Power provided to Applicants' witness Harris for use in Applicants' Exhibit 48-A compares the company's preferred resource plan with Big Stone II against a plan that includes a 115 MW hydro purchase in place of Big Stone II.

Q. Is Otter Tail's plan without the Big Stone II Project a least cost plan?

A. Otter Tail Power has said that its alternate plan is not a least cost plan because the company did not have time to execute its IRP-Manager model in full optimized fashion. Instead, Otter Tail simply substituted what appeared to be the next lowest cost resource from the preferred plan for Big Stone II in the alternate plan.[80] This means that there may be an optimized alternate plan that has an even lower-cost than the alternate plan examined by Otter Tail.

Q. Did the alternate plan examined by Otter Tails include more wind than the plan with Big Stone II?

A. No. Both plans were capped at 160 MW of wind.[81]

Q. Did the alternate plan examined by Otter Tail include more DSM than the plan with Big Stone II?

A. No. Both plans included the same amount of DSM.

Consequently, it is quite possible that there is a least cost plan with more wind and more DSM that has a lower overall present worth revenue requirement than the alternate plan examined by Otter Tail Power. Such a plan could reflect more DSM and more wind.

Q. Does Otter Tail Power Company's recent comparative analysis show that Big Stone II is a lower cost option than the hydro purchase reflected in the alternate plan?

A. No. As shown in Table 1 below, the difference in the present worth revenue requirements between the company's preferred resource plan with Big Stone II and the non-optimized no-Big Stone II alternate plan through the year 2020 is

80 Some, but not all, of the workpapers for Otter Tail's analysis of the alternative plan to Big Stone II Project were provided as the workpapers for the analysis presented in Applicants' Exhibit 48-A by Applicants' witness Harris, ,at Bates Page Number JCO0008272.

81 Updated Resource Breakdown, included in the materials provided as part of the workpapers of Kiah Harris for Applicants' Exhibit 48.

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Table 1. Otter Tail Power Revenue Requirements
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Q. Have you changed any of the assumptions underlying the Otter Tail Company figures presented in Table 1 above?

A. No. The annual revenue requirement figures for each plan shown in Table 1 above were taken directly from Otter Tail Power's workpapers. All we have done is to change the PW of Annual Revenue Requirements figures to 2011$ and to add the last three columns on the right hand side of Table 1 to show the differences between the two plans.

Q. What are the relative present worth revenue requirements of the two plans when the Commission's emissions externality values are included?

A. Using the Minnesota Commission's externality values has only a very minor effect, changing the relative difference in the present worth revenue requirements between the two plans to make the non-BSII Alternate Plan approximately 0.3 of a percent more expensive. This is essentially due to the fact that the CO_2

emissions from Big Stone II have an externality value of $0/ton because the plant would be located just across the border into South Dakota.

However, if you apply the Commission's high externality values to all of the CO_2 emissions, not just those in Minnesota, the no-Big Stone II Alternate Plan is less expensive than the plan with Big Stone II by about **[PROTECTED MATERIALS BEGIN**

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Q. What are the relative present worth revenue requirements of the two plans when greenhouse gas regulation costs are included?

A. As shown in Table 2 below, the non-Big Stone II Alternate Plan becomes the lower cost option if you apply any of the Synapse CO_2 price forecasts that we discussed in our November 17, 2006 Testimony.

Table 2. Benefits and (Costs) of Otter Tail's Preferred Resource Plan with Minnesota Commission Externalities and Synapse CO2 Prices

Scenario	Benefit/(Cost) of Otter Tail's Preferred Resource Plan with BSII compared to Alternate Plan with No BSII
Synapse Low CO2 Prices – Low MN Externality Values	($17 million)
Synapse Low CO2 Prices – High MN Externality Values	($19 million)
Synapse Mid CO2 Prices – Low MN Externality Values	($80 million)
Synapse Mid CO2 Prices – High MN Externality Values	($80 million)
Synapse High CO2 Prices – Low MN Externality Values	($141 million)
Synapse High CO2 Prices – High MN Externality Values	($142 million)

Consequently, Big Stone II is more expensive than the non-optimized Alternate Plan examined by Otter Tail Power if you accept all of the company's assumptions except that you either apply the Minnesota Commission's high externality values to all of the project's estimated CO_2 emissions or use any of the

Synapse CO_2 price forecasts. Moreover, these results suggest that it also is reasonable to expect that an optimized least cost no-BSII Alternate Plan that included more wind and more DSM would be even more economic than the non-optimized plan presented by Otter Tail Power as its "next best" alternative to the Big Stone II Project.

Q. Has Xcel Energy discussed the benefits of a combination wind and hydro plan for baseload generating capacity?

A. Yes. Xcel Energy has noted that its resource plan identified a 375 MW need for base load capacity and energy beginning in 2015. As explained by Xcel Energy, a combination of hydro and wind resources was its Preferred Proposal for addressing these needs:

> Base load resources deliver significant amounts of energy around the clock and are typically characterized by a high capacity factor with high fixed costs and relatively low operating costs.
>
> Our proposal offers a complementary combination of hydro and wind generation that is well suited to meet this base load need because of its relatively low costs and continuous operation. The [hydro] Resource will provide the necessary firm on-peak energy 16 hours per day, 5 days per week (a "5x16" resource product), while the Wind Resource will provide additional energy needed during the off-peak and weekends. Together, these [hydro]/Wind Resources offer capacity and energy that meet the base load needs and result in lower costs for our customers than other alternatives. Energy sales from the lower operating cost wind generation will be made into the MISO market during the higher-priced on-peak periods, offsetting the cost of any additional energy purchases made during lower-cost off-peak periods, to the extent purchases are necessary.
>
> Any incremental transmission infrastructure enhancements necessary to deliver the Wind Resource component of our Preferred Proposal will be addressed during the acquisition process for the Wind Resource. Hydro and wind are both well-tested and reliable technologies at the utility scale.[82]

[82] Xcel Energy's November 1, 2006 Petition to the Commission to Initiate a Competitive Resource Acquisition Process for 375 MW Base Load Generation , at pages 1-9 and 1-10.

Q. Did Xcel Energy compare this preferred hydro and wind combination to any alternatives that included coal-fired generating facilities?

A. Yes. One of the alternatives that Xcel Energy considered and determined was a higher cost option was a supercritical coal-fired facility similar to the Big Stone II Project.

Q. Have you seen any evidence that a similar hydro and wind combination would not be adequate to serve the needs for capacity and energy that Otter Tail Power forecasts?

A. No. As we explained in our testimony before the South Dakota Public Utilities Commission, this would be a good symbiotic resource combination for Otter Tail Power.[83]

IV.B. CMMPA

Q. Has CMMPA made the required showing before this Commission that renewable energy (hydro, wind, solar and geothermal) and energy conservation and load-management measures are not more cost-effective than the proposed Big Stone II Project?

A. No.

Q. Have you reviewed the modeling that CMMPA witness Robert Davis performed on behalf of CMMPA?

A. Yes. We reviewed the modeling that Mr. Davis from R.W. Beck performed for CMMPA using the Strategist model.

Q. Have you identified any flaws in the modeling that Mr. Davis describes in his October 2, 2006 Supplemental Testimony?

A. Yes. We identified the following flaws in the CMMPA modeling:

[83] South Dakota Public Utilities Commission Case No. EL05-022, Hearing Transcript of June 29, 2006, at pages 750-751.

- The model did not reflect any CO2 prices or costs associated with mandated restrictions on greenhouse gas emissions.
- The model was prevented from adding any new resources until 2011.
- There was no minimum reserve margin until 2011.
- CMMPA assumed that the commercial operations date for the Big Stone II Project was 2011.
- CMMPA did not reflect the **[PROTECTED MATERIALS BEGIN**

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- The availability of wind was limited to 40 MW with a capacity factor of **[PROTECTED MATERIAL BEGINS PROTECTED MATERIAL ENDS].**
- Only a relatively small amount of DSM at unreasonably high cost was available to the model.
- The "end-effects" period, i.e., the period post-2035, has a major effect on whether some or all of CMMPA's Big Stone II share is a part of its "least-cost" plan.

Q. Why was the model prevented from adding any new resources until 2011?

A. CMMPA has given no reason for this particular assumption. However, the impact of this assumption is that the model is more likely to choose the Big Stone II Project in 2011 to address accumulating capacity deficits because it has not been able to invest in DSM or alternative supply side options to meet demand in the meantime.

Q. Why did CMMPA not require Strategist to add capacity to meet a minimum reserve margin?

A. It's not clear at all. In fact, Applicant's Exhibit 42-A, "Resource Expansion Analysis Big Stone II Participating Members: Updated Analysis" acknowledges that prior to any resource additions in 2011, the CMMPA members will already have a capacity deficiency.[84] Indeed, CMMPA claims the first objective of this analysis was to "maintain adequacy and reliability of power supply. To meet this goal, load projections were first developed for the Big Stone II Members, including an additional 15% for planning reserves." Instead of modeling resources to make up this deficiency, CMMPA simply claims that "short-term capacity purchases could cover deficiencies early on."[85]

Q. What is the significance of assuming a commercial operations date for Big Stone II of 2012?

A. From discovery we've reviewed in this docket, it seems highly unlikely, even if all necessary permits were granted, that Big Stone II would be able to achieve commercial operation by 2011. In CMMPA's case, it may, therefore, be more cost-effective to add other capacity in an earlier year, rather than wait for Big Stone II and pay the additional capital costs that had been incurred due to the delay in the start of commercial operations at Big Stone II.

Q. What is the significance of CMMPA's assumptions regarding wind availability and capacity factor?

A. The wind availability assumptions had little impact on the modeling, until the capacity factor was adjusted. The **[PROTECTED MATERIAL BEGINS PROTECTED MATERIAL ENDS]** percent capacity factor assumed by CMMPA was unusually low and we've seen no reason to assume that wind resources with better capacity factors could not be available to CMMPA. The adjustment of the wind capacity factor had a significant effect on CMMPA's modeling as discussed later.

Q. Why was so little DSM made available in CMMPA's modeling?

A. The Testimony of Tim Woolf (Exhibit JI-5) addresses this issue.

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84 Page ES-2 of Applicants' Exhibit 42-A.

85 Page 1-3 of Applicants' Exhibit 42-A.

Q. Please describe the concept of end-effects.

A. End effects are costs calculated by simply taking the estimated system costs for the last year of the simulation and repeating those costs, unchanged, each year into the future. Given that CMMPA's planning period is already so long, through 2035, it should not rely upon a plan that only becomes cost-effective with the consideration of end-effects. Adding new capacity based on the belief (or hope) that it will begin to produce benefits (on a present value cumulative basis) 30 years or more in the future must be considered very speculative and imprudent. It is unreasonable to expect that every new increment of capacity will produce net benefits immediately after they start commercial operations. At the same time, however, it is extremely unreasonable to ask today's generation of customers to pay higher costs through 2035 with the hope that the new increment of capacity will provide a cumulative benefit for their children or grandchildren after that.

Q. Did end-effects have any significant effect on the inclusion of Big Stone II in CMMPA's least cost plan?

A. Yes. The results of our modeling later on in this section will discuss this effect.

Q. Please describe the modeling you performed.

A. Our entire modeling was based upon the Strategist database that CMMPA provided to us in response to MCEA IR 138. Unless noted below, we made no changes to CMMPA's assumptions.

We first fixed CMMPA's base case supply additions to see what would be the impact of assuming our Synapse low, mid and high CO_2 prices, as described in Exhibit JI-1.

The resulting system costs from those plans are shown in Figure 1, below.

Figure 1. System Costs under CMMPA's Base Case with CO_2 Costs [PROTECTED MATERIAL BEGINS

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This figure shows that CMMPA faces a significant risk from future CO_2 prices should it choose to pursue its preferred resource plan with the Big Stone II Project. In fact, CMMPA's costs under its preferred resource plan would be expected to increase by more than 50 percent even under Synapse's low CO_2 price forecast. Under Synapse's mid-CO2 price forecast, costs under CMMPA's preferred resource plan would more than double.

Q. Is it possible that the price curves shown in Figure 1 above actually understate the impact that the regulation of greenhouse gases could have on the cost of CMMPA's base or preferred resource plan?

A. Yes. The low, mid and high CO2 cost curves shown in Figure 1 above do not reflect any increase in natural gas prices due to the enactment of greenhouse gas regulations. Such an increase would be expected and would raise the cost of CMMPA's preferred plan even further under all of the Synapse low, mid and high CO2 price forecasts.

Unfortunately, CMMPA has not tried to model any similar scenarios to assess the risk that it faces as a result of its resource choices.

Q. Did you perform any additional modeling of CMMPA?

A. Yes. Exhibit JI-3-X shows the assumptions we changed in each scenario.

Q. What amount of Big Stone II was included in each scenario?

A. CMMPA modeled Big Stone II in 3 10.5-MW blocks. We kept this assumption in all scenarios. As mentioned previously, the end-effects period had a significant effect on the results in several scenarios. Table 3 shows the amount of Big Stone II capacity in the planning period and the study period (planning period + end effects).

Table 3. Big Stone II Capacity added in CMMPA scenarios

	Amount of BSII Selected based on Planning Period Results	Amount of BSII Selected based on Study Period Results
Base Case	31.5 MW	31.5 MW
Low CO_2	10.5 MW	31.5 MW
Mid CO_2	0 MW	21.0 MW
High CO_2	0 MW	0 MW
DSM	21.0 MW	21.0 MW
60 MW Wind + DSM + RM	21.0 MW	21.0 MW
Low CO_2 + Wind + DSM + RM	0 MW	0 MW
Mid CO_2 + Wind + DSM + RM	0 MW	0 MW

Q. Please describe the results of your model runs.

A. As Table 3 shows, the addition of Big Stone II is very sensitive to the modeling assumptions. In the scenarios with the word “Wind” in the title, we increased the wind capacity factor to 40% which tended to result in less Big Stone II being taken by the model. Please also note that the term “RM” in Table 3 means that the reserve margin was set at 15 percent in all years and the model was allowed to add capacity to meet that reserve margin.

The model consistently took a maximum of only two of the blocks of the DSM we made available to it, the "Residential Low" and "Commercial and Industrial Low."[86]

Q. Why did Strategist take only this level of DSM?

A. Interestingly enough, we believe that this is because not *enough* DSM was available to the model. That is, our assumptions were so conservative the result was that DSM was providing so little capacity to the model that it still required other capacity to meet CMMPA's reserve margin. As a result, it would only add DSM if it were cheaper than the energy cost of other resources. That is to say, if the mid levels of DSM at $25 and $35/MWh were not cheaper than a supply-side resource's running cost, it would not take the DSM.

Q. How would one test whether additional DSM could be cost-effective?

A. One simple way would be to increase the savings in the model to a level still likely to be cost-effective, but one that would give greater capacity benefit. For example, if a direct load control program were included.

Q. What conclusions can be drawn from the results of your modeling?

A. There are several conclusions that can be drawn from our modeling of CMMPA:

1. First, it is vitally important for CMMPA to re-examine its participation in the Big Stone II Project in light of the potential for federal regulation of greenhouse gas emissions. It would be imprudent for CMMPA to continue its participation in the Project without doing so or by merely using a single set of very low CO2 prices in such analyses. CMMPA should use a range of possible CO2 prices such as the forecasts presented by Synapse in this proceeding.

6. It is important to focus on the relative economics of each resource plan during the planning period through 2035. The large end effects assumed by CMMPA distorts the analysis and makes some scenarios appear lower cost because they might produce significant benefits in the far distant future after 2035. The relative timing of costs and benefits is an important consideration in resource planning. It would be imprudent for a utility to participate in a project that would not produce a net cumulative present worth benefit for its customers during the next 30 years as compared to other technically and economically feasible alternatives.

7. The Strategist model selects none of the Big Stone II Project during early the planning period (through 2035) and the study period (planning period + end effects) if we assume our High CO2 price forecast or if we assume either of our Low or Mid-CO2 price forecasts and allow the model to add capacity before 2011, allow wind to operate at very realistic capacity factors, and permit the model to select cost-effective DSM.

8. Even in the highly unlikely circumstances where there would be no regulation of greenhouse gas emissions, i.e., no CO_2 prices, the model still does not select all of CMMPA's share of the Big Stone II Project. This reinforces our belief that the economics of CMMPA's continued ownership of the remaining 21.5 MW of the Big Stone II Project must be re-evaluated under additional scenario and sensitivity analyses.

IV.C. MONTANA-DAKOTA UTILITIES

Q. Have you reviewed the modeling done in support of the Supplemental Direct Testimony filed by Hoa Nguyen and Jim Heidell?

A. Yes.

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[86] See the Testimony of Tim Woolf, Exhibit JI-5.

Q. Did you or anyone at Synapse discuss the content of MDU's modeling with MDU staff or representatives of MDU?

A. Yes. On November 8, 2006, we spoke with staff at MDU and Jim Heidell of PA Consulting. At our request, they very generously agreed to help us understand certain aspects of their modeling.

Q. Did you "informally depose" MDU or its representatives?

A. Our conversation did not constitute an informal deposition. We spoke on this one occasion for a period of 15 – 20 minutes.

Q. Has Montana-Dakota Utilities made the required showing before this Commission that renewable energy (hydro, wind, solar and geothermal) and energy conservation and load-management measures are not more cost-effective than the proposed Big Stone II Project ?

A. No, it has not.

Q. Upon what do you base this conclusion?

A. This conclusion is based upon our review of the modeling sponsored by Mr. Heidell and upon our own Strategist modeling.

Q. Please describe the flaws you have identified in the modeling presented by MDU.

A. Among the first things we noticed was how marginal Big Stone Unit II was, even under MDU's base case assumptions. In fact, as shown in Table 4 below, MDU's own modeling projects that the Big Stone II Project would operate at capacity factors of only 38 percent to 56 percent. These are significantly below what the other Applicants are forecasting for the plant.

Table 4. Big Stone Unit II Capacity Factor in MDU Modeling[87]

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
53	54	55	55	55	44	44	44	45	46	56	42	39	38

However, MDU's modeling did not assume that the company would make off-system sales. Consequently, the additional energy that MDU would receive from Big Stone II, that is, the difference between Big Stone Unit II's projected 88 percent annual capacity factor and the figures shown in Table 4 would presumably be used to make off-system sales.

Q. Does MDU have a financial incentive to make off-system sales?

A. Yes, it does. Hoa Nguyen of MDU testified in the Big Stone II siting permit proceeding before the South Dakota Public Utilities Commission that in North Dakota, where 60 percent of MDU's energy is sold, the Company "is allowed to keep 15 percent of the margin" of off-system, off-peak sales.[88]

Q. What other errors did you identify in the modeling?

A. Lack of risk analysis was a common error among all the Applicants, but PA Consulting's report explicitly acknowledges that limitation, saying

> PA's analysis was limited to base case scenarios using a combination of existing unit costs provided by Montana-Dakota, and PA generic unit cost assumptions. Risks related to fuel prices, load deviations from the forecast, environmental regulations, MISO market design, and a range of other factors were not included in the study.[89]

In particular, MDU did not include in its modeling any costs associated with mandated restrictions on greenhouse gas emissions.

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87 Applicants' Exhibit 41-B, page A-12.

88 South Dakota Public Utilities Commission Case No. EL05-022, hearing transcript at page 482, lines 10-17.

89 Applicants' Exhibit 41-B, page 2-1.

In addition, the amount of DSM available for the model to select was very limited, especially given the potential for DSM as described in Exhibit JI-6, the Testimony of Tim Woolf.

Q. Please describe the Strategist modeling you undertook.

A. Our goal from the beginning was to keep the MDU Strategist database intact; only making corrections to the database as a result of major errors in the modeling inputs. MDU provided its Strategist database in response to MCEA IR 138. The response provided us with 1 run. In the run, the following resources were available to the model during the planning period (2006-2025):

- 1160 MW of Big Stone II (in 10 116-MW block),
- 157.5 MW of wind (in 5 31.5-MW blocks),
- 217.5 MW of combustion turbines (in 5 43.5-MW blocks),
- 1300 MW of combined cycle (in 10 130-MW blocks),
- 580 MW of lignite coal (in 5 116-MW blocks),
- 580 MW of IGCC (in 5 116-MW blocks),
- 17.36 MW of DSM (in 1 7.36-MW block and 2 10-MW blocks, these 10-MW blocks are mutually exclusive),
- 225 MW of a baseload contract (in 3 75-MW block), and
- 105 MW of an Xcel peaking contract for one year (in 1 105-MW block).

Q. What changes did you make to MDU's modeling?

A. We wanted to test very specific scenarios to determine whether Big Stone Unit II would remain MDU's least-cost option. As such, we ran the following scenarios:

- Include the low CO_2 price as described in Joint Intervenors Exhibit-1 and input CO_2 emission rates for MDU's alternatives.

- Include the mid CO_2 price as described in Joint Intervenors Exhibit-1 and input CO_2 emission rates for MDU's alternatives.
- Increased wind resource availability to 315 MW.
- Increased DSM as described in the Testimony of Tim Woolf.
- Increased Big Stone II's capital cost by 10%.

In each of these scenarios, we made *no* other changes to the model.

Q. What were the results of this modeling?

A. Table 5, below, shows the amount of Big Stone II capacity included in the least cost plan as determined by Strategist, including MDU's preferred plan.

Table 5. Amount of Big Stone II Added in Least Cost Plan

Scenario	
MDU Preferred Plan	116 MW
Low CO_2 Price	0 MW
Mid CO_2 Price	0 MW
Increased Wind Availability	0 MW
Increased DSM	0 MW
Increased BSII Capital Cost 10%	0 MW

The addition of Big Stone II is highly sensitive to model assumptions and consequently, the model chose none of the Big Stone II Project in any of the cases we ran.

Q. What resources did the model pick as an alternative to Big Stone II?

A. It depends upon the scenario. In general additional wind and CT capacity is added instead of Big Stone II. Table 6 show the MW capacity additions of new resources under each of the five plans we ran above.

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Table 6. Capacity Additions of New Resources under Five Scenarios

Scenario	Xcel Contract	CT	Wind	MDU DSM 1	MDU DSM 2	MDU DSM 3
Low CO_2 Price		174 MW	158 MW	7 MW		10 MW
Mid CO_2 Price		174 MW	158 MW			
Increased Wind Availability	105 MW	131 MW	189 MW	7 MW		
Increased DSM	105 MW	131 MW	63 MW	n/a	n/a	n/a
Increased BSII Capital Cost 10%		174 MW	95 MW	7 MW		

In the "Increased DSM" scenario we "turned off" the DSM already in MDU's model and input the DSM described in the Testimony of Tim Woolf. The model took all available DSM.

Q. Would any of these least-cost plans substitute as MDU's preferred plan?

A. No. Additional analysis would be necessary to make that determination. For example, we have not performed a combination run in which both increased wind and DSM resources were made available to the model. Our intent was not to create a preferred plan but rather to test MDU's assertion that its least-cost plan includes 116 MW of Big Stone II and the sensitivity of that conclusion to the input assumptions made by MDU.

Q. What effect will the addition of Big Stone II have on MDU's ratepayers?

A. MDU has said that the Big Stone II Project would cause a 20 percent rate increase.[90] This was, however, based upon the previous, lower capital cost of Big Stone II. Therefore, the rate increase(s) that will be required can be expected to be higher than even this 20 percent estimate from MDU.

IV.D. MRES

Q. Has MRES made the required showing before this Commission that renewable energy (hydro, wind, solar and geothermal) and energy conservation and load-management measures are not more cost-effective than the Big Stone II Project?

A. No. Although the recent modeling discussed in the October 2, 2006 Supplemental Testimony of MRES witness Schumacher did include renewable alternatives, that modeling was significantly flawed and biased in favor of the Big Stone II Project.

Q. Have you spoken with MRES concerning its recent modeling of the Big Stone II Project?

A. Yes. On October 30, 2006, we spoke with MRES Staff for approximately 30 minutes. We later had a second phone conversation of approximately the same length on November 6, 2006. Both conversations were very helpful and served to illuminate issues that could possibly have taken weeks to resolve through discovery.

Q. Did you "informally depose" MRES or its representatives?

A. No. Although MRES answered a number of our questions, our conversations with MRES hardly constituted informal depositions.

Q. What model did MRES use for its modeling of the Big Stone II Project?

A. MRES used the Strategist model from New Energy Associates.

Q. What significant flaws and biases have you identified in MRES' recent Strategist modeling of the Big Stone II Project?

A. Our review of the testimony of MRES' witness Schumacher and the recent Strategist model input and output files has revealed the following flaws:

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[90] Applicants' response to MCEA Information Request No. 44.

- MRES did not reflect any carbon prices or costs from federally mandated restrictions of greenhouse gas emissions.
- MRES did not perform any sensitivity analyses to reflect any of the other risks and uncertainties associated with the Big Stone II Project.
- No additional DSM was modeled even though the cost of the Big Stone II Project had been increased by approximately 23 percent since MRES performed its earlier modeling. The same amount of DSM was available and picked in the modeling as was available in the modeling discussed in Gerald Tielke's June 1, 2006 Direct Testimony.
- The costs of the gas-fired alternatives considered by MRES was much higher than estimated gas facility costs provided to the Applicants by Big Stone project engineer, Black and Veatch, and much higher than the costs used in the Big Stone II Project modeling of the other Applicants.
- The capacity factor of several of MRES' wind resources was understated.
- MRES assumed that Big Stone II had a superior heat rate and lower operating and fixed costs compared to potential, future coal plant additions. It also assumed that Big Stone II's heat rate did not change regardless of changes in unit output.
- MRES failed to apply any AFUDC or IDC to the capital costs in its modeling. This favored the coal alternatives, including the Big Stone II Project which have higher estimated capital costs and longer projected construction durations.
- The addition of Big Stone II to MRES' system means that the company remains heavily reliant upon coal-fired generation and allows it to make significant off-system sales until additional load from Marshall, MN comes onto its system in 2016.[91]
- The cost of wind was much higher than was used in modeling by the other Applicants.

Q. How much higher were the costs of the gas alternatives considered by MRES as compared to the assumptions of the other Applicants and of Black and Veatch?

A. MRES' cost were, in most cases, more than twice as high as the CT and CC costs used by other Applicants as demonstrated in Table 7, below.

[91] This current load is supplied by Heartland Consumers Power District.

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Table 7. Comparison of Applicants and B&V CC and CT Inputs

[PROTECTED MATERIALS BEGIN

[1] From MCEA IR 138, in $2005.
[2] From MCEA IR 138, in $2006.
[3] From MCEA IR 138, in $2006.
[4] From DOC IR 126.
[5] From MCEA IR 174.

PROTECTED MATERIALS END]

There was also variation in the heat rates. Interestingly, MRES did not assume that the CC and CT heat rates remained constant regardless of output as it did for Big Stone II.

Q. For which wind resources was the capacity factor understated?

A. MRES included 40 MW of non-accredited wind in its modeling. **[PROTECTED MATERIALS BEGIN**

PROTECTED MATERIALS END]

Q. How do MRES' assumptions for Big Stone II and any alternative coal plants compare?

A. MRES assumed that Big Stone II had a better heat rate and lower fixed and operating costs than alternative plants the Strategist model could select.

Table 8. Big Stone II and Resource Coalition Project Inputs (2005$)
[PROTECTED MATERIALS BEGIN

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Q. What is the significance of assuming that Big Stone II has a better heat rate and lower fixed and operating costs than a future coal plant?

A. Essentially, MRES is telling the model that a coal plant as low cost and well performing as Big Stone II will never come along again. This biases the resource selection towards picking Big Stone II in 2011 over other resource options, even coal-fired units, that are available throughout the planning period.

Q. MRES assumed a higher capital cost for CC and CTs than the other Applicants did. Did it similarly assume a higher cost for Big Stone II than the other Applicants?

A. No. Conversely, MRES had one of the lowest capital costs for Big Stone II. The BSII assumptions by utility are shown in Table 9.

Table 9. Big Stone II Project Assumptions by Applicant
[PROTECTED MATERIALS BEGIN

[1] From MCEA IR 138, in $2005.
[2] From MCEA IR 138, in $2006.
[3] From MCEA IR 138, in $2006.
[4] From DOC IR 126.

PROTECTED MATERIALS END]

GRE's cost of Big Stone II stands out as much higher than the other Applicants' assumptions. We have no information to indicate why this might be, for example, if its capital cost includes AFUDC, transmission, etc. The general discrepancies among between the other applicants are also a mystery.

Q. What effect does the assumption of leaving out AFUDC have on the model's resource selection?

A. The amount of AFUDC accrued on a project will increase as construction time increases. As a result, resources with longer construction times such as Big Stone II will benefit from the assumption that there is no AFUDC. However, resources with relatively short construction times, such as wind and DSM, will be disadvantaged.

Q. You mentioned that Big Stone II will maintain MRES' reliance on coal-fired generation and allow for significant off-system sales. Please explain.

A. The dark blue area in Figure 2 represents coal-fired generation on MRES' system. Clearly, MRES will be heavily dependent, if not nearly exclusively, on its coal units to generate electricity throughout the planning period.

Figure 2. MRES Resources and Requirements in Preferred Plan
[PROTECTED MATERIAL BEGINS

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Since the model does not tell us which resources are being dispatched to make sales, it is not possible to assign specific GWh from specific resources to MRES' own energy requirements. That is, it is not possible to tell whether *specific* resources are being dispatched to sell into the market. What we do know, however, is that the addition of Big Stone II means that MRES *has* to sell at least some coal-fired generation into the market.

Q. How to do you know that the addition of Big Stone II would require MRES to sell coal-fired generation into the market?

A. In every year following the addition of Big Stone II and through 2017, MRES' coal-fired generation is greater that its energy requirements. Even if it were practical and economical to supply 100 percent of its energy requirements from coal, it would still have to sell energy from Laramie River Station or Big Stone II into the market or curtail the unit. Figure 3 shows this result.

Figure 3. MRES Generation Compared to Energy Requirements[92]
[PROTECTED MATERIAL BEGINS

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Coal generation is as much as [**PROTECTED MATERIALS BEGIN PROTECTED MATERIALS END]** greater than MRES energy requirements in this period, thus it is *very* likely that MRES would need to make significant off-system sales from Big Stone II in order to justify it economically.

Q. Has MRES tested the robustness of its assumption that it could make market sales at a price sufficient to recover both the operating and fixed costs of Big Stone II?

A. Not to our knowledge. The sensitivity analyses MRES supplied to us did not test differing assumptions of market prices.

[92] From response to MCEA IR 138.

Q. How do MRES' market sales compare to its portion of Big Stone II's energy during that period?

A. According to the Strategist model results for MRES's preferred plan, during the period 2011 to 2016 MRES's net economy energy sales (economy sales minus economy purchases) average **[PROTECTED MATERIAL BEGINS PROTECTED MATERIAL ENDS]** per year over this period. During the same period, MRES' share of the projected generation from Big Stone II averages **[PROTECTED MATERIAL BEGINS**

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Q. Is Big Stone II's capacity needed on the MRES system?

A. No. MRES's Strategist model results for the Company's "preferred plan" show that the 125 MW of Big Stone's capacity is entirely excess when it is added in 2011. Specifically, MRES's required reserve margin is 15 percent. But when Big Stone II is added in 2011 in the model, the system reserve margin jumps from **[PROTECTED MATERIALS BEGIN**

PROTECTED MATERIALS END] The reserve margins under MRES' preferred plan are shown in Exhibit JI-3-X, the "loads and resources summary report" from the Company's Strategist model run.

After Big Stone II is added in 2011, as load grows, the system reserve margin would decline gradually to 30 percent in 2015. In the year 2016, MRES expects to add Marshall, MN load. As a result, its reserve margin would return to 16 percent.

Q. What are the implications of this excess capacity?

A. Since MRES clearly does not need any of the capacity from Big Stone II for reliability and does not need most of the energy (and since its modeling certainly does not show that Big Stone II is more cost-effective than DSM and renewables), MRES has failed to meet the statutory requirements it must meet for a Certificate of Need. Beyond this is the question of whether it is prudent from an economic standpoint to engage in this kind of market speculation.

Some excess generating capacity is not necessarily imprudent or uneconomical. It is conceivable that the excess capacity, even though it is costly to build, could produce net economic benefits if the energy generated at the new plant is low cost and displaces significant amounts of higher cost energy generation or purchased power. Or, as suggested by MRES's modeling of its preferred plan, if the generation from the new plant can be sold off-system, at profits that justify its construction cost.

In the case of MRES's analysis of its preferred plan, in the six years following the addition of Big Stone II to its system (2011 to 2016), the annual net economy sales off-system average **[PROTECTED MATERIAL BEGINS PROTECTED MATERIAL ENDS]**. Expressed in terms of the output of Big Stone unit II, these sales represent more than half of the output of the unit.

The Company's preferred plan involves major power plant investment that will intentionally create significant excess capacity and result in large amounts of off-system sales. The economic rationale for such a plan should be examined very carefully and the risks should be evaluated rigorously before committing to that path.

Q. What are the underlying economics of MRES' plan and have the risks been rigorously evaluated?

A. MRES's plan to overbuild and make speculative off-system sales depends in large part upon access to low cost capital to finance the construction. Specifically, MRES's assumption is for a 6 percent discount rate, corresponding to its cost of capital. Note that with a 3 percent annual general inflation rate, that the 6 percent nominal cost of money amounts to a real cost of money of only about 3 percent.

This is significantly lower than the cost of capital to the investor-owned utilities in the region. With such a significantly lower cost of capital, it can be tempting for public power entities to overbuild their systems and profit on sales to investor owned companies that have higher costs. This is, however, a risky strategy, and in our opinion bad policy. Public power companies should focus on meeting the electricity requirements of their customers in a reliable, efficient, and low-risk manner. Speculation should not be allowed or encouraged.

In terms of risk analysis, MRES has done nothing that would test the robustness of this specific issue, i.e. the ability to make economic off-system sales.

Q. Are you aware of any situations in which an electric utility has imprudently overbuilt its system?

A. Yes. A small cooperative utility in Vermont, the Vermont Electric Cooperative (VEC), greatly overbuilt its system with nuclear and hydro-electric capacity. The regulatory commission later found that VEC had engaged in an imprudent investment strategy, "purchasing entitlements far in excess of its own needs for the purpose of 'brokering' wholesale power in the Northeast."[93] Without firm power sales contracts with credit-worthy buyers, it is possible that the entire debt load could fall upon the joint-action agency creating financial distress for its members. Indeed, VEC was bankrupted as a result of just such a plan. Other coops and public power entities have suffered from overbuilding.

Where it can, the Minnesota Public Utilities Commission should not allow MRES or other public power utilities to engage in speculative overbuilding that will subject their members to unnecessary risks.

Q. How did MRES' cost of wind resources compare to the assumptions by the other Applicants?

A. MRES was, by far, the highest. We've seen no explanation from MRES as to why their capital costs for wind resources are so much higher than what the other Applicants assume. Specifically, we calculated MRES' busbar cost of wind to be approximately **[PROTECTED MATERIAL BEGINS**

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93 Vermont Public Service Board order in Dockets 5810, 5811 and 5812, at page 35.

PROTECTED MATERIAL ENDS] yet most of the other Applicants assume a cost of wind energy of much less than that. For example, Applicants' witness Grieg has calculated a $60/MWh busbar cost of wind without the Production Tax Credit and about a $40/MWh busbar cost of wind with the PTC.[94]

The reason for this discrepancy appears to be that MRES assumed one of the highest capital costs of wind among all the Applicants at [**PROTECTED MATERIALS BEGIN**

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Q. Have you rerun the MRES Strategist model?

A. Yes. We did one run in which we "hardwired" all capacity additions in MRES' preferred plan with the exception of Big Stone II. The plan had to take at least some of Big Stone II in order to meet its peak demand requirements over the planning period, but the idea was to test when those capacity additions would come in. The model could add up to 125 MW of Big Stone II in 5 MW increments. Of the top 10-ranked plans in the planning period, which were all within one percent of the cost of each other, none added 125 MW of Big Stone II in 2011 and most added the majority of Big Stone II capacity (75 MW) in 2016 as might be expected given the addition of Marshall, MN load.

Q. Did you undertake any additional runs?

A. Yes, however, the amount of time between the receipt of modeling files from MRES following the filing of its Supplemental Direct testimony and the deadline for our Direct Testimony did not allow us sufficient time to finish our intended analysis. Our goal when we acquired our Strategist license was to use the model to test the sensitivity of the conclusion that Big Stone II was part of MRES' least cost plan. We made several diagnostic runs to understand how MRES had set up the model and what the main drivers were. It became clear, however, that the

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94 Applicants' Exhibit 47, page 7, lines 20-22, and at page 8, lines 3-4.

long run times for the model and the great sensitivity of the model results to its inputs would require more analysis than we had sufficient time for.

Q. Please explain.

A. One of the limitations of Strategist is that it can only consider a limited number of resources alternatives without incurring long run times. MRES addressed this by making a run with specified minimums and maximums for different resources and lowering or raising those ceilings and floors if needed for the runs that followed. Because Strategist cannot consider all alternatives simultaneously without incurring very long run times such an iterative process is necessary. MRES likely produced tens if not over a hundred runs in this manner in order to arrive at its "Preferred Plan." MRES did not produce all these runs in discovery nor did it apparently save them so it's impossible to say for certain how many runs it had to make.

Therefore, if we were to test the sensitivity of Big Stone II to even our low CO_2 price we could *not* just input the price and let the model pick from all resource alternatives since the run time would be very, very long.

Testing for scenarios such as this is very important since the Strategist model's results displayed great sensitivity to changes in its assumptions. As one example of the sensitivity of the model to changes in input assumptions, we fixed MRES's preferred capacity expansion plan and then input our low CO_2 price. As you may recall, the generation under the preferred plan is overwhelming from coal. The result was that economy energy purchases jumped to unrealistic levels. That is, that generation at MRES units was offset by economy energy purchases even assuming that these purchases also incurred a CO_2 emissions price.

Q. The model run that you did complete still shows the addition of Big Stone II capacity, doesn't that mean Big Stone II is still economic for MRES, though at a later date?

A. Not necessarily. Other assumptions would have to be changed and tested. For example, costs of wind, CC and CT resources, the level of DSM available to the model, the ability to make off-system sales, the lack of any CO_2 cost analysis among other variables. If indeed MRES still needs baseload capacity in the out years to serve Marshall, MN load, it would also be prudent to evaluate whether IGCC with carbon capture and sequestration would be preferable under greenhouse gas regulation.

Q. What should the Commission conclude from the modeling MRES did undertake?

A. MRES has not shown that DSM and renewables would not be more cost-effective than the Big Stone II Project. What its modeling does show is that the conclusion that Big Stone II is least cost based on a number of questionable assumptions, including the ability to make off-system sales at prices that would permit the recovery of both fixed and variable costs. We reiterate that participating in the Big Stone II Project is a speculative endeavor for which MRES has apparently not done any risk analysis.

IV.E. GRE

Q. Has Great River Energy (GRE) made the required showing before this Commission that renewable energy (hydro, wind, solar and geothermal) and energy conservation and load-management measures are not more cost-effective than the proposed Big Stone II Project?

A. No.

Q. What is the basis for this conclusion?

A. GRE's testimony that continued participation in the Big Stone II Project is an economic option is based upon its modeling using the Capacity Expansion Model ("CEM"), as discussed in the Supplemental Direct Testimony of Stan Selander. We have identified major flaws and deficiencies during our review of this modeling. Therefore, we certainly cannot agree that GRE's proves that the Big

Stone II Project is an appropriate least cost resource to include as part of GRE's resource portfolio.[95]

Q. GRE witness Richard Lancaster has testified that "GRE's analysis, however, went beyond the modeling results, because GRE is not comfortable making resource selection decisions based solely on modeling results."[96] What did this analysis entail?

A. Unfortunately, GRE has been unable to provide any evidence of what additional analyses or assessments, if any, it performed in addition to the CEM modeling to evaluate whether to continue its participation in the Big Stone II Project in light of the capital cost increase announced last summer. For example, MCEA IR No. 182 requested notes, minutes or reports pertaining to this and other similar statements by Mr. Lancaster in his testimony. However, GRE responded that it "does not have any notes, minutes or reports to provide."

Q. Without such evidence, should the Commission rely on GRE's claim that it performed those additional analyses?

A. No.

Q. What flaws and deficiencies did you identify during your review of GRE's capacity expansion modeling?

A. We identified the following problems with GRE's capacity expansion modeling:

- The results of the modeling do not make sense because the model selected substantially more Big Stone II capacity in 2011 in spite of the recent capital cost increase.
- GRE appears to be basing the conclusion that the Big Stone II Project remains an appropriate least cost resource to include as part of GRE's resource portfolio on the results of a single run of the Capacity Expansion Model. We have seen no evidence that GRE evaluated any risks and uncertainties in its most recent modeling and did not prepare any

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95 Applicants' Exhibit 37, at page 4, lines 15-18.

96 Applicants' Exhibit 36, at page 1, lines 17-21, and page 4, line 15, to page 5, line 3.

sensitivity analyses reflecting possible variations in key input assumptions.

- The model run discussed in the Supplemental Testimony of Stan Selander added 824 MW more capacity, including an additional 185 MW of Big Stone II, than the earlier modeling discussed in Mr. Selander's June 1, 2006 Direct Testimony.
- The "load" forecast presented by GRE witness Pritchard provides no evidence of the increased customer demands that would support the need for all of this additional supply side capacity. Mr. Pritchard's "load" study actually only presents a forecast of GRE's energy requirements,[97] not its customer demands.[98]
- GRE allows the model to select Big Stone II Project capacity in 2011 even though, as we have previously discussed, it is clear that the Project's actual commercial operation date will be May 2012, at the earliest, and it could be July 2013 or later.
- Because it selects so much new baseload capacity, including Big Stone II, the model generates substantially more energy than GRE requires for its own customer needs. Much of this excess generation comes from Big Stone II.
- It appears that during the recent capacity expansion modeling performed by GRE, the model included significantly fewer energy savings from DSM than GRE expects will be achieved. We expect that this will lead the model to over build new supply side capacity, including the Big Stone II Project.
- GRE's modeling does not reflect any CO_2 costs from restrictions of greenhouse gas emissions.
- GRE's supplemental modeling caps the amount of cost-effective wind that can be selected.
- GRE assumes that the wind Production Tax Credit will expire at the end of 2007.
- GRE assumes that new wind facilities can only achieve 30-35% annual capacity factors.

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[97] A load forecast is a projection of peak demand, i.e., MW needs. An energy requirements forecast is a projection of energy, i.e. MWh needs.

[98] Applicants' Exhibit 38, at page 2, line 11, and page 3, lines 6-10.

Q. Were you able to rerun the Capacity Expansion model to correct for any of these weaknesses?

A. No. Due to limited time and resources, we focused our attention on the Strategist model which was used by three of the Big Stone II Project Co-owners, that is, MRES, CMMPA and MDU. Consequently, our review of GRE's modeling was limited to an analysis of certain input files, an output spreadsheet (apparently created by GRE) for the single base case run that GRE gave us, and the documents that GRE provided in its Testimony and in response to discovery submitted by the Joint Intervenors and the DOC.

Q. How much more Big Stone II capacity does GRE's most recent modeling run select?

A. GRE's modeling run selects 310 MW in 2011 as compared to the 101 MW of the Project that were selected in the modeling that was performed prior to the estimated project cost increase announced last summer.

Q. Have you seen any evidence that GRE actually is considering increasing its ownership share Big Stone II to 310 or more MW?

A. **[PROTECTED MATERIAL BEGINS**

[99]

PROTECTED MATERIAL ENDS] Unfortunately, we only received this information on November 25, 2006. Consequently, we were unable to pursue the issue further with GRE to determine whether it is committed to remaining a Big Stone II Project Co-owner.

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[99] Applicants' supplemental response to MCEA IR No. 215, at Bates Page Number GRE0005267.

Q. What evidence shows that the resource plan suggested by GRE's most recent capacity expansion modeling would add 824 MW more new supply side capacity than the resource plan presented in Mr. Selander's June 2006 Direct Testimony?

A. Table 10 below compares the supply side capacity additions presented in Mr. Selander's June 1, 2006 Direct Testimony and the additions that were presented in his October 2, 2006 Supplemental Direct Testimony.

Table 10. GRE Capacity Additions from June 1 and October 2 Testimonies

	Combined Cycle		Simple Cycle CT		Big Stone Unit II		Wind		IGCC	
	Direct	*Supple-mental Direct*	*Direct*	*Supple-mental Direct*	*Direct*	*Supple-mental Direct*	*Direct*	*Supple-mental Direct*	*Direct*	*Supple-mental Direct*
2006	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	100	0	0
2009	0	0	62	130	0	0	100	200	0	0
2010	227	227	62	130	0	0	200	300	0	0
2011	227	227	62	130	101	310	217	400	0	0
2012	227	227	62	130	191	406	217	500	0	0
2013	227	227	62	130	296	505	217	600	0	0
2014	233	249	62	130	413	600	217	700	0	0
2015	499	539	62	130	428	600	217	800	0	0
2016	547	617	62	130	459	600	217	870	0	0
2017	575	740	71	130	538	600	217	897	0	0
2018	575	797	159	130	560	600	217	924	0	0
2019	609	797	200	130	601	600	217	949	0	83
2020	689	861	233	130	601	600	217	969	0	83
2021	746	929	292	130	601	600	217	1069	0	83
2022	803	976	351	130	601	600	217	1069	0	83
2023	872	976	403	130	601	600	217	1069	0	157
2024	962	976	444	130	601	600	217	1069	0	272
2025	1057	976	483	130	601	600	217	1069	0	407
2026	1154	1064	524	130	601	600	217	1069	0	457

If you total the columns for each plan, it is clear that over the entire period, 2006-2026, the proposed resource plan presented in Mr. Selander's Supplemental Direct modeling would add approximately 824 *more* MW of supply-side capacity than the proposed resource plan presented in his Direct Testimony modeling did.

Q. Is it possible that this is a result of the changes in GRE's load forecast since last Spring when the earlier modeling was prepared?

A. Yes. That is what we would expect. However, Applicants' witness Pritchard has testified that GRE will not be preparing a new "load" forecast until later in 2006.[100] This new forecast will be used by GRE for future resource planning but apparently was not available for use in this proceeding. Consequently, it appears that the CEM model may be selecting so much additional supply side capacity as the result of some interim load forecast that reflects the two factors discussed by Mr. Pritchard in his October 2006 Supplemental Testimony: there are a major increase in the number of ethanol plants expected to be built in the GRE service area and the higher expected wholesale price of energy.[101]

Q. What will happen if some of the expected ethanol plants are not built?

A. GRE's load and energy requirements forecasts will have to be reduced. However, by that time, GRE may have already added or committed to new capacity and may find itself with substantial excess capacity.

Q. How then should GRE consider such load uncertainty in its resource planning and its economic analyses of the Big Stone II Project?

A. Instead of basing a decision that the Big Stone II Project will remain an appropriate least cost resource to include as part of GRE's resource portfolio on the results of a single model run, GRE should have performed multiple sensitivities in which the key input assumptions were varied. The impact of changes in load and energy forecasts on the economics of adding the Big Stone II Project could have been evaluated in this way.

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[100] Applicants' Exhibit 3, at page 2, lines 10-11.

[101] Applicants' Exhibit 36, at page 4, lines 5-13.

Q. Have you identified any unusual results during your review of the output files from GRE's recent modeling of the Big Stone II Project?

A. Yes. As shown in Figure 4 below, it appears that as soon as the Big Stone II Project is added in 2011, **[PROTECTED MATERIALS BEGIN**

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PROTECTED MATERIALS END]

The generation figures presented in Figure 4 do not reflect sales and purchases, because without further documentation from GRE we could not discern exactly which contracts in its modeling were purchases and which were sales. However, the net effect of these sales and purchases is unlikely to have a material affect on the trends shown in Figure 4.

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102 Based on information from MCEA IR 139 and the Supplemental Direct Testimony of William Pritchard.

In fact, in every year after the Big Stone II Project is added, GRE's total amount of excess generation (MWh) is greater than the generation at Big Stone II as demonstrated in Figure 5.

Figure 5. Excess GRE Generation Compared to BSII Generation in CEM [TRADE SECRET MATERIAL BEGINS

TRADE SECRET MATERIAL ENDS]

Figure 5 also shows that most of this excess is made up of Big Stone II energy.

Q. Why would the model give a result showing so much more energy being generated at GRE's units than is needed to meet GRE's energy requirements?

A. Capacity additions to the model appear to be driven by deficits in capacity compared to GRE's load plus reserve margin requirements. However, those additions are not needed in order to generate additional energy to meet the needs of GRE's customers. This is likely not accounted for by the model since the capacity factor of many of GRE's units including its coal resources appears to be largely fixed (see Exhibit JI-3-X). Essentially, what the data is showing is that GRE needs firm capacity to meet its peak load and reserve requirements, but does not need additional energy from those units.

Q. Under this scenario, what sort of capacity should GRE be adding to meet its peak plus reserve requirements?

A. It should be adding peaking capacity. It makes no sense to add a baseload unit to meet peak demand if a utility system does not also require baseload energy. GRE's declining load factor, from 58.4% in 2006 to 48.2% in 2029,[103] tends to corroborate this.

In short, the modeling that GRE offers to show the need for Big Stone II simply does not do so. On the contrary, it shows that GRE needs peaking capacity rather than baseload, and that Big Stone II will provide energy that GRE does not need.

Q. Have you identified any other problems with GRE's modeling?

A. Yes. The CEM model appears to have selected far less DSM than was made available to it and produces substantially fewer savings than GRE expects can be achieved from the selected programs and measures.

Q. What is the basis for this conclusion?

A. In response to DOC IRs 124-127 and 129-130, GRE provided a table showing the conservation savings chosen in its modeling. These are "Incremental Annual Savings" and "Cumulative Annual Savings" in Table 11. However, our review of the CEM model outputs shows a different level of savings, "CEM Cumulative Energy Savings."

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[103] GRE Response to DOC IRs 124-127 and 129-130.

Table 11. GRE Conservation Resources in Modeling

	A	B	C
Year	Incre-mental Annual Savings (MWh) (a)	DOC IR Cumulative Savings (MWh) (a)	CEM Cumulative Energy Savings (MWh) (b)
2007	33,449	33,449	
2008	33,449	66,898	33,449
2009	33,449	100,347	33,449
2010	33,449	133,796	33,449
2011	33,449	167,245	33,449
2012	33,449	200,694	33,449
2013	33,449	234,143	33,449
2014	33,449	267,592	33,449
2015	33,449	301,041	33,449
2016	33,449	334,490	33,449
2017	33,449	367,939	33,449
2018	33,449	401,388	33,449
2019	33,449	434,837	33,449
2020	33,449	468,286	33,449
2021	33,449	501,735	33,449
2022	33,449	535,184	33,449
2023	33,449	568,633	33,449
2024	33,449	602,082	33,449
2025	33,449	635,531	33,449
2026	33,449	668,980	33,449

(a) From DOC IRs 124-127 and 129-130
(b) From MCEA IR 139

Q. What is the difference between the Cumulative Savings figures for GRE shown in Column B of Table 11 and the CEM Cumulative Energy Savings figures?

A. It is unclear why the CEM model would be reporting different cumulative savings figures than GRE reports that the model selected. So, the problem may just one of misreporting of the cumulative DSM savings selected by the CEM model.

However, it also may be that because of an error in the actual modeling, the model only did select DSM in the first year (as its output suggests). Therefore, there would be no incremental DSM savings in any subsequent years. In this case, the model will tend to select larger amounts of supply side capacity than it otherwise would pick.

Q. What effect does this different level of savings have on GRE's modeling?

A. If the different level of savings reported in the CEM modeling is a result of some error in the actual modeling, then the model will tend to pick greater amounts of capacity than it otherwise would. If, instead, this is a reporting error by GRE, than this will simply serve to make the "CEM Excess Generation" in Figure 5 that much greater.

Q. Are you confident that GRE actually has made all cost-effective DSM available to the CEM model?

A. The testimony of Tim Woolf describes the problems with GRE's specific analysis of DSM potential and the additional DSM cost-effective savings that GRE can be expected to achieve. Therefore, the answer to your question is no. We don't believe that GRE has made all cost-effective DSM available to the CEM model.

Q. Does GRE's CEM modeling establish that Big Stone II is a lower cost option than DSM?

A. No. As the Testimony of Tim Woolf describes, the amount of cost-effective DSM available to CEM was constrained by GRE assumptions.

Q. Have you identified any problems in GRE's modeling of wind resources?

A. Yes. We have identified deficiencies in GRE's modeling of wind. First, in GRE's recent Supplemental modeling, wind capacity additions were limited to 100 MW per year, up to a cap of 20% of generation.

This was a change from the earlier modeling discussed in Mr. Selander's June 1, 2006 Direct Testimony in which the model could add up to 100 MW of wind per year for the period 2006-2014 and then up to 300 MW per year thereafter. It is clear from the output of GRE's recent Supplemental modeling that all wind capacity available to the model is cost-effective even with the unrealistic assumption that the production tax credit ("PTC") for wind is not renewed after 2007. Therefore, the cap on wind additions of 100 MW per year that the model could select means that some cost-effective wind resources are excluded in favor more traditional supply side options such as coal and gas-fired facilities.

Q. Is GRE's modeling of wind flawed in any other ways?

A. Yes. At the same time that it was reducing the total amount of wind the model could select, GRE also, without any apparent basis, significantly reduced the assumed capacity factor that wind resources can achieve. In the modeling discussed in its June 1, 2006 Direct Testimony, GRE assumed that the wind facilities could achieve a 37.5 percent capacity factor. However, in its recent Supplemental Testimony, GRE now assumes only a **[PROTECT MATERIAL BEGINS PROTECTED MATERIAL ENDS]** capacity factor for wind resources.[104] As a result of making these unnecessary and unreasonable changes, GRE cannot show that renewables, particularly wind, are not more cost-effective than the Big Stone II Project.

Q. Do you think that GRE's assumption that the wind Production Tax Credit will be allowed to expire at the end of 2007 is reasonable?

A. No. We believe that 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 the resulting interest in providing subsidies to non-carbon emitting technologies. This is particularly true given the results of the recent Congressional elections.

Q. Have you identified any other flaws in GRE's recent modeling of the Big Stone II Project?

A. Yes. GRE's recent modeling presented in its Supplemental Testimony ignores the major risks associated with building fossil fuel-fired power plants. First, it does not appear that the Big Stone II Project capital cost that GRE used in its recent

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[104] Direct Testimony of Stan Selander, page 11, line 16.

modeling includes **[PROTECTED MATERIAL BEGINS**

. **PROTECTED MATERIAL ENDS]** Second, as it has done before, GRE's modeling does not reflect any costs due to CO_2 emissions from its plants, including the Big Stone II Project, over the entire planning period.

Q. In his Supplemental Direct testimony, GRE witness Richard Lancaster states that "adding a relatively small amount of baseload coal to our portfolio is a prudent business action"[105] and "future CO_2 regulation is likely, in my mind, but Big Stone Unit II will be one of the last plants to be affected, because it will be so efficient and therefore will emit less CO_2 than a typical plant."[106] Do you agree?

A. No. Mr. Lancaster's comment on the prudence of adding Big Stone II was made in relation to his claim that GRE needs an around the clock electricity source but needs to contain its exposure to natural gas price volatility. However, it is also important to consider whether acquiring Big Stone Unit II capacity is prudent if one considers "future CO_2 regulation [to be] likely."

We see no reason to assume that Big Stone Unit II will be "one of the last plants" affected by such regulation. Indeed, if CO_2 regulation takes the form of a cap and trade regulation (as is widely expected), *all* coal plants would be affected regardless of their relative efficiencies.

If GRE were serious about considering CO_2 regulation and analyzing the prudence of investing in Big Stone Unit II, it would, at a minimum, perform its modeling under scenarios of varying costs of such regulation. However, it has not done so.

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105 Supplemental Direct Testimony of Richard Lancaster page 5, lines 17-18.

106 Supplemental Direct Testimony of Richard Lancaster page 6, lines 12-14.

Q. It is possible to predict how GRE's expansion plan might change as a result of adding in Synapse's CO_2 price forecast?

A. It is impossible to say without doing that modeling specifically. However, one indication does come from GRE's own modeling.

GRE witness Selander's June 1, 2006, Direct Testimony discussed the results of GRE's CEM modeling that included Minnesota Commission's environmental externality values. Solely as a result of using the "high" Minnesota externality values, the model selected less of the Big Stone II Project (76 MW in 2011) than was picked in the Direct Testimony base case (101 MW in 2011) and did not reach GRE's full allocation of the unit until 2019. The model also selected all of the wind that was available through 2015. Significantly, the high Minnesota externality values do not apply to carbon dioxide emissions from the Big Stone II Project. Nor was the model allowed to select any DSM. Even though these modeling results are not definitive, it is interesting that just including the Minnesota Commission's externality values would lead the model to select less of the Big Stone II Project. It is reasonable to expect that the model would have selected even less of the Big Stone II Project if it had been able to select cost effective DSM and had to consider CO_2 prices that actually would apply to emissions from the Big Stone II Project.

IV.F. SMMPA

Q. Has Southern Minnesota Municipal Power Agency (SMMPA) made the required showing before this Commission that renewable energy (hydro, wind, solar and geothermal) and energy conservation and load-management measures are not more cost-effective than the Big Stone II Project?

A. No.

Q. What is the basis for this conclusion?

A. The results of the EGEAS modeling performed by SMMPA are presented by SMMPA witness, Larry Anderson. Mr. Anderson's conclusion that the Big Stone Unit II Project is least-cost for SMMPA is predicated upon the modeling of four cases. These four cases included:[107]

- The Big Stone Unit II alternative of 49 MW (BSII 49 MW 2012),
- A combustion Turbine alternative of 49 MW (CT 49 MW 2013),
- A combined Cycle alternative of 49 MW (CC 49 MW 2013), and
- A combustion Turbine/Combined Cycle alternative of 49 MW (ALL GAS 49 MW RESOURCES).

These cases were created by SMMPA and not by EGEAS in the sense that one might expect a capacity expansion model to function. In other words, the model was forced to include each of these alternatives in one of the four scenarios listed above. For example, in the "CT 49 MW 2013" case, EGEAS had to take a 49 MW CT in 2013. In the "BSII 49 MW 2012" case, EGEAS had to take 49 MW of Big Stone Unit II in 2012 and so on.

In each case, SMMPA set up the case so that the *same* amounts of wind and DSM were taken in the *same* years. It does not appear that the model had the option of replacing the Big Stone II Project with additional wind and/or DSM. Thus it would be erroneous to conclude that DSM and wind are not more cost-effective than the Big Stone II Project

In fact, in nearly every EGEAS base case and sensitivity since SMMPA's 2003 IRP, the same level of DSM and wind resources have been included in the base cases and the sensitivities. In its 2003 IRP, 8 out of 11 cases included the same level of wind and DSM. In its 2006 IRP, 13 out of 13 cases included the same

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107 Supplemental Direct Testimony of Larry Anderson, page 2, lines 18-22.

level of wind and DSM. In the supplemental modeling, it was 4 out of 4 cases. It would be more reasonable and in fact, is necessary, in a proceeding such as this to allow *increasing* amounts of DSM and wind resources in the model in order to understand at what level additional resources of these types would no longer be cost-effective. Indeed, doing this sort of exercise would allow SMMPA to determine whether renewables and energy efficiency are or are not more cost-effective than investing in the proposed Big Stone II Project.

Q. What resources has SMMPA considered in its modeling?

A. In his June 1, 2006 direct testimony, Mr. Anderson, states that SMMPA's Preferred Plan in its 2003 IRP included the following resources:[108]

- All four DSM programs considered.
- 16 Groups of Wind Turbines (in groups of 3.8 MW of nameplate capacity each) to be installed to comply with 100% of its REO.
- 3 Landfill Gas additions (in groups of 2.4 MW each).
- 3 Peaking Purchases (in groups of 12 MW each).
- One natural gas-fired, combined cycle unit (53 MW) installed in 2008, and:
- One Pulverized Coal Unit (53 MW) installed in 2013 assuming a cost of $1,200/kW.[109]

Mr. Anderson's most recent testimony states that SMMPA's least cost alternative now consists of:[110]

- Big Stone Unit II at 49 MW.

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[108] Direct Testimony of Larry Anderson, page 12, lines 15-22 and page 13, lines 1-3.

[109] SMMPA 2003-2018 Integrated Resource Plan, page VIII-6.

[110] Supplemental Direct Testimony of Larry Anderson, page 3, lines 1-4.

- All four DSM programs.
- Community-based Wind Energy Development (C-BED) at 31.6 MW
- Non-CBED wind at 152 MW
- One Biomass project (approximately 2 MW)
- Five Peaking Purchases of 10 to 20 MW
- Five generic 49 MW pulverized coal units.

Based on the corresponding modeling files provided in response to MCEA IR 139, these appear to be the resource additions over the period 2006-2035.

While we commend SMMPA for modifying its plan to add additional, cost-effective renewables to its system between the 2003 IRP and the current modeling upon which Mr. Anderson's supplemental direct testimony is based, for the reasons stated above, this new modeling still does not demonstrate that renewables and energy efficiency cannot be more cost-effective than the proposed Big Stone II Project in supplying energy and capacity for SMMPA.

Q. On page 4, lines 1-2 of Mr. Anderson's supplemental direct testimony, he states "[SMMPA's] revised analyses confirms [sic] that we still need 100 MW of new baseload beginning in 2008." Do you agree?

A. No. In fact, SMMPA's analyses don't show this at all. For example, even ignoring the criticisms of SMMPA's analyses as described above, in the BSII 49 MW 2012 case, the next baseload resource is added in 2016, not 2008. The bridging contract to meet SMMPA's needs is for *50* MW of *peaking* capacity, not 100 MW of baseload. There's no evidence that SMMPA needs 100 MW of baseload capacity when Big Stone Unit II comes online, let alone in 2008.

IV.G. HEARTLAND

Q. Has Heartland Consumers Power District made the needed showing before this Commission that renewable energy (hydro, wind, solar and geothermal) and energy conservation and load-management measures are not more cost-effective than the Big Stone II Project as required under Minnesota Statutes 216B.243?

A. No.

Q. Upon what do you base this conclusion?

As with the other Applicants, we interpret Heartland's modeling as the primary basis to make this showing. In his Supplemental Direct Testimony, John Knofczynski presents Heartland's modeling results and contends that Big Stone II is still least cost even with its increased capital cost.

Our review of Heartland's modeling revealed the following issues:

- First, Heartland's production cost modeling includes none of the resources it is required to evaluate under Minnesota Statutes, specifically renewables and demand-side management ("DSM");
- Heartland's modeling also did not account for the full cost of Big Stone II;
- Heartland's load forecast assumes that load will essentially double without having any sort of formal or informal commitments from most of the projected new load;[111]
- Heartland proposes to add 105 MW of new baseload coal capacity to its system, despite losing its largest customer (nearly 60 MW) in 2016;[112] and
- Even under Heartland's extreme load assumptions, the addition of Big Stone II will be made largely to enable off-system sales.

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[111] From response to DOC IR 91.

[112] From response to MCEA IR 132.

Q. What resources did Heartland evaluate in its modeling?

A. The resource dispatch output spreadsheets Heartland provided in response to MCEA IR 138 and 139 consistently show only the following resources:

1. Laramie River Station (existing coal unit)
2. Cooper (nuclear power PPA)
3. Whelan II (coal unit under construction)
4. Big Stone II
5. Customer Peakers
6. Combustion Turbine
7. Off-Peak Market
8. On-Peak Market

We've seen no analysis showing that Heartland's proposed resource mix, specifically Big Stone II, is more cost-effective than adding renewables and/or DSM above and beyond what Heartland currently has in its resource mix.[113]

In fact, when asked "If the capital costs of Big Stone Unit II have increased, why does your analysis still maintain that it is a low-cost resource for Heartland?" Mr. Knofczynski responded "[T]he projected cost of *the market power alternative* [emphasis added] is still more expensive than the projected costs of Big Stone Unit II."[114] Heartland's own witness agrees that Heartland has modeled no other alternative to Big Stone II.

Q. How did Heartland underestimate the cost of Big Stone II in its modeling?

A. Unlike most of the other Applicants, Heartland did not include any transmission costs nor an allowance for available funds used during construction (AFUDC).[115] The allowance for AFUDC will increase as construction times increase, so ignoring this cost will bias Heartland's analysis against resources with shorter

113 Direct Testimony of John Knofczynski, page 12, lines 9-20.

114 Supplemental Direct Testimony of John Knofczynski, page 7, lines 1-4.

115 Response to MCEA IRs 138 and 139.

construction times than a coal-fired facility, and will, overall, understate the cost of any plan including Big Stone II. This is in addition to failing, along with the other Applicants, to include a CO_2 regulatory cost value or to reflect the **[PROTECTED MATERIAL BEGINS**

PROTECTED MATERIAL ENDS].

Q. You stated that Heartland assumes essentially a doubling of load without having any sort of formal or informal commitment from most of that new load. Please explain.

A. One of the major drivers of Heartland's planning is the loss of its biggest customer, Marshall, MN in 2017. Heartland realizes the risk that this represents for the customers that remain on its system and is attempting to add new customers. If it cannot add sufficient load, more of its fixed costs will have to be spread over fewer customers, causing rates to increase. It has added new customers since early 2005. These new customers are included in Heartland's load forecast. However, Heartland also assumes a "load growth objective," that is, a significant "cushion" for additional, unidentified new load. While it is certainly prudent to attempt to attract new load [to mitigate rate shock in the face of a significant customer loss], there is serious risk in acquiring large amounts of new capacity without any sort of commitment from new customers (see, for example, Section X on MRES).

We have developed additional load forecast scenarios based on Heartland's original load forecast to show how dependent the accuracy of its load forecast is upon Heartland's new customers and its load growth objectives.

In our analyses, "Existing Load" is Heartland's existing customers including those added in early 2005. Heartland appears to be in negotiations with the municipal utilities that make up "Prospective Muni Load". "Load Growth Objective" is the goal for new load additions, all of which are unidentified, that was established by Heartland. "New Industrial Load" is 25 MW from the proposed expansion of a soybean facility in South Dakota that was announced in April of this year. "Contingency" is an unexplained 5 MW per year addition. Three load forecast scenarios assuming different combinations of these load types are depicted in Table X below.

Table 12. Heartland Load Forecast Scenarios

Load Included	Heartland Forecast	Muni Load	Muni Load + Soybean Load
Existing Load	X	X	X
Prospective Muni Load	X	X	X
Load Growth Objective	X		
New Industrial Load	X		X
Contingency	X		

The first scenario, "Heartland Forecast," is Heartland's original load forecast. The second, "Muni Load," includes Heartland's existing customers plus prospective municipal customers. The third scenario, "Muni Load + Soybean Load," includes existing customers, prospective municipal customers and the proposed soybean facility. Each of these three load scenarios from Table 12 are graphed in Figure 6 below.

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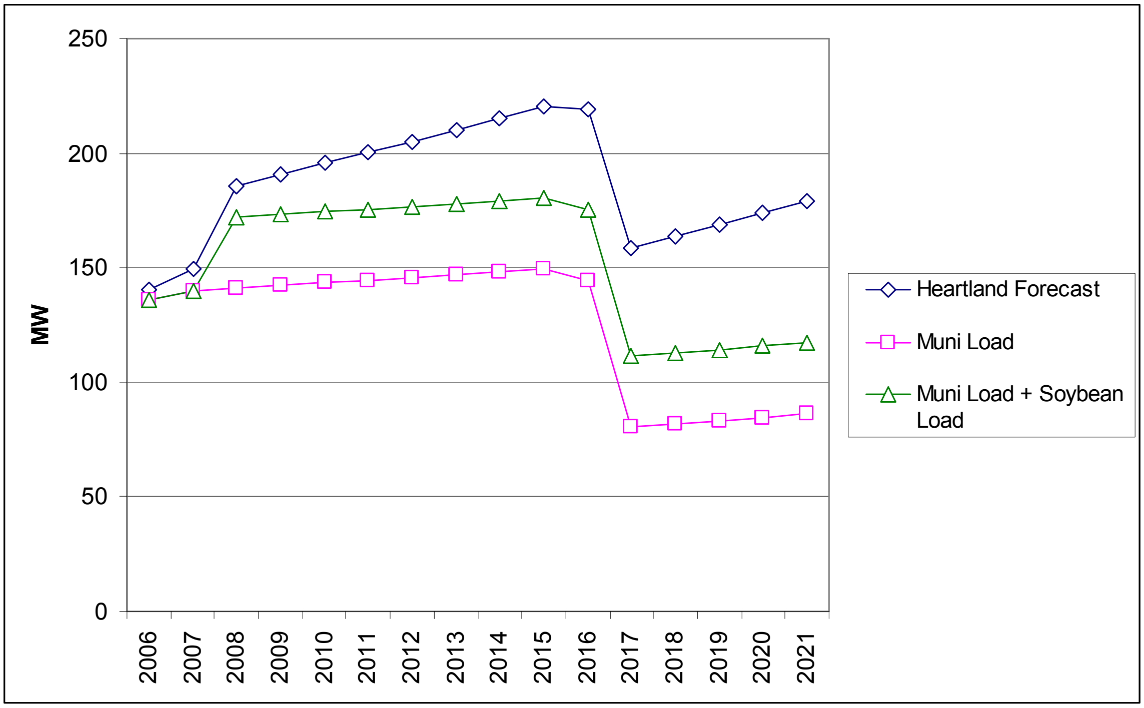
Figure 6. Three Load Forecast Scenarios for Heartland



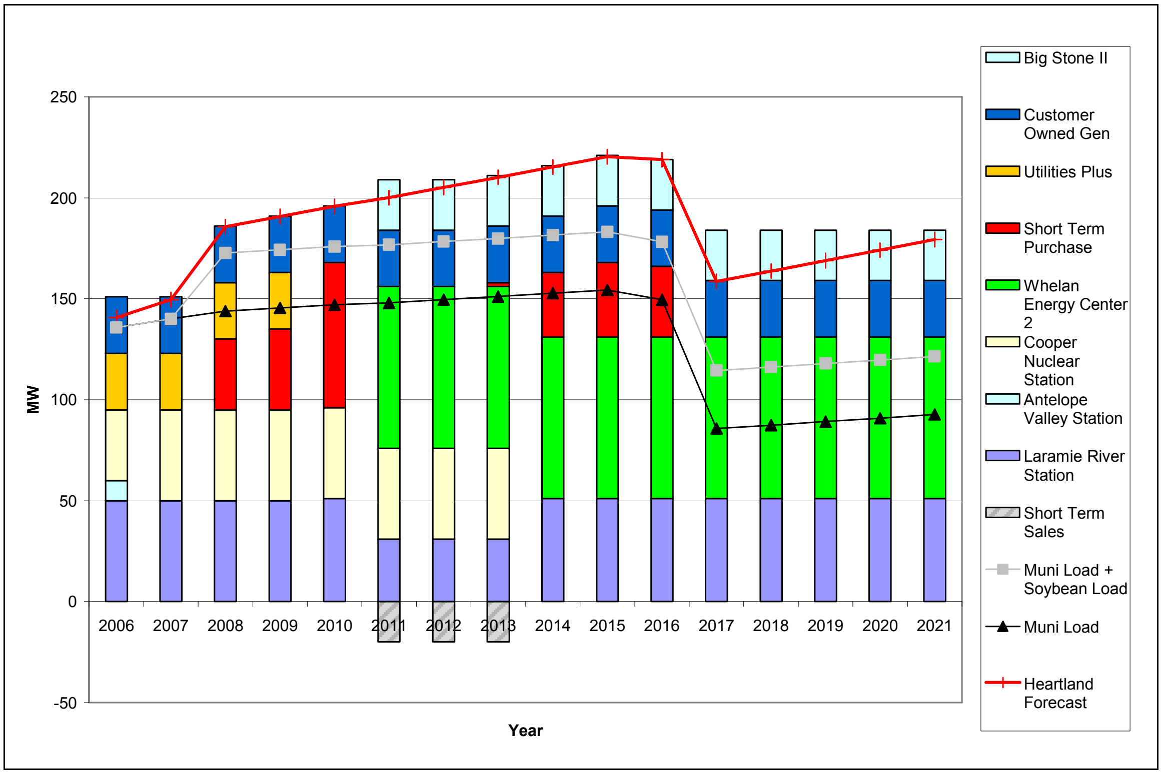
With the exit of Marshall, MN in 2017, the projected load in Heartland's forecast is approximately *double* the "Muni Load" forecast. Clearly, there is a risk to investing in new capacity while betting that this additional load can be acquired.

Q. Would the addition of Big Stone II be prudent even if Heartland were not able to attract new customers to match its load growth objectives?

No, it would not. On a simple peak comparison basis, without those new customers, Heartland will have significant extra capacity on its system, particularly after the exit of Marshall, MN from its system as shown in Figure 7.[116]

[116] All capacity additions, sales and purchases in this Figure are assumed from Heartland's plan provided in response to MCEA IR 132.

Figure 7. Comparison of Heartland Load Scenarios to Heartland's Resource Plan



If Heartland is not overbuilding by acquiring its share of Big Stone II, it is certainly betting its members' money that it can come up with *significant* new load.

Q. Let's assume that Heartland does come up with all of the new load it assumes in its forecast. Will Big Stone II be a prudent investment then?

A. Even ignoring Heartland's lack of consideration of renewables, demand-side management or the costs of greenhouse gas regulation, the answer is still no. Heartland's modeling shows that with exception of the period 2014-2016, the addition of Big Stone Unit II effectively backs off peaking units to zero and largely curtails market purchases. In fact, in 2017, all but 0.0009% of Heartland's energy comes from baseload coal plants![117] This would be an unprecedented

[117] Based on response to MCEA IRs 138 & 139.

situation for virtually any utility, and one that is generally considered far from economically optimal since Heartland's load is likely to have more variation than the expected output of baseload coal plants, meaning that baseload plants would have to ramp up and down with load in such a situation.

Q. You previously mentioned that the addition of Big Stone II allows significant market sales. Can you please explain?

A. Yes. Heartland supplied us with the two scenarios it examined in its production cost modeling: with and without Big Stone II. Other than the inclusion of Big Stone II, the generation at Heartland units in the two scenarios is identical. Therefore, if there is a difference in off-system sales between the two scenarios, that difference should be directly attributable to the addition of Big Stone Unit II.[118] Figure 8 demonstrates the increased magnitude of market sales that are made possible should Big Stone II come online in 2012.

Figure 8. Heartland Off-System Sales in the With and Without Big Stone II Scenarios

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Q. How do the increased market sales in the With Big Stone II scenario compare to the expected output from Big Stone II?

The additional market sales ("Sales Difference") are graphed in Figure 9. With the exception of the period 2014-2016 (the three years between the expiration of the PPA with Cooper nuclear station and the exit of Marshall, MN from Heartland's system), the difference in sales represents a significant portion of Heartland's share of Big Stone II's output.

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[118] We assume that Heartland's modeling is not showing arbitrage opportunities. That is, that it can make money simply by buying and selling power in the market.

Figure 9. Additional Sales b/c of BSII versus BSII Output
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Remember, this comparison assumes *all* the prospective load additions described above. Even so, Heartland's participation in Big Stone II would do little more than allow it to make speculative off-system sales.

Q. But aren't such sales a small and reasonable amount compared to the energy requirements of Heartland's system?

No. The ratio of off-system sales enabled by the addition of Big Stone II to Heartland's system energy requirements is also significant as demonstrated in Table 13 below.

Table 13. Market Sales as a Percentage of Heartland Energy Requirements
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Q. At pages 17 and 18, Mr. Knofczynski contends that "having another 5 MW for a total of 30 MW from Big Stone Unit II would be preferable." Do you agree?

A. No. In fact, Heartland's own consultants Burns & McDonnell, recommended that **[PROTECTED MATERIAL BEGINS**

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Most importantly, though, Heartland does not need one single megawatt of Big Stone II capacity to serve its customers and therefore, does not need the associated transmission capacity.

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[119] Response to MCEA Second Set of Requests for Production of Documents, SDPUC Docket No. EL-05-022, Request No. 5, incorporated by reference.

[120] From Burns & McDonnell presentation to Heartland on May 23, 2005 (bates stamp #HCPD000427-HCPD000429.

V. THE ANALYSES PRESENTED BY APPLICANTS' WITNESS HARRIS DO NOT SHOW THAT THE BIG STONE II PROJECT IS A LOWER COST OPTION THAN DSM AND/OR RENEWABLE ALTERNATIVES

Q. In Applicants' Exhibits 24-B, 48 and 48-B, Applicants' witness Harris presents the results of an analysis that the Applicants were directed to prepare by the Minnesota PUC concerning the generation and demand-side alternatives considered most viable to match each Company's share of Big Stone II. Have you been able to review all of the workpapers and input assumptions for this analysis?

A. No. At the October 8, 2006 motion hearing at which Applicants requested that Mr. Harris be permitted to file his analysis approximately two weeks after the filing of Applicants' October 2, 2006 supplemental testimony, the Applicants committed to providing the following information at the same time that they filed Mr. Harris' supplemental testimony and exhibit:

- Copies of all of Mr. Harris' workpapers.
- Electronic copies, in Excel or machine readable and useable format, of all input and output data files used in each of the analyses discussed or presented in the supplemental testimony [of Mr. Harris] and to develop all of the tables and exhibits presented in the testimony.
- The source documents and electronic files for all of the input assumptions and numbers used in each of the analyses discussed or presented in the supplemental testimony and to develop all of the tables and exhibits presented in the testimony.
- The correspondence between each of the Applicants and Mr. Harris concerning (a) the assumptions and figures used in each of the analyses discussed in the supplemental testimony; (b) the results of each of the analyses discussed in the supplemental testimony; and (c) his supplemental testimony in this proceeding.

Despite this commitment and a judge's order regarding our motion to compel, to date, we have not received all of the computer spreadsheets for all of the input data used by Mr. Harris. For example, we have only received the most summary annual revenue requirements figures for a number of the Applicants, most particularly, Otter Tail, MDU and MRES. For these Applicants, we have not been provided the detailed information we had requested, and the Applicants' had committed to provide, for the various cost elements used in the derivation or calculation of the annual revenue requirements figures that they have given to Mr. Harris for his analysis.

Q. Have you seen any credible evidence that the non-Big Stone II resource plans considered by Mr. Harris in Exhibits 24-B and 48-B actually represent the Applicants' individual next best resource scenarios, as Mr. Harris has testified?

A. No. Contrary to Mr. Harris' testimony, there is no evidence to support the claim that the individual utility alternatives to Big Stone II reflected in his economic analyses represent what would be each Applicants' next best resource alternative.[121] Indeed, there is no evidence that in the development of the purported 'next best' scenarios, any of the Applicants, except CMMPA included even the most minor additional wind capacity in place of Big Stone II. In addition, other than Otter Tail Power, none of the other Applicants have included any purchases of hydro capacity or energy. The materials we have received show further that none of the Applicants has included any additional demand-side management efforts in their 'next best' resource plans without Big Stone II.

Consequently, there is no evidence that what the individual Applicants have called their "next best" resource plans actually would be. That is, there is no evidence that these "next best" plans have lower costs than alternative plans that would include more wind, more aggressive implementation of cost-effective demand-side measures and increased purchases of hydro capacity and energy. In fact, Otter Tail Power has acknowledged that its alternate plan is not a least cost plan because the company did not have time to execute its IRP-Manager model in full optimized fashion. Instead, the Otter Tail simply substituted what appeared to

[121] Applicants' Exhibit 48, at page 2, lines 8-11, and at page 3, line 5.

be the next lowest cost resource from the preferred plan for Big Stone II in the alternate plan.[122]

Indeed, the alternative non-Big Stone II plans reflected in Mr. Harris' analysis really can be characterized as, other than for Otter Tail Power, highly risky plans that depend almost exclusively on coal-fired and natural gas-fired generation and on market purchases of power that probably also would be generated at coal-fired or natural gas-fired facilities.

Q. What are the sources of power that each of the Applicants use in their "next best" alternatives to Big Stone II that were provided to Mr. Harris?

A. Mr. Harris claims that the Applicants identified a variety of resource alternatives to meet their resource supply obligations if Big Stone II was unavailable, including market purchases, gas and coal-fired generation and renewable energy resources.[123] According to Mr. Harris, Applicants also would include demand-side management programs managed directly by the utility or indirectly through member utilities under both the with and without Big Stone II scenarios.[124]

However, a review of the materials provided by the Applicants reveals that only Otter Tail Power did, in fact, assume that Big Stone II would be replaced in full or in substantial part, by power generated by renewable resources.

- OTP assumed that Big Stone II would be replaced by 110 MW of hydro capacity from Manitoba Hydro.
- CMMPA assumed that Big Stone II would be replaced by 20 MW of natural combined cycle capacity in 2012, by another 10 MW of combined cycle capacity in 2014 and by 5.4 MW of wind starting in 2012.
- GRE assumed that Big Stone II would be replaced by generation at a new CT and by market purchases which would be heavily coal-fired.

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122 Kiah Harris Workpapers at Bates Page Number JCO0008272.

123 Applicants' Exhibit 48, at page 5, lines 9-11.

124 Ibid, at page 5, lines 11-13.

- Heartland assumed that Big Stone II would be replaced by market purchases that would be heavily coal-fired.
- MRES assumed that Big Stone II would be replaced by an IGCC facility in 2012, increased market purchases and by increased generation at the Exira facility.
- MDU assumed that Big Stone II would be replaced by the Lignite Vision 21 fossil-fired facility.
- SMMPA assumed that Big Stone II would be replaced by a 49 MW combustion turbine in 2013.

Q. Is there any evidence that the Applicants have reflected any additional demand-side management in their non-Big Stone II plans?

A. No. The workpapers for Mr. Harris' analysis that we have received, reveal that the Applicants have assumed essentially the same levels of capacity additions, and the same levels of energy generation in both the with and non-Big Stone II cases. This demonstrates that the Applicants have not reflected any additional demand-side management in their non-Big Stone II plans.

Q. Why do you consider the alternative to Big Stone II plans used in Mr. Harris' analysis to be "highly risky?"

A. The alternatives plans for each of the Applicants, other than for OTP, used by Mr. Harris rely to a very significant degree on coal-fired and natural gas-fired generation. As we have explained in Section III of this Testimony, we believe that emissions from these fossil-fired facilities will be subject to greenhouse gas regulations. In addition, new coal-fired facilities may be subject to capital cost increases and to some of the same sorts of production and coal-deliverability problems that have recently plagued existing coal-fired plants that depend on supplies from the Powder River Basin. Wind, at a minimum, significantly reduces the fuel price and environmental risks.

Q. Please comment on the testimony by Applicants' witness Harris that if Big Stone II is not constructed, there is no single best resource alternative that the Applicants would collectively pursue. Instead, each Co-owner would pursue a variety of strategies to meet their obligations.[125]

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

Q. Does Mr. Harris' analysis consider the potential for any greenhouse gas regulations?

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

Q. Even though most of the Applicants have only included fossil-fired resources or purchases from fossil-fired resources in their alternate plans, do not reflect any additional demand-side management, and do not consider the potential for greenhouse gas regulations, do the results of Mr. Harris' analysis show that Big Stone II would be the more economic option for each of the Applicants?

A. No. Table 8 in Applicants' Exhibit 48-A shows a $573 million (in 2011$) net present worth benefit in the revenue requirements in the Applicants' plans with Big Stone II over their next best plans.

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[125] Applicants' Exhibit 48, at page 3, lines 3-6.

However, a review of Mr. Harris' tables and workpapers shows that the MDU share of this $573 million "benefit" **[PROTECTED MATERIALS BEGIN**

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The total net present value revenue requirements savings for the other four Applicants, (that is, Otter Tail, MRES, CMMPA, and Heartland) total approximately **[PROTECTED MATERIALS BEGIN**

PROTECTED MATERIALS END of the benefit shown from Mr. Harris' analyses. Yet even this extremely minor figure overstates the benefits for MRES because the figures on Table 8 of Applicants' Exhibit 48-A show that participation in its next best plan would be more economic than continued operation in Big Stone II.

Q. What explains the fact that Table 8 in Applicants' Exhibit 48-A suggests that building Big Stone II would provide such a significant revenue requirements benefit for MDU?

A. MDU claims that its next best plan for Big Stone II would be to participate in a very expensive lignite burning facility. MDU chose this facility as its "next best" alternative to Big Stone II. This selection appears to have been based on MDU's 2005 IRP which only examined four options, three of which were coal-fired, with the fourth being reliance on purchased power.[126] Moreover, MDU did not use any computer model to compare supply-side and demand-side resources as part of its

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[126] Applicants' response to Interrogatory No. 27 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents in South Dakota Public Utilities Commission Case No. EL05-022.

2005 IRP.[127] Moreover, MDU had absolutely no economic studies that show that participation in the Lignite Vision 21 project would be its next best alternative to Big Stone II. Consequently, **PROTECTED MATERIALS BEGIN** **PROTECTED MATERIALS END** of benefit shown for MDU in Table 8 of Applicants' Exhibit 48-A lacks any credibility given that MDU 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.

Q. Were you able to examine the revenue requirements figures provided to Mr. Harris by Montana-Dakota in detail or to verify the annual plan costs and relative savings claimed by the company?

A. No. Despite a commitment by counsel for the Applicants, repeated requests by counsel for Joint Intervenors, and a the filing of a Motion to Compel, MDU has not provided any of the detailed information, worksheets and computer files in which it developed its estimated annual revenue requirements for the next best plan that did not include Big Stone II. Therefore, there was no opportunity for us to understand the bases for and to verify the reasonableness of the significant benefits the Montana-Dakota claims for Big Stone II over the Lignite Vision 21 alternative.

Q. Does Montana-Dakota's use of the Vision 21 Lignite Project as its next best alternative to Big Stone II also affect the emissions shown in Applicants' Exhibit 48-A?

A. Yes. Montana-Dakota's lignite alternative also dominates the NO_X, the CO_2, the CO, the PM_{10}, and the mercury emissions in the non-Big Stone II alternative case shown in Applicants' Exhibit 24-A and 48-A. Using the year 2016 as an

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[127] Applicants' response to Interrogatory No. 58 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents in South Dakota Public Utilities Commission Case No. EL05-022.

example, Montana-Dakota's alternative lignite facility would be responsible for approximately 34 percent of the NO_x emissions, 47 percent of the CO_2 emissions, 60 percent of the CO emissions, 37 percent of the PM_{10} emissions, and 96 percent of the mercury emissions in the non-Big Stone II alternative case.[128]

Q. What 'next best' plan did MRES present as its alternative to participating in Big Stone II?

A. MRES assumed that Big Stone II would be replaced by an IGCC facility in 2012, increased market purchases and by increased generation at the Exira facility.

Q. Does MRES assume that it would be able to sequester carbon and, thereby, reduce the CO_2 emissions at the IGCC facility it would add in 2012?

A. No. It appears that MRES assumes that the alternate IGCC facility would have essentially the same CO_2 emissions as the supercritical Big Stone II facility. Therefore, MRES is claiming that if it did not participate in Big Stone II, it would add a more expensive coal-fired facility without any significant reductions in CO_2 emissions. Moreover, MRES assumed that its alternate IGCC facility would purportedly be located in Minnesota and, therefore, would count against the MN Commission's externality values while the CO_2 emissions from the Big Stone II Project, located just across the border in South Dakota, would not.

Q. Do the annual revenue requirements figures presented in Table 8 of Applicants' Exhibit 48-A show that participating in Big Stone II would be more economic for MRES and its customers than the alternative of adding an IGCC facility in 2012, increased market purchases and by increased generation at the Exira facility?

A. No. When the annual revenue requirements in MRES' with and without Big Stone II Plans are present valued to 2011$ dollars using Mr. Harris' assumed 8 percent discount rate, the non-Big Stone II plan is more economic through 2020

[128] Revised Appendix A to Applicants' Exhibit 24-A, provided as Applicants' Exhibit 48-A.

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[129] **PROTECTED MATERIALS END**

Q. Have you changed or modified any of the input assumptions for this analysis?

A. No. This result is taken directly from the annual revenue requirements figures provided by MRES to Mr. Harris. In fact, despite repeated requests, a commitment by the Applicants' counsel, and the filing of a Motion to Compel, we have never received the workpapers and computer files from MRES in which these annual revenue requirements figures were developed.

Q. Is it reasonable to conclude that there might be an alternative plan for MRES, including more wind and DSM, that would be even more economic than the heavily fossil-fired 'next best' plan considered in Applicants' Exhibits 24-B and 48-A?

A. Yes.

Q. Have you examined the information that Heartland provided to Kiah Harris regarding its plans with and without the Big Stone II Project?

A. Yes.

Q. Do you have any comments on the information?

A. Yes. Heartland provided Mr. Harris with the dispatch outputs for its two cases. The costs attributable to Heartland's units were divided into two groups: energy/variable and fixed costs. The costs and revenues of market purchases and sales, respectively, were also included in the output. We found that market sales enabled by the addition of Big Stone II were really driving the difference in the net present value of the two cases and therefore, the conclusion that adding Big Stone II was preferable. The Net Present Values of the two cases with and without market sales is shown in Table 14, below.

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Table 14. NPVs of Heartland's Cases with and without BSII and with and without Market Sales

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Table 14 is simply another way of demonstrating what we've discussed previously; that Heartland's addition of Big Stone Unit II is really being made to support market sales.

VI. THE ANALYSIS PRESENTED BY APPLICANT WITNESS GREIG DOES NOT SHOW THAT THE BIG STONE II PROJECT IS A LOWER COST OPTION THAN DSM AND/OR RENEWABLE ALTERNATIVES

Q. Have you concluded that the analysis presented by Applicant witness Greig is evidence that the Big Stone II Project is a lower cost option than DSM and/or renewable alternatives?

A. No. The analysis presented by Mr. Greig is significantly flawed and biased in favor of the Big Stone II option.

Q. What is the basis for this conclusion?

A. Mr. Greig's analysis suffers from the following flaws:

- He does not examine DSM and hydro at all in his analyses.
- He rejects wind as a baseload resource and considers it as only a non-firm resource.[130] Therefore, he does not give it any capacity value.

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[130] Applicants' Exhibit 47, at page 7, lines 20-21.

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- He assumes no continuation of the wind Production Tax Credit.[131]
- He appears to use an estimated Big Stone II Project capital cost that does not reflect the additional **[PROTECTED MATERIALS BEGIN**

[132] **PROTECTED MATERIALS END]**

Q. Is it possible tht there are wind with hydro and/or demand-side management measures that would have lower costs than the wind-gas combination that Mr. Greig has presented in Applicants' Exhibit 47-A?

A. Yes. For example, as Mr. Woolf discusses in his testimony, there is evidence of additional, very low cost demand-side management measures available to the Applicants.

Q. Do you believe that wind can be a baseload resource?

A. Yes. Wind can be part of a portfolio of resources that can provide needed capacity and baseload energy.

Q. Is it reasonable to assume that the Production Tax Credit will not be renewed before it expires at the end of 2007?

A. No. As we noted earlier, we believe that 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 the resulting interest in providing subsidies to non-carbon emitting technologies. This is particularly true given the results of the recent Congressional elections.

Q. Do these same flaws invalidate Mr. Greig's carbon price break-even analysis?

A. Yes.

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[131] Applicants' Exhibit 47, at page 7, line 20, through page 8, line 8, and at page 9, lines 4-8.

[132] Applicants' Exhibit 47, at page 6, lines 20-1.

Q. Are you surprised that the Applicants have filed Mr. Greig's testimony and analysis in this proceeding?

A. Yes. The Applicants were very specific in their position in the hearings before the South Dakota Public Utilities Commission that such an comparison was not appropriate. For example, the Applicants noted the following in their responses to one of Joint Intervenors' Interrogatories:

> It must be noted that simply comparing $/MWh busbar costs of dissimilar projects is misleading and violates the most basic principles of integrated resource planning. Such a comparison completely ignores the impact of the costs and benefits a single resource can have on other resources, and provides only limited information on how any particular resource matches up with a utility's existing resource mix, the existing load requirements, or the electrical system in total.[133]

Consequently, we are surprised that the Applicants have filed Mr. Greig's analysis if they truly do believe this way about the limits of levelized cost analyses.

Q. Do you believe that such levelized analyses can serve a useful function?

A. Yes. Although we believe that the levelized analysis presented by Mr. Greig is fatally flawed, as discussed above, we believe that the use of levelized costs is a useful tool in the screening of possible alternatives to be studied in greater detail to capture the various factors noted by the Applicants.

Q. Does this complete your testimony?

A. Yes.

[133] Applicants' response to Interrogatory No. 17 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents in South Dakota Public Utilities COmission Case No. EL05-022.