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**
	)	

Supplemental Testimony of

David A. Schlissel

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

PUBLIC VERSION
TRADE SECRET INFORMATION REDACTED

DECEMBER 21, 2007

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1. Introduction

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

A. I am 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 testified previously in this Proceeding?

A. Yes. I filed testimony in this proceeding on November 17 and November 29, 2006.

Q. Have you included a current copy of your resume as an exhibit?

A. Yes. A current copy of my resume is included as Exhibit JI-35-A.

Q. What is the purpose of your supplemental testimony?

A. Synapse was retained by the Joint Intervenors to evaluate the supplemental testimony and analyses filed by the remaining Big Stone II Project Co-owners ("Applicants") in mid-November following the withdrawal of GRE and SMMPA from the Project. This testimony presents the results of our assessments of the Applicants' new testimony and analyses.

Q. Were there other members of the Synapse staff who also assisted in the analyses undertaken by Synapse as part of its evaluation of the Applicants' revised testimony and analyses?

A. Yes. Dr. David White, Bruce Biewald, Michael Drunsic, Richard Hornby, Robin Maslowski, and Robert Fagan also were members of the Synapse team for this project. Former Synapse staff member Anna Sommer also assisted me in the preparation of this testimony. Copies of their resumes are available at www.synapse-energy.com. Michael Drunsic and Robert Fagan also are filing supplemental testimony at this time.

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1. Construction of the proposed Big Stone II Project would be incompatible with the State of Minnesota's new requirements that greenhouse gas emissions be reduced below 2005 levels by 15 percent by 2015, by 30 percent by 2025 and by 80 percent by 2050.

2. Increasing numbers of proposed coal-fired power plants have been cancelled, delayed and rejected by state regulatory commissions or boards within the past year because of, or at least in large part due to, the uncertainties and risks regarding future carbon regulations and construction costs.

3. Developments in the twelve months since I last testified in this proceeding confirm the conclusion in my November 2006 testimony that the potential for future federal restrictions on CO_2 emissions and the potential for further increases in construction costs are very significant uncertainties and risks for the Big Stone II Project. However, the Applicants have not adequately considered these uncertainties and risks in the new testimony and analyses that they have submitted since GRE and SMMPA withdrew from the Project.

4. It is particularly important for the Applicants to examine their involvement in the Big Stone II Project in light of coming federal regulation of greenhouse gas emissions. It would be imprudent for the Applicants to continue their participation in the Project without fully considering the risk

of significantly higher CO_2 prices in its resource planning process. Instead of simply considering one very low CO_2 price in their analyses, the Applicants should use a broad range of possible CO_2 prices, such as the Synapse Low, Mid and High forecasts in order to more reasonably reflect uncertainty and risk.

5. Soaring power plant construction costs also will have a significant impact on the results of properly performed resource planning. Actual and estimated power plant capital costs have been strongly affected by the domestic and international competition for design and construction resources, manufacturing capacity and commodities. It would be imprudent to not allow for the possibility that these same factors which have led to the skyrocketing of power plant construction costs in recent years will continue to significantly affect project costs during the design and construction of the proposed Big Stone II Project. However, the Applicants have not prepared <u>any</u> scenarios or analyses that consider further increases in the cost of building the Big Stone II Project.

6. In their supplemental testimony and analyses, the Applicants still 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.

7. In their supplemental testimony and analyses, the Applicants still have not shown that the Big Stone II Project would be a lower cost option than renewable energy resources

For these reasons, my recommendation remains that 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 new investigations of the Applicants supplemental testimony and analyses in this proceeding.

A. We have reviewed the testimony and exhibits filed by the Applicants on November 13, 2007. Joint Intervenors also have submitted 78 information requests to the Applicants, some of which have been answered. In addition, we have reviewed the Applicants' responses to the discovery submitted by the Department of Commerce ("DOC"). We also have participated in several telephone conversations in which the Applicants graciously answered our questions. Finally, we have analyzed the modeling results presented by Otter Tail Power, MDU, CMMPA and MRES and have rerun the Strategist model for MDU, CMMPA and MRES.

Q. Does this testimony discuss MRES' new modeling analyses?

A. No. We are in the process of redoing our analysis of MRES because Mr. Schumacher has filed new Supplemental Testimony that corrected some of MRES' modeling data.

Q. Have you reviewed Heartland's new economic analyses?

A. No. Due to the expedited schedule in this proceeding we have not had time to evaluate Heartland's new economic analyses. Instead, we have focused on Otter Tail Power, MRES, CMMPA, and to a lesser extent, MDU.

2. Construction of the Big Stone II Project would be Incompatible with the State of Minnesota's Legislated Requirements for Reducing Greenhouse Gas Emissions

Q. What action has the Minnesota Legislature taken regarding future emissions of greenhouse gases?

A. In 2007, the Minnesota legislature adopted the Next Generation Energy Act of 2007, which among other things established state goals for deep greenhouse gas emission reductions for the state.[1] The state's goal is to reduce its greenhouse gas emissions by 15% by the year 2015, by 30% by 2025, and by 80% by 2050 (all below 2005 levels). The statute defines greenhouse gas emissions to include those associated with imported electricity, and would therefore count emissions associated with the Minnesota share of power generated at Big Stone II. A stakeholder process was established under the law and tasked with developing a plan to achieve these reduction goals, to be delivered to the legislature by February 1, 2008.

Q. Will construction and operation of the Big Stone II Project result in the reductions in CO_2 emissions required under the new Minnesota legislation?

A. No. The Big Stone II Project will emit between 3.7 and 4.3 million tons of CO_2 each year. This will result in increases, not decreases, in future CO_2 emissions. As a result, adding Big Stone II would be a step in the wrong direction and would be incompatible with the State of Minnesota's legislation requirements for future reductions in greenhouse gas emissions.

[1] Minn. Stat. ch. 216H.

Q. Is it reasonable to expect that the Big Stone II Project will result in the backing down or retirement of existing coal-fired power plants?

A. Not to a significant extent. The Applicants have claimed that the Big Stone II Project is needed to serve growing loads and to fill regional baseload needs.[2] That argument is inconsistent with any claim that construction of the Big Stone II Project will allow the retirement or backing down of existing coal-fired power plants.

Q. Do you have any comments about Applicant witness Uggerud's discussion of regional capacity needs?[3]

A. Yes. I have a number of comments about Mr. Uggerud's discussion of regional capacity needs.

First, I agree that serious actions need to be taken by the load serving entities, generators, state governments and the Midwest Reliability Organization ("MRO") to address possible capacity deficits. However, those actions need to be consistent with regional and state efforts to reduce CO_2 emissions and to increase the region's dependence on renewable resources. Building the Big Stone II Project, which would emit approximately 3.8 to 4.3 million tons of CO2 each year, would be a major step in the wrong direction at this time. The Commission should not be panicked into approving an uneconomic coal-fired power plant by the threat of a "looming generation capacity deficit" as suggested by Mr. Uggerud.[4]

Instead, the Commission should require that the Applicants adopt policies and alternatives that provide needed energy at the lowest cost, subject to considerations of risk. As I will explain, the Applicants have not shown that

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2 For example, see Applicants' Exhibit 114, at pages 2 through 4.
3 Applicants' Exhibit 114, at pages 2-4.
4 Id, at page 3, lines 11-14.

building a new multi-billion dollar coal plant is a less expensive and lower risk option than expanding efforts on renewable resources and energy efficiency and, where necessary, adding some efficient new gas-fired combined cycle and peaking capacity. This is especially true given the significant cost uncertainties surrounding regulation of greenhouse gas emissions and the ultimate cost and completion date of the Big Stone II Project.

Second, the North American Electric Reliability Corporation ("NERC") assessment cited by Mr. Uggerud only shows that additional capacity is needed during the peak summer hours. It does not show whether that additional capacity should be peaking capacity, intermediate capacity or baseload capacity. The Applicants' flawed and biased new modeling analyses are the only evidence that has been presented to show that adding new baseload generating capacity is the most economic option.

Third, there is no evidence that the capacity and load information in the NERC Long-Term Assessment relied upon by Mr. Uggerud reflects any of the many changes that are occurring in the region regarding energy usage and the types of capacity that will be needed. These changes include the new Minnesota statute establishing a statewide goal of achieving annual savings of 1.5 percent of retail energy sales of electricity and natural gas,[5] the new Minnesota Renewable Energy Objective Statute,[6] efforts in other states to reduce energy and capacity demands and to increase the amounts of electricity generated from renewable energy resources, actions at the federal level such as the recent adoption of new appliance standards as part of the new energy bill, developments in the MISO energy markets, and the development by MISO of rules allowing the participation of demand response resources in the ancillary services markets.

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[5] Minn. Stat. Sec. 216B.241 subd. 1c and Minn. Stat. Sec. 216B.2401.
[6] Minn. Stat. Sec. 216B.1691.

For example, when it announced its withdrawal from the Big Stone II Project in September 2007, Great River Energy cited the following as one of the reasons for its decision to leave the Project:

> The cost of Big Stone II has increased due to inflation and project delays. Although the costs of alternative resources have also increased, Great River Energy now anticipates the energy markets through the Midwest Independent System Operator (MISO), will provide access to additional lower-cost alternatives than initially assumed.[7]

Another significant new development is the agreement by nine states in the region, working together through the Midwest Governors Association, to adopt the goal of meeting at least 2 percent of regional annual retail sales of electricity through energy efficiency improvements by 2015, with additional savings in subsequent years, and adopted regional renewable energy goals of 10% by 2015, 20% by 2020, 25% by 2025, and 30% by 2030.[8] All of these changes will affect how much new capacity will be needed and what capacity will be the most economic to add.

Fourth, as Xcel Energy has explained in its recently filed 2007 Resource Plan, analyses are currently underway that may result in reduced regional reserve requirements:

> We currently plan to obtain sufficient capacity to meet all of our projected needs plus a 15% MAPP reserve margin. In the past year, there has been much discussion and change among Midwest utilities with respect to reserve margins . . . MRO is in the process of developing new resource adequacy standards for our region that will likely go into effect toward the end of 2008. . . early indications are that the reserve margin resulting from this [LOLE] study will be lower than the 15% reserve margin currently

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7 Great River Energy September 17, 2007 press release available at: http://www.greatriverenergy.com/press/news/091707_big_stone_ii.html

8 Midwest Governors Association, "Energy Security and Climate Stewardship Platform for the Midwest, 2007," Nov. 15, 2007. The Platform was agreed to by Indiana, Illinois, Iowa, Kansas, Michigan, Minnesota, Ohio, South Dakota, Wisconsin and the province of Manitoba.

> required. However, the MDC ratings of units are also lower than our URGE ratings . . . we expect an overall reduction in our planning reserve requirement but do not yet have enough information to calculate an estimate. In order to evaluate the impact of changing reserve margins on our future resource requirements, we evaluated our Resource Plan using reserve margins of 12% and 15% based on our median (50/50) peak forecast and our unit MDCs.[9]

Q. Is it possible that adding new baseload generating capacity could be the more economic option even if the capacity is not needed for system reliability or if there is only a need for peaking capacity?

A. Yes. It is possible that the addition of a new baseload generating facility can be the lowest cost option even if all of the capacity from that facility is not immediately needed to ensure that an adequate level of system reliability. However, as I will explain later in this testimony, the new modeling analyses presented by the Applicants are flawed and biased in favor of the Big Stone II Project and, therefore, do not represent credible evidence that the Project is the lowest cost option available to the Applicants.

Q. Is it even certain that the Big Stone II Project will be in service by 2013?

A. No. Completion of the Project in 2013 is not guaranteed. The recent experience of numerous other coal-fired power plant construction projects suggests that the completion of the Big Stone II Project will occur later and cost far more than the Applicants now admit.

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[9] Northern States Power Company, *2007 Resource Plan*, Docket No. E002/RP-07__, December 14, 2007, at pages 4-4 and 4-5.

Q. Mr. Uggerud expresses concern about relying "solely on natural gas, conservation or renewable energy instead" and "over-reliance on natural gas."[10] Are you recommending that the Applicants rely "solely" on natural gas, conservation or renewable energy?

A. No. I am recommending that the Applicants investigate and implement portfolios of alternatives to the Big Stone II Project that would include energy efficiency, more renewable resources, and, to the most limited extent necessary, the addition of new natural gas-fired capacity. In fact, regardless of what happens with the Big Stone II Project, the Applicants still will maintain their existing coal-fired facilities. So we are not recommending that any of them rely "solely' on natural gas, conservation or renewable energy.

Q. Do you agree with Mr. Uggerud that over-reliance on natural gas is a concern?

A. In general, I do agree that over-reliance on natural gas can be a concern. However, in this specific instance and in this specific area of the nation, it does not appear that the MRO would be overly reliant on natural gas if the Commission rejected the Applicants request to build the Big Stone II Project.

Figures 1 and 2 below are taken from the same NERC *2007 Long-Term Assessment Reliability Assessment 2007-2016*. These Figures show that in 2006, the region's generating capacity was 55 percent coal-fired and only 12 percent gas-fired (24 percent if gas-fired capacity and dual fuel capacity are considered together). It further shows that in 2012, the region's generating capacity will still be 55 percent coal-fired and only 13 percent gas-fired (still 24 percent if gas-fired and dual fuel are considered). The replacement of the Big Stone II Project, in part, by natural gas-fired capacity will not significantly change these figures. Thus, there is no real danger of over-reliance on natural gas in the upper Midwest.

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10 Applicants' Exhibit 114, at page 12, lines 14-18.

There could be a concern in other regions of the nation but not in the upper Midwest.

Figure 1: MRO Capacity Fuel Mix 2006

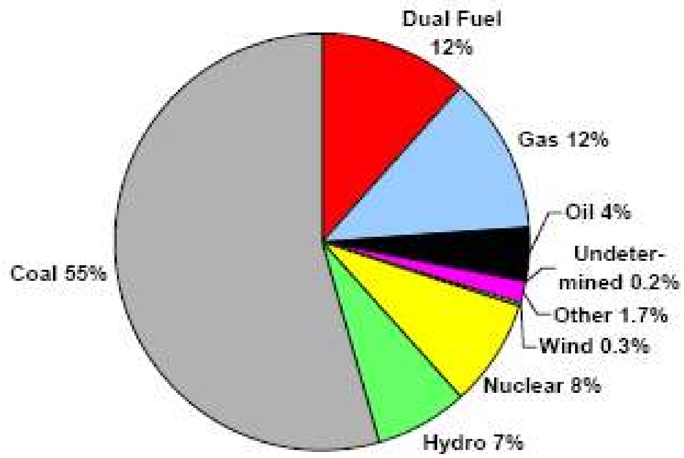
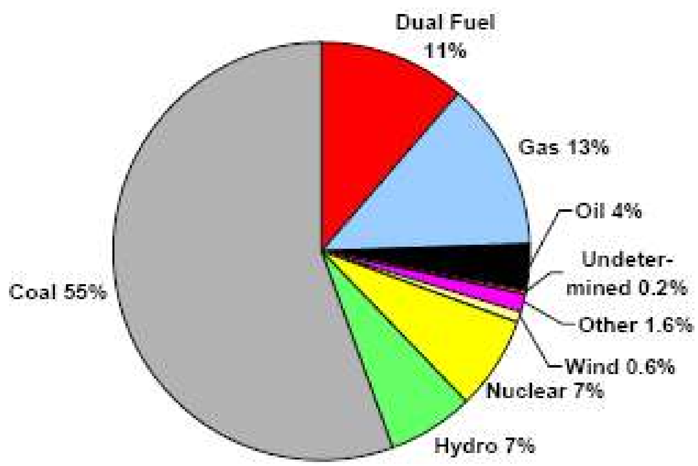


Figure 2: MRO Capacity Fuel Mix 2012



3. The Applicants Have Not Adequately Considered The Risks Associated With Building A New Coal-Fired Generating Unit

Q. Last year you testified that the Applicants had failed to adequately consider the risks associated with evaluating the economics of building the proposed Big Stone II Project. Is that still your conclusion after reviewing the supplemental testimony and analyses prepared by the Applicants this past fall after GRE and SMMPA withdrew from the Project?

A. Yes.

Q. You testified in Joint Intervenors Exhibit 3 that the potential for future restrictions on CO_2 emissions and the potential for large increases in the project's capital cost were the most significant uncertainties and risks facing the Big Stone II Project. Do these remain the most significant uncertainties and risks for the Project?

A. Yes. Developments over the past twelve months since I presented my November 29, 2006 testimony in this proceeding confirm and re-emphasize that the potential for future restrictions on CO_2 emissions and the potential for large increases in capital costs are very significant uncertainties and risks associated with building and operating new coal-fired generating plants like the proposed the Big Stone II Project.

I also want to note that there also are other potential uncertainties and risks for new coal plants. These other uncertainties and risks include the potential for higher fuel prices, fuel supply disruptions that could affect plant operating performance; the potential for increasing stringency of regulations of current criteria pollutants; and the potential for expanded state and/or federal energy efficiency and renewable energy requirements.

Q. What consideration have the Applicants given in their supplemental testimony to the risks associated with restrictions on future CO_2 emissions and capital cost increases?

A. The Applicants have only given very limited consideration to the risks associated with future CO_2 emissions and further Project construction cost increases and delays. For example, Otter Tail Power, MRES and CMMPA did assume a CO_2 price in their new modeling analyses. However, they each assumed that CO_2 prices would not exceed $9/ton, in nominal terms. As before, MDU did not assume any CO_2 prices in its new analyses (that is, MDU assumed that CO2 emissions have a zero price associated with them). None of the Applicants examined the impact of higher CO2 prices on the relative economics of the Big Stone II Project .

Similarly, in their new analyses each Applicant used the October 2006 Big Stone II Project capital cost estimate, updated to reflect an additional year of delay, [**TRADE SECRET MATERIALS BEGINS TRADE SECRET MATERIALS END]** in unspecified savings, and scaling down to smaller plant sizes. However, none of the Applicants conducted any sensitivity studies to consider the impact of further increases in the cost of building the proposed Project. Nor did the Applicants conduct any sensitivity studies to consider the impact of additional schedule delays on the relative economics of Big Stone II against alternative plans that included wind and energy efficiency. In fact, there is no evidence that the Applicants even have asked Black & Veatch to update its 2006 analysis of project costs and schedule.

Q. Is this a reasonable approach?

A. No. Higher CO_2 prices and increased Project construction costs or additional schedule delays, on their own or in combination, will impact the Project's economics relative to other alternatives and may make the proposed Big Stone II Project uneconomic for one or more of the Applicants. The important reason to prepare sensitivities is to determine what changes in CO_2 prices and/or construction costs would make the Project uneconomic and then to evaluate how likely those changes are. Unfortunately, the Applicants did not prepare these critical analyses. Instead, they have assumed that the current plant construction cost estimate and a flat $9/ton CO_2 price are the highest reasonable values. This is imprudent. Risk and uncertainty are inherent in all enterprises. They do not go away merely because they are ignored in economic analyses.

Q. Have other companies provided sensitivity analyses for key input parameters in their Integrated Resource Plans or in the modeling analyses presented in support of requests to build and operate new generating facilities?

A. Yes. We have seen such sensitivity analyses for key input parameters in many of the power plant cases in which we have been involved in recent years.

Q. Have you seen any recent instances in which companies have decided not to undertake new coal-fired power plants because of concerns over increasing construction costs and/or the potential for federal regulation of greenhouse gas emissions?

A, Yes. In just the past few months, a number of companies have announced that they will not pursue new coal-fired generating facilities. For example, in its Resource Plan filed in Colorado in November 2007, Xcel Energy concluded that:

> In sum, in light of the now likely regulation of CO_2 emissions in the future due to a broader interest in climate change issues, the increased costs of constructing new coal facilities, and the increased risk of timely permitting to meet planned in-service dates, Public Service does not believe it would be prudent to consider at this time any proposals for new coal plants that do not include CO_2 capture and sequestration.[11]

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[11] Public Service Company of Colorado, *2007 Colorado Resource Plan*, Volume 2 Technical Appendix, at page 2-34.

In its recently filed 2007 Resource Plan in Minnesota, Xcel Energy similarly noted that "given the likelihood of future carbon regulation, we have only modeled a future coal-based resource option that includes carbon capture and storage."[12] Xcel Energy also noted in its 2007 Minnesota Resource Plan that "Adding coal resources without sequestration would significantly add carbon and risk for our ratepayers."[13]

Minnesota Power Company also has announced that it is considering only carbon minimizing resources and would not consider a new coal resource without a carbon solution.[14] The Company also said that in the long-term it would consider pulverized coal and IGCC plants but only with proven carbon capture and CO_2 sequestration technologies.[15]

Idaho Power Company similarly has concluded that:

> Due to escalating construction costs, the transmission cost associated with a remotely located resource, potential permitting issues, and continued uncertainty surrounding GHG laws and regulations, IPC [Idaho Power Company] has determined that coal-fired generation is not the best technology to meet its resource needs in 2013. IPC has shifted its focus to the development of a natural gas-fired combined cycle combustion turbine located closer to its load center in southern Idaho.[16]

Avista Utilities also has announced that it will not pursue coal-fired power plants in the foreseeable future.

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12 Northern States Power Company, *2007 Resource Plan*, Docket No. E002/RP-07__, December 14, 2007, at page 4-1.
13 Id, at page 11-9.
14 *Petition for Approval, Minnesota Power's 2008 Resource Plan*, Minnesota Public Utilities Commission Docket No. E015/RP-07-1357, dated October 31, 2007, at page 5.
15 Id, at page 6.
16 U.S. Securities and Exchange Commission Form 10-Q, Third Quarter of 2007, Idaho Power Company, at pages 49-50.

Q. Have any proposed coal-fired generating projects been cancelled or delayed as a result of concern over increasing construction costs or the potential for federal regulation of greenhouse gas emissions?

A. Yes. According to published reports, approximately 20 coal-fired power plant projects have been cancelled or rejected by state regulatory commissions or boards in the past twelve months and more than three dozen others have been delayed, in part, because of concern over rising construction costs and climate change. For example:

- Rocky Mountain Power, a division of PacifiCorp, has just cancelled two proposed coal plants. The Company explained the following in a November 28, 2007 letter to the Public Service Commission of Utah:

  > Furthermore, due to the current uncertainty in the ability to quantify in any meaningful way the cost of compliance with potential federal CO2 legislation, Bridger 5 as a supercritical unit is no longer a viable option for 2014. Within the last few months, it has become apparent that Congress will enact some restriction upon carbon emissions, but the project cost impact upon new coal generation is currently within such a wide range as to make meaningful risk assessment futile. On November 13, 2007, the National Association of Regulatory Utility Commissioners adopted its first resolution acknowledging that climate change legislation addressing carbon emissions will occur. Within the last few months, most of the planned coal plants in the United States have been cancelled, denied permits, or been involved in protracted litigation. Accordingly, the Company submits that IPP 3, Bridger 5, and the IGCC option at Jim Bridger are no longer viable options for [its] 2012 RFP for the 2012 and 2014 time frame, respectively.
  >
  > **While the Company is not excluding new coal generation ownership from its 20 year options, absent some change in conditions, it cannot be determined at this time whether new coal generation will satisfy the least cost, least risk standards that would enable us to consider it as a viable option within our ten year plans.** (Emphasis added)[17]

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[17] A copy of this letter is attached as Exhibit JI-35-B.

- Xcel Energy announced in October 2007 that it was deferring indefinitely its plans to build an IGCC plant in Colorado because the development costs were higher than the utility originally expected.[18]

- Tenaska Energy cancelled plans to build a coal-fired power plant in Oklahoma in July 2007 because of rising steel and construction prices. According to the Company's general manager of business development:

  ".. coal prices have gone up "dramatically" since Tenaska started planning the project more than a year ago.

  And coal plants are largely built with steel, so there's the cost of the unit that we would build has gone up a lot… At one point in our development, we had some of the steel and equipment at some very attractive prices and that equipment all of a sudden was not available.

  We went immediately trying to buy additional equipment and the pricing was so high, we looked at the price of the power that would be produced because of those higher prices and equipment and it just wouldn't be a prudent business decision to build it."[19]

- Westar Energy announced in December 2006 that it was deferring site selection for a new 600 MW coal-fired power plant due to significant increases in the facility's estimated capital cost of 20 to 40 percent, over just 18 months. This prompted Westar's Chief Executive to warn: "When equipment and construction cost estimates grow by $200 million to $400 million in 18 months, it's necessary to proceed with caution."[20] As a result, Westar Energy has suspended site selection for the coal-plant and is considering other options, including building a natural gas plant, to meet growing electricity demand. The company also explained that:

  > most major engineering firms and equipment manufacturers of coal-fueled power plant equipment are at full production capacity and yet are not indicating any plans to significantly increase their production capability. As a result, fewer manufacturers and suppliers are bidding on

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[18] Denver Business Journal, October 30, 2007.
[19] Available at www.swtimes.com/articles/2007/07/09/news/news02.prt.
[20] Available at http://www.westarenergy.com/corp_com/corpcomm.nsf/F6BE1277A768F0E4862572690055581C/$file/122806%20coal%20plant%20final2.pdf.

new projects and equipment prices have escalated and become unpredictable.[21]

- TXU cancelled 8 of 11 proposed coal-fired power plants in the spring of 2007 , in large part because of concern over global warming and the potential for federal legislation restricting greenhouse gas emissions.[22]
- Four public power agencies suspended permitting activities for the coal-fired Taylor Energy Center in the spring of 2007 because of growing concerns about greenhouse gas emissions.[23]
- Tampa Electric cancelled a proposed integrated gasification combined cycle plant ("IGCC") in the fall of 2007 due to uncertainty related to CO_2 regulations, particularly capture and sequestration issues, and the potential for related project cost increases. According to a press release, "Because of the economic risk of these factors to customers and investors, Tampa Electric believes it should not proceed with an IGCC project at this time," although it remains steadfast in its support of IGCC as a critical component of future fuel diversity in Florida and the nation.
- The Orlando Utilities Commission announced in November 2007 that it was the coal gasification portion of a 285-megawatt integrated gasification combined cycle (IGCC) facility at the Stanton Energy Center. Construction will continue on the natural gas-fired combined cycle generating unit. The Commission cited the impact of possible federal and state regulations related to future emissions restrictions in the state of Florida as the primary reason for terminating construction.[24]
- In June 2007, the Tondu Corp. announced that it was suspending plans to build a planned 600 MW IGCC facility in Texas citing high costs and other concerns related to technology and construction risks.[25]

Q. Have you seen any instance where a participant in a jointly-owned coal-fired power plant project has withdrawn because of concern over increasing construction costs or the potential for future regulation of CO_2 emissions?

A. Yes. GRE announced in September 2007 that it was withdrawing from the proposed Big Stone II Project. According to GRE, four factors contributed most

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[21] Id.
[22] See www.marketwatch.com/news/story/txu-reversal-coal-plant-emissions.
[23] See www.taylorenergycenter.org/s_16asp?n=40.
[24] http://www.ouc.com/news/releases/20071114-secb.htm.
[25] http://www.reuters.com/article/companyNewsAndPR/idUSN1526955320070615

prominently to the decision to withdraw, including uncertainty about changes in environmental requirements and new technology and the fact that "The cost of Big Stone II has increased due to inflation and project delays."[26] GRE also cited the new Minnesota legislation which established the dual goals of using renewable resources for 25 percent of its load by 2025 and achieving a 1.5 reduction in annual energy sales through conservation measures.

Q. Have any proposed coal-fired generating projects been rejected by state regulatory commissions due, in whole or in part, to concerns over increasing construction costs or the potential for federal regulation of greenhouse gas emissions?

A. Yes. Although some new coal-fired power plant projects have been approved by state regulatory commissions and agencies during 2007, since last December proposed coal-fired power plant projects have been rejected by the Oregon Public Utility Commission, the Florida Public Service Commission, and the Oklahoma Corporation Commission. The North Carolina Utilities Commission rejected one of the two coal-fired plants proposed by Duke Energy Carolinas for its Cliffside Project. The Kansas Department of Health and Environment also has recently rejected proposed coal-fired power plants.

The decision of the Florida Public Service Commission in denying approval for the 1,960 MW Glades Power Project was based on concern over the uncertainties over plant costs, coal and natural gas prices, and future environmental costs, including carbon allowance costs.[27] In addition, the Oklahoma Corporation Commission voted in September of this year to reject Public Service of Oklahoma's application to build a new coal-fired power plant.[28]

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26 See www.greatriverenergy.com/press/news/091707_big_stone_ii.html.
27 Order No. PSC-07-0557-FOF-EI, Docket No. 070098-EI, July 2, 2007.
28 Cause No. PUD 200700012 signed Order No. 545240, October 2007.

The Minnesota Public Utilities Commission also has refused to approve an agreement under which Xcel Energy would have purchased power from a proposed IGCC facility due to concerns over the uncertainties surrounding the plant's estimated construction and operating costs and operating and financial risks.[29]

On October 18, 2007, the Kansas Department of Health and Environment rejected an application to build two 700 MW coal-fired units at an existing power plant site. In a prepared statement explaining the basis for this decision, Rod Bremby, Kansas's secretary of health and environment noted that "I believe it would be irresponsible to ignore emerging information about the contribution of carbon dioxide and other greenhouse gases to climate change and the potential harm to our environment and health if we do nothing."[30]

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 energy efficiency also have some uncertainties and risks. These include potential capital cost escalation, contract uncertainty and customer participation uncertainty.

Unfortunately, the Applicants have focused on the uncertainties and risks associated with the alternatives and have essentially ignored the significant uncertainties and risks associated with pursuing the Big Stone II Project.

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[29] Order in Docket No. E-6472/M-05-1993, dated August 30, 2007, at pages 16-19.
[30] See www.kansascity.com/105/story/323833.html.

4. The Big Stone II Applicants Have Not Adequately Considered The Risks Associated With Future Federally Mandated Greenhouse Gas Reductions

Q. What mandatory greenhouse gas emissions reductions programs are currently under review in the U.S. federal government?

A. To date, the U.S. government has not required greenhouse gas emission reductions. However, a number of legislative initiatives for mandatory emissions reduction proposals have been introduced in Congress. These proposals establish carbon dioxide emission trajectories below the projected business-as-usual emission trajectories, and they generally rely on market-based mechanisms (such as cap and trade programs) for achieving the targets. The proposals also include various provisions to spur technology innovation, as well as details pertaining to offsets, allowance allocation, restrictions on allowance prices and other issues. The federal proposals that would require greenhouse gas emission reductions that had been submitted in the current U.S. Congress are summarized in Table 1 below.

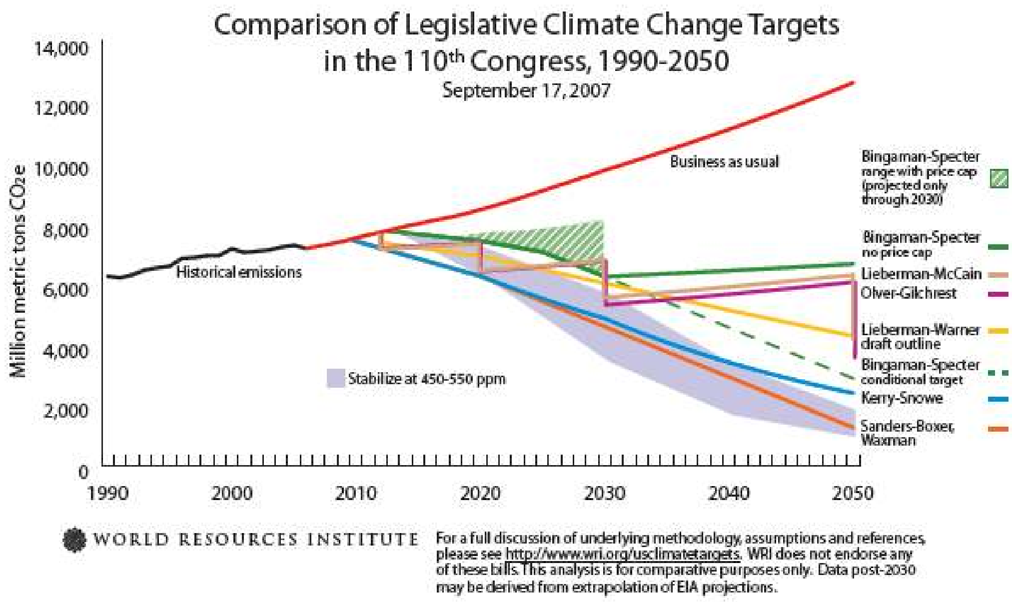
Table 1. Summary of Mandatory Emissions Targets in Proposals Discussed in the current U.S. Congress[31]

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
Feinstein- Carper S.317	Electric Utility Cap & Trade Act	2007	2006 level by 2011, 2001 level by 2015, 1%/year reduction from 2016-2019, 1.5%/year reduction starting in 2020	Electricity sector
Kerry-Snowe	Global Warming Reduction Act	2007	2010 level from 2010-2019, 1990 level from 2020-2029, 2.5%/year reductions from 2020-2029, 3.5%/year reduction from 2030-2050, 65% below 2000 level in 2050	Economy-wide
McCain-Lieberman S.280	Climate Stewardship and Innovation Act	2007	2004 level in 2012, 1990 level in 2020, 20% below 1990 level in 2030, 60% below 1990 level in 2050	Economy-wide
Sanders-Boxer S.309	Global Warming Pollution Reduction Act	2007	2%/year reduction from 2010 to 2020, 1990 level in 2020, 27% below 1990 level in 2030, 53% below 1990 level in 2040, 80% below 1990 level in 2050	Economy-wide
Olver, et al HR 620	Climate Stewardship Act	2007	Cap at 2006 level by 2012, 1%/year reduction from 2013-2020, 3%/year reduction from 2021-2030, 5%/year reduction from 2031-2050, equivalent to 70% below 1990 level by 2050	US national
Bingaman–Specter S.1766	Low Carbon Economy Act	2007	2012 levels in 2012, 2006 levels in 2020, 1990 levels by 2030. President may set further goals ≥60% below 2006 levels by 2050 contingent upon international effort	Economy-wide
Lieberman-Warner S. 2191	America's Climate Security Act	2007	2005 level in 2012, 1990 level in 2020, 65% below 1990 level in 2050	U.S. electric power, transportation, and manufacturing sources.

The emissions levels that would be mandated by the bills that have been introduced in the current Congress are shown in Figure 3 below:

31 More detailed summaries of the bills that have been introduced in the U.S. Senate in the 110th Congress are presented in Exhibit JI-35-C.

Figure 3: Emissions Reductions Required under Climate Change Bills in Current US Congress



The shaded area in Figure 3 above represents the 60% to 80% range of emission reductions from current levels that leading scientists now believe will be necessary to stabilize atmospheric CO_2 concentrations by the middle of this century.

Q. Are individual states also taking actions to reduce greenhouse gas emissions?

A. Yes. A number of states are taking significant actions to reduce greenhouse gas emissions, both individually and as part of regional efforts.

For example, Table 2 below lists the emission reduction goals that have been adopted by states in the U.S. Regional action also has been taken in the Northeast, Midwest and Western regions of the nation.

Table 2: Announced State and Regional Greenhouse Gas Emission Reduction Goals

State	GHG Reduction Goal	Western Climate Initiative member (15% below 2005 levels by 2020)	Regional Greenhouse Gas Initiative member (Cap at current levels 2009-2015, reduce this by 10% by 2019)	Midwestern Greenhouse Gas Accord
Arizona	2000 levels by 2020; 50% below 2000 levels by 2040	yes		
California	2000 levels by 2010; 1990 levels by 2020; 80% below 1990 levels by 2050	yes		
Connecticut	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 2001 levels in the long term		yes	
Delaware			yes	
Florida	2000 levels by 2017, 1990 levels by 2025, and 80 percent below 1990 levels by 2050			
Hawaii	1990 levels by 2020			
Illinois	1990 levels by 2020; 60% below 1990 levels by 2050			yes
Iowa				yes
Kansas				yes
Maine	1990 levels by 2010; 10% below 1990 levels by 2020; 75-80% below 2003 levels in the long term		yes	
Maryland			yes	
Massachusetts	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 1990 levels in the long term		yes	
Michigan				yes
Minnesota	15% by 2015, 30% by 2025, 80% by 2050			yes
New Hampshire	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 2001 levels in the long term		yes	
New Jersey	1990 levels by 2020; 80% below 2006 levels by 2050		yes	
New Mexico	2000 levels by 2012; 10% below 2000 levels by 2020; 75% below 2000 levels by 2050	yes		
New York	5% below 1990 levels by 2010; 10% below 1990 levels by 2020		yes	
Oregon	Stabilize by 2010; 10% below 1990 levels by 2020; 75% below 1990 levels by 2050	yes		
Rhode Island	1990 levels by 2010; 10% below 1990 levels by 2020; 75-80% below 2001 levels in the long term		yes	
Utah		yes		
Vermont	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 2001 levels in the long term		yes	
Washington	1990 levels by 2020; 25% below 1990 levels by 2035; 50% below 1990 levels by 2050	yes		
Wisconsin				yes

A number of regional efforts to reduce greenhouse gas emissions also have been undertaken since I testified last December. For example, on February 26, 2007, the Governors of Arizona, California, New Mexico, Oregon and Washington announced the formation of the Western Regional Climate Action Initiative to implement a join strategy to reduce greenhouse gas emissions. The initiative is to include (1) developing a regional target for reducing greenhouse gases, (2) developing a market-based program such as a cap-and-trade system and (3) participating in a multi-state greenhouse gas registry.[32]

In addition, in November of this year, the Governors of the six Midwestern states, including Minnesota, Illinois, Iowa, Kansas, Michigan and Wisconsin, and the Premier of Manitoba signed the Midwestern Greenhouse Gas Accord. This agreement committed the states to establishing greenhouse gas emissions targets and timetables, to developing a market based and multi-sector cap-and-trade mechanism to achieve those reduction targets, to developing a regional registry and tracking mechanism, and to developing and implementing additional steps as needed to achieve the reduction targets.[33] The Governors of Indiana, Ohio and South Dakota also signed the agreement as observers to participate in the formation of a regional cap-and-trade system.

Q. Have recent polls indicated that the American people are increasingly in favor of government action to address global warming concerns?

A. Yes. Polls indicate an understanding by the public of the challenge of climate change and strong support in the U.S. for governmental response to the threat.

For example, a summer 2006 poll by Zogby International showed that an overwhelming majority of Americans are more convinced that global warming is happening than they were even two years ago. In addition, Americans also are

[32] "Five Western Governors Announce Regional Greenhouse Gas Reduction Agreement," press release dated February 26, 2007.

connecting intense weather events like Hurricane Katrina and heat waves to global warming.[34] Indeed, the poll found that 74% of all respondents, including 87% of Democrats, 56% of Republicans and 82% of Independents, believe that we are experiencing the effects of global warming.

The poll also indicated that there is strong support for measures to require major industries to reduce their greenhouse gas emissions to improve the environment without harming the economy – 72% of likely voters agreed such measures should be taken.[35]

Other recent polls reported similar results. For example, a recent Stanford University/Associated Press poll found that 84 percent of Americans believe that global warming is occurring, with 52 percent expecting the world's natural environment to be in worse shape in ten years than it is now.[36] Eighty-four percent of Americans wanted a great deal or a lot to be done to help the environment by President Bush, the Congress, American businesses and/or the American public. This represents ninety-two percent of Democrats and seventy-seven percent of Republicans.

At the same time, according to a 2006 public opinion survey for the Massachusetts Institute of Technology, Americans now rank climate change as the country's most pressing environmental problem—a dramatic shift from three years ago, when they ranked climate change sixth out of 10 environmental concerns.[37] Almost three-quarters of the respondents felt the government should

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33 http://www.midwesterngovernors.org/resolutions/GHGAccord.pdf.

34 "Americans Link Hurricane Katrina and Heat Wave to Global Warming," Zogby International, August 21, 2006, available at www.zogby.com/news.

35 Id.

36 *The Second Annual "America's Report Card on the Environment" Survey by the Woods Institute for the Environment at Stanford University in collaboration with The Associated Press,* September 25, 2007.

37 *MIT Carbon Sequestration Initiative, 2006 Survey,* http://sequestration.mit.edu/research/survey2006.html

do more to deal with global warming, and individuals were willing to spend their own money to help.

Q. Have any of the Big Stone II Project Applicants assessed the potential impact of the climate change bills currently being considered in Congress on future CO_2 emissions allowance prices?

A. MRES appears to be following developments concerning federal regulation of greenhouse gases. However, I have not seen any evidence that the Applicants have attempted to quantify what are likely ranges for future CO_2 emissions allowance prices.

Q. What CO_2 prices have Otter Tail Power, MRES and CMMPA used in the supplemental modeling analyses of the Big Stone II Project that they have performed after GRE and SMMPA withdrew from the Project?

A. Otter Tail Power, MRES and CMMPA each used a nominal $9/ton CO_2 price in their new modeling analyses. This means that they assumed that the prices of CO_2 emissions allowances would not increase over time even with inflation. To the contrary, each of these Applicants has assumed that the real prices of CO_2 emissions allowances will decrease over time.

Q. What CO_2 price has MDU used in its recent modeling analyses of the Big Stone II Project?

A. MDU has not used any CO_2 price in its recent modeling analyses.

Q. What was the basis for the $9/ton CO_2 price used by OTP, MRES and CMMPA in their recent modeling analyses?

A. The Applicants witnesses have said that the have used a $9/ton based on a recommendation by the Department of Commerce concerning interim CO2 prices to be used for resource planning until the Minnesota Commission adopts a final set of required CO_2 prices.[38] It is my understanding that this $9/ton figure initially came from a 2003 settlement reached by Xcel Energy concerning the proposed Comanche power plant in Colorado.

Q. Is the manner in which OTP, MRES and CMMPA have applied the $9/ton CO_2 cost consistent with how Xcel Energy has used that price?

A. No. Xcel Energy has escalated the $9/ton price at the rate of inflation starting in the year 2010. As a result, the price remained constant in 2010 dollars. As I noted above, OTP, MRES and CMMPA have applied a $9/ton cost starting in 2013 and have not increased that cost in line with inflation. Consequently, the CO_2 prices that were used in the past by Xcel Energy subsequent to the Comanche Settlement were substantially higher than the CO_2 prices now being used by OTP, MRES and CMMPA.

Q. Does Xcel Energy now use the $9/ton CO2 price, escalated at the rate of inflation, in its resource planning?

A. Xcel Energy now uses a range of CO_2 prices in its recent planning, with a mid case of $20/ton starting in 2010 and escalating at 2.5 percent per year and high and low scenarios of $9/ton and $40/ton also starting in 2010 and escalating at the rate of inflation.[39]

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[38] See, for example, Applicants' Exhibit 116, at page 16, lines 13-14.
[39] Northern States Power Company, *2007 Resource Plan*, Docket No. E002/RP-07__, December 14, 2007, at page 4-4.

Q. Are the $9/ton CO_2 price forecasts used by Otter Tail Power, MRES and CMMPA in their new modeling analyses of the Big Stone II Project reasonable in light of the uncertainty surrounding future CO_2 costs and the stringent reductions in CO_2 emissions that would be required under the global warming bills that have been introduced in the current U.S. Congress?

A. No. As Xcel Energy indicates, a $9/ton CO_2 price may be reasonable as the lower end of a broad range of CO_2 prices being considered in resource planning analyses. But it not reasonable as the <u>highest</u> CO_2 price to use when developing a least cost, least risk resource plan. Given all of the uncertainties surrounding future greenhouse gas regulations and costs, it is prudent to consider a broad range of CO_2 price forecasts in resource planning, not just a single price trajectory or the narrow range of prices between $0/ton and $9/ton.

Also, the $9/ton CO_2 prices assumed by the Applicants in their new modeling analyses do not provide a significant economic incentive for the development and retrofitting of carbon capture and sequestration technologies on coal plants like Big Stone II because that price would be substantially below the currently estimated costs of carbon capture and sequestration.

Q. How do the CO_2 prices used by Otter Tail Power, CMMPA and MRES compare to the expected prices of CO_2 emissions allowances under the legislation currently being considered in the U.S. Congress?

A. Figure 4 below compares the CO_2 prices used by OTP, MRES and CMMPA in their new modeling analyses to the projected prices of CO_2 emissions allowances developed in recent studies of the prices that would be needed to achieve the emissions reduction targets in global warming legislation that has been introduced in the current Congress. These studies include:

- Analyses of Senate Bill S.280, the current McCain-Lieberman proposal, by the U.S. Environmental Protection Agency ("EPA") and the Energy Information Administration of the U.S. Department of Energy ("EIA").[40] The EPA examined seven different scenarios reflecting a range of assumptions concerning such important factors as the levels of offsets that would be allowed and the assumed levels of nuclear generation. The EIA examined eight different scenarios. Figure 5 shows the range of levelized costs in the scenarios studied by the EPA and the EIA.
- An Assessment of U.S. Cap-and-Trade Proposals was recently issued by the MIT Joint Program on the Science and Policy of Global Change. This Assessment evaluated the impact of the greenhouse gas regulation bills that are being considered in the current Congress. [41] The range of CO_2 costs for the three core scenarios studied by MIT are shown in Figure 5. These three scenarios analyzed (1) a reduction of greenhouse gas emissions of 80 percent from current levels by 2050; (2) a reduction of greenhouse gas emissions of 50 percent from current levels by 2050; and (3) stabilization of CO_2 emissions at year 2008 levels.
- The safety valve prices in Senate Bill S. 1766, the Low Carbon Economy Act introduced in July 2007 by Senators Bingaman and Specter. The safety valve price in this proposal starts at $12/ton in 2012 and escalates at a real rate of 5 percent per year.

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[40] *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007,* Energy Information Administration, July 2007, Supplement to the Energy and Markets Impacts of S. 280, Energy Information Administration, October 2007, and *EPA Analysis of the Climate Stewardship and Innovation Act of 2007, S. 280 in 110th Congress*, July 16, 2007.

[41] Twenty nine scenarios were modeled in the April 2007 MIT *Assessment of U.S. Cap-and-Trade Proposals*. These scenarios reflected differences in such factors as emission reduction targets (that is, reduce CO_2 emissions 80% from 1990 levels by 2050, reduce CO_2 emissions 50% from 1990 levels by 2050, or stabilize CO_2 emissions at 2008 levels), whether banking of allowances would be allowed, whether international trading of allowances would be allowed, whether only developed countries or the U.S. would pursue greenhouse gas reductions, whether there would be safety valve prices adopted as part of greenhouse gas regulations, and other factors.

In general, the ranges of the projected CO_2 prices in these scenarios were higher than the range of CO_2 prices in the Synapse forecast. For example, twelve of the 29 scenarios modeled by MIT projected higher CO_2 prices in 2020 than the high Synapse forecast. Fourteen of the 29 scenarios (almost half) projected higher CO_2 prices in 2030 than the high Synapse forecast. The full results of the MIT study are presented as Exhibit JI-35-D.

Figure 4: The CO_2 Prices Used by OTP, MRES and CMMPA Compared to the Expected Prices Under Legislation in the Current Congress and the Synapse CO_2 Price Forecasts

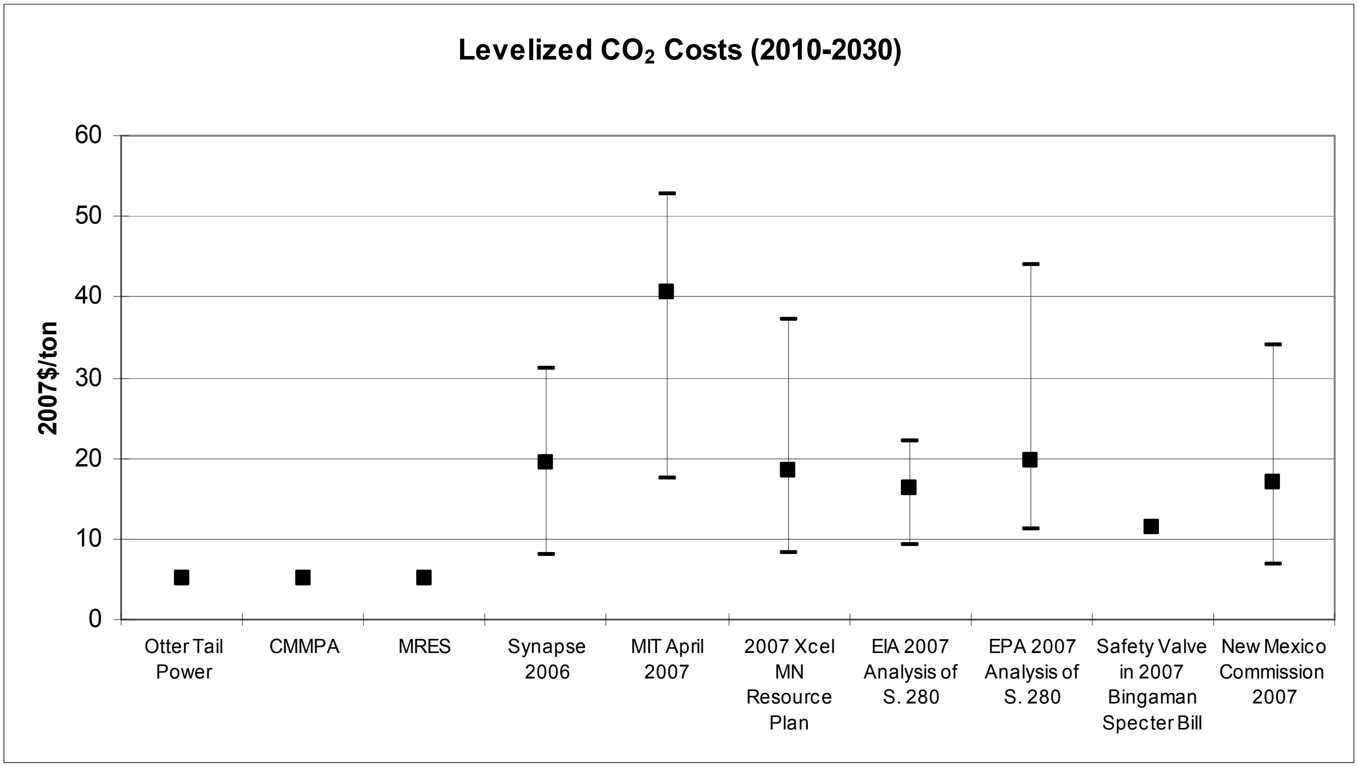

Figure 4 also includes the range of CO_2 prices that Xcel Energy has announced that it will use for resource planning[42] and the range of CO_2 prices that the New Mexico Public Regulation Commission has directed that utilities use in their electric resource planning.[43] Finally, Figure 4 includes, on a levelized basis, the Synapse forecasts of CO_2 prices that I presented in this proceeding in late 2006 in Joint Intervenors Exhibits 1 and 3.[44]

Thus, on a levelized basis, the CO_2 prices used by OTP, MRES and CMMPA are lower than even the lower ends of the ranges of CO_2 prices forecast by the EPA,

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[42] Public Service Company of Colorado, *2007 Colorado Resource Plan*, Volume 2 Technical Appendix, at page 2-30.

[43] A copy of the New Mexico Commission's June 2007 Order is included as Exhibit JI-35-E.

EIA and MIT based on the legislative proposals in the current U.S. Congress and even the safety valve prices in Senate Bill S. 1766, the Bingaman-Specter global warming legislation. The CO_2 prices used by Otter Tail Power, CMMPA and MRES also are below the lower ends of the ranges of CO_2 prices recently adopted for resource planning by Xcel Energy and the New Mexico Public Regulation Commission.

In contrast, the Synapse CO_2 price forecasts are consistent with all of these CO_2 prices forecasts.

Q. Why haven't you included the CO_2 prices that the Minnesota Commission recently adopted in Figure 4 above?

A. The Minnesota Commission has adopted a range of CO_2 prices from $4/ton to $30/ton. However, the Commission has not yet issued an Order which indicates the rate of inflation that should be applied to those costs. As a result, I did not include those prices in Figure 4 above. Nevertheless, it is clear that the Commission's range of CO_2 prices would extend significantly above the $9/ton cost assumed by OTP, MRES and CMMPA even if the costs remained flat in nominal terms and did not increase, even just at the rate of inflation.

Q. Is it credible to assume, as MDU does, that CO_2 costs will be zero, that is, there will be no federal regulation of CO_2 emissions at any time during the expected 40 to 60 year operating life of the Big Stone II Project?

A. No. Given the proposals being considered in Congress, public concern and scientific developments, it simply is not credible to project or assume that there will be no federal regulation of greenhouse gas emissions at any time over the next 40 to 60 years.

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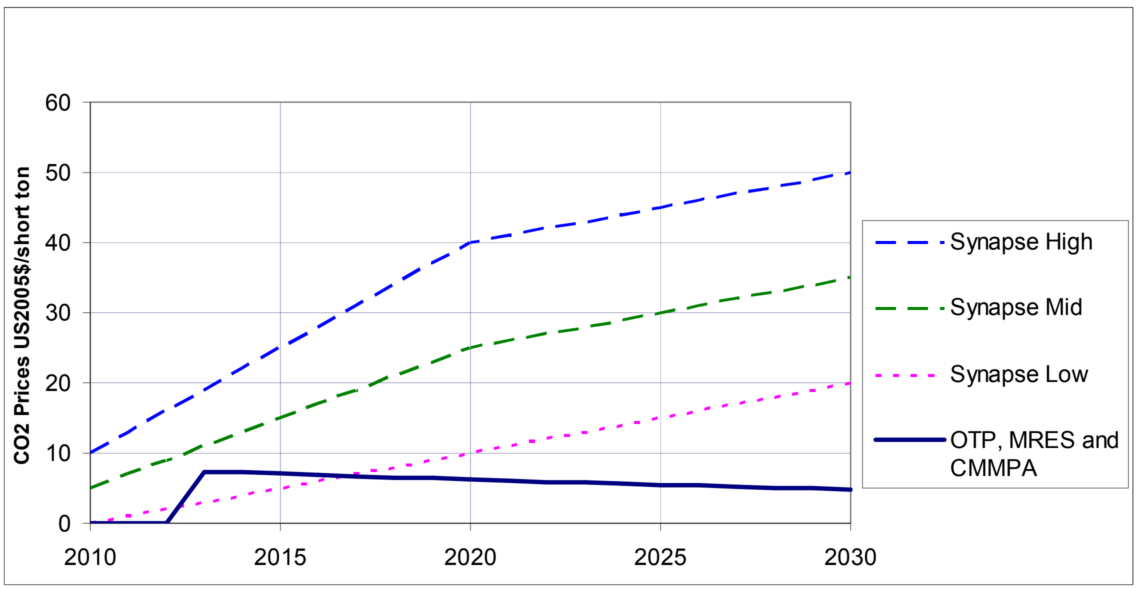
[44] A value that is "levelized" is the present value of the cost converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

Q. How do the Synapse CO_2 price forecasts compare to the annual CO_2 prices used by OTP, CMMPA and MRES in their supplemental modeling analyses?

A. The annual Synapse CO_2 price forecasts and the CO_2 prices used by Otter Tail Power, CMMPA and MRES, all in constant 2005 dollars, are shown in Figure 5 below:

Figure 5: Synapse and The Applicants' CO_2 Price Forecasts in Constant 2005 Dollars



Q. Are the Synapse CO_2 price forecasts shown in Figure 5 based on any independent modeling?

A. Yes. Although Synapse did not perform any new modeling to develop our CO_2 price forecasts, our CO_2 price forecasts were based on the results of independent modeling prepared at the Massachusetts Institute of Technology ("MIT"), the Energy Information Administration of the Department of Energy ("EIA"), Tellus, and the U.S. Environmental Protection Agency ("EPA").[45]

[45] See Table 6.2 on page 42 of 63 of Exhibit JI-1-F.

Q. What factors will affect the cost of CO_2 emissions allowances?

A. Exhibit JI-1-F identified a number of factors that will affect projected allowance prices. These factors include: the base case emissions forecast; whether there are complementary policies such as aggressive investments in energy efficiency and renewable energy independent of the emissions allowance market; the policy implementation timeline; the reduction targets in a proposal; program flexibility involving the inclusion of offsets (perhaps international) and allowance banking; technological progress; and emissions co-benefits.[46] In particular, Synapse anticipates that technological innovation will temper allowance prices in the out years of our forecast.

Q. Could carbon capture and sequestration be a technological innovation that might temper or even put a ceiling on CO_2 emissions allowance prices?

A. Yes.

Q. Do the Applicants believe that there is currently a commercially viable technology for carbon capture and sequestration from pulverized coal plants like the proposed Big Stone II Project?

A. The Applicants provided the following answer when asked whether they believe that there currently is a commercially viable technology for post-combustion carbon capture and sequestration for pulverized coal power plants:

> Currently a number of technologies exist or are in development for post combustion carbon capture. They range from the traditional amine absorber to membrane process to promising chilled ammonia, also to the development of enhanced amine processes. All of these technologies hold some degree of promise and opportunity. Only time will tell which ones will truly become commercially viable technology. By what we would consider today's standards, for the number of units in operation and cost, we would say there is no commercially viable technology in place

[46] Exhibit JI-1-F, at pages 46 to 49 of 63.

> today, but there are a number of very promising technologies under development, as indicated by the list … mentioned.[47]

Q. Is this a generally accepted view in the industry?

A. Yes. This conclusion is consistent with the general view in the electric industry. For example, a witness for Dominion Virginia Power presented testimony in July 2007 that noted that:

> carbon capture technology is not commercially viable or available at the present time. Furthermore, the successful integration of all of the technologies needed for a commercial-scale carbon capture and sequestration system has yet even to be demonstrated. As a result, it is not currently feasible to construct a power plant with technology that can capture and store carbon emissions.[48]

Even if such technology were available, retrofitting an existing coal plant with the technology for carbon capture and sequestration is expected to be very expensive, increasing the cost of generating power at the plant by perhaps as much as 68 to 80 percent or higher.

Q. Have you seen any estimates for the cost of carbon capture and sequestration at proposed pulverized coal plants such as the Big Stone II Project?

A. Yes. Hope has been expressed concerning potential technological improvements and learning curve effects that might reduce the estimated cost of carbon capture and sequestration. However, I have seen recent studies by objective sources that estimate that the cost of carbon capture and sequestration could increase the cost of producing electricity at pulverized coal-fired power plants by 60-80 percent, on a $/MWh basis.

For example, a very recent study by the National Energy Technology Laboratory ("NETL") has projected that the cost of carbon capture and sequestration would

[47] Applicants' Response to IR No. 292.a. A copy of this Response is included as Exhibit JI-35-F.

be about $75/tonne[49] of CO_2 avoided, in 2007 dollars, for pulverized coal plants.[50] This would translate into about $65/ton of CO_2 avoided, in 2005 dollars, a cost substantially above even the current Synapse High forecast.

The 2007 *Future of Coal Study* from the Massachusetts Institute of Technology estimated that the cost of carbon capture and sequestration would be about $28/ton although it also acknowledged that there was uncertainty in that figure.[51] The tables in that study also indicated significantly higher costs for carbon capture for new pulverized coal facilities, in the range of about $40/ton and higher.[52] Moreover, these costs were for new plants that were designed and built to include carbon capture technology at the outset. The MIT *Future of Coal Study* concluded that it would be much more expensive to retrofit carbon capture technology onto existing coal-fired power plants.[53] That means that the cost of retrofitting carbon capture technology onto plants that would already be built and in operation at the time that the technology becomes proven and commercially viable, like Big Stone II, could be significantly higher than the $40/ton figure shown in the MIT Study for new coal plants.

Similarly, in a recent proceeding at the West Virginia Public Service Commission, Appalachian Power Company has estimated the costs of electricity from a number of coal-fired technologies with and without carbon capture and sequestration.[54] Appalachian Power estimates that the cost of just capturing the

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48 Direct Testimony of Dominion Virginia Power witness James K. Martin in Virginia State Corporation Commission Case No. PUE-2007-00066, dated July 13, 2007, at page 7, line 11.

49 A tonne or metric ton is a measurement of mass equal to 1,000 kilograms or 1.1 tons.

50 *Cost and Performance Baseline for Fossil Energy Plants*, National Energy Technology Laboratory, Revised August 2007, at page 27.

51 *The Future of Coal*, *Options for a Carbon-Constrained World*, Massachusetts Institute of Technology, 2007, at page xi.

52 Id, at page 19.

53 Id, at pages 28-29.

54 Appalachian Power Company witness Renchek's Exhibit MWR-4, revised, in West Virginia Case No. 06-0033-E-CN.

CO_2 emissions from a new pulverized coal plant would be approximately \$43-\$46/MWh on a levelized basis.

I also have seen some preliminary estimates that some of the new technologies being examined may hold the promise of lowering carbon capture and sequestration costs to perhaps as low as \$20/ton of CO_2 avoided. However, those results are very preliminary and the associated technologies are untested.

Even when the technology for CO_2 capture matures, there will always be significant regional variations in the cost of the transportation and storage of the captured CO_2 due to the proximity and quality of storage sites.

Q. Is there any consensus when carbon capture and sequestration technology will become commercially viable for pulverized coal plants like the Big Stone II Project?

A. No. I have seen estimates that carbon capture and sequestration technology may be proven and commercially viable from as early as 2015 to 2030 or later, if, indeed, it is ever proven to be technically and commercially viable.

For example, the 2007 *Future of Coal* study from the Massachusetts Institute of Technology warned that:

> Many years of development and demonstration will be required to prepare for its successful, large scale adoption in the U.S. and elsewhere. A rushed attempt at CCS [carbon capture and sequestration] implementation in the face of urgent climate concerns could lead to excess cost and heightened local environmental concerns, potentially lead to long delays in implementation of this important option.[55]

[55] *The Future of Coal, Options for a Carbon-Constrained World, an Interdisciplinary MIT Study*, 2007, at page 15.

Q. Have the Applicants provided any assessments of the potential or the feasibility of sequestering the CO_2 from the proposed Big Stone II Project?

A. No. The have instead expressed faith that advances in technology in the future will enable the capture and sequestration of CO_2 emissions from Big Stone II at reasonable costs.[56]

Q. Have the Applicants included any costs associated with carbon capture and sequestration in either the estimated Big Stone II Project construction cost or in their new modeling analyses?

A. I am not aware of any significant costs for carbon capture and sequestration in the most recent, that is July 2006, Big Stone II Project construction cost estimate. There also is no evidence that the Applicants have included any costs associated with carbon capture and sequestration in their recent modeling analyses.

Q. Do you believe that the Synapse CO_2 price forecasts remain valid despite being based, in part, on analyses from 2003-2005 which examined legislation that was proposed in past Congresses?

A. Yes. Synapse believes it is important for the Minnesota PUC to rely on the most current information available about future CO_2 emission allowance prices, as long as that information is objective and credible. The analyses upon which Synapse relied when we developed our CO_2 price forecasts were the most recent analyses and technical information available when Synapse developed its CO_2 price forecasts in the Spring of 2006. However, new information shows that our CO_2 prices remain valid even though the original bills that comprised part of the basis for the forecasts expired at the end of the Congress in which they were introduced.

[56] For example, see the Applicants' Response to Joint Intervenors Information Request No. 292.(c), (d) and (e). Copies of these Responses are included in Exhibit JI-35-F.

Many of the new greenhouse gas regulation bills that have been introduced in the current Congress would require much steeper reductions in greenhouse gas emissions than would have been required under the bills that had been introduced in Congress at the time we developed our Synapse CO_2 price forecasts. It is reasonable to expect that the increased stringency of current bills will lead to higher CO_2 emission allowance prices. Thus, if anything, our Synapse CO_2 price forecasts may be too low given the increased stringency of the current bills being considered in Congress. The higher forecast natural gas prices that are being forecast today, as compared to the natural gas price forecasts from 2003 or 2004, also can be expected to lead to higher CO_2 emissions allowance prices.

Q. Would it be reasonable to assume that a new pulverized coal-fired plant like the Big Stone II Project will be grandfathered under federal climate change legislation or will be favored with the provision of extra CO_2 emission allowance allocations that could mitigate or offset the impact of CO_2 regulations?

A. No. It is unclear what provisions for grandfathering existing coal plants (that is, allocating them allowances for free), if any, will be adopted as part of future greenhouse gas legislation. At the same time, it is unrealistic to expect that many or all of the new coal-fired plants currently being proposed will be grandfathered because of the substantial reductions in CO_2 emissions from current levels that have to be made by 2050 just to stabilize atmospheric concentrations of CO_2 at 450 ppm to 550 ppm.

Meeting these goals will require either a reduction in dependence on coal for electricity generation or a very large investment in conversion of the current coal generating fleet in the U.S. The only realistic way either of these is going to happen is with a large marginal cost on greenhouse gas emissions such as a CO_2 tax or higher emissions allowance prices. It is not reasonable to expect that a new pulverized coal plant, like the Big Stone II Project, which will substantially increase the emissions of CO_2 into the atmosphere, will receive significant emission allowances under any U.S. carbon regulation plan.

For example, the National Commission on Energy Policy[57] has recently recommended that "new coal plants built without [carbon capture and sequestration] not be "grandfathered" (i.e., awarded free allowances) in any future regulatory program to limit greenhouse gas emissions."[58] A report of an interdisciplinary study at the Massachusetts Institute of Technology on *The Future of Coal* similarly noted that:

> There is the possibility of a perverse incentive for increased early investment in coal-fired power plants without capture, whether SCPC or IGCC, in the expectation that the emissions from these plants would potentially be "grandfathered" by the grant of free CO_2 allowances as part of future carbon emissions regulations and that (in unregulated markets) they would also benefit from the increase in electricity prices that will accompany a carbon control regime. Congress should act to close this "grandfathering" loophole before it becomes a problem.[59]

Additionally, it has been proposed in Congress that new coal-fired plants would be required to actually have carbon capture and sequestration technology. For example, a bill by Massachusetts Senator Kerry would limit CO_2 emissions from new coal-fired facilities to 285 lbs/MWh.[60] New coal-fired facilities would be defined as those that begin construction on or after April 26, 2007 and would certainly include the proposed Big Stone II Project.

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57 The National Commission on Energy Policy is a bipartisan group of 20 energy experts from industry, government, academia, labor, consumer and environmental protection.

58 *Energy Policy Recommendations to the President and the 110th Congress*, National Commission on Energy Policy, April 2007, at page 21.

59 *The Future of Coal, Options for a Carbon-Constrained World, an Interdisciplinary MIT Study*, 2007, at page (xiv).

60 This would be approximately 15 percent of Big Stone II's projected emissions of roughly 1 ton per MWh.

Q. Is it possible that natural gas demand could be higher due to CO_2 emission regulations and, as a result, natural gas prices can be expected to be higher than otherwise would be the case?

A. Yes. However, the effect is very complicated and will depend on a number of factors such as how much new natural gas capacity is built as a result of the higher coal-plant operating costs due to the CO_2 emission allowance prices, how much additional DSM and renewable alternatives become economic and are added to the U.S. system, the levels and prices of any incremental natural gas imports, and changes in the dispatching of the electric system. Thus it is very difficult to determine, at this time, the amount by which natural gas prices might be raised due to CO_2 emission regulations.

Q. What are your recommendations concerning the CO_2 prices that the Minnesota PUC should use in evaluating the Applicants' proposed Big Stone II Project?

A. I believe that unless the Minnesota Commission decides to use the range of CO_2 prices discussed at its December 6, 2007 session, it should use the Synapse forecasts of CO_2 prices to evaluate the relative economics of the proposed Big Stone II Project.

Q. How much additional CO_2 would the Big Stone II Project emit into the atmosphere?

A. A 500MW Big Stone II would emit approximately 3.7 million tons of CO_2 annually. A 580 MW Big Stone II would emit approximately 4.3 million tons of CO_2 each year.

Q. What would be the annual costs of greenhouse gas regulations to the Applicants and their customers under the Synapse CO_2 price forecasts if they proceed with the proposed Big Stone II Project?

A. The annual expenditures on CO_2 emissions allowances that the participants in the Big Stone II Project and their customers would have to pay in 2015, 2020 and 2030 under the Synapse low, mid and high price forecasts are shown in Table 3 below for a 500 MW plant and in Table 4 below for a 580 MW plant:

Table 3: 500 MW Plant Size - Annual Big Stone II Project Participant CO_2 Emissions Allowances Payments under Synapse Price Forecasts

Year	Synapse Low CO_2 Price Forecast	Synapse Mid CO_2 Price Forecast	Synapse High CO_2 Price Forecast
	(Millions of Nominal $)	(Millions of Nominal $)	(Millions of Nominal $)
2015	$24	$72	$119
2020	$54	$135	$216
2030	$138	$242	$346

Table 4: 580 MW Plant Size - Annual Big Stone II Project Participant CO_2 Emissions Allowances Payments under Synapse Price Forecasts

Year	Synapse Low CO_2 Price Forecast	Synapse Mid CO_2 Price Forecast	Synapse High CO_2 Price Forecast
	(Millions of Nominal $)	(Millions of Nominal $)	(Millions of Nominal $)
2015	$28	$83	$138
2020	$63	$157	$251
2030	$160	$281	$401

Q. What impact would assuming the Synapse range of CO_2 costs have on the total cost of power from the Big Stone II Project?

A. The increases in the cost of power from the Big Stone II Project from using the Synapse range of CO_2 prices, on a levelized basis, are shown in Tables 5 and 6, below, for the Investor Owned and Public Power Owners of the Big Stone II

Project. The base costs, without CO_2 prices, are taken from the testimony of Applicant witness Greig. These figures are for a 500 MW sized Big Stone II Project. The percentage increases would be slightly higher for a 580 MW sized plant.

Table 5: Investor Owned Utilities – Increased Cost of Power from Big Stone II Project Assuming Synapse CO_2 Price Forecasts

	Big Stone II Project Levelized Cost (2013-2032)	Percentage Increase
	($/MWh)	
$0/ton CO_2 Price	$77.65	
Synapse Low CO_2 Price	$88.13	13%
Synapse Mid CO_2 Price	$101.27	30%
Synapse High CO_2 Price	$138.03	47%

Table 6: Public Power Utilities – Increased Cost of Power from Big Stone II Project Assuming Synapse CO_2 Price Forecasts

	Big Stone II Project Levelized Cost (2013-2032)	Percentage Increase
	($/MWh)	
$0/ton CO_2 Price	$61.38	
Synapse Low CO_2 Price	$71.86	17%
Synapse Mid CO_2 Price	$85.00	38%
Synapse High CO_2 Price	$121.76	60%

5. The Applicants Have Not Adequately Considered The Risk Of Further Increases In The Estimated Capital Cost Of The Big Stone II Project

Q. What estimated capital costs for the Big Stone II Project have the Applicants used in their recent modeling analyses?

A. According to Applicant witness Rolfes, the currently estimated cost of a 500 MW ultra supercritical Big Stone II Project is $1.272 billion.[61] The currently estimated cost for a 580 MW unit is $1.411 billion.

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[61] Applicants' Exhibit 115, at page 1, lines 20-22.

Q. What is the currently scheduled commercial operation date ("COD") that the Applicants have used in their new modeling analyses?

A. The currently scheduled COD date for Big Stone II is the summer of 2013.

Q. How did the Applicants determine the currently estimated cost and COD for the Big Stone II Project that they have used in their new modeling analyses?

A. The derivation of the current project cost estimates for 500 MW and 580 MW sized plants was explained as follows in the information provided to potential Project participants:

[TRADE SECRET MATERIALS BEGIN….

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Q. Have you been able to fully evaluate the reasonableness of this cost estimate and scheduled completion date?

A. No. The Applicants refused to provide almost all of the detailed project information, correspondence, and meeting minutes that the Joint Intervenors requested in discovery.[63] This refusal has prevented us from determining whether the Applicants are aware of any significant new developments regarding the project's expected cost and schedule that they have sought to keep from the Hearing Examiners and the Minnesota Commission. This is an important issue because last year the Applicants had provided no information to the Commission or the parties in this proceeding concerning the project suspension or hiatus that began in early September 2006 until Joint Intervenors received project documents just before the filing date for our November 29, 2006 testimony.

Q. What is the current status of the Big Stone II Project?

A. Although some work may have been undertaken, it appears that no major design or procurement activities have been completed. Information that the Applicants have provided to potential new Project participants indicates that they intend **[TRADE SECRET MATERIALS BEGIN**
. **TRADE SECRET MATERIALS END]**"[64]

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[62] *Memorandum to Big Stone II Project Data Disk*, William Swanson, dated 11/7/2007, at Bates Page Number OTP0010464. A copy of this document is included as Confidential Exhibit JI-35-G.

[63] See the Applicants' Responses to Joint Intervenors Information Requests Nos. 228, 229, 230, and 236. Copies of these Responses are included in Exhibit JI-35-H.

[64] *Memorandum to Big Stone II Project Data Disk*, William Swanson, dated 11/7/2007, at Bates Page Number OTP0010464. A copy of this Response is included as Confidential Exhibit JI-35-G.

Q. Have the Applicants reflected in their recent modeling analyses any uncertainty regarding the ultimate cost or COD of the Big Stone II Project?

A. The current Big Stone II Project cost estimate does include a limited contingency allowance. However, the Applicants have not prepared any sensitivity analyses to examine the impact of larger increases in Big Stone II Project costs that would exceed this limited contingency.

Q. Have you seen any evidence that the Applicants are losing confidence in the current Big Stone II Project cost and schedule estimate?

A. **[TRADE SECRET BEGIN**

TRADE SECRET END][65] However, the Applicants also noted that **[TRADE SECRET MATERIALS BEGINS** [66]
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Q. When do the Applicants intend to produce a new cost estimate for the Big Stone II Project?

A. It appears that the **[TRADE SECRET MATERIAL BEGINS**

TRADE SECRET MATERIAL ENDS][67] Unfortunately, this will be after the Minnesota Commission has decided whether to grant a Certificate of Need for the Big Stone II Project.

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[65] Applicants' Confidential Response to Joint Intervenors Information Request No. 243, at Bates Page Number OTP0008037. A copy of this Response is included as Confidential Exhibit JI-35-I.

[66] Id.

[67] *Memorandum to Big Stone II Project Data Disk*, William Swanson, dated 11/7/2007, at Bates Page Number OTP0010464. A copy of this Response is included as Confidential Exhibit JI-35-G.

Q. Is it reasonable to expect that the estimated and/or ultimate cost of the project will be higher than the Applicants now estimate?

A. Yes. The costs of building power plants have soared in recent years as a result of the worldwide demand for power plant design and construction resources and commodities. There is no reason to expect that plant costs will not continue to rise during the years when the detailed engineering, procurement and construction of the Big Stone II Project will be underway. This is especially true given the extremely early stage of the engineering and procurement for the project.

For example, Duke Energy Carolinas' originally estimated cost for the 1600 MW two unit coal-fired Cliffside Project was approximately $2 billion. In the fall of 2006, Duke announced that the cost of the project had increased by approximately 47 percent ($1 billion). After the project had been downsized because the North Carolina Utilities Commission refused to grant a permit for two units, Duke announced that the cost of that single unit would be about $1.53 billion, not including financing costs. In late May 2007, Duke announced that the cost of building that single unit had increased by about another 20 percent. As a result, the estimated cost of the one unit that Duke is building at Cliffside is now $1.8 billion exclusive of financing costs. Thus, the single Cliffside unit is now expected to cost almost as much as Duke originally estimated for a two unit plant.

Q. Did Duke explain to the North Carolina Utilities Commission the reasons for the skyrocketing cost of the Cliffside Project?

A. Yes. In testimony filed at the North Carolina Utilities Commission on November 29, 2006, Duke Energy Carolinas emphasized that the competition for resources had had a significant impact on the costs of building new power plants:

> The costs of new power plants have escalated very rapidly. This effect appears to be broad based affecting many types of power plants to some degree. One key steel price index has doubled over the last twelve months alone. This reflects global trends as steel is traded internationally and there is international competition among

> power plant suppliers. Higher steel and other input prices broadly affects power plant capital costs. A key driving force is a very large boom in U.S. demand for coal power plants which in turn has resulted from unexpectedly strong U.S. electricity demand growth and high natural gas prices. Most integrated U.S. utilities have decided to pursue coal power plants as a key component of their capacity expansion plan. In addition, many foreign companies are also expected to add large amounts of new coal power plant capacity. This global boom is straining supply. Since coal power plant equipment suppliers and bidders also supply other types of plants, there is a spill over effect to other types of electric generating plants such as combined cycle plants.[68]

Duke further noted that the actual coal power plant capital costs as reported by plants already under construction were exceeding government estimates of capital costs by "a wide margin (i.e., 35 to 40 percent)." [69] Additionally, according to Duke, currently announced power plants were appearing to face another approximate 40 percent increase in costs." Thus, new coal-fired power plant capital costs had increased approximately 90 to 100 percent between 2002 and late 2006.

Q. Have other coal-fired plant projects experienced similar cost increases?

A. Yes. A large number of projects have announced significant construction cost increases over the past few years. For example:

- The cost of Westar's proposed coal-fired plant in Kansas, originally estimated at $1 billion, increased by 20 percent to 40 percent, over just 18 months.
- Similarly, the estimated cost of the now-cancelled Taylor Energy Center in Florida increased by 25 percent, $400 million, in just 17 months between November 2005 and March 2007.

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68 Direct Testimony of Judah Rose for Duke Energy Carolinas, North Carolina Utilities Commission Docket No. E-7, SUB 790, at page 4, lines 2-14, available on the North Carolina Utilities Commission website.

69 Id, at page 6, lines 5-9, and page 12, lines 11-16.

- The estimated cost of the Little Gypsy Repowering Project (gas to coal) in Louisiana increased by 55 percent between announcement of the project in April 2007 and the filing of a request for a license to build in July 2007.

Q. What are the sources of the worldwide competition for power plant design and construction resources, commodities and equipment?

A. The worldwide competition is driven mainly by huge demands for power plants in China and India, by a rapidly increasing demand for power plants and power plant pollution control modifications in the United States required to meet SO_2 and NO_x emissions standards, and by the competition for resources from the petroleum refining industry. The demand for labor and resource to rebuild the Gulf Coast area after Hurricanes Katrina and Rita hit in 2005 also has contributed to rising costs for construction labor and materials. The anticipated construction of new nuclear power plants also is expected to compete for limited power plant design and construction resources, manufacturing capacity and commodities.

Q. Is it commonly accepted that domestic United States and worldwide competition for power plant design and construction resources, commodities and manufacturing have led to these significant increases in power plant construction costs in recent years?

A. Yes. The worldwide competition for power plant resources is generally recognized as the driving force for skyrocketing construction costs. For example, a June 2007 report by Standard & Poor's, *Increasing Construction Costs Could Hamper U.S. Utilities' Plan to Build New Power Generation*, found that:

> As a result of declining reserve margins in some U.S. regions … brought about by a sustained growth of the economy, the domestic power industry is in the midst of an expansion. Standing in the way are capital costs of new generation that have risen substantially over the past three years. Cost pressures have been caused by demands of global infrastructure expansion. In the domestic power industry, cost pressures have arisen from higher demand for pollution control equipment, expansion of the transmission grid, and new generation. While the industry has experienced buildout

> cycles in the past, what makes the current environment different is the supply-side resource challenges faced by the construction industry. A confluence of resource limitations have contributed, which Standard & Poors' Rating Services broadly classifies under the following categories
>
> - Global demand for commodities
> - Material and equipment supply
> - Relative inexperience of new labor force, and
> - Contractor availability
>
> The power industry has seen capital costs for new generation climb by more than 50% in the past three years, with more than 70% of this increase resulting from engineering, procurement and construction (EPC) costs. Continuing demand, both domestic and international, for EPC services will likely keep costs at elevated levels.[70]

Standard & Poor's warned, therefore, that "it is possible that with declining reserve margins, utilities could end up building generation at a time when labor and materials shortages cause capital costs to rise, well north of $2,500 per kW for supercritical coal plants and approaching $1,000 per kW for combined-cycle gas turbines (CCGT)."[71]

Standard & Poor's also concluded that "as capital costs rise, energy efficiency and demand side management already important from a climate change perspective, become even more crucial as any reduction in demand will mean lower requirements for new capacity."[72]

Price increases have become so dramatic that the president of the Siemens Power Generation Group told the New York Times that "There's real sticker shock out

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[70] *Increasing Construction Costs Could Hamper U.S. Utilities' Plans to Build New Power Generation*, Standard & Poor's Rating Services, June 12, 2007, at page 1. A copy of this report is included as Exhibit JI-35-J.
[71] Id.
[72] id.

there."[73] He also estimated that in the last 18 months, the price of a coal-fired power plant has risen 25 to 30 percent. Similarly, in its 2007 Application to the Ohio Power Siting Board, American Municipal Power-Ohio noted that the price increases currently being experienced in the expected construction costs of coal based electric generation were "staggering."[74]

Finally, a September 2007 report on *Rising Utility Construction Costs* prepared by the Brattle Group for the EDISON Foundation of the Edison Electric Institute similarly concluded that:

> Construction costs for electric utility investments have risen sharply over the past several years, due to factors beyond the industry's control. Increased prices for material and manufactured components, rising wages, and a tighter market for construction project management services have contributed to an across-the-board increase in the costs of investing in utility infrastructure. These higher costs show no immediate signs of abating.[75]

The report further found that:

- Dramatically increased raw materials prices (e.g., steel, cement) have increased construction cost directly and indirectly through the higher cost of manufactured components common in utility infrastructure projects. These cost increases have primarily been due to high global demand for commodities and manufactured goods, higher production and transportation costs (in part owing to high fuel prices), and a weakening U.S. dollar.
- Increased labor costs are a smaller contributor to increased utility construction costs, although that contribution may rise in the future as large construction projects across the country raise the demand for specialized and skilled labor over current or project supply. There also is a growing backlog of project contracts at large engineering, procurement and construction (EPC) firms, and construction management bids have

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73 "Costs Surge for Building Power Plants, *New York Times*, July 10, 2007.

74 AMP-Ohio's May 2007 Application to the Ohio Power Siting Board, Section OAC 4906-13-05, at page 4.

75 *Rising Utility Construction Costs: Sources and Impacts*, prepared by The Brattle Group for the EDISON Foundation, September 2007, at page 31. A copy of this report is included as Exhibit JI-35-K.

begun to rise as a result. Although it is not possible to quantify the impact on future project bids by EPC, it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue.

- The price increases experienced over the past several years have affected all electric sector investment costs. In the generation sector, all technologies have experienced substantial cost increases in the past three years, from coal plants to windpower projects…. As a result of these cost increases, the levelized capital cost component of baseload coal and nuclear plants has risen by $20/MWh or more – substantially narrowing coal's overall cost advantages over natural gas-fired combined-cycle plants – and thus limiting some of the cost-reduction benefits expected from expanding the solid-fuel fleet.

- The rapid increases experienced in utility construction costs have raised the price of recently completed infrastructure projects, but the impact has been mitigated somewhat to the extent that construction or materials acquisition preceded the most recent price increases. The impact of rising costs has a more dramatic impact on the estimated cost of proposed utility infrastructure projects, which fully incorporates recent price trends. This has raised significant concerns that the next wave of utility investments may be imperiled by the high cost environment. These rising construction costs have also motivated utilities and regulators to more actively pursue energy efficiency and demand response initiatives to reduce the future rate impacts on consumers.[76]

Q. Is it reasonable to expect that the worldwide competition for power plant design and construction resources will continue to lead to further construction cost increases in future years?

A. Yes. I have seen no evidence that these long term factors will abate at any point in the foreseeable future. For example, a report by the consulting engineering firm of Burns and Roe for the City of Cleveland Division of Cleveland Public Power noted that it is difficult to predict the escalation of future power plant costs and expressed concern that "India is on the threshold of beginning a rapid expansion in the upcoming years will place additional pressure on the availability of raw

[76] Id, at pages 1-3.

materials, shop fabrication space and available work force for engineering, site management staff and field labor and supervision."[77]

Q. Do the Applicants agree that these are the factors that have been driving the significant increases that have recently been experienced in the estimated costs of building new coal-fired power plants?

A. Yes. In his testimony in this proceeding, Applicant witness Trout identified the following as among the factors that have led to increases in the costs of building new power plants:

> Since the initial [Big Stone II cost] estimate was prepared in 2004, the power generation industry has experienced significant pricing increases for various commodities including steel, alloy piping, cable and wire, and other critical commodities. These have contributed to a constantly changing market for commodities and power plant equipment….
>
> *   *   *   *
>
> - Major construction commodities have increased 30% to 80% during the last two years.
> - Labor rate escalation is currently double what it was two years ago.
>
> The global demands (the governments of China and India, for example) for huge expansion in the electricity production sectors will impact equipment prices and creates raw material and fabrication facility (shop space) shortages worldwide for all types of energy production projects. The U.S. electricity production industry announced multiple large projects for development and construction, some of which have supply contracts which have recently been awarded. The energy and process markets are experiencing tremendous growth at the same time.

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77 *Consulting Engineer's Report for the American Municipal Power Generating Station located in Meigs County, Ohio*, for the Division of Cleveland Public Power, Burns and Roe Enterprises, Inc., October 16, 2007, at page 10-9.

> - Suppliers and Subcontractors that downsized after the market collapsed in 2001 are challenged to grow their capacity and workforce.
>
> - Continuously increasing costs and longer delivery times for raw materials are influencing engineered equipment costs and commodity purchases.
>
> Increased costs for fuel have caused unexpected increases in fabrication and transportation costs for delivery of fabricated materials, as well as higher construction costs to build this project.[78]

In fact, Black & Veatch prepared a *Big Stone II Project Perspective Briefing Book for Owners' CEOs – Supplemental materials,* in the spring of 2007 that indicated the following concerning power plant construction costs and schedules:

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[78] Applicants' Exhibit 33 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, at page 27, line 20, to page 29, line 14.

[79] Applicants' Exhibit 33 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, at page 27, line 20, to page 29, line 14.

[80] Id, at Bates Page Number JCO0013931. A copy of this Response is included as Confidential Exhibit JI-35-L.

[81] Id, at Bates Page Number JCO0013932. A copy of this Response is included as Confidential Exhibit JI-35-L.

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- .[82] **TRADE SECRET MATERIALS END]**

Q. Have the Applicants assumed any increases in the cost of building the Big Stone II Project as a result of the recent project hiatus or suspension and the result delay of more than one year?

A. The Applicants have assumed that the cost of the Project will increase by the relative minor amount of 6 percent due to an additional year's escalation of costs. However, they have not reflected any major cost increases due to the worldwide competition I have described above. In fact, the Applicants have assumed they will be able to *reduce* the estimated cost of the Project by about **[TRADE SECRET MATERIALS BEGIN TRADE SECRET MATERIALS END]**by achieving unspecified cost savings.[83] Although we have not had the opportunity to review the internal project documentation prepared since last November, it seems very unlikely that the Project will be able to avoid the significant delays and cost increases that numerous other projects have experienced in the past twelve months.

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[82] Id, at Bates Page Number JCO0013934. A copy of this Response is included as Confidential Exhibit JI-35-L.

[83] *Memorandum to Big Stone II Project Data Disk*, William Swanson, dated 11/7/2007, at Bates Page Number OTP0010464. A copy of this Confidential document is included as Exhibit JI-35-G.

Q. It is reasonable to assume that the increased competition for power plant design and construction resources, commodities and manufacturing capacity factors that has led to the significant increases in power plant capital costs also will lead to construction delays?

A. Yes.

Q. Have the Applicants identified any specific factors which could prevent the Project from achieving the scheduled June 2013 in-service date?

A. Yes. A November 9, 2007 Big Stone II Memorandum that was provided to potential Project participants indicated that in order to realize a June 1, 2013 Commercial Operation Date certain project activities need to take place. These activities include:

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- [84] **TRADE SECRET MATERIALS END]**

However, the Memorandum indicated that there are some factors that may influence the achievement of these key dates:

- **[TRADE SECRET MATERIALS BEGIN**

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[84] Applicants Confidential Response to Joint Intervenors Information Request No. 243, at Bates Page Number OTP0008060. A copy of this Response is included as Confidential Exhibit JI-35-M.

.[85] **TRADE SECRET MATERIALS END]**

Q. Have you seen any evidence that suggests the possible magnitude of the increased costs that might be experienced when the contract bids for the Big Stone II Project are rebid or negotiated?

A. As I noted previously, we have not had access to recent internal Project documentation. However, **[TRADE SECRET MATERIALS BEGIN**

TRADE SECRET MATERIALS END].[86] For example, in its

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85 Id, at Bates Page Numbers OTP0008060 and 8061.

86 For example, see Bates Page Numbers OTP0006946, 6997, and 6949. Copies of these pages are included as Exhibit JI-35-N.

IRP filed last month in Colorado, Xcel Energy noted that "Boiler unit costs are reported to have increased 50 to 80% in the last year."[87]

Q. In your opinion, is it prudent for the Applicants to ignore the potential for significant Big Stone II Project cost increases and schedule delays in their recent modeling and economic analyses?

A. No. Although the current project cost estimate does include some contingencies, we believe that given the dramatic spike in coal plant construction costs over the last few years, it is reasonable to assume that the Project's construction cost may be substantially higher than the Applicants now acknowledge and that the Project's COD may be later than the Applicants now admit. This is especially true because all project contracts have not been let and many detailed design and all construction activities have not started. It is important to remember that the cost of this project already rose by more than 25 percent between 2004 and July 2006.88 Applicants have presented no evidence that the forces that caused that major price increase (and that are still causing "staggering" price increases around the nation) will not lead to further cost increases in the coming years.

In fact, even Applicant witnesses Rolfes and Trout have not foreclosed the potential for further increases in the Project's estimated capital cost. For example, 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.[89] He 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

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87 Public Service Company of Colorado, *2007 Colorado Resource Plan*, Volume 2 Technical Appendix, at page 2-36.

88 The estimated cost of the Project actually increased by significantly more than 25 percent in July 2006 but the Applicants offset much of that increase by assuming that substantial savings can be achieved in design and construction.

Unit II" and that "Until they do so, the project budget will be subject to further refinement."[90]

Q. Is it reasonable to expect that the Applicants could have updated their Project capital cost estimate at some point in the past year to reflect the industry-wide developments and cost trends you have described?

A. Yes. It was not necessary for the Applicants to wait until next June or so to prepare a Big Stone II Project cost estimate and schedule update. Such information should have been prepared so that the Commission would have the most up-to-date information when it deliberates whether to grant a certificate for the proposed Project.

Q. How should have the Applicants reflected the potential for further increases in the cost of the Big Stone II Project in their modeling analyses?

A. In order to more fully evaluate the risks of continuing with the proposed project, the Applicants should have prepared sensitivity studies that examined the relative economics of the Big Stone II Project against alternatives assuming that the capital cost of the project is substantially higher than they now estimate and that the Project may not be in-service in June 2013.

For example, the Applicants could have prepared sensitivity analyses in their modeling analyses that reflected capital costs, 10, 20 percent and/or 40 percent higher than its current estimated cost for the Big Stone II Project. It is not unreasonable to expect such additional cost increases at the Project in light of the industry-wide experience and the expectation that worldwide demand will continue to be a driving force for rising prices.

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89 Applicants' Exhibit 33 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, at page 24, lines 19-20, and at page 27, line 18, to page 28, line 14.

90 Applicants' Exhibit 33 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, at page 28, lines 14-17.

Q. Is it reasonable to expect that these same current market conditions also will lead to increases in the estimated costs of other supply-side alternatives such as natural gas-fired, wind or biomass facilities?

A. Yes. However, it is not necessarily reasonable to expect that all of the alternative technologies will experience the same cost increases as a coal-fired project like Big Stone II. For example, even Otter Tail Power has assumed that natural gas-fired simple cycle and combined cycle plants will experience lower escalation than the Big Stone II Project.[91] Unfortunately, as I will discuss later, some of the Applicants have assumed that natural gas-fired power plants will experience larger cost increases than the Big Stone II Project. However, there is no evidence to support this assumption.

Q. What impact would higher coal-plant capital costs have on the relative economics of energy efficiency as compared to the Big Stone II Project?

A. I have seen no evidence that the same worldwide demand for power plant resources has led to significant increase in the costs of energy efficiency measures. Therefore, it is reasonable to expect that higher coal-plant capital costs increase the relative economics and attractiveness of energy efficiency.

[91] Applicants' Exhibit 116, at page 6, lines 3-4.

6. The Applicants' Recent Modeling Analyses Do Not Show that the Big Stone II Project is a Lower Cost Option than Energy Efficiency and/or Renewable Alternatives

6.A. Otter Tail Power

Q. How many modeling analyses does Otter Tail Power witness Morlock discuss in his Supplemental Testimony?[92]

A. It is my understanding that Mr. Morlock's testimony and conclusions are based on just two model runs. In the first modeling run, Mr. Morlock determined what he considers to be "the optimized capacity expansion" plan without wholesale sales to the MISO spot market.[93] Mr. Morlock then reran the model, reflecting the same set of conditions, but with wholesale sales opportunities turned on. Other than that, both runs reflected all of the same assumptions about future costs and alternatives.

Most importantly, Mr. Morlock did not vary any other input assumptions other than turning the opportunity to make wholesale sales off and on. He did not examine the impact of higher CO_2 prices, higher Big Stone II Project construction costs, additional Project schedule delays, higher or lower fuel prices, higher or lower loads and energy requirements. He also did not compare the relative costs and benefits of alternate plans with or without the Big Stone II Project.

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[92] Applicants' Exhibit 116.
[93] Applicants Exhibit 116, at page 11, lines 8-16.

Q. You testified in Joint Intervenors Exhibit 3 that the evidence presented by Otter Tail Power in support of its claim that Big Stone II was its least cost option is unpersuasive for a number of reasons.[94] Is this still your conclusion based upon your review of the modeling analysis discussed by Applicant witness Morlock?

A. Yes. Otter Tail's claim that the Big Stone II Project remains an essential component of its overall plan is unpersuasive for a significant number of reasons.

First, Mr. Morlock's testimony and analysis really only show that the Big Stone II Project is a least-cost resource because it is picked as such by the IRP-Manager model, an out-of-date and severely limited model. Mr. Morlock provides absolutely no information on 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 impossible to evaluate the potential economic benefits that might be produced by implementing the Company's preferred plan against the risks associated with that plan or the benefits and risks of pursuing alternatives to the Big Stone II Project.

As I discussed at length last year in Exhibit JI-3, Otter Tail has acknowledged that the IRP-Manager model has significant limitations.[95] As I explained:

> 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. The Minnesota Commission should not

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[94] At page 39.
[95] At page 43, line 10, to page 45, line 2.

> rely on the results from the IRP-Manager model to find that building the Big Stone II Project is reasonable.[96]

When making such an important and far-reaching decision as whether to approve Otter Tail Power's participation in the proposed Big Stone II Project, the Commission should not rely on two modeling runs from such an out-of-date and limited model reflecting the very same set of assumptions about the future, with the only difference being the potential to make wholesale sales. Instead, the Commission should require Otter Tail to examine whether there are lower cost energy efficiency and renewables alternatives than Big Stone II using state-of-the-art capacity expansion and resource planning models such as the Strategist model used by CMMPA, MRES and MDU.

Second, Mr. Morlock did not examine whether the IRP-Manager model would take additional energy efficiency resources above the amounts required by the new Minnesota law.

Third, Otter Tail has not prepared any sensitivity analyses to examine the impact of changes in such key input assumptions as CO2 prices, the cost of the Big Stone II Project, the Project's in-service date, fuel prices, coal supply disruptions, etc. As I have shown in Sections 4 and 5 above, there is considerable uncertainty regarding future CO_2 prices and the ultimate capital cost of the Big Stone II Project. Mr. Morlock's IRP-Manager modeling ignores all of this uncertainty and only assumes that future CO2 prices will be $9/ton or less and that the final cost of the Big Stone II Project will not be any higher than the Applicants' current cost estimate.

Essentially, all that the modeling analysis discussed by Mr. Morlock shows is that the IRP-Manager model selects the Big Stone II Project as part of a least cost plan if the company's assumptions about plant costs, schedule, CO_2 prices, fuel prices,

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[96] At page 44, line 18, to page 45, line 2.

etc., are correct. There is no assessment of whether the Project would continue to be part of a least cost plan if key variables, such as CO_2 costs or plant capital costs vary, even in a modest way, from the company's assumed values.

Fourth, Otter Tail has used only a very low CO_2 price, that is, $9/ton in nominal terms, in its modeling analysis.[97]

Fifth, Mr. Morlock has artificially increased Otter Tail's need for new capacity from the Big Stone II Project by assuming that the company's required "planning reserve margin" will increase from **[TRADE SECRET MATERIALS BEGIN**

TRADE SECRET MATERIALS END]

Sixth Mr. Morlock incorrectly assumed **[TRADE SECRET MATERIALS BEGIN TRADE SECRET MATERIALS END]** in-service date for the Big Stone II Project. The Applicants' testimony in this case is that the plant is currently scheduled to come on-line on June 1, 2013.[98]

Seventh, as Mr. Fagan discusses, in its new IRP-Manager analyses, Otter Tail Power has improperly represented its net energy for load in the out years.

Eighth, in his new modeling analysis, Mr. Morlock makes a number of revised assumptions that increase the cost of and, therefore, disadvantage the alternatives to the Big Stone II Project. For example, he has increased the cost of transmission for the non-wind alternatives, such as natural gas-fired plants, to $250/kW. He also has made some adjustments that make the Manitoba Hydro alternative more expensive. At the same time that he adjusted upwards the costs of alternatives, Mr. Morlock used the Applicants' currently estimated cost for the Big Stone II Project that includes a **TRADE SECRET MATERIALS BEGIN**

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[97] Applicants' Exhibit 116, at page 3, line 5.
[98] Applicants' Exhibit 115, at page 2, lines 5-6.

TRADE SECRET MATERIALS END] due to unspecified savings in the generation portion of the project.

Given all of these biases, it really is no surprise that the IRP-Manager picked the Big Stone II Project in the modeling analysis presented by Mr. Morlock.

Q. You have mentioned that Otter Tail Power has used a \$9/ton CO_2 price. Is that price in nominal or constant year dollars?

A. The flat \$9/ton CO_2 price used by Otter Tail Power is in nominal dollars. This means that it declines over time in real terms.

Q. Is it realistic to assume that CO_2 prices will decline over time, in real terms?

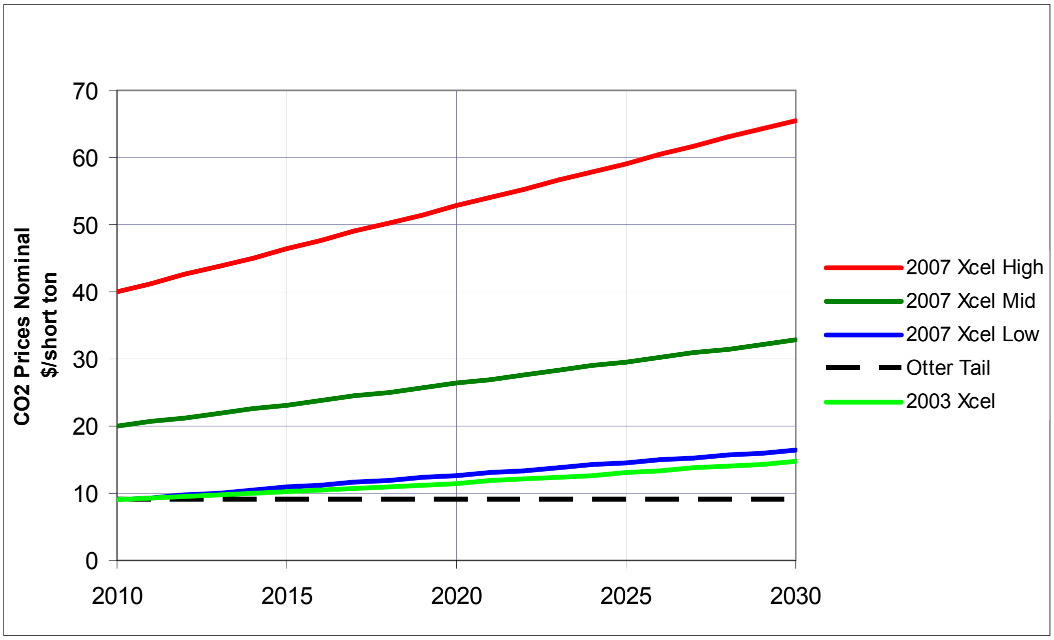
A. Absolutely not. I don't see any basis for assuming that CO_2 prices will decline over time in real terms. Instead, as shown in Figure 5 above and Figure 6 below, it is our Synapse assessment and the assessment of others, including Xcel Energy, that CO_2 prices will increase over the long-term at or above the rate of inflation, although there may be short run fluctuations up and down.

Q. Is Otter Tail Power's use of a constant \$9/ton CO_2 price consistent with the way that Xcel Energy has used a \$9/ton CO_2 price in resource planning?

A. No. Until recently Xcel Energy used a \$9/ton CO_2 price that would begin in 2010 and increase at the rate of inflation. As shown in Figure 6, below, this results in a higher set of annual CO_2 prices than have been used by Otter Tail Power in its recent modeling analyses.

Figure 6 also presents the CO_2 prices that Xcel Energy has recently announced that it is currently using in its resource planning. As can be seen, these CO_2 prices are significantly higher than the CO_2 price used by Otter Tail Power in its new Big Stone II Project modeling analyses.

Figure 6: Otter Tail and Xcel Energy CO_2 Price Forecasts



Thus, both the 2003 Xcel and the 2007 Low Xcel CO_2 prices are higher than the CO_2 price used by Otter Tail in its recent Big Stone II Project modeling analyses.

Q. Applicant witness Uggerud has testified that "most regulators" do not "believe the CO_2 cost should be higher than \$9/ton."[99] Was he able to provide any source documents or other written evidence which support this claim?

A. No. Otter Tail's response to a request for such source documents and other materials was that:

> Mr. Uggerud responds that referenced testimony is supported by his personal belief and conclusion, based on all materials he has read, and on the materials others with whom Mr. Uggerud has discussed the referenced topic have read, that as of the date of his testimony "most regulators" did not believe CO_2 emissions costs

[99] Applicants' Exhibit 114, page 7, lines 6-9.

> on each ton of CO_2 emitted by an electric generating station should exceed $9/ton.[100]

Mr. Uggerud was unable to provide even a single document that supports this claim.

Q. Is Mr. Uggerud's claim that "most regulators" do not believe the CO_2 cost should be higher than $9/ton credible?

A. No. It is complete speculation unless he is able to cite to or provide any supporting evidence and documentation. Indeed, I have not seen any polls of regulators regarding what the costs of CO_2 emissions should be. Moreover, a number of states, including Oregon, New Mexico and California require their utilities to consider CO_2 prices higher than $9/ton in their resource planning.

Q. Was Mr. Uggerud able to provide any evidence to support the judgment of Otter Tail Power that Congress will not impose a higher than $9/ton carbon cost?

A. No. Instead, Mr. Uggerud gave only a limited narrative answer that provided no specific evidence to support his claim that Congress will not impose a higher than $9/ton carbon cost.

Q. Is this judgment reasonable?

A. No. As I have shown in Figure 4 above, independent assessments by MIT, the EPA, and the EIA of the Department of Energy have shown that the legislation that has been introduced in the current Congress could lead to CO_2 emissions allowance prices far above $9/ton. Earlier in this proceeding, the Applicants argued that the climate change proposal that was being circulated by Senator Bingaman was the most probable option. Even the safety valve CO_2 prices in the

[100] Applicants' Response to Joint Intervenors IR No. 293. A copy of this Response is included as Exhibit JI-35-O.

Low Carbon Economy Act introduced by Senators Bingaman and Specter in July of 2007 would start at $12/ton in 2012 and increase at five percent above the rate of inflation. Obviously, this would mean CO2 prices that would start above $9/ton and climb far higher over time.

Q. What planning reserve margins does Otter Tail Power use in its new IRP-Manager modeling analyses?

A. The output files for the new modeling runs performed by Otter Tail Power suggest that the company has used the following planning reserve margins in its new modeling analyses.

[TRADE SECRET MATERIALS BEGIN

TRADE SECRET MATERIALS END]

The impact of the jump in the planning reserve margin in 2013 from **[TRADE SECRET MATERIALS BEGIN TRADE SECRET MATERIALS END]** would be to artificially inflate the amount of capacity that the model would add in that year, thereby increasing the amount of Big Stone II selected by the model.

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

A. No. Last year we considered 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 concluded that we would not be able modify Otter Tail Power's IRP-Manager database for use in the Strategist model in the five weeks we have had available to prepare this testimony.

Q. Didn't Otter Tail Power state last year that it was switching to the Strategist model for resource planning?

A. Yes.

Q. Has Otter Tail Power explained why it has not used the Strategist model to prepare its new Big Stone II Project related modeling analyses?

A. Yes. Mr. Morlock has presented a litany of problems that he says delayed the transition to the Strategist model. Now the Company is aiming to use the Strategist model for its 2008 Resource Plan analyses.[101]

Q. Is this reasonable?

A. No. The decision to proceed with the Big Stone II Project is a major financial commitment for the Company and a major risk for its ratepayers. The most up-to-date resource planning model should be used to evaluate the costs and risks of the Big Stone II Project and the various alternatives. Strategist is a far more robust tool for evaluating resource alternatives. In contrast, the IRP-Manager model is an inadequate and out-dated tool for examining the full range of risks posed by the proposed Big Stone II Project.

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[101] Applicants' Response to Joint Intervenors' Information Request No. 250. A copy of this Response is included as Exhibit JI-35-P.

Q. What is your conclusion regarding Otter Tail Power's recent modeling analyses?

A. Otter Tail Power has not presented credible evidence that the Big Stone II Project is a lower cost and lower risk option than a portfolio of alternatives that would include energy efficiency, renewable resources and, to the extent necessary, some natural gas-fired capacity.

6.B. CMMPA

Q. Has CMMPA shown that it needs any capacity from the Big Stone II Project in 2013 or subsequent years to ensure system reliability?

A. No. Table 7 below presents CMMPA's reserve margins with and without the Big Stone II Project for the years 2006-2035. These figures were taken directly from the output files of the Strategist modeling performed by CMMPA witness Davis. Thus, the results of CMMPA's own modeling shows that it would not need any capacity from the Big Stone II Project to meet a 15 percent reserve margin until 2033, at the earliest.

[TRADE SECRET MATERIALS BEGIN

TRADE SECRET MATERIALS END]

Q. Is it nevertheless possible that adding facilities to provide baseload energy would be an economic option for CMMPA even though it does not need any new capacity for reliability purposes?

A. Yes. That is theoretically possible. However, it is not likely given the relative costs of the Big Stone II Project and other resources. Moreover, CMMPA has not shown that the Big Stone II Project would be the lowest cost option for providing such baseload energy because its new modeling analyses are flawed and biased in favor of the Project.

Q. What flaws or biases have you identified in CMMPA's new Big Stone II Project modeling analyses?

A. We found the following flaws and biases in CMMPA's new modeling of the Big Stone II Project:

- CMMPA did not allow the Strategist model to add capacity, including wind, prior to 2013 even though it might be more economic to do.
- As Mr. Fagan has discussed, CMMPA underestimated the effect of the 1.5% CIP mandate and exaggerated the need for energy in the years beginning in 2020.
- CMMPA failed to model a reasonable range of future CO_2 prices.
- CMMPA failed to evaluate the impact of further increases in the construction cost and further delays in the completion of the Big Stone II Project.

Q. Did you rerun the Strategist model to correct for these flaws and biases?

A. Yes. We reran the model to (1) allow for the addition of capacity prior to 2013, (2) to examine a reasonable range of CO_2 prices, (3) to examine the consequences of further escalation in the cost of building the Big Stone II Project and (4) to correct for CMMPA's underestimation of the 1.5% CIP mandate.

Q. What were the results of your analyses?

A. The results of our runs are presented in Table 8 below:

Table 8: Synapse CMMPA Modeling Results – MWs of the Big Stone II Project selected by Strategist Model

Scenario	Synapse CO_2 Price Scenario		
	Low	Mid	High
Base	21	10.5	0
BSII Capital Cost +10%	10.5	0	Did Not Run
CIP Correction	21	0	Did Not Run

Thus, the Strategist model selected less Big Stone II Project capacity as part of its lowest cost plans when we used CMMPA's base case assumptions but with our Synapse Low and Mid CO_2 price forecasts. The Strategist model selected none of Big Stone II with our Synapse High CO_2 price forecast.

Similarly, the Strategist model only chose 10.5 MW of the Big Stone II Project when we increased the capital cost of the Big Stone II Project by 10 percent and used the Synapse Low CO_2 price forecast. The model did not select any of the Big Stone II Project in its lowest cost plan when we increased the Project's capital cost by 10 percent and used the Synapse Mid CO_2 price forecast. Given this result, we saw no reason to run the 10 percent higher Big Stone II capital cost with the Synapse High CO_2 price forecast. We also saw no need to examine the impact of larger increases in the Project's construction cost because so little of the Project was selected with only a 10 percent increase, we expect that none of the Project's capacity would be chosen if we assumed a 20 percent or higher capital cost increase.

Finally, the model chose just 21 MW of the Big Stone II Project when we corrected for the CIP underestimation error discussed by Mr. Fagan and the Synapse Low CO_2 price forecast. The model did not select any of the Big Stone II Project when we made the CIP correction and used the Synapse Mid CO_2 price forecast. Given this result, we saw no need to run the CIP correction with the Synapse High CO+ price forecast.

Q. What alternative capacity did the Strategist model add for CMMPA in those scenarios in which it did not select any of the Big Stone II Project?

A. Essentially the Strategist selected more wind and more gas-fired capacity in place of the Big Stone II Project. The specific alternative capacity selected in our modeling scenarios is shown in Table 9 below.

Table 9: Alternative Capacity Selected for CMMPA by the Strategist Model in Lowest Cost Plans in Synapse Analyses

	Base			BSII Capital Cost +10%		CIP Correction	
Year	Synapse Low CO_2 Price	Synapse Mid CO_2 Price	Synapse High CO_2 Price	Synapse Low CO_2 Price	Synapse Mid CO_2 Price	Synapse Low CO_2 Price	Synapse Mid CO_2 Price
2007							
2008							
2009							
2010	Wind (40 MW)	Wind (40 MW)	Wind (40 MW)	Wind (40 MW)	Wind (40 MW)	Wind (40 MW)	Wind (40 MW)
2011	CC (10 MW)	CC (10 MW)	CC (10 MW) Wind (40 MW)	CC (20 MW)	CC (10 MW) Wind (40 MW)	CC (10 MW)	CC (10 MW) Wind (40 MW)
2012							
2013	BS2 (21 MW)	BS2 (10.5 MW)		BS2 (10.5 MW)		BS2 (21 MW)	
2014							
2015		Wind (40 MW)		Wind (40 MW)	CC (10 MW)		
2016	Wind (40 MW)	Wind (40 MW)	Wind (40 MW)		Wind (40 MW)	Wind (40 MW)	Wind (40 MW)
2017				Wind (40 MW)			
2018			Wind (40 MW)				
2019	Wind (40 MW)				Wind (40 MW)	Wind (40 MW)	Wind (40 MW)
2020							
2021		Wind (40 MW)					
2022				Wind (40 MW)			
2023							
2024	Wind (40 MW)		Wind (40 MW)				
2025							
2026					Wind (40 MW)		
2027		Wind (40 MW)					
2028							
2029							
2030				Wind (40 MW)			
2031							
2032	Wind (40 MW)						
2033							
2034			CC (10 MW)				
2035							

6.C. MDU

Q. Have you identified any flaws or biases in the modeling analyses presented by MDU witness Heidell?

A. Yes. MDU's analyses are heavily biased in favor of the Big Stone II Project by the following:

- MDU failed to reflect any CO_2 prices whatsoever, let alone look at a reasonable range of possible CO_2 prices.
- MDU failed to evaluate the impact of further increases in the construction cost and further delays in the completion of the Big Stone II Project.
- MDU made a number of assumptions that heavily bias the analysis against natural gas-fired alternatives:
  - MDU assumed that the operating life and book life for the Big Stone II Project were set at 40 years while these inputs are set at only 25 years for the natural gas-fired CC and CT options.
  - MDU used a levelized charge rate for the CC and CT options of 11.54% (corresponding with the shorter book life) while the levelized charge rate for the Big Stone II Project was 9.97%.
  - The natural gas prices used by MDU in its modeling were **[TRADE SECRET MATERIALS BEGIN TRADE SECRET MATERIALS END]** than the natural gas price forecasts used by Otter Tail Power, MRES, CMMPA, and in the levelized cost analyses presented by Applicant witness Greig. This was especially true in the years 2012 through approximately 2018.
  - In its Base Case, MDU did not allow the model to choose a CC after 2013.
  - **[TRADE SECRET MATERIALS BEGIN**

    TRADE SECRET MATERIALS END]
- MDU did not allow the model to select increments of the Big Stone II Project. Instead, the model is required to choose all 116 MW of MDU's current share or none of the Project.

Q. What prices did MDU assume for the cost of building combined cycle natural gas-fired capacity?

A. MDU assumed a price of $1,795/kW in 2006 dollars. This was **[TRADE SECRET MATERIALS BEGIN TRADE SECRET MATERIALS END]** than the cost of a CC assumed by Otter Tail Power and CMMPA and was **[TRADE SECRET MATERIALS BEGIN**

.[102] **TRADE SECRET MATERIALS END]**

Q. Can you illustrate how much [TRADE SECRET MATERIALS BEGIN higher TRADE SECRET MATERIALS END] the natural gas prices used by MDU in its modeling analyses were than the natural gas prices used by the other Applicants in their new modeling analyses?

A. Yes. Figure 8 below presents the natural gas prices used by MDU, Otter Tail Power, CMMPA and MRES in their new modeling analyses and by Applicant witness Greig in his base case levelized cost analysis. As can be seen, the natural gas prices used by MDU were **[TRADE SECRET MATERIALS BEGIN**

TRADE SECRET MATERIALS END] than any of the other Applicants or Mr. Greig have assumed.

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102 For example, see the Applicants' Response to Joint Intervenors' Information Request No. 291, at Bates Page Number JCO0013878. A copy of this page is included in Confidential Exhibit JI-35-Q.

[TRADE SECRET MATERIALS BEGIN

TRADE SECRET MATERIALS END]

The natural gas prices used by MDU were especially high in the years 2012 through 2018 which are the years in which the model would be evaluating whether to add the Big Stone II Project or alternative gas-fired generating facilities.

Q. Do you have any observations about the testimony of MDU witness Heidell that the resource plans with the Big Stone II Project are less expensive than the resource plans without the Project?

A. Yes. MDU performed two sets of modeling analyses. One set for a 500 MW sized Big Stone II Project. A second for a 580 MW sized Project.

In MDU's base case modeling for the 500 MW sized Project, which reflected all of MDU's assumptions, the Strategist model included a full 116 MW share of the Big Stone II Project in its lowest cost plan. However, the lowest cost plan without the Big Stone II Project cost only $12.3 million more, in 2006 dollars, and, therefore, was just 0.56 percent more expensive than the plan with the Big Stone II Project. Moreover, the lowest cost plan *without* the Big Stone II Project actually cost 5.6 percent less expensive than the plan with the Project during the planning period which runs through 2026.

This means that even with MDU's chosen assumptions, including no CO_2 costs, the plan with the 500 MW Big Stone II Project was more expensive during the Project's first thirteen years of operations, i.e., 2013-2026. The end effects modeled by Strategist overcame the poorer economics of the Big Stone II Project during these first thirteen years of operations.

Similarly, in the MDU Strategist model runs for a 580 MW sized Project, the lowest cost plan without Big Stone II Project was 4.40 percent less expensive than the lowest cost plan with the Project during the period through 2026. Again, the end effects modeled by Strategist overcame the poorer economics of the Big Stone II Project during its first thirteen years of operations.

In other words, in MDU's own base case runs, that is, with the 500 MW and 580 MW sized Projects, Big Stone II was the more expensive option during the nearer-term period through 2026. It was only in the more distant, and more uncertain future, that the Strategist model presented Big Stone II as a lower cost option.

Q. Have you rerun MDU's modeling analyses to reflect more reasonable assumptions?

A. Yes. We have run a number of scenarios to see whether the Strategist model would include any of the Big Stone II Project if we included the Synapse CO_2 price forecasts or if we increased the Project's current estimated cost by a minor amount, that is, ten percent.

Q. What changes did you make to MDU's assumptions when you reran the Strategist model?

A. We modeled different CO_2 price scenarios: a \$9/ton price in 2013, increasing at the rate of inflation plus the Synapse Low CO_2 price forecast. We also ran scenarios in which the cost of building the Big Stone II Project was increased by 10 percent. In addition, we ran scenarios in which we corrected for the unreasonably short operating and book lives that MDU had used for the combined cycle and combustion turbine alternatives. Finally, in one scenario we allowed the model the option to select the Big Stone II Project in 23.2 MW increments. Thus, the model was not constrained to select none or all of the Big Stone II Project.

Q. What were the results of your analyses?

A. The amount of Big Stone II Project capacity selected by the Strategist model in each of the scenarios we examined are shown in Table 10 below. The MDU base case results for the 500 MW and 580 MW Big Stone II Projects are included for comparison purposes:

Table 10: Synapse MDU Modeling Results – MWs of the Big Stone II Project selected by Strategist Model

Scenario	MW of Big Stone II Selected
MDU 500MW Base Case with \$0/ton CO_2 Price	116
MDU 500MW Base Case + \$9/ton CO_2 Price Escalated at 2.5% Per year	0
MDU 500MW Base Case + Synapse Low CO_2 Price	0
MDU 500MW Base Case + 10% Higher BSII Capital Cost	0
MDU 500MW Base Case + Corected CC/CT Operating & Book Lives & LCR	0
MDU 580 MW Base Case with \$0/ton CO_2 Price	116
MDU 580MW Base Case + 10% Higher BSII Capital Cost	0
MDU 580MW Base Case + Synapse Low CO_2 Price + Corrected CC/CT Operating & Book Lives & LCR	0
MDU 580MW Base Case + Synapse Low CO_2 Price + Model Allowed to Select Big Stone II in 23 MW Increments	23

Thus, the Strategist model did not include any capacity from a 500 MW sized Big Stone II Project in its lowest cost plan when we assumed either (1) any CO2 price of \$9/ton or higher, (2) 10 percent escalation in the current Big Stone II Project capital cost or (3) more reasonable operating and book lives for combined cycle and combustion turbine capacity that the assumptions used by MDU in its modeling analyses.

The Strategist model also did not include any capacity from a 580 MW sized Big Stone II Project when we (1) increased the Project's capital cost by 10 percent or

(2) corrected for the unreasonably short combined cycle and combustion turbine operating and book lives used by MDU. The model selected only 23 MW of the Big Stone II Project when we reran the Company's base case with our Synapse Low CO_2 prices and allowed the model to select capacity from the Project in 23 MW increments.

Q. In the scenarios where you increased the capital cost of the Big Stone II Project by 10 percent, did you also increase the capital costs of the alternatives by a comparable amount?

A. No. As I noted earlier, MDU already had assumed extremely high capital costs for the combined cycle and combustion turbine alternatives. It was not necessary or appropriate to further increase the costs of these alternatives when we increased the cost of the Big Stone II Project. The costs for combined cycle and combustion turbine facilities assumed by MDU already accounted for any escalation above their reasonable values based on current market prices or the Black and Veatch projections.

Q. What alternative capacity did the Strategist model add for MDU in those scenarios in which it did not select any of the Big Stone II Project?

A. Essentially the Strategist selected more wind and more CT capacity in place of the Big Stone II Project. The specific alternative capacity selected in our modeling scenarios is shown in Table 11 below.

Table 11: Alternative Capacity Selected for MDU by the Strategist Model in Lowest Cost Plans in Synapse Analyses

Year	MDU 500MW Base Case + \$9/ton CO_2 Price (Escalated)	MDU 500MW Base Case + Synapse Low CO_2 Price	MDU 500MW Base Case + 10% Higher BSII Capital Cost	MDU 500MW Base Case + Corrected CC/CT Operating & Book Lives & LCR	MDU 580MW Base Case + 10% Higher BSII Capital Cost	MDU 580MW Base Case + Synapse Low CO_2 Price + Corrected CC/CT Operating & Book Lives & LCR	MDU 580MW Base Case + Synapse Low CO_2 Price + BSII Increments
2007							
2008	DSM	DSM	DSM	DSM	DSM	DSM	DSM
2009	DSM	DSM	DSM	DSM	DSM	DSM	DSM
2010	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)
2011	Wind (61.2 MW) CT (87 MW)	Wind (61.2 MW) CT (87 MW)	Wind (61.2 MW) CT (87 MW)	Wind (61.2 MW) CT (87 MW)	Wind (61.2 MW) CT (87 MW)	Wind (61.2 MW) CT (87 MW)	Wind (61.2 MW) Xcel Contract (105 MW)
2012	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	CT (43.5 MW) Wind (30.6 MW) Wind (30.6 MW)
2013							BS2 (23.2 MW)
2014							CT (43.5 MW)
2015							
2016							
2017	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	
2018							
2019							
2020							
2021							CT (43.5 MW)
2022							
2023							
2024	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	
2025							
2026							

7. The analysis presented by Applicant Witness Greig Does Not Show that the Big Stone II Project is a Lower Cost Option than Energy Efficiency and/or Renewable Alternatives

Q. You testified in Joint Intervenors Exhibit 3 that the Commission should not rely on the analysis presented by Applicant witness Greig because that analysis is significantly flawed and biased in favor of the Big Stone II Project.[103] Is Mr. Greig's new analysis similarly flawed and biased in favor of the Project?

A. Yes. The analysis presented by Mr. Greig in Applicants Exhibits 121 and 121-A is biased in favor of the Big Stone II Project in the following ways:

- Mr. Greig does not assume any low cost energy efficiency in his CCGT + Wind alternative, thereby ignoring the new Minnesota legislation that mandates energy efficiency savings of 1.5 percent per year.[104] Consequently, Mr. Greig's levelized analysis does not show that the Big Stone II Project is a lower cost option than energy efficiency. Indeed, the addition of low cost energy efficiency would lower the cost of the CCGT + Wind option as compared to Big Stone II.
- Mr. Greig only considered a very low and narrow range of future CO_2 prices, that is, from \$0/ton to \$9/ton. As I have demonstrated in Section 4 above, this is significantly below a more reasonable range of CO_2 prices that should be used in resource planning.
- Contrary to the assumptions used by his clients in their modeling analyses, Mr. Greig assumes no capacity credit for wind. He therefore overbuilds the amount of natural gas capacity. This leads him to unreasonably inflate the levelized cost of the CCGT + Wind alternative because it requires building more CCGT capacity.
- Mr. Greig does not prepare any sensitivity analyses to reflect the risk that the Project's ultimate cost may be significantly higher.
- Mr. Greig assumes that the two investor-owned utility Applicants would finance their investments in the Big Stone II Project and the CCGT + Wind alternatives with a capital structure that is 50 percent equity and 50 debt. **[TRADE SECRET MATERIALS BEGIN**

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[103] At pages 111-113.
[104] Minn. Stat. Sec. 216B.241 subd. 1c and Minn. Stat. Sec. 216B.2401.

[105]

.[106] **TRADE SECRET MATERIALS END]** Equity has a higher cost than debt (12% vs. 7.5% in Mr. Greig's analysis). Consequently, Mr. Greig's use of a 50/50 capital structure instead of the actual Otter Tail and MDU capital structures, causes him to understate the cost of financing both Big Stone II and the CCGT + Wind option. However, the effect is much more significant for Big Stone II which has a far higher construction cost that would need to be financed than the CCGT + Wind option. This biases the results of his analysis in favor of Big Stone II because his capital costs do not reflect the full costs of financing.

- Mr. Greig's scenarios that assume that the wind production tax credit will not be available in 2013 are unrealistic and contrary to the assumptions of his clients in their recent Big Stone II Project modeling.

Q. What wind capacity credits do the Big Stone II Project Applicants assume in their recent modeling studies?

A. CMMPA assumes a **[TRADE SECRET MATERIALS BEGIN TRADE SECRET MATERIALS END]** percent capacity credit for wind. MRES assumes a **[TRADE SECRET MATERIALS BEGIN TRADE SECRET MATERIALS END]** percent capacity credit for wind. MDU assumes a **[TRADE SECRET MATERIALS BEGIN TRADE SECRET MATERIALS END]** percent capacity credit for wind.

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105 See the Applicants' Confidential Response to Joint Intervenors' Information Request No. 243, at Bates Page Number, OTP0008601. A copy of this page is included in Confidential Exhibit JI-35-M.

106 Id, at Bates Page Number OTP0008605.

Q. What impact would assuming a capacity credit for wind have on the results of Mr. Greig's analysis?

A. Assuming a capacity credit for wind would mean that less combined cycle capacity would need to be built in the CCGT + Wind alternative. This should lead to a lower levelized cost.

Q. Have any of the Applicants assumed that the wind Production Tax Credit will remain in effect through 2013?

A. Yes. Mr. Morlock has testified that Otter Tail Power has assumed in its recent modeling that the Federal Production Tax Credit would be renewed for five years through 2013 but then not be available that point.[107]

Q. Is this a reasonable assumption?

A. I agree that it is reasonable to assume that the wind Production Tax Credit will be renewed through 2013. The prospects for the Credit after that point are uncertain. However, it has been renewed on a number of occasions and may again be renewed by the Congress in or before 2013. In any event, I agree with Mr. Morlock that the Production Tax Credit will be in effect through at least 2013. For this reason, Mr. Greig's scenarios that assume no PTC should be given little or no weight.

Q. Have you seen how any other investor owned utilities that provide service in Minnesota have addressed the potential extension of the wind Production Tax Credit?

A. Yes. In its recently filed 2007 Resource Plan filing, Xcel Energy has assumed that the Production Tax Credit will be extended through 2015.[108]

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[107] Applicants' Exhibit 116, at page 9, lines 1-7.
[108] At page 4-4.

Q. Have you requested information from Otter Tail Power and MDU regarding their current and projected capital structures and costs of equity and debt?

A. Yes. We wanted to see how Mr. Greig's results would change if his analysis reflected both Otter Tail and MDU current actual capital structures and plans for the future instead of just a 50/50 mix of equity and debt. Unfortunately, the Applicants objected to providing this information.[109] The Judges have now directed the Applicants to provide this information but they have not yet done so. Therefore, we have been unable thus far to evaluate the significance of changing Mr. Greig's analysis to reflect more realistic assumptions.

Q. Have you recalculated Mr. Greig's analysis to correct for each of the flaws that you have identified above?

A. No. Due to the extremely accelerated schedule in this proceeding and lack of information produced in discovery we have only had the chance to correct Mr. Greig's analysis to reflect the set of Synapse CO_2 price forecasts.

Q. What were the results of your recalculation of Mr. Greig's levelized analysis using the Synapse CO_2 price forecasts?

A. The results of our recalculation of Mr. Greig's analysis changing only the assumed CO_2 prices from the \$0/ton and \$9/ton figures used by Mr. Greig to the Synapse Low, Mid and High price forecasts are shown in Tables 12, 13, and 14 below.

[109] For example, see the Applicants' Responses to Joint Intervenors' Information Requests Nos. 282 through 287. Copies of these Responses are included in Exhibit JI-35-R.

Table 12: Greig Analysis with Synapse Low CO_2 Price Forecast

	CCGT + Wind	500 MW Big Stone II	580 MW Big Stone II
	($/MWh)	($/MWh)	($/MWh)
Greig Gas Cost - $1.00/MMBTU	$85.53	$87.72	$85.36
Greig Gas Cost - $0.50/MMBTU	$87.16	$87.72	$85.36
Greig Base Gas Cost	$88.94	$87.72	$85.36
Greig Gas Cost + $0.50/MMBTU	$91.05	$87.72	$85.36
Greig Gas Cost + $1.00/MMBTU	$93.46	$87.72	$85.36

Table 13: Greig Analysis with Synapse Mid CO_2 Price Forecast

	CCGT + Wind	500 MW Big Stone II	580 MW Big Stone II
	($/MWh)	($/MWh)	($/MWh)
Greig Gas Cost - $1.00/MMBTU	$88.43	$103.27	$101.07
Greig Gas Cost - $0.50/MMBTU	$90.37	$103.27	$101.07
Greig Base Gas Cost	$92.77	$103.27	$101.07
Greig Gas Cost + $0.50/MMBTU	$95.22	$103.27	$101.07
Greig Gas Cost + $1.00/MMBTU	$97.72	$103.27	$101.07

Table 14: Greig Analysis with Synapse High CO_2 Price Forecast

	CCGT + Wind	500 MW Big Stone II	580 MW Big Stone II
	($/MWh)	($/MWh)	($/MWh)
Greig Gas Cost - $1.00/MMBTU	$92.08	$120.00	$117.90
Greig Gas Cost - $0.50/MMBTU	$94.50	$120.00	$117.90
Greig Base Gas Cost	$97.00	$120.00	$117.90
Greig Gas Cost + $0.50/MMBTU	$99.50	$120.00	$117.90
Greig Gas Cost + $1.00/MMBTU	$102.00	$120.00	$117.90

Thus, changing only the CO_2 prices makes both the 500 MW and the 580 MW sized Big Stone II Project options significantly more expensive than the CCGT + Wind alternative in each of the natural gas price scenarios with the Synapse Mid and High CO_2 price forecasts. With the Synapse Low CO_2 price Forecast, the CCGT + Wind and 500 MW Big Stone II Project are close in price with low natural gas prices; the 500 MW Big Stone II Project has a slightly lower levelized cost with higher natural gas prices. Finally, with the Synapse Low CO_2 price Forecast, the 580 MW has a lower cost than the CCGT + Wind option except that the levelized cost of the 580 MW coal and CCGT + Wind alternatives narrows with lower natural gas prices .

Q. Why have you included the Greig Gas Cost - $0.50/MMBTU and Greig Gas Cost - $1.00/MMBTU natural gas prices in your recalculation of Mr. Greig's levelized analysis?

A. I included the two lower natural gas prices in my recalculation of Mr. Greig's levelized analysis to reflect the great uncertainty surrounding future natural gas prices. Mr. Greig talks about the uncertainty surrounding natural gas prices, but only examines sensitivities that reflect higher natural gas prices than he assumes in his base case. I have included the two lower natural gas price forecasts to reflect the possibility that natural gas prices will be lower than Mr. Greig now projects in his base case. In fact, as shown in Figure 8 above, the gas prices used by OTP, CMMPA and MRES in their new modeling analyses are [**TRADE SECRET MATERIALS BEGIN TRADE SECRET MATERIALS END]** than those used by Mr. Greig.

Q. What do you think would be the impact of correcting for the other flaws you have found in Mr. Greig's analysis?

A. Assuming some low cost energy efficiency, a reasonable capacity credit for wind, further increases in the cost of the Big Stone II Project, and more realistic capital structures for Otter Tail Power and MDU almost certainly would improve the relative economics of the CCGT + Wind alternative compared to the Big Stone II Project.

Q. Have you revised Mr. Greig's analysis for the public power participants in the Project?

A. No. Early last week we discovered a flaw in Mr. Greig's Excel file workbooks for the public power entities that prevented us from affecting the ultimate levelized prices by changing the CO_2 costs. We asked for an opportunity to talk with Mr.

Greig to discuss this problem. However, the Applicants did not respond to this request until Tuesday, December 18th. Unfortunately, it is now too late to address this issue before we must file my testimony.

Q. What is your overall conclusion regarding the levelized price analysis presented by Applicant witness Greig?

A. The Commission should not rely on Mr. Greig's levelized price forecast as evidence that the Big Stone II Project will be a lower cost option for Otter Tail Power and MDU than wind or energy efficiency in combination with some natural gas-fired combined cycle capacity.

Q. Does this complete your testimony?

A. Yes.