OTP/MDU EXHIBIT 337

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

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER CORPORATION D/B/A

OTTER TAIL POWER COMPANY

AND

MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

PREFILED REBUTTAL TESTIMONY

OF

THOMAS HEWSON

PRINCIPAL

ENERGY VENTURES ANALYSIS, INC.

APRIL 23, 2008

304 PU-06-481 Filed 04/23/2008 Pages: 165
Application for Trade Secret Protection/Applicants' Prefiled Rebuttal Testimony
Otter Tail Corporation and Montana-Dakota Utilities Co.
Lindquist & Vennum PLLP by Todd Guerrero

PREFILED REBUTTAL TESTIMONY OF THOMAS HEWSON

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BEFORE THE NORTH DAKOTA SERVICE COMMISSION

PREFILED REBUTTAL TESTIMONY OF THOMAS HEWSON

I. INTRODUCTION

Q: Please state your name.

A: Thomas A. Hewson, Jr. I am a principal at Energy Ventures Analysis, Inc., (EVA) an energy consulting firm located at 1901 North Moore Street in Arlington Virginia.

Q: On whose behalf are you submitting testimony?

A: Otter Tail Power Company and Montana-Dakota Utilities Co., (the "Applicants").

Q: What are your qualifications?

A: I have over 30 years of experience as an environmental consultant on energy issues. My responsibilities at EVA include conducting environmental studies of the electric power industry. These studies include assessments of the cost and performance of electric power environmental control options, development of environmental compliance strategies, emission allowance market forecasts, and evaluations of existing and proposed future environmental regulations on electric power operations. I have testified in several state proceedings and to Congress on the effects of proposed environmental regulations on individual state power production costs, on state emissions and on environmental benefits. I have testified on behalf of the Big Stone II Applicants in both South Dakota and Minnesota proceedings dealing with the carbon risk and wind alternative risks. A copy of my résumé is provided as OTP/MDU Exhibit 338.

Q: What is the purpose of your rebuttal testimony?

A: I will respond to Mr. Schlissel's criticisms regarding the risk inherent in building a new coal plant—namely from future carbon dioxide regulation and from construction cost escalation.

In his testimony, he says these two issues are largely responsible for several utilities deciding not to pursue new coal-fired generating powerplants. In addition, while construction costs have indeed increased for the Big Stone II project, they have also escalated for all other competing generation options as well, so coal remains the low cost baseload alternative. I will also provide evidence that while many projects have been delayed, numerous coal projects remain active and are being pursued by power providers as part of their lowest cost baseload resource option. The U.S. Department of Energy in its electricity system modeling confirms that coal power will likely remain a low cost baseload generation alternative even under future climate change regulation.

Second, I will respond to Mr. Schlissel's testimony on the wind alternative costs and the outlook for the extension of the Production Tax Credit (PTC). Studies by Burns and McDonnell show that without the PTC, the wind-gas alternative is unable to effectively compete with the coal based alternative. Mr. Schlissel argues that the extension of the PTC will allow wind in combination with building a natural gas combined cycle plant to become a competitive alternative to the preferred Big Stone II option. I will discuss Mr. Schlissel's failure to adequately consider risk factors for wind power resources – particularly his assumption that the wind energy PTC will be extended forever; his apparent assumption that Applicants can purchase below market-cost wind power; and his assumption that future CO2 regulation will not affect the future price of wind power (by generally uplifting wholesale electric prices). Mr. Schlissel's position seems to be that Applicants should only consider rosy scenarios for wind resources and worst-case scenarios for carbon-emitting resources. I will provide evidence that the Applicants have been conservative in their wind cost assumptions for this screening analysis.

In addition, I will explain why there is a material risk that the PTC will expire before Big Stone II is built.

II. FUTURE CARBON REGULATION RISK

Q: In Mr. Schlissel's Supplemental Direct Testimony (pp. 41-54), he argues that the Big Stone II Applicants have not adequately considered the risks associated with future federally mandated greenhouse gas reductions. Do you agree with his criticism?

A: I do not. The Applicants are specifically required not to take carbon risk into account in North Dakota resource selection decisions. North Dakota Code § 49-02-23 is very specific in that it does not allow the electric utilities to take into account any "alleged costs of complying with future laws or regulations that have yet to be enacted" in the selection of electric resources. Since neither North Dakota nor Congress has adopted any legislation to regulate carbon dioxide emissions from the electric utility sector, the Applicants must exclude any quantification of potential future carbon risks in their resource selection.

Beyond that, the carbon risk issue has been raised by interveners in the Big Stone II permitting proceedings in both South Dakota (Case No. EL05-022) and Minnesota (MPUC Docket Numbers CN-05-619 and TR-05-1275). In both of these proceedings, I was asked by the Applicants to examine the project carbon risk issue.

Q: What was your conclusion about the project carbon risk issue in these other state proceedings?

A: My conclusion was that future carbon regulation would likely <u>not</u> change the Applicant's selection of the coal-fired Big Stone II plant as the lowest cost resource option. In both proceedings, I found that Mr. Schlissel, representing the environmental intervenors in both proceedings, significantly overstated project carbon risk. His position on carbon risk was the same in those proceedings as in this North Dakota proceeding.

Q: Would you please summarize your findings dealing with the carbon risk issue in these proceedings and why you conclude that Mr. Schlissel has overstated this risk even if it was considered?

A: My carbon risk findings for the Big Stone II projects are summarized as follows:

- A material risk exists that Congress will enact future legislation to control carbon dioxide emissions from the electric utility industry. However, great uncertainty remains over the type of program that may be adopted.

- While the most important program provisions affecting compliance cost remain uncertain (affected sources, emission limit, trading, offset credit limitations, implementation schedule, cost caps, etc.), Congress appears to be much more likely to adopt a cap and trade program than an emissions' tax program. This preference was demonstrated in the Lieberman-Warner bill (S.2191), a proposal that was approved in December 2007 by the Senate Committee on Environment and Public Works, making it the only bill mandating greenhouse gas emission reductions to be reported out of a Congressional committee to date.

- Under the preferred cap and trade programs being debated by Congress, a portion of emission allowances will be allocated at no cost to affected parties to reduce their compliance cost impact. In the case of the proposed Lieberman-Warner S 2191 bill, the ***Big Stone II facility would be allocated "no cost" allowances equivalent to roughly half of its emissions through 2026 (section 3902(a)(2)) before being phased out in 2031. Therefore, the Applicants would be required to purchase allowances and/or offsets to cover the other half of projected plant emissions—not 100 percent as assumed by Mr. Schlissel*** in his testimony. In the other leading Congressional proposals—Bingaman Specter (S 1766), Feinstein-Carper (S 317), and Oliver (HR 620)—Big Stone II would also be entitled to an allocation of "no cost" allowances.

- Under all leading Congressional proposals, the Applicants could further lower their carbon emission liability and cost through purchase of lower cost domestic and/or international offsets in lieu of purchased allowances. In the case of the Lieberman Warner proposal, the Applicants could purchase domestic offset allowances as an alternative compliance measure to cover up to 15 percent of the plant emissions (Subtitle D, Section 2402). International carbon credits could also be used to cover an additional 15 percent of their emissions (Subtitle E, Section 2405). Current domestic offset prices range from \$2 – 5/ton CO_2e (carbon dioxide equivalents), far less than the costs of direct emission reduction options. While these offset prices would likely rise under new climate change legislation, they would remain less than future carbon allowance trading prices and will play an important role in reducing compliance costs. ***The use of these lower-cost offset credits to cover an additional 15-30 percent of the facility emissions was not considered by Mr. Schlissel in his carbon risk evaluation***. As a result, Synapse again overstates the facility's carbon risk.

- The remaining facility carbon emissions liability (22-37 percent of the total emissions) in the short and intermediate term would be covered through purchased allowances.

- In the long-term after the no-cost allowances are phased out in 2031, allowance prices should be significantly influenced by the commercial development of carbon capture and sequestration technologies that should provide a technology based price cap on future allowance prices. The Electric Power Research Institute believes that the cost of the existing MEA carbon capture technology will be reduced from near $100/ton today to $30-35/ton in the near term and decrease to $20-23/ton in the intermediate term through use of alternative sorbents. One alternative sorbent process developer, Alstrom, estimated that its chilled ammonia process for carbon capture being demonstrated in Wisconsin this year will have estimated costs of $20/ton CO2e removed. The DOE goal as outlined in its Carbon Sequestration Technology Roadmap and Program Plan 2006 has a goal of 90 percent carbon capture with less than a 10 percent increase in the cost of energy by 2012. This DOE goal would translate to a carbon removal cost of approximately $5-10/ton CO2 captured. At these costs, coal technologies would remain the lowest baseload generation alternative.

III. WIND POWER RISKS

Q: Mr. Schlissel in his testimony identifies potential uncertainties and risks for new coal plants. Does he discuss and quantify the uncertainties and risks for his preferred alternatives—renewables and energy conservation?

A: While Mr. Schlissel lists only three uncertainties (p. 19) for renewable and energy efficiency options, he does not attempt to discuss or quantify them. He has also provided only a partial list of these risk factors.

Q: Are there significant economic risks in his preferred wind alternative?

A: Yes. While wind power itself poses no CO_2 risk, the wind option poses a much greater capital risk, output performance risk, and a larger economic risk from loss of large governmental renewable subsidy programs. In addition, since wind must be backed up by natural gas power, wind does have a CO_2 price risk as well.

Wind production costs are dominated by capital investment costs. Their overall costs are more capital intensive (on a $/kwh basis) than conventional fossil fuel alternative costs, making wind turbines far more vulnerable to capital escalation risk. With recent turbine demand outstripping turbine production capacity, turbine orders have backed up and costs have escalated rapidly. With increasing demand caused by state renewable portfolio requirements, carbon dioxide control regulation, and few turbine manufacturers, a significant risk exists that these capital cost escalation market risks could continue.

Additionally, being a capital-intensive alternative, the wind production costs are highly sensitive to turbine output performance. Mr. Schlissel does not detail his wind power production assumptions. However, it appears that he may have adopted some of the Applicants' conservative (low) wind acquisition cost assumptions. For instance, Burns and McDonnell, in its November 2007 evaluation comparing the cost of Big Stone Unit II to alternatives (OTP/MDU Exhibit 327), assumed wind acquisition costs of $40/MWh (in 2006$) for a turbine producing power at a highly productive 40 percent annual capacity factor. Applicant witness Jeff Greig recognized this is a highly "conservative" (low) price assumption (OTP/MDU Exhibit 326 at pp. 7-8).

Moreover, according to the EIA-DOE wind power production data, the 2005 average output capacity factor for Minnesota wind projects was reported to be closer to 32 percent

(OTP/MDU Exhibit 339 TAH-SR-2) than the 40% assumed by Burns & McDonnell. At this lower capacity factor, a wind project would produce 20 percent less power and its production costs would increase by roughly $10/MWh, which creates a material impact on the cost-effectiveness of wind-gas alternatives compared to Big Stone Unit II. The fact that a $40/MWh market-wind cost is highly conservative and at least $10/MWh too low is easily supported by recent wind acquisition bids to Minnesota utilities. If one considers that regional renewable portfolio standards, including North Dakota's 10% objective, will encourage even greater wind production, there is a significant risk that wind developers may be forced into areas with poorer wind resources that will result in lower power outputs, higher production costs and higher wind acquisition costs.

In addition, the fact that this area experiences arctic-like temperature conditions at times during the winter season, together with associated operating limitations of existing wind machine technologies under such conditions, further challenges performance and cost assumptions for likely wind performance levels here.

Q: Can you comment on whether the Wind Production Tax Credit is another potential wind alternative credit risk?

A: Yes. As illustrated by the Burns and McDonnell analysis, the wind PTC has significant impacts on wind production costs and the competitiveness of the wind-based options. Without the tax credit, the wind-gas option analyzed by Burns & McDonnell is not competitive with Big Stone Unit II even using a $30/ton CO2 value applied to all CO2 tons. Currently, this tax credit is slated to terminate at the end of this year. It appears that if the credit is extended again, it will once again only be for one year.

Part of the concern and future risk of an extension is finding offsetting cost reductions and/or tax increases to offset tax revenue losses. As the future level of wind generation increases to meet expanding state renewable portfolio standard requirements, the projected lost tax revenues from the PTC extensions will continue to increase, making it increasingly difficult to find offsetting revenue increases.

As I am sure the Commission is aware, the on-again, off-again nature of the wind energy tax credit has plagued the wind industry since the inception of the credit. Outside the unsuccessful efforts last summer to extend the credit, one need only look at the history of the PTC to understand this risk. Congress has extended the credit five times since it was enacted but only twice before it lapsed and left the industry on the verge of collapse.

Q: Are you saying that the wind energy PTC is likely to expire permanently?

A: I believe that there is a material risk the wind PTC will expire before Big Stone II is built and that as illustrated by the Burns & McDonnell studies, its expiration would have significant impacts on the attractiveness of the wind-based alternatives. In addition, Congress may consider that the PTC is no longer needed to meet its original purpose—to support the development of new lower cost wind technology improvements. Mr. Schlissel, however, appears to ask this Commission to assume that the PTC will always be available. I believe such an assumption is not prudent.

Q: Could higher carbon dioxide penalties make wind a more attractive alternative also influence wind acquisition costs?

A: Yes. I would expect that high carbon dioxide compliance costs would result in significant increases in wind power acquisition costs as a result of (1) increases in wind turbine capital costs from higher demand, (2) increased demand for wind projects pushing future wind projects into areas with increasingly lower quality wind resources (and thereby poorer output performance and higher production costs) and (3) higher regional power prices providing leverage for wind developers to negotiate higher power purchase prices (I am aware of some wind power purchase contracts, for instance, that are specifically linked to the regional power prices).

As a result, the baseload alternative analyses completed by Burns & McDonnell in November 2007 OTP/MDU Exhibit 327 are very conservative in assuming \$40/MWh and \$52/MWh wind cost scenarios. Mr. Schlissel's testimony does not account at all for the possibility that wind costs will increase if there is a significant CO_2 tax.

Q: Are there other significant risks associated with Mr. Schlissel's preferred alternative?

A: Yes. Since wind must be combined with natural gas combined cycle to provide a baseload alternative, there are also significant price risks associated with natural gas prices. If either fewer new coal-plants are permitted/constructed or some generation is switched to lower carbon fuels, natural gas demand would rise and trigger significant natural gas price increases. Applicants' witness Daniel Klein discusses these price effects in more detail in his rebuttal testimony.

IV. NEW COAL FIRED POWER PLANT CONSTRUCTION

Q: In his April 9, 2008 testimony (pp 12-18), Mr. Schlissel mentions recent cases in which companies have decided not to pursue coal-fired powerplants because of state regulatory commission action, concerns about increased construction costs, and/or the

potential for federal regulation of greenhouse gas emissions. Do you believe that the industry is moving away from proposing new coal plants?

A: No. Although some companies clearly have cancelled or delayed their plans for new coal plants due to regulatory uncertainty combined with construction cost increases, the number of active coal projects are far greater than the number of cancellations. EVA closely tracks new plant construction projects for its clients, including the Electric Power Research Institute and the North American Electric Reliability Corporation, (NERC) and for its electricity industry forecasting projects. According to our analysis, many companies are still pursuing coal plants, and many have their coal plants under construction.

Q: How many companies are actively pursuing coal-fired powerplants?

A: EVA is currently tracking 130 active coal-fired powerplant projects. Twenty-seven coal-fired powerplant projects are under construction (15,394 MW) and are expected to be brought online over the next five years (OtP/MDU Exhibit 340 TAH-SR-3). An additional 9 coal-fired powerplant projects (5,179 MW) are sufficiently advanced in permitting, engineering and project financing that EVA considers them as highly probable. These utilities have announced online dates within the next five year period. Another fifteen coal-fired projects (8,426 MW) are in earlier developmental stages but are located in areas that need power and coal is the lowest cost resource alternative. EVA rates these projects as "possible." Finally, there are an additional 79 projects (44,825 MW) that have been announced. These projects are only at the initial stages without permits, power contracts or financing.

In these 130 cases, the project developers have concluded that coal provides the lowest cost resource alternative. Accordingly, despite regulatory uncertainty and cost increases, many companies still believe coal plants are the best alternative.

This conclusion of the cost competitiveness of coal is also shared by the US Department of Energy in its latest Annual Energy Outlook-2008 released in March 2008. In Table A9 of this report, DOE projects that under existing laws and their generation technology construction cost outlook, coal-based alternatives would be the dominate new baseload generation alternative, accounting for 91,200 MW of needed new generating capacity by 2030. This is far greater than the estimates for alternative baseload alternatives natural gas combined cycle (33,400 MW), nuclear (16,600 MW) and biomass (11,700 MW).

Q: Have there been examples of other non-coal based projects that have been cancelled or delayed?

A: There are numerous examples of canceled or delayed generating plants that go beyond coal-based alternatives to include natural gas combined cycle, renewables, nuclear, peaking turbines, etc. It has not been unusual that multiple announced projects can compete for the same power market demand and that not all can win the needed power contracts to obtain financing.

For example, in April a regional utility withdrew from a proposed expansion of the Judith Gap wind energy project in Montana, citing all-in costs and uncertainties regarding necessary backup capacity. So, non-coal projects are not immune to delays or cancellations as Mr. Schlissel's omission of them in his testimony suggests.

Q: Mr. Schlissel testifies that many of the coal plants are being canceled or delayed due to concerns about escalating coal construction costs and/or greenhouse gas regulation. Do you share his observation?

A: We too have observed a rapid escalation in capital construction costs that have affected all generating options—not just coal based options. Construction costs for wind and nuclear have increased at far faster rates than coal over the last 5 years. This observation has also been made by many others. For instance, a September 7, 2007 report of the Brattle Group for the Edison Foundation found that

> "[t]he 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.[1]

Also, some companies have delayed (not cancelled) projects to further study risks from greenhouse gas regulation. These companies often had the flexibility to delay coal projects to see how future environmental regulations change and come into greater focus. Other utilities' needs are much more immediate and must take action now. As demonstrated by this project, coal remains several companies' lowest cost resource option even with greenhouse gas regulation risk. This same conclusion was reached by most active coal projects.

V. CONCLUSION

Q: Could you please summarize your conclusions for this testimony.

A: Yes. Mr. Schlissel has significantly overstated the near and intermediate carbon risk and penalty by assuming Big Stone II would receive no free allowance allocation nor have any access to lower cost offset credits that could cover approximately 63-78 percent of the facility

[1] Brattle Group, Rising Utility Construction Costs: Sources and Impacts, September 2007, p. 2. Exhibit JI-35-K.

emissions. Mr. Schlissel also overestimates the long term carbon price risk by assuming no future advancements in carbon capture and sequestration technology that could lower costs and cap carbon prices.

Mr. Schlissel argues that there is a significant capital cost risk from construction escalations that are partially responsible for many coal project delays/cancellations. In addition, while construction costs have indeed increased for the Big Stone II project, they have also escalated for all other competing generation options as well so coal remains the low cost baseload alternative. DOE in its construction cost outlook for the 2008 Annual Energy Outlook also concludes that coal will remain the dominant baseload generating option through its 2030 forecast period. EVA is tracking 130 announced coal projects in which the developers had concluded that coal was the lowest cost resource alternative.

Mr. Schlissel promotes wind alternatives that also have large capital and production cost risk. Applicant studies by Burns & McDonnell show that without the PTC, the wind-gas alternative is unable to effectively compete with the coal based alternative. Given the growing wind share from state renewable portfolio standards and the difficulties of finding offsetting costs from growing revenue losses from the tax credit, there is a material risk that the tax credit will expire before the planned Big Stone II plant online date. Despite the continual difficulties in getting the tax credit extended, Mr. Schlissel argues that the extension of the PTC will allow wind in combination with building a natural gas combined cycle plant would become a competitive alternative to the preferred Big Stone II option.

Mr. Schlissel fails to adequately consider risk factors for wind power resources – particularly his assumption that the wind energy PTC will be extended forever; his apparent assumption that Applicants can purchase below market-cost wind power; and his assumption that future CO_2 regulation will not affect the future price of wind power (by generally uplifting wholesale electric prices). Mr. Schlissel's position seems to be that Applicants should only consider rosy scenarios for wind resources and worst-case scenarios for carbon-emitting resources

Q: Does this conclude your testimony?

A: Yes.

RESUME OF

THOMAS A. HEWSON JR.

Q: PROFESSIONAL EXPERIENCE

1981-Present Energy Ventures Analysis, Inc.
Principal

Responsible for power industry market studies. Provides regular power industry forecasts of future electricity demand growth, generation mix, environmental compliance and production cost changes for Fuelcast subscribers and individual client studies. Completed numerous studies examining the effect of future environmental regulation and utility deregulation on fuel prices, supplier capacity decisions (new, repower, retire), generation/environmental technology choice, wholesale electric prices and emission allowance values. Provided market assessments for new fuel, generation and pollution control technologies. Directed industrial utility group examining repowering technology options, costs and risks. Completes studies on renewable power options, costs, incentives and price impacts. Performs assessments of electricity demand, energy conservation potential and alternative energy charge frameworks for power consumers.

Responsible for corporate emission allowance forecasts and assessments. Provides ongoing forecasts of emission trading market prices and fundamentals of existing Acid Rain SO2 market, seasonal NOx market, CAIR, RGGI and individual state new source offset markets. Assesses future market trading values for mercury and carbon dioxide. Evaluates wide range of state legislative multi-pollutant proposals and their effect on regional production costs, state GDP, and environmental benefits. Engaged in developing new rules and regulations to expand existing emission allowance trading markets to include non-traditional sources (e.g. mobile sources).

Directs technical feasibility and environmental permitting studies. Expert in electric utility repowering technologies, fuel upgrading and environmental control technologies. Work includes several plant specific analyses on the costs of reducing SO2 emissions through allowance purchases, switching to lower sulfur fuels, least emission dispatching, plant retirements, repowering and FGD scrubber retrofits for all major coal and oil fired utility stations. Examined feasibility/costs of hazardous waste treatment/disposal for all major industrial waste streams in Louisiana.

1976- 1981 **Energy and Environmental Analysis, Inc.**
Project Manager

Responsible for environmental and regulatory analysis. Examined, for governmental and industrial clients, the requirements and associated impacts on current industrial practices of the Clean Water Act, Clean Air Act, Resource Conservation and Recovery Act, Toxic Substances Control Act, Safe Drinking Water Act, Fuel Use Act, Natural Gas Act, Natural Gas Policy Act, Surface Mining and Reclamation Act and Occupational Safety and Health Act. Results of these policies, economic and technical analyses have been used for Congressional hearings, EPA rulemaking, court testimony, industrial policies, administrative hearings and permit negotiations. Developed Federal and state regulatory compliance strategies for the Department of Energy and several industrial clients. On behalf of several clients, he has applied for construction, NPDES, air, solid waste, hazardous waste, water use and land use permits.

Responsible for solid waste/hazardous waste management analyses. Evaluations have included analyses of solid waste and hazardous waste treatment/disposal options for the fertilizer, fermentation ethanol, petrochemical, inorganic chemical, electric utility, synthetic fuel, pulp and paper and mineral processing industries.

Publications

Mr. Hewson has presented and published several papers on the electric utility industry and emission allowance markets. Also co-author on two papers on innovative wastewater treatment technologies.

Educational Background

1976 B.S.E. (Civil Engineering), Princeton University.

Mr. Hewson was appointed for a 2-year term as a Member of the Alexandria Environmental Policy Commission in 2005. He served as Commission Vice Chairman in 2006 until his term expired in January 2007.

<u>Testimony in State Regulatory Proceedings:</u>

A: Public Utility Commissions

Progress Energy Florida Modular Cooling Tower Eligibility for Cost Recovery under Florida Environmental Cost Recovery Clause and Fuel Clause-- Testimony to Florida Public Utility Commission Docket # 060162-EI (March 2007) on behalf of Florida Office of Public Council

TECO FGD Reliability Upgrade Program Project Eligibility for Cost Recovery under Florida Environmental Cost Recovery Clause– Testimony to Florida Public Utility Commission Docket # 050958-EI (March 2007) on behalf of Florida Office of Public Council

Identifying the Carbon Risk for a New Power Generation Decision— Big Stone II – Testimony to South Dakota Public Utilities Commission Case EL05-022 (June 2006) & Minnesota Public Utilities Commission Docket Numbers CN-05-619 & TR-05-1275 (December 2006, January 2008) on Behalf of Big Stone II Partnership

Identifying the Wind Power Alternative Risk for a New Power Generation Decision— Big Stone II – Testimony to South Dakota Public Utilities Commission Case EL05-022 (June 2006) & Minnesota Public Utilities Commission Docket Numbers CN-05-619 & TR-05-1275 (December 2006, January 2008) on Behalf of Big Stone II Partnership

Assessment of Environmental Claims for Proposed Highland Wind Energy Project—Testimony to Virginia State Corporation Commission Case # PUE-2005-00101 Rezoning Petition ZP-702 (October 2006) on Behalf of Highland Citizens Group

Assessment of Generation Claims of Proposed Roth Rock Project—Testimony to Maryland Public Service Commission Case # 9008 (October 2005) on Behalf of Citizens Group

Assessment of Environmental Claims of Proposed East Haven Wind Farm—Testimony to Vermont Public Service Board Case # 6911 (April 2005) on Behalf of Kingdom Commons Group

Evaluation of NRDC Proposed Alternatives to SCE Mohave Power Powerplant—Testimony to California Public Utility Commission Docket U-338-E (July 2004) on Behalf of Peabody Coal Company

Evaluation of Aurora-GVEA Chena Powerplant Power Purchase Agreement—Testimony to Alaska Regulatory Commission Docket #U-02-60 (September 2003) on behalf of Aurora Energy

Evaluation of Proposed Environmental and Renewable Provisions of the New England Electric System Deregulation Settlement Agreement—Testimony to Massachusetts Department of Public Utilities Docket 96-25 (November 1996) on Behalf of Center for Energy and Economic Development

State Environmental Agencies:
Mercury Policy Options and Impact on Georgia Ratepayers- Testimony to Georgia Dept of Natural Resources for its proceeding to develop Mercury Rule to Implement CAMR (December 2006) Testimony on Behalf of CEED

Evaluation of Delaware Multi-Pollutant Proposed Regulation 1146—Testimony to Delaware Dept of Natural Resources and Environmental Control for its proceeding on state CAMR and CAIR Rules --May 2006 and September 2006 on Behalf of CEED

Impact of Mercury Regulations on Pennsylvania Coal-Fired Powerplants- Testimony to Pennsylvania Dept of Environmental Protection for its proceeding to develop Mercury Rule to Implement CAMR (November 2005) Testimony on Behalf of Pennsylvania Coal Association

Challenges in Setting Mercury Limitations in Massachusetts—Testimony to Massachusetts Department of Environmental Protection in its proceeding to set mercury control limits to implement Massachusetts Executive Order. Testimony was made on Behalf of CEED (October 2002)

State Legislative Energy Committees

Greenhouse Gas Control Policy Alternatives in Minnesota Testimony to Minnesota Senate Energy Committee (February 2007)

Advancements in Clean Coal Technology Presentation to Wisconsin Joint Legislative Council (November 2006)

Advancements in Coal Technology Presentation to Idaho House Energy Environment and Technology Committee (February 2006, March 2006)

Coal Market Trends Presentation to National Conference of State Legislatures (November 2004)

EFFECT OF PROPOSED MULTI-POLLUTANT REGULATIONS ON SALEM HARBOR POWER PLANT-- TESTIMONY TO MASSACHUSETTS JOINT COMMITTEE ON ENERGY AND GOVERNMENTAL REGULATIONS FOR ITS HEARING ON SALEM HARBOR STRICTER AIR EMISSIONS REQUIREMENTS (MARCH 2003)

Evaluation of Assembly Bill A5577 to Control SO2, NOx and CO2 (April 2001) Presentation to Energy Committee Members of NY State Assembly

Evaluation of New Hampshire Proposed Multi-Pollutant Bill HB 284 Testimony to New Hampshire Energy Committee (March 2001)

Power Industry Presentations (Partial listing)

Mr. Hewson has and continues to give presentations on major environmental issues facing the electric utility industry each year to both legislative and industry forums. A partial listing of the papers that were on his shelves is provided below.

Four Common Arguments on Why New Coal Plants Should Not Be Built: Fact or Fiction? (April 2008) ACCCE Webinar

Advancements in Coal Technology (June 2006) Presentation to Mid-American Regulatory Conference

Emerging US Environmental Regulation & Legislation (May 2004) Presentation to American Coal Council

Emerging US Environmental Regulation- The Impact on North American and International Coal Markets (February 2002) CoalTrans Americas Conference panel presentation

Power and Coal Markets under Siege from Tightening Environmental Requirements- The Battle Continues *(Sept 1999) Coal Marketing Days Conference*

The Future of Coal Processing Technologies (November 1995, January 1996) Presentations to Coal Preparation Research: How to Help Industry and Who Pays for it? and to EPRI Upgraded Coal Interest Group

Characterizing the Trace Element Content of Utility Coals (August 1995) 3rd International Conference on Managing Hazardous and Particulate Air Pollutants

Future Outlook for the Utility Coal Market (March 1995) Presentation to Eight Utility Coal Conference

1990 Clean Air Act Impacts on Utility Coal Markets (September 1994) Presentation to Pittsburgh International Coal Conference

Overview of Coal Processing Technology (September 1994) EEI Construction Committee Fall Meeting

Coal's Competitive Position with Natural Gas as a Power Generation Fuel (April 1994) Presentation to Kentucky Coal Conference

Utility Market Assessment of Repowering Technology Options- Will Repowering Be an Important Future Utility Trend or a Fad? (November 1993) Presentation to PowerGen 93

Integrated Analysis of Fuel Technology and Emission Allowance Markets Under the 1990 Clean Air Act (November 1993) Presentation to PowerGen 93

Title III Air Toxic Provisions: Major Unresolved Issues and Concerns (February 1993) Engineering Foundation Conference

Advanced Coal Cleaning Technologies: Are They the Promised Land or Mirage for Utility Compliance Under the 1990 Clean Air Act (October 1992) Presentation to Pittsburgh International Coal Conference

Current Outlook for Future Environmental Regulation Affecting Coal-Fired Powerplants *(November 1991) CBI Conference Coal-Fired Powerplants in the New Generation Portfolio*

Exhibit TAH-SR-2
2005 Minnesota Wind Power Production Data

pltname	State	Capacity MW 2005	Generation GWh 2005	Capacity Factor 2005	
Wind Turbine	MN	0.8	2,509	38.2%	
Storm Lake 1 Wind Power	MN	112.5	272,806	27.7%	
Buffalo Ridge Windplant WPP 1993	MN	21.9	46,299	24.1%	
Lake Benton 1 Wind Power Facility	MN	107.3	254,923	27.1%	
Lake Benton II Wind PO Facility	MN	103.5	278,642	30.7%	
Storm Lake II Wind PO Facility	MN	60.0	193,189	36.8%	
Woodstock Windfarm	MN	10.2	24,921	27.9%	
Lakota Ridge	MN	11.2	29,024	29.6%	
Shalokatan Hills	MN	11.8	35,198	34.1%	
Tsar Nicholas LLC	MN	1.9	5,680	34.1%	
Sun River LLC	MN	1.9	5,428	32.6%	
Julia Hills LLC	MN	1.9	5,231	31.4%	
Jessica Mills LLC	MN	1.9	5,603	33.7%	
Jack River LLC	MN	1.9	5,617	33.7%	
Autumn Hill LLC	MN	1.9	5,275	31.7%	
Winter Spawn LLC	MN	1.9	6,182	37.1%	
Twin Lake Hill LLC	MN	1.9	6,094	36.6%	
Spartan Hills LLC	MN	1.9	5,681	34.1%	
Soliloquoy Ridge LLC	MN	1.9	5,920	35.6%	
Ruthton Ridge LLC	MN	1.9	6,042	36.3%	
Hope Creek LLC	MN	1.9	6,011	36.1%	
Hadley Ridge LLC	MN	1.9	5,524	33.2%	
Florence Hill LLC	MN	1.9	5,182	31.1%	
Agassiz Beach LLC	MN	1.9	5,512	33.1%	
Wilmont Hill LLC	MN	3.2	6,084	22.0%	
Kas Brothers Windfarm	MN	1.5	4,090	31.1%	
Champepaden Wind Power	MN	2.0	6,610	38.1%	
Moulton Wind Power	MN	2.0	6,192	35.3%	
Minwind	MN	3.8	10,491	31.5%	
G McNeilus Wind	MN	32.0	95,059	33.9%	
Minwind 3-9	MN	11.6	36,439	35.9%	
Chanarambie Power Partners	MN	85.0	256,064	34.4%	
Viking Wind Partners	MN	12.0	40,252	38.3%	
Moraine Wind LLC	MN	51.0	146,295	32.7%	
TG Windfarm	MN	2.0	5,856	33.4%	
CG Windfarm	MN	2.0	6,055	34.6%	
Bisson Windfarm LLC	MN	2.0	6,159	35.2%	
Tofteland Windfarm LLC	MN	2.0	6,052	34.5%	
Westridge Windfarm	MN	2.0	5,849	33.4%	
Fey Windfarm LLC	MN	2.0	6,400	36.5%	
Windcurrent Farms LLC	MN	2.0	6,245	35.6%	
K-Brink Windfarm LLC	MN	2.0	5,681	32.4%	
DL Windy Acres LLC	MN	2.0	6,575	37.5%	
Boeve Windfarm LLC	MN	2.0	6,521	37.2%	
B&K Energy Systems LLC	MN	2.0	6,331	36.1%	
Allendorf	MN	1.2	354	3.4%	
NAE Shaokatan Power	MN	1.6	561	4.0%	
Trimont Area Wind Farm	MN	100.5	44,092	5.0%	Start-up
Adams Wind Farm	MN	24.0	56,952	27.1%	
Stahl Wind Energy	MN	1.7	5,204	34.9%	
Carstensen Wind	MN	1.7	4,875	32.7%	
Northern Lights Wind	MN	1.7	5,137	34.5%	
Lucky Wind	MN	1.7	4,642	31.2%	
Greenback Energy	MN	1.7	4,941	33.2%	
Total 2005		829.4	2,024,549	31.9%	

Source: EIA 906 Data Reports

Exhibit TAH-SR-3
Constructed, Probable and Possible Coal Plants

Owner	Name	Unit	Size (MW)	Technology	State	Status	Start Year
Black Hills	Wygen	2	90	PC	WY	Construction	2008
Arkansas River Power	Lamar	1	39	FBC	CO	Construction	2008
WPS Resources	Weston	4	531	PC	WI	Construction	2008
Newmont Mining	TS Power	1	203	PC	NV	Construction	2008
Santee Cooper	Cross	4	600	PC	SC	Construction	2009
East Kentucky Power	Spurlock	4	268	FBC	KY	Construction	2009
Omaha Public Power	Nebraska City	2	663	PC	NE	Construction	2009
Wisconsin Energy	Elm Road	1	615	PC	WI	Construction	2009
TXU	Sandow Repower	5	581	FBC	TX	Construction	2009
Xcel - PSCo	Comanche	3	750	PC	CO	Construction	2009
San Antonio	Spruce	2	750	PC	TX	Construction	2009
TXU	Oak Grove	1	855	PC	TX	Construction	2009
Salt River Power	Springerville	4	400	PC	AZ	Construction	2009
Springfield, IL	Dallman	4	200	PC	IL	Construction	2010
Great River Energy	Spiritwood Cogen	1	99	FBC	ND	Construction	2010
LG&E Energy	Trimble County	2	750	PC	KY	Construction	2010
TXU	Oak Grove	2	855	PC	TX	Construction	2010
Wisconsin Energy	Elm Road	2	615	PC	WI	Construction	2010
Kansas City P&L	Iatan	2	850	PC	MO	Construction	2010
LS Power	Plum Point	1	665	PC	AR	Construction	2010
Springfield, MO	Southwest	2	300	PC	MO	Construction	2011
GenPower/FirstReserve	Longview	1	695	PC	WV	Construction	2011
Basin Electric	Dry Fork	1	385	PC	WY	Construction	2011
Peabody/CMS	Prairie State	1,2	1,500	PC	IL	Construction	2011
LS Power	Sandy Creek	1	925	PC	TX	Construction	2012
East Kentucky Power	Smith	1	278	FBC	KY	Probable	2010
Municipal Energy Nebraska	Whelan	2	220	PC	NE	Probable	2011
AEP	Turk	1	600	PC	AR	Probable	2011
Southern Montana G&T Coop	Highwood	1	250	FBC	MT	Probable	2011
Black Hills	Wygen	3	100	PC	WY	Probable	2011
Santee Cooper	Kingsburg (Pee Dee)	1	600	PC	SC	Probable	2012
Duke Energy	Cliffside	6	800	PC	NC	Probable	2012
Dominion Virginia	Virginia City	1	585	FBC	VA	Probable	2012
Otter Tail Power	Big Stone	2	500	PC	SD	Probable	2012
LS Power	Longleaf	1,2	1,200	PC	GA	Probable	2012
Wellington Development	Greene Energy	1	525	FBC	PA	Possible	2009

Exhibit TAH-SR-3
Constructed, Probable and Possible Coal Plants

Owner	Name	Unit	Size (MW)	Technology	State	Status	Start Year
Western Greenbrier Cogen	Rainelle	1	98	FBC	WV	Possible	2009
Jamestown BPU	Carlson	10	43	FBC	NY	Possible	2011
Sithe Global Power	River Hill	1	290	FBC	PA	Possible	2011
East Kentucky Power	Smith	2	278	FBC	KY	Possible	2012
Sithe Global Power	Desert Rock	1,2	1,500	PC	NM	Possible	2012
Duke Energy	Edwardsport IGCC	9	630	IGCC	IN	Possible	2012
Sierra Pacific	Ely Energy	1	750	PC	NV	Possible	2012
Alliant Energy	Nelson Dewey	3	300	FBC	WI	Possible	2012
FutureGen	Mattoon	1	275	IGCC	IL	Possible	2012
AEP	Mountaineer IGCC	2	600	IGCC	WV	Possible	2012
AMP-Ohio	AMPGS	1	500	PC	OH	Possible	2013
Associated Electric Coop	Norborne	1	689	PC	MO	Possible	2013
AMP-Ohio	AMPGS	2	500	PC	OH	Possible	2013
Sierra Pacific	Ely Energy	2	750	PC	NV	Possible	2013
Western Farmers Electric	Hugo	2	750	PC	OK	Possible	2013
Alliant Energy	Sutherland	4	630	PC	IA	Possible	2013
Santee Cooper	Pee Dee	2	600	PC	SC	Possible	2014
Minnkota Power	Young	3	500	PC	ND	Possible	2015
		TOTAL MW	29,525				