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**
	)	

Rebuttal Testimony of

Robert M. Fagan

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On Behalf of

Fresh Energy

Izaak Walton League of America – Midwest Office

Wind on the Wires

Union of Concerned Scientists

Minnesota Center for Environmental Advocacy

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Table of Contents

Exhibits

I. INTRODUCTION AND KEY CONCLUSIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Robert M. Fagan. I am a Senior Associate at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts, 02139.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am an energy economics analyst and mechanical engineer with 20 years of experience in the energy industry. My work has focused on myriad electric power industry issues, especially economic and technical analysis of competitive electricity markets development, electric power transmission pricing structures, and assessment and implementation of demand-side resource alternatives. I hold an M.A. from Boston University in Energy and Environmental Studies (1992) and a B.S. from Clarkson University in Mechanical Engineering (1981). Details of my experience are provided in my resume as Exhibit JI-8-A.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

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. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the direct testimonies of Mr. Hwikwon Ham and Dr. Steve Rakow of the Minnesota Department of Commerce; and Mr. Eric Laverty of the Midwest ISO ("MISO") on issues related to wind integration.

Q. WHICH AREAS OF THE TESTIMONIES DO YOU RESPOND TO?

A. I respond to a number of issues addressed in the three testimonies. These include:

- Conclusions drawn by Mr. Ham concerning the "positive impact"[1] of the project on meeting the State's energy need;
- Mr. Ham's statement that he "confine[s] [his] discussion in this testimony to the State's overall energy need in generic terms instead of identifying specific types of energy needed"[2];
- Mr. Ham's definition of "region" and his use of MRO (Midwest Reliability Organization) and MISO as the region[3]; and
- Mr. Ham's conclusion that the project is not needed to improve general regional transmission reliability, but rather is an outlet for the Big Stone II generation, yet it could lead to more wind interconnection and fuel diversity.[4]
- I respond to Dr. Rakow's discussions of "Analysis Under Renewable Preference" [5] and the extent to which he examines the Applicants' contentions that the Big Stone II alternative is less expensive than power generated from renewable energy sources; and
- I also respond to Dr. Rakow's discussions of "Determination of Size, Type, and Timing" [6], in particular his attempts to ascertain if a wind unit was

[1] Ham, Direct Testimony, 4:18; 7:12.

[2] Ibid., 4: 12-13.

[3] Ibid., 5: 3-5.

[4] Ibid., 6: 20-26.

[5] Rakow, Direct Testimony, 24:1-18.

[6] Ibid., 17:18.

available for selection as an expansion unit during the resource planning period to compete for a utility's supply-side needs[7]; and

- To Dr. Rakow's suggestion that Otter Tail Power ("OTP") explain its basis for constraining wind additions to 20%[8]; and
- To Dr. Rakow's discussion of the Applicants' screening process and the extent to which the Applicants considered other generation and transmission alternatives[9]; and Dr. Rakow's determination "that the Applicants' list of available alternatives was reasonably complete with one exception"[10].
- I respond to Mr. Eric Laverty's testimony on the "used and useful[ness]" of the Big Stone II transmission interconnection facilities in the absence of the Big Stone II generation plant[11], and his contentions that granting the request for the certificate of need is in the best interests of Minnesota end use customers.[12]

Q. WHAT KEY CONCLUSIONS DO YOU REACH?

A. I reach the following conclusions:

1. Mr. Ham's "positive impact" conclusion is unsupported. Mr. Ham concludes that the Big Stone II Project (generation and transmission[13]) "will"[14] or

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[7] Ibid., 18: 16-18.

[8] Ibid., 23: 16-18.

[9] Ibid., 25: 6-21; 26: 1 – 27:4.

[10] Ibid., 29: 1-2.

[11] Laverty, Direct Testimony, 18:1-25.

[12] Ibid., 19: 23-27.

[13] Mr. Ham appears to include both the generation and the transmission components of the proposed Big Stone II project when concluding "positive impact". He states it will have a positive impact "by providing transmission to import energy generated not only from the Big Stone II generation project but also wind-generated energy or other energy…" (Ham, Direct, 4: 18-20).

"may"[15] provide a positive impact on meeting the State's energy need, but he does not define what "positive impact" means nor does he actively address any alternatives to the Big Stone II Project. His view appears to be that since the State has a need for energy and capacity, this project results in a positive impact on State energy need because it will allow energy to be imported into the State of Minnesota. His conclusion does not account for the economics of the project relative to other alternatives – for example he doesn't address the project's transmission opportunity costs; and his "positive impact" conclusion is not supported by any quantitative analysis. Furthermore, while Mr. Ham states that he "confine[s] [his] discussion to the State's overall energy need in generic terms instead of identifying specific types of energy needed"[16], he nonetheless offers a specific finding that this particular project will provide a "positive impact".

2. Dr. Rakow's finding of no "significant issues"[17] with the Applicants' capacity expansion modeling inputs is surprising, since, for example, Dr. Rakow himself recognizes Otter Tail Power's limitation on wind additions to 20%; other individual Applicant modeling incorrectly restricts the ability of wind power to provide a larger share of supply-side requirements[18]. Dr. Rakow's concern appropriately implies that 20% of OTP system capacity is an unnecessary constraint on wind acquisition. As I discuss in Section III, technically-driven wind integration limitations, to the extent they exist, occur at the regional level, not at a company-specific level; nothing prevents OTP from purchasing or building considerably more cost-effective wind available

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[14] Ham, Direct Testimony, 4:18.

[15] Ibid., 7:12.

[16] Ham Direct, 4: 12-13.

[17] Rakow, Direct, 22: 10-12.

[18] See for example, Direct Testimony of David A. Schlissel and Anna Sommer, 38: 13-15; 44: 8-10; 77:10-11; 85:17 – 86:13.

to them from competing suppliers. Additionally, Dr. Rakow should have addressed this critical inquiry to all of the Applicants, because as noted a number of them either imposed artificial caps on the amount of wind their modeling could select or used faulty modeling input assumptions that resulted in selection of less than a maximum amount of cost-effective wind resource.[19] Applicants have failed to recognize the potential for, and economic attractiveness of, increased wind power penetration in the region. OTP and the other Applicants apparently, and incorrectly, use their own service territory, rather than the broad Upper Midwest region, as a geographical confine for supply resources.

3. The Applicants' have not demonstrated that the Big Stone II Project is less expensive than alternatives that include more wind and DSM, as the Direct Testimony of David A. Schlissel and Anna Sommer illustrates[20] and as required by the Minnesota "renewable preference" statute, but Dr. Rakow seems to suggest no particularly substantive concerns with the Applicants' demonstration in this regard[21].

In a related section, Dr. Rakow limits his assessment of the potential for wind power to serve as an alternative supply resource to a determination that the Applicants' have made a wind unit available to fill expansion needs[22]. That is insufficient to determine if the Applicants have met the State's "renewable preference" statute because it does not examine the extent to which the Applicants' have allowed wind power resources to compete with Big Stone II generation.

[19] Op. Cit., David A. Schlissel and Anna Sommer, Direct Testimony.

[20] Ibid.

[21] Rakow, Direct Testimony, 24:1-18.

[22] Ibid., 20: 6-8.

4. Dr. Rakow does not appear to find fault with the Applicants' discussion of a limited set of alternatives – such as the Applicants' exclusion of combinations of wind and DSM[23] - even though the statute indicates that reasonable combinations should be addressed, as Dr. Rakow notes.[24] He does not examine the extent to which the Applicants' have properly considered the potential for significantly large amounts of wind power to be available for purchase or development in the Upper Midwest region. Given Dr. Rakow's acknowledgement that wind is a lower-cost energy resource than the Big Stone generation facility[25]; and given the large level of wind power present in the MISO queue for interconnection[26]; and given the potential to reliably and cost-effectively integrate far more wind onto the system than is currently integrated[27], a logical assessment should have been made that the Applicants' have not proven that the Big Stone II Project is a more cost-effective supply resource than alternative options that include more wind power.

5. Mr. Ham defines "region" to include MRO and MISO, and appears to recognize the importance of the regional structure to reliability. However, he does not delve deeply enough into regional transmission coordination changes: such changes greatly influence the extent to which Minnesota can rely on relatively inexpensive wind power to meet the State's energy needs. Increased coordination capability and authority held by the Midwest ISO (in contrast to past regional coordination structures) will allow for significantly increased penetration of wind resources into the region, providing

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[23] David A. Schlissel and Anna Sommer, Direct Testimony, 38: 3-26.

[24] Rakow, Direct, 25: 21, describing the Minnesota Rules part 7849.0260, subpart B.

[25] Rakow Direct Testimony, 13: 27-28.

[26] The MISO generation interconnection queue contains over 14,000 MW of wind in the states of MN, SD and ND as of the end of November, 2006.

[27] Op. cit., David A. Schlissel and Anna Sommer, Direct Testimony.

economically favorable alternatives to the Big Stone Project, as I address in Section IV.

6. Mr. Ham cites the potential for increased fuel diversity as one reason the Big Stone II Project may bring a positive benefit.[28] However, the project's interconnection will only increase coal-supplied power. The Big Stone II generation facility will also utilize existing or other proposed transmission resources (i.e., transmission not included as part of the Big Stone II project, since the project's proposed transmission connections do not extend to the Twin Cities area) that could otherwise be used to increase fuel diversity.

7. Mr. Ham concludes that the project could give increased fuel diversity to the region, but he bases this on an assumption that the project will increase outlet capability for wind. In contrast, the project will only result in the interconnection of an additional coal-fired resource; the incremental transmission benefit from the project is zero. Additional transmission investment would be required to increase outlet capacity to allow for more wind power.

8. Mr. Laverty's assertion that the Big Stone II transmission facilities would be "used and useful" even in the absence of the Big Stone II generation facility is faulty. That the facilities would be physically used is but a trivial outcome arising from the characteristics of a networked transmission system. Facility "usefulness" implies an economic characteristic that Mr. Laverty has not examined, and has not demonstrated would exist with these facilities in the absence of the Big Stone II generation plant. Mr. Laverty does not attempt to determine the *extent* to which such facilities would be used, or the opportunity cost of spending transmission resources to connect an uneconomical coal plant. Mr. Laverty or MISO have not conducted an assessment to determine if the Big Stone II transmission facilities represent an optimal or even near-optimal

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[28] Ham, Direct Testimony, 6:23-26.

transmission expansion plan in the absence of the Big Stone II generation plant.

9. Mr. Laverty offers no support for his contention that granting the certificate of need is in the best interests of Minnesota end users. The MISO has not conducted any studies determining the economic impacts on Minnesota of the Big Stone II generation plant, the Big Stone II transmission facilities absent Big Stone II generation, or some other alternative that excludes the Big Stone II generation and transmission facilities and includes some other set of transmission projects.

II. BACKGROUND

Q. WHAT BACKGROUND INFORMATION DO YOU PRESENT IN SUPPORT OF YOUR RESPONSES TO MR. HAM, DR. RAKOW AND MR. LAVERTY'S TESTIMONY?

A. I present background information that 1) describes the Upper Midwest bulk electric power system and the nature of its operational control; and 2) describes the key technical factors affecting the integration of wind power resources onto the bulk electric power system. I first explain why this information is relevant to my responses to the testimonies.

Q. HOW IS THE UPPER MIDWEST BULK ELECTRIC POWER SYSTEM AND THE NATURE OF ITS OPERATIONAL CONTROL RELEVANT TO MR. HAM, DR. RAKOW AND MR. LAVERTY'S TESTIMONY?

A. The extent to which wind power resources in the region are economic relative to proposed coal-fired resources is dependent in part on bulk power system transmission access and regional dispatch coordination issues; electricity suppliers see the financial impact of transmission tariff and wholesale market provisions such as imbalance penalties or the ability to secure firm transmission service, and this impact affects the overall economics of supply options.

Mr. Ham and Dr. Rakow's testimonies both address the economics of wind-powered alternatives to the proposed Big Stone II Project, and Mr. Laverty draws economic conclusions in his recommendation that the Big Stone II project will be in the best interests of Minnesota end users. The relative economic costs and benefits of coal-fired vs. wind-powered resource options can change significantly depending on the institutional arrangements that determine how the shared electric power system is accessed and operated. Such access and operational protocols are contained in transmission tariffs and wholesale market rules. Thus the manner in which the Upper Midwest transmission grid operation affects and is affected by wind resources is relevant to the witnesses' exploration of the Big Stone II Project's relative economics.

Q. HOW ARE WIND INTEGRATION ISSUES RELATIVE TO MR. HAM, DR. RAKOW AND MR. LAVERTY'S TESTIMONY?

A. Mr. Ham and Dr. Rakow both present information that does not comprehensively challenge the Applicants' presentation of wind power availability, sufficiency as a potential supply resource, or relative economic attractiveness. Mr. Ham concludes that the Big Stone II Project would provide a "positive impact" on the State's energy needs without exploring the extent to which exploitation of Upper Midwest wind resources might provide a *more* "positive impact" on the State's energy needs than the Big Stone II Project.

Q. PLEASE DESCRIBE THE UPPER MIDWEST BULK ELECTRIC POWER SYSTEM.

A. The Upper Midwest bulk electric power system includes transmission systems, generation connected to transmission systems, and the operational control of those facilities in the Upper Midwest region. It includes a geographical expanse covering at least the six states of Minnesota, North Dakota, South Dakota, Wisconsin, Iowa and Nebraska, and at least the connections to Manitoba, Upper

Peninsula Michigan, and Illinois.[29] It includes MISO and non-MISO controlled transmission facilities, in particular the non-MISO facilities controlled by the Upper Great Plains region of the Western Area Power Administration ("WAPA").

Q. WHAT IS THE CURRENT CONFIGURATION OF THE UPPER MIDWEST REGION BULK POWER SYSTEMS?

A. The upper Midwest region consists of many individual "balancing authority" areas, formerly known as control areas.[30] Exhibit JI-8-B is a subsection of the NERC Operating Manual[31] "bubble diagram", or schematic representation of the individual balancing authorities and their interconnections to adjacent areas. It also shows the NERC reliability region known as "MRO" or Midwest Reliability Organization. It also includes state and provincial geographic boundaries.

The MRO region encompasses the former MAPP (Mid-Continent Area Power Pool) area plus the Wisconsin and Upper Peninsula Michigan areas of the former MAIN (Mid-American Interconnected Network) region, plus eastern Iowa entities that were part of MAIN. [32] See Exhibit JI-8-C, taken from a MRO publicly posted presentation[33], for a comparison of the MAPP and MRO region boundaries.

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[29] There is no need to define exact boundaries of the "Upper Midwest" bulk power grid for the purposes set out in this testimony. The important point is to understand that coordination of the electrically-interconnected region, including the Upper Midwest, extends across state and provincial boundaries and certainly includes at a minimum the whole of the MISO region (see Exhibit JI-6-F MAPP-MISO Transmission Tariff Map) and the Upper Great Plains region of the Western Area Power Administration. Furthermore, MISO's seams agreements and day-to-day communications with neighboring systems illustrate that coordination actually takes place across the entire Eastern Interconnection, which extends from the Canadian Maritimes to Florida to Texas and to the Rocky Mountains.

[30] Revision of NERC terminology resulted in a change from "control area" to "balancing authority".

[31] NERC Operating Manual, June 15, 2006. Available at www.nerc.com.

[32] MAPP still exists as a FERC-approved "Regional Transmission Group", with a Regional Transmission Committee ("RTC"), but its reliability functions are now coordinated through MRO and MISO. Sixty percent of the former MAPP load is now served under the MISO tariff; 40% is served under MAPP RTG tariffs. Some entities in eastern Wisconsin and upper peninsular Michigan have transmission coordinated through MRO but loads are registered in the Reliability First reliability region.

[33] Available at http://www.midwestreliability.org/documents.html, "Regional Reliability and Transmission Update" presentation, slide # 21.

MRO consists of entities that are members of the Midwest ISO, and non-MISO entities.

Exhibit JI-8-D shows the applicable regions utilizing the MISO transmission tariff, and those using non-MISO member tariffs and the MAPP regional tariff. In the MISO region, all entities are subject to MISO's centralized unit commitment and dispatch protocols, and take transmission service under a comprehensive MISO Open Access Transmission Tariff. In the non-MISO MRO region, all entities conduct their own unit commitment, scheduling and dispatch, coordinate transmission use across the MISO-region boundary under a seams operating agreement between MAPP and MISO, and take transmission service under their own tariffs and using the limited-scope MAPP Schedule F regional tariff.

Q. WHAT IS THE BIGGEST DIFFERENCE BETWEEN OPERATING UNDER THE MISO RTO, AND OPERATING IN THE NON-MISO MRO REGIONS?

A. Entities operating under the MISO RTO tariff and market rules are subject to centralized unit commitment and dispatch of generation and settle energy transactions based on MISO's system of locational marginal pricing, or LMP, in effect since April 1, 2005. Transmission congestion impacts are handled internally in MISO using security-constrained economic dispatch. When MISO implements its ancillary services markets, there will be a region-wide spot market for reserves and regulation and improved efficiencies in unit commitment and dispatch.

Non-MISO entities operate their systems using their own commitment and dispatch protocols; and a system of "transmission loading relief" is in effect for curtailing transmission use when the system is congested. Congestion issues across MISO and non-MISO areas are resolved using the protocols in the MISO-MAPP seams operating agreement.

Q. WHO IS RESPONSIBLE FOR CONTROL OF THE BULK ELECTRIC POWER SYSTEM?

A. Overall coordination of the bulk power stem – which includes ensuring day-to-day and hour-by-hour reliability across the entire grid, region-level re-dispatching for transmission congestion relief, and scheduling transactions with adjacent regions - is the responsibility of the Midwest ISO and the transmission owners and operators in the region who are not members of MISO, such as WAPA or the Nebraska Public Power District. Transmission-owning MISO members are responsible for localized operations of their individual systems.

Q. WHAT ARE SOME OF THE KEY CIRCUMSTANCES THAT SHAPE THE NATURE OF THE CONTROL OF THE BULK ELECTRIC POWER SYSTEM IN THE UPPER MIDWEST?

A. The existence – since April of 2005 – of MISO spot electricity markets, the planned introduction of MISO-administered ancillary service markets, and MISO's role as a NERC regional reliability coordinator are key circumstances that provide MISO with a greater degree of coordination and control of the Upper Midwest power grid than it had prior to April 2005.

Q. WHAT IS THE EFFECT OF MISO'S INCREASED COORDINATION ABILITY AND RESPONSIBILITY WITH RESPECT TO WIND POWER INTEGRATION?

A. MISO's increased coordination ability and authority enables greater technical penetration of wind power resources onto the bulk power system compared to what would be achievable absent such broad regional coordination: i.e., compared to an Upper Midwest bulk power grid control structure with individual control area coordination, no hourly spot energy markets, and balkanized ancillary and transmission service provision.

Q. WHAT ARE THE KEY TECHNICAL FACTORS ASSOCIATED WITH INCREASED INTEGRATION OF WIND TURBINE GENERATOR (WTG) RESOURCES ONTO THE POWER GRID?

A. A number of key technical factors drive the extent to which WTG can be integrated into any given power system. These factors affect the operation of the regional grid. They include:

1. **Temporal wind and load patterns**. The relationship of the temporal wind patterns (and thus the hourly energy output patterns of wind resources) to the temporal variations in load: operationally, these patterns affect the level of required regulation, load following and contingency resources necessary for reliable grid operation[34];
2. **Spatial diversity of wind resources**. The spatial diversity (or geographic dispersion) of wind resources and thus the pattern of aggregate wind power output in a region at any given moment: operationally, spatially diverse wind resources generally result in reduced temporal variation of aggregate wind plant output (in effect, a "smoothing" of aggregate regional wind output)[35], when compared to temporal variation associated with a single wind plant;
3. **Wind output forecasting systems**. The type of wind forecasting systems in place, and thus degree of error around the "predictability" of wind output in various advance time frames (e.g., 20 minutes ahead of real-time, hour-ahead, 12-hours ahead, day-ahead, etc.)[36]; operationally, the use of state of the art forecasting improves wind power output scheduling

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34 *Wind Integration Study – Final Report*, prepared for the MN DOC and Xcel Energy by EnerNex and Wind Logics, Sept. 10, 2004. See, for examples, the discussion and figures on pages 91-102 in the section entitled "Impact of Wind Generation on Generation Ramping – Hourly Analysis".

35 *Characterization of the Wind Resource in the Upper Midwest*, Task 1 of the Wind Integration Study prepared for the MN DOC and Xcel Energy by EnerNex and Wind Logics, Sept. 10, 2004, see the discussion on pages 39-41 and the subsequent graphs and figures.

36 See, for example, *Overview of Wind Energy Generation Forecasting* submitted to New York State Energy Research and Development Authority and the New York State Independent System Operator, Prepared By: TrueWind Solutions, LLC and AWS Scientific, Inc., December 17, 2003.

and reduces prediction errors that contribute to the bulk of wind integration costs.

4. **Transmission availability**. The availability of transmission to carry wind power to market.
5. **Scale of Regional Coordination**. The scale of the controlled region, i.e., the relative size of the "system" onto which a given block or blocks of wind power is injected. This scale influences whether or not limitations on the ability to inject more wind are related to actual technical constraints, or to the institutional frameworks that define the size of the system. For example, injecting the output of, say, 500 MW of wind plants onto a "system" the size of the Great River Energy control area – approximately 2,800 MW of generation and 1,650 MW of projected load in 2011[37] - would seem to introduce unnecessarily larger regulation or reserve requirements, relative to injection into a larger, coordinated system such as one defined by the MRO-MISO load deliverability region, defined to include on the order of 20,000 MW of load in 2011[38].

Q. HAVE THE FIRST THREE FACTORS BEEN EXAMINED IN DETAIL IN RECENT WIND INTEGRATION STUDIES?

A. Yes. In wind integration studies completed over the past few years, the first three of these factors generally are considered in great detail.[39] These studies describe

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37 Based on Table 6.3.1, Midwest ISO West Control Area Summary for 2011 Summer Peak Baseline Reliability Plan Models, in the Draft 2006 MISO Transmission Expansion Planning Report.

38 Ibid.

39 For example, see the Xcel Energy and Minnesota Dept. of Commerce *Wind Integration Study, Final Report*, prepared by EnerNex and Wind Logics, September 2004; *The Effects Of Integrating Wind Power On Transmission System Planning, Reliability, and Operations, Report On Phase 2: System Performance Evaluation*, prepared by GE Energy for the New York State Energy Research and Development Authority, March 2005; or NREL's presentation at the 2006 European Wind Energy Association conference, *Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*, by Brian Parsons, March 2006. For a summary of key results and insights from recent wind integration studies, see *Wind Plant Integration: Cost,*

the fundamental near-term operating considerations required to reliably integrate WTG resources onto power grids. The general characteristics of WTG technology and integration matters are now relatively well-known, and their study has become increasingly sophisticated. Power system operators have been successfully scheduling generation output to meet variable system-wide load since the beginning of power system operation in the early part of the 20th Century. While current system operational procedures may need to adapt (or rather, continue to adapt) to a resource base with greater output variability than that associated with conventional fossil resources, the underlying technical foundations for successfully operating a system with greater levels of wind are known and straightforward.

Q. WHAT HAVE SOME OF THE MORE RECENT STUDIES SHOWN, IN GENERAL, FOR WIND INTEGRATION COSTS?

A. Generally, the studies show that at low levels of wind penetration, up to 10-20% of installed capacity, there are some minimal operational costs (on the order of less than $5/MWh) to integrating wind.[40] These costs can be lowered with better forecasting, especially since most of the cost generally is in the day-ahead, scheduling and unit commitment time frame. As noted in the Forecasting Overview study referenced in footnote 36, forecasting capabilities are projected to improve, thus likely leading to even lower integration costs at these penetration levels:

> "Finally, there is an expectation that an improvement in the quality and quantity of global, regional and local area atmospheric data, the development and application of more sophisticated statistical and physics-based atmospheric models and data assimilation schemes for those models and the availability of greater and lower cost computing power will yield substantial improvement in forecast performance over the next 10 years. Although there is likely to be some improvement

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Status, and Issues, by Edgar A. DeMeo, William Grant, Michael Milligan, and Matthew J. Schuerger, from the November/December 2005 issue of IEEE Power and Energy Magazine.

[40] See, for example, UWIG's (Utility Wind Integration Group) summary report, *Utility Wind Integration State of the Art*, May 2006, for an abbreviated summary of integration cost study results.

> across all forecast time horizons, the most significant improvements are likely to be made for the start (3-5 days) of the medium range forecasting period and the start of the short term forecast period (6-18 hours)."[41]

Q. CONCERNING THE FOURTH FACTOR, IS THERE ENOUGH TRANSMISSION AVAILABLE TO CARRY WIND POWER TO MARKET?

A. There is considerable room on the existing transmission systems in the region, although conservative rating mechanisms[42] and inflexible tariff mechanisms[43] may artificially restrain the amount of wind power that can be carried on the system. I understand that the evolution of transmission system tariff protocols will address the possibility of making "conditional firm" transmission, or its equivalent, available for use by WTG resources.[44] Conditional firm transmission service is one form of modified transmission service that recognizes that the transmission resource may not be available 100% of the time, but allows for purchase of a product that is more firm – i.e., less susceptible to interruption – than traditional "non-firm" transmission service. Ongoing transmission planning

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[41] Op. Cit., page 21.

[42] See for example, MISO Draft 2006 Transmission Expansion Plan, Section 3.5.5, Real Time Ratings.

[43] Current tariff mechanisms under FERC Order 888 are under review by FERC. See FERC Notice of Proposed Rulemaking (NOPR) on open access transmission, Preventing Undue Discrimination and Preference in Transmission Service, May 19, 2006, Docket Nos. RM05-25-000 and RM05-17-000). For example "Transmission customers, especially those customers seeking service to or from new generation resources, must be given greater flexibility of service to meet their needs comparable with the flexibility provided on behalf of bundled retail native load. New generation resources often face a grid that cannot accommodate requests for long-term firm transmission, at least not without the significant delay required by transmission construction, despite the fact that redispatch options may exist that would allow that resource to be accommodated." P. 304

[44] Op. Cit., FERC NOPR on open access transmission: FERC proposed two solutions, redispatch and a form of conditional firm service: "The first option focuses on generation redispatch to accommodate long-term firm point-to-point service, while the second option creates a modified form of firm point-to-point service that includes non-firm service in a defined number of hours of the year when firm point-to-point service is not available." P. 305. See also FERC Staff Briefing Paper, *Assessing the State of Wind Energy in Wholesale Electricty Markets*: "Transmission services that allow for the unique operational characteristics of wind energy such as conditional firm, curtailable firm, priority nonfirm, and hourly firm may offer wind generators increased certainty for gaining access to the transmission grid." November 2004, Page 4.

and construction appears to promise increased transmission resources, for example from the Buffalo Ridge area, and from the Dakotas.[45] As with most new supply-side resources, transmission upgrades are often required.

Q. HOW IS THE FIFTH FACTOR, SCALE OF REGIONAL COORDINATION, BEST ADDRESSED?

A. System scale is best considered by asking the following questions: what is the size of the system onto which wind generation for use by the Applicants would be injected? What is the size of the system that must be studied to determine the level of wind integration that can be considered? In other words, what is the appropriate boundary to draw to study the potential for wind integration to meet some or all of the Applicants' need for energy and capacity? This issue is explored in more detail in the next section in the context of Mr. Ham and Dr. Rakow's conclusions and findings.

III. MR. HAM'S "POSITIVE IMPACT" CONCLUSION AND DR. RAKOW'S FINDINGS ON RENEWABLE PREFERENCE AND WIND UNIT AVAILABILITY DO NOT ADDRESS THE FULL POTENTIAL FOR WIND INTEGRATION IN THE UPPER MIDWEST REGION

Q. DO MR. HAM'S AND DR. RAKOW'S CONCLUSIONS AND FINDINGS ADDRESS THE EXTENT OF WIND POWER POTENTIAL AND HOW SUCH POTENTIAL MAY AFFECT THE RELATIVE ECONOMICS OF MEETING MINNESOTA'S ENERGY NEEDS USING MORE WIND POWER THAN THE APPLICANTS' PREFERRED PLAN?

A. No. Mr. Ham's "positive impact" conclusion and Dr Rakow's findings on the Applicants' renewable resource analysis offer no hint of the magnitude of wind power resources that may be viable and economic alternatives to the Big Stone II project.

[45] See for example, the CapX 2020 Technical Update, May 2006; and the 2005 Minnesota Biennial Transmission Projects Report.

Q. DO YOU HAVE SUCH INFORMATION?

A. Yes. I describe overall wind power potential in the Upper Midwest region in the context of wind integration concerns. This information helps to assess the true near-term availability of renewable resource alternatives to Big Stone II, and thus helps to inform any assessment of whether or not the Applicants have demonstrated (under the renewable preference statute) that their preferred plan (Big Stone II Project) is less expensive than other alternatives. It illustrates, for example, that Dr. Rakow's questioning of OTP's 20% wind constraint is spot on; indeed the wind constraints in all of the Applicants' various modeling processes need to be compared to any technical limitations that may exist in the real world.

Q. HOW MUCH WIND POWER CAN BE INTEGRATED INTO THE UPPER MIDWEST REGION POWER GRID?

A. The upper bounds of the technically feasible level of wind integration are not known with any precision. As the level of wind penetration increases, requirements for operating reserves and regulation may increase. This will depend on the relative patterns of wind and load, the impact of geographical dispersion of wind resources, and the quality and comprehensiveness of wind forecasting tools in use. But at this time there is no particular "ceiling" to the level of wind penetration possible on any given system, and European experience meeting 100% of a region's load for some time intervals suggests that any technical limitation is quite high. Adequate transmission facilities also need to be in place to support wind integration, although significant room remains on existing transmission systems in the MISO region, which often use conservative, "static" ratings that reduce the amount of energy that could otherwise be transmitted. A section of MISO's draft transmission expansion planning document discusses this aspect of the conservatisms present in transmission line ratings.[46]

[46] See MISO MTEP06 draft report, section 3.5.5, "Real Time Ratings", pages 6-9.

Q. WHAT WIND PENETRATION LEVELS ARE ASSUMED IN RECENT WIND INTEGRATION STUDIES?

A. Many integration studies completed over the past 5 years use penetration assumptions ranging from a few percent to upwards of 30% of the installed capacity of a region[47], but the upper bound is certainly higher than reflected in this range, as evidenced by the penetration levels seen in some European countries. See Exhibit JI-8-E. It is sensible to conduct integration studies assuming lower penetration levels because it takes a while before new resources and associated transmission is built. Minnesota and/or MISO or regional utilities will likely be performing wind integration studies for at least the next few decades, and future studies will be examining much higher levels of penetration than current studies assume. The 2004 study done for the Minnesota Department of Commerce[48] modeled the impact of 1,500 MW of wind on a single upper Midwest region, the NSP control area. The modeling parameters used 11,426 MW as a capacity resource base, thus wind is 13% of the base capacity; the modeled peak load was 9,933 MW. In contrast, I understand that the forthcoming Minnesota Department of Commerce wind integration study will evaluate wind penetration levels associated with meeting up to a 25% energy requirement[49], which equates to approximately 40% installed capacity.

Q. WHAT UPPER MIDWEST REGION AGGREGATIONS EXIST?

A. There are a number of regional aggregations that exist and it is helpful to identify and consider their scale when assessing wind penetration. They include, from

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[47] See for example, Slide 18 from NREL's presentation at the 2006 European Wind Energy Association conference, *Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*, by Brian Parsons, March 2006.

[48] Wind Integration Study – Final Report, prepared for Xcel Energy and the Minnesota Department of Commerce by EnerNex Corporation and Wind Logics, Inc., September 28, 2004.

[49] MISO Draft 2006 Transmission Expansion Plan, Section 7.3, West Planning Region Exploratory Study, page 1: "Minnesota Wind Integration Study. The state of Minnesota Public Utility Commission was commissioned by the Minnesota legislature to study a Renewable Energy Requirement for 15%, 20% and 25% energy by 2020."

largest to smallest: 1) the full MISO region, with centralized dispatch over a region with upwards of 116,030 MW peak load (2006) in its market footprint[50]; 2) the broader MISO West Planning Region (US and Canada), at 43,756 MW of projected 2011 load; 3) the US portion of the MISO West Planning Region, at 40,728 MW of 2011 peak load; 4) the CapX 2020 region, at 20,704 MW of projected 2011 load; and 5) the MRO-MISO Load Deliverability Region, at 20,403 MW of projected 2011 load. See Exhibit JI-8-F.

Q. PLEASE EXPLAIN EXHIBIT JI-8-F.

A. Exhibit JI-8-F compares the sizes of different territorial aggregations of the Upper Midwest bulk electric power system. I created this exhibit using public data on projected loads and using different wind penetration assumptions. The magnitude of connected wind power resources is shown for different penetration level assumptions for the different regions, based on projected load data for the year 2011. It displays the results of a fundamental set of calculations illustrating the overall magnitude of the wind power resource in the region if it were constrained by technical integration considerations.

Q. IS IT CORRECT TO CONSIDER ONE OF THE APPLICANTS' INDIVIDUAL SYSTEMS AS AN APPROPRIATE SCALE WHEN CONSIDERING WIND POWER POTENTIAL FOR THE APPLICANTS?

A. No. Dr. Rakow notes that Otter Tail Power has limited its wind option to 20%.[51] This suggests that Otter Tail has not considered the proper system scale when assessing how much wind they could procure to meet energy and capacity requirements. Given the broad regional coordination performed by MISO, it is technically inappropriate to consider a small scale system - such as one

[50] MISO news release, August 1, 2006. The MISO "market" footprint includes all load and resources subject to MISO's unit commitment and dispatch protocols. MISO also serves as the reliability coordinator for a larger region (including non-MISO MAPP and Manitoba) with a total peak load (2006) of 136,520 MW.
[51] Rakow, Direct Testimony, 23: 16-18.

represented by a single Applicant, or even the aggregation of the Applicants, with a combined projected peak load in 2011 of 5,854 MW[52] - when analyzing the upper bounds on the level of reliably-integrated wind resources.

Q. USING THE MIDEST ISO WEST PLANNING REGION, WHAT IS THE WIND POWER POTENTIAL AVAILABLE TO THE APPLICANTS?

A. If one were to use an arbitrary and relatively conservative penetration level of 20% wind (by installed capacity) in the Midwest ISO West Planning Region (encompassing more or less the former MAPP region[53]), there would be available approximately 10,000 MW of wind capacity (based on projected 2011 load levels).

Q. HOW MUCH WIND POWER ALREADY EXISTS IN THE UPPER MIDWEST REGION?

A. The six-state region (MN, ND, SD, IA, WI, NE) that includes most of the US MRO area plus additional non-MRO regions currently has just under 2,000 MW of installed wind capacity.[54]

Q. HOW MUCH "HEADROOM" EXISTS FOR ADDITIONAL WIND POWER IN THE UPPER MIDWEST REGION?

A. Headroom for regional wind installations on the order of 8,100 MW exists even under an arbitrary penetration rate of 20% installed capacity. This amount far exceeds the energy supply needs of the Applicants. See Exhibit JI-8-F.

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[52] Based on peak load values provided in joint applicants' appendix K.

[53] The Midwest ISO West Planning region includes the following "balancing authorities" or what was formerly known as control areas: Alliant West, Alliant East, Wisconsin Energy Corp., Wisconsin Public Service, Madison Gas and Electric, Upper Peninsula Power Company, Xcel, Minnesota Power, Southern Minnesota Municipal Power Agency, Great River Energy, Otter Tail Power, Lincoln (NE) Energy System, the Upper Great Plains region of WAPA, and Manitoba Hydro.

[54] American Wind Energy Association, October 2006.

Q. WHAT IS THE LEVEL OF WIND CAPACITY ASSOCIATED WITH REGIONAL WIND PENETRATION LEVELS OF APPROXIMATELY 40% OF INSTALLED CAPACITY, OR APPROXIMATELY 25% BY TOTAL ENERGY SHARE?

A. Exhibit JI-8-F illustrates approximate levels of installed wind capacity using various penetration assumptions for 2011 peak load assumptions. Forty percent by capacity equates to approximately 25% by energy share. Using the MISO West Planning Region, with a 2011 peak load of 43,756 MW and a presumed installed generation base of 50,319 MW (at 15% planning reserve margin), wind penetration of 25% of energy share would equate to 20,128 MW of installed wind capacity. Using the MRO-MISO Load Deliverability region with 20,400 MW of peak load and a presumed installed generation base of 23,463 MW (about the same size as the CapX 2020 region), wind penetration at 25% of energy share would equate to installed capacity of 9,385 MW.

Q. HOW IS THIS RANGE RELEVANT TO THE TESTIMONIES OF MR. HAM AND DR. RAKOW?

A. This simple computational exercise demonstrates that a significant wind resource base exists[55] to meet supply-side energy needs of regional utilities, and at least some portion of capacity needs depending on the applicable capacity accreditation procedure. The "positive impact" concluded by Mr. Ham does not appear to take into account alternatives that include wind resources that are less expensive than the Big Stone II generation option (as shown in the direct testimony of David A. Schlissel and Anna Sommer), and Dr. Rakow does not directly address these fundamental alternatives when describing the Applicants' "Analysis Under Renewable Preference".

[55] The wind resource exists, although the capacity is not yet built. MISO's generation queue as of the end of November 2006 includes over 14,000 MW of wind in the states of MN, ND, and SD.

Q. WHAT IS THE WIND INTEGRATION EXPERIENCE WITH OTHER ELECTRIC POWER SYSTEMS?

A. The European countries of Germany, Denmark and Spain have considerable penetration of wind power into their electric power systems. In some regions in Europe, average wind generation penetration exceeds 20% of *energy* needs over the course of a year, with instantaneous values greater than 100% of local energy needs (i.e., wind meets all local energy needs and wind power is exported from the region). Exhibit JI-8-B contains a series of slides from a Utility Wind Integration Group ("UWIG") short course on wind and it includes slides showing wind penetration levels for these countries.

Q. DR. RAKOW ADDRESSED THE APPLICANTS' "ANALYSIS UNDER RENEWABLE PREFERENCE". HAVE THE APPLICANTS DEMONSTRATED THAT THE ALTERNATIVE SELECTED IS LESS EXPENSIVE THAN POWER GENERATED BY A RENEWABLE ENERGY SOURCE?

A. No. As the above information shows, a considerable wind power resource exists for the Applicants to consider. The Applicants have not addressed alternatives that would take advantage of the wealth of wind power resources in the region.

IV. MR. HAM, DR. RAKOW AND MR. LAVERTY DO NOT CONSIDER IMPORTANT CHANGES TO THE REGION'S BULK POWER SYSTEM CONFIGURATION AND CONTROL AND ITS IMPACT ON WIND INTEGRATION POTENTIAL.

Q. HOW DO MR. HAM, DR. RAKOW AND MR. LAVERTY ADDRESS THE IMPACT OF UPPER MIDWEST REGION CONFIGURATION ISSUES ON THE ECONOMICS OF ALTERNATIVES TO THE BIG STONE II PROJECT?

A. Mr. Ham's conclusion of "positive impact", Dr. Rakow's findings on the Applicants' renewable resource analysis and Mr. Laverty's recommendation on the Applicants' request for a certificate of need do not consider the importance and relevance of recent and ongoing changes to the Upper Midwest Region bulk power system configuration and control and its impact on wind integration potential. To address these elements I briefly summarize these issues, which include:

1. MISO's April, 2005 commencement of centralized unit commitment and dispatch across a broad region and commensurate administration of spot locational electricity markets;
2. MISO's proposal to effectively consolidate control area or balancing authority functions through development of operating reserve and regulation market structures; and
3. MISO's role as the NERC regional reliability coordinator, and the development of seams and operating agreements between MISO and its neighbors.

Q. PLEASE ILLUSTRATE WITH ONE SPECIFIC EXAMPLE THE WAY CENTRALIZED COORDINATION BY MISO WILL IMPROVE THE TECHNICAL INTEGRATION OF WIND RESOURCES IN THE REGION.

A. The benefits of spatial diversity of wind resources can be more readily captured with a common dispatch of resources. Wind forecasting information could be delivered directly into control rooms to improve real-time system operation. For example, future control improvements could allow for MISO to obtain real-time wind forecasting and scheduling information for all wind resources in the Upper Midwest region, reducing prediction errors and thus reducing operational costs.[56]

[56] See for example *Wind Forecasting: Wind Forecasting Tools and Methods for Improved System Operation and Control*, presented by Mark Ahlstrom of Wind Logics, at "A Short Course on the Integration of Wind Power Plants", September 26-29, 2006.

Q. PLEASE SUMMARIZE THE EFFECTS OF THE MISO ENERGY MARKETS, MISO PROPOSED ANCILLARY SERVICE MARKET DEVELOPMENT AND GENERAL TRENDS TOWARDS GREATER REGIONAL COORDINATION ON THE ABILITY TO INTEGRATE AND SELL WIND POWER IN THE REGION.

A. There has recently been a sea change in the way the Upper Midwest regional power grid is dispatched and transmission use is coordinated. Prior to April, 2005, individual utilities controlled their own generation dispatch and unit commitment, and arranged all import and export transactions themselves. The region consisted of 35 somewhat self-contained control areas, roughly representing each utility or groups of utilities. See Exhibit JI-8-B. The commencement of MISO spot electricity markets in April of 2005, in conjunction with transmission operations seams agreements with neighboring regions and the proposed development of co-optimized energy dispatch and ancillary service markets heralds unprecedented technical coordination opportunities. Such coordination can lead to more efficient use of regional capacity reserves, including more efficient use of regulating and load following capacity, and thus will create greater opportunity for wind power plants to reliably integrate and sell their output.

The evolution continues, as MISO and PJM explore “joint” markets[57], MISO gains experience with its commitment and dispatch operations, and new ancillary service market structures are developed.

All of these developments will improve the ability to efficiently integrate greater amounts of wind resources into the system, primarily by expanding the scope of the marketplace, removing institutional barriers to wind power transactions and

[57] MISO and PJM continue to discuss the potential development of a “joint and common market”. The status of these efforts is documented in regular reports to FERC.

using transmission systems more efficiently. In summary, the increased coordination capability of MISO allows for the following:

1. **Reduced wind integration costs**. Centralized dispatch and the forthcoming creation of MISO-wide regulation and operating reserve markets across a 116,000 MW peak load region allows for greater operational flexibility across a system with variable output resources. In particular, the cost impact of variable output wind on the power system's need for regulating and load following resources is lessened when an aggregate of many individual wind plants across the entire MISO system is considered, as is done under centralized dispatch.
2. **Increased utilization of the existing transmission system.** MISO's security-constrained dispatch internalizes all transmission constraints and allows for increased utilization of the existing transmission system. Inefficient curtailment practices in place prior to spot market start-up are minimized, thus allowing wind resources greater access to at least non-firm transmission availability.
3. **Access to spot energy imbalance markets without penalty**. Prior to the start-up of MISO's markets, wind resources faced imbalance penalties tied to each transmission owner's area and open access transmission tariff (OATT). MISO's OATT exempts intermittent resources from such penalties[58], and thus reduces the financial risk faced by wind power. This allows for more favorable economics facing wind plants due to reduced risk and thus will tend to increase the amount of wind power available for sale to the market.
4. **Access to Ancillary Service Markets**. Those who choose to rely on wind power need access to both energy and ancillary service resources to complement the intermittent nature of the wind resource. Currently, and until MISO ancillary service market commencement (Regulation – 2007, Reserves – 2008) consumers of wind energy need to arrange for ancillary services

[58] Midwest ISO Open Access Transmission Tariff, section 40.3.4.d.i.

within individual control areas in the Upper Midwest region. After commencement of these markets, it will be easier to obtain those services through the MISO markets.

5. **Fewer barriers to interregional energy exchange**. The seams agreements in place between MISO and its neighbors will give Upper Midwest wind generation a greater reach into markets adjacent to the region in which the wind plant is installed. For example, wind resources locating in the non-MISO, MRO region will have improved access to MISO markets because of the MISO-MAPP seams agreement. The ongoing discussions between PJM and MISO on development of a "joint" market between the region portends an even greater degree of access and coordination, and thus gives wind resources from the Upper Midwest an even larger marketplace to consider selling to.

V. BIG STONE II TRANSMISSION FACILITIES ARE LIKELY NOT OPTIMAL IN THE ABSENCE OF BIG STONE II GENERATION AND THE INCREMENTAL TRANSMISSION CAPACITY ARISING FROM APPLICANTS' BIG STONE TRANSMISSION FACILITIES PROPOSAL IS ZERO

Q. WHAT DO YOU ADDRESS IN THIS SECTION?

A. I address a portion of the testimony of Mr. Eric Laverty of MISO, in particular the following two questions and answers concerning the proposed Big Stone II transmission facilities:

"Q. Would the new 230kV lines, the upgraded lines, and the potential conversion to 345kV of one of the 230kV facilities be used and useful without the Big Stone 2 plant?

A. We believe so based on the studies described earlier. The Midwest ISO has taken a preliminary review of this question and has drawn some insights as to the system-wide benefits of these transmission lines. We reviewed the addition of the new lines in conjunction with the 1300 MW worth of requests for service discussed above, made up of requests from southwestern Minnesota wind and various resources in the Dakotas, and found that the upgrades did relieve some constraints on the transmission system. Other constraints were not completely relieved but the loadings were reduced in magnitude to the point where solutions to those constraints that do not involve new ROW can be entertained. The ability to credibly entertain those types of upgrades raises the bar on benefits needed to justify other new ROW projects for the remaining constraints.

Further, as the Midwest ISO studied the 1300 MW of transmission service requests with the Big Stone 2 project, we assumed the ability to convert the 230 kV line to 345 kV especially when combined with the Cap X facilities. This proposed upgrade set was key to our results to enable most of those transmission requests.

Lastly, with the transmission system constrained in a west-to-east direction, these west-to-east new transmission lines are a good step in relieving those constraints. The nature of the transmission constraints, load growth, and proposed development in this area are such that no one new facility will relieve them all, rather a coordinated set of upgrades will be required to relieve the constraints and provide additional capacity to most of Minnesota. The Midwest ISO is confident that these facilities fit well in such a plan."[59]

"Q. What is the Midwest' s ISO position on whether or not the Big Stone transmission facilities request pending before the MPUC should be granted?

A. The Midwest ISO' s position on this request is that it should be granted as being in the best interest of the end-use customers in Minnesota."[60]

Q. DID THE MIDWEST ISO CONDUCT A STUDY TO DETERMINE WHETHER OR NOT THE BIG STONE II TRANSMISSION FACILITIES WERE AN OPTIMAL OR NEAR-OPTIMAL TRANSMISSION SYSTEM INVESTMENT IF THE BIG STONE II GENERATION PLANT WAS NOT BUILT?

A. No, MISO did not conduct such a study. As noted above, Mr. Laverty states that the Big Stone II transmission facilities will be "used and useful", but he does not state the extent to which they will be used. Stating that the facilities will be "used" is trivial: as part of a networked regional transmission grid, the facilities would certainly transfer power and thus technically would be physically used. But usefulness implies economic usefulness, the extent of which has not been shown by Mr. Laverty. To what extent would they be so used, particularly in

[59] Laverty, Direct Testimony, 18: 1-25.

[60] Laverty, Direct Testimony, 19: 23-27.

comparison to alternative arrangements for bolstering the 345 kV grid in the region? What is the opportunity cost associated with what might be a sub-optimal transmission interconnection investment, given a likely need for more transmission in the region to maximize the use of Buffalo Ridge wind resources? Neither Mr. Laverty nor the Applicants have addressed this.

Mr. Laverty does not state whether or not a different portfolio of transmission investment – one that excludes the Big Stone II interconnection facilities, but might include other transmission facilities serving more of a network support role and less of a generation interconnection role – might be a better deal for Minnesota's end use customers.

Q. DID THE SOUTHWEST MINNESOTA – TWIN CITES EXTRA HIGH VOLTAGE (EHV) DEVELOPMENT STUDY[61] ASSESS WHETHER OR NOT THE BIG STONE II TRANSMISSION FACILITIES WERE AN OPTIMAL OR NEAR-OPTIMAL TRANSMISSION INVESTMENT CHOICE IF BIG STONE II WERE NOT BUILT?

A. No, it did not. That study presumed the presence of Big Stone II and its associated transmission facilities.

Q. HAS ANY TRANSMISSION PLANNING STUDY CONSIDERED WHETHER OR NOT THE BIG STONE II TRANSMISSION FACILITIES ARE AN OPTIMAL OR NEAR-OPTIMAL INVESTMENT CHOICE IF THE BIG STONE II GENERATION PLANT WERE NOT BUILT?

A. No; not to my knowledge. For example, the CapX 2020 technical study lists a number of different "Category I" projects, and also presumes the presence of the Big Stone II facilities.[62] But it does not address the question of whether the Big Stone II transmission facilities make sense if Big Stone II itself is an uneconomic resource choice.

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[61] Vol. 1, Prepared by Xcel Energy, November 9, 2005.

[62] 2005 Minnesota Biennial Transmission Projects Report, Section 6: CapX 2020 Vision Plan, Table 5 and Table 6, page 37.

Q. HOW MUCH ADDITIONAL TRANSMISSION FOR WIND WILL THE APPLICANTS' PROPOSED BIG STONE II TRANSMISSION UPGRADES CREATE?

A. The proposed upgrades will not produce any incremental outlet benefit. At a minimum additional transmission work would be required to allow operation of the proposed facilities at 345 kV, and yet even more work might be necessary to actually achieve increased firm transfer capability beyond that achieved with the project facilities themselves.[63]

In response to an information request made by the MN Department of Commerce[64], the applicants stated that the Buffalo Ridge outlet capability will increase to a total of 1,900 MW if the Big Stone - Granite Falls line is operated at 345 kV, the Southwest MN to Twin Cities 345 kV EHV project is in place, and southwestern MN improvements identified in the BRIGO study[65] are in place. However, the 1,900 MW transfer capability from the region will occur even with the Big Stone facilities operating at 230 kV (the SW MN TC EHV study modeled the Big Stone project transmission facilities as operating at 230 kV[66]). Thus, the increment is zero. While the applicants state that simply constructing the Big Stone to Granite Falls line at 345 kV instead of 230 kV "will help significantly expand transmission outlet in the Buffalo Ridge area"[67], they do not say exactly what the incremental effect is, because it will require additional investment to see such an effect.

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[63] Response to MN Dept. of Commerce information request no. 17, November 7, 2005, page 4. The EHV study described on that page assumes operation of the Big Stone II transmission facilities at 230 kV. The response describes the "availability" of a 345/115 kV station at Canby, but the Big Stone II Project facilities do not include such 345/115 kV transformation.

[64] Ibid.

[65] Applicants' Appendix E, "Buffalo Ridge Incremental Generation Outlet Electric Transmission Study".

[66] SW MN TC EHV, page 11.

[67] Response to MN DOC No. 17, page 5.

Q. WILL THE PRESENCE OF THE BIG STONE II GENERATION FACILITY LIMIT THE ABILITY OF WIND GENERATION IN THE REGION TO BE IMPORTED INTO THE TWIN CITIES AREA?

A. Yes. The proposed Big Stone II transmission facilities do not extend all the way into the Twin Cities area, and thus the Big Stone II generation output must rely on other facilities – such as the proposed CapX 2020 Southwest Minnesota – Twin Cities EHV project, and other regional facilities - to reach the Twin Cities area. The use of the transmission system for Big Stone II generation would preclude use by wind resources in the region for the same amount of transmission capacity.

Q. WHAT OTHER ASPECTS OF THE BUFFALO RIDGE AREA TRANSMISSION FACILITY STUDIES ARE NOTEWORTHY IN RESPECT TO THE APPLICANTS' PETITION?

A. The SW MN Twin Cities EHV 345 kV project, considered as a "Group I" CapX 2020 project[68], serves as a major 345 kV path to the Buffalo Ridge area, yet it runs separate from and south of the Big Stone – Granite Falls path. It illustrates that improving Buffalo Ridge generation outlet capability does not necessarily require an upgrade to the Big Stone – Granite Falls line. It is only because of the proposed generation at Big Stone that the Big Stone II transmission facilities are being proposed; not because they are an optimal choice to increase outlet capacity from the Buffalo Ridge area to the Twin Cities.

Q. IF ANY ADDITIONAL CAPACITY IS MADE AVAILABLE, WILL IT BE USED FOR WIND POWER TRANSFERS?

A. It is not certain that additional capacity will be used for wind power transfer. All transmission is supposed to be available on a non-discriminatory basis under the conditions of *pro forma* FERC open access transmission tariffs. The MISO tariff

[68] See Section 6: CapX 2020 Vision Plan, from the 2005 Minnesota Biennial Transmission Projects Report, November 1, 2005, Table 5, "Group I Projects" page 37.

follows the FERC protocols. The reservation of transmission for wind capacity can only be made with specific wind power projects. Once new transmission capacity is in place, non-wind resources in theory have an equal opportunity to access and reserve the transmission; however, as noted above, if the Big Stone II generation facility is in place, it will likely use up 630 MW of firm space on the regional transmission system.

Q. WILL THE PROPOSED PROJECT IMPROVE FUEL DIVERSITY IN THE REGION, AS SUGGESTED BY MR. HAM?

A. No. The proposed project would result in 630 MW of coal-fired generation. Increased fuel diversity arising from increased utilization of wind resources does not occur with the interconnection of facilities for coal-fired generation.

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF MR. LAVERTY'S TESTIMONY AND THE RELEVANT REGIONAL TRANSMISSION STUDIES[69]?

A. I conclude that the facilities being proposed serve primarily as interconnection facilities for the Big Stone II plant itself, and do not provide any incremental capacity. Additional transmission investment is required to obtain incremental transmission capacity. I also conclude that neither the Applicants nor anyone else have demonstrated that the proposed Big Stone II transmission facilities represent a good investment choice to benefit Minnesota end users, as they have not evaluated the opportunity cost of such an investment. That is, no one has sought to determine what an optimal or near-optimal transmission expansion plan would look like assuming the absence of Big Stone II.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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[69] For example, the SW MN TC EHV study; the BRIGO study; and the MISO Draft 2006 Transmission Expansion Plan.

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SUMMARY

Mechanical engineer and energy economics analyst with 20 years experience in the energy industry. Activities focused primarily on electric power industry issues, especially economic and technical analysis of transmission pricing structures, wholesale electricity markets, and assessment and implementation of demand-side alternatives.

In-depth understanding of the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the US and Canada, including the following areas of expertise:

- Wholesale energy and capacity provision under market-based and regulated structures.
- Extent of competitiveness of existing and potential wholesale market structures.
- Transmission use pricing, encompassing congestion management, losses, LMP and alternatives, financial and physical transmission rights; and transmission asset pricing (embedded cost recovery tariffs).
- Physical transmission network characteristics; related generation dispatch/system operation functions; and technical and economic attributes of generation resources.
- RTO and ISO tariff and market rules structures and operation.
- FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution.
- Demand-side management, including program implementation and evaluation; and load response presence in wholesale markets.
- Building energy end-use characteristics, and energy-efficient technology options.
- Fundamentals of electric distribution systems and substation layout and operation.
- Energy modeling (spreadsheet-based, GE MAPS and online DOE-2 residential).
- State and provincial level regulatory policies and practices, including retail service and standard offer pricing structures.
- Gas industry fundamentals including regulatory and market structures, and physical infrastructure.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. 2004 – Present. Senior Associate
Responsibilities include consulting on issues of energy economics, analysis of electricity utility planning, operation, and regulation, including issues of transmission, generation, and demand-side management. Provide expert witness testimony on various wholesale and retail electricity industry issues. Specific project experience includes the following:

- Evaluation of wind energy "firming" premium in BC Hydro Energy Call in British Columbia.
- Evaluation of pollutant emission reduction plans and the introduction of an open access transmission tariff in Nova Scotia.
- Evaluation of the merger of Duke and Cinergy with respect to Indiana ratepayer impacts.
- Review of the termination of a Joint Generation Dispatch Agreement between sister companies of Cinergy.
- Assessment of the potential for an interstate transfer of a DSM resource between the desert southwest and California, and the transmission system impacts associated with the resource.
- Analysis of various transmission system and market power issues associated with the proposed Exelon-PSEG merger.
- Assessment of market power and transmission issues associated with the proposed use of an auction mechanism to supply standard offer power to ComEd native load customers.
- Review and analysis of the impacts of a proposed second 345 kV tie to New Brunswick from Maine on northern Maine customers.

Tabors Caramanis & Associates, Cambridge, MA 1996 -2004. Senior Associate.

- Provided expert witness testimony on transmission issues in Ontario and Alberta.
- Supported FERC-filed testimony of Dr. Tabors in numerous dockets, addressing various electric transmission and wholesale market issues.
- Analyzed transmission pricing and access policies, and electric industry restructuring proposals in US and Canadian jurisdictions including Ontario, Alberta, PJM, New York, New England, California, ERCOT, and the Midwest. Evaluated and offered alternatives for congestion management methods and wholesale electric market design.
- Attended RTO/ISO meetings, and monitored and reported on continuing developments in the New England and PJM electricity markets. Consulted on New England FTR auction and ARR allocation schemes.
- Evaluated all facets of Ontario and Alberta wholesale market development and evolution since 1997. Offered congestion management, transmission, cross-border interchange, and energy and capacity market design options. Directly participated in the Ontario Market Design Committee process. Served on the Ontario Wholesale Market Design technical panel.
- Member of TCA GE MAPS modeling team in LMP price forecasting projects.
- Assessed different aspects of the broad competitive market development themes presented in the US FERC's SMD NOPR and the application of FERC's Order 2000 on RTO development.

- Reviewed utility merger savings benchmarks, evaluated status of utility generation market power, and provided technical support underlying the analysis of competitive wholesale electricity markets in major US regions.
- Conducted life-cycle utility cost analyses for proposed new and renovated residential housing at US military bases. Compared life-cycle utility cost options for large educational and medical campuses.
- Evaluated innovative DSM competitive procurement program utilizing performance-based contracting.

Charles River Associates, Boston, MA, 1992-1996. **Associate**. Developed DSM competitive procurement RFPs and evaluation plans, and performed DSM process and impact evaluations. Conducted quantitative studies examining electric utility mergers; and examined generation capacity concentration and transmission interconnections throughout the US. Analyzed natural gas and petroleum industry economic issues; and provided regulatory testimony support to CRA staff in proceedings before the US FERC and various state utility regulatory commissions.

Rhode Islanders Saving Energy, Providence, RI, 1987-1992. **Senior Commercial/Industrial Energy Specialist**. Performed site visits, analyzed end-use energy consumption and calculated energy-efficiency improvement potential in approximately 1,000 commercial, industrial, and institutional buildings throughout Rhode Island, including assessment of lighting, HVAC, hot water, building shell, refrigeration and industrial process systems. Recommended and assisted in implementation of energy efficiency measures, and coordinated utility DSM program efforts.

Fairchild Weston Systems, Inc., Syosset, NY 1985-1986. Facilities Engineer. Designed space renovations; managed capital improvement projects; and supervised contractors in implementation of facility upgrades.

Narragansett Electric Company, Providence RI, 1981-1984. Supervisor of Operations and Maintenance. Directed electricians in operation, maintenance, and repair of high-voltage transmission and distribution substation equipment.

EDUCATION

Boston University, M.A. Energy and Environmental Studies, 1992
Resource Economics, Ecological Economics, Econometric Modeling

Clarkson University, B.S. Mechanical Engineering, 1981
Thermal Sciences

Additional Professional Training
Completed coursework in Solar Engineering; Building System Controls; and Cogeneration at Worcester Polytechnic Institute and Northeastern University (1984, 1988-89).
Completed Illuminating Engineering Society courses in lighting design (1989).
Utility Wind Integration Group, Short Course on Integration and Interconnection of Wind Power Plants Into Electric Power Systems (2006).

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

TESTIMONY

British Columbia Utilities Commission. In the Matter of BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan. Pre-filed Evidence filed on behalf of the Sierra Club (BC Chapter), Sustainable Energy Association of BC, and Peace Valley Environment Association. October 6, 2006. Testimony addressing the "firming premium" associated with 2006 Call energy, liquidated damages provisions, and wind integration studies.

Maine Joint Legislative Committee on Utilities, Energy and Transportation. Testimony before the Committee in support of an Act to Encourage Energy Efficiency (LD 1931) on behalf of the Maine Natural Resources Council, February 9, 2006. The testimony and related analysis focused on the costs and benefits of increasing the system benefits charge to increase the level of energy efficiency installations by Efficiency Maine.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of Air Emissions Strategy Capital Projects. Filed Jaunary 30, 2006. The testimony addressed the application for approval of installation of a flue gas desulphurization system at NSPI's Lingan station and a review of alternatives to comply with provincial emission regulations.

New Jersey Board of Public Utilities. Direct and Surrebuttal Testimony filed before the Commission addressing the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations (the proposed merger), BPU Docket EM05020106. Joint Testimony with Bruce Biewald and David Schlissel. Filed on behalf of the New Jersey Division of the Ratepayer Advocate, November 14, 2005 (direct) and December 27, 2005 (surrebuttal).

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing the proposed Duke – Cinergy merger. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 42873, November 8, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Ameren's proposed competitive procurement auction (CPA). Testimony filed on behalf of the Illinois Citizens Utility Board in Dockets 05-0160, 05-0161, 05-0162. Direct Testimony filed June 15, 2005; Rebuttal Testimony filed August 10, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Commonwealth Edison's proposed BUS (Basic Utility Service) competitive auction procurement. Testimony filed on behalf of the Illinois Citizens Utility Board and the Cook County State's Attorney's Office in Docket 05-0159. Direct Testimony filed June 8, 2005; Rebuttal Testimony filed August 3, 2005.

Indiana Utility Regulatory Commission. Responsive Testimony filed before the Commission addressing a proposed Settlement Agreement between PSI and other parties in respect of issues surrounding the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Consolidated Causes No. 38707 FAC 61S1, 41954, and 42359-S1, August 31, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission in a Fuel Adjustment Clause (FAC) Proceeding concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E, and related issues of PSI lost revenues from inter-company energy pricing policies. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 38707 FAC 61S1, May 23, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 41954, April 21, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Eastern Maine Electric Cooperative, Inc.'s Petition for a Finding of Public Convenience and Necessity to Purchase 15 MW of Transmission Capacity from New Brunswick Power and for Related Approvals. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2005-17, July 19, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Maine Public Service Company Request for a Certificate of Public Convenience and Necessity to Purchase 35 MW of Transmission Capacity from New Brunswick Power. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2004-538 Phase II, April 14, 2005.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff (OATT). Filed April 5, 2005. The testimony addressed various aspects of OATTs and FERC's *pro forma* Order 888 OATT.

Texas Public Utilities Commission. Testimony filed before the Texas PUC in Docket No. 30485 on behalf of the Gulf Coast Coalition of Cities on CenterPoint Energy Houston Electric, LLC. Application for a Financing Order, January 7, 2005. The testimony addressed excess mitigation credits associated with CenterPoint's stranded cost recovery.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-2002-0120, et al., Review of the Transmission System Code (TSC) and Related Matters, Detailed Submission to the Ontario Energy Board in Response To Phase I Questions Concerning the Transmission System Code and Related Matters, October 31, 2002, on behalf of TransAlta Corporation; and Reply Comments for same, November 21, 2002. Related direct and reply filings in response to the Ontario Energy Board's "Preliminary Propositions" on TSC issues in May and June, 2003.

Alberta Energy and Utilities Board. Testimony filed before the Alberta Energy and Utilities Board, in the Matter of the Transmission Administrator's 2001 Phase I and Phase II General Rate

Application, no. 2000135, pertaining to Supply Transmission Service charge proposals. Joint testimony filed with Dr. Richard D. Tabors. March 28, 2001. Testimony filed on behalf of the Alberta Buyers Coalition.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-1999-0044, Critique of Ontario Hydro Networks Company's Transmission Tariff Proposal and Proposal for Alternative Rate Design, January 17, 2000. Testimony filed on behalf of the Independent Power Producer's Society of Ontario.

MAJOR PROJECT WORK – BY CATEGORY

Electric Utility Industry Regulatory and Legislative Proceedings

For the staff of the Nova Scotia Utility and Review Board, conducted an economic analysis of the proposed installation of flue gas desulphurization equipment by Nova Scotia Power, Inc., and alternatives to the installation, to conform to Nova Scotia provincial emission regulations. (2005-2006)

For the staff of the Nova Scotia Utility and Review Board, analyzed a proposed Open Access Transmission Tariff by Nova Scotia Power, Inc. (2005)

For the Maine Office of Public Advocate, analyzed multiple aspects of the proposed installation of a second 345 kV tie line between Maine and New Brunswick. The analyses focused on the impacts to Northern Maine electric consumers. (2005)

Electric Utility Industry Restructuring

For the Citizens Action Coalition of Indiana, analyzed the proposed merger between Duke and Cinergy, with a focus on global protections available for PSI ratepayers and the allocation of projected merger cost and savings. (2005)

For the Citizens Action Coalition of Indiana, analyzed the termination of the Joint Generation Dispatch Agreement between Cincinnati Gas and Electric and PSI with a focus on PSI ratepayer impacts. (2005)

For TransAlta Energy Corporation, developed an issues and information paper on recent Ontario and Alberta market development efforts, focusing on the likely high-level impacts associated with day-ahead and capacity market mechanisms considered in each of those regions. (2004)

For a wholesale energy market stakeholder, participate in New England and PJM RTO markets and market implementation committee meetings, review and summarize material, and advocate on behalf of client on selected market design issues. (2004) Performed similar activities for separate client in New England. (2001)

For a group of potential generation investors in Ontario, analyzed the government's proposed wholesale and retail market design changes and produced an advocacy report for submission to the Ontario Ministry of Energy. The report emphasized, among other things, the importance of retaining a competitive wholesale market structure. (2004)

For a large midwestern utility, supported multiple rounds of direct and rebuttal testimony to the US FERC by Dr. Richard Tabors on the proposed start-up of LMP markets in the Midwest ISO utility service territories. Testimony substance included PJM-MISO seams concerns, FTR allocation options, grandfathered transactions incorporation, FTR and energy market efficiency impacts, and other wholesale market and MISO transmission tariff design issues. Testimony also included quantitative analysis using GE MAPS security-constrained dispatch model runs. (2003-2004)

For the Independent Power Producers Society of Ontario, with TCA Director Seabron Adamson, developed a position paper on resource adequacy mechanisms for the Ontario electricity market. (2003)

For TransAlta Energy Corp., provided direct and reply testimony to the Ontario Energy Board on the Transmission System Code review process. Analyzed and reported on transmission "bypass" and network cost responsibility issues. (2002-2003)

For a commercial electricity marketer in Ontario, with TCA staff, analyzed Ontario market rules for interregional transactions, focusing primarily on the Michigan and New York interties, and assessed the current Ontario electricity market policy related to "failed intertie transactions". (2002)

For ESBI Alberta Ltd., then Transmission Administrator (TA) of Alberta, served as a key member of the TCA team exploring congestion management issues in the Province, and providing guidance to the TA in presenting congestion management options to Alberta stakeholders, with a particular focus on new transmission expansion pricing and cost allocation issues. (2001)

For a coalition of power producers and marketers in Alberta, filed joint expert witness testimony with Dr. Tabors on the nature of certain transmission access charges associated with supply transmission service. (2001)

For a prospective market participant, served as a core member of the project team that developed summary reports on the New York, New England and PJM wholesale electricity spot market structures. The reports focused on market structure fundamentals, historical transmission flow patterns, forecasted transmission congestion and costs, transmission availability and FTR valuation and market results. (2001)

For the ERCOT ISO, served as a key TCA team member helping to develop and assemble a set of protocols to guide the principles, operation and settlement of the forthcoming Texas competitive wholesale electricity market. (2000)

For the Independent Power Producer's Society of Ontario, served as expert witness and filed evidence with the Ontario Energy Board supporting an alternative transmission tariff design, and critiquing Ontario Hydro Networks Company's (OHNC) proposed rate structure. Also a member of OHNC's Advisory Team on net versus gross billing issues and a leading proponent of a progressive, embedded-generation-friendly tariff structure. (1999-2000)

For a large midwestern utility, designed transmission tariff and wholesale market structures consistent with the proposed establishment of an Independent Transmission Company paradigm for transmission operations. (1999-2000)

For a coalition of independent power producers and marketers in Alberta, helped develop evidence submitted by Dr. Tabors and Dr. Steven Stoft with the Alberta Energy and Utilities Board supporting an alternative to ESBI's proposed transmission tariff. The evidence critiqued the fairness and efficiency of ESBI's proposed tariff, and offered a simple alternative to deal with Alberta's near-term southern supply shortage. (1999)

For Enron Canada Corp., provided ongoing technical support and policy advice during the tenure of the Ontario Market Design Committee (MDC). Presented material on congestion pricing before the committee, and submitted technical assessments of most wholesale market development issues. (1998-1999)

Member of the Ontario Wholesale Market Design Technical Panel. The panel's responsibilities included refinement of the wholesale market design as specified by the Market Design Committee, and specification of the market's initial operating requirements. Also served on two sub-panels: bidding and scheduling; and ancillary services. (1998-1999)

For Enron Canada Corp, assessed the generation markets in Ontario and Alberta and recommended policies for maximizing competitive market mechanisms and minimizing stranded cost burdens. Authored reports on stranded costs in Ontario, and on the legislated hedges structure in Alberta. (1997 - 1998)

For an independent power producer, assessed New England markets for electricity and assisted in valuation of generation assets for sale. (1997)

In support of testimony filed by CCEM (Coalition for Competitive Electric Markets) with the FERC, assessed alternative transmission pricing and wholesale market structures proposed for the NY, NE and PJM regions. The filings proposed market mechanisms to produce competitive wholesale electric energy markets and zonal-based transmission pricing structures. (1996-1997)

Electric Utility Mergers and Market Power Analysis

For the New Jersey Ratepayer Advocate, provided jointly sponsored expert testimony (with Bruce Biewald and David Schlissel) on the potential market power effects of the proposed Exelon-PSEG merger. (2005-2006)

For the Citizens Utility Board (Illinois), provided direct and rebuttal testimony on potential market power and transmission impacts and other issues associated with ComEd's proposal to procure standard offer power through a market-based auction process. (2005)

For the Citizens Utility Board and other clients (Illinois), provided direct and rebuttal testimony on issues associated with Ameren's proposal to procure standard offer power through a market-based auction process. (2005)

In support of FERC-filed testimony by Dr. Richard Tabors, conducted a detailed examination of the accessibility of transmission service for wholesale energy market participants on the American Electric Power and Central and Southwest transmission systems. This included evaluating all transmission service requests made over the OASIS for the first six months of 1998 for the two utility systems, and a subsequent, more detailed assessment of AEP's transmission system use during all of 1998. (1998-1999)

For a US western electric utility, served as a member of the team that conducted detailed production cost modeling and strategic market assessment to determine the extent or absence of market power held by the client. (1998)

For an independent power producer, supported FERC-filed testimony on market power issues in the New York State energy and capacity markets. This included detailed supply-curve assessment of existing generation assets within the New York Power Pool. (1997)

Worked with a local economic consulting firm for a Western State public agency in conducting an analysis of the projected savings of a series of proposed electric and gas utility mergers. (1997)

For a southwestern utility company, supported CRA in conducting an analysis of the competitive effects of a proposed electric utility merger. For a northwestern utility company, analyzed the competitive effects of a proposed electric utility merger. (1995-1996)

For the Massachusetts Attorney General's Office, conducted a study of the potential for market power abuse by generators in the NEPOOL market area. (1996)

DSM Competitive Procurement and DSM Evaluation

For the Natural Resources Council of Maine, analyzed the costs and benefits of increasing the system benefits charge (SBC) in Maine to increase efficiency installations by Efficiency Maine. Testimony before the Maine Joint Legislative Committee on Energy and Utilities. (2006)

For Southern California Edison (SCE), working as a sub-contractor to Sargent and Lundy, analyzed the potential for an interstate transfer of a DSM resource between the desert southwest and California. For the same project, also analyzed transmission impacts of various alternatives to replace power supply from the currently closed Mohave generation station for SCE. (2005)

For two separate large New England utilities, conducted impact evaluations of large commercial and industrial sector DSM programs. (1994-1996)

For a New England utility, worked on the project team developing a set of DSM evaluation master plans for incentive-type and third-party-contracting type DSM programs (1994)

For EPRI, wrote an overview of the status of DSM information systems and the potential effects of an increasingly competitive utility environment. (1993)

For two separate large New England utilities, helped to develop competitive procurement documents (DSM RFPs) for filing before the Massachusetts Department of Public Utilities. (1993, 1994)

For a midwestern utility, conducted a trade ally study designed to determine the influence of trade allies on the market for energy efficient lighting and motor equipment. (1992-1993)

DSM Implementation

Conducted detailed site visits and suggested efficiency improvement strategies for over 1,000 commercial, industrial and institutional buildings in Rhode Island. Performed end-use energy analysis and coordinated implementation of improvements. Worked with local utility DSM program personnel to educate building owners on DSM program opportunities. (1987-1992)

Energy Modeling

For various clientele, worked closely with the TCA GE MAPS modeling group on various facets of security-constrained dispatch modeling of electric power systems across the US and Canada. Specific tasks included assisting in designing MAPS model run parameters (e.g., base case and alternative scenarios specification); proposing modeling designs to clients; supporting input data gathering; interpreting model results; and writing summary reports, memos & testimony describing the results. (2002-2004)

For a group of potential electricity supply investors in Ontario, modeled the impact of proposed generation plant phaseout trajectories on investment requirements for new supply in Ontario. (2004)

For the Independent Power Producer's Society of Ontario, conducted a retrospective quantitative analysis of the Ontario market energy and ancillary service prices during the 15 months of the new wholesale market to determine the extent of infra-marginal rents available that could have supported entry for new generation. (2003)

In support of proposals to the US Dept. of Defense for military housing privatization, performed DOE-2 model runs using an online tool; and created a spreadsheet modeling tool to analyze the efficiency and cost effectiveness of new and renovated residential construction for base housing. Performed life-cycle utility cost analysis and prepared energy plans specifying building shell, equipment and appliance efficiency measures at 15 separate Army, Navy, and Air Force installations around the nation. (2001-2003)

For the Independent Power Producer's Society of Ontario, conducted a rate impact analysis of Ontario Hydro Networks Company proposed transmission tariff. (1999-2000)

For the University of Maryland at Baltimore, conducted a life-cycle cost analysis of alternative proposals for district-type thermal energy provision, comparing existing steam delivery systems to new hot-water systems. (1998)

For the UMass Medical Center (Worcester), conducted an energy use and cost allocation analysis of a large hospital complex to assist in choosing among electric and thermal energy supply options. (2000)

For an independent power producer, developed a spreadsheet-based tool to assess the rate impact of a clean coal facility in Maryland compared to alternative gas-fired supply options. (1996-1997)

For a private consulting firm, examined electric end-use and generation capacity information in seven industry energy models and reported the sensitivities of each model to varying levels of input aggregation. (1995)

For a private industrial firm in Virginia, developed a Monte-Carlo simulation-based spreadsheet model to solve a capital budgeting problem involving long-term choice of industrial boiler equipment. (1995)

For a New England utility, developed a spreadsheet model to help determine economic decision-making processes used by energy service companies when delivering third-party procured DSM. (1995)

Petroleum and Natural Gas Industry Analysis

For a private independent power producer, conducted an analysis of the rate impacts of the Warrior Run clean coal (fluidized bed combustion) power plant in Maryland under various assumptions of natural gas prices and environmental regulation scenarios. (1996-1997)

For a British consulting firm, researched and presented findings on the current status of natural gas restructuring efforts in the US and their impact on regional US markets for power generation. (1996)

For a Canadian law firm representing Native Canadian interests, conducted a detailed analysis of natural gas netback pricing for Alberta gas into US Midwest and West Coast markets over a thirty-year period. (1995)

For a US natural gas pipeline consortium, performed an econometric analysis of the demand for natural gas in the state of Florida. (1992-1993)

PAPERS, PUBLICATIONS AND PRESENTATIONS

Interstate Transfer of a DSM Resource: New Mexico DSM as an Alternative to Power from Mohave Generating Station. Jointly authored with Tim Woolf, Bill Steinhurst and Bruce Biewald. To be presented at the 2006 ACEEE Summer Study on Energy Efficiency in Buildings and published in the proceedings. (2006)

SMD and RTO West: Where are the Benefits for Alberta? Keynote Paper prepared for the 9th Annual Conference of the Independent Power Producers Society of Alberta, with Dr. Richard D. Tabors, March 7, 2003.

A Progressive Transmission Tariff Regime: The Impact of Net Billing, presentation at the Independent Power Producer Society of Ontario annual conference, November 1999.

Tariff Structure for an Independent Transmission Company, with Richard D. Tabors, Assef Zobian, Narasimha Rao, and Rick Hornby, TCA Working Paper 101-1099-0241, November 1999.

Transmission Congestion Pricing Within and Around Ontario, presentation at the Canadian Transmission Restructuring Infocast Conference, Toronto, June 2-4, 1999.

The Restructured Ontario Electricity Generation Market and Stranded Costs. An internal company report presented to the Ontario Ministry of Energy and Environment on behalf of Enron Capital and Trade Resources Canada Corp., February 1998.

Alberta Legislated Hedges Briefing Note. An internal company report presented to the Alberta Department of Energy on behalf of Enron Capital and Trade Resources Canada, January 1998.

Generation Market Power in New England: Overall and on the Margin. Presentation at Infocast Conference: New Developments in Northeast and Mid-Atlantic Wholesale Power Markets, Boston, June 1997.

The Market for Power in New England: The Competitive Implications of Restructuring. Prepared for the Office of the Attorney General, Commonwealth of Massachusetts, by Tabors Caramanis & Associates with Charles River Associates, April 1996. R. Fagan was a key member of the team that produced the report.

Estimating DSM Impacts for Large Commercial and Industrial Electricity Users. Lead investigator and author, with M. Gokhale, D.S. Levy, P.J. Spinney, G.C. Watkins. Presented at The Seventh International Energy Program Evaluation Conference, Chicago, Illinois, August 1995, and published in the Conference Proceedings.

Sampling Issues in Estimating DSM Savings: An Issue Paper for Commonwealth Electric. Prepared with G.C. Watkins, Charles River Associates. Report for COM/Electric System, filed with the MA Dept. of Public Utilities (MDPU), April 28, 1995, Docket # DPU 95-2/3-CC-l.

Demand-side Management Information Systems (DSMIS) Overview. Electric Power Research Institute Technical Report TR-104707. Robert M. Fagan and Peter S. Spinney, principal investigators, prepared by Charles River Associates for EPRI, January 1995.

Impact Evaluation of Commonwealth Electric's Customized Rebate Program. With P.J. Spinney and G.C. Watkins. Charles River Associates, Initial and Updated Reports, April 1994, April 1995, and April 1996.1995 updated report filed with the MDPU, April28, 1995, Docket # DPU 95-2/3-CC-I. The initial report filed with the MDPU, April 1, 1994.

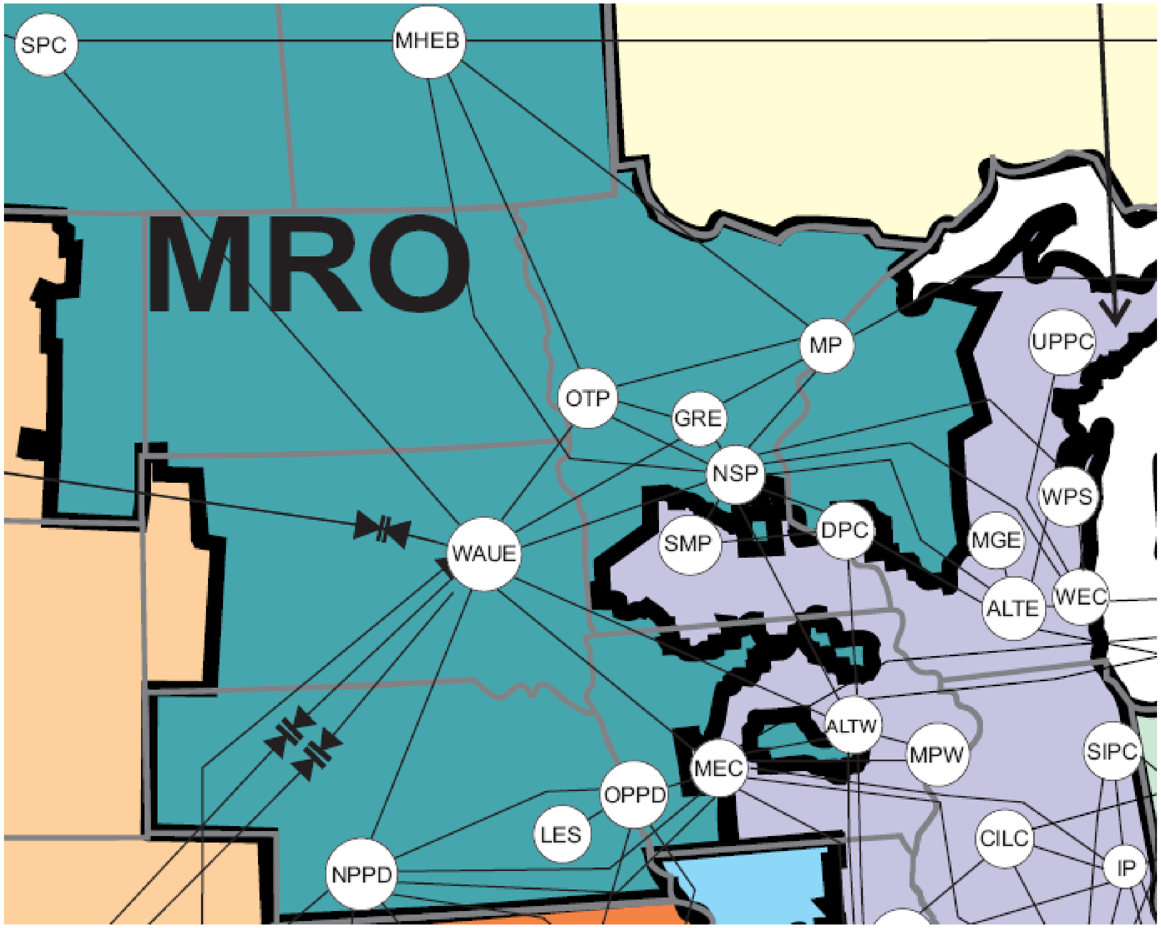
Northeast Utilities Energy Conscious Construction Program (Comprehensive Area): Level I and Level II Impact Evaluation Reports. With Peter S. Spinney (CRA) and Abbe Bjorklund (Energy Investments). Charles River Associates Reports prepared for Northeast Utilities, June and July 1994.

The Role of Trade Allies in C&I DSM Programs: A New Focus for Program Evaluation, Paper authored by Peter J. Spinney (Charles River Associates) and John Peloza (Wisconsin Electric Power Corp.). Presented by Bob Fagan at the Sixth International Energy Evaluation Conference, Chicago, Illinois, August 1993.

Resume dated December 2006.

NERC Control Areas in the Upper Midwest Region

Exhibit JI-8-B

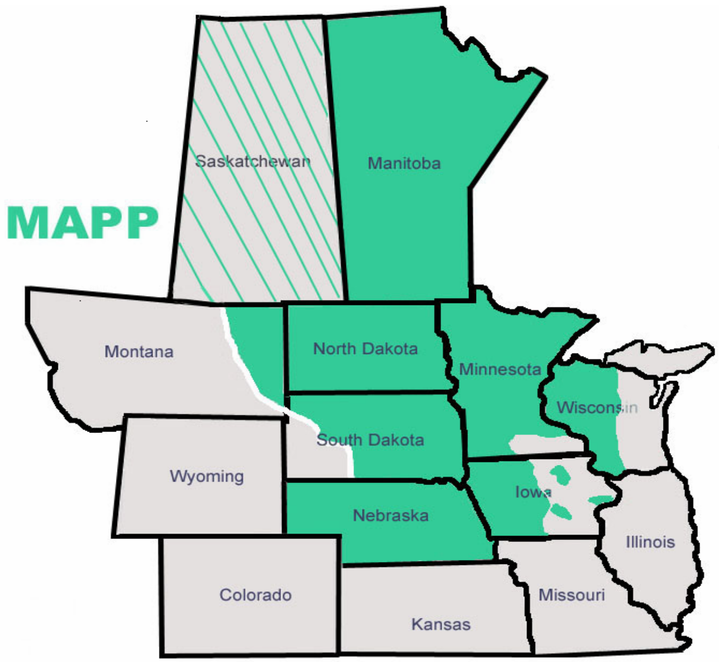


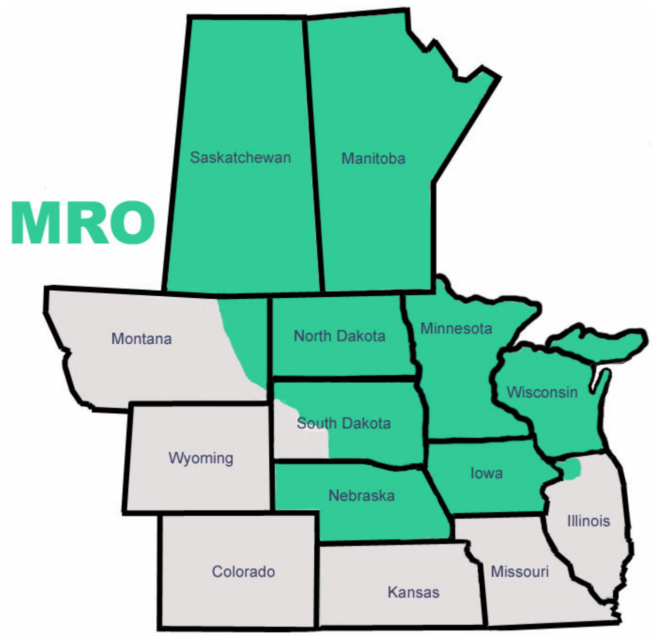
MRO Region Balancing Authorities

Alliant Energy	ALTE
Alliant Energy	ALTW
Dairyland Power Cooperative	DPC
Great River Energy	GRE
Lincoln Electric System	LES
Madison Gas and Electric Company	MGE
MHEB, Transmission Services	MHEB
MidAmerican Energy Company	MEC
Minnesota Power, Inc.	MP
Muscatine Power and Water	MPW
Nebraska Public Power District	NPPD
Northern States Power Company	NSP
Omaha Public Power District	OPPD
Otter Tail Power Company	OTP
SaskPower Grid Control Centre	SPC
Southern Minnesota Municipal Pwr Agcy	SMP
Upper Peninsula Power Co.	UPPC
Western Area Power Administration	
- Upper Great Plains East	WAUE
Wisconsin Public Service Corporation	WPS

Source: NERC Operating Manual, June 2006

Expanded Membership- Footprint Comparison



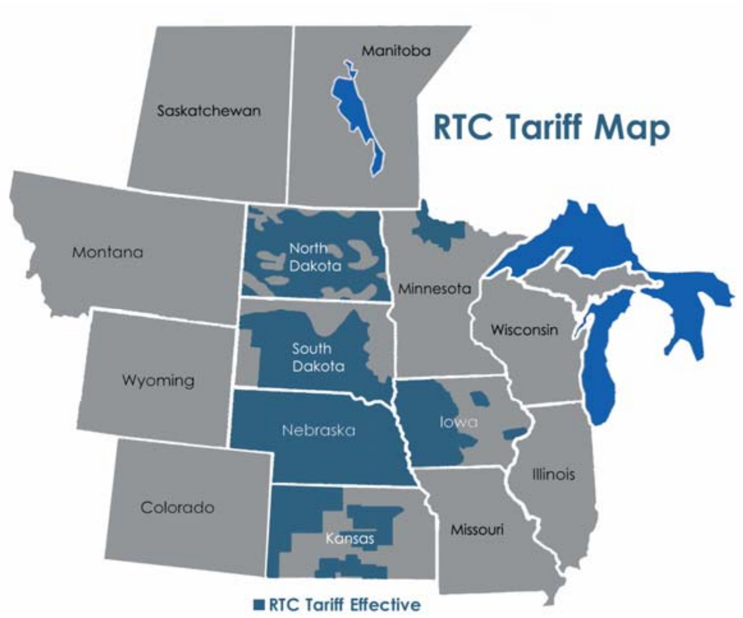


Note: Northern MAIN Utilities- Reliability functions transfer to MRO on January 1, 2006

MIDWEST RELIABILITY ORGANIZATION

Exhibit JI-8-D

Regional Transmission Tariff Map



MIDWEST RELIABILITY ORGANIZATION

Areas With Highest Wind Share

Country/ Region	Installed Wind Capacity (2002)	Total Installed Power Capacity	Average Annual Penetration Level	Peak Penetration Level
Western Denmark:[3]	2,315 MW	7,018 MW	~ 18 %	**> 100 %**
Thy Mors	~ 40 MW	Part of the Western Danish System	>50 %	**~ 300 %**
Germany:	12,000 MW	119,500 MW	~ 5 %	
Schleswig Holstein	1,800 MW	Part of the German System	~ 28 %	**> 100 %**
Papenburg	611 MW	Part of the German System	~ 55 %	**> 100 %**
Spain:	5,050 MW	53,300 MW	~ 5 %	
Navarra	550 MW	Part of the Spanish System	~ 50 %	**> 100 %**
Island Systems:				
Swedish Island of Gotland	90 MW	No Local Generation in normal state	~ 22 %	**> 100 %**
Creak Island of Crete	70 MW	640 MW	~ 10 %	N. A.
Wind-Diesel System Denham, Australia	690 kW	2,410 kW	~ 50 %	**~ 70 %**

3

Wind Energy Targets

	Germany	**Denmark (W+E)**	**Spain**	**Ireland**
Targets GW [Year]	50.3 [2020]	**3.6+1.2 [2020]**	13.0 [2011]	1.0 [2010]
Max. Penetration Level with Constant Interconnection Capacity	92 %	**W: 92 % E: 36 %**	75 %	46 %
For Comparision today's max. penetration level with Intercon. Cap.	30 %	**W: 61,5 % E: 21,2%**	45 to 48 %	14 %

4

Exhibit JI-8-E Page 2

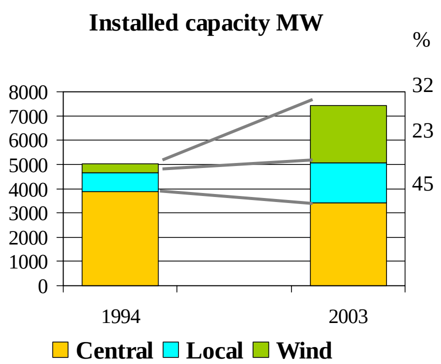
Historical Key Figures

	1998	1999	2000	2001	2002	2003
Consumption TWh	20.4	20.5	20.7	20.9	20.9	21.0
Production TWh	24.9	22.6	21.0	23.1	23.5	27.4
CHP TWh	6.2	6.4	6.2	6.8	6.7	6.8
Wind power TWh	2.1	2.4	3.4	3.4	3.8	4.4
Wind power in % of consumption	10.3 %	11.7 %	16.4 %	16.3 %	18.2 %	21.0 %
Exchange TWh	- 4.5	- 2.1	- 0.3	- 2.2	- 2.6	- 6.3

11

A Complete Change

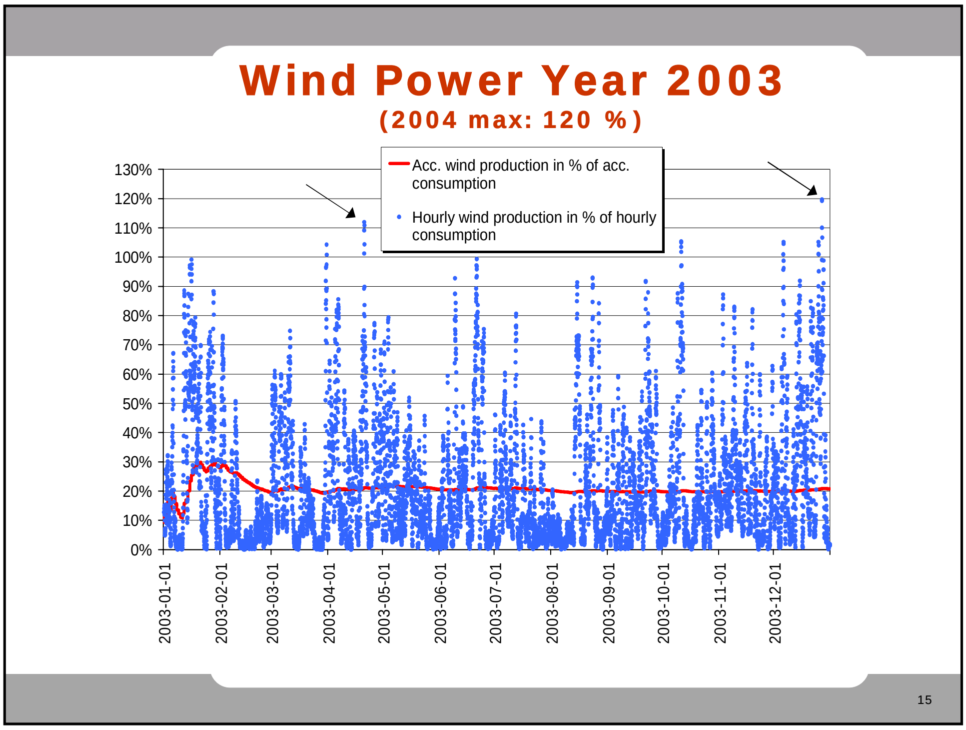
- More than 50 % local installed capacity
  - Prioritized
  - Installed in local grids
  - Beyond normal regulation
- 21 % wind energy
  - Wind power exceeding system load in several cases

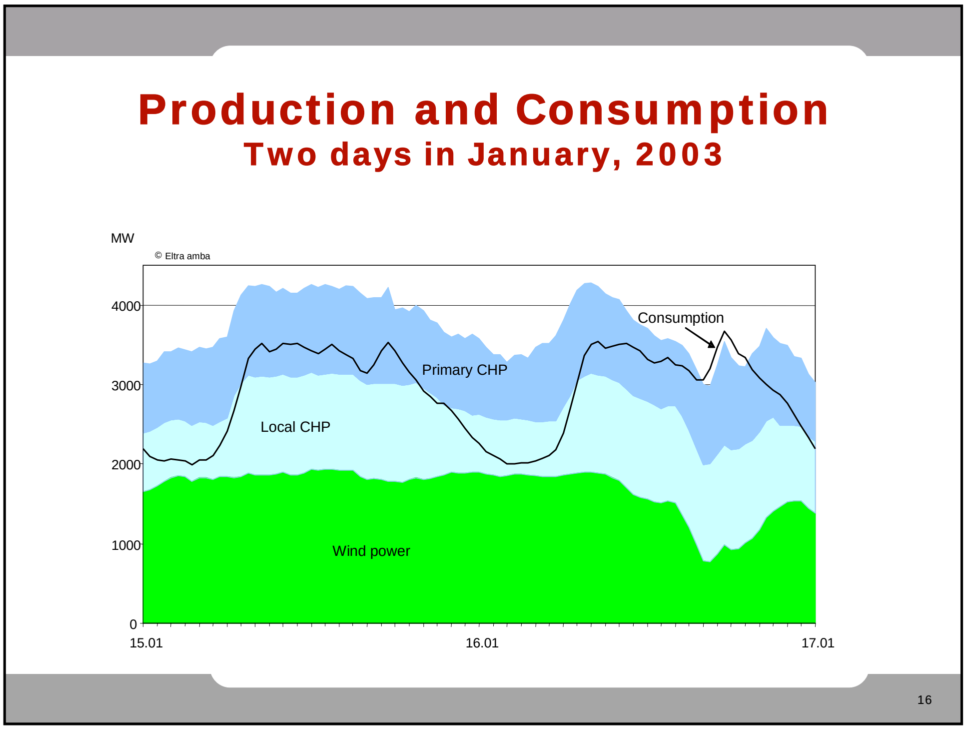


It was not planned exactly that way

12

Exhibit JI-8-E Page 3





Wind Capacity Potential and Headroom Above Existing Wind, MW
In the Upper Midwest Under Different Assumptions of Regional Scale

				Installed Wind MW at Different Capacity and Energy Share Assumptions				
Wind Capacity Potential			Capacity	10%	20%	25%	30%	40%
Region Definition	2011 Peak Load, MW	2011 Peak + 15%, MW	Energy	6.4%	12.8%	16.0%	19.1%	25.5%
MISO West Planning Region	43,756	50,319		5,032	10,064	12,580	15,096	20,128
MISO West Excluding Manitoba	40,728	46,837		4,684	9,367	11,709	14,051	18,735
CapX 2020 Region	20,704	23,809		2,381	4,762	5,952	7,143	9,524
MRO-MISO Load Deliverability Region	20,403	23,463		2,346	4,693	5,866	7,039	9,385
Headroom Calculations								
MISO West Planning Region	43,756	50,319		5,032	10,064	12,580	15,096	20,128
Existing Wind Six States				1,947	1,947	1,947	1,947	1,947
Remaining after subtracting existing				3,085	8,117	10,633	13,149	18,181
MRO-MISO Load Deliverability Region	20,403	23,463		2,346	4,693	5,866	7,039	9,385
Existing Wind Six States				1,947	1,947	1,947	1,947	1,947
Remaining after subtracting existing				399	2,746	3,919	5,092	7,438
Applicants' Territories	5,854	6,732						

Note: Wind energy share estimated based on average annual capacity factor of 37.5% for wind turbine generators and a average annual system load factor of 60%. Existing wind in the six noted states based on AWEA data from October, 2006. Six states: MN, ND, SD, IA, WI, NE.

Data sources: MISO MTEP06 Draft Report, Section 6.3, West Planning Region Reliability Analysis, Table 6.3-1, Midwest IO West Control Area Summary for 2011 Summer Peak, Baseline Reliability Plan Models.
CapX 2020 Technical Update 5/19/2005, Table 1, 2009 Load escalated to 2011 using average growth rate of 2.49%/year.
Applicants' Appendix K information.