FILED WITH
Executive Secretary

OCT 22 2007

IOWA UTILITIES BOARD

STATE OF IOWA

BEFORE THE IOWA UTILITIES BOARD

IN RE:	)	
APPLICATION OF INTERSTATE POWER AND LIGHT COMPANY FOR A GENERATING FACILITY SITING CERTIFICATE	)	**DOCKET NO. GCU-07-01**

Direct Testimony and Exhibits

of

Robert M. Fagan

Synapse Energy Economics, Inc.

On Behalf of

Iowa Office of Consumer Advocate

PUBLIC VERSION

October 22, 2007

Table of Contents

List of Exhibits

Appendix A:	Resume of Robert Fagan
Schedule A:	Data Request Responses Provided By IPL in Response to OCA Data Request Nos. 9, 13, 21, 71, 104, and 162.
Schedule B:	Evolution of Commerical Wind Technology
Schedule C:	Capacity and Cost Trends

I. INTRODUCTION, SUMMARY AND RECOMMENDATIONS

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, including economic and technical analysis of competitive electricity markets development, electric power transmission pricing structures, examination of utility-scale wind power potential and integration, 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 Appendix A.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Iowa Office of Consumer Advocate.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to examine Interstate Power and Light's (IPL) treatment of utility-scale wind power in its resource plans used in their application for the proposed Sutherland Generating Station Unit No. 4 (SGS 4) coal plant. I also address IPL's proposed used of an 18% planning reserve margin.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony addresses various aspects of utility-scale wind power in Iowa and IPL's inclusion of wind resources in its resource plan, and IPL's use of an 18% planning reserve margin:

1. **Iowa's Abundant, Economical Wind Resource is Cheaper than New Coal.** Iowa has an abundant and economical wind resource whose potential has yet to be fully tapped. For example, an identified site demonstrates the potential for average annual net capacity factors likely on the order of at least [redacted] for 80 meter hub heights. Higher hub heights could result in even greater annual capacity factors at these sites. This level of wind resource results in wind being the cheapest available baseload supply-side energy resource to meet incremental needs in Iowa even when IPL's unrealistically "low" carbon price scenario is considered, as demonstrated in the OCA's EGEAS modeling runs. Wind power is an even better bargain when considering more realistic CO2

---

[1] See, for example, Confidential Schedule B to Exhibit RMV-1, IPL witness Vosberg in Docket No. RPU-07-5, Application For A Determination of Ratemaking Principles, Volume IV: Confidential. This Schedule is a confidential wind resource analysis that includes the average annual capacity factor for a wind farm at a certain potential site in Iowa.

price scenarios such as those noted in Mr. Schlissel's testimony. IPL should install as much wind as its energy needs demand (after first securing lower cost energy efficiency resources) and its system can handle before considering more expensive and emissions-risky coal options. Based on current assessment of wind power in the Upper Midwest region, IPL could reliably accommodate up to at least 25% of its retail energy needs with wind power.

2. **IPL Misrepresents Wind's Ability to Economically Meet Energy Needs.** IPL analytically misrepresents the ability of wind power to economically serve a significant fraction of IPL's incremental energy needs. It does this by 1) using an unrealistic "base" case that excludes carbon dioxide cost impacts; 2) underestimating the capacity value of wind; 3) artificially and unnecessarily constraining the EGEAS resource planning model from choosing economic wind power options as resource alternatives; and 4) capping the availability of new wind resources at 800 MW over the planning period, far below the level of wind that can be accommodated on the regional power network. These misrepresentations result in IPL "missing" up to 1,039 MW of economic wind power available for installation during the planning period 2007-2022, in their base case. IPL is "missing" up to 639 MW of economical wind power in their "low" and "high" carbon price scenarios.

3. **IPL Can Install Wind to Meet up to 25% of Their Retail Energy Needs by 2022, Rather Than 9.1% as They Propose.** A recent technical study on wind integration potential in the Upper Midwest region demonstrates that a wind power penetration that allows for wind power to serve of up to 25% of

the region's energy needs is possible with relatively minor increases in ancillary service costs to accommodate the wind resource. IPL states that a 25% penetration of wind energy into IPL's energy mix is acceptable. IPL can install more economic wind than they have planned for 2022 and still be below 25% penetration rate (by retail energy). IPL's base resource plan contains 618 MW of wind power in 2022. A plan to meet 25% of retail needs with wind power would result in 1,657 MW of wind[2], 1,039 MW more than IPL assumes in its base resource plan. IPL's "high" and "low" carbon scenarios contain only 1,018 MW of wind, still 639 MW below a 25% penetration (by energy needs) level.

4. **IPL's New Wind Capacity Credit Values Are Too Low**. IPL-modeled wind capacity credit values of 10% for new wind facilities are too low. Based on current and projected capacity factors during peak periods for the best wind resources, and considering the methods used to assess capacity valuation of the wind resource, a 20% to 25% range for planning purposes is more reasonable.

5. **IPL's Planning Reserve Margin is Too High**. IPL's use of a planning reserve margin of 18% is too high. IPL provides no analytical documentation in support of such a high value. A more reasonable "base" case planning reserve value, based on the MAIN Guide #6, is between 15% and 16.2%. A 16.2% planning reserve value results in a 2013 requirement that is 56 MW

[2] Assuming a wind resource average annual capacity factor of 38%.

less than IPL's capacity need value using 18%. An 18% value is reasonable only for more extreme planning sensitivities.

6. **For the Same Amount of Energy, Wind Power's Economic Development Effects are Likely Greater than the Proposed Coal Plant's Effect.** Using wind power to deliver IPL's incremental energy needs instead of power from the proposed coal plant will likely bring greater economic benefits to Iowans than what would be seen with the coal plant. The benefits of construction and secondary indirect benefits associated with capital investment accrue to both coal and wind plants. However, wind alternatives do not need to purchase fuel from out of state, and cheaper wind-powered electricity leaves more dollars in the pockets of electricity consumers – money that can be spent elsewhere in the economy. Numerous studies have documented the economic benefits of local wind power. In addition, Iowa has already benefited from wind-related manufacturing jobs and investment, and could continue to benefit from this effect, especially if local utilities, such as MidAmerican and IPL, indicate a willingness to invest in as much economical wind power as is needed.

Q. WHAT DO YOU RECOMMEND?

A. I recommend the IUB deny IPL's application for a Generation Facility Siting Certificate on the grounds that IPL has not shown the proposed coal plant to be a reasonable alternative to meeting energy and capacity needs. At a minimum, after first obtaining all cost-effective energy efficiency resources, building or buying more wind-powered supplies is a more economical approach to meeting incremental energy supply needs than building a new coal plant.

II. CAPACITY CREDIT VALUES

Q. WHAT ARE THE CAPACITY CREDIT VALUES USED IN THE EGEAS MODELING BY IPL FOR EXISTING WIND GENERATING PLANTS?

A. IPL's modeled capacity credit values for eight existing wind plants are found in the EGEAS edit files from the 2007 Electric Resource Plan. IPL lists existing annual wind plant capacity values that range from [redacted]% to [redacted]%, meaning that these existing plants are credited with a capacity contribution of from [redacted]% to [redacted]% of their nameplate value. The total nameplate value of these plants is just under 250 MW, and the capacity credit value totals just over [redacted] MW, for an aggregate capacity credit value for the eight plants of [redacted]%.

Q. WHAT ARE THE EXISTING CAPACITY CREDIT VALUES BASED ON?

A. They are based on actual historical capacity factors over all the months of the year.[3] Data on actual capacity factors was provided in response to data request 104.

Q. WHAT ARE THE CAPACITY CREDIT VALUES USED IN THE EGEAS MODELING BY IPL FOR NEW WIND GENERATING PLANTS?

A. IPL's modeled capacity credit value for new wind plants is 10%.

---

[3] From the response to data request No. 104: "From a historic data perspective, a facility's median output for each month is determined, and then for a particular month the average of the monthly median values for up to ten years of historic data serves as the basis for that month's planning capacity." Page 2.

Q. WHAT ARE THOSE VALUES BASED ON?

A. There is no supporting analytical documentation provided for using a value of 10%. In response to data request number 104, Mr. Kitchen states the following[4]:

> "The capacity values for the wind facilities are intended to represent the capacity value each facility contributes towards IPL's planning reserves obligation."

And

> "Over the last few years the projected planning capacity for new facilities has been correlated to that of an existing facility, with adjustments made for differences in nameplate capacity and expected annual capacity factor based on simple scalars for both parameters."

Q. IS THERE ANY INFORMATION ABOUT PROJECTED CAPACITY VALUES FOR POTENTIAL NEW PLANTS THAT IPL WOULD BUILD OR PURCHASE?

A. Yes. In particular, IPL has indicated in its Application for a Determination of Ratemaking Principles[5] that particular potential new wind facilities would have an annual net capacity factor of approximately [redacted]%.

Q. IS THIS ANNUAL CAPACITY FACTOR GREATER THAN THE ANNUAL CAPACITY FACTORS FOR ANY OF THE EXISTING PLANTS?

A. Yes. For example, the Beaver wind plant had an annual capacity factor of about [redacted]% in 2006 and an assigned capacity credit value of [redacted]%. The Adams wind

---

[4] Ibid., page 2.

[5] Docket No. RPU-07-5, volume IV: Confidential, Exhibit RMV-1, Schedule B, pages 49-50.

plant had an annual capacity factor of [redacted]% in 2006, and IPL assigns it a capacity credit value of [redacted]%.[6]

Q. IF "ADJUSTMENTS WERE MADE FOR …DIFFERENCES IN EXPECTED ANNUAL CAPACITY FACTORS" AS STATED BY MR. KITCHEN[7], WOULD YOU THEN EXPECT THE MODELED CAPACITY CREDIT VALUES FOR NEW PLANTS TO BE HIGHER THAN 10%?

A. Yes, absolutely. If the new wind plants are expected to be high performing, based on detailed, documented wind studies, it would be consistent for IPL to properly account for that expectation with a reasonable capacity credit value that is certainly higher than 10% and likely exceeds the [redacted]% assigned to the [redacted] wind plant.

Q. WHY SHOULD NEW WIND PLANTS GET A HIGHER CAPACITY CREDIT PERCENTAGE THAN THE "BEST" CAPACITY-PERFORMING EXISTING WIND PLANT, [redacted]?

A. Because the data on the potential [redacted] site analyzed by [redacted] and described by IPL in its filing[8] show [redacted]

---

[6] See EGEAS edit files for IPL base case, response to data request no. 9.; and wind plant capacity factor data in response to data request no. 104.

[7] Response to data request 104, page 2.

[8] Docket No. RPU-07-5, Exhibit RMV-1, Confidential Schedule B.

[redacted], and comparatively are [redacted].

Q. WHAT IS THE EFFECT IF THE CAPACITY CREDIT VALUES OF IPL'S POTENTIAL WIND RESOURCES REFLECT A CAPACITY CREDIT VALUE OF 25% INSTEAD OF 10%?

A. The effect is to increase the capacity value of every 200 MW of new wind from 20 MW to 50MW. IPL's base case includes 400 MW of "new" wind by 2022. Even if one was to accept that only 400 MW of new wind by 2022 should be chosen in the resource plan – which I don't, given the beneficial economics of new wind - using a low capacity credit value of 10% instead of 25% undercounts the capacity resource by 60 MW, a significant amount given the level of indicated resource need.

Q. WHAT CAPACITY CREDIT VALUE WAS USED BY MIDAMERICAN IN ITS APPLICATION FOR A DETERMINATION OF RATEMAKING PRINCIPLES?

A. MidAmerican used a 20% capacity credit value in its application for ratemaking principles for 540 MW of future wind power.[9]

[9] Iowa Utilities Board, Docket No. RPU-07-2.

III. IPL WIND IN RESOURCE PLAN

Q. HOW MUCH WIND POWER DOES IPL HAVE IN ITS PLANNED RESOURCE PORTFOLIO?

A. IPL's base case indicates a total installed wind capacity in 2022 of 618 MW, producing 2,016 GWh per year. This reflects 9.1% of IPL's total energy need of 22,059 GWh in 2022. In their "low" and "high" carbon-constrained cases, IPL's installed wind capacity in 2022 is 1,018 MW, producing 3420 GWh per year, or 15.5% of their total energy need.

Q. WOULD MORE WIND BE AN ECONOMICAL CHOICE, ESPECIALLY RELATIVE TO IPL'S PROPOSED COAL PLANT?

A. Yes, if even minimal CO2 costs, expected for the near future, are properly factored in. This is clearly shown in the additional EGEAS runs performed by the OCA, as additional wind up to the maximum allowed is chosen as an economic selection.

Q. WHY DOESN'T IPL'S RESOURCE PLANNING TOOL SELECT MORE WIND POWER IF IT IS ECONOMICAL?

A. Because IPL's EGEAS modeling in the base case includes no carbon cost, and it includes two artificial constraints on the amount of wind power that can be selected or is available to be selected. First, as described in the testimony of Mr. Mike Drunsic and Mr. David Schlissel, IPL limits the amount of economic wind power plants the model can choose and thus artificially forecloses the model's ability to choose resources with the lowest system cost to IPL. Second, IPL caps the overall amount of wind power the model has access to at 800 MW of new wind over the planning period. This is far below the level of wind power that can be reliably accommodated on IPL's system.

Q. WHAT HAPPENS WHEN THE FIRST ARTIFICIAL CONSTRAINT, REGARDING THE ABILITY OF EGEAS TO SELECT ECONOMIC RESOURCES, IS REMOVED?

A. IPL's resource planning tool, the EGEAS model, selects more wind power when the critical constraint is removed in those cases with carbon costs factored in. As described in Mr. Schlissel's, Dr. Larry Shi's, and Mr. Drunsic's testimony, Synapse and the OCA ran EGEAS with this constraint removed and it selected the maximum amount of additional wind (per IPL's inputs on this maximum) as economic, i.e., 800 MW in total of new wind power over the planning period 2007-2022.

Q. WHAT HAPPENS WHEN THE SECOND CONSTRAINT, CONCERNING THE OVERALL SYSTEM CAP ON NEW WIND UNITS, IS REMOVED?

A. The model selects additional economic wind resources up to the new cap in the scenarios with carbon costs accounted for. We used a new cap of 1,400 MW of additional wind, approximately equal to meeting up to 25% of IPL's retail energy need in 2022. All of this 1,400 MW of new wind is selected as economic, for a total wind resource of 1,618 MW in 2022.

Q. HOW MUCH MORE WIND COULD IPL ACCOMMODATE ON ITS SYSTEM?

A. IPL could accommodate additional wind power at least up to a level where wind production represents 20 to 25% of IPL's retail generation need in 2022, or a total of approximately 1,325 MW (20%) to 1,657 MW (25%) of wind[10]. IPL has noted in its response to discovery request no. 162 that it believes that it can accommodate 20% to 25% of its retail energy needs with wind.

Q. ARE THERE STUDIES CONFIRMING THAT UP TO 20% TO 25% OF IPL'S RETAIL ENERGY NEEDS COULD BE MET WITH WIND POWER?

A. Yes. A seminal study conducted for the Minnesota Dept. of Commerce and issued in December of 2006 looked at the wind integration levels in the MN/IA region of up to 25% of retail energy needs, and concluded that such levels of wind power integration could be accommodated reliably and with little overall increased costs to system control requirements, generally expressed as a need to have sufficient ancillary services to operate the power system reliably.[11]

---

[10] At an assumed average annual capacity factor of 38%.

[11] Enernex Corporation, "Final Report – 2006 Minnesota Wind Integration Study, Volume I", prepared for the Minnesota Public Utilities Commission by Enernex Corporation, in Collaboration with The Midwest Independent System Operator, November 30, 2006. The full report, Volume I, Volume II, and the accompanying presentation material, is available online at http://www.uwig.org/opimpactsdocs.html.

Q. HOW MUCH WIND POWER WOULD EXIST IN 2022 IF IPL MET 20% TO 25% OF ITS NEEDS WITH WIND POWER?

A. Meeting 20% of IPL's electricity needs with wind power in 2022 equates to 1,325 MW of wind (38% capacity factor). Meeting 25% of IPL's energy needs in 2022 with wind power equates to approximately 1,657 MW of wind power. At higher capacity factors, these levels would be proportionately lower. Thus, an additional 707 to 1,039 MW of wind power beyond what IPL has in its base resource case would need to be harnessed in order to reach a 20% to 25% target in 2022.

Q. HOW MUCH CAPACITY VALUE WOULD THIS LEVEL OF ADDITIONAL, ECONOMIC WIND BRING TO IPL'S SYSTEM?

A. Even at IPL's too-low capacity crediting level of 10%, this amount of wind would bring an additional 71 to 104 MW of accredited capacity to IPL's system. At a more reasonable level ranging from 20 to 25%, the additional wind would result in 142 MW (20% retail energy, 20% capacity credit) to 260 MW (25% retail energy, 25% capacity credit) of accredited capacity.

IV. PLANNING RESERVE MARGIN

Q. WHAT PLANNING RESERVE MARGIN DOES IPL USE IN ITS APPLICATION?

A. IPL uses an 18% reserve margin.

Q. WHAT IS BASIS FOR IPL'S USE OF AN 18% RESERVE MARGIN?

A. IPL bases its use of 18% on the extreme upper end of a 15% to 18% range noted in the current MAIN (Mid-America Interconnected Network) Guide #6.[12] IPL does not document analytically why it chose to use the 18% value, rather than some other value in the range, such as the midpoint or a value based on a particular sensitivity case for the loss of load expectation (LOLE) modeling runs that are the key analytical tool used to help determine a planning reserve margin value.[13] IPL states that using the 18% value is justified because IPL uses a load forecast of "normal" weather.

Q. WHAT DOES THE MAIN GUIDE #6 SAY ABOUT THE RANGE OF PLANNING RESERVE MARGIN GOALS?

A. The MAIN Guide #6 states that

> "Consideration of all of the sensitivity cases examining the effects of alternative assumptions (cases 6 through 12) would indicate a range of 15.0% to 16.2%."

It also states that the range has been lowered in recent years as NERC GADS data has shown lower outage rates for generation.[14] They state

---

[12] "MAIN Guide #6 Generation Reliability Study 2005-2014", Prepared by the MAIN Reserve Margin Working Group. Provided in response to data request No. 13, Attachment A.

[13] Loss of load studies estimate how much generation is required to minimize the likelihood of an event that results in not having enough generation to serve load to no more than one day in ten years.

[14] One of the main reasons a planning reserve margin is needed is because generation plants are not 100% reliable. They can experience "forced" outages, or planned maintenance outages. For this reason, generation capacity greater than the forecasted peak load is required to account for the possibility that a portion of generation capacity might not be available because of outage on any given day. NERC GADS data reflects the performance of generation units in terms of their availability or outage rates.

> "Variations in unit performance have become the driving force behind changes in the reserve margin target, as LFU [load forecast uncertainty] and LFU multiplier fluctuations have been modest over the last ten years."

Lastly, it states

> "The Reserve Margin Working Group acknowledges that, while its best estimate of the required reserve margin is approximately 15%, a combination of adverse changes could increase that by as much as three percentage points".

Q. WHAT DOES THIS MEAN?

A. The MAIN Guide #6 sets a range of planning reserve margin based on loss of load expectation studies that would indicate 15.0% to 16.2% requirements to achieve a "one day in ten" level of reliability. They further state that the load forecast uncertainty is modest. Based on a combination of adverse circumstances, they allow for an upper end of 18%.

Q. IPL STATES THAT USING NORMAL WEATHER LEADS THEM TO USE THE UPPER END OF THE RANGE, 18%. GIVEN THE METHODOLOGY DESCRIBED IN THE MAIN GUIDE #6, IS THIS REASONABLE?

A. No. Load forecast uncertainty is already accounted for in the range given by the MAIN Guide #6, and it states that such uncertainty is modest.

Q. WHAT DOES WPL, IPL'S SISTER COMPANY, USE IN ITS RESOURCE PLANNING FOR PLANNING RESERVE MARGIN?

A. WPL uses 15%. Notably, the same document that provides this data also indicates that IPL uses 15% for "internal" planning purposes, but 18% in the filed resource plan.[15]

Q. WHAT IS THE DEFAULT MINIMUM VALUE USED BY THE MIDWEST ISO IN ITS TARIFF?

A. Module E ("Resource Adequacy") of the MISO Open Access Transmission Tariff states that the default value is 12% for any MISO entity that is not bound by another state or Regional Reliability Organization (RRO, such as the Midwest Reliability Organization, the MRO).[16]

Q. WHAT IS THE PLANNING RESERVE MARGIN USED BY PJM?

A. PJM currently uses a planning reserve margin of 15%.[17] This value is much lower than the PJM value of 20%, applicable for the 1999/2000 planning year. PJM's planning reserve requirement has trended down over time due to improved generator availability and increased load diversity associated with the larger control area PJM has become with integration of additional regions.

---

[15] Alliant Energy, "Strategic Planning Process, 2007-2011, Integrated Resource Planning", John Larsen. Provided in response to data request No. 21. Data request No. 71 indicated that the date of the presentation by Mr. Larsen was April 4, 2006. Page 2 of the presentation contains the "Key IRP Assumptions" including the planning reserve margin.

[16] Midwest ISO Open Access Transmission Tariff, Module E. Available at www. Midwestiso.org.

[17] http://www.pjm.com/planning/res-adequacy/reserve-requirement.html.

Q. WHAT IS THE NEW PLANNING RESERVE STANDARD THAT WILL BE IN PLACE ONCE THE MRO LOLE STUDY PROCESS IS COMPLETED?

A. MRO's draft standard RES-501-MRO-01 "Generation Planning Reserve Requirements" will be in place, once approved. I also understand that new "loss of load expectation" studies are underway by the Midwest Planning Reserve Sharing Group.[18] Those studies will determine a new planning reserve margin.

Q. DOES THE PROPOSED STANDARD CONTAIN LANGUAGE ON LOAD FORECASTING THAT IS TO BE USED IN DEVELOPING RESERVE MARGINS?

A. Yes. That standard states in part "Use load developed from the expected 50:50 probability load forecast". It is my understanding that the use of "normal" loads is common in LOLE studies.

Q. WHAT IS THE EFFECT OF IPL USING AN 18% PLANNING RESERVE MARGIN, INSTEAD OF A LOWER VALUE?

A. If 18% is an exaggerated planning reserve margin, then IPL will have exaggerated its need for new capacity. For example, with a reserve margin of 16.2%, the upper end of the value determined by the LOLE studies contained in the MAIN

[18] Response to data request 13.

Gudie #6, IPL's capacity need in 2013 is 3,607, or 56 MW less than the 3,663 MW computed with an 18% planning reserve margin.[19]

V. ECONOMIC BENEFIT OF WIND VS. COAL

Q. IPL'S APPLICATION CONTAINS NUMEROUS LETTERS OF SUPPORT FOR THE PROPOSED COAL PLANT, MANY DESCRIBING MACROECONOMIC, OR ECONOMY-WIDE, BENEFITS. ARE THESE BENEFITS SUPERIOR TO MACROECONOMIC BENEFITS THAT ACCRUE TO IOWANS FROM LOCAL ENERGY EFFICIENCY AND WIND POWER RESOURCES?

A. No. Studies have shown that macroeconomic benefits associated with local (in-State) wind power and installation of energy efficiency resources are at least as great, and possibly greater, than macroeconomic benefits associated with the proposed coal plant.[20] Energy efficiency and wind resource macroeconomic benefits are also more distributed than those of the proposed coal plant, thus distributing the benefit geographically across Iowa. Iowans will also have more money in their pockets to distribute throughout the economy if a less-expensive resource option, not the coal plant option, is chosen. Lastly, the proposed plant

---

[19] Based on a 2013 projected summer peak load of 3,104.3 (Kitchen, Direct Tstimony, Exhibit BRK-1, Schedule A). Total capacity need = (planning reserve % x Peak Load) + Peak Load.

[20] For example, see these two reports from the National Renewable Energy Laboratory (NREL): 1) NREL, S. Tegen, "Comparing Statewide Economic Impacts of New Generation from Wind, Coal, and Natural Gas in Arizona, Colorado, and Michigan", Technical Report NREL/TP-500-37720 May 2006. 2) NREL, M. Pedden, "Analysis: Economic Impacts of Wind Applications in Rural Communities" June 18, 2004 — January 31, 2005 Eugene, Oregon. Subcontract Report NREL/SR-500-39099 January 2006. Also see the American Council for an Energy Efficient Economy (ACEEE) Report, "The Twin Pillars of Sustainable Energy: Synergies between Energy Efficiency and Renewable Energy Technology and Policy", Bill Prindle and Maggie Eldridge, American Council for an Energy-Efficient Economy; Mike Eckhardt and Alyssa Frederick, American Council on Renewable Energy, May 2007 ACEEE Report Number E074.

would use out-of-state fuel, a direct flow of dollars out-of-state. The following quote well-summarizes the economic development effect of wind power and energy efficiency:

> "Efficiency and renewables also provide complementary economic development benefits by generating investment and employment in different sectors, which expands the total economic stimulus effect. The majority of utility expenditures in most states is exported to national and global energy companies, so efficiency and renewable investment is in fact the best way to generate new economic activity within a state's borders."[21]

VI. WIND POWER IN THE IOWA AND UPPER MIDWEST REGION

Q. PLEASE SUMMARIZE THE CURRENT STATE OF UTILITY-SCALE WIND TURBINE GENERATOR TECHNOLOGY AND ECONOMIC ATTRACTIVENESS.

A. Electric utility grid-scale wind technology and economic attractiveness has improved dramatically in the past few decades. This has resulted in increased commercialization of wind power, as technological improvements have led to decreasing unit costs and improved reliability and thus increased attractiveness as a utility supply resource. The decreasing unit costs can be traced in part to increasing economies of scale. As the industry's technological sophistication

---

[21] American Council for an Energy Efficient Economy (ACEEE), "The Twin Pillars of Sustainable Energy: Synergies between Energy Efficiency and Renewable Energy Technology and Policy", Bill Prindle and Maggie Eldridge, American Council for an Energy-Efficient Economy; Mike Eckhardt and Alyssa Frederick, American Council on Renewable Energy, May 2007 ACEEE Report Number E074. Page iv.

advanced, the size of wind turbines increased. Schedule B shows the evolution of US commercial wind technology.

The overall trend of decreasing unit costs and increasing cumulative installed capacity is shown in Schedule C. The increasing cumulative installed capacity is likely due to decreasing unit costs coupled with the presence of renewable portfolio standards in the US and the federal production tax credit for renewable generation. According to the American Wind Energy Association, as of June 30, 2007 there was 12,634 MW of installed wind capacity in the US.[22]

Q. PLEASE SUMMARIZE THE SIZE, PERFORMANCE AND RELIABILITY OF CURRENT UTILITY-SCALE WIND TECHNOLOGIES AND POWER PLANTS.

A. As seen in Schedule B, the size of wind turbines has steadily increased since the 1980s, allowing the capture of scale economics and contributing significantly to lower per unit costs. On-shore utility scale wind farms currently utilize megawatt or multi-megawatt scale turbines on towers extending 60 to 100 meters high. While earlier wind turbines utilized simple asynchronous induction generator technology with little reactive power or voltage control, current technology includes more advanced turbine-generator components with greatly improved

---

[22] http://www.awea.org/utility/wind_overview.html.

reactive power and voltage control and thus increased reliability.[23] The mechanical availability of generator technologies has also improved, allowing for higher energy production and reduced forced outage rates.

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.[24] 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").

---

[23] "Doubly-fed asynchronous generators" and "synchronous or induction generator with full-size power converter" are two of the more advanced categories of wind generators. See page 30 of "Making Connections", by Robert Zavadil, Nicholas Miller, Abraham Ellis, and Eduard Muljadi in the November/December 2005 issue of IEEE Power and Energy.

[24] 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 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.

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

A. Overall coordination of the bulk power system 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 in early 2008, 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[25];
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)[26], 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

---

25 *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".

26 *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.

output in various advance time frames (e.g., 20 minutes ahead of real-time, hour-ahead, 12-hours ahead, day-ahead, etc.)[27]; operationally, the use of state of the art forecasting improves wind power output scheduling 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.

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

---

27 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. http://www.uwig.org/forecst_overview_report_dec_2003.pdf.

wind forecasting and scheduling information for all wind resources in the Upper Midwest region, reducing prediction errors and thus reducing operational costs.[28]

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. 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

---

[28] 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.

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

6. **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.

7. **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

[29] 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.

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.

8. **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[30], 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.

9. **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 (2008) consumers of wind energy need to arrange for ancillary services 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.

10. **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-

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

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.

Q. HOW MUCH WIND CAN BE INTEGRATED ONTO THE IPL OR THE MISO-REGION GRID?

A. The Minnesota Department of Commerce Wind Integration Study examined in detail the level of wind integration possible in the region. The report contains an impressive amount of information concerning the technical factors associated with integrating wind into the region's grid. One key conclusion is that up to 25% of the region's annual energy needs can be reliably accommodated by wind power, at relatively minimal ancillary service cost increases.[31] For the IPL service territory, the same percentage of wind power (i.e., meeting 25% of IPL's load) in 2022 equates to approximately 1,637 MW, assuming a 38% average annual capacity factor.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

[31] Final Report – 2006 Minnesota Wind Integration Study, Volume I. Prepared for the Minnesota Public Utilities Commission by EnerNex Corporation. The full report, Volume I, Volume II, and the accompanying presentation material, is available online at http://www.uwig.org/opimpactsdocs.html.