Thank you for the opportunity to participate in today’s technical conference. I am appearing on behalf of the Municipal Energy Agency of Nebraska (MEAN), for which I am the Manager of Planning and Engineering, and the Transmission Access Policy Study Group (TAPS), of which MEAN is a member. We appreciate that the Commission is focusing on the particular needs of intermittent resources, particularly wind energy. The needs of wind energy resources are not unlike the needs of other high installed cost, low energy cost, generating resources that can’t be sited in everyone’s backyard. These needs include a reliable and robust transmission system, an effective approach to planning, building and funding needed transmission improvements, assurances of long-term deliverability at a predictable price, and comparable treatment in the provision of ancillary services such as energy imbalance service.

MEAN is a political subdivision of the State of Nebraska. We are a municipal joint action agency that provides power supply and related energy services to 55 municipalities, one public power district, and one power authority, in four states (Nebraska, Colorado, Kansas, and Wyoming). Of these members, 48 are Requirement Participants (with a combined load of nearly 400 MW) to whom MEAN is committed to supply long-term, firm requirements power.
MEAN and its municipal participants have a vital interest in wind energy. We developed the MEAN Wind Energy Facility in Kimball, Nebraska, the first utility scale wind facility in the state of Nebraska. In addition, we will be participating in a new development, the Ainsworth Wind Energy Facility, which will be the largest wind facility in the state of Nebraska when it goes into commercial operations in October 2005. Approximately 3-4% of MEAN’s energy requirements will be supplied by renewable energy when the Ainsworth Wind Energy Facility becomes operational. As a transmission dependent utility (TDU), MEAN is dependent for transmission access on vertically-integrated utilities, some of whom we compete with at wholesale and retail in attracting wholesale participants and industrial load, and in rate comparisons.

TAPS is an informal association of TDUs in more than 30 states, promoting open and non-discriminatory transmission access. TAPS members have supported the Commission’s initiative to form truly independent, cost-effective regional transmission organizations and to foster efficient investment in transmission and generation facilities. TAPS recognizes the critical importance of truly non-discriminatory open access to the development of wind power and other alternative sources of power, and to TAPS members’ ability to continue to provide reliable service to their customers at a reasonable, predictable cost. A number of TAPS members own or have long-term purchase power contracts for wind power.

This technical conference is important and timely. Wind energy is going to become an increasing part of the energy resource portfolios in the Upper Midwest and Western regions in which MEAN operates. For example, Colorado’s recently approved initiative requiring a 10% renewable portfolio standard will accelerate wind energy
development in this area. Wind is easily the lowest cost resource that will meet this renewable portfolio standard.

It’s not just state mandates that are prompting our interest in wind. MEAN’s municipal members are increasingly requesting that renewable resources, including wind energy, be a part of the resource portfolio. One MEAN participant has a stated goal that 80% of its energy requirements be supplied by renewable resources, which represents an increase of over 30% from its current portfolio of 50%. This additional appetite for renewable resources will most likely be satisfied by wind energy resources.

From the perspective of a small, transmission dependent utility, several key issues are crucial not only for the future of wind energy development, but for serving load in a reliable, low-cost manner:

- strengthening the grid, by promoting grid investment, so that it can accommodate and promote investment in all network resources, including wind;
- providing the long term rights to delivery at a predictable cost that are necessary to promote investment in and secure financing of high installed cost resources;
- adopting reasonable approaches to recognize and credit the capacity provided by wind generation; and
- eliminating the current undue discrimination against TDUs (and especially those with wind resources) with regard to the ancillary services, particularly unavoidable imbalance penalties.

1. A Stronger Grid is Necessary to Accommodate All Network Resources, Including Wind

It is increasingly apparent that transmission investment and capability are problems not only for wind resources, but for existing and planned network resources. In recent years, transmission investment has not kept pace with load growth, degrading reliability and creating congestion costs. This weakened grid is particularly problematic
for wind resources. In general, the areas with the best wind resources tend to be remote areas with low loads and relatively little existing transmission infrastructure.

TAPS prepared a White Paper, “Effective Solutions for Getting Needed Transmission Built at Reasonable Cost,” (TAPS White Paper, June 2004)¹ to highlight issues related to transmission investment and propose mechanisms to address them. The TAPS White Paper takes an in-depth look at the reasons that transmission investment has been lagging in recent years, ways to increase transmission investment, and ways to pay for increased transmission investment, while minimizing costs to consumers. The TAPS White Paper addresses some issues that are important in the context of this Technical Conference and we will highlight those issues throughout these comments. The primary issue raised in the TAPS White Paper relative to this Technical Conference is quite simple: Failure to adequately address the increasingly weak transmission infrastructure will result in less investment in wind resources, more reliance on natural gas-fired generation that can be built close to load centers, and excessive transmission congestion costs. All of these will raise costs to consumers.

At least outside the RTO context, there has been less of a focus recently on regional planning than in the past. As a result of wholesale competition and the evolution of the wholesale market, information that was routinely shared among utilities is now considered “market-sensitive” or “confidential and proprietary.” This makes planning large-scale transmission improvements difficult at best. Instead of reflecting a long-range view of the planned resources and load growth that need to be cost-effectively

accommodated by the regional grid, planning has become a queue-driven process, with arbitrary and inefficient results that discourage both transmission and generation investment.

Take an example where three wind farms in the same geographic area were proposed within four months of each other. While transmission providers are permitted (though not required) to group interconnection requests received within no longer than a 180 day period, typically transmission providers evaluate each wind farm independently. Perhaps the first wind farm can be accommodated without system improvements. The second farm requires construction of two new 115 kV lines. The third farm requires construction of a new 345 kV line. If all three farms were considered together, perhaps a lower cost alternative (for example, one 345 kV line and one 115 kV line) could have been developed. The inherent lumpiness of transmission investment heightens the burden on the small developer/transmission customer who gets hit with expansion costs, and highlights the need for a more expansive, regional approach. However, the secrecy and rigid procedures for queue priorities and study requests make least-cost regional planning impossible.

The roulette wheel quality of the process also is a problem. In this example, the first wind farm doesn’t pay for any of the improvements, but enjoys the improved reliability provided by the upgrades paid for by the second and third wind farms. This fundamental inequity discourages transmission investments and encourages the addition of generation wherever it can be squeezed in without requiring transmission upgrades, as

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2 See Section 4.2 of the Large Generator Interconnection Procedures, as approved in Orders 2003 and 2003-A.
opposed to being placed where the generation is most cost effective given a more rational, integrated approach to planning for regional needs.

Participant funding is often mentioned as the means to secure future transmission investment. MEAN and TAPS believe that nothing could be further from the truth. This mechanism is poorly adapted to our AC grid. Benefits and beneficiaries are many, difficult to assign, change over time, and can be enjoyed by “free riders.” Most wind resource developers (and would-be developers of remote coal-fired generating units) are understandably reluctant to fund system improvements that benefit competitors and can be used by others (including “native load”) by simply paying the tariff rate. Participant funding encourages a game of chicken, with needed transmission investment delayed in the hope that others will step up to fund investment for uncertain returns (e.g., congestion revenues on the path decongested).

The TAPS White Paper outlines two models that have a track record of facilitating transmission investment necessary to accommodate new large-scale network resources that are remote from load centers. One structural solution is the stand-alone transmission company open to ownership by all area utilities. Because such a company’s sole business is transmission, expansion projects do not have to compete internally against generation for the vertically integrated utility’s capital. Nor is a stand-alone company tempted to avoid transmission investments to protect its generation from competition. Inclusive stand-alone companies, such as American Transmission Company, have successfully attracted investor capital and enjoy solid credit ratings.

Another structural solution is the shared or joint transmission system, of which examples

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3 TAPS White Paper, at 8.
exist in Georgia, Indiana and the Upper Midwest. Two or more neighboring utilities contribute their transmission facilities to create a combined system. If open to all area utilities, the joint system expands access to capital, reduces regulatory conflicts and facilitates siting. In either model, the investor in a new transmission facility is assured a rate of return on its investment, and all customers on the system that use or benefit from the facilities pay for them.

TAPS endorses regional rates that reflect the characteristics of high voltage, “backbone” transmission lines.\(^4\) Spreading the costs of such lines across a region (rather than just locally) would match the broad regional benefits obtained, and reduce opposition from local consumers and state regulators.\(^5\)

The TAPS White Paper also advocates an open, regional, planning process to ensure cost-effective and efficient solutions, while facilitating siting. Finally, TAPS suggests a number of regulatory solutions to reduce risks and therefore cost of grid investment, and attract capital from large investor pools, such as pension funds, looking for stable, close to fixed-rate returns. For example, performance-based rates that reward companies for reducing congestion costs, satisfying customers, adopting inclusive planning processes, and opening transmission investment to all area utilities, while punishing companies that perform poorly, is one way to prompt movement in the right direction.


\(\text{\textsuperscript{5}}\) Depending upon the degree of grid integration, FERC might assign the costs of major backbone facilities across all regional loads even outside the RTO context. \textit{See Ft. Pierce Utils. Auth. v. FERC}, 730 F.2d 778, 783-85 (D.C. Cir. 1984).
In short, if the Commission is serious about promoting wind power (and otherwise promoting competitive generation markets), we need to focus on effective means to foster a robust grid at reasonable cost.

2. All Network Resources, Including Wind, Need Long-Term Deliverability

Generation additions typically have a lifespan of 15 to 50 years or more. At the minimum, Congress has recognized that providing Production Tax Credits and Renewable Energy Production Incentives for renewable energy facilities for a period of ten years is necessary to ensure that projects are built.

MEAN has long-term commitments to serve 31 of its all-requirements participants. These commitments extend through the life of the indebtedness associated with MEAN’s power supply resources, which is currently through 2038. The resource planning and investment decisions were based on securing long-term firm rights to delivery of MEAN’s resources to its loads.

Wind farms are no different than other high installed cost, low energy cost resources that must be constructed remotely from load. What is needed to obtain financing is long-term rights to deliver the output of the wind farm to the purchaser for the term of the project at a predictable price. The economics of such a project, whether it be coal or wind, depend on delivered cost over the life of the project. Thus, long-term rights to firm deliveries at a predictable, affordable cost were necessary to obtain financing of our most recent project, a 52 MW share in a 790 MW coal-fired generating project. It makes no sense to pay the high installed cost of a wind or coal unit if load may be stuck paying congestion charges – i.e., LMPs (assuming an RTO eventually covers the area) that reflect natural gas prices.
My understanding is that RTOs today offer Financial Transmission Rights (FTR) of one year (or less). I doubt that such a short-term right will demonstrate to lenders a sufficient revenue stream to support the payment of debt service for ten or fifteen years (or more). Nor will the less–than-firm transmission products discussed in Staff’s paper do the trick.

The lack of long-term FTRs is a concern for Moody’s and other financial rating agencies that routinely assign credit rating to public power utilities. In a report prepared in September 2004, 6 Moody’s indicated:

[T]here is potential risk in the short-term marginal pricing model being used in various regional energy markets in the U.S. Without long-term contracts for transmission rights and price certainty for the transmission of energy from new generation facilities, cost recovery in the long term may not be assured. The certainty of cost recovery represents a major factor in the credit assessment of financings for new generation projects.

It is critical for the development of network resources, including wind, for there to be an absolute assurance of long-term deliveries at an affordable, predictable price for the life of the resource. Failure to fully respect existing long-term firm rights and to provide for new long-term transmission rights in RTO markets will needlessly increase the cost of financing new projects, increasing the ultimate cost to consumers. TAPS suggests adoption of a planning model, where the network resource designation process is tied into the planning process, which in turn is tied to the assignment of the long term transmission rights.

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3. Reasonable Approaches to Capacity Credits for Wind are Necessary

The capacity value of all resources, including wind, is important in areas with rigid reserve requirements like MAPP\textsuperscript{7} and in markets where Installed Capacity (ICAP) is a distinct product like the PJM. Some regions do not allow wind to be accredited for capacity, while others recognize wind as a capacity resource only to the extent it is actually producing energy during peak conditions.

TAPS members have not formulated a position with regard to capacity credits for wind. However, in general, the approach to accrediting wind and other intermittent resources as a capacity resource should be reasonable, reflect the actual operating characteristics, and not degrade the reliability of the interconnected grid.

From MEAN’s perspective, the approach that the Mid-Continent Area Power Pool (MAPP) Generation Reserve Sharing Pool has used – basing capacity accreditation on the actual energy output during the four hours surrounding the member’s individual system peak – has been reasonable and has not resulted in adverse impacts to regional reliability. Typically, the amount of capacity that can be accredited is less than 20\% of the nameplate capacity. This approach assigns a realistic amount of capacity accreditation to wind resources without unfairly subsidizing wind or jeopardizing reliability, and appears similar to the Staff Paper’s description of approaches adopted in PJM, ISO-NE and NYISO.

\textsuperscript{7} The MAPP Generation Reserve Sharing Pool requires members to maintain 15\% capacity reserves with financial penalties for failure to comply. Wind is accredited based on the average actual production during the four hours surrounding the member’s system peak demand.
4. Comparable Treatment is Necessary for Ancillary Services for Intermittent Resources

On November 12, TAPS filed comments that include an example demonstrating the current non-comparable treatment of non-control area utilities when it comes to energy imbalance, and especially with regard to wind. Under the Order 888 OATT, non-control area utilities are subject to ancillary service Schedule 4, which covers the “difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within a control area.” Under this service, outside a return-in-kind deviation band (of +/- 1.5%, with a 2 MW minimum), the customer is subject to a payment obligation designed as a penalty. Typically, the charge for out-of-band energy imbalance service is the greater of $100/MWh or 110% of the control area’s incremental cost of supplying energy that replaces the under-deliveries. Because 110% of incremental cost rarely reaches $100/MWh, for most hours the charge is $100/MWh.

TAPS’ example, based on actual operating experience of a 102 MW wind farm developed and operated by FPL Energy, illustrates the huge burden these energy imbalance charges would impose on a TDU (Oklahoma Municipal Power Authority) for its 51 MW share of the wind farm, while Oklahoma Gas and Electric Company, who receives the remaining 50% of the output but is a control area utility, feels no pain.

Staff’s paper seems to recognize the issue but suggests that an answer may be the use of statistical models for advance scheduling and updated schedules. As TAPS Comments’ explained, although OMPA made every effort to accurately schedule this wind resource (in accordance with the model provided by FPL Energy) and to adjust the schedule to the extent permitted — i.e., 20 minutes before the hour, or effectively 30 minutes given tagging complexities, using information one hour old, Schedule 4 charges...
would more than double its energy cost from the wind farm if OMPA were taking service for this resource under an OATT.

Plainly, something needs to be done to address this severe discrimination against non-control area utilities, as compared with control area utilities, with regard to the treatment of imbalances generally, and in particular with respect to wind. This inequity denies TDUs the opportunity to participate in the development of wind power on a basis comparable to control area utilities. Thankfully, the Western Area Power Administration – Rocky Mountain Region (WAPA-RMR) has approached ancillary services for renewable resources in a fair and reasonable manner. It treats wind resources separately from other network resources for energy imbalance calculations and does not have a scheduling bandwidth. Imbalances are charged or credited based on system incremental/decremental costs, without any outside bandwidth penalties. This approach keeps WAPA-RMR whole on costs caused by energy imbalances related to wind, treats all participants in renewable resources on a comparable basis, and does not result in penalty costs to TDU owners of renewable resources (or a corresponding windfall to the transmission owners/control area operators). While TAPS believes that the OATT’s narrow imbalance bandwidth and high penalties should generally be revisited to achieve comparable treatment of control area and non-control area utility imbalances, the WAPA-RMR approach would be a step toward addressing this discrimination with regard to wind power.

WAPA-RMR has also taken what MEAN considers a fair approach to the provision of regulation and frequency response service to network customers with intermittent renewable resources. It is planning to allow a network customer to provide up to 10% of its annual peak demand from intermittent renewable resources without
charging for additional regulation and frequency response service. For customers with a
greater percentage of wind resource, and for those customers that are not serving load
within the control area, the cost of regulation and frequency response service is provided
at a cost-based rate based on the amount of regulation and frequency response service
that is actually used by the customer. The approach allows the customer to self-provide,
find alternative suppliers through dynamic scheduling, or pay a cost-based rate to
WAPA-RMR.

Thanks for the opportunity to address these important issues. I look forward to
your questions.