What Comes First?

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Transmission Planning and Competitive Electricity Market Operation for Delivery of Wind Energy

WIND POWER IS A MATURE PARTICIPANT IN THE POWER GRIDS OF EUROPE. In North America, however, wind power is still a small player but growing rapidly. As such, power grid operators in North America are just beginning to learn how to incorporate wind power into transmission grids and how to manage the variable power output of wind plants.

It's a Chicken-and-Egg Thing

The challenge for wind energy transmission can be viewed as a "chicken and egg" situation. Transmission owners are not currently able to build new high-voltage transmission lines to remote areas where there may be a high potential wind energy resource but little existing generation or load. Bottlenecks in high-load corridors typically have priority for the limited funds available for building new transmission lines. Wind plant developers, as a result, are not able to build new wind power plants in remote wind-rich areas, as illustrated in Figure 1, unless there is a transmission line capable of transferring the plant output to major load centers. So today, wind developers find it necessary to locate wind plants in less-attractive wind regions that are closer to existing transmission lines with available capacity.

In the days of vertically integrated electric power utilities, generation and transmission facilities were planned simultaneously. In half of the country, integrated resource planning no longer exists and in all of the country the transmission and generation parts of utilities have been functionally separated (as instigated by deregulation). With this separation, coordinated planning of transmission to serve new remote generation becomes a major conundrum. How do transmission owners justify and pay for major capital investments for new transmission that may not be fully loaded with wind power until several years in the future?

Transmission planning is gradually becoming more proactive to address regional renewable portfolio standard (RPS) policies and the growing demand for clean energy generation. Several states are making major progress with ideas for matching transmission investments with new renewable energy resources:

- ✔ Texas is developing a concept called competitive renewable energy zones, (CREZs). Under this plan, the public utilities commission and the grid operator, ERCOT, are assessing wind resources throughout the state, selecting high-potential areas for detailed analysis, and developing transmission upgrades to integrate wind power from these areas into the existing state power grid. Colorado recently enacted a policy similar to the CREZ.
- ✔ The California independent system operator (CAISO) won U.S. Federal Energy Regulatory Commission (FERC) approval for creating a new transmission category to interconnect remote, locationally constrained resources such as renewables. The California ISO is now working with stakeholders to develop implementation language and transmission tariffs, with a schedule to file these provisions at FERC before the end of 2007.
- ✔ At least five states are forming transmission infrastructure authorities as a means of stimulating more transmission and to create an energy exporting opportunity for states with energy-rich resource areas such as wind. New Mexico's recently created transmission authority, the Renewable Energy Transmission Authority, is required to only finance new transmission lines that carry 30% or more of the energy with renewable energy generation.
- ✔ The U.S. Department of Energy (DOE), using its authority under the Energy Policy Act of 2005, recently nominated the Mid-Atlantic region and parts of California, Arizona, and Nevada as "critical transmission corridors." If finalized by DOE, proposed transmission in

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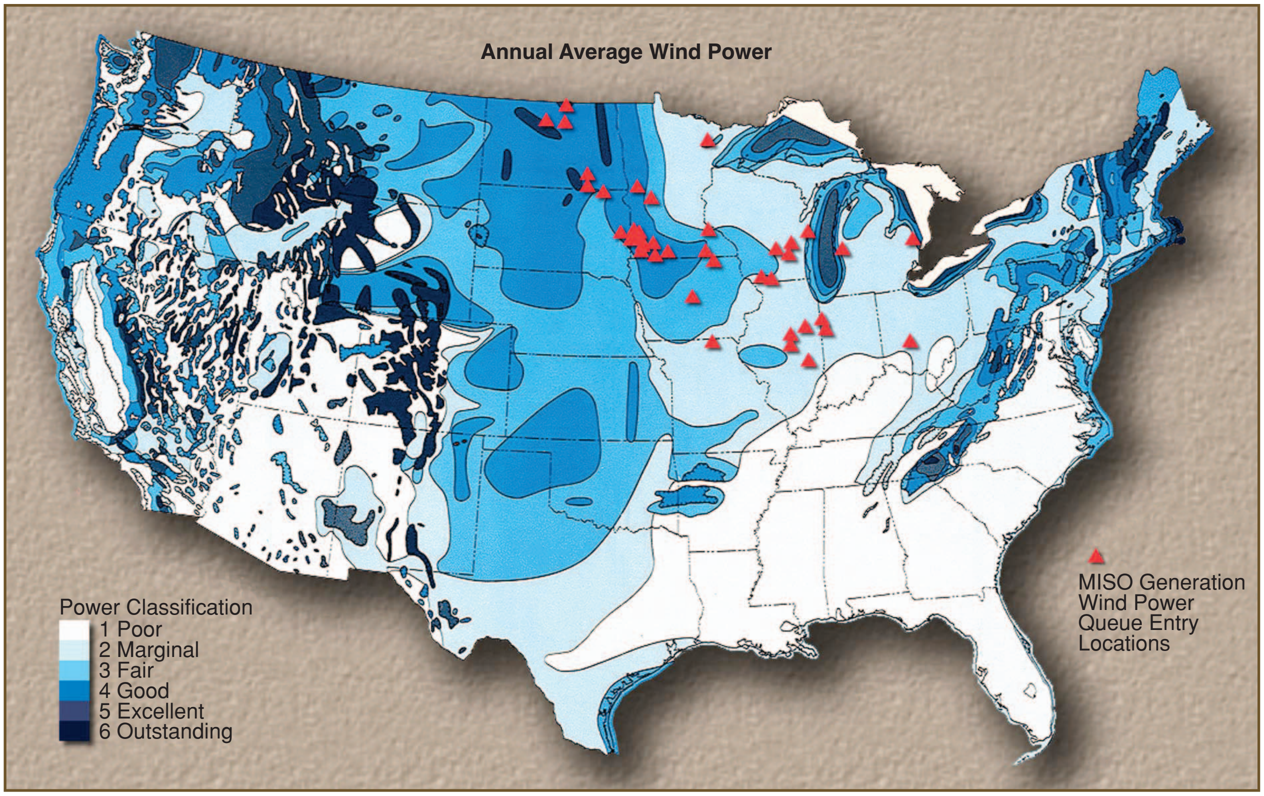

figure 1. Wind power map of the United States (http://rredc.nrel.gov/wind/pubs/atlas/maps/chap2/2-01m.html).

these critical transmission corridors could potentially be reviewed and perhaps approved by FERC if states do not approve a proposed transmission project within a year, or if states lack adequate authority to approve transmission.

- ✔ In the western United States, the Western Governors Association developed the Clean and Diversified Energy Initiative with the goal of stimulating up to 30 GW of clean energy resources, as well as the transmission infrastructure necessary to deliver the energy from the sources to the load centers.
- ✔ The Midwest ISO (MISO) is looking even further into the future by investigating feasibility of transmitting upward of 40,000 MW from numerous wind energy sites to load zones in the Mid-Atlantic states.

Can Siblings Learn to Play Together . . . Nicely?

Power grid operation has evolved around the concept of dispatching generation resources to match the requirements of the load. In fact, dispatchable generators are programmed to follow dispatch orders precisely. Failure to deliver power per dispatch orders results in financial penalties.

Wind generation does not fit this control scheme. The power output of wind plants, an example of which is illustrated in Figure 2, is a function of the variations in wind and weather. Wind generation can be estimated in advance using state-of-the-art wind forecasting tools, but power output cannot follow dispatch orders. How can power grids be operated in a secure and fair manner while accommodating the variable nature of the wind energy? FERC has updated its rules relating to energy imbalances for "intermittent" generation resources such as wind. Several grid operators, like the New York ISO (NYISO), are re-thinking their operating and market rules and are developing new ideas to maximize the benefit of clean wind generation while maintaining high grid reliability and providing fair compensation to all participants in a competitive generation market.

Planning, Markets, and Operation— A View from NYISO

The issues that must be addressed by wind developers and operators in a competitive marketplace can be categorized by time scale as shown in Figure 3.

There is competition at each time scale, except for the shortest time scale that deals with the real-time operation of the system. In the order of time scale, the issues are:

- ✔ assessment of the physical and financial viability of a project and the position of that project in the queue of all projects requiring assessment
- ✔ participation in capacity markets
- ✔ participation in the day-ahead market
- ✔ participation in the real-time or balancing market
- ✔ real-time operation, performance, penalties, and costs.

The rules, markets, and deliberations taking place in New York and involving the NYISO are cited below and are intended to be representative. The NYISO is still in the process of formulating the final rules and procedures that will apply to wind generation, so some of what is written here is preliminary.

PHOTO COURTESY OF CARL DOMBEK, MIDWEST ISO

figure 2. 50 MW Mendota Hills Wind Plant in Paw Paw, Illinois.

Physical and Financial Planning

The physical planning of any generation project involves several assessments of the impact of the project on the transmission system. Each assessment is more detailed than the previous. Generically, these are:

- ✔ feasibility study
- ✔ system reliability impact study
- ✔ facilities study and cost allocation
- ✔ interconnection agreement.

Some of these assessments can be done only by the owner of the transmission at the project site or by a more regional transmission planner such as an ISO. The cost of each assessment is typically borne by the project and an "up-front" charge is typically levied. The demand for assessment services may exceed the resources available and it is typical to establish a first-come first-served queue. All projects, whether wind related or not, enter this queue.

Capacity Market

Where they exist, capacity markets provide payments to energy suppliers based on capacity. These payments fall outside the energy market. The rationale for capacity payments is that they permit energy suppliers to bid their short-run marginal costs in the energy market since the longer-term investment costs would be covered by the capacity payments. However, output of a wind plant seldom reaches its full rating, and peak wind generation levels are usually not coincident with peak load levels. Recognizing the apparent mismatch between the time when wind power is most likely available and when electricity is most in demand, three fundamental questions must be asked:

1) should wind resources be allowed to participate in capacity markets where they exist; if so
2) how should the capacity be determined
3) what are the obligations of the wind resources that receive a capacity payment?

One approach is to allow participation of wind generators in the capacity market but to limit that capacity to the average of that actually measured during selected peak hours. Using this method, the capacity assigned to a wind generator may be substantially less than the nameplate rating of the generator. Studies conducted by the NYISO place this between 10% and 40% of the wind generator's nameplate rating.

The sale of capacity in New York requires the generator to participate in a day-ahead energy market. This rule seems unduly burdensome to wind resources that, because of the inherent uncertainty of wind energy output, risk entering into a day-ahead obligation that cannot be satisfied in real time. The NYISO is exploring the elimination of this requirement for wind generators. Instead, a day-ahead forecast of wind generator output would be used to ensure the reliability of the system for the next day, but the wind generator need not take on a day-ahead obligation.

Day-Ahead Market

The day-ahead market performs two functions. It provides a financial obligation to buyers and sellers for the next day, and it assures that sufficient resources will be available to meet the next day's load. The first of these two functions provides a

figure 3. Issues that must be addressed by wind developers and operators in a competitive marketplace.

financial basis for real-time balancing. In the absence of a day-ahead market, special balancing rules are required to handle deviations from a presumed schedule. The second of these functions is driven by reliability concerns and the lengthy start-up periods required of many generators. The reliability function is performed, in one way or another, in all energy markets, even those without an explicit day-ahead market.

A day-ahead wind energy forecast is needed for the proper evaluation of reliability. In many respects this is similar to the need for a day-ahead load forecast. Both the day-ahead wind energy forecast and the day-ahead load forecast are used to guarantee that enough generating resources will be available to meet the next day's expected load. The use of forecasts should be limited to the evaluation of reliability. Wind generators need not be prohibited from selling energy in a day-ahead market. However, care must be taken that wind energy is not counted twice in any reliability evaluation—once as an accepted offer to sell energy and again as a forecast of energy production.

Real-Time Market

Energy markets that lack a two-settlement structure must devise special rules for handling imbalances. These rules vary from market to market but often involve balancing at the real-time price plus or minus a penalty. Such systems may impose unnecessary risk on the wind generators, and special rules, such as netting of imbalances over a longer period of time, have been proposed where balancing penalties exist. Recent developments on balancing penalties are discussed in the regulatory and policy section.

Electricity markets that have two settlements, day-ahead and real-time, have a natural mechanism for balancing energy. The system is always economically dispatched, both day-ahead and real-time, to make the best use of generation and transmission resources. Energy deviations in these markets simply settle at real-time prices. Thus, no special rules are required for wind generators. Any energy production that had not previously been sold day-ahead must be sold at real-time prices. Shortfalls must be re-purchased at the same prices. Settlement rules for wind generators need be no different than those for other generators.

Real-Time Performance

The reliable and efficient operation of the electrical system and the electricity markets depends on the good behavior of generators. Deviations from expected output can affect energy clearing prices and penalties may be imposed on generators who do not follow their schedule within a tolerance. The application of behavioral penalties to generators that have no control of behavior is not productive, however. The NYISO has eliminated penalties on classes of generators that have limited control of their output and is currently pursuing the elimination of these penalties on wind generators as well.

While it may be inappropriate to penalize a generator for behavior beyond its control, if that behavior has a quantifiable cost, costs can be assigned to the generator. In the case of wind generators there will be a cost associated with the necessary wind energy forecasting functions and wind generators will be expected to contribute, at least in part, to this cost. The variability of wind generator output may increase the need for regulation and frequency control service. To date, studies indicate that for the foreseeable future there will be virtually no impact on the quantity of regulation service required. However, if experience shows otherwise, the NYISO will most likely move to have some or all of the increased cost assigned to wind generators.

A number of policy changes have been made over the last few years to better integrate wind energy into the electric transmission system. Wind energy as a nondispatchable, variable resource does not fare well with traditional capacity-based point-to-point transmission service because of the costly payments for capacity that wind generators will not use and the requirements to maintain scheduled levels of output. The ideal market structure would be large regional power pools where output can be accepted as it is available. While there have been minimal changes in market structure in U.S. electricity markets, there has been increasing recognition that wind can be integrated reliably under rules that recognize its technical differences.

FERC Order No. 890

The most significant recent policy development was FERC Order No. 890. FERC has authority over sales for resale in interstate commerce of transmission and energy, as well as reliability rules and oversight of reliability organizations. Order No. 890 reviewed all aspects of transmission service and it required certain changes, including some that are of particular interest to wind generators. Among these are generator imbalances, new means of offering firm transmission service including re-dispatch and conditional firm service, and principles for transmission planning. These policies impact transmission service for delivery into, through, or out of utility transmission systems. They do not affect delivery within a utility's own system, where the generators are typically designated to serve native load as part of the utility's network service, which means they are essentially pooled.

Order No. 890 virtually eliminated penalties for generator imbalances—the charges applied to generation that exceeds or falls short of scheduled delivery. Wind generators and other resources labeled "intermittent" by FERC often have such output deviations. Prior to Order No. 890, these deviations were penalized at a level of up to \$100/MWh, which is well in excess of wind energy prices and so severe that no wind generators could function under such a cost burden. Order No. 890 established a policy that deviations of up to 1.5% were settled at the system cost, and above 1.5% at 110% of incremental cost or 90% of decremental cost. There is a third deviation band, but intermittent resources were exempted. This cost-based approach provides for much lower cost impacts on wind generators.

> A wealth of creativity has hit transmission policy in the past two years, with several states and regions serving as the creative laboratory for new ideas.

Order No. 890 also modified the terms and conditions of transmission services to better accommodate wind generators and utilize spare capacity on the transmission system. Transmission services previously were available to transmission customers only if the transmission path had available transfer capability in all 8,760 hours in a year. Some customers like wind generators do not need service in every hour and are willing to have their transactions curtailed on occasion. For this reason, conditional firm service was created and required by FERC to be available in every jurisdictional transmission provider's tariff. The service offers promise to provide more transmission capacity to the market than was previously available. FERC required that the conditions be fixed for a period of only two years, so it will be difficult for generators wishing to finance new projects with the service. FERC also encouraged longer terms for conditional firm service, and wind generators can negotiate with the transmission provider for more certainty in the amount of curtailment they may experience.

Similar to conditional firm service, re-dispatch creates more capacity that can be offered to the market. Re-dispatch means that some generators are ramped up on the export side of a constraint and others are ramped down on the import side of the constraint, relieving the constraint and making more transmission available to be used. This service was actually already required in FERC tariffs, but Order No. 890 clarified the requirements and made the service more useable. The transmission provider must make these opportunities available. The customer must pay the generators for changing their output. Similar to conditional firm service, the FERC requirement does not provide long-term certainty for what these costs will be, so it will have limited usefulness in financing new projects.

The next important change in FERC Order No. 890 is a set of principles that all transmission providers must follow. These principles include coordination, openness, transparency, information exchange, comparability, dispute resolution, and regional participation. These planning principles are likely to encourage regional transmission solutions that will help resources like wind that require long-distance transmission.

Energy Policy Act Transmission Corridors

The Energy Policy Act ("EPAct") of 2005 included two provisions for long-distance transmission corridors that seek to streamline and facilitate siting of transmission lines. Section 368 provided for energy corridors over federal land and required inter-agency coordination to perform a programmatic environmental impact statement. Section 1221 provided for federal "backstop" siting authority for FERC for facilities in an area designated by the DOE as a "National Interest Electric Transmission Corridor." After completing the required study of congestion in 2006, DOE designated two draft corridors, one in the Mid-Atlantic region, and the other in Southern California and parts of Arizona and Nevada.

Designation of transmission corridors out of wind-rich areas in the Great Plains and interior West could help the development of needed infrastructure. There is political resistance to the corridors DOE proposes to designate, so it is not clear that the process under the new law will succeed.

Wind Energy Trunkline Policies

An important policy issue for the wind industry is to solve the chicken-and-egg problem with transmission out of wind-rich areas. The status quo is that transmission planners are in a reactive mode, responding to interconnection requests from generators. But in pockets of wind-rich resource areas that are remote from the grid and for which the optimally sized line is much larger than what one project or developer needs, the generators find the costs prohibitive and do not enter the interconnection queue. So generation awaits transmission and vice versa.

Policies in a few states and now at FERC support a proactive approach to build the transmission first in advance of generation. The most developed of these at the time of this writing is the Texas Competitive Renewable Energy Zone policy, discussed in the next section. Minnesota has similar planning to the resource, as well as up-front cost recovery for the transmission owners. Colorado has a new law, SB 100, which does the same. California has a state backstop policy but also a policy by the California ISO that was approved by FERC in the spring of 2007 that provides for up-front financing of the transmission lines. The next section describes the Texas policy, which is a model for others.

The Texas Experiment: Competitive Renewable Energy Zones

To support a fledgling renewable energy industry, the Texas Legislature enacted the first renewable energy goal in 1999 as part of Senate Bill 7. Signed into law by then Governor George W. Bush, SB 7 required that a minimum of 2,880 MW of renewable generation be installed in Texas by 1 January 2009. Wind development in Texas quickly hit its stride, with over 900 MW of wind capacity installed by the end of 2001. Today, Texas leads the U.S. wind market with over 2,700 MW of wind power installed.

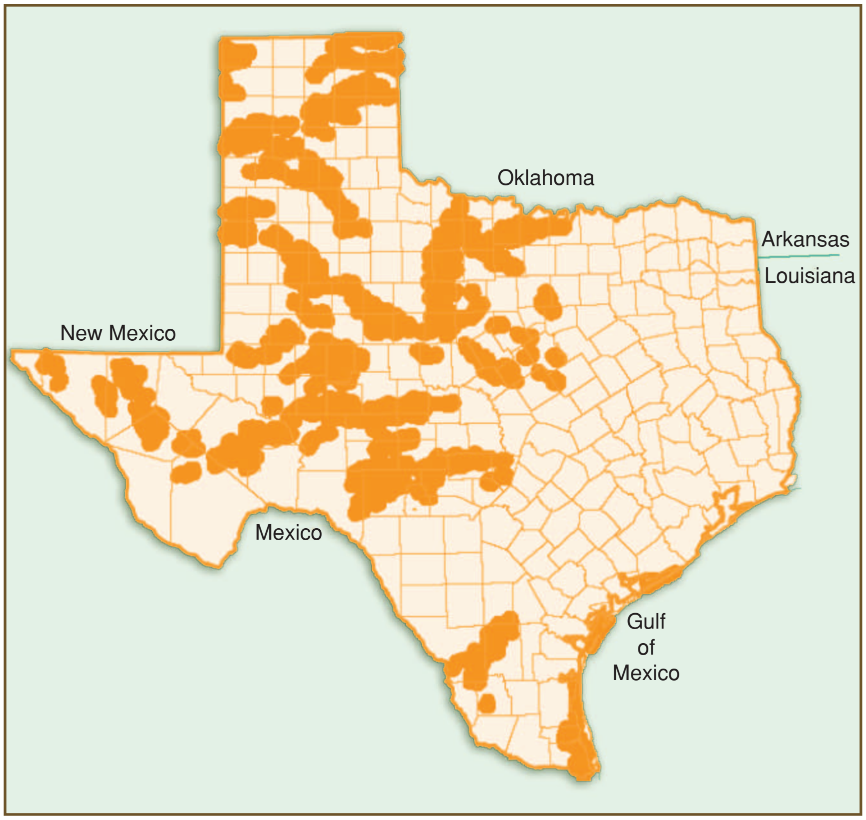

figure 4. Competitive renewable energy zones in Texas.

Many of these early wind plants were sited without regard for available transmission capacity. In one particular area, near McCamey, Texas, over 750 MW of wind generation capacity were built on the high mesas before it was understood that the long 138-kV circuits that connected this area to the rest of ERCOT did not provide sufficient capacity to maintain voltage levels under contingency.

The transmission solution was clear: new 345-kV circuits were needed from McCamey to Twin Butte (approximately 120 miles) and from McCamey to Odessa (an additional 60 miles) integrating McCamey in a looped circuit. However, the costs of these new circuits had to be justified, and given the way transmission is paid for in ERCOT, this led to a paradox, which is often called the chicken-and-the-egg problem.

In ERCOT, retail customers pay for all transmission improvements. Transmission companies, separated from generation companies as part of the restructuring of the electric industry, may include capital costs for transmission improvements that are "used and useful" in their revenue requirement fees, also called their total cost of service. Transmission projects are considered "used and useful" if they are needed to maintain system reliability, if they are part of a generation interconnection, or if they are expected to result in significant system production cost savings. Developers of new generation must provide collateral for the transmission infrastructure improvements required to connect their site to the grid, but after their facility is operational, these funds are returned to the developer and the interconnection improvements are added to the transmission owner's total cost of service.

Without more wind generation in the McCamey area, there was not enough wind energy curtailment to justify the cost of the new 180 miles of 345-kV circuits. But without more transmission, no wind company was willing to invest in new wind plants in the McCamey area. As new wind plants were built in other parts of the State, wind developers found that this was a recurring problem—although they could connect to the ERCOT transmission grid, they were not assured that their wind plants would not be curtailed due to insufficient network transmission capacity, resulting in a loss of earnings from energy sales, production tax credits, and renewable energy credits.

In 2005, the Texas Legislature acted again to raise the goal for renewable energy and to break the impasse between transmission improvements and wind development. Senate Bill 20 raised the renewable energy goal to 5,000 MW of new renewable generation by 1 January 2015 and instructed the Public Utility Commission of Texas (PUCT) to establish Competitive Renewable Energy Zones (CREZs) throughout the state and to designate new transmission projects to serve these zones. These new transmission projects will not be required to meet the "used and useful" standard, meaning that the transmission companies could start constructing them prior to development of interconnecting wind resources.

To fulfill the requirements of Senate Bill 20, the PUCT requested that ERCOT complete a study of wind generation potential throughout the state and develop options for transmission improvements to connect these areas to load. ERCOT identified 25 areas in the state with significant potential for wind generation and developed several transmission solutions that can provide sufficient transmission capacity to carry generation from these areas to the Dallas/Fort Worth and central Texas load centers. These wind zones are depicted by the blue regions in Figure 4.

In December 2006, the PUCT initiated a contested-case proceeding that was scheduled to end in August 2007, which will lead to the designation of new CREZs and transmission upgrades to serve wind generation in these zones. Numerous parties are participating in this case, including two ISOs (ERCOT and the Southwest Power Pool), wind generation developers, transmission owners, retail power representatives, and interested landowners. The PUCT is expected to designate CREZ zones based on the sufficiency of wind resources and suitable land areas, and based on financial commitments of generators. Transmission owners will be required to submit their applications to construct the proposed transmission upgrades within one year of the final CREZ order. The PUCT will be selecting from a wide range of options: some parties have nominated zones with as little as 1,000 MW of new wind capacity, while other parties have nominated areas with as much as 4,500 MW of wind generation potential.

Economic Justification for Long-Distance Transmission

The Midwest ISO's footprint covers all or part of 15 Midwestern states and the Canadian province of Manitoba, some 920,000 square miles in all. Within that broad swath of middle America is a rich wind power resource; by the Midwest ISO's estimate, the potential generating capacity of wind in the Midwest is 400,000 MW.

To satisfy a generation expansion plan that calls for 20% wind energy across the Midwest ISO footprint by 2027, only one-tenth of that, or 40,000 MW, is required. However, when 40,000 MW of wind power is added to an area like the Midwest, which has significant baseload coal and nuclear generation, it could potentially curtail some of that low-cost generation from full output.

On the positive side, it is environmentally desirable to displace coal with this clean form of energy. In addition, excess capacity could be exported and used to meet electricity demand in other areas beyond the Midwest. This would be particularly attractive to the heavily populated areas along the Eastern seaboard where the cost of land, population density, and other factors make it more difficult to site and build most types of generation, including wind plants.

However, there are challenges to be met before the industry is able to turn that potential into reality. Recent studies show the existing infrastructure can accommodate some additional wind energy; however, the integration of the lion's share of the Midwest's wind potential will require the construction of additional 765-kV lines to move the power across the Midwest ISO footprint, to the market to the east—the PJM Interconnection—and to its ultimate destinations.

Figure 5 shows where wind energy resources exists in the Midwest ISO footprint, existing 765-kV lines, and the proposed system of new 765-kV lines that will be needed to move wind power to the areas where it will be consumed. Importantly, the proposed new lines would need to be built as a system, not a set of lines built in sequence. Each section is a grid linked to other grids.

The wind energy generated would be bought and sold through the existing energy markets. But because wind cannot be dispatched as other forms of generation can, wind is a "price taker." Operators of wind turbines that are generating electricity take the prevailing price at the time of generation. Because that price is set at the margin by other types of generation, the future revenue stream is difficult to predict.

Nonetheless, revenue received from the sale of wind energy could partially offset the capital costs associated with developing wind power and the infrastructure needed to get it from the source of generation to the sink.

The construction of additional high-voltage infrastructure will have additional benefits beyond moving wind power from west to east. Because the electrical grid is interconnected, benefits will flow from existing interconnections with other areas. Accordingly, as these other areas will enjoy some benefits, some sort of compensation arrangements will likely be made and the revenue realized could also help offset the costs of wind development.

Because of the intermittent nature of wind energy, dispatchable generation must be available to be moved up and down to offset wind power's peaks and valleys, for load-following, reactive power needs, voltage support, and other

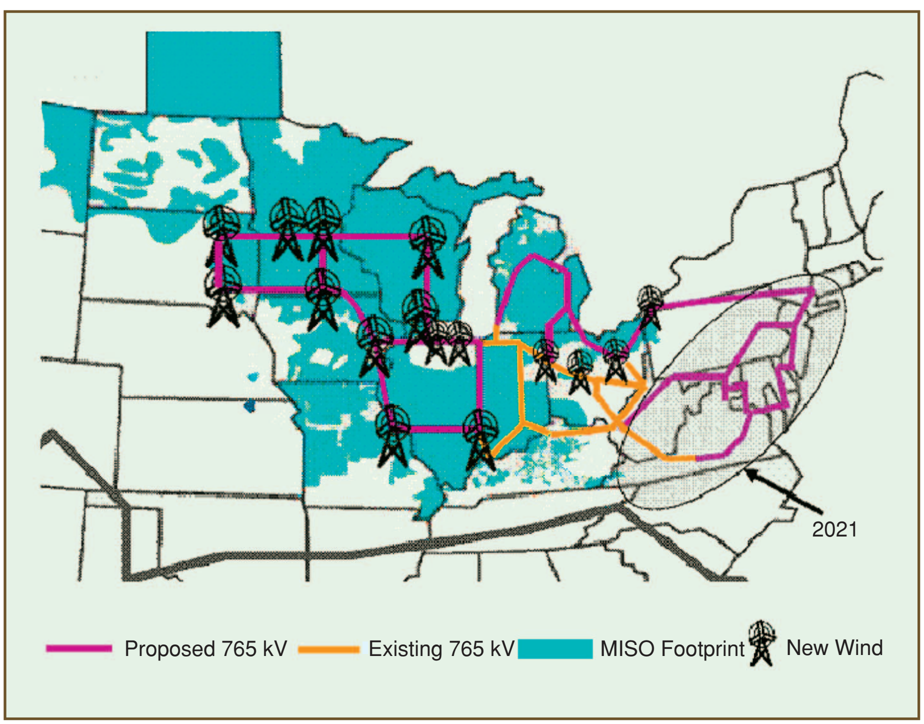

figure 5. Wind energy resources in the Midwest ISO footprint.

PHOTO COURTESY OF CARL DOMBEK, MIDWEST ISO

figure 6. Existing 138 and 345 kV transmission lines in rural area near Pendleton, Indiana.

concerns. While the short-term peaks and valleys of wind generation tend to level out with larger numbers of turbines built across a larger physical landscape, dispatchable generation must still be maneuvered to maintain the integrity of the system and to reduce the area control error (ACE) that may occur when wind generation changes. To that end, consolidation of smaller control areas into fewer, larger areas, or an ancillary services market, will further help spread the "peaks and valleys," and may also serve to reduce the number of ACE performance violations and associated penalties.

Key points of the MISO study are:

- ✔ The 765-kV overlay is the first time a system has been designed to address market-based electricity flows. At present, market flows are being forced through a system that was not designed with a market in mind.
- ✔ Preliminary results indicate that the integration of wind energy on the scale proposed would be cost-effective in the near term; that it would pay for itself through existing market mechanisms.
- ✔ Transmission costs are currently allocated to individual states. While this point would likely require approval of a new tariff or tariff provisions by FERC, under the new system, costs for the transmission system would be allocated among the users of that system.
- ✔ It is possible to bring a significant amount of new wind generation on-line within a very short period of time—a feat that has not been possible before now due to the long lead time for building baseload plants.

Cost Allocation for New Transmission

While siting new transmission facilities (see Figure 6) is typically cited as a barrier, cost allocation for new transmission (i.e., how new transmission is paid for) is more problematic. The emergence of wholesale competition and open access transmission has opened the transmission grid to multiple parties, and this complicates the question of who pays for new transmission.

A variety of transmission cost allocation methods are in practice today. ERCOT "rolls in" the cost of new transmission across its wholesale load. The other extreme, known as "participant funding" is to require generators to pay for all new transmission, and that is used to some degree in each of the regions that have independent transmission system operators. Adding to the complexity is that reliability transmission projects—those built to ensure that NERC reliability criteria are met—may have different cost recovery for transmission than economic transmission projects that are built to either access new generating resources, to reduce transmission congestion or to lower the cost of serving customers.

In FERC Order No. 2003 addressing generator interconnection, FERC stated that transmission built for interconnecting generators should be paid by generators but reimbursed over five years, either financially, with credits against transmission service for the interconnecting generator, or with financial transmission rights. The costs of transmission built for network customers or for maintaining grid reliability are typically spread across all customers. However, Order No. 2003 also allows regional transmission organizations (RTOs) to propose exceptions to this general rule, as FERC views RTOs as an independent entity that also may be able to negotiate regional, stakeholder-driven transmission cost allocation proposals.

As a result, FERC has approved several RTO proposals that have adopted different approaches to transmission cost recovery that generally combine elements of having all customers pay and assigning costs to beneficiaries of new transmission projects as determined through modeling. The Southwest Power Pool (SPP) and the Midwest ISO both use a combination of a "beneficiary pays" approach and allocating costs to all customers in their region. Specifically, the Midwest ISO, for transmission facilities above 345 kV for reliability purposes, allocates 20% of the costs to all customers and 80% to beneficiaries as identified through modeling. SPP allocates 33% of the cost of projects in its base reliability plan (projects built for reliability) to all customers, and 67% to zones identified as beneficiaries through SPP's megawatt-mile method. For economic transmission projects, SPP relies upon project sponsors that are willing to fund the project in exchange for transmission revenue credits.

More recently, FERC approved the same 80-20 split for economic transmission projects in the Midwest ISO that are above 345 kV and cost over US$5 million. To qualify for the 20% cost allocation to all customers, transmission projects must meet two tests. First, the present value of the production cost benefit and the locational marginal pricing benefit, as determined through modeling, must be greater than zero. Second, the benefit/cost ratio, defined as the project benefit divided by the project cost, must exceed a certain level that is lower for short-term projects (1.2 if the project is to be operational within one year) as compared to long-term projects (3.0 for projects with an operation date of ten years or more from when approved by the Midwest ISO).

Elsewhere, ISO New England rolls in the costs for transmission upgrades or new transmission for reliability or economic reasons where there is not general agreement on how to allocate costs. Finally, in a recently issued order, FERC directed PJM to have all customers pay the costs for new transmission facilities over 500 kV and to convene a stakeholder process for determining cost recovery for new transmission below 500 kV.

FERC further defined its transmission cost allocation policy in Order 890 for regional transmission projects that include several owners or for economic transmission projects. For these projects, FERC said it would rely upon regional flexibility and consider three factors: whether a cost allocation proposal fairly assigns costs among participants; whether a cost allocation proposal provides sufficient incentives to build new transmission; and whether the proposed transmission is backed by state regulatory authorities and market participants in the region. There is increasing recognition that there are many beneficiaries of high-voltage grid backbone transmission lines and that more sharing of costs by all users can benefit system reliability, congestion mitigation, and renewable energy development, so this barrier may be overcome as policies evolve.

Conclusions

The New York ISO's experience with wind power illustrates some common themes that help integrate wind power: large balancing area, large markets, and the availability of fast subhourly markets, such as a real-time market and ancillary services markets. Two-settlement markets (i.e., day-ahead and real-time markets) also provide a natural mechanism for balancing energy and pricing energy imbalances. Wind forecasting is also another important means of successfully integrating wind generation.

A wealth of creativity has hit transmission policy in the past two years, with several states and regions serving as the creative laboratory for new ideas. California is home of one such innovation, with FERC's recent approval of the California ISO's separate transmission category for locationally constrained resources. Texas is in the midst of implementing its CREZ concept, which has tremendous potential for building transmission to access wind-rich resource areas, and this concept has been picked up by Colorado as well. Finally, at least five states have enacted transmission infrastructure authorities, with the intent of using revenue bonds to stimulate new transmission. New Mexico requires its transmission infrastructure authority to finance new transmission that carries at least 30% of the energy with renewable energy generation.

Nationally, DOE proposed two National Interest Electric Transmission Corridors, and while it is being challenged politically, these corridors could spur additional new transmission. RTOs, in response to encouragement by FERC, are experimenting with different cost recovery strategies for new transmission. And in Order No. 890, FERC removed the threat of punitive imbalance penalties for wind generators, approved the concept of conditional firm transmission with the goal of encouraging more use of existing transmission, and provided greater specificity to re-dispatch service.

These proposals are all new and not fully implemented, and little new transmission has been put forward under these proposals, much less developed. Nevertheless, these real policy changes are a remarkable turn-around from just a few years ago when these ideas were just beginning to be developed.

For Further Reading

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