Regulatory Assistance Project
Issuesletter
May 2005

Wind Resources and Transmission System Operations

By Ed Holt

With the renewal of the federal production tax credit (PTC) in October last year, the US is on track to add over 2,000 MW of wind this year, breaking previous records. Important as the PTC is, however, the biggest market barrier facing wind development in the U.S. is transmission and the grid operating rules. System operating rules written for conventional, dispatchable generation do not easily accommodate resources that by their physical nature are variable.

It's not just wind that is a variable resource—others such as solar and to a lesser extent run-of-the-river hydro share this characteristic—but wind has lots of untapped potential and is growing in bulk power markets. So if wind is going to fulfill its promise of a clean, renewable and indigenous electricity supply, it needs transmission operating rules that don't discriminate.

Why is wind power different? Two answers: distance from loads, and intermittency of generation.

Many windy areas are remote from loads. On average, strong wind sites are located a distance of 500 miles from major metropolitan centers. For example, the Dakotas, often called the Saudi Arabia of wind, have significant wind resources but are far from the heavy population and commercial centers of the Twin Cities, Milwaukee and Chicago.

Remoteness has costs, including (1) the distance to interconnect with a transmission line, (2) multiple fees (pancaked rates) for transmission through several service areas if there is no single transmission system operator (like an RTO), (3) or if there is an RTO, congestion pricing if, as would likely be the case, the generator is located on the "wrong" side of the congestion point, and finally (4) greater transmission line losses because of the distance required to reach load centers.

Wind is also intermittent, meaning it generates electricity only when the wind blows. Historically, grid operation is based on dispatchable generation that can be adjusted, depending on electricity demand. Fossil and nuclear generation can be scheduled well in advance, but it is difficult for wind generators to provide firm schedules far in advance because of their dependence on the weather.

This Issuesletter discusses a number of grid operation issues and their effect on wind resource development. Topics include scheduling and imbalance penalties, transmission tariff flexibility, transmission planning and interconnection queues and capacity credit for intermittent resources. We summarize the issues and indicate some possible ways to address them. For a more complete discussion, including the topic of reliability, you can find a longer version of this paper on RAP's website www.raponline.org under the Renewable Energy featured discussion category.

Scheduling and Imbalance Penalties

FERC Order 888, issued in 1996, established pro forma Open Access Transmission Tariffs (OATT) that transmission owners must use unless they provide something better that FERC approves. For regions not served by an ISO or RTO, the pro forma tariffs are the default market rules.

The OATT included imbalance charges for generators whose output deviates significantly from pre-arranged schedules. The purpose of the imbalance charges is to "enhance reliability, encourage accurate scheduling and discourage gaming." How do they work? If output deviates by +/- 1.5% of the scheduled amount, the generator must pay a penalty specified by the transmission provider. Although FERC does not specify the penalty amount, the industry standard has become 100 mills or 10 cents/kWh for underperformance—a very stiff penalty. If the generator produces more than is scheduled, the transmission provider may offer only a fraction of the market price.

This discriminated against wind, according to many advocates, because intermittent resources have difficulty in predicting their output, and have little control over their dispatchability.

On April 14, 2005, FERC proposed to amend the imbalance tariff provisions under the OATT "that have become outdated and have become unjust, unreasonable, unduly discriminatory or preferential, as applied to intermittent resources."[1] Specifically, FERC proposed to establish an intermittent generator imbalance bandwidth of +/- 10% for differences between the amount scheduled to be generated and the actual amount generated for each hour. Deviations within the +/- 10% bandwidth will be priced at the transmission provider's system incremental or decremental cost at the time of the deviation.

Because California has the most installed wind capacity in the U.S., it is not surprising that the Cal ISO was the first to address the problem. It adopted, and FERC approved in 2002, a tariff amendment called the Participating Intermittent Resource Program. Participating wind generators provide site-specific wind data to the Cal ISO, which contracts for a wind speed forecast for each participating site. The forecast is for day-ahead, rolling seven hour ahead and a final forecast 2 hours and 45 minutes ahead of the hourly market. The participant can choose to opt in or out of the program on an hourly basis. If the participant submits a schedule equal to the forecast for that hour, he is considered in the program, and deviations are netted across a calendar month and settled at a monthly weighted-average price, without additional penalties. With an unbiased, state-of-the-art forecast, the expected net deviation should be close to zero. This is significant because it provides participants with predictable income and financial stability.

Most ISOs have taken steps to eliminate or limit punitive charges for intermittent resource deviations, but it remains an issue especially in the West where there are no ISOs except in California. Nevertheless, several utilities have modified their transmission tariffs to accommodate intermittent resources. The Western Area Power Administration's Rocky Mountain Region has waived the penalty bandwidth for intermittent resources and simply requires a financial settlement at market prices, netted at the end of the month. Pacificorp has also eliminated the 100 mills/kWh imbalance penalty and instead charges the incremental cost of energy plus 10% for imbalances. Both Pacificorp and the Bonneville Power Administration have modified tariffs to allow intermittent generators to change their day-ahead schedule up to 20 minutes before the hour without incurring a penalty. This combination of tariff changes and scheduling changes make the system more usable for wind generators.

Based on this experience, presenters and commenters at a recent FERC technical conference titled "Assessing the State of Wind Energy in Wholesale Electricity Markets" (Docket No. AD04-13-000) urged the Commission to:

- Eliminate punitive charges for imbalances;
- Consider, as a *quid pro quo,* requiring that scheduling be based on state of the art forecasting;
- Settle deviations over longer time periods and support payment for net deviations at market prices; and
- Allow wind to schedule as close as possible to real-time delivery.

In instances where a transmission provider's tariff includes a generator imbalance charge provision more lenient than the one described in the proposal, FERC proposed that the transmission provider assess the lesser charge.

The proposal also emphasizes FERC's intent in Order No. 888 that transmission providers must allow generators to modify schedules up to 20 minutes before the hour of delivery. This will minimize exposure to the costs associated with imbalances, and had apparently not been fully or uniformly implemented.

Firm and Non-Firm Service

ANOTHER ASPECT of FERC Order 888 that affects intermittent resources is the basic division of tariff options for the delivery of capacity and energy into firm and non-firm point-to-point service. Neither is a good match for intermittent generators. Non-firm service is limited to a year at a time. Intermittent generators need longer commitments to ensure that they can get their output to market, and new wind generation projects need long-term arrangements to attract financing.

To reserve firm transmission, on the other hand, generators must purchase 100% of their need for the duration of the reservation, and they must pay for the reservation whether they use the transmission capacity or not. Over the course of a year, wind plants typically need only 25-40% of their annual capacity, though at times they may need 100% of generating capacity and at other times 0%. As a result of the resource's intermittent nature, wind generators are unable to maximize their use of reserved transmission capacity and may be forced to pay for more service than they really need, hurting their economic viability.

Reserving transmission capacity is a challenge for intermittent generators, but transmission availability in general is a problem in many parts of the country. Participants in the FERC technical conference identified increased transmission capacity as an urgent need. But at the same time there is evidence that the transmission system is not being used as efficiently as it could be. In fact, although there is a lack of available transmission capacity, many transmission lines are congested no more than 20 to 50 hours per year. In other words, transmission may be contractually committed but not used, tying up capacity and making it unavailable for other opportunities.

There are a couple possible solutions to the

1 FERC, Docket No. RM05-10-000, *Imbalance Provisions for Intermittent Resources,* Notice of Proposed Rulemaking.

problem of unused transmission capacity. One is to adopt a network tariff in which all users pay, like the interstate highway system. This approach is common among RTOs. Instead of the generator reserving transmission capacity to serve a specific load, the utility transmission owner manages all generating plants on its network to meet all loads within the network. Utilities operating transmission under Order 888 may take this approach, but few do so because point-to-point service seems more logical for independent power producers with a single generating facility.

Another solution developed by Pacificorp, is called "partial firm" aimed at utilizing unused capacity on its transmission system. The service is a 10-year firm contract offered for most of the year, but with a defined period when scheduling is not allowed, or when the generator may be curtailed or tripped off-line. For the unavailable period, the generator can go to the secondary market and buy non-firm capacity if available. Although there are concerns that this new service may be too expensive or not firm enough, the Pacificorp approach is creating a lot of interest.

Other alternative transmission products under discussion include allowing reservation of firm transmission capacity equivalent to the intermittent unit's effective capacity, thus simulating an energy-based access fee; and hourly firm point-to-point transmission service. While some transmission owners stop short of calling for new tariffs, they have expressed cautious interest, including the idea that alternative tariff designs should be available to all generators, not just intermittent ones.

Any new transmission service should be evaluated carefully, because other generators may be affected by different ways of using the transmission system. But overall, there is general agreement that the transmission system needs to be used more efficiently.

The Interconnection Queue

A KEY QUESTION facing any project developer is whether the proposed generator can get connected to the grid. It's an obvious need, and critical to project finance. After a project has determined that a proposed site is acceptable, the developer applies to the transmission provider for an interconnection. If there is insufficient capability to accommodate a service request, the transmission provider must perform a system impact study to determine what system upgrades would be necessary. To manage requests for service, every transmission provider has an intake process, referred to as a queue.

The rationale for the interconnection queue is that it serves to protect the rights of various project developers on a first-come, first-served basis. Queue position has real commercial significance, so some projects file just to get a place in line without any certainty that they will actually be built. But the queue implies that projects near the top of the list will be built first, ignoring the fact that some projects like wind can move a lot faster than others.

Projects may wait several years in the queue before an interconnection study can be conducted. A long wait can have serious consequences for some renewable technologies that are evolving rapidly. For example, with a lapse in time, wind turbine size and consequent site configuration may change. Power purchase agreements, essential for financing wind, often set an operational date which, if missed, may result in financial penalties. Finally, the production tax credit, with its short-term renewals, may expire again, affecting project financial viability. In short, the window of opportunity may close while a project is in the queue, and this is more likely for wind projects with short construction cycles.

FERC Order 2003 requires that electrical design be completed before a project can get into the queue. Some developers complain that this presents a chicken and egg situation, because developers need information from the grid to be able to design the project—information that is available only after they get into the queue. Others complain that by the time they get their turn for study, things have changed.

What can be done about these problems? FERC is inclined not to provide wind projects with essential, but confidential system data in advance of getting in the queue because of a concern about unwarranted disclosure of critical energy infrastructure information and commercially sensitive data.[2] One option might be to allow project developers more flexibility to update project designs if they are in the queue for very long. Another possibility is to allocate queue position according to first use date, not first filing date.

Another approach is for the transmission provider to undertake a cluster analysis. PJM, for example, encourages filing for interconnection studies every six months, and will study the proposed projects as a group. PJM also will give developers a system model and allow them to conduct their own studies to aid in the project design process. The Edison Electric Institute also supports analysis of multiple interconnection requests on a regional level. This works more easily in regions with an RTO. Where there are many transmission providers and no RTO, multi-state transmission planning is voluntary and challenging.

Capacity Value

BECAUSE WIND is an intermittent resource, some question whether it offers any capacity value to an electric system. Whether wind is credited with any capacity value matters because it is a factor in determining what costs may be added to intermittent generators, in two ways. First, with low or no capacity value, generators must acquire more ancillary services to meet reliability requirements. Second, with respect to transmission system upgrades, capacity value influences cost allocation. New renewable projects without capacity value will be assigned all of the cost of transmission system upgrades that might be necessary for an interconnection to the grid. On the other hand, attributing some capacity value suggests that a generator may provide reliability benefits to the grid, and hence a portion of the cost may be allocated to all transmission users.

On the first point, there are now a number of studies showing that adding 10%-20% wind to electric systems will cost no more than

2 See FERC, Notice of Proposed Rulemaking, Interconnection of Wind Energy and Other Alternative Technologies. Docket No. RM05-4-000, January 24, 2005.

3 See reports available at the Utility Wind Interest Group, www.uwig.org, under Operating Impacts.

$5/MWh in ancillary services for reliability.[3] These costs should be allocated to the intermittent generators, but the studies contradict the claim of some that wind must be backed up by an equal amount of dispatchable capacity. The cost of backup services also depends on the kind of resources available for providing reserves. And it depends on how large the system is—1000 MW of wind in a small control area creates a bigger problem than 1000 MW of wind in a large RTO.

On the second point, the capacity value for most generating units is typically measured by the unit's maximum sustainable output during peak demand conditions. Wind's intermittent production profile makes this difficult, however. The capacity value will vary from one wind plant to another because of the differing wind regimes at each site relative to peak demand. The proper method of estimating capacity value is the effective load carrying capacity (ELCC) using a system model.[4] Calculating ELCC is labor and data intensive, however, so grid operators prefer simpler approximations.

In their search for an easier way, grid operators don't agree on how to assign capacity value to new wind projects. ISO New England relies on historic capacity factor, but may change to performance during the top 100 critical hours. PJM sets an initial capacity value for wind at 20% of nameplate capacity, which is then adjusted based on actual operating experience, resulting in a rolling three-year average capacity value. ERCOT assumes 10% of installed capacity, and Southwest Power Pool looks at the wind plant's performance during the top 10% of the hours of highest system load. These simplified methods may overstate or understate a wind generator's true capacity value, however, so it is best to rely on the ELCC method.

"Regulators need to be aware of the barriers facing intermittent resource development, as these barriers may make it more difficult to achieve public policy goals."

Implications for State Regulators

MOST OF THESE technical issues will be addressed by FERC in its interconnection standards or by transmission providers. What, then, is the role for state regulators?

First, many states have adopted policies to encourage renewable energy. Regulators need to be aware of the barriers facing intermittent resource development, as these barriers may make it more difficult to achieve public policy goals. Existing grid operation practices are the legacy of a generation fleet with similar operating characteristics. As new generation with different characteristics is added to the fleet, rules should accommodate this new diversity while protecting reliability. Change may require support and encouragement from state regulators.

Second, several of these technical issues boil down to added cost and cost allocation. Regulators should be prepared to question cost allocation recommendations, to consider whether new renewable projects provide system benefits or only project benefits, and potentially to allocate costs differently from conventional thinking.

4 ELCC is measured by a system dispatch model. It requires modeling a base case without the new generator, and then modeling the system with the new generator. The incremental load supported by the new generator is its carrying capacity.

Third, state regulators that participate in regional state committees established to guide RTO work may have to place a higher priority on issues affecting intermittent resources, whether they be imbalance penalties, the interconnection queue or capacity value. At the least, state regulators can encourage RTOs, where they exist, to be careful not to disadvantage wind unless reliability requirements necessitate different treatment.

Finally, these issues are more significant in areas where there is no ISO or RTO because control areas are smaller and larger wind projects can have a bigger impact there. Without an ISO or RTO, transmission providers are operating under older FERC rules with less flexibility than the discretion given to RTOs. Hence system engineers who are used to dealing with conventional power plants may need to be encouraged to reconsider their thinking about wind and other intermittent resources, and to examine system integration impacts carefully before demanding costly technical fixes that may not be justified.

Ed Holt is President of Ed Holt & Associates, a renewable energy policy and green power marketing consulting firm located in Harpswell, Maine. He may be contacted at edholt@igc.org. **He thanks Kevin Porter and Charlie Smith for their review and comments.**

The Regulatory Assistance Project
177 Water Street
Gardiner ME 04345-2149

Pass The Word

Pass this Issuesletter around to others and let us know who we should add to our mailing list. As always, we welcome ideas for future issues.

The Regulatory Assistance Project

MAINE
177 Water Street
Gardiner, Maine 04345-2149
Tel (207) 582-1135 Fax (207) 582-1176

VERMONT
50 State Street, Suite 3
Montpelier, Vermont 05602
Tel (802) 223-8199 Fax (802) 223-8172

PROJECT DIRECTORS
Cheryl Harrington, David Moskovitz, Richard Cowart,
Frederick Weston, Wayne Shirley, Richard Sedano

RAP ASSOCIATES
Peter Bradford, Jim Lazar

WEB
www.raponline.org