Integration of Wind and Electricity Supply: A Review of Recommendations

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Integration of Wind and Electricity Supply: A Review of Recommendations

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Introduction

This paper seeks to summarize the fundamental issues surrounding the topic of wind integration, and describe what electricity delivery experts say are ways to address these issues. This effort focuses on PJM, a large regional transmission operator with many interconnection points, making it an important participant in the supply of electricity in much of the eastern U.S. PJM is currently conducting its first system-wide variable generation integration study.

Delivering electricity that includes wind power is more complicated than delivering it without wind. From an engineering standpoint it is more of a challenge. More resources have to be committed to maintaining stability, which reduces overall efficiency, depending on the type of resource committed. Managing stability has implications for both short and long-term. With variable resources such as wind, the system must prepare for more real-time fluctuation in both supply and demand while without variable resources supply is more controlled. Utilizing wind also complicates planning for future power adequacy as wind patterns vary from year to year.

What is successful wind integration? Successful integration allows electricity consumers to take advantage of wind's most desirable attributes, primary that its marginal production has near-zero costs, emissions or water consumption. Successful integration also does not waste fossil resources to accommodate wind. As the amount of installed wind has increased, it has been observed that the marginal costs of wind to the system are greater than the marginal cost of turbine operation due to the variable nature of wind and the resulting dependence on other generators in the system for balance (FERC 2011). Power plant dispatch decisions are based on marginal cost, which does not include the indirect costs of maintaining system reliability at other plants, a portion of which can at times be attributed to wind. If coal plants, especially older coal plants, are used to balance wind's variability then integration will be more costly (Puga 2010).

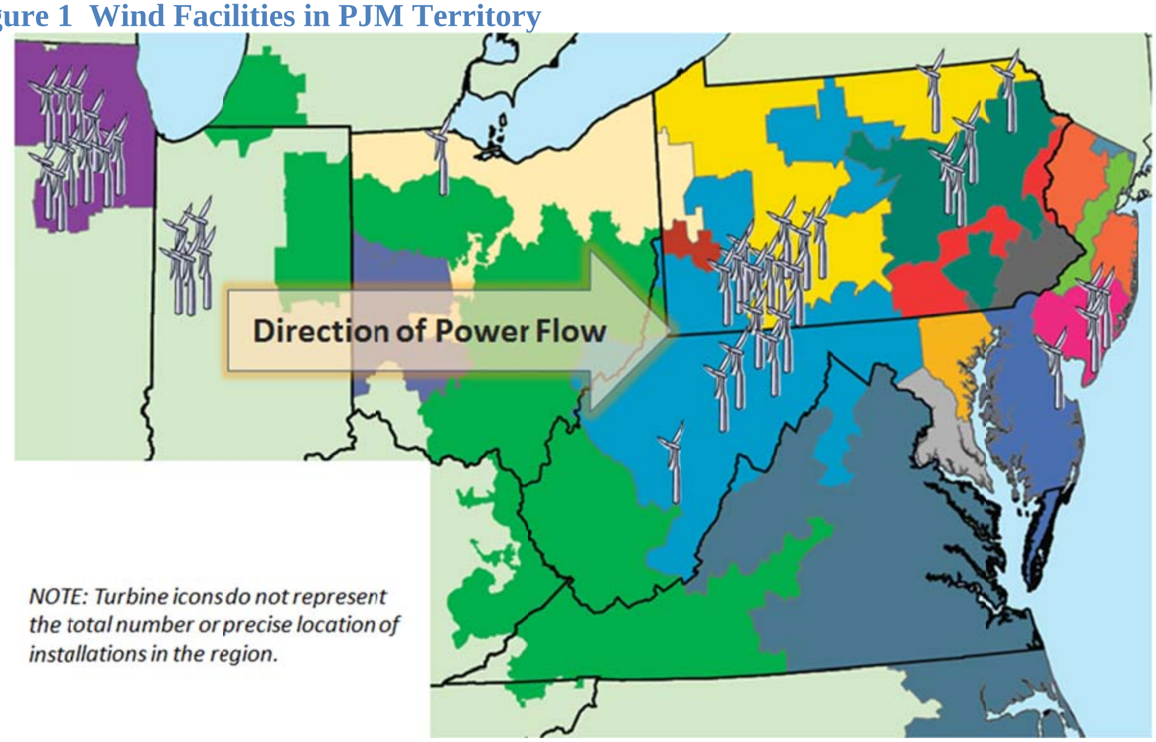
Much of the literature of wind integration studies argues that successful integration is not a question of reliability, but a question of cost and efficiency (DeCesaro, Porter and Milligan 2009). The North American Electricity Reliability Corporation (NERC) has studied balancing authorities with high wind penetration levels and state that variable generation "has not appreciably affected the reliability of the bulk power system" (NERC 2010). Delivery of electricity can be managed with wind, provided that total supply is maintained regardless of what power wind is contributing. Others argue that the overscheduling of non-wind resources required to ensure reliability with higher wind penetration creates a less reliable system because of the increase in dispatch instructions (Forbes, Stampini and Zampbelli 2010).

So why try to integrate wind when using fossil resources is easier? It is easier to engineer a reliable electricity delivery system with stored fuel. But fossil resources are finite, not sustainable and underpriced relative to the externalities that they generate. Fossil and nuclear energy require large quantities of water to operate and fossil fuels release emissions into the atmosphere. Many are concerned that the price of fossil fuels, and thus the price of electricity are not high enough to reflect the externalities created by extraction and emissions and that physical reliance on these resources is excessive relative to the eventual need to replace them with sustainable resources. Given the societal level of these issues, and the benefits of sustaining electricity consumption choices, it is appropriate for government to support alternatives.

Wind energy is available in large quantities and can be converted into electricity with conventional technology. It is thus one of the best prospects for widespread installation of renewable energy production capacity. However, the inflexible nature of much of the incumbent electricity infrastructure and the variable nature of wind tremendously complicate the ability to efficiently utilize wind energy. These features complicate system operations in many time periods: real-time, near-term (hour-to-hour), short-term (day-ahead) and long-term (years).

There are many studies and reports published on wind integration (Campbell 2009) (GE Energy 2010) (NERC 2008) (NREL 2010). This paper focuses on efforts in the PJM Interconnection as West Virginia and its electric utilities are part of the PJM and West Virginia is located centrally in the region as presently defined. As PJM operates a very large system, its success with integrating wind will impact the destiny of the resource. PJM is also closely connected with other large systems focused on integrating wind, including others that also use five minute markets such as the Midwest Independent System Operator (MISO) and the New York ISO (NYISO). Strong connections to other large utilities such as TVA in the south are also maintained. Figure 1 shows the PJM dispatch territory.

Figure 1 Wind Facilities in PJM Territory



How Wind Impacts the System

The variable nature of wind impacts the way electricity is controlled on the system. Increased variability is experienced by the system in multiple time periods and affects system operations at the local level, the balancing area level and the interconnection level. Because it is asynchronous[1] wind decreases the inertia on the system and contributes to imbalance of both voltage and frequency, two key elements of the electricity system that are managed instantaneously with automatic controls (NERC 2010).

The population of studies that assess the impact of wind on systems are typically divided into three time periods: regulation[2] (very short-term; up to 10 minutes), load-following (10 minutes to several hours) and unit commitment (longer than an hour but up to a day or more in the future) (DeCesaro, Porter and Milligan 2009). It is important to acknowledge that wind, and other variable resources, are not the only type of plants that have such system impacts. Some types of fossil plants, including coal plants, may also create a need for regulation due to an inability to respond to an automatic generation control signal (Milligan 2011).

Wind in the system looks like negative load to the system operator (PJM 2011). The quantity of load needed to be served by non-wind resources is referred to as "net load" to illustrate the changed shape of what must be supplied. A system with integrated wind needs the ability to more actively deploy load-following generation or more load-management capability (USDOE: EERE 2008). As a system operator manages available generation on its system to balance load it is optimizing the mix of resources based on both economic and reliability criteria. The process is termed "security-constrained economic dispatch" referring to the dispatch of the generators in merit-cost order as long as reliability is not compromised. The optimization process considers the level of power likely to be available in the near-term from all plants. Coal or natural gas resources are often economically curtailed because of wind but they are curtailed or re-dispatched because of other coal and gas plants as well, depending on relative marginal cost and transmission constraints.

Integration includes the ability to prepare for up and down wind ramping and to control wind generation via dispatch instructions, including the ability to curtail it when availability of other generators may be reduced if they are curtailed to accommodate wind. To achieve reliability most effectively the dispatch process must have the option to curtail wind. Although wind curtailment reduces the effectiveness of renewable mandates, planning for some wind curtailment as opposed to zero is more efficient for the system as a whole (NREL 2010).

Overall, integrating wind means more changes in output by conventional generators to balance the demand and supply of electricity (NREL 2009). This induced cycling by conventional

[1] Asynchronous generators often operate with a rotational speed that is slower than the speed of the utility grid to which they are connected, thus reducing system inertia and frequency response.
[2] PJM describes "regulation" as the capability of a specific resource with real-time control and response capability to increase or decrease its output in response to a control signal to control for frequency deviations.

generators causes increased fuel consumption per unit of generation, likened to the difference in fuel economy achieved by automobiles in city stop-and-go driving vs. highway driving (Inhaber 2010). City driving is much less efficient than highway driving and a frequently cycling fossil power plant is less efficient than one producing a stable output. However, it is very difficult to attribute how much system-wide cycling is due to wind when it is the interaction between all types of generators that determines actual dispatch.

For example, a report on the interaction between wind and coal generation in Colorado illustrates that on few days in 2008 wind generation caused coal plants to cycle to the point that they emitted more than they would have if they had not been curtailed (Bentek Energy 2010). That interaction may have been substantially different if natural gas prices had not been high on September 28-29, possibly causing less gas generation to be on-line and thus leaving the cycling to coal plants. Nominal Colorado industrial natural gas prices were $15.93/mcf in September of 2008, the second highest monthly price of the decade; October of 2008 had the highest price of the decade (EIA 2011).

The Colorado incident is a good example of what can happen with wind, but it is a very short-term example and is not representative of daily events (Prager 2010). It illustrates well the importance of the total generation portfolio, the geography of that portfolio, the size of the balancing area, the relative prices of fossil fuels, and the timeframe being evaluated. A comparable incident has not been reported in the PJM region.

Wind is expected to decrease the required capacity of conventional generation for some regions by an amount equivalent to 20 to 25 percent of installed wind (New York Independent System Operator 2010). However, due to wind-induced cycling that already occurs, it will be difficult to displace all the fuel used to produce a MWh of conventional generation for every MWh of wind generation. In PJM, wind has primarily displaced coal-fired generation, with natural gas second, but it has also displaced petroleum-based fuels, land-fill gas, municipal solid waste, hydro, nuclear, system imports and even wind power (Monitoring Analytics 2010).

Much thought has been given to whether wind generation will increase the need for various types of system reserves used to maintain reliability. The answer depends on the type of reserve and the level of wind in a system. Contingency reserves, the spinning reserves in place to make up for the unexpected loss of the largest generator in a system, have been predicted by most to be unchanged because of wind (NERC 2010, NREL 2010, NYISO 2010). However, an increase is expected in at least one ISO, the New England ISO (GE Energy 2010). The required contingency reserve in various systems is in the range of 1,200 to 1,700 MW but the level of installed wind, and the associated potential ramping in a 10 or 15-minute period could create a need for contingency reserves. For this particular set of conclusions the NYISO looked at integration of 8 GW of wind while the NEISO looked at 12 GW. Contingency reserves must be spinning, i.e. they must be online and available within a few minutes, because of the nature of unexpected outages.

NERC recommends that with increasing penetration of renewables balancing authorities should permit contingency reserves to be used more frequently to correct energy imbalances. NERC specifically states that contingency reserves be used more often to balance a loss of wind generation (North American Electric Reliability Corporation 2011).

It is widely stated that wind generation increases need for regulation services (GE Energy 2010, National Renewable Energy Laboratory 2010). Regulation is used to control for frequency deviations on the grid and must be provided by resources with real-time telecommunications that are capable of changing output very quickly in response to a regulating control signal. Regulation service is provided in a very short time frame, i.e. seconds to less than 5 minutes, and must be provided by spinning reserves. Because regulation is the most expensive of the balancing services this is a cost assigned to wind integration (Hines 2010).

NYISO determined that integrating 8 GW of wind would not impact system reliability but would increase need for regulation services by nine percent per GW of wind (NYISO 2010). Table 1 shows the results of the Eastern Wind Integration & Transmission Study, which models the amount by which PJM's regulation reserves might need to increase in four wind expansion scenarios, from 1,055 MW that would be required in the absence of wind power (NREL 2010).

Table 1 Eastern Wind Integration Study – Select Scenario Results

EWITS Scenario	Additional Regulation Needed in PJM	Total Installed Wind in PJM (MW)	Additional Regulation as % of Wind MW	PJM Wind Penetration (% of annual energy D)	US Wind Penetration (% of annual energy D)	Geography of Wind Development
Scenario 1	939 MW	22,669	4.1%	7.8%	20%	high quality on-shore resources, much in Midwest
Scenario 2	1,304 MW	33,192	3.9%	11.1%	20%	fewer Midwest resources plus some off-shore
Scenario 3	3,408 MW	78,736	4.3%	25.6%	20%	more eastern development plus aggressive off-shore
Scenario 4	4,355 MW	93,736	4.6%	30.5%	30%	very aggressive on- and off-shore

As part of its effort to identify the quantity of additional reserves needed due to wind PJM is monitoring wind ramp data for maximum up and down ramping. As of June 2011, the maximum 15-minute downward wind ramp experienced in PJM was 590 MW and the maximum 15-minute upward ramp was 608 MW (PJM 2011). For a 60-minute period the maximum down and up ramps were 1,005 MW and 928 MW respectively. Based on these observations, and with current wind capacity of about 5 GW throughout the system, the need for additional contingency reserves in PJM has not been observed. However, moving to 22 or 33 GW of wind could change this. As the amount of wind capacity grows, the ramping observations are likely to increase.

Individual utilities are also working to integrate wind. Because wind generation can impact individual plants by causing them to cycle their output more or to be curtailed to below their ideal operating level, some utilities have been developing integrated resource plans for wind and fossil assets for several years. Such plans characterize the impact local wind generation may have on system operation and reserve requirements (Xcel Energy 2003). PacifiCorp conducted a wind integration study in 2010 and determined that both regulation and load following reserve services increase with higher wind penetration compared to load only (PacifiCorp 2010).

The Nature of Wind in PJM

Wind turbines are one of only a few asynchronous, or induction, generators on the system, meaning that they can add to or draw power from the grid. They are of variable speed but provide a constant frequency electrical output (Vittal 2010). Wind turbines have no inertia but add power to the system which affects the synchronizing capability of conventional generators, thus affecting both the voltage and frequency of the system, thus increasing the need for regulation reserves in order to maintain stability. Wind turbines also take power from the system at low wind speeds. As shown in Table 2, the minimum hourly aggregate wind output in 2010 was actually negative (PJM 2011).

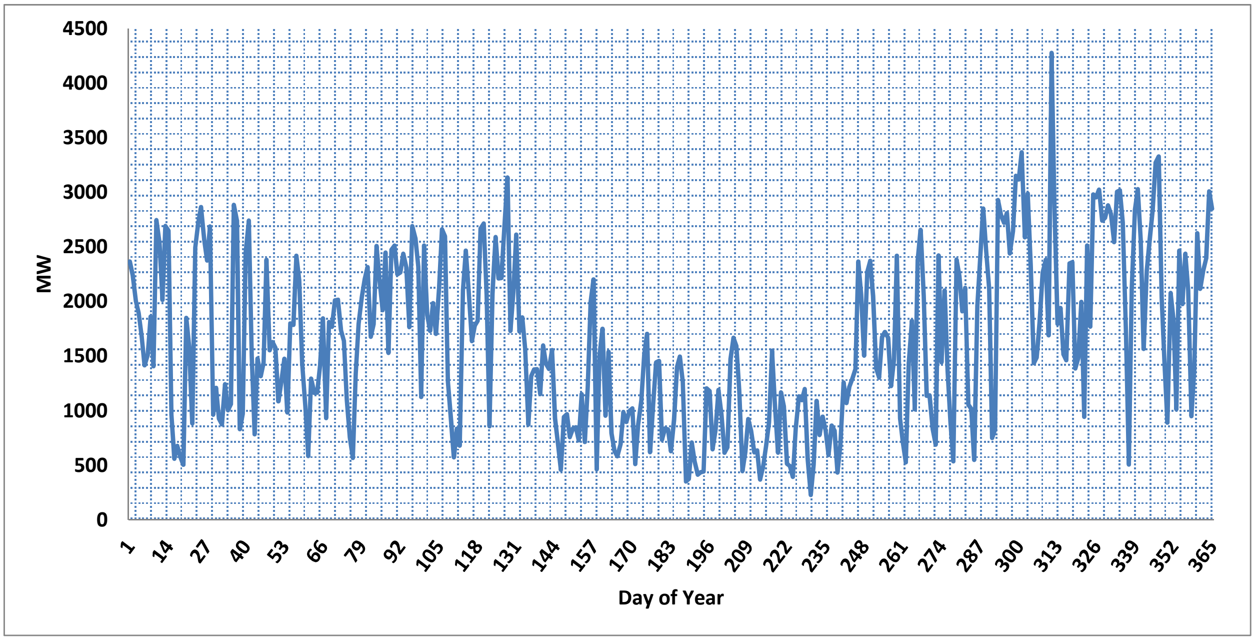
Table 2 Some Recent Key PJM RTO Wind Statistics

	MW	Date of Event	Time of Event	As of Date
Wind Capacity	4,711	-	-	June 2011
Max Hourly Wind (2011)	3,774	February 13, 2011	7-8pm	August 31, 2011
Min Hourly Wind (2011)	-10.0	August 29, 2011	6-7pm	August 31, 2011
Max 2011 RTO Load	157,803	July 21, 2011	4-5pm	July 21, 2011
Min 2011 RTO Load	50,650	April 24, 2011	4-5am	July 21, 2011
Max Hourly Wind (2010)	3,387	October 28, 2010	11am-12pm	
Min Hourly Wind (2010)	-1.0	August 19, 2010	11am-12pm	

Total installed wind capacity in PJM was 4,711 MW as of June 2011 (PJM 2011). As of August 31 the maximum hourly average wind power generated in 2011 was 3,774 MW between 7 and 8pm on February 13 and represented almost 80 percent of total wind capability in the RTO. The minimum wind output for 2011 was -10 MW, occurring between 6 and 7pm on August 29. Output data is net of curtailment, although as of 2010 PJM had rarely curtailed wind, and had done so manually (PJM 2010).

Figure 2 provides a year's worth of maximum daily wind output, illustrating seasonal changes. Because wind is less available in the summer months, and because the peak load in PJM is in the middle of summer, more non-wind resources must be available to meet load during the summer. This data also illustrates the greater range of wind output in many winter, spring and fall months, variability for which the system operator must be prepared for.

Figure 2 Maximum Daily Wind Output in PJM, 2010 (MW)



A longer-term impact of wind's variability is the effect on system planning. Because annual and seasonal capacity factors vary from year to year with weather, deciding what level of capacity credit[3] should apply varies by regional standards. PJM allows the peak season capacity factor of 13 percent to apply for planning purposes, a figure based on actual non-curtailed wind output (PJM 2009). Plants with capacity credit are considered a capacity resource by PJM, have capacity interconnection rights and can receive payments for participating in PJM's Capacity Market (PJM 2009).

The challenges of short-term integration are illustrated with diurnal, hourly peak wind output. Wind does not usually peak when load peaks, i.e. wind and load peaks are not coincident. As shown in Figure 3 wind peaks most often around midnight and is thus out of phase with load during the morning ramp up and the evening ramp down. The frequency of peak load by hour of day in PJM is shown in Figure 4.

[3] Capacity credit is the portion of installed capacity allowed to count toward total system capacity, including installed reserve margins, needed to ensure that enough capacity is available to meet future peak load.

Figure 3 Hour of Daily Peak Wind Output in PJM, 2010 (# of Days at Hour)

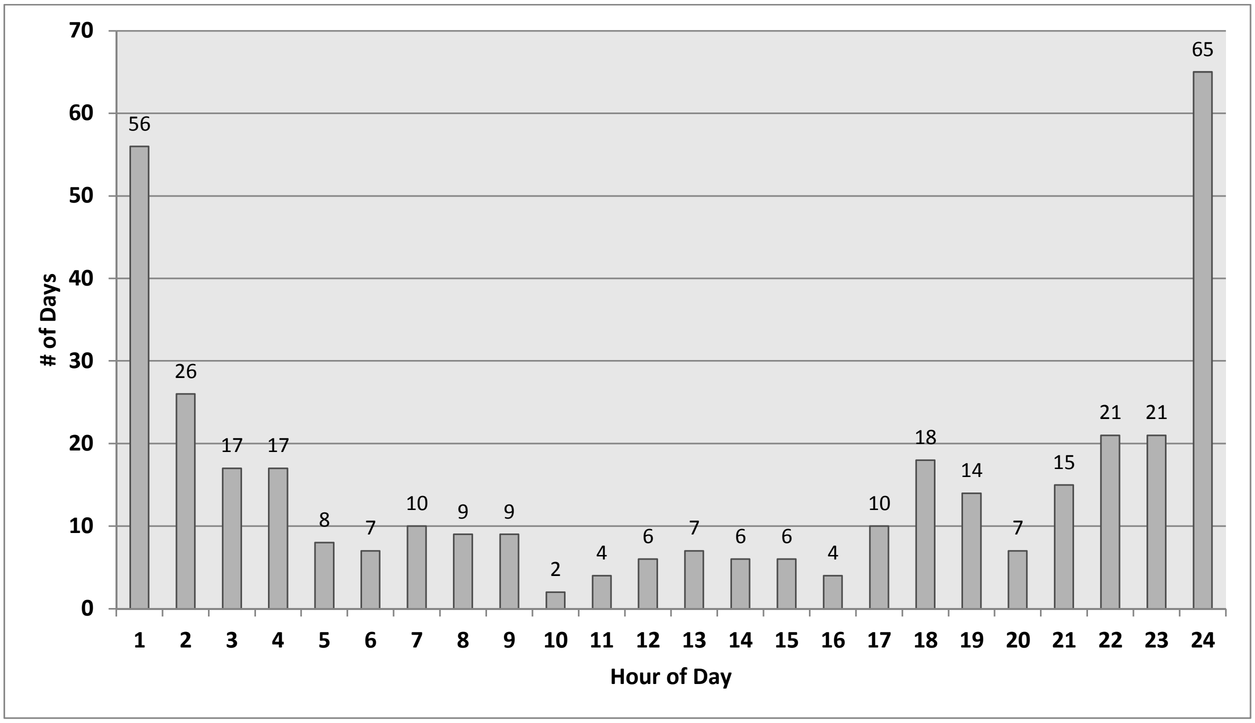
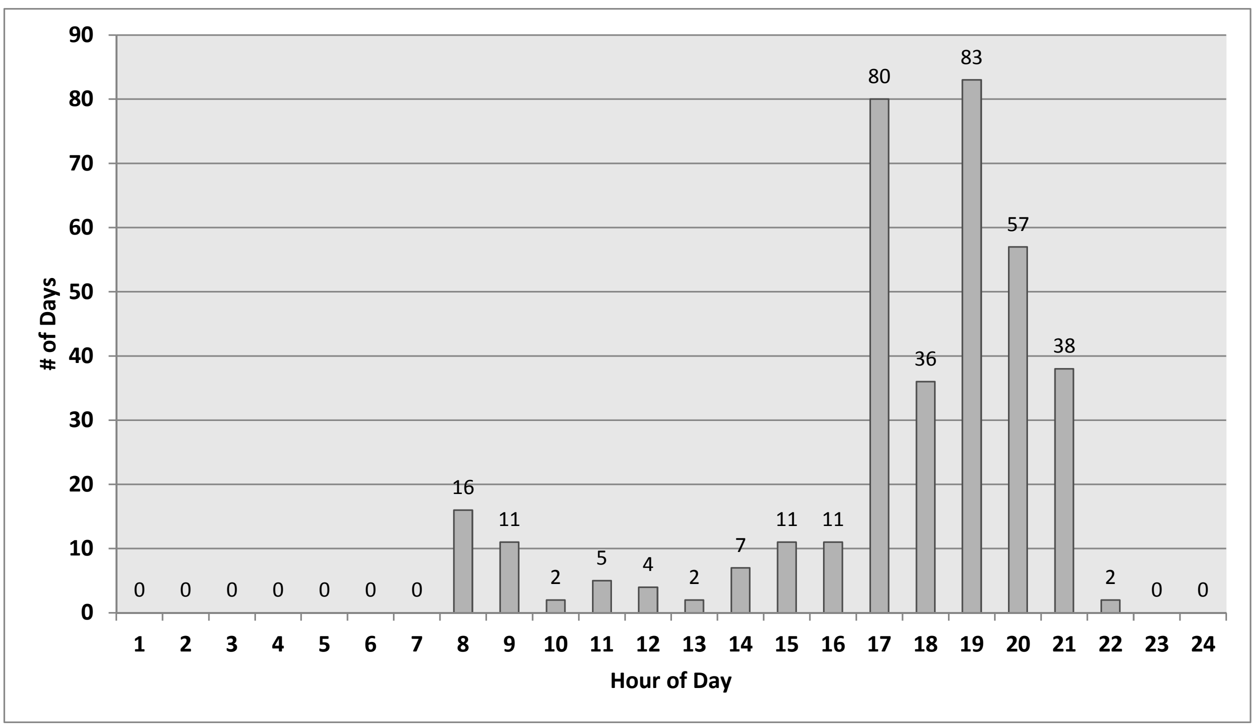
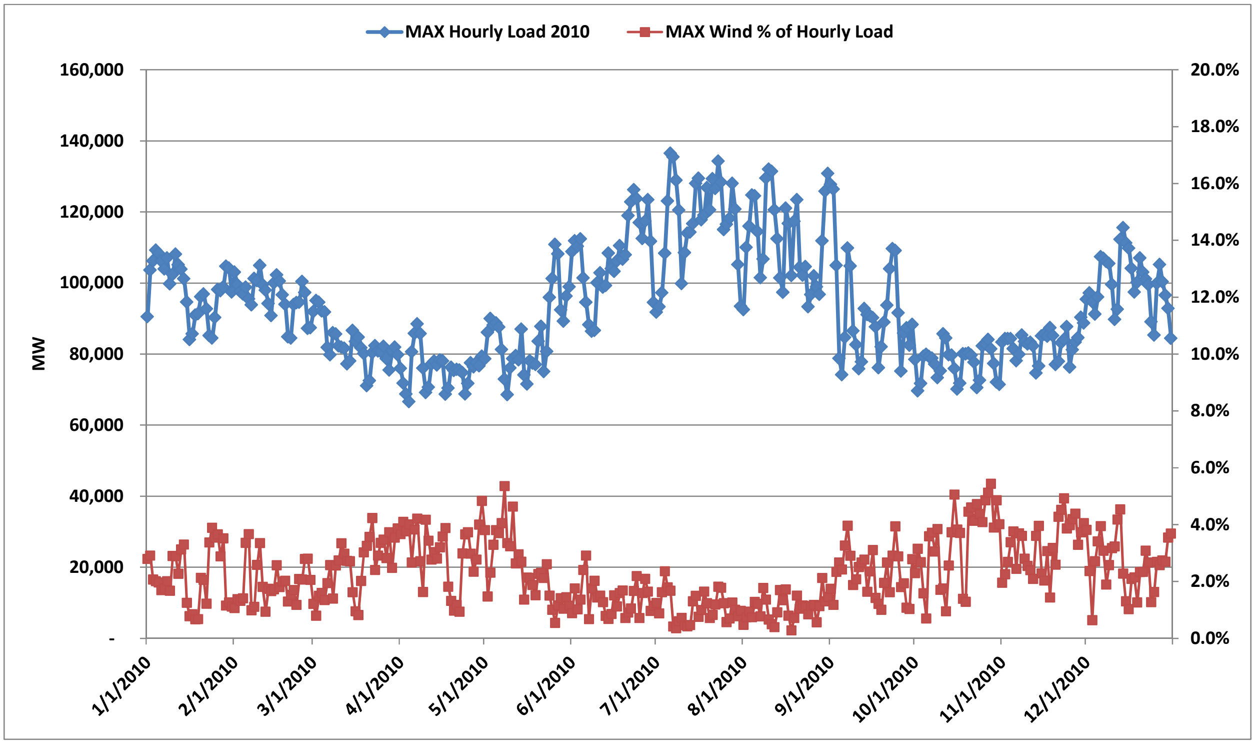


Figure 4 Hour of Daily Peak Load in PJM, 2010 (# of Days at Hour)



Combining information from the graphs above further illustrates the seasonal divergence of wind output and demand for electricity. Maximum electricity load is seen in July and August. In 2010, wind power contributed between zero and 5.4 percent of hourly load in PJM.

Figure 5 Maximum Hourly Load per Day and Wind as Max % of Hourly Load in PJM, 2010



PJM has not yet completed its own wind integration study but has initiated a study via a contract with GE Energy that will be complete in late 2012 (PJM 2011).

The PJM Renewable Integration Study is has two primary goals:

1) Determine for the PJM balancing area, the operational, planning and market effects of large-scale integration of wind power as well as mitigation/facilitation measures available to PJM, and
2) Make recommendations for the implementation of such mitigation/facilitation measures.

Some specific issues the study is expected to address include: entry and exit of supply resources, wind forecasting including output variation in areas with complex terrain, future fossil fuel prices, price response characteristics of demand resources and operating costs for new and existing units (PJM 2010).

Recommendations

Many of the recommended methods to integrate wind, such as combining balancing areas and expanding use of intra-hour markets, are already part of the trend toward greater interconnection in electricity supply. Other proposed solutions, such as energy storage and demand response have also been promoted for decades. Such resources if deployed routinely to reduce peak load would reduce reliance on system reserves provided by fossil resources, thus allowing the benefits of wind energy to be more fully realized. But as these non-traditional resources are slow to develop and physically limited, utilities are obligated to find other ways of serving whatever load is on the system and to do so within the numerous reliability constraints set by NERC.

Most recommendations to integrate wind regard modifying and expanding the existing operating system and the protocols that govern how and which plants are dispatched and re-dispatched throughout the daily electricity demand cycle in response to price signals, transmission constraints and load patterns. Many protocols require technology to be successful, but are not a technology solution, while some technologies such as fast- or slow-ramping energy storage are partial solutions in themselves.

NERC has evaluated the potential impact of variable resource integration extensively. Many of its recommendations focus on the potential effects of using non-conventional resources, such as demand-side response and energy storage, as reserves to balance wind's variation. These include strategies to optimize this contribution such as ensuring that appropriate communication exists between such resources and the system operator, adjusting reliability standards to expand the types of resources that are allowed to provide various reserves and services, and developing the correct price signals for those services (NERC 2010).

Most on-turbine technology options that could be used to reduce wind's short-run contribution to system variability are only partial solutions to integration and are not broadly recommended for immediate implementation. The recommendations closest to being implemented are regulatory, largely to be imposed by the Federal Energy Regulatory Commission (FERC), or market-based and designed to improve the fairness by which variable and fossil resources are compensated in the marketplace. Because FERC's role is to regulate transmission services, which must be scheduled by generators prior to generation, recommendations related to its rules largely involve changes in tariffs paid to owners of transmission.

Technology Recommendations

Incorporating additional electronic controls on wind turbines can partially resolve some of the issues related to its tendency to complicate compliance with real-time grid control performance standards. Wind turbines can be built to operate like synchronous generators providing reactive power (GE 2010). However, there are few firm recommendations or requirements to do this. Costs may be substantial and could significantly alter the wind component supply chain. Most discussion of this type of integration solution seems to be confined to academic and electrical engineering circles. IEEE characterizes many of these technology solutions, such as inertial response and other components that make wind turbines behave as synchronous generators, as the "Wind Plant of the Future" (Piwko and et al 2009). An example of a turbine-level technology is a doubly-fed induction generator controls on turbines providing pitch control for frequency regulation (McCalley 2010).

In spite of a lack of strong recommendations to integrate new components in wind turbines, there is some belief that truly successful, large-scale integration of wind will only be accomplished with turbines that act more like conventional plants. Such plants would be scheduled automatically over short periods of time with a known degree of accuracy, provide ancillary services including spinning reserves in both the up and down direction and frequency regulation, possess inertial response, voltage control and reactive power control with state-of-the-art power electronics. As this technology already exists it is a matter of economics, not ability (Smith and Parsons 2007).

One physical characteristic of modern wind turbines that increases availability and is already deployed is low voltage ride-through (LVRT), a technology that was implemented through operating standards. In 2005 PJM accepted a proposal by NERC and AWEA to require new wind facilities of greater than 20 MW to have LVRT capability for certain levels of voltage loss (PJM Interconnection, LLC 2005). FERC Order 661 requires wind turbines to remain in service during a fault for up to nine cycles at a voltage as low as zero (Stoel Rives, LLP 2009). While this does impose an additional expense on wind generators, this capability allows them to generate more in situations where they would previously have just disconnected from the grid. Such technologies make wind more "grid-friendly."

Solutions to decreased inertia and real-time output variation that can be alleviated by turbine-level technology can also be accomplished by fast-moving energy storage or load control (McCalley 2010). These resources could provide similar benefits as on-turbine technology but would have to be fully dispatchable and controllable by the system operator. These resources exist in small quantities, e.g. industrial demand-response units, grid-connected electric vehicles, pumped storage, but are presently not numerous enough to match the variability of large-scale wind. NERC has identified demand response, electric vehicles and several types of energy storage as technically capable of supporting all ten specific reliability functions it identified in its assessment of the impact of variable resources on system reliability, from the very short-term inertial impacts to unit commitment, although it expects situations with the longest response times and limited duration of response to be most suited to these resources (NERC 2010).

Increase the Flexibility of the System

Wind is a very flexible type of generation, both up and down (especially), but it is variable and not as regularly variable as load. NERC has stated that the electricity supply system must become more flexible in order to successfully integrate wind and that both supply-side and demand-side resources can provide this (NERC 2010). The characteristics of other generation on the system, i.e. the balance of generation, are very important as this determines the source of flexibility and the efficiency of integration.

Proposed flexibility solutions involve a combination of physical attributes and institutional protocols. Recommended sources of flexibility include expanded use of intra-hour markets, consolidation of balancing authorities, expansion of the type of reserves used for various ancillary services, lowering minimum generation levels of base load plants and enhanced communication between wind facilities, utilities and system operators.

NERC states that there are no technical limitations to non-conventional resources such as demand-response, electric vehicles and energy storage providing flexibility-related reliability functions but that economics will be the determining factor in widespread deployment (North American Electric Reliability Corporation 2010).

NERC has proposed a new type of reserve called "Variable Generation Tail Event Reserve" be created to cover the infrequent, but large ramps of variable generation. This type of reserve would be like conventional contingency reserves but would be assigned to cover generation ramping events, such as those created by wind resources. Such as reserve is needed because NERC reliability rules require contingency reserves to be restored within 90 minutes, making wind generation tail events too slow to use conventional contingency reserves. Because a large variable energy resource ramp often takes two hours or longer to reach a maximum level, reserves are needed that can respond for the entire duration of the ramp (NERC 2010).

It is also expected that any load that can supply replacement reserve or supplemental operating reserves will be able to supply Variable Generation Tail Event Reserves. In fact, NERC considers the potential aggregate contribution of demand response, electric vehicles and various types of energy storage to variable generation tail events reserves to be "significant" (NERC 2010). This is because these types of resources match the longer response time-frame of wind ramps with less concern regarding over-deployment that would occur with conventional generation being used as such a reserve.

Another integration recommendation is to expand use of shorter market intervals, such as the five-minute markets already in place at PJM and other ISOs. Such intra-hour markets make adjustment to serve changing load more optimal as plants can incorporate the latest information about their position. With tighter, intra-hour markets these schedules can be adjusted closer to real-time as wind forecasts change.

FERC has also proposed mandating 15-minute transmission scheduling for all utilities and balancing authorities (FERC 2011). According to FERC, intra-hour scheduling is fairer to variable generators because the re-dispatching that occurs optimizes use of available generation and reduces transmission imbalance charges that might be levied on wind generators who have reserved transmission capacity (Morgan Lewis 2011). Markets that only settle once an hour will be based on somewhat old wind and weather data by the time the generation actually occurs. The impact on conventional reserves is also greater with less frequent scheduling because actual generation may not match the associated transmission schedules, causing an unnecessary reliance on a public utility transmission provider's reserves (Morgan Lewis 2011).

To incentivize development of more flexible units it is recommended that the market for ancillary services be expanded to cover more types of faster-ramping units or demand resources (Puga 2010). A somewhat similar recommendation is to incentivize generation services that are bundled with variable renewable output to supply firm capacity and energy (EEI 2011). As NERC is the entity that sets guidelines for what types of resources qualify to provide different types of reserves, such decisions will be reliability based.

One recommended way to incentivize use of more efficient reserves is to change balancing authority rules to allow non-spinning reserve and supplemental operating reserves to be used to compensate for large wind ramps instead of regulation services (Campbell 2009). Expanded use of non-spinning reserves is one way to avoid system efficiency losses associated with idling or cycling spinning reserves to accommodate wind ramps. Spinning reserves can include demand response resources but they must be attained within ten minutes from a request. In addition, current rules allow PJM to implement no more than 10 interruptions in a given delivery year from qualified load management programs (PJM 2011). Some quick-start, non-synchronous resources such as hydro facilities and combustion turbines can provide reserves in 10-minute intervals but these reserves are generally part of the contingency or primary reserve category and held for that purpose (PJM 2010).

Supplemental reserves are not synchronized to the system but they are part of PJM's total operating reserves and are calculated, along with contingency reserves, to address load forecast error and forced outage rates (PJM 2010). Current reliability rules in the United States require non-spinning reserves and supplemental operating reserves to only be in service for a period of time (usually 1 hours to 2 hours) that is shorter than the wind ramps that may occur over a longer period of several hours (DeCesaro, Porter and Milligan 2009). Because net load (load minus wind output) varies more than load alone, incorporating wind forecast errors would increase the time period needed substantially.

Another FERC-proposed rule is to require expanded communication between wind facilities and public utility transmission providers regarding outages and output forecasts, not just between wind facilities and the system operator (Morgan Lewis 2011). This would allow utilities that transmit wind power that they do not control to have more complete information about how much wind is on their systems.

As wind output increases, especially during light load periods, traditional utility base load plants may need to operate below their optimal levels. The concept of increasing "base load turn-down levels" is one that is regularly mentioned in integration literature (NREL 2010). Such base load flexibility comes with an efficiency penalty, illustrated by the analogy of city driving vs.

highway driving. Or, if load is extremely low like in the early morning hours of fall and spring it may be impossible to further reduce base load output. If base load plants are already generating at their stated economic minimums, PJM will not dispatch them down further unless it is for reliability reasons. PJM is currently developing light load criteria to alleviate the growing problem of thermal overloading during the hours of 1 to 5am (PJM 2011). This effort focuses on reliability and ensuring that enough generation is available to respond to the morning load increase.

Due to reliability rules that obligate power delivery, flexible resources must also prove availability. For example, concern is sometimes raised about the availability of natural gas to fill in the gaps created by wind. Gas plants are typically more flexible than coal plants and suffer less efficiency loss when cycled and are thus better suited to back up wind. It has been recommended for reliability reasons that NERC should require gas turbines to keep a two-week supply of some other fuel that could be safely burned in place of gas (Bayless 2010). NERC recommends that gas pipeline flow is made more flexible to ensure deliverability matches reserve needs (North American Electric Reliability Corporation 2010).

Ideally, all this flexibility will be managed automatically. With the right tools, including always-on real-time communication and monitoring capabilities and a fleet of immediately responsive plants, this is possible. It is also very important that flexibility be appropriately valued by the market in order to have sufficient amounts of response capability supplied (National Renewable Energy Laboratory 2009). If plants or demand resources supplying ancillary services, or plants being curtailed to accommodate wind, are not financially motivated to provide those services integration will not be successful.

Develop Financial Mechanisms to Ensure Fairness and Availability

The very low marginal cost of wind is good for consumers in the short run. No resource can compete with wind at this price and are thus outbid in the wholesale market for electricity. But whether marginal prices provide the right signals to provide for a generation portfolio with the required flexibility characteristics is unclear (NREL 2010). There are costs associated with increased flexibility that are at odds with the dispatch of generating units based on marginal cost.

As suggested by FERC and others, the marginal costs of a wind facility may not account for the true marginal cost of providing firm wholesale power due to increased real-time cycling of conventional plants to accommodate wind. Pricing structures may be needed that allow generators providing ancillary services to recover their costs, even though they are operating at lower capacity factors, in order to ensure their availability and keep them economically feasible (Bayless 2010, National Renewable Energy Laboratory 2010).

FERC's interpretation of this issue is described as a "cost recovery gap that presently exists for the recovery of the capacity costs associated with the mitigation of generator imbalances" (Morgan Lewis 2011). Part of this gap shows up in the need for public utility transmission providers to provide regulation services to balance wind output, an issue that FERC proposes to resolve by allowing utilities to charge wind facilities for regulation. Under FERC's proposed Schedule 10 providers can charge a rate specific to variable resources, not the rate associated with load variability, if it is shown they cause a different cost (Morgan Lewis 2011). The Schedule 10 tariff would cover the costs of regulation reserve capacity held to accommodate load fluctuation and generation fluctuation, whereas current tariffs only cover load fluctuation.

FERC Schedule 10 is one of three proposed changes to the current Open Access Transmission Tariff (OATT) and Large Generator Interconnection Agreement (LGIA) listed in a recent FERC Notice of Proposed Rulemaking designed specifically to facilitate the integration of variable resources into the bulk power system. The other two proposed rules are to transition to intra-hour transmission service schedules and to require that public utility transmission providers be given wind facility data that can be used for system power output forecasting (Morgan Lewis 2011). The aim of these changes is to ensure that public utility transmission providers are able to recover all costs associated with accommodating fluctuations in generation associated with variable resources.

PJM supports the three actions in the FERC proposal assuming that choosing to use Schedule 10 is optional. PJM also suggests that FERC should "allow for regional differences" rather than mandating a 15 minute scheduling interval for all utilities and RTOs (Federal Energy Regulatory Commission 2011). The American Wind Energy Association and most wind facility owners are not supportive of Schedule 10 as many fear the costs would not be imposed fairly. As the rule would apply to all generators, natural gas trade associations are also unsupportive. Utilities and utility trade associations are generally supportive of all the recommendations, although some utilities express discomfort with 15-minute scheduling intervals.

In PJM, the issue of "lost opportunity costs" has recently been raised. Lost opportunity costs are allocated to generators that are curtailed for reliability reasons when they would normally have remained on-line due to their economics. PJM is working to equalize the rules under which wind plants receive such payments if they are in compliance with the operating agreement and following dispatch instructions. A recent proposal to increase the level of compensation from a facility's scheduled day-ahead position to the lesser of PJM's forecasted position or the facility's desired output was approved by PJM's Market Implementation Committee and will be filed with FERC at the end of 2011 (PJM 2011). Currently, wind facilities only receive lost opportunity cost payments to their day-ahead position (PJM 2011).

Other operating protocols are currently being designed in an attempt to be fairer to wind. Some recommendations regard the issue of cost causation and a desire to be certain that this is correctly assigned. While wind undoubtedly contributes to fossil cycling and imposes reserve costs wind generators' positive contribution to reserves is often neglected. This blurs the ability to accurately assign cost causation and may excessively penalize wind while ignoring its positive contributions. NREL recommends using a performance-based metric to capture both costs and contributions, e.g. calculation of wind's contribution to reserve levels as well as its own need for reserves (Milligan 2011).

Increase the Ability to Anticipate Wind Output

Accurately predicting day-ahead electricity load is vital to efficient electricity supply. Errors in forecasting cause under- or over-commitment of generating units which increases operating costs. Wind forecasting can never be perfect, but the better the expectation of wind output, the less re-dispatching needed to make way for it or cover for it. Improvements in short-term forecasts would reduce the impact on regulation requirements (National Renewable Energy Laboratory 2010) which is the most inefficient way to balance wind variability.

System operators must be able to measure the variability of the wind within time periods. A large balancing authority has an advantage because wind power forecasting error decreases as geographical area increases (Botterud 2011). Use of intra-hour markets allows the system to take advantage of changing forecasts and to incorporate that information in real-time dispatch decisions.

Wind forecasting is difficult due to the many variables that influence output. A facility may have various levels of output at a same forecasted wind speed depending on the number of turbines in service, the rate of change in wind speed, direction of wind and weather conditions. The key piece of information needed is how much output the wind facility will produce, i.e. where it will be on its power curve. This is another level of uncertainty, in addition to weather uncertainty, that is important when incorporating forecasts. In the ERCOT system, there is a tendency to under-forecast wind (Electric Reliability Council of Texas 2008).

Wind forecast data is one of the items FERC has proposed to require wind generators to provide public utility transmission providers to which they are interconnected. This includes site-specific information on, among other things: temperature, wind speed, wind direction and atmospheric pressure (Morgan Lewis 2011).

PJM's wind forecasting model is designed by Energy & Meteo, and uses a combination of several numerical weather models weighted according to the weather situation, site-specific power curves based on historical data, and a shorter-term model (0-10 hours) based on wind power measurements and numerical weather prediction. Wind turbine deration data is integrated in the forecast (Exeter Associates 2009).

The PJM tool includes four separate forecasts for different time periods. A long-term forecast provides hourly data from 48 hours ahead to 168 hours ahead. A medium-term forecast is updated from 6 hours ahead to 48 hours ahead. A short-term forecast is updated with a frequency of every 10 minutes using a forecast interval of 5 minutes for the next 6 hours. A ramp forecast is updated every 10 minutes at 5 minute intervals for the next 6 hours (Exeter Associates 2009).

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The cost of PJM's wind forecasting system is passed along via its tariff. This is common among other systems incorporating forecasts, but some RTOs charge the wind facilities themselves, e.g. NYISO (Exeter Associates 2009). As of September 2011, PJM was receiving good meteorological data from 55 percent of wind facilities in its territory and is working to improve that rate (PJM 2011).

Expand transmission

Transmission expansion is a necessity for successful wind integration. Transmission enhances the capacity value and thus capacity credit of wind generation (National Renewable Energy Laboratory 2010). This is because it would allow increased transmission of more high quality Midwestern wind with a higher capacity factor, including a higher peak load factor, to eastern markets. According to NERC "resolving transmission constraints is critical because larger balancing areas lose much of the benefits associated with size if constraints are in play (North American Electric Reliability Corporation 2011)."

More transmission would mean less wind is curtailed because there will be fewer constraints throughout the system. Without expanded transmission, wind facilities are also more likely to compete with each other to get on the system, defeating the intent of a renewable portfolio standard. Some believe that transmission expansion will comprise the largest cost component of wind integration (Kahn 2010).

FERC Order 1000 may encourage transmission development by expanding the traditional right to develop from public utility domain to include independent developers. As part of this order, FERC has required regional transmission operators to come up with a way to allocate the costs of new transmission to beneficiaries (Moser 2011). This means that PJM will be making such decisions for its region, which can be expected to be closely tied to the same decisions in the MISO. This is expected due to the fact that MISO wind is imported into the PJM system (PJM 2011).

The size of a transmission facility built to integrate wind should not be built to handle all the target wind generation at its maximum coincident output. Some wind can at times be curtailed more economically than building transmission that would be loaded only for a few coincident hours. Planning for some curtailment is thus likely to be more cost effective than designing a transmission system for the peak coincident output of all wind facilities (National Renewable Energy Laboratory 2010). Enhanced transmission will also facilitate the sharing of flexible supply and demand resources that can be used to accommodate wind energy (NERC 2010).

An example of a non-conventional transmission expansion plan is high-voltage DC lines (HVDC). An HVDC line would behave like a generator as it would have no load and would thus be fed into a receiving utility system like a merchant power plant. Current efforts to build HVDC lines are focused on delivering high-quality wind from Kansas and Oklahoma into the TVA system. To provide firm power an HVDC line would purchase ancillary services at an amount of about 10 percent of wind capacity (Glotfelty 2011).

The role of the FERC in deciding how integration costs are assigned is very important. Some of its recent recommendations for integrating variable generation are summarized below.

- Mandatory 15-minute transmission scheduling for all utilities and balancing authorities
- Expanded communication between wind facilities and transmission providers regarding facility output; this includes requiring wind facilities to provide wind forecasting data to utilities
- Allow utilities to charge wind facilities a wind-specific rate for regulation reserve capacity shown to be required because of wind
- Require RTOs (such as PJM) to come up with a way to allocate the costs of new transmission to beneficiaries

Conclusions

Current recommendations to integrate wind focus on methods of operating the system to ensure reliability and covering the costs of balancing the electricity delivery system to accommodate its variability. Integrating wind reliably is said to be a surmountable engineering challenge, but integrating wind efficiently has many more uncertainties.

The challenges of wind integration exist in multiple time periods, with second-to-second stability affects that could be resolved with modifications to on-turbine technology, minute-to-minute balancing affects that could be resolved with a combination of on-turbine technology and very fast-acting reserves, hour-to-hour load-following affects that could be resolved with ample supply of flexible generation and responsive load, and longer-term unit commitment affects that can be reduced through incorporation of reliable wind forecasting data.

Many of the recommendations to improve the efficiency of integration support the type of generating equipment and non-traditional resources that many have been advocating for decades, such as energy storage, modern transmission and demand-side management. Few strong recommendations are currently being made to alter the components in wind turbines in a way that would allow them to participate in the market like conventional generators.

There are ubiquitous recommendations to incentivize non-traditional electricity resources such as demand-side management and expand use of non-spinning resources as operating reserves, but there is much uncertainty regarding how extensively such resources could be utilized. NERC and RTO standards limit the frequency with which demand-side resources can be called upon and reliability standards govern use of non-spinning resources. Such standards may need to be changed to allow use of these resources in quantities large enough to support wind. NERC supports changing standards and has also proposed a new category of reserves called “tail event reserves” that could be used specifically to support wind and other variable resources.

Allocating to wind facilities the costs of operating reserves used to balance wind variability will make integration costs more transparent. However, due to the high level of interconnectedness in the system and the large number of generators already cycling in response to intra-hour market signals and to system imbalances caused by other fossil generators, and in spite of wind, there are issues of fairness when system costs are allocated specifically to wind.

In the near-term, the current non-wind generating mix is a very important determinant in how efficiently wind is utilized from day to day. Fossil fuel prices matter quite a bit because when natural gas prices are high coal plants have to cycle more to accommodate wind, especially in off-peak hours.

As wind penetration increases, the existing fleet of base load plants is likely to be forced to operate below their preferred levels of output more frequently than before. Wind is expected to displace conventional generation, but not at a megawatt per megawatt basis. As wind expands more generation capacity, or responsive load, will be needed to respond to more potential output fluctuation.

The process of moving toward better integration includes ongoing studies by all major ISOs, many other balancing authorities, utilities and NERC. This includes development of flexibility metrics that can be used to assess the adequacy of various flexible resources responding to real-time demand and supply conditions. It is recommended that balancing authorities coordinate their integration efforts, but most utilities and ISOs are pushing for the ability to develop unique solutions. ISOs such as PJM that have access to a wide range of services and are highly connected to other systems are in a good position to test response to various incentives and protocols.

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