NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC IVGTF Task 2.4 Report

Operating Practices, Procedures, and Tools

March 2011

to ensure the reliability of the bulk power system

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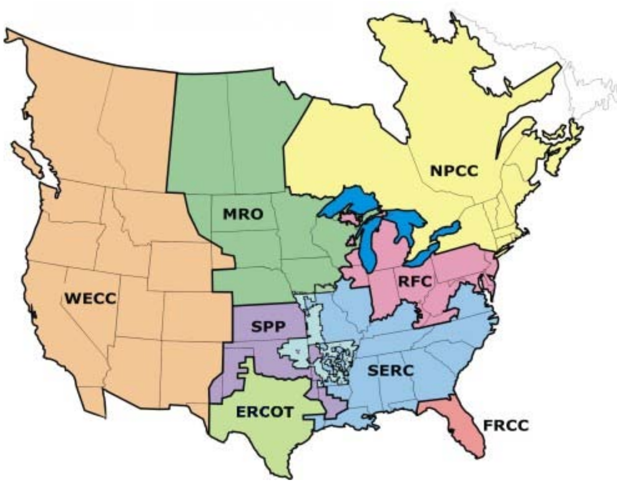
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority for reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports[2] on the reliability and adequacy of the North American bulk power system divided into the eight Regional Areas as shown on the map below (See Table A).[3] The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: *The highlighted area between SPP and SERC denotes overlapping Regional boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.*

Table A: NERC Regional Entities

FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP** Southwest Power Pool, Incorporated
NPCC Northeast Power Coordinating Council, Inc	**TRE** Texas Reliability Entity
RFC Reliability*First* Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro, making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have a framework in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

[2] Readers may refer to the *Reliability Concepts Used in this Report* Section for more information on NERC's reporting definitions and methods.

[3] Note ERCOT and SPP are tasked with performing reliability self-assessments as they are Regional planning and operating organizations. SPP-RE (SPP – Regional Entity) and TRE (Texas Regional Entity) are functional entities to whom NERC delegates certain compliance monitoring and enforcement authorities.

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1. Executive Summary

With the onset of the increase in the use of variable energy resources, NERC published its 2009 *Accommodating High Levels of Variable Generation* report,[4] which identified the importance of obtaining timely operational results to increase reliability to the system. The report discusses the impact of variable generation on power system operations and the need to modify operating practices, procedures and tools. The goals of this report are to address "*the impacts on commitment and/or dispatch along with reserve management practices*".

The described tools represent the industry's best practices to date and, going forward, the best current source to identify general requirements of advanced operator tools. There are significant differences in the actual scope and implementation of the individual operator tools, which can be mainly attributed to the differences in the systems and associated markets for which the tools were developed. Some of the tools are intended to provide comprehensive information about existing system operating conditions and expected short-term changes, so that the operator can decide the most appropriate control action. These operator tools include additional visualization displays and calculation of system performance metrics for determining what measures should be undertaken to mitigate possible adverse effects. The following is a preview to these tools and objectives.

Alberta Electric System Operator, AESO developed a Dispatch Decision Simulation Tool (DDST) that continues to be tested and validated in actual system operations. The DDST provides the operator with visualization of existing system status, upcoming system changes, and the impact on system area control error (ACE) and ramping capability for variations in forecast or implementation of mitigating strategies. DDST is used to support operators' decision-making processes as one component of a complex arrangement of systems, tools and procedures required to efficiently operate the market and ensure reliable operation.

Bonneville Power Administration, BPA developed the operational protocols, specified in its Dispatcher Standing Order (DSO) 216, that provide for a semi-automated mechanism for holding wind generators to their schedules when large imbalances occur. BPA initiated the implementation of Phase II of this effort, in which its Automatic Generation Control (AGC) system was augmented to directly send generation output limit alarms and notifications to each wind plant. The objective is for all wind plants to take necessary action to either curtail their over-generation when balancing reserves are near depletion, or limit their transmission schedule (E-tag) to the amount of the power being generated when incremental balancing reserves are near depletion.

Electric Reliability Council of Texas, ERCOT has developed an improved wind-ramp forecasting algorithm and associated visualization tool called the ERCOT Large Ramp Alert System (ELRAS). ELRAS provides operators with the probability that a ramp event of increasing amplitude may occur over three time periods: 15 minutes, 1 hour, and 3 hours. The tool shows conventional weather graphics to provide additional situational awareness and ramp specific information to the operator, including insights into the

[4] http://www.nerc.com/files/Special%20Report%20-%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf

underlying weather regimes that are likely to cause the ramp event and details on the characteristics of the forecasted ramp event. In addition, ERCOT has also developed its Market Analyst Interface (MAI) tool for assisting ERCOT system operators in detecting possible insufficiencies for both capacity and balancing energy bids during upcoming hours. The MAI tool uses the expected wind output, online generation, and the load forecast to determine if sufficient available capacity and balancing energy exist.

Apart from the described operator tools, ERCOT is currently developing a risk-based reliability assessment tool. The objective of the tool is to evaluate the reliability risk level in a quantitative way (loss-of-load risk) in real-time by using probabilistic methods and to provide usable advice to the operator when additional resources are needed to maintain operational reliability. The risk-based reliability assessment tool will consider unit forced outage rates, as well as wind and load forecast uncertainty.

The underlying principle of these tool developments is to improve operator situational awareness, provide operators with an evaluation of events likely to occur and their impact on the system, and provide operators with guidance on the effectiveness of possible mitigating measures. The following describes an operator decision-making support tools describing how variable energy resources are managed.

Situational awareness

- Aggregating data on current system status from various sources including EMS/SCADA, load and variable generation forecast systems, and operational planning and/or market results identifying available resources to provide succinct, meaningful displays that support situational awareness.

Real-time reliability/risk assessment

- Evaluation of various dimensions of risk associated with the present and future operating conditions considering elements such as total ramping capability from available resources (supply and demand) and the uncertainty in unit availability, load, and variable generation.

Operator decision support

- Evaluation and recommendation of mitigating actions that can be implemented to solve predicted or realized reliability/security concerns.

2. Introduction

> ***This report addresses Task 2-4 of the IVGTF report work plan:***
>
> *With high levels of variable generation, existing operating practices in unit commitment and/or dispatch along with reserve management will need to change in order to maintain bulk power system reliability. For example, probabilistic methods may be needed to forecast uncertainty in wind plant output and be included in the operations planning process. The Committee should, further, increase the awareness of these needs through established NERC programs and/or initiatives.*

A combination of public policy, incentives and economics is driving a rapid growth of variable generation in the electric power system. The majority of states/provinces now have renewable portfolio standards, with many requiring over 20 percent of electricity energy sales be generated by renewable energy sources within the next five to fifteen years. The majority of these requirements will be addressed by adding significant amounts of wind and solar energy to the bulk power system. There is already over 39 GW of wind plant capacity installed in the U.S. and Canada.

Wind and solar power plants exhibit greater variability and uncertainty because of the nature of their "fuel" sources. This adds to the variability and uncertainty the power system must already deal with from load and conventional generation. Variable generation includes more than wind and solar resources: both established types like run-of-river hydro and emerging technologies, such as wave energy. While the majority of attention in this report is on wind and solar generation, most technologies of variable generation share similar characteristics (though to a different extent) since the variability is largely driven by weather or other hard to predict phenomena.

Improved operating practices, procedures and tools are critical to integrate variable generation into the power system, as well as improve the control performance and reliability characteristics of the power system. System resources supporting reliability, such as flexible generation and responsive load, are finite. Operating practices, procedures, and tools that maximize the effective use of limited responsive resources improve reliability and facilitate variable generation integration.

This report focuses on the operating timeframe – from the next 48 hours to real-time. The report examines three categories of operations activities that support reliability: *prepare, observe, and act*. These three categories are roughly chronological with preparation occurring first, followed by observation and action when required. The categories are not mutually exclusive: many practices, procedures, and tools useful in preparing for operations are also used to observe and/or to act.

There also is interaction between these three categories. For example, robust preparation can reduce the burden for required action to some extent, and enhanced observation can facilitate selection of the appropriate action. Therefore, the framework provides a useful structure to discuss variable generation integration in balance with bulk power system reliability.

This report discusses operational and market system impacts, provides background on what can be realistically expected from variable generation, and proposes recommendations for power system operations. The report focuses on wind resources, since it is currently the most advanced with over 39,000 MW deployed in the North America. Similar operating practices and integration approaches are also likely to apply to other variable generation resources as well.

3. Prepare, Observe/Analyze, and Act

Operation involves three roughly sequential sets of activities: *prepare, observe/analyze, and act.* Preparation involves predicting expected future conditions and arranging for sufficient resources to support reliable operations. Observation and analysis involves monitoring the power system in real-time to assure that conditions are as expected. Action is required both to implement the prepared operating plan and to respond to observed conditions that differ from the expected and that threaten reliability. All three require a good deal of ongoing analysis. Some of the analytical tools are common to all three activities.

3.1 Prepare

Preparing for actual real-time operations could include the full array of planning functions including generation and transmission capacity expansion but here we are limiting the discussion to the operating environment: roughly 48 hours prior to and through real-time. Preparation involves forecasting expected future conditions for load and for variable generation, determining what resources and reserves are required, scheduling generation to meet load, scheduling reliability resources, screening for possible contingencies, resolving transmission congestion problems, arranging interchanges and cooperative activities with neighbors, and training.

Preparation itself involves both analysis and action. Regions differ in how structured the process is and how formal it needs to be. Regions with simpler operating environments, for example smaller balancing authorities (BAs) with fewer or more flexible generators, may not require elaborate processes to assure reliability. A relatively simple day-ahead assessment may find that the same selection of resources from the available mix that is required to meet the next day's peak demand and energy requirements may also provide adequate flexibility and reserves. BAs with a complex resource mix may require more formal unit commitment processes to assure adequate energy supply, reserves, and operating flexibility. Increased amounts of variable generation may increase the need for flexible resources to respond to the variability and uncertainty, and increase the need to formalize the analysis process.

3.1.1 Forecasting

Variable generation forecasting in the operational time frame is fully covered under the NERC IVGTF Task 2.1 report: *Variable Generation Power Forecasting for Operations*.[1] Day-ahead load forecasting is the basis for selecting which generators will be operated to meet the energy and reliability reserve requirements. Variable energy resources (VER) increase the net-load uncertainty and require additional forecasting tools. The IVGTF Task 2.1 report concluded that significant benefits are available with good wind power forecasts, even if the forecasts are not perfect. The magnitude of the benefit, and specific forecasting requirements, are dependent upon the degree to which the forecast can facilitate a more economic dispatch relative to the present mechanisms.

1. Aggregate forecast accuracy improves with the size of the region forecast and aggregation across broad geographical regions can significantly reduce output variability and associated operating reserve requirements. In general, the aggregate uncertainty should

also be mitigated by such aggregation, but the uncertainty and impacts from rare events may require more consideration.

2. Large system or market size and system flexibility improves the operator's ability to deal with variability.
3. Methods for clear and efficient prioritization of renewable resources during curtailment conditions are important for both reliability and economics. For example regions should evaluate adding negative curtailment pricing to their dispatch algorithms to encourage logical and efficient responses from all resources. Regions should also evaluate tools to manage over-generation conditions by ensuring sufficient system flexibility remains available to manage load and resources when non-dispatchable resources crowd out dispatchable resources.
4. Variable generation power forecasts in multiple time frames are critical for both maintaining system reliability and economic operation.
5. At any given point in time, the value of the forecast will depend on the operating state of the bulk power system.
6. The accurate forecasting of ramp events potentially represents a significant challenge for power system reliability with respect to the integration of variable generation, although because the variability remains even when uncertainty is reduced, work toward improved forecasting must be balanced with improvements in system operations and flexibility.
7. The relative value of ramp forecasts will depend on the system posture. Uncertainty values surrounding the forecast can be adjusted to best suit the needs of the system operator.
8. Electrical (power, availability, curtailment) and meteorological data from wind and solar plants, delivered to the forecaster and system operator on a timely and reliable basis, are critical for forecast accuracy.

The IVGTF Task 2.1 report also indicated that the value of wind plant output forecasting has been explored and quantified in a number of wind integration studies. A 2005 New York State Energy Research and Development Authority (NYSERDA) sponsored study conducted for the New York Independent System Operator (NYISO) by General Electric (GE) examined a future New York system with 10 percent wind by capacity (3,300 MW of wind on a 33,000 MW peak load system). The study found that a state-of-the-art wind plant output forecast could provide 79 percent of the benefit of a perfect forecast. Failing to consider the wind power forecast in the unit commitment leads to an over-commitment of fossil generation and inefficient use of that capacity. Similar findings were obtained in another study by GE for the California Energy Commission in 2007. [2] For a future high penetration scenario for California (30 percent of energy from renewable generation, mostly wind), the state-of-the-art forecast provided 82 percent of the benefit of a perfect forecast. When the wind plant forecast is included in the Reliability Unit Commitment, system reliability is increased through the identification of the additional reserves needed to manage the additional uncertainty due to the wind power.

In addition, the value of accurate wind forecasts is realized in Germany, where the Transmission System Operators (TSOs) are required to pay for the balancing reserves needed to compensate for unpredicted variations of their share of wind power production. They normally use several forecasting services at the same time (*e.g.*, 10 services at Amprion GmbH), and use a weighted sum of these forecasts adjusted to observed weather patterns. As a result, the day-ahead wind power production forecast root mean square error goes below 4.5 percent.

3.1.2 Reserve Requirements

Reserves are required to maintain the generation/load balance and to compensate for the variability and uncertainty of load (regulation, load following, and forecast uncertainty), forced outages of conventional generation (contingency reserves), and variable generation. Regions differ in their reserve definitions and their reserve requirements but they all share some fundamental characteristics. Table 1 provides reserve descriptions that are reasonably consistent across North America, while Table 2 provides reserve descriptions based on European terminology with two North American RTOs included for comparison. Detailed reserve requirements are provided in Appendix A. The largest conceptual difference between North American and European reserve definitions is that contingency reserves are explicitly defined in North America while they are not in Europe, where all reserves are used to respond to all imbalances. Reserves are distinguished by the response speed with faster reserves typically being scarcer.

Table 3 lists relevant definitions from the NERC *Glossary of Terms Used in Reliability Standards*. [3] The definitions are somewhat overlapping and not completely consistent or precise. The term "Load Following" is not defined in the NERC Glossary, but it is generally understood to mean the adjustment of generation and responsive load over periods of several minutes to hours to compensate for changes in net demand. Generation movement in the load following time frame typically includes consideration of economic-dispatch commands from the balancing area energy management system (EMS) based on short-term demand forecasts, unit commitment and dispatch. Five minute scheduling intervals are common with generation clearing points established two or three intervals prior. [4]

Regulation service requires a commitment on the part of resources to respond in a faster time frame. Since regulation may involve both increases and decreases in power output, a regulating unit can be required to leave capacity both up and down and, due to the faster response time, must allow their units to be moved automatically by the system operator. The dispatch of units for regulation is often based on response rates rather than strictly on economics. Consequently, analysis of current market operation reveals that regulation can be quite expensive [5]. Conversely, dispatch of units in the load following time frame can be obtained in response to sub-hourly economic scheduling of generation, and therefore is less expensive. However, the distinction between load following and regulation may be affected with large amounts of variable generation, particularly if periods of production and variability are correlated between sites. Historically, demand changes in the load following time period followed relatively easy-to-forecast directional trends, i.e., increasing in the morning and decreasing in the evening. With the addition of a large amount of variable generation, the net load (demand minus unscheduled energy production) can change the periods of maximum net load, for example a large PV penetration can shift the daily peak downwards. Large amounts of variable generation which are correlated in output, such as concentrated areas of wind production, combined with short-term forecast error can introduce a greater variability within the time period typically considered load following, requiring economic dispatch in both directions, up and down, and making optimization of the unit commitment more challenging.

Table 1: North American Reserve Descriptions [6]

Service Description					
Service	**Response Speed**	**Duration**	**Cycle Time**	**Market Cycle**	**Price Range* (average/max) $/MW-hr**
Normal Conditions					
Regulating Reserve	Online resources, on automatic generation control (AGC) that can respond rapidly to AGC requests for up and down movements; used to track the minute-to-minute fluctuations in system load and to correct for unintended fluctuations in generator output to comply with NERC's Control Performance Standards (CPSs) Reliability Standard.				
	~1 min	**Minutes**	**Minutes**	**Hourly**	**33-60* 300-600**
Load Following or Fast Energy Markets and	Similar to regulation but slower. Bridges between the regulation service and the hourly energy markets.				
	~5-10 minutes	**5 min to hours**	**5 min to hours**	**Hourly**	
Contingency Conditions					
Spinning Reserve	Online generation, synchronized to the grid, that can begin to increase output immediately in response to a major generator or transmission outage and can reach full output within 10 minutes to comply with NERC's Disturbance Control Standard (F)				
	Seconds to <10 min	**10 to 120 min**	**Hours to Days**	**Hourly**	**6-27 70-2000**
Non-Spinning Reserve	Same as spinning reserve, but need not respond immediately; resources can be offline but still must be capable of reaching full output within the required 10 minutes				
	<10 min	**10 to 120 min**	**Hours to Days**	**Hourly**	**1-3 60-400**
Replacement or Supplemental Reserve	Supplemental reserve is used to restore spinning and non-spinning reserves to their pre-contingency status; it must have a 30-60 minutes response time.				
	<30 min	**2 hours**	**Hours to Days**	**Hourly**	**1-4 2-36**
Other Services					
Voltage Control	The injection or absorption of reactive power to maintain transmission-system voltages within required ranges.				
	Seconds	**Seconds**	**Continuous**	**Year(s)**	**$0-$4/kVar-yr**
Black Start	Generation, in the correct location, that is able to start itself without support from the grid and which has sufficient real and reactive capability and control to be useful in energizing pieces of the transmission system and starting additional generators.				
	Minutes	**Hours**	**Months to Years**	**Year(s)**	

***** Up and down regulation prices for California and ERCOT are combined to facilitate comparison with the full-range prices of New York

Table 2 European Reserves and Sample North American Designations. [Adapted from References 7 & 8]

<table>
<tr><th></th><th>Primary Frequency Control Reserves</th><th>Secondary Frequency Control Reserves</th><th colspan="9">Tertiary Frequency Control Reserves</th></tr>
<tr><td rowspan="2">PJM</td><td rowspan="2">Frequency Response</td><td colspan="8">Operating Reserve</td><td rowspan="2" colspan="2">Reserve beyond 30 minutes</td></tr>
<tr><td>Regulation</td><td colspan="3">Spinning Reserve</td><td colspan="4">Quick Start Reserve</td></tr>
<tr><td rowspan="3">CAISO</td><td rowspan="3">Spinning Reserve</td><td colspan="7">Operating Reserves</td><td rowspan="3" colspan="3">Replacement Reserve and Supplemental Energy</td></tr>
<tr><td>Regulation</td><td colspan="6">Contingency Reserves</td></tr>
<tr><td colspan="2">Spinning Reserve</td><td colspan="5">Non-Spinning Reserve</td></tr>
<tr><td>Germany</td><td>Primary Reserve</td><td>Secondary Reserve</td><td colspan="6">Minutes Reserve</td><td colspan="3">Hours Reserve and Emergency Reserve</td></tr>
<tr><td rowspan="2">France</td><td rowspan="2">Primary Reserve</td><td rowspan="2">Secondary Reserve</td><td colspan="9">Tertiary Reserve</td></tr>
<tr><td colspan="4">Rapid 15 Minute Reserve</td><td colspan="5">Complementary 30 Minute Reserve</td></tr>
<tr><td>Spain, Netherlands, Belgium</td><td>Primary Reserve</td><td>Secondary Reserve</td><td colspan="9">Tertiary Reserve</td></tr>
<tr><td rowspan="2">Great Britain</td><td>Operating Reserve</td><td rowspan="2">(does not exist)</td><td colspan="5">Operating Reserve</td><td colspan="4">Contingency Reserve</td></tr>
<tr><td>Response Primary/Secondary High Frequency</td><td colspan="2">Regulating Reserve</td><td colspan="3">Standing Reserve</td><td colspan="3">Fast Start</td><td>Warming and Hot Standby</td></tr>
<tr><td>Sweden</td><td>Frequency Reserve and Disturbance Reserve</td><td>(does not exist)</td><td colspan="9">Seven different types of reserves</td></tr>
<tr><td>Australia</td><td>Contingency Reserve Fast/Slow/Delayed</td><td>Regulating Service and Network Loading Control</td><td colspan="9">Short -Term Capacity Reserve</td></tr>
<tr><td>New Zealand</td><td>Instantaneous Reserve Fast/Sustained Over Frequency</td><td>Frequency Regulating Reserve</td><td colspan="9">(No name)</td></tr>
</table>

Table 3: Operating reserve definitions from NERC Glossary of Terms. [3]

Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)

Contingency Reserves

The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

Operating Reserves

That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

Operating Reserves-Spinning

The portion of Operating Reserve consisting of:

Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or

Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Operating Reserves-Supplemental

The portion of Operating Reserve consisting of:

Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the disturbance recovery period following the contingency event; or

Load fully removable from the system within the disturbance recovery period following the contingency event.

The aggregate impact on system balancing on a fast time scale (minute-to-minute) due to variability from wind generation can be mitigated to some extent by geographic diversity. Large aggregations of geographically dispersed wind generation have relatively little correlated minute-to-minute variability. Analysis of high speed wind generation data shows that a typical 100 MW wind plant exhibits a minute-to-minute variability of about 1 MW (as measured by the standard deviation of these variations), and that they are uncorrelated with the variations of other wind plants. [9] Actual CAISO 1-minute load and wind data for May 2010 showed that the load varied between 18,918 MW and 29,437 MW while wind production varied between 13 MW to 1,706 MW. An analysis of the wind data showed the minute-to-minute variability ranged between -114 MW and 100 MW. As shown in Figure 1, the profile of the minute-to-minute wind variation mimics a normal distribution curve with a standard deviation of 6.31 MW.

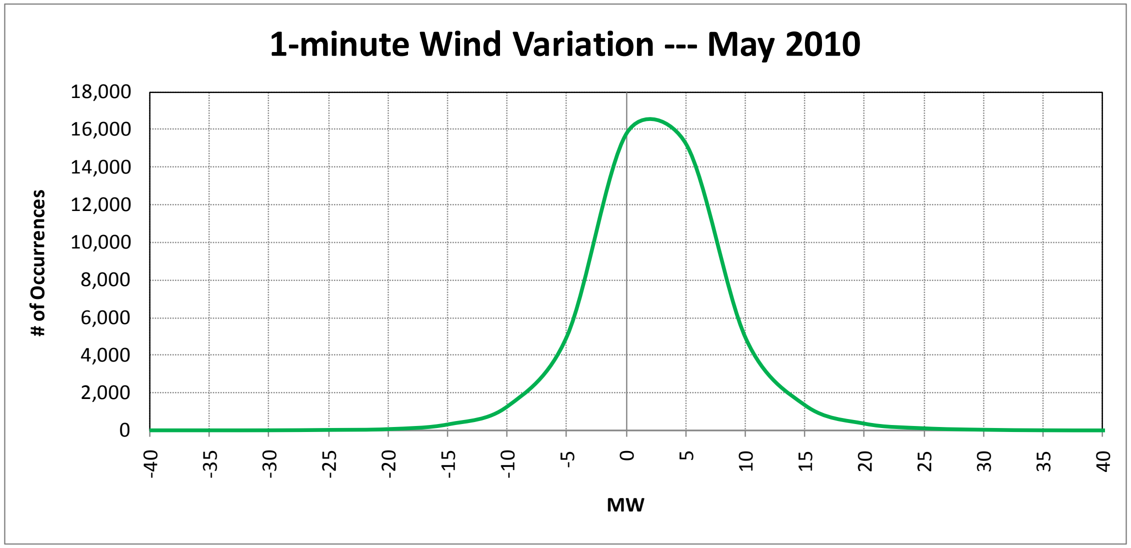

Figure 1: Distribution of 1-minute wind variability for May 2010

Similarly, the minute-to-minute load variability ranged between -386 MW and 384 MW and the load-wind variability ranged between -385 MW to 375 MW. As shown in Figure 2, the profile of the minute-to-minute load variation (red dashed curve) also mimics a normal distribution with a standard deviation of 31.7 MW. Also shown in Figure 2 is the profile of the minute-to-minute load-wind variation (blue dotted curve) which also mimics a normal distribution curve with a standard deviation of 31.77 MW. Numeric results are presented in Table 4.

The formula for a typical normal distribution function is:

$$PDF_N(\varepsilon) = \frac{1}{\sqrt{2\pi\sigma^2}} e^{-\frac{1}{2}\left(\frac{\varepsilon-\varepsilon_0}{\sigma}\right)^2}, \quad -\infty \le \varepsilon \le +\infty$$

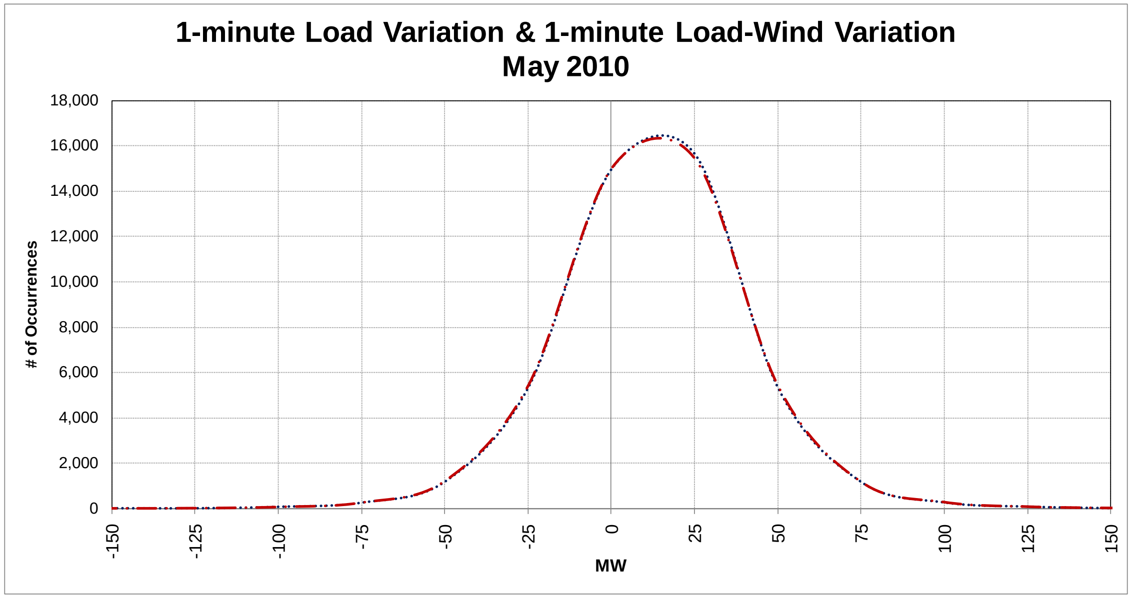

Figure 2: Distribution of 1-minute load and load-wind variability for May 2010

Table 4 Summary of statistical minute-to-minute variability of load, wind and load-wind

	1-minute Load Deltas (MW)	1-minute Wind Deltas (MW)	1-minute Load-Wind Delta (MW)
Average	0.02	0.01	0.01
Minimum	-386	-114.48	-385
Maximum	384	100.06	375
Standard Deviation	31.70	6.31	31.77

As the calculations and data show, the effect of the fast variations in aggregate wind production is negligible. Regulation requirements from wind uncertainty have a larger impact over the sub-hourly and hourly time frames. Note that a BA’s regulation capacity requirement is also driven by short-term forecast errors, scheduling practice, uninstructed deviations of conventional resources from their set-points and deviations of interchange flows from their schedules.

The actual impact will be dependent upon the characteristics of the source energy resource (wind or solar energy), geographic dispersion of the variable resources, and size of balancing area. Small balancing areas that are isolated or with limited interchange capability may experience a significant impact on the regulation requirements on the fast time scale from variable generation, particularly if the resource is concentrated into a particular geographic location. This is the experience on the isolated power systems on the islands of Hawaii and Maui. [10]

3.1.3 Quantifying Reserve Requirements

Utilities have long experience in determining each type of reserve required to meet reliability metrics CPS1&2 and DCS. Uncertainty and variability in both load and conventional generation drive the reserve requirements. Analytical techniques for quantifying reserve requirements with high penetrations of variable renewable, especially wind, have been developed. [4,11,12]. Experience with the growing wind fleet both in Europe and North America has helped verify and refine those techniques.

3.1.3.1 Frequency Response and Inertia

Power systems must remain operable through faults and contingencies. In the dynamic stability time frame, there is no opportunity for operator actions to stabilize the system. The system must remain stable through the automated response of the equipment on the system. The immediate response to any power imbalance on the system is through the primary frequency response, historically provided by the inertial response and governor droop from synchronous generators and loads on the interconnection. The system operator must have the proper mix of generation resources online to ensure that the system can remain stable and operable through reasonably anticipated events.

Frequency response in North American interconnections has been declining for decades. NERC and FERC are actively working to understand and address the cause. Inverter interfaced generators (and motor drives) are inherently insensitive to frequency disturbances since they isolate the prime mover from the power system frequency. It is by displacing directly connected synchronous generators that inverter interfaced generation may reduce the power system's inherent inertia and frequency response. However, this issue has been taken up by a number of parties and addressed to a significant degree, specifically for wind turbines.

Inverter controls can be designed to deliberately respond to power system frequency disturbances, emulating inertia and/or mimicking governor response. Response can be very fast and accurate. Reducing generation in response to over frequency is straightforward. Increasing generation in response to under frequency disturbances is more difficult. For inertia emulation, the inverter must be capable of sustaining short duration over-currents and there must also be a short term source of extra energy. Extra energy can be temporarily extracted from the rotating mass of a modern wind turbine rotor or by operating at less than possible output for the available energy. Synthetic inertia from wind turbines is now commercially available. Synthetic inertia response from solar plants may be available in the future.[5] For under-frequency response in the governor-type timeframe variable generation must essentially be "pre-curtailed" in order to have access to energy of sufficient duration and magnitude.

[5] While solar photovoltaic generators do not inherently have a source of stored energy that could supply synthetic inertia storage might be added to the inverter's DC bus if this capability was found to be necessary. Other alternatives may be more attractive. Solar thermal plants have similar inertia characteristics as other conventional steam generators.

Each region or BA should analyze the dynamic performance for faults and contingencies, to ensure there remains adequate frequency response as the generation fleet changes. Additionally, some coordination with neighboring BAs may be required. As variable generation resources become a significant proportion of the online generation, it will be necessary for variable resources to contribute to system balancing and grid management in order to maintain system reliability. This will require additional technical and interconnection requirements. Section 3.3.4. (Controlling Variable Generation) provides some additional discussion about possible active power controls from variable generation resources. Interconnection requirements must be designed for the anticipated levels of variable generation resources. It can be challenging to justify the need for active power controls for projects connecting when the contribution of variable generation is relatively small for a given balancing area; but the aggregate impact of the anticipated variable generation levels must be considered as it is difficult to require retrofitting more sophisticated controls on existing resources.

3.1.3.2 Regulation and Load Following

Regulation and load following both compensate for variability and uncertainty of net load with regulation addressing variability within the shortest scheduling interval and load following addressing intra-hour to inter-hour variability as shown in Figure 3. Short term load forecasts are quite accurate. Conversely, sub-hourly forecasts of variable generation remain a challenge with present forecasting techniques. Persistence[6] is currently the best short term wind or solar forecast. [1] As a result, regulation requirements for load alone are dominated by short term variability with short term uncertainty being relatively unimportant. As alluded to by the analysis in section 3.1.2 for variable generation, the opposite is true: regulation requirements will be driven more by short-term uncertainty than by short-term variability. This is because short term load forecasts are quite good while persistence is currently the best short term wind or solar forecast.

Sub-hourly generation scheduling points are based on short-term forecasts of net load in an existing 5-minute scheduling environment, for example, the clearing point is based on projections of demand made 15 to 20 minutes before the interval. Participating units are instructed to move to cover the projected change in load; any difference between the forecast load and the actual load for the interval (assuming that all generating units follow dispatch instructions precisely) must be covered by regulation. The short-term aggregate forecasts of large amounts of load can be quite accurate resulting in little regulation required to cover the forecast error (regulation is required to cover load variability within the interval). Wind generation forecast errors (based on persistence forecasting) over these same time periods are less accurate. Errors in the short-term forecast of wind generation will therefore increase the requirement for regulation.

Adding significant amounts of VER increase the variability and uncertainty of net load. Regulating resources are required to compensate for changes in net load that are faster than the shortest scheduling interval. Therefore, systems and markets that operate

[6] Persistence is the assumption that the current output will be the future output, so a persistence schedule simply uses the current output value as the predicted value for the next time period.

closer to real-time should have improved forecasting accuracy and will be able to support more frequent generator schedule changes to deal with variability. For example, hour-ahead scheduling or markets accommodate variable generation better than day-ahead schedules, and sub-hourly scheduling and dispatching are even better. A coordinated series of regularly clearing markets, or the equivalent flexibility for scheduling and dispatching in a non-market system, provides the best ability for dispatchable resources to adjust to changing wind and solar conditions. [1] NYISO, MISO, PJM, ISO-NE, CAISO and ERCOT, for example, re-dispatch the entire bulk power system every 5-minutes, which lessens the variability of the wind resources from one dispatch interval to the next. The variability of wind output from one dispatch interval to the next would be far greater if the system was only re-dispatched once per hour.

Load following can be provided by sub-hourly and hourly scheduling of dispatchable resources. Regulation requires dedicated capacity to respond to variability and uncertainty in the sub-scheduling interval time frame. If there is insufficient capacity available to respond to the economic dispatch signals that provide load following additional flexible capacity must be made available.

Aggregation and diversity greatly reduce net load variability and uncertainty. With load alone, in practice, the normalized variability of larger aggregations of load (larger BAs) is much less than for smaller areas. The same phenomenon is observed with wind generation because of spatial and geographic diversity effects. In areas of the country where geographic diversity is not achieved significant following requirements[7] can result. As the number of turbines grows and the area over which they are installed expands, the aggregate variability and uncertainty declines.

[7] In the Bonneville Power Administration BAA, most wind generation is located in the Columbia River Gorge area, a relatively small area with good wind potential and access to transmission. BPA estimated a “perfect scheduling” following requirement of more than 10 percent of nameplate capacity. (+272.5/-290.5 on an installed fleet of 2,515 MW for the Summer of 2010).

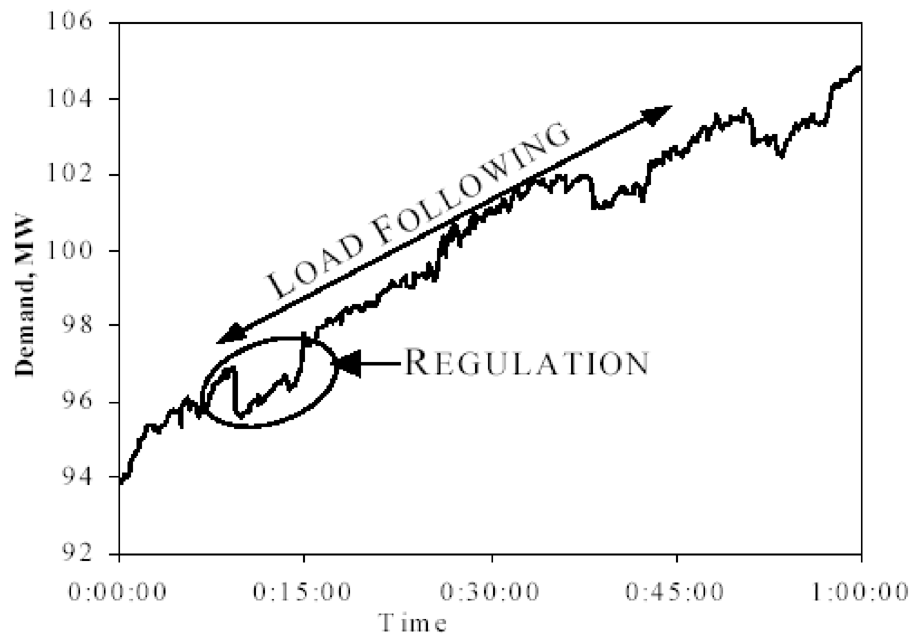

Figure 3: Depiction of regulation and load following characteristics of demand [4]

Methods are being developed to quantify regulation and load following requirements for systems with high wind penetration based on forecasted wind and load levels. [4] Wind variability varies based on the level of production at each wind plant relative to the power curve of the turbines. Variability is greatest when turbines are producing energy in the mid-point of the power curve as small changes in wind energy result in significant changes in output. There is less variability when there is low wind and there is less variability when wind is high and turbines are on the flat part of the production curve. (This excludes consideration of the rapid decline of wind energy that can occur at the high wind speed threshold, which results in rapid shut-down of turbines and may result in rapid start-up once the high wind speed event is over). Wind variability also declines as larger amounts of wind generation are aggregated together. Figure 4 shows both effects of aggregation and production levels.

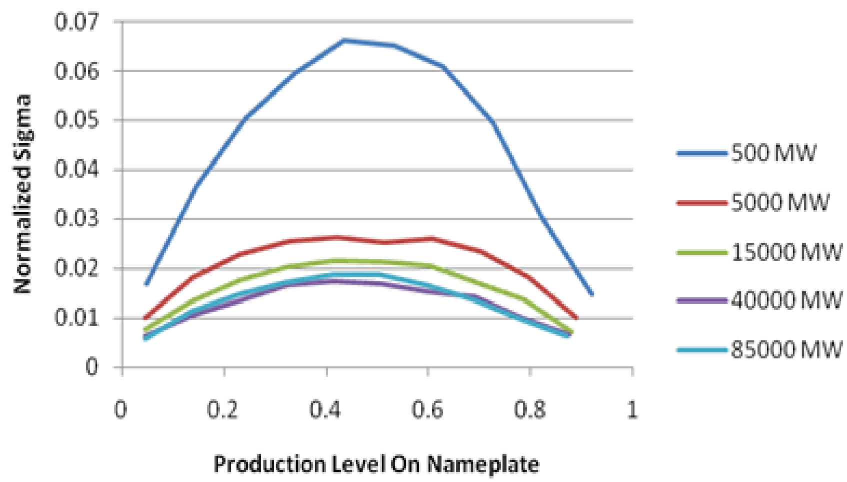

Figure 4: Normalized 10-minute variability for five different groups of wind generation. The 500 MW scenario is part of the 5000, which is part of the 15000, and so on. [4]

Time series data can be used to statistically characterize the short-term uncertainty of the BAs wind fleet. Aggregate ten-minute forecast errors can be plotted against aggregate wind production as shown in Figure 5. A curve can be fitted to the data providing a method for estimating the wind fleet regulation requirement based on current production level. The greater the amount of data the better the curve fit. The system regulation requirement is the statistical sum of the load and wind regulation requirements.

Uncertainty in the amount of wind generation to be delivered in the next hour has an effect on the load following requirements. A similar procedure to that used to characterize the very-short-term forecast errors can characterize the expected hour-ahead error for wind generation. The expected next-hour forecast errors exhibit characteristics similar to those of the very-short-term forecasts; the highest errors occur when the aggregate wind production is in the midrange of capability, and the errors decline for lower and higher production levels as shown in Figure 6.

Load following can be obtained from generation being economically dispatched. If there is insufficient generation capacity currently available on economic dispatch to respond to a reduction in wind generation output the shortfall could possibly be covered by additional spinning reserve, quick-start (non-spinning) generation, or demand response. All three of these reliability resources are typically more abundant and lower cost than regulating reserves.

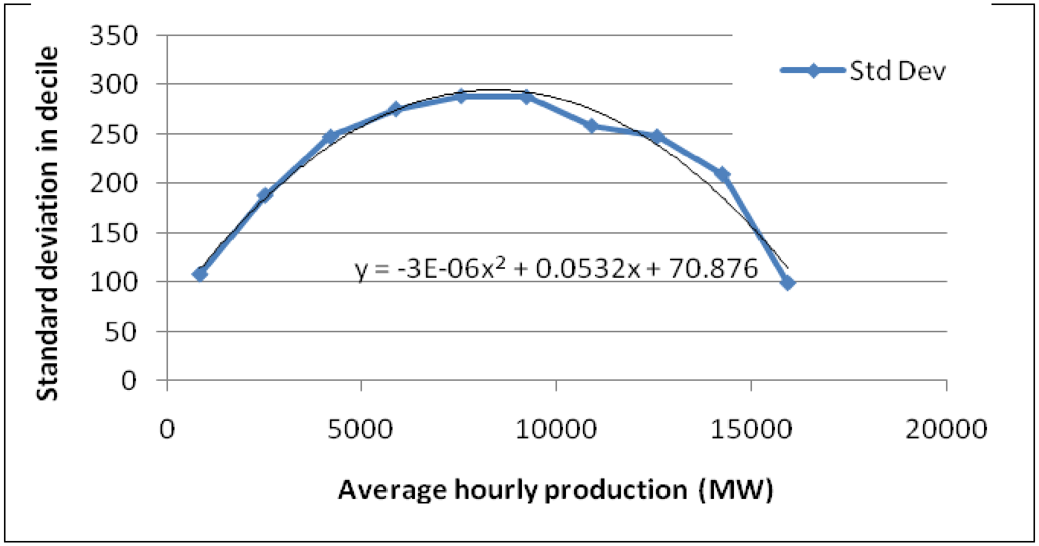

Figure 5: Illustration of short-term (ten minute ahead) wind generation forecast errors as a function of average hourly production [4]

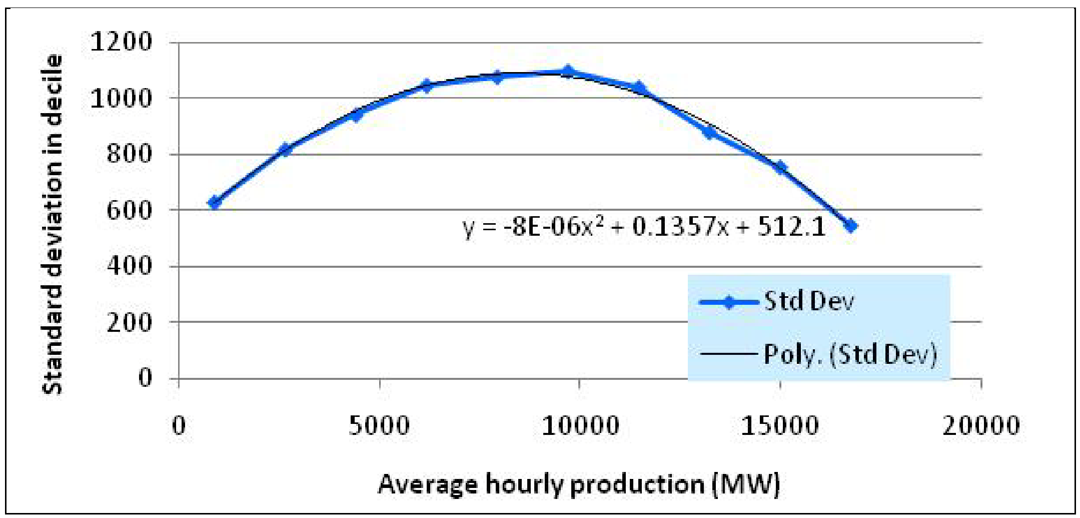

Figure 6: Standard deviation of 1-hour persistence forecast error [4]

If there is insufficient generation turndown reserve or export capability available on economic dispatch to respond to an increase in wind generation output, a possible solution is to curtail the wind generation in order to avoid excess energy production. Large, unexpected increases in aggregate wind generation are infrequent. Times when the dispatchable resource mix can not immediately accommodate the increase are rarer still. Infrequent, short curtailment of variable generation to avoid excess energy can be an effective and economic method to assure reliability and manage excess energy conditions, enabling a larger amount of variable generation to be installed to deliver energy during higher demand periods than if the variable generation were restricted to the amount the system could accept under the most restrictive minimum demand or export conditions.

A BA should monitor the availability of dispatchable generation and responsive load compared with the combined load ramping and wind uncertainty requirements. One strategy might be for the BA to assure that one standard deviation of hour-ahead aggregate wind variability was covered by economic response and two standard deviations are covered by spinning and non-spinning contingency-like reserves.

3.1.3.3 Contingency Reserve Requirements

Contingency reserve requirements differ from region to region but most are driven by the size of the largest generator, transmission facility, or credible event. Wind and solar generators are individually relatively small with interconnection transformers typically smaller than 200 MVA as shown by Figure 7. Consequently, VER currently have no impact on contingency reserve requirements as they are currently defined. Small BAs that are not part of a reserve sharing pool may have individual wind or solar plants that constitute a significant amount of generation (comparable to the size of the largest contingency event) and could impact contingency reserve requirements.

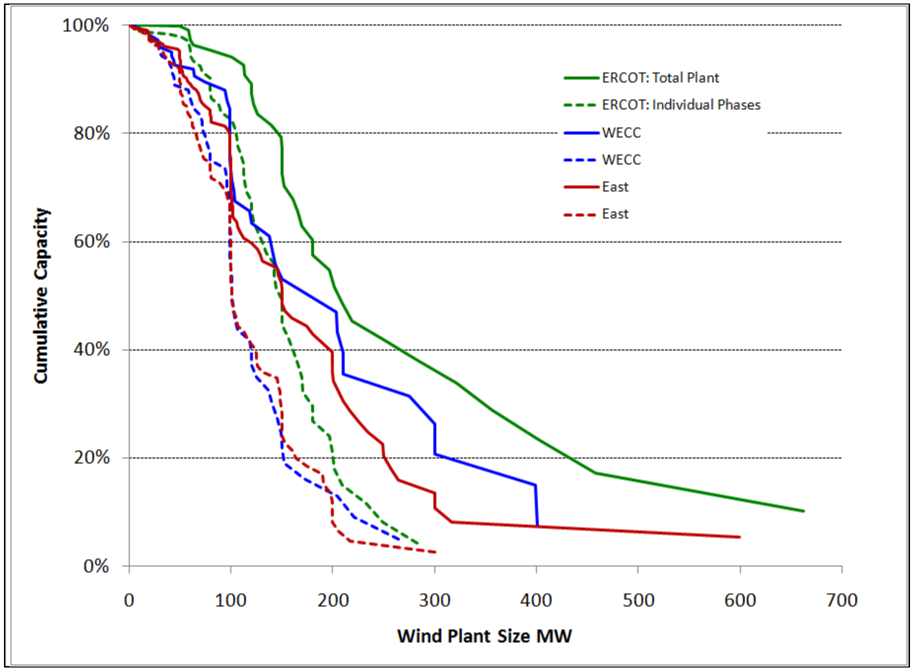

Figure 7: Individual wind plants are typically too small to impact contingency reserve requirements.

Another consideration can be aggregate loss of distributed resources during faults and contingencies. As penetration levels of distributed resources rise, the aggregate loss of these resources during off-normal frequency and voltage conditions can result in a significant contingency event, or can compound the system impact of existing severe contingencies. [13]

It may be desirable to evaluate if large wind and solar ramping events qualify as contingencies. The power system has benefited through reserve sharing and there may be an opportunity to further reduce costs while increasing reliability if contingency reserves can be used to respond to VER ramping events. The IVGTF Task 1-2 report on *Accurate Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* offers some insight as it discusses how high penetrations of variable generation can change the tails of the loss of load probability distribution. [14]

3.1.3.4 Voltage Support and Reactive Power Capability

Reactive power resources are as important as real power resources for maintaining power system reliability. As with real power, reactive power reserves are required that can respond to contingencies. Analysis is required to determine what dynamic and static reactive power resources are required to maintain voltages throughout the power system and to prevent voltage collapse. Because transmission system inductance is typically much greater than resistance, reactive power cannot be moved as far as real power and voltage support is a more localized problem. The system operator must monitor current conditions as well as the available reserves.

The FERC Large Generator Interconnection Agreement (LGIA), Appendix G, requires wind generators to be capable of supporting transmission system voltage by maintaining a power factor of 0.95 leading to 0.95 lagging (measured at the Point of Interconnection) if the Transmission Provider's System Impact Study shows that this is necessary to assure safety or reliability. [15] This requirement is similar to the reactive power support required from conventional generators. Wind generating plants are also required to remain in-service during three-phase faults with normal clearing (up to 9 cycles) and single line to ground faults with delayed clearing, unless clearing the fault effectively disconnects the generator from the system. This is a requirement that is not imposed on conventional generators.

ERCOT requires wind generators to be capable of producing reactive power equal to ±95 percent power factor at nameplate capacity [measured at the point of interconnection (POI)]. ERCOT establishes a voltage schedule that the generator must follow. The reactive power must be available at all MW output levels down to 10 percent of nameplate capacity and may be met by a combination of the generators themselves and/or dynamic VAR capable devices. When a wind-powered generation resource (WGR) is operating below 10 percent of its nameplate capacity and is unable to support voltage at the POI, ERCOT may require the wind generator to disconnect from the ERCOT System. [16]

In addition, ERCOT also has Voltage Ride-Through (VRT) requirements for wind generators. Wind generators are required to set generator voltage relays to remain in service during all transmission faults based on the plot shown in Figure 8 below. The applicability of this requirement is based the date of the signing of a Generation Interconnect Agreement [17].

3.1.4 Scheduling Resources to Meet Load and Supply Reserves

Once reserve requirements to meet net load (load net wind and solar generation) are established the system operator needs to assure that adequate resources will be available in real-time. Wide area security constrained unit commitment and economic dispatch enhances reliability by extracting the greatest responsiveness from a broad array of resources.

Large thermal generators require significant time to prepare to operate and, therefore, the unit commitment decision must be made a day or more in advance. The decision to start other generators can be made closer to real-time. In general, forecasting accuracy for load, wind, and solar improves closer to real-time. Improvements are also being made to ramp event forecasts. With access to current information of the power plant and the weather, forecasting errors are reduced for shorter periods ahead compared to periods further into the future. Therefore, systems and markets that operate closer to real-time have improved forecasting accuracy and support more frequent generator schedule changes to deal with variability. For example, hour-ahead scheduling or markets accommodate an overall dispatch that includes variable generation better than day-ahead schedules, and sub-hourly scheduling and dispatching are even better. A coordinated series of regularly clearing markets, or the equivalent flexibility for scheduling and dispatching in a non-market system, provides the best ability for conventional generation to adjust to changing wind and solar conditions. [1] Unit commitment decisions should be made as soon as required so that the selected generation can be brought on line but as late as possible to minimize forecast errors and to select the best mix of needed resources. Regulation and contingency reserves are explicitly procured or scheduled. Load following flexibility typically results from the economic unit commitment and dispatch. If additional resources are required to assure sufficient flexibility to meet reliability metrics (CPS1&2 and DCS) then the unit commitment process must be further constrained via the commitment of resources as reserves, non-economic dispatch or restrictions on output.

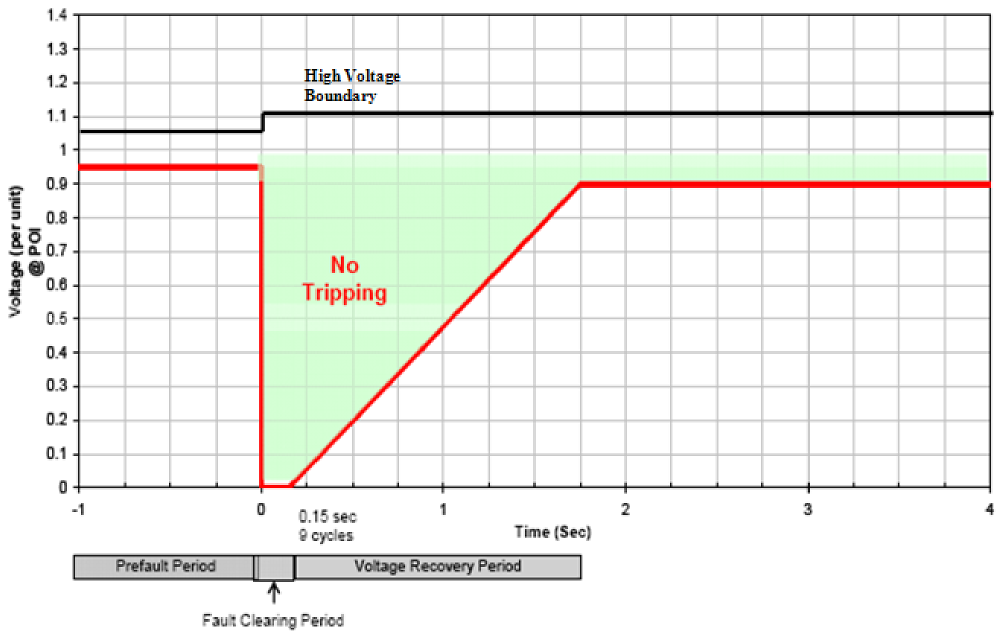

Figure 8: Voltage Ride-Through Boundaries for Wind-powered Generation Resources in ERCOT

The NYISO started operating a wind power forecasting program in June 2008 [18]. A day-ahead forecast is used for reliability and allows NYISO to consider the anticipated levels of wind power for the next operating day when making day-ahead unit commitment decisions. Forecasts are also used in NYISO's real-time security constrained dispatch. These forecasts are blended with persistence schedules, weighing more heavily on persistence schedules in the nearer commitment/dispatch intervals, and gradually shifting weight to the forecasts as the commitment intervals look farther out in time. [1]

3.1.5 Transactions with Neighbors

Transacting with neighboring BAs for energy supply and reserves can effectively reduce variability and uncertainty at the same time it increases the pool of responsive resources. Transactions can be for multi-hour blocks of energy or can be to dynamically share ACE or anything in between. The benefits of inter-BA transactions are further discussed in Section 3.3.2 and 3.3.3.

3.2 Observe/Analyze

The extent to which VER impacts power system operations strongly depends on the increased variability and the system's flexibility as well as the operators' ability to understand how to best use all of the available resources. The system operators' need to observe and analyze the power system increases with the addition of variable generation. The full complement of supervisory control and data acquisition (SCADA) and energy management system (EMS) tools is still required. Additional information is required from the variable generators themselves.

The system operator still needs to monitor the load and update the short term load forecast. The system operator needs to monitor voltages and flows on the transmission system and assure that reserves are adequate to deal with potential contingencies. State estimation and security constrained unit commitment and economic dispatch analysis continue to be valuable tools for assuring reliability. Variable generation must now be factored into all of this analysis. The increased variability increases the importance of monitoring real and reactive reserves and increases the value of automated analysis tools.

Two different types of additional information are required to maintain reliability while dealing with high penetrations of variable generation: weather related data and plant data. Both impact the variable generation output.

Short term wind and solar forecasts should be updated regularly. Some European system operators use multiple independent forecasts updated as often as every fifteen minutes (Appendix B) to provide an estimate of the aggregate wind fleet output. Centralized forecasts are more accurate. While most of the weather data comes from outside sources (satellites, radar, ground stations, etc.) meteorological data from the wind and solar plants themselves is also required. Providing the central forecaster with current conditions, including equipment status, at all the wind and solar plants improves the fleet forecast.

Weather situational awareness is a system to provide actionable severe weather alerts. These alerts can be provided in various forms, such as a web-based real-time system to enable operators to visualize and react to high wind events. An example is the high wind warning system based on a geographic information system platform that was developed for Xcel Energy in 2008. [19] Included in that system were U.S. Storm Prediction Center watches, warnings, and convective outlooks in both graphical and text format; high wind forecasts for winds exceeding 20 meters/second; and real-time color-coded high wind observations. Most importantly, operators should be able to quickly identify the amount of their variable generation that could be impacted by an extreme event.

Forecasting ramp events are particularly important and the subject of current research and development. [1] Large, infrequent ramp events on interconnected power systems (Figure 9) are similar to conventional contingency events except that the slow speed (multiple hours) and greater uncertainty of the outcome for the system operator (i.e. how long will the ramp continue, might the ramp change direction) may make ramp events ineligible to use reserves being held to cope with conventional contingencies[8]. The fastest ramp events typically occur as the result of high wind speed shutdown. A ramp forecast can tell the system operator when additional reserves are required or when they can be released, however, accurate forecasting of ramp events remains a challenge. Generally speaking, the larger and longer-lived the feature, the better it can be predicted.

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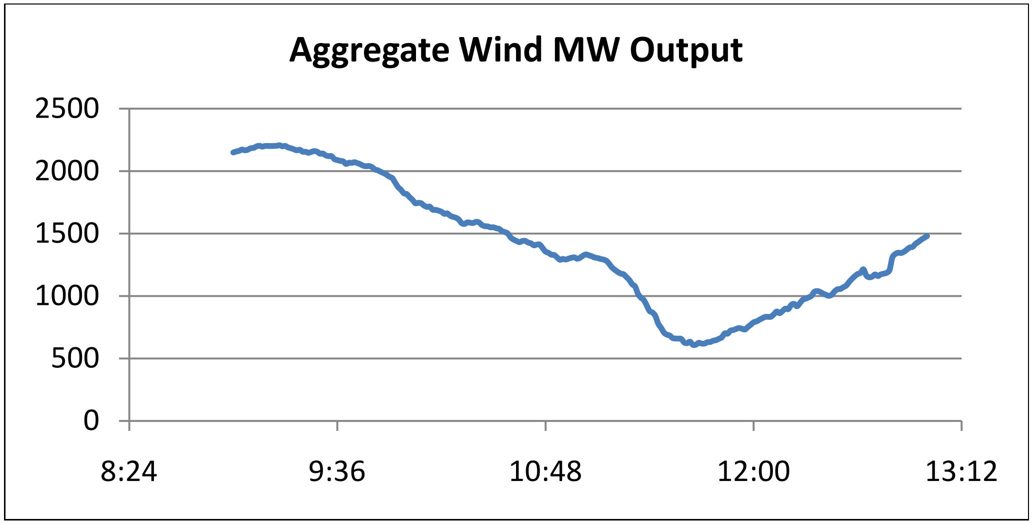


[8] These statements do not apply to smaller or island systems where a single 100 MW wind plant, for example, can present a fast ramp which is large for that power system.

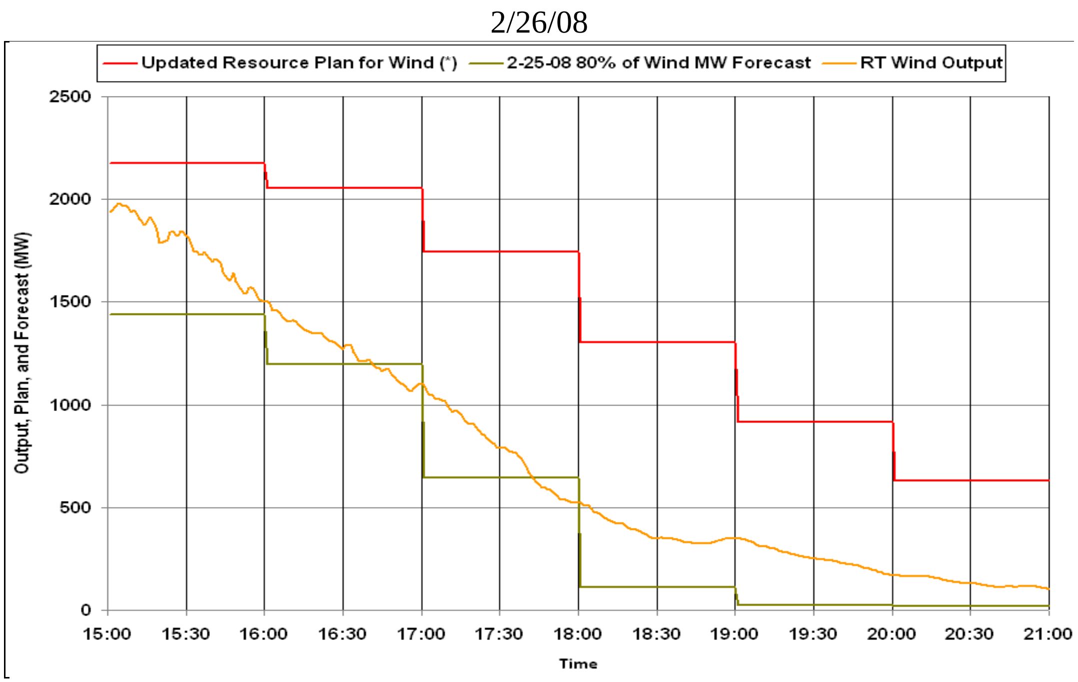


Figure 9: Large wind ramping events are much slower than conventional contingencies as shown by these two ERCOT plots with the loss of 1500 and 2000 MW of wind over two and four hours respectively. [20 & 21]

The system operator and the forecaster also need information on the current plant capabilities. Any wind turbines or solar panels that are out of service must be factored into the power production forecast that is based on the wind and solar forecasts. Without this information not only will the current power forecast be in error but the accuracy of future forecasts will be degraded. The system operator will not have an accurate estimation of the wind or solar plant's real and reactive capabilities. The data that should generally be considered a standard requirement for wind power forecasting would be the following: [1]

- meteorological information (wind speed, direction, temp, pressure, humidity)
- power output,
- wind turbine outage/availability information (including icing-related issues)

- plant curtailment information (including deployment instructions in MW and/or estimated MW output available if a current curtailment is lifted)

ERCOT requires wind plants to supply real-time SCADA data including:
- Net MW output
- Number of turbines available
- Estimated “un-curtailed” net MW output
- Wind speed
- Wind direction
- Barometric pressure
- Temperature

Similar requirements are imposed on wind resources in California, which participate in the California Participating Intermittent Resources Program (PIRP).

ERCOT requires each wind plant to provide an estimate of the current plant unconstrained output (Estimated “un-curtailed” net MW output) based upon the current wind and the currently available turbines. While this has no use when the plant is unconstrained (current plant output itself is a perfect “estimate”) it is important when wind output is curtailed because it provide the system operator with an estimate of what the generation will go to if the curtailment is released. By requiring the wind plant operator to supply the estimation during unconstrained times ERCOT and the wind plant operator get a verification of the forecast accuracy and, presumably, the estimation accuracy for each wind plant will rise as experience is gained.

Weather and turbulence forecasts need not be perfect to be useful and system operator’s experience will grow along with their ability to use forecasts to advantage. It may be more useful to view forecasting in terms of identifying periods of operational risk or uncertainty, so operators can take mitigating action under those conditions, instead of focusing on accuracy of forecasting. Regardless of the accuracy of the VER forecasting, if the information is not integrated into the operator control processes, little value will be derived. Hence, more integration of forecasts and forecast certainty with bulk power system reliability analysis tools is a growing need if operators are to receive warnings of reliability concerns in a more holistic way. [1]

3.2.1 Current experience with Advanced Visualization and Decision Supporting Tools

Several utilities and ISOs that are already integrating significant levels of wind generation have begun development of tools for aiding operators in making decision to mitigate the new levels of uncertainty and variability experienced on their systems. A description of a few of these ongoing efforts is provided in this section.

3.2.1.1 AESO Operator Tools for VER

AESO manages the Alberta Interconnected Electric System (AIES), which has a peak load of approximately 9,800 MW. The AIES is a relatively isolated system with limited interconnections to grids outside Alberta, and therefore a limited ability to share balancing services. The generation in the AESO system, is mainly large base-load coal-fired plants along with a significant amount of base-load cogeneration. Current wind capacity on the AESO system is approximately 500 MW with more than 12,900 MW of additional wind power projects in the AESO's interconnection queue. [22] The AESO facilitates Alberta's hourly wholesale electricity market in which generators submit day-ahead supply curve offers that are used to create the Energy Market Merit Order (EMMO). Wind generators are treated as a price taker supplying energy to the market at a $0 bid price. [23]

After conducting a number of analytical studies to identify operational impacts of integrating wind into their system, in 2007 the AESO developed and released the Market and Operational Framework (MOF) for Wind Integration. [24] The MOF provides guidance to the AESO and stakeholders regarding the necessary mitigating measures, obligations, and cost allocation procedures associated with wind integration. One of the key recommendations in the MOF was the development of new tools for the System Operator to incorporate wind forecasting into operational processes and effectively manage wind power ramp rates. [25]

To this end, the AESO has developed a working prototype of a wind-related operator tool called the Dispatch Decision Simulation Tool (DDST) that continues to be tested and validated in actual system operations. [26] The DDST aggregates wind power and load forecast information, present and potential future energy market merit order dispatches, and the remaining regulating reserves and load following (ramping) capability into a single operator dashboard. An example screen capture of the prototype dashboard is shown in Figure 10, where forecast system changes (wind, load, interchange) are shown in the right column, EMMO and market information are shown in the middle column, and system ramping and regulation performance/capability are shown in the left column. It is important to highlight that the DDST is not intended to replace operators by making decisions for them, but rather to assist operators in the decision-making process as one component of a complex arrangement of systems, tools and procedures required to efficiently operate the market and ensure reliable operation. [27]

The DDST provides the operator with visualization of existing system status and upcoming system changes as well as the impact on system ACE and ramping capability for variations in forecast or implementation of mitigating strategies. Figure 11 depicts the general architecture and logic of the DDST.

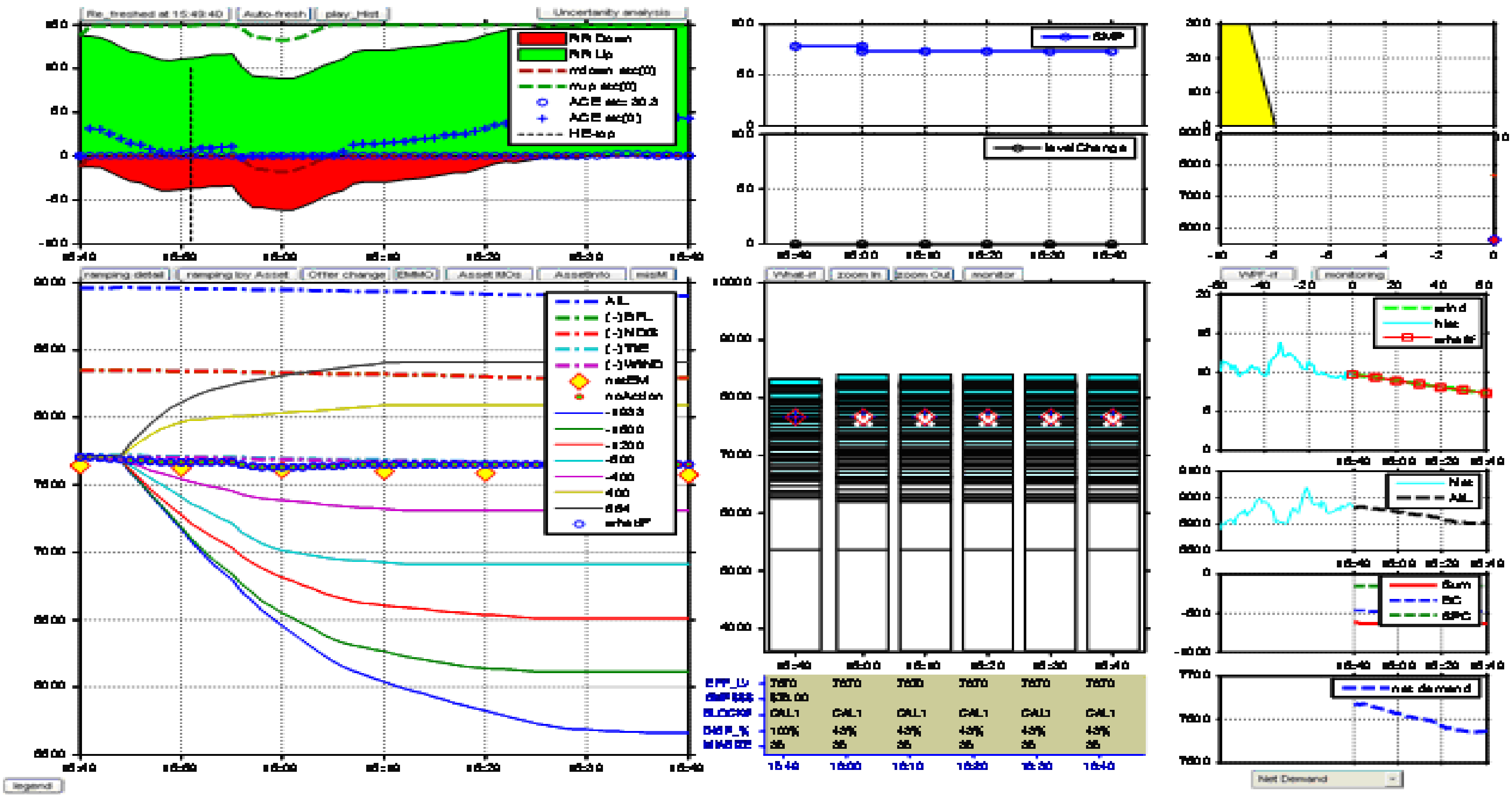


Figure 10: Screen Capture of AESO's Prototype DDST for Wind Integration

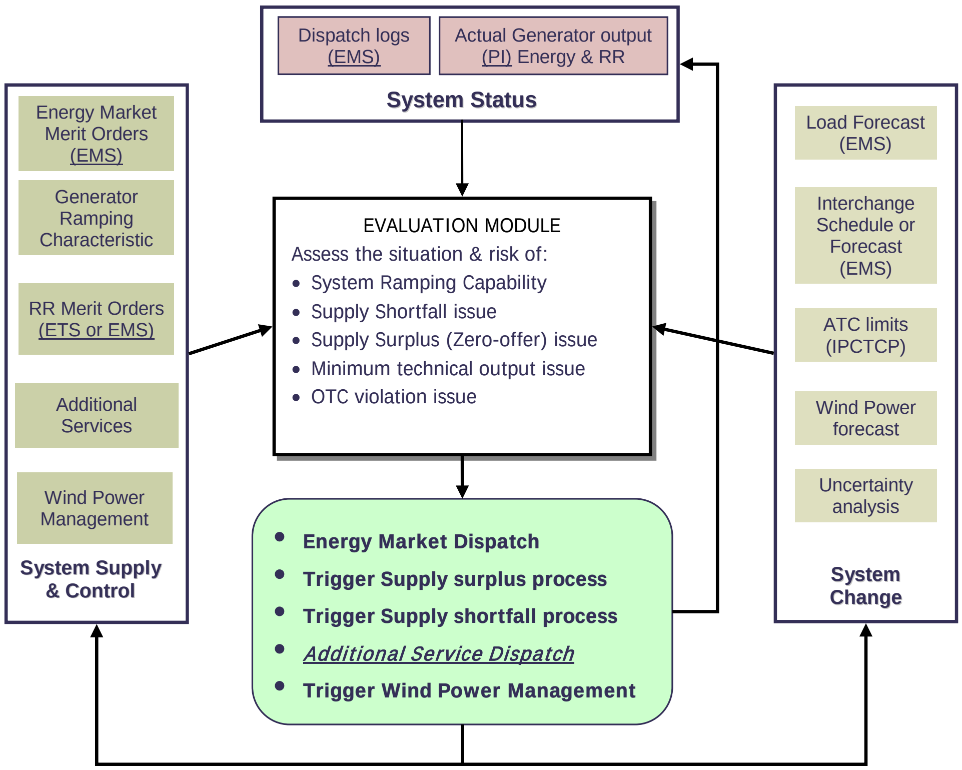


Figure 11: General Architecture of AESO's Prototype DDST for Wind Integration

As shown in this block diagram, the DDST evaluations are predicated on three types of input: system status, system changes, and system supply & control resource availability. The DDST uses these inputs to determine the net change ramp rate requirement and whether system surplus/shortfall conditions or operational violations are expected. Based on these evaluations, the operator can then use the DDST to conduct *"What If"* analyses to evaluate the effectiveness of using available resources to address operating concerns.

3.2.1.2 ERCOT Operator Tools for VER

ERCOT is the independent system operator of the power system covering 85 percent of the state of Texas's electric load. ERCOT's peak demand is approximately 62,500 MW. ERCOT has the highest installed wind capacity of any U.S. BA with approximately 8,300 MW installed as of April 2009 and another 50,000 MW in the interconnection queue. Most of this wind capacity is in west Texas. [28] The ERCOT power system is operated as a single BA, with no synchronous interconnections with other BAs.

ERCOT has developed an improved wind ramp forecasting approach and associated visualization tool for operators, known as the ERCOT Large Ramp Alert System (ELRAS). [29] A prototype ELRAS dashboard is shown in Figure 12, which shows ramp event probability of increasing amplitude occurring over three time periods – 15 minutes, 1 hour, and 3 hours. Figure 12 also shows conventional weather graphics to provide additional situational awareness to the operator. In addition to providing probabilities of a ramp occurrence, ELRAS provides ramp specific information to the operator, including insights into the underlying weather regimes that are likely to cause the ramp event and details on the characteristics of the forecasted ramp event. [30]

ERCOT has also developed its Market Analyst Interface (MAI) tool for assisting the ERCOT system operators to detect possible insufficiencies for both capacity and balancing energy bids during upcoming hours. The MAI uses the expected wind output, online generation, and the load forecast to determine if sufficient available capacity and balancing energy exist. The available capacity is calculated as the sum of the upper limits of all online generation, minus the load forecast minus any ancillary service obligations. The balancing energy requirement is estimated as the load forecast minus the summed planned MW from online generators. Based on these calculations, the system operator may take actions to alleviate any deficiencies. [31]

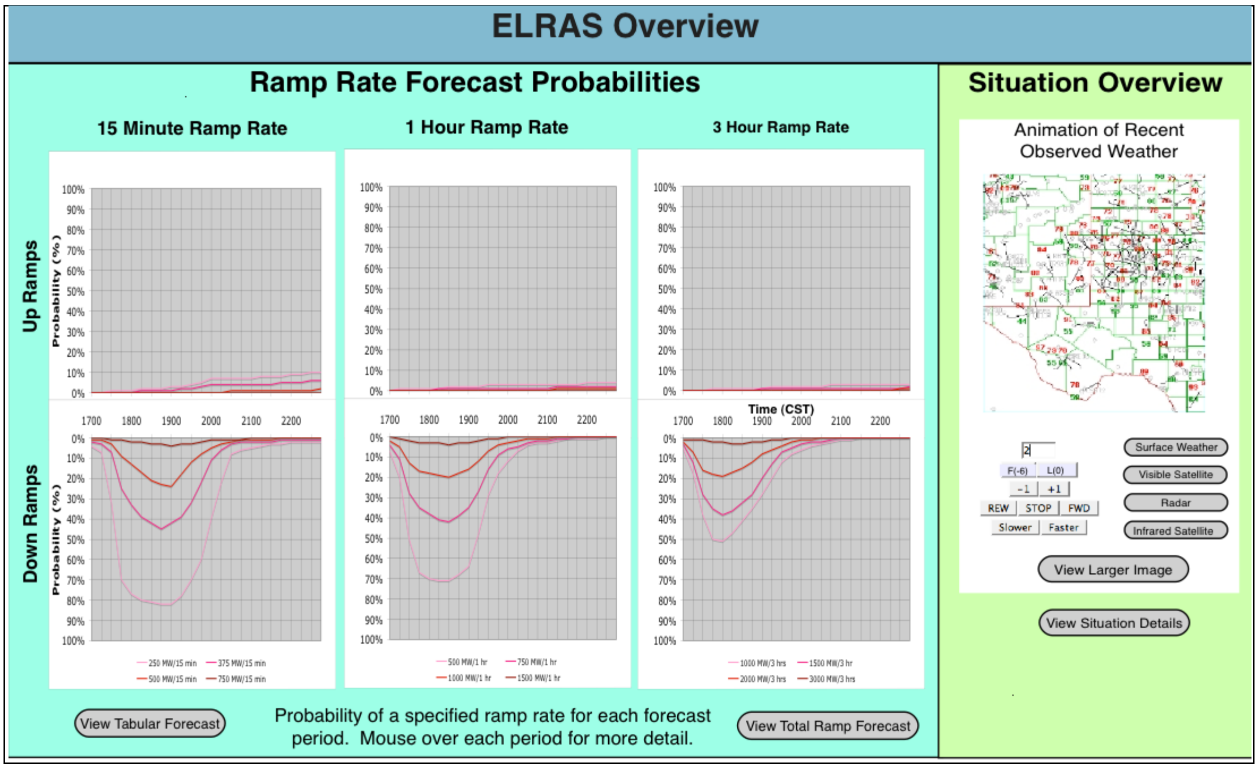


Figure 12: Prototype Dashboard of Ramp Probabilities for ERCOT's Large Ramp Alert System.

Apart from the described operator tools, ERCOT is currently developing a risk based reliability assessment tool. The objective of the tool is to evaluate the reliability risk level in a quantitative way (loss-of-load risk) in real-time by using probabilistic methods and to provide usable advice to the operator when additional resources are needed to maintain operational reliability. The risk based reliability assessment tool will consider unit forced outage rates, as well as wind and load forecast uncertainty. [31]

3.2.1.3 BPA Operator Tools for Variable Generation

As of August, 2010, BPA had over 3,000 MW of installed wind generation within its 10,500 MW peak load BA and expects to add more than 1000 MW by October 2011 to reach a penetration of 40 percent of installed capacity relative to peak load. Many of the wind projects are concentrated in a single region such that the variability in output across the wind plants is highly correlated resulting in large ramps in wind power. BPA is a predominantly hydro system comprising approximately 90 percent of their generating capacity with the remainder coming from nuclear and contracts for gas peaking capacity from other suppliers. BPA uses the federal dams to provide balancing, but the ability of the hydro system to balance the BPA grid is becoming more limited as wind generation grows.

BPA initiated actions in 2007 to improve wind power forecasting and other measures to better accommodate swings in wind energy. BPA has been working with other regional stakeholders through the Wind Integration Team (WIT) on integrating increasing amounts of wind energy into the transmission grid. In February 2009 BPA established a work plan to complete the remaining integration tasks. The objective of the work plan is to develop more sophisticated and cost-effective tools to manage large amounts of wind power in the system. One key element of the work plan is the development of new operational controls for variable generation.

BPA has experienced numerous situations where over- or under-generation of wind plants has caused reserves to be depleted or nearly depleted. To address this issue, BPA developed the operational protocols specified in its Dispatcher Standing Order (DSO) 216 that provide for a semi-automated mechanism for holding wind generators to their schedules when large imbalances occur. DSO 216 requires all wind plants to take actions if necessary to either curtail their over-generation (generation above schedule) when balancing reserves are near depletion or limit their transmission schedule (E-tag) to the amount of the power actually being generated when incremental balancing reserves are near depletion.[32] On October 1, 2009, BPA initiated the implementation of Phase II of this effort, in which BPA's AGC system was augmented to directly send generation output limit alarms and notifications to each wind plant.

As a complement of this automated operational control, BPA has launched a web-based software tool known as Generation Adviser to monitor the current balancing reserves limit, the amount of balancing reserves that are in use, and certain limit and curtailment alarms. Figure 13 shows a screen capture from two separate visualization screens from the public access area of the Generation Advisor. The top plot in Figure 13 shows BPA's aggregate wind generation output and wind schedules for the period of December 3-10 of 2009. The bottom plot shows the corresponding balancing reserves deployed over the period.

The plots show that wind generation ramped up sharply in the late hours of Dec 6 and early morning hours of Dec 7. While the ramp rate was not particularly fast (2 MW/min.) the ramp size (nearly 2000 MW) coupled with the uncertainty of how long it would continue presented operating challenges. More than 90 percent of reserves were deployed, which resulted in generation limit instructions being issued through BPA's AGC. The plots further show that wind generation then ramped down through the night hours of Dec 7 and morning hours of Dec 8 resulting in 100 percent of incremental reserves being depleted. This down ramp resulted in BPA dispatchers issuing instructions for all wind plants to limit their transmission schedules to actual generation for the remainder of that one hour.

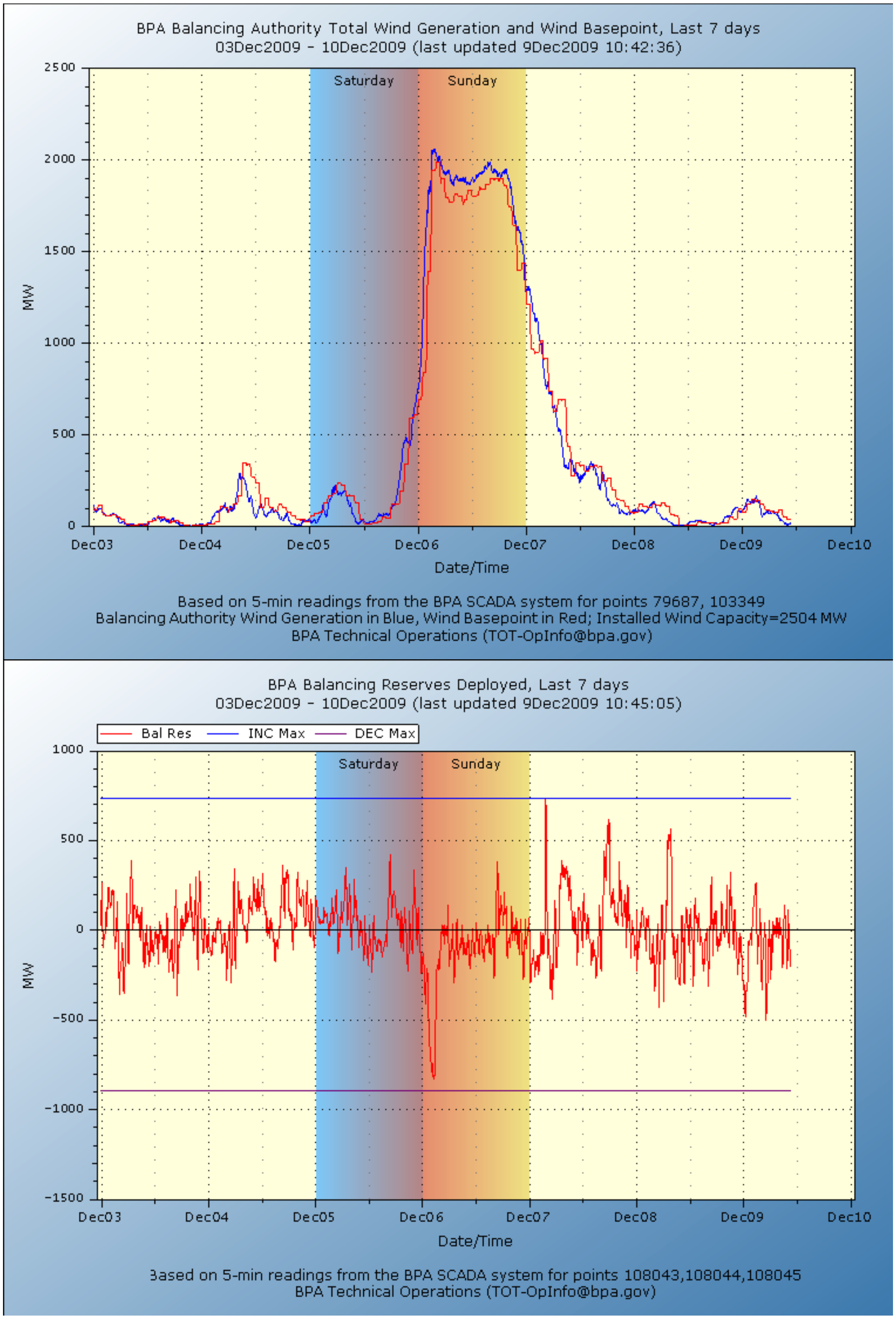


Figure 13: BPA Generation Advisor for Monitoring Balancing Reserve and Wind Schedules

BPA has launched several innovative data visualization displays. These displays provide operators with a patented multi dimensional data visualization display that packs more information in a single display in an easy to read lay out. These displays bring together telemetry data with maps and the data is used to draw shapes on the maps. As the data changes, the shapes change in an intuitive and obvious way. The displays provide operators with a holistic view of wind plants and highlight anomalies. Below is BPA's Windsock Display (Figure14).[9] This display illustrates wind speed and direction data from 14 meteorological weather stations installed and maintained by BPA. The size of the object is linked to wind speed and the long tail shows the direction the wind is blowing, analogous to a wind sock.

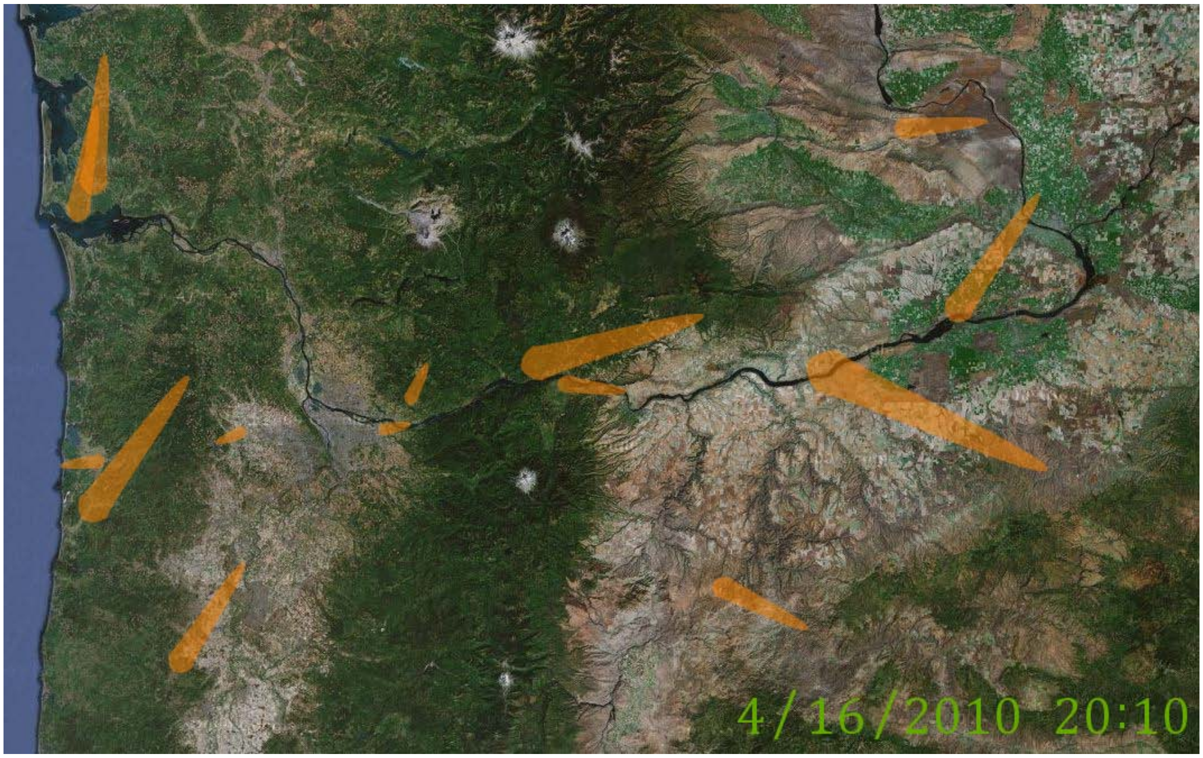


Figure 14: BPA's Windsock Display shows the system operator wind speed and direction to help forecast output from the region's wind fleet.

Also available to operators through the iCRS application is the Generation Maps display (Figure 15). This multi dimensional display provides wind speed and direction information as well as wind plant current generation, past generation, schedule error, multiple color options like generation relative to capacity. The display has a static mode and movie mode, so operators can watch the current status or an animation loop of the last several hours. The display is particularly useful for tracking wind ramps and storm systems as they move through the wind build out area and are intelligently designed to communicate more information than traditional displays while also reducing eye strain and operator fatigue.

[9] http://transmission.bpa.gov/business/operations/Wind/WindAnimation.aspx

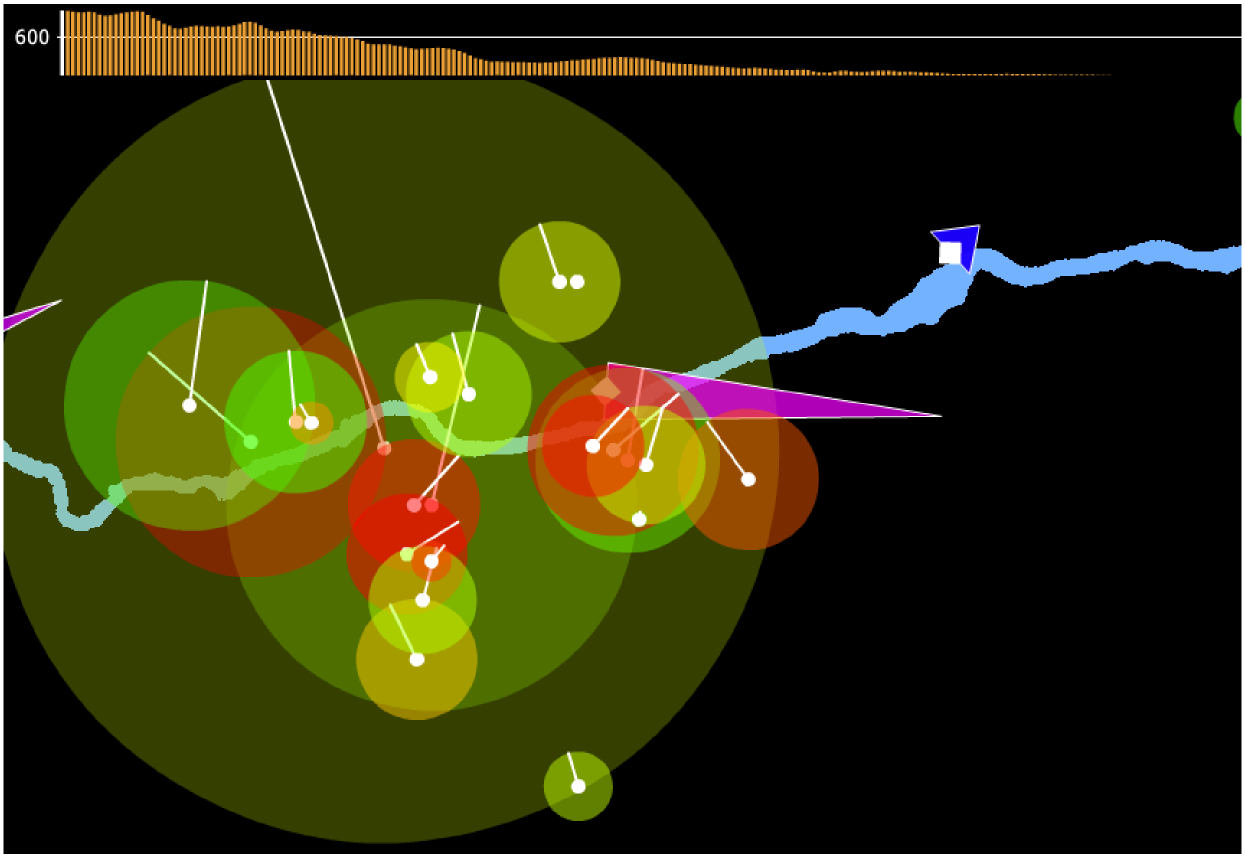


Figure 15: BPA's Generation Maps display provides wind speed and direction information as well as wind plant current generation, past generation, and schedule error with multiple color options like generation relative to capacity.

BPA has also begun allowing scheduling changes at 30 minute intervals to, at least on occasion, supplement the normal hourly scheduling process for variable generation over generation and expects to open up a general 30 minute scheduling opportunity by summer 2011.

3.2.1.4 NYISO Operator Tools for Variable Generation

The NYISO's system peak load is approximately 37,500 MW (Summer 2009). [33] As of October 2009, wind generation capacity was 1,275 MW, which represents about 3.5 percent penetration level with respect to peak load. Nearly 8,000 MW of power proposals are being studied by the NYISO for interconnection to the grid, including more than 2000 MW of offshore wind development. [34] The New York ISO system is well interconnected with the New England ISO, Hydro Québec, Ontario Hydro and PJM.

NYISO operating experience with its existing wind plants has revealed two primary operating concerns unique to the wind generators:

- Sub-optimal performance of wind plants in response to negative price signals associated with transmission congestion, and
- Large wind ramps associated with local weather conditions.

Many of NYISO's wind power developments are concentrated in northern and western regions, where they experience congested transmission paths that at times make it difficult to deliver all the potential wind output to the load centers in the southeastern regions of the state. When such transmission congestion occurs, generators can face negative prices. NYISO's security constrained economic dispatch (SCED) optimally re-dispatches generators down to reduce the congestion based on each generator's expressed economic willingness to generate as shown in submitted bid curves. Wind generators, however, have not historically submitted bid curves to be included in the SCED. As a result, NYISO has experienced occasions during periods of negative pricing where wind plant operators have then instantaneously reduced output from full power to zero to avoid producing power at a financial loss. To mitigate this effect, the NYISO implemented in May 2009 the integration of wind into its SCED. Under the new dispatch procedures, wind generators are required to submit their economic bid curves just like conventional generators for inclusion in the real-time market SCED. These economic offers indicate the price below which each generator does not want to generate. Generators can specify up to eleven MW/price combinations at which they want to operate. NYISO can then use the submitted bid curves to determine the least-cost means of meeting load requirements while maintaining reliability. [35]

NYISO has also identified the need to provide operators a tool that alerts them of the potential for significant wind ramp events. For that reason, the NYISO is developing a new forecasting system with the capability to predict wind ramps. The ramp forecasting requires that wind speed and wind direction data from meteorological towers within 5 km from all wind turbines be transmitted directly to NYISO every 30 seconds. The tool will also include a visualization dashboard to display all wind generators' activities such as: plant output, percent of plant capability, wind curtailment, wind speed and direction, and color contour indicating plant wind speed. Figure 16 is an example of how the future visualization dash board will display information on wind plants output and status.

3.2.1.4 HELCO Operator Tools for Variable Generation

Hawaii Electric Light Co (HELCO) has a peak load of approximately 195 MW and a minimum load of approximately 80 MW. In 2009, wind energy provided 13.3% of the total net-to-system generation. During individual hours, wind energy routinely exceeds 20% of the net-to-system generation on the transmission system, and under certain conditions can be over 30%. This energy is from two wind plants. The system operations projection screen provides 15 minute strip-chart style trends for each wind plant. Each chart trends the wind output, system frequency, and wind speed (from a 2-second analog scan for each data point). This trend allows the operator to easily determine when frequency excursions are the result of wind changes: the wind power output and frequency have the same trend shape and are parallel when the wind change causes the excursion. The wind speed trend indicates clearly when the speed is in excess of the maximum power output threshold. The system operators take the wind speed, and resultant wind variability in the past several minutes, into consideration in determining the regulating reserve requirement. In addition to the variable wind energy, HELCO has a large amount of distributed PV which is not telemetered. As of June 2010, 9.6 MW of distributed PV capacity is connected in locations throughout the island, which is 5 to 6 percent of the day peak, an amount which impacts reserve requirements and commitment of transmission connected generation. Without visibility, the system operator sees the production from the distributed PV as a reduction in the net to system demand. To assist the operator in projecting the system day peaks, a system display has been developed which shows the available solar irradiance potential throughout the island, based upon numerous PV panels installed around the island at telemetered switching and distribution stations as shown in Figure 17. The potential energy from these panels is converted into a per-unit energy value which is used to estimate production from the installed capacity in the area of the station.

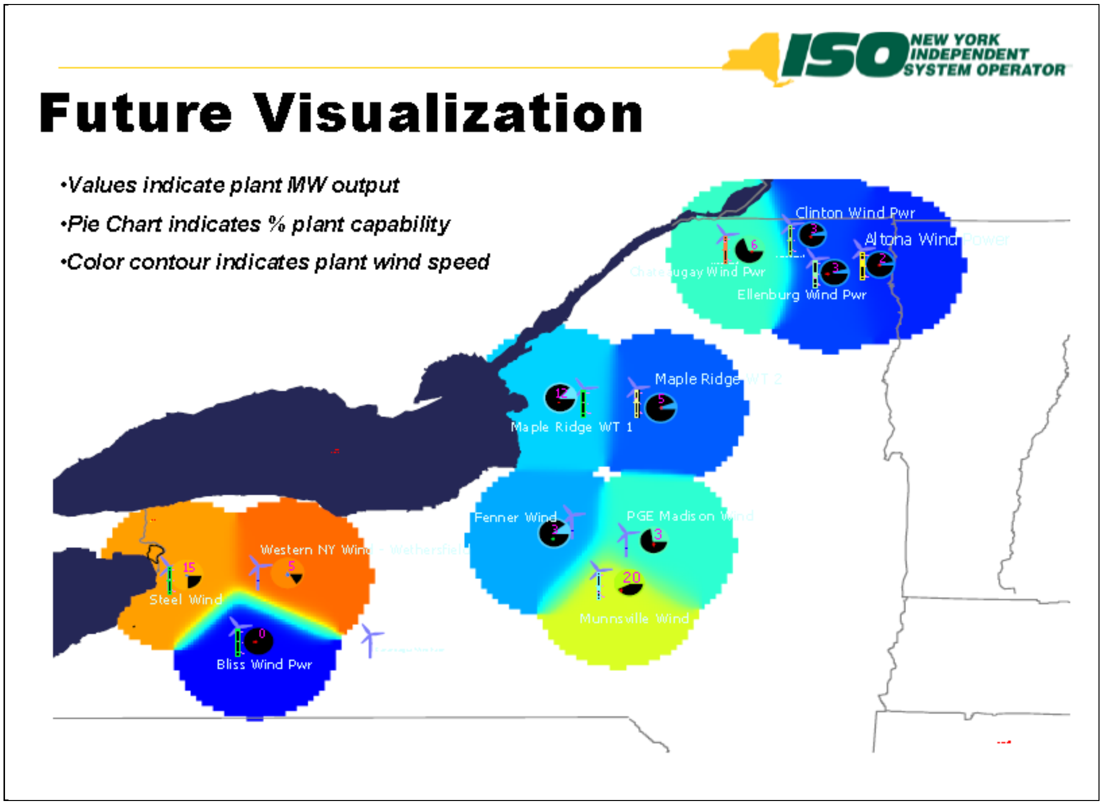


Figure 16: Example Visualization Dashboard from NYISO's Augmented Wind Forecast Tool. [36]

3.2.2 General Requirements for Visualization and Operator Supporting Tools

Even though some of the described tools are already in advanced prototype phases, in general industry development and implementation of VER focused operational tools is at its dawn. The described tools represent industry best practices to date and are the best current source to identify general requirements of advanced operator tools going forward. There are obviously significant differences in the actual scope and implementation of the individual tools, which can be mainly attributed to the differences in the systems and associated markets for which the tools were developed. Some of them are intended to provide the operator comprehensive information about existing system operating conditions and expected short-term changes so that the operator can decide the most appropriate control actions. These tools include additional visualization displays and calculations of system performance metrics that inform the operator for determining what measures should be undertaken to mitigate possible adverse effects. Others, like the BPA's tool, are designed to continuously monitor or calculate certain metrics and automatically send adjustment signals to power plants through the AGC system should specified trigger conditions be met.

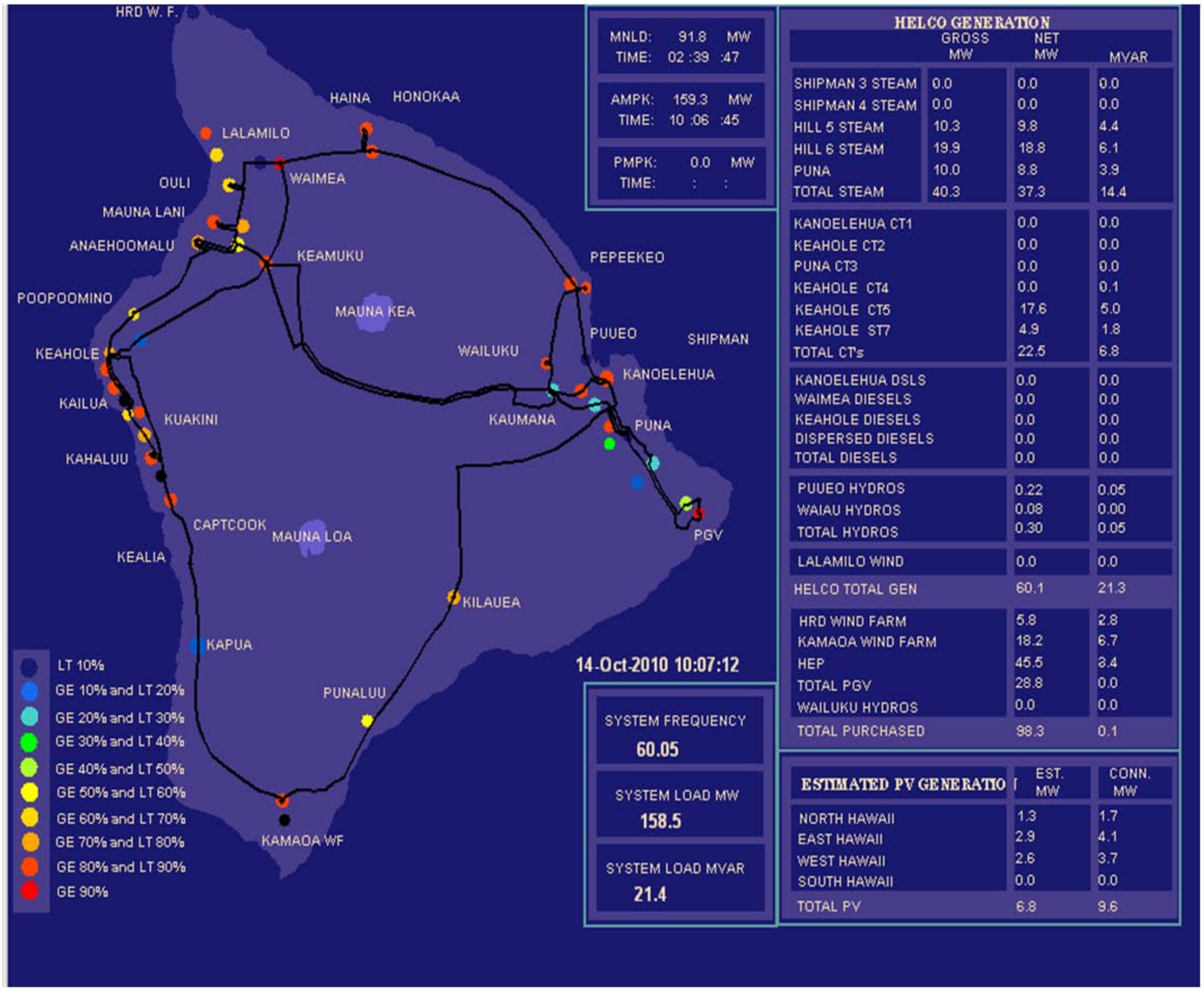


Figure 17: Example of HELCO's Solar Visualization and Estimation Display

Although there are differences in the objectives, features and functionality of the different systems' operator tools, the underlying principle is to improve operator situational awareness, provide operators with an evaluation of events likely to occur and their impact on the system, and provide operators with guidance on the effectiveness of possible mitigating measures. [37] The following are the main features that an operator decision making support tool for managing variable generation should preferably have:

1. Situational awareness – aggregating data on current system status from various sources including EMS/SCADA, load and VER forecast systems, and operational planning and/or market results identifying available resources to provide succinct, meaningful displays that support situational awareness.

2. Real-time reliability/risk assessment – evaluation of various dimensions of risk associated with the present and future operating conditions considering elements such as total ramping capability from available resources (supply and demand) and the uncertainty in unit availability, load, and VER.
3. Operator decision support – evaluation and recommendation of mitigating actions that can be implemented to solve predicted or realized reliability/security concerns.

3.2.3 Distributed Variable Generation Considerations

The impact of distributed generators should be considered because they are less visible to the system operator and can behave in unexpected ways. This is likely to be a more significant issue for solar energy in the future, as the economics and characteristics of solar energy could lead to a relatively large amount of distributed solar generation on the distribution system. While there is some growing level of distributed wind energy, most wind energy seems are likely to be installed as utility-scale wind plants on the transmission system.

The power system reliability concern with variable generation on the distribution system is due to the limited amount of visibility and control. New processes such as direct telemetry, reporting procedures and trend analyses may be required to create visibility. Such information could then be used to develop accurate forecasts, output information, and when necessary, dispatches for distributed generation. For example, in Ontario the IESO plans to coordinate and provide local distribution companies with centralized wind forecasting and dispatch information to facilitate reliable penetration of distributed variable generation. Germany has established grid codes for distributed resources (MV Directive 2008) which include requirements for Active Power Control for wind, hydro, and PV plants. Required compliance for PV resources went into effect in 2010 which has resulted in commercially available capabilities for Active Power Control for suppliers to the German market.

Even for a system without much visibility and control, however, this does not mean that forecasting providers cannot forecast such generation. This is already done on a production basis in Germany where a large proportion of the wind and solar generation is on the distribution system [14]. Development of distribution-side variable generation power forecasts (or integrated “load net variable generation” forecasts) will have growing value, particularly when solar costs come down and the level of residential and commercial solar installations grow. These “load net variable generation” forecasts will also need to take into account price sensitive demand, dynamics of the “load net variable generation” when releasing control, impacts on bulk power system reliability and any control of variable generation to accurately depict historical quantities. As the use of distributed variable generation increases there will be increasing need to address visibility, forecasting and potentially some level of control for such generation. [1]

3.3 Act

As with a power system that has no variable generation, the system operator takes actions based both upon scheduled activities and in response to changing system conditions. Some actions are closely tied to observation and analysis in a continuous control loop. Automatic generation control (AGC) moves generation in response to fluctuations in net load and continuously updated analysis of CPS1&2 or CPM& Balancing Authority ACE Limit (BAAL) requirements. Other actions are in response to an episodic change in conditions (sudden failure of a large generator) and entail an immediate, often automatic response followed by slower actions that restore the system to a normal operating state. Variable generation may increase the frequency of response but does not alter the general nature. The system operator still accommodates generation and load schedules and adjusts reserves.

3.3.1 Control of Conventional Resources

The system operator has two basic methods for controlling generation and responsive load. Generators are committed and then dispatched in economic order, while respecting reliability constraints, to meet the expected load. Generators and responsive loads are also scheduled to supply reliability reserves. Both of these activities are still required on systems with high penetrations of variable generation.

The increased variability and uncertainty associated with wind and solar generation increases the value of flexibility in the control of conventional resources. Large thermal units must still be committed a day or more in advance but having the flexibility to delay the unit commitment decision for more flexible units (combined cycle, for example) until twelve or six hours before the operating hour, when the wind and solar forecasts are more accurate, can facilitate more efficient use of resources and therefore greater reliability. Similarly, sub-hourly energy scheduling can provide access to the full physical flexibility capabilities of conventional resources.

With greater amounts of variable resources on the system, some conventional responsive generation may be displaced. The number of starts and stops on peaking and cycling units can be increased. A greater number of control actions and larger magnitude of changes, to regulating and load-following units can be anticipated as the result of the greater amount of variability in apparent (net) load.

3.3.2 Inter BA Scheduling

System operators operate the system they are given. They do not have the ability to change the generation mix. They cannot increase the size of their balancing area (BA) to obtain aggregation benefits or to gain access to additional flexible resources. With access to sufficient ancillary services, transmission capability and compatible generation characteristics on their own and in neighboring systems they can transact with their neighbors, however, and gain many of the same benefits that are inherent in larger BAs. High penetrations of variable generation increase the value of inter-BA transactions but do not change the basic nature.

Some Balancing Area Operators have implemented interchange schedule operating practices known informally as “firm within the hour”. In contrast, most Balancing Areas allow a transmission customer to adjust interchange schedules within the clock hour to manage their energy imbalance, subject to reasonable limits. The firm-within-the-hour balancing areas may experience increased requirement for load-following reserves or other balancing resources to offset the wind output scheduling error over an entire operating hour. Some research has suggested that this operating practice may contribute to increased capacity requirements for Balancing Areas. [38]

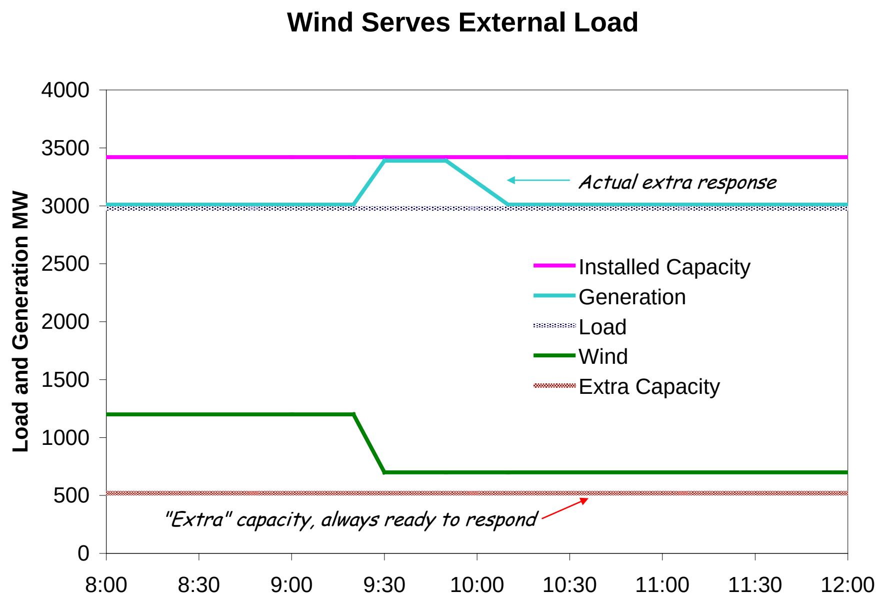
Faster inter-BA scheduling can reduce the reserve requirements in two distinct ways. First, if wind or solar generation is produced in one BA but is serving load in another under a practice where the physical host BA is firming the schedule and only hourly transactions are allowed the physical host BA must hold sufficient reserves to respond to changes in generation. [39] Figure 18 presents a stylized illustration of the added reserves a physical host BA must carry when a wind generator delivers energy to load in another BA if only hourly inter-BA schedules are allowed. In the example the wind drops unexpectedly at 9:30am and the host BA must cover the generation shortfall until the top of the next hour. This reserve provides little or no reliability benefit; the load BA must have sufficient generation to cover the loss of wind. There is only a small delay in the load BA’s reserve deployment. Implementing sub-hourly scheduling between the host and load BAs can eliminate the added reserve requirement, freeing those responsive resources to serve other reliability needs.

This extra capacity impact was calculated using an actual example from the Pacific Northwest. [40] BPA delivers approximately 80 percent of the wind that is physically located within its BA off-system. WECC scheduling practice is to change schedules at the top of the hour, allowing for a 20-minute ramp period. Using public data from BPA’s web site, the study calculated the impact of the extra capacity requirement on BPA with the hourly scheduling change. It also compared this to the capacity impacts with a 30-minute schedule change, and a 10-minute schedule change (both calculated 10 minutes before real-time). Figure 19 illustrates this for 2009. During the year, additional wind capacity was coming online, and maximum wind output is 1,886 MW. Using the existing hourly schedule, set 2 hours ahead, the maximum annual capacity obligation for BPA is 617 MW; the minimum is -956 MW. BPA has indicated in its rate proceedings that minimum-run issues during periods of high wind can be problematic. The average capacity obligation is not a good metric to measure the differences because it is near zero in all cases. However, the sum of the absolute differences for the hourly schedule is 876,013 MW-hours, whereas the same metric for the 10-minute schedule change is 156,100. This represents more than an 80 percent improvement in overall schedule deviations for the year.

3.3.3 Inter-BA Cooperation

The NERC IVGTF Task 2.1 Report: *Variable Generation Power Forecasting for Operations* [1] also found benefits from larger BAs or from BA cooperation:

> *A large, flexible bulk power system provides many advantages for economically and reliably facilitating and managing variable generation. Physical size is beneficial because the correlation between the power production from multiple wind or solar plants diminishes as those plants are geographically farther apart. Flexibility is important; particularly the flexibility to make commitment decisions closer to real-time, since as the time frame decreases, wind and solar plants are less correlated, which reduces aggregate variability. The reduction in correlation as a function of both timeframe and geographic spread are shown in the graphs below (Figures 20 and 21).*



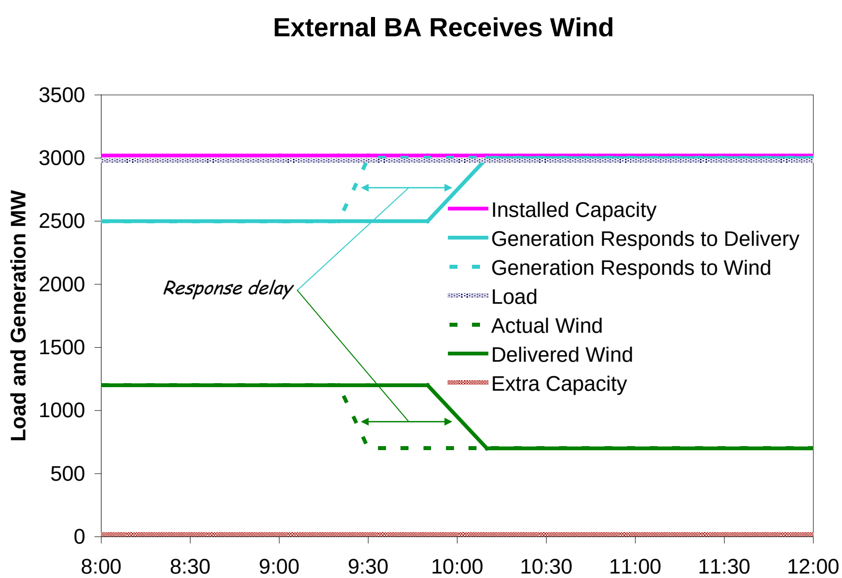


Figure 18: Wind serving loads outside the host BA requires additional capacity; the host covers the wind delivery until the end of the scheduling period, 1 hour. The BA that receives the wind does not get a capacity benefit, only a delay in response speed. [38]

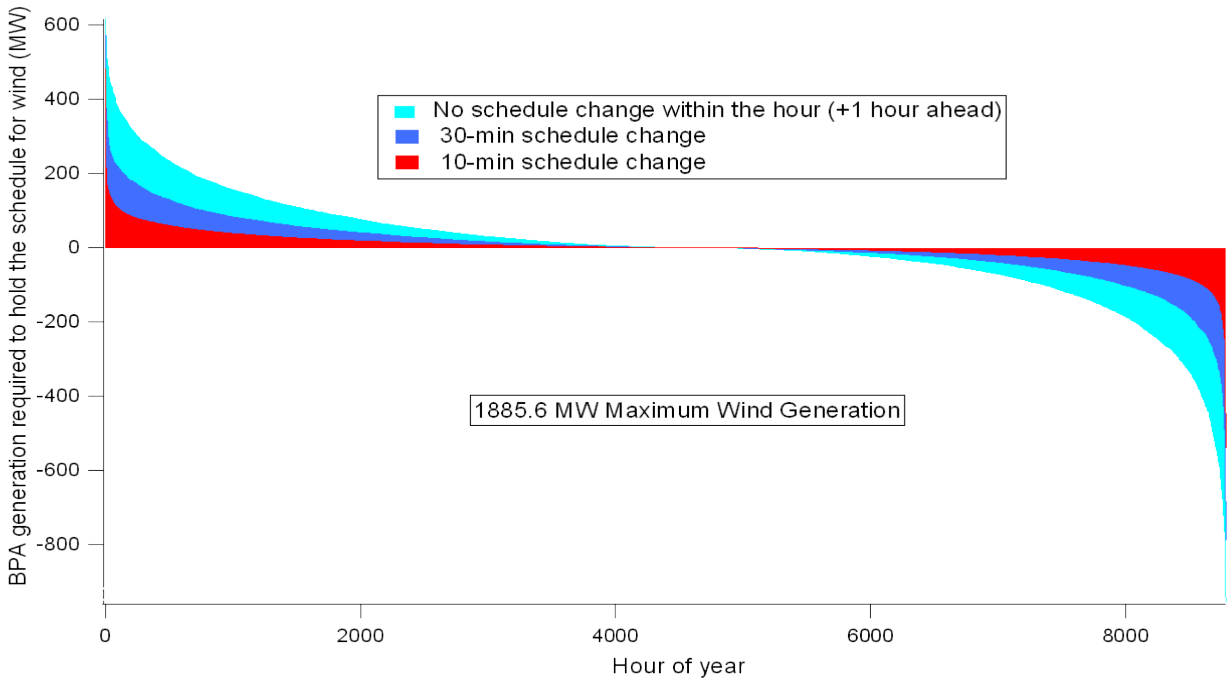


Figure 19: Frequency and amounts of excess capacity under alternative scheduling periods.

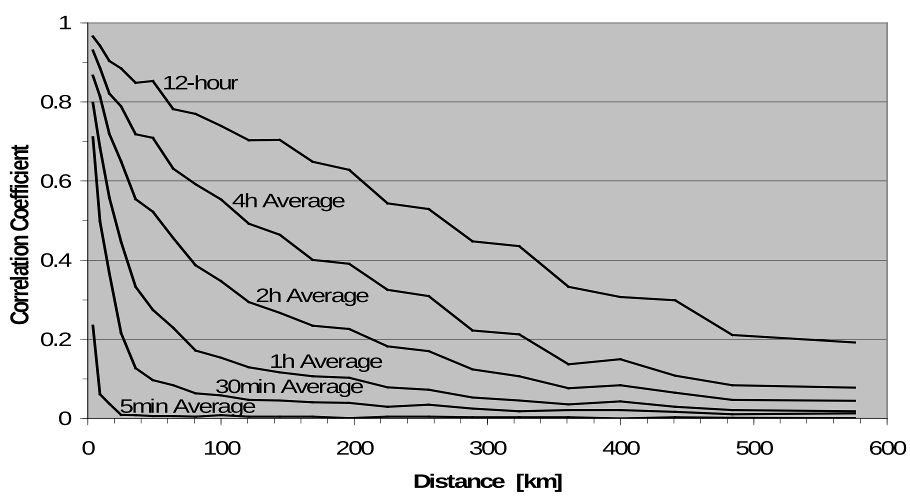


Figure 20: Wind generator variability loses correlation as the distance between machines increases and as the time frame of interest decreases [1].

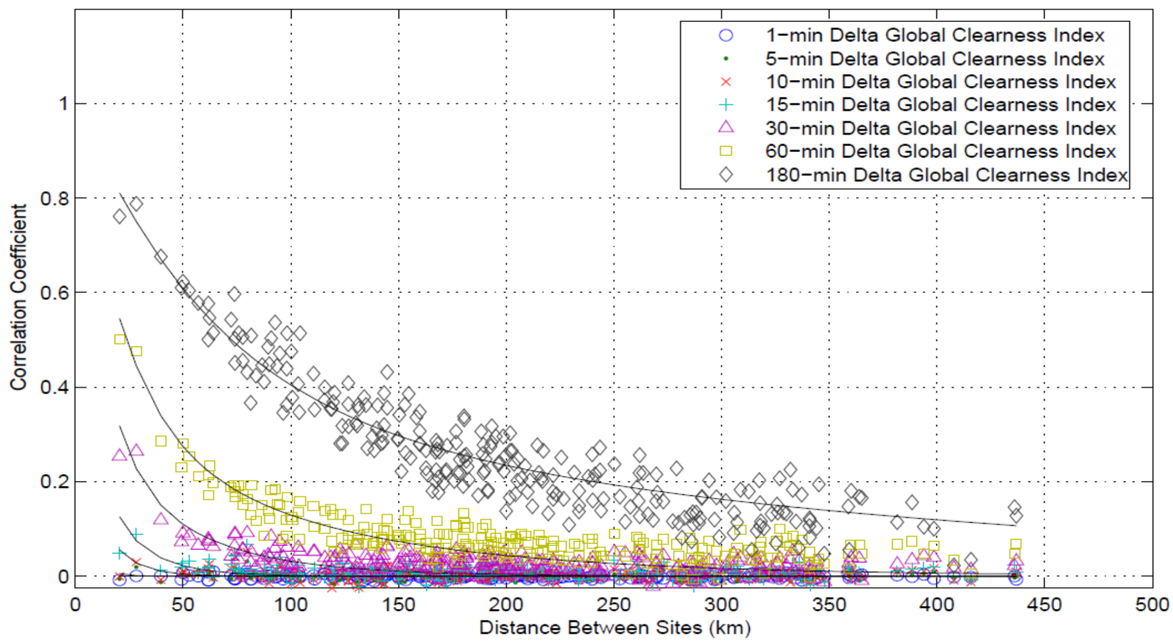


Figure 21: Like wind, solar generator variability loses correlation as the time frame of interest decreases and the geographical spread increases [41].

Larger geographic and electrical size also tends to reduce aggregate forecasting error. Table 4 shows that the wind power forecasting error is reduced significantly when forecasted wind output from all four regions of Germany is compared with forecasted wind output from a single region. In general, there can be a 30 percent-50 percent reduction in forecasting error that results from aggregation and geographic dispersion of wind power, as compared with the error of individual or geographically concentrated wind plants [42]. Thus, in many cases power system operators can more accurately predict and plan for changes in wind generation when systems are larger and this principle may also apply to other types of variable generation.

Wind Forecasting Accuracy		
Forecasting Error (NRMSE)	All four Germany control zones (~1000 km spread)	One Single Germany Control Zone (~350 km spread)
Day ahead	5.7%	6.8%
4 hours ahead	3.6%	4.7%
2 hours ahead	2.6%	3.5%

Table 4: Wind power forecasting accuracy improves when larger geographic areas are considered [42].

BAs can also reduce ramping requirements by both aggregating the ramping obligation and pooling the ramping resources. This is very similar to reserve sharing pools that have enhanced reliability for decades. Contingency reserve sharing pools rely on the fact that contingency events are highly uncorrelated. The probability that a large generator will fail in two BAs at the same time is very low. The contingency reserves in all of the BAs can safely respond to a contingency in any one BA and still be available to respond when needed in another BA. Similarly, short term load variability and wind ramping requirements are sufficiently uncorrelated so that inter-BA cooperation has significant benefits.

Sub-hourly, inter-BA scheduling can capture much of the aggregation benefits of larger BA size. Short-term load variability is highly uncorrelated. Short-term wind and solar generation variability are uncorrelated as well. Larger aggregations of load, wind, and solar exhibit lower net variability. [43,44] A study of five minute data from four Minnesota BAs prior to the MISO consolidation show the loads ramp in opposite directions a considerable amount of the time as shown in Figure 22. Sub-hourly scheduling between the BAs (or consolidating them as MISO did) can eliminate the need for multiple BAs to ramp in opposite directions. Wind increases both the ramping requirements and the benefits of BA cooperation but does not change the nature of the benefit.

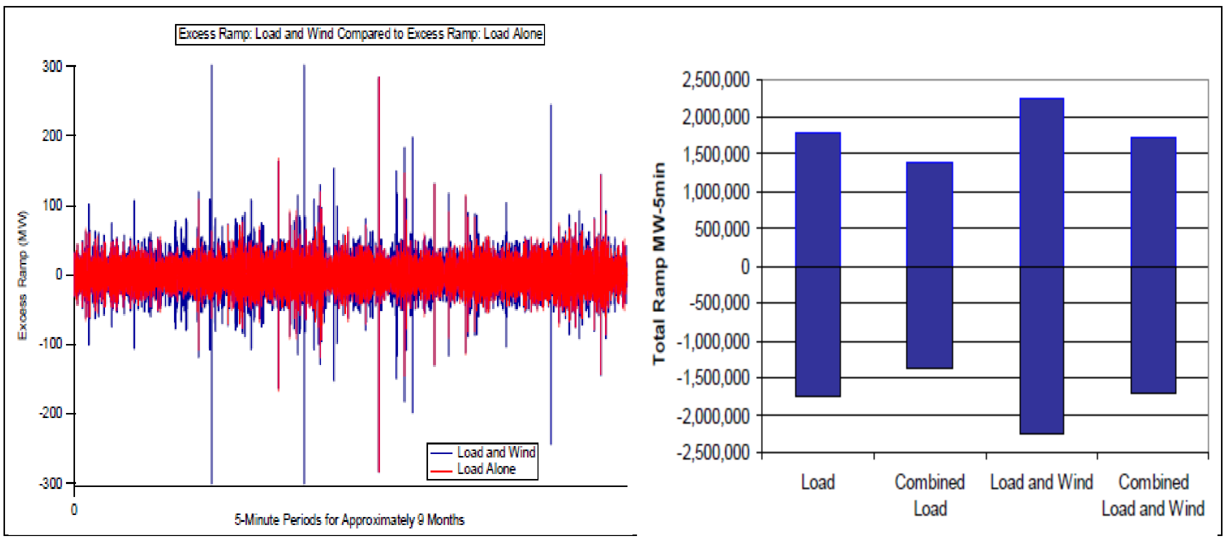


Figure 22: Sub-hourly scheduling can reduce excess ramping among cooperating BAs for load alone and for load with variable generation.

A later study examined the benefits of sub-hourly scheduling between thirteen BAs in the Pacific Northwest. [40] Ten minute wind data from the WWSIS study was used to examine a fairly high 16 percent annual energy penetration. Figure 23 shows benefits for pooling load variability alone but greater benefits when load and wind variability are netted. For net load, which is an indicator of what the power system must be operated to, the variability index difference between combined and separate BA cases is significant – approximately a 30 percent reduction in the footprint.

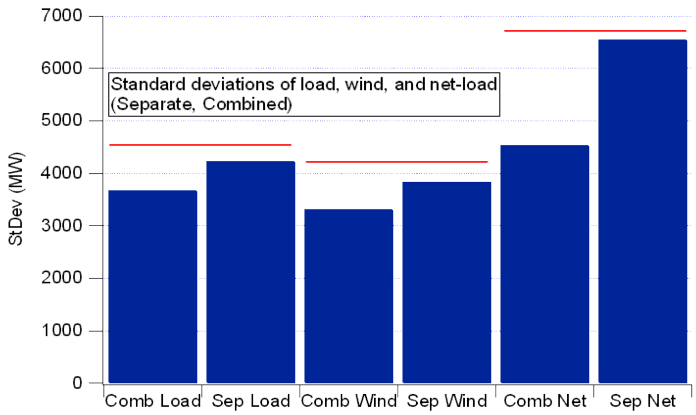


Figure 23: Per-unit variability is reduced by pooling for load, wind, and net load.

Sub-hourly scheduling can also facilitate cooperation among BAs to reduce ramping capacity requirements. The same study examined the maximum daily ramping requirements for individual BAs and for the pooled aggregation. [40] Ramp durations from ten minutes to twelve hours were analyzed for load alone and for the high wind penetration case. Sharing ramping requirements among the BAs reduces the average daily ramping requirement for load alone over all ramp durations. The benefits are greater for the maximum annual load ramping requirement and greater still for the combination of load and wind, as shown in Figure 24.

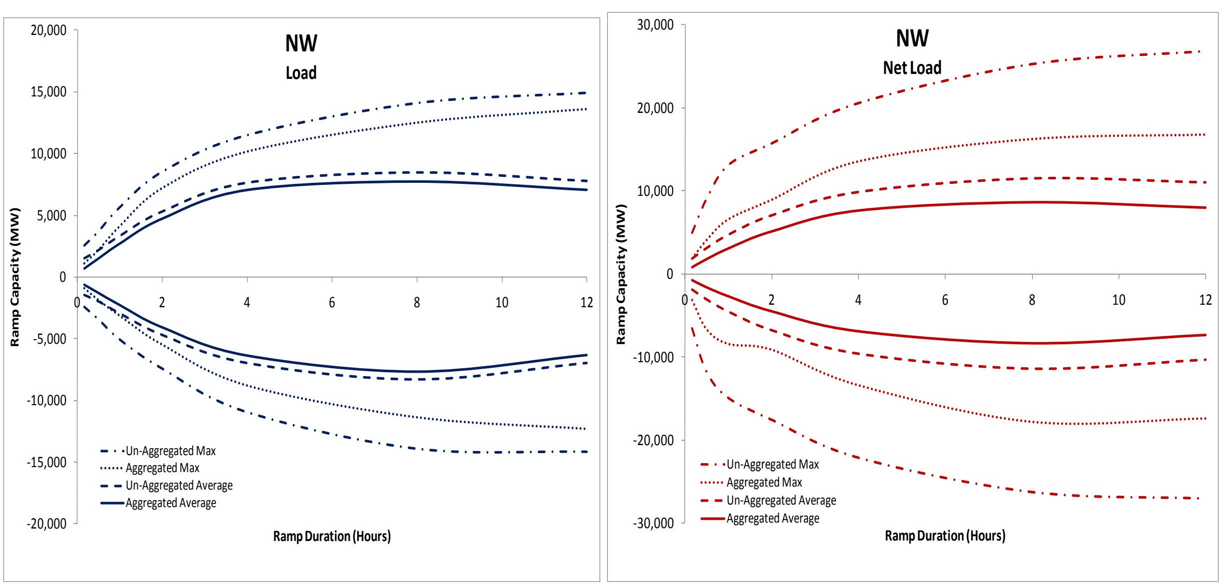


Figure 24: Ramp duration curves show the benefit of BA cooperation for ramping adequacy.

3.3.3.1 ACE Diversity Interchange

Dynamically combining area control error (ACE) from multiple BAs can further facilitate the efficient use of reserves. The ACE Diversity Interchange (ADI) project, run by Northern Tier

Transmission Group (see www.nttg.biz) calculates the net regulation requirement among several balancing areas and sends out revised signals to participating generators on automatic generation control. While balancing requirements are the same as pre-ADI second-to-second balancing movements are reduced for participants as uncorrelated variations partially cancel out. A number of European BAs are implementing a similar, though more extensive ACE sharing scheme.

3.3.4 Controlling Variable Generation

Variable generation is variable because the "fuel" source varies, limiting the maximum available output. Variable generation output from modern wind and solar plants can typically be controlled to any level below what the sun or wind is currently making available, however. The control can be both faster and more accurate than what is possible from conventional generators with inverters capable of cycle-to-cycle control and wind turbine blades capable of second-to-second control. Modern wind and solar plants can be controlled fast enough to provide both regulation and stability response. This response capability can be very useful for enhancing reliability and reducing the requirements for other reserves but that usefulness has limitations.

The essentially zero marginal cost for wind and solar ("free fuel") makes it generally desirable to use as much wind and solar output as can be reliably accommodated. Unlike fuel-consuming generators, or hydro with poundage which can hold water for later use, there is no fuel (or water) savings when wind or solar generation is curtailed. The wind or sunshine is lost forever. Wind and solar are the first resources used in an economic dispatch. Still, this use is based on the near zero marginal cost. Wind and solar must be curtailed when required for reliability reasons and should be curtailed when the cost of responding to the increased variability exceeds the fuel and emissions savings achieved by backing down other resources.

Having control capability to curtail VER is technically feasible and may be justified on the basis of economics and reliability. Deciding when to exercise control presents a more difficult problem for the system operator. There is always a concern that a system operator will choose to use the fastest, most accurate control capability available when addressing a reliability problem, without considering all of the economic implications. The industry has been successful in addressing a similar concern with respect to firm load-shedding. At times, firm load-shedding can be the best resource available to address a serious reliability problem, and a system operator should never hesitate to use it when it is required. Firm load-shedding also has the interesting economic characteristic that there is no direct economic consequence for the system operator or the traditional utility because the interrupted loads are not always compensated for the interruption. Still, system operators understand that interrupting firm load does have very significant consequences for the loads and the reliability resource is only used when absolutely necessary.

Curtailing excess generation involves a number of complex tradeoffs (limiting ramp rates is a similar but less contentious issue and is discussed below.) There are times when generation exceeds load and the excess generation must be rapidly and accurately curtailed to maintain reliability. Deciding which generation to curtail is complex. Wind and solar would normally be the last generation curtailed based simply on marginal production cost. If the other generation is at minimum load, however, curtailment might require turning a unit off. Cycling a unit off and back on is expensive and typically involves long shutdown and restart processes. Control capability is also limited by the unit size which could result in curtailing much more generation than was required. It would make little sense to cycle a nuclear plant off and back on to deal with over generation lasting only twenty minutes, for example. Conversely, it is not wise to establish rules and procedures that reward generators for being less flexible by exempting them from curtailment. This may encourage others to establish high minimum loads and long cycle times. Possible solutions include allowing negative prices that apply to all generators that stay on line during curtailment events or paying generators for response. Where constraints exist, and are difficult or infeasible to remove, and where the constraints would restrict the amount of variable generation on a system, active power control capability facilitates can support the addition of variable resources while preserving reliability by allowing them to connect and produce energy at times the constraint is not in effect.

3.3.4.1 Ramp Rate Control

Ramp rates can be controlled when wind or solar are increasing output. High ramp rates can result from increases in wind or solar directly but normally occur when a wind or solar facility has been off line and is returning to service. In either case limiting up ramps is technically possible for modern plants and has little adverse economic consequence. Communications and controls are the dominant costs.

ERCOT requires each wind plant to limit its ramp rate to no more than 10 percent of capacity per minute when the plant is either responding to or is being released from a curtailment instruction. Ramp rate limits are not imposed at other times. Other grid codes with ramp rate restrictions include Ireland, Germany, and Hawaii.

3.3.4.2 Limit Energy Production (Curtailment)

Transmission constraints and excess energy conditions can make it necessary to limit variable generation. Depending on the congestion frequency this can be economically significant with the lost production being more important than the communications and controls costs. On the other hand, use of curtailment can permit larger amounts of installed capacity and therefore greater production, by allowing the increased production during periods when the energy can be accepted, than if the capacity were restricted to the most limiting conditions. Wind curtailment initiatives are at an early stage of discussion or implementation. A detailed description of case studies and current initiatives can be found in [45]. Curtailment may also be necessary during system restoration periods, when the production of unscheduled variable energy could slow or conflict with restoration of the system.

Most bulk power systems do not provide compensation when variable generation must be curtailed for either constrained transmission or reliability reasons, but power purchase agreements between wind energy producers and host utilities may contain such contract provisions. Ontario has provisions to provide financial incentives to encourage wind generators to reduce production if the system is approaching Surplus Baseload Generation (SBG) conditions.

At least indirectly, the implications of the Production Tax Credit (PTC), renewable energy credits and renewable portfolio standards for wind power plants in the U.S. can also impact both economic and reliability decisions. Historically, the PTC is a significant portion of wind project revenue for the first ten years of the project and resources that are no longer eligible for the production tax credit (or elected to use an investment tax credit rather than a production tax credit) may have a different price tolerance for curtailment. The sale of renewable energy credits may also be an important source of revenue for wind and solar generators, and curtailment may also impact the ability of utilities and other entities to meet renewable portfolio standards, if applicable. Because of these factors, wind projects may be motivated to generate even if electricity prices are negative. These financial arrangements are not visible to regional markets that accommodate the resource output as a “price-taker” not eligible to set the market clearing price.

The practical implications of this can create both economic and reliability concerns. For example, in market regions such situations can create concerns if the market is not able to accommodate negative price offers as a means to prioritize the value of curtailment in the process of maintaining system reliability. In any system, when the conditions for curtailment are not specific to a single entity (e.g., excess energy conditions, overload of transmission facilities, limited downward regulation capability), the guidelines and policies under which resources are curtailed should be clear and fair and reasonable to all parties and efficient to administer. [1]

3.3.4.3 Synthetic Inertia

Some modern wind plants can provide synthetic inertia. Though the turbine and generator mass itself is isolated from the power system through an inverter and will not naturally provide frequency response there is energy stored in the rotating mass and it can be tapped through programmed inverter control if desired. Appropriate sizing of the inverter, generator and other equipment, along with necessary controls, can provide inertia response to the power system. Solar technology is not as advanced in this area yet. The inverters potentially have the required response speed but there is not an obvious source of stored energy in current solar plants.[10] The inertial response occurs in the dynamic time frame and does not require instruction from the system operator.

3.3.4.4 Regulation

Modern wind turbines are capable of supplying minute-to-minute regulation. This capability has been tested in Quebec and is regularly provided in Denmark, as shown in Figure 25. [46] The response speed and accuracy are better than most conventional generators can supply. Solar plants should be able to provide similar quality regulation.

Supplying regulation up requires the wind or solar plant to spill wind or sunshine. Since there is no fuel cost savings it is relatively expensive for wind and solar to provide up-regulation if sufficient response exists from conventional generation. Figure 26 compares the costs incurred by a large coal fired generator when it provides regulation with the cost a wind plant incurs. The coal plant fuel savings (even considering the degraded heat rate) makes regulation from the thermal plant more attractive most of the time. [47] Regulation from wind may be attractive near minimum load conditions, especially under conditions where curtailment for excess energy is necessary and therefore the energy reserves are available for up-regulation, and where down-regulation can become a limiting factor on the power system. Provision of regulation by variable

[10] While solar photovoltaic generators do not inherently have a source of stored energy that could supply synthetic inertia storage might be added to the inverter’s DC bus if this capability was found to be necessary. Other alternatives may be more attractive. Solar thermal plants have similar inertia characteristics as other conventional steam generators.

resources may permit a greater number of conventional generators to be displaced and ultimately allow variable resources to provide a greater share of the energy portfolio.

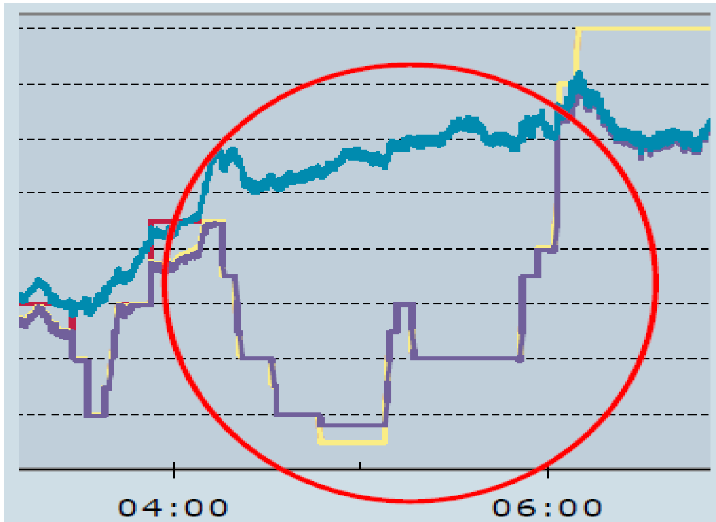


Figure 25: Danish wind plants often provide regulation as shown by the turquoise plot of wind capability and the purple plot of controlled output. [46]

Load can provide regulation, ramping response, and contingency reserves as well. [48] ERCOT routinely obtains half of its contingency reserves from Load Acting as a Resource. ALCOA consistently sells regulation from its Warrick Indiana aluminum smelter to MISO. Advances in communications and controls are making demand response a viable resource for a range of bulk power system reliability services and a valuable tool for power system operators.

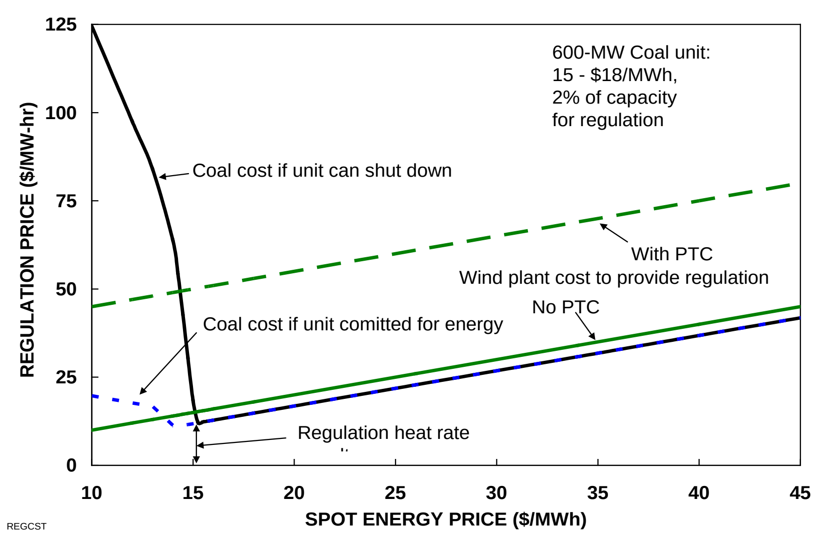


Figure 26: The cost of supplying regulation is a function of the price of energy for both thermal and wind generators. [41]

4. Implications for NERC Standards

One of the goals of this activity is to evaluate needed changes to NERC's Reliability Standards. Several NERC Reliability Standards may need to be updated. The Standards requiring enhancement are the following:

- **BAL-002 (Disturbance Control Performance)** - The standard may need to be revised to include sudden changes in wind output as "credible contingencies" under the Standard. This would ensure that these events are analyzed during reserve calculations. The applicable section of the standard is Requirement 3.1. Additionally, changes to this Standard may need to be addressed with various reserve sharing groups, many of which have differing rules regarding contingencies.

- **BAL-005 R-11 –** This Standard may need to be updated to include the various types of ramp rates that a Balancing Authority may need to use in the Scheduled Interchange values to calculate ACE. Controlled and uncontrolled ramp rates may need to be included in the analysis since both types can be encountered by variable generation.

- **COM-002 (Communication and Coordination)** - The Standard may need to be revised to clarify the meaning of "voice and data links" as used in the Standard. To avoid problematic interpretations, the standard should specify that "voice and data links" are those identified in Interconnection Agreements or other governing agreements between the Transmission Operators and the variable generator.

- **EOP-002 R6 –** This Standard may need to be updated to reflect curtailment capabilities of various types of generation as one of the possible remedies available to Balancing Authorities. This would ensure that a Balancing Authorities has examined various types of remedies that are available when experiencing problems meeting the Control Performance and Disturbance Control Standards.

- **IRO-004 (Reliability Coordination – Operations Planning) –** This Standard may need to be updated to reflect forecasting information available to variable generation that is to be made available for next-day studies. Currently, the Standard indicates that parties "shall provide information required for system studies, such as critical facility status, load, generation, operating reserve projections, and known Interchange Transactions". Forecasting of variable generation could be added to the list in order to provide an accurate day-ahead study.

- **IRO-005 (Reliability Coordination - Current Day Operations)** - This Standard may need to be updated to include active monitoring of forecasting conditions such as weather fronts, icing and/or high wind conditions by the Reliability Coordinator. The active monitoring would ensure that the Reliability Coordinator is aware of conditions that may arise in the immediate future. This would create consistency with the purpose of the standard which is: *"The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas."*

- **TOP-002 (Normal Operations Planning)** - This Standard may need to be updated to include a section about forecasting, identifying the data submitted by variable generators as the method of providing generation information to the Transmission Operators, and also recognizing forecasting as the best way to estimate generation, albeit subject to some unavoidable uncertainty due to the variability and complexity of weather conditions. This would assist in system operations, especially in day-ahead or hour-ahead operations.
- **TOP-006 (Monitoring System Conditions) –** Requirement 5 discusses the use of "monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action". This Standard may need to be revised to include specific tools such as input from a forecaster and/or real-time data from wind and solar plants such as meteorological towers, sonic detection and ranging (SODAR) and real-time turbine telemetry.

In addition, NERC Reliability Standards that address the reasonable and effective use of regional forecasts and local wind/solar facility forecasts should be encouraged and used to schedule variable generation to assist in accurate system operation.

5. Conclusions and Recommendations

Improved operating practices, procedures and tools can help reliably integrate variable generation into the power system as well as improve the reliability of the power system in the absence of variable generation. Reliability resources such as flexible generation and responsive load are finite. Operating practices, procedures, and tools that reduce variability and uncertainty while they maximize the effective use of limited responsive resources improve reliability and facilitate variable generation integration.

Variability and uncertainty can be reduced through aggregation. Larger aggregations of wind and solar generation are proportionately less variable. Forecast accuracy is also improved for larger wind and solar aggregations. Net variability is also reduced when VER are aggregated with load, and it is net variability that must be balanced to maintain reliability. The pool of flexible resources (generators and responsive load) increase as the size of the BA is increased. Balancing should be conducted over the largest geographic area possible, either through consolidating smaller BAs or through coordinated operations.

Wind and solar forecasts get progressively more accurate closer to real-time. Unit commitment and economic dispatch should be performed as close to real-time as possible. Five minute economic scheduling of generation is common in North America. The IVGTF suggests that those balancing areas who face significant integration of variable resources consider studying the benefits of sub-hourly scheduling to manage the integration of variable generation. Depending on the current or projected BA system characteristics, assuming sufficient transmission is available, there may be benefits to intra-hour interchange scheduling, in the form of reduced ancillary services, more flexibility and ability to manage the variability, while still meeting the requirements of NERC's Reliability Standards.

Conclusions:

1. Increasing system variability increases the importance of operators having visibility to system conditions, access to tools to resolve conditions and clear rules on when to implement those tools.

2. Aggregate forecast accuracy improves with the size of the forecast region.

3. Aggregation across broad geographical regions significantly reduces output variability and associated operating reserve requirements. In general, the aggregate uncertainty should also be mitigated by such aggregation, but the uncertainty and impacts from rare events may require more consideration.

4. Large system or market size and flexibility improve the ability to deal with variability.

5. Methods to ensure efficient prioritization of renewable resources during curtailment conditions are important for both reliability and economics. For example, regional markets should evaluate adding negative curtailment pricing to their dispatch algorithms to encourage logical and efficient responses from all resources.

6. Electrical (power, availability, curtailment) and meteorological data from wind and solar plants, delivered to the forecaster and system operator on a timely and reliable basis, are critical for forecast accuracy and reliable operations.

Recommendations:

1. Wind and solar plants should have the capability to send and receive real-time data (meteorological and electrical) through SCADA systems using standard communication protocols for use in forecasting and system operation.

2. Wind plant output forecasts, often several of them, should be adopted as standard system and market operation tools for economic operation and system reliability purposes. Ramp forecasts as well as hourly energy forecasts should be considered.

3. NERC Regions should consider what control capabilities should be required for new VER to assure reliability. Procedures should be developed that limit the use of VER control capabilities to situations where it is required to maintain reliability or when accepting the energy results in excessive costs.

4. Interconnection requirements for all generation technologies (VER and conventional) need to be designed for anticipated rather than existing conditions, considering aggregate impacts, and effects of displacing conventional generation. Interconnection requirements should address control capability, ride-through, inertial response, voltage regulation, etc. It is difficult to modify requirements on existing facilities after-the-fact.

5. Tools, including visualization, are needed for system operators to process and present the wide-range of information (aggregate forecasts, status of VER, ramping capabilities, geographic coverage of ACE sharing, etc) to the system operator.

6. Changes to operating rules and practices are critical:
   a. Sub-hourly markets with sufficient liquidity, or the ability to otherwise dispatch generation closer to real-time with sufficient flexibility, can be very effective in addressing the variability and uncertainty of variable generation.
   b. Incorporating the variable generation power forecast into unit commitment and dispatch procedures is important for economical and reliable operation.
   c. More frequent unit commitment can use updated forecasts of VER and load.
   d. Consider adjusting reserve requirements based on forecast VER output levels. This would allow the reserves to capture the fact that the volatility of wind output is different for different output levels.
   e. Mechanisms to incent dispatch behavior consistent with system needs. For example, the interaction between variable resources supported by tax credits and renewable energy credits or monetized environmental benefits and a significant proportion of baseload generation with significant minimum generation requirements suggests that the capability to capture negative price offers for resources may be needed to clear markets.

7. The benefits of larger balancing areas with fewer transmission constraints are overwhelming. Resolving transmission constraints is critical because larger balancing areas lose much of the benefits associated with size if constraints are in play. Different parts of the country are exploring how to achieve the benefits of larger areas through direct balancing area consolidation or through efforts at "virtual consolidation" where separate balancing areas work together on particular issues. Smaller areas, such as island systems, will have special challenges that require additional control. Larger operating areas, with minimal transmission constraints and diverse variable generation assets, should be capable of dealing with the expected levels of variable generation.

8. Input into the NERC Standards process has suggested potential enhancements for consideration by the Standards Authorization Drafting Groups.

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Appendix I: Regional Reserve Requirements and Operating Practices

This appendix provides region specific details on reserve requirements and operating practices as they relate to variable renewable generation integration. The lists are not comprehensive in terms of either the organizations addressed or even the requirements within each organization. Instead it provides a sampling of requirements to provide a general idea of current practices.

A-1 Contingency Reserves

Contingency reserves are required to respond to sudden loss of generation and to restore the frequency within the first few minutes of an event.

Common Practice

Many entities (ISO-NE, NYISO, IESO, …) establish a ten minute reserve requirement based on 100 percent of the largest credible contingency with at least 50 percent required to be spinning reserve and the remaining being non-spinning reserve. Thirty minute reserves are required to cover 50 percent of the second largest credible contingency.

Spinning Reserve is that unloaded Operating Capacity available on units connected to and synchronized with the interconnected electric system and ready to take load immediately in response to a frequency deviation. Many entities allow technically capable responsive loads to provide spinning reserve. Non-spinning reserve is that amount of Operating Capacity or the equivalent, some or all of which may not be connected to the interconnected network but which can be connected and fully applied to meet the NERC DCS requirements (fast-start generation). All entities allow technically capable responsive loads to provide non-spinning reserve.

CAISO

The CAISO contingency reserve requirement is determined as the greater of the largest credible contingency or 5 percent of the load served by hydro generation and 7 percent of the load served by thermal generation. At least half of the contingency reserve must be spinning reserve. Spinning reserve must be synchronized to the system, must be frequency responsive and the awarded spinning reserve capacity must be deliverable within a 10-minute timeframe from notification to deliver the spinning reserve.

The CAISO currently procures one-hundred percent (100 percent) of its Ancillary Services requirements in its day-ahead market. Incremental Ancillary Services is procured as needed in the real-time market.

ERCOT

ERCOT Responsive Reserve Service is a ten minute reserve service. ERCOT procures a minimum of 2300 MW however this value can go as high 2800 MW under extreme conditions. The decision to procure up to 2800 MW is based on a Reserve Discount Factor (RDF). The RDF is intended to represent an average amount of system wide capability that has been shown to be historically undeliverable. ERCOT's Responsive Reserve amount exceeds the ERCOT Contingency Reserve requirement, which is set equal to the most severe single contingency.

Non-spinning reserve service is a 30 minute product in ERCOT. The MW requirement for Non-spinning reserves is calculated for each hour of the day each month. Historical wind forecast errors and load forecast errors are used in determining the MW values.

Demand side resources can provide up to 50 percent of the Responsive Reserve in ERCOT. Responsive Reserve can be provided by:

- Unloaded Generation Resources that are On-line
- Resources controlled by high set under-frequency relays
- Direct Current (DC) tie-line response. The DC tie-line response must be fully deployed within fifteen (15) seconds on the ERCOT System after the under frequency event

Load following energy and Non-spin reserves are deployed as practicable and if necessary to minimize the use of the 10 minute reserves.

Non-spinning Reserve can be provided by:

- Off-line Generation Resource capacity, or reserved capacity from On-line Generation Resources, capable of being ramped to a specified output level within thirty minutes
- Loads acting as a Resource that are capable of being interrupted within thirty minutes and that are capable of running (or being interrupted) at a specified output level for at least one hour

Hawaii Electric Light Co. (HELCO)

HELCO operates a small autonomous grid on Hawaii Island and is not subject to NERC operating criteria. HELCO's contingency reserve policy requires sufficient generation be available to cover the anticipated peak demand after loss of the largest online unit. To minimize production costs, HELCO considers the capacity of offline available units, in addition to online reserve capacity, in calculating the available contingency reserve. Loss of any of the larger generators during on-peak conditions often results in underfrequency load-shedding. HELCO maintains a fleet of small diesel units for fast-starting reserves; these units can typically cover generator contingencies and allow restoration of shed load within five to ten minutes. The addition of significant wind resources has lead to an increase in available online up-reserves as compared to historical reserves, due to must-run units operating at reduced outputs to accommodate wind production. The amount of must-take energy often results in excess energy during off-peak conditions, requiring all dispatchable units to be brought to minimum (with consideration for down-reserves) followed by curtailment of must-take energy resources which include wind, geothermal, and run-of-river hydroelectric resources. The frequent excess energy condition led to the need to define a minimum down-reserve, to be determined by the largest single contingency loss of load.

Midwest ISO

The day-ahead Midwest ISO (MISO) market-wide contingency reserve requirement is based on largest MISO contingency. Non-spinning reserve is called Supplemental Reserve in MISO. MISO carries around ~1050 MW Supplemental reserve and between 704 and 800 MW Spinning Reserve.

MISO also calculates Zonal Minimum Operating Reserve requirements to electrically disperse Reserve so as to deliver them reliably when needed. Wind Forecast is used in the study process that determines the minimum Zonal reserve requirements.

SPP

The SPP RTO does not procure Operating Reserves. Each individual Balancing Authority within SPP is required to comply with the SPP Criteria regarding Operating Reserves. The Spinning Reserve allocated to any generating unit shall not exceed the amount of capacity increase that will be realized by prime-mover governor action due to a drop in frequency to 59.5 Hertz (less than or equal to 16.7 percent of unit capability at a 5 percent droop setting).

Non-Spin/Supplemental Reserves are called Ready Reserves in SPP. SPP specifically allows non-spinning reserve from a number of additional resources:

- Operating Capacity made available by voltage reduction. The voltage reduction shall be made on the distribution system and not on the transmission system.
- Operating Capacity that can be fully applied from a change in the output of a High Voltage Direct Current terminal.
- Interruptible pumping load on pumped hydro units.
- Generating units operating in a synchronous condenser mode.
- Operating Capacity and contingency reserve, provided firm transmission has been purchased, being held available under contract by another Balancing Authority above its own operating reserve requirements and available on call.
- Operating Capacity that can be realized by increasing boiler steam pressure, by removing feed water heaters from service, and/or by decreasing station power use.

WECC

The WECC contingency reserve requirement for BAs or reserve sharing is the greater of the largest credible contingency or 5 percent of the load served by hydro generation and 7 percent of the load served by thermal generation. At least half of the contingency reserve must be spinning. Reserve Sharing Groups in WECC also have practices and rules that impact the location and deployment of contingency reserves.

A-2 Regulation

Regulation is the centralized control of real-power generation or consumption by the system operator in order to control ACE and meet NERC CPS 1 and 2 requirements.

Common Practice

AGC signals are typically sent to regulating resources every 4 seconds. The regulation quantity is determined by each BA based on how much is required to meet the CPS standards and is often in the range of 1 percent to 3 percent of the peak BA load, depending on the BA size (larger BAs require relatively less regulation).

BPA

Balancing reserve requirements are determined via a method that uses the historical errors of wind and load (except wind imbalance due to forecast error has been adjusted downward to assume ongoing forecast improvement) to arrive at a combined reserve requirement. As variable generation increases there is a much smaller increase in the balancing reserve requirement to continue to provide a 99.5 percent confidence of having sufficient balancing reserves to meet extreme wind/load deviations.

CAISO

The CAISO's real-time market is executed every 5-minute to balance load and resources on a forward-looking basis above and beyond the normal function of its Automatic Generation Control (AGC) algorithm. Since the real-time market is forward looking, AGC is mainly a control rather than an energy service responding to short-term imbalances caused by frequency and interchange deviations. Regulation in the CAISO's Balancing Authority area is defined as the difference between the actual generation requirement and the short term 5-minute forecast.

The CAISO currently procures Regulation up and Regulation down separately and in different amounts for each hour to address the fact that operational needs for Regulation vary throughout the day. Regulation up and Regulation down are determined separately for each operating hour and is based on the maximum expected coincidental 10-minute changes in the Demand forecast, Generation Self-Schedule changes, and hourly Intertie fluctuation. The CAISO calculation of Regulation requirements begins and ends in the middle of the hour in order to capture ramp changes between hours. The regulation requirement identifies the worst coincidental peak ramp rate in 5 minutes and assumes the ramp continues for 10 minutes.

The CAISO does not typically recalculate the variable Regulation requirements in its real-time market, however if necessary adjustments could be made in the real-time market. Efforts are currently underway to modify the existing regulation procurement method with a tool that calculates the Regulation requirement needs in the day-ahead and real-time markets based on the latest load, wind and solar forecast and stochastic characteristics, day-ahead market awards and self-schedules, and hour-ahead intertie awards and self-schedules.

ERCOT

Regulation is dispatched every 4 seconds in ERCOT based on system frequency deviations from scheduled frequency. Regulation can be provided by generation resources and controllable load resources.

The MW requirement for each hour of the day is determined monthly. The amount of MWs procured is based on the amount historically deployed and the amount of time in which regulation service was exhausted. Additionally, the amount wind generation resource capacity that has come into the system since the historical deployments took place is considered.

HELCO

AGC operates in constant frequency control (CFC) mode. Regulating reserves are maintained as the minimum amount of up and down reserves on units responsive to AGC regulation, to balance the system within the hour. As an autonomous system without interties, all system imbalance manifests itself as frequency error and therefore supplemental regulation control must return the system to target frequency as soon as possible. All regulation is provided by conventional generating units. A policy has been established to have no fewer than three units on regulation control at any time, to provide for sufficient system response capabilities following loss of one of the regulating units. AGC operates on a 4 second cycle.

The regulating reserve requirement for each hour of the day is determined by the system operator. Historically, the regulating reserve could be kept very small, due to the fact that demand was very stable (approximately 2% of system demand). In determining the reserve requirements today, the system operator considers the anticipated changes in demand and the observed variability of the wind resources on the system. Wind plant production is presented in a strip-chart format for the past hour, as well as the measured wind speeds at the wind facilities and system frequency. When wind production is high (wind speeds allow maximum output) or low (wind is at minimum) regulating reserves are not increased to cover wind variability, but when wind production is in the mid-point of production, regulating reserves are increased. Wind plants are often the primary driver of system frequency error. Several changes were made to AGC to avoid exacerbating frequency error by attempting to correct for minor wind-production variations induced in frequency variations, including increasing the no-control ACE deadband. Even with these changes, the addition of wind resulted in a large increase in the number and magnitude of regulation controls to those units participating in supplemental regulation.

The high penetration of distributed solar (approximately 6% of daytime loads) has recently increased the challenges for the system operator by changing the apparent demand on the system. HELCO is experimenting with ways to estimate the solar production in real-time to assist the system operator in determining the impact on regulating reserves. Due to the large amount of must-take energy on the system, the average regulating up-reserves have somewhat increased. Production of wind energy during minimum demand periods has resulted in a significant decrease in average down regulating reserves.

Figures A-1 and A-2 show the average reserve for each hour of the day for periods prior to and following the addition of a 20.5 MW wind plant on the HELCO system in 2007.

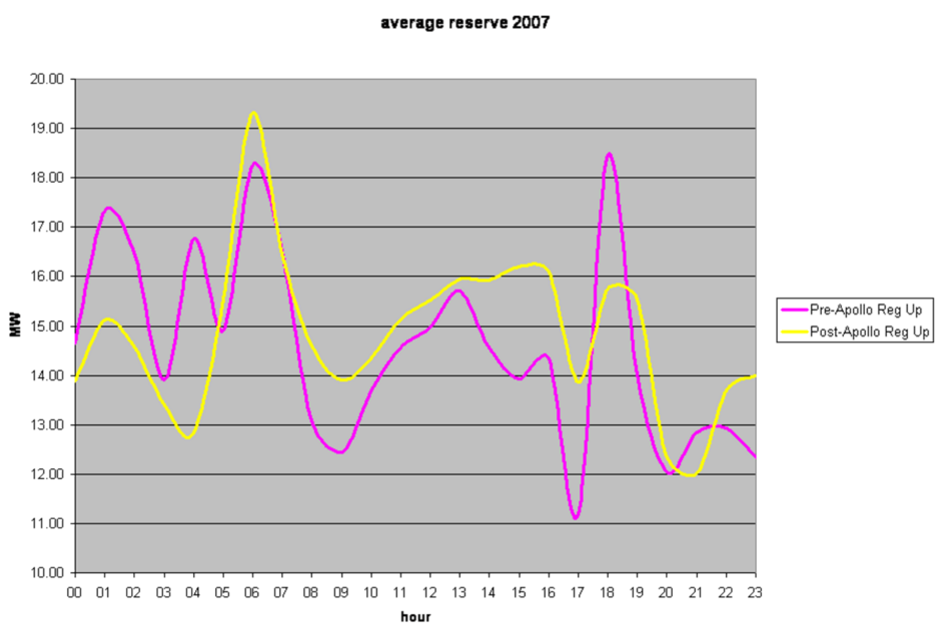

Figure A-1 Impact on HELCO average regulating reserve up following addition of a 20.5 MW wind plant.

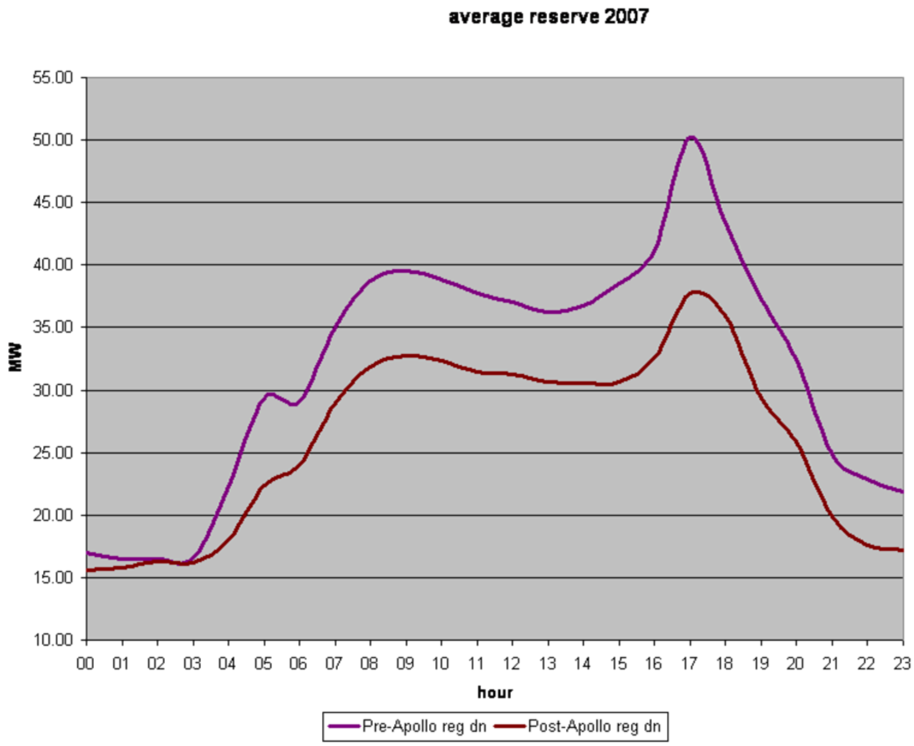

Figure A-2 Impact on HELCO average regulating reserve down following addition of a 20.5 MW wind plant

MISO

Midwest ISO (MISO) market wide regulating reserve requirements are established and posted for each hour of the operating day no later than 48 hours prior to the operating day. The requirements are reviewed daily to ensure compliance with ERO standards. Based on CPS compliance requirements and Midwest ISO load profiles, regulating reserve for flat load periods is determined to be around ~400 MW and for ramping periods ~500 MW.

A-3 Control Requirements and Ability of Variable Resources to Provide Reserves and Response

In general, wind plant operators must have control of their facilities and respond to system operator commands. The ability of variable renewable generators to supply reserves differs from region to region.

BPA

Variable generation effectively provides over generation reserves via feathering for tail events when balancing reserves are exhausted and that resource is over generating, Curtailment is also used for local transmission issues. Because a high proportion of variable generation is exported, curtailments are used for under generation tail events. BPA is in the process of testing a pilot program to allow self-provision of balancing reserves. The pilot began in September 2010. To date potential self providers have indicated an intention to employ dispatchable generation as the primary tool of self-supply, but variable generation feathering is also an option.

BPA is also exploring mid-hour schedule changes to allow variable generation schedulers to use other resource to absorb or back up variable generation error and protect against feathering or curtailment orders.

CAISO

The CAISO is exploring market rules and incentives to encourage greater participation by wind and solar resources in its economic dispatch. Greater economic dispatch control, including curtailment and ramp rate limitations, can be used in targeted circumstances to mitigate over-generation or shortfalls in regulation and load following capability.

The CAISO is also proposing to modify provisions in its tariff to facilitate the participation of non-generator resources in its ancillary service market on a comparable basis with generators. The modification would include reducing the minimum rated capacity for a generator or non generator resource to provide ancillary services from 1MW in size to 500 kW in size. The CAISO is also proposing to reduce the continuous energy for ancillary service from the existing 2 hours requirement to 30 minutes for spinning and non spinning reserve, 60 minutes for day-ahead regulation, and 30 minutes for real-time regulation. The CAISO believes these changes would create opportunities for more demand response as well as a broader spectrum of resource types to participate in its ancillary services markets.

The CAISO is also exploring mid-hour schedule changes for variable generation as a means of real-time balancing needs.

ERCOT

Variable generation resources are expected to be able to respond to dispatch instructions from ERCOT. There are also rules which require newer wind generators to provide governor-like response to frequency deviations.

Wind generators must limit ramp rates to 10 percent per minute when responding to or releasing from an ERCOT deployment, except during Force Majeure events, or if there is a demonstrated decrease in available wind resources, or if a wind generator operating under a Special Protection Scheme (SPS) is decreasing output to avoid SPS activation. ERCOT can also request wind generators to ignore the ramping limit requirement if necessary to maintain system reliability.

HELCO

Wind plants can receive direct curtailment control instructions from the system operator, which are most often utilized for excess energy conditions, but also on occasion for transmission system constraints or when the wind plant is a major contributor or cause of another system problem. Variable generation resources must respond without delay to dispatch instructions from the system operator. The curtailment is a continuous control which sets an upper limit for the plant output. The minimum curtailment is to zero. Curtailment is implemented through the wind plant control system and has the effect of also smoothing wind plant output. The curtailment has been used on rare occasions to smooth wind output when extremely volatile wind conditions resulted in excessive frequency control problems (+/- 0.1 Hz). When curtailing for excess energy conditions, the system operator will curtail resources according to a fixed order of priority.

Wind generators must limit ramp rates to two MW per minute when responding to or releasing from curtailment, during startup, and during wind up-ramps. The ramp rate is not enforced during loss of wind. In order to avoid causing a system disturbance or underfrequency load-shed event due to high wind-speed shutdown, the wind plants perform self-curtailment when wind speeds approach the cutout levels.

IESO

Wind plant operator must follow requests within 5 minutes of notification. Variable generators must keep production schedules as up to date as possible.

ISO-NE

Plants must have control over facilities and accept curtailment instructions by the ISO 24/7. Variable generators are allowed to provide reserves if they meet the technical requirements. Wind plants are allowed to participate in economic dispatch, but are not required to participate. Generally they self scheduled energy into the real-time market.

MISO

Intermittent Generation resources are not eligible to submit Operating Reserve Offers in Midwest ISO Market. MISO allows intermittent resources to inject energy freely (price takers in Real Time market), with Security constraint economic dispatching around the intermittent in order to stay within the physical transmission system limitations. However, after the MISO Reliability Coordinator has exhausted SCED and TLR relief and there is still congestion and the intermittent resource is contributing to congestion, the RC may issue a manual curtailment/redispatch. In 2011 MISO is planning on implementing the Dispatchable Intermittent Resource product to allow variable generation to offer into the Real Time Energy Market and respond to dispatach signals generated by the Security Constrained Economic Dispatch System.

NYISO

Wind plants must be able to accept electronic basepoint signals. During constrained operations, wind plants must follow the re-dispatch signal and meet the basepoint output limit within 5 minutes. Penalties for non-compliance equal to MW above basepoint multiplied by the regulation clearing price. A 3 percent error is allowed. Variable generators are allowed to provide reserves if they meet the technical requirements.

SPP

Variable generators are allowed to provide reserves if they meet the technical requirements.

A-4 Use of Demand Response

Demand response is increasingly being used as a power system reliability resource.[6] It may be effective at reducing variable renewable generation integration challenges. In 2007 FERC issued order 890 which states "Demand response must be evaluated on a comparable basis to services provided by generation resources in meeting mandatory reliability standards, providing ancillary services and planning the expansion of the transmission grid."

BPA

Demand side resources are allowed to provide non-spinning reserve and BPA is implementing a Smart Grid initiative which includes small amounts of demand resources responsive to variable generation under generation.

CAISO

The CAISO is in the process of refining its systems, tools and market rules to fully integrate all forms of demand response to enhance the efficiency of its markets and to enable the integration of renewable energy resources. Specifically, the CAISO is expending efforts on price responsive demand response, dispatchable demand response and demand response in context of smart grid technology. Price responsive demand is expected to represent the majority of demand response whereby customers can choose to consume or not consume based on receiving timely energy prices that reflect grid conditions. The CAISO allows dispatchable demand resources to operate in the wholesale market in accordance with the requirements and time-scales of its markets. Like generators, these resources are modeled in the CAISO's systems and are scheduled, bid and settled through the market. Smart grid technology would enable the integration and participation of high volume of smaller distributed resources to autonomously respond to prices that reflect grid conditions or to aggregate into resources of sufficient size to participate into the ISO markets.

ERCOT

Demand side resources are allowed to provide at least some amount of regulation, responsive reserve, and non-spinning reserve.

HELCO

Underfrequency load-shedding is utilized in lieu of online contingency reserves. Loadshedding for typical loss of generation events is restored within five to ten minutes, by bringing online fast-starting diesel units. The fast-starting diesel units have also been used to restore system balancing due to wind ramp events. The underfrequency load-shed scheme was modified, in part to address wind down-ramp events, to add a time-delay block to operate at a higher frequency with a time delay. HELCO has also used curtailable loads for anticipated generation shortfalls; these loads were dispatched by phone instruction rather than through automated controls.

IESO and NYISO

Demand response is used as part of reliability products under the emergency capacity and energy plans as well as providing energy in Day Ahead and Real Time markets under Day Ahead and Real Time price programs.

Over 10 percent of ISO-NE and 5 percent of NYISO Capacity is procured as demand response.

MISO

Demand response Type-1 (physical load interruption) can only provide contingency reserve. Demand response Type-11 (controllable interruption) can provide Regulating and Contingency reserve.

SPP

Demand side resources, called Variable Dispatch Demand Response, are a dispatchable resource that can respond to interval level dispatch instructions issued by SPP to reduce the withdrawal of energy from the transmission grid.

A-5 Energy and Ancillary Service Market Structure

Many regions (ISO-NE, NYISO, and MISO) have day ahead and hour ahead location based energy markets (LMP). They have day-ahead hourly ancillary service markets.

BPA

Energy markets in the Pacific Northwest are bilateral. BPA provides Balancing Reserves, Energy and Generation Imbalance and Contingency Reserves as ancillary services.

CAISO

The CAISO operates day-ahead and real-time markets. The day-ahead market closes for bid and schedule submission at 10:00 A.M., the day prior to the operating day. The variability in wind and solar generation, coupled with the variability in load, will have an impact on both the regulation and load following requirements. The inability to accurately account for anticipated output from variable resources in the day-ahead timeframe can therefore significantly impact the commitment of conventional resources used in real-time.

The CAISO's real-time market closes 75 minutes before the operating hour. The objective of the real-time market is to execute a 5-minute dispatch to balance load and resources on a forward-looking basis. Under normal operating conditions, the CAISO's real-time pre-dispatch and real-time economic dispatch processes work together to ensure enough capacity is on-line to meet real-time demand. Significant wind variability and the lack of an accurate wind forecast can result in inadequate capability to meet 5-minute demand variations.

Wind generation contributes to uninstructed deviation because wind production levels can change significantly from one dispatch interval to the next. Conventional resources are expected to remain at their operating point from one 5-minute operating interval to the next 5-minute operating interval if the resources are not instructed to move to new operating levels. On the other hand, since wind generation output changes frequently and significantly, the hourly schedule of wind generation does not represent the actual wind generation. The dispatch of conventional resources cannot accurately reflect the actual output of wind generation. As more variable resources are integrated into the grid, Balancing Authorities are faced with increase challenges due to the unpredictability and variability of variable resources. Studies done by the CAISO indicated that the integration of more variable generation into its operating jurisdiction increases the requirement for the load-following capability as well as regulation capability [11]

ERCOT

ERCOT has a bilateral market for day-ahead energy and a zonal energy imbalance (real-time) market. ERCOT is transitioning to a Day-Ahead and Real-Time LMP-based energy market in late 2010.

IESO

Real-Time market based on a Province-wide clearing price for energy. Energy suppliers can commit resources in day-ahead commitment process; market clearing prices and dispatch still set in real-time market.

[11] Integration of Renewable Resources, November 2007, transmission and operating issues and recommendations for integrating renewable resources on the California ISO-controlled Grid http://www.caiso.com/1ca5/1ca5a7a026270.pdf

SPP

SPP operates a Real Time Energy Imbalance Market and is working on Day-Ahead LMP-based energy and ancillary services markets.

A-6 Scheduling Variable Generation Energy

BPA

Wind power is scheduled by individual market participants who receive Generation Imbalance service for schedule errors. During system over or under generation events inaccurate schedules are limited or curtailed to contain the event.

CAISO

Wind and solar resources are not required to bid in the CAISO's day-ahead market but are required to self-schedule in the real-time market. Although wind resources are not required to bid into the day-ahead market, scheduling coordinators may submit schedules. Accordingly, for the wind production not scheduled, the CAISO must forecast and integrate the wind's expected hourly production into the day-ahead market software applications to both ensure that adequate resources are committed for the next trading day and that resources are not overcommitted. In this way, the forecast of expected wind production influences the quantity of capacity committed in the day-ahead and real-time markets.

Wind production in California is especially hard to predict because it does not follow a predictable day-to-day production pattern. Figure A-3 shows the daily wind production patterns for the month of April in the Tehachapi area. The heavy green line shows the average hourly production for the month.

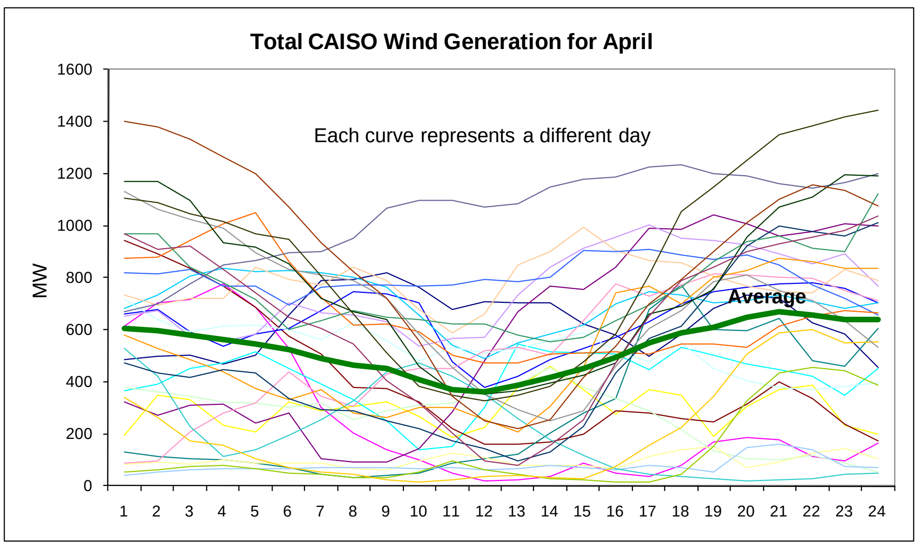

Figure A-3: Daily Production of a Wind Area for the month of April

As wind and solar capacity becomes a larger component of the generation portfolio, the probability of inexact commitment in the day-ahead market becomes greater. Such circumstances will present operational challenges absent significant flexibility in the conventional generation fleet, i.e., available quick start units, resources that can provide regulation and/or resources with fast ramping capabilities.

ERCOT

Wind is scheduled like other resources, as part of a Qualified Scheduling Entity's (QSE) portfolio. ERCOT requires the low sustainable limit for wind generators to be set at most to 10 percent of the resource's registered nameplate capacity. Wind generators in service before 2003 are exempt.

IESO

Variable renewable generators are required to submit energy forecasts. Energy from variable renewable energy generation is accepted as generated—wind resources are treated as price-takers.

ISO-NE

Variable generators can submit a bid curve or self-schedule into the day-ahead market, but they not required to do so. Resources with a Capacity Supply Obligation must offer or self-schedule into real-time market.

HELCO

Wind, hydro and solar production are treated as must-take energy unless system constraints prevent its acceptance (i.e.; excess energy, transmission constraints, or other system impact).

MISO

Intermittent Resources must submit a Day-Ahead forecast of its intended output for the next day. Wind Resources are treated as Price takers in the Real Time Energy Market. Set Points for wind are equal to the output of the unit in real-time. In 2011 MISO is planning on implementing the Dispatchable Intermittent Resource product to allow variable generation to offer into the Real Time Energy Market and respond to dispatch signals generated by the Security Constrained Economic Dispatch System.

NYISO

Wind bids a price curve that can include negative prices. Bidding is required for real-time and is optional for day-ahead. Wind is scheduled with other generation. The price-quantity offers submitted by each wind plant will determine the basepoint economic dispatch for each wind plant.

SPP

Wind is scheduled by individual market participants. The schedule is only a hedge and ignored during dispatch. Intermittent generator dispatch instructions are an 'echo back' of the SCADA seen at the time the snapshot is taken for the dispatch interval.

A-7 Wind Forecasting Requirements

Regions differ in forecasting requirements. Some employ centralized wind and solar generation forecasts while others require each plant to provide a forecast of its output.

BPA

BPA uses a centralized wind forecasting system for system prep in real-time. Wind plants use their own forecasts for scheduling purposes. BPA is working with wind plant owners on data requirements to enhance forecasting and state awareness.

CAISO

The CAISO uses a centralized forecasting provider to forecast wind and solar production in the day-ahead and hour-ahead timeframes. An advisory day-ahead production forecast is provided at 05:30 for 18 hours to 42 hours ahead of time and is updated daily. A refined forecast is provided 105 minutes before each operating hour with a seven hour advisory forecast. Only wind and solar generators participating in the CAISO's Participating Intermittent Resource Program[12] (PIRP) are required to schedule to their hour ahead forecast. The scheduling coordinators representing the PIRP resources must use the hour-ahead forecast to submit their bids in the hour ahead scheduling process and real-time market. PIRP resources that schedule consistent with the CAISO's rules and timelines are entitled to a monthly averaging of locational marginal prices (LMPs) associated with their uninstructed imbalance energy deviations netted over the month as opposed to settlement of actual deviations at the actual LMPs. This enables variable resources to smooth out the financial impact of output deviations, which are otherwise settled at real-time five minute LMPs.

For the wind production not in PIRP, the CAISO must forecast and integrate the wind and solar expected hourly production into the day-ahead market software applications to both ensure that adequate resources are committed for the next trading day and that resources are not overcommitted.

ERCOT

ERCOT has a centralized forecast of wind power output both for the aggregate and for the individual wind generation resources. Forecasts are created for each hour for a rolling 48-hour period. Two separate forecasts are created for each hour. The first is the most likely resource output for that hour and second is an 80 percent probability of exceedance forecast. The most likely resources output forecast is used for day ahead capacity studies. The error in this forecast is used in determining the Non-spin Reserve Service requirement for each month.

IESO

Wind operators provide individual forecasts. Forecasts must be provided by 11 a.m., covering every hour of the remainder of that day and the next day. Wind operators must provide updates if actual output is reasonably expected to differ from the forecast by 2 percent or 10 MW, whichever is greater. A persistence forecast is used for real-time scheduling. IESO will adopt a centralized forecasting in 2010.

ISO-NE

Completed by Resource Owner and included in unit commitment. A persistence forecast is used in real-time.

[12] The PIRP program requires wind and solar resources to self schedule into the real-time market.

HELCO

There is no requirement to provide advanced notice or forecast of production by transmission or distribution connected wind, solar, and hydro resources. Maintenance activities for the transmission-connected facilities are typically communicated to the system operator but may be the same day as the maintenance is performed. All wind and solar forecasting is done by the system operator. The system operator uses the actual wind production trends from the past hour for near-term wind forecasts. Hours-ahead and day-ahead wind forecasts are developed by the system operator from publicly available marine weather forecasts. HELCO is working with NREL and AWSTruePower on research into field equipment measurements for observational targeting to improve intra-hour and near-term forecasting of the production from the most variable large wind plant. Of particular interest is capturing periods likely to have intra-hour variability or ramp events, and therefore, require additional online reserves. Run of river hydro is fairly stable and near-term forecasting can be quite accurately estimated from weather conditions.

MISO

Midwest ISO uses a centralized forecasting system. Forecasting is done at the CpNode level, Zones, Regions and MISO Market total. Hourly forecasts for 7 days are updated hourly. Wind Forecast data is used in Daily Reserve requirement calculations and also in the Reliability Assessment Commitment Process.

NYISO

NYISO uses a centralized wind forecasting system. Wind plants must meet technical requirements and provide meteorological data. The forecast is used in the day-ahead unit commitment. The real-time wind forecast is integrated into real-time commitment and dispatch.

SPP

SPP wind forecasts are provided by individual market participants. Hourly schedules are updated from the day-ahead Resource Plan/Native Load Schedule submittals. The forecasts are used by the individual market participants.

Appendix II: International Wind & Solar Integration, Techniques & Operating Practice

Operating experience from Spain, Germany and Denmark, three countries with high wind penetration, provide insights into reserve requirements, sub-hourly energy scheduling, and forecasting practices. The information in this appendix was drawn from the Northwest Wind Integration Forum Technical Work Group workshop on International Large Scale Wind and Solar Integration Techniques and Operating Practices: Germany, Denmark, and Spain. The workshop was held on July 29 and 30, 2010 in Portland Oregon.

B-Spain

Spain currently has 19.2GW of wind power, 3.4GW of solar PV, and 0.5GW of solar thermal generation operating in a power system with a peak load of 45.5GW. There is 61.2GW of conventional generation providing a 35 percent reserve margin. Wind supplied 14 percent and solar supplied 2 percent of the electricity supply in 2009. Peak wind generation was 12.9GW on 2/24/2009 and maximum wind penetration was 54 percent on 11/8/2009. Wind generation is expected to grow to 29GW and solar is expected to grow to 4.5GW by 2016 and 40GW and 15.5GW respectively by 2020. 73 percent of the wind is connected at the transmission level and is observable by the system operator. 27 percent must be estimated. [49]

The transmission system operator (TSO) operates a day ahead energy market and four intra-day energy markets. Variable renewable are reported to have no impact on the primary or secondary reserve requirements and minimal impact on the tertiary reserves.

B-1 Reserves

Spain uses the three European reserves (primary, secondary, and tertiary reserves) and running or hot reserves.

Primary Reserve: Individual generators respond to frequency deviations within 30 seconds and sustained for 15 minutes (approximately North American governor response). Wind generation has no impact on primary reserve requirements.

Secondary Reserves: Generators on AGC respond to system operator control commands to control frequency and intertie flows to France. Generators respond within ~2 minutes and sustain response for 15 minutes (approximately North American regulation). Wind generation ramps only slightly affect secondary reserves when the ramps are opposite to system demand. There is presently no need to contract for additional secondary reserves.

Tertiary Reserves: Generators offering energy response within 15 minutes and sustained for up to 2 hours (approximately North American load following). Tertiary reserve requirements are only slightly affected by wind generation ramps when these ramps are opposite to system demand. Figure A-2 shows that tertiary reserve procurements have not increased significantly with increased wind penetration.

Running Reserves or Hot Reserves: Manageable generation reserves that can be called upon within 15 minutes to approximately 2 hours. Include tertiary reserves and consist of the running reserves of connected thermal units and hydro and hydro pump storage reserves. Wind generation forecast errors significantly increase running reserve requirements. of wind power.

Required reserves are determined stochastically considering wind forecast error, load forecast error, and conventional generation contingency requirements. "With the help of the combined probability density function, the required reserve levels at different time horizons and with different confidence intervals can be calculated."

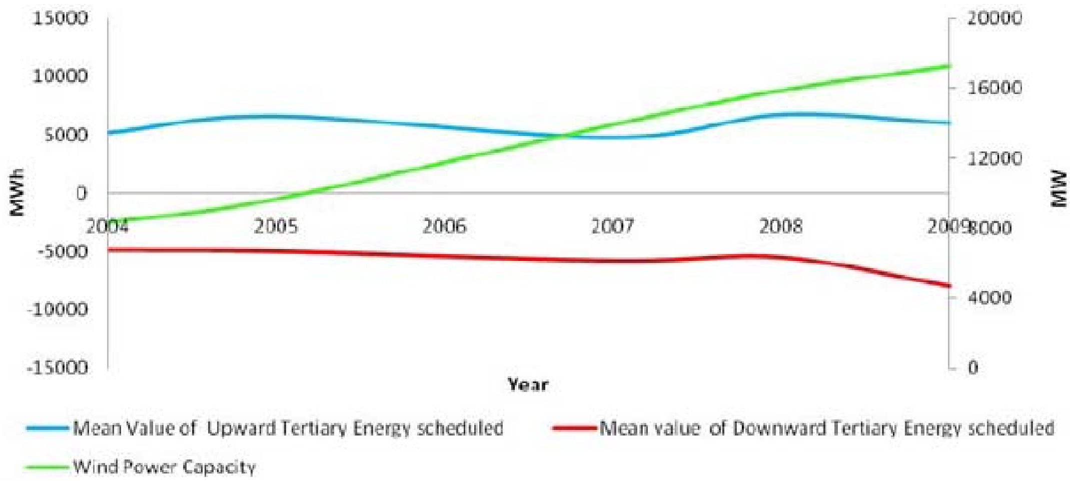

Figure B-1-1: The increase in wind generation has had no impact on primary or secondary reserve requirements and minimal impact on tertiary reserve requirements in Spain.

B-2 Scheduling Wind Power

At 11am, after the day-ahead bilateral schedules are received, the system operator uses the 85 percent confidence wind forecast to determine if sufficient conventional units are scheduled to operate and commits additional generation if required. Wind power may only be curtailed as a last resort if required to maintain reliability. Wind must offer full production at best forecast estimate. The power system must take the variable renewable generation ahead of all other generation: "Renewable non manageable generation will be reduced only in those cases in which it became the only way to solve the technical constraint." Variable renewable generation keeps 15 percent of the energy payment if it is curtailed in real-time for reliability reasons. All generators, including wind and solar, must pay energy imbalance costs for deviations from schedules. The maximum ramp experienced with 19GW of installed wind has been 1800MW over two hours or roughly ±1500MW/hour. Demand ramps are significantly greater at 4000MW/hour. Wind is now required to ride through voltage dips.

B-3 Forecasting

Spain uses a central forecast for all wind resources. An hourly wind production forecasts covering the next ten days is updated hourly. A nodal 15 minute wind production forecasts for the next 48 hours is updated every 15 minutes. Statistical forecasts predict 15 percent, 50 percent, and 85 percent confidence bands. Forecast accuracy has been steadily improving as shown in Figure B-3-1:. The system operator uses five independent forecasts to obtain this accuracy and finds it very useful for reliable operations.

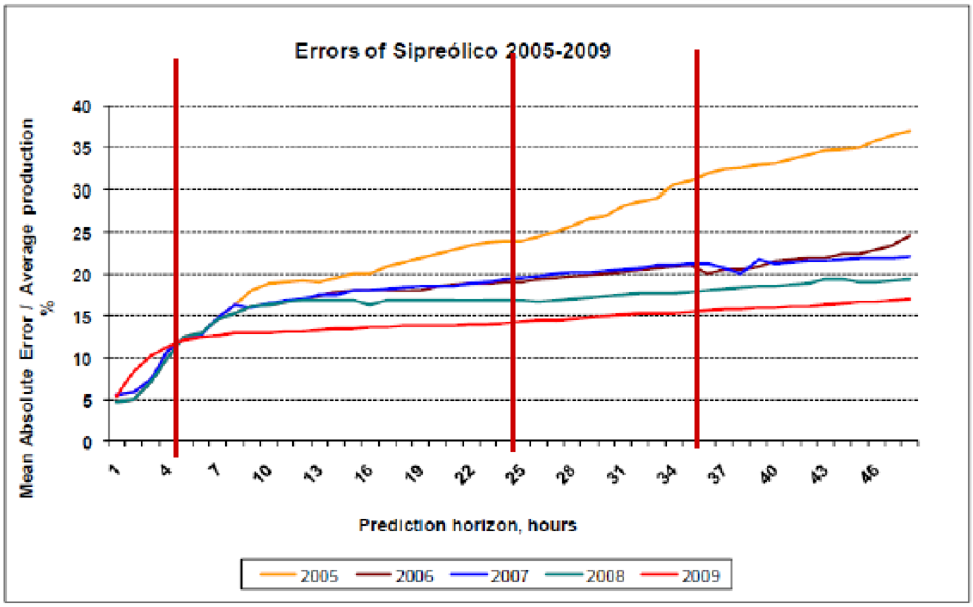

Figure B-3-1: Spain's central wind forecast accuracy has steadily improved since 2005.

C-Germany

Germany currently has 26GW of wind and 10GW of solar PV operating with a peak load of 80GW. Wind and solar supplied 8.0 percent and 1.3 percent of Germany's electricity respectively, in 2009. Germany has a 30 percent RPS goal for 2020 and expects to increase the wind fleet to 48GW with the additional capacity being off shore. Most of the wind and solar generation is currently connected at the distribution level and the transmission operator has only limited visibility of the generation output. The largest ramp events have been 5GW over 8 hours. [49,50]

Four Transmission System Operators (TSOs) operate the German power system. German TSOs are obligated to connect renewable generators though the generators pay for the interconnection (except offshore wind). The TSO is obligated to upgrade the transmission system if that is required to integrate the renewable. Wind plants greater than 100kW are now required to have remote control capability. They are also paid a bonus if they have fault ride through, reactive power, or frequency response capability.

TSOs are required to purchase wind and solar generation connected to their systems. They resell the generation in the wholesale market and are reimbursed for any price difference through an uplift charge paid by all customers. An equalization scheme shares the obligation among the four TSOs based on their load ratio share.

Germany is directly interconnected with eight other European countries. Loop flows have been a historic problem for decades. The introduction of large amounts of wind in northern Germany adds to the loop flow problem with power flowing out of Germany through the Netherlands, Poland and the Czech Republic and returning to southern Germany through Austria, Switzerland, and France. Interestingly, Nordpool is often able to help reduce congestion in Central Europe by forcing counter flows through Denmark, Norway, Sweden and Finland by controlling DC ties.

C-1 Reserves

Germany uses the three European reserves plus a “special wind reserve”. Variable renewable are reported to have no impact on the primary or secondary reserve requirements and minimal impact on the tertiary reserves. The special wind reserve is small and seldom used.

Primary Reserve: Individual generators respond to frequency deviations within 30 seconds (approximately North American governor response). Germany is responsible for 630MW of primary reserve or about 0.8 percent of peak load. All of Europe requires 3000MW of primary reserve. Primary reserve capacity is procured through a market.

Secondary Reserve: Generators on AGC respond to system operator control commands within 15 minutes (approximately North American regulation). Hydro plants typically fill the secondary reserve requirements. The German TSOs typically procure about 2,200 MW of down regulation and 2,700 MW of up regulation capacity or the regulation up capacity or ~±3 percent of peak load. Secondary reserves are paid for capacity for being available and energy when they are required to respond.

Tertiary Reserves: Generators offering energy response within 15 minutes (approximately North American load following). Capacity is procured day-ahead and energy is dispatched in economic order. German TSOs procure about 2,400 MW of the downward capability and 2,300 MW of the upward capability tertiary reserve capacity ~±3 percent of peak load.

Special Wind Reserves: Some German TSOs procure an additional small amount (±150MW) of wind reserve that is infrequently used.

C-2 Energy Markets

There are four energy markets: day-ahead hourly, intra-day (4 periods of six hourly intervals), reserve energy, and balancing energy. The large amount of wind results in negative energy prices when wind production is high.

C-3 Forecasting

Germany uses a central wind forecasting system to greatly increase forecast accuracy. A single wind plant typically has a root mean square (RMS) day-ahead forecast error of 10 percent to 20 percent. A single TSO may have 7.5 percent to 10 percent RMS error. A central forecast for all of Germany reduces this error to 5 percent to 7 percent. This error is further reduced to 4.5 percent through combinatorial forecasting employing ten individual forecasts.

D- Denmark

The Danish power system is composed of two asynchronous networks that are interconnected through a DC cable. Western Denmark is synchronously interconnected with Germany and Central Europe. Eastern Denmark is synchronously interconnected with Sweden and NordPool. Western Denmark has DC ties to Nordpool and Eastern Denmark has DC ties to Germany.

Wind penetration is very high in Denmark. Western Denmark has a peak load of 3.7GW and 2.7GW of wind. Eastern Denmark has 2.7GW of load and 0.9GW of wind. Denmark is integrating another 1.3GW of wind. Denmark's goal is to be fossil fuel independent. Western Denmark currently obtains 25 percent of its electric energy from wind. Obtaining 30 percent of total Danish energy (all sectors) from renewable by 2020 will require obtaining 50 percent of electric energy from wind. Much of the future wind installations will be off shore. There is currently 0.7GW off shore. [46,52]

There are many hours per year when wind generation exceeds load and power must be exported, typically to Norway and Sweden. High wind penetration requires that the conventional generators to be flexible. Coal plants are capable of 35 percent minimum load. Some coal plants are capable of 10 percent minimum load. They elected to install this capability to increase profits, it was not mandated.

Significant thermal storage has been added to district heating cogeneration plants to increase their flexibility. A single thermal storage tank can hold the equivalent of 2500MWH. Grid codes also require wind plant control capability and wind plants often provide regulation, as shown in Figure D-1-1. The choice to offer to supply regulation is made by the wind plants, it is not a system operator requirement. The TSO has only had to curtail wind twice. When the first off shore wind plants began operating ramp rates were unexpectedly high due to the concentration of turbines. Ramping controls have been effective and ramps are no longer a problem.

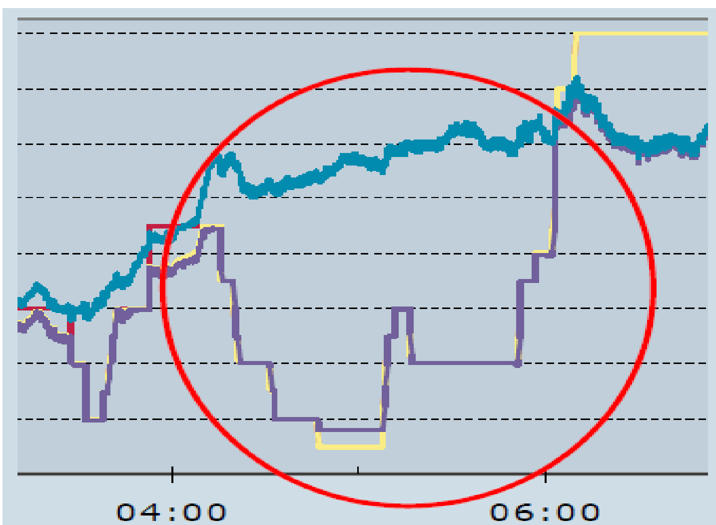

Figure D-1-1 Danish wind plants often provide regulation as shown by the turquoise plot of wind capability and the purple plot of controlled output.

D-1 Reserves and Energy

Primary reserves are purchased a week in advance. Secondary reserves are purchased day ahead. Tertiary reserves are obtained from a real-time balancing energy market but the TSO assures that there will be sufficient liquidity in the market by purchasing tertiary capacity day-ahead. Winners in the tertiary capacity auction are obligated to bid into the tertiary energy market in real-time but they are not guaranteed their energy will be taken. The TSO only buys up reserves and has successfully assumed that down reserves are always available. Tertiary capacity is typically inexpensive. European operations do not distinguish between contingency reserves and reserves required for normal operations. Primary, secondary, tertiary reserves and "regulating energy" are used to compensate for all imbalances. "Regulating energy" in Denmark is equivalent to sub-hourly energy markets in North America and is not the dedicated, minute-to-minute capacity on AGC which is called "regulation" in North America.

Tertiary *capacity* must come from resources in Denmark to assure availability in case transmission ties are out of service. The actual adjustable balancing energy is obtained from a common Nordic regulating market. Energy can come from Central Europe as well since EnergyNet is a partner. Up and down energy are priced separately. Energy schedules change every five minutes but individual generators that are supplying balancing energy cannot be required to change direction more frequently than 15 minutes. Consequently it is possible for the TSO to be purchasing up and down balancing energy at the same time.

Up regulation energy prices tend to be higher than the hourly energy price (spot price) while regulation down energy prices tend to be lower, as shown in Figure D-1-2:. Most of the regulating energy comes from Norway and Finland.

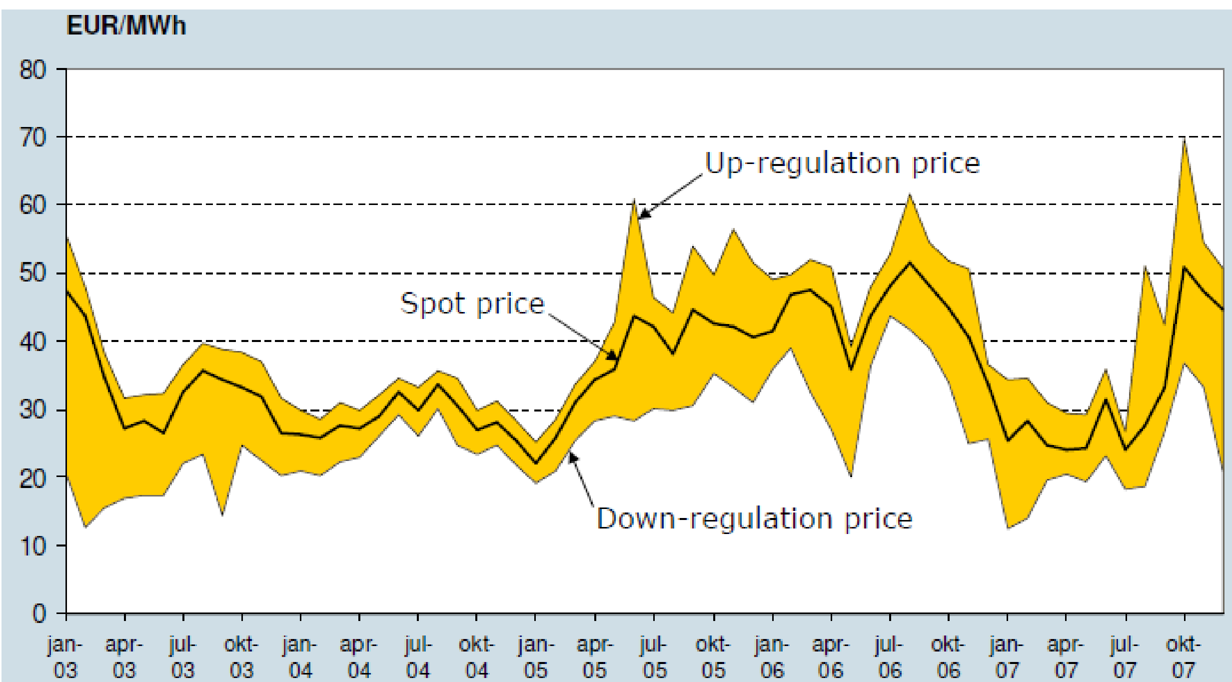

Figure D-1-2: Danish up and down "regulation" are the equivalent of sub-hourly energy market prices in North American markets.

The energy market closes 1 hour before the operating hour. Generators bid into the regulating up and down market 45 minutes before the operating hour.

"Balancing energy" refers to a purely accounting function of truing up individual production deviations after the fact. Transactions are purely financial, unlike regulation which physically deals with aggregate production deviations.

There is congestion in NordPool and congestion revenues must be spent on transmission upgrades.

D-2 Forecasting

Denmark uses a central wind forecasting system. Forecasts are updated four times per day. Four independent forecasts are combined to increase accuracy. Forecasting is critical because a 1 meter/second difference in wind speed results in a 450MW difference in wind fleet generation.

Abbreviations Used in this Report

Abbreviations	
ACE	Area Control Error
ADI	ACE Diversity Interchange
AESO	Alberta Electric System Operator
AGC	Automatic Generation Control
AIES	Alberta Interconnected Electric System
BA	Balancing Area or Balancing Authority
BAAL	Balancing Authority ACE Limit
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CPS	Control Performance Standard
DCS	Disturbance Control standard
DDST	Dispatch Decision Simulation Tool
DR	Distributed resources
DSO	Dispatch Standing Order
ELRAS	ERCOT Large Ramp Alert System
EMMO	Energy Market Merit Order
EMS	Energy Management System
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GE	General Electric Company
ISO	Independent Service Operator
IVGTF	Integration of Variable Generation Task Force
LGIA	Large Generator Interconnection Agreement
MAE	Mean Absolute Error
MAI	Market Analysis Interface
MISO	Midwest Independent Transmission System Operator
MOF	Market and Operational Framework
MRO	Midwest reliability Organization
MW	Mega watt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council, Inc.
NRMSE	Net Root Mean Squared Error
NYISO	New York Independent System Operator
NYSERDA	New York State Energy and Research Development Agency
PIRP	California Participating Intermittent Resources Program
PJM	PJM Interconnection
POI	Point of interconnection
PTC	Production Tax Credit
QSE	Qualified Scheduling Entity
RC	Reliability Coordinator

RDF	Reserve Discount Factor
RFC	Reliability First Corporation
RMS	Root Mean Squared
RTO	Regional Transmission Organization
SBG	Surplus Baseload Generation
SCADA	Supervisory Control and Data Acquisition
SCED	Security Constrained Economic Dispatch
SERC	SERC Reliability Corporation
SODAR	Sonic Detection and Ranging
SPP	Southwest Power Pool
SPP-RE	SPP Regional Entity
SPS	Special Protection System
TLR	Transmission Loading Relief
TRE	Texas Regional Entity
TSO	Transmission System Operator
VER	Variable energy resource
VRT	Voltage Ride-Through
WECC	Western Electricity Coordinating Council
WIT	Wind Integration Team

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