Transmission System Operation Challenges with Large Wind Penetration

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Abstract: The State of California's renewable energy policies and energy incentives are the main drivers of renewable generation development occurring in the Pacific Northwest. The largest wind integration efforts are happening within the Bonneville Power Administration's (BPA) Balancing Area (BA). BPA is approaching a 40 percent wind penetration factor. Such a large wind penetration imposes significant challenges on the transmission system operation requiring more system studies in operational time frame. These challenges include needs for additional voltage regulation requiring more switching operations, dealing with higher ramping rates and carrying additional regulation reserve as well as additional difficulty in Columbia River management (river scheduling). This paper discus some of those challenges in more details.

Keywords: Bonneville Power Administration (BPA), Balancing Area (BA), System Operating limits (SOL), Transmission System Operation, Wind Penetration.

INTRODUCTION

In 1999, California had a total installed wind capacity of 1616 MW, Oregon had only 25 MW, and Washington State had no wind projects at all. By the end of 2010, total wind installed capacity in California had grown to 2739 MW, Oregon had reached 2095 MW, and Washington State had installed 1964 MW of wind capacity.[1] The biggest integration efforts in the Pacific Northwest Region are happening within Bonneville Power Administration (BPA). This is understandable because BPA is the biggest Transmission System operator. To support renewable energy production, BPA is providing integration services for renewable resources (mostly wind) in its transmission system. Currently, the total installed capacity of the BPA wind fleet is around 4500 MW.

Putting it in perspective, BPA's peak load is about 10,500 MW, yielding a current wind penetration factor of around 40 percent. Most of the wind generating fleet is located in the Columbia Gorge so there is less benefits of spatial diversity of the wind.

Integration of such a large amount of wind power into the system brings about its challenges due to the volatile nature of wind itself. The wind's volatility adversely affects both hydro and transmission system operation.

Many efforts have been undertaken and implemented within the BPA in order to accommodate such a large amount of wind penetration, and many new services have been tailored to accommodate customers' needs for balancing wind generation

The Wind Integration Team at BPA has proposed and already implemented several solutions to help minimize adverse impacts of wind power production. They include:

- implementing transmission system enhancement projects;
- introducing wind integration rate charges for wind generators to cover additional balancing costs incurred;
- establishing new reliability protocols that require wind generators to adjust their schedules down to actual output if they substantially under-generate relative to their schedule or reduce output if they substantially over-generate relative to their schedule;
- developing a wind forecasting system;
- creating sub-hourly transmission scheduling protocols to allow power schedule changes to better match within-hour variations in wind generation; allowing wind operators to sell power when wind output quickly increases;
- allowing wind generators to purchase balancing capacity from suppliers other than BPA;

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- creating a third-party market for balancing services;
- using dynamic schedules to allow wind generators physically located on BPA's system to be remotely balanced by other utilities using electronic signals;
- evaluating energy storage and smart grid technologies' potential in the BPA footprint;
- implementing the area control error (ACE) diversity interchange (ADI) program; and
- employing self supply options for within-hour balancing services available for generator owners and operators, and evaluating the benefits of participating in cooperation or consolidation schemes with the other BAs.

While most of these services are tailored to meet balancing needs, they could also affect Transmission System Operation by creating unusual power flow patterns or voltage profiles, introducing power oscillation into the system, and by adding a quantitatively significant amount of new information and number of real-time monitoring variables to the Transmission System Dispatcher's responsibilities.

This paper discusses three major issues related to the large amount of wind generation from an operational perspective:

1) the impact of regulation reserve and balancing with respect to hydro operation;
2) the impact of a large amount of wind on the transmission system, especially during ramping events; and
3) the increased dynamic within the control center and its impact on operation personnel.

OPERATION WITH A LARGE AMOUNT OF THE WIND GENERATION IN THE SYSTEM

To date, the power industry has been concerned primarily with the variability of load. Load historical data has been collected over the past decades; consequently, load forecasting techniques are relatively accurate and the power industry is accustomed to dealing with load variability. Normally, power generation schedules are based on load forecasts and interchange obligations of the BA. The schedules are corrected hourly and units are ramped up or down every hour to follow generation schedules. If more power is required, units are scheduled to ramp up. If less power is required, units are scheduled to back off. Physically, more or less steam or water is allowed into the turbines, thereby enabling generation output to follow the schedules. The regulation reserve provided by units on Automatic Generation Control (AGC) compensates for uncertainty within the hour, balancing the slack.

Wind is a different story because it is not dispatchable under the current scheduling practice and regulations. Wind's variability makes forecasting wind generation inaccurate, especially in the longer term. Wind forecasting is very challenging in Columbia Gorge. Very small changes in wind speed can significantly affect wind generators' output. Consequently, variations in wind plants' output are generally large and have to be compensated for, which requires a large amount of regulation reserve. Generally, this is not a problem for small Wind Penetration Factors (WPF), but in the case of large WPF wind integration becomes major challenge.

IMPACT ON GENERATION

Business Model

Wind plants are often owned by Independent Power Producers (IPPs). As the source BA, BPA provides Generation Imbalance Service, by default,[2] for IPP-owned wind facilities; even though most of the wind is exported from Bonneville's BA, thus obligating BPA to carry a large amount of regulation reserve. Regulation reserve (regulation, load following, and generation imbalance[3]) is provided from Federal Hydro Projects. Federal Hydro Projects include 31 dams on the Columbia River and its tributaries, with a total nameplate rating of installed hydro generation capacity of 20,430 MW. It is worth mentioning that installed capacity is frequently unavailable due to different hydro constraints. Only a few of the Hydro Projects are on AGC. Most of the projects are Run-of-River projects. There is no large storage capacity in the Pacific Northwest. Hydro Projects are owned and operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. Management of hydro projects is very complex and subject to many constraints based on the Endangered Species Act (which requires flow to

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[2]FERC Order 890, Schedule 9.

[3]Generation Imbalance is an integral of Scheduled MW flow minus Actual MW flow over one clock-hour period.

support fish migration and spawning) and the Clean Water Act (which imposes minimum generation conditions). Power production is of lower priority for the Federal System of Dams. More information on Columbia River Hydro system operation and operational constraints can be found in [1, 2].

Wind plants have their own marketers and schedulers; BPA does not perform the scheduling function for wind plants. Wind operators do that themselves based on the market and their independent weather forecasts. The Energy Market in the Pacific Northwest is based on hourly transactions. Each individual Wind Generation Facility is allocated a certain amount of incremental/decremental (INC/DEC) reserve to allow for schedule deviations. The total amount of maximum INC and DEC reserve allocated for wind is calculated monthly and is pro-rated among participants. Reserve calculation is based on Columbia River predicted flow and environmental constraints. Reserve is distributed in real time. If reserves are unavailable from the Columbia Basin, BPA purchases them from the market to fulfill its reserve obligation. During low water conditions, the normal business practice is to store the water and go to the market and buy energy during low-cost hours. Currently, BPA has to generate excess energy it would not otherwise generate to be able to lower the generation to provide DEC reserve when needed.

While wind plants are required to ride through faults the current business model and regulation rules do not require wind facilities to participate in frequency or voltage control (e.g. NERC reliability standards-VAR-002-WECC-1 only applies to synchronous generators and synchronous condensers). If a wind plant over-generates (generating above the schedule), BPA backs off its own generation and purchases the extra generation from the wind owner, paying 90 percent of the day-ahead market price. If a wind plant under-generates (generating below the schedule), BPA has to supply the deficit to the wind operators for 110 percent of the day-ahead market price. Because of scheduling inaccuracy and the impossibility of scheduling accurate day-ahead wind operation, BPA's marketers are forced to go to the hourly market to meet reserve obligations and non-power obligations imposed by various Hydro constraints. This business practice results in forced purchases and sales, or the spilling of water. It has been recognized [3] that poor prediction of large wind deviation and weather patterns can significantly increase differences between day-ahead market and real-time market prices. It is worth noting that wind has ability to drive the energy prices to a negative value, especially at night when energy demand is low.

Market incentives for renewable resources can motivate wind operators to generate above schedule even when there is no need for generation. This over-

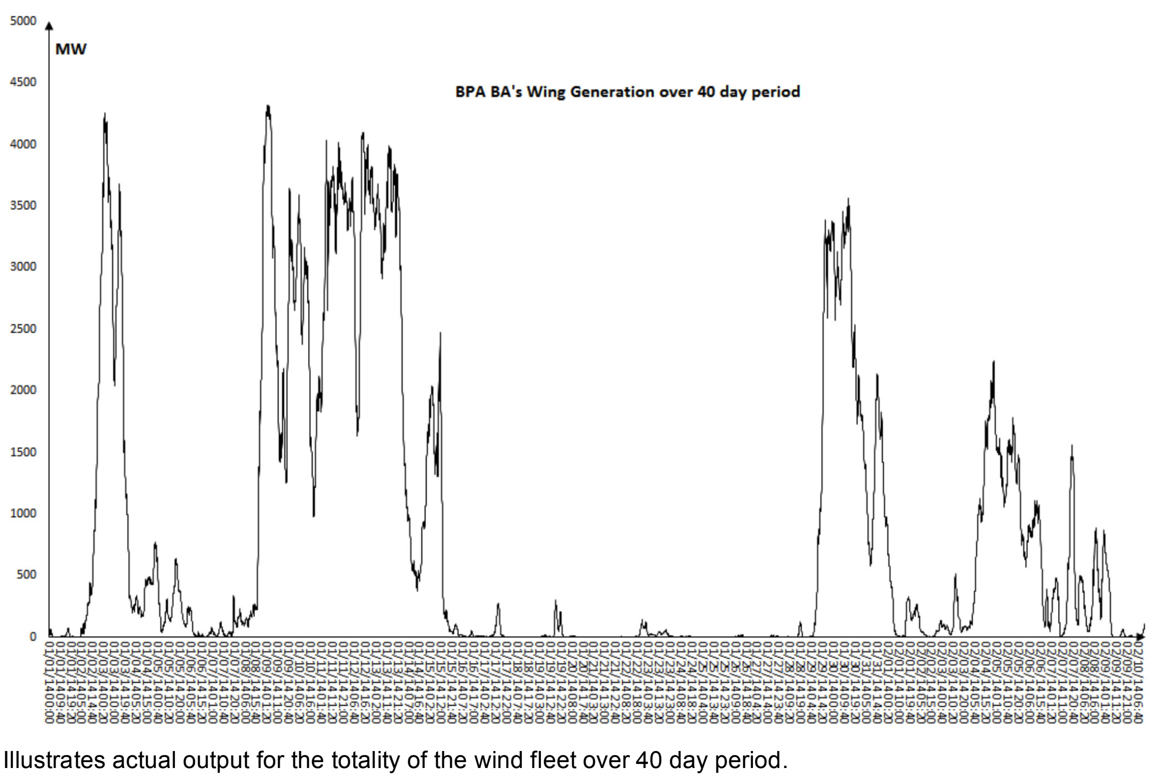

Figure 1: Illustrates actual output for the totality of the wind fleet over 40 day period.

generation leads to the accumulation of generation imbalance. That can be particularly troublesome during light loading conditions at night or during water spill operations for fish protection. Such operational practices can conflicts with reliability standards and environmental obligations.

Accumulation of generation imbalance can significantly affects Federal Hydro System operation by accumulating or draining too much water from the reservoirs, depending on whether the wind plants continually over-generate or under-generate. Hydro System Operators are required to maintain maximum and minimum elevation levels and to ensure that tailwater and forebay rate-of-change levels are kept within specified ranges due to environmental constraints (Endangered Species Act, Clearwater Act). Figure **1** illustrates variability of the wind.

Schedule and Wind Output Curtailment

Wind facilities are required to have a communication link *via* ICCP or SCADA[4] remote terminal units so that they can receive real-time data on Balancing Reserve status and follow dispatch instructions. When schedules significantly deviate from actual generation and reserves are deployed to maximum, Transmission Operators can curtail schedules or generation to preserve system integrity, depending on whether wind facilities are under-generating or over-generating. The operational and reliability protocol Dispatcher Standing Order 216 (DSO 216) is tailored to provide instructions for operation when the regulation reserve limits are reached. In the case where maximum INC reserves have been deployed, dispatchers have the option of curtailing schedules (e-Tag). In the case where the maximum decrement (DEC) reserves have been deployed, the wind plant operators are instructed to reduce generation to schedule. In the first case, the sink BA has to find a replacement for the curtailed generation elsewhere. In the second case, if the wind facility fails to reduce its output, then the dispatcher can disconnect it from the grid. There is a Failure to Comply Penalty Charge of as incentive. More details on curtailment of the schedules and generation are given in [6, 7]. An efficient alternative to schedule curtailment might be the deployment of contingency reserves, but so far there is no agreement within the Northwest Power Pool on the contingent status of wind events.

Tagging of the Wind Energy

Unscheduled decrease in wind generation coupled with exhaustion of incremental reserve can lead to curtailment of schedules. In that case the balancing obligation is shifted from the source end BA to the receiving end BA. For that reason, the receiving end BA needs to carry on additional reserve. The possible curtailment of wind energy schedules leads to a tagging issue associated with renewable energy products. Transmission transaction e-Tags describe the quality of the product (energy) transmitted. The current NERC and WECC product codes include:

1. Firm Energy (can be curtailed only in case of a reliability issue or to meet seller's statutory obligation for native load)

2. Non-Firm Energy (can be curtailed for any reason or for no reason)

3. Firm Contingent Energy (energy from designated source-can be interrupted only due to deration or outage of the source)

4. Firm Provisional Energy (can be interrupted only if the interruption is within the recall time and for conditions allowed by applicable provisions governing interruption of service, as mutually agreed to by the parties)

Currently, wind is tagged as firm energy. Since wind energy schedules are occasionally curtailed due to insufficiency of wind, wind energy does not qualify as Firm Energy. There is no NERC or WECC product code specified for renewable generation sources. Qualifying Wind Energy differently than Firm Energy can affect quality of the product and can negatively affect the price of wind energy (discriminate wind energy against other form of the energy). A possible solution for that issue is to consider the lack of wind as a contingency. In case of a lack of wind, schedules need not to be curtailed and contingency reserves could be deployed instead.

Impact on Hydro System during Extreme Water Conditions

During high water flow conditions, the usual practice is to let water pass through turbines and generate as much electricity as possible. The turbine intake is

[4]Inter-control Center Communications Protocol (ICCP) or Supervisory Control and Data Acquisition (SCADA).

below the water surface so the water passed through the turbines does not come into the contact with air. If the water is spilled through the spillways, the spilled water comes into the contact with air and saturates with nitrogen. Too much nitrogen in the water kills the fish (protected salmon).

There are legal limits in the amount of nitrogen in the water set by the Northwest States. During such extreme conditions, Bonneville cannot back generation to provide DEC reserve. Consequently, the amount of DEC reserve has to be decreased temporarily. Figures **2** and **3** illustrate such an extreme case. During the period from June 9–11, 2010, the water runoff was unusually high due to an abundance of precipitation and snow pack melting. Such meteorological conditions were coupled with an abundance of wind. Consequently, to protect the endangered salmon, the amount of DEC reserve available for the wind plants was temporally reduced as shown in Figure **2**. Figure **3** illustrates the wind generation output subjected to frequent curtailments due to the unavailability of the DEC reserves. Such operating conditions can be avoided if energy storage capable of shaping the energy is available or if the wind project provides its own regulation reserve.

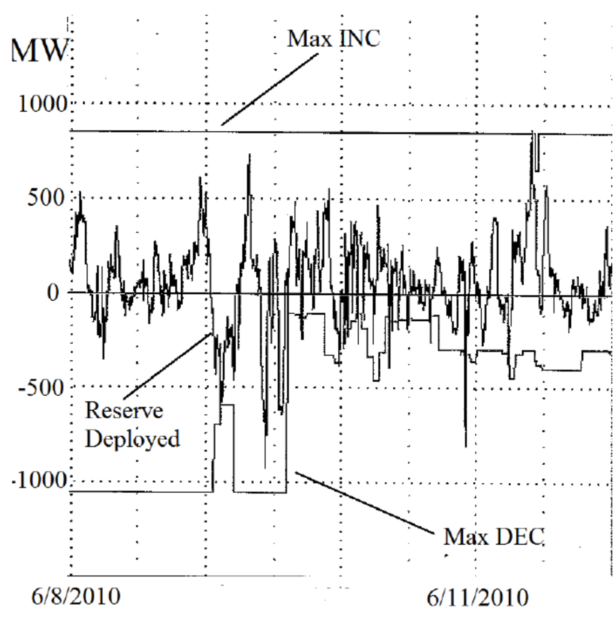

Figure 2: Station Control Error (SCE) for the wind fleet in the Bonneville Balancing Area with the regulation reserve band temporally reduced due to extreme meteorological conditions.

During such extreme conditions most of Northwest's thermal generation is shut down or reduced to minimum operating levels. The generator owners obtain free or low cost energy for replacement from hydro. Thermal power plant owners normally save money under such conditions. However, wind power projects, under current regulation, if replaced with hydro, are not eligible for federal Production Tax and /or state Renewable Energy Credits. The situation was even worse in 2011 due to largest snowpack since 1997. Iberdrola, PacificCorp, NextEra Energy Resources, Horizon Wind Energy, and Invenenergy jointly have filed a complaint with FERC against BPA [7]. Owners of the wind projects request to be compensated for curtailed energy. It would, consequently harm Northwest rate payers and preferential customers because they would bear the cost of compensating the wind projects to decrease output.

Adding new wind facilities will decrease the amount of regulation reserve available individually for each wind project since the same amount of regulation reserve will be shared among more wind projects. In order to better plan for further increases in renewable resource integration in the region, BPA works with all stakeholders to exploit and enable different options for providing regulation reserve. Most of those options are oriented toward transferring regulation obligations to the sinking BA or to a third party. They include Netting Resources, Customer Supply Generation Imbalance, Dynamic Transfer, and Intra-hour Scheduling. Some of these options are briefly described in the paper. More detail on these pilot programs are given in Comments of the Bonneville Power Administration to FERC [4].

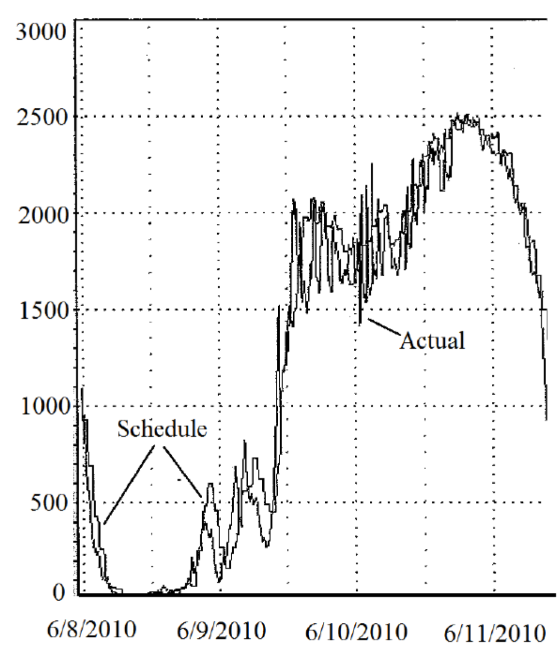

Figure 3: Wind schedule and actual during frequent curtailment of wind output.

Netting of the Wind Resources

DSO 216, with the objective to facilitate wind operation, a new business practice has been introduced [5, 8] allowing the netting of wind resources. Two or more wind facilities are allowed to aggregate wind resources within BPA's BA *via* a Netting Agent, creating a single virtual entity. The idea behind netting is that SCE_{TOTAL} of netted wind facilities will partially cancel each other due to the diversity of wind conditions for the facilities that are spatially distributed in different regions of BPA's Balancing Area. In that case, if one wind plant is out of the reserve boundaries, the SCE for that plant might be canceled out by the other wind plant that is netted with it. The SCE for the individual plant is given by (1):

$$|SCE_i| = |MW_{actual\_i} - MW_{scheduled\_i}| \quad (1)$$

Total SCE_{TOTAL} for all wind fleet is given by (2):

$$|SCE_{TOTAL}| = \left|(\sum_{i-1}^{N} MW_{actual\_i} - \sum_{i=1}^{N} MW_{scheduled\_i})\right| \quad (2)$$

Where:

N is the number of netted wind farms

i=1 to N

The reason for netting is (3):

$$|SCE_{TOTAL}| \leq \sum_{i-1}^{N} |SCE_i| \quad (3)$$

While netting does not change the assessment of generation imbalance for individual plants within the generation imbalance account, it adds additional flexibility for wind plant operators within netted group regarding curtailments.

Customer-Supplied Generation Imbalance (CSGI)

CSGI is another pilot program helping wind facility operators to integrate into the BPA Transmission System [4]. Under this initiative, the customer (operator of one or more wind farm) corrects its own SCE using one or more of its own or contracted remote resources. The generators are netted (wind and customer owned generators for balancing purposes), and the customer has to keep its SCE within the specified predefined band (INC/DEC).

Intra Hourly Scheduling

Another pilot program is Intra Hourly Scheduling [4]. It allows wind operators to increase their schedules within the hourly time frame (30 minutes past the hour) if they are able to find a buyer for their power. The intent behind Intra Hourly Scheduling is the adjustment of schedules. The success of the program depends largely on the market dynamic and the ability to sell and buy energy within an hourly timeframe. Since the market in the Pacific Northwest functions hourly, this initiative requires regional support to come to full fruition.

Dynamic Transfer (DT)

DT makes use of Dynamic Schedules and offers Pseudo Tie functionality as a supplemental regulation service. The service electronically offsets a part of the ACE to another BA.

The AGC of the Host BA and that of the Attaining BA are electronically linked; a portion of the ACE is transferred from the Host BA to the Attaining BA. A portion of the ACE transferred might be the SCE — in the case of a complete transfer of Regulation Service for the wind plant or a difference between the wind plant actual and a maximum allocation of reserve allowed for the plant at the time of the transfer — or some arbitrary amount of reserve in the case of partial transfer of Regulation Service of Wind Plant.

The ACE equation is given by (4):

$$ACE = NI_A - NI_S - 10B(F_A - F_S) \quad (4)$$

NI_A is the algebric sum of actual flows on all tie lines

NI_s is the algebric sum of scheduled flows on all tie lines

The implimentation of DT is as follows:

NI_S – Net Interchange Schedule tie line flow is affected

If the Host BA transfers part of the ACE (SCE_i for i-th plant to Attaining BA) then new NI_S term in (4) is given by (5)

$$NI_{S\_new} = NI_{S\_old} - SCE_i \quad (5)$$

Where:

NI_{S_old} is NI_S without Dynamic Transfer

SCEi is given by (1).

SCE_i can be positive or negative. If SCE_i is positive DEC is requested and if SCE_i is negative INC is requested.

In both cases, the Host BA has to stay unaffected and the Attaining BA has to provide regulation. If DEC is requested, the Attaining BA has to reduce generation so its ACE has to decrease for an amount equal SCE_i. In that case $|SCE_i|$ has to be subtracted from the Attaining BA schedule and added to the Host BA schedule to offset the Native BA change in ACE. The opposite is true for an INC reserve request.

The frequency bias B in the ACE equation is affected by Dynamic Regulation. $B=1/R + D$, where D is system damping (load vs. frequency) and $1/R=1/R_1 +1/R_2+\ldots+1/R_N$ where R_i is the droop characteristic of the i-th unit.

There are also many issues that may require additional bilateral agreements among the parties involved such as control offset on compliance standard or Disturbance Compliance Standard reporting. More details on DT are given in [4, 9-12].

IMPACT ON TRANSMISSION SYSTEM OPERATION

Most of the initiatives related to wind integration are related to regulation reserve acquisition and to wind forecast. While accurate wind forecasting leads to better scheduling and decreases the amount of regulation reserve that has to be carried, it still does not change the variability of wind and its impact on the transmission system. The wind variability transferred into the system variability can be significant, especially in the case of large penetration factors. Wind-related ramping events along with the wheeling of regulation reserve through the transmission grid from one BA to another are reflected in the flows through the grid. Even in the case of perfect schedules, wind fluctuations change flow patterns through the transmission system and significantly impact transmission system operation. These fluctuations affect voltages, displace conventional resources, and impact reserve deployment capabilities.

Voltage Issues

While load follows a generally well-predicted pattern, the wind does not. For that reason, dynamic voltage regulation is necessary for large wind penetration. Fluctuating output from wind farms has the potential to affect system voltages at the points of connection with the transmission grid and further through the system. Wind plants are exempted from having to maintain specified voltage schedules; they are not required to be on Automatic Voltage Regulators (AVR)-. NERC and WECC standards for voltage control apply to synchronous generators only (VAR-002). However, there are requirements for keeping power factor within predefined range.

Early wind projects within the Bonneville BA relied on switched capacitors for voltage support. Currently, BPA dynamic voltage requirements for wind projects include Dynamic VAr devices capable to regulate a 34.5 kV bus within +/- 0.95 PF. The wind generator types (WTG) 3 and 4 have to be within +/- 0.95 PF dynamic capabilities and for WTG types 1 and 2, the requirements are that Hybrid Dynamic VAr device operate at 50 percent continuous range and 50 percent switched capacitors. There is a variety of WTG and voltage control devices currently installed in wind facilities. It has been demonstrated [16, 17] that dynamic voltage support from the distribution level can significantly benefit the transmission system by improving the voltage profile, improving reliability, and significantly increasing transfer capacity.

In everyday operation of the power system, it is common to switch shunt reactive devices during load ramping hours, once or twice a day. The typical life cycle of the circuit breaker is 2000 to 5000 switching operations. Wind changes the power transfer patterns throughout the grid and consequently affects voltages requiring more frequent switching, shortening breakers' life expectancy.

Ramping Rates

It has been observed that wind ramps of over 500 MW can occur within a five-minute timeframe. Table **1**

Table 1: Largest Ramping Rates Experienced within BPA's BA

	Up MW	Installed Capacity	Down MW	Installed Capacity
1h	1580	2830	-1167	2830
30 min.	1053	2830	-739	1496
5 min	428	2830	-724	1496

shows the largest incremental and decremental ramping events experienced within the Bonneville BA over different time spans.

For comparison purposes, in 2010 installed wind capacity in Spain was around 19,000 MW and highest ramping rate was 1,500 MW/hour while installed wind capacity in Germany was 26,000 MW with highest ramping rate of 1000 MW/hour [18, 19]. It can be seen from Table **1** that BPA's BA ramping rates are significantly higher than that of Spain and Germany. Ramping rates for 3,000 MW of installed capacity in BPA's operating region are equivalent to the ramping rate in Spain having 19,000 MW of installed wind capacity. This difference demonstrates that wind projects in BPA are concentrated across small geographical area. It is to be expected that ramping events will further increase in magnitude with an increase in installed capacity at Columbia Gorge.

There are no regulation requirements for ramping rates of wind facilities. Even if regulation requirements were to exist, large ramping down events cannot be controlled. Coupled with the loss of large conventional generation units, large and unpredicted ramping rates can put the integrity of the Interconnection at a risk. More details on ramping events within the Bonneville BA can be found in [20]. It is worth noting that wind ramps and load ramps do not necessarily coincide with each other. Figure **4** shows load profile (upper trace) and wind profile (lower trace) for one specific day. In that specific example it can be seen that during morning load pick up wind generation ramps down, putting additional stress on the system operators and increasing need for balancing the system.

At the same time, additional regulation reserve wheeling through the system on larger scale (dynamic scheduling, CSGI, etc.) will also affect line loading and voltage profiles, thus requiring more dynamic voltage regulation. The consequence of not having enough dynamic voltage regulation devices in the system and not having the wind plant on AVR is either a decrease in the available units' MW capability for the units on AVR or unacceptable voltage profiles. Since wind farms displace conventional hydro units that are normally on AVR (VAR-002 R1 NERC Standards), wind farms can contribute to the deterioration of the voltage response during voltage disturbances.

Frequency Response

The impact of large-scale wind integration on frequency response in the Western Interconnection is not well known. However, the issue is a source of concern because wind displaces conventional units, mostly hydro, which have large rotational masses. Moreover, wind farms do not have a droop characteristic so they do not participate in arresting frequency deviations during disturbances. Consequently, the increased integration of wind resources has the potential to slow frequency recovery. It is anticipated that some kind of inertia dispatch will be needed to maintain adequate frequency response.

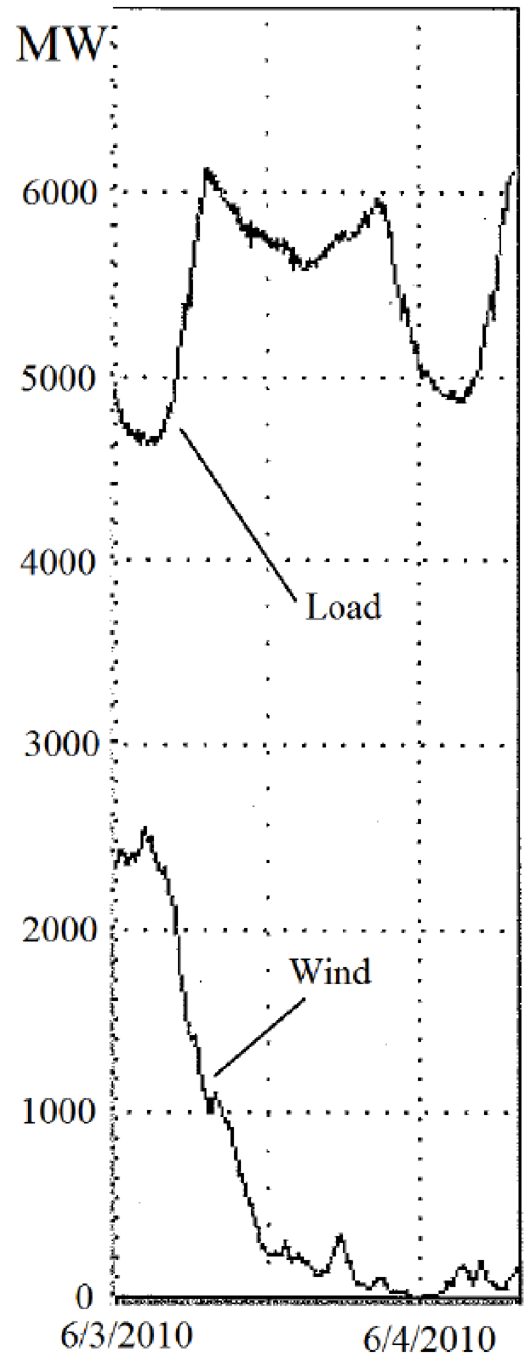

Figure 4: Load (upper trace) and wind generation (lower trace) for one day period.

Frequency response of the Interconnection is assessed through disturbance monitoring by measuring the time needed for frequency recovery. In an attempt to better understand how wind generation affects frequency response, the WECC Reliability Coordinator (RC) function has initiated an effort to baseline the frequency response of the Interconnection vs. total wind generation. Although wind plants are capable of providing inertial and frequency response (type 1 and 2 inherently; type 3 and 4 through appropriate inverter control) they are currently not required to do so.

Impact on Remedial Action Schemes (RAS)

There is large number of RASs within WECC and the Pacific Northwest. The role of RASs is to automatically mitigate emergency system conditions such as path overloads. They are triggered automatically, based on preprogrammed thresholds and operating conditions. Many RASs include a drop in generation as part of their mitigation scheme that can relieve line or path loading very quickly. When generation is dropped as part of a RAS, AGC is automatically blocked to avoid picking up dropped generation. If the cause of the RAS triggering is not immediately mitigated, the generation dispatcher needs to contact the scheduler and request an e-Tag curtailment prior to returning the AGC to service. Once the e-Tag is curtailed, the set points for the units are changed and the AGC is placed back in service. Since wind displaces conventional units, RAS effectiveness is potentially changed. Adding more wind on-line displaces more conventional units. At some point there will be no RAS-associated generation to drop if there is an overabundance of wind generation on-line. The effectiveness of the single RAS depends on quantity of wind generation on-line (full wind *vs*. no wind). Additional studies need to be performed to assess the effectiveness of RASs for different wind conditions. The consequence of failing to adjust remedial actions is potentially dropping too much or too little generation.

i) Impact on System Studies

Large amounts of wind variability, displacement of conventional generation due to wind, the wheeling of regulation reserve through the transmission system, and reactive power issues cause stress on the transmission system. Consequently, more frequent operation studies are needed. One of the main challenges that transmission system operation faces is correct System Operating Limit (SOL) and Available Transfer Capability (ATC) assessment. While thermal limits are generally well known, they usually apply to short transmission lines (up to 50 mi.). For the longer lines; however, voltage stability and transient stability limits are typically the determining factors for power transfer capacity.

These limits are much more difficult to assess accurately and are generally set very conservatively. They are identified by planning and operation studies. In the environment where there is a high wind penetration, it is increasingly important to rely on studies initialized from real-time snapshots to perform more frequent reliability assessment of the Power System.

Routinely, system operation studies and reliability analyses are executed for operations planning to ensure that the system can operate reliably, to prepare for scheduled outages or in case of the system events (N-1, N-1-1, N-x). Operational studies are usually performed a few days in advance based on static cases from the planning model. Such a case is adjusted to resemble, as much as possible, the current system conditions or to reflect predicted system conditions. This procedure can be time-consuming and yield inaccurate results. Because of wind volatility and inaccuracy of long-term wind forecasts, it is more difficult to plan for operations. Near real-time studies become a necessity for ATC evaluation. Such studies are often based on cases provided from State Estimator (SE) within the EMS platform.

The SE provides the platform for Real-Time Contingency Analysis (RTCA), Real-Time Voltage Stability, and Real-Time Transient Stability Assessment. The SE also can automatically generate save cases after each run to facilitate post mortem analysis if needed. Following are a few examples of modern studies based on a real time snapshot similar to those that are carried by WECC Reliability Coordinators.

ii) Near Real-Time Study

When system conditions warrant (predicted wind gusts, dynamic schedule during heavy loading conditions, etc.) or prior to a scheduled outage, a snapshot from the SE should be used as a starting point for powerflow analysis. After adjusting the wind farm output according to the wind forecast or dynamic schedule, one can run the powerflow again. The two obtained solutions should be compared for differences in flows and voltages to assess any potential reliability issues. After that, a contingency analysis can be performed together with voltage stability and transient stability analyses.

iii) Impact on Contingency Analysis

System Operation is especially concerned with the impact of the most severe contingencies on the system. Usually, the most severe contingencies are the loss of a large nuclear unit, a DC link, or a major transmission line. A large amount of geographically concentrated wind generation can lead to the loss of a large number of wind farms in short time period due to excessive wind. For example, for a Vestas V82-1.65 MW wind turbine, cut out speeds are: 10 minutes for 44.7 mi/h, 1 minute for 53.68 mi/h and 1 second for 71.58 mi/h. Such system conditions are usually not studied adequately and their impact on the system is largely unknown.

Model Quality

The quality of the studies depends on the quality of the model. If the power system model does not have an acceptable level of accuracy, then the studies are unreliable. Within the Western Interconnection, each BA updates its own area planning model and submits the model to the WECC Technical Studies Subcommittee where updates are integrated within one common Interconnection model, called “base case.” The base-case model is usually heavily stressed, presenting either a hot summer or cold winter case. That is referred to as a Planning Model because it is mainly used and maintained by the system planning community. The base-case model is then distributed within the planning and operation community where additional tuning can be done to adapt the model to the planner’s own needs. This process is cumbersome. The power flow program can have difficulties converging due to load and generation imbalance, and there are no breakers included in the model (bus-oriented model) so the topology within the system might be incorrect if the lines are fed *via* auxiliary bus. Moreover, such a model is not benchmarked against real time. In the case of unplanned events, the Operation Study Engineer must adjust the system topology, load profile, and generation profile before executing studies, resulting in a time-consuming and error-prone model.

Impact on Transmission System Dispatchers

The operational problems that result from ever expanding wind generation programs can have a significant impact on operating personnel in the control room. To better facilitate wind integration on the system, new ancillary services and operating procedures will be required. While many of the more recent initiatives are mainly used to arithmetically manipulate ACE and to wheel regulation reserves from external remote resources, wind variability and additional ancillary services significantly affect the way that the transmission system operates. Unusual power flows, voltage profiles, and power swings during ramping events each require heightened situational awareness and greater attention from transmission system operators. These changes will undoubtedly contribute to an increase in dispatch operation complexity. More switching will be required, more alarms will be signaling on the dispatch console, and there will be greater a possibility of confusion and human error. Wind ramps might occur at any time: during load pick up hours, during the contingent state of the system, or in the middle of the night when power is not needed.

Varying types of events can coincide with one another challenging operation. It is well known that severe weather can have a disastrous impact on the Power System without wind. Strong wind gusts coupled with large concentration of wind farms geographically concentrated can impose additional challenges on the Power System Operation due to wind cutout event. Such conditions are not well studied. The compounding complexity associated with wind variability coupled with the impacts of wind-related services might result in an operator’s inability to realize what is occurring on the system in real-time. It is necessary to provide dispatch operators with the tools that will, in real-time, provide adequate situational awareness and indicate where the problem areas exist.

CONCLUSIONS

Large Wind Penetration Factors impose challenges on Transmission System Operations and specifically on Regulation Reserve requirements. One of the largest obstacles to the successful integration of a large amount of renewable energy into the grid is the lack of well-balanced, clearly-defined reliability standards for renewable resource responsibilities and obligations for voltage control, frequency control, rates of ramping and reserve provision. Currently defined standards are prone to interpretation, and wind is often exempt from compliance with those standards.

Additionally, the amount of generation reserve is limited. It is dependent on circumstances such as the quantity of the snow packs, the amount of precipitation, or environmental obligations. Wind sites are usually clustered within a BA. If the source BA is required to provide all generation imbalance reserve, even when wind generation serves outside loads, the reserve demands will reduce or even stop the rate of the wind integration. For the transmission operator, it becomes more difficult to provide integration services for renewable sources with an increase in the penetration factor.

While most efforts address regulation reserve requirements and weather forecasting, much less attention is paid to the improvement of the model quality on which the operational studies are based. The traditional method of performing system studies, operational as well as planning, needs to be changed to accommodate the rapid integration of wind and other renewable resources. Ensuring that near real-time studies are based on a snapshot from real-time is imperative due to wind volatility and all activities related to the reserve wheeling through the transmission system. Such studies are prerequisite to move to faster market and to decrease regulation reserve requirements. While Real-Time Applications allowing such studies are readily available, they are not used adequately and utilities cannot rely on them. The key issue is the model and real-time data quality.

At the same time, high wind penetration adds more variables in real-time operations. Dispatchers do not have an abundance of time to react to changes in operating conditions. Large wind ramping events can coincide with contingencies, storms, unpredicted load build up, or other system events. Dispatchers need clear, filtered information to know what is occurring on the system at a glance.

DISCLAIMER

This paper represents the opinion of the authors. It is not meant to represent the position or opinions of Peak reliability or its Members.

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