GE Energy

PJM Renewable Integration Study

Task Report:
REVIEW OF INDUSTRY PRACTICE AND EXPERIENCE IN THE INTEGRATION OF WIND AND SOLAR GENERATION

Prepared for: **PJM Interconnection, LLC.**

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November 2012

Foreword

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1. INTRODUCTION

This report describes the current state of the art with variable generation integration, mostly focused on the United States but providing a few international examples where particularly relevant. The report is predominantly based on an extensive literature review with input from General Electric (GE) and PJM.

The report is divided into sections on energy market scheduling, the visibility of distributed generation to grid operators, energy imbalances, reserves, contingency reserves, wind and solar forecasting, consideration of variable generation as a capacity resource, and active power management of variable power generation. The report closes with a discussion of the GE team's views on the best practices for integrating variable generation

2. ENERGY MARKET SCHEDULING

There is a great diversity of scheduling practices, both within the United States and internationally. All Regional Transmission Organizations (RTOs) in the United States, other than the Southwest Power Pool (SPP), operate day-ahead markets with a security constrained unit commitment that includes a day-ahead auction for energy and various ancillary services, with a subsequent reliability unit commitment. A real-time market clears energy and ancillary services based on bids or self-scheduled supply and demand.[1] The New York Independent System Operator (NYISO) integrates the reliability unit commitment with the day-ahead market, but for the other RTOs, the reliability unit commitment follows the day-ahead market and is not used to set day-ahead energy prices.

Once the day-ahead market schedules are determined, hourly schedules are revised to incorporate changes in grid conditions and market participant positions (including self-schedules) until a scheduling deadline before real-time. RTOs also continue to do intra-hour unit commitment assessments for a number of intervals ahead, then conduct the real-time dispatch market within the operating hour on intervals as low as five minutes.[2] PJM, for instance, receives day-ahead bids for energy and offers for regulation until 12:00 p.m. day-ahead, then posts day-ahead locational marginal prices (LMPs) and hourly schedules at 4:00 p.m. Between 4:00 p.m. and 6:00 p.m., PJM operates a re-bidding period to ensure that PJM has scheduled enough generation to meet PJM's load forecast for the next day and for the following six days.[3]

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[1] SPP filed a petition with the FERC in February 2012 to convert to day-ahead locational marginal pricing energy and ancillary services markets by 2014. Presently, SPP has a bilateral market with an open access transmission tariff and an energy imbalance market.

[2] ISO/RTO Council, *Comments of the ISO RTO Council in Response to the Federal Energy Regulatory Commission's Notice of Inquiry Seeking Public Comment on the Integration of Variable Energy Resources*, Docket RM10-11-000 (FERC, April 13, 2010), http://www.isorto.org/site/c.jhKQIZPBImE/b.4344503/k.83C1/FERC_Filings.htm.

[3] PJM, *PJM Manual 11: Energy & Ancillary Services Market Operations, Revision: 54* (Norristown, PA: PJM, October 1, 2012), https://www.pjm.com/~/media/documents/manuals/m11.ashx.

Outside of RTOs, bilateral markets in the United States operating in the Western and Southeastern regions have separate scheduling requirements for both generation and transmission, as compared to RTOs that coordinate transmission scheduling with generation dispatch instead of arranging them separately. Under Order 890, the Federal Energy Regulatory Commission's (FERC's) *pro forma* open access transmission tariff requires transmission customers to schedule firm point-to-point service on an hourly basis by 10:00 a.m. and non-firm transmission service by 2:00 p.m. the day before service is required, or in a reasonable time generally accepted by the region and consistently adhered to by the transmission provider. Schedules submitted after these times must be accommodated if practical. Transmission providers have the discretion, but are not required, to accept schedule changes no later than 20 minutes before real-time (the actual hour of operations).[4]

Transmission in bilateral markets in the United States typically follows a set schedule for each hour, established an hour or more ahead of service. Because changes are only allowed for unanticipated events, changes in electricity demand within the hour cannot be met with changes in schedule. Therefore, transmission providers must carry enough reserves to cover the largest potential contingency during that hour, even if it is only for a short period of time. Some transmission providers in the West are experimenting with intra-hour transmission scheduling, such as the Joint Initiative[5] and the Bonneville Power Administration (BPA).

Outside the United States, the United Kingdom allows schedules to be changed up to one hour before real-time power operations begin, and the Australian

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[4] FERC, *Preventing Undue Discrimination and Preference in Transmission Service*, Docket Nos. RM05-17-000 and RM05-25-000, Order No. 890 (FERC, February 16, 2007), http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

[5] The Joint Initiative was formed in mid-2008 by representatives of ColumbiaGrid, the Northern Tier Transmission Group and WestConnect. The Joint Initiative is a development forum where participants discuss matters such as standard business practices and procedures for intra-hour scheduling.

power exchange allows rebidding up to five minutes before actual resource dispatch.[6] Elbas is a short-term market operating in the Nordic Region, and market closing times range between five minutes and two hours, depending on the participating country.[7] Germany operates as a single price area energy market, which includes day-ahead, intra-day, and reserves markets. The intra-day market allows bids to be placed up to 45 minutes before scheduled delivery (see Table 1).[8]

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[6] Australian Energy Market Operator, *An Introduction to Australia's National Electricity Market* (Australia: AEMO, July 2010), 10, http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Introduction-to-the-NEM;
National Grid, *National Electricity Transmission System Seven Year Statement* (England: National Grid, May 2011), http://www.nationalgrid.com/NR/rdonlyres/4AB92B80-499A-4D3A-84E4-BBE884CBBA55/49900/NETSSYS2011.pdf.

[7] Nord Pool Spot, *Elbas 3.1 User Guide* (Norway: Nord Pool Spot, October 2012), 5, http://www.nordpoolspot.com/Global/Download%20Center/Elbas/Elbas-3.1_user-manual.pdf.

[8] B. Ernst, U. Schreier, F. Berster, J.H. Pease, C. Scholz, H.P. Erbring, S. Schlunke and Y.V. Makarov, *Large-Scale Wind and Solar Integration in Germany* (Richland, WA: Pacific Northwest National Laboratory, February 2010), 25, http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19225.pdf.

Table 1 *Market Closing Times in Various Electricity Markets*[9]

MARKET	CLOSING TIME
PJM (Day-Ahead Market)	12:00 p.m. before the day in question; no changes possible after 12:00 p.m.
California ISO	10:00 a.m. the day before for the day-ahead market. Hour-ahead closes one hour and 15 minutes before real-time.
Western Utilities, U.S. (non-RTOs)	One hour before real time; schedule changes on the hour. No sub-hourly scheduling other than individual pilot initiatives. Transmission scheduled separately.
Australia Power Exchange	Rebidding possible until the resources are used for dispatch (i.e., up to five minutes before the time in question).
National Grid (England and Wales)	One hour before the half-hour in question.

[9] CAISO, *Business Practice Manual for Market Operations*, Version 26, May 7, 2012, https://bpm.caiso.com/bpm/bpm/version/000000000000169;
PJM, *Energy and Ancillary Services Market Operations*, October 1, 2012, http://www.pjm.com/~/media/documents/manuals/m11.ashx;
Australian Energy Market Operator, *An Introduction to Australia's National Electricity Market* (Australia: AEMO, July 2010), 10, http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Introduction-to-the-NEM;
National Grid, *National Electricity Transmission System Seven Year Statement* (England: National Grid, May 2011), , http://www.nationalgrid.com/NR/rdonlyres/4AB92B80-499A-4D3A-84E4-BBE884CBBA55/49900/NETSSYS2011.pdf;
Nord Pool Spot, *The Nordic Electricity Exchange and The Nordic Model for a Liberalized Electricity Market* (Norway: Nord Pool Spot, June 2012), 9, http://www.nordpoolspot.com/Global/Download%20Center/Rules-and-regulations/The-Nordic-Electricity-Exchange-and-the-Nordic-model-for-a-liberalized-electricity-market.pdf;
Nord Pool Spot, *Elbas 3.1 User Guide* (Norway: Nord Pool Spot, October 2012), 5, http://www.nordpoolspot.com/Global/Download%20Center/Elbas/Elbas-3.1_user-manual.pdf;
B. Ernst, U. Schreier, F. Berster, J.H. Pease, C. Scholz, H.P. Erbring, S. Schlunke and Y.V. Makarov, *Large-Scale Wind and Solar Integration in Germany* (Richland, WA: Pacific Northwest National Laboratory, February 2010), 25, http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19225.pdf;
Gitte Agersbaek, *Integration of Wind Power in the Danish Energy System* (Portland, Oregon: Wind Integration Forum, July 2010), 10-11;
Kevin Porter, Christina Mudd, Sari Fink, Jennifer Rogers, Lori Bird, Lisa Schwartz, Mike Hogan, Dave Lamont and Brendan Kirby, *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge*, Western Governors Association, June 2012, http://www.rapon-line.org/featured-work/meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration.

Table 1 *Market Closing Times in Various Electricity Markets (Continued)*

MARKET	CLOSING TIME
Nord Pool Elspot (Day-Ahead Market)	12:00 p.m. before the day in question; no changes possible after 12:00 p.m.
Nord Pool Elbas (Intraday Market)	Market closing time varies by pricing area: • The Netherlands and Belgium – Five minutes • Germany – 30 minutes • Denmark, Sweden, Finland and Estonia – 60 minutes • Norway – 120 minutes
Germany (TSOs)	15-minute schedules between TSOs are fixed values and can be updated 45 minutes in advance within the country. For external schedules, border-specific rules apply (i.e., this is separate from Nord Pool).
Denmark	3:00 p.m. before the day in question is the deadline for market players' nominations to Energinet.dk (Energinet.dk is part of a common Nordic regulating power market which operates along the same fundamental principles as the spot market).

2.1. SCHEDULING BETWEEN RTOs OR BALANCING AUTHORITIES

Transactions between RTOs, or between an RTO and a generator outside the RTO footprint, are generally scheduled on an hourly basis (see Table 2). However, some regions have implemented intra-hour scheduling across balancing authority areas. For example, PJM and the Midwest Independent Transmission System Operator (MISO) have implemented intra-hour scheduling across their interties.[10] California Independent System Operator (CAISO) has a pilot program to test intra-hour scheduling over interties with BPA. Launched in October 2011, the pilot program allows energy from wind resources in the BPA balancing authority area to be scheduled into CAISO on the half-hour. Participants can update the second half of their hourly schedules either up or down, and BPA adjusts their schedules into CAISO accordingly. The pilot

[10] Transmission lines that link balancing authority areas.

program will initially run for one year and is limited to 400 MW.[11] Other RTOs are considering moving to intra-hour scheduling between RTOs or other balancing authorities.[12] NYISO and PJM began intra-hour scheduling in June 2012 at the Keystone proxy generator bus. NYISO implemented intra-hour scheduling with Hydro-Québec in July 2011, and is working with the Independent System Operator of New England (ISO-NE) on intra-hour scheduling.[13]

Table 2 *ISO and RTO Scheduling on Interties (Excluding Dynamic Schedules)*[14]

ISO/RTO	INTERTIE SCHEDULING INTERVAL	TIMING OF INTERCHANGE SCHEDULE RAMPS
CAISO	One hour	The standard is 20 minutes across the top of the hour for changes in self-schedules.
ISO-NE	NE-NY – hourly NE-NB – hourly NE-HQ – hourly	
MISO	Quarter hour	
NYISO	One hour, except sub-hourly at one generator proxy bus with PJM	Five minutes before and five minutes after the top of the hour.
PJM	One hour; energy schedules can change on the quarter hour	Interchange schedule changes occur on the quarter hour. The changes ramp in over a 10-minute period, starting at five minutes before the schedule change to five minutes after the schedule change.
SPP	One hour	

[11] BPA Transmission Services Business Practices, *CAISO Intra-Hour Scheduling Pilot Program, Version 3* (Portland, OR: BPA, effective October 17, 2011), http://transmission.bpa.gov/ts_business_practices/Content/7_Scheduling/CAISO_IntraHour_Sch.htm.

[12] IRC (ISO/RTO Council) Briefing Paper, *Variable Energy Resources, System Operations and Wholesale Markets* (n.p.: IRC, August 2011), http://www.isorto.org/atf/cf/%7b5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7d/IRC_VER-BRIEFING_PAPER-AUGUST_2011.PDF.

[13] Juliana Brint, "NYISO, PJM to Begin Intra-Hour Scheduling," *Megawatt Daily*, June 8, 2012.

[14] ISO/RTO Council, *Comments of the ISO RTO Council in Response to the Federal Energy Regulatory Commission's Notice of Inquiry Seeking Public Comment on the Integration of Variable Energy Resources*, Docket RM10-11-000 (FERC, April 13, 2010), http://www.isorto.org/site/c.jhKQIZPBImE/b.4344503/k.83C1/FERC_Filings.htm;
Juliana Brint, "NYISO, PJM to Begin Intra-Hour Scheduling," *Megawatt Daily*, June 8, 2012.

2.2. MISO LOOK AHEAD COMMITMENT TOOL

In 2009, MISO began studying what it termed "look ahead" capabilities, which involve developing systems that allow for advance preparations for resource commitments and dispatch in real-time. This led to the creation of the Look Ahead Unit Dispatch System (LAUDS), a multi-phase look-ahead framework that is intended to improve the commitment of fast-start resources and the dispatch management of slow-ramping units. The first phase, which is comprised of the Look Ahead Commitment (LAC) tool, was approved by FERC for implementation in March 2012.[15] The second phase will involve development and implementation of the Look Ahead Dispatch (LAD) system.

Currently, real-time unit commitment is done through the Intra-day Reliability Assessment Commitment (IRAC), which has hourly granularity. According to MISO's LAC tariff filing, the IRAC has certain limitations:

- It is a manual off-line process and not all the inputs and initial conditions are automatically generated. As it is an off-line model, the state estimator is not used for system topology.
- The hourly granularity does not result in an adequate analysis of near-term conditions and, therefore, does not show intra-hour ramp shortages due to changes in interchange schedules or wind and load forecasts.
- The IRAC process takes too long and is not suitable or accurate enough for determining resource commitments in the near term.[16]

The new LAC tool will be used to complement the IRAC process. It is an automated on-line near-term look at system conditions that runs every 15 minutes, or can be run on demand. The inputs are automatically generated using the state estimate for system topology. The intra-hour granularity allows

[15] FERC, *Order Conditionally Accepting Tariff Filing*, Docket No. ER12-923 (FERC, March 29, 2012), http://www.ferc.gov/EventCalendar/Files/20120329141959-ER12-923-000.pdf.

[16] MISO, *Midwest Independent Transmission System Operator, Inc.'s Section 105 Filing to Amend Open Access Transmission, Energy and Operating Reserve Markets Tariff to Provide for Look Ahead Commitment*, Docket No. ER12-923 (FERC, January 27, 2012).

the LAC to account for changes in interchange schedules and wind and load forecasts. The LAC creates up to three different near-term scenarios that operators can consider. Operators can also alter the input conditions to the scenarios, if needed, to account for unexpected recent events, such as transmission and/or generation outages. MISO notes that the IRAC system aimed to reduce resource commitment costs, whereas the LAC model uses an algorithm that minimizes total production costs, which will lead to lower costs overall on the MISO system.[17]

PJM has two near-term commitment tools: the Real-Time Security Constrained Economic Dispatch (RT SCED) and the Intermediate Security Constrained Economic Dispatch (IT SCED). RT SCED covers 10-20 minutes ahead and is used for on-line unit dispatch, while IT SCED looks ahead from 15 minutes to two hours, and the grid operator can adjust startup and minimum run times of combustion turbine units. The grid operator can also optimize the time frame of the look-ahead interval for IT SCED.[18]

2.3. FERC FINAL RULE ON VARIABLE GENERATION

In June 2012, FERC issued a final rule regarding the integration of variable energy resources (VERs). The final rule includes two specific reforms to the *pro forma* Open Access Transmission Tariff (OATT): (1) transmission providers are required to offer the option of scheduling transmission service in 15-minute intervals or less. Transmission providers are free to offer scheduling at shorter intervals; and (2) generator provision of meteorological and operational data to transmission providers to improve power production forecasting. FERC decided not to require a new OATT generic ancillary service rate schedule under which the transmission provider will provide regulator service to transmission

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[17] Ibid.;
Juliana Brint, "NYISO, PJM to Begin Intra-Hour Scheduling," *Megawatt Daily*, June 8, 2012.
[18] PJM, "How PJM Dispatches and Controls," PJM Member and State Training, September 19, 2012, http://www.pjm.com/training/~/media/training/core-curriculum/ip-gen-101/how-pjm-oper-and-dispatch.ashx.

customers delivering energy from generation located within a transmission system operator's (TSO's) balancing authority area. FERC did offer guidance on how it will review proposed charges.[19] RTOs such as PJM with day-ahead sub-hourly scheduling and real-time energy markets will comply with the transmission scheduling provisions of FERC's final rule.

[19] FERC, *Integration of Variable Energy Resources*, 139 FERC ¶ 61,244, Docket No. RM10-11-000, Order No. 764 (FERC, June 22, 2012), http://ferc.gov/whats-new/comm-meet/2012/062112/E-3.pdf.

3. ENERGY IMBALANCES

3.1. ENERGY IMBALANCE PROVISIONS IN FERC ORDERS 888 AND 890

Simply defined, energy imbalances are the difference between advance generation schedules, such as day-ahead, and what is actually delivered in real-time. Because the difference between advance schedules and actual deliveries may be significant for variable generation, energy imbalance provisions are of special interest and can substantially impact how variable generation bids and schedules in local or regional power markets.

One example, although no longer applicable, of the impact of energy imbalance provisions was when FERC issued Order 888 in 1996. FERC required transmission providers to offer energy imbalance service as one of six ancillary services, and also allowed transmission providers to impose a penalty if energy deliveries varied by 1.5% or more (either higher or lower) from advance energy schedules. Typical energy imbalance provisions for an Order 888-style, open-access transmission tariff generally include the following:

- For hourly energy delivered by a generation resource less than the energy scheduled, a charge is imposed as the greater of: (1) the transmission provider's incremental cost, plus a percentage adder; or (2) a market index, plus a percentage adder; or (3) a pre-set price, such as 100 mills/kilowatt hours (kWh).
- For hourly energy delivered by the generation resource that is greater than the scheduled amount, a credit equal to some amount less than 100% of the transmission provider's incremental cost or market index.

The energy imbalance provisions effectively eliminated the ability of variable generation to compete in wholesale power markets, absent special provisions to minimize or eliminate the impact. As a result, several transmission providers and RTOs received FERC approval for special provisions for variable generation, some of which are still in effect and are summarized later in this section. In 2007, FERC issued Order 890 that, among other things, revamped the energy imbalance provisions in Order 888. Under Order 890, FERC requires that imbalances of less than or equal to 1.5% of scheduled energy, or up to 2 MW, be netted monthly and settled at the transmission provider's incremental or decremental cost. Imbalances of between 1.5% and 7.5% of scheduled energy, or between 2 MW and 10 MW (whichever is larger), are settled at 90% of decremental costs and 110% of incremental costs. Imbalances greater than 7.5% (or 10 MW, whichever is larger) would be settled at 75% of the system decremental cost for overscheduling imbalances or 125% of the incremental cost for underscheduling imbalances. Intermittent resources, however, would be settled at 90% of decremental costs and 110% of incremental costs for imbalances greater than 7.5% or 10 MW.[20]

3.2. TREATMENT OF ENERGY IMBALANCES FROM VARIABLE GENERATION AT RTOs AND OTHER BALANCING AUTHORITIES

FERC has historically accorded a degree of deference to RTOs in setting market rules, as FERC views RTOs as independent entities that do not own generation and transmission assets, and therefore are not subject to the potential conflict of favoring generation assets through ownership and operation of transmission facilities. In addition, the *pro forma* tariffs in both Order 888 and Order 890 allow FERC-jurisdictional utilities to submit revisions to the *pro forma* tariff that are comparable or superior to the FERC *pro forma* tariff. After the issuance of the energy imbalance provisions in Order 888, many RTOs received FERC approval of various provisions specific to energy imbalances from variable energy generation.

For PJM, balancing operating reserve charges are allocated to variable generation and other resources for deviations in real-time from day-ahead schedules.

[20] FERC, *Preventing Undue Discrimination and Preference in Transmission Service*, Docket Nos. RM05-17-000 and RM05-25-000, Order No. 890 (FERC, February 16, 2007), http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

Generators can self-schedule at a fixed output or within an operating range and will not be assessed balancing operating reserve charges if they follow PJM dispatch directions, and will also be eligible for operating reserve credits. A generator can decide not to follow PJM dispatch and will not be assessed balancing operating reserve charges if real-time output matches day-ahead schedules, but it will not be eligible for operating reserve credits. Differentials less than 5% or 5 MW incur no deviation charges.

For the ISO-NE market, energy deviations between real-time and day-ahead markets are also settled at the real-time LMP. Wind resources are exempt from a share of certain uplift costs that are allocated based on deviations.

In 2004, CAISO implemented its Participating Intermittent Resources Program (PIRP), covering variable generation forecasting. If a generator is participating in PIRP, then hourly deviations are settled at a monthly weighted market-clearing price and accumulated for the monthly average of energy imbalances. CAISO has proposed that monthly imbalance charges from PIRP facilities be allocated to the scheduling coordinators of load serving entities (LSEs) buying the energy from PIRP facilities, instead of being uplifted across the entire CAISO. If a variable generation resource does not participate in PIRP, then it is subject to 10-minute imbalance energy charges.

Under NYISO's market rules, if a variable generation resource is scheduling day-ahead, the resource must buy or sell deviations at real-time LMPs. Up to 3,300 MW of installed wind and solar capacity is exempt from under-generation penalties when output differs from the real-time schedule during unconstrained operations.

In the Electric Reliability Council of Texas (ERCOT), all generation resources are settled in real-time based on their Real-Time Settlement Point Price (RTSPP) and their net injection at the generation resource's settlement point. The settlement intervals are 15 minutes and the RTSPPs are calculated using the Nodal LMPs. Generation resources may be charged a penalty for deviating from their real-time base point instructions. For wind generation, penalties are determined by examining periods when they have been given an economic dispatch below their high dispatch limit (or capability). During these periods, if a wind resource is generating more than 10% above its expected base point, it will be charged for the deviation based on real-time prices.

BPA assesses persistent deviation penalties for positive and negative schedule deviations that exceed both 15% of the advance hourly schedule and 20 MW in an hour for three consecutive hours. Variable energy generators that meet or beat a 30-minute persistence schedule are exempt from such penalties.

As discussed in greater detail below, Dispatchable Intermittent Resources (DIRs) in MISO can be assessed Excessive or Deficient Energy Deployment Charges if an 8% tolerance band is exceeded for four or more consecutive 5-minute intervals within an hour. Both Intermittent Resources and DIRs in MISO are subject to Revenue Sufficiency Guarantee Charges for positive scheduling deviations for DIRs for day-ahead schedules, and for positive and negative deviations for Intermittent Resources. DIRs (but not Intermittent Resources) can receive real-time make-whole credits. Deviations less than between 6 MWh and 30 MWh are exempt. Generators are also exempt during events beyond their control, such as wind speed cut-out during high wind events.

3.3. SCHEDULING OF VARIABLE GENERATION

Historically, variable energy generation has been scheduled at or close to real-time in order to avoid potentially large energy imbalance charges in the day-ahead market. For PJM, wind and other variable generation that is considered a capacity resource must bid into the day-ahead market; otherwise, wind and other variable generation resources that are not considered capacity resources can, but are not required to, bid into day-ahead markets. A wind resource participating only in PJM's real-time market receives the real-time LMP for energy provided. Similarly, in MISO, if an Intermittent Resource is designated as a capacity resource, then it must offer into the day-ahead market. Otherwise, the Intermittent Resource can – but has no obligation to – offer into the day-ahead market. In MISO, Intermittent Resources and Dispatchable Intermittent

Resources have an incentive to participate in the day-ahead market because these resources can receive Revenue Sufficiency Guarantee charges. In NYISO, wind that is designated as a capacity resource is not required to bid into the day-ahead market in NYISO. In ISO-NE, wind resources can submit a bid curve or self-schedule into the day-ahead market, but are not required to do so. Capacity resources with a Capacity Supply Obligation must offer or self-schedule into the real-time market.

As variable generation penetration increases, some RTOs are imposing additional scheduling requirements. In NYISO, wind resources bid a price curve that can include negative price bids. This is required for the real-time market and is optional for the day-ahead market. If the wind resource needs to limit its output, the price and quantity offers submitted by each wind plant will determine the reduced base point for each wind plant for economic dispatch. During constrained operations in NYISO, variable generators must follow dispatch signals within five minutes, and are subject to non-compliance penalties equal to the MW above basepoint multiplied by the regulation clearing price. A 3% error is allowed.

PJM dispatches wind based on the economic offers of wind generators. Like other generators, wind plants are subject to deviation charges if they do not follow PJM's dispatch signal.

3.4. MISO'S DISPATCHABLE INTERMITTENT RESOURCES

One significant change came in MISO, which introduced and implemented a Dispatchable Intermittent Resource category. MISO submitted its DIR filing to FERC in November 2010.[21] FERC issued an order conditionally accepting the

[21] MISO, *Electric Tariff Filing Designating Dispatchable Intermittent Resources*, Docket No. ER11-1991 (FERC, November 1, 2010), http://www.ferc.gov/EventCalendar/Files/20110228175927-ER11-1991-000.pdf.

tariff revisions in February 2011.[22] Instead of creating an entirely new category, MISO made DIRs a subset of its existing Generation Resource (GR) category; therefore, all tariff language relating to GRs also applies to DIRs. MISO modified the relevant portions of the tariff to include new rules that would integrate DIRs into GR operations. DIRs are defined as resources that are constrained by "forecast-dependent fuel availability."[23] A DIR cannot control the availability of its fuel but it can control the amount currently available fuel that it uses. This makes DIRs dispatchable downward, and these resources can therefore participate in market-based solutions to congestion and minimum generation events.

Prior to these changes, all intermittent resources in MISO were classified as Intermittent Resources (IRs), which operate the same as GRs in the day-ahead market but not in the real-time market. IRs are not considered dispatchable and therefore do not set LMPs and are ineligible for any real-time make-whole provisions. MISO's real-time security constrained economic dispatch system evaluates IRs as dispatchable resources but cannot use them to manage congestion. If IRs need to be curtailed, this is accomplished manually by the MISO operators. Manual curtailment of resources is not reflected in LMPs. MISO noted in the FERC filing that in 2009, operators recorded 1,100 instances of manual curtailments and in 2010, there had already been a similar amount of curtailment calls just through July of that year.[24]

DIRs are treated similarly to GRs in the real-time market, except they cannot provide operating reserves. The other difference between GRs and DIRs is that GR offers must include an Hourly Economic Maximum Limit (HEML), which

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[22] FERC, *Order Conditionally Accepting in Part and Rejecting in Part Tariff Filing and Requiring Compliance Filings*, 134 FERC ¶ 61,141, Docket No. ER11-1991-000 (FERC, February 28, 2011), http://www.ferc.gov/EventCalendar/Files/20110228175927-ER11-1991-000.pdf.

[23] MISO, *Electric Tariff Filing Designating Dispatchable Intermittent Resources*, Docket No. ER11-1991 (FERC, November 1, 2010), http://www.ferc.gov/EventCalendar/Files/20110228175927-ER11-1991-000.pdf.

[24] Ibid.

indicates the maximum dispatch point at which that the GR can operate. Since DIRs are only dispatchable down (not up), DIR offers are bound by the Forecast Maximum Limit (FML). The FML is the expected real-time capability for each hour based on a rolling forecast of twelve 5-minute periods. The FML is independent of any downward dispatch currently in effect and can be updated in real-time. It can be provided by the DIR owner up to the time immediately prior to MISO executing security constrained economic dispatch. In addition, MISO will continually calculate and maintain a default FML, which MISO will use if the DIR owner has not submitted an updated FML within the last 30 minutes, or if the FML submitted is beyond the feasible limit for the DIR.[25]

MISO still has an IR designation but has limited the resources that can qualify as IRs. Beginning March 1, 2013, all wind-powered resources must register as DIRs if they began operation after April 1, 2005.[26] Non-wind renewable energy resources have the option of registering as IRs or DIRs if they choose to install (or already have) the equipment needed to be compatible with MISO's security constrained economic dispatch. A wind resource that began operation after April 1, 2005 can only register as an IR if it can demonstrate, on a quarterly basis, that it has a combination of the following in an amount that equals its installed capacity: Network Integration Transmission Service (NITS); Network Resource Interconnection Service (NRIS); or Long-Term Firm Point-to-Point Transmission Service. MISO stated that resources meeting this requirement must have installed equipment that enables them to serve any load as a Network Resource, which by definition is a resource whose output is under contract to a Network Customer and can meet that customer's load "on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program."[27]

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[25] For example, greater than the capacity of the resource, and therefore, clearly in error.
[26] MISO has indicated that wind facilities installed since April 1, 2005 have the technical capability to install the necessary equipment at reasonable cost. Older wind facilities have the option of upgrading their equipment and registering as DIRs but are not required to do so.
[27] MISO, *Electric Tariff Filing Designating Dispatchable Intermittent Resources*, Docket No. ER11-1991 (FERC, November 1, 2010), 7.

Once a resource (of any kind) chooses to register as a DIR, it cannot revert back to IR status.[28]

Settlements for DIRs are the same as for GRs, with DIRs now eligible to receive real-time make-whole payments. This includes the Day-Ahead Margin Assurance Payment (DAMAP), which is a make-whole payment provided when real-time dispatch is below day-ahead dispatch, causing the resource to lose against its day-ahead result; and the Real-Time Offer Revenue Sufficiency Guarantee Payment (RTORSGP), which compensates a resource when its real-time dispatch is above its day-ahead dispatch, but the real-time LMP is below the offer cost.[29] Consequently, DIRs are now also subject to the same intolerance bands and potential Excessive Deficient Energy Charges (EDEDC) as GRs. DIRs are subject to EDEDC penalties when their average operation over a dispatch interval is outside the MISO tolerance band for four or more consecutive 5-minute dispatch intervals within an hour. MISO's tolerance band is set at 8%; therefore, average operation outside the tolerance band is above 108% or below 92% of average dispatch. MISO does not assess penalties to deviations less than 6 MW but will assess the penalty for deviations greater than 30 MW. Within the 6-30 MW bounds, the 8% rule applies. MISO amended the EDEDC rules to allow a DIR to request an Excessive/Deficient Energy Exemption (EEE) under certain conditions – extremely high winds or other extreme weather-related conditions.[30]

MISO filed a report to FERC in February 2012 documenting the first year of DIRs, noting that performance results indicate the 8% tolerance band is reasonably attainable. MISO indicated that some DIRs had high levels of compliance with dispatch instructions while others struggled at first but were improving over time. One DIR with almost 2,000 MW of generation was meeting the 8%

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[28] The above does not apply to Qualifying Facilities under PURPA.

[29] MISO, Dispatchable Intermittent Resource Workshop II, October 17, 2011, https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/Workshop%20Materials/DIR%20Workshops/20111017%20DIR%20Workshop%202%20Presentation.pdf.

[30] Ibid.

tolerance band for more than 98% of the time.[31] MISO also noted that analysis of the first six months of DIR operation indicates that DIRs get dispatched at their FML for about 95.2% of the time, and for a portion of the remaining time, the DIRs were not dispatched at FML due to ramp constraints.[32]

MISO is beginning to see more wind scheduled in day-ahead markets, perhaps because of DIR. Day-ahead scheduling of wind in MISO amounted to 2.8 gigawatts (GW) in fall 2011, up 25% from earlier in 2011. Figure 1 compares the difference between day-ahead and real-time wind output in MISO between 2009 through November 2011, with wind being slightly under-scheduled.[33]

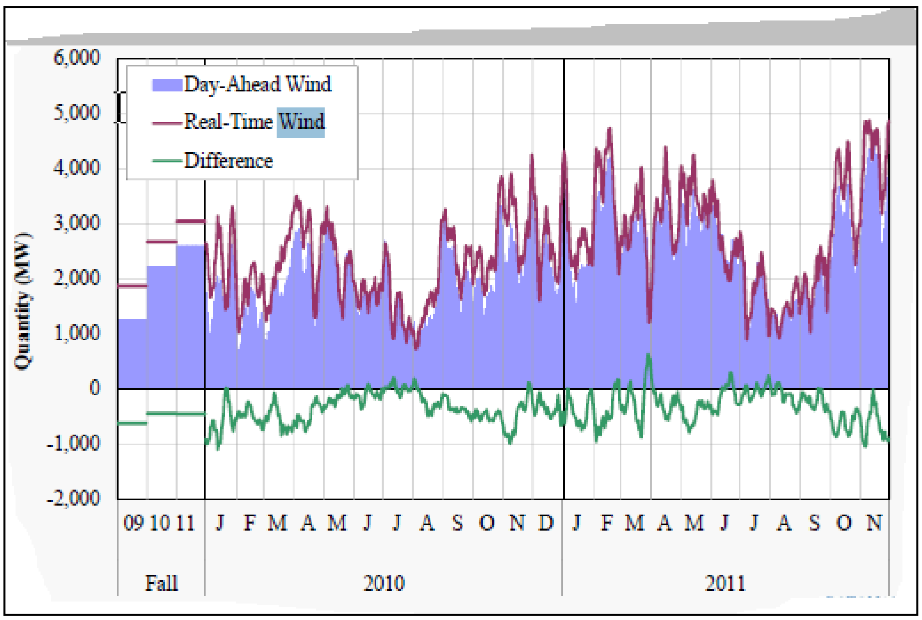

Figure 1 *Wind Output in Real-Time and Day-Ahead Markets in MISO Seven-Day Moving Average; 2009-November 2011*[34]

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[31] MISO, *Compliance Filing of the Midwest ISO Regarding Dispatchable Intermittent Resources*, Docket No. ER11-1991 (FERC, February 28, 2012), https://www.midwestiso.org/Library/Repository/Tariff/FERC%20Filings/2012-02-28%20Docket%20No.%20ER11-1991-000.pdf.

[32] Ibid.

[33] David B. Patton, *IMM Quarterly Report: Fall 2011 September-November* (Fairfax, VA: Potomac Economics, December 2011), http://www.potomaceconomics.com/uploads/midwest_presentations/IMM_Quarterly_Report_Fall_2011_Final.pdf.

[34] Ibid.

3.5. INTERNATIONAL EXAMPLES OF ENERGY IMBALANCES AND VARIABLE GENERATION

In Spain's electricity market, all generators, including wind and solar, are responsible for paying for the costs of any schedule deviations and the costs of the balancing energy necessary. A penalty is applied if the individual plant schedule deviations are opposite to grid needs. Therefore, if a generator produces less than is scheduled, it pays the market price for balancing generation if the deviation supports the grid, or the maximum "up reserve" price if the deviation is not in support of the grid. If a generator produces more than is scheduled, it pays the balancing cost for a generator not to produce and is paid by the grid operator the market price if the extra generation is in support of the grid, and the minimum price if not.[35]

Denmark uses a two-price imbalance system, where a market participant will pay imbalance charges if their hourly imbalance is in the same direction as the system imbalance for that hour. Denmark has a peak load of 6,400 MW and a minimum load of 1,800 MW, both as of 2010.[36] The installed wind capacity was 3,871 MW and solar capacity was 16 MW.[37] Conversely, a market participant is paid the spot market price for that hour (i.e., the hourly price of Nordpool's

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[35] Jorge Hidalgo López, "Wind Development and Integration Issues and Solutions," Presentation before the Northwest Wind Integration Forum, Portland, OR, July 29-30, 2010, http://www.nwcouncil.org/energy/wind/meetings/2010/07/WIF%20TWG%20072910%20Hidalgo%20072610.pdf.

[36] H. Holttinen, A.G. Orths, P.B. Eriksen, J. Hidalgo, A. Estanqueiro, F. Groome, Y. Coughlan, H. Neumann, B. Lange, F. van Hulle and I. Dudurych, "Currents of Change," *IEEE Power and Energy* 9, no. 6, November/December 2011, 47-49.

[37] Wind capacity in Spain from European Wind Energy Association, *Wind in Power: 2011 European Statistics*, February 2012, http://www.ewea.org/fileadmin/files/library/publications/statistics/Wind_in_power_2011_European_statistics.pdf; Solar capacity from European Photovoltaic Industry Association, *Global Market Outlook for Photovoltaics until 2016*, May 2012, Figure 6, http://files.epia.org/files/Global-Market-Outlook-2016.pdf.

regulation market) if the imbalances are in the opposite direction of the system imbalance.[38]

In Germany, all renewable energy is pooled amongst the TSOs, and energy and costs are equalized based on the real-time redistribution of the renewable energy and associated imbalances in proportion to the load shares in each control area. The TSOs are responsible for balancing the difference between their 15-minute shares of renewable energy and their share of actual renewable energy production.[39] During the day, the TSOs change their market positions by buying and selling in the intraday market based on updated short-term variable generation forecasts.[40]

3.6. VIRTUAL BIDDING

Virtual bidding occurs when market participants make an offer to buy or sell without taking a physical position, as every sale (or purchase) placed in day-ahead is closed by a purchase (or sale) in real-time. Virtual bidding allows financial companies a means of participating in power markets without physical assets. These companies may try to capture price divergences between markets of different time intervals (such as day-ahead versus real-time) and can add market liquidity, reduce market inefficiencies and mitigate the market power of other buyers and sellers.

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[38] Kevin Porter, Christina Mudd and Michelle Weisberger, *Review of International Experience Integrating Variable Renewable Energy Generation,* prepared for PIER Renewable Energy Technologies Program, California Energy Commission (Columbia, MD: Exeter Associates, January 2007), http://www.energy.ca.gov/pier/project_reports/CEC-500-2007-029.html.

[39] B. Ernst, B. Oakleaf, M. L. Ahlstrom, M. Lange, C. Moehrlen, B. Lange, U. Focken and K. Rohrig, "Predicting the Wind," *IEEE Power and Energy Magazine* 5, no. 6, November/ December 2007, 78-89, http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=4383126&url=http%3A%2F%2Fieeexplore.ieee.org%2Fxpls%2Fabs_all.jsp%3Farnumber%3D4383126.

[40] B. Ernst, U. Schreier, F. Berster, J.H. Pease, C. Scholz, H.P. Erbring, S. Schlunke and Y.V. Makarov, *Large-Scale Wind and Solar Integration in Germany*, prepared for the DOE (Richland, WA: Pacific Northwest National Laboratory, February 2010), http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19225.pdf.

Virtual bidding takes place in all of the organized markets in RTOs in the United States. Virtual bidding takes place at different levels of granularity in different Independent System Operators (ISOs) and RTOs, whether nodal (ISO-NE, MISO, PJM) or zonal (NYISO). Virtual positions are included in RTO simultaneous feasibility tests and price determination processes as real positions.

With regard to variable energy generation, virtual bidders may employ commercial variable generation forecasts to compare against the day-ahead variable generation forecast if made available by the RTO. It is possible that in the future, as it is presently with load forecasting in some systems, RTOs and market participants will rely upon multiple commercial and other sources of variable generation forecasts to produce a consensus forecast or weighted average forecast for market and reliability operations.

Virtual bidders may also place virtual bids to arbitrage against the differential between day-ahead and real-time variable generation forecasts or on other expectations of variable generation output in real-time that is not reflected in day-ahead schedules and prices. Virtual bids may also be placed to account for any positive or negative bias in variable generation forecasts, to reflect the difference in forecast errors between day-ahead and close-to-real-time forecasts, to predict locational congestion in real-time that may not be anticipated in day-ahead, or to take day-ahead positions if variable generators are under-scheduling day-ahead. For the latter, some RTOs, including NYISO and MISO, state that virtual bidders are providing that function.[41]

A question exists as to whether virtual bidding can minimize some common variable generation integration issues, such as day-ahead underscheduling by variable generators or to make up for variable generation forecasting errors. There has been little research on this question and little in the way of empirical

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[41] ISO/RTO Council, *Comments of the ISO RTO Council in Response to the Federal Energy Regulatory Commission's Notice of Inquiry Seeking Public Comment on the Integration of Variable Energy Resources*, Docket RM10-11-000 (FERC, April 13, 2010), http://www.isorto.org/site/c.jhKQIZPBImE/b.4344503/k.83C1/FERC_Filings.htm.

results to assess. One question to consider is whether virtual bidding will capture private market economic gains that could be realized for load should variable generation forecasting be more accurate, or if grid operators are more confident in relying on the variable generation forecasts in making unit commitment schedules and decisions.

4. VISIBILITY OF DISTRIBUTED GENERATION

4.1. DISTRIBUTED GENERATION

What constitutes a distributed generation resource is not perfectly defined in the industry; however, it is generally understood to consist of electric power sources not directly connected to the bulk power transmission system. Distributed generation (DG) consists of non-renewable and renewable energy resources; however, a growing portion of DG consists of variable generation resources such as solar photovoltaics (PV) and small wind turbines. The distribution system changes more dynamically than its transmission system counterpart, with little visibility of these changes to the bulk power system operator.[42] Distributed generation itself is commonly "invisible" to system operators in the United States. These resources go unseen by system operators and cannot usually receive dispatch commands. This is particularly true for behind-the-meter resources connected at customer sites, which are netted out with the customer load.

Although this has generally posed little problem in the past, as distributed generation has been only a small contributor to total generation, DG is projected to grow rapidly in the coming years in the United States.[43] Over the next ten years, Plug-in Electric Vehicles (PEVs) are expected to increase to as much as 3,800 MW, while distributed energy storage projections show an increase to roughly 1,000 MW. Solar PV is also expected to have significant growth to over 10 GW by 2016.[44] In California, for example, where solar photovoltaic power

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[42] NERC, *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources* (Princeton, NJ: NERC, August 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf.

[43] KEMA, Inc., *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, CEC-400-2011-011 (Oakland, CA: KEMA, Inc., December 2011), http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf.

[44] NERC, *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources*, (Princeton, NJ: NERC, August 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf.

represented approximately 78% of total installed DG capacity at the end of 2011, solar DG is projected to increase to over 3,000 MW in the next decade, thanks in large part to California's Million Solar Roofs program. While this would represent less than 6% of CAISO's peak load, it could comprise over 10% of the generation dispatched during spring or fall shoulder month load periods.[45] Should 3,000 MW of distributed solar in California trip for grid events, it would more than double all of the Western Electricity Coordinating Council's (WECC's) frequency response obligation. In addition, 1,700 MW of wind qualifying facilities under the Public Utility Regulatory Policies Act (PURPA) and distributed solar capacity for Pacific Gas & Electric (634 MW), Southern California Edison (395 MW), and San Diego Gas & Electric (114 MW) is not visible to CAISO.[46]

With the rapid projected growth of distributed generation, the lack of visibility for system operators is becoming cause for concern. Their concerns can be divided into the impact of DG on load forecasting and the potential for large amounts of DG to drop off the grid in response to system disturbances.

First, we discuss the effect of DG on load forecasting. In offsetting local load, DG can significantly change the electricity demand patterns, complicating scheduling and planning. If enough energy is invisible to the system operator, the risk of over-scheduling generation to meet load demand is increased. Alternatively, the system operator could underestimate the amount of load that needs to be served should the distributed generation become unavailable. In this case, the system operator may not have sufficient available generation, resulting in unserved energy. That, in turn, could prompt grid operators to increase the level of reserves required to account for not being able to "see" DG.

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[45] KEMA, Inc., *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, CEC-400-2011-011 (Oakland, CA: KEMA, Inc., December 2011), http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf.

[46] Jim Blatchford, "Solar Forecasting Research," Presentation before the Utility Wind Integration Group Workshop on Variable Generation Forecasting, Tucson, AZ, February 8-9, 2012.

CAISO reports that load forecasts are being affected by distributed generation, particularly distributed solar. Figure 2 illustrates the effects of non-metered solar generation. CAISO is now incorporating forecasts of non-metered solar into its load forecast, based on the difference of a full sun forecast and a weather-based forecast.[47]

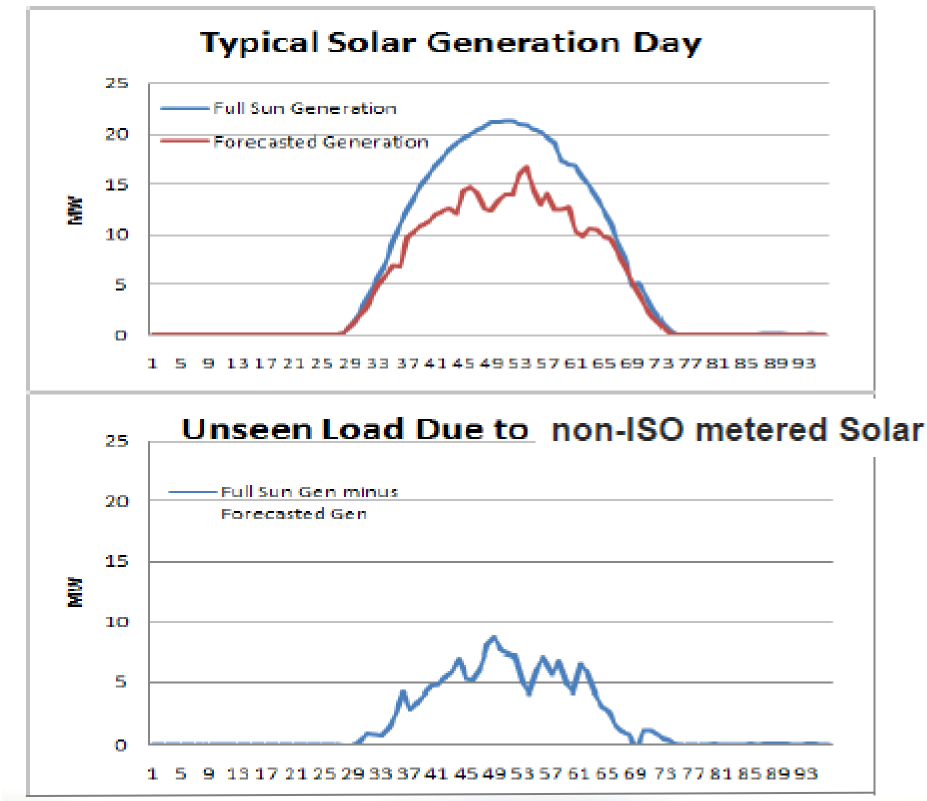

Figure 2 *Example of Non-Metered Solar Generation in the California ISO*[48]

It is also possible that in transmission-constrained areas, local DG could meet area load, to the point that transmission is now underused. If locally-generated distributed generation went off-line because of a grid event, then transmission lines could overload if the loads are unexpectedly transferred onto the higher-

[47] Jim Blatchford, "CAISO Solar Integration," Presentation before the Utility Wind Integration Group Solar Integration Workshop, Maui, HI, October 11, 2011.
[48] Ibid.

voltage network. Additionally, DG can alter the power system's frequency and voltage response by displacing other generation that would usually be on-line.[49]

Second, we consider the effect of DG on grid operations if there are system disturbances. With the expected future growth of distributed generation, the interaction between North American Electric Reliability Corporation (NERC) reliability standards and IEEE Standard 1547 becomes more prominent. IEEE Standard 1547 was developed between 1999 and 2003 and was reaffirmed by IEEE in 2008. IEEE Standard 1547 defines functional requirements for interconnecting DG up to 10 MVA that is technology neutral and is not a design handbook, application guide, or an interconnection agreement.[50] The standard is focused on power quality, interconnection safety, and safety during and after distribution system events. Therefore, quick tripping of DG was required to avoid islanding of generation while feeder faults are cleared, to limit the contribution of DG to grid faults, and to minimize concerns for distribution system protection. The standard does not allow DG to provide voltage control, or to ride through grid disturbances involving abnormal voltage or frequency conditions.[51] IEEE Standard 1547 conflicts with NERC requirements for bulk power system reliability, whereby the main concern is maintaining frequency and local voltage during and after transmission system events, and generators

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[49] KEMA, Inc., *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, CEC-400-2011-011 (Oakland, CA: KEMA, Inc., December 2011), http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf.;
NERC, *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources* (Princeton, NJ: NERC, August 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf.

[50] IEEE Standards Association, IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems, http://grouper.ieee.org/groups/scc21/1547/1547_index.html.

[51] NERC, *Special Report: Accommodating High Levels of Variable Generation* (Princeton, NJ: NERC, April 2009, http://www.uwig.org/IVGTF_Report_041609.pdf.

are required to not trip within specified voltage vs. time and frequency vs. time requirements.[52]

If significant growth of distributed generation continues, there could potentially be a large, unexpected drop-off in generation as DG responds to a voltage or frequency excursion, resulting in some of the reliability issues mentioned earlier. At the extreme, if DG is at sufficiently high levels, the drop-off DG in response to a frequency or voltage disturbance could lead to cascading blackouts if the system is unprepared. Additionally, there is an aggravating effect to dropping DG in response to a low-frequency or low-voltage event. If significant DG goes off-line during a low-voltage event, it will appear to system operators that system load has increased and lead to further voltage reductions.[53]

Few anticipated the growth, actual and planned, of distributed generation at the time IEEE Standard 1547 was proposed and implemented. Absent reconciliation between NERC reliability standards and IEEE Standard 1547, transmission system events could result in widespread tripping of DG facilities, both during system faults and grid voltage swings that may occur after the fault.

Figure 3 and Figure 4 compare the IEEE Standard 1547 and NERC requirements for voltage and frequency.

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[52] Nick Miller, "IEEE Standard 1547 – Where Are We Going: A Report from the DG User Group," Presentation before the Utility Wind Integration Group Technical Workshop, San Diego, CA, April 24-26, 2012.

[53] NERC, *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources* (Princeton, NJ: NERC, August 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf.;
KEMA, Inc., *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, CEC-400-2011-011 (Oakland, CA: KEMA, Inc., December 2011), http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf;
Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.

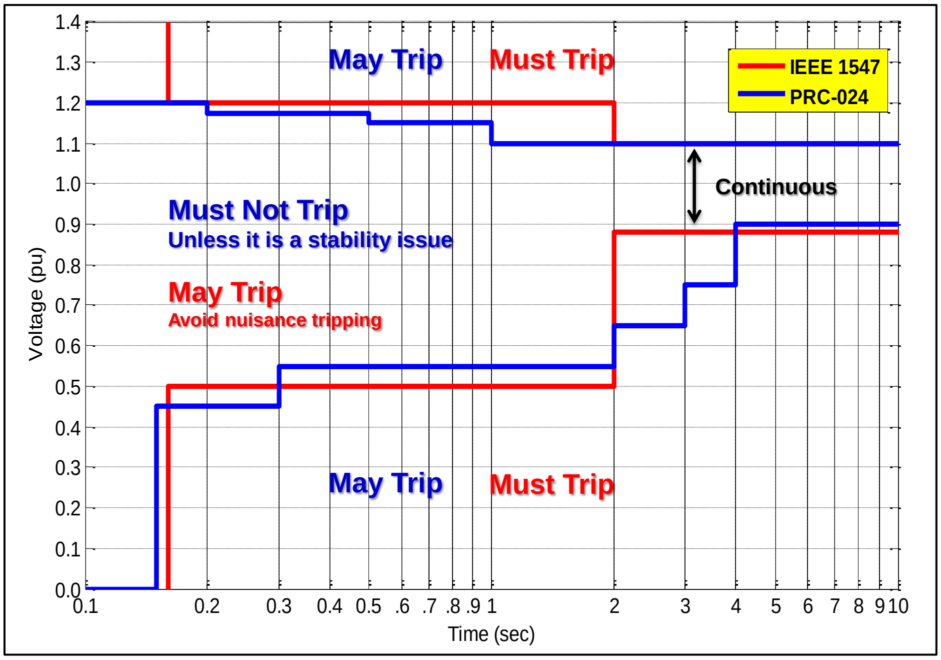

Figure 3 *Voltage Tolerance Requirements between NERC PRC-024 (Blue) and IEEE 1547 (Red)*[54]

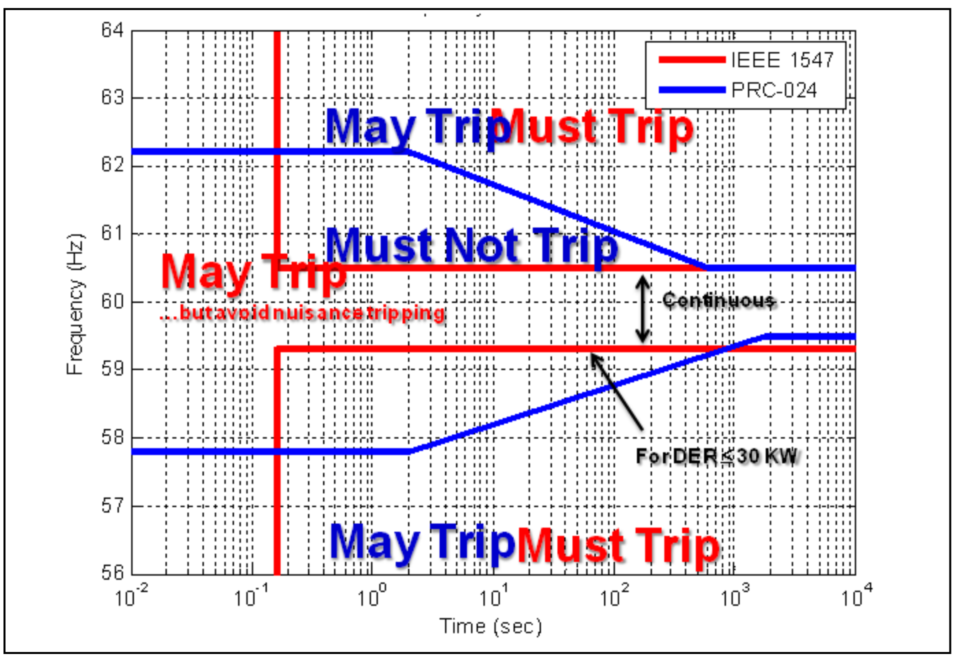

Figure 4 *Comparing Frequency Requirements of NERC PRC-024 (Blue) and IEEE 1547 (Red)*[55]

[54] Nick Miller, "IEEE Standard 1547 – Where Are We Going: A Report from the DG User Group," Presentation before the Utility Wind Integration Group Technical Workshop, San Diego, CA, April 24-26, 2012.

The Hawaii Electric Light Company (HELCO) has been grappling with issues related to IEEE Standard 1547. Solar PV in HELCO provided as much as 5.5% of typical peak load in 2009. HELCO has experienced the voltage and frequency excursions that exceed levels detailed in IEEE Standard 1547 criteria during faults. Of particular concern is the potential loss of DG during an under-frequency event. Frequency is a system-wide parameter, which means all DG could trip off in such a case. Such a large loss of generation would exacerbate the low-frequency situation. A system assessment found that even at low DG levels, the system impact could be significant with load-shedding and intensified under-frequency.[56]

Of the 12 states in PJM with renewable portfolio standards or goals, eight have technology set-asides that include solar as one of the eligible technologies. PJM conducted its own analyses with solar scenarios of 14%, 20% and 30% for both distributed and central station applications. As depicted in Figure 5 and Figure ***6***, PJM found that faults on the PJM Bulk Electric System (BES) would cause voltage drops severe enough to initiate disconnection of solar in compliance with IEEE Standard 1547. The analysis concluded that distributed generation (including solar) needs to ride through voltage and frequency disturbances.[57]

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[55] Ibid.

[56] NERC, *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources* (Princeton, NJ: NERC, August 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf.

[57] Mahendra Patel, "A NERC View," IEEE Standard and Industry Needs Panel Discussion before the Utility Wind Integration Group's Distributed Generation Users Group Meeting, San Diego, CA, April 24, 2012.

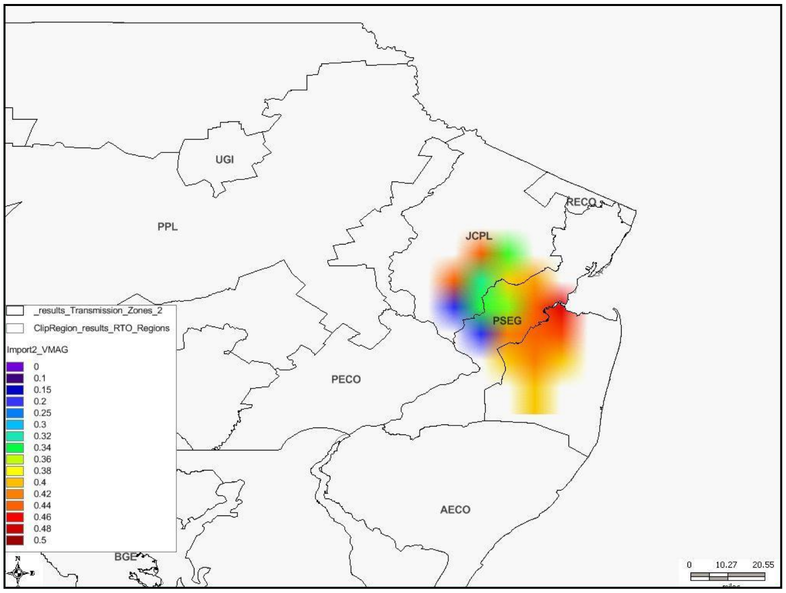

Figure 5 *Voltages in PJM below 0.5 P.U. for a BES fault at 500 kV Bus with High Solar at Substation One*[58]

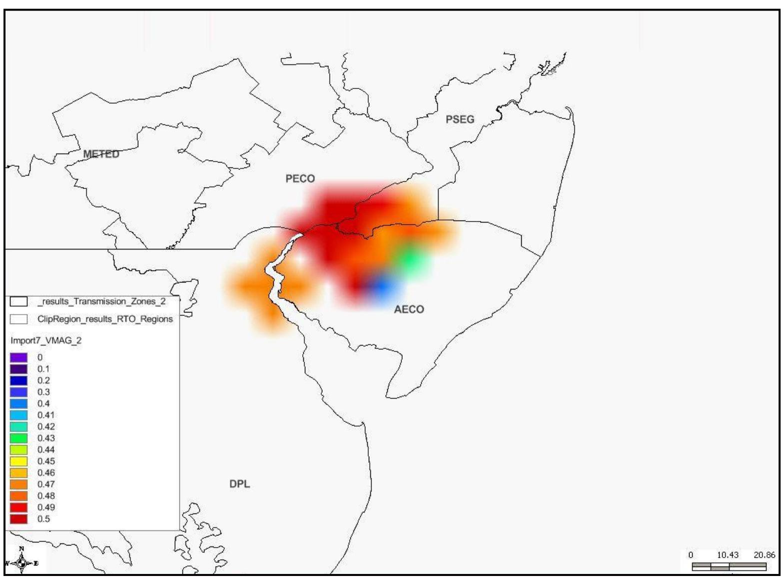

Figure 6 *Voltages in PJM below 0.5 P.U. for a BES fault at 500 kV Bus with High Solar at Substation Two*[59]

58 Ibid.

59 Ibid.

The IEEE is considering an immediate revision to IEEE Standard 1547 that would allow DG facilities to actively regulate voltage, consider alternatives to tripping of DG facilities for voltage and frequency events, and increase the size limit covered by IEEE Standard 1547 from 10 MVA to 20 MVA. IEEE may also undertake a longer and more deliberative process to address other requested revisions to IEEE Standard 1547.[60]

The NERC Planning Committee could also incorporate DG into the NERC Registry Criteria. The NERC Statement of Compliance Registry Criteria outlines which entities must register with, and be subject to, NERC's reliability standards. By and large, DG is not included among those required to register, however the criteria states that it will include all entities that NERC determines could potentially have a material impact on bulk power system reliability. Should DG penetration continue to grow, NERC may view DG as having a material impact on reliability and thus recommend registration.[61]

In absence of reconciliation of IEEE-1547 and low-voltage ride-through standards, or perhaps in combination with reconciliation, grid operators can take other steps to make DG systems more visible to grid operators:

- DG plants could be required to be metered.
- Allow grid operators to have telecommunications and remote control capability to some clusters of DG in the grid operator's region. Such a step would ease resynchronization in the event of a breakup of the transmission grid.

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[60] Nick Miller, "IEEE Standard 1547 – Where Are We Going: A Report from the DG User Group," Presentation before the Utility Wind Integration Group Technical Workshop, San Diego, CA, April 24-26, 2012.

[61] NERC, *Special Report: Accommodating High Levels of Variable Generation* (Princeton, NJ: NERC, April 2009), http://www.uwig.org/IVGTF_Report_041609.pdf;
NERC, *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources* (Princeton, NJ: NERC, August 2011), 39, http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf.

- Further collaboration and communication between RTOs and/or large balancing authorities and distribution utilities regarding DG data collection systems and transmittal of information between distribution utilities and RTOs and/or large balancing areas on area net load, aggregate DG energy and local weather information.[62]
- Communicate with FERC and state utility commissions about the need to modify interconnection requirements to require solar DG facilities to regulate voltage and to stay on-line during grid disturbances for voltage and frequency events.

4.2. INTERNATIONAL EXAMPLES OF DG VISIBILITY TO GRID OPERATORS

The European Network of Transmission System Operators for Electricity (ENTSO-E) estimates that 80% of installed photovoltaic capacity in Europe is connected to low voltage grids. Existing standards in Europe allow DG capacity to disconnect if frequency falls below 49.5 hertz (Hz) or exceeds 50.2 Hz. ENTSO-E estimates that 35 GW of PV capacity could disconnect in overfrequency events. Italy has over 11.5 GW of PV capacity that could disconnect below 49.7 Hz and over 50.3 Hz. This has prompted Italy to require PV installations to meet transmission-level standards for system frequency after April 1, 2012.

The ENTSO-E report made three recommendations:

- To harmonize existing national laws, national and international standards, national rules and the practices of Distribution System Operators with system requirements.

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[62] KEMA, Inc., *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, CEC-400-2011-011 (Oakland, CA: KEMA, Inc., December 2011), http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf;
NERC, *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources* (Princeton, NJ: NERC, August 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf.

- To define system compatible requirements for new installations including a transitional period. ENTSO-E noted that this is underway in several countries with high levels of distributed solar capacity.
- To design and implement a retrofit program for countries with high levels of distributed solar capacity.[63]

ENTSO-E is now conducting dynamic studies to evaluate grid impacts from decreasing system inertia because of increasing amounts of renewable energy installations. The studies are expected to be published by the end of 2012.[64]

Turning to individual countries, Germany is the world leader in installed solar capacity, with 24 GW as of 2011, and is among the world leaders in wind capacity, with 29 GW as of 2011.[65] Solar provides about 3% of Germany's generation, while wind provides 8%. Of the solar capacity in Germany, 80% is interconnected to the low voltage grid.[66]

In Germany, "distributed generation" is a general term that by and large encompasses generation connected at low and medium voltage distribution grids, and generation for self-supply.

Germany has formulated technical rules related to DG and variable generation. This includes requiring DG to ride-through low-voltage events and requiring both active and reactive power management capability. Germany also requires distributed system operators to apply forecasting methods, although it stops short of specifying a specific forecasting model to use and to coordinate such forecasts with transmission system operators. About 25% of solar capacity in

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[63] ENTSO-E, "Assessment Report of the System Security with Respect to Disconnection Rules for Photovoltaic Panels Published," Brussels, Belgium, June 6, 2012, https://www.entsoe.eu/news/announcements/newssingleview/article/assessment-report-of-the-system-security-with-respect-to-disconnection-rules-for-photovoltaic-panels/?tx_ttnews[backPid]=28&cHash=d5b706e76f57154d4d9a49ab21deeaad.

[64] Ibid.

[65] Nick Miller, "IEEE Standard 1547 – Where Are We Going: A Report from the DG User Group," Presentation before the Utility Wind Integration Group Technical Workshop, San Diego, CA, April 24-26, 2012.

[66] Ibid.

Germany provides forecasting data roughly every 15 minutes to the distribution system operator. This requirement stemmed from when transmission system operators in Germany had to activate all of their contracted negative operating reserves (about 4,800 MW) for several hours as a result of large errors in day-ahead solar forecasts on September 6, 2010 (see Figure 7).[67]

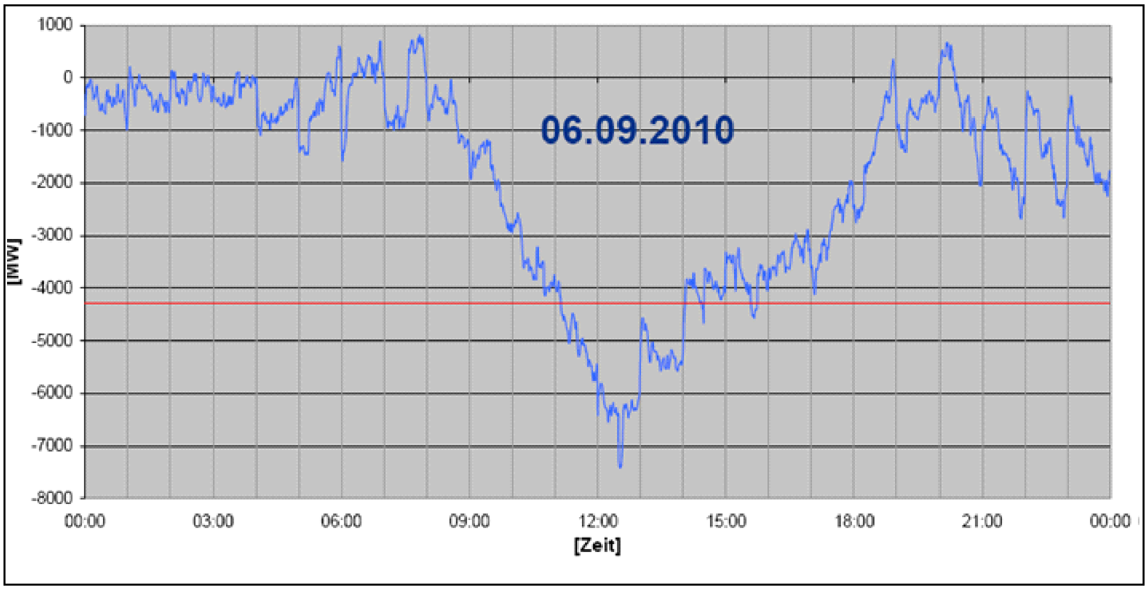

Figure 7 *Negative Balancing Power Requirement (Blue) and Contracted Reserves (Red) in Germany on September 6, 2010*[68]

Note: Blue line: total negative power balancing reserve actually required; Red line: sum of negative secondary and tertiary power reserve contracted (over and above primary regulating reserve of approximately 600 MW).

Additionally, Germany requires that all DG units equal to or greater than 100 kilowatts (kW), with the exception of solar PV, be remotely observable and dispatchable for the transmission system operator. Solar PV systems less than 100 kW are exempt from requirements to measure power output. However, solar PV units between 30 kW and 100 kW are required to be able to reduce output remotely in case of grid congestion. Further, solar less than 30 kW must

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[67] KEMA, Inc., *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, CEC-400-2011-011 (Oakland, CA: KEMA, Inc., December 2011), http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf.

[68] Ibid.

be able to reduce output remotely in case of grid congestion or to reduce maximum power to 70% of installed capacity.[69] Germany just launched an initiative to retrofit old PV installations – 315,000 in all – over three years to comply with these technical requirements.[70]

Germany is also proposing measures to incorporate DG into the dynamic support network, including requirements that, in the wake of a fault clearance, DG be required to consume reactive power equal to or less than it consumed prior to the fault, and that DG provide reactive power to the system.[71]

Spain has over 4 GW of solar photovoltaics and is the fourth leading country in the world in photovoltaics installed capacity behind Germany, Italy, and Japan. Spain is the world leader in Concentrating Solar Power (CSP) capacity, with 1,150 MW installed as of the end of 2011, 400 MW of which was installed in 2010. Another 1.1 GW of CSP capacity is under construction.[72]

Nearly all of the PV in Spain is connected to the distribution grid, while 70% of the CSP in Spain is connected to the transmission grid. Lack of grid operator awareness of solar PV is considered a problem, as the PV plants are not required to send Red Eléctrica de España (REE) real-time production and operation information. Spain currently only has real-time measurement data of about

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[69] Hendrik Neumann, "Variable Generation Developments in Germany," Presentation before the Utility Wind Integration Group Fall Technical Workshop, Lahaina, HI, October 12-14, 2011.

[70] ENTSO-E, "Assessment Report of the system security with respect to disconnection rules for photovoltaic panels published," Brussels, Belgium, June 6, 2012, https://www.entsoe.eu/news/announcements/newssingleview/article/assessment-report-of-the-system-security-with-respect-to-disconnection-rules-for-photovoltaic-panels/?tx_ttnews[backPid]=28&cHash=d5b706e76f57154d4d9a49ab21deeaad.

[71] KEMA, Inc., *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, CEC-400-2011-011 (Oakland, CA: KEMA, Inc., December 2011), http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf;
NERC, *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources* (Princeton, NJ: NERC, August 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf.

[72] REN 21, *Renewables 2012 Global Status Report* (Paris: REN 21 Secretariat, June 2012), http://www.map.ren21.net/GSR/GSR2012_low.pdf.

150 MW of PV. For now, Spain uses meteorological predictions to estimate how much solar PV exists each hour. Spain has real-time information for all CSP plants.

While solar PV does not have the ability to ride through voltage drops, because solar PV is mostly connected to the distribution grid, they are not as vulnerable to faults on the transmission system. Nonetheless, Spain is considering amending its grid code to apply to solar systems.[73] Spain also has an overfrequency plan where renewable energy projects larger than 10 MW are disconnected at different frequency levels. Renewable energy projects under 10 MW only disconnect if the frequency is over 51 Hz, which is more stringent than existing European standards.[74]

[73] NERC, *Flexibility Requirements and Potential Metrics for Variable Generation: Implications for System Planning Studies,* (Princeton, NJ: NERC, August 2010), http://www.uwig.org/IVGTF_Task_1_4_Final.pdf.

[74] ENTSO-E, "Assessment Report of the System Security with Respect to Disconnection Rules for Photovoltaic Panels Published," Brussels, Belgium, June 6, 2012, https://www.entsoe.eu/news/announcements/newssingleview/article/assessment-report-of-the-system-security-with-respect-to-disconnection-rules-for-photovoltaic-panels/?tx_ttnews[backPid]=28&cHash=d5b706e76f57154d4d9a49ab21deeaad.

5. RESERVES

5.1. INTRODUCTION

Reserves can be defined as additional capacity and responsive load, either on-line or off-line, above that needed to meet electricity demand in order to maintain reliability if actual load or generation differs from what is expected, or to account for unexpected changes such as a sudden loss of generation or transmission.

The types and characteristics of reserves vary in response speed (seconds to minutes), whether they are on-line or off-line, and duration time (minutes to hours). Different entities define the amount of reserves, who can provide them, when they should be utilized, and how they are utilized based on reliability and allowable risk criteria. How reserves are defined and used can vary significantly from region to region. Furthermore, there are a multitude of terms used to define comparable or similar reserves.

Table 3 includes comparable definitions from NERC, with the exception of load following. The definitions somewhat overlap and are not exact. "Load following" is not listed by NERC but is considered to mean the change of generation and responsive load over several minutes or hours to account for changes in net load (load minus wind minus solar). For generation, this encompasses economic-dispatch commands from short-term demand forecasts, unit commitment and dispatch.

Table 3 *NERC Reserve Definitions*[75]

SERVICE	RESPONSE SPEED	DURATION	CYCLE TIME	MARKET CYCLE	PRICE RANGE* (AVERAGE/MAX) $/MW-HR
	SERVICE DESCRIPTION				
	Normal Conditions				
Regulating Reserve	On-line 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 (CPS) Reliability Standard.				
	~1 min	**Minutes**	**Minutes**	**Hourly**	**33-60* Avg. 300-600 Max.**
Load Following or Fast Energy Markets	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	On-line 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 ten minutes to comply with NERC's Disturbance Control Standard (F).				
	Seconds to <10 min	**10 to 120 min**	**Hours to Days**	**Hourly**	**6-27 Avg. 70-2,000 Max.**
10-Minute Non-Spinning Reserve	Same as spinning reserve, but need not respond immediately; resources can be off-line but still must be capable of reaching a specified output within the required ten minutes.				
	<10 min	**10 to 120 min**	**Hours to Days**	**Hourly**	**1-3 Avg. 60-400 Max.**
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 minute response time.				
	<30 min	**2 hours**	**Hours to Days**	**Hourly**	**1-4 Avg. 2-36 Max.**

[75] NERC, *IVGTF Task 2.4 Report: Operating Practices, Procedures and Tools* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-4.pdf.

Table 3 *NERC Reserve Definitions (Continued)*

SERVICE	RESPONSE SPEED	DURATION	CYCLE TIME	MARKET CYCLE	PRICE RANGE* (AVERAGE/MAX) $/MW-HR
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.

The characteristics of variable generation are such that changes to the definition, timing, duration and amount of reserves may be necessary at higher levels of variable generation. Variable generation can have maximum and minimum generation at different time periods, with some element of variability and uncertainty as to the amount and timing of variable generation during those time periods. Multiple variable generation integration studies are finding that at higher penetrations of variable generation, additional reserves may be necessary to maintain reliability, or new methods of utilizing reserves and amended rules and policies, or both, may be needed to reflect the increased variability and uncertainty of higher levels of variable generation. Different integration studies have used different methods in an attempt to quantify how much reserves will be needed with higher levels of variable generation.

As more variable generation is added to the grid, different grid operators have adjusted existing practices, or implemented new practices. This section is a high level overview of actions related to reserves that various grid operators in the

United States have taken, plus a few international examples.[76] The discussion is drawn from past integration studies and current experience, to the extent information is available. We will begin with a description of regulation and load following, and then turn to the individual actions taken by grid operators with regard to reserves and variable generation. Tables summarizing regional practices for defining reserves and determining the needed quantity of reserves are provided in Appendix A.

5.2. REGULATION

Regulation addresses the fast and frequent variations in load and generation that contribute to energy imbalance. Regulation is used to address imbalances caused by load or generation changing within the shortest applicable market or economic dispatch interval that may be as short as five minutes or as long as up to an hour. Variable generation increases very short-term imbalances between generation and load, and regulation is used to correct the imbalance.[77] A rough rule of thumb is the additional regulation needed is equal to about 1% of the nameplate capacity of a 100 MW wind plant.[78]

Table 4 depicts examples of how some RTOs determine regulation requirements. PJM's regulation requirement is determined in whole MW for daily on-peak (between 5:00 a.m. and 11:59 p.m.) and off-peak (midnight to 4:59 a.m.). PJM's on-peak regulation requirement is equal to 1% of the daily forecasted peak load, and the off-peak regulation requirement is equal to 1% of the daily forecasted valley load. PJM sends two regulation signals. The first is the assigned hourly regulation quantity, in MW, that is cleared from the regulation market and is

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[76] A much more detailed discussion is available in NREL's Conference Paper, *Operating Reserves and Wind Power Integration: An International Comparison* (Golden, CO: NREL, October 2010), http://www.nrel.gov/docs/fy11osti/49019.pdf, and in the NERC *IVGTF Task 2.3 Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-3.pdf.

[77] Erik Ela, Michael Milligan and Brendan Kirby, *Operating Reserves and Variable Generation,* (Golden, CO: NREL, August 2011), http://www.nrel.gov/docs/fy11osti/51978.pdf.

[78] NERC, *IVGTF Task 2.4 Report: Operating Practices, Procedures and Tools* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-4.pdf.

sent on a 10-second scan rate. The second signal is Reg A, which is the real-time instantaneous resource owner fleet regulation signal that moves regulating resources in the regulation owner's resource fleet within the fleet capacity, and is sent on a 2-second scan rate.

Table 4 *Regulation Requirement Definition from Various Regional Transmission Organizations*[79]

REGION	REQUIREMENT DEFINITION
PJM	Based on 1% of the peak load during peak hours and 1% of the valley peak during off-peak hours.
NYISO	Set requirement based on weekday/weekend, hour of day, and season.
ERCOT	Based on 98.8 percentile of regulation reserve utilized in previous 30 days and same month of previous year and adjusted by installed wind penetrations.
CAISO	Use a requirement floor of 350 MW up and down regulating reserves which can be adjusted based on load forecast, must-run instructions, previous CPS performance, and interchange and generation schedule changes.
MISO	Requirement made once a day based on conditions and before the day-ahead market closes.
ISO-NE	Based on month, hour of day, weekday/Sat/Sun.

Some of the RTOs use combined up and down regulation while ERCOT and CAISO have separate regulation up and regulation down requirements (see Table 5). The combined regulation requirements suggest that the upward and downward requirements must be equal, and any resource providing regulation must be able to provide the same amount of up and down regulation. Regions with separate services can have different regulation requirements and different resources providing varying amounts of up and down regulation. It also allows grid operators to more finely tune their regulation needs, particularly if there are hours where one type of service (either regulation up or regulation down) is

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[79] Erik Ela, Michael Milligan and Brendan Kirby, *Operating Reserves and Variable Generation*, (Golden, CO: NREL, August 2011), http://www.nrel.gov/docs/fy11osti/51978.pdf.

needed and the need can switch back and forth between the two regulation services.

Table 5 *Combined Versus Separate Regulation Requirements in RTOs*[80]

REGION	REQUIREMENT DEFINITION
PJM	Combined
NYISO	Combined
ERCOT	Separate
CAISO	Separate
MISO	Combined
ISO-NE	Combined

5.3. LOAD FOLLOWING

Load following can be considered as capacity available during normal system conditions to assist in meeting expected schedule imbalances or to follow system ramping requirements, such as the morning pick-up in load or the evening drop-off in load. Load following is a slower response than regulation (several minutes to a few hours) and does not require automatic centralized response. Load following is not a defined FERC ancillary service, nor is there a NERC standard or direction. Load following is secured from intra-hour and hourly energy markets. Because load follows a predictable daily path, the ramping and energy required to follow can be provided from energy markets.

The addition of variable generation can make following net load less predictable, as variable generation may not be well correlated with time-of-day load patterns. For some hours, units with higher ramp rates or greater flexibility may need to be available. Figure *8* illustrates seven hours of a typical load ramp, with the blue line reflecting the actual load and the red line reflecting the hourly average.

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80 Ibid.

The red line could be the schedule that is used in making unit commitment decisions. The trend is monotonically increasing and units can be scheduled at some point during the hour. As an example, the first half of hour 17 is below the hourly average and the second half of the hour is above the hourly average. In real-time, generating resources can be instructed to start toward the middle of the hour rather than at the top of the hour based on actual conditions.

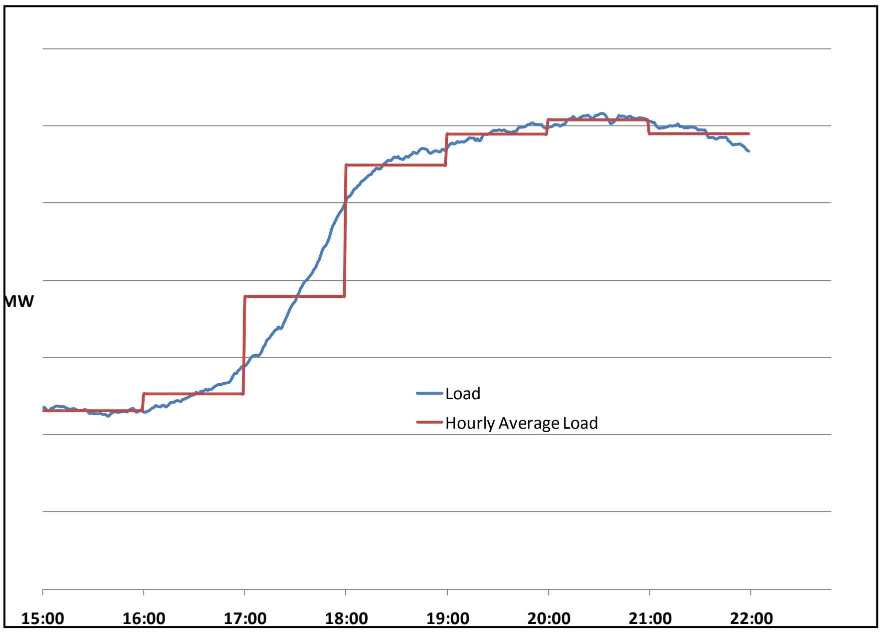

Figure 8 *Typical Load Ramp and Hourly Average Schedule to Follow Load*[81]

Figure 9 is the same ramp with variable generation netted from the load to depict the net load. The trend is not monotonically increasing or decreasing as was depicted in Figure 8. As an example, the unit commitment (if done on an hourly basis) in hour 18 would schedule to the hourly average, and in hour 19 generation units may be turned off. Under an hourly unit commitment schedule, the sharp increase in hour 18 may be difficult for the on-line units to accommodate. This suggests that some load following reserve capacity with identified ramping capabilities may be needed to manage sub-hourly variability, if making unit commitment decisions on an hourly basis. Alternatively, a separate load following reserve may not be necessary if unit commitment is done

[81] Ibid.

on a sub-hourly rather than hourly basis. Sub-hourly markets, scheduling and/or dispatch may be able to follow the increased variability with net load by adjusting the dispatch of conventional generators and responsive loads in response to changes in net load. However, the increased uncertainty of variable generation shows up in errors with prediction of the net load and of variable generation, and there may still be a need for additional following reserves because of increased uncertainty, regardless of the length of the commitment or dispatch interval.[82]

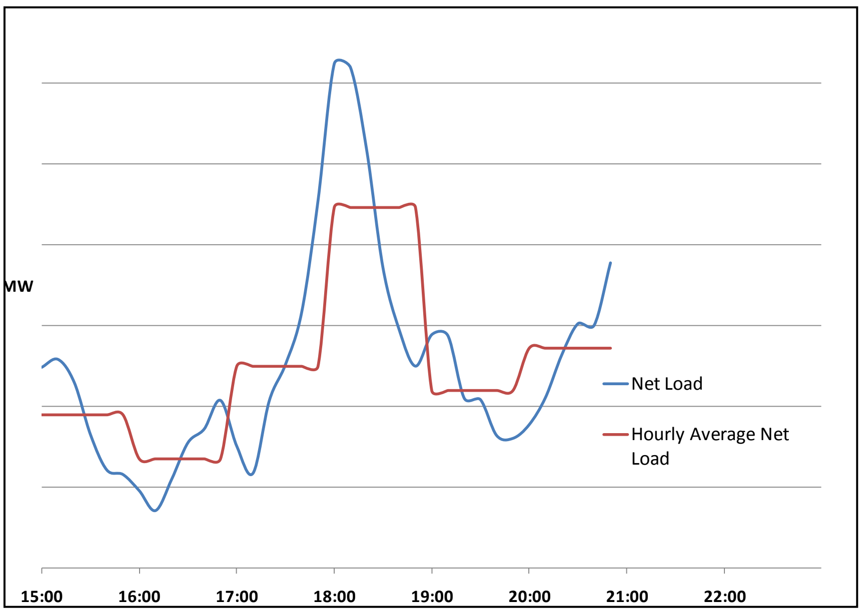

Figure 9 *Net Load vs. Hourly Average Load for Seven-Hour Period*[83]

Wind and solar ramps on a multi-hour basis can add to uncertainty. The tail events of such ramps can be extreme, their occurrence is not easily or precisely forecasted in the planning time frame, and they are not well correlated with time of day. Figure 10 and Figure 11 illustrate ramps in BPA's balancing area for two-plus years for 5-minute, 30-minute and 60-minute trends in wind generation.

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[82] Ibid.

[83] Ibid.

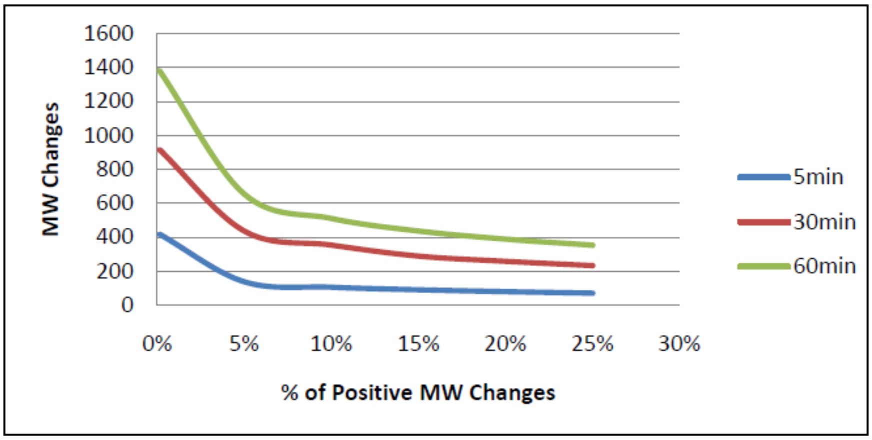

Figure 10 *BPA's Largest Wind Generation Up Ramps*[84]

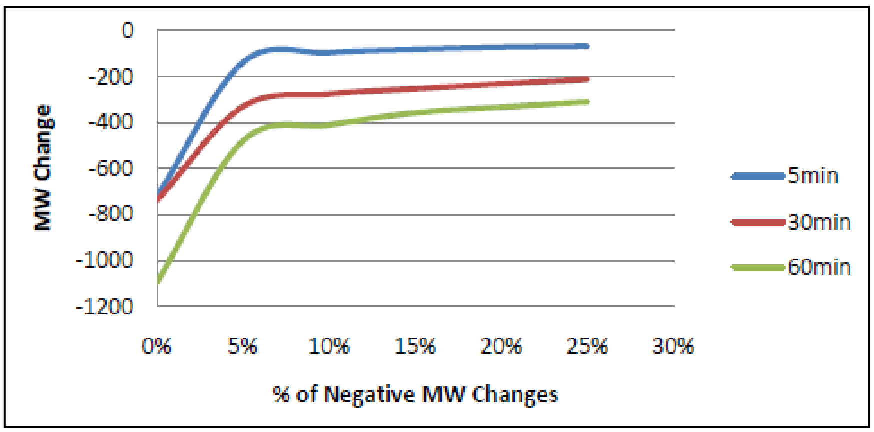

Figure 11 *BPA's Largest Wind Generation Down Ramps*[85]

ERCOT's experience is depicted in Figure 12 and Figure 13, with 1-minute data. The data includes periods of wind curtailment, and some of the ramps may have been because of following instructions from ERCOT. Also, the figures should be interpreted carefully; i.e., 5% of the time where wind output increased over a three-hour period by 2,000 MW or more.

[84] NERC, *IVGTF Task 2.3 Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-3.pdf.
[85] Ibid.

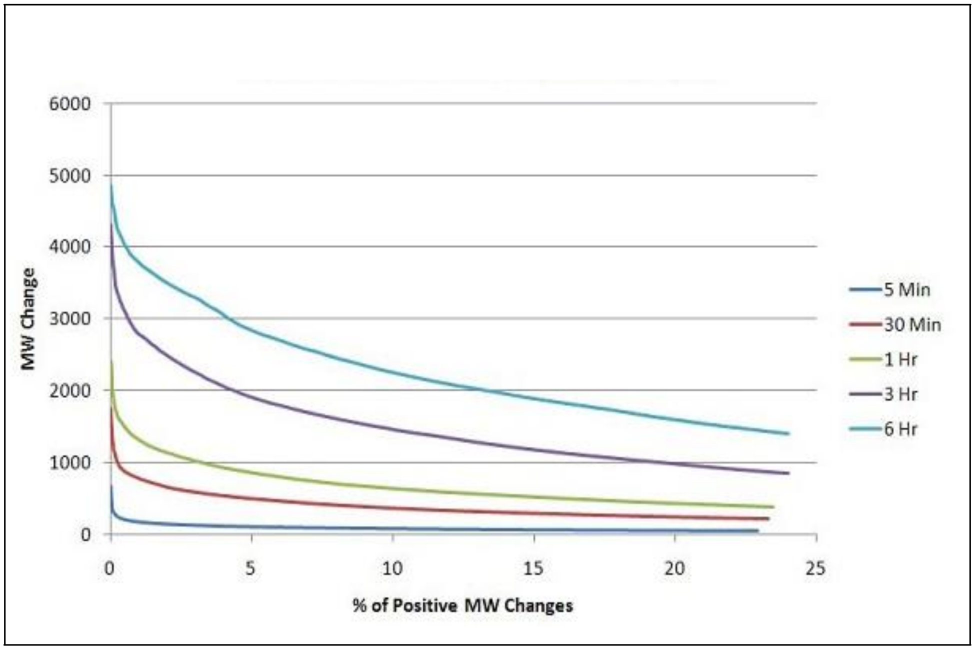

Figure 12 *Duration Plot for Positive MW Changes in ERCOT Aggregate Wind Output over Different Time Frames for Six Months in 2010*[86]

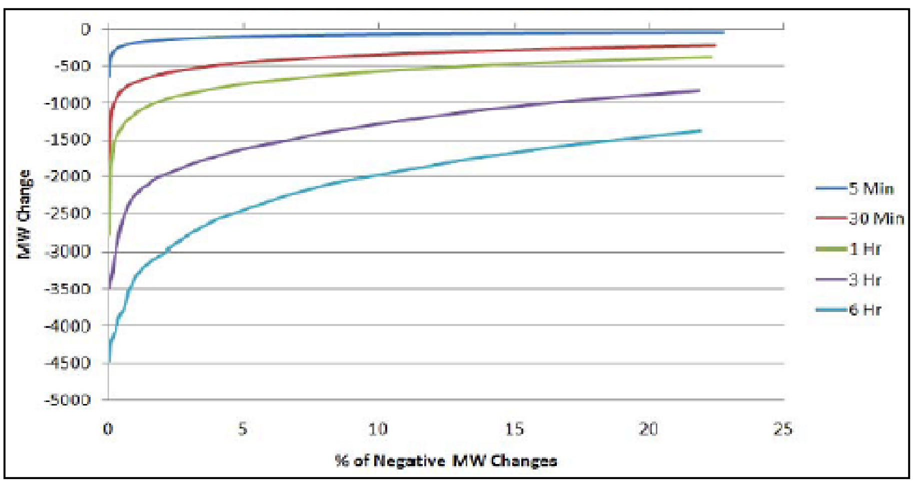

Figure 13 *Duration Plot for Negative MW Changes in ERCOT Aggregate Wind Output over Different Time Frames for Six Months in 2010*[87]

Some grid operators are developing variable generation ramp forecasts in an attempt to better forecast the predictability and timing of such ramps, as covered in the forecasting section. Another option if variable generation ramps are rare

[86] Ibid.

[87] Ibid.

enough, or if unpredicted ramp events are rare enough, is to call upon contingency reserves, but then those reserves may not be available if another contingency emerges, such as the sudden loss of a generating unit.[88] The flexibility of available generation or responsive demand resources will determine whether a balancing area can accommodate the increased variability and uncertainty with variable generation and variable generation ramps, or whether actions such as increasing resources in day-ahead commitment or creating a new or revised ancillary service, such as a ramping reserve, will be necessary.[89] Such a ramping reserve would cover the probability of an event (e.g., 5%) not being covered by spinning or non-spinning reserves, or if applicable, contingency reserves.[90] CAISO and MISO are experimenting with different approaches as discussed below.

5.4. CAISO FLEXIBLE RAMPING CONSTRAINT

CAISO received FERC conditional approval for creating a new ancillary service known as the Flexible Ramping Constraint. CAISO began experiencing shortages in ramping capability that it attributes to multiple factors such as resources shutting down without sufficient notice, errors in variable generation forecasts, sudden changes in expected deliveries, contingencies, and high hydro runoff. CAISO said the ramping shortage is most noticeable during the morning and evening ramps as load increases.

CAISO identifies a Flexible Ramping Constraint and compensates generators and loads when it schedules them to alleviate the constraint. A stakeholder initiative, Renewable Integration Market and Product Review Phase 2, is developing a more complete market-based solution with a new flexible ramping ancillary service and bid-based pricing.

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[88] NERC, *IVGTF Task 2.4 Report: Operating Practices, Procedures and Tools* (Princeton, NJ: NERC, March 2011, http://www.nerc.com/files/IVGTF2-4.pdf.

[89] NERC, *IVGTF Task 2.3 Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-3.pdf.

[90] Erik Ela, Michael Milligan and Brendan Kirby, *Operating Reserves and Variable Generation,* (Golden, CO: NREL, August 2011), http://www.nrel.gov/docs/fy11osti/51978.pdf.

The Flexible Ramping Constraint allows CAISO to procure upward ramping capability from "committed, flexible generation resources and proxy demand response resources that are not designated to provide regulation or contingent operating reserves, and whose upward ramping capability is not committed for load forecast needs."[91] CAISO estimates how much flexibility is required between 15-minute real-time unit commitment and five-minute real-time dispatch. The flexibility need is then applied to hour-ahead scheduling, short-term unit commitment and real-time dispatch. If CAISO decides that additional up-ramp capability is required, it removes designated generation and responsive load from energy markets, ancillary service markets, or both so that these resources are available for ramping.

Compensation under the initial program is determined from the opportunity cost of the marginal Flexible Ramping provider. If, for example, the spinning reserve price is $5/MWh and the marginal resource bid is $3/MWh to supply spinning reserve, the payment to all Flexible Ramping providers for that interval would be the $2/MWh lost opportunity cost. If the marginal resource bid for spinning reserve is $7/MWh, there would be no compensation for supplying Flexible Ramping because the resources would not have been selected to supply spinning reserve. Compensation is among the issues FERC is reviewing. If the amount of reserves decreases between the 15-minute unit commitment and the five-minute real-time dispatch, CAISO may release reserves to participate in real-time dispatch.

The costs for Flexible Ramping are currently allocated to load. CAISO found that 80% of the load-following requirements are attributable to loads and 20% are attributable to wind and solar variations. Cost allocation is the other issue FERC has set for rehearing.[92] In August 2012, CAISO filed a settlement with FERC over

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[91] CAISO, *Order Accepting and Suspending Proposed Tariff Changes and Establishing Hearing and Settlement Judge Procedures,* 137 FERC ¶ 61,191, Docket No. ER12-50-000 (FERC, December 12, 2011), http://www.ferc.gov/EventCalendar/Files/20111212180110-ER12-50-000.pdf.
[92] Kevin Porter, Christina Mudd, Sari Fink, Jennifer Rogers, Lori Bird, Lisa Schwartz, Mike Hogan, Dave Lamont and Brendan Kirby, *Meeting Renewable Energy Targets in the West at Least*

the issue of cost allocation. CAISO plans to allocate 75% of the costs to scheduling coordinators based on their share of total hourly measured demand. The other 25% will be assigned to scheduling coordinators based on gross supply deviations by individual resource (i.e., scheduling coordinators cannot net deviations within a resource portfolio). Charges to deviations will initially be incurred daily but will soon change to monthly.

Ultimately, CAISO hopes to convert the flexible ramping constraint into an ancillary service that will address both upward and downward ramping. CAISO is in discussions with stakeholders about such a service.

5.5. MISO RAMP MANAGEMENT

As a part of its Wind Integration initiative, MISO has been examining how to include ramping capability in real-time operations. MISO predicts that the increasing levels of variable generation will likely increase the need for better ways to manage variation in net load. MISO's Ramp Management project intended to develop methods for real-time dispatch to provide controlled resources with a determined quantity of ramp capability, allowing the controlled resources to respond more efficiently to the varying net load served by these resources. The aim is to:

- Aid reliable operations by keeping sufficient ramp capability available for use in real-time dispatch to address variations in ramp requirements;
- Reduce price volatility by reducing instances of transitory shortages arising from ramp shortages; and
- Acquire ramp capability through a market mechanism so a price signal can be sent to the market.[93]

Cost: The Integration Challenge, Western Governors Association, June 2012, http://www.rapon-line.org/featured-work/meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration.

[93] MISO, "Ramp Capability in MISO Markets," Presentation before the Stakeholder 4th Technical Workshop, December 13, 2011, 4, https://www.misoenergy.org/Events/Pages/Ramp20111213.aspx.

MISO dispatches generation units in 5-minute intervals to provide the most economic solution to the expected level of variation in net load. Generation units have varying ramping rates and, therefore, varying abilities to respond to unanticipated deviations, which sometimes require generation to ramp up quickly. This can lead to short-term scarcity situations and price spikes. The Ramp Management project is examining how grid operators can estimate the quantity of ramp capability that will be needed in the next dispatch interval in order to respond to the expected variability and unexpected variations of net load. MISO will then apply these determinations in both the day-ahead and real-time markets. To this end, MISO is developing the Ramp Capability Model. The Ramp Capability Model will forecast ramping requirements (system-wide and zonal, if required) that will address the desired level of expected variability and uncertainty in the net load within a defined response time. The model will take into account each resource's ramp capability (through their offers) and create a ramp capability demand curve to model the costs of not meeting a set level of variability. The requirements are set based on the forecast net load variability and an administratively set uncertainty level. The model output will be simultaneously co-optimised with energy and ancillary services to ensure that the required level of ramping capability is available to meet expected variations in net load. Up and down ramp constraints will be enforced in real-time dispatch as enough rampable resource capacity is withheld for future ramping needs, which then changes the dispatch and prices of energy and ancillary services.

Compensation for the ramping services will be based on the opportunity costs for the capacity withheld from other services, the ramp resource offers, and the derived demand curve prices if the full amount of ramp capability is not cleared. The awarded ramp resource will be paid the clearing price and will be eligible for make-whole payments. They will be subject to real-time performance monitoring and deviation penalties. MISO is aiming to implement the new ramp management system in late 2012.[94]

5.6. REPORTS ON RESERVES FROM INDIVIDUAL GRID OPERATORS

5.6.1. BONNEVILLE POWER ADMINISTRATION

BPA's peak load was 9,538 MW as of January 2011 and its minimum load was 3,797 MW as of September 2011.[95] Installed wind capacity in BPA was 4,711 MW as of May 2012 and there was 14 MW of solar capacity as of September 2012.[96]

BPA's reserve requirements are divided into regulation, load following with perfect schedules (LFPS), and load following with either submitted or estimated schedules and/or load forecasts (LFES). The difference between LFPS and LFES is considered imbalance. Regulation is defined as the difference between actual regulation and the 10-minute average; LFPS is the difference between the 10-minute average and perfect schedule; and LFES is the difference between the 10-minute average and submitted or estimated schedules and/or the load forecast. An increment and decrement component for each reserve is calculated, with 0.25% of the extremes in each case removed, leaving 99.5% of all values; i.e., the reserve amounts necessary to ensure that there are enough reserves to meet system requirements 99.5% of the time. The results are then used to determine BPA's reserve capacity requirements (see Table 6). BPA noted that reducing the 99.5% probability will lower reserve requirements but increase the time BPA would need to limit or curtail wind. BPA is assuming 5,380 MW of wind

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[94] MISO, Ramp Management, https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/RampManagement.aspx
[95] BPA, *Data for BPA Balancing Authority Total Load, Wind Gen, Wind Forecast, Hydro, Thermal, and Net Interchange*, http://transmission.bpa.gov/business/operations/wind/.
[96] Wind data from BPA, "Wind Generation Capacity in the BPA Balancing Authority Area," May 2012, http://transmission.bpa.gov/business/operations/wind/WIND_InstalledCapacity_Plot.pdf; Solar data from BPA, "Winery pairs vines with volts, leads the way for solar on BPA's grid," September 2012, http://www.bpa.gov/news/newsroom/Pages/Winery-pairs-vines-with-volts-leads-the-way-for-solar-on-BPA%27s-grid-.aspx.

capacity for 2012 and 6,530 MW for 2013, using a 30-minute persistence wind schedule.[97]

Table 6 *BPA's Reserve Requirements for 2012 and 2013*[98]

Percentage of time covered (percentile used for calc)	2012		2013	
	Dec Reserve	Inc Reserve	Dec Reserve	Inc Reserve
99.5	-1410	1114	-1622	1433
99	-1217	974	-1389	1242
95	-735	663	-850	855

5.6.2. CAISO

CAISO has an all-time peak load of 50,270 MW that occurred on July 24, 2006, and a minimum load of around 20,000 MW. CAISO also has 4,697 MW of installed wind capacity and about 900 MW of solar interconnected with CAISO. This does not include any distributed solar generation.[99]

In a series of variable generation integration studies, CAISO has been evaluating the necessary grid operational requirements to accommodate higher levels of variable generation. A study of the CAISO system on a California-only basis under a 20% Renewable Portfolio Standard (RPS) with approximately 6,700 MW of wind and 2,250 MW of solar generation, found that total procurement of regulation and load-following would increase by 11-37%, depending on the season.[100] However, both hourly and 5-minute dispatch simulations suggested

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[97] Bart McManus, "Reserve Calculation Methodology," Presentation before the Utility Wind Integration Group Spring Technical Conference, San Diego, CA, April 24, 2012.
[98] Ibid.
[99] Jim Blatchford, CAISO, Personal Communication, October 15, 2012.
[100] CAISO, *Integration of Renewable Resources – Operational Requirements and Generation Fleet Capability at 20% RPS* (Folsom, CA: CAISO, August 31, 2010),

that for almost all hours of the year, the existing gas fleet in the CAISO footprint could provide the additional reserves and necessary operational flexibility. CAISO did find some examples of overgeneration in spring months under high hydro conditions, which could be alleviated by curtailing inflexible imports (allowing for additional commitment of dispatchable gas plants to provide downwards ramping).

Subsequently, CAISO has evaluated several alternative renewable resource scenarios for 33% RPS in 2020, modeled on a WECC-wide basis. In these studies, the sum of wind and solar resources is around 17-18,000 MW, distributed within California and in other states. The preliminary simulations have generally found that integration of wind and solar is operationally feasible, although at least one sensitivity case suggested that additional flexible generation could be needed. Follow-up analysis is examining further sensitivities on forecast errors, the application of stochastic planning methods, further consideration of reserve sharing with other balancing area authorities, and other factors.[101]

Presently, CAISO defines regulation as the difference between actual generation requirements and the short-term 5-minute forecast. CAISO procures regulation up and regulation down separately and in different amounts hourly to reflect that the need for regulation varies throughout the day. Hourly regulation up and regulation down, each determined separately, is based on the maximum expected coincidental 10-minute changes in the demand forecast, changes in generation self-schedules, and hourly intertie fluctuations. The regulation calculations also identify the worst coincidental peak ramp rate in five minutes and assume the ramp continues for ten minutes. Estimations of regulation needs

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http://www.caiso.com/Documents/Integration-RenewableResources-OperationalRequirementsandGenerationFleetCapabilityAt20PercRPS.pdf.

101 CAISO, *Track I Direct Testimony of Mark Rothleder on Behalf of the California Independent System Operator Corporation,* Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, Rulemaking 10-05-006 (Public Utilities Commission of the State of California, Submitted July 11, 2011), http://www.cpuc.ca.gov/NR/rdonlyres/1DE789A2-29EB-4E95-9284-9E680C0113E6/0/CAISOTestimony70111_FINAL.pdf.

are performed in the middle of the hour to ensure ramp changes between hours are reflected.[102]

CAISO is assessing three alternative methods for projecting day-ahead regulation requirements. The first method is one in which CAISO would conduct a statistical analysis of all sources of uncertainty, defined as load, wind, solar, schedule deviations, and frequency deviations, with the aim of keeping Area Control Error (ACE) close to zero. The second method is also a statistical analysis of past regulation up, regulation down, positive ACE, and negative ACE values, with the goal of identifying enough regulation up and down to keep ACE at zero. The third method is based on the Balancing Authority ACE Limit, or BAAL, and is a statistical analysis of ACE and frequency. CAISO will select one or a combination of methods once they have enough data to make an evaluation.[103]

CAISO also projects flexible capacity needs up to 24 hours ahead of time through load, wind, and solar forecasts; real-time operating data; committed resources; known generator forced outages; and interchange schedules. CAISO updates it flexible capacity analysis every five minutes at 90% and 95% confidence levels. Ultimately, CAISO plans to incorporate its Flexible Capacity Requirement in its day-ahead market by estimating its hourly up and down flexibility capacity requirement with a 60% confidence interval, and in real-time pre-dispatch with a 95% confidence interval.[104]

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[102] NERC, *IVGTF Task 2.4 Report: Operating Practices, Procedures and Tools* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-4.pdf.

[103] Clyde Loutan, "Reserve Calculation Methodology for Systems with Variable Generation," Panel Discussion before the Utility Wind Integration Group Spring Technical Conference, San Diego, CA, April 25, 2012.

[104] Ibid.

5.6.3. ERCOT

ERCOT has a maximum peak load of 68,379 MW that was recorded in August 2011.[105] The average monthly peak load is about 54 GW.[106] Installed wind capacity is just over 10 GW, while installed solar capacity is about 70 MW, excluding distributed solar generation.[107]

Regulation is used every four seconds in ERCOT to balance supply and demand. Inputs for determining regulation needs are historical 5-minute net load changes, historic deployment of regulation, recent CPS1 performance, and installed wind capacity.

ERCOT determines its regulation needs based on past or expected wind capacity. ERCOT examines the up and down regulation service (for every hour) that has been used in the past 30 days and for the same month last year, and applies a 98.8% deployment value. After that, ERCOT estimates the amount of wind capacity for the past 30 days and the same month of the last year. If the estimate of wind capacity in the last 30 days is higher than for the same month of the last year, ERCOT will use the look-up factors in Table 7 to determine how much additional regulation may be needed. For example, if 2,000 MW of additional wind was added in January 2011 as compared to January 2010, then 8.4 MW of additional regulation will be needed for the hour ending at 9:00 a.m. in the month of January (4.2 MW *2).[108]

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[105] ERCOT, "ERCOT Peak Demand Surpasses New June Record," June 27, 2012, http://www.ercot.com/news/press_releases/show/26237.

[106] David Maggio, ERCOT, Personal Communication, September 26, 2012.

[107] Wind capacity is from ERCOT, *System Planning Monthly Status Report September 2012*, http://www.ercot.com/content/news/presentations/2012/SystemPlanningReport-Sept2012.pdf; Solar capacity is from Texas Office of the Governor, Economic Development and Tourism, *Texas Renewable Energy Industry Report*, July 2012, http://governor.state.tx.us/files/ecodev/Renewable_Energy.pdf.

[108] Erik Ela, Michael Milligan and Brendan Kirby, *Operating Reserves and Variable Generation,* (Golden, CO: NREL, August 2011), http://www.nrel.gov/docs/fy11osti/51978.pdf.

Table 7 *Additional Up-Regulation per 1,000 MW of Incremental Wind Generation Capacity in ERCOT*[109]

INCREMENTAL MW ADJUSTMENT TO PRIOR-YEAR UP-REGULATION 98.8 PERCENTILE DEPLOYMENT VALUE PER 1,000 MW OF INCREMENTAL WIND GENERATION CAPACITY, TO ACCOUNT FOR WIND CAPACITY GROWTH																								
	Hour Ending																							
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Jan.	2.8	4.2	3.1	3.7	2.5	0.4	2.3	2.2	4.2	5.9	7.6	5.7	4.7	3.3	2.8	2.3	4.0	8.6	4.2	2.7	1.6	2.7	1.4	1.6
Feb.	3.6	4.0	2.9	2.9	1.5	1.8	5.2	3.5	4.9	6.0	5.1	5.2	5.3	4.2	4.3	3.5	3.8	8.6	5.5	1.9	1.4	3.1	1.9	2.2
Mar.	5.5	5.3	4.6	4.2	2.6	3.3	7.1	7.9	6.8	5.7	4.2	3.4	2.8	2.6	2.7	2.3	2.9	7.7	6.8	2.1	1.1	3.0	1.5	2.8
Apr.	3.1	3.6	5.0	4.0	2.4	2.5	8.5	11.6	10.0	5.6	4.2	3.4	3.2	2.5	2.1	2.1	3.5	9.2	8.2	4.1	1.0	0.8	0.0	1.4
May	3.6	3.3	4.3	4.3	4.2	3.3	8.7	8.8	8.1	5.7	6.0	4.4	3.6	3.8	3.9	4.2	4.7	11.6	5.9	0.6	0.0	1.0	1.4	2.5
Jun.	2.3	2.6	3.3	3.7	3.9	2.4	8.5	8.2	6.6	4.5	4.2	3.1	2.5	2.5	0.7	0.2	1.3	7.5	3.3	1.7	0.7	0.3	0.6	1.3
Jul.	1.0	2.8	4.4	3.7	3.0	3.2	11.2	10.2	6.5	5.3	3.3	2.2	1.4	0.4	-0.9	-1.3	0.3	3.4	0.9	1.1	0.1	0.0	1.0	1.2
Aug.	1.4	3.8	4.5	4.5	2.2	0.9	6.3	6.8	6.6	6.6	3.2	2.6	2.1	1.2	1.4	1.3	1.3	4.6	1.2	0.9	0.7	0.8	1.1	1.3
Sep.	3.2	4.0	3.7	3.5	1.8	1.9	6.9	7.7	8.3	6.9	3.5	4.8	3.8	2.3	1.6	1.2	3.0	9.2	3.1	0.9	0.1	0.4	0.8	1.9
Oct.	3.4	2.8	2.4	2.2	1.7	1.8	5.0	5.8	6.1	5.9	4.0	5.4	3.2	2.2	1.2	1.7	3.1	6.8	0.8	2.1	0.0	0.2	1.8	2.5
Nov.	2.7	3.2	3.6	3.0	2.2	2.3	4.6	5.3	6.9	6.8	5.1	5.6	4.1	3.7	1.8	1.7	5.8	12.8	4.8	3.8	1.0	1.6	2.2	1.4
Dec.	2.8	2.4	1.4	2.1	1.2	0.4	2.8	2.7	3.8	4.6	6.8	7.0	6.0	4.4	3.3	3.0	5.0	9.9	4.3	2.6	2.1	4.3	2.0	1.5

In the past, the only input was historic deployment of regulation. Between 2007 and 2010, regulation requirements were increasing somewhat; the implementation of nodal markets in December 2010 sharply reduced regulation needs in ERCOT (see Figure 14).

[109] Ibid.

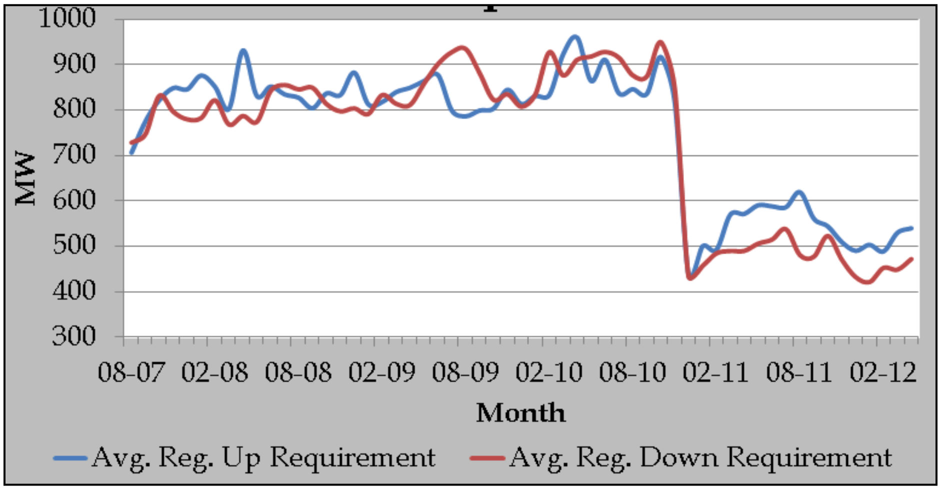

Figure 14 *Average Monthly Regulation Reserve Requirements in ERCOT*[110]

ERCOT examined the first 11 months of nodal operation with and without wind, and found that the impact of wind on regulation needs was less than 10%, with more effect on regulation up than on regulation down (see Table *8*).

[110] David Maggio, "Methodology for Calculating Reserves in the ERCOT Market," Presentation before the Utility Wind Integration Group Spring Technical Conference, San Diego, CA, April 24, 2012.

Table 8 *Impact of Wind on Up and Down Regulation Requirements in ERCOT*[111]

MONTH	AVG. ACTUAL REG. UP REQUIREMENT	AVG. ESTIMATED REG. UP REQUIREMENT WITH NO WIND	DIFFERENCE IN AVERAGE REQUIREMENT
Dec. '10	436.2	433.3	3.0
Jan. '11	499.2	477.9	21.3
Feb. '11	491.3	471.3	19.9
Mar. '11	569.0	513.6	55.4
Apr. '11	570.5	526.6	43.9
May '11	589.7	539.0	50.7
Jun. '11	587.2	516.8	70.4
Jul. '11	585.4	505.0	80.4
Aug. '11	618.5	536.7	81.8
Sep. '11	559.9	535.4	24.5
Oct. '11	543.1	531.5	11.6

For spinning reserves, ERCOT maintains a 10-minute reserve of at least 2,300 MW and may be increased to 2,800 MW. ERCOT uses spinning reserves to maintain system frequency following a system event. Spinning reserves can be supplied from unloaded generation resources that are on-line, resources controlled by under-frequency relays, or a direct current tie-line response that can be fully provided within 15 seconds of a system event. Demand-side resources can supply up to half of the capacity.

ERCOT uses non-spin reserves as a 30-minute service from off-line generators, unloaded generation capacity and demand resources that can be interrupted within 30 minutes and can run or be interrupted at a certain output level for at least one hour. The non-spin reserves replenish 10-minute reserves, account for

[111] Ibid.

forecast uncertainty, and address system disturbances. ERCOT estimates the need for non-spinning reserves for each hour of the day for each month.[112]

The main input for non-spin reserves is net load forecast error; historically, it was acquired during peak load hours equal to ERCOT's single largest generator. Non-spin requirements have fluctuated more, in part because of changing methodologies and differences in forecast error from one study period to the next (see Figure 15).

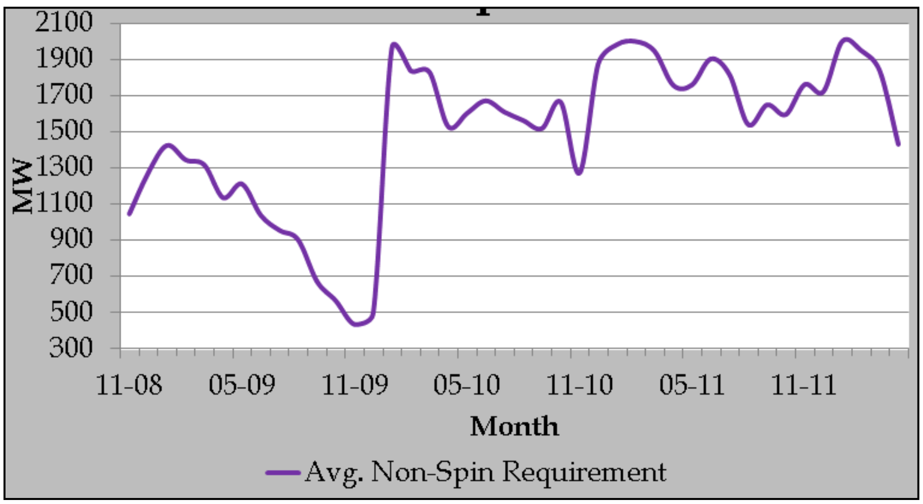

Figure 15 *Requirements for Non-Spinning Reserves in ERCOT November 2008 through December 2011*[113]

ERCOT also analyzed the first 11 months of nodal operation with and without wind, and the impact of wind on non-spinning reserves was more noticeable as the hours-ahead forecast error is more affected by wind (see Table 9). Non-spin requirements are based on taking a snapshot of forecast errors at midnight every night. ERCOT said it and ERCOT market participants can make commitment decisions closer to real-time and it is reviewing whether it can review forecast

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[112] NERC, *IVGTF Task 2.3 Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-3.pdf.

[113] David Maggio, "Methodology for Calculating Reserves in the ERCOT Market," Presentation before the Utility Wind Integration Group Spring Technical Conference, San Diego, CA, April 24, 2012.

error closer to commitment time, such as six hours ahead instead of midnight, and still have time to commit units to account for forecast error.[114]

Table 9 *Average Non-Spin Requirement in ERCOT with and without Wind Forecast Error, December 2010 through October 2011*[115]

MONTH	AVERAGE ACTUAL NON-SPIN REQUIREMENT	AVERAGE ESTIMATED NON-SPIN REQUIREMENT WITH NO WIND FORECAST ERROR	DIFFERENCE IN AVERAGE REQUIREMENT
Dec. '10	1875.8	1548.2	327.7
Jan. '11	1982.8	1801.8	181.0
Feb. '11	2000.0	1908.2	91.8
Mar. '11	1946.0	1624.2	321.8
Apr. '11	1757.3	1004.2	753.2
May '11	1760.2	1284.3	475.8
Jun. '11	1903.5	1680.0	223.5
Jul. '11	1815.7	1410.5	405.2
Aug. '11	1539.8	1320.0	219.8
Sep. '11	1649.2	1356.0	293.2
Oct. '11	1595.7	1276.0	319.7

5.6.4. HAWAII ELECTRIC LIGHT COMPANY (HELCO)

Utilities operating on Hawaii's islands must operate autonomously without support from other utilities. In other words, each utility operates as an island utility in Hawaii with relatively small loads and generation capacity, making wind and solar integration more challenging. HELCO, serving the big island of Hawaii, has a load of 190 MW, an installed wind capacity of 33.5 MW, and distributed generation capacity (including solar) of 12.9 MW. Minimum load is

[114] Ibid.
[115] Ibid.

about 90 MW.[116] For the entire state of Hawaii, about 78 MW of solar, mostly behind-the-meter, was in place as of the end of 2011.[117]

Since HELCO does not have interties with supporting systems, all system imbalances are represented as frequency errors, and regulation is used to restore frequency. At least three generating units are on-line at all times to ensure enough system response if one of the units providing regulation goes off-line. Regulation requirements are determined daily by hour, accounting for system frequency, wind generation in the past hour, and measured wind speeds. Regulating reserves are increased if wind production is expected to be at the mid-point of production, but they are not increased if wind production is at minimum or maximum production. In addition, about 6% of HELCO's daytime load is now coming from distributed solar. HELCO has added regulating up-reserves and reported the availability of down regulation reserves has decreased.[118]

5.6.5. ISO-NEW ENGLAND

ISO-NE has a peak load of 25,853 MW as of July 2012, with an all-time peak of 28,130 MW that occurred in July 2006.[119] The minimum load is about

116 Marc Matsuura, "Hawaiian Electric Company Systems Overview and Variable Generation Issues," Presentation before the Utility Wind Integration Group Fall 2010 Workshop, October 13, 2010, Maui, HI.

117 Hawaiian Electric Company, Maui Electric Company and Hawaii Electric Light Company, *2011 Corporate Sustainability Report*, http://www.heco.com/vcmcontent/StaticFiles/pdf/2011HECOSustainRpt.pdf.

118 NERC, *IVGTF Task 2.4 Report: Operating Practices, Procedures and Tools* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-4.pdf.

119 ISO-NE, *Net Energy &Peak Load Report*, October 2012, http://www.iso-ne.com/markets/hstdata/rpts/net_energy/index.html.

10,000 MW.[120] The installed wind capacity is 524 MW, with solar capacity at 125 MW, both as of April 2012.[121]

The New England Wind Integration Study, commissioned by ISO-NE and conducted by GE and Enernex, found that additional regulation will be needed at wind energy penetration levels as low as 9%. Average regulation for load was only 82 MW, increasing to 161 MW at 9% and 313 MW in the 20% wind energy scenario. The main reason for this increase in regulation is short-term errors in wind forecasting, and the economic dispatch is not able to adjust fast enough to accommodate short-term wind forecast errors.

The study also determined that additional 10-minute spinning reserve would be needed at higher levels of wind penetration to maintain current levels of contingency response, and recommended that ISO-NE increase 10-minute spinning reserves by the same amount as regulation; i.e., about 80 MW for 9%, 125 MW for 14% and 310 MW for 20% wind. ISO-NE obtains 10-minute spinning reserves with regulation, and either regulation will have to be allocated separately from 10-minute spinning reserves or additional 10-minute spinning reserves would have to be secured.

The study also found that additional 10-minute non-spinning reserves, or a separate market product for wind to cover extreme increases or drops in wind generation, will be needed at 20% wind penetration. The study estimated that another 300 MW of non-spinning reserves would be needed for the 20% best

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[120] NERC Integration of Variable Generation Task Force, *Operating Survey for ISO-New England*, November 2009, http://www.nerc.com/docs/pc/ivgtf/NERC%20IVGTF%20Operator%20Survey%20Rev%201%20%28BH_ISONewEngland%29.pdf.

[121] Wind capacity data is from ISO-NE, "Wind Energy Update, Planning Advisory Committee Meeting", May 2012, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/may162012/wind_energy.pdf; Solar capacity data is from ISO-NE, "Solar Photovoltaics in New England, Planning Advisory Committee Meeting", May 2012, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/may162012/solar_photovoltaics.pdf.

onshore wind sites case and 150 MW for the 9% case. Generation capacity displaced by wind could be a source of non-spinning reserves if the resources are still available and do not retire or shut down. Having a separate mechanism to ensure displaced capacity that can provide 10-minute non-spinning reserves may be necessary, according to the study.[122]

5.6.6. MIDWEST ISO

MISO's record peak load was set on July 23, 2012 at 98,576 MW. The minimum load is about 39,000 MW. The installed wind capacity is 12,444 MW as of September 2012. There is minimal solar capacity interconnected to MISO, although there may be distributed solar generation that is unreported.[123]

Regulation requirements for MISO are 300 to 500 MW in each direction, depending on load level and time of day. MISO has found little impact of wind on regulation. Specifically, one-minute wind generation variability has had little impact on net load one-minute variability. The standard deviation of short-term wind generation forecast error ranges from between 0.5% to 1% of wind generation capacity. The impact of the short-term wind forecast on net load variability is therefore low.

MISO's contingency reserve is currently set at 2,000 MW based on the largest generation unit and transmission corridor. About half of it is spinning, with the remainder from supplemental reserves that is a mix of on-line and off-line resources, including demand response. MISO has zonal requirements in seven zones for contingency reserves due to transmission deliverability issues. So far, wind has no impact on contingency reserves in MISO, as wind events have a longer latency period than a contingency event. Wind drops, the majority of them forecasted, of 6 to 7 GW have occurred over eight hours. More rarely, wind

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[122] Gene Hinkle, Richard Piwko, Gary Jordan, Amanvir Chahal, Nick Miller, Shakeer Meeran, Robert Zavadil, Jack King, Tom Mousseau and John Manobianco, *New England Wind Integration Study* (Schenectady, NY: GE Energy, December 2010), http://www.uwig.org/newis_es.pdf.
[123] Matt Schuerger, Energy Systems Consulting Service, Personal Communication, October 16, 2012.

ramps of plus or minus 2,000 MW have occurred in 20 minutes. So far, MISO has not used contingency reserves for non-contingency events such as wind ramps.[124]

5.6.7. NEW YORK ISO

NYISO's peak load is 33,865 MW as of July 2011, with a record peak of 33,939 MW that occurred in August 2006.[125] The minimum load is about 12,000 MW. The installed wind capacity is about 1,600 MW. There is 32 MW of solar interconnected with NYISO, and another 110 MW of solar that is behind the meter.[126]

In its 2010 integration study, NYISO found that at 3,500 MW of wind and then-projected 2011 load of 34,768 MW peak demand, regulation requirements increased by 5 MW based on a weighted average. The largest increase for that scenario was 100 MW, from 175 MW to 275 MW from June through August. At 8,000 MW of wind and 2018 projected peak load of 37,130 MW, the overall weighted average regulation requirement increased by 116 MW, from 175 MW to 291 MW. The maximum increase is 225 MW (from 175 MW to 400 MW) from June through August, with the highest regulation requirement at 425 MW, also from June through August.[127] NYISO said no immediate changes are planned for adding regulation, as only 1,400 MW of wind is presently in operation in NYISO as of May 2012.[128]

NYISO also found that for 8 GW of wind, the hourly net-load up and down ramps exceeded by about 20% the ramps that resulted from load alone. NYISO determined that it had sufficient resources to withstand the net-load ramps.

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[124] Nivad Navid, "Reserve Requirement Identification with the Presence of Variable Generation," Presentation before the Utility Wind Integration Group Spring Technical Conference, San Diego, CA, April 26, 2012.
[125] NYISO, "NYISO Key Facts," http://www.nyiso.com/public/media_room/key_facts/index.jsp.
[126] David Edelson, NYISO, Personal Communication, September 26, 2012.
[127] NYISO, *Growing Wind: Final Report of the NYISO 2010 Wind Generation Study* (Rensselaer, NY: NYISO, September 2010), http://www.uwig.org/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf.
[128] David Edelson, NYISO, Personal Communication, May 28, 2012.

NYISO also found that no change was needed in the amount of operating reserves needed to cover the largest instantaneous loss of source or contingency event. The NYISO system is designed to withstand the loss of 1,200 MW instantaneously with replacement within ten minutes. By comparison, a significant loss of wind generation occurs over several minutes to hours. Analysis of the simulated data found that for 8 GW of installed wind, a maximum drop in wind output of 629 MW occurred in ten minutes, 962 MW in 30 minutes, and 1,395 MW in one hour.[129]

5.6.8. XCEL ENERGY

Xcel Energy is a holding company with utility subsidiaries operating in eight states; some operating in MISO and SPP and others as vertically integrated utilities. Xcel has 4,865 MW of wind, including 1,375 MW on AGC. Xcel reports that no additional reserves have been needed in MISO for its Northern States Power Co. affiliates or for its Southwestern Public Service Co. affiliate in SPP. Indeed, Xcel Energy reports that in its balancing authority area in MISO, wind increased from 400 MW to 1,200 MW without any change in the utility's flexibility reserves or regulation requirements because of MISO's five-minute dispatch.[130]

Of Xcel's total installed wind capacity, Public Service Company of Colorado (PSCo) has 2,168 MW; Northern States Power has 1,945 MW and Southwestern Public Service has 752 MW.[131] System-wide, Xcel has 256 MW of solar.[132] Table 10 depicts peak and minimum load by Xcel affiliate, all as of 2011.[133]

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[129] NYISO, *Growing Wind: Final Report of the NYISO 2010 Wind Generation Study* (Rensselaer, NY: NYISO, September 2010), http://www.uwig.org/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf.

[130] Kevin Porter, Christina Mudd, Sari Fink, Jennifer Rogers, Lori Bird, Lisa Schwartz, Mike Hogan, Dave Lamont and Brendan Kirby, *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge*, Western Governors Association, June 2012, http://www.rapon-line.org/featured-work/meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration.

[131] Stephen Beuning, Xcel Energy, Personal Communication, May 14, 2012.

Table 10 *Peak and Minimum Load by Xcel Energy Affiliate, 2011*[134]

AFFILIATE NAME	PEAK LOAD (MW)	MINIMUM LOAD (MW)
PSCo	7,371	2,818
Northern States Power	9,900	3,500
Southwestern Public Service	6,331	2,707

PSCo has an internal guideline to hold additional flexible reserves. Flexible reserves are defined as being available within 30 minutes, and how much is held is dependent on current levels of wind generation. The flex reserves cover two types of wind events: wind cut-off at high wind speeds and downwind ramps. PSCo's system operators will take notice when wind speeds exceed 20 meters per second and may increase flexible reserves. PSCo can also use regional contingency reserves for over speed wind trips, but has not done so. In addition, SPP's reserve sharing group can also commit contingency reserves for the loss of wind during high wind speeds.[135]

Xcel Energy is requiring future wind generators to be able to provide set-point capability. Xcel Energy is also retrofitting 19 existing wind plants by adding automatic generation control, primarily in the MISO. Wind curtailment has been reduced as system operators have more confidence in maintaining system balance with operation of wind plants that have automatic generation control.[136]

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[132] Xcel Energy, "Solar Power on Our System: Xcel Energy is Ranked No. 5 Among U.S. Utilities for Solar Capacity", http://www.xcelenergy.com/Environment/Renewable_Energy/Solar/Solar_Power_on_Our_System.

[133] Energy Information Administration, Form EIA-861 Data Files, Released: September 20, 2012, http://www.eia.gov/electricity/data/eia861/index.html; and FERC Form 714 for Year Ending December 31, 2011 for PSCo, SPS and Midwest ISO.

[134] Ibid.

[135] Liam Noailles, "How We Do it at Xcel Energy," Panel Discussion before the Utility Wind Integration Group Spring Technical Workshop, San Diego, CA, April 25, 2012, http://www.uwig.org/San_Diego2012/Noailles-calculating_reserve.pdf.

[136] Kevin Porter, Christina Mudd, Sari Fink, Jennifer Rogers, Lori Bird, Lisa Schwartz, Mike Hogan, Dave Lamont and Brendan Kirby, *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge*, Western Governors Association, June 2012, http://www.rapon-

5.7. EXPERIENCE OF GERMANY AND SPAIN WITH RESERVES AND VARIABLE GENERATION

Germany: As of 2010, Germany had a peak load of 80 GW and a minimum load of 34.6 GW.[137] As of the end of 2011, Germany had over 29 GW of wind capacity, and over 30 GW of solar capacity was operating as of August 2012.[138] Overall, installed wind capacity in Germany is expected to be 31 GW by the end of 2012 and total installed solar capacity in Germany will be 32 GW, meaning that solar capacity will exceed wind capacity for the first time in Germany.[139]

The German Transmission System Operators (TSOs) utilize three types of balancing reserves. The primary regulation reserves, equivalent to frequency response, are automatically controlled generation that responds to frequency variations. All TSOs in Europe are required to provide 3,000 MW of primary reserve capacity that can begin operating within 30 seconds. The 3,000 MW is equal to the outage of two major nuclear plants, each with a capacity of 1,500 MW. The German share is 630 MW. The secondary reserves, equivalent to regulation, are up and down regulation reserves that can be deployed within five minutes. The German TSOs acquire about 4,900 MW (–2,200 MW for regulation down and 2,700 MW for regulation up). This is provided mainly by hydro power and pumped storage hydro plants. The tertiary reserves, equivalent to

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line.org/featured-work/meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration.

137 H. Holttinen, A.G. Orths, P.B. Eriksen, J. Hidalgo, A. Estanqueiro, F. Groome, Y. Coughlan, H. Neumann, B. Lange, F. van Hulle and I. Dudurych, "Currents of Change," *IEEE Power and Energy* 9, no. 6, November/December 2011, 47-49.

138 Wind capacity is from European Wind Energy Association, Wind in Power: 2011 European Statistics, February 2012, http://www.ewea.org/fileadmin/files/library/publications/statistics/Wind_in_power_2011_European_statistics.pdf; "Solar capacity from German Solar Power Capacity Hits All-Time High… Again (More Solar than Rest of Europe)," http://cleantechnica.com/2012/09/24/german-solar-power-capacity-hits-all-time-high-again/.

139 Brian Parkin, "German Solar Capacity to Exceed Wind for First Time, FAZ Says," Bloomberg News, July 21, 2012, http://www.bloomberg.com/news/2012-07-21/german-solar-capacity-to-exceed-wind-for-first-time-faz-says.html.

load following, must be available within 15 minutes.[140] German TSOs acquire –2,400 MW of downward tertiary reserve capacity and 2,300 MW of upward tertiary reserve capacity. In addition, 50Hertz, one of the German TSOs, also requires that "renewable energy substitutes" be available to help smooth fluctuations in energy supply, in particular from wind power. These are pre-qualified energy resources that are able to provide positive and/or negative primary, secondary, and "minute" reserves.

Since 2009, three of the four German TSOs have shared in an optimized shared secondary reserve system that economically dispatches plants to balance energy in the entire three-TSO area. Table 11 shows the estimated reductions in reserves through the shared secondary reserves market. The fourth German TSO is now also participating in the shared secondary reserve system. Because wind and solar have significant geographic diversity, ramping is not as large a concern in Germany. The need for reserves is mostly for forecast errors; however, the forecast errors are more in the hourly (or longer) time scale, and therefore, faster reserves are less needed to balance wind and solar variability. Balancing of forecast errors is achieved mainly via the intraday trading platform operated by the power exchange, with bids and offers allowed up to 45 minutes before real-time. The remaining imbalances will be covered by reserves.[141]

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140 B. Ernst, U. Schreier, F. Berster, J.H. Pease, C. Scholz, H.P. Erbring, S. Schlunke and Y.V. Makarov, *Large-Scale Wind and Solar Integration in Germany* (Richland, WA: Pacific Northwest National Laboratory, February 2010), http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19225.pdf.

141 B. Ernst, U. Schreier, F. Berster, J.H. Pease, C. Scholz, H.P. Erbring, S. Schlunke and Y.V. Makarov, *Large-Scale Wind and Solar Integration in Germany* (Richland, WA: Pacific Northwest National Laboratory, February 2010), http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19225.pdf.

Table 11 *Reserve Reductions in Germany through Shared Secondary Reserve System (MW)*[142]

TYPE OF RESERVE	UP RESERVES BEFORE	UP RESERVES AFTER	DOWN RESERVES BEFORE	DOWN RESERVES AFTER
Primary Regulation	135	135	N/A	N/A
Secondary Reserve	630	532	-450	-464
Tertiary Reserve	350	288	-756	-532

Spain: The Red Eléctrica de España (REE) is the Spanish transmission operator, with ownership shared by the Spanish government and private ownership. REE evaluates the need for reserves through continuously running a probabilistic function with demand forecast error, wind power forecast error, and thermal generation outages, with confidence levels ranging from 80% to 99%.[143] For reserves, as indicated in Table 12, four types are utilized in Spain: primary regulation (roughly equivalent to regulation), secondary regulation (roughly equivalent to load following), tertiary regulation, and ramping (also called "hot reserves"). Primary regulation is required in Spain and is a non-paid service by all conventional generation units.[144] Generators with primary regulation responsibilities operate with a reserve margin of 1.5%, must respond to frequency deviations within 30 minutes, and be sustained for 15 minutes. Wind generation has had no impact on primary regulation.[145]

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[142] Ibid.

[143] Jorge Hidalgo López, "Wind Development and Integration Issues and Solutions," Presentation before the Northwest Wind Integration Forum, Portland, OR, July 29-30, 2010, http://www.nwcouncil.org/energy/wind/meetings/2010/07/WIF%20TWG%20072910%20Hidalgo%20072610.pdf.

[144] Michael Milligan, Pearl Donohoo, Debra Lew, Erik Ela, Brendan Kirby, Hannele Holttinen, Eamonn Lannoye, Damian Flynn, Mark O'Malley, Nicholas Miller, Peter Børre Eriksen, Allan Gøttig, Barry Rawn, Madeleine Gibescu, Emilio Gómez Lázaro, Andre Robitaille and Innocent Kamwa, *Operating Reserves and Wind Power Integration: An International Compariso*n (Golden, CO: NREL, October 2010), http://www.nrel.gov/docs/fy11osti/49019.pdf.

[145] NERC, *IVGTF Task 2.4 Report: Operating Practices, Procedures and Tools* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-4.pdf.

Table 12 *Impact of Wind Power on Ancillary Services in Spain*[146]

TYPE	DEFINITION	INFLUENCE OF WIND POWER ON RESERVE
Primary Regulation	Action of speed regulators from generator units responding to changes in system frequency. (<30 seconds to 15 minutes)	Not influenced by wind power.
Secondary Regulation	Automatic action of central algorithm and AGCs in the generation units that provide this service responding to changes in system frequency and power deviations with respect to France. (≤100 seconds to 15 minutes)	Only slightly affected by wind generation ramps when these ramps are opposite to system demand. Presently, no need to contract further reserve bands.
Tertiary Regulation	Manual power variation with respect to a previous program in less than 15 minutes. (<15 minutes to 2 hours)	Only slightly affected by wind generation ramps when these ramps are opposite to system demand.
Running Reserves or Hot Reserves	Manageable generation reserves that can be called upon within 15 minutes to approximately two hours. Includes tertiary reserves and consists of the running reserves of connected thermal units and hydro and hydro pump storage reserves. (15 minutes-2 hours to 4-5 hours)	Significant influence of wind power. Reserve provision must be increased to take into account wind power forecast errors. Reserves are checked from day D-1 once market results are received until real-time.

Secondary regulation is provided by generators on automatic generation control. REE purchases up to ±1,500 MW of secondary regulation for system balancing in real-time. About 16 GW of quick response hydro capacity is among the providers of secondary regulation.[147] Generators providing secondary regulation must respond within two minutes and be able to operate at a sustained level for 15 minutes. Wind generation has had little impact on secondary regulation,

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[146] Jorge Hidalgo López, "Wind Development and Integration Issues and Solutions," Presentation before the Northwest Wind Integration Forum, Portland, OR, July 29-30, 2010, http://www.nwcouncil.org/energy/wind/meetings/2010/07/WIF%20TWG%20072910%20Hidalgo%20072610.pdf.

[147] Michael Milligan, Pearl Donohoo, Debra Lew, Erik Ela, Brendan Kirby, Hannele Holttinen, Eamonn Lannoye, Damian Flynn, Mark O'Malley, Nicholas Miller, Peter Børre Eriksen, Allan Gøttig, Barry Rawn, Madeleine Gibescu, Emilio Gómez Lázaro, Andre Robitaille and Innocent Kamwa, *Operating Reserves and Wind Power Integration: An International Comparison* (Golden, CO: NREL, October 2010), http://www.nrel.gov/docs/fy11osti/49019.pdf.

noticeable only if wind ramps are opposite that of system demand. Spain has not had to acquire additional secondary regulation with higher levels of wind and solar generation.[148]

For tertiary regulation, generators must respond within 15 minutes and operate at sustained levels for up to two hours. Tertiary regulation is used for manual generation adjustments to meet changes in generation and load.[149] Tertiary regulation is dispatched 15 minutes before the beginning of the operating hour, or within the hour as required. Tertiary regulation is an optional service but with a mandatory bid, with compensation determined by market mechanisms. Presently, wind generation affects the level of tertiary regulation modestly and only if wind ramps are opposite that of system demand.

Ramping or hot reserves can be called upon within 15 minutes and must be capable of sustained operation for up to two hours. Ramping reserves include tertiary regulation and the reserves of operating thermal units, hydro and pumped storage hydro plants. Wind forecasting errors have increased the need for ramping reserves.[150]

REE reports that both up and down reserves may be insufficient in certain hours due to outages of conventional generation, demand prediction errors, wind or solar forecast errors, wind units tripping because of high wind, or not enough flexible generation. If up reserves are insufficient, REE may commit additional thermal units through real-time dispatch. If there are insufficient down reserves, then REE may de-commit thermal units in real-time. If down reserves are still

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[148] NERC, *IVGTF Task 2.4 Report: Operating Practices, Procedures and Tools* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-4.pdf.

[149] Michael Milligan, Pearl Donohoo, Debra Lew, Erik Ela, Brendan Kirby, Hannele Holttinen, Eamonn Lannoye, Damian Flynn, Mark O'Malley, Nicholas Miller, Peter Børre Eriksen, Allan Gøttig, Barry Rawn, Madeleine Gibescu, Emilio Gómez Lázaro, Andre Robitaille and Innocent Kamwa, *Operating Reserves and Wind Power Integration: An International Comparison* (Golden, CO: NREL, October 2010), http://www.nrel.gov/docs/fy11osti/49019.pdf.

[150] NERC, *IVGTF Task 2.4 Report: Operating Practices, Procedures and Tools* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-4.pdf.

insufficient, REE may curtail non-dispatchable renewable generation as a last resort.[151]

Table 13 provides the amount of energy, in GWh, that REE has procured for different ancillary services between 2007 and 2010, as well the energy subject to deviation management and restrictions in real-time.[152] The secondary regulation band has stayed relatively flat, while secondary regulation has risen between 2007 and 2010 in both the increasing and decreasing directions. Tertiary regulation has also gone up in the increasing direction between 2007 and 2010, while tertiary regulation in the decreasing direction rose between 2007 and 2009 but dropped back in 2010. Deviation management in both directions has more than doubled between 2007 and 2010, while restrictions in real-time in the decreasing direction more than tripled while remaining relatively flat in the increasing direction, also for between 2007 and 2010.

[151] Jorge Hidalgo López, "Wind Development and Integration Issues and Solutions," Presentation before the Northwest Wind Integration Forum, Portland, OR, July 29-30, 2010, http://www.nwcouncil.org/energy/wind/meetings/2010/07/WIF%20TWG%20072910%20Hidalgo%20072610.pdf.

[152] Deviation management is resolving differences between generation and demand from one intraday market to the next and is comparable to imbalance energy in the United States. Restrictions in real-time are defined as limitations due to insufficient secondary and tertiary regulation reserves, insufficient reserve capacity for voltage control, or insufficient reserve capacity for service restoration. Red Eléctrica De España 2010.

Table 13 *Reserves and Managed Energy for REE in Spain 2007-2010 (GWh)*[153]

	2007		2008		2009		2010	
	INCREASE	DECREASE	INCREASE	DECREASE	INCREASE	DECREASE	INCREASE	DECREASE
Secondary Regulation Band	718	520	717	526	718	526	727	531
Secondary Regulation	949	1,188	1,127	1,123	1,072	1,406	1,165	1,724
Tertiary Regulation	1,752	2,107	2,450	2,008	2,238	3,287	2,726	2,983
Deviation Management	829	1,330	1,190	997	1,253	3,018	2,198	2,675
Restrictions in Real-Time	864	358	620	596	821	640	887	901

5.8. STORAGE AND FERC ORDER 755

Several flywheel storage plants have been developed in RTOs, including PJM. Storage can provide several valuable grid services, including instantaneous and short-term balancing, regulation, and load shifting. Nevertheless, variable generation integration studies have generally found that while higher levels of variable generation may increase the use of existing storage (mainly pumped hydro), additional storage is not necessary or economically justified. The Western Wind and Solar Integration Study, for instance, evaluated the price arbitrage benefits of additional pumped storage. A 100 MW pumped storage plant was added and provided with perfect foresight of spot prices. At 30% variable generation and a perfect forecast, the 100 MW pumped storage plant had an annual operating value of $0.5 million, or a capital value of $35/kW. Under a state-of-the-art forecast, spot prices are higher because of forecast errors, and the 30% case increased the annual operating value of the pumped storage

[153] Red Eléctrica de España, *2010: The Spanish Electricity System Summary* (Madrid: Red Eléctrica de España), http://www.ree.es/ingles/sistema_electrico/pdf/infosis/sintesis_REE_2010_eng.pdf.

plant to $3.8 million, or about $380/kW, but this was still less than needed to make such a plant economically viable.[154]

Storage will benefit from FERC Order 755 issued in October 2011 that outlines issues related to frequency regulation compensation and directs RTOs/ISOs to modify their OATTs to better compensate resources that can provide faster and more responsive regulation service.[155] Regulation service is routinely used by RTOs/ISOs to balance supply and demand on the grid. This service has been traditionally supplied by generators connected to the system operator's automatic generator control (AGC) signal. Regulation service is increasingly provided by other resources, such as demand response and electricity storage. This has resulted in a regulation supply resource base where resources differ with respect to ramping capabilities, ability to increase or decrease the amount of regulation service, and accuracy of response to AGC dispatch signals. According to FERC, the current compensation methods for regulation service do not take into account these differences; thus traditional practices can result in economically inefficient dispatch.

Faster resources that are able to ramp up and/or down more quickly can more accurately respond to AGC dispatch signals and avoid overshooting. FERC notes that compensation for regulation service needs to acknowledge and reward not just the amount of regulation service that a resource provides but also the speed at which it can provide it.

FERC directed RTOs/ISOs to develop a two-part compensation system for regulation service that includes a "performance payment" to compensate resources that do more work and to account for a resource's accuracy. The first part will consist of a capacity (or option) payment for the amount the resource

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[154] GE Energy, *Western Wind and Solar Integration Study*, prepared for NREL (Schenectady, NY: GE Energy, May 2010), http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf.

[155] FERC, *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064, Docket Nos. RM11-7-000 and AD10-11-000, Order No. 755 (FERC, October 20, 2011), http://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf.

holds in reserve. The capacity payment must be market-based, derived from bids, and in the form of a uniform clearing price that includes the marginal resources opportunity cost. Part two of the compensation is a payment for performance. This payment must also be market-based reflecting resource bids. FERC does not mandate the specific form for this payment nor the bidding parameters or other technical specifications, but does direct that it also be a uniform clearing price.

FERC notes that accuracy means how well a resource follows the operator's dispatch signal; therefore, this measurement needs to be tied to the AGC dispatch signal, not to a resource's contribution to ACE correction. As with the compensation components, FERC does not mandate a certain method for accounting for accuracy but does note that the method developed will have to be the same for all resources.

FERC set a compliance filing deadline of April 30, 2012, for the RTOs/ISOs to outline how they plan to meet the Order 755 requirements. Implementation must occur by October 2013.[156]

5.8.1. CALIFORNIA ISO FILING

CAISO submitted its compliance filing on April 27, 2012, outlining tariff amendments that would implement a uniform capacity payment for resources providing regulation. The tariff would also include the marginal unit's opportunity costs and establishes a performance payment that reflects the quantity of regulation service provided by a resource when that resource accurately follows a dispatch signal.[157] CAISO notes that it already has a uniform capacity payment and is making only a minor revision to allow resources to calculate and submit their own opportunity costs with their bids. For the performance payment, CAISO proposes to establish a "mileage" payment based

[156] SPP is not required to submit a compliance filing as it currently does not administer wholesale energy markets.

[157] CAISO, *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Docket No. ER12-1630, Order No. 755 (FERC, April 27, 2012).

on how accurately a regulation resource responds to dispatch signals and the expected mileage from 1 MW of regulation capacity in any given hour.

5.8.2. ISO-NEW ENGLAND FILING

ISO-NE submitted its compliance filing on April 30, 2012, describing the methodology that it proposes to employ that will be based on both the capacity and the service that a resource provides for regulation.[158] ISO-NE is proposing to transition their regulation auction to the Vickrey approach, which is designed to minimize total cost based on an evaluation of incremental system cost savings. Under the new design, resources would submit a two-part bid that includes a regulation capacity offer and a regulation service offer. The bids can be modified at any time prior to the selection interval. The regulation service will be based on mileage, specifically a resources movement at the claimed rate of response, in MW, in response to the dispatch signal. The Vickrey approach would select regulation resources, based on both bids, to minimize the cost of providing the needed regulation for each interval. Resources would then be paid the system opportunity cost, containing two components: the realized cost (actual mileage cost plus capacity cost, including energy opportunity cost) and the incremental cost savings to the system.[159]

5.8.3. MIDWEST ISO FILING

MISO submitted their compliance filing on April 30, 2012, outlining their proposed two-part regulation service and compensation.[160] MISO proposes to have resources submit two-part regulation offers consisting of a regulation capacity offer and a regulation mileage offer – the capacity that is reserved for regulation service and the movement that a resource provides in response to automatic dispatch instructions. Compensation will be based on both of these

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[158] ISO-NE and New England Power Pool, Compliance Filing, *Regulation Market Changes*, Docket No. ER12-1643, Order No. 755 (FERC, April 30, 2012).

[159] Ibid.;

Prepared Direct Testimony of Peter Cramton on behalf of ISO-NE, 3.

[160] MISO, Compliance Filing, Docket No. ER12-1664, Order No. 755 (FERC, April 30, 2012).

components – the cost of scheduling regulation as given by the capacity offers, and the cost of regulation mileage for the anticipated deployment of regulation on the resources that were cleared in each 5-minute dispatch interval.

5.8.4. NEW YORK ISO FILING

NYISO submitted its compliance filing on April 30, 2012, describing a new "regulation movement multiplier" that it proposes to use in establishing regulation service schedules.[161] Under this proposal, the NYISO regulation market would have two distinct regulation components that would be bid and settled separately – regulation capacity and regulation movement. Regulation capacity is the existing regulation product and is settled at the regulation capacity market price that includes the marginal resource's opportunity cost. Regulation movement is the amount of capacity, both up and down, that can be delivered in six seconds. Resources would need to submit separate regulation movement bids indicating the price ($/MW) for each MW of regulation movement that the resource would provide when instructed. Each resource would also have to provide two response rates for use in scheduling and dispatching its resources – the regulation capacity response rate which is the service the resource is capable of providing over five minutes, and the regulation movement response rate which is what the resource can deliver in six seconds. NYISO's real-time software would then separately calculate a market-clearing price for regulation movement for each interval, based on the regulation movement bid of the marginal resource for that interval.

5.9. DEMAND RESPONSE AND RESERVES

NERC and others have identified demand response as an additional source of flexibility that could aid in integrating variable generation. Indeed, several research studies have provided examples of demand response and variable energy integration. NREL's Western Wind and Solar Integration Study (WWSIS)

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[161] NYISO, Compliance Filing, *Proposed Compliance Tariff Revisions*, Docket No. ER12-1653, Order No. 755 (FERC, April 30, 2012).

found a shortfall of contingency reserves in the 30% wind case for 89 hours per year. Rather than procuring additional spinning reserves, the WWSIS suggested that demand response encompassing about 1,300 MW of load could provide the needed contingency reserves at lower cost.[162] Indeed, the estimated annual benefits of using demand response instead of spinning reserves from thermal generators in high wind scenarios ranged $310,000 to $450,000 per MW.[163] Another paper modeling wind under various scenarios found that in high wind scenarios in ERCOT, the benefit of using real-time pricing for all customers to help balance the system was estimated to be $6 to $10 per MWh of wind generation.[164] PJM and MISO have the most demand response capacity with 11,647 MW and 8,052 MW, respectively. Demand response provides about 8% of the demand for both PJM and MISO.

Overall usage of demand response as a resource increased from 30 GW to 43 GW between 2010 and 2011 for all NERC regions combined, although a separate NERC assessment projected a drop-off to 40 GW in 2012.[165] NERC projects demand response will increase to about 50 GW by 2017, then stay at that level, mostly because of uncertainty in estimating future demand response beyond what is currently planned.[166] (See Figure 16.)

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[162] GE Energy, *Western Wind and Solar Integration Study*, prepared for NREL (Schenectady, NY: GE Energy, May 2010), http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf.

[163] Peter Cappers, Andrew Mills, Charles Goldman, Ryan Wiser and Joseph H. Eto, *Mass Market Demand Response and Variable Generation Integration Issues: A Scoping Study*, prepared for the Office of Electricity Delivery and Energy Reliability, DOE (Berkeley, CA: Lawrence Berkeley National Laboratory, October 2011), http://eetd.lbl.gov/ea/ems/reports/lbnl-5063e.pdf, citing GE Energy's *Western Wind and Solar Integration Study.*

[164] Ramteen Sioshansi and Walter Short, "Evaluating the Impacts of Real-Time Pricing on the Usage of Wind Generation," IEEE Transactions on Power Systems, May 2009, 24 (2): 516–524, http://idei.fr/doc/conf/eem/papers_2008/sioshansi.pdf.

[165] NERC, *2012 Summer Reliability Assessment* (Atlanta, GA: NERC, May 2012), http://www.nerc.com/files/2012SRA.pdf.

[166] NERC, *2011 Long-Term Reliability Assessment* (Atlanta, GA: NERC, November 2011), http://www.nerc.com/files/2011%20LTRA_Final.pdf.

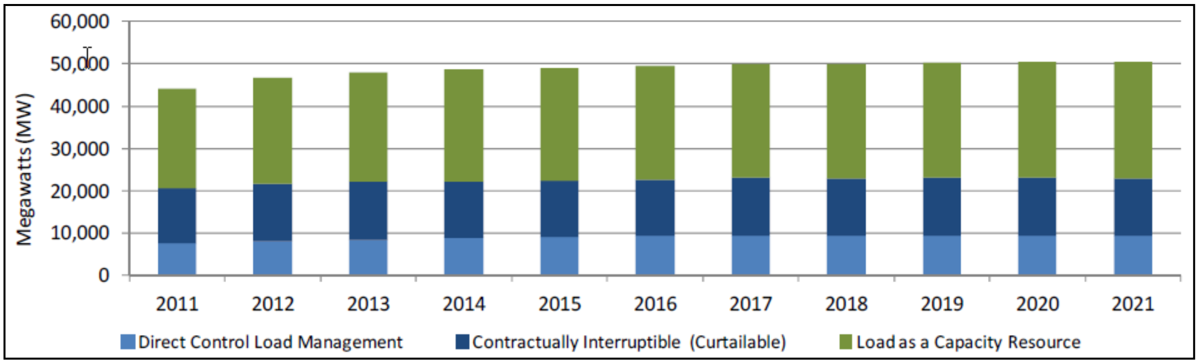

Figure 16 *NERC Projections on On-Peak and Controllable Demand Response 2011-2018*[167]

Demand response has the potential to offer several types of operating reserves. Response can be quicker than generation for most responsive loads. The response can be automated as well, and different loads can be set to trip at different frequencies, thus providing a frequency droop curve that simulates generator governor response. Also, demand response has the characteristic of contingency reserve of being ready but with events happening infrequently and actual deployment being relatively short in duration. One example of load providing regulation is that of Aloca's aluminum smelter in Warick, Indiana that participates in MISO's ancillary services market.[168]

System operators are using demand response more frequently to provide ancillary services, although this is a recent development and only a small amount of demand response is used to provide ancillary services. Figure 17 illustrates the amount of demand response providing regulation, spinning reserves, non-spinning reserves, and emergency energy, by NERC reliability region.

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[167] Ibid.

[168] Erik Ela, Michael Milligan and Brendan Kirby, *Operating Reserves and Variable Generation* (Golden, CO: NREL, August 2011), http://www.nrel.gov/docs/fy11osti/51978.pdf.

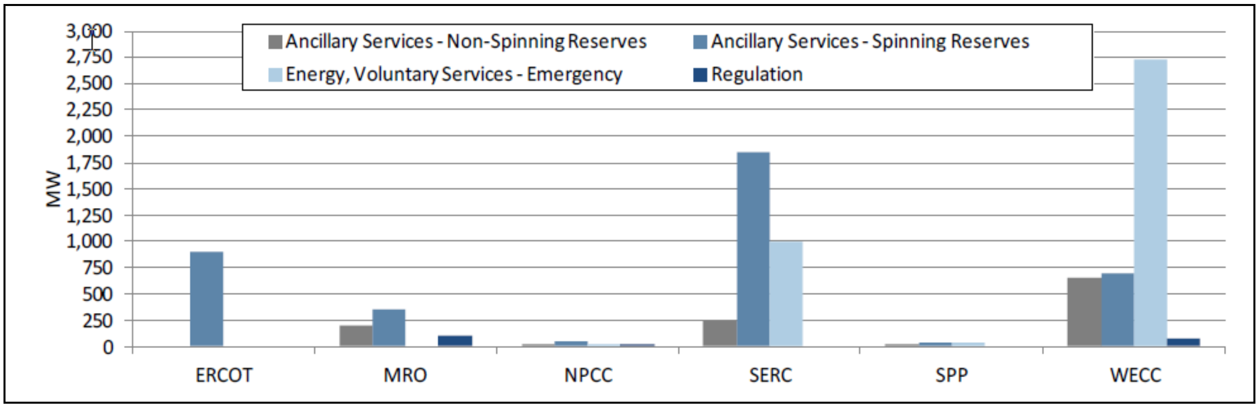

Figure 17 *Demand Response Used to Provide Ancillary Services, by NERC Region*[169]

Several RTOs and balancing authorities allow demand response to provide specific reserves, albeit with some limits on the amount demand response can provide. A non-comprehensive list is found below:

- Demand response in PJM can provide regulation, synchronized reserves and day-ahead reserves, limited to 25% for each category and to providing two of these services, not all three.[170] A stakeholder process is underway in PJM to raise the limit to 33%. Demand response can also provide nonsynchronized reserves and supplemental reserves.
- Loads in ERCOT can be registered for ERCOT's LAaR program (Loads Acting as a Resource) that can provide contingency reserves either manually or if frequency drops below 59.7 Hz during emergency events. ERCOT limits LAaR to providing 50% of ERCOT's non-spinning reserve requirement, or 1,150 MW.[171]

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[169] NERC, *2012 Summer Reliability Assessment* (Atlanta, GA: NERC, May 2012), http://www.nerc.com/files/2012SRA.pdf.

[170] Synchronized reserve is defined as generation or load that can respond within ten minutes and must be synchronized to the grid. Synchronized reserves are obtained for two zones in PJM: the Reliability First Corporation and for SERC. PJM website: Demand Response Training, http://www.pjm.com/sitecore/content/Globals/Training/Courses/ol-dsr.aspx.

[171] Erik Ela, Michael Milligan and Brendan Kirby, *Operating Reserves and Variable Generation* (Golden, CO: NREL, August 2011), http://www.nrel.gov/docs/fy11osti/51978.pdf.

- MISO divided demand response into Type 1 and Type 2. Type 1 demand response can supply energy at fixed target MW reduction when committed, or to provide contingency reserves when not committed. Type 2 demand response can also supply energy and operating reserves and is treated as negative generation.[172]
- WECC allows demand response to provide non-spinning reserves but not spinning reserves.[173]

To date, demand response development and the growth of variable generation capacity have largely proceeded in parallel but without much consideration of better connecting the two. Continuing growth of variable generation capacity and the emergence of smart grid initiatives may prompt more of an intersection of demand response and variable generation. Advances in communication infrastructure will also enable use of demand response and allow greater participation by residential and small commercial customers. By 2020, roughly 65 million advanced meters (that would access about 47% of U.S. households) may be added in the United States that could allow electricity consumption information to be accessed and stored at sub-hourly to hourly levels (15-60 minutes) and could allow customers to manage their energy consumption through time-based rates and provide near-real-time feedback to customers on their consumption patterns.[174]

Several initiatives are underway both in the United States and internationally that are attempting to shift load to different time periods, or in some cases, to have load respond to movements in variable energy generation. The Mason

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[172] James Ellison, Leigh Tesfatsion and Verne Loose, "A Survey of Operating Reserves Markets in U.S. ISO/RTO-Managed Electric Energy Regions," Preprint submitted to *Energy Economics*, March 8, 2012.
[173] Erik Ela, Michael Milligan and Brendan Kirby, *Operating Reserves and Variable Generation* (Golden, CO: NREL, August 2011), http://www.nrel.gov/docs/fy11osti/51978.pdf.
[174] Peter Cappers, Andrew Mills, Charles Goldman, Ryan Wiser and Joseph H. Eto, *Mass Market Demand Response and Variable Generation Integration Issues: A Scoping Study*, Prepared for the Office of Electricity Delivery and Energy Reliability, U.S. DOE (Berkeley, CA: Lawrence Berkeley National Laboratory, October 2011), http://eetd.lbl.gov/ea/ems/reports/lbnl-5063e.pdf.

County Public Utility District #3 in Washington has a pilot with 100 residential customers to use water heaters to store energy when variable generators are producing power.[175] Elsewhere in the Pacific Northwest, BPA is testing deployment of new and existing water heaters, space heating, and old storage systems as distributed energy storage to provide load following in the 10-minute to 90-minute time frame. About 75% of water heaters in the Pacific Northwest are electric, providing a potential controllable load of 8,000 MW. Nationally, only 9% of water heaters are electric.[176] The Northwest Power and Conservation Council said thousands of megawatts could be realized from commercial and industrial customers shifting some of their daytime load to nighttime but may face increased peak demand charges absent regulatory changes. The Council states that shifting 10% of the region's demand to light load hours would alleviate oversupply problems in the Pacific Northwest from periods of high wind and hydro production in the spring that have led BPA to curtail wind production, and could ultimately save $100 million annually.[177]

On a larger scale, Denmark is using large water tanks with combined heat and power plants as storage when wind production is high. Denmark presently receives about 20% of its generation from wind and has set a target of 50%. As a result, Denmark is investigating expanding thermal energy storage with its CHP

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175 Kevin Porter, Christina Mudd, Sari Fink, Jennifer Rogers, Lori Bird, Lisa Schwartz, Mike Hogan, Dave Lamont and Brendan Kirby, *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge*, Western Governors Association, June 2012, http://www.raponline.org/featured-work/meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration.

176 Diane Broad, "Smart End-Use Energy Storage and Integration of Renewable Energy," Presentation before the Utility Wind Integration Group Fall 2011 Technical Meetings, Lahaina, HI, October 14, 2011.

177 Northwest Power and Conservation Council, *Recommendations of the Oversupply Technical Oversight Committee to the Wind Integration Forum Steering Committee,* April 26, 2012, http://www.nwcouncil.org/energy/Wind/otoc/OTOC%20Infrastructure%20Recommendations%20Final.pdf.

plants, increasing use of electric heat pumps, and other demand response initiatives.[178]

A 2011 scoping study by Lawrence Berkeley National Laboratory (LBNL) assessed key issues and opportunities for demand response from residential and small commercial customers and variable energy generation. The report found that the largest variability and uncertainty in variable generation occurs between one and 12 hours, which matches well with demand response. The report also found that variable time-based retail rates, such as real-time pricing, combined with customer automation and controls, has the largest potential to address variable generation integration. However, that option faces the biggest regulatory and institutional obstacles, as there is little regulatory or industry support for changing residential and small commercial customers to real-time pricing rates.

The LBNL report also determined that incentive-based demand response programs, such as direct load control or providing emergency demand response, also have the potential to help with variable generation integration: if residential customers will consider participating in demand response programs with short durations and frequent events, if load aggregators can participate successfully, and if customers accept control and/or automation technologies. Finally, several regulatory and institutional issues were identified, such as adjusting retail market tariffs to allow utilities or aggregators of retail customers to differentially dispatch demand response customers, changing reliability rules that would allow aggregators or large customers to provide the full variety of bulk power services, and expanding wholesale market product definitions and market rules

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[178] Kevin Porter, Christina Mudd, Sari Fink, Jennifer Rogers, Lori Bird, Lisa Schwartz, Mike Hogan, Dave Lamont and Brendan Kirby, *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge*, Western Governors Association, June 2012, http://www.raponline.org/featured-work/meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration.

to allow demand response to offer and be paid for providing services to integrate variable energy generation.[179]

5.10. INTEGRATION CHARGES

Historically, load has paid for the costs of operating reserves, regardless of whether some loads or generation induce greater need for certain operating reserves than others. The issue of whether variable generation should bear some or all of the costs of incremental operating reserves is a matter of debate in some regions. Already, a small number of utilities are charging wind generators for operating reserves. BPA imposes a wind energy balancing charge that is equal to about $5.40/MWh. BPA reduces this charge to $3.60/MWh for those that participate in BPA's Committed Intra-hour Scheduling Pilot program where wind generators submit schedules every half hour. The pilot runs through September 2013 and is limited to 1,200 MW of wind capacity.[180] FERC has also approved a higher generator regulation and frequency response services charge for wind energy in the Westar Energy balancing area, equivalent to about $0.7/MWh; this interim tariff will be in place until SPP implements its consolidated balancing market and ancillary services market in 2014.[181] Puget Sound Energy (PSE) proposed an increase in Regulation and Frequency Response Service that charges a higher rate for wind energy exporting from the PSE balancing area; the resulting charge would be about $9.50/MWh and is based on an assumption of hourly scheduling. FERC is currently reviewing PSE's

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[179] Peter Cappers, Andrew Mills, Charles Goldman, Ryan Wiser and Joseph H. Eto, *Mass Market Demand Response and Variable Generation Integration Issues: A Scoping Study*, Prepared for the Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy (Berkeley, CA: Lawrence Berkeley National Laboratory, October 2011), http://eetd.lbl.gov/ea/ems/reports/lbnl-5063e.pdf.

[180] BPA, 2012 Wholesale Power and Transmission Rate Adjustment Proceeding: Administrator's Final Record of Decision, July 2011, http://www.bpa.gov/corporate/ratecase/2012/.

[181] FERC, *Order Granting Rehearing in Part, Denying Rehearing in Part, Instituting Section 206 Proceeding, and Establishing Refund Effective Date*, 137 FERC ¶ 61,142, Docket Nos. ER09-1273-002, ER09-1273-004 and EL12-4-000 (FERC, November 17, 2011), http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12820105.

proposal.[182] FERC rejected an earlier proposal from PSE in 2010 as its integration cost methodology was based on incremental capacity that PSE may never develop.

In late 2010, FERC issued a proposed rule concerning variable generation integration that would allow transmission providers to set a rate, subject to FERC approval, to recover capacity costs the transmission provider incurs for providing balancing between scheduling periods to a generator (generator regulation service), but only after implementing intra-hour scheduling and variable generation forecasting.[183] However, in its final rule (Order No. 764), FERC declined to adopt a new Schedule 10, deciding instead to evaluate proposed charges related to variable generation integration on a case-by-case basis. FERC received numerous comments urging flexibility in the design of capacity services needed to integrate VERs into transmission systems, suggesting that the proposed *pro forma* generator regulation service may not be the most efficient and economical service with which to integrate VERs. FERC did, however, provide a framework for transmission providers to use as guidelines in developing such charges, and established some general principles to evaluate individual proposals.[184]

There is considerable disagreement over how to calculate integration costs for wind and solar to reflect the variability or uncertainty of wind and solar power. Model simulations that set a base case without variable generation and then compare the base case with one or more scenarios of increasing variable

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[182] FERC, *Order Accepting and Suspending Proposed Tariff Revisions, Subject to Refund, and Establishing Hearing and Settlement Judge Procedures*, Puget Sound Energy, Inc., 137 FERC ¶ 61,063, Docket No. ER11-3735-000 (FERC, October 20, 2011), http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12795296.

[183] FERC, *Notice of Proposed Rulemaking on the Integration of Variable Energy Resources*, 133 FERC ¶ 61,149, Docket No. RM10-11 (FERC, November 18, 2010), http://www.ferc.gov/whats-new/comm-meet/2010/111810/E-1.pdf.

[184] FERC, *Final Rule on the Integration of Variable Energy Resources*, 139 FERC ¶ 61,246, Docket No. RM10-11, Order No. 764 (FERC, June 22, 2012), http://www.ferc.gov/whats-new/comm-meet/2012/062112/E-3.pdf.

generation will identify the difference in system costs between the base case and the scenarios, but it is difficult to separate the *integration* costs from the value of the energy being produced. The value of the savings in fuel and energy from higher wind and solar generation will exceed the integration costs. Determining an appropriate zero-fuel-cost proxy resource to compare variable generation is also difficult. A flat block may have higher or lower on-peak energy delivery, re-introducing an energy value that again makes it difficult to separate the energy and integration values. Using multiple blocks can match the energy value but can introduce ramping between blocks. Policy and regulatory issues also abound, not the least of which is that other generation technologies cause integration costs that are not assigned to those technologies. Among these include contingency reserve requirements from large generators, regulation requirements from block schedules, nuclear plants that increase cycling of other generators, and gas scheduling restrictions that impose costs on other generators.[185]

5.11. SUMMARY OF RESERVES SECTION

It is generally agreed that an increase in the total amount of reserves will be needed at higher levels of variable generation. Grid operators will vary in how they deploy reserves with higher levels of variable generation, with some choosing additional regulation while some will rely on load following reserves. Because compensation for regulation includes capital, energy production and variable costs, regulation will be a more expensive reserve to use than load following reserves where compensation does not include a capital component.

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[185] Michael Milligan, Erik Ela, Bri-Mathias Hodge, Brendan Kirby, Debra Lew, Charlton Clark, Jennifer DeCesaro and Kevin Lynn, *Cost-Causation and Integration Cost Analysis for Variable Generation* (Golden, CO: NREL, June 2011), http://www.nrel.gov/docs/fy11osti/51860.pdf.

Other trends with deploying reserves with higher levels of variable generation are described below:

- One trend is to determine the amount of reserves dynamically to reflect periods of low or high risk to reliability, instead of a static amount that varies little or not at all by time of day or during the year. Some grid operators are switching from acquiring reserves by time of day and season to scheduling reserves day-ahead or several hours ahead, based on forecasted hourly wind and/or solar generation, in order to avoid carrying excess reserves for most hours of the year. Utilizing multiple markets, including a very short-term market, can also reduce the quantity of reserves, as Germany has demonstrated.
- Small increases in regulation if wind and solar are widely dispersed/diverse. The larger impacts are on longer-term reserves (15 minutes to one hour).
- Increasing interest in ensuring there are sufficient reserves to manage ramping, either through holding flexible generation (Xcel), using a model to determine if sufficient short-term ramp capability is available (MISO) or through developing additional categories of reserves to address ramping constraints (CAISO).
- Although still at small levels, RTOs are using demand response in greater quantities to provide reserves.

6. CONTINGENCY RESERVES

6.1. INTRODUCTION

In addition to the normal variations in supply and demand, there are contingency events; events that occur in an extremely short time period that are unplanned and difficult or impossible to predict. Contingency reserve is capacity that is available to be called on in the event of a system contingency, typically loss of a large generator. In general, contingency reserve requirements are based on the largest contingency that can occur on a specific grid. The contingency reserve requirement may be based on a single contingency, or the single contingency plus some fraction of a secondary contingency. Typically, a portion of the contingency reserve is spinning reserve, meaning it is synchronized with the grid and ready to respond within a short time period (such as ten minutes) to a contingency event. NERC defines several categories of initiating contingency events:

- Single Contingency: initiated by a single failure of an element in the bulk power system. An outage of a device, line or element that may or may not lead to additional elements being lost in a Common Mode Failure because elements are electrically or physically linked.[186] Common Mode Failures of linked elements are still a single contingency.
- Multiple Contingency: the loss of two or more Bulk Electric System elements at the same time. Multiple contingencies may be the result of limited cascading of elements or multiple outages due to a regional event such as a hurricane, volcano, etc.

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[186] A Common Mode Failure is the failure of two or more systems or components due to a single event or cause when the systems/components fail in the same way.

- High Impact Contingency: an event or series of events that result(s) in wide spread element outages that encompass all or major parts of an interconnection with loss of both load and generation that exceed those in the single and multiple contingencies described above. High Impact Contingencies also have major impacts on the interconnection and may take days to restore.
- Bulk Electric System Disaster: loss of the entire interconnected bulk electric system.

Balancing Authorities maintain reserves to respond to contingency events in accordance with the reliability standards established by NERC. In the United States, NERC's BAL-002 reliability standard requires that a balancing authority or regional entity maintain at least enough contingency reserve to cover the most severe single contingency. NERC requires that balancing authorities re-balance their system within 15 minutes of a major disturbance. Each of the regional reliability organizations have established detailed specifications for balancing area contingency reserve requirements sufficient to meet the NERC standard. More information is also presented in Appendix A.

6.2. VARIABLE GENERATION AND CONTINGENCY RESERVES

There have been several studies analyzing the operational and reliability impacts of large penetrations of wind and solar on electric operating systems. A summary of the study findings found that the impact on contingency reserves is smaller in size, and an instantaneous drop in all of wind and solar capacity is highly unlikely. In its 2010 study, NYISO concluded that with 8 GW of wind installed, there was still no change in the amount of operating reserves required to cover a loss of up to 1,200 MW within ten minutes and a loss of wind, should it happen, in that amount would occur over a number of hours.[187] With few

[187] NYISO, *Growing Wind: Final Report of the NYISO 2010 Wind Generation Study* (Rensselaer, NY: NYISO, September 2010), http://www.uwig.org/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf.

exceptions, the majority of the wind and solar integration studies find that an increasing amount of wind and solar power does not lead to an increased need for contingency reserves (see Table 14).

Table 14 *Summary of Wind Integration Studies Findings on Contingency Reserves*[188]

LOCATION	STUDY DATE	AMOUNT OF WIND (MW) ON SYSTEM	IMPACT OF WIND ON CONTINGENCY RESERVES
New York	2004	3,300 MW – 10%	Not affected – largest single contingency is unchanged.
New York	2010	8,000 MW – 20%	Not affected – largest single contingency is unchanged.
Minnesota	2006	3,441 MW – 15% 4,582 MW – 20% 5,688 MW – 25%	Not affected.
Eastern Wind Integration and Transmission Study	2010	20% and 30%	Not affected.
Western Wind and Solar Integration Study	2010	Up to 35%	Found contingency reserve shortfall for 89 hours of the year due to scenarios with wind forecast errors. Study concluded that it was more cost-effective to have demand response address the 90 hours of contingency reserve shortfalls rather than increase spinning reserves from 20% to 25%.
Spain		40%, 40 GW offshore and 5 GW onshore	Does not really examine contingency events and reserves. Unit commitment is redefined, and operational reserves were found to be sufficient to deal with wind ramps.
All Island Grid Study (Ireland)	2007	2-6 GW of wind with 9,618 MW total system load	Variable generation requires additional spinning reserve but the loss of the largest generator on the system is the most significant factor.
The Netherlands	2009	Up to 12 GW	Secondary Reserves of nearly 1,600 MW – twice the size of the single largest unit were required in the worst case scenario.

[188] Michael Milligan, Pearl Donohoo, Debra Lew, Erik Ela, Brendan Kirby, Hannele Holttinen, Eamonn Lannoye, Damian Flynn, Mark O'Malley, Nicholas Miller, Peter Børre Eriksen, Allan Gøttig, Barry Rawn, Madeleine Gibescu, Emilio Gómez Lázaro, Andre Robitaille and Innocent Kamwa, *Operating Reserves and Wind Power Integration: An International Comparison* (Golden, CO: NREL, October 2010), http://www.nrel.gov/docs/fy11osti/49019.pdf.

In general, the wind and solar integration studies do not focus on the need for fast responding contingency reserves but instead emphasize the impact on regulation, load following, and supplemental reserves as required to address wind ramping events that occur over a longer time horizon. Only the Netherlands considered frequency reserves; the fast reserves required for initial response to a contingency event.[189]

These studies indicate that given the relatively slow ramp of wind output events compared with the typical contingency event which involves an instantaneous failure of an element within the bulk power system, it may seldom be necessary to deploy contingency reserves due to a sudden loss of wind generation.[190] Large reductions in aggregate wind generation would need to occur over a broad geographic area and do not occur suddenly but over several hours and are often weather events that are somewhat predictable.[191]

Two wind events in ERCOT in 2007 and 2008 illustrate this point. In 2007, wind production decreased by about 1,500 MW over two hours. In 2008, the decrease in wind production was about 1,700 MW over three-and-a-half hours. Both of these drops in wind were less than ERCOT's single largest contingency of 2,300 MW, representing the loss of both units at the South Texas nuclear plant. However, NERC reliability requirements dictate that contingency reserves should be restored before 105 minutes have lapsed from the start of a contingency event. Most wind ramps take place over a longer time frame than 105 minutes. A reserve service oriented toward wind ramps can be slower

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189 Michael Milligan, Pearl Donohoo, Debra Lew, Erik Ela, Brendan Kirby, Hannele Holttinen, Eamonn Lannoye, Damian Flynn, Mark O'Malley, Nicholas Miller, Peter Børre Eriksen, Allan Gøttig, Barry Rawn, Madeleine Gibescu, Emilio Gómez Lázaro, Andre Robitaille and Innocent Kamwa, *Operating Reserves and Wind Power Integration: An International Comparison* (Golden, CO: NREL, October 2010), http://www.nrel.gov/docs/fy11osti/49019.pdf.

190 NERC, *IVGTF Task 2.3 Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-3.pdf.

191 NREL, *Eastern Wind Integration and Transmission Study* (Knoxville, TN: EnerNex Corporation, January 2010), http://www.nrel.gov/wind/systemsintegration/ewits.html.

responding than normal contingency reserves. Alternatively, operating reserves can respond to a wind ramp event in minutes and in layers, or from the energy market if it is robust and flexible enough.[192]

A separate question is whether it is acceptable to deploy contingency reserves to address a reliability event that occurs as a result of wind variability. Balancing authorities with high levels of wind penetration may experience down ramps that look like a contingency event, and/or operating conditions such as wind plants tripping off-line at their point of interconnection that look like a contingency event. NERC's Integration of Variable Generation Task Force (IVGTF) recommends that "Each region or reserve-sharing group should permit Contingency Reserve Deployment under imbalance energy circumstances made more likely with increasing penetrations of renewables."[193]

FERC's Notice of Proposed Rulemaking (NOPR) on the Integration of Variable Energy Resources in 2010, since finalized, directed NERC to specifically address whether "some additional type of contingency reserve service (beyond the services provided under schedule 5 and 6 of the *pro forma* OATT) would ensure that VERs are integrated into the interstate transmission system in a non-discriminatory manner, while remaining consistent with NERC reliability standards."[194] In comments filed with FERC in March 2011, NERC responded that large wind ramping events have characteristics that are both similar to and different from those of conventional generator contingency events. NERC characterizes wind events as large and infrequent, yet slower than typical contingency events and possible to forecast.[195] NERC's Standard BAL-002

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[192] NERC, *IVGTF Task 2.3 Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-3.pdf.

[193] Ibid.

[194] FERC, *Notice of Proposed Rulemaking on the Integration of Variable Energy Resources*, 133 FERC ¶ 61,149, Docket No. RM10-11 (FERC, November 18, 2010), http://www.ferc.gov/whats-new/comm-meet/2010/111810/E-1.pdf.

[195] FERC, *Comments of the North American Electric Reliability Corporation in Response to the Federal Energy Regulatory Commission's November 18, 2010 Notice of Proposed Rulemaking on the Integration of*

requires ACE to be restored within 15 minutes of the initiating contingency event with contingency reserves restored and replaced within 105 minutes of the event. These NERC requirements may not match well with wind ramps since the ramps can be longer than the disturbance recovery period as well as the reserve restoration period. System operators reinstate reserves much faster (within approximately ten minutes following the disturbance recovery period). Therefore, including two hour wind ramps as contingencies may be incompatible with existing practice.

NERC indicates that using contingency reserves to support wind events may present a problem. The issues are: identifying the point at which the event occurs, and maintaining compliance with the reliability standards that do not accommodate a longer event time horizon. Still, NERC finds that it may be appropriate to use contingency reserves in response to part of a wind ramp and that shared contingency reserves could be used to initiate the response while allowing for time to allocate other resources (demand or supply) for the wind ramp. NERC acknowledges that some entities are looking at ways in which contingency reserves might be deployed to help manage large, infrequent wind ramps and recommends further analysis to better determine the predictability, duration, and magnitude of ramping events that would trigger a contingency reserve response. NERC also suggests that the electric power industry develop rules on the deployment of contingency reserves, and deployment and restoration for wind ramps.

In FERC Order No. 764, FERC noted that the electric power industry has different views on whether contingency reserves should be used for wind events.

Variable Energy Resources, Docket No. RM10-11 (FERC, March 2, 2011), http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12580612.

Because of this, FERC decided it was best to let the industry work through the issues, with help from FERC and FERC staff as needed.[196]

6.3. CONTINGENCY RESERVES AND DISTRIBUTED GENERATION

The growth in distributed solar generation such as rooftop solar systems can affect contingency reserves if there is a significant loss of such distributed generation in response to grid faults or voltage events. By way of example, 16 states and the District of Columbia have distributed generation requirements or set-asides as part of their renewable portfolio standards, most of which apply to solar.[197] Just in 2011, utilities in the U.S. interconnected over 62,500 solar PV systems, amounting to 1.5 GW of capacity, and expect to interconnect 150,000 such systems annually by 2015.[198]

As noted elsewhere in this report, the IEEE-1547 standard requires distributed generation systems to trip in response to changes in voltage or frequency. Should total capacity of distributed generation for a grid operator exceed their contingency requirement, and the aggregate distributed generation capacity disconnects in response to a voltage or frequency disturbance, that can either result in a new contingency definition or compound existing system contingencies.[199]

Absent changes to IEEE-1547, worse case scenarios include grid operators having to carry incremental contingency reserves equal to 100% of estimated distributed

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[196] FERC, *Final Rule on the Integration of Variable Energy Resources*, 139 FERC ¶ 61,246, Docket No. RM10-11, Order No. 764 (FERC, June 22, 2012), http://www.ferc.gov/whats-new/comm-meet/2012/062112/E-3.pdf.

[197] Database of State Incentives for Renewables and Efficiency, "Renewable Portfolio Standard Policies with Solar/Distributed Generation Provisions," September 2012, http://dsireusa.org/documents/summarymaps/Solar_DG_RPS_map.pdf.

[198] Solar Electric Power Association, *SEPA Top Ten Utility Solar Rankings 2011* (Washington, DC: SEPA, May 2012), http://www.solarelectricpower.org/media/252486/2011-sepa-utility-solar-rankings-top-10-executive-summary.pdf.

[199] NERC, *IVGTF Task 2.4 Report: Operating Practices, Procedures and Tools* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-4.pdf.

generation production, at a possible cost of $5-15/MWh. Such practices could limit the addition of distributed generation capacity if the needed contingency reserves are unavailable or limited in supply. For these reasons, and as noted elsewhere in this report, efforts are underway to fast track changes to IEEE-1547 to at least make distributed generation neutral (if not beneficial) in case of grid disturbances while maintaining the protections for human safety and grid islanding that are provided by IEEE-1547.[200]

[200] Nick Miller, "IEEE Standard 1547 – Where Are We Going: A Report from the DG User Group," Presentation before the Utility Wind Integration Group Technical Workshop, San Diego, CA, April 24-26, 2012.

7. WIND AND SOLAR FORECASTING

7.1. WIND FORECASTING

The importance of incorporating variable generation forecasting has been stressed in several industry reports in recent years. NERC stated that "enhanced measurement and forecasting of variable generation output is needed to ensure bulk power system reliability," and that wind forecasting "must be incorporated into real-time operating practices as well as day-to-day operational planning."[201] The U.S. Department of Energy (DOE) reported that "the seamless integration of wind plant output forecasting – into both power market operations and utility control room operations – is a critical next step in accommodating large penetrations of wind energy in power systems."[202] A recent survey of grid operators worldwide found near unanimous agreement that integrating a significant amount of wind will largely depend on the accuracy of the wind power forecast.[203] These reports are in addition to multiple wind integration studies that have found that incorporating state-of-the-art wind forecasts into day-ahead generator scheduling and commitment processes will result in potential annual operating savings – through reduced operation and maintenance (O&M) costs and increased unit efficiencies from not over-committing conventional generating units – to range from $20 million to $510 million, depending on the amount of wind capacity that was studied (see Table 15).[204]

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[201] NERC, *Special Report: Accommodating High Levels of Variable Generation* (Princeton, NJ: NERC, April 2009), http://www.uwig.org/IVGTF_Report_041609.pdf.

[202] DOE, *20% Wind Energy by 2030* (Washington, DC: DOE, 2008), http://www.20percentwind.org/20p.aspx?page=Report.

[203] Lawrence E. Jones, *Strategies and Decision Support Systems for Integrating Variable Energy Resources in Control Centers for Reliable Grid Operations* (Washington, DC: Alstrom Grid, Inc., 2011), http://www1.eere.energy.gov/wind/pdfs/doe_wind_integration_report.pdf.

[204] Richard Piwko, "The Value of Wind Power Forecasting," Presentation before the Utility Wind Integration Group Workshop on Wind Forecasting Applications for Utility Planning and Operations, Phoenix, AZ, February 18-19, 2009, http://www.nrel.gov/wind/systemsintegration/pdfs/2011/lew_value_wind_forecasting.pdf.

Table 15 *Projected Impact of Wind Forecasts on Grid Operating Costs*[205]

			PROJECTED ANNUAL OPERATING COST SAVINGS	
	PEAK LOAD	WIND GENERATION	STATE-OF-THE-ART FORECAST VS. NO FORECAST	ADDITIONAL SAVINGS FROM PERFECT FORECAST VS. STATE-OF-THE-ART FORECAST
California	64 GW	7.5 GW	$ 68 M	$ 19 M
	64 GW	12.5 GW	160 M	38 M
New York	33 GW	3.3 GW	95 M	25 M
Texas	65 GW	5.0 GW	20 M	20 M
	65 GW	10.0 GW	180 M	60 M
	65 GW	15.0 GW	510 M	10 M

Perhaps a result of these reports, but also because of increases in wind capacity throughout the U.S. and the impressive amount of wind (and increasingly, solar) in interconnection queues, more and more RTOs and utilities in the United States have been incorporating wind forecasting. With ISO-NE launching wind forecasting in 2012, all RTOs in the U.S. have wind forecasting in place. In addition, more and more utilities in non-RTO regions such as the Western U.S. are also incorporating wind (and solar, in some cases) forecasting.

Wind forecasts can predict the overall shape of wind production most of the time, and more advanced techniques are under development. Large deviations can occur in level and timing from extreme events that are difficult to forecast. Such deviations can lead to large wind forecast errors. The steepness of the power curve for wind turbines can also lead to forecast errors, as power output increases from 10% to 90% in the wind speed interval between 6-12 meters per second. Another source of wind forecast errors is from wind turbines shutting down operation in storm events, where the turbine stops and power drops to zero. These events can be difficult to predict and contribute to large wind

[205] Ibid.

forecast errors, as wind forecasts are designed to minimize mean or root mean square error. However, that underestimates large weather changes which can lead to wind ramps. Some RTOs and utilities are using separate forecasts on the probability of wind ramps. ERCOT and the Alberta Electric System Operator (AESO) have implemented such a ramp forecasting tool.

Wind forecasts use numerical weather prediction (NWP) models as input that predict wind speed, wind direction and other meteorological estimates like turbulence factors, typically in hourly resolution for several days. Day-ahead forecasts use only NWP data and have a forecast range of six hours to one or more days. For shorter forecast periods up to eight hours, on-line measurement data (wind production and wind measurements) is combined with NWP data. How often NWP data is updated affects wind forecast accuracy. Older data increases the wind forecast horizon and the forecast error. NWP data is updated one to four times per day. If only updated once per day, it can then be almost 24 hours for the next forecast update. NWP data is also computationally time-intensive and can take several hours to compute. If data is 24 hours old, NWP calculations take six hours, and wind power production is forecasted eight hours ahead, then forecasts may be based on data that is 38 hours old, which can negatively affect wind forecast accuracy. Short-term forecasts have two update cycles – one for the on-line measurement data and one for the NWP data. On-line measurements can be updated continuously and are given more weight in shorter time horizons.

The accuracy of wind forecasts depends on the site, time of year, quality of data on individual wind turbine availability and outages, and weather conditions. A representative mean average error for a one-hour-ahead forecast for a single wind power plant varies from 4% to 12% of wind plant capacity. The mean absolute error for day-ahead wind power forecasts for a single wind plant varies from 12% to 25% of nameplate wind capacity. These values can be reduced by as much as 50% if wind plants are aggregated over a broad geographic region.[206] In contrast, day-ahead hourly load forecast errors range from 1% to 3%.[207] Because forecasts are less accurate the further out they are from real-time, the use of forecasts closer to real-time will result in the use of more accurate forecasts. Existing scheduling practices use wind forecasts from 24 to 48 hours before time of operation. In addition to more frequent availability than every six hours of national forecasts, improvements of mesoscale modeling methods and data, and faster running time of mesoscale wind forecasts, adding intra-day unit commitment (such as a 6-hour ahead commitment) in addition to the day-ahead commitment could result in more accurate (and more valuable) forecasts.[208]

Adoption of wind forecasting is a recent phenomenon in the United States. Outside of CAISO, which adopted wind forecasting in 2004, the other RTOs in the United States began forecasting in 2008 or later.[209] Three of the ISOs (ERCOT, MISO and NYISO) began in 2008; PJM began in 2009; SPP in 2011; and as noted, ISO-NE began in 2012. A survey of balancing authorities in the West involved in wind forecasting found similar results, with eight of the 11 balancing authorities surveyed beginning wind forecasting in 2008 or later; two of those eight beginning in 2011.[210] Appendix B includes a comparison of selected wind forecasting systems by utility or RTO in North America.

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206 NERC, *IVGTF Task 2.1 Report: Variable Generation Power Forecasting for Operations* (Princeton, NJ: NERC, May 2010), http://www.nerc.com/docs/pc/ivgtf/Task2-1%285.20%29.pdf.

207 Debra Lew, Michael Milligan, Gary Jordan and Richard Piwko, *The Value of Wind Power Forecasting* (Golden, CO: NREL, April 2011), http://www.nrel.gov/wind/systemsintegration/pdfs/2011/lew_value_wind_forecasting.pdf.

208 Richard Piwko, "The Value of Wind Power Forecasting," Presentation before the Utility Wind Integration Group Workshop on Wind Forecasting Applications for Utility Planning and Operations, Phoenix, AZ, February 18-19, 2009, http://www.nrel.gov/wind/systemsintegration/pdfs/2011/lew_value_wind_forecasting.pdf.

209 Jennifer Rogers and Kevin Porter, *Central Wind Power Forecasting Programs in North America by Regional Transmission Organizations and Electric Utilities: Revised Edition 2008-2010* (Golden, CO: NREL, March 2011), www.nrel.gov/docs/fy11osti/51263.pdf.

210 Kevin Porter and Jennifer Rogers, *Survey of Variable Generation Forecasting in the West* (Golden, CO: April 2012), www.nrel.gov/docs/fy12osti/54457.pdf.

7.2. SOLAR FORECASTING

Solar forecasting is not as far along as wind forecasting, primarily because solar market growth has been quite recent and because solar penetration by energy remains quite small in most RTOs and utility service territories in the United States. To the authors' knowledge, only CAISO and a small number of utilities in the West are forecasting for solar. Because of that, this section will primarily focus on developments in wind forecasting. Solar forecasting will likely develop should solar markets and capacity continue to grow. Because most solar capacity in the Northeast is distributed solar, solar forecasting in the eastern United States will likely be similar to solar forecasting underway in Germany, where solar is also on the distribution system. In contrast, wind development in the United States is predominantly large utility-scale facilities in contrast to Denmark and Germany, where wind development consists mostly of multiple smaller facilities that are spread out across the country and installed mostly on distribution systems.

Forecasting for solar is necessary as well. The short-term variability of a single PV plant can be high, although as noted, there are diversity benefits with multiple PV plants. The output of solar generation depends on the amount of solar radiation that reaches the surface. That, in turn, depends on clouds (i.e., the amount of clouds, or the concentration of water or ice in clouds), the amount of water vapor, and the quantity of aerosols. Hour-ahead solar PV forecasts rely on statistical models, using time series of on-site insolation measurements, off-site measurements of clouds and solar insolation, and satellite images of water vapor channels that might interfere with solar radiation. Day-ahead solar PV forecasts use physics-based models, with forecasts of transmissivity the major variable. Solar power forecasting is comparable to wind power forecasting, but once the sun has risen, clouds are the main factor in the variability of solar power generation and the uncertainty of the solar power forecast. In the short-term, some clouds are fairly stable and move with the winds at the level of the clouds. For longer time scales, clouds can change shape, increase their size, or break apart. Numerical weather prediction models will likely be required to simulate cloud changes.

Multiple methods will be required to forecast solar output at various time scales. Presently, short-term solar forecasts are based on cloud observations and movements. Sky imagers near solar plants can help locate approaching clouds and estimate the impact clouds will have on estimated solar power production. In addition, satellite images can help indicate the direction and speed of approaching clouds. For longer time periods, numerical weather prediction models will be needed, such as estimating solar insolation for multiple days.[211]

7.3. FORECASTING TIME FRAMES

The time frames for forecasting can be roughly divided into a short-term forecast and a day-ahead forecast. The short-term forecast extends out approximately for the next six to eight hours and is updated frequently (every five to 15 minutes) with a fine time resolution (such as forecasts in 5-minute intervals). As an example, PJM's short-term wind forecast is updated every ten minutes, with each forecast at 5-minute intervals for the next six hours. Grid operators use these forecasts to identify additional reserves that may be needed to maintain reliability, for look-ahead planning and hourly planning, and to provide input into operating strategies or mitigation plans.

The day-ahead forecast generally provides hourly forecasts for the next several days, sometimes with a medium term (the next 48 hours) and a longer-term forecast (beyond 48 hours to several days ahead). PJM, for instance, has both a medium-term forecast that is updated hourly from six hours ahead to 48 hours ahead, and a longer-term forecast that is also updated hourly, from 48 hours ahead to 168 hours ahead.

[211] NERC, *IVGTF Task 2.1 Report: Variable Generation Power Forecasting for Operations* (Princeton, NJ: NERC, May 2010), http://www.nerc.com/docs/pc/ivgtf/Task2-1%285.20%29.pdf.

For very short-term forecasts (the next five to ten minutes), persistence forecasts (i.e., the current value will be the same five to ten minutes from now) is considered the standard and is difficult to improve upon. For the next few hours, forecasts incorporate both statistical models with recent wind production values, although some forecasts may blend in NWP values after the first two hours. As an example, NYISO uses persistence forecasts exclusively for very short-term forecasts and blends in short-term forecasts for up to the next eight hours. For longer-term forecasts of roughly six hours to six days, NWP forecasts are mostly relied upon. After six to ten days, NWP models are not as accurate and climatology forecasts (i.e., long term averages by season and time of day) are used.[212]

7.4. RAMP FORECASTS

Wind ramps have received considerable industry attention, in part because of the magnitude of the ramps, the speed at which they can occur, and several specific events that have been discussed frequently in the press. One commonly cited example is the drop-off in wind in ERCOT in 2008 that, when combined with faulty load projections and unexpected generation outages, prompted ERCOT to call upon its interruptible load customers to maintain reliability. A simple definition of a ramp event is a large change in wind or solar power production over a short time interval, such as 30-90 minutes.[213]

ERCOT, SPP and AESO are among the few balancing authorities in North America that receive a separate ramp forecast that is used in operations, with the AESO's ramp forecasting beginning in December 2011. AESO has a maximum

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[212] NERC, *IVGTF Task 2.1 Report: Variable Generation Power Forecasting for Operations* (Princeton, NJ: NERC, May 2010), http://www.nerc.com/docs/pc/ivgtf/Task2-1%285.20%29.pdf.

[213] A more detailed discussion of the contributors to wind ramps and how these can be forecasted is available in the study conducted by Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.

peak load of 10,609 MW that took place in January 2012.[214] The minimum load is about 6,650 MW as of 2010.[215] The installed wind capacity is 972 MW as of August 2012, and there is no utility-scale solar interconnected to AESO.[216] ERCOT's Large Ramp Alert System (ELRAS) forecasts probabilistic ramping events of a defined magnitude and length of time. ELRAS generates 15-minute regional and system-wide forecasts for the next six hours and is updated every 15 minutes. ERCOT's system operators use ELRAS for situational awareness. SPP's ramp forecast also forecasts probabilistic ramping events with predefined confidence intervals and duration, and length and time of the ramp. SPP has a peak load of 54,949 MW, a minimum load of 19,140 MW, installed wind capacity of 7,576 MW, and installed solar capacity of about 50 MW.[217] PJM, NYISO, MISO and CAISO are considering developing a separate ramp forecast.[218]

The interest in developing a separate ramp forecast stems from the desire of grid operators to manage extreme events to ensure that load is met reliably. Forecasting systems now in operation tend to emphasize minimizing forecast errors, but doing so may not adequately show the length and severity of a ramp event.[219] There is not universal agreement amongst variable generation forecasters that a separate ramp forecast is required. Those who do agree on the requirement say that phase errors are common in determining the timing and magnitude of a ramp.[220] A contrasting viewpoint is if a rapid update cycle is

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[214] AESO, "Electricity Statistics," August 2012, http://www.energy.alberta.ca/Electricity/682.asp.
[215] AESO, *2010 Annual Market Statistics* (Calgary, Alberta: AESO, March 2011), http://www.aeso.ca/downloads/AESO_2010_Market_Stats.pdf.
[216] AESO, "Electricity Statistics," August 2012, http://www.energy.alberta.ca/Electricity/682.asp.
[217] Derek Hawkins, SPP, Personal Communication, October 16, 2012.
[218] Jennifer Rogers and Kevin Porter, *Wind Power and Electricity Markets* (Reston, VA: Utility Wind Integration Group, 2011), http://www.uwig.org/windinmarketstableOct2011.pdf.
[219] Mark Ahlstrom, James Blatchford, Matthew Davis, Jacques Duchesne, David Edelson, Ulrich Focken, Debra Lew, Clyde Loutan, David Maggio, Melinda Marquis, Michael McMullen, Keith Parks, Ken Schuyler, Justin Sharp and David Souder, "Atmospheric Pressure: Weather, Wind Forecasting and Energy Market Operations," *IEEE Power and Energy*, November/December 2011, http://www.uwig.org/ahlstrom.pdf.
[220] Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for

performed, then the resolution of the short-term forecast should be sufficient to detect ramps. Another alternative is to change present forecasting systems to penalize forecast errors during ramping periods. This would give ramping periods higher priority when the forecast is being prepared and tuned.[221]

7.5. COST ALLOCATION

Most utilities and RTOs in the United States pay for their variable generation forecasting system without passing along any of the costs to generators. PJM is among this group. The AESO, CAISO and NYISO all charge wind generators (and in CAISO's case, solar generators) for forecasting. AESO does not publicize the amount they charge wind generators for forecasting. NYISO charges a monthly fee of $500 and a separate fee of $7.50 per MW. CAISO charges wind and solar generators $0.10/MWh.[222]

7.6. IMPLICATIONS OF SCHEDULING REQUIREMENTS FOR VARIABLE GENERATION FORECASTING

To meet day-ahead scheduling requirements, wind models begin running several hours before day-ahead schedules are due. For day-ahead schedules due at noon, for example, the models begin running at midnight, using observations from the day before. Figure 18 illustrates that forecast preparation starts 48 hours before the day-ahead market closes, and if scheduling of generation and dispatch is completed before weekends and holidays, the forecasts can be several days old.

ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.

221 Mark Ahlstrom, James Blatchford, Matthew Davis, Jacques Duchesne, David Edelson, Ulrich Focken, Debra Lew, Clyde Loutan, David Maggio, Melinda Marquis, Michael McMullen, Keith Parks, Ken Schuyler, Justin Sharp and David Souder, "Atmospheric Pressure: Weather, Wind Forecasting and Energy Market Operations," *IEEE Power and Energy*, November/December 2011, http://www.uwig.org/ahlstrom.pdf.

222 Ed DeMeo, Kevin Porter and Charlie Smith, *Wind Power and Electricity Markets* (Reston, VA: Utility Wind Integration Group, 2011), www.uwig.org/fercwork1204/windinmarketstable.pdf.

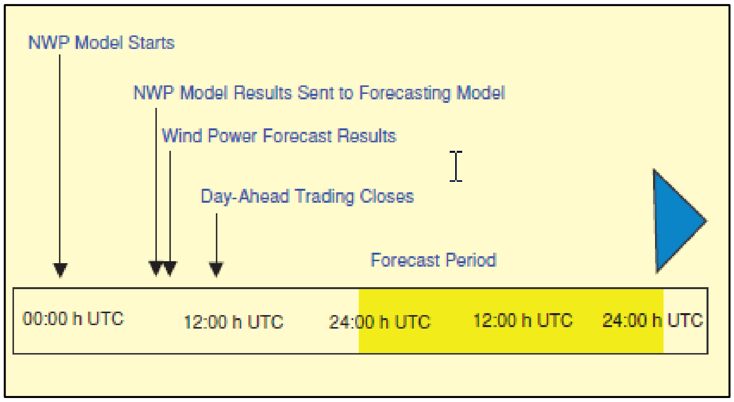

Figure 18 *Typical Schedule for Wind Power Forecasts and Day-Ahead Scheduling*[223]

Variable generation forecasts are more accurate closer to real-time. The utilization of intra-day unit commitment can allow the use of variable generation forecasts that are closer to real-time and more accurate, reducing the need for reserves as compared to using a day-ahead variable generation forecast. Using wind as an example, Figure 19 shows the difference in actual wind generation compared to forecasts two hours ahead, four hours ahead and day-ahead in Germany. Running intra-day unit commitment algorithms, in addition to day-ahead unit commitment, and using the results to inform forecasts – or using a more stochastic approach to unit commitment with frequent rolling updates – may be useful strategies for taking advantage of short-term variable generation forecasts.[224]

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[223] B. Ernst, B. Oakleaf, M. L. Ahlstrom, M. Lange, C. Moehrlen, B. Lange, U. Focken and K. Rohrig, "Predicting the Wind," *IEEE Power and Energy Magazine* 5, no. 6, November/December 2007, 78-89, http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=4383126&url=http%3A%2F%2Fieeexplore.ieee.org%2Fxpls%2Fabs_all.jsp%3Farnumber%3D4383126.

[224] Peter Meibom, Helge V. Larsen, Rüdiger Barth, Heike Brand, Aidan Tuohy and Erik Ela, *Advanced Unit Commitment Strategies in the United States Eastern Interconnection* (Golden, CO: NREL, August 2011), http://www.nrel.gov/docs/fy11osti/49988.pdf.

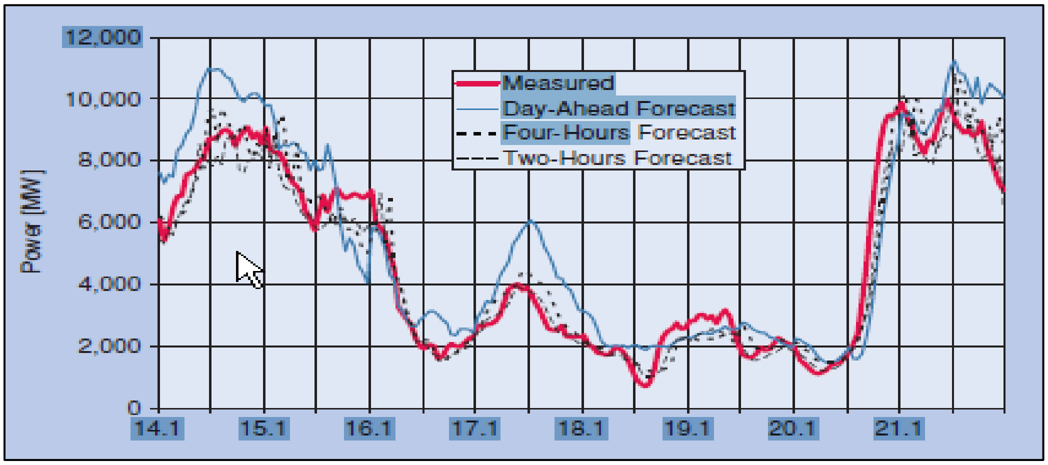

Figure 19 *Comparing Intra-Day and Day-Ahead Wind Power Forecasts in Germany with One Week of Data*[225]

Note: The Y axis is the date (e.g., 14.1 is January 14th).

As shown, wind forecasts closer to real-time tend to be closer to actual measured wind production. Submitting schedules within shorter periods of time before the real-time market begins will allow for more accurate predictions of wind generation, although some trade-offs are involved. Having a shorter period of time before the start of real-time market operations leads to a need for more flexible secondary reserves, or perhaps higher costs from the increased starting and stopping of conventional units, as those shorter periods of time would not allow sufficient time to change unit commitment decisions for conventional generating units.[226]

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[225] B. Ernst, B. Oakleaf, M. L. Ahlstrom, M. Lange, C. Moehrlen, B. Lange, U. Focken and K. Rohrig, "Predicting the Wind," *IEEE Power and Energy Magazine* 5, no. 6, November/December 2007, 78-89, http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=4383126&url=http%3A%2F%2Fieeexplore.ieee.org%2Fxpls%2Fabs_all.jsp%3Farnumber%3D4383126.

[226] Timur Gül and Till Stenzel, *Variability of Wind Power and Other Renewables: Management Options and Strategies* (Paris: International Energy Agency, 2005), http://www.uwig.org/IEA_Report_on_variability.pdf.

7.7. FORECAST APPLICATIONS

The day-ahead markets provide a financial vehicle for market participants to buy and sell energy. In most regions, the day-ahead market uses a security constrained unit commitment (SCUC) that determines the most economic selection of resources to meet bid-in load requirements with consideration of the transmission network. Additionally, a second SCUC estimates what additional resources are necessary (if any) over and above what has already been self-committed for bilateral contracts and committed by other markets, such as the day-ahead market and the ancillary services market, to meet the expected real-time demand. This is often referred to as a "reliability unit commitment" and will usually differ from the day-ahead market in that an ISO provided forecast is used as input.

In the United States, centralized wind power forecasting is not generally used to affect day-ahead market schedules. Instead, wind power forecasts are normally used to ensure that enough generation is committed to meet expected load, transaction schedules and/or reserve requirements.[227] This is in contrast to Germany, where the TSOs sell the day-ahead renewable energy forecast into the day-ahead spot market.[228] Spain requires wind generators to offer production to the day-ahead market with their best forecast, and to update their schedules in intra-day markets with updated forecasts.[229] In Canada, AESO hopes to

[227] Kevin Porter and Jennifer Rogers, *Status of Centralized Wind Power Forecasting in North America May 2009-May 2010* (Golden, CO: NREL, April 2010), http://www.nrel.gov/docs/fy10osti/47853.pdf.
[228] H. Holttinen, A.G. Orths, P.B. Eriksen, J. Hidalgo, A. Estanqueiro, F. Groome, Y. Coughlan, H. Neumann, B. Lange, F. van Hulle and I. Dudurych, "Currents of Change," *IEEE Power and Energy* 9, no. 6, November/December 2011, 47-59.
[229] Jorge Hidalgo López, "Wind Development and Integration Issues and Solutions," Presentation before the Northwest Wind Integration Forum, Portland, OR, July 29-30, 2010, http://www.nwcouncil.org/energy/wind/meetings/2010/07/WIF%20TWG%20072910%20Hidalgo%20072610.pdf.

incorporate wind forecasting into its EMS in the near future, perhaps in 2012, but no definite timetable has been set.[230]

Some RTOs incorporate forecasts into hour-ahead or real-time scheduling or dispatch. NYISO, for example, incorporates its real-time wind forecasts (updated every 15 minutes for the next 15 minute interval) into real-time commitment and dispatch. The hour-ahead wind forecasts are used as the energy schedule in CAISO's real-time operations. Ontario IESO will use its centralized wind forecast for real-time dispatch when it begins later in 2012.

The RTOs use the forecasts for other applications as well. ERCOT uses wind forecasts in determining monthly needs for non-spinning reserves. MISO also uses its wind power forecasts to conduct week-ahead and intra-day reliability analysis and to determine wind's impact on transmission flowgates.[231] Demonstrations of using stochastic unit commitment with ensemble forecasts and dynamic reserve requirements are occurring in Ireland. In Germany, localized wind forecasts are being demonstrated to estimate potential transformer congestion associated with higher levels of wind power.[232]

Variable generation integration studies indicate that economic gains from using wind power forecasting can only be realized if wind power forecasts are integrated with day-ahead schedules. Some may contend that this would represent a significant change in procedure for ISOs and RTOs, or a preferential treatment of wind relative to other types of generation. However, similar to the ISO's and RTO's creation of a load forecast today, the ISO's and RTO's creation of a combined "load net wind" forecast could be used after clearing the financial day-ahead market in the reliability commitment process (usually considered the

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[230] Kevin Porter and Jennifer Rogers, *Survey of Variable Generation Forecasting in the West* (Golden, CO: April 2012), www.nrel.gov/docs/fy12osti/54457.pdf.
[231] Ed DeMeo, Kevin Porter and Charlie Smith, *Wind Power and Electricity Markets* (Reston, VA: Utility Wind Integration Group, 2011), www.uwig.org/fercwork1204/windinmarketstable.pdf.
[232] Ecar Energy, *Wind Integration in Electricity Grids: International Practice and Experience* (np: Australian Energy Market Operator, October 2, 2011), http://www.aemo.com.au/planning/0400-0049.pdf.

first stage of the next day's real-time market). The ISO and RTO process to commit sufficient resources to supply anticipated load may have to account for the increased uncertainty around the wind power forecast. That said, the "load net wind" forecast should contribute to more efficient market operation and dispatch, improve overall operating reliability, and should not financially benefit wind generators over what they would otherwise receive as price-takers in the real-time market, so this is quite analogous to the use of an improved system load forecast that is created by the ISO or RTO.

7.8. USE OF CONFIDENCE INTERVALS OR EXCEEDANCE LEVELS

System operators may incorporate a probability of exceedance as part of their forecast. For example, ERCOT uses a 50% exceedance level for its short-term wind power forecast that is updated hourly and covers the next 48 hours. PJM uses a 70% confidence interval but can change the confidence interval with Energy & Meteo, PJM's forecasting vendor, as necessary.[233] AESO receives a minimum and maximum band and forecasts with 80%, 95% and 98% confidence intervals. AESO typically uses the 80% confidence interval for determining the amounts of reserves needed and the 98% confidence interval for day-ahead planning. Xcel Energy uses a 75% confidence interval with its wind forecast, while Southern California Edison uses multiple confidence intervals at 10% increments, depending on the particular circumstances.

A trade-off with using confidence intervals and exceedance levels is that more reserves may need to be committed than necessary under many circumstances. At least in part due to this reason, ERCOT dropped its exceedance level from 80% to 50%. In addition, a high confidence interval or exceedance level (e.g., 90-95%) will result in a wide band of potential outcomes, making the forecast less useful. BPA initially used a 95% confidence interval but found that the forecast

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[233] Kevin Porter and Jennifer Rogers, *Status of Centralized Wind Power Forecasting in North America May 2009-May 2010* (Golden, CO: NREL, April 2010), http://www.nrel.gov/docs/fy10osti/47853.pdf.

interval was so wide that the forecast had little meaning. BPA now asks forecasting companies to provide "predictive intervals" with an upper and lower band, with the intervals wider during high-wind times and narrower during periods of low wind. BPA evaluates the performance of forecasting companies by how small the interval is and how often wind generation has occurred outside of the interval.[234]

7.9. ENSEMBLE FORECASTS

Ensemble forecasts can refer to either a number of wind forecasts from different models (provided by either a single or multiple forecasting companies) or multiple forecasts from the same model from the same vendor, with small perturbations in the initial conditions of the model. Ensemble forecasts are designed to target major sources of uncertainty in the weather forecasts, such as large scale weather fronts that are a source of uncertainty for New England.[235] Ensemble forecasts can be weighted to reflect past performance or to focus on particular weather situations.

Among RTOs in North America with forecasting in place, all use a single forecasting provider that prepares ensemble forecasts either with multiple numerical weather prediction (NWP) models or varying dynamic or physical processes within the NWP model. For PJM and MISO, Energy & Meteo uses three NWP models weighted by weather and historical performance. The same vendor also provides wind forecasting for SPP, and runs one NWP model every six hours, and two every 12 hours. In contrast, WEPROG, the forecasting provider for AESO, uses a multi-scheme approach that contains 75 ensemble members to replicate weather uncertainty for the next six days. Each ensemble

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[234] Kevin Porter and Jennifer Rogers, *Survey of Variable Generation Forecasting in the West* (Golden, CO: April 2012), www.nrel.gov/docs/fy12osti/54457.pdf.

[235] Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.

member has a different set of equations to represent different physical or dynamic processes.[236]

Of note is that no RTO in North America uses multiple forecasting providers. This is contrast to Germany which uses multiple forecasting companies.[237] In 2009, CAISO found no additional value from using wind power forecasts from multiple providers. CAISO suggested that this conclusion could be altered if payments to wind power forecasting providers were based on a two-part fee structure, with a small flat rate and a second payment based on the quality of the wind power forecasts.[238] At least three balancing authorities in the Western Interconnection (BPA, Glacier Wind and Southern California Edison) use multiple forecasting companies. BPA's final forecast is generally a blend of persistence, probabilistic and ensemble forecasts. Glacier Wind does not strictly use ensemble forecasting, as different forecasting companies have different processes, but some "human ensemble" takes place as the company examines the different wind forecasts and makes operating decisions based on the forecasts.[239]

7.10. DATA REQUIREMENTS FOR FORECASTS

Early experience with wind forecasting in North America determined that data availability and data quality affected the accuracy of the forecast. Consequently, RTOs and utilities have made data access and quality priorities for launching and maintaining a central wind-power forecasting system. Table 16 provides some older forecasting results from CAISO that show that wind projects with

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[236] Ed DeMeo, Kevin Porter and Charlie Smith, *Wind Power and Electricity Markets* (Reston, VA: Utility Wind Integration Group, 2011), www.uwig.org/fercwork1204/windinmarketstable.pdf.

[237] B. Ernst, B. Oakleaf, M. Ahlstrom, M. Lange, C. Moehrlen, B. Lange, U. Focken and K. Rohrig, "Predicting the Wind," *IEEE Power and Energy Magazine* 5, no. 6 November/December 2007, 78-89, http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=4383126&url=http%3A%2F%2Fieeexplore.ieee.org%2Fxpls%2Fabs_all.jsp%3Farnumber%3D4383126.

[238] Jim Blatchford and Phillip de Mello, *Revised Analysis of June 2008 –June 2009 Forecast Service Provider RFB Performance*, March 25, 2010 (Folsom, CA: CAISO, 2010), http://www.caiso.com/2765/2765e6ad327c0.pdf.

[239] Kevin Porter and Jennifer Rogers, *Survey of Variable Generation Forecasting in the West* (Golden, CO: April 2012), www.nrel.gov/docs/fy12osti/54457.pdf.

greater amounts of data available to forecasters have a lower annual Mean Average Error (MAE) for forecasting the next operating hour.

Table 16 *Examples from CAISO on Data Availability and Wind Forecast Performance*[240]

DATA AVAILABILITY AND WIND FORECASTING PERFORMANCE FACILITY	DATA AVAILABILITY	NEXT OPERATING HOUR FORECAST ANNUAL MAE (% CAPACITY)	NEXT OPERATING HOUR FORECAST ANNUAL NET DEVIATION
A1	98.37%	11.30%	-0.18%
A2	87.18%	14.59%	2.18%

That said, there is some difference of opinion over how much data is needed to prepare a variable generation forecast. A basic trade-off exists between obtaining retrieving security acquiring more data for improving forecasts and the cost of the infrastructure and complexity to secure that data. Some maintain there are diminishing returns as the data becomes more granular and is obtained closer to real-time. In addition, some forecast providers optimize forecasts to power production and do not require wind speed data,[241] while other forecast providers desire or prefer wind speed data.[242]

The basic data to include are the latitude, longitude, hub height and metered power output, both current and historical. The production data allows a forecaster to derive an empirical relationship between forecasted wind speeds and production. A manufacturer's power curve or other estimate for power conversion can be used as a substitute until production data is available. Other

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240 Jim Blatchford, "Wind Energy Forecasting 101," PJM Emerging Resources Stakeholders Forum, May 15, 2008.

241 Mark Ahlstrom, James Blatchford, Matthew Davis, Jacques Duchesne, David Edelson, Ulrich Focken, Debra Lew, Clyde Loutan, David Maggio, Melinda Marquis, Michael McMullen, Keith Parks, Ken Schuyler, Justin Sharp and David Souder, "Atmospheric Pressure: Weather, Wind Forecasting and Energy Market Operations," *IEEE Power and Energy*, November/December 2011, http://www.uwig.org/ahlstrom.pdf.

242 Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.

data to include are current turbine availability in real-time and day-ahead that allows forecasters to adjust forecasts in accounting for out-of-service wind turbines. Curtailment information from transmission limitations or instructions from system operators should also be part of the forecast; otherwise, forecast accuracy will degrade as the forecast will not reflect the difference between forecasted and actual production. The curtailment information is also helpful for updating historical power data. Finally, wind speed data from meteorological towers and/or the air temperature, wind direction, humidity and air pressure data at the wind turbines can also be collected.

For individual wind turbines, PJM requires turbine capacity, minimum/maximum wind speed, manufacturer power curves, geographic location, hub height, ambient temperature operating limits, and information on installation of cold weather packages. Along with these turbine-specific requirements, PJM also requires that the initial project data required include aggregate historic power output, meteorological and outage data, and the aggregate reactive capability curve. For wind plants as a whole, PJM requires the real-time aggregate wind plants' MW output. At least one meteorological tower (or wind speed and direction from selected wind turbine anemometers and wind vanes) with wind speed and wind direction data is required, temperature and pressure data is preferred, and humidity data is accepted.

These requirements are similar across the RTOs except for MISO. NYISO has comparable requirements, and applies a daily penalty of $500 or $20/MW for lacking data or for providing poor quality data. PJM does not impose a penalty for not providing data or providing poor quality data. In contrast, MISO does not require wind-turbine-specific information. Instead, MISO provides latitude, longitude, hub heights, maximum and historical production, and real-time output to Energy & Mateo, MISO's forecasting vendor.[243]

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[243] Kevin Porter and Jennifer Rogers, *Status of Centralized Wind Power Forecasting in North America May 2009-May 2010* (Golden, CO: NREL, April 2010), http://www.nrel.gov/docs/fy10osti/47853.pdf.

7.11. FORECASTING FOR OFFSHORE WIND

More research and development is needed on offshore meteorology as input for offshore wind forecasting. Fewer measurements of current wind conditions, surface temperatures and other meteorological factors over water are available to tune forecast models. Data sources for offshore wind measurements tend to come from weather buoys that are three to five meters above the ocean, as compared to wind turbine hub heights that are 80 meters or more above the ocean. In addition, wind conditions over land and water are quite different, as wind over ocean will vary because of changing ocean conditions. Should these issues be addressed, some believe errors in offshore wind forecasting could be lower than land-based sites for sites five miles or more offshore.[244]

7.12. VARIABLE GENERATION FORECASTING IN SPAIN

Spain has more than 700 wind projects with different owners, each having different requirements for operation, switching and maintenance. In the past, REE said it had trouble contacting wind plant owners for emergency generation reductions, plant outages, or for maintaining transmission assets near generation interconnection points. Now, wind projects greater than 10 MW must be connected to a control center, with wind generators bearing the cost. The control center is connected to the Control Center for Renewable Energies, known as CECRE in Spain; that in turn is connected to REE. The wind projects are aggregated into wind clusters, with one cluster for each transmission system node. The CECRE is for special regime generation and has a particular focus on wind power. CECRE analyzes maximum wind generation in real-time that can be accommodated and sends directives to wind generators if curtailments are needed. Wind generators must adjust their production to required set-point

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[244] Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.

within 15 minutes. This is only done for wind generation but can be extended to other renewable energy technologies.[245]

Over 70% of Spain's wind capacity is connected to REE's transmission network, allowing REE to monitor wind production. REE uses a central wind forecast for all wind generation. The wind forecast provides hourly wind forecasts for the next ten days, and a forecast by transmission system node that is updated every 15 minutes for the next 48 hours. Confidence intervals at 15%, 50% and 85% are provided, with the 85% level used to determine if there are enough units committed. REE uses an ensemble wind forecast of five independent wind forecasts.[246] REE said improvements in wind forecasting have resulted in fewer reserves needed to account for wind forecast errors, particularly at the day-ahead time scale (see Figure 20).

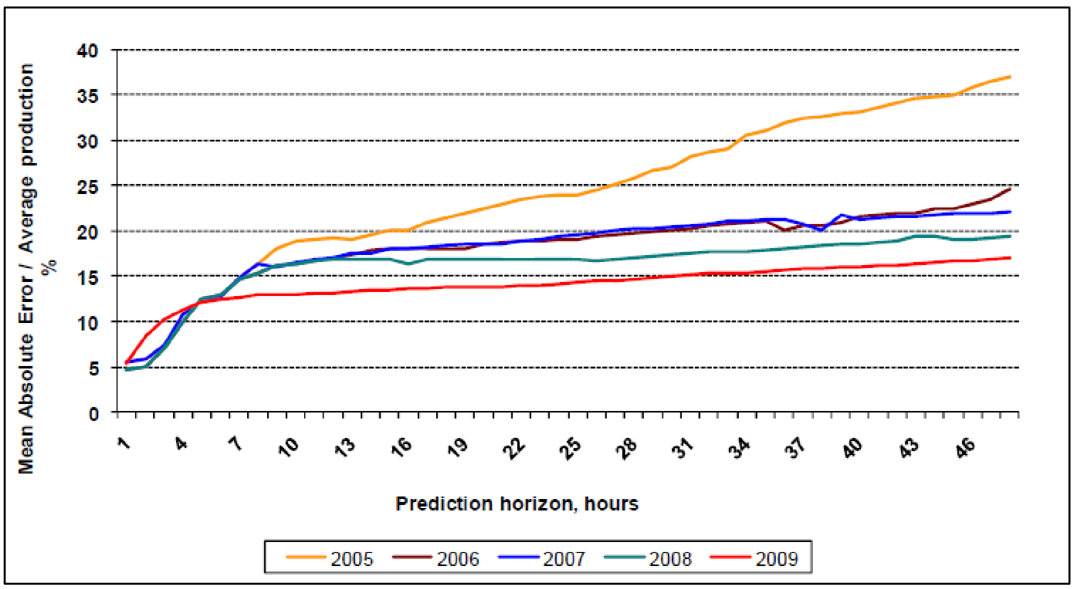

Figure 20 *Hourly Wind Forecast Error for Next 48 Hours, 2005-2009*[247]

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[245] Jorge Hidalgo López, "Wind Development and Integration Issues and Solutions," Presentation before the Northwest Wind Integration Forum, Portland, OR, July 29-30, 2010, http://www.nwcouncil.org/energy/wind/meetings/2010/07/WIF%20TWG%20072910%20Hidalgo%20072610.pdf.

[246] NERC, *IVGTF Task 2.1 Report: Variable Generation Power Forecasting for Operations* (Princeton, NJ: NERC, May 2010), http://www.nerc.com/docs/pc/ivgtf/Task2-1%285.20%29.pdf.

[247] Jorge Hidalgo López, "Wind Development and Integration Issues and Solutions," Presentation before the Northwest Wind Integration Forum, Portland, OR, July 29-30, 2010,

As indicated in Figure 21, REE reports that the mean average error for hourly wind forecasts for the next ten days ranges from between 10% and 15% for day-ahead to about 30% from five days ahead to nine days ahead.[248]

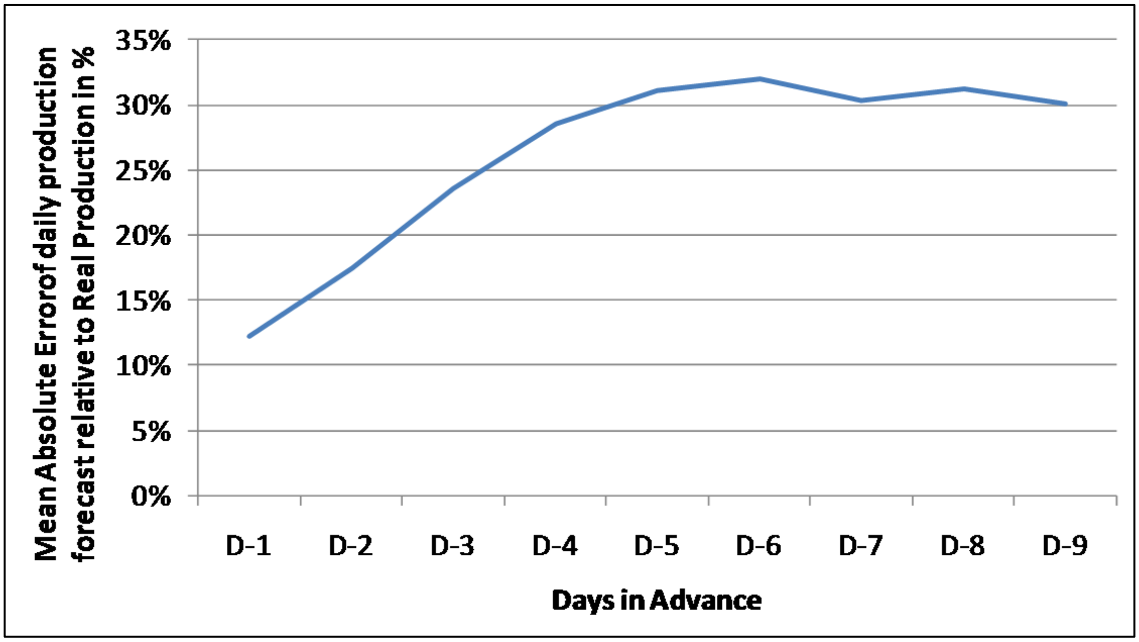

Figure 21 *Hourly Forecast Error Based on Production for Next Ten Days[249]*

Spain coordinates forecasting and scheduling of solar plants, and although the early indications suggest that solar forecast accuracy is not very good beyond six hours, the forecast error is tolerable because of the coincidence of solar with peak demand. One example is the solar forecast inaccuracy from the 12.3 MW Guadarrangque solar PV plant, which was about 50% from August 2009 to September 2010, with the lowest value being 25.4%. But in an example of diversity of solar production among multiple solar PV plants, the aggregated

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http://www.nwcouncil.org/energy/wind/meetings/2010/07/WIF%20TWG%20072910%20Hidalgo%20072610.pdf.

[248] Ibid.

[249] Ibid.

data from over 70 solar PV rooftop installations showed an average deviation of less than 1% from expected solar generation.[250]

7.13. VARIABLE GENERATION FORECASTING IN GERMANY

The German TSOs utilize several forecasting services at the same time and use a weighted sum of these forecasts adjusted to observed weather patterns. For example, Amprion uses ten different wind forecasts which are entered into a "combination tool," which then produces an optimal forecast while taking into account the weather situation. 50Hertz combines three different forecast tools to create a weighted sum forecast for the TSO's area and for Germany as a whole. The combination of forecast models takes advantage of the fact that these models deal with weather situations differently, with some performing better under specific conditions while other models are better predictors under other specific weather conditions. Input data is upscaled from about 130 locations throughout Germany.

Due to the implementation of these aggregate forecasting methods, the day-ahead wind power production forecast root mean square error for a single wind plant ranges between 10% and 20% to about 7.5 to 10% for a control area, and averages about 4.5% for Germany as a whole. Large forecast errors occur once or twice a year but build up slowly because of the geographic diversity of wind projects in Germany. TSOs sell the day-ahead forecasted amount into the day-ahead spot market; they also sell the difference between the day-ahead and intra-day forecast into the intra-day spot market. Any remaining deviations are covered by balancing reserves.[251]

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[250] International Energy Agency, *Harnessing Variable Renewables: A Guide to the Balancing Challenge* (Paris: OECD/IEA, May 2011).

[251] B. Ernst, U. Schreier, F. Berster, J.H. Pease, C. Scholz, H.P. Erbring, S. Schlunke and Y.V. Makarov, *Large-Scale Wind and Solar Integration in Germany* (Richland, WA: Pacific Northwest National Laboratory, February 2010), http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19225.pdf.

For solar, the German TSOs also use several forecast providers. The forecasts are based on different combinations of weather forecasts, satellite data on global radiation, statistical methods, and on-line data for hundreds of PV installations. Solar forecasts range from 15 minutes to four days. Solar forecast accuracy is comparable to wind power, with about 4.5% RMSE for day-ahead, under 4% for intraday, and about 1% for a few hours ahead. Like wind, solar forecasts can be subject to large errors for a few days each year.[252]

[252] KEMA, Inc., *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, CEC-400-2011-011 (Oakland, CA: KEMA, Inc., December 2011), http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf;
NERC, *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources* (Princeton, NJ: NERC, August 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf.

8. CAPACITY VALUE OF VARIABLE GENERATION

Put simply, the capacity value of a generator is the amount of additional demand that can be met with the addition of that generator while maintaining existing levels of reliability. Grid operators determine a planning reserve that consists of installed capacity in excess of load to maintain reliability in case of unexpected outages of generators or errors in either wind or load forecasts. This planning reserve is applied in the planning time frame (i.e., one year or more), and is a determination of system adequacy; i.e., that there is sufficient installed generation to meet load obligations.

Common measures used for capacity adequacy evaluation include Loss of Load Expectation (LOLE) and Loss of Load Probability (LOLP). LOLP is the probability that load will be greater than available generation at a given time. LOLE is the expected number of hours or days where load will not be met over a defined time period, such as 0.1 days per year, or one day in ten years.[253] LOLE also forms the basis for determining the contribution that any given generator can provide to capacity adequacy, known as Equivalent Load Carrying Capability (ELCC), after accounting for the generator's forced outage rate.[254] A generator helps meet resource adequacy if it decreases the LOLE in some time periods.[255]

The contribution of conventional generators to capacity adequacy is generally a function of the generating unit's capacity and forced outage rates. For variable generators, the contribution to adequacy is dependent on the unit's time of delivery of production and the LOLE reductions that would be provided. Wind

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[253] Other metrics besides LOLE can be used, such as Expected Unserved Energy.

[254] A. Keane, M. Milligan, C. D'Annunzio, C. Dent, K. Dragoon, B. Hasche, H. Holttinen, N. Samaan, L. Soder and M. O'Malley, "Capacity Value of Wind Power," *IEEE PES Transactions on Power Systems* 26, no. 2, May 2011, 564-572.

[255] NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF1-2.pdf.

generators generally have high mechanical availability, exceeding 95% in many instances; i.e., the forced outage rate is often below 5%. Since wind plants generate power when the wind is blowing, the amount of power that wind can generate is a function of the wind speed throughout the year. As a result, the effective forced outage rate for wind generators can be much higher, from 50% to 80%.[256]

In addition, the capacity value of wind will differ by geographic area and climatic region, depending on the strength of the wind resource and to what extent wind is correlated with load. High capacity factors and high correlation between wind output and demand will result in a higher capacity value. For example, the capacity value of wind in Ireland will likely be higher than that in ERCOT, based on one year's worth of data, as there is a closer correlation between wind production and demand in Ireland as compared to ERCOT (see Figure 22).

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[256] Michael Milligan and Kevin Porter, *Determining the Capacity Value of Wind: A Survey of Methods and Implementation*, NREL/CP-500-38062 (Golden, CO: NREL, May 2005), http://www.nrel.gov/docs/fy05osti/38062.pdf.

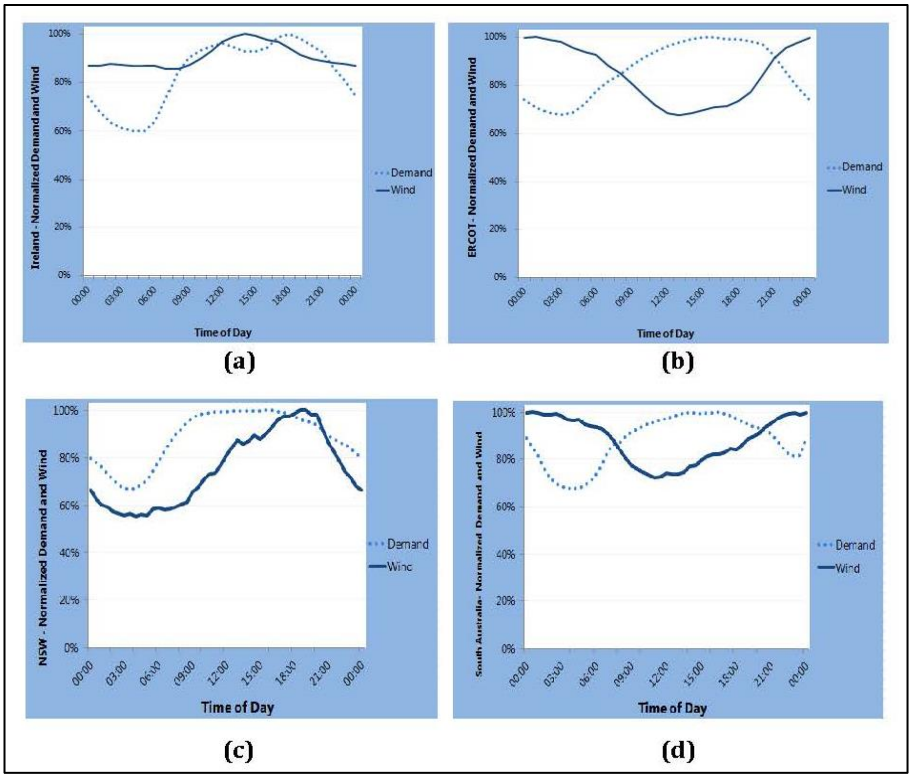

Figure 22 *Average Wind and Demand Data for Ireland, ERCOT, New South Wales and South Australia*[257]

Notes: Wind and demand data normalized to (a) Ireland, one year data, 2010; (b) ERCOT, one year data, 2010; (c) New South Wales, six months data, November 2010 to April 2011; and (d) South Australia, six months data, November 2010 to April 2011.

As with capacity factors, the capacity value of wind and solar can vary inter-annually.[258] Therefore, multiple years of wind data, whether production data or simulated through modeling, is desirable to confidently estimate capacity value. Because of these factors, the capacity value of wind cannot simply be assumed by

[257] Ecar Energy, *Wind Integration in Electricity Grids: International Practice and Experience* (np: Australian Energy Market Operator, October 2011), http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/0400-0049%20pdf.ashx.

[258] Ibid.

applying a forced outage rate to installed capacity, as can be done with conventional generation.[259]

Higher penetration of wind tends to reduce the capacity value of wind plants. Figure 23 depicts the results of several studies in Europe of the capacity value of wind at differing penetration levels.

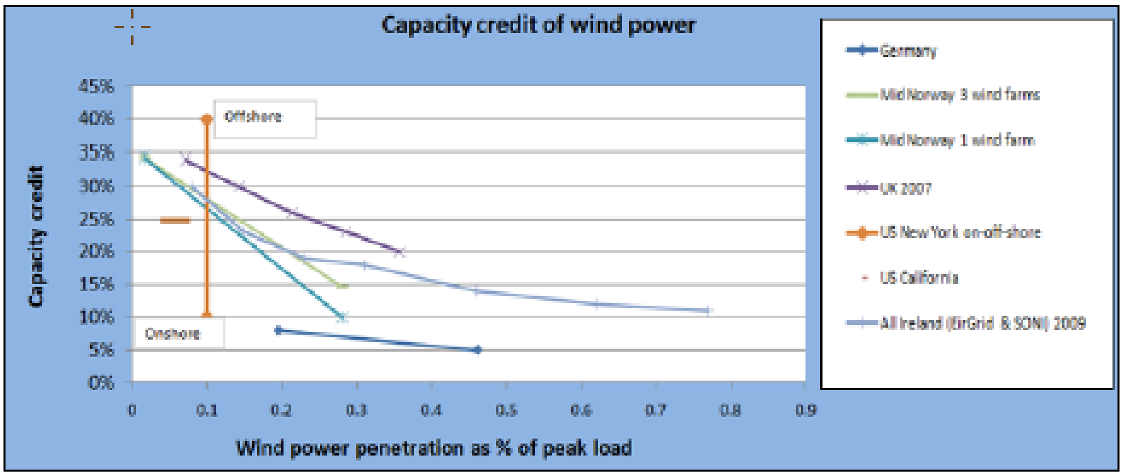

Figure 23 *Examples of the Capacity Credit of Wind Power*[260]

The level of wind capacity value is a matter of debate in some regions, due to the variability of wind power and its relationship with load. Utilities and other entities typically allocate some capacity value to wind power, although at a lower level than other energy technologies.[261] Generally, the capacity value of wind varies from 5% to 40%, with lower capacity values for wind in higher wind

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[259] A. Keane, M. Milligan, C. D'Annunzio, C. Dent, K. Dragoon, B. Hasche, H. Holttinen, N. Samaan, L. Soder and M. O'Malley, "Capacity Value of Wind Power," *IEEE PES Transactions on Power Systems* 26, no. 2, May 2011, 564-572.

[260] Hannele Holttinen, Peter Melbom, Antje Orths, Frans van Hulle, Bernhard Lange, Mark O'Malley, Jan Pierik, Bart Ummels, John Olav Tande, Ana Estanqueiro, Manuel Matos, Emilio Gomez, Lennart Söder, Goran Strbac, Anser Shakoor, João Ricardo, J. Charles Smith, Michael Milligan and Erik Ela, *Design and Operation of Power Systems with Large Amounts of Wind Power, Final Report, IEA Wind Task 25, Phase one (2006-2008)* (Finland: VTT, 2009), http://www.ieawind.org/AnnexXXV/PDF/Final%20Report%20Task%2025%202008/T2493.pdf.

[261] Michael Milligan and Kevin Porter, *Determining the Capacity Value of Wind: A Survey of Methods and Implementation*, NREL/CP-500-38062 (Golden, CO: NREL, May 2005), http://www.nrel.gov/docs/fy05osti/38062.pdf.

penetrations, a low capacity factor at times of peak load, or if wind power production has a negative correlation with load. Higher wind capacity values will be more present for lower wind penetration or high production at times of peak load.[262]

Because wind and solar generation are relatively new technological additions to the grid, techniques for calculating CV are still evolving. Methods for determining the capacity value of wind and solar can be divided into:

- Peak period methods, whereby system performance during a particular time of day and/or season (such as summer or winter peak) determines the capacity value; or
- Statistical techniques (such as ELCC) to estimate the change in LOLE when adding resources.

In addition, peak period methods may be discounted by a confidence interval, whereby the capacity value must occur at or more than a certain percentage of time. Less common, but still in place are simple single point estimates that are meant as placeholders until additional data is available or additional analysis can be conducted, or both. Portland General Electric, for instance, uses a capacity value of 5% for solar.[263]

Peak period methods have the advantage of being straightforward and may be useful when there is a lack of data on wind and solar generation, or load data, to more rigorously estimate the capacity value. Largely for these reasons, peak

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[262] Hannele Holttinen, Peter Melbom, Antje Orths, Frans van Hulle, Bernhard Lange, Mark O'Malley, Jan Pierik, Bart Ummels, John Olav Tande, Ana Estanqueiro, Manuel Matos, Emilio Gomez, Lennart Söder, Goran Strbac, Anser Shakoor, João Ricardo, J. Charles Smith, Michael Milligan and Erik Ela, *Design and Operation of Power Systems with Large Amounts of Wind Power, Final Report, IEA Wind Task 25, Phase one (2006-2008)* (Finland: VTT, 2009), http://www.ieawind.org/AnnexXXV/PDF/Final%20Report%20Task%2025%202008/T2493.pdf.

[263] Portland General Electric Company, *2009 Integrated Resource Plan* (Portland, OR: PGE, November 5, 2009), http://www.portlandgeneral.com/our_company/news_issues/current_issues/energy_strategy/docs/irp_nov2009.pdf.

period methods were initially adopted when wind and solar generation began being added to the grid, and it allowed grid operators to build up an operating record that could be used in more quantitative methods. Peak period methods have the disadvantage of incorporating only the peak hours when there may be other hours that could be of risk to reliability, such as during planned maintenance outages of large baseload generation. In addition, because substantial variation in annual capacity values are often observed, a long history of production data will be needed to approximate capacity value.[264] Earlier work shows that the capacity credit of wind can be approximated close to ELCC by measuring the capacity factor of wind during the top 1% to 10% of the top load hours.[265]

Multiple steps are required to determine the ELCC of a wind or solar plant. The LOLE is first determined without the wind or solar plant. A table of conventional generation capacity levels and forced outage probabilities is prepared, with the cumulative probabilities providing the LOLP. The table is used with at least one year's worth of hourly load time series data, and the LOLE is calculated. Loads can be adjusted to meet a desired LOLE target. The time series for the wind or solar plant output is considered negative load and is combined with the load time series. The LOLE is re-calculated and will be lower (better) than the targeted LOLE. The load data is then increased, and the LOLE recalculated until the target LOLE is met. The increase in peak load is the ELCC of the wind or solar plant.[266]

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[264] Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.

[265] Michael Milligan and Brian Parsons, "A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators," NREL/CP-440-22591, presented at Solar '97, Washington, D.C., April 27-30, 1997, http://cwec.ucdavis.edu/rpsintegration/library/NREL-CP-440-22591%20Mar97%20Milligan%20Parsons.pdf.

[266] A. Keane, M. Milligan, C. D'Annunzio, C. Dent, K. Dragoon, B. Hasche, H. Holttinen, N. Samaan, L. Soder and M. O'Malley, "Capacity Value of Wind Power," *IEEE PES Transactions on Power Systems* 26, no. 2, May 2011, 564-572.

ELCC requires a significant amount of load and wind data, and the availability and adequacy of such data can be an issue. In addition, because wind, solar and load are influenced by metrological conditions, care must be taken to ensure that the hourly profiles of wind, solar and load are taken from the same historical year to maintain the correlation with weather. Inter-annual variability will affect ELCC results as well, and multiple years of data are necessary to derive a long-term capacity value.[267] Recent work using ten years of wind data for the Republic of Ireland found that with one year of data, the wind ELCC can be estimated with an error of –30% to +20%, compared to a long-term capacity value. With four or five years of data, the variations are within 10% of the long-term capacity value.[268] Other parameters can affect ELCC calculations, such as hydro generation schedules (often correlated with load) and import-export schedules (also often correlated with load). Maintenance schedules for conventional generation plants can also affect ELCC results if the outages affect LOLP during shoulder seasons, and high levels of wind or solar generation occurs during that time.[269]

There is not as much available information on the capacity value of solar, in part because distributed and utility-scale solar are only now being developed in significant quantities. In general, solar will have higher capacity values if the solar generation is perfectly correlated with peak loads, and lower capacity values if the correlation with peak loads is not as strong, or if clouds or haze reduces solar output during peaks.[270] Solar will also have a higher capacity

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267 Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.

268 A. Keane, M. Milligan, C. D'Annunzio, C. Dent, K. Dragoon, B. Hasche, H. Holttinen, N. Samaan, L. Soder and M. O'Malley, "Capacity Value of Wind Power," *IEEE PES Transactions on Power Systems* 26, no. 2, May 2011, 564-572.

269 Ibid.

270 NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF1-2.pdf.

credit than wind where peak loads are driven by summer cooling demands. Conversely, the capacity credit of solar will be lower if peak load occurs in the evening. As with wind, the capacity credit of solar decreases with higher solar penetration levels.[271]

PJM uses a peak period method, whereby the capacity credit for wind and solar is based on the generator's capacity factor between 2:00 p.m. to 6:00 p.m. local prevailing time, from June 1 through August 31. The capacity credit is a rolling three-year average, with the most recent year's data replacing the oldest year's data. For new wind projects with insufficient wind generation data, PJM applies a "class average" capacity credit of 13% of nameplate capacity, to be replaced by the wind generator's capacity credit as noted earlier once the wind project is in operation for at least a year.[272] The class average for solar plants is 38% of nameplate capacity.[273]

Other RTOs that use a peak period method include ISO-NE, NYISO and IESO. NYISO has both a summer and winter capacity credit, with a summer capacity credit for existing wind projects determined by a wind plant's capacity factor between 2:00 p.m. and 6:00 p.m. during June, July and August from the previous year. A winter capacity credit for wind is determined by the capacity factor of wind between the hours of 4:00 p.m. and 8:00 p.m. during December, January and February from the previous year.[274] New onshore wind projects are assigned

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[271] Richard Perez and Thomas E. Hoff, "Energy and Capacity Valuation of Photovoltaic Power Generation in New York," Prepared for the Solar Alliance and the New York Solar Energy Industry Association, March 2008, http://www.asrc.cestm.albany.edu/perez/publications/Utility%20Peak%20Shaving%20and%20Capacity%20Credit/Papers%20on%20PV%20Load%20Matching%20and%20Economic%20Evaluation/Energy%20Capacity%20Valuation-08.pdf.

[272] PJM, *PJM Manual 21: Rules and Procedures for Determination of Generating Capability, Revision: 09* (Norristown, PA: PJM, May 1, 2010), http://pjm.com/~/media/documents/manuals/m21.ashx.

[273] PJM, *PJM Manual 18: PJM Capacity Market, Revision: 16* (Norristown, PA: PJM, September 27, 2012), http://www.pjm.com/~/media/documents/manuals/m18.ashx.

[274] NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF1-2.pdf.

a summer capacity credit of 10% and a winter capacity credit of 30% of their nameplate capacity. New offshore wind projects are assigned a capacity credit of 38% of their nameplate capacity for both summer and winter.[275] For resources qualified in its Forward Capacity Market, ISO-NE also provides a capacity credit for winter and summer, with the summer capacity credit calculated by the rolling average of the median net output of the variable renewable energy generator between 1:00 p.m. and 6:00 p.m. from June through September for the previous five years and a winter capacity credit from the median output between 5:00 p.m. and 7:00 p.m. from October through May for the past five years. New variable energy generators have to supply at least one year's worth of on-site data such as summer and winter wind speed data for wind, water flow data for run-of-the-river hydro, and irradiance data for solar facilities.[276]

IESO also uses a peak period method, measuring wind output during the top five contiguous daily peak demand hours for winter and summer, and for monthly shoulder periods. Two data sources are used – simulated data over a 10-year period, and wind plant data from 2006 onward. The IESO model selects the lesser value of the two data sets for winter and summer and shoulder periods. For its 18-month projections and seasonal assessments, IESO uses median values for wind for the winter and summer seasons and shoulder period months. For annual resource adequacy reviews, IESO calculates probability distributions for the winter and summer seasons and shoulder period months that are inputted into a GE-MARS model. That model then randomly generates a probability value to determine the capacity value of wind.[277]

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[275] Abigail Krich, "Advancing Renewable Alternatives," FERC/RTO Training Session, Institute for Policy Integrity, New York University School of Law, June 15, 2011, http://policyintegrity.org/documents/Advancing_Demand-side_and_Renewable_Alternatives.pdf.
[276] Jennifer Rogers and Kevin Porter, "Wind Power and Electricity Markets," Utility Wind Integration Group, November 2011, www.uwig.org/fercwork1204/windinmarketstable.pdf.
[277] NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF1-2.pdf.

Other utilities outside of RTOs also apply peak period methods, or variations thereof. Idaho Power estimates a capacity value for wind of 5%, based on the capacity factor of wind during the utility's summer peak times between 3:00 p.m. and 7:00 p.m.[278] Public Service of New Mexico (PNM) assigns a 5% capacity value to wind and a 55% capacity value to PV, based on contribution to PNM's summer peak.[279] Tri-State Generation and Transmission Association provides wind a 2% capacity value and between 20% to 57% for solar PV, based on expected capacity at Tri-State's peak.[280] Figure 24 presents some of this information.

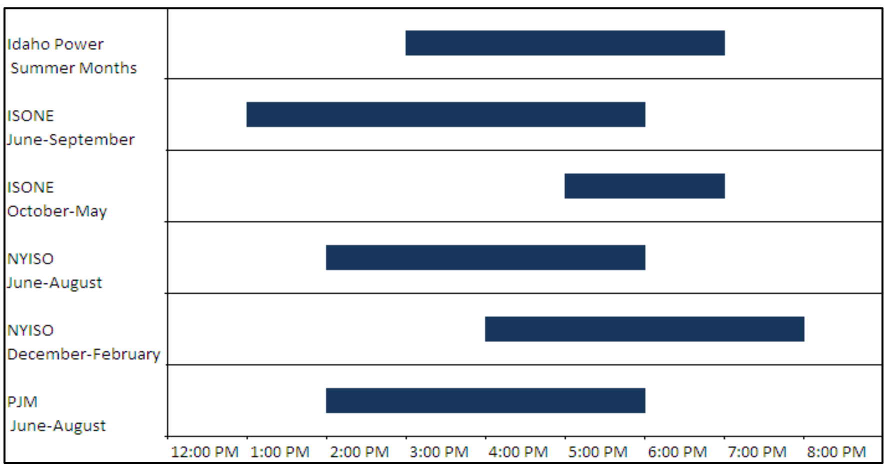

Figure 24 *Selected Time Periods Used for Peak Period Capacity Value Estimation Methods in the United States*[281]

Others apply the peak period method but apply an exceedance factor. SPP assigns a monthly capacity value of wind to the output level that a wind plant meets or exceeds in 85% of the top 10% of load hours in the month. The capacity

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[278] Idaho Power, *2011 Integrated Resource Plan* (np: Idaho Power Company, June 2011), http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2011/2011IRPFINAL.pdf.

[279] PNM Integrated Resource Planning Department, *Electric Integrated Resource Plan: 2011-2030*, Public Service Company of New Mexico (np: July 2011), http://www.pnm.com/regulatory/pdf_electricity/irp_2011-2030.pdf.

[280] Tri-State Generation and Transmission Association, *Integrated Resource Plan/Electric Resource Plan for Tri-State Generation and Transmission Association, Inc.* (np: November 2010), http://www.tristategt.org/ResourcePlanning/documents/Tri-State_IRP-ERP_Final.pdf.

[281] Jennifer Rogers and Kevin Porter, *Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States*, September 2010-February 2012 (Golden, CO: NREL, March 2012), http://www.nrel.gov/docs/fy12osti/54338.pdf.

values for wind plants in SPP are typically about 10% of rated capacity. The California PUC determines capacity reserve requirements in California, and the capacity value for wind is based on three years of plant output that equals or exceeds 70% of the values occurring between 4:00 p.m. and 9:00 p.m. for January through March and November and December, and between 1:00 p.m. and 6:00 p.m. from April through October.[282] The revised California RPS requires the California PUC to do an ELCC study for wind and solar.[283] BPA uses a summer and winter capacity value of zero for wind after examining monthly capacity factors for wind between 2003 and 2008 and only accepting values that were exceeded 85% and 95% of the time.[284]

ELCC methods are being applied, although they can show varying results if conducted for multiple years due to variations in annual wind and solar resources. MISO determines an ELCC in wind annually and found a capacity credit of 8% in 2010, 12.9% in 2011 and 14.9% in 2012.[285] ERCOT assigns an 8.7% capacity contribution to wind based on ELCC methods but plans to update its ELCC analysis by late 2012.[286] Public Service of Colorado (PSCo), a subsidiary of Xcel Energy, assigns a capacity value of 12.5% to wind based on earlier ELCC work. PSCo also performed a solar ELCC analysis for three sites in Colorado with hourly load data and estimated solar production for 2004 and 2005. The

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282 NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF1-2.pdf.

283 California Legislative Counsel, *SBX1*, bill to amend the California RPS, February 2011, http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html.

284 NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF1-2.pdf.

285 MISO Loss of Load Expectation Working Group and Regulatory and Economic Studies Department, *Planning Year 2012 LOLE Study Report* (np: MISO, November 18, 2011), https://www.misoenergy.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report.pdf.

286 Jennifer Rogers and Kevin Porter, *Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States*, September 2010-February 2012 (Golden, CO: NREL, March 2012), http://www.nrel.gov/docs/fy12osti/54338.pdf.

average solar capacity value ranged from 59%-63% for fixed panel photovoltaic, 69-75% for single-axis tracking PV, and 68-81% for solar thermal parabolic trough. Solar thermal plants with thermal storage were not studied, as it was assumed the storage would increase the capacity value to 100%.[287] For its 2011 integrated resource plan that is under regulatory review, Xcel used a 55% capacity value for a generic PV plant.[288] Based on an ELCC analysis of chronological hourly wind data for different regions, BC Hydro assumes a capacity value of 24% for onshore and offshore wind and solar.[289]

Hydro-Québec used a Monte Carlo simulation model to chronologically match hourly wind generation and load data for a time frame spanning 36 years. The wind data was derived from meteorological data from weather stations, and then extrapolated to particular wind sites. The data was augmented through the assessment of 14 extreme cold weather events, using high resolution numeric weather prediction models. Hydro-Québec determined wind's capacity credit for winter is 30% of nameplate capacity and less for the summer.[290]

Table 17 presents the results of these and other studies on the capacity value of wind and solar, and the methods used.

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[287] Xcel Energy, *An Effective Load Carrying Capability Analysis for Estimating the Capacity Value of Solar Generation Resources on the Public Service Company of Colorado System*, February 2009.

[288] Xcel Energy, *Public Service Company of Colorado 2011 Electric Resource Plan: Volume II Technical Appendix* (np: October 2011), http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/Exhibit-No-KJH-1-Volume-2.pdf.

[289] Jennifer Rogers and Kevin Porter, *Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States*, September 2010-February 2012 (Golden, CO: NREL, March 2012), http://www.nrel.gov/docs/fy12osti/54338.pdf.

[290] NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF1-2.pdf.

Table 17 *Wind and Solar Capacity Value in the United States*[291]

REGION/UTILITY	METHOD	NOTE
APS	LOLE	Average capacity value from 2003 to 2007 for a 100 MW installation of distributed solar generation: • Solar hot water technologies: 44.6% • Daylighting: 64.4% to 65.5%, depending on penetration levels • Residential PV: 33.4% to 45.2%, depending on the tilt and direction of the technology • Commercial PV, south-facing with a 10° tilt: 47.4% • Commercial PV, 0° tilt and north-south single-axis tracking: 70.2%.
BC Hydro	ELCC	24% for onshore and offshore wind. Solar assumed to have the same value as onshore wind. ELCC method using wind output-duration tables based on synthesized chronological hourly wind data for different regions.
Bonneville Power Administration	Exceedance	0%. Summer monthly capacity factor between 2003 and 2008, 85% and 95% exceedance.
City of Toronto Case Study	Various	Garver ELCC approximation for solar PV ranged from 23% to 37%, depending on location, orientation and penetration level. Two other methods based on time period and peak load estimated a capacity value of 40% for solar PV.
CPUC/CAISO	Exceedance	70% exceedance factor. Capacity values set monthly. Uses monthly hourly wind and solar production data from previous three years between 4:00 p.m. and 9 p.m. January through March and November through December and between 1:00 p.m. and 6:00 p.m. April through October. Diversity benefits added to capacity value.
Eastern Wind Integration and Transmission Study	ELCC	Ranged from 16.0% to 30.5% (with existing transmission system) and from 24.1% to 32.8% (with a transmission overlay).
ERCOT	ELCC	ELCC based on random wind data, compromising correlation between wind and load (8.7%). New ELCC study began in 2012.
Hydro-Québec	Monte Carlo Simulation	30%. Monte Carlo model chronologically matches wind and load data for 36-year period.
Idaho Power	Peak Period	5% capacity value for wind during peak load that generally occurs in summer months between 3:00 p.m. and 7:00 p.m.

[291] Jennifer Rogers and Kevin Porter, *Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States*, September 2010-February 2012 (Golden, CO: NREL, March 2012), http://www.nrel.gov/docs/fy12osti/54338.pdf.

Table 17 *Wind and Solar Capacity Value in the United States (continued)*

REGION/UTILITY	METHOD	NOTE
ISO-NE	Peak Period	For existing wind: rolling average of median net output 1:00 p.m. to 6:00 p.m. June through September for past five years for summer capacity credit; 5:00 p.m. to 7:00 p.m. October through May for past five years for winter capacity credit. For new wind: based on summer and winter wind speed data, subject to verification by ISO-NE and adjusted by operating experience.
MISO	ELCC	12.9% for 2011 planning year; 14.7% for 2012 planning year.
NorthWestern Energy	Peak Period	Assigned capacity value of 0 based on wind generation during top 100 load hours from January 2006 through December 2010.
NPPD		17% (method not stated).
NREL Study	Various	CSP with no TES: 45% to 95%, depending on SM and location. CSP with TES: usually above 90% in all cases; used capacity-factor based method.
NW Resource Adequacy Forum	Peak Period	5% sustained wind ELCC, 30% annual wind ELCC. Being studied further for potential revision.
NY PV Study	ELCC and Solar Load Control Capacity	Solar PV capacity value varied by penetration level, location and orientation. ELCC method: ranged from 31% to 90%. Solar Load Control Capacity method: ranged from 32% to 88%.
NYISO	Peak Period	Existing wind: capacity factor between 2:00 p.m. and 6:00 p.m. June through August and between 4:00 p.m. and 8:00 p.m. December through February. New onshore wind: assigned summer capacity credit of 10%, winter capacity credit of 38% for both winter and summer.
Ontario IESO	Peak Period	Seasons and monthly shoulder periods wind output from the top five contiguous daily peak demand hours taken for two data sets (ten years simulated wind data and wind production data since 2006). Smaller capacity value selected for each season and shoulder period month.
PacifiCorp	ELCC	Sequential Monte Carlo method. In July 2008, averaged about 8.53% per 100 MW of nameplate capacity (decreased as the amount of wind increased).
PGE	Rule of Thumb	5% for wind and solar. To be modified as more data becomes available.
PJM	Peak Period	Existing wind and solar: June through August, hour ending 2:00 p.m. to 6:00 p.m. local time, capacity factor using 3-year rolling average. New wind assigned 13%; fold in actual data when available. New solar assigned 38%; fold in actual data when available.
PNM	Peak Period	Wind 5%, solar 55%. Assessed by the amount of capacity supplied at peak.

Table 17 *Wind and Solar Capacity Value in the United States (continued)*

REGION/UTILITY	METHOD	NOTE
PSCo/Xcel	ELCC	For wind, 12.5% of rated capacity based on 10-year ELCC study. Capacity credit set at 55% for utility-scale PV plant.
SPP	Peak Period	Top 10% loads/month; 85th percentile.
Tri-State	Peak Period	Wind: <1 MW of peak hour capacity for each 50 MW block. Peak hour capacity value for PV solar power ranged from 20% to 57%.
WWSIS	LOLE/LOLP	Wind: Between 10% and 15% at 10%, 20% and 30% penetration. Solar PV: Between 25% and 30% at 1%, 3% and 5% penetration. CSP with TES: Between 90% and 95% at 1%, 3% and 5% penetration.

9. ACTIVE POWER MANAGEMENT OF VARIABLE POWER GENERATION

9.1. MINIMUM LOAD

Several variable generation integration studies have determined that at high levels of wind generation, minimum load issues will become more pronounced; i.e., there will be more generation (including wind) than needed to meet load. For example, a GE study in 2007 for the California Energy Commission found that 20% of the hours in the 33% renewables scenario resulted in a net load minimum being lower than the load-alone minimum. From a planning perspective, it is probably not economical to design the grid to meet the absolute net load minimum but rely on other active power management measures discussed in this section.

Some areas are already having problems with minimum load and wind generation. A much discussed example involved BPA in 2011 and 2012. Wind capacity in BPA grew from 250 MW in 2005 to over 4,000 MW in 2012. In spring 2011, high wind generation was combined with a large and sustained runoff from snow melt that produced more hydropower than usual. As of June 2011, estimated stream flows on the Columbia River system were at 136% or more of normal at numerous dams through the summer. As a result, BPA had far more generation than load for some hours in spring 2011. BPA implemented what it called the environmental redispatch policy on an interim basis in May 2011. The policy allowed BPA to curtail wind and thermal power generation in lieu of spilling excess water over the dams, and for BPA to provide replacement power at $0/MWh. BPA will not sell power at negative prices. BPA curtailed about 100,000 MWh of wind generation in 2011, and a smaller amount in 2012.[292] Upon complaint from several wind generators, FERC determined BPA's practice

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[292] Ros Davidson, "Hydropower Oversupply to Cost Wind Less Than Feared," *Windpower Monthly*, July 25, 2011, http://www.windpowermonthly.com/news/1081668/Hydropower-oversupply-cost-wind-less-feared/.

violated past FERC orders, the wind generators' existing interconnection contracts, and their associated firm transmission rights. In early 2012, FERC ruled that BPA was not in compliance with open access transmission requirements and ordered BPA to file new transmission tariff provisions.[293]

HELCO experiences periods of minimum load with high amounts of renewable energy. HELCO brings dispatchable units to minimum levels, accounting for the need for down-reserves, and will at times curtail wind, geothermal and run-of-river hydroelectric resources. HELCO has also defined a minimum down-reserve to be determined by the largest single contingency loss of load.[294]

SPP experiences periods of minimum generation in spring and fall of each year, which coincides with high wind output. For this reason, SPP decided to have separate regulation up and regulation down reserves.[295] NYISO has not experienced high wind and minimum load issues to date. If wind is curtailed, NYISO reports that it is because of ramp limitations or other constraints where wind might have the most impact on the constraint or be the most economical solution.[296] ERCOT said that because they can schedule and dispatch wind, they can manage high wind and minimum load events by moving wind to lower output levels (a.k.a. curtailment).[297] CAISO reports that wind tends to peak between midnight and 1:00 a.m. and minimum load is usually around 4:00 a.m., so CAISO has not had issues with minimum load and wind yet. CAISO is expecting over-generation during the day by 2020 with high solar and moderate wind.[298]

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[293] Ros Davidson, "Wind Project Owners Act to Stop Nightly Curtailments," *Windpower Monthly*, June 27, 2011, http://www.windpowermonthly.com/news/1076810/Wind-project-owners-act-stop-nightly-curtailments/?DCMP=ILC-SEARCH.

[294] NERC, *IVGTF Task 2.4 Report, Operating Practices, Procedures and Tools* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-4.pdf.

[295] Jason Smith, SPP, Personal Communication, June 26, 2012.

[296] David Edelson, NYISO, Personal Communication, June 26, 2012.

[297] David Maggio, ERCOT, Personal Communication, June 26, 2012.

[298] Clyde Loutan, CAISO, Personal Communication, June 26, 2012.

9.2. CURTAILMENT PRACTICES

Past wind integration studies in the United States have stated that at higher levels of wind penetration, wind generation may need to be curtailed for a small number of hours per year, such as during periods of low demand and high wind production, or to decrease the rate of upward ramping from wind plants.

Wind curtailment is presently occurring in some regions and countries in large part because of transmission constraints.[299] In Texas alone, nearly 8% of potential wind generation was curtailed in 2011. Xcel Energy estimated that 2.6% of wind generation in its service territories was curtailed in 2011, a decrease from 3.4% in 2010. MISO (excluding Xcel Energy's service territory within MISO) also experienced decline in the amount of wind generation curtailed in 2011, with curtailment estimated at 3% compared to 4% in 2010. The amount of wind curtailment just in these samples lowered the national capacity factor of wind in the United States by 1-2% in 2011 (see Table 18).[300] Although data is scarce, various levels of wind curtailment also occurred in China, Germany, Ireland and Spain, as discussed below.[301]

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[299] Jennifer DeCesaro and Kevin Porter, "Wind Energy and Power System Operations: A Review of Wind Integration Studies to Date," *Electricity Journal*, December 2009, www.nrel.gov/docs/fy10osti/47256.pdf.

[300] Ryan Wiser and Mark Bolinger, *2010 Wind Technologies Market Report* (np: U.S. DOE, June 2011), http://eetd.lbl.gov/EA/EMP/reports/lbnl-4820e.pdf.

[301] Kevin Porter, Jennifer Rogers and Ryan Wiser, "Update on Wind Curtailment in Europe and North America," Presentation before the Energy Foundation's China Sustainable Energy Program, June 2011.

Table 18 *Selected Examples of Wind Curtailment in GWh in the United States, 2007-2011 and as % of Potential Wind Generation*[302]

	2007	2008	2009	2010	2011
Electric Reliability Council of Texas (ERCOT)	109 (1.2%)	1,417 (8.4%)	3,872 (17.1%)	2,067 (7.7%)	2,622 (8.5%)
Southwestern Public Service Company (SPS)	N/A	0 (0.0%)	0 (0.0%)	0.9 (0.0%)	0.5 (0.0%)
Public Service Company of Colorado (PSCo)	N/A	2.5 (0.1%)	19.0 (0.6%)	81.5 (2.2%)	63.9 (1.4%)
Northern States Power Company (NSP)	N/A	25.4 (0.8%)	42.4 (1.2%)	42.6 (1.2%)	54.4 (1.2%)
Midwest Independent System Operator (MISO), less NSP	N/A	N/A	250 (2.2%)	781 (4.4%)	657 (3.0%)
Bonneville Power Administration (BPA)	N/A	N/A	N/A	4.6* (0.1%)	128.7* (1.4%)
Total Across These Six Areas:	**109 (1.2%)**	**1,445 (5.6%)**	**4,183 (9.6%)**	**2,978 (4.8%)**	**3,526 (4.8%)**

*A portion of BPA's curtailment is estimated assuming that each curtailment event lasts for half of the maximum possible hour for each event.

So far, wind curtailment is can be roughly organized into six types:

- Interconnection agreements, whereby as a condition of interconnection, wind generators may be required to curtail generation upon request if transmission constraints or grid conditions dictate;
- As part of power purchase agreements. Xcel Energy, for instance, has negotiated a set amount of wind curtailment at no cost or reduced cost to the purchasing utility for some of its wind projects in Colorado;
- Market-based bidding, which is where PJM fits in. Both PJM and NYISO allow wind generators to bid a price that includes their willingness to curtail operations. Because of the value of the federal production tax credit and renewable energy credits, the wind bids may be zero or even negative;
- Maximum daily operating limits, usually on an area-specific basis when there is a concentration of wind plants developed in a single transmission constrained region. Until 2009, ERCOT used day-ahead load projections to calculate and assign operating limits to the wind plants for the next day in West Texas;

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302 Ryan Wiser and Mark Bolinger, *2010 Wind Technologies Market Report* (np: U.S. DOE, June 2011), http://eetd.lbl.gov/EA/EMP/reports/lbnl-4820e.pdf.

- Differentiation by technology, whereby wind turbines without advanced control capabilities would be curtailed first; and
- Curtailing after available reserves are reduced to a specified level. BPA requires wind generators to reduce schedules to the lower of their scheduled amount or actual generation, once 90% of balancing reserves have been utilized.

Compensation for curtailment similarly varies. Until ERCOT transitioned to its LMP-based market in 2010, it made out-of-merit energy payments for curtailments in real-time. Southern California Edison provides make-whole payments for energy, as does Germany and Ireland. For curtailments beyond what Xcel Energy negotiates in their power purchase agreements, the company provides make whole payments for both fixed and variable wind plant costs in Minnesota and make whole payments, including the Production Tax Credit, for curtailments in Colorado that are above the contracted amounts.[303] In Spain, compensation for real-time curtailments is a percentage of the wholesale price of electricity, currently set at 15%.[304] No compensation is provided by Portugal and most (if not all) of the RTOs in the U.S., including PJM.

A well-known example of wind curtailment occurred when BPA curtailed over 100 GWh of wind power in 2011 and another 20 GWh in April and May of 2012.[305] Amid managing high wind generation, requirements to manage hydro production to follow dissolved oxygen levels to preserve salmon populations under the Endangered Species Act, low load, and reluctance to allow negative pricing, BPA curtailed thermal and wind generation, and replaced it with hydro prices at $0/MWh in 2011. In December that same year, FERC ruled that BPA's interruption of firm transmission service to others without interrupting BPA's

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[303] Sari Fink, Christina Mudd, Kevin Porter and Brett Morgenstern, *Wind Energy Curtailment Case Studies, May 2008-May 2009* (Golden, CO: NREL, October 2009), www.nrel.gov/docs/fy10osti/46716.pdf.

[304] Kevin Porter and Sari Fink, "Examples of Wind Curtailment," Presentation before the Energy Foundation's China Sustainable Energy Program, June 2010.

[305] Hilary Milam, "BPA May Not Curtail Wind Again in 2012," *Megawatt Daily*, June 4, 2012.

own transmission service violated Federal Power Act requirements.[306] In March 2012, BPA filed with FERC its proposed Oversupply Management Protocol for thermal and wind power, to be in effect until March 2013. The protocol applies to all generators with 3 MW or more of capacity in BPA's balancing area. Each generator has to submit minimum generation information to BPA and cost-of-curtailment to an independent evaluator. If minimum load situations emerge, BPA will dispatch thermal generation to minimum generation levels. After that, BPA will inform wind generators that they must reduce to minimum levels. Generators have to respond to BPA's orders to within 4 MW of their minimum generation levels within ten minutes, and will be penalized if they fail to do so. BPA will again replace curtailed generation with free hydro and will reimburse wind generators for the value of lost production tax credits and renewable energy credits.[307] BPA has proposed an oversupply management charge rate to recover its costs for reimbursing wind generators that will be applied equally to both wind generators that purchase transmission from BPA and to BPA's hydropower customers.[308]

For PJM, wind curtailment may occur during times of transmission constraints or light load events. For transmission constraints, wind can be curtailed along with other generation based on $/MW impact for transmission constraints. PJM uses economic bids for determining curtailment due to light load events, whereby generators submit emergency (usually zero for wind, but wind generators can submit a greater value) and economic minimum and maximum facility output. PJM requires generators to adjust their output level when operating in the range between the economic minimum and maximum facility output. Generators cannot submit an economic minimum in the real-time energy market that exceeds the greater of the resource's physical minimum operating level or the

[306] Hilary Milam, "Northwest Studies Next Steps after FERC's Rejection of BPA 'Environmental Redispatch'," *Electric Utility Week*, December 19, 2011.
[307] Hilary Milam, "BPA Sets Out Rules for Oversupply Compliance," *Megawatt Daily*, March 9, 2012.
[308] Hilary Milam, "BPA Progresses on Oversupply Rate Case," *Megawatt Daily*, May 10, 2012.

level of its capacity interconnection rights. For wind plants, the capacity injection rights are typically equal to 13% of maximum facility output. PJM does not keep track of how much wind has been curtailed but reports that wind has been curtailed during minimum load periods.

Intermittent Resources are curtailed out of market in MISO for transmission congestion and minimum generation events, with the order of curtailment based on the impact on the transmission constraint and priority of transmission service. MISO will curtail variable and other generation during minimum generation events after using the emergency range (between energy minimum and energy maximum) of conventional generation first. As noted earlier, MISO is converting wind generators from Intermittent Resource status in MISO to Dispatchable Intermittent Resources, and managing curtailment through dispatch rather than out-of-market actions.

NYISO handles wind curtailment through real-time economic dispatch, with the centralized forecast used as the upper limit. Over-generation charges may apply if wind is dispatched down and does not respond, but wind is exempt from under-generation charges, up to 3,300 MW of installed wind capacity. During constrained operations, wind plants must follow NYISO's re-dispatch signal and meet the basepoint output limit within five minutes. Outside of a 3% error, NYISO will impose non-compliance penalties for capacity above the basepoint multiplied by the regulation clearing price.

As of December 1, 2011, AESO temporarily limits real power production from wind plants when system conditions are such that the total amount of available real wind power cannot be accommodated and all other control methods have been exhausted. In contrast, CAISO does not currently require intermittent resources to respond to real-time curtailment requests except for transmission overloads.[309]

[309] Ed DeMeo, Kevin Porter and Charlie Smith, *Wind Power and Electricity Markets* (Reston, VA: Utility Wind Integration Group, 2011), www.uwig.org/fercwork1204/windinmarketstable.pdf.

9.3. INTERNATIONAL EXAMPLES OF CURTAILMENT

In China, wind curtailments in some regions (particularly in Inner Mongolia and in the north, northeastern and northwestern regions) can be severe at times, sometimes to as low as 20% of potential wind production because of transmission constraints and coal-fired CHP plants that are used to meet heat demands and are relatively inflexible.[310]

In Germany, wind curtailment can occur on both the distribution and transmission grids since wind capacity is installed on both. Distribution grid operators are allowed to curtail wind generation if no other alternative is available to maintain reliability; wind projects are compensated by the lost value of the feed-in tariff.[311] In 2009, 74 GWh were curtailed out of a total of 37,809 GWh generated from wind projects on distribution lines in Germany, or about 0.2% of total wind production. TSOs in Germany can curtail supply or demand if grid security is jeopardized, and wind projects are not compensated if they are curtailed. No wind curtailment was initiated by TSOs in 2009.

Germany implemented curtailment rules in 2010 whereby if load falls below 60% of the peak load of the previous year, while wind production is above 60% of installed wind capacity, wind curtailment is allowed. In addition, beginning in 2011, TSOs could place limited bids in the spot market's second auction, which occurs if the clearing price is below €-150 EUR/MWh. The four TSOs in Germany divide their total renewable energy in-feed under Germany's feed-in law, and

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[310] Kat Cheung, *Integration of Renewables: Status and Challenges in China* (Paris: International Energy Agency, 2011), http://www.iea.org/papers/2011/Integration_of_Renewables.pdf.

[311] H. Holttinen, A.G. Orths, P.B. Eriksen, J. Hidalgo, A. Estanqueiro, F. Groome, Y. Coughlan, H. Neumann, B. Lange, F. van Hulle and I. Dudurych, "Currents of Change," *IEEE Power and Energy* 9, no. 6, November/December 2011, 47-49.

place ten random limited bids between €-150 and €-350 EUR/MWh.[312] Even with these changes, wind curtailment increased sharply in 2010 to 150 GWh.[313]

In Spain, wind curtailment totaled 315,230 MWh in 2010 (~0.7% of potential wind generation), with 64% attributed to over-generation (i.e., too much wind generation and not enough load); 27% for insufficient distribution line capacity, and 9% for insufficient transmission line capacity.[314] Wind curtailment appears to be less in 2011 at least through October, with 48,276 MWh of wind generation curtailed or about 0.14% of wind production. Furthermore, over-generation was less of a factor for curtailment in 2011. Insufficient distribution accounted for 56% of the curtailment in 2011, followed by insufficient transmission with 27%, and over-generation accounting for the remainder.[315]

In Spain, variable generation receives 15% of the projected energy payment if it is curtailed in real-time to maintain reliability.[316] If REE, the grid operator in Spain, must curtail renewable non-manageable generation such as wind and solar, then generators must adapt their production to the given dispatch point within 15 minutes. If there are more than three reductions in a month or more than ten reductions in a year, then REE must develop an investment plan to address the constraint.[317]

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312 Kevin Porter, Jennifer Rogers and Ryan Wiser, "Update on Wind Curtailment in Europe and North America," Presentation before the Energy Foundation's China Sustainable Energy Program, June 2011.

313 German Wind Energy Association, "Wind Power Losses from Grid Disconnections Up by as Much as 69% in Germany," January 11, 2012, http://www.wind-energie.de/en/infocenter/articles/wind-power-losses-grid-disconnections-much-69-percent.

314 Kevin Porter, Jennifer Rogers and Ryan Wiser, "Update on Wind Curtailment in Europe and North America," Presentation before the Energy Foundation's China Sustainable Energy Program, June 2011.

315 Kilian Rosique, Asociación Empresarial Eólica, Personal Communication, December 23, 2011.

316 NERC, *IVGTF Task 2.4 Report: Operating Practices, Procedures and Tools* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-4.pdf.

317 Jorge Hidalgo López, "Wind Development and Integration Issues and Solutions," Presentation before the Northwest Wind Integration Forum, Portland, OR, July 29-30, 2010, http://www.nwcouncil.org/energy/wind/meetings/2010/07/WIF%20TWG%20072910%20Hidalgo%20072610.pdf.

Curtailment has also increased in Ireland. In 2008, wind projects were curtailed only three times but increased to 0.2% of wind energy production in 2009 and 1.2% in 2010. Wind plants are compensated for lost production. The jump in curtailment for 2010 was attributed to higher-than-usual capacity factors for wind plants in the second half of 2010, an increase in wind capacity of about 200 MW, and the outage of the sole pumped storage plant in July 2010.[318]

Curtailment is significantly less in other countries with high wind penetration by energy contribution. Denmark has had little wind curtailment, thanks to its strong interconnections with Germany and Norway and the availability of hydro resources in Nordic Countries, a new 600 MW connection between Eastern and Western Denmark. Onshore wind turbines that are no longer applicable for subsidies in Denmark are generally automatically curtailed when the price is zero or negative. Newer offshore wind projects are not eligible for a subsidy when spot prices are zero or negative.[319]

There has not been any curtailment in Portugal for 2009 and 2010, partly because only contracts signed after 2007 allow curtailment, and then only for technical reasons, with no compensation paid to generators. Portugal has integrated its wind successfully thanks to a flexible resource mix featuring hydro that is used to balance the wind power, a grid code that requires certain capabilities from wind projects (discussed further below), using phase shift transformers and dynamically rating transmission lines,[320] exporting wind for free to Spain in 2009

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[318] H. Holttinen, A.G. Orths, P.B. Eriksen, J. Hidalgo, A. Estanqueiro, F. Groome, Y. Coughlan, H. Neumann, B. Lange, F. van Hulle and I. Dudurych, "Currents of Change," *IEEE Power and Energy* 9, no. 6, November/December 2011, 47-49.

[319] Edward James-Smith, Ea Energianalyse, Personal Communication, May 24, 2011.

[320] H. Holttinen, A.G. Orths, P.B. Eriksen, J. Hidalgo, A. Estanqueiro, F. Groome, Y. Coughlan, H. Neumann, B. Lange, F. van Hulle and I. Dudurych, "Currents of Change," *IEEE Power and Energy* 9, no. 6, November/December 2011, 47-49.

and 2010, relying on pumped hydro in Portugal, and limiting imports from Spain.[321]

9.4. FREQUENCY RESPONSE

Changes in system frequency are caused by imbalances between load and generation. Grid codes or interconnection requirements for new generation usually require conventional thermal or hydro generators to have a speed governor system to adjust the amount of mechanical power being delivered to the turbine-generator drive-train through controlling fuel or steam flows. Another contributor to frequency response for synchronous generators is inertia. Inertial response is inherent to synchronous generators and is rarely discussed in existing grid codes – it is basically an expected function of synchronous generators.[322]

A topic of industry and academic discussion is whether the displacement of synchronous generation by asynchronous generation (such as wind and PV plants) could result in reduced inertia and primary frequency response, leading to larger frequency excursions. As the contribution of wind power by energy reaches a pivotal point (e.g., 10% by energy penetration), the displacement of conventional generators by wind power could reduce the effective primary or governor response and the inertia of the system. That, in turn, could contribute to large changes in frequency, particularly on isolated systems or in periods of low load. This should not be as much of a concern for large grids such as PJM with extensive external interconnections. The current U.S. grid code for wind power does not specifically address frequency response.[323]

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[321] Kevin Porter, Jennifer Rogers and Ryan Wiser, "Update on Wind Curtailment in Europe and North America," Presentation before the Energy Foundation's China Sustainable Energy Program, June 2011.

[322] Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.

[323] Ibid.

To date, there have not been any inertia-related events or frequency control issues on larger and well-connected grids.[324] The discussion of frequency response and variable generation occurs in a larger context of the reported decline in the availability of frequency response from generators. Historically, nearly all generators were relied upon to provide frequency response, but that has changed as nuclear plants, most wind turbines in North America, and newer natural gas plants do not provide governor response. In addition, other generators that could provide governor response are operated in such a way (e.g., at maximum capability) that does not allow for providing governor response. Therefore, the prospect that the addition of variable generation which could displace conventional generation that provides frequency response and inertia response has prompted industry and academic discussion. A report prepared by Lawrence Berkeley National Laboratory for FERC found that that the integration of variable generation in the United States is not related to nor is a contributor to the decrease in the quality of frequency control. That same study did find that higher levels of variable generation could result in 1) lower system inertia that may increase the requirement for primary frequency control reserves; 2) displacement of conventional generation that provides primary frequency control reserves; 3) affect the location of primary frequency control reserves, as re-dispatch of demand and supply resources may contribute to transmission congestion that precludes delivery of frequency response reserves; and 4) impose increased requirements on secondary frequency control reserves.[325] Another review said the concern with frequency response, at least for the Eastern

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[324] Ecar Energy, *Wind Integration in Electricity Grids: International Practice and Experience*, (np: Australian Energy Market Operator, October 2, 2011), http://www.aemo.com.au/planning/0400-0049.pdf.

[325] Joseph H. Eto, John Undrill, Peter Mackin, Ron Daschmans, Ben Williams, Brian Haney, Randall Hunt, Jeff Ellis, Howard Illian, Carlos Martinez, Mark O'Malley, Katie Coughlin and Kristina Hamachi LaCommare, *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation* (np: Lawrence Berkeley National Laboratory, December 2010), http://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf.

Interconnection, is not an inertial issue but from operating practices in providing primary and secondary control of generation.[326]

Another review of frequency response under high levels of variable generation was done by GE for CAISO. The study mostly focused on two cases: a winter low-load and high-wind case, and a weekend morning high-wind and high-solar case. Wind and solar penetration for these two cases was 37% (11 GW) and 50% (15 GW). The study also assumed that some thermal plants in California would be retired because of once-through-cooling regulations. Most of the simulations concentrated on the trip of two units at the Palo Verde Nuclear plant, the largest loss-of-generation event in WECC at 2,690 MW. The study determined that none of the cases, even with high levels of wind and solar generation, resulted in under-frequency load shedding or stability problems. Several other conclusions were also reached in the study:

- The study implicitly assumed that secondary reserves (regulation and load following) are available to manage the variability of wind and solar generation. If secondary reserves are not available, then the amount of primary frequency response capability may decrease before big events take place.
- Less than one-third of committed generation contributes to primary frequency response under some operating conditions.
- New market mechanisms will be needed in the future to ensure sufficient supply of primary frequency response capability at high levels of wind and solar generation.[327]

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326 Ecar Energy, *Wind Integration in Electricity Grids: International Practice and Experience*, (np: Australian Energy Market Operator, October 2, 2011), http://www.aemo.com.au/planning/0400-0049.pdf.

327 Nicholas W. Miller, Miaolei Shao and Sundar Venkataraman, *CAISO Frequency Response Study*, Final draft (Schenectady, NY: General Electric International, Inc., November 9, 2011), http://www.uwig.org/Report-FrequencyResponseStudy.pdf.

Additional requirements with regard to frequency response will likely be placed on wind plants. Hydro-Québec has such requirements currently. Hydro-Québec is interconnected to the Eastern Interconnection with a 4 GW HVDC link. Hydro-Québec requires wind plants to contribute to reducing large (>0.5 Hz), short-term (less than ten seconds) frequency deviations comparable to the inertial response of a conventional synchronous generator whereby the inertia constant equals 3.5 seconds. The frequency control capabilities must be available permanently, not just restricted to critical periods of time.[328] In addition, wind generators must be able to increase generation to 5% above their current output during under-frequency events for a duration of ten seconds.[329]

For a period of time, Hydro-Québec was the only grid operator in North America to require wind generators to provide frequency response, but that has changed, as a very recent trend among some RTOs and grid operators in North America is to require new wind projects to comply with frequency response requirements, or to provide frequency response. Effective December 1, 2011, ERCOT requires wind projects with standard interconnection agreements signed after January 1, 2010 to have primary frequency response capabilities. Providers of frequency response or inertial response are not paid to provide such service in ERCOT.[330] Wind plants must have adjustable dead bands comparable to conventional resources, and a similar droop to the other resources of 5%.[331] A personal communication with a ERCOT representative suggested that most of the wind interconnection agreements were signed before 2010, but some more

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[328] Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.

[329] Erik Ela, Michael Milligan and Brendan Kirby, *Operating Reserves and Variable Generation* (Golden, CO: NREL, August 2011), http://www.nrel.gov/docs/fy11osti/51978.pdf.

[330] Ed DeMeo, Kevin Porter and Charlie Smith, *Wind Power and Electricity Markets* (Reston, VA: Utility Wind Integration Group, 2011), www.uwig.org/fercwork1204/windinmarketstable.pdf.

[331] Erik Ela, Michael Milligan and Brendan Kirby, *Operating Reserves and Variable Generation* (Golden, CO: NREL, August 2011), http://www.nrel.gov/docs/fy11osti/51978.pdf.

recent wind projects were preparing to meet ERCOT's primary frequency response requirement.[332]

Also effective December 1, 2011, the AESO requires non-exempt wind projects to meet frequency response requirements. BPA has also proposed to require all wind projects over 20 MW to have over- and under-frequency control in the control systems, and may require the same wind projects to feather for over-frequency, or if able to feather wind generation in advance, to increase generation for an under-frequency event.[333]

Various utilities in Hawaii have implemented or proposed several active power requirements for wind projects. Hawaiian utilities face significant challenges in integrating variable generation – strong wind and solar resources, a small grid, and no interties to neighboring utilities. Therefore, variable generation in Hawaii can have a large impact on utility regulation requirements. As a result, three wind plants in Hawaii have battery storage systems to help with system frequency. The 21 MW Auwahi Wind project on Maui has a 10 MW battery unit that could store up to 4.4 MWh of wind generation.[334] The 30 MW Kahuku wind project on Oahu has a 15 MW battery to help with system frequency and to store wind power as needed.[335] However, a fire destroyed the battery storage warehouse of the Kahuku wind project in August 2012. The cause of the fire is

[332] David Maggio, ERCOT, Personal Communication, August 26, 2011.
[333] Ed DeMeo, Kevin Porter and Charlie Smith, *Wind Power and Electricity Markets* (Reston, VA: Utility Wind Integration Group, 2011), www.uwig.org/fercwork1204/windinmarketstable.pdf.
[334] Lahaina News, "Work Begins on Auwahi Wind Project," *Lahaina News,* May 10, 2012, http://www.lahainanews.com/page/content.detail/id/508131/Work-begins-on-Auwahi-Wind-project.html?nav=20.
[335] First Wind, "Welcome to Kaheawa Wind," http://www.firstwind.com/projects/kaheawa-wind; Hawaii's Energy Future, "Wind Energy," http://www.hawaiisenergyfuture.com/articles/Wind_Energy.html.

under investigation.[336] Finally, the Kaheawa I and II wind projects, collectively 51 MW, also include battery storage systems.[337]

HECO's October 2011 RFP for 200 MW or more of renewable energy for Oahu included several control requirements for wind projects, including curtailment capability, frequency regulation, capability to provide reactive power at 90% lagging and 95% leading, and the ability to ride through over-voltage and under and over-frequency events. HECO is also requiring ramp rate control of 2 MW/minute for projects of 5 MW to 25 MW, 3 MW/minute for 25 to 50 MW, 3 to 5 MW/minute for 50 to 100 MW, and 5 to 10 MW/minute for 100 to 200 MW. Generators are limited in size to 200 MW unless a larger generator can limit the loss of generation to 200 MW in a single contingency event.[338]

Being an island grid without interconnections, Hawaii's challenges in integrating wind and solar generation are non-trivial. Larger interconnected grids such as PJM's are unlikely to face these types of issues until variable generation reaches a higher penetration.

Other grid operators outside of North America require wind projects to contribute to frequency control. Ireland and the United Kingdom require wind generators to provide for two types of frequency response and to be capable of switching from one to the other. The first type of frequency response is Limited Frequency Sensitivity Mode which requires that wind generators reduce generation at 40% of their instantly available capacity when system frequency increases beyond 50.2 Hz. In addition to Ireland and the United Kingdom, Germany also has this requirement for over-frequency. The second type of

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[336] Eric Wesoff, "Battery Room Fire of Kahuku Wind Energy Storage Farm," *Green Tech Grid*, August 3, 2012, http://www.greentechmedia.com/articles/read/Battery-Room-Fire-at-Kahuku-Wind-Energy-Storage-Farm.

[337] Xtreme Power, "Wind Projects", http://www.xtremepower.com/projects/wind.php.

[338] HECO, *Competitive Bidding Process for 200 MW or More of Renewable Energy Delivered to or on Oahu*, *Draft Request for Proposals*, Docket No. 2011-0225 (Hawaii Public Utilities Commission, October 14, 2011), http://www.heco.com/vcmcontent/GenerationBid/HECO/CompetitiveBid/Books%201%20and%202%20-%20Draft%20RFP%20and%20Appendices%20A%20through%20Q.pdf.

frequency response requires frequency regulation with configurable droop characteristics with deadband control, which requires wind generators to operate below their available capacity to provide both upward and downward frequency within a deadband. These requirements are in place in the Ireland, United Kingdom, Spain and Denmark grid codes for wind, subject to some differences. Grid codes will also specify the range of system frequency that a wind turbine must be able to tolerate for a defined period of time, as detailed in Table 19.[339]

Table 19 *Frequency and Rate of Change of Frequency (ROCOF) Limits in Selected Grid Codes*[340]

Grid Code	Frequency Minimum	Frequency Maximum	ROCOF
Ireland	47 Hz	52 Hz	±0.5Hz/s
UK	47 Hz	52 Hz	
Denmark	47 Hz	52 Hz	±2.5Hz/s
Spain	47.5 Hz	51.5 Hz	±2Hz/s
Germany	47.5 Hz	51.5 Hz	
Alberta	57 Hz	61.7 Hz	
Quebec	55.5 Hz	61.7 Hz	
ENTSO-E Draft Requirements			±2Hz/s Remain connected for 1.25s over 2Hz/s

Because wind power is "spilled" in order to provide frequency response, the marginal cost of using wind power to provide the frequency response is approximately the spot price plus tax credits plus renewable energy credits. In nearly all cases, it will be more economical to provide frequency response with conventional generation than from wind plants. For isolated grids, small grids,

[339] Ecar Energy, *WP2: Review of Grid Codes* (np: Australian Energy Market Operator, October 2, 2011), http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/0400-0050%20pdf.ashx.
[340] Ibid.

and/or for difficult operating periods such as low load and high wind, wind plants may need to provide frequency response.[341]

9.5. RAMP RATE LIMITS

In some instances, pitch controlled wind turbine generators can control the rate of change in output, including the rate of increase of power when wind speed is increasing, the rate of increase in power when a wind curtailment is released, and the rate of decrease in power when a wind curtailment limit is imposed.[342]

Industry practice in the United States on ramp rate limits for wind projects is evolving. Like most grid operators and RTOs in the United States, PJM does not currently impose any limitations on the ramp rates of wind or solar plants. In ERCOT, non-exempt wind resources must limit their ramp rate to 10% per minute when responding to or when being released from an ERCOT deployment (such as during a wind curtailment), except during Force Majeure events, if there is a demonstrated decrease in available wind resources, or if a wind resource is operating under a Special Protection Scheme (SPS) and is decreasing its output to avoid an SPS activation. ERCOT can also request wind resources to ignore the ramping limit requirement if necessary to maintain system reliability.

In Alberta and effective as of December 2011, the AESO requires wind generators to limit up ramps to between 5% and 20% of maximum authorized power. If directed by the AESO, wind generators must limit one-minute power output from exceeding 2% of maximum authorized power. The wind projects must

[341] Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.
[342] Ibid.

disconnect within 30 minutes if they cannot implement AESO's instructions. BPA is requiring new wind projects to have ramp rate limitation capability.[343]

Active power control requirements are also present in international grid codes, a sample of which is presented in Table 20. Denmark requires implementation to begin within two seconds and to be fully implemented within 30 seconds, while Ireland requires implementation to begin within ten seconds and full compliance as soon as possible.

Table 20 *Summary of Active Power Control Requirements from Various Grid Codes[344]*

Grid Code	Output Cap	Delta Control	Gradient Limit	Commence Implementation Time	Implementation Time
Ireland	Yes	Yes	As set by TSO between 1 and 30MW/min	10 seconds	ASAP
UK	No requirements specified				
Denmark	Yes	Yes	As instructed by TSO	2 seconds	30 seconds
Spain	Yes	Yes			
Germany	Yes		10%/min		
Alberta	Must disconnect if not capable		10%/min		10 minutes
Quebec	No requirements specified				
ERCOT	Yes				
ENTSO-E Draft Requirements	Yes	Yes (Types C,D)	20%/min		

Many wind projects can adjust output quite quickly, and that can be helpful for some grid events. In some cases though, grid operators have been surprised by the rapid response of wind projects to market signals, such as rapidly decreasing power output in response to drops in LMP prices. That kind of response can be

343 Utility Wind Integration Group (UWIG), compiled by Ed DeMeo, Kevin Porter and Charlie Smith, *Wind Power and Electricity Markets* (Reston, VA: UWIG, 2011), www.uwig.org/fercwork1204/windinmarketstable.pdf.

344 Ecar Energy, *WP2: Review of Grid Codes* (np: Australian Energy Market Operator, October 2, 2011), http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/0400-0050%20pdf.ashx.

too fast and can be potentially destabilizing. As a result, some grid operators have imposed limits on the ramp rate at which wind plants can respond to market signals.[345]

[345] Robert Zavadil, Nicholas Miller, Glenn Van Knowe, John Zack, Richard Piwko and Gary Jordan, *Technical Requirements for Wind Generation Interconnection and Integration*, prepared for ISO-NE (np: GE Energy, November 3, 2009), http://www.uwig.org/ISONEFinal16Nov09Interconnectionreqnewis_report.pdf.

10. BEST PRACTICES IN INTEGRATION OF VARIABLE GENERATION

The previous sections consisted of an extensive literature review on industry practice and experience with integrating wind and solar generation. This section summarizes the GE team's views on the "best practices" in integrating wind and solar generation. Our format will be to state a best practice, followed by a short description of why it is considered a best practice. A section on additional options is also included to consider new and innovative practices that do not have sufficient operating experience to be fully classified as a best practice but should be monitored.

Energy Market Scheduling

- Sub-hourly scheduling and dispatch, for both internal (within-RTO and within-utility) and for scheduling on external interconnections with other balancing authorities, is a best practice.

Sub-hourly scheduling and dispatch is considered a best practice as it allows grid operators to follow net load variability over finer time scales than hourly, as is the case in most non-RTO regions in the U.S. In addition, sub-hourly scheduling unlocks existing generation flexibility that would not be as available in hourly scheduling and dispatch. Sub-hourly scheduling and dispatch is common among most of the RTOs in the U.S. Sub-hourly scheduling among external interconnections with other balancing authorities is not as common. Most external schedules between RTOs and between utilities not in RTOs tend to be hourly schedules. That said, some RTOs such as PJM are instituting sub-hourly scheduling on some external interties. PJM, for example, has adopted sub-hourly scheduling on external schedules with MISO and started sub-hourly scheduling at NYISO's Keystone proxy generator bus on June 20, 2012.

Visibility of Solar Distributed Generation

- Install telecommunications and remote control capability to clusters of solar DG in PJM's service area. Alternatively, have distribution utilities install such capability and communicate data and generation to PJM.
- Include solar in variable generation forecasting.
- Account for the impacts of non-metered solar DG in load forecasting.
- Follow and/or participate in industry efforts to reconcile provisions in IEEE-1547 and Low-Voltage Ride-Through Requirements.

PJM is likely to have significant amounts of additional distributed generation, particularly distributed solar, over the next several years, particularly in response to the solar requirements that are part of many state RPS requirements in the Mid-Atlantic. The increased amount and the lack of visibility of distributed generation could negatively affect load forecasting. In addition, the lack of reconciliation between low-voltage ride-through requirements and IEEE-1547 could lead to potential future reliability issues for PJM.

Absent such reconciliation, PJM can undertake various measures such as installing telecommunications and remote control capability in areas with large amounts of solar DG. Alternatively, the transmission owners and/or distribution utilities can install telecommunications and remote capability and communicate data to PJM.

Solar will need to be accounted for in both generation forecasting and load forecasting. Although the emphasis in this section has been on solar DG, utility-scale solar is also growing. PJM has 3.6 GW of solar in its interconnection as of the end of 2011, although only 40 MW of solar was on-line at that time.[346] Utility-scale solar can be integrated into wind forecasting systems. Solar forecasts can be prepared by metering a fraction of utility-scale solar on the grid and scaling

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[346] Overall, PJM reports that 1,000 MW of solar capacity is installed in PJM as of May 2012, including both DG and central solar. See http://pjm.com/about-pjm/renewable-dashboard/solar-power.aspx.

up the forecast and production data by participating solar plants. In addition, solar plants can be required to participate in a variable generation forecasting system as a condition of interconnection, and provide solar resource and production data as they come on-line.

Non-metered solar DG can affect the accuracy of a load forecast if there is a significant amount of non-metered solar and it is not accounted for in load forecasting. Non-metered solar DG can be estimated through measuring the difference between full sun output and a forecast based on current weather conditions.

Reserves

- Consider separating regulation requirements into regulation up and regulation down if there is a shortage of regulation for certain hours, if there is a disproportionate need for a certain type of regulation (up or down), or if there is a desire to more finely tune regulation requirements.
- Have operating reserve requirements set by season or by level of expected variable generation, instead of a static requirement that changes infrequently.
- Rely on demand response to provide some reserves.
- Require wind and solar generators to be capable of providing AGC.

Most RTOs require that regulation is a combined service, namely that both regulation up and regulation down are provided as a single service. Two RTOs – CAISO and ERCOT – have separated regulation requirements into regulation up and regulation down. Doing so recognizes the different demands that variable generation places on regulation (such as on regulation down during high wind/minimum load events). Furthermore, it would allow wind generators to potentially provide regulation down if called upon. That said, RTOs and other grid operators that have ample quantities of regulation and can draw upon look-ahead unit commitment tools and sub-hourly markets to identify the need for regulation may not need to separate regulation into regulation up and regulation down. That may be the case for PJM.

Some grid operators also adjust their regulation requirements to vary when higher levels of variable generation are expected, such as by season or by month, or to adjust regulation requirements based on changes in installed variable generation capacity, as ERCOT does.

Turning to demand response, recent variable generation integration studies such as the WWSIS have noted that demand response could be called upon to provide contingency reserves instead of requiring additional generation. ERCOT allows up to half of its non-spinning reserves (1,150 MW) to provide 30-minute non-spinning reserves. Other RTOs also use demand response to provide ancillary reserves, although the amount is still relatively small. Because demand response is still relatively new, some RTOs limit the amount of demand response they will use as they gain greater operating experience. Demand response in PJM, for instance, can supply regulation, synchronized reserves and day-ahead reserves, but demand response is limited to 25% for each category, and demand response can serve only two of the three categories. Other RTOs and grid operators have comparable limits for demand response. These limits will likely be eased as greater experience with demand response is gained.

Variable generation can provide various types of reserves if the reserves can meet the technical requirements. Only MISO and CAISO specifically prohibit wind power from providing reserves. Wind generators can accept AGC signals but would require wind generators to spill a portion of wind energy to do so. Grid operators should require wind and solar generators, as a condition of interconnection, to be capable of providing AGC. Wind generators, for example, can provide down regulation during nighttime hours or when there is a risk of minimum load.

Wind and Solar Forecasting

- Implement a centralized forecasting system for wind and utility-scale solar that offers day-ahead, very short-term (0-6 hours), short-term (6-72 hours), and medium or long-term forecasts (3-10 days).

- Incorporate estimates of non-metered solar production into day-ahead and short-term load forecasts if there is a significant amount of solar DG either already installed or predicted.
- Ensure that short-term wind and solar forecasting systems can capture the probability of ramps, or implement a separate ramping forecast.
- Institute a severe weather warning system that can provide information to grid operators during weather events.
- Monitor the use of confidence intervals and consider adjusting them periodically.
- Integrate the wind and solar forecasts with load forecasts to provide a "net load" forecast.
- Institute requirements for data collection from wind and solar generators.

A growing number of utilities, transmission providers and RTOs are implementing wind forecasting, and a smaller number are expanding into solar forecasting. The different time frames of forecasts serve a unique purpose and should be part of any forecasting system. The medium to long-term forecasts provide a climatological overview of what to expect, such as the possibility of storms or high wind events. The day-ahead forecasts, as the name implies, will provide day-ahead wind and solar forecasts. Short-term and very-short-term forecasts will provide near-term updates of wind and solar forecasts.

The short-term and very-short-term forecasts should be evaluated to see whether they are adequate in predicting wind ramps, or whether a separate ramp forecast is needed. There is some controversy among variable generation forecasters and the wind power industry as to whether a separate ramp forecast is necessary as some maintain, or whether continual and frequent updating of forecasts is sufficient for predicting ramps. PJM, for example, is relying on its short-term wind forecast as part of its Intermediate Security-Constrained Dispatch to identify potential wind ramps in the near future. Regardless of whether a separate ramp forecast is adopted or not, a severe weather warning system should also be added to advise grid operators of the potential for extreme meteorological events.

Except for CAISO, we are not aware of any utility, RTO or transmission provider that is forecasting for non-metered solar. Because of the rapid growth of solar DG systems, some at least rudimentary forecasts may be needed for non-solar DG. Otherwise, load forecasts may be inaccurate on high solar days.

A number of utilities and RTOs use a confidence interval as part of their forecasts. These confidence intervals should be periodically evaluated and perhaps changed if the forecasts are proving sufficiently accurate and grid operators are comfortable with the forecast.

Previous variable generation integration studies have suggested that incorporating variable generation forecasts directly into reliability commitment schedules, such as using a load net wind and solar forecast, would result in reduced total system operating costs through decreased fuel consumption, operation and maintenance costs, and more efficient plant dispatch overall. Few, if any, grid operators use their wind and solar forecasts in this manner, and are not capturing the full benefits of forecasts. A combined "load net wind" forecast could be used after clearing the financial day-ahead market in the reliability commitment process (usually considered the first stage of the next day's real-time market). The ISO and RTO process to commit sufficient resources to supply anticipated load may have to account for the increased uncertainty around the wind power forecast. That said, the "load net wind" forecast should contribute to more efficient market operation and dispatch, should improve overall operating reliability, and should not financially benefit wind and solar generators over what they would otherwise receive as price-takers in the real-time market. It is comparable to the use of an improved system load forecast that is created by the ISO or RTO.

With regard to data for forecasts, FERC Order No. 764, issued in June 2012, requires transmission providers to amend their *pro forma* Large Generation Interconnection Agreements to institute data requirements for wind and solar generators over 20 MW. More specifically, FERC is requiring wind generators to provide site-specific meteorological data including, but not limited to, temperature, wind speed, wind direction, and atmospheric pressure. For solar generators, FERC is also requiring site-specific meteorological data including, but not limited to, temperature, atmospheric pressure, and irradiance. FERC-jurisdictional entities that have forecasting systems may want to evaluate whether additional data is needed and include such requirements in their compliance filing to FERC. In addition, some RTOs impose penalties on wind and/or solar generators if they fail to provide data, or do not provide quality data. FERC-jurisdictional entities may want to decide whether they want to include such a provision as well.

Intra-Day Unit Commitment

- Consider establishing intra-day unit commitment, if one is not already in place, and incorporate short-term wind and solar forecasts.

Wind and solar forecasts are more predictable and more accurate the closer they are to real-time as compared to day-ahead forecasts. Running intra-day unit commitment algorithms, in addition to day-ahead unit commitment, and using the results to inform forecasts – or using a more stochastic approach to unit commitment with frequent rolling updates – are useful strategies for taking advantage of short-term variable generation forecasts. As noted earlier, PJM uses short-term wind forecasts when it runs Intermediate Security-Constrained Dispatch. ERCOT is considering whether it can review wind and solar forecasts six hours ahead of real-time operations.

Look-Ahead Dispatch

- Consider Establishing a Look-Ahead Dispatch for Very Short Time Frames

A variation of intra-day unit commitment is MISO's Look-Ahead Unit Dispatch System for even shorter time periods, such as two hours ahead. Look-ahead dispatch could result in more precise scheduling of variable energy generation and less need for manual actions by grid operators in response to changes in system conditions, load demand or generation, whether from variable energy generation or other generation. PJM has something comparable with

Intermediate Security-Constrained Dispatch that looks ahead from 15 minutes to two hours, with grid operators able to adjust the look-ahead time.

Capacity Value of Wind and Solar

- Conduct an ELCC Study of Wind and Solar at Regular Intervals

Recent work from the NERC IVGTF concluded that the ELCC approach is superior to time-based approximation methods (e.g., the capacity of wind or solar during peak hours). Time-based approximation methods have the disadvantage of assuming the hours included are weighed equally, while ELCC methods put greater weight on higher-risk hours. That said, approximation methods are often used if data is unavailable. Such methods can be reasonable if they are regularly benchmarked to an ELCC study. MISO conducts an ELCC study of wind every year. That may be too frequent for some grid operators, but ELCC studies should not be considered a one-time occurrence, as wind and solar production can vary from year to year.

Wind Ramps

- Require Wind Generators to be Equipped with Ability to Limit Ramps

ERCOT, BPA and AESO are among the grid operators that impose ramp rate limits on wind generators. Such ramp rate limits are reasonable in smaller balancing areas with limited interconnections and high amounts of wind. For larger balancing areas, simply requiring wind plants to have the ability to limit the rate of power increase, to be enabled or disabled by instruction from PJM, is sufficient. Such ramp rate limits are not necessary under all operating conditions but can be useful in certain circumstances. If dispatched down or knocked off-line for reasons such as cutting out for high wind speeds, wind generators can ramp up to full capacity very quickly. In that case, the use of ramp limits on wind plants may be useful. In addition, grid operators should not impose ramping down limits due to decreases in wind speed, although such limits due to curtailment, shut-down sequences, or other control measures can be reasonable.

Frequency Response

- Do Not Impose Frequency Response Requirements on Wind Generators Unless it is Absolutely Necessary

ERCOT, BPA and AESO are among grid operators who are requiring wind generators to provide frequency response. However, this requirement incurs a power efficiency penalty for wind generators. Frequency response can also be obtained more economically from other generation sources than wind.

Other Potential Best Practices

There are new innovations and practices that show promise but have not garnered enough operating experience to be classified as a best practice. These are discussed further below.

Short-Term Dispatch and Scheduling Requirements for Wind

- Consider Including Wind in Short-Term Dispatching and Scheduling

Several RTOs have instituted short-term scheduling requirements for wind generators to follow, with some RTOs imposing penalties for non-compliance. The details vary by RTO.

- MISO's Dispatchable Intermittent Resources require the submission of 5-minute forecasts by node, or the acceptance of MISO's default wind forecast. MISO can levy an Excessive or Deficient Energy Deployment Change if an 8% tolerance band is exceeded for four or more consecutive 5-minute intervals within an hour.
- ERCOT may impose penalties on wind plants if wind plants have been given an economic dispatch below their high dispatch limit, and wind plants deviate more than 10% from that base point.
- NYISO requires wind resources to bid a price curve in real-time, then uses those price bids to determine reduced base points for each wind plant during economic dispatch. If wind is dispatched down, NYISO can levy

over-generation if wind generators do not follow the dispatch signal. Wind is exempt from under-generation charges.

- PJM economically dispatches wind plants based on a wind plant's offer in real-time.

With the help of wind forecasts, short-term scheduling and dispatch requirements for wind generation can help improve overall scheduling and perhaps reduce the need for short-term reserves. It can also serve as a transition towards incorporating wind and solar forecasts into day-ahead scheduling and dispatch, which is classified as a best practice.

Contingency Reserves and Variable Generation

- Consider Using Contingency Reserves for Very Large but Infrequent Wind Ramps

To date, variable generation integration studies and the experience of a small sample of RTOs and utilities discussed earlier have found that higher amounts of wind capacity do not lead to an increased need for contingency reserves, as wind facilities tend to be smaller in size and an instantaneous drop in wind capacity is highly unlikely. However, as noted earlier, the loss of DG solar capacity could potentially be considered a contingency event should DG solar capacity reach projected capacity additions, and if IEEE-1547 and low voltage ride through requirements are not reconciled.

Separately, the electric power industry is debating whether contingency reserves can be called upon for large but infrequent wind ramps. Few do so currently. As noted earlier, NERC indicates that it may be appropriate to use contingency reserves in response to large but infrequent wind ramps, while allowing time for other resources to cover the wind ramp. This issue bears further monitoring, but using contingency reserves to at least partly cover very large wind ramps may be an economical means of addressing very large wind ramps, instead of building new generation that would operate for only a small number of hours per year.

New or Revised Reserves

- Consider Establishing a Slower Responding and Longer-Lasting Reserve to Cover Wind Ramps
- Monitor Industry Initiatives to Acquire or Encourage More Flexible Reserves

Present NERC requirements dictate that contingency reserves be restored no more than 105 minutes from the start of a contingency event. Most wind ramps last longer than that, and this has given rise to discussion as to whether a slower responding and longer lasting reserve may be needed. Alternatively, layers of different operating reserves can respond to a wind ramp and at different time intervals, or the energy market itself, if the market is deep enough and flexible.

Some RTOs and utilities are considering whether to introduce new reserves in anticipation of higher levels of variable generation, such as CAISO's Flexible Ramping Constraint or the MISO Ramp Management project. These initiatives are quite new, thus not enough operating experience has been obtained to evaluate these initiatives and to recommend a "best practice." However, the differences in approach between CAISO and MISO is noteworthy, as CAISO has developed a new service and cost structure, while MISO is essentially holding back more generation in its commitment stack to ensure ramping needs are met.

Integration Charges

- Monitor Industry and Regulatory Discussions on Integration Charges

Load pays for most types of reserves, but there is increasing discussion as to whether variable generators should pay for part or all of the costs of certain reserves. In its final rule on variable generation, FERC recently decided not to require transmission providers to add a generator regulation service but instead to consider any proposed charges on a case-by-case basis. We note that there is considerable disagreement within the electric power industry and among academic researchers over how to craft integration charges. Therefore, no recommendation is being made at this time other than to monitor industry developments on this issue.

Virtual Bidding

- Do Not Rely Upon Virtual Bidding to Cover for Forecasting Errors

Some in the electric power industry have suggested that virtual bidding can address scheduling and dispatch inefficiencies from wind forecast errors. There is little academic or industry research to support or contradict this view. Our view is that the use of a state-of-the-art forecasting system, coupled with incorporating the forecast into unit commitment and operations, should drive forecasting errors as low as possible and should not leave consistent and sustained opportunities for virtual bidding. However, if the forecast is not state-of-the-art and is not incorporated into unit commitment and operations, then more reserves will likely have to be committed. More opportunities will be available for virtual bidders who use state-of-the-art forecasts to capture the financial gains resulting from poor operating practices. The energy market will settle satisfactorily but costs will be higher than necessary.

APPENDIX A: REGIONAL PRACTICES FOR ANCILLARY SERVICES

Table A-1: Summary of Ancillary Services	
Regions	*Time Frame*
	Frequency Response: 0 – 30 seconds
ERCOT	Primary frequency response is not an Ancillary Service Market Product. All online Generation Resources must have their turbine governors in service and unblocked.
IESO & NYISO	Frequency response is not a stand-alone Ancillary Service product.
PJM	Frequency response is not a stand-alone Ancillary Service product. All resources providing spinning reserve must be synchronized to the grid and must be frequency responsive. The PJM RTO operates in accordance with NERC Resource and Demand Balancing (i.e. BAL) standards to ensure its capability to use reserves to balance resources and demand in real-time and to return Interconnection frequency within defined limits following a Reparable Disturbance.
WECC	Frequency response is not a stand-alone Ancillary Service product. All resources providing spinning reserve must be synchronized to the grid and must be frequency responsive. The WECC is in the process of developing Frequency Responsive Reserve (FRR) criteria. At this point, it is not clear if this criteria would replace spinning reserve or if FRR would be a subset of spinning reserve. The current proposal is to base FRR on a NERC category C event. The proposal is to share the total WECC FRR obligation among the respective BA proportional to a BA's load and generation.
	Regulation: 4 seconds – 5 minutes
ERCOT	Regulation is deployed through ERCOT's EMS system. 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 study also considers how much wind generation resource capacity has come into the system since the historical deployments took place.
IESO	The IESO contracts for the regulation service. Regulation Service acts to match total system generation to total system load (including transmission losses) and helps correct variations in power system frequency. Response times may range from tens of seconds to a few minutes. This service is currently provided by contracted generation facilities with automatic generation control (AGC) capability, which permits them to vary their output in response to signals sent by the IESO. Terms and conditions of contract include: ➢ Minimum of ±100 MW of automatic generation control (AGC) must be scheduled at all times ➢ Minimum overall ramp rate requirement for Ontario is 50 MW/minute

Table A-1: Summary of Ancillary Services	
Regions	*Time Frame*
NYISO	Regulating reserve is the online reserve available for control via Automatic Generation Control and shall be sufficient to meet NERC control performance standards. Regulation is dispatched through a BA's Energy Management system every 6 seconds. The regulation requirement is determined for each hour of the day for each month of the year.
MISO	Regulation is online reserve that is responsive to a BA's Automatic Generation Control signal. There is no requirement on a BA to carry a set amount of regulating reserve, however, a BA is required to carry sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the BA to meet NERC's Control Performance Criteria. Regulation is dispatched through a BA's Energy Management system every 4 seconds.
PJM	Regulation refers to the control action that is performed to correct for load changes that may cause the power system to operate above or below 60 Hz. Regulation for the PJM RTO is supplied by Regulation Class from resources that are located within the metered electrical boundaries of the PJM RTO. Regulation is scheduled in the following ways: ➢ Self-Scheduled Resources ➢ PJM RTO Regulation Market ➢ The total PJM Regulation Requirement for the PJM RTO is determined in whole MW for the on-peak (0500 – 2359) and off-peak (0000 – 0459) periods of the day. ➢ The PJM RTO on-peak Regulation Requirement is equal to 1 percent of the forecast peak load for the PJM RTO for the day. The PJM RTO off-peak Regulation Requirement is equal to 1 percent of the forecast valley load for the PJM RTO for the day. ➢ The requirement percentage may be adjusted by the PJM Interconnection, if the adjustment is consistent with the maintenance of NERC control standards. PJM regulation resource owners will receive 2 regulation signals: ➢ AReg – Assigned Regulation. This is the assigned hourly regulation quantity (MW) that is cleared from the regulation market system. This value, although typically static for the hour, will be sent on a 10-second scan rate. ➢ RegA – Real-time instantaneous resource owner fleet regulation signal (+/- MW). This signal is used to move regulating resources in the owner's fleet within the fleet capability (+/- TReg). This value will be sent on a 2-second scan rate.
SPP	Regulating Reserve is an amount of Spinning Reserve responsive to AGC, which is sufficient to provide normal regulating margin. The BA minimum Regulating Reserve is equal to an amount necessary to maintain compliance with control performance standards while scheduling all Contingency Reserves to other BAs.

Table A-1: Summary of Ancillary Services	
Regions	***Time Frame***
WECC	Regulation is spinning reserve that is responsive to a BA's Automatic Generation Control signal. There is no requirement on a BA to carry a set amount of regulating reserve, however a BA is required to carry sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the BA to meet NERC's Control Performance Criteria. Regulation is dispatched through a BA's Energy Management system every 4 seconds.
	Spinning Reserve: 10 mins – 105 mins
ERCOT	ERCOT maintains a 10-minute reserve service of at least 2300 MW. This is for normal conditions and can go up to 2800 MW. Demand-side resources can provide up to 50 percent of this MW requirement. It may be provided from the following: ➢ Unloaded Generation Resources that are on-line; ➢ Resources controlled by high set under-frequency relays; or ➢ Direct Current (DC) tie-line response. The DC tie-line response must be fully deployed within fifteen seconds on the ERCOT system after the under frequency event. These reserves are maintained by ERCOT to restore the frequency of the ERCOT system within the first few minutes of an event that causes a significant deviation from the standard frequency. Load-following energy and non-spin reserves will be deployed as practicable and if necessary to minimize the use of the 10-minute reserves.
IESO	The IESO administers markets for three classes of Operating Reserve (OR): 10-minute spinning, 10-minute non-spinning and 30-minute OR. Ten-minute spinning and non-spinning OR must be provided by resources whose energy can be made available within 10-minutes of the contingency to restore the balance between supply and demand. Ten-minute spinning OR can be offered by generators that are actually synchronized to the power grid. Thirty-minute OR can be offered by spinning or non-spinning resources that are available to provide energy within 30 minutes of activation. The IESO created an OR market to efficiently purchase OR from market participants and subsequently activate it, when needed, to quickly restore the balance between supply and demand. Market participants can offer OR to the IESO-administered markets at the same time that they bid or offer energy (to offer operating reserve, there must be an energy bid or offer of at least as many megawatts). Ten minutes operating reserve requirements are based on the largest single recognized event (contingency) on the system. Ten-minute spinning reserve is normally 25 percent of the 10-minutes OR (single largest contingency) on the system. Note that as per Northeast Power Coordinating Council Inc. (NPCC Inc.) criteria, 100 percent of an area's 10-minute reserve requirement shall be synchronized reserve except as mentioned below. An area is required to adjust its synchronized reserve requirement based on its ability to recover from reportable events within fifteen minutes. This synchronized reserve requirement may be decreased to a minimum of 25 percent of the 10-minute reserve requirement based upon the area's past

Table A-1: Summary of Ancillary Services	
Regions	*Time Frame*
	performance in returning its Area Control Error (ACE) to pre-contingency values, or to zero, within fifteen minutes. Specific additional requirements of NPCC operating reserve criteria (A-06) are available via following link: http://www.npcc.org/documents/regStandards/Criteria.aspx In addition, the IESO procures 30-minute reserves based on the largest contingency plus half of the second largest contingency that could occur under a given IESO-controlled grid operating configuration. IESO, Ontario is also part of a shared activation of reserve group which includes PJM, NYISO, NBSO and ISONE. More information on IESO's/Ontario operating reserve (spinning and non-spinning) requirements is available via following link: http://www.ieso.ca/imoweb/marketsAndPrograms/op_reserve.asp
NYISO	Synchronized Operating Reserve – At least one-half of the 10-minute operating reserve will consist of unused resource capacity, which is synchronized and ready to achieve claimed capacity including load reductions achieved by reducing consumption, or resource capacity, which can be made available by curtailing pumping hydro units or canceling energy sales to other systems. The 10-minute operating reserve requirement shall be the greater of the operating capacity loss caused by the most severe contingency observed under normal transfer criteria, or the largest energy loss caused by the cancellation of an interruptible energy purchase from another system.
MISO	Online generation resources able to be loaded within the DCS recovery period. Regulating Reserves in excess of requirement may be used for Spinning Reserves. BA must carry 40 percent of their Contingency Reserve requirement as Operating Reserve – Spinning. Operating Reserve – Spinning must be fully restored within 90 minutes of the end of the DCS recovery period, which is 15 minutes from the initial event.
PJM	Synchronized Reserve is reserve capability that can be converted fully into energy or load that can be removed from the system within 10 minutes of the request from the PJM dispatcher and must be provided by equipment electrically synchronized to the system. The RTO will be arranged into two (2) zones. All companies within PJM, excluding the SERC companies, are part of the Reliability*First* Corporation (RFC) reliability region and will thus be grouped together into a single synchronized reserve zone. The SERC companies are part of a separate reserve sharing agreement and therefore, comprise a second synchronized reserve zone. The RFC Synchronized Reserve Zone Requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid. The requirement will be defined as the greater of the Reliability*First* Corporation (RFC) imposed minimum

Table A-1: Summary of Ancillary Services	
Regions	*Time Frame*
	requirement or the largest contingency on the system. The Southern Synchronized Reserve Zone Requirement is defined as the Dominion load ratio share of the largest system contingency within VACAR, minus the available 15-minute quick start capability within the Southern Synchronized Reserve Zone. Synchronized market clearing is a joint optimization between regulation and Synchronized reserves. The goal of the optimization is to minimize the total cost of producing energy, regulation, and Synchronized reserve. Resources cannot be committed for both Tier 2 Synchronized and regulation during the same hour
SPP	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. 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). At least half of the Contingency Reserve shall be Spinning Reserve.
WECC	A BA is required to carry Spinning Reserve equivalent to 50 percent of its *Contingency Reserve* obligation. Contingency reserve is an amount of spinning and non-spinning reserve, sufficient to meet the Disturbance Control Standard and shall be at least the greater of: (1) The most severe single contingency (at least half of which must be spinning reserve); or (2) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation (at least half of which must be spinning reserve). For generation-based reserves, only the amount of unloaded generating capacity that can be loaded within 10-minutes of notification can be considered as spinning reserve. Spinning reserve must be replenished within 105 minutes following a contingency. A BA must have documentation that it maintained 100 percent of minimum Spinning Contingency Reserve required based upon data averaged over each clock hour except within the first 105 minutes following an event requiring the activation of Contingency Reserves.

Table A-1: Summary of Ancillary Services	
Regions	***Time Frame***
	Non Spinning Reserve: 10 – 105 minutes
ERCOT	Like Regulation, 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. Non-spinning reserve service is a 30 minute product and is 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 30 minutes; or ➢ Loads acting as a Resource that are capable of being interrupted within 30 minutes and that are capable of running (or being interrupted) at a specified output level for at least 1 hour. Deployed for the Operating Hour in response to loss-of-Resource contingencies, load forecasting error, or other contingency events on the ERCOT System.
NYISO	Nonsynchronized Ten Minute Operating Reserve – The remainder of the 10-minute operating reserve may be composed of nonsynchronized resource capacity such as hydro, pumped storage hydro, and quick start combustion generation including load reductions achieved by starting generation, which can be synchronized and loaded to claimed capacity in 10 minutes or less. The 10 minute operating reserve requirement shall be greater of the operating capacity loss caused by the most severe contingency observed under normal transfer criteria, or the largest energy loss caused by the cancellation of an interruptible energy purchase from another system
MISO	Off-line generation able to be loaded or Interruptible Load able to be removed within the DCS recovery period. Spinning reserve in excess of requirement may be used for Supplemental
PJM	Nonsynchronized Reserve is reserve capability that can be fully converted into energy or load that can be removed from the system within 10 minutes of the request from the PJM dispatcher and is provided by equipment not electrically synchronized to the system. The resources that generally qualify in this category are currently shutdown run-of-river hydro, pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle, diesels and interruptible demand resources. PJM must schedule sufficient Primary Reserves (including synchronized reserves and nonsynchronized reserves) to satisfy the Reliability*First* (RFC) and VACAR requirements. RFC Primary Reserves shall not be less than the largest contingency. RFC Primary Reserves must be made up of at least 50 percent Spinning Reserves. No more than 25 percent of RFC

Table A-1: Summary of Ancillary Services	
Regions	*Time Frame*
	Primary Reserves should be interruptible load. (Standard BAL-002-0, BAL-002-RFC-02). VACAR Primary Reserve Requirements are determined annually, which is 431 MW. PJM triggers the Primary Reserve Emergency Procedures on the Mid-Atlantic Control Zone based on a Primary Reserve Requirement of 1700 MW due to potential deliverability issues. Primary Reserve Requirements for the RFC portion of the PJM footprint is 150 percent of the largest generator. PJM is planning to add the 10-min nonsynchronized reserves into the existing ancillary service market in 2010.
SPP	Non-Spinning/Supplemental Reserves are called Ready Reserves in SPP. Ready Reserve is that the 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 Acceptable types of Ready Reserves: ➢ The amount of Operating Capacity connected to the bus that will not be realized by prime-mover governor action. The realization of this capacity may require the governor speed level to be reset. ➢ That portion of fast starting generating capacity at rest, such as hydroelectric, combustion turbines, and internal combustion engines as prime movers that can be started and synchronized. ➢ Operating Capacity that can be realized by increasing boiler steam pressure, by removing feedwater heaters from service, and/or by decreasing station power use. ➢ 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 ➢ Interruptible or curtailment of loads under contract. ➢ Power deliveries that can be recovered provided a clear understanding exists between the transacting parties to avoid both parties crediting their respective operating reserves by this transaction. ➢ Generating units operating in a synchronous condenser mode. ➢ Interruptible pumping load on pumped hydro units. ➢ 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.

Table A-1: Summary of Ancillary Services	
Regions	*Time Frame*
NYISO	The thirty (30) minute operating reserve portion of the NYISO's operating reserve requirement is that portion of unused resource capacity or interruptible load which can and will be made fully available as promptly as possible, but in no more than thirty (30) minutes. The thirty (30) minute operating reserve requirement shall be equal to one-half of the ten (10) minute operating reserve necessary to replace the operating capacity loss caused by the most severe contingency observed under normal transfer criteria.
WECC	A BA is required to carry Non-Spinning Reserve equivalent to 50 percent of its Contingency Reserve obligation. Non-Contingency reserve does not have to be synchronized to the grid. For generation-based reserves, an off-line resource must be able to synchronize to the grid and generate up to its awarded Non-Spinning Reserve capacity within 10-minutes. Acceptable types of non-spinning reserve: ➢ Load which can be interrupted within 10 minutes of notification; ➢ Interruptible exports; ➢ On-demand rights from other Bas; ➢ Spinning reserve in excess of requirement; and ➢ Off-line generation that qualifies as non-spinning reserve
Other	
	ERCOT: Primary frequency response is not an Ancillary Service Market Product. All online Generation Resources must have their turbine governors in service and unblocked. **NYISO:** The thirty (30) minute operating reserve portion of the NYISO's operating reserve requirement is that portion of unused resource capacity or interruptible load which can and will be made fully available as promptly as possible, but in no more than thirty (30) minutes. The thirty (30) minute operating reserve requirement shall be equal to one-half of the ten (10) minute operating reserve necessary to replace the operating capacity loss caused by the most severe contingency observed under normal transfer criteria. **MISO:** Frequency Response is not a stand-alone Ancillary Service. **PJM:** Supplemental Reserve is reserve capability that can be fully converted into energy or load that can be removed from the system within a 10-30-minutes interval following the request of the PJM dispatcher. Resources providing Supplemental Reserve need not be electrically synchronized to the system.

Table A-1: Summary of Ancillary Services	
Regions	*Time Frame*
	In PJM, the supplemental reserves are cleared in day-ahead scheduling reserve market: ➢ Voluntary, offer-based market for 30-minute reserve that can be provided by both Generation and Demand Resources. ➢ Market is designed to clear existing supplemental (operating) reserve requirements as defined by RFC/NERC. ➢ Day-ahead, forward market that clears simultaneously with day-ahead market. ➢ Costs of Supplemental Reserve Market will be allocated to real-time load ratio share. While MAIN and ECAR reserve definitions center around 10-minute reserves, supplemental reserve is tracked and reported in real-time for the entire PJM footprint via Instantaneous Reserve Checks (IRC). It is still under discussion by stakeholders whether PJM needs to add supplemental reserve as another product to the existing A/S market. **SPP:** In the future market design, SPP is expected to be a consolidated BA. The design currently includes the definition of 'Reserve Zones' used to ensure deliverability with minimum and maximum Operating Reserve requirements in each zone. The SPP Future Market, as contemplated, will include spin, supplemental, regulation up, and regulation down products. The SPP CBA will set the system requirements for regulation up, regulation down, spinning reserves and supplemental reserves. ➢ MP obligations are load ratio share of system requirements. ➢ MP has the option to supply its own obligation or purchasing from market. **WECC:** Should the IVGTF be looking at a separate Ancillary Service to supplement loss of wind generation? Should contingency reserve be used for loss of wind generation? ***Ancillary Services*** **WECC** - The current WECC Contingency Reserve requirement represents a holistic approach to carrying Contingency Reserves for the entire Western Interconnection. The Load Responsibility calculation is used to "transfer" Contingency Reserve responsibility between BAs. Energy with associated Contingency Reserve can be exported and imported between Balancing Authority Areas. However, if Contingency Reserve is associated by agreement with the energy transaction, the responsibility for the Contingency Reserve obligation will remain with the Source BA. In other words, the BA exporting energy that has associated

Table A-1: Summary of Ancillary Services	
Regions	*Time Frame*
	Contingency Reserve would increase its "Load Responsibility" by the amount of the energy being exported. The BA importing the energy has the ability to reduce its "Load Responsibility" by the same amount. This has the effect of maintaining the appropriate amount of Contingency Reserve on a Western Interconnection wide basis. **Ontario** - Real-time markets for synchronized operating (spinning) reserve are available within 10 minutes, while non-synchronized operating reserve is available within 10 minutes; 30-minute reserve (synchronized and non-synchronized) are available within 30 minutes with having supplemental reserves. Requirements to ensure the availability of sufficient *generation capacity* and *ancillary services* to the *IESO-administered markets are set forth as per market rules chapter 5, section 4. S*ee section 4 in: http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter5.pdf Performance standards for ancillary services are available via following Web link: http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter5appx.pdf **Additional Contracts for Ancillary Services** In order to ensure the reliable operation of the power system, the IESO contracts for additional four ancillary services. These are: ➢ black-start capability; ➢ emergency demand response program (EDRP); ➢ regulation service; and ➢ reactive support and voltage control service. Ancillary service costs are borne by loads. The IESO is committed to a fair, competitive process to award these contracts. Information on ancillary services contracts is available via following Web link: http://www.ieso.ca/imoweb/marketdata/ancilSrvContracts.asp **Reliability Must-Run Resources/Contracts** The IESO may need to call on specific registered facilities, excluding non-dispatchable load facilities, to maintain the reliability of the IESO-controlled grid whenever sufficient resources for the provision of physical services, other than contracted ancillary services, are not otherwise offered in the IESO-administered markets. Such applicable registered facilities are referred to as reliability must-run resources and shall be procured through reliability must-run contracts **Wind and Ancillary Services Market in Ontario** Wind cannot offer into ancillary service markets in Ontario.

Table A-1: Summary of Ancillary Services	
Regions	*Time Frame*
	Northeast Power Coordinating Council Inc (NPCC) Operating Reserve Criteria The Northeast Power Coordinating Council, Inc. (NPCC) is the cross-border regional entity and criteria services corporation for northeastern North America. Access to NPCC can be found at via the following Web link: http://www.npcc.org/. The IESO adheres to the requirements set forth in the NPCC operating reserve criteria document A-06. Background of NPCC operating reserve criteria is outlined below. In the continuous operation of electric power systems, operating capacity is required to meet forecast demand, including an allowance for error, to provide protection against equipment failure which has a reasonably high probability of occurrence, and to provide adequate regulation of frequency and tie line power flow. The operating capacity in excess of that required for actual load is commonly referred to as operating reserve. This document establishes standard terminology and minimum requirements governing the amount, availability, distribution, and shared activation of operating reserve. The objective is to facilitate a high level of reliability in the NPCC region that is, as a minimum, consistent with the Operating Policies and Standards specified by the North American Electric Reliability Council (NERC). The requirements of NPCC operating reserve criteria (A-06) are available via following Web link: http://www.npcc.org/documents/regStandards/Criteria.aspx

Source: NERC, *IVGTF Task 2.3 Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/IVGTF2-3.pdf.

APPENDIX B: INFORMATION ON SELECTED VARIABLE GENERATION FORECASTING FACTORS IN NORTH AMERICA[347]

	PJM	NYISO	ISO-NE	MIDWEST ISO
Type of Wind Forecasting System	Centralized wind forecasting since April 2009. Wind plants must meet technical requirements and provide meteorological data.	Centralized wind forecasting system in place since June 2008; used for individual wind plant economic dispatch decisions since May 2009. Wind plants must meet technical requirements and provide meteorological data.	Phase 1 of centralized wind forecasting system is scheduled to be in place 3Q 2012. Implementation work ongoing.	Centralized wind forecasting since June 2008.
Description of Wind Forecasts	Long-term: Provided hourly, from 48 hours ahead to 168 hours ahead. Medium-Term: Updated from six hours ahead to 48 hours ahead. Short-term: Updated with frequency of every ten minutes, forecast interval of five minutes for the next six hours. Forecast on the following aggregation levels: wind projects; electrically close wind farms; Transmission Owners; Regional – West, Mid-Atlantic; Council – RFC or SERC (currently none in SERC); PJM RTO.	Day-ahead forecasts updated twice daily, covering next two operating days at 4:00 a.m. and 4:00 p.m. Real-time forecasts updated every 15 minutes on a 15-minute interval basis, covering an 8-hour time horizon. Real-time forecast is blended with persistence forecast to develop wind plant schedules in real-time commitment (which looks ahead in 15-minute intervals for 2.5 hours) and real-time dispatch, which looks ahead in five to 15-minute intervals for 60 minutes. 100% persistence used in very short-term.	No centralized wind forecasting yet.	5-minute granular forecasts for each Commercial Pricing (CP) node (100+), and updates every five minutes are provided for the next six hours. MISO also receives hourly updated forecasts from Energy & Meteo for each hour beyond 6 hours for the next 6 ½ days, for the same CP nodes. Energy & Meteo provides forecasts at four levels: CP nodes, zones, regions, and all of MISO. Three different Numerical Weather Prediction (NWP) models are used for each of these levels. Dispatchable Intermittent Resources also receive a separate 5-minute forecast (See "Incorporation of Wind into System Dispatch/AGC"). Integrating the two 5-minute forecasts is under consideration.

347 Jennifer Rogers and Kevin Porter, *Wind Power and Electricity Markets* (Reston, VA: Utility Wind Integration Group, 2011), http://www.uwig.org/windinmarketstableOct2011.pdf.

	PJM	NYISO	ISO-NE	MIDWEST ISO
Wind Forecast Tools/Techniques	Physical model that uses NWP forecasts as input. Energy & Meteo uses NWP input, a combination of three numerical weather models weighted according to the weather situation and historical performance; site-specific power curves based on historical data; and a shorter-term model (0-10 hours) based on wind power measurements and NWPs.	Uses ensemble forecasts and statistical analysis to prepare wind power forecasts. Uses the following inputs: grid point output from regional-scale and global-scale NWP models, measurement data from several meteorological sensors, high-resolution geographical data, and meteorological and generation data from wind projects.	No centralized wind forecasting.	Physical model that uses NWP forecasts as input. Energy & Meteo uses NWP input, a combination of three numerical weather models weighted according to the weather situation and historical performance, site-specific power curves based on historical data, and a shorter-term model (0-10 hours) based on wind power measurements and NWP input.
Availability of Ramp Forecast	Updated every ten minutes at 5-minute intervals for next six hours. Currently under evaluation for potential use in operations.	No ramp forecast; under consideration.	No centralized wind forecasting.	No ramp forecast; under consideration.
Wind Forecast Cost Allocation	PJM pays for the central wind power forecasting service.	Fee assessed to each wind project. Charge includes the sum of a monthly fee of $500 and a separate monthly fee of $7.50 per MW of nameplate capacity. Fees are subject to change as more wind projects are added.	No centralized wind forecasting.	MISO pays for the central wind power forecasting service.
Wind Forecast Utilization	Used to determine whether there is sufficient generation scheduled within PJM to meet expected load, transaction schedules and reserve requirements.	Used in determining if enough generation is committed day-ahead to serve forecasted load. Real-time wind forecast integrated into real-time commitment and dispatch.	Phase 1 will incorporate wind power forecast into the day-ahead scheduling and commitment process and also the scheduling and commitment update process that occurs periodically within the operating day. Phase 1 will also include displays and alarms to enhance operator situational awareness.	MISO uses the wind forecast to inform their reliability unit commitment, for transmission outage coordination, transmission security, and peak load analysis, and potential impact of wind ramps on flowgates. Refer to Incorporation of Wind into Dispatch and AGC.

	SPP	ERCOT	CAISO	ALBERTA ESO
Type of Wind Forecasting System	Centralized wind forecasting since January 2011.	Centralized wind forecasting since July 2008.	Centralized wind forecasting since 2004 (PIRP). All intermittent generators, whether in PIRP or not, pay $0.10/MWh. Exports out of CAISO subject to export fee. Wind generators must provide meteorological data. Solar generators must provide solar insolation date. Variable energy generation from dynamic transfers eligible for PIRP by November 2012.	Centralized wind forecasting since January 2010. Currently rolling out real-time (10-minute) site specific data. Wind generators must provide wind speed, wind direction, temperature and pressure every ten minutes. Power data including turbine availability, net to grid and power limit are also required.
Description of Wind Forecasts	5-minute forecast for two hours ahead, updated every five minutes. Hourly forecast for the upcoming 24-hour period, updated hourly. Hourly forecast for each hour beginning 25 hours in the future, updated every four to six hours.	Short-Term Wind Power Forecast (STWPF): Hourly 50% probability of exceedance forecast for an upcoming 48-hour period, updated hourly and delivered 15 minutes past the hour. Similarly, an 80% probability of exceedance forecast is also provided.	Next day: production (MW) for each hour of the next calendar day, delivered by 5:30 a.m. Next hour: production (MW) for each of the next seven hours, delivered by 15 minutes after each hour and at least one hour and 45 minutes before real-time. For hour-ahead and day-ahead forecasts, AWS Truepower also applies 80% and 20% MW probability of exceedance values. Expanding forecast for intermittent dynamic transfers for intra-hour instead of hourly. Developing interval forecasting tool for sub-hourly and two hours ahead.	Day-ahead forecast up to six days (144 hours), updated every 24 hours. Will begin short-term hourly forecast and ramp forecast in December 2011 and it will be updated every ten minutes.

	SPP	ERCOT	CAISO	ALBERTA ESO
Wind Forecast Tools/Techniques	Three different NWP models are used, with one that is run every six hours, and two that are run every 12 hours. Wind power forecast is generated with individual power curves per generation resource and weather model. Higher level forecasts are optimized to reflect influence between all underlying generation resources. Forecasts are combined using statistical methods to analyze forecast performance and calculate dynamic factors for specific weather regimes for each generation resource, as well as for all higher level forecasts in real-time. Very short-term forecast (0 - 6 hours) on all levels is performed using a very short-term module taking into account current generation.	AWS Truepower uses an integrated forecast system based on physical and statistical models: -Days-ahead: Uses an ensemble composite of statistically adjusted Numerical Weather Prediction (NWP) forecasts. -Hours-ahead: Uses time series methods, feature detection algorithms, and a rapid update NWP in addition to the ensemble composite above. Wind plant output models are also used to transform predictions of meteorological variables to power output forecasts.	Uses ensemble forecasts and statistical analysis to prepare wind power forecasts. Uses the following inputs: grid point output from regional-scale and global-scale NWP models, measurement data from several meteorological sensors, high-resolution geographical data, and meteorological and generation data from wind projects. Solar insolation data requested from solar projects.	WEPROG uses a short-range ensemble prediction system based on a multi-scheme approach, which is an integrated weather forecasting system that uses 75 individual forecasts to replicate weather uncertainty for the next six days. Each ensemble member is based on a single NWP kernel, where the ensemble members are generated by varying dynamic and physical processes within the NWP model.

	SPP	ERCOT	CAISO	ALBERTA ESO
Availability of Ramp Forecast	Forecast probabilistic ramping events with predefined confidence ranges per site, including event duration and magnitude.	AWS Truepower provides the ERCOT Large Ramp Alert System (ELRAS) which forecasts probabilistic ramping events of predefined magnitude and duration. ELRAS generates 15-minute regional and system-wide forecasts for the upcoming six hours, updating every 15 minutes. At present, the ramp forecasts provided by ELRAS are only used by ERCOT's System Operators for situational awareness.	Currently investigating a wind ramp tool similar to the ERCOT ELRAS tool, which does forecasting of ramps using a probabilistic algorithm.	Ramp forecast will begin in December 2011.
Wind Forecast Cost Allocation	SPP pays for the central wind power forecasting system.	ERCOT pays for the central wind power forecasting system.	Fee assessed on all eligible intermittent resources of $0.10/MWh, and CAISO covers about $0.03/MWh from within its operating budget. CAISO also charges an export fee for energy from PIRP facilities exported outside the CAISO balancing area.	A $/MWh charge to wind generators, and reconciling the differences between wind power forecast costs and revenue from the surcharge annually.

	SPP	ERCOT	CAISO	ALBERTA ESO
Wind Forecast Utilization	Wind forecast is currently used for reliability capacity and next-day planning. With implementation of SPP's Day-Ahead and Ancillary Services market in 2014, the wind forecast will be used to determine validity of day-ahead offers and commitment.	Qualified Scheduling Entities (QSE) representing wind resources must use the most recently provided Short-Term Wind Power Forecast (STWPF) in their Current Operating Plans (COP). The COPs are then used in both the Day-Ahead and Hour-Ahead Reliability Unit Commitment Studies which ensure that an adequate amount of capacity is available to reliably operate the system. QSEs shall adjust the provided forecasts for any unreported unavailability. Wind forecasts are also used in determining monthly requirements of non-spinning reserves.	The wind generation forecast is used as the energy schedule for real-time operations. Day-ahead forecasts advisory.	AESO uses wind forecast to project their need for next-day operating reserves and procurement, as well as real-time operation for energy market dispatch, short-term adequacy and Available Transfer Capability (ATC). Expected to incorporate wind forecast into energy management system in the near future.

	ONTARIO IESO	BPA	XCEL ENERGY (PSCO)
Type of Wind Forecasting System	Wind operators provide forecasts. Forecasts must be provided by 11:00 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% or 10 MW, whichever is greater. Penalty can be assessed for not meeting wind forecasting obligations. Centralized forecasting to be implemented in 2012 for distribution-connected wind generators with an installed capacity of 5 MW or greater, and all wind resources directly connected to the IESO-controlled grid.	Began wind forecasting in December 2009. BPA moving toward a blended wind power forecasting model. Included is BPA's internal automated forecasting system and external forecasting subscription services. The internal forecasting system is the bench mark for external vendor performance.	Centralized wind forecasting since October 2009.
Description of Wind Forecasts	Currently, market participant wind generators submit forecasts containing an expected output value or quantity for each dispatch hour. Real-time scheduling done on a 5-minute basis, relying on a telemetry snapshot of wind output from ten minutes prior to setting the schedule in real-time. With the implementation of centralized forecasting, market participant wind generators will have their forecasts provided via a central forecast.	Hourly forecast for the next three days, updated hourly. Forecast done on plant-by-plant basis, then rolled up to BPA's balancing area. Persistence forecast updated every minute and sent to internal and external forecast. Forecast performance evaluated within a forecast prediction interval, and how often forecast is outside that interval.	Receive two forecasts every 15 minutes. One is week-ahead with hourly granularity and updated every 15 minutes. The second is a 3-hour forecast with 15-minute granularity. Xcel applies a 75% confidence interval around expected forecast.

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Wind Forecast Tools/Techniques	Currently operating a decentralized forecasting system, where wind generators submit a forecast of expected generation output. Forecast accuracy is subject to compliance requirements; wind generators required to provide updates if actual output is reasonably expected to differ from original forecasts by 2% or 10 MW, whichever is greater. Decentralized forecasting will eventually be replaced by centralized wind power forecasting in 2012.	Moving toward blend of the three forecasts. BPA's internal forecast is mostly automated and pulls in NOAA, weather and wind production data. Aggregate wind forecast posted on BPA's web site. BPA also uses data from 20 BPA-owned met towers, also posted on BPA's web site.	Uses mix of public and private weather forecasts to produce wind forecasts. Forecast is weighed by past performance.
Availability of Ramp Forecast	None.	No specific ramp forecast; expect ramp prediction to be part of regular forecast.	Ramp forecast under research and development but not using ramp forecast now.
Wind Forecast Cost Allocation	A monthly charge will be assessed to all withdrawals (mostly load) from the IESO grid to pay the centralized forecasting service provider when centralized forecasting is in place.	BPA paying for wind forecasts currently, but will incorporate wind forecasting costs into the variable generation rate for the next BPA rate case for 2014.	Xcel Energy pays for the wind forecasting services and R&D.
Wind Forecast Utilization	Day-ahead forecasts aid assessment of expected system conditions leading up to real-time. Forecasts are included in pre-dispatch every hour; results used to aid decisions on day-ahead unit commitment, spare generation on-line, and intertie transaction scheduling. Real-time scheduling uses persistence wind forecasts. Will use centralized wind forecast for dispatch in 5-minute increments.	Used for forecasting small amount of wind that serves BPA load (about 20%); for determining amount of balancing reserves that is needed, both up and down; real-time situational awareness; short-term planning; and wind event alerts.	Forecasts used for day-ahead planning including need for day-ahead natural gas purchases. Also used in real-time by system operators for short-term commitment and dispatch but not integrated into EMS.