NEW YORK INDEPENDENT SYSTEM OPERATOR

10 Krey Boulevard ⬥ Rensselaer, NY 12144

April 12, 2010

ELECTRONICALLY SUBMITTED

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: 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

Dear Secretary Bose:

On behalf of the ISO RTO Council ("IRC"), the New York Independent System Operator, Inc. submits the attached white paper entitled Variable Energy Resources, System Operations and Wholesale Markets ("IRC White Paper") as a joint response to the Commission's January 21, 2010 Notice of Inquiry Seeking Public Comment on the Integration of Variable Energy Resources ("VERs").[1] The IRC appreciates the opportunity to present its collective observations and experiences integrating VERs into competitive wholesale energy markets across North America. The IRC is an industry organization that originally formed in the mid-1990s to support the introduction of competition and open access transmission service in wholesale power markets. It is now comprised of the 10 current North American ISOs and RTOs that work together in a collaborative fashion through the IRC to develop effective tools, standards, protocols and procedures to improve competitive energy markets across North America.

IRC members have accommodated and facilitated the largest growth of renewable energy resources, such as wind and solar generation, through the various wholesale market rules and the open access transmission policies they administer. New analytical tools and methods are being developed by these ISOs and RTOs to identify and address the operational requirements and reliability issues that may arise with the rapidly expanding growth of VERs on the power system. Market design is also evolving to keep pace with the policy demand for additional penetration of VER resources. The enclosed IRC White Paper, prepared by the IRC Markets Committee and its consultant KEMA Inc., provides a coordinated, detailed response to the Commission's NOI that describes these efforts.

[1] Integration of Variable Energy Resources. Federal Energy Regulatory Commission Notice of Inquiry. Docket No. RM10-11-000. Issued January 21, 2010 , ("NOI")

The IRC White Paper presents the current development of state-of-the-art procedures and analytical tools being used by the ISOs and RTOs located in the United States. It highlights operational issues and market design considerations being driven by the expansion of VERS within different ISOs and RTOs, reflecting regional differences, such as resource mix, electric topology, market design and regulatory framework. It also provides a discussion of the next steps currently being taken to advance these operational tools and procedures as well as market design to address the substantial growth of VERs expected in the future. In addition, a comparative survey of the experiences and developments that have taken place in Canada and Europe is also presented.

The IRC respectfully requests that the Commission consider this joint submittal, in addition to the individual responses submitted by its ISO and RTO members, in response to the Commission's Notice of Inquiry.

Respectfully submitted,

/s/ Craig Glazer
Craig Glazer
Vice President – Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, NW, Suite 600
Washington, D.C., 20005

/s/ Raymond W. Hepper
Theodore J. Paradise
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

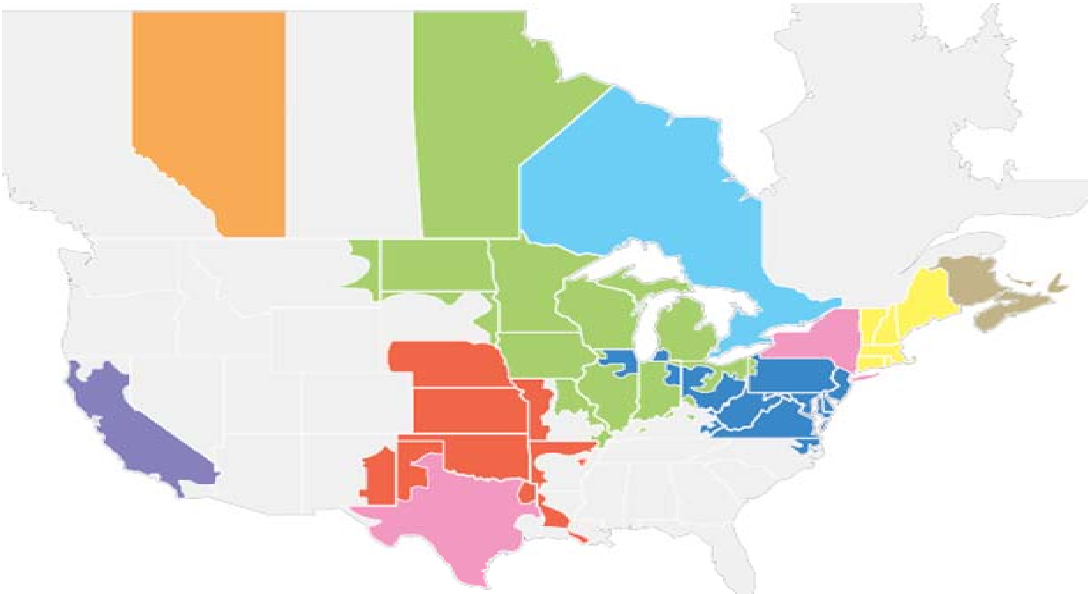
/s/ *Stephen G. Kozey*
Stephen G. Kozey
Vice President and General Counsel
Midwest Independent Transmission System Operator, Inc.
701 City Center Drive
Carmel, Indiana, 46032

/s/ Stacy Duckett
Stacy Duckett
General Counsel & Corporate Secretary
Southwest Power Pool
415 North McKinley
#140, Plaza West
Little Rock, AR 72205-3020

/s/ Robert E. Fernandez
Robert E. Fernandez
General Counsel
New York Independent System Operator, Inc.
10 Krey Blvd.
Rensselaer, N.Y. 12144

/s/Matthew Morais
Matthew Morais
Assistant General Counsel
Electric Reliability Council of Texas
7620 Metro Center Drive
Austin, Texas 78744

/s/ Anthony J. Ivancovich
Anthony J. Ivancovich
Assistant General Counsel-Regulatory
California Independent System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630



ISO/RTO Council White Paper

Variable Energy Resources, System Operations and Wholesale Markets

Incorporating a response to

The Federal Energy Regulatory Commission's
Notice of Inquiry on Integration of Variable Energy Resources
(Docket No. RM10-11-000)

April 12, 2010

The Alberta Electric System Operator (AESO), California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), Ontario's Independent Electricity System Operator (IESO), ISO New England, Inc. (ISO-NE), Midwest Independent Transmission System Operator, Inc. (Midwest ISO), New York Independent System Operator (NYISO), New Brunswick System Operator (NBSO), PJM Interconnection, L.L.C. (PJM), Southwest Power Pool, Inc. (SPP), and KEMA assisted in the preparation of this report.

Acknowledgements

The development of this report for the IRC was performed under the leadership of the IRC Markets Committee. The IRC Markets Committee Task Force on Wind integration led the report development and provided the substantive input for the US and Canadian surveys, with support and significant contributions from KEMA on the US survey, the literature review and the European survey (with additional review and input by IRC members). The contributors and reviewers include:

IRC Wind Integration Task Force and contributors

Udi Helman (CAISO), Team Lead; John Dumas (ERCOT), Jonathan Lowell (ISO-NE), Mike Robinson (Midwest ISO), Robb Pike (NYISO), Emilie Nelson (NYISO), Paul Sotkiewicz (PJM), David Souder (PJM), Kenneth Schuyler (PJM), Emily Davis (SPP), George Porter (NBSO), Darren Matsugu (IESO), Brian Rivard (IESO), Jeff Nish (AESO), Kelly Gunsch (AESO), and Miranda Erickson (AESO)

IRC Markets Committee

Rana Mukerji (NYISO), Chair; Cheryl Terry (AESO), Keith Casey (CAISO), Andy Ott (PJM), Don Tench (IESO), Robert Ethier (ISO-NE), Richard Doying (Midwest ISO), Carl Monroe (SPP), Richard Dillon (SPP), Betty Day (ERCOT), and George Porter (NBSO)

KEMA

Ralph Masiello, David Hackett, Betty Seto, Colin Rickert, Alicia Abrams, Christian Hewicker, and Holger Ziegler

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List of Exhibits:

Acronyms

AESO	Alberta Electric System Operator
AGC	automatic generation control
ATC	Available Transfer Capability
AWEA	American Wind Energy Association
BA	Balancing Authority
BAA	Balancing Authority Area
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CREZ	Competitive Renewable Energy Zones
EIA	Energy Information Agency
ERCOT	Electric Reliability Council of Texas
FCM	forward capacity market
FERC	Federal Energy Regulatory Commission
IESO	Independent Electricity System Operator (Ontario)
ISO-NE	Independent System Operator of New England
ISO	Independent System Operator
IVGTF	Integration of Variable Generation Task Force (NERC)
LSE	load-serving entity
Midwest ISO	Midwest Independent System Operator
MW	megawatt
MWh	megawatt-hour of energy
NBSO	New Brunswick System Operator
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
PIRP	Participating Intermittent Resource Program (California ISO)
PJM	PJM Interconnection, L.L.C.
PSC	Public Service Commission
PUC	Public Utility Commission
REC	Renewable Energy Credit
RA	Resource Adequacy
RTO	Regional Transmission Organization
RPS	Renewable Portfolio Standard
SCE	Southern California Edison
SPP	Southwest Power Pool
WECC	Western Electricity Coordinating Council

1. Introduction and Overview

The formation of Independent System Operators and Regional Transmission Organizations (ISOs/RTOs) began in the mid-1990s to support the introduction of competition in wholesale power markets[1] At present, two-thirds of the population of the United States and more than one-half of the Canadian population are served by transmission systems and organized wholesale electricity markets run by ISOs or RTOs. These ISOs/RTOs ensure that the wholesale power markets in their regions operate efficiently, treat all market participants fairly, provide all transmission customers with open access to use of the regional electric transmission system, and support the reliability of the bulk power system. Currently, 10 ISOs/RTOs operate in the United States and Canada. The ISO/RTO Council (IRC) is an industry organization consisting of representatives of the North American ISOs/RTOs including Alberta Electric System Operator (AESO), California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), Ontario's Independent Electricity System Operator (IESO), ISO New England (ISO-NE), Midwest Independent Transmission System Operator (Midwest ISO), New York Independent System Operator (NYISO), New Brunswick System Operator (NBSO), PJM Interconnection (PJM), and Southwest Power Pool (SPP). The IRC works collaboratively to develop effective processes, tools, and standard methods for improving competitive electricity markets across North America.

One of the most important responsibilities of ISOs/RTOs is to maintain reliable bulk power system operations in real-time. They provide critical reliability services including outage coordination, generation scheduling, voltage management, ancillary services provision, and load forecasting. ISOs/RTOs enhance reliability through their large geographic scope – by dispatching generation over a broad region they reduce the number of decision makers managing the grid, which simplifies coordination and improves reliability. ISOs/RTOs also use sophisticated computer models to analyze the real-time state of electrical flows on the grid and identify potential reliability problems, as well as to meet consumer load at least-cost, using software that works on a wider scale and with a higher level of technical sophistication than that used by smaller control areas.

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[1] This subsection is from the IRC, "2009 State of the Markets Report", available at http://www.isorto.org/atf/cf/{5B4E85C6-7EAC-40A0-8DC3-003829518EBD}/2009%20IRC%20State%20of%20Markets%20Report.pdf. The rest of that report provides additional background on the findings summarized here.

Most ISOs/RTOs coordinate competitive wholesale spot markets in which energy providers submit supply offers and purchasers submit demand bids. A market clearing price balances supply and demand, selecting least-cost supplies until demand is met. ISO/RTO wholesale markets further enhance reliability by informing all market participants of real-time grid conditions through the public posting of electricity and ancillary service prices and other key system information. High prices signal to loads and off-line generators able to respond in a timely manner where more low-cost generation or load reduction are needed and valued.

A variety of analyses have concluded that the implementation of competitive power markets based on centrally-coordinated economic dispatch has reduced the cost of electric power within the regions served, relative to the level of costs that would otherwise have been incurred. The consumer benefits of centrally-coordinated wholesale markets are reflected in declines in fuel-adjusted wholesale electric prices in ISO/RTO regions. These declines in power prices within ISOs/RTOs, relative to the levels that would otherwise have prevailed, reflect a number of factors, including: the cost reductions made possible through security-constrained economic dispatch; incentives for improved generator availability; optimizing reserves over larger areas; investments in new more efficient generating units; and retirement of uneconomic facilities.

As discussed extensively in the remainder of this white paper, ISOs/RTOs accommodate and facilitate the development of renewable resources. ISOs/RTOs provide fertile ground for such “green power” by providing one-stop shopping for interconnection to the grid, access to an energy spot market, reliance on financial mechanisms such as financial transmission rights and day-ahead market schedules to define transmission system entitlements, and coordination of dispatch over a broad region with many dispatchable resources. Wholesale electricity markets coordinated by ISOs/RTOs support the development of renewable resources by providing a flexible and competitive marketplace for the output of the renewable resource, ensuring the resource owner is not limited to selling its power only to the local control area operator.

1.1 ISOs and RTOs and the Integration of Renewable Resources

Variable energy resources (VERs), notably wind and solar generation, are currently seen as the renewable energy resources likely to fulfill the majority of near-term (5-10 years) policy objectives of State renewable portfolio standards (RPS) and national and regional climate policy goals. Exhibit 1-1 shows the growth in wind production in ISOs/RTOs since 2004. What is clear from the table is that the rate of increase in wind capacity and generation has been accelerating in most regions. In 2008, wind power provided 42% of total new US generating nameplate capacity, up from just 4% in 2004.[2] While proposed federal standards envision up to 20% of total energy from renewables[3] within the next two decades, some states are mobilizing for up to 33% renewable energy by 2020.[4] which would require an unprecedented pace of capacity additions and system operational changes. In addition, US greenhouse gas policy could further accelerate renewable power production. These trends have required US ISOs and RTOs to accelerate preparation for system operations, wholesale markets and planning processes with substantial VER generation.

The functional capabilities that ISOs/RTOs bring to this task have been recognized as the superior wholesale power market model for reliable and efficient renewable integration. Due to their regional scope, advanced system operational capabilities, transparent hourly and sub-hourly markets for energy and ancillary services, support for resource adequacy and markets for capacity, and Order 890 compliant transmission planning procedures, ISOs/RTOs are a key element in the North American infrastructure for a cleaner power system. However, the much higher quantities of renewable energy being mandated through RPS, and likely accelerated by greenhouse gas policy, are requiring that ISOs/RTOs evaluate renewable integration requirements across all aspects of their core functions.

The IRC has promulgated several papers and other products of relevance to integration of VERs. In 2007, the IRC issued a paper on Increasing Renewable Resources: How ISOs and RTOs Are Helping Meet This Public Policy Objective.[5] ISOs/RTOs -- as well as other entities within their footprints and both governmental and nongovernmental researchers -- have also published operational and market studies on aspects of renewable integration, and have numerous ongoing activities (some of which are listed in Exhibit 1-2 below). These studies have helped to begin to define the operational needs that will be needed at different levels of VER penetration and are also informing evaluation of wholesale market requirements and impacts. In June 2009, the IRC sponsored a workshop for ISO and RTO technical experts to review all aspects of operational and market experience with VERs. In addition, as discussed in this

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2 US Department of Energy, *2008 Wind Technologies Market Report*, July 2009, available at http://www1.eere.energy.gov/windandhydro/pdfs/46026.pdf.

3 The definitions of eligible renewables under RPS vary among states, most notably with respect to whether hydroelectric resources are counted.

4 E.g, California has a 33% RPS established by Executive Order of the governor and pending before the State legislature.

5 Available at http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-03829518EBD%7D/IRC_Renewables_Report_101607_final.pdf

report, individual ISOs/RTOs have filed for market rule changes over the past 2 years to address aspects of VER integration into the wholesale markets.

The IRC has also sponsored collection of information and evaluation of the operational and market potential for non-generation resources, such as demand response and plug-in hybrid electric vehicles (PHEVs) that will provide essential capabilities for renewable integration over time. The ISOs/RTOs have been performing various studies on these questions as well and are currently preparing draft wholesale standards for submission to NIST that address the integration of demand response, distributed generation, and storage with wholesale markets and grid operations. In March 2010, the IRC released a white paper[6] assessing the impact of PHEV on the grid and markets and which identifies potential roles that PHEV can play in providing market products such as ancillary services.

Another related effort on the operational and reliability assessment of VERs is the NERC Integration of Variable Generation Task Force (IVGTF), on which several ISOs and RTOs actively participate. The IVGTF published an initial report on its findings in April 2009 and has an agenda of ongoing follow-up activities.[7]

On January 21, 2010, the Federal Energy Regulatory Commission (FERC) issued a Notice of Inquiry (NOI) on Integration of Variable Energy Resources.[8] FERC sought comments on the extent to which barriers exist that may impede the reliable and efficient integration of VERs[9] into the electric grid and whether reforms are needed to eliminate those barriers.[10] FERC sought to explore whether existing rules, regulations, tariffs, or industry practices within the Commission's

[6] ISO/RTO Council, *Assessment of Plug-in Electric Vehicle Integration with ISO/RTO Systems,* IRC, KEMA and Taratec, March 2010, available at http://www.isorto.org/atf/cf/{5B4E85C6-7EAC-40A0-8DC3-003829518EBD}/IRC_Report_Assessment_of_Plug-in_Electric_Vehicle_Integration_with_ISO-RTO_Systems_03232010.pdf.

[7] NERC, *Special Report, Accommodating High Levels of Variable Generation* (April 2009), available at http://www.nerc.com/files/IVGTF_Report_041609.pdf. Materials from the IVGTF are available at http://www.nerc.com/filez/ivgtf.html.

[8] Federal Energy Regulatory Commission, *Integration of Variable Energy Resources*,130 FERC ¶ 61,053 (Docket No. RM10-11-000); 18 CFR Chapter I. Available at http://www.ferc.gov.

[9] FERC specified that for purposes of the NOI, the term variable energy resource refers to renewable energy resources that are characterized by variability in the fuel source that is beyond the control of the resource operator. This includes wind and solar generation facilities and certain hydroelectric resources. NOI at footnote 1.

[10] *Id.* at P 1.

jurisdiction may hinder the reliable and efficient integration of VERs, resulting in rates that are unjust and unreasonable and/or terms of service that unduly discriminate against certain types of resources.[11] Accordingly, FERC sought comment on how best to reform any such rules, regulations, tariffs, or industry practices.[12]

The FERC NOI is organized into seven sections, each with several questions. Section A addresses data and forecasting; section B, scheduling flexibility and scheduling incentives; section C, day-ahead market participation and reliability commitments; section D, Balancing Authority coordination; section E, reserve products and ancillary services; section F, capacity markets; and section G, real-time adjustments. This paper is structured around the NOI sections, with additional information from the U.S., Canadian and European wholesale market operators.

There is some overlap between the FERC NOI questions and the current NERC IVGTF agenda; this paper notes where ISOs/RTOs are themselves waiting for IVGTF results as a basis for further decisions on VER integration.[13]

Exhibit 1-1: Wind Generation in North American ISOs and RTOs, 2004-2008

	Alberta	CAISO	ERCOT	IESO	ISO-NE	Midwest ISO	BNSO	NYISO	PJM	SPP	ISO/RTO Total
Wind Nameplate Capacity (megawatts)											
2004	251	2560	1385	0	1	Confidential	0	48	245	428	4918
2005	255	2670	1854	0	1	871	0	246	307	996	7200
2006	362	2820	2875	396	5	1032	0	390	357	1246	9483
2007	498	2820	4785	475	5	1462	0	424	1328	1627	13423
2008	498	2820	8005	704	31	3008	96	1064	2114	2915	21254
Wind Generation (hourly average in megawatts)											
2007	163	599	997	116	2	434		99	154	521	3086
2008	176	544	1735	134		947		142	377	698	4753

Source: IRC State of the Markets Report, 2009 (labeled Table 9)

11 *Id.* at P 4.

12 *Id.* In this NOI, the Commission will not address issues related to transmission planning and cost allocation, as the Commission is considering those issues in a different proceeding (*Transmission Planning Processes Under Order No. 890*, Docket No. AD09-8-000 (Oct. 8, 2009) (notice of request for comments).

13 The NERC IVGTF work plan for 2009-2011 is available at http://www.nerc.com/docs/pc/ivgtf/IVGTF_Work_%20Plan_111309.pdf.

Exhibit 1-2: Selected ISO/RTO Activities on renewable resource development and integration

ISO/RTO	Name of program	Web link
CAISO	Green links	http://www.caiso.com/green/greenhome.html
	Integration of Renewable Resources Program	http://www.caiso.com/1c51/1c51c7946a480.html
Midwest ISO	Renewable Energy Gateway	http://www.midwestiso.org/page/Renewable+Energy+Gateway
NYISO	Greening the Grid	http://www.nyiso.com/public/energy_future/issues_trends/greening_the_grid/index.jsp
PJM	Renewable Energy Dashboard	http://www.pjm.com/about-pjm/newsroom/renewable-dashboard.aspx
	Intermittent Resources Working Group (IRWG)	http://www.pjm.com/committees-and-groups/working-groups/irwg.aspx
ISO NE	New England Wind Integration Study (NEWIS)	http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/newis_report.pdf
SPP	Wind Integration Q&A	http://www.spp.org/publications/SPP_Wind_Integration_QA.pdf

1.2 Operational Issues associated with VER integration

Variable energy resources have three key characteristics that create additional operational requirements (and will have market impacts):

- Uncertainty prior to the actual dispatch interval about VER production, as reflected in day-ahead, hour-ahead and real-time production forecast errors.
- The variability of VER production, which has increasingly greater impact on system operations with higher VER penetration, although depending on the region it may be mitigated by geographical diversity of resources and diversity of types of VERs (e.g., a resource mix that includes both wind and solar).
- The lack of dispatch control over VER production. Even where dispatch control is established, policies such as renewable portfolio standards and production tax credits, as well as greenhouse gas emissions constraints, will encourage VER operators to maximize VER production. Hence, system operators will still seek to take all VER energy as far as possible within system operating constraints. As a result, VER dispatch control over time will help mitigate the operational requirements but will not alter the overall shift from largely predictable supply to an increasingly variable supply.

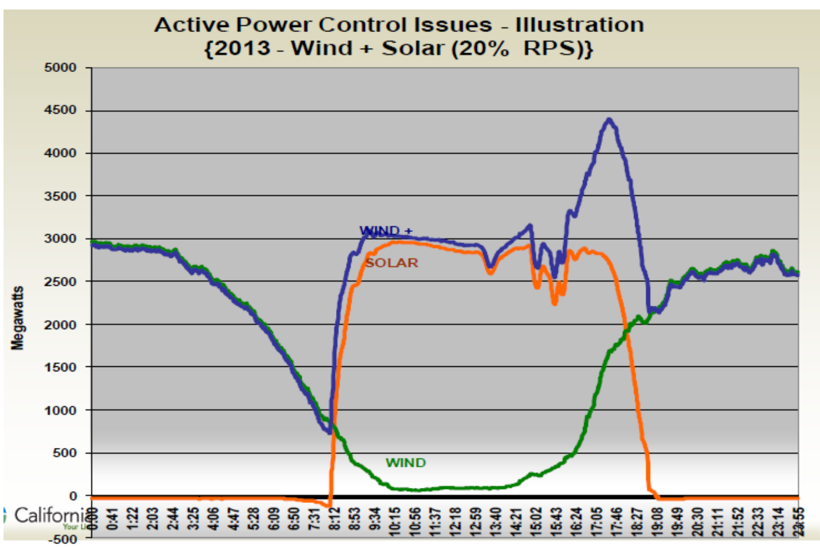
The combination of these characteristics results generally in the following potential operational impacts and requirements as VER production increases:

- Less efficient unit commitment due to forecast uncertainty over VER production,
- Higher system ramps in the upwards and downwards direction to account for variability of supply,
- Increased load following/VER following requirements,
- Increased Regulation requirements in the upward and downward direction, typically varying by hour,
- Increased operating reserve requirements at higher levels of VER production, and
- Increased frequency and magnitude of minimum generation or over-generation events.

While the combination of different renewable technologies, such as wind and solar, may, where possible, smooth out the average production profile, they may also result in ever more complex operational requirements. For example, Exhibit 2-1 below shows the sharp, rapid morning and evening ramps that may become a daily occurrence in California by 2012 under the currently expected mix of wind and solar in the renewable resource portfolio to meet a 20% RPS.[14] In addition, the figure illustrates the variability that will be inherent at times in solar resources, particularly solar photovoltaic. With even high wind and solar capacity anticipated in California from 2012-2020, these ramps will become of even greater magnitude.

Over the past few years, ISOs and RTOs, along with academic researchers, other research organizations and consulting firms, have been utilizing a number of analytical methods both to identify the operational requirements associated with VERs, and to verify that power systems can meet the new requirements. Most of these studies are listed in the literature search provided with this paper (Section 4 and Appendix A below). The literature shows that research into the operational impacts of VERs has evolved over the past few years, including a number of large-scale regional production simulations that incorporate large numbers of wind and solar resource profiles at different locations. In some regions, the resource planning assessments reflected in these production simulations are being integrated with traditional transmission planning methods to result in studies that more explicitly combine interconnection and integration of renewables. Through continued coordination, in part through the IRC, ISOs and RTOs will continue to share and compare analytical approaches and research results.

Exhibit 1-3: Combined wind and solar production profiles in California under a 20% RPS



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[14] This is the renewable resource portfolio currently reflected in load serving entities' contracts submitted to the California Public Utilities Commission (CPUC).

1.3 Market Issues associated with VER integration

The operational issues associated with VERs raise a number of questions for ISOs/RTOs in their function as wholesale market operators, including the design and performance of the energy, ancillary service and capacity markets. As noted, the current market designs, as well as those under implementation (e.g., in ERCOT), appear to provide a sound foundation for VER integration and participation, even as each ISO and RTO is modifying its own rules accordingly in response to, or in anticipation of, VER operational requirements. The FERC NOI is focused on how to facilitate VER participation in the wholesale markets for energy and reserves, and also raises questions about whether new market products are needed or the design and operation of existing product markets needs to be changed. These issues have been contemplated by ISOs/RTOs for several years and some design changes are already in evidence. For example, several markets have recently required that VERs submit economic offers into the real-time market to allow for more efficient dispatch during congestion and in over-generation conditions. Most ISOs/RTOs are examining potential changes to ancillary service procurement to reflect both the variability and forecast error associated with VERs. As will be noted in more detail below, one development is the prospect that any additional procurement of ancillary services will be targeted to the hours with the greatest operational impact by VERs.

Another key market issue is the effect of VERs on wholesale market prices. In the near term, this is manifesting in increased occurrence of negative locational marginal prices in the off-peak hours in some locations and under some system conditions, including congestion. Over the longer-term, most production simulation studies with higher levels of VERs show substantial displacement of fossil energy by the zero-priced renewable energy, resulting in drops in energy prices and fossil generation revenues (although this price reduction could be offset by carbon pricing).[15] Over time, this price impact could become more substantial, especially in high renewable energy states such as Texas and California.

A key finding in discussions among IRC members is that because of different regional scope of each market and different generation mixes (especially the availability of faster ramping resources), there will be different operational and market needs and impacts. Clearly, system operators with large regional scope have a wider resource portfolio for providing ramp and

[15] See, e.g., See PJM, Potential Effects of Proposed Climate Change Policies on PJM's Energy Market, January 23, 2009, available at http://www.pjm.com/~/media/documents/reports/20090127-carbon-emissions-whitepaper.ashx. This study shows the renewable energy reduces energy prices while carbon pricing increases them. Similar studies have been conducted for several ISO/RTO regions.

ancillary services, although these requirements will vary by location and can also be accessed more efficiently through BA coordination, as discussed in Section 2.D. Availability of dispatchable hydro and pumped storage will also provide some systems with greater integration capabilities than others.

1.4 Overview of Paper

This paper provides the additional perspective on integration of VERs gathered from these recent activities by the IRC and its members. As noted above, the paper is also responsive to the FERC NOI. Section 2 of the paper largely follows the structure of the NOI, but provides additional background and perspective based on other IRC activities. This section provides the results of a survey of U.S. IRC members that addresses the questions in the NOI, each of which can be found in the text boxes set aside in each sub-section. ISOs/RTOs will also cover some or all of these questions in their individual NOI comments, but this paper provides a valuable comparative view on operational and market issues. On a number of particular NOI questions, such as the need for specific tariff revisions, the IRC defers to its individual members to provide their views.

Section 3 adds further comparative results by reviewing the experiences of system operators in other countries. This survey includes submissions by the Canadian members of the IRC, as well as a survey of European renewable integration experience.

Section 4 is the summary of a literature survey that identifies which categories of wholesale market and system operations each paper surveyed covers. Appendix A provides the findings of the literature survey in tabular form, with each paper cross-referenced to the NOI section topics.

Section 5 provides an up-to-date survey of RPS policies by States that are within ISO and RTO footprints.

2. Key Issues in Renewable Integration and Market Development with Responses to FERC NOI Topics

A. Data and Forecasting (NOI Topic A)

ISO and RTO control centers and market operations are rapidly being upgraded, as warranted by the volume of VERs on each system, to incorporate day-ahead, hour-ahead and real-time forecasts VER renewable production as well as new operational tools that will increasingly become integral to system operations at higher levels of renewable capacity. Several ISOs and RTOs have also visited and/or surveyed the more advanced European control centers for renewable resource system operations such as the Spanish system operator's renewable control center described in Section 3. In combination with the investments in advanced market and system operational software and solution algorithms made by ISOs/RTOs for conventional system operations, these investments in renewable control capabilities – along with developments in smart grid – will provide the US power system with the capability to efficiently and reliable integrate the much higher levels of VER capacity currently required by policy targets.

Forecasting Variable Energy Resource Production

As noted above, there are two key characteristics to VER production that are central to renewable integration: the high forecast errors associated with VER production prior to real-time and the inherent variability of such production. Reducing forecast error in each time-frame consistent with the operation of day-ahead and intra-day security constrained unit commitment and real-time security constrained economic dispatch will allow for more efficient commitment and dispatch of conventional resources and a reduction in the procurement of ancillary services. In addition, there will be an inter-play between the VER forecast errors and load forecast errors that may mitigate or exacerbate the net impact on system and market operations.[16]

[16] To the extent that VERs and load are both over-forecast or under-forecast in the forward time-frame, then the combination of errors may mitigate the inefficiency of unit commitment and dispatch to some degree. To the extent that the errors are the opposite from each other (i.e., VER production is over-forecast, load is under-forecast, and vice-versa), the inefficiency may be exacerbated.

A.1 What are the current practices used to forecast generation from VERs?

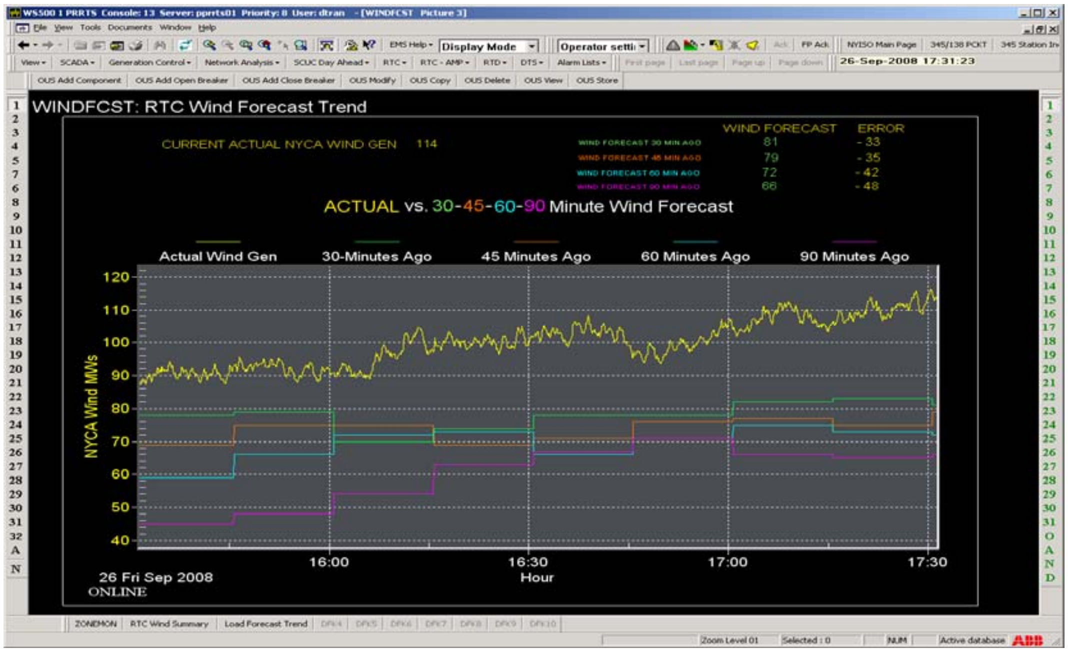
To that end, ISOs/RTOs have become major consumers of VER forecasting services, and are both driving the VER industry to improve its provision of data to improve centralized forecasts as well as providing market-driven incentives for improvement of decentralized forecasting. An equally important development is the evolving application of forecast data in new or upgraded operational and market tools, including real-time visualization capabilities that will assist system operators in situational awareness and probabilistic ramp forecasting tools that may increasingly inform unit commitment and dispatch algorithms over time. ISOs/RTOs are making continuous investments in upgrading their operational capabilities, through surveys of commercial tools and through research collaboration to develop new ones. Exhibit 2-1 shows a screen shot of a wind forecast trend tool in use at NYISO. Exhibit 2-2 shows a screen shot of the current CAISO wind forecasting display. CAISO has significant new visualization capabilities as well, which will be incorporated into its new control center in 2010-11.

The discussion of current forecasting practices that follows has three sub-topics: the status of centralized VER forecasting and a description of the vendors and methodology; the data that VER operators are required to provide to the forecast vendor; and the time-frames of the forecasts and accuracy in those time-frames.

ISOs/RTOs have been at the forefront of developing centralized VER forecasting since 2004, when CAISO established the first such ISO/RTO program in the US under its Participating Intermittent Resource Program (PIRP). Since then, formal, centralized processes for forecasting wind energy have been established in all the ISOs/RTOs, except ISO New England and SPP, where such processes are under evaluation.[17] CAISO has recently begun to develop a centralized solar energy forecast; the potential operational impact of the combination of wind and solar production is shown above in Exhibit 1-2.

[17] The dates of operation of central wind forecasts in the ISOs and RTOs are surveyed, along with other forecast characteristics, in K. Porter and J. Rogers, “Central Wind Power Forecasting Programs in North America by Regional Transmission Organizations and Electric Utilities,” NREL Subcontract Report, NREL/SR-550-46763, December 2009.

Exhibit 2-1: NYISO Wind Forecast Trend Tool for Operators



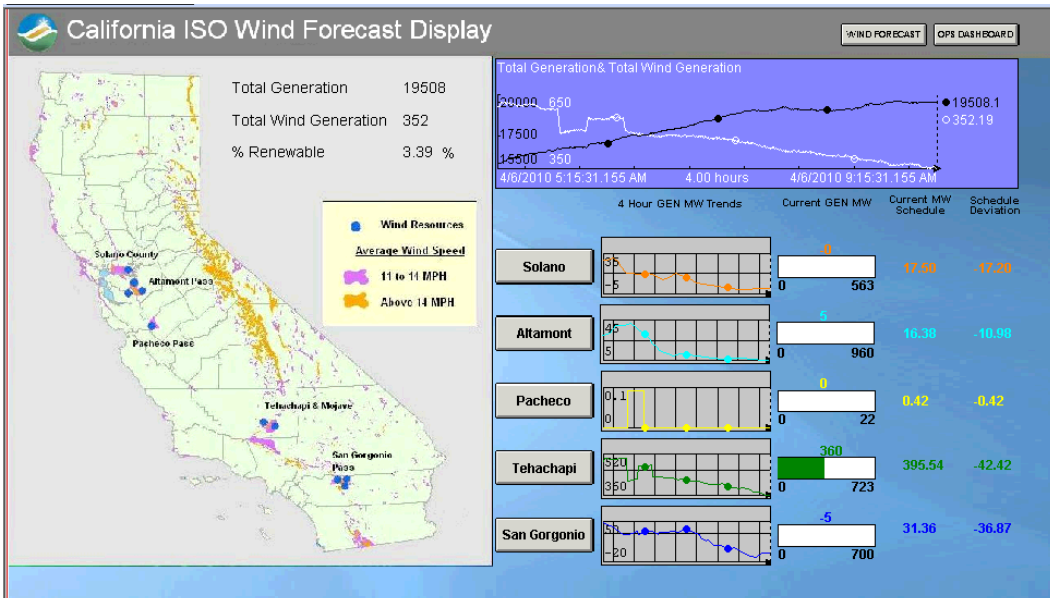
To date, the centralized VER forecasting systems used by the US ISOs/RTOs have utilized two different commercial vendors.[18] PJM and Midwest ISO currently use the Energy & Meteo GmbH system, which is based upon a physical model that uses Numerical Weather Prediction (NWP) forecasts as inputs,[19] a combination of three numerical weather models, each weighted according to the weather situation, site-specific power curves based on historical data, and a shorter-term model (0-10 hours) based on wind power measurements and NWPs.

CAISO, ERCOT, and NYISO currently use AWS Truewind systems, but with some differences in inputs and applications. AWS Truewind uses ensemble forecasts and statistical analysis that utilize 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.

18 Ibid.

19 The National Weather Service (NWS) and National Oceanographic and Atmospheric Administration (NOAA) provide the numerical weather prediction models tuned to providing temperature and rain forecasts for the entire United States. These models are the baseline inputs to the forecasters' wind and solar predictions.

Exhibit 2-2: California Wind Forecast Display



An open question is whether ISOs/RTOs should explicitly develop centralized forecasting systems that utilize multiple sources of forecasts, either under contract or through voluntary relationships. For example, CAISO has recently completed a study of three commercial wind forecasting vendors, each of which improved the ISO's current day-ahead and hour-ahead forecasts, but concluded that employing all three forecasts was not necessary at this time.[20] In other regions and countries (such as Germany) multiple forecasts are used. Most of the ISOs/RTOs find that they can achieve a better aggregate VER forecast using a centralized forecast than they can obtain from the sum of the forecasts developed by the VER operators. However, ISO-NE and Midwest ISO also receive energy forecasts directly from the VER operators, which could complement central forecasts. Other entities, such as large load-serving entities with RPS obligations, within ISO and RTO footprints are also potential consumers of

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20 See CAISO, "Revised Analysis of June 2008 – June 2009 Forecast Service Provider RFB Performance," March 25, 2010, available at http://www.caiso.com/2765/2765e6ad327c0.pdf. The determination not to procure all three forecasts at present was based on the reliability of forecast delivery and the correlations between the forecast providers. Some further results of this study are discussed below.

advanced forecasting capabilities to assist in efficient VER scheduling.[21] In some markets, and especially at higher VER penetration, virtual bidders may also seek to acquire commercial VER production forecasts to assist in arbitrage of the day-ahead to real-time locational marginal prices for energy. Hence, it is possible, as with load forecasting in some systems today, that over time, ISOs/RTOs – as well as other entities within their markets – will make use of multiple commercial and other sources of forecast services to develop a consensus forecast or weighted average for use in market and reliability operations.

A crucial input into the centralized forecasts is VER data. ISOs/RTOs generally require VERs to provide a range of real-time meteorological data, such as wind speed/direction,[22] barometric pressure, humidity and ambient temperature as well as current MW output, along with physical data such as power curve, location and hub height to forecast providers. Since there are differences in the required generation data among the ISOs/RTOs, there will also be different results from the same vendor. Lessons learned for improvements in data collection and quality are discussed in the next section.

Until recently, VER scheduling in ISOs/RTOs was conducted in the hour-ahead time-frame using forecasts provided in that time-frame. More recently, particularly in systems with high and increasing VER production, day-ahead forecasting has become more important and efforts are being made to improve such forecasts both for the ISOs/RTOs reliability unit commitments and to encourage additional day-ahead VER scheduling. For example, CAISO currently has a centralized vendor provided day-ahead (18.5-42.5 hours ahead) forecast and an hour ahead (105 minutes ahead) forecast for those units that participate in the PIRP. CAISO is also developing an intra-hour 15-minute ahead forecast (for the next 2 hours) that is highly based on a persistence model. At the NYISO, day-ahead, hour-ahead and intra-hour VER forecasts are developed and continuously updated with real-time measured output data for utilization within the scheduling and dispatch systems. Elsewhere (PJM and Midwest ISO), intra-hour forecasts are also in place or under development, providing the capability to detect ramps and incorporate real-time forecast updates.

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21 For example, in CAISO, Southern California Edison (SCE), which will be the scheduling coordinator for many of the VERs sited in southern California, is also improving its centralized forecasting capabilities using a commercial vendor, as well as establishing curtailment provisions within its renewable energy contracts to manage its financial exposure in the CAISO markets.

22 Wind direction is important because it affects the "shadow effect" for a given wind farm – turbines are typically constructed so as to minimize shadow effect for a given direction but conversion efficiency will decrease for some other directions.

Practices vary in how these forecasts are incorporated into the scheduling process. Currently, in the day-ahead timeframe, VER forecasts are only advisory with no binding commitments or schedules issued for VERs (although, as discussed below, market rules vary as to whether VERs that are capacity resources are required t0 schedule in the day-ahead markets). In the hour-ahead timeframe, the scheduling process is either bid-based or VERs are scheduled by a market entity based on the vendor forecast for that resource (such as a scheduling coordinator in CAISO).

A.1 (cont.) Will current practices in forecasting VERs' electricity production be adequate as the number of VERs increases? If so, why?

ISOs/RTOs have been continuously evaluating and improving their forecasting practices in anticipation of the significant increase in VER production (mainly wind, but also solar in California) that could take place during the 2010-2020 timeframe. This increase would result in doubling or tripling capacity and energy from VERs, with some ISOs or RTOs expecting target VER penetration levels around 20-33% of total energy production, reflecting renewable portfolio standards (see discussion in Section 6). Some needed changes to current practices are discussed here and others in the subsections that follow.

VER forecasting needs to be improved in the day-ahead and 2 hour-ahead time-frames as well as in the shorter term (15 minutes and less) time-frames that affect quick-start unit commitments and economic dispatch instructions. Improvements are measured by the magnitude and frequency of forecast errors, their occurrence in particular periods of the operating day and rate of change between periods, and the impact on errors of geographical diversity and the technology mix. Forecast errors (typically measured in Mean Absolute Errors, MAE, or Root Mean Square Error, RMSE) in the day-ahead forecast typically range from 6%-10% MAE of installed capacity, but a couple of ISOs/RTOs measure errors of >10% MAE of installed capacity in the production forecast.

A particularly important forecasting problem is the ability to forecast the onset, severity, and timing of ramps or high speed cutouts of VER production from high levels to near zero energy output and back with sub-15 minute accuracy. Due to transmission congestion and related issues, VER energy forecasting needs to be improved on a locational basis, not simply a large area aggregate basis. This is discussed further below.

In some ISOs/RTOs, some basis for forecasting VER production from distributed resources – those "behind the meter" or on the distribution circuits – will be required as the amounts of such

VERs increase. They are invisible today in many ISOs/RTOs but are subject to the same meteorological effects as grid connected VERs. With the deployment of smart grid technologies around the country this is practical and it should be the responsibility of the load serving entity or the local distribution company to provide actual and forecast data for distribution level VER on a "take out point" basis to the ISOs/RTOs. This is also discussed further below.

Measures for improving VER forecasting

Since several ISOs/RTOs already have state-of-the-art forecasting systems, or ones that are close to state-of-the-art, the current focus is on how to continuously improve the existing systems and transfer the lessons learned to VER forecasting systems in earlier stages of development. In addition, the market rules regarding the benefits of accurate VER forecasting have to be aligned with the responsible VER forecasting entity to provide the incentive to ensure the most accurate VERs forecasts.

These lessons apply to the quality of data collected as well as the rules for sampling. Accurate forecasts rely fundamentally on high quality data made available in a timely manner to the forecast providers for use within their models. All ISOs/RTOs have experienced the effect of poor data quality on forecast quality, requiring improvements where necessary to telemetry data from VER sites.

A.2 What is necessary to transition from the existing power generation forecasting systems for wind and solar generation resources to a state-of-the-art forecasting system? What type of data (e.g., meteorological, outage, etc.), sampling frequency, and sampling location requirements are necessary to develop and integrate state-of-the-art forecasts, and what technical or market barriers impede such development?

In addition, ISOs/RTOs have found that the outage information of the site must be provided within a reasonable time after a forced outage or de-rate is detected. Scheduling of planned outages and de-rates also generally needs improvement with respect to both the timing and capacity changes.

Typically, there are rules for how far from a sensor a wind turbine can be or how many meteorological data collections towers (met towers) are needed. However, there are no standardized data requirements for wind VERs and only CAISO currently monitors meteorological conditions for solar plants. A common format for communicating data between wind farms and control centers, similar to ICCP, is necessary. Barriers to getting high quality data (i.e. more sensors per wind project or area and higher sampling frequency) are mostly driven by economics and relate to installation and maintenance of sensor equipment. Some ISOs/RTOs also note that they do not have visibility to VERs installed below the take-out point or that data requirements affect only VERs that enroll in certain programs (such as the PIRP in CAISO).[23]

The system operator should be able to require measurement information at a functional level; for instance, to be able to require that wind speed information is sufficiently accurate and proximate to enable calculation of wind farm production within a certain accuracy. When discussing actual wind speed and actual production, the accuracy tolerance can reasonably expected to be within 1%. This will enable the system operator to eliminate sensor error as a factor in developing forecasting tools.

One approach to stimulating improvements among forecasting vendors is through competitive solicitations for forecasting needs with well-specified requirements. Several ISOs/RTOs have conducted such solicitations, including AESO and CAISO. For example, over 2008-09, CAISO undertook an evaluation of wind forecast vendors.[24] Some findings of that study regarding the potential for forecast improvement and some fairly general recommendations are summarized here, directly excerpted from the study.

First, the CAISO specified, and the vendors delivered, improvements in both the prior day-ahead and hour-ahead forecast errors. The aggregate day ahead forecast error was reduced to less than 15%, calculated as the root mean square error (RMSE). This level of forecast error represents a substantial improvement over past CAISO experience with day-ahead forecasts. The aggregate hour-ahead forecast errors was reduced to less than 10% RMSE, which represents a 20% improvement in forecast accuracy over the CAISO's prior hour ahead forecast methodology.

Second, the results confirmed that for most hours of the day, both the day-ahead and hour-ahead forecast errors were below the aggregate error, with higher than average errors concentrated in less than 25% of hours.[25] As an illustration, the (anonymous) day-ahead

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23 In that regard, there is the expectation in CAISO that all future VERs will be enrolled in PIRP, but this remains to be seen.

24 See CAISO, "Revised Analysis of June 2008 – June 2009 Forecast Service Provider RFB Performance," March 25, 2010, available at http://www.caiso.com/2765/2765e6ad327c0.pdf.

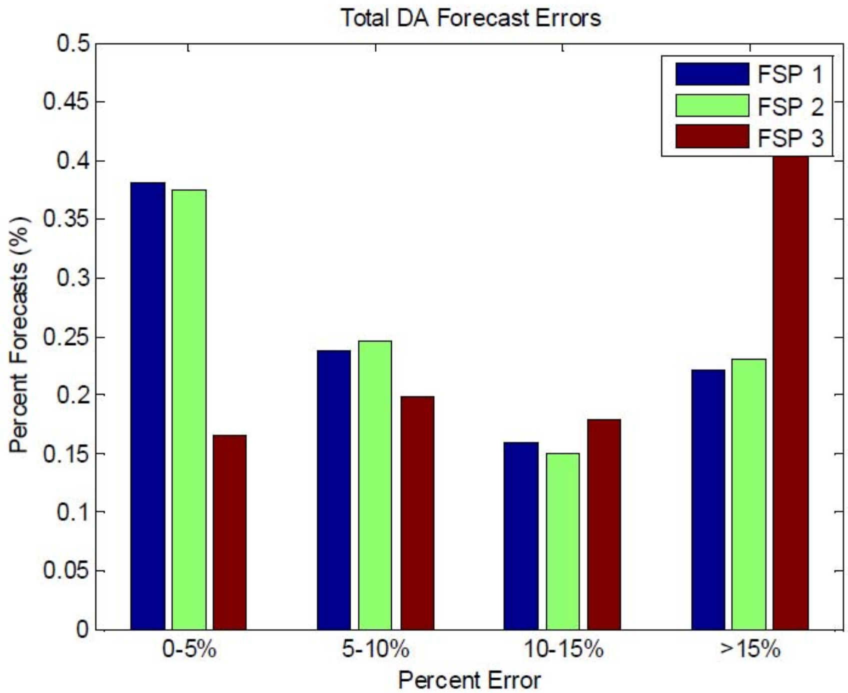
25 For example, of the day-ahead errors, nearly 40% had an absolute error of less than 5%; over 60% of all day ahead forecasts demonstrated an absolute error of less than 10%; and over 75% of all day ahead forecasts have an absolute error of less than 15%. Similarly to the day-ahead forecasts, the majority of the hour-ahead forecasts had lower than 10% RMSE: approximately 50% of the hour ahead forecasts have an absolute error of less than 5%; approximately 75% of hour ahead forecasts

forecast error performance of the competing vendors, labeled as Forecast Service Providers (FSP), is shown in Exhibit 2-3.

Third, because the vendors were providing forecasts for wind resources at multiple locations, the results showed that geographic diversity and aggregation of forecasts for individual wind facilities improve overall forecasting accuracy in both the day-ahead and hour-ahead time frames. Fourth, forecast performance was found to be best at production levels greater than 80% of total capacity and, on the other hand, less than 20% of total capacity. This suggests that forecast accuracy will be higher during the relatively infrequent periods of high capacity utilization and the periods of low wind generation output. Low wind generation output generally coincides with the winter season and high ambient temperatures, which correlates to high demand. Production is most volatile in the wind facilities' mid-range of production.

demonstrate an absolute error of less than 10%; and nearly 90% of all hour ahead forecasts demonstrate an absolute error of less than 15%.

Exhibit 2-3: Day-ahead forecast errors of alternative wind forecast vendors



The study results, as well as discussions with other balancing authorities seeking to improve forecasting, led to a number of recommendations intended to improve forecast quality. In addition to recommendations for improvements in data quality, already discussed above, the study showed significant advantages in regional day-ahead forecasts, as forecast accuracy was improved when several wind plants are considered together. This advantage was particularly evident for the day-ahead forecasts, which would be used to inform the ISO/RTO's day-ahead market in which most next-day unit commitment decisions must be made. Using a regional day ahead forecast does not eliminate the need for more accurate sub-regional forecasting for congestion management purposes.

Another recommendation was to consider lowering the confidence levels required of day-ahead forecasts. The study specifications required 90 percent and 95 percent confidence levels. The 95 percent level in particular did not provide useful information because of the large interval size and the inability to achieve that performance target. Applying an 80 percent confidence interval may result in a smaller and, therefore, more useful intervals if the confidence interval approach is desired. Adopting an exceedance approach,[26] as currently done by ERCOT for day-ahead wind scheduling,[27] could potentially provide advantages over a confidence interval approach. For example, using this method would set a level in which forecast providers are 80 percent confident that the day-ahead production will exceed, rather than a band surrounding the forecast. An advantage of the exceedance approach is that it provides greater certainty that the forecast error will be in a particular direction.

A further recommendation is that continual analysis of forecasts on an ongoing basis can ensure the ISO is receiving the quality forecasts that it expects. The analysis can also be used to provide feedback to the forecast provider in an effort to improve forecasts. Continual forecast evaluations would naturally occur with a dedicated forecasting staff.

Finally, the recommendations include that federal weather agencies should be required to improve forecasts. The ISO/RTOs should actively coordinate with other balancing authorities impacted by VERs to advocate for improvements to these models.

Forecasting extreme VER ramp events

The severity of VER ramping events is highly dependent on both the weather causing the ramp and geographic diversity of VERs in the ISOs/RTOs region. Wind ramps can be caused by air mass changes, thunderstorms, cold fronts, nocturnal stabilization, pressure changes, and other transient atmospheric events. Ramping of any one wind farm due to a fall off in wind speed is not as dramatic an event as the loss of a major conventional plant today. However, a fall off, such as high speed cutout, in wind speed that affects all the VERs in one region within a narrow time frame may be as severe as or more severe than a single conventional generator failure. Geographic diversity will lessen the effect of a fall off within a narrow time frame across multiple wind farms. With highest penetration of wind capacity in the US, ERCOT has also experienced the most significant wind ramp events.[28]

[26] Exceedence would be given as a minimum level that the resource is expected to exceed the specified production percent of time.

[27] See http://nodal.ercot.com/docs/pd/ems/pd/wpforc/TN.EMS.61C01.WindPowForecastingReqSpec.doc.

[28] For discussion, see, e.g., E. Ela and B. Kirby, "ERCOT Event on February 26, 2008: Lessons Learned," *Technical Report,* NREL/TP-500-43373, July 2008.

A.3 What data, forecasting tools and processes do System Operators need to more effectively address ramping events and other variations in VER output, and to validate enhanced forecasting tools and procedures?

Ideally, the timing, magnitude, and rate of the ramp could be forecasted. A 300 MW wind farm that ramps to zero across 30 minutes is a different magnitude of problem than one that ramps to zero in five minutes. Forecasting wind speed variability sufficiently well is not within current state of the art, perhaps because there are differences in the geographical terrain, inadequate wind sensors and near real time wind speed information available to permit it. Historical NOAA data is not sufficient to develop solutions.

A number of ISOs/RTOs have been working with researchers and forecast vendors to develop such tools. For example, ERCOT recently implemented a ramp forecast tool in its control room. The tool looks 6 hours ahead with a granularity of 15 minutes and it designed to warn system operators of periods in which there is a significant probability of a large ramp in wind power output. This is performed at both the system level and on a regional basis. Forecasted attributes of the ramp event and weather information are also included as part of the tool.[29]

A.4 What operational, outage and meteorological data should the Commission require VERs to provide to non-VER System Operators? To what size resources, in MWs, should any such data requirements apply, and what revisions to the pro forma OATT would be necessary to accommodate these requirements?

Consideration should be given to expanding the collection facilities for meteorological data that are local to the VERs and from neighboring systems that reside close to a VER at the proper boundary level height. As the penetration of VERs increase, the application of redundant instrumentation and communication paths are necessary to ensure visibility of the VER energy is continually available to the System Operators.

As noted above, VER operators should provide the System Operator with day ahead forecasted VER availability and actual VER availability in real time. Over time the System Operator will be able to determine its own outage statistics for each VER facility for use in capacity planning and reserve requirement determination.

The VER operator should provide meteorological data sufficiently close to the facility and accurate such as to enable calculation of power production within 1%. Each VER operator of a

[29] See http://www.ercot.com/news/press_releases/2010/nr-03-25-10a.

facility should provide wind speed and direction information for that facility. The ISO and RTO System Operator should have the information to generate or have generated an accurate centralized forecast or if the ISO or RTO uses a distributed VERs forecast, retain the responsibility to identify and certify forecast service providers.

Availability of meteorological data for forecasting

A.5 State-of-the-art forecasts may necessitate the sharing of meteorological data across regions to assure that the movement of weather patterns can be accurately predicted and analyzed. To what extent should meteorological data be made publically available to aid in the development of state-of-the-art forecasts? Should the Commission require public utilities to maintain a meteorological data reporting system? If so, should such a system be akin to or in collaboration with Open Access Same Time Information System (OASIS) postings? In order to retain the confidentiality of commercially sensitive data reported by VERs for the purpose of developing state-of-the-art forecasts, what limits and/or safeguards should be established to protect operational data and generator outage reports?

There is currently some degree of shared weather forecasts across ISOs/RTOs, and this may increase with higher VER penetration. Since most forecasters use NOAA/National Weather Service based forecast models which are regional in scope, real-time meteorological data from the VER sites can be shared with neighboring ISOs/RTOs or balancing authorities to extend the wide area visibility of meteorological actual conditions using existing data exchange communication protocols, such as ICCP. PJM and Midwest ISO use a common forecast vendor, and they do share wind power forecasts and permit the vendor to share real-time telemetered data to enhance each others' forecast accuracy.

In some cases, meteorological data from neighboring regions is available but not uniformly requested at this time. Sharing of forecast and actual data especially among adjacent systems will be valuable in the future, especially as the number of reporting locations increases and the accuracy of those reports improve.

In the future, as needed, near-term meteorological data (day-ahead, hour-ahead) could be shared more extensively between the ISOs/RTOs and other Reliability Coordinators whether the source is the one that the ISO or RTO procures, provided via the VER, or provided by local utility systems. This has a market implication in that all generator and demand response resources in a market will not have awareness of likely VER production for their own scheduling and bidding capability. On the other hand, it precludes the VER from having local competitive advantage with such operational data. This would not preclude forecasting services from adding other value added information capabilities that were not made public. Generator availability forecasts and outage reports should be treated on the same basis for VER as for conventional generation resources.

Combining decentralized and centralized forecasting

As noted, most ISOs/RTOs use a centralized forecasting procedure and others are evaluating the VERs forecasting methods as the penetration of VERs increases.[30] There appears to be a consensus that a centralized forecast is needed, rather than the collection of multiple individual VER operator forecasts (given the quality differences that may occur between such individual forecasts). There is also the view that multiple central forecasts coming into the System Operator may provide an advantage as operators learn the properties of each forecasting method and results for particular conditions. However, there was no consensus on how to mix both centralized and decentralized forecasts at the same time and whether that would result in an improved ISO/RTO forecast.

A.6 Should the Commission encourage both decentralized and centralized meteorological and VER energy production forecasting? For example, should transmission providers have independent forecasting obligations as part of their reliability commitment processes similar to what is done today for demand forecasting?

As noted above, transmission providers or load-serving entities may be a part of the data collection in that their facilities may contribute to the measurement and data collection process. However, it is not clear that each transmission provider or load-serving entity in an ISO/RTO market should be required to additionally provide VER forecasting services to the System Operator.

[30] Porter and Rogers, "Central Wind Power Forecasting Programs in North America by Regional Transmission Organizations and Electric Utilities," op. cit.

Forecasting Distributed VERs and Operational Impacts

A.7 To what extent is a lack of data regarding the operational status and forecasted output of distributed, or behind-the-meter, VERs leading to a need for additional reserves? To what extent would the provision of such data reduce the need for System Operators to rely on reserves?

For regions with high penetration of distributed VERs, LSEs and Distribution companies will eventually be required to provide VER actual production and forecast information on a "take out point" basis to the system operator if the VER production is not visible to the ISO or RTO. They should also be required to provide regular estimates of installed VER capacity on the distribution circuits and behind the meter on the same basis.

Today the largest US concentration of distributed solar VER is in the Southwest and is still not a significant contribution to the total generation. For instance, there is 400 MW of distributed Photovoltaic (PV) and solar thermal generation in California as of 2009, but this is forecast to double by 2012 and to grow nearly tenfold by 2020. These projections may be conservative as costs decrease and incentives are extended. At 400 MW, the behavior of solar in a system whose peak load is approximately 56,000 MW is insignificant.

No ISO or RTO currently considers distributed VERs when considering reserve requirements. But as penetration increases for distributed or behind-the-meter VERs, ISOs/RTOs' reserve requirements could be impacted. Moreover, with the increase in solar VERs and in concentration (e.g., in Southern California) VERs may become an operational issue. CAISO is conducting operational simulations of 33% RPS in California, including a "high Distributed Generation" scenario that will calculate Regulation and load-following requirements associated with 15,000 MW of distributed solar PV.[31]

At the present time, the cost effectiveness of measuring distributed PV output would be dubious, absent the deployment of Smart Grid technologies in these areas. Consideration should be given to requiring distributed generation measurement and data collection whenever Smart Grid technologies are deployed where PV exists.

[31] These results will be available in 2010.

B. Scheduling Flexibility and Scheduling Incentives (NOI Topic B)

Effect of shorter scheduling intervals

For the ISOs/RTOs, there are differences in the scheduling intervals for (a) the internal ISO/RTO scheduling processes (that is, in the markets) and (b) the inter-ties with neighboring balancing area authorities, including both other ISO/RTOs and non-ISO/RTO regions.

> *B.1 Would shorter scheduling intervals allow System Operators to more efficiently manage the ramps of VERs and/or demand? To what extent would the availability of intra-hour scheduling decrease the overall reliance on regulation reserves to manage the variability of VERs?*

Turning first to internal scheduling, the scheduling intervals used by ISOs/RTOs vary between the day-ahead and real-time processes and markets. All the US ISOs/RTOs with the exception of SPP and ERCOT currently operate day-ahead markets with security-constrained unit commitment (SCUC) that consist of a day-ahead auction market for energy and certain ancillary services, followed by a reliability unit commitment (which is either integrated with the day-ahead market and used to set day-ahead energy prices, as in NYISO, or follows after that market and is not used to set day-ahead energy prices, as in the other ISOs and RTOs).[32] The scheduling interval in the day-ahead markets and subsequent reliability unit commitments is hourly (24 hours). After the day-ahead market schedules are finalized, the hourly schedules are adjusted to reflect changes in system conditions and market participant positions (including self-schedules) until a scheduling deadline prior to the real-time operating hour. The system operators also conduct additional unit commitment assessments that are typically on a intra-hourly basis (often on 15-minute time intervals) for a number of intervals ahead, and then conduct the real-time dispatch market within the operating hour on intervals of 5-10 minutes. These internal scheduling processes and their implications for VER integration are discussed in more detail under Topics C, E, and G below.

With respect to inter-tie scheduling intervals for ISOs/RTOs, these are summarized in Exhibit 2-4. The first column shows the scheduling intervals; the second column shows the ramp schedules across the ties. This table does not include dynamic schedules from external

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32 In CAISO, the day-ahead reliability unit commitment – called the "residual" unit commitment – can also set next day capacity prices for non-Resource Adequacy resources.

resources, which are typically scheduled consistent with the ISO/RTO's economic dispatch (but currently only account for a very small percentage of imports). Dynamic schedules are discussed further below under Topic D.

Exhibit 2-4: ISO and RTO scheduling intervals on inter-ties (excluding dynamic schedules)

ISO/RTO	Inter-tie Scheduling Interval	Timing of interchange schedule ramps
California ISO	1 hour	The standard is 20 minutes across the top of the hour for changes in self-schedules
ISO-New England	NE-NY - hourly. NE-NB - hourly. NE-HQ - hourly.	
Midwest ISO	quarter-hour	
New York ISO	1 hour	5 min before and 5 min after the top of the hour
PJM	1 hour	Interchange schedule changes ramp in over a 10-minute period, every 15 minutes starting at 5 minutes before to 5 minutes after the hour.
SPP	1 hour	

In general, schedules on the inter-ties of renewable energy, with the exception of dynamic schedules, are "firmed" and do not require any additional reserves for purposes of VER integration within the ISO or RTO. If the intra-hour scheduling was for dynamic scheduling, then the ISO or RTO conducting the dynamic schedule would be responsible for some or all of the integration requirements associated with the schedule. Since dynamic schedules are typically on a 5 minute basis, the integration requirements, including ancillary services, are procured by the originating ISO or RTO.[33] As discussed in responses to the questions below, there is a

[33] See, e.g., CAISO, Dynamic Transfer Straw Proposal, March 10, 2010, available at http://www.caiso.com/2755/2755e7b852d20.pdf.

general view that while shorter scheduling intervals on the inter-ties may provide some benefits for renewable integration, the implementation costs likely outweigh any potential benefits at this time.

Implementation of Intra-hour Scheduling on Interties

> *B.2 What are the benefits and costs of allowing resources and transactions to schedule on an intra-hour basis, and what tariff and/or technical barriers exist to implementing intra-hour scheduling? Are there best practices that could be implemented to facilitate greater intra-hour scheduling?*

ISOs/RTOs are supportive of moving towards intra-hour scheduling across the inter-ties for purposes of VER integration where merited by system needs, and some have already implemented such scheduling. In the Midwest ISO, moving to quarter-hour scheduling for external resources helped reduce the volatility in net actual interchange and hence reduced the need for market operators to carry reserves, driving down costs. PJM notes that it already checks out its internal 15 minute schedules with neighboring balancing authority areas. In addition, NBSO has conducted an intra-hour schedule change pilot with ISO New England. There has been substantial analysis of the costs and benefits of greater coordination between ISOs, and some of the bilateral agreements, such as between Midwest ISO and PJM, or PJM and NYISO, may become the basis for any changes in scheduling intervals, as appropriate. One general observation is that while market efficiencies could be achieved with more frequent inter-ISO scheduling to allow more rapid balancing of generation changes in each region, a closely coordinated process would be required to allow for such intra-hourly scheduling to achieve its desired outcomes.

The benefits of such changes are likely to become more significant at higher VER penetration, particularly in the larger RTOs such as PJM and Midwest ISO. Clearly, where there are transmission constraints that would allow VERs to be more efficiently integrated through a more closely coordinated dispatch with a neighboring market, such changes would be beneficial.

There will also be costs to such changes. In many cases, current software cannot currently handle intra-hour scheduling or a substantial expansion of economic dispatch across the interties (i.e., dynamic scheduling). To the extent that certain functions are performed by control room operators and telephone communication, as opposed to software and electronic communications, there is a practical limit to the frequency with which all the necessary market and reliability functions can be performed. Costs for additional manual adjustments and software development have not yet been determined.

B.3 Are there an optimum number of intervals within the hour for scheduling? What time increments would be necessary and/or desirable in order to achieve optimum flexibility while still meeting the relevant reliability requirements?

Each ISO/RTO would have to assess the cost impact of implementing shorter schedule periods (whether through static or dynamic schedules) in terms of market interface tools, the co-optimization scheduling software, and the settlements software. Additionally the market participants would have adjustments to make to their own systems. Even though several ISOs have demonstrated that such a change can be made successfully, the costs that each of the other ISOs would entail will not be trivial. In addition, there may be the need for tariff changes, e.g., to address how integration costs (e.g., ancillary services and uplifts associated with market operations) are allocated between external and internal VER.

As noted, most ISOs/RTOs agree that moving to intra-hourly scheduling could improve VER integration across market seams. However, there is as yet no consensus about the exact number of intervals or when particular ISOs/RTOs should implement intra-hourly scheduling across particular boundaries with other systems to facilitate VER integration, which may be a function of the locational distribution of VERs.

B.4 Identify any reliability issues that may result from changes to the scheduling rules. What changes, if any, to NERC Reliability Standards would be needed to fully implement additional scheduling flexibility while still ensuring reliability?

With respect to the reliability issues associated with changing scheduling rules on the inter-ties, as long as the importing and exporting balancing authority areas have agreed clearly which is taking responsibility for the firming and shaping of the sub-hourly schedules, there should be no reliability issues. However, the ISOs/RTOs will further examine this issue following the forthcoming results from the NERC IVGTF.

Impact of intra-hour scheduling on other transmission scheduling procedures

B.5 How would intra-hour scheduling affect the operation of other processes such as available transfer capability (ATC), the E-Tag system, issuance of dispatch instructions for generation and/or demand resources, transmission loading relief procedures, and/or dynamic schedules? What costs would be incurred as a result?

Scheduling of external transactions with neighboring control areas involves coordinating day-ahead and real-time schedules and dispatch, transmission reservations, E-tags, and available transfer capability (ATC). Intra-hour scheduling would clearly affect all these scheduling and reliability procedures on the interties, each of which would need to be adapted. All production and back office software systems are linked to scheduling procedures and would need to be updated to support such a change. While some ISOs/RTOs have already implemented aspects of such changes (as shown in Exhibit 2-4), there has been no cost-benefit analysis of such changes that considers all the relevant factors, such as the level of VERs being scheduled across the interties, regional VER integration capabilities, and the potential mix of static and dynamic schedules. However, this type of analysis is beginning to be undertaken in some regions.

The ATC calculations today are hourly: the ATC for the next hour explicitly uses the static and dynamic schedules for the next hour and if all ramps per NERC standards are met before and after the hour there should be no limit violations.[34] If internal resources are scheduled at 15 minutes during a period of load pickup, for instance, and interchange is still on a one hour basis, then it is possible that the ATC would need be adjusted during the hour.

A related question is whether high VER levels across control area boundaries will necessitate changes in the ATC calculation itself to allow more flexibility in dispatching across the boundary in response to VER behavior, especially when it deviates significantly from forecast. An example could be a balancing authority area that is importing large amounts of VER and taking responsibility for firming the VER which it then contracts to hydropower resources in another adjacent area in effect purchasing reserves from that area. The ATC may have to reflect this contingent usage.

[34] The transmission reservation for dynamic schedules for the hour (assuming that other schedules remained hourly) are developed based on expected delivery from the dynamically scheduled resource. This becomes part of the ATC calculation.

In some ISOs/RTOs, transmission line-loading relief on the interties during the operating hour is currently conducted when operating conditions change; the ISO/RTO then first curtails dispatchable transactions if possible (within the time-frame of the market software updated to reflect the changed conditions) and then undertakes pro rata curtailments of self-scheduled transactions. Physical curtailment is clearly less efficient than price-based redispatch; however, to the extent that intra-hour scheduling is implemented, it should improve the efficiency of transmission line-loading relief by allowing for schedule changes within the hour that now take place only across the operating hours.

B.6 If intra-hour scheduling is implemented in non-RTO/ISO regions, how would RTO/ISO scheduling practices at interties be affected? Would intra-hour scheduling at interties present problems for RTO/ISO markets? If so, describe the problems and feasible solutions for intra-hour scheduling at interties.

ISOs/RTOs have not presented any significant barriers to changing scheduling practices at the interties if the non-ISO/RTO regions move to intra-hour scheduling. The software and market design requirements were discussed above.

Effect of exemption from third-tier penalties

In Orders 890 and 890-A, FERC sought to provide "consistency among transmission providers in the application of imbalance charges, and to ensure that the level of the charges provides appropriate incentives to keep schedules accurate without being excessive."[35] Specifically, the Commission endorsed a three-tier imbalance charge in which each tier represents successive deviations from schedules and in which VERs are exempt from the third and most severe imbalance tier and associated charge, but are rather charged at the second tier rate.[36]

[35] "Preventing Undue Discrimination and Preference in Transmission Service", Order No. 890, 72 FR 12266, FERC Stats. & Regs. ¶31,241, P 72, (March 15, 2007) ("Order 890"), "Preventing Undue Discrimination and Preference in Transmission Service", Order No. 890-A, 73 FR 2984 (January 16, 2008), FERC Stats & Regs. ¶31,261, P 287 ("Order 890-A").

[36] Order 890 established that: "imbalances of less than or equal to 1.5 percent of the scheduled energy (or two megawatts, whichever is larger) will be netted on a monthly basis and settled financially at 100 percent of incremental or decremental cost at the end of each month. Imbalances between 1.5 and 7.5 percent of the scheduled amounts (or two to ten megawatts, whichever is larger) will be settled financially at 90 percent of the transmission provider's system decremental cost for over-scheduling imbalances that require the transmission provider to decrease generation or 110 percent of the

B.7 Has the exemption from third-tier penalty imbalances worked as a targeted exemption that recognizes operational limitations of VERs, or has it encouraged inefficient scheduling behaviors to develop? If the latter, what reforms to this exemption would encourage more accurate scheduling practices?

The three-tier imbalance charge is applicable to non-ISO/RTO regions; ISOs/RTOs settle imbalances on the basis of real-time locational marginal prices. As noted above and discussed further below, ISOs/RTOs have differed in how they settle real-time imbalances for VERs, but this is not a function of a three-tier imbalance charge.

Incentives for Improved VER Scheduling

As discussed in Section A, almost all ISOs/RTOs have now implemented or are planning state-of-the-art centralized forecasting systems (with efforts at continuous improvement). Within that framework, the ISOs/RTOs differ as to the type of incentives that are used to encourage VERs to provide data to the forecasting vendor that can be used to establish accurate schedules.

B.8 Assuming that efficient forecasting and scheduling practices help minimize deviations between scheduled and actual energy output of VERs, are additional incentives needed to encourage VERs to submit schedules that are informed by state-of-the-art forecasting? What would be the proper incentives?

There seem to be several approaches to obtaining the needed data from VER operators:

- by exposing them to real-time curtailments, on an

incremental cost for under-scheduling imbalances that require increased generation in the control area. Imbalances greater than 7.5 percent of the scheduled amounts (or 10 megawatts, whichever is larger) will be settled at 75 percent of the system decremental cost for over-scheduling imbalances or 125 percent of the incremental cost for under-scheduling imbalances." Intermittent resources (VERs) are exempt from the third tier of these penalties.

economic or physical basis, for congestion and over-generation, which provides the incentives to provide data for more accurate forecasts; or

- through a subsidy-based incentive approach, such as netting and averaging of imbalance charges, which also has to require the specific data and monitoring systems that VERs must provide.

An example of the latter is the CAISO PIRP rules, which allow for an averaged monthly imbalance energy payment for deviations from the unit's hourly schedule, in exchange for providing information to establish a state-of-the-art forecast.

Another incentive approach is that used by ERCOT, which currently requires day-ahead schedules for schedulers with wind resources to get updated with an “80% probability of exceedance forecast”. Further, the VER must outperform the ERCOT centralized forecast in current day operations or they must use ERCOT's forecast.

Another incentive being considered in some ISOs/RTOs is some degree of ancillary service cost allocation to VERs for carrying additional reserves due to VER variability.

Incentives for Improved VER Scheduling in ISOs and RTOs

One of the advantages of the ISO/RTO market design is that it does provide the right inter-temporal and locational price signals to encourage more accurate scheduling by VERs, whichever incentive approach is adopted. The market designs can accommodate any further revisions to further encourage such behavior.

B.9 Under an RTO/ISO market design, are there sufficient incentives to encourage VERs to submit accurate schedules? What costs and/or penalties should be assigned to VERs when their real-time output is not accurately scheduled on a forward basis? Should VERs be treated the same as conventional resources with respect to deviations from their production schedules?

There is no consensus among the ISOs/RTOs as to which aspects of VERs scheduling should be treated exactly the same as conventional resources. All the markets currently waive some charges associated with deviations from hour-ahead production schedules, whether uplift charges (e.g., Midwest ISO, NYISO) or the netting and averaging of energy imbalance charges under the PIRP in CAISO. However, there is also the general sense that as VER capacity increases, the market rules should encourage much greater responsiveness by VERs to market price signals.

C. Day-Ahead Market Participation and Reliability Commitments (NOI Topic C)

Historically, VERs have scheduled at, or close to, real-time in the ISO/RTO markets to avoid the more significant energy imbalance charges that would be associated with scheduling in the day-ahead time-frame. More recently, there has been increased market and policy interest in accommodating VERs in the day-ahead markets. This section first briefly describes these markets and then addresses several key issues.

Most ISO/RTO market designs include voluntary, financial day-ahead auction markets with security constrained unit commitment (SCUC), followed by reliability unit commitments and then by physical real-time markets that clear using security constrained economic dispatch (SCED).[37] The day-ahead auction market typically clears energy and ancillary services on the basis of bid-in, or self-scheduled, supply and demand. That is, it is not required to clear the actual forecasted demand, but relies on administrative rules and economic incentives to achieve that result. For example, where there is a resource adequacy, or capacity, requirement, conventional capacity resources are required to offer their available capacity into the day-ahead auction market; as discussed below, day-ahead offer obligations to VER capacity resources currently vary among the ISOs/RTOs. Almost all the ISO and RTO day-ahead markets also allow both physical and “virtual” bids – both supply and demand.[38] Virtual bids are energy-only bids that may or may not reflect a physical resource. Virtual bidders currently play a role in arbitraging differences in the day-ahead and real-time market prices, and in so doing improve the efficiency of the markets and mitigate the market power of other sellers and buyers. In the future, as discussed below, virtual bidders are expected to play an increased role in accounting for the impact of VERs on the day-ahead auction markets.

The day-ahead auction market results in a set of schedules for each accepted supply offer and locational marginal prices for supply as well as aggregated locational marginal prices for non-price responsive demand submitted into the market; these prices and quantities are used for financial settlement. Following the day-ahead auction market, the ISOs/RTOs run next day reliability unit commitments that clear physical supply against the ISO/RTO’s next-day load forecast. These procedures use eligible generators’ start-up and no-load bid costs to cover commitment costs, but do not calculate energy clearing prices. These reliability commitments or

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37 This basic design has been implemented in CAISO, ISO-NE, Midwest ISO, NYISO and PJM.

38 CAISO will introduce virtual bidding (called convergence bidding) in early 2011.

assessments then continue into the operating day to reflect changes to schedules and system conditions.

C.1 Day-ahead Market Participation by VERs

VERs have begun to participate in the day-ahead energy markets in some ISOs/RTOs, although in most markets not at levels that provide good estimates of their next-day production; VERs are not yet eligible to be participants in the day-ahead ancillary service markets to the extent that they exist in particular ISO/RTO markets.

C.1.1 Does the lack of day-ahead market participation by VERs present operational challenges or reduce market transparency as the number of VERs increases?

As noted above, the ISO and RTO day-ahead markets are largely financial markets with no physical requirement to follow day-ahead schedules. Virtual bidders are explicitly not going to fulfill their day-ahead positions, although they are attempting to forecast locational physical market outcomes in real-time.[39] To the extent that VERs do not submit schedules or bids into the day-ahead energy markets, bid-in day-ahead load will be met through other (non-VER) resources. As is currently the case, those supply resources, whether physical or virtual, will not necessarily be in the same locations as the VERs, so the day-ahead solution may not identify the same transmission congestion as the solution with VERs represented at their physical locations. However, virtual bidders have an incentive to place their bids to reflect real-time locational marginal prices to the extent that real-time congestion can be forecast. The additional issue with attempting to anticipate VER production is that virtual bidders will not have the day-ahead VER production forecast unless they subscribe to a forecasting service. To the extent that the day-ahead solution is not converging with the real-time conditions, this will require that system operators resolve the congestion through the intra-day procedures and real-time markets.

At the current levels of VERs, ISO/RTO markets are not experiencing substantial lack of convergence that is requiring additional interventions by operators. In addition, the markets with higher levels of VER production as a percentage of total load (see Exhibit 1-1) either do not yet have a day-ahead market (ERCOT) or have day-ahead markets that do not yet have virtual bidders (CAISO). Hence, there has been no real test of the impact of high VER capacity on the

39 Virtual bidding takes place at different levels of granularity in different ISOs and RTOs, whether nodal (ISO-NE, Midwest ISO, PJM) or zonal (NYISO).

functioning of the day-ahead market. If VER capacity continues to expand at the expected rates, there should be much further empirical data on this question over the next 2-3 years.

With respect to market transparency, in the scenario with no or minimal VER participation day-ahead, the energy markets may not be less transparent per se (they will function more or less the same as they do today), but, as noted, more experience is needed to understand better the impact of higher VER production on day-ahead to real-time market price convergence and determine what further changes, if any, are needed in the provision of VER day-ahead forecasts to allow the market to respond efficiently.

VER scheduling and out-of-market commitments

"Out-of-market" instructions, sometimes called "manual" instructions, typically refer to commitment, dispatch or de-commitment instructions given by ISO and RTO system operators that do not result from day-ahead or real-time market software solutions. There are variations among the ISOs/RTOs in how these instructions take place and how they are subsequently integrated into market solutions. In general, out of market instructions can take place when there are transmission or generation operating constraints, or intertie flows, that are not fully reflected in the market model, or when outages have altered the topology of the network model and there is a lag in updating the model for market purposes. If the out-of-market commitment or dispatch is out-of-merit order, with a bid above the prevailing locational marginal price, then the resource may need to be paid an uplift to cover its bid costs. Generally, such out-of-market instructions take place in the operating day (real-time market) and are minimal compared to market-based instructions and settlements.

C.1.1 (cont.) Will out-of-market commitments increase as the number of VERs increases? If so, why?

VERs can cause an increase in day-ahead and intra-day out-of-market instructions. One example in the day-ahead market time-frame is that the under-scheduling of VERs could result in a need to manually decommit physical units scheduled day-ahead if virtual bids have not compensated for such under scheduling.[40] Similarly, an increase in minimum generation or over-generation events due to VERs that could not be resolved through market bids in the day-ahead or real-time markets could require increased resort to a physical curtailment protocols

[40] For example, in CAISO physical resources committed day-ahead through the Integrated Forward Market (IFM) are decommitted (if needed) through manual instructions following the Residual Unit Commitment (RUC).

rather than market-based scheduling (see further discussion below in Section 2.G). Another example could be that if the intra-day VER forecast error is such that system operators have to send additional instructions in between market commitment and dispatch instructions, for example due to look-ahead ramp forecasts. ISOs/RTOs will be evaluating how to best integrate such ramp forecasts into market software over time so as to minimize out-of-market instructions.

To this date, a few ISOs/RTOs have begun to report an increase in out-of-market commitments or dispatches due to increasing VER participation. However, it does not appear to be widespread at this time.

Day-ahead market designs and increasing VERs

As noted, ISO and RTO market designs provide a foundation for alignment of day-ahead and real-time market schedules and prices with high VER penetration because almost all physical and reliability transmission constraints and generator operating characteristics are represented in the day-ahead market. The question is whether additional changes to the design of the markets are needed to account for VER production variability and forecast error.

C.1.2 How can new or existing market design features assure that the day-ahead market will accurately represent real-time system conditions and that day-ahead and real-time energy prices will converge under the scenario of increasing numbers of VERs?

VERs can be accommodated by the day-ahead markets in several different ways, not necessarily mutually exclusive. First, VERs can voluntarily take positions in the day-ahead market consistent with their expected output in real-time so as to hedge their real-time financial settlements.

Currently, in CAISO, ISO-NE, NYISO and SPP, there is no obligation on VERs to schedule any of their capacity day-ahead. However, like conventional resources, VERs should have an economic interest in scheduling at least some of their output day-ahead to hedge real-time price volatility. The general observation here is that in markets where VER day-ahead scheduling is voluntary, due to various factors – including possibly contract terms that shield them from market prices, real-time settlement rules, and lack of familiarity with the ISO/RTO markets in some cases – some VERs, as well as scheduling coordinators for those VERs, seem to be scheduling less day-ahead than they should for purposes of hedging, even without any additional rule changes or further subsidies to provide such a hedge. Improvements in voluntary scheduling may be forthcoming with further experience in the markets by the VER operators and the entities that are contracting with them.

Second, VERs can be required to take positions in the day-ahead market consistent with their expected output in real-time, perhaps based on their status as capacity resources or through other incentives.

PJM, Midwest ISO and ERCOT currently impose day-ahead scheduling requirements on some or all VERs. In PJM, all capacity resources are required to schedule day-ahead, and this obligation is extended to VERs that are capacity resources (however, non-capacity resources in PJM, including VERs, do not have this day-ahead must-offer requirement). Neither Midwest ISO nor ERCOT have a capacity market, and ERCOT does not yet have a day-ahead market, but both require some degree of day-ahead scheduling by VERs. In Midwest ISO, VERs that are designated as meeting capacity requirements are required to submit offers in the DA market.

Third, as noted above, virtual bidders can voluntarily take positions in the day-ahead market based on expectations that VER output in real-time is not being reflected in day-ahead schedules and prices. An open question is the degree to which virtual bidders will take the day-ahead positions not (voluntarily) taken by VERs. Some ISOs/RTOs, including NYISO and Midwest ISO, already report that virtual bidders are providing thus function.

Reducing Barriers to VER Scheduling in Forward Markets

There are no specific market rules that create barriers to VER participation in the ISO/RTO day-ahead markets, hence the primary barrier to such participation is uncertainty over the resources' production in real-time (as well as in some markets, existing market rules that provide incentives to VERs to schedule in real-time).[41] Day-ahead markets are hourly markets, and if VER output is both uncertain and expected to vary substantially over a particular hour, then clearing through the day-ahead market will provide a more uncertain hedge to VERs than to conventional resources. However, there is no obvious solution to this at present (except to let virtual bidders take the risk, as is being reported in some markets).

[41] For example, in CAISO, submitting bids into either the day-ahead or real-time markets would currently make VERs that participate in the PIRP ineligible for the PIRP settlement rules in real-time. These rules allow for netting and averaging of imbalance charges for deviations between hourly VER schedules and actual production.

The NOI (C.1.3) questions whether the "timing" of the day-ahead market could be modified to facilitate VER participation. This could refer either to when the day-ahead market is conducted or to the time-steps used in the day-ahead market (i.e., hourly). Most day-ahead markets are conducted in the morning or midday of the prior day. If the day-ahead market was conducted later in the prior day, then in principle VERs could have the benefit of more accurate next day forecasts when they submit day-ahead schedules. However, this would decrease the flexibility of conventional resources, some of which may need sufficient start-up time before the operating hour and may also affect the flexibility of demand response, which also benefits from an earlier forecast of next-day conditions.

C.1.3 Do current RTO/ISO market designs place undue barriers to participation in forward markets by VERs? Could the timing of certain RTO/ISO market design elements, such as the day-ahead market, be modified in a manner that would facilitate VERs to participate more in the day ahead market rather than primarily in the real time market? If so, how?

The other interpretation of this question could be to decrease the time-step in the day-ahead market, for example to a half-hourly scheduling and settlement interval, to facilitate VER scheduling. This approach is feasible, but there has been no study of its likely impact on market performance.

More accurate day-ahead forecasts of VER production should facilitate participation of VERs in the day-ahead market. In markets where VER capacity resources are already required to provide a day-ahead schedule, this would primarily apply to energy-only VERs. As centralized day-ahead forecasts are improved and made available for usage by the individual VER operators, there should be a corresponding improvement in their ability to support day-ahead scheduling decisions. Better tools are needed to forecast weather events and the impact of these events on the VERs energy over time.

C.1.4 Would the use of more accurate forecasting tools facilitate participation of VERs in the day-ahead market rather than primarily in the real time market? If so, how?

As discussed above, a related topic that has received little attention to date is whether to provide the day-ahead forecasts to other market participants, such as virtual bidders.

Not only will the markets and VERs benefit from improved forecasting but also from a better understanding of the error distribution of forecasts as the latter is what will drive the cost of managing VER variability in the day-ahead time-frame.

Financial risks of VER day-ahead schedules

Currently, all ISOs/RTOs treat day-ahead VER schedules the same as schedules for conventional resources for purposes of financial settlement. That is, any deviations in real-time production from the MWh cleared through the day-ahead market would be settled at real-time prices. However, there are some markets that allow VERs that schedule day-ahead not to be exposed to day-ahead uplift charges. For example, in Midwest ISO, VERs currently are forgiven from Revenue Sufficiency Guarantee (RSG) charges, for deviations from their day-ahead positions. In ISO-NE, VERs are not subject to charges for Real-Time NCPC (i.e. uplift costs) based on day-ahead/real-time deviations. However, these uplift charges are typically a small fraction of the financial settlements for energy deviations.

C.1.6 Will changes to the financial risk of participating in the day-ahead market encourage VERs to participate in day-ahead markets, and will this participation result in day-ahead market schedules that accurately reflect real-time market activity?

The NOI question C.1.5 implies a day-ahead netting approach to mitigate financial exposure similar that offered for real-time deviations from hour-ahead schedules under the CAISO's PIRP. For example, the central wind forecaster would promulgate a day-ahead forecast, and any VER willing to submit a day-ahead schedule equal to that forecast would not be exposed to real-time imbalance charges, whether settled on an intra-hourly basis or netted over some time period (such as the PIRP monthly netting approach). The advantage of this approach is that it would encourage additional voluntary VER day-ahead scheduling; the disadvantage is that an increasing quantity of energy would not be re-settling financially at actual real-time prices, and hence the redispatch incentives in real-time for VERs could be further weakened. In addition, the real-time re-settlement costs not borne by VERs would be shifted to wholesale buyers.

C.1.5 Should the financial risk of VERs' participating in the day-ahead market be different than the risk imposed on other resources in that market in recognition of their unique characteristics? Are there settlement practices, such as netting deviations, which could be employed to address VERs' participating in the day-ahead market? If so, what are they?

If markets can provide the right incentives for some entity, whether the VER or a financial entity, to take the day-ahead position, then day-ahead market solutions will reflect expected VER output. More time and experience with high VER production is needed to determine which is the right design approach.

It should also be noted that ERCOT, while not yet operating a day-ahead market, currently requires wind day-ahead schedules to get updated with an “80% probability of exceedance forecast”; ERCOT does not assign any penalties for schedule deviations in real-time.

As discussed above, changes to how VERs are settled financially for deviations from day-ahead schedules could encourage additional day-ahead participation. However, such rules would have a significant impact on market incentives in real-time, with a potential negative impact on market operations as VERs penetration increases. Most ISOs/RTOs feel that the current day-ahead market construct provides the right basis for VER participation, with day-ahead market participants finding their natural level of risk tolerance over time.

C.2 Reliability Commitments

Intra-day reliability assessments and VER integration

ISOs/RTOs currently operate reliability assessment and commitments on two time-frames: day-ahead (24-hour) and real-time (intra-day, multi-hour). The day-ahead reliability unit commitment clears physical supply resources against a next-day load and VER forecast conducted by the ISO or RTO. In this time-frame, the ISO/RTO can procure additional generation capacity as needed to meet next day load forecasts. Within the operating day, the function of the intra-day reliability commitments is to establish a more efficient commitment of system resources to reflect updated information on system conditions, including schedule changes, outages and, more recently, VER forecasts.

C.2.1 Would the implementation of a formalized and transparent intra-day reliability assessment and commitment process prior to each operating hour reduce the amount of reserves needed and/or reduce system uplift costs? What would be the optimal time (e.g., 4 to 6 hours ahead of the operating hour) for such a process?

Exhibit 2-5: Intra-day reliability assessment and unit commitment procedures

ISO/RTO	Scheduling Interval	Look-ahead Interval
California ISO	15 minutes	1-3 ¾ hours
ISO-New England	5 minutes	15 minutes to 1 hour, rerun unit commitment very 3 hours
Midwest ISO	15 minutes	2-3 hours
New York ISO	15 minutes.	2 ½ hours
PJM	15 minutes	2 hours (need to verify with PJM Ops)
SPP		1 hour

Additional Intra-day Markets and VER Integration

C.2.2 Would an additional market that coincides with the timing of an intra-day reliability commitment process be beneficial in the forward scheduling of VERs?

With one exception, ISOs/RTOs have not previously implemented an additional market with financial settlement in between the day-ahead market and the real-time dispatch market.[42] ISOs/RTOs do have some experience with setting advisory or actual prices in the hour-ahead time-frame for imports and exports.

In the redesign of the California ISO wholesale markets, an hour-ahead market was debated, but not included in the final design, although an hour-ahead scheduling process is used to calculate hourly real-time prices for settlement on the interties.[43] Since both the day-ahead market and the real-time dispatch market will continue to be needed, an additional market would add another settlement requirement to all sellers and buyers and would require consideration of when to re-settle virtual bids (which are currently re-settled on the basis of real-time prices). Hence, such a market implemented for adjustments due to VER output would have to be justified as a needed component of the market design as well as a demonstration made that it would be sufficiently liquid.

[42] The exception was an hour-ahead market operated by the California PX in 1998-9, which was terminated (before the California PX itself was terminated) due to lack of liquidity.

[43] The hour-ahead scheduling process price is the final settlement price for the interties, which are not re-settled again at real-time dispatch interval prices.

C.2.2 (cont.) If such a market is implemented, would an intra-day reliability commitment process be necessary? Should the frequency of scheduling intervals resulting from such a market coincide with intra-hour schedules discussed above?

The intra-day reliability commitments as currently implemented are rolling look-aheads conducted every 5-15 minutes for a several hour forward period. Hence, each sub-hourly interval that is used for financial settlement in real-time has already been subject to several evaluations in the context of the reliability commitments, each closer and closer in time to the actual interval. So even if another market was added to the intra-day design, the rolling reliability commitments are likely to be necessary because after the financial settlements would take place, there would be further information on VER output that could require additional commitment or re-dispatch decisions.

If an additional market was to be established, the time-step used for settlement could be between one-hour and the dispatch interval prevailing in that ISO/RTO. Additional granularity in the settlement period increases the volume of market transactions for sellers (buyers typically settle on the basis of integrated hourly real-time prices). If the time-step was hourly, then this market would result in a situation for VERs not dissimilar to that which is currently in place in CAISO: VERs schedule hourly based on an hour-ahead forecast, and are settled for imbalances between the hour-ahead schedule and the actual output in the dispatch period. If the market was settled on sub-hourly intervals, then similarly, the imbalances would be between the schedule and the actual output in the dispatch interval.

VER Forecasting in Reliability Assessments

C.2.3 What role should centralized forecasting of VERs' output play in reliability assessment and commitment processes?

Since there are only two formal markets – day-ahead and real-time – in which VER expected output can be integrated into the market commitment and dispatch, the reliability assessment and commitments that take place in between these markets can be expected to play a larger role in system resource optimization over time. As such, ISOs/RTOs have begun to integrate centralized VER forecasts into the day-ahead reliability unit commitments. For example, the CAISO's day-ahead residual unit commitment procedure can explicitly consider forecasted wind production in evaluating whether to commit additional dispatchable resources. Similarly, the NYISO includes the forecasted wind production in evaluating whether to commit additional resources day-ahead to meet forecasted load.

Several ISOs/RTOs, including CAISO, NYISO and Midwest ISO, have integrated a short-term wind forecast into real-time commitment and dispatch in the intra-day timeframe. The NYISO uses a blending of wind power forecasts provided by the forecast provider and persistence forecasts based on the last actual power output reading of wind plants for the real-time energy markets.

D. Balancing Authority Coordination (NOI Topic D)

In the NOI, FERC seeks to explore whether increased coordination among balancing authorities has the potential to enlarge the base of generation and demand available to customers, thereby making variability more manageable and ultimately reducing overall costs. FERC also raises questions on ways to increase customer access to energy, capacity, and reserve products through the use of pseudo-ties, dynamic scheduling, and/or other tools and agreements.[44] All the ISOs/RTOs consist of one single balancing authority, with the exception of SPP which is developing rules to consolidate into a single balancing authority.[45] There are also well-established market rules governing the inter-ISO/RTO market boundaries. In addition, several ISOs and RTOs have boundaries with non-market regions that consist of multiple balancing authorities. For example, CAISO directly interacts with twelve other balancing authorities in the WECC (including those in the state of California); PJM directly interacts with nine neighboring balancing authorities, while the Midwest ISO interfaces with ten balancing authorities. Scheduling across these boundaries requires coordination to ensure consistency and issues such as check-out, ramping, reserve management, curtailment and variability with regards to dynamic schedules need to be managed.

Several ISOs and RTOs have recent experience with consolidation of multiple balancing authorities, most notably the regional consolidation undertaken by Midwest ISO and underway in SPP. Both entities have undertaken studies of the costs and benefits of such consolidation and should be consulted on the details.

44 NOI at P 32.

45 SPP currently has 15 balancing authorities within its footprint.

Scope of Balancing Authorities and VER Integration

D.1 Will smaller balancing authorities, when operated individually, have higher VER integration costs than geographically or electrically larger balancing authorities? If so, why?

In general, smaller balancing authorities will face higher VER integration costs than larger balancing authorities, due both to having fewer resources under dispatch control to provide ramp and additional ancillary services and to not capturing some reduction in variability due to geographical aggregation of VERs. Even larger balancing authorities may need to coordinate with each other as VER penetration increases, as evidenced by recent efforts by CAISO and BPA to evaluate regional integration requirements.

D.2 Should the Commission encourage the consolidation of balancing authorities? If so, indicate the potential for and impediments to consolidation among balancing authorities and the means by which the Commission should encourage consolidation.

All of the ISO/RTOs are probably at a size beyond which additional balancing area consolidation would result in further significant savings, especially as transmission congestion and reliability issues also become a factor in operations with higher VERs. Management of market-to-market borders provides a well understood framework for improving coordination of VER integration among ISOs and RTOs.[46]

Outside the ISOs/RTOs, the Commission should work with regional groupings to evaluate the opportunities and appropriate sizing of any BA consolidation.

Coordination among Balancing Authorities to Facilitate VER Integration

ISOs/RTOs are evaluating, as needed, how to expand existing tools and arrangements and devise new ones to improve operational coordination among balancing authorities, including market-to-market coordination and coordination between ISOs/RTOs and non-market regions.

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[46] See, e.g., the history of managing seams among the northeastern ISOs and RTOs, available at http://www.pjm.com/documents/ferc-manuals/seams-issues.aspx.

D.3 What tools or arrangements (e.g., dynamic schedules, pseudo-ties, and virtual balancing authorities) are available and/or could be enhanced or created to reduce barriers to greater operational coordination among balancing authorities? What role should the Commission play in facilitating inter-balancing authority coordination?

These tools and arrangements are particularly important for ISOs/RTOs that expect substantial renewable imports to meet state RPS requirements, such as CAISO.[47]

Dynamic transfers and pseudo-tie arrangements are typically used when LSEs within the ISO/RTO territory have ownership or contractual arrangements with resources outside the territory. Or they can be used by generators outside the ISO/RTO that seeks to use the integration services of that entity. CAISO, Midwest ISO, PJM and SPP all have existing resources under these arrangements. These types of arrangements effectively place some or all of the resource's capability under the "importing" ISO/RTO's operational control. In a sense, then, these types of arrangements are not really inter-balancing authority operational coordination.

One aspect of increased use of various types of dynamic transfers of VERs is that they raise many design and cost allocation issues that have not yet been fully resolved in the context of internal VER integration. For example, based on its ongoing evaluation of increased dynamic transfers[48] that may facilitate the transfer of VER, CAISO notes that dynamic schedules and pseudo-tie arrangements need to address a range of issues including provision of Regulation, balancing services, intertie transmission utilization and allocation, control procedures, automated transaction coordination to facilitate scheduling, and more frequent scheduling changes and joint scheduling decisions to improve interchange.

Small Generation-only Balancing Authorities

No small, generation-only balancing authorities exist today within the ISO and RTO footprints. CAISO has been examining how to interact with generation-only balancing authorities that are seeking to dynamically transfer their production into the ISO.[49] As discussed in that paper, for

[47] The California Public Utility Commission has recently been advocating the use of dynamic transfers so that out-of-state renewable resources can count as essentially internal California resources for purposes of allocating tradable RECs.

[48] See CAISO, Dynamic Transfer Straw Proposal, op. cit.

[49] See CAISO, Dynamic Transfer Straw Proposal, op. cit. pp. 17-18.

D.4 What are the costs and benefits, if any, associated with the proliferation of small generation-only balancing authorities? How do NERC Certification and Reliability Standards encourage or discourage the creation of small generation only balancing authorities?

those generator-only balancing authorities that are single generators, the challenges of dynamic transfers from these balancing authority area include (1) increased potential for increased requirements for the ISO to firm, shape and load follow for a single resource, particularly an intermittent resource, (2) proper accounting and compensation for inadvertent flows, (3) whether aggregation as described above offers a better solution than participation as a generator-only balancing authority area, (4) whether NERC/WECC reliability is met, and (5) impacts pertaining to intermittency.

The CAISO notes further in this preliminary analysis that a generation-only balancing authority area with multiple independent units behind a meter or delivery point can be preferable to a single-generator balancing authority area, when, for instance, it has two or more independent thermal units, even if there is shared capacity to reach the top of its combined maximum range. With this configuration, if one unit has an outage, a second unit can still act as an independent generator, offering backup and reserves if necessary. However, in either case, it will be beneficial to enter into dynamic transfer arrangements on a case-by-case basis as a pilot project, to give such entities time to prove the reliability and deliverability of their projects.

VER Balancing Authorities

Reflecting developments in non-ISO/RTO regions, FERC is interested in the potential for types of balancing authorities designed for improved VER integration and coordination. ISOs/RTOs are supportive of FERC's efforts at improved regional operational and market integration, but have not addressed NOI questions D. (5)-(9), which do not appear to pertain to ISOs/RTOs.

E. Reserve Products and Ancillary Services (NOI Topic E)

ISOs/RTOs procure sufficient ancillary services to meet reliability standards set by NERC and regional reliability authorities. There are currently four types of market-based ancillary services—regulation, ten-minute spinning reserves, ten-minute non-spinning reserves, and 30-minute reserves—while the other services, such as voltage support/reactive power and black start, are procured through tariff rates. As shown in Exhibit 2-6 the market-based ancillary service products are not procured uniformly among the ISOs/RTOs, and market rules have also developed differently in response to stakeholder interest and market requirements. In addition, there are other reliability requirements, such as frequency response and inertial support, that are not specifically procured as ancillary services but are nevertheless operating requirements that may be affected by VER interconnection and production.

Two major changes in the ancillary service markets with implications for VER integration were triggered by FERC Orders No. 890[50] and 719.[51] The first is that FERC-jurisdictional ISOs/RTOs are required to establish scarcity pricing, which several markets had already implemented in different ways. Some designs for scarcity pricing specifically trigger price increases when procurement of regulation or operating reserves is deficient. Through the substitution properties and co-optimization, a penalty price triggered through a shortage of a lower quality reserve can increase the price for the higher quality reserve, and if energy is also constrained in this period, the energy price will also be set by the scarcity penalty.

These deficiencies typically take place during peak load days, when the ISO/RTO has to convert reserves to energy to serve load. They can also be triggered by ramp constraints, when the system cannot carry the regulation or operating reserves in certain hours due to the speed of the ramp.[52] Or they can be triggered in over-generation conditions, when there is insufficient downwards capability to fulfill Regulation down requirements. The ramp and over-generation constraints are expected to increase in frequency and magnitude with higher levels of VERs. Thus there is the potential that VER integration will lead to more frequent instances of scarcity pricing.

The second significant change is the requirement to facilitate the participation of non-generation resources in the ancillary service markets. Although there are differences in these rules among the ISOs/RTOs, which largely build on existing ancillary service market designs, the participation of such resources is expected by some analysts to provide an increasing amount of the ancillary services and general ramp needed for renewable integration over time. However, it should also be realized that at higher levels of VERs, there will be substantial available fossil capacity on the system displaced from energy that can also provide ancillary services; until carbon pricing increases the cost of such resources, they could have a dampening effect on the market revenues of non-generation resources even with high VERs.

[50] "Preventing Undue Discrimination and Preference in Transmission Service", Order No. 890, 72 FR 12266, FERC Stats. & Regs. ¶31,241, P 72, (March 15, 2007) (Order No. 890).

[51] "Wholesale Competition in Regions with Organized Electric Markets", Order No. 719, 73 FR 64,100, FERC Stats. & Regs. ¶ 31,281 (Oct. 28, 2008) (Order No. 719).

[52] To protect reserves during system ramps, most ISOs and RTOs have "ramp-sharing" constraints that allocate ramp among the different market products.

Exhibit 2-6: ISO and RTO Bid-Based Markets for Ancillary Services

Ancillary Service	Description	ISO/RTO
Regulation (or automatic generation control, AGC)	The ability to increase or decrease energy output on a second-by-second basis for energy balancing	NYISO, ISO-NE, PJM, CAISO, Midwest ISO
Ten minute spinning (or synchronous) reserve	Reserves available (MW) within ten minutes from generators synchronized with the grid (or demand response)	NYISO, ISO-NE, PJM, CAISO, Midwest ISO
Ten minute non-spinning or nonsynchronous Reserve	Reserves available (MW) within ten minutes from generators not synchronized with the grid or demand response.	NYISO, ISO-NE, CAISO, Midwest ISO
Thirty minute or supplemental Reserves	Reserves available (MW) within thirty minutes or more from generators either synchronized or not synchronized with the grid or demand response.	NYISO, ISO-NE, PJM

Existing Reserve Products and VER Integration

The existing market-based ancillary service products procured by ISOs/RTOs on behalf of LSEs include regulation, ten-minute spinning reserves, ten-minute non-spinning reserves and 30-minute supplemental reserves.[53] The quantities that ISOs/RTOs are required to procure of these reserves are established by guidelines from NERC and regional reliability authorities; as noted, not all ISOs/RTOs procure the same products or the same quantities of particular products. The hourly ancillary service procurement targets may also be fixed or variable over the operating day.

[53] These types of ancillary services were defined under FERC Order 888 (1996); see http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp.

E.1 To what extent do existing reserve products provide System Operators with the most cost-effective means of maintaining reliability during VER ramping events? To what extent would the other reforms discussed herein, if implemented, mitigate the need for additional reforms to existing reserve products without adversely impacting system reliability?

ISOs/RTOs have worked for years, with FERC oversight and initiative, to refine the design of the bid-based wholesale ancillary service markets to achieve efficient use of system resources to procure these services. Key characteristics of these designs, although not implemented the same way in each market, include simultaneous rather than sequential clearing of reserves, co-optimization of energy and reserves, hierarchical substitution of reserves to reflect that higher quality reserves can substitute for lower quality reserves, and scarcity pricing of reserves to ensure that market prices reflect shortage conditions. These designs will become the basis for any further changes to ancillary services procurement needed for VER integration.

The effectiveness of the current types of ancillary services or their market designs as the most cost-effective means for reliably addressing VER ramps remains to be seen. To the present, no ISO or RTO, with the exception of ERCOT, has procured additional ancillary services to address VER forecast uncertainty or variability. However, operational assessments by the ISOs and RTOs and other entities, such as the NERC IVGTF,[54] have suggested at least the following possible adjustments to ancillary service procurement:

- Additional reserves on a 10-minute or greater basis to account for conditions where VER variability may eventually be greater than the single or second largest contingency on the system;
- Additional non-contingency reserves to “follow” VERs within the hour; this is because at high levels, VER variability may exceed the upward or downward ramp capability of the resources committed through the hourly schedules developed by the day-ahead market and subsequent reliability assessments;
- Additional procurement of Regulation, possibly on a variable basis throughout the operating day, to address the impact of VER variability on AGC within the real-time dispatch interval.

54 NERC, *Special Report, Accommodating High Levels of Variable Generation* (April 2009), op.cit.

If and when the ISOs/RTOs procure additional ancillary services to address VER integration, the question is not whether the design of the existing markets will efficiently procure such ancillary services, but rather whether the cost-effective mix of ancillary services is being targeted. Specifically, several studies have argued that the ISOs/RTOs should not procure additional high quality reserves, such as Regulation and ten-minute spinning reserves, to address wind variability, but rather a lower quality reserve, such as a 30-minute ancillary service, that would presumably be cheaper to procure.[55] Once the procurement target is set, however, there has been little contention that the market clearing mechanisms themselves need to change.

The ISOs/RTOs generally seek the least-cost bid-based procurement of ancillary services, and there is the expectation that as operational assessments clarify needs, they will seek to procure the right mix of ancillary services to meet that objective. With regard to the lower quality reserves, ISO-NE and NYISO currently carry supplemental reserves in real-time, but these are primarily procured to meet 30 minute contingencies rather than to follow VERs although the reserves could be utilized for VER ramping if necessary.[56] Other markets are considering whether to implement such products, in part due to increased VER output.[57]

[55] See, e.g., Kirby, Brendan, "Statement of Brendan Kirby," Consultant to the American Wind Energy Association, FERC March 2, 2009 Technical Conference

[56] PJM procures 30-minute reserves to satisfy the RFC requirements day-ahead. PJM only monitors 10-minute reserves in real-time, but carries in total 10 minute the same percentage of total reserve as NYISO (150% of largest contingency). ISO NE carries 100% of the largest and 50% of the second largest contingency.

[57] For example, CAISO has a review process to determine whether to implement an additional 20-30 minute reserve product and the rules for that product. In the alternative, Regulation is the primary ancillary service that currently supplements the real-time energy market in meeting load within the hour. Regulation is defined here as the AGC or demand response or storage under automated controls that would be needed to meet actual load net of VER output in between the ISO's 5 minute dispatch instructions and taking generator response to those instructions into account. CAISO has forecast that additional Regulation Up and Down reserves will be needed at higher levels of VERs. See California ISO, *Integration of Renewable Resources*, available at http://www.caiso.com/1c51/1c51c7946a480.html. Improvements in forecasting would decrease the need for Regulation, which is in part a function of forecast error and in part VER variability. Currently, the CAISO's ten-minute spinning reserve and non-spinning reserves are largely contingency-only and would not be deployed for VER ramping events.

Optimizing Reserve Procurement when Integrating VERs

> *E.2 How could System Operators, managing the variability of VER resources, more fully utilize forecasting information and knowledge about existing system conditions to optimize reserve requirement levels?*

The determination of how much additional ancillary services of any type may need to be procured to support VER integration will be a function of both VER production forecast error and variability. In addition, it will be a function of the resource capabilities on the system, including VER dispatchability. Clearly, optimizing reserve requirements will have a greater market effect in the forward time-frame, such as the day-ahead market, when most of the reserves for the operating day are procured (although this varies by market and by reserve product).

The following example will illustrate this. Operational assessments of wind resources in California under a 20% RPS have shown, for example, that the need to procure additional Regulation Up and Regulation Down will vary substantially by hour, reflecting the wind ramps and production profiles over the operating day.[58] Operators will be able to use tools based on the statistical methods used in these assessments to estimate next-day Regulation needs on a variable basis. If that additional Regulation is procured entirely in the day-ahead market, as are all ancillary services currently in CAISO, then clearly the accuracy of the day-ahead forecast will play a significant role in setting the procurement target. In addition to taking steps to improve the day-ahead VER forecast, CAISO and other researchers are developing ramp tools that better forecast the ability of dispatchable resources to meet the next-day or next-hour ramps. These tools will help further optimize the procurement of Regulation. Several other ISOs and RTOs have similar tools and research underway.

In the real-time market time-frame, operators will gain additional ability to optimize both the energy dispatch and any residual procurement of reserves through improvements in forecasting as well as dispatch control over VERs. Several market operators, including NYISO and PJM, note that the capability to manage VER ramps and over-generation through the dispatch will greatly assist in optimizing the dispatch.

58 California ISO, "Integration of Renewable Resources", op. cit.

Need for Load-following/VER-following Reserve Product

In the ISOs/RTOs, with hourly day-ahead markets and 5-10 minute real-time dispatch markets, load following is essentially equivalent to the change in upwards and downwards ramp over the hour from the hourly schedule going into the operating hour. The ISOs/RTOs meet these load following requirements through both the day-ahead market solutions and the additional reliability commitments that continue through the operating day on various time-scales to update the hourly schedule. Contingency reserves are positioned to account for any unplanned outages that cannot be covered through the dispatch function, and Regulation provides any balancing needed within the 5 minute dispatch interval that is not already provided by units following economic dispatch instructions.

E.3 Would a load following or similar reserve product facilitate the reduction of costs associated with ensuring that sufficient reserve capacity is available to address the uncertainty and variability associated with VERs? If so, what are the ideal characteristics of such a product?

Several new tools, or extensions of existing tools, are currently under exploration for load/VER following by the ISOs/RTOs. As discussed in Section A, all ISOs/RTOs employ various types of visualization software, which is being augmented with VER production output and forecasts. These will enhance operators' ability to make supplemental within-day reliability commitments as conditions warrant.

With this background, a load-following or VER-following reserve would be needed if VER variability and forecast error were such that they exceeded the ramp capabilities of the units committed and dispatched within the operating hour. This becomes a possibility at higher levels of VER output, and would have to be managed along with any changes to the procurement of other ancillary services and any changes to unit commitment ramp algorithms to manage the ramps within particular hours. The additional reserve would provide that additional capability, presumably on a non-contingency basis. It would also be procured on an hourly basis that would reflect the high VER ramp hours when such a reserve was needed.

To date, ISOs/RTOs have not identified the exact point of VER production when such a load-following/VER-following is needed alongside the existing energy dispatch mechanisms and other ancillary services. Operational simulations in California have suggested that this need may arise somewhere between a 20% to 33% RPS, but much further analysis is needed to validate this result and confirm its relevance to other systems. The Midwest ISO has done some preliminary studies that suggest that a load following reserve product may be the most effective approach to address VER variability in its footprint.

Contingency Reserves, Extreme Ramps and VER Integration

E.4 Existing contingency reserve products were designed to be utilized by System Operators to respond to disturbances (i.e., contingency events) due to a loss of supply and to assure system reliability. Does or should the definition of a contingency event include extreme VER ramping events? If so, would an additional level of contingency reserves be needed to achieve the same level of system reliability? In responding to this question, please include a proposed definition of "extreme ramping event."

As noted above, the reconsideration of ancillary service definition and procurement is in the nascent stages, and the IRC does not have a consensus view on when extreme VER ramp events should be included in the definition of contingencies for purposes of operating reserve procurement.

Ramp forecasting is an area of ongoing research for several ISOs though it should be noted that VER ramp forecasting is considered relatively difficult to predict. This is due to the fact that sudden/severe ramp events can often be caused by unusual weather phenomenon like vertical mixing events between stable lower atmosphere and an unstable upper atmosphere as opposed to horizontal mixing which can be tracked easily or modeled using numerical weather prediction. Since they are generally phenomenon that occurs outside the usual range of events this makes them harder to predict.

Several ISOs/RTOs have experienced significant extreme ramps of VERs, some caused in the upward direction by wind events, while others are in the downwards direction when a large number of units cut-out due to high wind. CAISO, Midwest ISO and BPA are working jointly on forecasting of such ramp events. At CAISO, ramp forecasting tools that include wind variability are currently in development in different systems where the objective is to check the ramp capability of resources committed through markets. PJM is developing ramp forecasting tools that include wind variability where the objective is to check the ramp capability of resources committed through markets; however ramping events are first addressed by regulating reserves and system re-dispatch. Also, ERCOT has recently implemented a ramp forecast tool which was discussed in Section A.

E.5 Should a new category of reserves, that would be similar to contingency reserves, be developed to maintain reliability during VER ramping events in a cost effective manner? If so, what benefit would such reserves provide to System Operators and customers?

FERC has asked whether a new category of contingency reserves specifically developed to address VER ramp events is appropriate (NOI question E.5). If this new category of reserves is similar to the load-following/VER-following reserve discussed above, then it would simply be such a product but perhaps with further technical specifications to ensure that it could follow more extreme ramp events. Alternatively, it could be a separate product, such as a "fast" reserve product, for which the ISO and RTO would procure smaller quantities of response capability but position them in particular hours that have higher probability of extreme ramps. In either case, the operational assessments conducted so far have not yet determined the need for such a product alongside the existing reserve products. The cost effectiveness of imposing on the ISO or RTO a "one day in 10 year" standard for high speed cutout events must be carefully considered. Carrying reserves for such an event will become more and more expensive. Alternatively, maintaining the ability to forecast ramping phenomena by wind farm with a 15-minute or lesser time period accuracy will enable other measures to be taken. However, it may be necessary at some level of VER penetration, which would likely vary among the ISOs/RTOs. The Midwest ISO is currently analyzing the potential for this new category of reserves.

Reserve-sharing and VER Integration

In principle, an expansion of regional reserve capability could lower the costs of VER integration, depending on the scope of the BA and whether reserving capacity on the interties is an efficient solution compared to other options. However, there has been no explicit review of this by ISOs/RTOs and there are a variety of existing arrangements that would need to be surveyed. CAISO does not participate in reserve sharing arrangements with neighboring balancing authorities, but does procure reserves from entities in neighboring. Similarly, PJM does not participate in a reserve sharing group, but in contingency events, will share reserves with one or more of ISO-NE, NYISO, NBSO and IESO to enable a more rapid recovery. Midwest ISO also has a contingency reserve sharing policy.

E.6 Could the expanded use of reserve-sharing programs between balancing authorities contribute to lowering the costs associated with integrating VERs? If so, how?

The ISOs/RTOs have not yet examined the impact of VERs on existing reserve-sharing arrangements, whether organized or ad hoc. Reserve sharing in general will mean that inter-area transmission capacity has to be held in reserve so as to allow the utilization of shared reserves across interfaces. To the extent that these interfaces are congested already, this sharing may be of limited benefit compared to development of internal BA resources such as demand response to manage VER ramping.

Modifications to pro forma OATT Ancillary Service Provisions to address VER Integration

E.7 Should the ancillary services provisions of the pro forma OATT be revised or new provisions added to expressly address the added reserve capacity necessitated by increased number of VERs? If so, how?

FERC is interested in whether the ancillary service provisions of the pro forma OATT should be changed to reflect VER operational requirements. The IRC does not have a consensus position on this question. However, once further clarity is achieved on specific ancillary service changes that are needed, changes to the *pro forma* OATT could be needed.

New Sources of Reserves for VER Integration

There are a variety of arrangements among the ISOs/RTOs with regards to aggregators, reserve products and pooling arrangements to respond to VER ramping however there seems to be no indication that VER ramping is currently treated as a unique reliability event. CAISO for instance procures reserves from entities in neighboring BA. CAISO and Bonneville Power Administration (BPA) have a research agenda to address VER integration. CAISO also has participated in studies of the potential benefits of fast Regulation by the California Energy Commission and Pacific Northwest Labs. In the case of PJM, regulating reserves are used to respond to ramping events, and energy storage resources are able to provide regulating reserves. There are no inter-balancing authority pooling arrangements and all ancillary services must participate in only one market. They also employ an Ace Diversity Index (ADI) to allow offsetting ACE response.

Under Order No. 890, non-generation resources are eligible to participate in the ISO/RTO ancillary services markets. The industry is still exploring the use of new resources such as fast storage, demand response, and Vehicle to Grid integration to facilitate renewables integration. Energy storage resources have a number of characteristics that are particularly suited for facilitating renewable integration. They can provide a fast response to control signals, frequency response and automated dispatch commands. They have high ramp rates and are easy to start and stop. They are thus well-suited providing the regulation services that RTOs/ISOs have identified as potentially important to renewable integration. On a larger scale, such as pumped storage, storage can substantially shift loads and take advantage of the potential off-peak surplus in clean energy (due to excess wind production) and mitigating over-generation conditions. Increased price-responsiveness by consumers of power (demand response), especially during periods of sharp ramps and over-generation, will also facilitate renewable integration.

E.8 Are there new sources and/or providers for reserve products (such as inter-balancing authority pooling arrangements, demand response aggregators and/or storage devices) that can be used to maintain reliability and lower reserve costs during VER ramping events? Based on experience, are there characteristics of these new sources of reserves that would positively or negatively impact their ability to match the reserve product needs presented by the variability of VERs?

As with storage, there is much interest in demand response for purposes of shifting consumption to the periods with surplus renewable energy (and energy prices are thus low or negative) and also curtailing use (at a price) during real-time operations, if warranted by the variability of renewable output. There are also opportunities for demand response to provide ancillary services, including regulation service. Demand response also provides capacity that can reduce load on peak days, during which wind production may not be sufficient (see discussion of resource adequacy below). As these new technologies and others, especially those falling under "Smart Grid" are developed and deployed, market products and protocols will develop to make use of them.

VERs as Ancillary Service Suppliers

E.9 To what extent are VERs capable of providing reserve services? Should VERs be expected to provide reserve services? What are the tariff and technical barriers that may impede VERs from providing these reserve products?

Participation of VERs in providing reserve services is an emerging phenomenon and there doesn't currently appear to be any major tariff and technical barriers. VERs that are withholding production (feathered wind turbines or PV with inverters off) can be turned "on" and ramped up quickly. ISOs and RTOs are generally in favor of allowing VERs to participate in providing reserve services, as long as they meet eligibility requirements and are sufficiently tested. However, there do not appear to be any VERs currently providing reserve services.

There are some markets in which VERs would have to make choices among existing pricing provisions if they were to provide ancillary services. For example, in CAISO, participation in the PIRP, which provides netting and averaging of real-time energy imbalances, specifically excludes VERs from taking part in the ancillary services market. However, any capacity not offered into the ancillary services market would be eligible for the imbalance pricing. These rules may require revisiting in the future.

VERs and Frequency Responsive Reserves

E.10 To what extent should all resources, and VERs in particular, be required to provide Frequency Response? How would such a requirement be implemented?

At high levels of VER there is a strong possibility that systems operations will require additional frequency response from some resources in order to compensate for reduced rotating mass (inertia) and governor response when conventional generation is off line. Some VER technologies are capable of providing these capabilities easily, such as concentrating solar thermal, others less so. Where it is technically feasible VERs should be required to provide inertial and frequency response in similar proportion to conventional units. Where it is not feasible, either the VER or the market operator will have to "procure" inertial and frequency response from conventional units kept on line for reliability purposes or from new technologies such as flywheel storage deployed for the purpose.

With the exception of ERCOT and Midwest ISO, penetration of VERs has been sufficiently small that there has not yet been a requirement for the VERs to provide frequency response, or for other resources to provide additional frequency response for purposes of VER integration. It is currently a requirement for future VER to provide primary frequency response in ERCOT and it is being currently examined as a requirement for existing VER. As the penetration of VERs increases then the need for frequency response will be necessary for all VERs. In addition, the NERC IVGTF is investigating frequency response requirements and a report is expected in the coming months.

Reactive Power Requirements and other Reliability Requirements

With respect to reactive power requirements for VERs there was a variety of responses. Midwest ISO has already made it part of generation interconnection agreements and CAISO is currently examining the issue. ERCOT is not looking into this requirement but indicates that it warrants further investigation by FERC. ISO-NE indicates that it like to see the reactive power requirements established in Order No. 661 revisited, and establish a dynamic reactive power management requirement for VERs. On the other extreme, PJM felt wind resources must only be able to maintain power factors within the range specified by FERC Order 661A.

E.11 Should the Commission revisit the reactive power requirements set forth in Order No. 661? What other requirements, if any, should apply to VERs to ensure that all resources contribute to grid reliability in a manner that is not unduly discriminatory?

F. Capacity Markets (NOI Topic F)

Historically, the primary driver behind capacity markets or capacity requirements is to ensure that ISOs/RTOs are able to maintain resource adequacy requirements that are equal to the system's forecasted peak load plus a reserve margin.[59] Capacity markets also have a secondary purpose to ensure that capacity resources are able to generate enough revenues to recover their fixed, going-forward costs of operation, including fixed investment costs. If the revenues accruing to capacity resources from participation in energy and capacity markets are not sufficient to recover fixed, going-forward costs including investment costs, then new generating resources, regardless of type, will either not enter the market, and existing resources may retire.

[59] Several regions have a centralized capacity market that allow for fulfillment of the resource adequacy requirement through a transparent auction mechanism, while other ISOs/RTOs have only a bilateral RA market or a backstop capacity procurement mechanism. A few ISOs/RTOs have no resource adequacy requirement, including ERCOT and AESO.

Capacity requirements and markets will play a role in adapting the power system and markets to higher levels of VER penetration in the following ways:

- Determining the value of VER resources as capacity resources to ensure supply adequacy over time;
- Providing revenues to cover the fixed costs of conventional generation resources needed on the grid for local reliability support and renewable integration but facing declining revenues in energy and ancillary services at higher levels of renewable energy production;
- Providing revenues to eligible non-generation resources that can support wind integration, such as demand response and storage of sufficient scale.

The capacity that is purchased in capacity markets must also be able to perform at system peaks based upon expectations regarding its ability to perform, as indicated by forced outage rates or historic performance in those hours. Consequently, from a reliability perspective, nameplate capacity has little relevance if a resource does not have a reasonable expectation of performing at its nameplate rating during system peaks. As the IRC noted in its prior report on renewable resources, due to its variability and production profiles, wind is primarily an energy resource, and not a capacity resource. Moreover, while they do have a capacity value, VERs are not only variable energy resources, but also variable capacity resources. Wind capacity value changes year by year. Exhibit 2-7 below summarizes several of the VER capacity rules discussed in the remainder of this section.

Exhibit 2-7: Key Rules for Wind Resources as Capacity Resources

ISO/RTO/Regulatory Agency	Rules for Calculation of Wind Capacity	Obligations on Wind Capacity Resources in Energy Markets	Other Capacity Market Rules for Wind Resources
PJM	Initial year of operation: 13% of nameplate capacity based on class average capacity factor during summer peak hours. Subsequent years based on rolling 3-year average of output during the hours of 3-7	Wind resources are obligated to make their committed capacity available in the day-ahead market	Wind resources receiving RPM payments are not subject to: - peak period availability penalties - winter and summer testing requirements - peak season maintenance

ISO/RTO/Regulatory Agency	Rules for Calculation of Wind Capacity	Obligations on Wind Capacity Resources in Energy Markets	Other Capacity Market Rules for Wind Resources
	pm from June to August.		compliance
New York ISO	*Summer capacity credit*. Initial year of operation: 10% of nameplate capacity. Subsequent years use an average of output during the hours of 2-6 pm from June to August of the prior year. *Winter capacity credit*. Initial year of operation: 30% of nameplate capacity. Subsequent years use an average of output during the hours of 4-8 pm from December to February of the prior year.	No obligation to offer in the day-ahead market.	
ISO-New England	*Summer capacity credit*. Rolling 5-year average of output during the hours of 2-6 pm from June to September. *Winter capacity credit*. Rolling 5-year average of output during the hours of 5-7 pm from October to May.	Resources may, but are not obligated to, offer into the day-ahead market. They must offer into the real-time market consistent with resource characteristics.	
California Public Utilities Commission (CPUC) / California ISO	Resource adequacy requirement is monthly. For each month, a rolling 3-year average	There is no obligation to offer into either the day-ahead market or real-time markets. Hour-	

ISO/RTO/Regulatory Agency	Rules for Calculation of Wind Capacity	Obligations on Wind Capacity Resources in Energy Markets	Other Capacity Market Rules for Wind Resources
	of monthly output during the hours of 12-6 pm on weekdays using an exceedance approach. Initial years of operation can use average for existing wind resources in zone.	ahead scheduling is voluntary with incentives through the Participating Intermittent Resource Program.	

Capacity Rating Rules for VERs

There are currently different capacity rating rules among the ISO and RTO markets as well as some debate between analysts over the appropriate methods for determining such ratings, essentially between types of average peak hour capacity valuation methods and the Effective Load Carrying Capability (ELCC) approach, which attempts to calculate capacity value on an annual basis (rather than just peak hours).

Capacity rating of VERs, when calculated, has been done based upon expected performance during system peaks (see the summary in Exhibit 2-7). PJM capacity valuation procedures allow existing wind and solar photovoltaic resources to receive capacity credit based on a rolling average of actual performance during the prior three summers, otherwise new resources may receive capacity credit up to their class average capacity factors as determined during peak summer hours.[60] In NYISO, existing VER capacity rating is based upon demonstrated performance during average peak hours in an applicable capacity auction period, new VER capacity ratings are based upon pre-defined

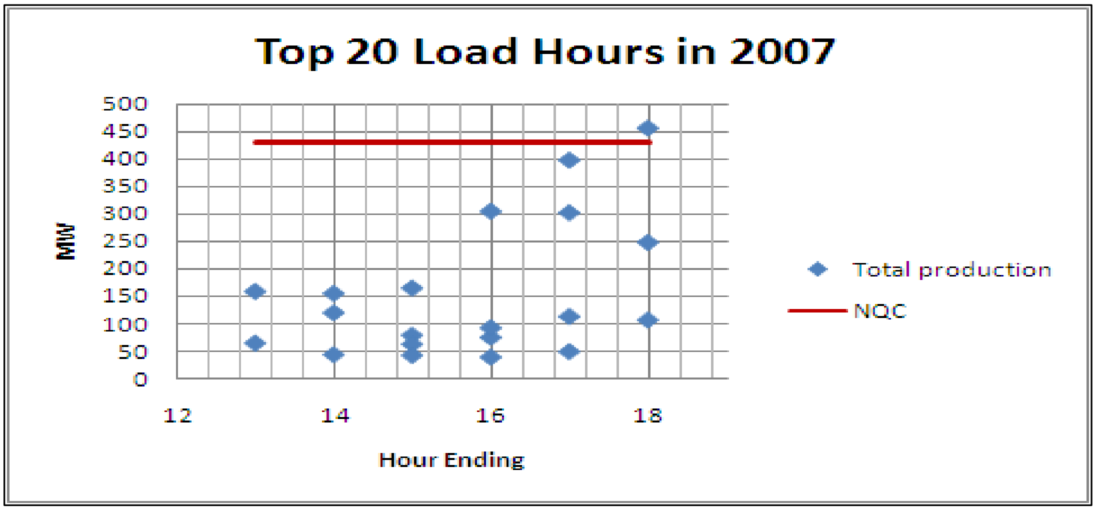
F.1 Should the Commission examine whether capacity rating rules as applied to VERs are unduly discriminatory and investigate whether standard rules may be appropriate?

60 Since the inception of the RPM capacity Market in PJM through the 2012/2013 Base Residual Auction, there has been wind with 440 MW of capacity value that has cleared in RPM auctions. The 440 MW of capacity value has an approximate nameplate capacity value of 3,385 MW. By 2015 PJM estimates 10,000 to 12,000 MW of nameplate capacity to be in service with an estimated capacity value for reliability of 1,300 to 1,560 MW.

average capacity factors. ISO-NE also has used the peak hour averaging method, but is reviewing alternative methods as well as part of its assessment of operations and markets with VERs. Midwest ISO runs an imbalance capacity market and VERs can participate if they can meet the deliverability requirements.[61] The Midwest ISO annually performs a statistical analysis to determine Unit Capacity (UCAP) ratings for VERs.

In California, the VER capacity ratings are determined by the California Public Utilities Commission (CPUC). Like the eastern ISOs and RTOs, the CPUC has historically used a rolling peak hour average method, but has recently adopted a more restrictive peak hour measure based on the VER production in peak hours that exceeds a level of output (an exceedance measure). This was due to a CPUC finding that the Net Qualifying Capacity (NQC) of wind resources based on the rolling 3 year average peak hour production (2003-2006) was not met in most peak hours in 2007. Exhibit 2-8 shows that in the 20 peak load hours in 2007, wind production failed to meet or exceed its NQC in all but one hour. The new exceedance approach has reduced the capacity value of VERs in California.

Exhibit 2-8: VER Peak Load Production in CAISO, 2007



Each market will undoubtedly continue to need rules for capacity rating tailored to the VER types and characteristics prevalent in the region and the particular resource adequacy

61 In the Midwest ISO, about 4000 MW of the 7600 MW of wind are utilized to meet the capacity requirements with an expectation of 15,000 MW of VER in service between 2015 to 2020.

requirements in the region. General principles for the methodology used in determining capacity rating rules – essentially the peak hour averaging methods – have been used in common, but there is no clear approach that has had sufficient empirical evaluation. Moreover, at higher levels of VERs, small errors in determining VER capacity value – which is substantially variable year to year – can lead to insufficient dispatchable capacity resources being procured to serve peak hour needs. This has been the concern in California, and one motivation for the more restrictive approach to VER capacity value now in place.[62]

The methods used for capacity valuation are not discriminatory because resource adequacy requirements are used to meet longstanding LOLE practices that try to ensure enough resources are available to meet peak load conditions.

VER Capacity Obligations in Day-ahead Markets

F.2 Do obligations for capacity resources to offer into the day-ahead market unfairly discriminate against VERs? If so, how?

As a part of the capacity obligation, conventional capacity resources are generally required to offer their capacity in the day-ahead energy market. CAISO, ISO-NE and NYISO exempt VER capacity from this offer obligation, while PJM and Midwest ISO require all capacity resources to submit an offer in the day-ahead market. In markets that exempt VER capacity resources from day-ahead offers, there are currently few such offers, requiring other resources to be committed or virtual suppliers to meet day-ahead load. Another approach is that implemented by ERCOT, which does not have a capacity obligation, but requires VERs to schedule day-ahead on the basis of a measure of expected production in real-time provided by the centralized forecast.

As noted above, ISOs/RTOs are examining different approaches to provide incentives to VERs to schedule day-ahead. The obligation on VER capacity resources is one such approach, and given its limited application, it is premature to state that such an obligation is discriminatory. Whichever existing or new market rule becomes the basis for VER day-ahead obligations, at

62 For example, under the 33% renewable portfolio standard, the VER MW capacity is expected to be around 21,000 MW by 2020 in the CAISO, such that a significant overestimate in valuing VER capacity could lead to not procuring sufficient resource adequacy from conventional dispatchable capacity. Moreover, at higher levels of VER the existing generation will become increasingly reliant on capacity revenues.

higher levels of VERs, it is necessary to have well-defined rules to ensure that day-ahead markets clear efficiently.

Impact of increasing VER Capacity on the Revenues of other Capacity Resources

F.3 As more VERs choose to become capacity resources, will existing processes for compensating capacity services adequately compensate all generating resources that may be needed for reliability services? If not, what reforms may be necessary? For instance, should the Commission examine formation of forward ancillary services capacity markets?

As VER levels increase, they will, even at low capacity factors, account for an increasing share of the capacity requirement. Resources that provide reliability services are compensated through all the ISO/RTO markets, including energy (when they are providing incremental or decremental energy, e.g., as Regulation), ancillary services, and where available, resource adequacy capacity markets. It is the overall effect of VERs on these markets that needs to be considered in addressing this question. Based on simulations, the issue may not only be the increasing capacity value of the VERs displacing other capacity resources, but as importantly their impact on energy market prices, in particular during hours when there is surplus renewable energy on the system. It is also important to recognize the linkages that already exist between the received energy and ancillary services revenues and the going forward value of capacity. As energy revenues decrease for all other resources, they will increasingly need to recover their fixed, going-forward costs (or investment costs for new resources) through other markets, whether forward or daily markets for ancillary services or capacity.

Currently, only ISO-NE has a forward market for reserves. The Commission could study whether such a market construct is necessary generally under higher VERs, or whether existing capacity markets are the venue for additional design changes (see below). Some ISOs/RTOs are currently looking at whether the existing product portfolio (capacity, operating reserves and imbalance energy) are sufficient to ensure reliable grid operation or whether additional reserve products are needed. However, there is substantial operational assessment that is still needed before market design decisions are made.

Operational Flexibility Requirements for Capacity Resources

F.4 Should capacity markets incorporate a goal of ensuring sufficient generation flexibility to accommodate ramping events in addition to the goal of ensuring sufficient generation to meet peak demand?

Historically, ISOs/RTOs have relied on energy and ancillary service markets to signal the need for generation flexibility, while capacity has remained measured largely as MW. Energy market locational marginal prices do increase as ramp is constrained, and with the advent of scarcity pricing there will be additional signals for ancillary service shortages as well as unserved energy. However, there is a timing issue such that with the rapid onset of VERs at high levels providing energy and capacity, questions have arisen as to whether capacity requirements or capacity markets should incorporate separate specifications for capacity with the quick start and ramping capability to ensure that ISOs/RTOs can meet extreme ramping events caused by VERs. This is an empirical question that needs to be addressed in timely fashion.

At current penetration levels, no ramp deficiencies are reported from Midwest ISO, NYISO and PJM. CAISO production simulation studies to date have suggested that the ISO conventional generation fleet has sufficient flexibility to accommodate a 20% RPS (due in 2012) and studies are underway to evaluate higher VER penetration levels.

At high VER levels, some market participants in CAISO have argued that some new form of ramping pricing or compensation may be required to elicit the required capabilities from the conventional generation fleet or from new resources. However, there has been no quantitative analysis yet to evaluate this claim. The California Public Utilities Commission is also considering whether to alter the resource adequacy product or its long-term procurement planning requirements on LSEs to account for needed generation (and non-generation) operational characteristics. Several other ISOs/RTOs have begun to analyze this issue.

G. Real-time Adjustments (NOI Topic G)

Real-time energy markets are designed to manage the difference between day-ahead schedules for generation and load, and real-time, or operational, conditions, as due to forecast errors, outages, and other factors. Real-time energy markets minimize the bid production cost of maintaining system energy balance (supply equals demand) while ensuring ancillary service requirements are maintained, transmission limits are not violated, and individual generator constraints are honored. ISOs/RTOs manage this process through the use of bids/offers provided by individual generating units. Cost minimization requires that market operators dispatch resources by using the lowest bid/offer resources first before dispatching more expensive resources without regard to generator type. In addition to dispatching resources based on cost as reflected in bids/offers, ISOs/RTOs also offer resources the opportunity to self-schedule output, with appropriate notice; self-schedules are treated as price-taking resources that prefer to operate regardless of the market price for energy. Often in real-time operations, system operators need to re-dispatch generation in order to manage transmission congestion to ensure that transmission limits are not violated. Similarly, each system has protocols that address curtailment due to minimum generation, or over-generation, events to the extent that markets have failed to resolve such events. ISOs/RTOs use the lowest cost bids/offers first in order to relieve any transmission constraints that may arise in much the same way as the lowest cost bids/offers are used to maintain energy balance.

Impact of VERs on Economic Dispatch and Curtailment Practices

Several ISOs/RTOs have recently changed their redispatch and over-generation curtailment practices to reflect the impact of increasing numbers of VERs. These are discussed further in the subsequent sections.

G.1 How have redispatch and curtailment practices changed with increased numbers of VERs? Are there any shortcomings of current redispatch and curtailment practices?

Real-time energy markets provide a built-in incentive to follow dispatch instructions since units will only be dispatched if the market price is greater than their bid/offer, and conversely will only be dispatched downward if their bid/offer is greater than the market price. Few of the ISOs/RTOs offer specific incentives to VERs to follow dispatch instructions since the real-time energy market design already provides the right incentives. Specific incentives may only be necessary if VERs are unable to express their willingness to curtail through bids/offers and/or cannot respond to dispatch signals.

In most of the ISOs/RTOs, VERs have the capability to respond to specific dispatch instructions and most market rules have a response requirement to participate in the markets. In general, the VERs can respond down but they are limited in responding up. Wind resources have the capability to reduce their output in response dispatch instructions very quickly. For example, all wind resources in NY have a required response rate of at least 6.7% of nameplate per minute. Some VER achieves this response manually while others have control center systems that support the automatic reduction of plant output. Moreover, VERs could adjust bids/offers into the energy market expressing a willingness to be dispatched down based upon operational concerns or external financial decisions. These financial decisions could be rooted in operational wear and tear, staffing levels in the control room, external incentives (e.g., renewable energy credits, production tax credits, or revenue swaps). This may result in VERs making negative bids/offers signaling they are willing to run at negative prices due to the value of renewable energy credits and the production tax credits in particular.

With respect to real-time market operations, the NYISO and PJM allow wind generators to bid a price, including negative prices, that reflects their willingness to curtail operations if reductions in generation are desired in real-time effectively treating wind generation identically to other generators, and these wind generators receive 5-minute dispatch signals similar to other generators.

G.2 Do existing redispatch and curtailment processes unduly discriminate against VERs? If so, how should they be modified?

As noted above, several of the markets that have not yet established clear market rules for economic dispatch of VERs are in the process of doing so. In the CAISO, VERs to date have not provided bids/offers into the energy market that can be used for re-dispatch; in part this is because the current rules for the PIRP do not offer netting/averaging of imbalances to resources that have submitted bids into the markets. The CAISO has noted an increased need for re-dispatch for congestion related to the increase in VERs, and has changed its curtailment practices for VERs in some congestion cases and during more severe over-generation conditions. The CAISO will launch an initiative to develop additional bid-based dispatch of VERs in 2010. The Midwest ISO currently does not re-dispatch VERs by bid/offer and has recorded an increase in manual dispatching of resources to manage congestion that may be caused by VERs. Midwest ISO has also initiated a stakeholder process to address the issue. The timing of these implementations will vary by region simply because of other pricing rules and contractual issues that need to be addressed on a regional basis.[63]

63 For example, the CAISO currently has a Decremental bid floor of -$30/MWh, which will need to be addressed for all resources simultaneously along with the process to address VER bidding for economic dispatch. Similarly, the CAISO has the existing market rules for PIRP that offer VERs a netting of imbalance quantities and averaging of imbalance charges (for that netted quantity) as long as they do *not* offer bids into the CAISO real-time market. Hence, the CAISO's process to implement economic dispatch of VERs will have to address a number of issues not confronted in other ISOs and RTOs.

VERs that self-schedule are not re-dispatched based on bids/offers, but are often only re-dispatched once all available bids/offers are exhausted. Most RTOs rules in this regard are similar. Re-dispatch procedures are essential to manage congestion or maintain energy balance once all available offers have been exhausted.

G.3 Some RTOs/ISOs will redispatch VERs based on required economic bids. Should all RTOs/ISOs implement similar practices? Why or why not?

As already noted, the timing of this implementation will vary by region simply because of other pricing rules and contractual issues that need to be addressed on a regional basis.[64]

Redispatch and Curtailment Procedures outside RTOs and ISOs

G.4 Should transmission loading relief protocols be altered to allow reliability coordinators in non-RTO/ISO regions to consider economic merit when considering curtailing VERs? If so, how? Similarly, should redispatch and curtailment protocols in non-RTOs/ISOs be revised to consider economic merit for all resources? If so, how?

The IRC does not have a consensus position on economic redispatch outside ISOs/RTOs. However, as a general matter, ISOs and RTOs prefer that non-RTO/ISO regions use economic dispatch and transparent pricing. The experience of the ISOs and RTOs in seeking economic dispatch of VERs would certainly apply in these other regions.

64 For example, the CAISO currently has a Decremental bid floor of -$30/MWh, which will need to be addressed for all resources simultaneously along with the process to address VER bidding for economic dispatch. Similarly, the CAISO has the existing market rules for PIRP that offer VERs a netting of imbalance quantities and averaging of imbalance charges (for that netted quantity) as long as they do *not* offer bids into the CAISO real-time market. Hence, the CAISO's process to implement economic dispatch of VERs will have to address a number of issues not confronted in other ISOs and RTOs.

VERs and Minimum Generation Events

VERs are already affecting the frequency of minimum generation, or over-generation events, in some regions, but the nature of these conditions as well as market rules and operational protocols vary among the ISOs/RTOs.

> *G.5 Is the increasing number of VERs affecting operational issues that arise during minimum generation events? Are there ways to minimize curtailments during a minimum generation event? Should conventional base-load resources be offered incentives to lower their minimum operating levels or even shut down during minimum generation events to reflect an economically efficient dispatch of resources? If so, what would be the benefits and costs of doing so?*

In PJM during real-time operations, a Minimum Generation Emergency Event is initiated after all units are at Economic Minimum and additional generation reduction is required. During a Minimum Generation Emergency Event, all Emergency Reducible Generation (ERG) is reduced by an equal percentage (i.e., 20%, 30%, etc.), where the available ERG is equal to the Economic Minimum minus Emergency Minimum. PJM does not differentiate between resource types during a Minimum Generation Emergency Event. However, after all ERG has been utilized, PJM will consider the impact of directing wind to shut down prior to de-committing steam generation. PJM dispatchers can recommend that specific generating units not required for current area protection or not required for the subsequent on-peak period be shut down first.

CAISO does not currently require VERs to respond to real-time curtailment requests except for transmission overload issues. However, there are plans to implement such tariff provisions in the near future to deal with over-generation problems. CAISO anticipates increased over-generation conditions by the 20% RPS, due in particular to spring high wind, light load and high hydro conditions. [65]

ERCOT curtails over-generation events through market decremental offers. ISO-NE backs down dispatchable generation to minimum economic limits and reduce external transactions until the event is resolved.

Midwest ISO will curtail wind during Minimum Generation Events along with other generation resources according to economic order. In May 2009, Midwest ISO approved non-tariff changes to the Emergency Operating Procedure for Supply Surplus (RTO-EOP-003, Min Gen) that

[65] California ISO, "Integration of Renewable Resources", op. cit.

include a curtailment sequence which comes close to treating wind similar to other technologies. If curtailments are required, de-commitment of generation or reduction in scheduled generation will be executed in the following order: Generation identified in the reliability assessment commitment process; Generation above the day-ahead schedule from non-designated network resources; Generation above the day-ahead schedule from designated network resources; non-designated network resources committed in the day ahead market; and designated network resources and firm imports committed in the day ahead market. Midwest ISO offers an incentive that is available to all resources to operate at emergency limits and receive compensation based on offers at that range during such emergency conditions.

Increasing VER dispatch capabilities and incentives

G.6 To what extent do VERs have the capability to respond to specific dispatch instructions? Are there any advanced technologies that could be adopted by VERs to control output to match system needs more effectively? Should incentives be put into place for VERs that can respond to dispatch instructions? If so, what types of incentives would be appropriate?

In most ISOs/RTOs, VERs are required to respond to dispatch instructions or face penalties for failure to follow instructions. For example in NYISO, VERs that do not follow dispatch instructions, when dispatched down in response to system constraints, are charged a financial penalty for the amount of over-generation (outside a threshold) in the similar way other resources would be penalized for failing to meet dispatch instructions. This applies only during those instances where the NYISO has applied a wind output limit dispatch instruction to the resource. The over-generation charge is the regulation clearing price times the MWs over the base-point signal (with a 3% tolerance of error). In the Midwest ISO, the VERs are not required to follow dispatch instructions and there is a stakeholder process investigating the VERs integration into the economic dispatch.

4. International Experience on Related NOI Topics

This section provides an overview of the current state of Canadian and European integration of large-scale renewable energy. The Canadian IRC members – AESO, IESO, and NBSO – have contributed comments in this section that provide details of VER integration as well as answering some of the NOI questions.

4.1 Wind Integration in Canada

Wind integration in Canada is particularly relevant as Canada shares several grid inter-ties with the U.S. grid system at several locations. Canadian ISOs are similar to US system operators in that wind is currently taken as it is produced and is therefore a price taker. This results in curtailment policies when the wind generation surplus can not be mitigated by ramping down Regulating Reserve and Load Following units. There seems to be some indication (in the case of AESO) that such policies result in somewhat increased strain on ramping units providing Regulating Reserve, Ancillary Services and Load Following.

4.1.1 Independent Electricity System Operator of Ontario

The Independent Electricity System Operator (IESO) works at the heart of Ontario's power system, connecting all participants - generators that produce electricity, transmitters that send it across the province, retailers that buy and sell it, industries and businesses that use it in large quantities and local distribution companies that deliver it to people's homes. IESO addressed the relevant FERC VERs NOI topics for Ontario in the following subsections.

Forecasting of Variable Energy Resources

Currently, the IESO utilizes production forecasts provided by individual wind facilities to derive an aggregate forecast for near term production and to economically schedule other resources around this forecast. Each facility is obligated under the market rules to provide their best estimate of production for the 24 hours of the following day and their accuracy is subject to compliance requirements. Revised forecast submissions must be submitted if actual production is expected to differ from the original forecast by the greater of 2% or 10MW. In real-time, the IESO uses persistence forecasting to schedule resources on a 5 minute basis. This real-time schedule is created by a telemetry snapshot taken 10 minutes prior to the scheduling interval.

Given the expected additions to variable generation capacity in the next several years through Ontario's Feed-in Tariff (FIT) and other renewable expansion initiatives, the IESO is anticipating that current practices may need revisions or updates, where applicable. The recently launched FIT program has seen applications totaling in excess of 8,000 MW of potential generation projects, with almost 80% of these wind-powered. As a result, the IESO has begun the process of transitioning from a decentralized to centralized forecasting program. Under centralized forecasting, individual resources will no longer be required to submit forecasts but instead will be required to submit data to be used as inputs in the forecast. While the specifics of the implementation remain to be developed, some higher level design principles have been established.

The overarching theme of wind integration in Ontario is a much closer relationship between the IESO and wind facilities with respect to the provision of data. This is anticipated to not only apply to transmission-connected facilities, but also to facilities embedded within the distribution system. With a large number of resources under the FIT program expected to be embedded, this could pose challenges to reliable and efficient system operation. Therefore in order to improve the visibility of "behind the meter" resources to the IESO, the centralized wind forecasting program will encompass all embedded variable generation 5 MW or greater.

The IESO is developing the data needs that include the provision of meteorological data, wind farm outages, static plant data, spatial representation, real-time telemetry and historical information. Meteorological variables such as wind speed, wind direction, barometric pressure and ambient temperature are key parameters in determining the forecast performance that can be achieved for a specific facility. The timely reporting of outages is necessary not only from a system operation perspective, but also in forecasting processes; the misreporting of turbine availability distorts the relationship between meteorological variables and generation output. Static plant information describes the physical layout of the facility and performance details of the turbines employed. Spatial representation captures the data measurement locations within a facility, particularly important with larger multi-turbine wind farms. Real-time telemetry will be necessary not only to satisfy forecasting requirements, but also for operational and visibility needs. Historical meteorological and outage data is required to initialize and calibrate forecasting models, with two years of data being preferred.

The IESO is in the process of developing various facility size thresholds for which different data requirements may apply. The cost of satisfying all of the data requirements may present a challenge to smaller facilities, an issue that has been identified by some stakeholders.

The IESO has also indicated to market participants that it is prepared to share the actual forecasts that are generated by the forecasting vendor. However, no discussion of making the meteorological data used to develop those forecasts publicly available has occurred to date, though some stakeholders have expressed an interest in receiving this information.

Scheduling Flexibility and Scheduling Incentives

The IESO currently schedules internal resources on a 5 minute basis. Consequently, there may be little opportunity for shorter scheduling intervals to improve efficiency in response to VER variability. Work being done by the Integration of Variable Generation Task Force (IVGTF) may identify whether the need for more frequent dispatch exists.

Reducing the scheduling timeframe for intertie transactions however, from one hour to a shorter duration (i.e.: 5, 10, 15, 30 minutes), may provide some additional flexibility. This would necessitate a resolution of seams issues with those neighboring jurisdictions who do not currently schedule intertie transactions intra-hourly.

As the transition to a centralized forecasting program occurs, VERs will no longer be required to submit schedules of forecast production. The responsibility of forecasting is no longer borne by the facility, however there will exist a responsibility of timely data submission. For transmission and distribution-connected FIT resources, the IESO expects to issue economic dispatch instructions; intermittent generators submit a price at which they expect to reduce their production, which is used in pre-dispatch scheduling. Future capacity additions are expected to be dispatched economically in real-time. Compliance measures will be enforced with respect to these dispatch instructions. VERs would be treated the same as conventional resources, such that their output would be required to fall within the appropriate compliance deadbands.

Day-Ahead Market Participation and Reliability Commitments

No forward market exists in Ontario, however all intermittent generators are required to submit forecasts into the day-ahead commitment process (DACP) to allow for commitment decisions on imports and non-quick start generation. The IESO is presently implementing an Enhanced Day-Ahead Commitment (EDAC) process. The introduction of 24-hour optimization should provide better scheduling of resources around the forecasted variability of intermittent generation. The integration of centralized wind forecasting within the EDAC process is essential in realizing efficiency gains, as these forecasts are used as a primary input. These changes will not have an impact on intermittent generation participation – no day-ahead financial position is taken by VERs in either DACP or EDAC.

Intra-day, the IESO maintains a reliability assessment and commitment process through its Spare Generation On-line (SGOL) program. This program provides the recovery of certain costs to eligible generating resources in exchange for access to their generation capacity and availability that might not otherwise be online.

Reserve Products and Ancillary Services

The IESO administers markets for three classes of Operating Reserve (OR): 10-minute spinning, 10-minute non-spinning and 30-minute OR. In order to ensure the reliable operation of the power system, the IESO also contracts for additional four ancillary services; black-start capability, emergency demand response, regulation service and reactive support/voltage control service.

Operating reserve is co-optimized with the energy market on a five-minute basis, in order to economically schedule resources in both markets. Thus far, the IESO has not yet identified a need for a new reserve product to address VER uncertainty. Work is currently being undertaken by the IVGTF to consider potential reforms to standards and processes for reserves – the IESO looks with great interest at the findings of this subcommittee.

At present, wind cannot offer into ancillary service markets in Ontario. Intermittent generators are unable to provide reserve services in Ontario, as they are non-dispatchable. Were dispatchability to be introduced and these facilities became dispatchable resources, a scenario could be envisioned where contingency reserve could be provided. This would occur where VERs have been economically dispatched down and wind conditions exist such that they could increase their output, they may be eligible to be scheduled to provide contingency reserve. However, the implementation of such a change has yet to be fully considered. VERs are expected to maintain governor response capability for frequency events, where such technology exists. Regulation service is currently procured through a competitive contracting process, with a pilot program in development investigating the provision of regulation services from non-generation resources. Where these technologies can be competitively procured, these new providers would have positive impacts to the available resource mix.

Reserve requirement levels are dependent on the size of the two largest single generation contingencies on the IESO-controlled grid, with the size of the largest contingency being scheduled for 10 minute operating reserve and half of the second largest contingency being scheduled for 30 minute operating reserve. As wind output has yet to be forecast to exceed this amount, no policy has been established regarding the operating reserve requirement with the respect to the loss of wind under either a centralized or decentralized forecast scenario. As part of the NPCC Regional Reserve Sharing program, the IESO reduces the amount of 10-minute spinning reserve that it must carry by 100 MW. Provided neighboring jurisdictions do not anticipate simultaneous VER contingencies from “losing wind”, this could potentially lower the costs of integration.

4.1.2 New Brunswick System Operator

The New Brunswick System Operator (NBSO) administers a physical bilateral market and performs an hour-ahead security constrained economic dispatch. NBSO is responsible for the real-time balancing of supply and demand for a balancing area comprised of two provinces – New Brunswick and Prince Edward Island - and the northern part of the state of Maine. The winter peak load and spring minimum loads are approximately 3,500 MW and 1,000 MW, respectfully. The current capacity of Variable Energy Resources (all wind power generation) is approximately 400 MW. Under minimum load conditions the level of VER production could reach 40%. The generation mix in the area is diverse, and includes a modest amount of hydro storage. The total interconnection capability with neighbors is approximately 2,200 MW for imports and 2,700 MW for exports.

Data and Forecasting of Variable Energy Resources

NBSO is currently using VER production values from market participants' day-ahead bilateral schedules as a forecast of VER production for the purpose of performing day-ahead resource adequacy assessment. The persistence method is used to forecast the wind power production for the upcoming hour in the production of the hour-ahead security-constrained economic dispatch.

NBSO is also receiving day-ahead wind power production forecasting service for one wind farm within the balancing area on a trial basis. Wind farm data as received from the wind farm is provided to the forecasting company. The forecasting service provider uses meteorological data and the real-time data to produce a forecast of production as a percentage of total available production capacity for the wind farm.

A commercial service for both day-ahead and within-the-day are expected to be contracted within the current year. Total available generation capacity, actual generation production, wind speed, wind direction, and temperature are to be provided to the NBSO supervisory and control system from each VER facility in real-time. This data will be passed on to the commercial forecast service provider. The preliminary day-ahead forecast to be provided each morning will predict hourly VER production values for each VER facility in the balancing area for the upcoming 5 days. The final day-ahead forecast is to be provided early each afternoon and will predict VER production for each facility for each hour of the next day.

The commercial forecasts will be made available to the market participant for each facility, but any use of the forecast will be at the user's risk. The NBSO's forecasts of the aggregate VER production will be published in order to improve market participant overall knowledge of expected system conditions. Market participants will be notified of emerging surplus energy situations that may result in curtailment of VER production. Such notice provides VER

Generators as well as other market participants with additional time to seek export sales outside the NBSO balancing area.

Sharing of actual and forecast meteorological data between system operators is an approach that NBSO is pursuing with its neighboring system operators. Having this additional actual data would allow NBSO's wind power production forecasting service provider to produce better forecasts. In addition, the exchange of forecasts would allow system operators to implement ensemble forecasting techniques reducing the risk of missing the forecast of a significant wind event. Regulatory direction from Canadian and US regulators may make it easier for system operators to make such exchanges without breaching confidentiality provisions in contracts, tariffs, and market rules.

Scheduling Flexibility and Scheduling Incentives

Market participants representing generators bear the risk of deviations from schedules which are settled at the hourly marginal price of balancing energy. The price and quantity risks of deviations provide a degree of incentive for accurate scheduling, but both over and under supply are settled at fair market value. NBSO reserves the right through its market rules to invoke sanctions in the case of poor scheduling practices arising from intentional or otherwise avoidable forecasting errors. Unscheduled production also bears a higher risk of curtailment in the case of a surplus of zero incremental cost energy. In the case of VERs that are exporting and creating renewable energy credits in external renewable markets, the credits are typically the lesser of the actual energy produced from the facility or the amount scheduled for physical delivery to the external market. As a consequence, there is some incentive for over-scheduling so as to reduce the likelihood of foregoing renewable energy credits arising from an under forecast error. This incentive for over-scheduling is mitigated to some extent by the risk of a high price on the settlement of energy imbalance.

In recognition of the unique nature of VER production, generators are not required to acknowledge dispatch instructions and operate within dispatch instruction bandwidths.

Day-Ahead Market Participation and Reliability Commitments

NBSO's market design does not have a financial day-ahead market. There is, however, an obligation for load-serving entities to submit day–ahead balanced schedules. To date NBSO has largely accepted the scheduled production as submitted by the load-serving entity. Once NBSO's procurement of a commercial wind power production forecasting service is in place, the day-ahead commitment of facilities for the market will make use of NBSO's wind power production forecast as opposed to the production levels that are implied within the balanced schedules of the load-serving entities that are scheduling to use the VERs.

In the future it may be necessary for NBSO to formalize the approach it will take in determining whether or not the VER production levels that are implied within the load-serving entities' balanced schedules are realistic. This approach would need to be supplemented with a defined method for addressing such an occurrence.

As penetration levels increase and more experience is gained with forecast errors, it will likely become appropriate to perform day-ahead resource adequacy assessments based on a somewhat conservative assumption of VER production so as to reduce the cost and reliability risks arising from under commitment of dispatchable capacity. A supplemental approach would be to determine at what level of VER forecast error significant costs or reliability risks would be incurred. Combining this information with the forecaster's probabilistic forecast could facilitate more prudent decisions on unit commitment in light of higher levels of VER in the future.

Balancing Authority Coordination

NBSO continues to pursue greater coordination with its neighboring balancing authorities, including with respect to facilitating the integration of VERs. As an example, NBSO has conducted an intra-hour schedule change pilot with ISO New England. NBSO has also led discussions with adjacent balancing authorities with respect to intra-hour schedule changes and accommodating ancillary service transactions between balancing areas.

Reserve Products and Ancillary Services

NBSO has implemented an obligation on VERs in the balancing area to self-supply or purchase the incremental regulation and load following service that are required due the introduction of VERs, and reassesses the requirements for these services as the levels of VERs increase. The current charge is 0.25$/MWh. This charge has been implemented primarily in order to mitigate interjurisdictional cost shifting.

While the addition of wind will require added regulation and load following service the NBSO monitors the possible requirement for additional reserve. Current VER penetration levels do not affect reserve requirements, but increased levels may lead to a required increase in the future.

Capacity Markets

NBSO's market design does not have a financial capacity market, but does place a capacity obligation on load serving entities. VER facilities are credited with providing eligible installed capacity in a given capability period based on the facility's three-year historical capacity factor for the respective capability period multiplied by the nameplate capacity. NBSO performs occasional modeling to confirm the reasonableness of this approach. There is an expectation that at higher levels of VER penetration this approach may need to be modified to avoid overstating the contribution of VERs to reliability.

VER facilities have the option to be specifically excluded as a Capacity Resource in the NBSO control area. This allows VER facilities to participate in Renewable Energy Credit markets outside of New Brunswick.

Real-time Adjustments

NBSO performs security-constrained economic dispatch based on bid prices from generators on an hourly basis. To the extent feasible, significant real-time changes are addressed by an intra-hour security-constrained economic dispatch. In the case of surplus generation, renewable VERs are priced at $0.00/MWh, whereas other generators can only bid down to $0.01/MWh. Accordingly, the renewable VERs are less likely to be curtailed. In order to prepare for situations in which even the zero-priced VERs must be curtailed, a deterministic allocation of curtailments amongst VER's is being implemented. This approach gives first priority to scheduled VER production in keeping with the nature of a physical bilateral market. To the extent that curtailments are required to balance the system, VER production that is in excess of bilateral schedules will be curtailed in proportion to the level of unscheduled production based on the NBSO forecast. If further curtailments are required, scheduled VER production will be curtailed in proportion to the scheduled amounts, again, to the extent that curtailments are required to balance the system.

The NBSO requires wind generators to provide NBSO with direct control of maximum production limits. Such control provides dispatch certainty that will avoid reliability risks during periods of surplus VER production, reduce the need to take preventative action in advance, and decrease the risk of having to reject 100% of the production by tripping breakers.

Summary

NBSO continues to follow technology improvements and industry trends. As tools such as forecasting, demand response, and intra-hour tie schedule changes develop, the ability to integrate VERs is expected to continue to improve. Regulatory acceptance and support of such new and enhanced tools would facilitate these improvements.

4.1.3 Alberta Electric System Operator

Alberta has large wind resources with currently in excess of 500 MW of wind integrated into the grid and a strong interest in pursuing greater levels of wind penetration. Alberta Electric System Operator (AESO) has recently undertaken a grid integration study and published two recommendation papers from the findings of the study in September 2007 and March 2009 titled “Market & Operational Framework for Wind Integration in Alberta" and (similarly) “Implementation of Market & Operational Framework for Wind Integration in Alberta”[66]. The papers note that Alberta has adopted a leadership position in wind power development in Canada and has participated in cutting-edge wind integration studies. The large size and generation mix of Alberta’s electricity market and relatively small interconnection capability means Alberta has a limited ability to ‘share’ or dampen the wind power variability in the near term. AESO produced some of the first interconnection standards for wind in North America with the introduction of several cutting-edge wind integration standards. AESO also launched a wind power forecasting project and created the “Market and Operational Framework” (MOF) for wind integration in Alberta in September of 2007. The purpose of the MOF is to ensure that if the AESO has access to an accurate (within some reasonable deviation) forecast of wind power, they can create operational plans using the following strategies:

Energy Market Merit Order (EMMO),

Regulating Reserves

Load/Supply Following Services and

Wind Power Management (WPM).

The AESO currently operates an “imbalance market” by which the variability of both supply and demand is accommodated as described in the second paper:

“The AESO system operator manages supply-demand balance on a minute-to-minute basis considering load forecasts, operating uncertainties (i.e. unit de-rates and outages) and using current resources, rules and procedures. When wind suddenly ramps up or down, generating

66 “Implementation of Market & Operational Framework For Wind Integration in Alberta,” AESO Recommendation Paper, March 2009

resources (predominantly coal, gas or hydro-electric) must be immediately dispatched to offset the imbalance. In practical terms, energy from wind generation is accepted as delivered and any resulting imbalances will be offset with intra Alberta resources or potentially with power exchanged from other provinces"

(Note that this is similar to the Ontario policy of absorbing all the available wind energy so that wind is not scheduled but rather viewed as reduced load). The Energy Market Merit Order is described in the first paper:

"The Energy Market Merit Order (EMMO) is the primary mechanism by which the relative economic merit of supply offers are evaluated and dispatched to meet load requirements. With implementation of the Must Offer Must Comply rules, offers contained within the EMMO are price and volume certain two hours prior to the start of the delivery hour, which is referred to as T-2. At T-2, the ramping capability of the EMMO is also known. The EMMO can be dispatched by the system operator as often as is necessary in combination with the regulating reserves … to maintain supply demand balance."

The wind integration study also indicated that adding more Regulating Reserve could help resolve smaller wind events. At AESO, Regulating Reserves are fast-response resources that are used in real time to maintain supply demand balance within the 20 minute timeframe. They are controlled directly by the Automatic Generation Control system (AGC). They must also be able to ramp to regulation range within 10 minutes. The study found that regulating reserves are the primary mechanism for load balancing of wind integration in the 10 minute timeframe. The study of wind integration found that the 20 minute variability of net load of demand plus wind increased marginally over load-only profiles with increasing wind penetration, suggesting that it could be reasonably managed with small increases in regulating reserves. The larger risk however comes from wind ramping events that come in the 20 minute to several hours time range.

Load supply and following is similar to regulating reserves but is slower to respond and is generally used for the 20 minutes to hourly timeframe and plays a large role when wind is ramping in the opposite direction of load. The phase II study also found that Regulating Reserve may need to be complimented with additional Load Following services for larger wind penetration scenarios.

There may be scenarios however when the Energy Merit Market Order, Regulating Reserve, and Load Following do not allow the system to absorb all the available wind power and therefore wind power output must be curtailed. AESO is enforcing new standards of Wind

Power Management where by wind power may be curtailed based on a number of possible scenarios including:

Forecast loss of wind with insufficient ancillary and/or ramping services.

Wind supply surplus conditions.

Insufficient ancillary services due to market conditions or emergency conditions.

Large unforeseen wind gusts.

Islanding conditions.

It was also noted that geographical diversity of aggregated wind power will likely reduce the need to use these tools over time. As mentioned, accurate wind power forecasting is a critical component to the MOF to ensure the efficient and effective execution of the above operational plans. AESO undertook a forecasting pilot project to compare the predictive accuracy of a variety of forecasting methodologies across Alberta using different forecast horizons. They are also implementing a standard by which wind power facilities forecast their power for the next day as well as the next two hours on an hourly basis (and possibly other time frames as deemed useful). The system controller then incorporates the forecast into the MOF strategy. Under this scenario, since wind is non-dispatchable, wind is forecasted with energy schedules priced at $0 and wind suppliers are “price takers” in the market.

Also recently, a presentation by AESO[67] for IRC was given on March of 2010 regarding the study (i.e. recommendation papers) and the market impact of wind integration in Alberta’s grid operations. AESO indicated that if Energy Market Merit Order is modified to be optimized with respect to ramp rate there will be an increase in price volatility. This is due to the fact that units would be dispatched more frequently but for shorter durations. More specifically units will be given preferential order based on their ramping ability rather than capacity, thus driving up price during up-ramps. During down-ramp events the price of energy will drop until it reaches $0 per MWh which results in a curtailment signal and should also result in some self-mitigation by wind producers since they are price takers in the market. AESO suggested that if ancillary services are used instead there is less of an effect on price volatility. The presentation went on to suggest that larger penetrations of wind into the AESO grid would result in the increased possibility of supply surplus events (i.e. curtailment):

[67] “Wind Integration: Preliminary Near Term Operational and Market Impact Studies Results”, Alberta Electric System Operator Presentation to IRC, March 2010.

- In the most extreme cases experienced by AESO in 2008,150 MW of over-supply was observed above min-by-min stability levels.
- AESO expects that participants could manage $0 offers during periods of extreme surplus of energy to self-mitigate most of these events assuming they had the right signals (presumably SCADA based).
- Without mitigation measures AESO anticipates increased area control errors. Some mitigation strategies they suggested were:
  - Provide a wider range of regulating reserves in all hours
  - “Over-dispatching” the market merit order to create the maximum possible ramp rate.
  - Wind power management (which presumably implies curtailment policies and signaling events).
- They went on to suggest that accurate wind power forecasting tools would be required to manage this complexity.

In another (wind integration study follow-up) presentation in September 2007, AESO provided periodic reports of the current state of wind management issues on its system.[68] This report indicated that the instantaneous MW cannot exceed +5% of the maximum authorized MW and the 1 minute average cannot exceed 2% of the maximum authorized MW. AESO is also implementing new SCADA system signals that have the ability to control/curtail wind farm MW output with respect to “Wind Power Management” in the Market Operation Framework outlined in the wind integration recommendation papers. These protocols are being put into place to measure speed, pressure, temperature, and direction at various meteorological tower locations. AESO requires that historical data for up to 2 calendar years in the vicinity of the turbines is available. Recently (in 2006), AESO conducted a pilot project to compare different forecasting methods and services. New curtailment policies were also put into place.

[68] “Alberta Electric System Operator Market Services Stakeholder Session”, AESO Stakeholder Presentation, January 2010.

4.2 Integration of Variable Energy Resources in Europe

Europe has been a leader in the integration of VERs for a number of years, with several countries having greater VER capacity as a percentage of load than the power systems in the United States. European transmission system operators have experience with VER forecasting, operational requirements, and cross country issues (equivalent to coordination between North American balancing authorities). This section reviews European Community regulation before considering integration issues and conditions in several European countries.[69]

4.2.1 European Commission Directives on Renewable Energy

European renewable policy is developed both at the European Commission level and by national policies. In Directive 2001/77/EC, the RES-E Directive, the European Union established the objective of a 22% share of energy from renewable energy resources by 2010. Most recently, the European Commission has issued *Directive 2009/28/EC of the European Parliament and of the Council (23 April 2009) on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC (Text with EEA relevance)*.[70] The summary of this Directive notes the following key features:

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[69] This section draws from KEMA as well as surveys conducted by CAISO (including some excerpts from CAISO, *Integration of Renewable Resources*, November 2007), and the California Energy Commission.

[70] Available at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0028:EN:NOT.

[71] Available at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0028:EN:NOT.

“Each Member State has a target calculated according to the share of energy from renewable sources in its gross final consumption for 2020. This target is in line with the overall '20-20-20' goal for the Community.

Moreover, the share of energy from renewable sources in the transport sector must amount to at least 10 % of final energy consumption in the sector by 2020.

The Member States are to establish national action plans which set the share of energy from renewable sources consumed in transport, as well as in the production of electricity and heating, for 2020. These action plans must take into account the effects of other energy efficiency measures on final energy consumption (the higher the reduction in energy consumption, the less energy from renewable sources will be required to meet the target). These plans will also establish procedures for the reform of planning and pricing schemes and access to electricity networks, promoting energy from renewable sources.

> Member States can “exchange” an amount of energy from renewable sources using a statistical transfer, and set up joint projects concerning the production of electricity and heating from renewable sources. It is also possible to establish cooperation with third countries. The following conditions must be met: the electricity must be consumed in the Community; the electricity must be produced by a newly constructed installation (after June 2009); the quantity of electricity produced and exported must not benefit from any other support. […]
>
> Member States should build the necessary infrastructures for energy from renewable sources in the transport sector. To this end, they should: ensure that operators guarantee the transport and distribution of electricity from renewable sources; provide for priority access for this type of energy.”[72]

"Energy from renewable sources" is defined to include energy from renewable non-fossil sources, including wind, solar, aerothermal, geothermal, hydrothermal and ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases. The “indicative trajectory” for each national target in 2020, and interim years, is found in Annex 1 of the Directive and is calculated based on each member state’s share of renewables in 2005:

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72 Available at http://europa.eu/legislation_summaries/energy/renewable_energy/en0009_en.htm.

S2005 + 0.20 (S2020 – S2005), as an average for the two-year period 2011 to 2012;
S2005 + 0.30 (S2020 – S2005), as an average for the two-year period 2013 to 2014;
S2005 + 0.45 (S2020 – S2005), as an average for the two-year period 2015 to 2016;
S2005 + 0.65 (S2020 – S2005), as an average for the two-year period 2017 to 2018;

where S2005 = the share for that Member State in 2005 as indicated in the table below, and S2020 = the share for that Member State in 2020 as indicated in the table below.

Of this renewable resource development, wind generation is the primary VER, but with increasing amounts of solar thermal in Spain and solar PV being boosted by tariff structures in Spain, Germany and elsewhere. In 2005, Europe had approximately 40 GW of wind capacity, increasing to 66 GW by the end of 2008.[73]

Exhibit 4-1: National Targets for 2020

	Share of energy from renewable sources in gross final consumption of energy, 2005 (S2005)	Target for share of energy from renewable sources in gross final consumption of energy, 2020 (S2020)		Share of energy from renewable sources in gross final consumption of energy, 2005 (S2005)	Target for share of energy from renewable sources in gross final consumption of energy, 2020 (S2020)
Austria	23.3 %	34 %	Latvia	32.6 %	40 %
Belgium	2.2 %	13 %	Lithuania	15.0 %	23 %
Bulgaria	9.4 %	16 %	Luxembourg	0.9 %	11 %
Cyprus	2.9 %	13 %	Malta	0.0 %	10 %
Czech Republic	6.1 %	13 %	Netherlands	2.4%	14 %
Denmark	17.0 %	30 %	Poland	7.2 %	15 %
Estonia	18.0 %	25 %	Portugal	20.5 %	31 %
Finland	28.5 %	38 %	Romania	17.8 %	24 %
France	10.3 %	23 %	Slovak Republic	6.7 %	14 %
Germany	5.8 %	18 %	Slovenia	16.0 %	25 %

73 European Transmission System Operators, European Wind Integration Study (EWIS), *EWIS Interim Report*, June 2008, available at http://www.wind-integration.eu/downloads/library/EWIS-Interim-Report.pdf.

	Share of energy from renewable sources in gross final consumption of energy, 2005 (S2005)	Target for share of energy from renewable sources in gross final consumption of energy, 2020 (S2020)		Share of energy from renewable sources in gross final consumption of energy, 2005 (S2005)	Target for share of energy from renewable sources in gross final consumption of energy, 2020 (S2020)
Greece	6.9 %	18 %	Spain	8.7 %	20 %
Hungary	4.3 %	13 %	Sweden	39.8 %	49 %
Ireland	3.1 %	16 %	United Kingdom	1.3 %	15 %
Italy	5.2 %	17 %			

4.2.2 Some characteristics of the European grid relevant to VER integration

Europe's electrical grid is divided into several different areas/markets, some of which often share power, such as Scandinavia (i.e. Nordel) and Mainland Europe (i.e. UCTE), and some that are more isolated, such as Ireland (ATSOI) and the UK (UKTSOA). The regional differences in market and grid regulation combined with the large penetrations of wind power are currently creating some challenges for integrating large amounts of wind power. Europe's transmission system operators work collaboratively to identify issues related to the large increase in wind penetration in the European Grid. The European Wind Integration Study (EWIS), conducted by a multinational consortium of transmission system operators, identified the following issues regarding current and future integration of wind energy:[74]

1) Large load flows affect neighboring transmission systems and reduce available cross border trading capacities

2) Need for additional/new grid infrastructure:

- New overhead lines are necessary to transport the surplus of electricity produced in these regions to where it is consumed.

74 Ibid.

- The high wind bottlenecks on internal and cross border lines in northern Europe are already an issue. If a circuit is unavailable due to a disturbance in the grid the remaining lines can be overloaded up to 180%.

During serious grid failures, wind farms generally disconnect themselves completely instead of supporting the grid with auxiliary power. This can lead to even more serious power failures (cascading effect). Therefore (the paper recommends) wind farms should also have to support the grid during failure events.

The need for balancing power increases proportionally with the growing wind power capacity.

High wind power production remote from main electricity demand centers produces higher grid losses within the transmission system.

High wind power production causes regional overloading of transmission lines.

4.2.3 Collaborative Efforts for Forecasting Wind Power

In spite of some of the barriers to large scale wind integration, Europe has advanced in collaborative efforts to improve wind energy forecasting. One key European wind forecasting tools has been compiled as the ANEMOS wind forecasting distributed software application.[75] ANEMOS was designed as a comprehensive, distributed, multi-model wind power forecasting tool. A consortium of 23 partners from seven different countries reviewed the various sub-models that went into the final modeling package which includes a large variety of capabilities:

- Numerical weather prediction for short term (i.e. 1-2 hour ahead) and long term prediction (i.e. day-ahead).
- Advanced statistical and machine learning models for short term prediction (i.e. 1-2 hour ahead).
- Mesoscale modeling combined with integration of wind resource maps (i.e. WAsP wind resource grids) for the interpolation of upper atmosphere wind speeds to surface levels for both long term and short term prediction.

[75] This discussion draws from "Next Generation Forecasting Tools for the Optimal Management of Wind Generation", 9th International Conference on Probabilistic Methods Applied to Power Systems KTH, Stockholm, Sweden - June 11-15, 2006. Additional information can be found at http://anemos.cma.fr/.

These tools were benchmarked for performance to determine whether they should be included in the initial ANEMOS software project and outlined the technical specifications of the project. The benchmarking consisted of fine tuning these forecasting algorithms using real data from Germany, Spain, Denmark, Ireland and Greece. The algorithms were ranked in terms of their performance in a variety of terrain types and for a variety of forecast horizons (1-24 hours). The relationship between terrain complexity and forecast error was also examined and it was shown that increasing the complexity of terrain tends to increase the error of the forecast model. In addition, comparisons of statistical models that can yield a probabilistic result vs. deterministic models were included.

The ANEMOS project was designed to be a distributed software package for use across multiple regions that can participate in forecasts. The multinational consortium set up to review the technical specifications for ANEMOS currently uses the software as a distributed package for model sharing where users can run various models as a prediction service. They can also run ANEMOS as a stand alone application. The tool allows for a variety of “plug and play” forecasts and models to be incorporated so the user is not restricted to a fixed set of forecasting tools (i.e. as more advanced forecasting algorithms/models become available they can be added to a “tool box”). Currently several of these plug-and-play models are being used with the software that cover a wide range of end user requirements such as short term predictions (0-6 hours) using statistical/machine learning models, physical models, hybrid models, regional forecasts using upscaling/downscaling techniques, online uncertainty estimation, probabilistic forecasts, risk assessment, etc. The software can be set up remotely so that multiple users/countries can run ANEMOS as a remote server and share information/forecasts via a web server using standardized data formats and files. There is also the option to run the software in a distributed manner where by the software can operate on multiple servers and the failure of any operation on one server can be mitigated by a different server taking over those responsibilities. Currently seven countries are using ANEMOS (either collaboratively or independently) for wind forecasting purposes.

4.2.4 Selected Regional and National Studies

As with the United States, examining selected VER integration studies by country and category allows for further insight into the specific challenges faced and progress made by the system operators and wind producers in Europe. Both Denmark and Ireland are small systems with high wind penetration, but different in that Denmark has substantial interties with neighboring systems, while Ireland is an island system. Germany and Spain have substantial wind capacity in larger power systems. These country experiences are discussed briefly below. A few notably studies are also highlighted.

Denmark

Denmark currently has more than 2,000 MW of installed wind generation capacity, with the objective to increase the amount of wind generation to 5,500 MW, equivalent to 50% of total electric demand. Most of the current wind generation capacity is from small units that are less than one MW each. The units are widely distributed throughout the country, with the largest concentration in western Denmark. Many of the wind generators are connected to the distribution system rather than to the transmission grid. The goal is to replace many of these small turbines with new larger units over the next five years.

The geographical dispersion effect of wind farms across Denmark results in an hourly maximum drop of 20% of installed capacity, where as the standard reduction was roughly 3%.[76] Furthermore, the maximum change in output per minute was 6 MW out of 2400 MW of installed capacity or 0.25%. This indicates that geographical dispersion plays a strong role in the reduction of intra-hour variability in Denmark, reducing balancing requirements.

Denmark can handle the large amount of wind generation in part because of its transmission ties to Norway, Sweden and Germany. Hydro systems in the NordPool provide much of the regulation required as well as providing operating reserves to Denmark. The 15 minute variability of the wind generation production is relatively small at approximately 8%, which enables the transmission system operator to forecast and schedule wind energy on an hourly basis.

Ireland

By end of 2009, ESB National Grid for Ireland had about 1,260 MW of wind generation connected to the grid, with peak wind production at almost 40% of total demand for some hours. Ireland is an island system, and hence (unlike Denmark) cannot lean on a large interconnected grid to help them with the integration of large amounts of wind generation. Ireland has conducted a number of studies on the operational impact of large amounts of wind generation. In July 2004, the interconnection standard document WFPS1 (Wind Farm Power Station Grid Code Provisions) was published, establishing Low Voltage Ride Through, voltage control and frequency response requirements. A particular concern in Ireland is frequency issues and how to limit ramp changes from wind parks. There is also recognition that wind generation is an

[76] International Energy Agency, “Variability of Wind Power and Other Renewables,” 2005.

intermittent resource and cannot reliably meet peak load demands. One analytical result is that in Ireland, an additional 85 MW of fossil fueled generation (operating reserves) is needed for every 100 MW of wind generation.

Irish research has produced a number of unit commitment studies that are also informing US system operators. For example, a study of the application of stochastic optimization in unit commitment of Irish electric grid with high wind penetration evaluated the optimum balancing, scheduling, unit commitment and unit cycling for integration of large penetrations of renewable energy up to 34%.[77] Stochastic optimization utilizes a distribution of forecast probabilities as opposed to a single deterministic forecast. It was determined that stochastic optimization results in a 0.25% drop in schedule costs vs. deterministic scheduling with "imperfect" forecasting, however with "perfect forecasting" this number increases to 1.75%. This indicates that the additional information from probabilistic forecasts is more valuable and useful than from a single deterministic forecast alone in terms of schedule costs. However, another finding was that large penetrations of renewable energy result in high unit cycling rates, which causes a large amount of wear and tear and increases cost. This is an issue of increasing interest in the US systems.

Germany

Germany currently has more than 25 GW of installed wind generation capacity and expects to have 36 GW installed by 2015. The majority of the wind generation facilities are in northern Germany, although some wind facilities are spread throughout the country. The four German transmission system operators (TSO) must take all the energy produced by the wind generators, and they all share the balancing error in accordance to their market share.

A study commissioned by Deutsche Energie-Agentur (DENA) investigated the reliability and stability of the extra high voltage transmission network up to the year 2015.[78] Grid codes in Europe have been used to regulate the interconnection of wind turbines into the grid and are used as functional specifications for their construction. DENA found that grid safety criteria under the currently existing grid codes for turbines that went into operation before 2003/4 would have resulted in wide scale regional voltage sags and grid instability. The reason was that if voltage had dropped by more than 20% or more in a given network segment the older (2003/4 and prior) wind turbines operating under the grid codes at the time would have disconnected

[77] Aidan Tuohy, Niamh Troy, Andrej F. Gubina, and Mark O'Malley, "Managing Wind Uncertainty and Variability in the Irish Power System", IEEE 2009.

[78] Deutsche Energie-Agentur (DENA), "Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020", DENA Grid Study, 2006.

themselves suddenly from the grid. This would have triggered a cascading effect throughout the German and European grid possibly violating the 3,000 MW reserve capacity requirement and resulting in complete shutdown. The study led to a change in grid codes in 2004 such that all new wind turbines would disconnect themselves from the grid at an 80% or greater drop in voltage which would ensure stability of the grid somewhere between 2010 and 2015 as the rate of growth of the newer grid code wind turbines outpaces the older grid code turbines. It should be noted however there has been no reported occurrence of such a wide scale event even though it is hypothetically possible.

Spain

Spain has a national renewable energy strategy to reach 30.3 % of gross electricity consumption by 2010 defined by the Plan on Renewable Energies, RD 661/ 2007, which grants eligibility not only to so-called non-consumable energy sources (solar, wind, etc), but also to the production of electricity from biomass, bio fuels, co-generation and residuals. As a rule, eligibility is limited to installations with a nominal capacity up to 50 MW.

RD 661/ 2007 introduced significant modifications compared to the former support scheme. Similar to the former scheme, under RD 661/2007 an eligible renewable energy producer may choose between:

- a guaranteed feed-in tariff in €c per kWh of renewable electricity produced, or
- a market premium on top of the hourly electricity market price, if it decides to sell its generation directly on the wholesale market (organized market or negotiated agreement).

Remuneration is specific to the technology used and the capacity installed. Producers using controllable renewables may opt for a demand-orientated fixed tariff instead of a time-independent tariff and, thus, benefit from a higher remuneration during times of high load. On the contrary, the premium option is only available to non-consumable sources, biomass and bio fuels.

In addition to the feed-in remuneration, renewable energy producers may acquire additional income from several bonuses. With regard to better integration of renewable sources, the following should be mentioned:

- Complementary payment for constant supply of reactive power by installations larger than 10 MW, according to a predetermined day profile;

- Payment for guaranteed availability of capacity by controllable technologies to RES-E producers selling their electricity directly to the market;
- Bonus for invariance of production in the case of voltage discontinuity.

On a voluntary basis, those renewable producers which run under the premium model and operate controllable renewables installations may offer ancillary services (to the control power market) with a minimum offer of 10 MW required. Besides, the bonuses for constant supply of reactive power and for invariance of production in the case of voltage discontinuity may be interpreted as non-market based provision of system services.

Renewable energy producers benefit from priority of dispatch subject to system security. However, when approached by an application for grid connection, the system operator, Red Eléctrica de España (REE), may impose regional/local capacity constraints due to security of supply reasons and reject the application.[79] Additionally, any installation larger than 10 MW has to be connected to a local generation control center (GCC). This transmits online information to the system operator and gives the renewable installation the ability to comply with real-time dispatch instructions for system stability purposes.

With a system-wide peak load of 45,500 MW, REE depends heavily on flexible generation to back up 15,950 MW of installed wind (as of 2009), which supplies 10 percent of the country's total electric power. Currently, 19,838 MW of installed combined-cycle gas generation and 4,800 MW of pumped hydroelectric generation are used to meet REE's load ramps of up to 4,000MW/hr and wind ramps of up to 1,172 MW/hr upward and 785 MW/hr downward. Spain has a total capacity of over 80,000 MW, including gas resources built to accommodate the growth in wind. To facilitate the integration of wind into their operations, REE manages a centralized renewable generation control center,[80] which collects all information about current wind generation and provides a centralized forecast. All wind production facilities with total installed capacity of 10 MW or greater must be controlled by a compliant control center, and be able to execute orders within 15 minutes at all times.

Other measures used by REE include roughly 2,500 MW of load that is interruptible up to 10 times per year, as well as mandatory regulation service margins of 1.5 percent of installed capacity from all generators connected to the grid. REE typically has as much as 1,000 MW of

[79] REE has extensive materials in English that describe power system resources and operations; see http://www.ree.es/ingles/publicaciones/publicaciones_on_line.asp.

[80] See information materials at http://www.ree.es/ingles/publicaciones/publicaciones_folletos.asp#cecre.

regulation capacity available to meet swings in load and wind. Using these measures, REE reliably meets the demands that wind puts on their system. However, REE still faces significant challenges in managing congestion caused by wind, as well as reliability issues such as trips at wind generators caused by low-voltage conditions.

5. Literature Search for Related Paper on NOI Topics

In addition to the papers and studies published by the ISO/RTOs, the project team searched the following sites for papers or studies related the topics and related questions in the NOI. The purpose was to document relevant material within the past few years on the subject related to the NOI.

3) Institute of Electrical and Electronic Engineers (IEEE)
4) State Agencies such as the California Energy Commission (CEC) and New York State Energy Research and Development Authority (NYSERDA)
5) State commissions and energy agencies (relevant to ISO territory)
    - CAISO – Integration of Renewable Resources Program (IRRP) and Renewable Energy Transmission Initiative (RETI)
    - California Public Utility Commission
    - Minnesota Public Utility Commission
    - Northwest Power and Conservation Council (NW Council)
6) American Wind Energy Association (AWEA)
7) Utility Wind Integration Group (UWIG)
8) US Department of Energy National labs such as National Renewable Energy Laboratory (NREL), Pacific Northwest National Laboratory (PNNL), and Lawrence Livermore National Laboratory (LBNL)
9) DOE and Western Renewable Energy Zones (WREZ) w/ Western Governor Association.
10) FERC – references in NOI
11) Wind forecasting vendors: AWS Truewind and 3Tier

Appendix A, Summary of Literature Search, provides the name of the article/report, source of the article/report, authors, date published, relevance to the NOI topic areas (A-G), and a summary; where the NOI areas are:

a) Data and Forecasting (approximately 42 related articles/reports),

b) Schedule Flexibility and Scheduling Incentives (approximately 39 related articles/reports),

c) Day-Ahead Market Participation and Reliability Commitments (approximately 13 related articles/reports),

d) Balancing Authority Coordination (approximately 20 related articles/reports),

e) Reserve Products and Ancillary Services (approximately 33 related articles/reports),

f) Capacity Markets (approximately 11 related articles/reports), and

g) Real-time Adjustments (approximately 27 related articles/reports).

Some key findings from the review of the literature search in Appendix A are:

a) Data and Forecasting (Section A of the NOI)

The most common approach (2, 3, 13, 20, 22, 23, 31, 37, 40 and 63) to VERs energy forecasting is a centralized forecast. As discussed in the Scheduling Flexibility and Scheduling Incentive section, near-term forecasts are typically more accurate. As the forecast points moves out in time the accuracy declines.

VER related events (1, 40, 53, 60, 63, 65, and 70), such as thunderstorms, micro-cells or weather fronts, can result in forecasting errors. Further errors can arise from the models employed and the periodicity in the forecast update. More severe events such as ramping events require better tools for operations particularly for ramping events due to vertical mixing (58, 64). Various forecasting approaches (3, 8, 29, 44, 58 and 64) have been used, such as numerical, statistical/machine learning and mesoscale models, as well as hybrid approaches. A general consensus exists that improvements have been made and more work is required.

Two papers (40 and 72) report that improvement in VER energy forecast will require more data such as abundant and higher quality meteorological and energy generation data, sophisticated wind plant data gathering and communications systems, turbine availability, and detailed statistical or physical plant output model formulations.

b) Scheduling Flexibility and Scheduling Incentives (NOI Topic B)

Most of the references support the position to use shorter scheduling intervals in real-time operations. Two European references (1 and 74) support shorter scheduling intervals using examples where the VERs imbalance energy costs decreased and the amount of reserves requirements declined, respectively, when moving from a two hour look ahead scheduling to one hour look ahead.

Intra-hour scheduling was supported (22, 45, and 59) to reduce the variability component and provide more frequent access to the flexible conventional generators.

In terms of the incentives question, none of the references addressed this topic.

c) Day-Ahead Market Participation and Reliability Commitments (NOI Topic C)

The references do not take a position on the issues addressed in this NOI topic. However as discussed in the scheduling section, most US ISOs/RTOs operate day-ahead markets and most also perform intra-day reliability unit commitment on various time-scales.

d) Balancing Authority Coordination (NOI Topic D)

Most of the references support the concept that a larger balancing authority size provides for geographical diversity in the VERs, a larger mix of generation to support ramping events, and smaller integration cost for VERs (16, 20, 22, 23, 34, 36, 40, 45, 52, 53, 62, 65, 66, and 69). Benefits of the larger balancing authorities are supported by the European Transmission System Operators (16), BPA reference (69) and in ISOs/RTOs studies (34, 52, and 65).

e) Reserve Products and Ancillary Services (NOI Topic E)

Most of the references support the finding that VER integration will require an increase in procurement of reserve products and ancillary services, and possibly the mix of reserves. Regulation reserves are impacted when a high penetration of VERs materialize. Several references (22, 30, 31, 32, 49, 50 and 59) identify the need to separate regulation from load following needs. In addition to having diversity (65) in the mix of generation to support VERs, several references (47, 52 and 69) identify further diversity from reserve sharing with neighbors via interconnection agreements.

European Transmission System Operators (TSOs) revised their grid codes to require the wind farms to provide voltage ride through (VRT) capability (25 and 73) to help maintain grid stability. NERC (53) is also looking at standardizing the basic requirements in these interconnection procedures and standards, such as the ability of the generator owner and operator to provide: Voltage regulation and reactive power capability; Low and high voltage ride-through; Inertial-response (effective inertia as seen from the grid); Control of the MW ramp rates and/or curtail MW output; and Frequency control (governor action, AGC etc.) as ways to enhance system reliability with high penetration of VERs.

Storage (46, 48 and 82) was proposed in one reference to offset the variability of wind to maintain the reliability of system. Other products (16 and 45) such as demand side management and demand response, smart grid, and Plug-in Electric Vehicles can be used to mitigate the variability of VERs.

f) Capacity Markets (NOI Topic F)

There were no references that directly addressed the questions in NOI or stated that discrimination exists against VERs in the ISOs/RTOs markets. There are several references on the methods used to compute VER capacity factors (12, 26 and 56).

g) Real-time Adjustments (NOI Topic G)

Several of the papers/studies in Exhibit 4-1 identify direct or indirect impacts on curtailment or re-dispatch of generation as part of real-time adjustments to maintain reliability. In general, most of the references did not directly address the questions in the NOI. However, many of the references support the US ISOs/RTOs on the need to curtail generation during over-generation and for congestion relief.

Ireland and several European TSOs (13, 36, and 47) supported the need for a coordinated approach to address curtailment events, recognize the increase in redispatch cost due to VERs variability, and analyze resulting costs to conventional generators (wear and tear related to increase cycling) as well as the need for sufficient on-line conventional plants with fast controls during high wind situations. One paper (46) looked at the use of storage to offset the variability of wind to maintain the reliability of system.

6. U.S. Renewable Portfolio Standards

This appendix provides an update to information included in the IRC's 2007 report on renewable resources; some of the description below is taken verbatim from that report, while other sections are new. In general, renewable portfolio standards (RPS) require load-serving entities annually to meet a specified percentage of their retail sales from eligible technologies that generally (but not always) are limited to renewable energy technologies. Typically, the RPS increases over time, and a penalty may be levied if the RPS target is not met. In nearly all cases, the RPS is set by energy, not capacity. In many states, RPS compliance may involve renewable energy credits (RECs). A REC represents one MWh of renewable energy generation and can be bought, sold or traded before being used for RPS compliance. Exhibit 6-1 shows an up-to-date survey of RPS policies (note recent RPS updates to Kansas, Missouri and New Mexico are reflected in the map).

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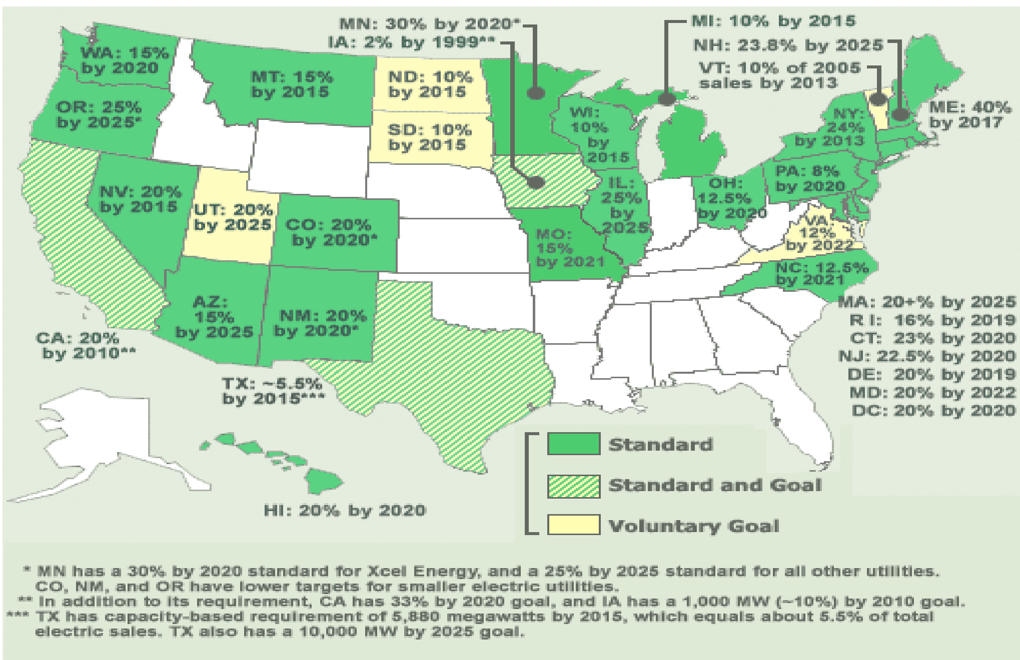
Exhibit 6-1: State RPS Policies

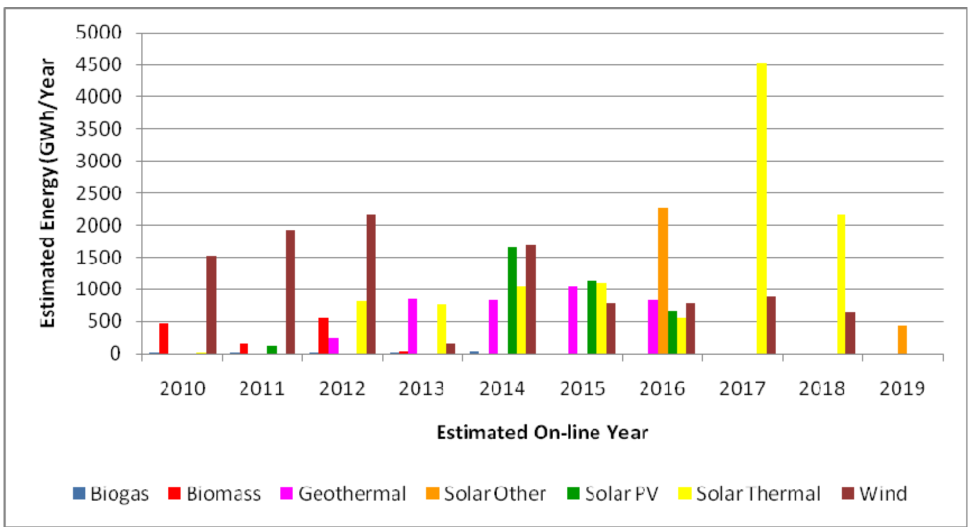


Source: Union of Concerned Scientists

California ISO

Renewables have had an important presence in California since the late 1970s and 1980s, due to aggressive state implementation of the Public Utility Regulatory Policies Act of 1978 and federal and state tax incentives. The state helped launch the U.S. wind industry, and had the most installed wind capacity of any state until it was surpassed by Texas in 2006. California enacted its 20% RPS by 2017 in 2003 and amended the RPS in 2006 to accelerate the 20% target to 2010. Based on existing contracts and transmission construction, this goal is now expected to be achieved in 2012-13. In addition, the Governor of California has signed an executive order for a statewide 33% RPS by 2020, and the California legislature is expected to pass legislation enforcing this higher RPS in 2010. Exhibit 5-2 shows the expected renewables based on load-serving entity contracts filed with the California Public Utility Commission and the CAISO generation queue through 2019.

Exhibit 6-2: Expected energy from renewable generation additions in California by fuel type, 2010 – 2019.



California has perhaps the most complex RPS in the nation. Utilities are required to annually submit draft renewable resource procurement plans and solicitations for review and approval by the California Public Utilities Commission. Once approved, utilities select bids that meet a least-cost, best-fit test. Utilities must also work with a procurement review group on the RPS solicitations and the bids. If bids exceed a market price reference, then utilities can receive supplemental energy payments from the California Energy Commission to make up the difference, if there is sufficient funding in the California Energy Commission's New Renewable Resources account. RECs are allowed for RPS compliance in California now that the Western Regional Generation Information System (WREGIS) is in operation, and the California Public Utilities Commission and the California Energy Commission are determining the rules for REC trading. California's RPS allows utilities to bank renewable generation for up to three years, and the amended RPS statute may allow utilities to miss RPS requirements if sufficient transmission is not available and "all reasonable efforts have been made" to provide transmission capacity and to use flexible delivery points.

California is rich in renewable resources, but a significant amount of potential renewables are in regions with little or under-developed transmission networks, particularly in southern California. Therefore, transmission will be a critical element towards achieving the California RPS requirements. There are several renewable transmission planning initiatives underway that are attempting to identify the most environmentally and economically desirable renewable zones and overcome barriers to transmission development, including the Renewable Energy Transmission Initiative (RETI)[81] and a current joint effort by the CAISO, investor-owned utilities and publicly owned utilities that are also balancing authorities, called the California Transmission Planning Group (CTPG).[82]

New York ISO

New York has a 24 percent RPS by 2013 with an additional 1 percent to be met from voluntary green power purchases. New York's RPS also contains two tiers: one tier for medium-to-large renewable energy facilities known as the main tier, and a tier for customer-sited generation facilities. In addition, the New York RPS allows existing renewable energy facilities to petition for inclusion in the RPS if necessary to maintain the facility's operation. New York presently receives 19.3% of its energy from renewable, almost entirely from hydro.

For the main tier, another unique feature of the New York RPS is that utilities in New York do not actually procure renewable energy generation as RECs. Instead, utilities pay a fee to the New York State Energy Research Development Authority (NYSERDA), who in turn conducts an auction for RECs. NYSERDA then distributes RECs proportionate to the fees utilities

81 See http://www.energy.ca.gov/reti/index.html.

82 See www.ctpg.us.

contributed to NYSERDA.[83] NYSERDA has conducted four REC auctions in the period 2005 thru 2009[84] for a combined total award of 1,426 MW of renewable resources. NYSERDA provides capacity- or performance-based incentives for customer-sited generation facilities.

The New York ISO has over 1,200 MW of interconnected wind capacity. There are more than 7,000 MW of wind capacity in its interconnection queue. The State is estimated to have a wind resource potential of 7,080 MW.

Before the New York PSC finalized adoption of the RPS, NYSERDA and the New York ISO commissioned a study to assess the grid impacts of 10% wind energy, or about 3,300 MW of wind. The study, conducted by GE Energy Consulting, found that the New York grid could accommodate that level of wind penetration.

GE also recommended that the NYISO implement a centrally administered, day-ahead wind forecasting system. The NYISO implemented its day-ahead and real-time wind forecasting service in 2008.

The NYISO currently exempts up to 3,300 MW of wind generation from over and under-generation penalties. In June 2009, the NYISO, with stakeholder and FERC approval implemented market rules that fully integrated wind generators into its 5-minute economic dispatch, allowing wind generators to specify their economic willingness to limit their output when the system is constrained.

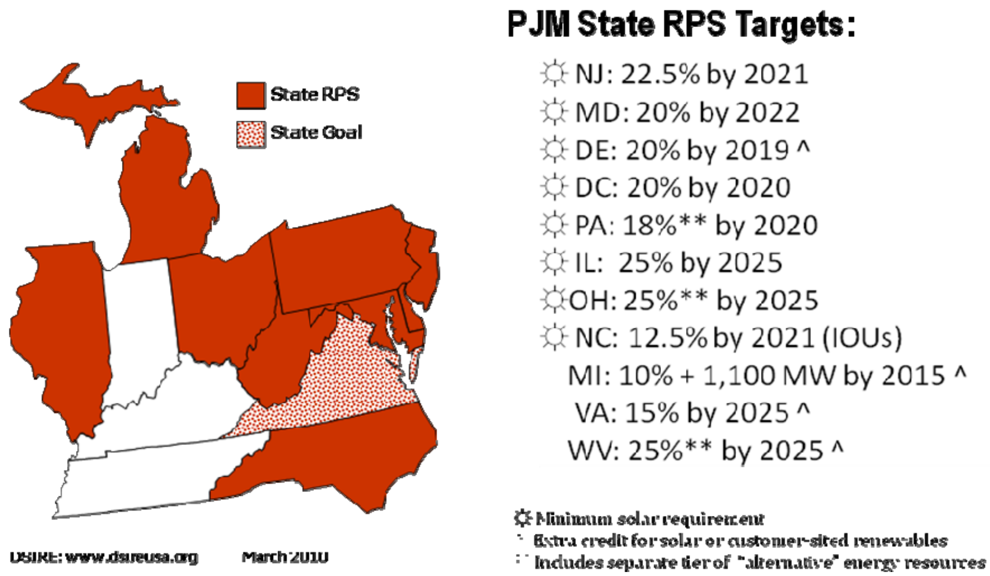
PJM

PJM serves all or parts of thirteen states and the District of Columbia. Eleven of the fourteen have state RPS policies, the details of which are outlined below in Exhibit 5-3 and Exhibit 5-4. Eight of the state RPS policies within PJM have separate set-asides for solar within their RPS. PJM estimates that these state RPS policies will require about 100,000 GWH of existing and new renewable generation by 2020.

83 "New York's Renewable Portfolio Standard," New York State Energy Research Development Authority. http://www.nyserda.org/rps/index.asp.

84 See http://www.nyserda.org/rps/PastSolicitations.asp.

Exhibit 6-3: PJM State RPS Policies



Like New England and Texas, PJM has a tracking system, known as the Generation Attribute Tracking System (GATS). PJM created a separate subsidiary, known as PJM Environmental Information Services, Inc. ("PJM-EIS"), to manage the tracking system apart from the PJM membership. The costs of GATS are paid through a combination of registration fees, volumetric fees imposed on load-serving entities that participate in GATS and for certificate transfers into certain accounts, although no fee is charged if a load-serving entity is using the certificate to comply with a state RPS requirement. GATS is used not only to meet state RPS policies but also state environmental disclosure and fuel disclosure requirements and to help support voluntary bilateral green power markets that focus on renewable energy generation. As of March, 2010, GATS has 6,385 registered renewable energy generators and 3,871 subscribers. In 2009, PJM-EIS issued over 700 million certificates from GATS

PJM does not charge imbalance penalties for schedule deviations, such as the energy imbalance penalties set out in Order 888 (market rules that account for the unique characteristics of renewables are available in most ISOs/RTOs). Because wind is a small percentage of PJM's energy mix (0.83% in 2009), PJM takes wind as a price taker in the real-time market and does not require wind generators to bid into the day-ahead market, except as noted below for wind generation that is an installed capacity resource. PJM imposes an operating reserve charge for differentials greater than 5 MW, in order to recover the costs from decommitting already committed generators. On average, the operating reserve charge is generally about $2-3/MWh, although it can vary.

PJM has a financial installed capacity market. For wind, PJM measures the capacity value of wind generation between hours ending 3 p.m. to 6 p.m., inclusive, between the months of June and August. PJM will use a three-year rolling average, as adjusted for unforced outages for both individual wind projects and for all wind projects to determine a class average. Because wind generation data is relatively scarce, PJM has used a proxy value of 13% until more wind generation data is available. Wind generators that decide to be an installed capacity resource must submit an offer in the day-ahead market. PJM also has streamlined and accelerated interconnection projects for generation projects below 20 MW.

PJM's large balancing area, geographic diversity of its wind resources, and fast markets (i.e., 5-minute dispatch) all help mitigate the operational impacts associated with integrating variable output resources within PJM. Nonetheless, PJM is proactively taking steps to mitigate potential impacts on operations. PJM formed the Intermittent Resources Working Group (IRWG) to address market, operational, and reliability issues specific to variable resources. In April 2009, PJM implemented a centralized wind power forecasting service. The wind power forecast is used in Day-Ahead transmission analysis, and to ensure that sufficient generation resources are scheduled to meet forecast load, transaction schedules, and reserve requirements. In June 2009, PJM implemented changes to improve wind resource management: generating resources are now able to submit negative price offers, enabling wind resources to submit flexible offers that better reflect the price at which they will reduce output. In November 2009, the IRWG started work on new assignments in the areas of assessing operational impacts, examining interconnection standards, and reviewing interconnection study methodologies for intermittent resources.

Exhibit 6-4: State RPS Policies in PJM

State	Class	RPS	Eligible Technology	Non-Compliance Penalties (per MWh)
DE	N/A	20% by 2020, with 2.005% from solar	Solar, wind, ocean tidal, ocean thermal, fuel cells powered by renewable fuels, small hydroelectric facilities, sustainable biomass, anaerobic digestion and landfill gas	$50 for non-solar, $250 for solar. Non-compliance fee increased to $80/MWh for non-solar and $300 for solar if non-compliance fees paid in previous years.
DC	Tier 1	20% by 2020	Solar, wind, biomass, landfill gas, wastewater-treatment gas, geothermal, ocean and fuel cells fueled by "tier one" resources	$50
	Tier 2	0% by 2020	Hydropower, municipal solid waste	$10
	Solar	0.4% by 2020	Solar	$500
MD	Tier I	20% by 2022, 2% from solar	Solar, wind, qualifying biomass, methane from the anaerobic decomposition, geothermal, ocean, fuel cells powered by methane or biomass, and small hydroelectric plants	$40 for non-solar Tier 1, $450 for solar in 2008 and declining to $50 by 2023
	Tier 2	0% by 202019	Hydroelectric power, waste-to-energy facilities, and poultry-litter combustion	$15
PA	Tier 1	8% by 2020, with 0.5% from solar	Photovoltaic energy, solar-thermal energy, wind, low-impact hydro, geothermal, biomass, biologically-derived methane gas, coal-mine methane and fuel cells	$45 for non-solar; twice the market price of solar credits for solar
	Tier 2	10% by 2020	Waste coal, distributed generation (DG) systems, demand-side management, large-scale hydro, municipal solid waste, pulping process and wood-manufacturing byproducts, and integrated combined coal gasification (ICCG) technology	$45
NJ	Class I	17.88% by 2021	Solar, wind, wave or tidal action, geothermal energy, landfill gas, anaerobic digestion, fuel cells using renewable fuels, and certain sustainable biomass	$50
	Class II	2.5% by 2021	Small hydro < 30 MW, and resource-recovery	$50
	Solar	2.12% by 2021	Solar	$693 currently, declining to $594 in 2015/16

State	Class	RPS	Eligible Technology	Non-Compliance Penalties (per MWh)
OH	Renewable	12.5% by 2024	Wind, geothermal, biomass, methane gas, landfill gas, non-treated biomass products, solid waste, fuel cells, storage facilities and hydroelectric	$45
	Solar	.5% by 2024	Solar PV and Solar Thermal	$400 in 2010 and 2011, declining by $50 every two years thereafter
IL		25% by 2025 with 1.5% from solar	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Biodiesel	
MI		10% +1100 MW by 2015	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, CHP/Cogeneration, Coal-Fired w/CCS, Gasification , Anaerobic Digestion, Tidal Energy, Wave Energy	
WV		25% by 2025	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, Other Non-Renewable Alternative Energy Resources (see summary for list), Anaerobic Digestion, Small Hydroelectric, Biodiesel	
VA		15% by 2025	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Energy from Waste, Anaerobic Digestion, Tidal Energy, Wave Energy	
NC		12.5% by 2021 including 0.2% from solar	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, CHP/Cogeneration, Hydrogen, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy	

Southwest Power Pool

Except for Texas, no state in the Southwest Power Pool (SPP) has a RPS. Because SPP includes only a small part of Texas that state's RPS will be addressed in the section on the Electric Reliability Council of Texas.

SPP is home to some of the richest wind resources in the country. The states that comprise SPP include Texas (second best potential wind resource); Kansas (third best potential wind resource); Oklahoma (eighth); and Arkansas (27th).85 The American Wind Energy Association estimates there is as much as 150 GW of wind potential in the SPP region.

However, much of this wind resource is in remote areas with undersized transmission. Because of that, there has been interest in planning and building transmission to access these wind resources. SPP's Extra High Voltage (EHV) Study assesses the future reliability and capacity needs to the year 2026 and beyond. To meet those needs, it suggests overlaying the SPP footprint with a 500 and 765 kilovolt transmission system and integrating it with the existing systems of Entergy, the Midwest Independent System Operator, and PJM Interconnection. An EHV overlay would enhance electric reliability and provide greater access to all types of generation, including renewable energy from wind farms in the central portion of the United States. Another component is the "X Plan", which represents an efficient transmission expansion plan for delivering wind energy in the Central and South Plains to the existing electric grid. The suggested transmission lines form the shape of an "X". The V Plan is a leg of the X Plan between Comanche County and Wichita, Kansas. The X Plan has been incorporated into the EHV Study and the SPP 2009 Transmission Expansion Plan.

Exhibit 6-5: The "X Plan" in Southwest Power Pool

SPP administers a regional open access transmission tariff; ensures regional electric reliability; monitors regional scheduling; and conducts regional transmission planning. In February 2007,

85 Wind potential estimates from the American Wind Energy Association's Wind Project Data Base at their web site, www.awea.org.

SPP implemented a regional, offer-based energy imbalance market. SPP does not yet operate a day-ahead wholesale market.

SPP has its own method of determining the capacity credit of wind that is used for long-term planning. SPP does not have a financial market for installed capacity and instead uses capacity value for long-term planning. For wind, SPP determines the capacity value monthly. SPP begins by examining the highest 10% of load hours in the month. Wind generation from those hours is then ranked from high to low. The wind capacity value is selected from this ranking, and it is the value that is exceeded 85% of the time (the 85th percentile). Up to 10 years of data are used if available. For the wind plants studied in the SPP region, the capacity values ranged from 3% to 8% of rated capacity.

SPP also has explored whether to re-rate constrained transmission lines to allow more wind power onto the lines. Because wind generation is primarily at off-peak times and that the transmission carrying capability is rated at peak times, it is thought that more wind generation potentially could be carried on transmission paths than conventional rating criteria would suggest. SPP did an analysis of potential high wind resource areas and measured whether the wind resource could be correlated to load. SPP also would require wind companies to install real-time monitoring equipment. SPP's concept is still under consideration and has not proceeded to implementation.

Midwest ISO

Of the 15 states the Midwest ISO serves, four states have established Renewable Portfolio Standards: Illinois, Iowa, Minnesota, and Wisconsin. (See Exhibit 5-6) Minnesota and Wisconsin increased their RPS in 2007 and 2006, respectively. Currently, there is about 3008 MW of wind in the Midwest ISO's footprint. For wind alone, the Midwest ISO is estimated to have 400,000 MW of wind resource potential.

The Midwest ISO does not schedule wind in the day-ahead market but instead takes wind generation in real-time market as it is generated. The Midwest ISO does not have a capacity market and therefore does not evaluate the capacity value of wind. Wind generation is assigned a 15% capacity credit in generation expansion planning.

The Midwest ISO was among the first to proactively include wind in its transmission planning process, beginning with its first Midwest Transmission Expansion Plan (MTEP) in 2003 and continuing through the current year plans. The Midwest ISO studied the transmission planning needs and system impacts of including up to 10,000 MW of wind. For the high wind case, the

2003 MTEP found marginal cost savings of $215 million as compared to the reference case, and $335 million as compared to the high gas case.

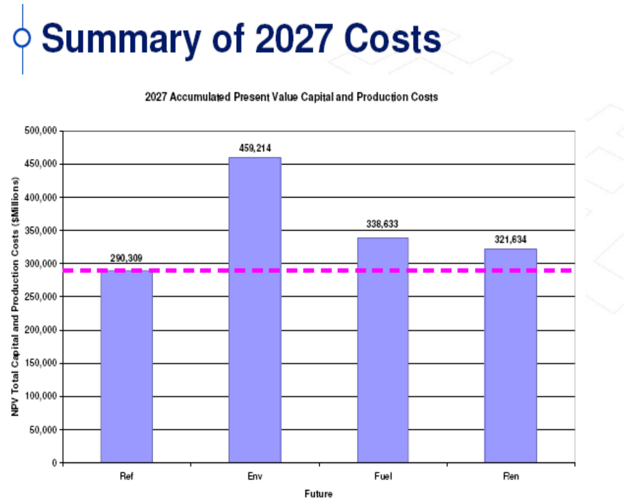
Exhibit 6-6: State RPS Policies in the Midwest ISO

State	Class	RPS	Eligible Technology	Penalties (per MWh)
WI	N/A	10% State-wide by 2016 (Varies by utility)	Tidal and wave action, fuel cells using renewable fuels, solar, wind, geothermal, hydropower less than 60 megawatts, and biomass	Range from $5,000 to $500,000
IL		10% by 2015 and 25% by 2025. At least 75% is to come from wind power.	Wind power, solar energy (thermal and photovoltaic), biodiesel, crops and untreated, unadulterated organic waste biomass, trees and tree trimmings, and hydropower from existing facilities.	The cost of procuring renewable energy resources is capped to a rate impact of 0.5% in any one year.
IA	N/A	105 MW	Photovoltaics, wind, biomass, hydro, municipal solid waste	Utilities are in full compliance and no penalties were ever specified.
MN	Xcel Energy	25% by 2020	Wind	PSC may order compliance via building facilities, purchasing renewable power, or buying RECs. If still non-compliant, PSC may impose financial penalties, not to exceed the costs of compliance.

State	Class	RPS	Eligible Technology	Penalties (per MWh)
	Xcel Energy	5% by 2020	Solar, hydroelectric facilities less than 100 megawatts (MW), hydrogen and biomass -- which includes landfill gas, anaerobic digestion and municipal solid waste.	PSC may order compliance via building facilities, purchasing renewable power, or buying RECs. If still non-compliant, PSC may impose financial penalties, not to exceed the costs of compliance.
	Other Utilities	25% by 2020	Solar, wind, hydroelectric facilities less than 100 megawatts (MW), hydrogen and biomass -- which includes landfill gas, anaerobic digestion and municipal solid waste.	PSC may order compliance via building facilities, purchasing renewable power, or buying RECs. If still non-compliant, PSC may impose financial penalties, not to exceed the costs of compliance.

For the 2006 MTEP plan, the Midwest ISO studied the potential system impact of a 10% renewable energy requirement across the Midwest ISO by 2027. For the 2008 MTEP plan, which is in progress, the Midwest ISO is studying a 20% wind energy scenario across the Midwest ISO footprint. Such a requirement would be equivalent to about 40,000 MW of wind capacity. The Midwest ISO determined that the 20% renewable scenario would be about 10% more expensive than a reference case but less costly than a higher fuel cost case and an environmental case (see Exhibit 5-7). Preliminary results show that the benefits obtained by loads and generation would be able to support the annual costs of transmission to distribute energy efficiently and have a substantial amount left to support the justification for building the transmission for the simulation year 2021.

Exhibit 6-7: Estimated Costs of Various Scenarios in the Midwest ISO's 2008 MTEP Plan



As part of its study, the Midwest ISO incorporated a series of 765-kV transmission lines to transmit the wind power into higher electricity cost areas in the Mid-Atlantic states in PJM. More specifically, the transmission was placed in the lower cost areas within the Midwest ISO to the highest-price areas in PJM. Exhibit 5-8 illustrates the placement of the transmission and the wind power.

The Midwest ISO's preliminary analysis, as illustrated in Exhibit 5-9 suggest possible locational marginal price reductions of about 10% within the Midwest ISO and ~5% within PJM. The Midwest ISO is exploring the concept further and may conduct a more detailed study sponsored by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy with PJM, SPP, and other participants if adequate funding can be obtained.

The Midwest ISO also has participated in the CAP-X transmission planning initiative involving Minnesota's electric utilities. The Midwest ISO also participated in Minnesota's 20% wind integration study that was released in late 2006. The study found that with the transmission that is planned and with some control area consolidation that Minnesota could incorporate 20% wind energy adequately and without impact on electric reliability.[86]

[86] "Final Report—2006 Minnesota Wind Integration Study", Enernex Corporation, November 30, 2006. http://www.uwig.org/windrpt_vol%201.pdf.

Exhibit 6-8: Placement of Transmission and Wind Power in the Midwest ISO's 2008 MTEP Plan

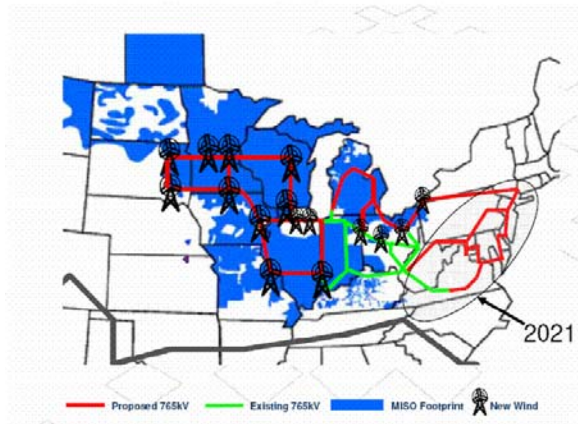
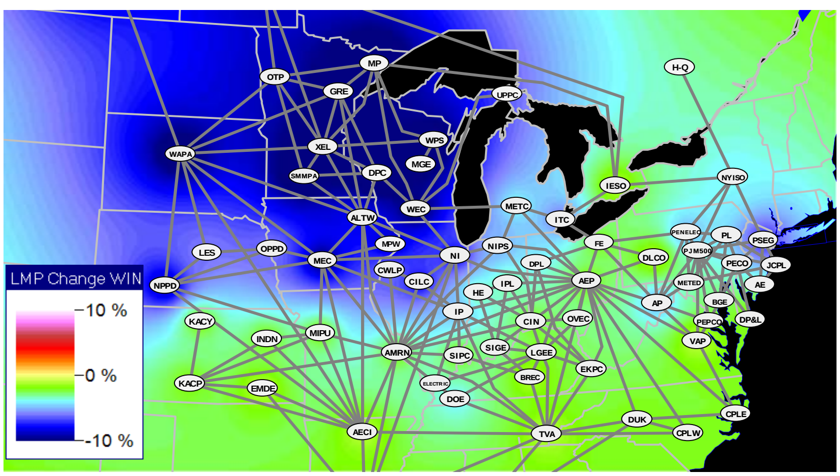


Exhibit 6-9: Potential Locational Marginal Price Reductions for a 20% Renewable Energy Requirement in Midwest ISO 2006 MTEP.



Electric Reliability Council of Texas

Texas has perhaps the most successful state RPS in the country. Enacted in 1999, the Texas RPS is unique in that it is based on capacity rather than a percentage of energy. The Texas

RPS required 2,880 MW of new and existing renewable energy capacity by 2009, a requirement that was exceeded in 2006. Texas also surpassed California as the state with the most installed capacity of wind power in 2006. Wind power represents 96% of the 9,558 MW of renewable energy capacity in Texas.

Eligible renewable energy technologies under the Texas RPS include solar, wind, geothermal, hydroelectric, wave or tidal energy, or biomass or biomass-based waste products, including landfill gas, that are installed after September 1999. The RPS applies to all retail energy providers including municipal and cooperative utilities. Retail energy providers that do not meet RPS targets are subject to a penalty of the lesser of $50/MWh or 200% of the market price of RECs. The capacity targets are converted to energy by the average capacity factor of renewable energy resources that participate in the Texas RPS.

As part of implementing the Texas RPS, the Public Utility Commission of Texas (PUCT) instituted a REC tracking program in July 2001 that will continue through 2019 and appointed ERCOT as the administrator. ERCOT, in turn, contracted with Automated Power Exchange to design the REC tracking program. The REC tracking system creates accounts for participants to track the production, sale, transfer, purchase, and retirement of RECs. Credits can be banked for 3 years, and all renewable additions have a minimum of 10 years of credits to recover over-market costs. A 2004 amendment changed the formula for calculating final REC purchase requirements, added a mechanism to account for corrections to retail sales data, and allows the program administrator of the REC-trading program to petition for deadline changes under certain circumstances. The PUCT may impose a ceiling on the price of RECs and may suspend the RPS to ensure grid reliability.

In 2005, the Texas Legislature enacted SB 20, strengthening the Texas RPS to increase the renewables requirement to 5,880 MW by 2015, with 500 MW of that to come from non-wind eligible renewable energy technologies. Even this target is likely to be surpassed before the 2015 deadline. About 6.4% of the electricity generated in Texas during 2009 came from renewable energy resources, up from 5.1% for 2008.

SB 20 also introduced the concept of competitive renewable energy zones, or CREZ. Under SB 20, the Public Utility Commission of Texas (PUCT) is authorized to identify areas with sufficient renewable energy potential, identify the transmission facilities that could serve the area, and establish the need for new transmission facilities serving the area, even if no specific renewable generation projects exist or are under construction. The CREZ indicate areas within Texas with high clean energy potential; transmission infrastructure is to be built between the CREZ and load centers. In addition, SB 20 authorized the PUCT to order a utility to construct or expand transmission to help meet the Texas RPS, and required the PUCT to approve RPS-related transmission applications within 181 days, or the application is approved. The impetus for this approach comes primarily from prior experience with wind projects in west Texas, where there was insufficient available transmission. The CREZ approach is intended to address the "chicken and egg" problem where transmission is not built until it is needed for new generation and developers are reluctant to build without sufficient transmission available. Once a CREZ has been identified, utilities are guaranteed cost recovery of the transmission built to serve that area.

In 2006, the PUCT instituted rules laying out guidance on how it will designate CREZ areas. One of the factors that the Commission would consider in designating CREZs would be the financial commitments of wind project developers to building in the zone, and the rule includes mechanisms to minimize the risk that transmission facilities built to serve CREZs would be under-utilized. The 2006 rule does not designate any CREZ. Rather, it establishes the procedure for the contested dockets in which designations will be made and establishes what will be considered a financial commitment. The rule requires ERCOT to study the wind energy production potential statewide and establishes criteria for designating CREZs.

The Commission anticipates issuing its first order later in 2007. Once the CREZ order is entered, the affected transmission utilities will have one year to prepare their applications for Certificates of Convenience and Necessity (CCNs). The CCN proceeding is expected to take six months after which construction would take another one to two years. As a result, transmission from the first group of CREZs is expected to be available by 2010 or 2011.

ERCOT also hired GE Energy Consultants to examine how much ancillary services are needed to ensure grid reliability with increasing amounts of wind power. Four scenarios were studied. The first scenario included 5,000 MW of wind, with the locations of wind projects derived from current and near-future wind project locations. The second and third scenarios included 10,000 MW of wind but in different locations. One of the two scenarios included more wind from the coastal region of Texas while the other had no coastal wind but more wind in the Panhandle region. The fourth scenario has 15,000 MW of wind in the Panhandle region. The results from the study were made available early in 2008.

ISO-New England

All six states that comprise ISO-New England have RPS policies, although Vermont's is a RPS goal that does not turn into a RPS requirement until 2013, and only if utilities do not meet incremental load growth with renewable energy and energy efficiency. A description of each state's RPS policy, with the exclusion of Vermont, is provided in Exhibit 5-10.

Exhibit 6-10: State RPS Policies in ISO-New England

State	Class	RPS	Eligible Technology	Penalties (per MWh)
MA	N/A	4% by 2009, 1%/yr increase thereafter until date determined by State	Solar; wind; ocean thermal, wave, and tidal; fuel cells using renewable fuels; landfill gas; and low emission, advanced technology biomass	$55.13, adjusted for inflation
RI	N/A	16% by 2020	Solar, wind, ocean, geothermal, small hydro, eligible biomass, fuel cells using renewables	$50, adjusted for inflation
NH	Class I	16% by 2025	Wind, geothermal, hydrogen from biomass or methane, ocean, methane gas, eligible biomass	$57.12,
	Class II	0.3% by 2025	New solar after January 1, 2006	$150
	Class III	6.5% by 2025	Existing biomass and methane plants that began operating before 2006	$28
	Class IV	1% by 2025	Existing small hydro < 5 MW and began operations before 2006	$28
ME	N/A	30% by 2000	Fuel cells, tidal power, solar arrays and installations, wind power installations, geothermal installations, hydroelectric generators, biomass generators, or municipal solid waste	License revocation or fines, or payments into a renewable energy R&D fund, based on the market price difference between eligible and non-eligible generation

State	Class	RPS	Eligible Technology	Penalties (per MWh)
CT	Class I	20% by 2020	Solar, wind, new sustainable biomass, landfill gas, ocean thermal power, wave or tidal power, low-emission advanced renewable-energy conversion technologies, and new small run-of-the-river hydropower	$55/MWh
	Class II	3% by 2020	Trash-to-energy facilities, biomass facilities not included in Class I and certain hydropower facilities	$55/MWh
	Class III	4% by 2020	Customer-sited CHP generation	$55/MWh

ISO-New England was the first ISO or RTO to include a certificate tracking system that tracks emissions and generation attributes for all energy generation, not just renewables. Like PJM, all states in ISO-New England use the New England Power Pool's Generation Information System for compliance with individual state policies on renewable portfolio standards, environmental disclosure, and emissions portfolio standards.

Depending on the size of the facility, ISO-New England schedules intermittent power producers differently:

- Wind capacity under 5 MW is treated as a "settlement only resources." These resources do not have to bid in the day-ahead market; instead, they generate into the grid at real-time and get the real-time nodal price. The capacity value of these resources is considered the same as the capacity factor of the project, minus forced outages.
- Wind capacity over 5 MW would be considered Intermittent Power Resources. These resources can submit bids into the day-ahead market, but if they don't, they must self-schedule into the re-offer period. As with Settlement Only Resources, the capacity value of these resources is considered the same as the capacity factor of the project, minus forced outages.

A study of wind potential for its region commissioned by ISO-New England determined that there is a maximum potential of about 94,000 MW without accounting for environmental, recreational or other screening criteria (Exhibit 5-14). Of this, 60,000 MW (about 64%) is onshore and the remainder is off-shore. The report also determined that the typical capacity value for wind would be 19% in the summer and 41% in the winter for onshore sites, and 26% in the summer and 46% in the winter for offshore sites.[87] Additional information is available from the ongoing ISO NE NEWIS study Wind Scenarios and Transmission Overlays.[88]

Exhibit 6-11: Maximum Theoretical Wind Generation

Zone	MW
Maine	39,379
Vermont	7,997
New Hampshire	5,598
SEMA	4,552
WCMA	1,432
Rhode Island	488
NEMA	226
Connecticut	175
Offshore Shallow	25,679
Offshore Deep	8,295
Total	93,821

Source: "Technical Assessment of Onshore and Offshore Wind Generation Potential in New England", Levitan and Associates, May 1, 2007.

87 Levitan and Associates, "Technical Assessment of Onshore and Offshore Wind Generation Potential in New England", May 1, 2007. http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/may212007/levitan_wind_study.pdf.

88 ISO NE Planning Advisory Committee NEWIS report Wind Scenarios and Transmission Overlays http://www.newengland-rto.org/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/jan212010/index.html.

Appendix A - Summary of the Literature Search

Appendix A Summary of the Literature Search

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics							Summary of Content
			A	B	C	D	E	F	G	
1	Impact of the wind forecast error on the French balancing system 2009 IEEE Bucharest Power Tech Conference, June 28th - July 2nd, Bucharest, Romania	Vincent Lavier and Maria Giralt-Devant Jul 2009	X	X		X	X		X	This paper examines the relationship between forecast error, grid system balance and price. The analysis focuses on the impact of forecasting errors on this price vs. quantity of energy imbalance (MWh) curves. The study used a model based on France's publicly available balancing data to construct price vs. quantity curves for the French power system using forecasts of 2 hours ahead vs. forecasts of 1 hour ahead to determine the impact of shortening the forecast horizon on the balancing cost of energy (at the time of the paper France uses a 2 hour ahead forecasts for the real time market). The relationship between the energy imbalance (i.e. forecast error) and the cost of balancing energy is based on the order in which imbalanced energy is purchased/ sold by the RTO/TSO: Lower priced energy offers are purchased before higher priced energy offers and the reverse is true for selling energy. However, this relationship implies that the cost of an energy imbalance due to a deficit wind forecast error is not equalized by the cost of an energy imbalance due to a surplus forecast error (i.e. the deficit will necessarily be higher). Since

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics A	B	C	D	E	F	G	Summary of Content
										forecast errors generally increase with forecast horizon, this then implies the shorter forecast windows will reduce balancing costs which are passed on to the wind producer. The paper then supports this claim using actual public balancing data from the French TSO and shows that 2-hour ahead scheduling is roughly twice as expensive for the wind producer in terms of imbalance penalties. The authors claim that changing the regulatory framework to allow the market to respond or bid into one hour forecasts from 2 hour forecasts will reduce the imbalance penalties for wind producers two-fold at the current wind penetration level (2.5 GW) and even more so for larger penetrations aimed for in the future (increasing with increased penetration)

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics A	B	C	D	E	F	G	Summary of Content
2	Building a Smarter Smart Grid Through Better Renewable Energy Information 3Tier IEEE Smart Grid Presentation Final http://www.3tier.com/en/about/publications/building-smarter-smart-grid-through-better-renewable-energy-information/	Cameron W. Potter, Member, IEEE, Allison Archambault and Kenneth Westrick Apr 2009	X	X						The paper focuses on the concept of a smart grid being able to automatically respond to events such as renewable energy ramps and load imbalances with unit commitment and load balancing services using forecasting and other communication services specifically geared to renewable generation. The section on forecasting is particularly relevant (see next cell). The authors state "However, it is the hour ahead forecasts that help with the load following of the power system that gain the most in a smart grid. Typically the hour ahead forecasts employ statistical methods primarily based on the most recent observations." This would seem to reinforce the idea that shorter term forecast intervals and markets are perhaps the most relevant to keeping costs low. The paper goes on to say "Typically the hour-ahead forecasts employ statistical methods primarily based on the most recent observations. The first phase in developing this type of forecast consists of identifying, compiling and integrating data from a wide variety of sources: location of turbines and anemometers, available observation records, etc. The second phase consists of developing and training various self-learning forecasting

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics A	B	C	D	E	F	G	Summary of Content
										methods using all the available data. The final product provides a timely, relevant and accurate forecast. Taking advantage of a vast communication network the forecast of renewable energy will be able to utilize this information from an even wider set of sources.
3	Next generation forecasting tools for the optimal management of wind generation 9th International Conference on Probabilistic Methods Applied to Power Systems KTH, Stockholm,	G. Kariniotakis, I. H-P. Waldl, I. Marti, G. Giebel, T.S. Nielsen, J. Tambke, J. Usaola, F. Dierich, A. Bocquet, and S. Virlot 2006	X	X						The paper discusses the construction and development of multi-platform, distributed software application called ANEMOS designed for comprehensive, multi-model wind forecast prediction. The paper describes the various sub-models that went into the final modeling package which includes a large variety of modeling capabilities including: Numerical weather prediction (for short and long term prediction). Advanced statistical and machine learning models (for short term prediction). Mesoscale modeling combined with integration of wind resource maps (i.e. WAsP wind resource grids) for the

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics A	B	C	D	E	F	G	Summary of Content
	Sweden - June 11-15, 2006									interpolation of upper atmosphere wind speeds to surface levels. The paper discussed how these tools were benchmarked for performance to determine what went into the final ANEMOS software project. The benchmarking consisted of fine tuning a variety of different forecasting algorithms using real data from Germany, Spain, Denmark, Ireland and Greece. The algorithms were ranked in terms of their performance in a variety of terrain types and for a variety of forecast horizons (1-24 hours). The relationship between terrain complexity (i.e. "Delta Rix") and forecast error was also examined and it was shown that increasing the complexity of terrain tends to increase the error of the forecast model. In addition, statistical models that can yield a probabilistic result vs. a deterministic result were examined and have also been included in the Anemos project. The Anemos project was designed to be a distributed software package for use across multiple regions that can participate in forecasts. Currently 7 countries are using this software for wind forecasting purposes.

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4	A Clean, Green Power Grid California Energy Commission (CEC)	CEC no date	X							This was mostly a promotional 3 page document promoting CAISO's efforts in VER integration across three initiatives: Integration of Renewable Resources Program (IRRP), Participating Intermittent Resource Program (PIRP) and Infrastructure improvements for integration.
5	Assessment of Reliability and Operational Issues for Integration of Renewable Generation California Energy Commission (CEC)	Consortium of Electric Reliability Technology Solutions Jan 2005								This document provides a summary of project steps to review, assess, catalog and report on experiences and best practices from other regions for integrating large amounts of renewables, as inputs to the CEC's *Integrated Energy Policy Report (IEPR)*.

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics A	B	C	D	E	F	G	Summary of Content
6	Intermittency Analysis Report California Energy Commission (CEC)	Intermittency Analysis Project Team July 2007		X	X		X	X		Scenario-based analysis of system impacts of higher levels of intermittent renewables. Detailed technical analysis of existing and future infrastructure needs, addressing potential operational strategies, developing a set of utility "best practices" and tools for integrating intermittent renewables. In-state generating resources should be targeted for providing scheduling flexibility hourly. Consider allowing import and export scheduling to occur more frequently and at other times than on the hour. Expanded ancillary service markets, incentives and requirements may be necessary to reduce costs and improve revenues for generation providers. New proposed contracts and existing long-term contracts should be reviewed to increase grid flexibility and adequacy. Consider measuring, verifying and cataloguing the flexibility characteristics of individual generating resources. The requirements for hourly schedule flexibility increase over time due to system load growth and additional VERs. The available ramping capability of on-line units, both up and down, was found to be largely adequate. For the expected VERs growth trajectory, overall hourly flexibility

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										requirement is expected to be about 130 MW/hr greater than that required for load alone. Under artificially accelerated renewable expansion, the incremental requirement is about 400 MW/hr.
7	Intermittent Wind Generation: Summary Report of Impacts on Grid System Operations California Energy Commission (CEC)	KEMA-XENERGY June 2004								This paper summarized results of large scale VERs on grid operations, including dispatch, voltage support, ancillary services and congestion. Research areas and regions included Germany, Denmark, Netherlands, Spain, and UK. Results are superseded by later studies.

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8	California ISO Wind Generation Forecasting Service Design and Experience California ISO	Yuri Makarov, David Hawkins, Eric Leuze, Jennie Vidov n.d.	X							The paper focuses on the California ISO experience gained with wind generation forecasting requirements and methods. The article discusses persistence forecasting methods and models have been able to provide relatively good forecasts for the next hour and 1 hour ahead. The article puts forward a number of requirements and assessment criteria for selecting the best vendor for providing hourly MWh forecasting services for projects participating in the CAISO market structure. For participating wind generators bidding in the hour-ahead market under the CAISO scheduling timeline, forecast must be made for an operation hour - 2.5 to 3.5 hours ahead
9	Integration of Renewable Resources Program (IRRP) -- High Level Program Plan California ISO	CAISO Apr 2008								Outlines tasks for the program (e.g. develop new ramp forecasting and planning tool), but does not describe any details associated with existing CAISO practices. Tasks: (1) Develop new ramp forecasting and planning tool for real time operations; (2) Over-generation problems, (3) Improve accuracy of Day-ahead Energy Forecasts for wind, (4) Improve accuracy of Same Day Energy Forecasts for wind generators, (5) Develop new

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics A	B	C	D	E	F	G	Summary of Content
										graphical displays for Real-Time Operators so they can anticipate Wind Generation Forecast Production; (6) Link Renewables forecasting to MRTU; (7) Scheduling/Managing imports and exports of renewables; (8) Impact on resource adequacy, (9) Modeling of wind generation facilities and (10) Changes to PIRP II for Hour-Ahead forecasting and scheduling
11	Renewable Resources and the California Electric Power Industry: System Operations, Wholesale Markets and Grid Planning California ISO	CAISO Jul 2009	X	X	X			X		Document describes redesigned wholesale market for energy and ancillary services for CAISO since April 2009. Document describes the hour-ahead, fifteen minute and 5 minute scheduling process and how the ISO finalizes output schedules for the operating hour (for its wind resources). The CAISO Participating Intermittent Resources Program (PIRP) has resources provide telemetry to a wind forecast vendor, which provides them with an hour-ahead wind schedule that can be submitted to the ISO. ISO plans to introduce "convergence bidding" for day-ahead and real-time prices. No requirement (and weak incentives) for renewable resources to schedule or offer power into the forward market. Most renewable resources bid or schedule only in the real-time market (hourly). Need to change incentives

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										for renewables to schedule day ahead (otherwise, will lead to increased over-commitment of thermal generation and divergence of prices between the day-ahead and real-time market).
12	Integration of Wind into System Dispatch New York ISO	Rick Gonzales, Rana Mukerji, Mike Swider, David Allen, Robb Pike, David Edelson, Emilie Nelson, John Adams Oct 2008	X	X	X				X	NYISO can optimize wind output by evaluating each plant's economic preferences within real-time Security Constrained Economic Dispatch (SCED) process, as with other generating resources. Integrating increased wind facilitated by using NYISO market software to include wind - evaluating wind plant operations on a 5 min basis to minimize the period and amount of generation curtailment, eliminating need for manual intervention by system operators to address system reliability issues and minimizing periods of extreme negative locational based marginal price (LBMP) in real-time markets. Wind operators have no requirement to indicate willingness to be re-dispatched through its economic offers, therefore,

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics							Summary of Content
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										NYISO rely on manual intervention to re-dispatch wind plants when needed to address reliability. Wind dispatch proposal allows each wind plant to provide NYISO with real-time energy bids (75 minutes before each operating hour) in price-quantity pairs to indicate the price levels (LBMP) at which it would prefer to operate. Special market rules for intermittent renewables - exempt them from financial penalties for deviations from expected schedules. NYISO has expanded the eligibility of intermittent resources for special market rules from 500 MW to 3300 MW. Initiated a centralized wind forecasting system integrating wind into the NYISO day-ahead and real-time market software systems in order to better predict the output of wind projects for system dispatch. NYISO - 1200 MW of wind by summer 2009, potential for another 6500 MW by 2011.

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12	Counting the Capacity Value of California's Intermittent Renewable Resources CalWEA, AWEA	Thomas Beach and Patrick McGuire (Crossborder Energy), Nancy Rader (CalWEA), Michael Goggin (AWEA) Jan 2009						X		Proposal submitted to CPUC as part of Phase 2 of Rulemaking 08-01-025. AWEA proposes to retain the existing rules - the net qualifying capacity (NQC) for an intermittent renewable resource should be its achieved capacity factor over the utility's summer on-peak period, based on a three-year rolling average of a project's on-peak output. The document argues against an exceedance method for RA and supports ELCC analyses. Also included in this PDF as an appendix is the NREL report "Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation" Milligan and Porter, June 2008 CPUC has assessed capacity value of intermittent resources in designing the "least-cost, best-fit" (LCBF) analysis for evaluating bids from new renewables submitted under RPS. Commission adopted the ELCC approach to determine capacity value of wind resources. CPUC has not adopted explicitly the use of ELCC for RA counting purposes - uses historical wind output in the Standard Offer No. 1 (SO1) on-peak period averaged over last 3 years.

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics A	B	C	D	E	F	G	Summary of Content
										CPUC has adopted two methods for valuing wind capacity: (1) for determining wind's contribution to RA requirements and (2) for valuing wind capacity in new RPS contracts. Both methods assess wind output across peak hours.
13	The Control of a Power System with a High Wind Power Penetration: Ireland's Experience CIGRE 2008 Conference Paper C2-302	Ivan Dudurych, Hugh Jones, Michael Power from EirGrid plc, Ireland 2008	X	X			X		X	A new wind dispatch application in the Ireland National Control Centre SCADA/EMS system has been developed to provide NCC operators with the capability to curtail or constrain the MW output of wind power stations in a coordinated fashion. Aggregated models of individual wind power stations are developed for that application.

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14	Wind Power Forecasting and Application of Batteries for Stabilization in Japan CIGRE 2008 Conference Paper C2-308	K. Sakamoto and M Matsumoto from Tohoku Electric Power Co. and K. Yoshimoto from Central Research Institute of Electric Power Industry, Japan 2008	X							Looks at the integration of wind into balancing areas with a two prong approach: Better wind power forecast and the use of storage devices to stabilize the fluctuations. The paper describes representative works on both technologies for wind power.
15	Assessing the benefits of wind power curtailment in a hydro-dominated power system CIGRE 2009 Conference, Calgary, CA	JOEL EVANS, ZIAD SHAWWASH University of British Columbia, Civil Engineering Vancouver, British Columbia,	X						X	This paper introduces a novel concept of curtailing wind power based on hydroelectric forecasts/activities which, if optimized can increase the value of wind from 0.2% to up to 1.0%. The study was done using data from British Columbia hydro electric dams and wind farms. The idea is to curtail the wind and release hydroelectric power instead at critical moments of peak congestion. By synchronizing their efforts, both the hydroelectric and wind producers can see a net increase in the value of wind power of 0.2 - 1%.

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics A	B	C	D	E	F	G	Summary of Content
	http : //www.cigre.org	Canada Jul 2009								The findings are not clearly stated in terms of profit, only in terms of wind energy price. Furthermore, such a small increase in price seemed marginal for the undertaking.
16	Case Study for the Integration of 12 GW Wind Power in the Dutch Power System by 2020 CIGRE 2009 Conference, Calgary, CA http : //www.cigre.org	M. Gibescu, W.L. Kling B.C. Ummels TU Delft TU Delft & Siemens Wind Power E. Pelgrum and R.A. van Offeren TenneT TSO B.V.	X	X	X	X	X			For this case study of 20% wind in 2020, we use realistic time series of aggregated 15-minute wind power production and forecast, based on one year of wind speed measurements and forecasts at various locations in the Netherlands and its coastal waters, and multi-turbine wind farm models. The technical capabilities of the foreseen conventional generation portfolios of the Netherlands and its neighboring countries are modeled in detail, in terms of ramping abilities, fuel efficiency, and minimum up and down times. Particular attention is also paid to wind energy developments in Germany, since high correlations exist between the wind power outputs of the two countries. A preliminary evaluation in terms of margin at peak load,

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		Jul 2009								minimum load problems, and ability of conventional units to follow the load less wind variations is made, based on the net load duration curves of Netherlands and Germany in 2020. It is shown that smaller amounts of wasted wind (i.e. wind energy that cannot be taken by the system) due to minimum load problems occur when exchanges of excess wind energy can be scheduled between the two countries close to the operation time. This shows the importance of having larger geographic areas and well-organized cross-border trading to facilitate larger amounts of integrated wind energy. However, wasted wind cannot be completely avoided due to correlations in low load – high wind situations between the two countries. These results are confirmed through detailed chronological simulations of one year of operation, using a unit commitment and economic dispatch tool specifically adapted to perform wind integration studies. The potential for demand-side management to allow for a better integration of wind power is briefly explored. Impact of high wind energy during low load periods Benefits of larger BA (Germany and Netherlands) to accommodate variability

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics A	B	C	D	E	F	G	Summary of Content
										Potential for Demand side management to permit higher wind presentation
17	Manitoba Hydro Wind Power Reserve Requirements CIGRE 2009 Conference, Calgary, CA http : //www.cigre.org	T.S. Molinski, Manitoba Hydro' Canada Jul 2009	X				X			There is a strong public and political desire to incorporate wind power in most grids including that of Manitoba Hydro. This paper describes Manitoba Hydro's plans to incorporate wind power over the next 20 years and the associated wind integration costs. Since Manitoba Hydro currently has excess hydro power that supplies a domestic load of approximately 20 TWh/year and 10 TWh/year of export power sales, any new power source (hydro, wind, etc.) added between now and 2020-2024 must be sold on the export power market. It is for this reason that Manitoba Hydro must pay "great" attention to the costs associated with purchasing and integrating locally produced wind

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics A	B	C	D	E	F	G	Summary of Content
										power before reselling it on the export market. Manitoba Hydro desires to pass on the maximum value to wind developers less its direct cost such as the shaping and firming costs and wind integration costs. The Manitoba Hydro wind integration costs are considered specific to Manitoba Hydro, since the ability to provide reserves and the Manitoba Hydro response to hydraulic inefficiencies is unique to Manitoba Hydro. The wind integration impacts and related costs were studied over low, medium, and high water supply conditions. Additional reserves are required because of wind volatility and wind generation forecast error. Reductions in wind generation are of the most concern because other generation must be increased to counter balance the shortfall in wind generation. The article is unique to Manitoba. It develops the wind integration cost and the amount of reserves needed for VERs.

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18	Method for Studying and Mitigating the Effects of Wind Variability on Frequency Regulation CIGRE 2009 Conference, Calgary, CA	U.D. Annakkage, University of Manitoba, Winnipeg, Canada. D.A. Jacobson. Manitoba Hydro, Winnipeg, Canada. D. Muthumuni, Manitoba HVDC Research Centre, Winnipeg, Canada July 2009								This paper presents a simulation-based approach to study the effect of wind energy variation on the frequency regulation of a power system. In North America, the quality of frequency regulation is defined in terms of two indices known as Control Performance indices (CPS1 and CPS2). The power system is modeled as a control system with equivalent representation of turbine-governor dynamics. The system inertia is modeled as a single equivalent inertia. The power system external to the system under consideration is modeled as a single equivalent. The model is then used to study the sensitivity of CPS indices to wind variation and the settings of the Automatic Generation Controller parameters. The model also gives the amount of regulation reserves utilized in each simulated scenario. The effect of cyclic variations in wind power has also been quantified. It has been shown that the CPS1 index is sensitive to the gains of the AGC system. Therefore, tuning of AGC could be a good measure to improve the CPS1. On the other hand, the improved performance has been achieved at the expense of requiring more Regulating Reserves. This also indicates that the AGC

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										could be tuned to reduce the required amount of AGC at the expense of control performance. Ramp rates could be introduced to limit the rate at which the wind power generators increase their output. Not applicable to the NOI
19	Integration of Large Wind Generation in the Italian Power System: Security Enhancement and Prediction System Development CIGRE 2009 Conference, Calgary, CA; C2-304	T. BAFFA SCIROCCO(*), V. BISCAGLIA, C. SABELLI from Terna,Italy E. GAGLIOTI, A. IARIA fromCESI RICERCA, Italy 2008	X							In these last years the Italian electric system has faced a large wind power integration (from 780 MW in 2002 to 2611 MW in 2007), that has had a considerable impact in the two main islands, Sicily and Sardinia, where the installed wind power is an important share of the total load demand. After a short overview on the Italian wind power integration the paper presents: the system security enhancement related to a lower setting of minimum voltage protections (20% of VNOM); and the development of a Wind Power Prediction System (WPPS) to support operators in the transmission system management. The paper reports detailed evaluation results of the

Index #	Article or Report Name Source and Link	Authors Date	VERs NOI Topics A	B	C	D	E	F	G	Summary of Content
										analyses performed on the Italian network areas of Sardinia, Sicily and South Continent, concerning both the investigation on voltage protections and the prediction system performance.
20	Impact of Balancing Areas Size, Obligation Sharing, and Ramping Capability on Wind Integration Conference Paper - NREL/CP-500-41809 To be presented at WindPower 2007 Conference &	M. Milligan, Consultant National Renewable Energy Laboratory B. Kirby Oak Ridge National Laboratory Jun 2007	X	X		X	X			Balancing area reserve sharing holds the promise of significantly reducing wind integration costs. It also reduces utility costs without wind. Some recent studies of integrating wind into large power systems indicate that wind integration costs may rise more smoothly than previously assumed, based on analysis of smaller power systems. The "hockey stick" pattern of dramatically increasing wind integration cost above some threshold wind penetration may not be as pronounced as expected. The existence and location of this dramatically increasing integration cost could have important implications regarding the cost of achieving 20% of all domestic electricity from wind. This paper examines wind integration

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	Exhibition, Los Angeles, California, June 3–6, 2007									costs as a function of balancing area size to determine if the larger system size helps mitigate wind integration cost increases. Using data from Minnesota, we show that ramping requirements can be reduced by balancing area consolidation. We also examine the ERCOT and NYISO sub-hourly energy markets to understand how they incentivize generators to respond to ramping signals without having to explicitly pay for the service. Because markets appear to have the ability of bringing out supply response in sub-hourly energy markets, and because existing thermal resources appear to have significant untapped ramping capability, we believe that a combination of fast energy markets and combined balancing area operations can increase the grid's ability to absorb higher wind penetrations without experiencing significant operational problems or costs. Summarized other studies

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21	20% Wind Energy by 2030 - Increasing Wind Energy's Contribution to U.S. Electricity Supply DOE - Department of Energy http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf	NREL with multiple contributors This report was prepared by DOE in a joint effort with industry, government, and the Nation's national laboratories (primarily the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory). Jul 2008	X			X	X	X		The report considers some associated challenges, estimates the impacts and considers specific needs and outcomes in the areas of technology, manufacturing and employment, transmission and grid integration, markets, sitting strategies, and potential environmental effects associated with a 20% Wind Scenario by 2030. Conclusions are drawn from other research studies and papers.

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22	2008 Wind Technologies Market Report DOE - Wind & Hydropower Technologies Program, Office of Energy Efficiency and Renewable Energy of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.	Primary authors: Ryan Wiser and Mark Bolinger, Lawrence Berkeley National Laboratory With contributions from: Galen Barbose, Andrew Mills, and Anna Rosa (Berkeley Lab); Kevin Porter and Sari Fink (Exeter Associates); Suzanne Tegen, Walt Musial, Frank	X	X		X	X			Nonetheless, key conclusions in 2008 that continue to emerge from the growing body of integration literature include the following: • Wind integration costs rise with higher levels of wind penetration, but are below $10/MWh – and often below $5/MWh – for wind capacity penetrations of as much as 30% of the peak load of the system in which the wind power is delivered.48 • Regulation impacts are often found to be relatively small, whereas the impacts of wind on load-following and unit commitment are typically found to be more significant. • Larger balancing areas, such as those found in RTOs and ISOs, make it possible to integrate wind more easily and at lower cost than is the case in smaller balancing areas. • The successful use of regional wind power forecasts by system operators can significantly reduce integration challenges and costs. Wind forecasts are most accurate and effective when aggregated across large, electrically interconnected areas. • Intra-hour scheduling (e.g., 5-10 minute schedules) provides access to flexibility in conventional power plants that lowers the costs of integrating wind.

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		Oteri, Donna Heimiller, and Billy Roberts (NREL); Kathy Belyeu and Ron Stimmel (AWEA) July 2009								• Wind integration costs tend to rise with increasing natural gas prices, though the economic value of wind energy similarly increases with higher gas prices. Conclusions are drawn from other studies and research.
23	Impact of Variable Renewable Energy on US Electricity Markets IEEE - To be published	J.C. Smith (UWIG), Stephen Beuning (XCEL), Henry Durrwachter (Luminant Energy Company LLC), Erik Ela (NREL), David Hawkins	X	X	X	X	X		X	This paper reviews the design and operation of a number of large, regional organized markets in the US, as well as the operation of stand-alone single balancing area bilateral markets, from the viewpoint of integrating large amounts of variable output renewable energy sources. Significant differences between the two types of markets are noted. In addition, a series of shortcomings of the first generation market designs are discussed, and some thoughts on the design changes required to enable greater participation of variable output generators in the market are provided. Topics: (A) Sample of current US market design and

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		(CAISO), Brendan Kirby, Warren Lasher (ERCOT), Jonathan Lowell (ISO-NE), Kevin Porter (Exeter), Ken Schuyler (PJM), and Paul Sotkiewicz (PJM) 2010								operation with variable renewable resources (PJM, ISO-NE, NYISO, CAISO, ERCOT and standalone BA (bilateral)); (B) Market design considerations for operation with high penetration of renewable energy
24	Wind Integration Issues and Solutions in California IEEE 1-4244-1298-6/07	David L. Hawkins (CAISO), James Blatchford (CAISO), and Yuri V. Makarov (PNNL) Jun 2007	X	X	X		X	X	X	The purpose of the California ISO intermittent resources program is to ensure the successful integration of wind generation and other renewable resources with the planning, market, and operation of the power grid. This paper addresses the market integration and operational wind integration issues in California and briefly discusses the transmission interconnection issues. Explains the MRTU market design and Participating Intermittent Resources (PIR) program.

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25	European Wind Integration Study (EWIS) for a successful integration of Wind power into European Transmission System IEEE 2008	European Transmission System Operators L. Dale, D. Klaar, L. Fischer, JM Rodriguez, F. Vermeulen, W. Winter 2008	X	X		X	X		X	Europe's transmission system operators work collaboratively to identify issues related to the large increase in wind penetration in the European Grid. The paper outlines a number of threats to grid stability due to large penetration of wind power: 1) Large load flows affect neighboring transmission systems and reduce available cross border trading capacities 2) Need for additional/new grid infrastructure: -New overhead lines are necessary to transport the surplus of electricity produced in these regions to where it is consumed -For the high wind bottlenecks on internal and cross border lines in northern Europe are detected...If a circuit is unavailable due to a disturbance in the grid the remaining lines can be overloaded up to 180%. 3) During serious grid failures wind farms generally disconnect themselves completely instead of supporting the grid with auxiliary power. This can lead to even more serious power failures (cascading effect). Therefore wind farms should also have to support the grid during failure events. 4) The need for balancing power increases proportionally

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										with the growing wind power capacity. 5) High wind power production remote from main electricity demand centers produces higher grid losses within the transmission system. 6) High wind power production causes regional overloading of transmission lines. The paper goes on to make the following recommendations; 1) Harmonization of European support scheme for renewable energy distribution. 2) Speed up the approval processes for new grid infrastructure 3) Adjust the market rules for imbalance management: "To let the market solve the problem of imbalance management wind generation should be made responsible for unbalances they create and provide adequate resources for balancing from the market, as already in place in some countries". 4) Improve connection requirements for wind turbines: "In order to effectively tackle this problem (see item 3 in previous cell) all power generators – including wind power producers - should be obliged to meet certain operational

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										requirements such as fault-ride through capability or voltage support". 5) "In order to maintain sufficient conventional capacities as well as their reasonable allocation over the respective grid areas the existing priority rules for the transport of RES electricity need to be re-examined. Furthermore it should be noted that national priority rules become legally questionable as they do not only discriminate against conventional electricity but also against 'green' electricity from other EU member states"
26	Evaluating Wind Capacity Value in New York and California IEEE 2008	Nicholas W. Miller and Gary A. Jordan 2008				X	X	X		The paper focuses on the concept of "Effective Capacity Factors" which is somewhat unclear but seems to be defined as the capacity factor of wind energy as determined by the percent of wind turbine capacity rating that is realized during peak hours of the day. A comparison between the states of New York and California is then drawn One interesting part of the paper compares the reduction in LOLP (loss of load probability or increase in reliability) of adding MW of wind power across the state vs. small generator MW capacity near the load consumption centers

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										(i.e. NYC) and concludes for the years 2001-2002 that 3,300 MW of wind is roughly equivalent to 300MW of small generator capacity in terms of LOLP. However overall the paper is unclear in its intention and focus. For instance, the definition of "effective capacity" seems to change throughout the paper and the comparison between New York and California is not "apples to apples" as the charts and graphs used for comparison are not consistent. That said however, the main point of the paper seems to be that the effective capacity (using the definition of effective capacity mentioned previously) of wind power in New York is characteristically low due large amounts of wind being produced in low demand periods where as in California it is high(er). However such definitions of "effective capacity" are not meaningful if there is not a detailed analysis performed on whether or not non-peak wind energy will be curtailed and what the correlation is between time-of-day wind production and price of energy.
27	The Future Impact of Wind on BPA Power System Load Following and Regulation	Yuri V. Makarov1, Shuai Lu1, Bart McManus 2, John Pease2								A simulation of the BPA load balancing system was performed. The authors used historical data and stochastic processes to simulate the load following and regulation requirements. This allowed them to mimic the actual power system operations. The capacity, ramp rate

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	Requirements IEEE 978-1-4244-1744	1 Pacific Northwest National Laboratory, U.S.A. 2 Bonneville Power Administration, U.S.A May 2008								and ramp duration characteristics are extracted from the simulation results. The simulation used real load data from the BPA in 2006, a load forecast, wind power time series data, and wind forecasts to simulate the load balancing requirements and scheduling services. The comparison year 2010 was simulated by incrementally scaling the load and wind capacity factors according to projected values. Forecasts for both load and wind were provided at the 1 hour (hour-ahead market) and 10 minute (load following) intervals for the simulation. System load following and regulation capacity requirements are calculated accordingly. Also, the ramp rate and ramp duration data obtained from the analysis can be used to evaluate generation fleet ramp requirements and regulating units' energy requirement, respectively. The results were calculated as the maximum requirement that occurred for each category. The increased capacity requirements with 6300 MW of wind energy integrated into the BPA system in 2010 are as follows: Load following capacity: 400 MW up, 500 MW down Load following ramp: 55 MW/min up, 30 MW/min down

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										Regulation capacity: 90 MW up, 60 MW down Regulation ramp: 30 MW/min up, 35 MW/min down. Furthermore, a table was provided showing maximum up-ramp and down-ramp regulation capacity requirements both with and without wind, on a 24 hour basis for the years 2006 and 2010 for comparison. The results show an enormous increase in the maximum regulation capacity requirements to meet the demands imposed by future wind growth that is anticipated in 2010 vs. 2006. Since we are already in 2010, it would be interesting to see how their prediction compares to what actually occurs in 2010.
28	The Future Impact of Wind on BPA Power System Ancillary Services IEEE 978-1-4244-1904-3/08	Yuri Makarov, Shuai Lu, Bart McManus, and John Pease March 2008								A simulation of the BPA load balancing system was performed. The authors used historical data and stochastic processes to simulate the load following and regulation requirements. This allowed them to mimic the actual power system operations. The capacity, ramp rate and ramp duration characteristics are extracted from the simulation results. The simulation used real load data from the BPA in 2006, a load forecast, wind power time series data, and wind forecasts to simulate the load balancing requirements and scheduling services. The comparison year 2010 was simulated by incrementally scaling the load and wind capacity factors according to projected values.

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										Forecasts for both load and wind were provided at the 1 hour (hour-ahead market) and 10 minute (load following) intervals for the simulation. The ramp rate and ramp duration data obtained from the analysis can be used to evaluate generation fleet ramp requirements and regulating units' energy requirement, respectively. The results were calculated as the maximum requirement that occurred for each category. A table was provided showing maximum up-ramp and down-ramp regulation ramp requirements both with and without wind, on a 24 hour basis for the years 2006 and 2010 for comparison. The results show an enormous increase in the maximum ramp regulation requirements to meet the demands imposed by future wind growth that is anticipated in 2010 vs. 2006. Since we are already in 2010, it would be interesting to see how their prediction compares to what actually occurs in 2010.

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29	A literature review of wind forecasting technology in the world IEEE 978-1-4244-2190-9/07	Yuan-Kang Wu and Jing-Shan Hong Sep 2007	X	X						A good overview of the comparison of wind forecasting models and their various pros and cons. The models reviewed/compared were: 1) Numerical Weather Prediction (i.e. physical/meteorological models) 2) Machine learning algorithms: Artificial Neural Networks, Bayesian 3) Statistical/Linear-Regression models (i.e. ARIMA) 4) Hybrid models that combine 1:3 5) Spatial Correlation Models: Computing lags between neighboring meteorological towers/locations 6) Spatial Smoothing Models: Models 1:4 that attempt to predict aggregated wind farm output dispersed over a wide geographical region with greater accuracy There were several key findings of noteworthy significance. According to the paper, numerical weather prediction models are ideal for long term predictions (i.e. 6-24 hour-ahead) where as machine learning and statistical models are better for shorter term predictions (i.e. 1-3 hour-ahead). NWP models tend to take large amounts of computational resources as they must compute the

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										interaction of air flow with the terrain and roughness which can take several hours to update however they tend to be quite accurate once this data has been acquired. On the other hand machine learning algorithms are relatively cheap in terms of computational power requirements and can be calculated using only the locally available met tower data. Artificial Neural Networks in particular are remarkably accurate in the 1-3hr time range and are typically better than linear (i.e. ARIMA) models. A significant improvement can be realized by training any of the above Statistical/Machine learning models with spatial extensions models of aggregated wind farm output which can reduce the forecast error a further 30-50% of the error of the individual wind farm output. Also, the paper states that up to 20% improvement in forecasts can be realized by calibration of the wind speed to the specific wind turbine at the location of the wind farm vs. manufacturer's power curve where much error is added to the forecast.

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30	Regulation Requirements with High Wind Generation Penetration in the ERCOT Market IEEE 978-1-4244-3811	R. A. Walling, L. A. Freeman, W.P. Lasher June 2009					X			Wind generation increases the variability and unpredictability of system net load and inevitably leads to changing requirements for ancillary services procurement. One type of ancillary service that is affected by wind generation is regulation. This paper summarizes the results of a major study of wind integration in the ERCOT system, in which the magnitude and timing of changes in regulation requirements are thoroughly analyzed. The adequacy of existing resources to accommodate this regulation requirement was also investigated, and found to be generally sufficient. ERCOT simulations shows with increased wind capacity penetration (23%) only modest increases in reserves are needed and in particular regulation down requirements. The simulation studied "regulation A/S requirements that may change seasonally.

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31	Impact of Wind Generation on System Operations in the Deregulated Environment: ERCOT Experience IEEE 978-1-4244-4241	Shun-Hsien Huang, David Maggio, Kenneth McIntyre, Vijay Betanabhatla, John Dumas, John Adams Jun 2009	X	X			X		X	ERCOT has been experiencing an increase in installed wind capacity over the past several years. At present, there is approximately 7500MW of installed wind capacity in the ERCOT Interconnect and there are observed instances of significant wind generation variation (approximately 27% of installed wind capacity over two hour periods). Additionally, the rapid rate of wind generation installation has easily outpaced the up-gradation of transmission facilities in the region. These things, along with the high variability in wind generation, have imposed several challenges to ERCOT Operations. Voltage regulation utilizing inductive generators is a new experience for ERCOT, and new requirements have been placed on frequency control and ancillary service in the ERCOT system. This paper will address current operational challenges observed by ERCOT during high wind output and extreme wind variation conditions and will share some of the experience gained by ERCOT Operations during such scenarios. Good summary of the operational issues encountered by ERCOT with the increased penetration of wind energy.

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32	Reliability Assessment of Wind Integration in Operating and Planning of Generation Systems IEEE 978-1-4244-4241-6/09	Yi Zhang and A. A. Chowdhury California ISO June 2009					X			The integration of large amount of wind generation will have significant impact on both long-term planning and real-time operation of power systems. The intermittent and energy limited characteristics are important factors in wind generation integration modeling. In terms of probabilistic reliability, new wind generation interconnection cannot meet the adequacy requirement by itself as load increases. Addition of conventional capacity is needed to compensate the intermittency of wind generation. The same is also true in real time operation. Scheduling wind generation in real-time can result in the reduction of system security; hence the requirement of operating reserve may increase. Reliability assessment based on probabilistic method is used in this paper to evaluate the impacts of wind integration from different aspects of planning and operation of a power system. Different reliability models of wind generation are presented.

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33	Reliability-based Long Term Hydro/Thermal Reserve Allocation of Power Systems with High Wind Power Penetration IEEE PESGM-01275	Peng Wang, Lalit Goel, Yi Ding, and Loh Poh Chang Nanyang Technological University, Singapore July 2009					?			In a power system with high wind power penetration, reserve allocation is a major problem of system planning and operation due to the uncertainty and fast fluctuation of wind speeds. In order to achieve long term sustainable solution for electricity supply, the impacts of the installation of wind farms on system reliability have to be carefully studied. This paper describes the impact of installation of wind farms on the system reserve and reliability from a long term planning point of view.
34	The Evolution of Wind Power Integration Studies: Past, Present, and Future IEEE PESGM-0186	Erik Ela, Michael Milligan, Brian Parsons, Debra Lew, and David Corbus (NREL, Golden, CO) July 2009		X		X	X			The rapid growth of wind power as a generation resource in the past decade has given many utilities and Regional Transmission Organizations (RTO) concerns due to its unconventional characteristics. Because of these concerns, many of these entities have initiated studies that evaluate the feasibility of large amounts of wind power onto their system and the operational impacts present. This paper will discuss some of the past major studies, mostly focusing on the United States, and the basic methodologies that were used during these studies. The paper will also review many of the different results and conclusions of the studies and discuss how they have helped the power industry as a whole. Lastly, the authors

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										will attempt to share their ideas on some of the limitations of the current and past integration studies, and some insight on how these may be evolving in the future. Larger BA (Midwest ISO) and intra-hours dispatch - less A/S requirement and less cost for wind integration and more units involved in provide balancing energy.
35	Realistic Operational Simulation of Wind Projects (abstract) IEEE PESGM-0428	Zuyi Li and Mohammad Shahidehpour, Illinois Institute of Technology, and Frank Bristol, Acciona Energy NA, Chicago, IL Jul 2009								Abstract: "The profitable operation of a wind project depends on two critical indices: wind energy deliverability and locational marginal prices (LMP). The traditional optimal power flow (OPF) study has been widely used to obtain those indices. However, the traditional OPF study generally provides only the peak load hour results, which ignore temporal constraints of power system components that are considered in day-ahead market operations. This paper proposes the use of a Mixed-Integer-Programming (MIP)-based security-constrained unit commitment (SCUC) software tool for more realistic electricity market simulations. The SCUC-based study provides hourly LMP prospects over one day, one week, and up to one year.

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										Such simulation studies could relate LMPs to the daily/weekly load patterns for a thorough assessment of wind projects. The proposed SCUC approach has been used for the evaluation of several wind projects in various locations in the U.S."
36	Managing Wind Uncertainty and Variability in the Irish Power System IEEE PESGM-0470	Aidan Tuohy, Niamh Troy, Andrej F. Gubina, and Mark O'Malley Jul 2009	X	X		X	X		X	Paper discusses the results of applying mixed-integer, stochastic optimization algorithm for optimizing unit commitment, planning and balancing schedules. Additionally the paper examined the effect of the scheduling on unit cycling and hence equipment costs were examined. Finally they looked at utilizing stochastic optimization in the Irish energy grid. An optimization algorithm was used to find the optimum balancing, scheduling, unit commitment and unit cycling for integration of large penetrations of renewable energy up to 34%. Stochastic optimization utilizes a distribution of

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										forecast probabilities as opposed to a single deterministic forecast. It was determined the stochastic optimization results in a 0.25% drop in schedule costs vs deterministic scheduling with "imperfect" forecasting, however with "perfect forecasting" this number increases to 1.75%. The paper goes on to point out however that large penetrations of renewable energy result in high unit cycling rates (turning on and off of generators) which causes a large amount of wear and tear and increases cost. It is thought that the changing of various market regulation rules however could mitigate this effect. The paper concludes "It is shown that using this stochastic type of optimization will improve the schedules compared to those obtained using deterministic schedules. The uncertainty of wind is also shown to increase the number of start-ups and the use of mid merit gas units for the future Irish system. The cycling of base-load units is shown to increase with increased wind penetration, which will cause deterioration in these units, and possibly will require a change in market operation to mitigate this."

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37	IEEE Paper Abstract: "Impact of high penetration of wind on power system operations" IEEE PESGM-0489	Panel session the IEEE PES general meeting in Calgary in Jul 2009	X	X						In 2004, the NYISO studied the impact of the 3,300 MW of potential wind generation. The potential is now much greater. NYISO has initiated several actions in response to this increased potential: • Implemented a performance tracking system for existing wind plants. • Implemented a centralized forecasting process for wind plant output. • Developing in conjunction with stakeholders a wind energy management proposal. • Updating the original study for wind generation potential by studying installed wind plants ranging from 3,500 to 8,000 MW. • Participating in and following Regional and National wind study initiatives. The primary focus of these actions is to focus on several issues that have been identified as important to successfully integrating much higher penetrations of wind generation. They are: 1) transmission, 2) system flexibility, 3) operator awareness and practices, and 4) wind generator plant performance and standards.

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										High level panel session. No much details
38	The Role of Wind Forecasting in Utility System Operation IEEE PESGM-0993	J. Charles Smith, Mark L. Ahlstrom, Robert M. Zavadil, Ali Sadjadpour, and C. Russell Philbrick Jul 2009								This is a high level overview paper that deals with presenting information on forecasting-related decision support for wind producers and system operators. The paper begins with an introduction to forecasting algorithms and concepts as well as a brief recap of the role that forecasting plays in the industry today. The primary aim of the paper however is to make suggestions regarding how to organize and implement forecasts and weather alert systems in a coherent way so that system operators can make well informed decisions. The paper discusses the different types of forecasting

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										methods (physical modeling vs. AI/machine learning) but goes on to talk about how certain forecasting data is often improperly communicated. A couple examples are when sudden curtailments occur or extreme weather related shut-down events that result in turbines being offline/destroyed: typically this information gets filtered out from the forecast even when it could be included as the wind forecast is often done at an aggregate level for an entire wind farm or region and because of SCADA limitations. This would imply that real-time monitoring of equipment should be a part of the forecast. Furthermore the paper goes on to talk about the monitoring of weather events using meteorological data presented to the user in geographical/map format, animated in real-time along with the current forecast. The location of lightning strikes can be displayed on such maps and their temporal information (i.e. color changing over time) can give the system operator a view of which farms might have equipment damage or have to go offline. This allows for late-breaking changes to be made to the forecast at critical moments when the system operators still have time to respond.

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39	A Whirl of Activity IEEE Power & Energy Magazine, IEEE Power and Energy Society; November/December 2009	Richard Piwko, Ernst Camm, Abraham Ellis, Eduard Muljadi, Robert Zavadil, Reigh Walling, Mark O'Malley, Garth Irwin, and Steven Saylors Dec 2009								Discusses the IEEE subcommittees that look at wind. Nothing relevant.
40	Change in the Air IEEE Power & Energy Magazine, IEEE Power and Energy Society; November/December 2009	William Grant, Dave Edelson, John Dumas, John Zack, Mark Ahlstrom, John Kehler, Pascal Storck, Jeff Lerner, Keith Parks, and Cathy Finley Dec 2009	X	X	X	X	X		X	As wind grows to represent a larger percentage of total generation resources and continues to generate a larger share of the energy consumed by end users, more effort is being directed at developing the tools and information that grid operators need to operate the system reliably. Some of the issues are common throughout the various regions, while some areas have unique problems due to system limitations. Operational differences vary, from the size of the balancing authority (BA) to the amount and type of ramp available to follow the load and wind output, the availability of units to cycle during low-load periods, and the size and type of reserves, including demand side

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										management, available for unplanned events. One tool that has been identified as necessary regardless of the system being operated is the ability of the grid operator to forecast wind plant output, including wind events on the system. This article will highlight how different grid and market operators are addressing this issue and why forecasting is important. The article will also address current forecasting practices and future challenges in improving forecasting capabilities. Review the NYISO market design for wind resources, review a wind event in ERCOT (slight drop in the regions wind speed) and both highlight the need for better wind forecasting of ramps and changes in weather (no matter how slight). Provided a good overview of wind power forecasting techniques and issues related to obtaining required data from wind farms. Forecasting of ramping events has proven to be an operational challenge due to the effects on changes in energy level produced. Further work of ramp events is recommended.

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41	Island Breezes IEEE Power & Energy Magazine, IEEE Power and Energy Society; November/December 2009	Marc Matsuura Dec 2009								Paper talks about the current issues regarding the 40% renewable energy integration benchmark set by the state of Hawaii for the year 2030 and what the issues exist for the various island electric systems that together make up the collective electric grid for the state of Hawaii. The study focuses on the electric grid areas covered by HELCO (main or big island of Hawaii), MECO (Maui) and HECO (Oahu). Because small island systems do not have interchange or interconnection with other areas and have typically smaller peak loads, they are more sensitive to deviations in frequency, trip events and unit failures. Therefore their regulating reserve requirements are much higher than for standard grid areas in the mainland US. None the less, the goal of 40% renewable integration (largely composed of wind) is being undertaken by the state of Hawaii. Some issues being faced by HELCO revolve around the tuning of the AGC system so that the SGC is not responsive to sudden changes in frequency below a certain threshold of +/- 0.2Hz, the reason being that a feedback effect often occurs where by the backup power winds up kicking in just as the wind resumes after a sudden curtailment, thus

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										amplifying the deviation in Hz rather than reducing it. They are also working with NREL to better predict ramp events associated with sudden increases in wind as they have a 2MW ramp limit in both directions. MECO has virtually all its wind power in one place and (like HELCO) can lose virtually all its wind power within the course of an hour. They too are experimenting with changing their regulating reserve capacity requirements based on their wind power/forecast (they count on their quick starting generation should the wind farm suddenly lose power). MECO is currently examining adding an additional 42 MW of wind power (up to 80% wind penetration). HECO is currently without any wind power but is also reviewing the changes needed to integrate up to 40% of their energy from wind. To accommodate this they are looking into energy storage solutions, upgrades to their transmission capabilities, modifications to cycling and changes to operational procedures to allow for such large penetrations of renewable energy.

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42	The View from the Top IEEE Power & Energy Magazine, IEEE Power and Energy Society; November/December 2009	John Lawhorn (Midwest ISO), Dale Osborn (Midwest ISO), Jay Caspary (SPP), Bradley Nickell (WECC), Doug Larson (Western Interstate Energy Board), Warren Lasher (ERCOT), and Manzar Ea. Rahman (AEP) Dec 2009								The challenge of integrating large amounts of renewable energy resources into the electric sector requires updated transmission analysis techniques. Economic planning, primarily in the form of value based planning over interconnection wide areas, is needed before performing the traditional single-hour, capacity-based reliability analyses. Covers the planning aspects of wind integration

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43	Up with Wind IEEE Power & Energy Magazine, IEEE Power and Energy Society; November/December 2009	Dave Corbus, Debbie Lew, Gary Jordan, Wilhelm Winters, Frans Van Hull, John Manobianco, and Bob Zavadil Dec 2009								Article focuses on three important aspects of large regional wind-integration studies: wind data development, transmission analysis, and the modeling of wind-integration scenarios. The article reviews a variety of different studies performed across a number of different grid areas including North America and Europe. The wind data development section focuses on a number of large scale wind integration studies with penetration levels up to 35% or more. The article briefly outlines how the studies used synthetic wind data and synthetic forecasts combined with unit commitment models to show what the impact on the grid and cost of energy would be. One study (Western Wind Integration and Solar Study) found that the price of energy would increase if wind was gathered from the best locations and transported to areas of high load vs. if lower capacity wind farms were constructed at or near the areas of peak demand to reduce transmission costs. The study goes on to review some of the European wind studies which seem to suggest there are significant barriers in the grid and market regulation to Europe realizing 30% (or more) renewable penetration. The aggregation of large scale

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										wind farms for production and forecasting seemed to (somewhat) help mitigate the negative effects of intermittency and uncertainty for the European studies. According to the EWIS study, European TSOs are already actively addressing the issues associated with wind integration, including: - establishing direct connections to large onshore and offshore wind plants -planning for interconnection with increasingly active distribution networks -reinforcing network pinch points within and between national networks - developing balancing arrangements through enhanced control arrangements and market mechanisms - developing appropriate, harmonized grid codes to facilitate large-scale wind entry
44	Where the Wind Blows IEEE Power & Energy Magazine, IEEE Power and Energy Society;	Thomas Ackermann, Graeme Ancell, Lasse Diness Borup, Peter Børre Eriksen, Bernhard Ernst,	X	X						Article discusses the current integration of increasing penetrations of wind power and how it has successfully been managed. The article states, both in the introduction and conclusion, that there have been no incidents in which the wind has directly or indirectly been a major factor causing operational problems for the system. This is a strong statement but the article goes on to back it up with

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	November/December 2009	Frank Groome, Matthias Lange, Corinna Möhrlen, Antje G. Orths, Jonathan O'Sullivan, and Miguel de la Torre Dec 2009								concrete evidence. Furthermore the article emphasizes that there are a number of parameters that are being monitored that indicate the need for active management in the near future (and in some cases already today). Europe (altogether): Aim is to bring Europe up to 20% renewable integration by 2020 across all EU members Nordic Power Market (Denmark, Norway, Sweden, Finland): Regulating power expenses paid by the TSO are transferred to the players responsible for the imbalance. This is done in the regulating power market. Denmark aims to use the best available wind forecasts (5% error for day-ahead market). Nord pool spot price market currently sets the cost of energy to be zero during periods of high wind and high congestion but they are interested in using negative spot prices in the future to encourage consumption during these high wind, low demand periods. Spain:

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										11.5% wind penetration. Wind variability and forecast uncertainties are one of the main challenges for wind-energy integration in isolated or weakly interconnected systems such as the Spanish one. Imbalances must not be greater than 1,300 MW and must be corrected within ten minutes. One solution they are using is to base their spinning reserve requirements one day in advance using a probabilistic forecast at 85% confidence. This method saves reserves and costs in those days with stable climatic conditions, and the method itself increases the amount of reserves for possible wind-forecast errors in those days when the weather (and hence wind generation) is less predictable. On average, 630 MW of additional reserves must be procured to compensate for wind-forecast errors. Ireland: Currently at 11% when combined with hydro. Aim is to bring Ireland up to 40% renewable penetration by 2020. Following a two-year analysis of frequency events, there is a correlation between high wind scenarios and a light system. This has particular relevance in a relatively small power system with little interconnection, such as the Irish

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										one. To help manage this issue, an investment is being made in an online wind-power generation secure level assessment tool (WSAT) to support operational decisions in real time. This tool will be able to assess the highest instant secure amount of wind generation on the power system based on voltage and transient stability analyses of transfers between wind and conventional power generation in the base case and all trip and credible contingency scenarios. Overview of Wind Forecasting Issues: NWP and Statistical/machine learning models were discussed. Particular emphasis was given to hybridized or combination models that use ensemble or model filtered approaches that use weighted combinations of numerical weather prediction and statistical model outputs.
45	Wind Power Myths Debunked IEEE Power & Energy Magazine, IEEE Power and Energy Society;	Michael Milligan (NREL), Kevin Porter (Exeter Associates), Edgar DeMeo (Renewable	X	X		X	X			The natural variability of wind power makes it different from other generating technologies, which can give rise to questions about how wind power can be integrated into the grid successfully. This article aims to answer several important questions that can be raised with regard to wind power. Although wind is a variable resource, grid operators have experience with managing variability that

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	November/December 2009	Energy Consulting Services), Paul Denholm (NREL), Hannele Holttinen (VTT Technical Research Centre of Finland), Brendan Kirby (NREL), Nicholas Miller (General Electric), Andrew Mills (Lawrence Berkeley National Laboratory), Mark O'Malley (University								comes from handling the variability of load. As a result, in many instances the power system is equipped to handle variability. Wind power is not expensive to integrate, nor does it require dedicated backup generation or storage. Developments in tools such as wind forecasting also aid in integrating wind power. Integrating wind can be aided by enlarging balancing areas and moving to sub-hourly scheduling, which enable grid operators to access a deeper stack of generating resources and take advantage of the smoothing of wind output due to geographic diversity. Continued improvements in new conventional generation technologies and the emergence of demand response, smart grids, and new technologies such as plug-in hybrids will also help with wind integration. Grid operators handle wind variability using existing flexible generation resources, wind forecasting, and sub-hourly scheduling; wind production is more predictable when evaluated closer to real time (5–7% MAE). Sub-hourly schedules also let grid operators access the flexibility of other generating units. Additionally, large balancing areas (or utility control areas) help with wind variability, because wind variability is smoothed over

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		College Dublin), Matthew Schuerger (Energy Systems Consulting Services), and Lennart Soder (Royal Institute of Technology, in Stockholm) Dec 2009								larger geographic areas. When geographically dispersed wind energy is added to a large balance energy area, the amount of reserve capacity does not increase but the deployment of reserves occurs more often.

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46	Dynamic sizing of energy storage for hedging wind power forecast uncertainty. IEEE Power Engineering Society General Meeting 2009, Calgary, Canada (presentation) http://www2.imm.dtu.dk/~pp/docs/pinsonetal_dynsizing.pdf	P. Pinson, G. Papaefthymiou, B. Klockl, and J. Verboomen July 2009			X				X	In market conditions where program responsible parties are penalized for deviations from proposed bids, energy storage can be used for compensating the energy imbalances induced by limited predictability of wind power. The energy storage capacity necessary for performing this task will differ between delivery periods, according to the magnitude and the evolution of forecast errors in each delivery period. A methodology is presented for the assessment of the necessary storage capacity for each delivery period, based on the degree of risk that the power producer accepts to be exposed to. This approach leads to a dynamic assessment of the energy storage capacity for different delivery periods. In such a context, energy storage is used as a means of risk hedging against penalties from the regulation market. Study on using storage to mitigate the variability of VERs where the market rules penalized the VERs for imbalance. Also proposes an approach to find the optimal storage size based on the variability of the VERs. European authors; data for simulation was Vattenfall Denmark

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47	Experience From Wind Integration in Some High Penetration Areas IEEE TRANSACTIONS ON ENERGY CONVERSION, VOL. 22, NO. 1, MARCH 2007	Lennart Soder, Lutz Hofmann, Antje Orths, Hannele Holttinen, Yih-huei Wan, and Aidan Tuohy Mar 2007		X			X		X	The amount of wind power in the world is increasing quickly. The background for this development is improved technology, decreased costs for the units, and increased concern regarding environmental problems of competing technologies such as fossil fuels. The amount of wind power is not spread equally over the world, so in some areas, there is comparatively a high concentration. The aims of this paper are to overview some of these areas, and briefly describe consequences of the increase in wind power. The aim is also to try to draw some generic conclusions, in order to get some estimation about what will happen when the amount of wind power increases for other regions where wind power penetration is expected to reach high values in future. European Authors Authors examine four sites in Europe and one site in US (Public Service Company of New Mexico) with medium to high penetration of wind. They listed common issues (sufficient power plants at low wind, sufficient power plants with fast controls during high wind, sufficient reserves for wind ramps, etc.) and how the sites handled the issues (internally and via interconnections to neighbors

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48	Value of Bulk Energy Storage for Managing Wind Power Fluctuations IEEE TRANSACTIONS ON ENERGY CONVERSION, VOL. 22, NO. 1, MARCH 2007	Mary Black (CE Electric U.K) and Goran Strbac (Imperial College, UK) Mar 2007					X			This paper considers the impact of uncertain wind forecasts on the value of stored energy (such as pumped hydro) in a future U.K. system, where wind supplies over 20% of the energy. Providing more of the increased requirement for reserves from standing reserve sources could increase system operation efficiency, enhance wind power absorption, achieve fuel cost savings, and reduce CO2 emissions. Generally, storage-based standing reserve's value is driven by the amount of installed wind and by generation system flexibility. Benefits are more significant in systems with low generation flexibility and with large installed wind capacity. Storage is uniquely able to stock up generated excesses during high-wind/low-demand periods, and subsequently discharge this energy as needed. When storage is combined with standing reserve provided from conventional generation (e.g., open-cycle gas turbines), it is valuable in servicing the highly frequent smaller imbalances. Generally, value is gained by using standing reserve to provide the greater part of additional balancing required by uncertainty in wind generation forecast. Reducing the relative contribution

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										from spinning reserve increases system operation efficiency, increases wind power absorption, achieves fuel cost savings, and reduces CO2 emissions. A major factor affecting storage value is flexibility in the conventional generation mix. The value of storage-based standing reserve is driven by the amount of wind installed and the flexibility of the generation system.
49	Impacts of Integration of Wind Generation on Regulation and Load Following Requirements of California Power Systems In Proceedings of 5th International Conference on the	Makarov YV, C Loutan, J Ma, P De Mello, and S Lu. Jun 2008.		X			X		X	This paper describes a methodology to evaluate the amount of required regulation and load following capability to maintain reliability in the CAISO Control Area. The hour-ahead wind generation forecast was assumed to be a part of the future CAISO/Scheduling Coordinator (SC) scheduling system. The methodology is based on a mathematical model of the CAISO's actual scheduling, real-time dispatch and regulation processes. CAISO actual 2006 data and simulated 2010 data are analyzed by season. Load following and regulation requirements, including the

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	European Electricity Market - EEM 2008, pp. 1-6. Institute of Electrical and Electronics Engineers, Piscataway, NJ. doi:10.1109/EEM.2008.4579027 http://www.pnl.gov/publications/abstracts.asp?report=233955									capacity, ramping, and duration requirements by operating hour within a season of 2006 and 2010 was analyzed simultaneously

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50	Evaluating Impacts of Wind Generation on Regulation and Load Following Requirements in the California ISO Service Area. In Windpower 2008 Conference & Exhibition, June 104, 2008, Houston, Texas., pp. 372-377 American Wind Energy Association, Washington, DC. http://www.pnl.gov/publications/abstracts.asp?report=240986	Makarov YV, C Loutan, J Ma, P De Mello, and S Lu. Jun 2008.		X			X		X	The paper analyzes the impact of integrating wind generation on the regulation and load following requirements of the California Independent System Operator (CAISO). These requirements are simulated and compared for the study cases with and without wind generation impacts included into the study for the years 2006 and 2010. Regulation and load following models were built based on hour ahead and 5-minutes ahead load and wind generation forecasts. In 2006, the CAISO system peaked at 50270 MW. Wind generation (at the installed capacity of 2600 MW) had limited impact on the requirement of load following and regulation in the CAISO Control Area. However, in 2010, (with an expected installed capacity of approximately 6700 MW) this impact will significantly increase. The results provide very useful information for the CAISO to adjust its scheduling and real-time dispatch systems to reliably accommodate future wind generation additions on the CAISO Control Area.

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51	Understanding Variability and Uncertainty of Photovoltaics for Integration with the Electric Power System LBNL - ERNEST ORLANDO LAWRENCE BERKELEY NATIONAL LABORATORY http://eetd.lbl.gov/EA/EMP	Andrew Mills1, Mark Ahlstrom2, Michael Brower3, Abraham Ellis4, Ray George5, Tom Hoff6, Benjamin Kroposki5, Carl Lenox7, Nicholas Miller8, Joshua Stein4, and Yih-huei Wan5 1. Lawrence Berkeley National Laboratory 2. WindLogics Inc. 3. AWS Truwind, LLC	X	X					X	The National Renewable Energy Laboratory, Sandia National Laboratories, the Solar Electric Power Association, the Utility Wind Integration Group, and the Department of Energy recently hosted a day-long public workshop on the variability of photovoltaic (PV) plants. The workshop brought together utilities, PV system developers, power system operators, and several experts to discuss the potential impacts of PV variability and uncertainty on power system operations. The workshop was largely motivated by a need to understand and characterize PV variability from the perspective of system operators and planners to avoid unnecessary barriers to the rapid development and interconnection of PV to the electric power system. Understanding PV variability will allow system planners and operators to develop effective measures to manage variability at different levels of PV penetration. The workshop generated considerable discussion on the topic and a number of lessons were learned by the end of the day. This paper explores the issue of variability and uncertainty in the operations of the U.S. power grid and presents a number of the findings from the workshop.

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		4. Sandia National Laboratories 5. National Renewable Energy Laboratory 6. Clean Power Research, LLC 7. SunPower Corporation 8. GE Energy Dec 2009								General paper on the topic

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52	2006 Minnesota Wind Integration Study. Volume 1 Minnesota Public Utilities Commission	EnerNex Corporation and Midwest Independent System Operation (Midwest ISO) Nov 2006		X		X	X			Report studies impacts on reliability and costs associated with increasing wind capacity to 20% of MN retail electric sales by 2020. Analysis of capacity value of wind generation based on 2003-2005 load and wind patterns. The aggregate flexibility of units on line within Midwest ISO during any hour is found to be adequate for compensating most of the changes in wind generation. The report found that wind generation would have modest impacts on time frames associated with regulation or the real-time market. The additional amount of reserve capacity for these services would also be modest. Sharing balancing authority functions substantially reduces requirements for certain ancillary services such as regulation and load following (with or without wind). The required amount of regulation capacity was found to be reduced by almost 50 percent. Additional benefits found with other services such as load following. In 2007, the Midwest contingency Reserve Sharing Group commenced operations and was intended to reduce the contingency reserve obligation of the MN utilities. The results of the loss of load probability (LOLP) analysis were slightly lower than the capacity accreditation

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										determined by the MAPP Reserve Sharing Group policy for accrediting intermittent generation. The policy was first developed for small hydro systems, and uses an after-the-fact accounting procedure based on the amount of energy deliveries during a 4 hour window around the monthly peak hour. Midwest ISO developed ancillary services market to consolidate balancing authority functions. Midwest ISO utilizes computer tool called PROMOD for hour-by-hour analysis of energy market operations and transmission facility utilization. Generating units committed based on costs, operating characteristics, and transmission constraints, and then dispatched to meet the specified load on an hourly basis. NYISO - Uses day-ahead load forecasts as part of generation commitment and scheduling process. Can use current operational processes dealing with uncertainty in load forecasting to cover uncertainty associated with wind. Day-ahead and hour-ahead energy markets have sufficient flexibility to accommodate wind without any significant changes.

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53	Accommodating High Levels of Variable Generation NERC Web site http://www.nerc.com/docs/pc/ivgtf/IVGTF_Report_041609.pdf	NERC's Integration of Variable Generation Task Force (IVGTF) members Apr 2009	X	X	X	X	X			The report is covers 1) Characteristics of Variable Generation (including Diversity) 2) Transmission and Generation Planning Impacts, 3) System Operations (Current & future resources & tools), 4) Other and Future Considerations and 4) NERC Standard Review. Recommendations are made support bulk power system planning and operations along with next steps. Generally applies to all ISOs. Good high level issue summary.
54	The Effects of Integrating Wind Power on Transmission System Planning, Reliability and Operations New York State Energy Research and Development Authority (NYSERDA)	GE Energy Consulting March 2005	X		X					Reliability assessment - contribution of prospective wind generation towards meeting NY state requirements for loss of load expectation (LOLE). With centralized wind forecasting, wind can be held accountable to similar standards as conventional generation in meeting their day-ahead forecasts, although imbalance penalties should not be imposed. Wind project would settle discrepancies between their forecast and actual outputs in the energy balancing market. Any penalties for imbalance should be eliminated. No operating conditions were found to justify the need for

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										wind power curtailment at a statewide level (i.e. backing down all wind generators at the same tie). NYISO recommended to require a power curtailment feature on new wind farms to help handle temporary local transmission limitations. Curtailments done by NYISO sending a maximum power order to wind farms that is similar to existing process for re-dispatch of thermal generator via plant operator, or via SCADA for unmanned generation facilities. Envisioned at farm-level function, not turbine level.
55	Predicting Sudden Changes in Wind Power Generation North American Wind Power (Oct. 2008) http://www.awstruewind.com/files/NAWP_AWSTruewind1008.pdf	Noah Francis (AWS True Wind) Oct 2008	X	X					X	The paper focuses on forecasting wind ramp events as opposed to merely forecasting wind farm output: "The ability to predict sudden, significant changes in wind power generation is emerging as a top priority for grid managers. In most cases, forecasts of hour-by-hour generation over the next day or two solve the grid operator's wind integration problem. However, an unforeseen ramp-up or ramp-down in generation, so-called ramp events, can leave operators scrambling to balance supply and demand while inducing substantial costs."

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										According to the paper "significant ramp events are relatively rare, but an effective forecasting solution for that handful of hours each year may mean more to a grid manager than does the general forecasting solution for all the remaining hours.". Some potential solutions to the problem include: - In some cases such as a spike in wind associated with a cold front, upgrading to a numerical weather prediction algorithm supplemented with up-stream off-site data will help to predict surge events more accurately (with a significant reduction in cost vs. cost of upgrade). - In other cases such as the spike in wind associated with a large thunderstorm front a probabilistic model (with confidence intervals) would be needed as grid operators need to know the uncertainty surrounding the occurrence of a specific event. State-of-the-art pattern recognition algorithms combined with warnings from the National Weather Service could help to accomplish this.

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56	The Northwest Wind Integration Action Plan Northwest Power and Conservation Council	Northwest Power and Conservation Council (Steering Committee and Technical Working Group) March 2007						X		Document addresses issues that need to be resolved in the Northwest, especially related to actions addressing transmission marketing, planning and expansion and the limited market for control area services. Calls for the formation of a Northwest Wind Integration Forum. Forum had assigned a provisional, 15% sustained capacity value to wind. Capacity adequacy metric is based on the sustained peaking capacity value of a resource's average contribution to the system over 5 sequential, 10 hour peak load days (50 hour sustained capacity).
57	How do Wind and Solar Power Affect Grid Operations: The Western Wind and Solar Integration Study NREL Conference Paper - NREL/CP-550-46517 To be presented at	D. Lew and M. Milligan, National Renewable Energy Laboratory G. Jordan, L. Freeman, N. Miller, K. Clark, and R. Piwko, GE	X			X	X			The Western Wind and Solar Integration Study is one of the largest regional wind and solar integration studies to date, examining the operational impact of up to 35% wind, photovoltaics, and concentrating solar power on the WestConnect grid in Arizona, Colorado, Nevada, New Mexico, and Wyoming. This paper reviews the scope of the study, the development of wind and solar datasets, and the results to date on three scenarios. Study is still underway - preliminary results.

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	the 8th International Workshop on Large Scale Integration of Wind Power and on Transmission Networks for Offshore Wind Farms Bremen, Germany October 14–15, 2009 http://www.osti.gov/bridge	Oct 2009								

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58	An Analysis of the Errors and Uncertainty in Wind Power Production Forecasts Paper presented for Wind Power 2006 (AWEA) in Pittsburgh http://www.awstruewind.com/files/AWEA_Windpower_2006_ForecastingErrors.pdf	John W. Zack (AWS True Wind) Oct 2006	X	X						Paper on forecasting of ramp events. Author begins by discussing the role of the shape of the wind speed distribution and power curve on wind power forecasting errors. A steep power curve for the wind farm combined with a narrow wind distribution near the steepest region of the power curve will have the highest wind forecasting error (the reverse is true as well) and the greatest impact on grid integration. The paper goes on to discuss how difficult it is to forecast ramp events depending on what kind of event is being forecast. Ramp events due to horizontal movements are detectable with numerical weather prediction modeling and access to surface data upstream from the wind farm. However, ramp events due to vertical mixing are much more difficult to predict. The paper emphasized the need to predict vertical mixing/movement with a combination of physics modeling and surface data to detect vertical mixing events. The paper looks at a case study from San Gorgino CA where a combined physics-based model with surface anemometer data was able to detect just such an event. A case study of the San Gorgonio Pass was examined, During the onset of the event, wind speeds high in the

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										pass were very high (around 20 m/s) as well as wind speeds near the wind farm on the easterly slopes below the pass (also around 20 m/s). Then suddenly the wind speeds on the easterly slopes dropped to near zero where as the wind speed at the pass remained constant. Later that day the wind speed on the easterly slope suddenly increased again back near the 20 m/s mark. The paper concludes that this behavior was the result of "neutral stability" in the lower atmosphere combined with high upper atmosphere wind speeds which meant a vertical mixing event was a high probability. The combination of the physics based model with surface data provided some clues about the likelihood of such an event however the exact timing is difficult to calculate without remote sensing equipment to monitor the stability of the upper atmosphere at around 1K height. It is this region, that if properly monitored, can help predict the onset of a vertical mixing ramp event the author concluded. He did not mention what equipment was capable of performing this task (SODAR?). Case study was done in California

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59	Operational Impacts of Wind Energy Resources in the Bonneville Power Administration Control Area - Phase I Report PNNL-17558, Pacific Northwest National Laboratory, Richland, WA.	Makarov YV, and S Lu 2008	X	X			X		X	This report presents a methodology developed to study the future impact of wind on BPA power system load following and regulation requirements. The methodology used in this study provides capacity requirement information and analyzes the ramp rate requirements for system load following and regulation processes. - Shorter load following interval (10 minutes) results in smaller regulation requirements - Forecast errors on wind and load increase the load following and regulation requirements, sometimes dramatically - The distribution of load following and regulation requirements is not normal: There are infrequent occasions that the system needs very high capacity and ramp capability for balancing processes. The tail events are usually the results of high wind and load ramps superposed on forecast errors..

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60	Low Probability Tail Event Analysis and Mitigation in BPA Control Area: Task 2 Report PNNL-18769, Pacific Northwest National Laboratory, Richland, WA.	Lu S, YV Makarov, CA McKinstry, AJ Brothers, and S Jin. 2009	X						X	Task report detailing low probability tail event analysis and mitigation in BPA control area. Tail event refers to the situation in a power system when unfavorable forecast errors of load and wind are superposed onto fast load and wind ramps, or non-wind generators falling short of scheduled output, causing the imbalance between generation and load to become very significant. As penetration of intermittent sources increases in the system, the balancing reserve requirement is more variable. Determining whether the system will have sufficient reserve capacity in real-time operation becomes more difficult. The methodology presented in this report will help to address this problem.

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61	Market Protocols in ERCOT and Their Effect on Wind Generation Preprint submitted to Energy Policy, August 26, 2009	Ramteen Sioshansi (Ohio State University) and David Hurlbut (NREL) Aug 2009			X					In this paper, the issues that have arisen in designing market protocols that take account of these special characteristics of wind generation and survey the regulatory and market rules that have been developed in Texas. The paper discusses the perverse incentives some of the rules gave wind generators to over-schedule generation in order to receive balancing energy payments, and steps that have been taken to mitigate those incentives. Finally, the paper discusses more recent steps taken by the market operator and regulators to ensure transmission capacity is available for new wind generators that are expected to come online in the future. The paper reviewed the zonal and nodal market designs and recent changes for VERs. It proposes to replace the point model for wind in RUC with a model to more explicitly model the random nature of wind.

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62	Wind integration - Spanish successful story - Future challenges Presentation at MIT CEEPR Fall 2009 Workshop; Cambridge, December 3-4 2009	Jose Arceluz and Juan Rivier (Iberdrola Renovables) Dec 2009		X		X			X	Covers Iberdrola's operations in Europe and the USA. In Europe they have a large balancing region to accommodate wind and as the wind power penetration grows, they will more wind spillage and impacts from wind ramps. In the USA, wind integration costs are less in larger balancing areas, larger balancing areas provide a better resource mix, and intra hours schedule periods better accommodate wind.
63	CAISO's Plan for Integration of Renewable Resources	David L. Hawkins Jul 2008	X	X						Describes CAISO 2008-09 work plan: Track 1 - Develop operational tool (e.g. wind and solar energy forecasts and graphic displays for gird operations, Track 2 - Identify market and operational barriers, Track 3 - Engineering studies to analyze impact of solar, storage, transmission constraints, ramping and regulation requirements, Track 4 - Development of market products, Track 5 - Changes to large generator interconnection. Presentation cites need for more data on operating characteristics of new types of solar generation, and to finish the RETI studies and determine transmission

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										required to interconnect the renewables proposed for the designated areas. Summary at end of presentation includes the following points: Need for new wind generation forecasting tools Need for new conventional generation with greater flexibility ("wind needs partners") Need new power management procedures New tools for grid operators to anticipate changes from wind
64	Optimization of Wind Power Production Forecast Performance During Critical Periods for Grid Management Presented for Wind Power 2007 in Los Angeles CA	John W. Zack (AWS True Wind) Jun 2007	X	X					X	Another paper focused on the forecasting of ramp events in California. The paper presents an overview of issues associated with the development and implementation of a forecast system designed for optimal performance in the prediction of large ramp events. "The accurate forecasting of large ramp events can facilitate the procurement of the right amount of regulation, which will decrease system costs and ultimately enable larger amounts of wind penetration....For the hours-ahead forecast time horizon, the key issue in predicting large ramp events associated with these types of weather systems is monitoring and projecting the movement of the large-scale weather

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	(Poster Presentation) http://www.awstruewind.com/files/AWEA_Windpower_2007_Forecasting.pdf									systems and the associated low-level wind speed features." Paper claims that numerical weather prediction models are best suited for forecasting ramp events that are associated with the movement of large scale weather fronts. It also goes on to explain that not all ramp events can be attributed to weather fronts and that some may be attributed to "mesoscale circulations" such as sea breezes, mountain valley winds, drainage flows and gap flows. These processes have a shorter life cycle and are more difficult to predict. Accordingly, they are better predicted by having a multitude of surface level meteorological data upstream and downstream from the event. Yet another form of ramping occurs when there is a vertical mixing event that is quite difficult to predict which an area that needs improvement is. Lastly, the paper mentions thunderstorm fronts and that a combination of surface measurements, Doppler and numerical weather prediction can be effective in determining if such an event is likely to occur. AWS is currently exploring how to predict such events by first predicting the probability of the event, which if above a certain threshold will trigger a model-

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										switching event in the forecast that is tuned to that event. This is an area of ongoing research. "An analysis of the frequency of large ramps in California indicated that large ramps are a relatively infrequent event at most wind farms with ramps of over 75% of capacity in 2 hrs or less occurring in much less than 0.5% of the 2-hr periods. An examination of the causes of large ramp events in California indicated that large ramp events can be caused by a number of different processes. Optimal forecast performance is likely to be achieved using a multi-scheme forecast system in which individual schemes are formulated for each significant type of process that can generate a large ramp event"

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65	SPP WITF Wind Integration Study SPP Final Report For Southwest Power PoolPrepared By: Charles River Associates CRA Project No. D14422	Charles River Associates Jan 2010	X	X	X	X	X		X	The Wind Energy study was performed for the year 2010 with the assumption that SPP operates as a single balancing authority (BA) with a co-optimized energy and ancillary service market (Day 2 Market). Three wind penetration levels were studied and each was compared to the current system conditions (Base Case, with approximately 4% wind penetration). The three penetration levels were 10%, 20%, and 40% by annual energy (10% Case, 20% Case, and 40% Case, respectively). Detailed studies were performed on the 10% and 20% Cases; the 40% Case was examined in those portions of the study that related to wind characteristics. The goal of the study was to identify the challenges of integrating high levels of wind penetration into the SPP transmission system. In order to meet that objective, it was necessary to identify transmission upgrades needed to accommodate the studied wind power additions with minimal curtailment. This was not an economics study; no economic optimization, such as an analysis of the tradeoff between building transmission upgrades and curtailing wind, was performed. Furthermore, the transmission upgrades implemented in the study were based on the assumed wind plant locations and sizes.

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										Consolidating SPP into a single BA, as is planned, should reduce overall needs for reserves and flexible resources. To accommodate higher wind penetration levels, however, more operational flexibility (more start-ups and cycling of units) is required. The need for flexible units increases as the forecast error increases. A robust transmission system could reduce local generation requirements. Additionally, as the operational needs for non-wind units change, resulting changes in the commitment and dispatch bring about new flow patterns. Coordinated planning between wind and transmission is therefore essential. Ancillary service requirements depend on the wind penetration level. The increase of wind power leads to a need for increased regulation capability. The regulation requirement increase accelerates as the wind penetration level increases. Wind regulation needs are time- varying and can be reduced by improvements in forecast accuracy. The study findings show that regulation-up and regulation-down requirements are not symmetric and could differ significantly from one another. Furthermore, wind may be able to provide regulation down during high-

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										wind periods. Therefore, CRA recommends that these two ancillary services be separated. A new type of ancillary service, such as load-following reserves, which are not currently defined or required in SPP, may become highly beneficial as the net load forecast variability increases with higher wind penetration levels. As with regulation, the need for these reserves is also time-dependent and not symmetric in each direction. The study found that forecast errors increase startups of flexible units and reduce generation of less flexible units, which typically have lower marginal costs. Forecast errors were observed to have different impacts depending on whether the deviation from the forecast was positive or negative.

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66	Eastern Wind Integration and Transmission Study: Executive Summary, Project Overview and Study Subcontract Report NREL/SR-550-47086 National Renewable Energy Laboratory	Prepared for: The National Renewable Energy Laboratory Prepared by: EnerNex Corporation Jan 2010	X	X		X	X	X	X	In general, though, the study shows the following: • High penetrations of wind generation—20% to 30% of the electrical energy requirements of the Eastern Interconnection—are technically feasible with significant expansion of the transmission infrastructure. • New transmission will be required for all the future wind scenarios in the Eastern Interconnection, including the Reference Case. Planning for this transmission, then, is imperative because it takes longer to build new transmission capacity than it does to build new wind plants. • Without transmission enhancements, substantial curtailment (shutting down) of wind generation would be required for all the 20% scenarios. • Interconnection-wide costs for integrating large amounts of wind generation are manageable with large regional operating pools and significant market, tariff, and operational changes. • Transmission helps reduce the impacts of the variability of the wind, which reduces wind integration costs, increases reliability of the electrical grid, and helps make more efficient use of the available generation resources. Although costs for aggressive expansions of the existing

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										grid are significant, they make up a relatively small portion of the total annualized costs in any of the scenarios studied.
67	Transforming Electricity Delivery - Strategic Plan U.S. DOE Office of Electricity Delivery and Energy Reliability	U.S. DOE Research (R&D) Division Sept 2007								Glossy document that describes DOE support for "next generation" technologies, tools and techniques. Four key activities include: High temperature superconductivity, visualization and controls, renewable and distributed systems integration and energy storage and power electronics.

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68	Western Renewable Energy Zones - Phase 1 Report U.S. DOE Office of Electricity Delivery and Energy Reliability	Western Governors Association and U.S. DOE June 2009								Document identifies areas in the West (CA, OR, WA, ID, NV, AZ, NM, CO, UT, MT, and WY) with potential for large scale development of VERs. Looks at discrete areas and creating boundaries that could justify the construction of regional transmission. Not very relevant.
69	Large Wind Integration Challenges and Solutions for Operations/System Reliability UWIG (GE Presentation to UWIG)	Bart McManus, Bonneville Power Authority Oct 2008	X	X		X	X	X	X	The presentation looked at calculating balancing requirements for planned wind generation. The analysis involved computing leads (upstream wind) and lags (downstream wind) for planned wind from existing wind that were multiplied by installed and planned capacity to derive estimated output of wind farms. For example, if a planned 100 MW wind farm (A) had a 20 minute lead before an existing 200 MW wind farm (B) and a 10 minute lag after an existing 50 MW wind farm (C) and both B and C were equally indicative of the output of A, A would have the following estimated generation for any minute: A = (100/200)*(B+20minutes)*0.5 + (100/50)*(C-10minutes)*0.5

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										According to the presentation: 1) Currently have hourly schedules: 10 minute schedule changes would solve ~80% of the issues BPA is anticipating. 2) A self supply of reserves for large wind operators would offload half of the requirements for Bonneville Power Authority. 3rd party supply has potential to offload more. 3) Feed Forward AGC is needed - Looks ahead to what is coming for control rather than correcting error - Lots of short-term forecasting needed for this both wind and load. 4) ACE Diversity Interchange: - Enables multiple Balancing Authorities to share diversity in an Interconnection - Minimal impact to other Balancing Authorities effort, both wind and load.

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70	Ramp Forecasting: Meteorology and Challenges Wind Logics presentation to UWIG http://www.uwig.org/iowawork/Finley.pdf	Cathy Finley (Wind Logics) Oct 2009	X							Presentation focused on the meteorological and physical basis for ramp events and how they can be used to predict them. The discussion focuses on how meteorologists see a series of ramp events vs. what the grid operator(s) sees: The grid operator sees it as a random ramping of wind power where as the meteorologist sees it as a meteorological event that is tied to (somewhat) to predictable physical processes. "From a forecasting perspective, all ramps are not the same. Wind energy ramp events can be caused by a large range of meteorological phenomenon. Ability to forecast a ramp event depends on meteorological event causing the ramp (some predicted much better than others). In general, the larger and longer-lived a feature, the better it can be predicted in 12-48 hour frame (i.e. large-scale weather systems such as mid-latitude cyclones better predicted than thunderstorms)"

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71	Wind Integration Study Xcel Energy and Minnesota Department of Commerce	EnerNex Corporation and Wind Logics Sept 2004		X			X			Study assesses the impact of 1500 MW of wind generation spread over hundreds of square miles and characterizes how large, geographically diverse wind plants would appear in aggregate to the system operators. Ancillary service costs resulting from integrating wind generation are relatively modest for the growth in US wind generation expected in the next 3-5 years. Some of the discussion around capacity ratings is outdated, comparing the MAPP capacity credit with the ELCC approach. (The MAPP algorithm selects wind generation data from a 4 hour window including the peak, and applies it on a monthly basis.) Liquid wholesale markets administered by Midwest ISO can reduce hourly integration costs of wind, by providing an alternative to using internal resources to compensate for the variability of wind. Another option is the analysis and development of algorithms for unit commitment and scheduling that explicitly account for the uncertainty in wind generation forecasts and lead to operating strategies that "win" more than they "lose" over the long-term.

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72	Technical Requirements for Wind Generation Interconnection and Integration GE, Enernex, AWS True Wind Presentation for ISO-New England	GE, Enernex, AWS True Wind Nov 2009	X	X	X				X	A large number of interesting/useful findings in this paper include: - It is difficult to discern between different forecasting methods independent of location, type of algorithm/method used because of sensitivity to these conditions. - European forecasts are sometimes thought to outperform North American forecasts but this is typically only due to the fact that they aggregate their wind power forecasts across multiple regions which is known to significantly reduce forecasting error. - Finally, improvements to plant output (i.e. wind power forecast) models could potentially benefit very short term forecasts as well as longer time scales of wind energy forecasting. The improvements are likely to come from more (1) abundant and higher quality meteorological and energy generation data, (2) sophisticated wind plant data gathering and communications systems, and (3) detailed statistical or physical plant output model formulations.

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73	Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020 IEEE PESGM-01275	Deutsche Energie Argentur July 2006				X	X	X	X	Broad overview paper of grid integration related issues for Germany as a result of the large VER penetration level goals sought for 2020 In Germany, a study commissioned by Deutsche Energie-Agentur (DENA) investigated the reliability and stability of the extra high voltage transmission network up to the year 2015. Grid codes in Europe have been used to regulate the interconnection of wind turbines into the grid and are used as functional specifications for their construction. DENA found in 2003 that grid safety criteria under the currently existing grid codes for turbines that went into operation before 2003/4 would have resulted in wide scale regional voltage sags and grid instability. The reason was that if voltage had dropped by more than 20% or more in a given network segment the older (2003/4 and prior) wind turbines operating under the grid codes at the time would have disconnected themselves suddenly from the grid. This would have triggered a cascading effect throughout the German and European grid possibly transgressing the 3,000 MW reserve capacity and resulting in complete shutdown. The study led to a change in grid codes such that new grid codes were enforced in 2004 such that all

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										new wind turbines would disconnect themselves from the grid at an 80% or greater drop in voltage which would ensure stability of the grid somewhere between 2010 and 2015 as the rate of growth of the newer grid code wind turbines outpaces the older grid code turbines. It should be noted however there has been no reported occurrence of such a wide scale event even though it is hypothetically possible. That said, the study illustrates how the simple changing of interconnection rules can lead to a significant increase in grid stability and reliability.
74	Variability of Wind Power and Other Renewables International Energy Agency Report, 2005	International Energy Agency Report, Jul 2005	X	X	X		X	X	X	Broad overview paper of wind variability and forecasting issues for Europe as a whole Currently the European country of Denmark has the highest wind penetration rate at 22% which provides a good example for case studies. One such study performed by the International Energy Agency Commission determined that the geographical dispersion effect of all the wind farms across Denmark results in an hourly maximum drop of 20% of installed capacity where as the standard reduction was roughly 3%. Furthermore it was determined that the maximum change in output per minute

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										was 6 MW out of 2400 MW of installed capacity or 0.25%. This indicates that geographical dispersion plays a stronger role in the reduction of intra-hour variability and hence balancing requirements than one might suspect looking at the variability of individual wind farms. The study also went on to mention that the reduction in the reserve requirements needed in the electricity market when comparing a persistent forecast (i.e. pick the last observation of power and project that 2 hours ahead) to a perfect forecast was more than double. This indicates that the increased accuracy in wind forecasting that is currently being achieved in Europe will significantly reduce the amount of reserve requirements needed over time.

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75	Analyzing and Optimizing Supply and Demand of Intermittent Renewable Electricity Through Transmission Load Flow Modeling Precourt Energy Efficiency Center Stanford University Funded Project Final Survey Report	Mark Jacobson, Stanford University no date								The main focus of this project was to explore the feasibility and quantify the effects of combining solar, wind, geothermal, and hydroelectric power with remaining conventional power to meet the time dependent electric power demand in California while also meeting an aggressive carbon emissions reduction target. Two aspects of the feasibility of expanded grid integration were studied. First, we examined the effects of injecting power from large renewable plants throughout California directly onto the high-voltage transmission lines already in place using power flow modeling of the California transmission system. In the second stage of the study, we assumed additional transmission infrastructure development in order to focus on the problem of planning a renewable and conventional portfolio for the state that best mitigates the intermittency of wind and solar while meeting an 80% reduction in carbon emissions from the California electric power sector. The project also involved mapping winds offshore of California and examining the feedback of wind turbines to energy in the atmosphere. The power flow study found that, with increased capacity in 31 transmission lines, renewable energy sources could

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										provide at least 70% of California's electricity on a typical summer day in 2016. For reference, this same portfolio would have provided 50% of generation on a typical winter day in 2007 (See Figures 1 and 2). Additional transmission infrastructure upgrades would likely be necessary in order to maintain system stability during extreme meteorological and/or load events.
76	Alberta Electric System Operator Market Services Stakeholder Session AESO Presentation to IRC	AESO Jan 2010				X			X	Overview of current state of wind management issues at AESO (Alberta Electric System Operators). Ramp rate limits: Instantaneous MW can not exceed +5% of the maximum authorized MW and the 1 minute average can not exceed 2% of the maximum authorized MW. New SCADA system signals have the ability to control/curtail wind farm MW output New protocols are being put into place to measure speed, pressure, temperature, direction at various met tower locations. Historical data for up to 2 calendar years in the

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										vicinity of the turbines is required for forecasting purposes. AESO conducted a pilot project in 2006 to compare different forecasting methods/services New Curtailment policies also were put into place
77	Ontario Wind Integration Study Final Report to: Ontario Power Authority (OPA) Independent Electricity System Operator (IESO) Canadian Wind Energy Association (CanWEA)	Devin Van Zandt (GE), Lavelle Freeman (GE), Gao Zhi (GE), Richard Piwko (GE), Gary Jordan (GE), Nicholas Miller (GE), Michael Brower (AWS Truewind) Oct 2006				X	X	X	X	An extensive study was done in 2006 commissioned by the Ontario Power Authority and authored by General Electric and AWS True Wind which examined several scenarios of incremental increases of wind integration as shown below: Scenario, Year, Description, Nameplate as % of Peak Hourly Load, % of Total Yearly Energy 1, 2009 Load plus 1,310MW of planned/existing nameplate wind capacity, 4%, 2% 2, 2020 Load plus 5,000MW of nameplate wind capacity, 17%, 7% 3, 2020 Load plus 6,000MW of nameplate wind capacity, 20%, 8%

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										4, 2020 Load plus 8,000MW of nameplate wind capacity, 27%, 11% 5, 2020 Load plus 10,000MW of nameplate wind capacity, 33%, 13% The study made the following conclusions: 1. The average capacity value of the wind resource in Ontario during the summer (peak load) months is around 17%. The capacity value was in between 38% to 42% during winter months and from 16% to 19% during the summer months. Because 87% of the periods within 10% of the load peak occur during the summer months, the yearly capacity is weighted heavily toward the summer season. The overall yearly capacity value is approximately 20% of total nameplate capacity for all wind penetration scenarios. 2. For each scenario, the incremental regulation needed to maintain current operational performance is small. The study concluded that the increase in regulation is only 11% with 10,000 MW of wind and 4% with 5,000 MW and that this additional regulation could be handled within the current system operational framework. 3. The 10-minute operating reserve requirement is meant

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										to accommodate the loss of a single (large) unit, but not a concurrent large drop in generation and sudden increase in load. Accordingly, the 10-minute wind power variability was analyzed as a requirement for operating reserves. The study indicated that 5,000 MW of wind requires incremental operating reserves that are negligible but at higher wind penetrations, the incremental operating reserve increases becomes significant. Presently, the largest unit exposure on the Ontario bulk power system is 900 MW. For the 6,000 MW and 8,000 MW wind penetration cases, the wind output dropped by more than 900 MW in ten minutes 4 times. With 10,000 MW of wind, the wind output dropped more than 900 MW 10 times. This indicates that an increase in operating reserve requirement is likely to occur due to extreme weather ramping events associated with large wind penetration. 4. In many scenarios, the minimum net-load with wind scenario is significantly less than the minimum load-only scenario (i.e. viewing wind as reduced load). The implications of this are that during low-load periods online generation may have to either curtail wind or reduce other sources of generation. In the latter case however, if the minimum load-with-wind point drops far enough down into

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										the generation stack, then only less responsive generation units may be online to serve and balance load. Also, the response rate of the units balancing the load during these periods is greater. 5. Increased penetrations of wind up to 10,000 MW would not push the hourly (and beyond) variability much beyond the current operating point (i.e. less than the operating limit). However, the number and size of extreme one-hour and multi-hour net-load-with-wind “deltas” increase significantly with high wind penetration. With the addition of 10,000 MW of wind, the maximum one-hour net-load-with-wind upward-delta increases by 34%, and the maximum one-hour net-load-with-wind downward-delta increases by 30%. This data indicates that with large amounts of wind, a significant increase in hourly ramping capability is needed for stable operations. Currently the most sustained ramping (up and down) occurs during the summer morning load rise and evening load decline periods. During these hours, the units might need to continually ramp over three hours or more For the year 2020 load with 10,000 MW of wind scenario, the maximum upward three-hour load-wind delta increases by 17% and the maximum downward three-hour delta increases by

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										33%. 6. The analysis shows that sudden (less than 10-minute) province-wide interruptions of wind generation power output are extremely unlikely and "do not represent a credible planning contingency". When sudden changes in wind output do occur, the study shows that the spatial correlation of wind sites is weak enough to limit the impact of individual site or group changes on the aggregate wind output. Such sudden changes would typically be the result of extreme weather incidents such as windstorms and ice storms, which are often the major sources for wind tower structural integrity damage. Furthermore, the study indicates that storms such as hurricanes, tornadoes and ice storms that can severely damage a wind turbine/farm are not capable of wholesale damage to structures across Ontario within "ten minutes or less" (i.e. such events are unlikely in the extreme).
78	Amendment to Market Rules for Non-Dispatchable Variable Generators	New Brunswick System Operator Market Report Dec 2009	X	X	X	X	X	X	X	An extensive legal memo documenting vital changes to NBSO's most recent policies (as of Dec , 2009) regarding changes in market rules related to VER capacity commitments, forecasting, unit scheduling, data requirements (SCADA), curtailment policies and other related information.

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	Market Rule Amendments for Non-Dispatchable Variable Generator									Important changes regarding VER market regulation policies are: 1. VERs are considered exempt from the requirement (6.10.3) of having to immediately report any issue that would result in them being unable to fulfill a market obligation (vs. non-VER generation). 2. VERs are exempt from the requirements 6.13.3A and 6.13.3B stating that ""Dispatch Instructions continue in effect until superseded by later Dispatch Instructions, by activation of Operating Reserve, or by other direction by the SO. In the event that a Market Participant does not receive a Dispatch Instruction at a time when it reasonably expects to receive such a Dispatch Instruction, it shall promptly contact the SO for clarification"". VER production is beyond the producer's control and so the NBSO has waived this requirement 3. VER generators are exempt from the requirement 6.13.4 stating that "the tolerance band for compliance with energy Dispatch Instructions shall be the greater of +/- 10 MW or 3% of the dispatched output level in the case of a Generation Facility". Again, since VER production is beyond the producer's control the NBSO has waived this

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										requirement 4. VERs are exempt from the requirements 7.6.8 that excludes Non-Dispatchable VERs from the normal way in which re-dispatch costs are calculated. 5. Modification to section 6.4.1 (italicized): “With the exception of Non-Dispatchable Variable Generators, if the Capacity Resource is a Generation Facility within New Brunswick or an External Dispatchable Facility, submit Dispatch Data and ensure that the Capacity Resource is available to synchronize to the SO-controlled Grid and ramp promptly to supply its full Committed Capacity with no more than 12 hours advance notice; Or if the Capacity Resource is a Generation Facility located outside New Brunswick other than an External Dispatchable Facility, ensure that the Capacity Resource is available for scheduling of a firm import to New Brunswick with no more than 12 hours advance notice and otherwise as provided for in this Chapter; Or if the Capacity Resource is a Non-Dispatchable Variable Generator within New Brunswick, ensure that the Capacity Resource is available to synchronize to the SO-controlled Grid and ramp promptly to supply its full Committed Capacity, subject to the limitation of the variable energy

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										input, with no more than 12 hours advance notice". The language was modified to account for the fact that most VERs can not guarantee ramping capabilities within a 12 hour window. 6. Modification to section 6.5.1 for inclusion of power limitations in the balancing schedule where by "The intent of the proposed change is to ensure that the balanced schedule for a Non-Dispatchable Variable Generator would take into consideration the forecast production as well as any known power limitation placed on the facility by the SO. Generally the SO expects that the schedule would reflect the generators forecast production and would also respect any power limitations that are placed on the facilities for the upcoming hour or hours" 7. Additions in section 4 that state that NDV Generators will be required to provide SCADA capability that meets the SO's requirements. SCADA data will include meteorological data and wind farm output however individual turbine unit output is not required (as is the case for conventional generation units). Other SCADA requirements included: a. Responding to MW limits sent by the SO through the SO's SCADA system.

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										b. Holding the MW output to the limit established by the SO subject to the variability of the ambient conditions. c. Voltage control set point. d. Opening the Facility breaker at the point of common coupling. 8. Additions in section 6.7 that state that NBSO must take VER forecast variability into consideration including in the day ahead market for scheduling of conventional units (section 6.8). Dispatch optimization must also take this into consideration (section 6.9). 9. Section 6.10 allows VERs to provide timely (i.e. hourly) forecasts that NBSO uses to update its forecast of VER total production at any time. 10. Section 6.13 ensures that hourly forecasts are incorporated into the normal forecast update process prior to each hour. 11. Section 2 was modified to reinforce the requirement that NBSO have the ability to issue direct control instructions to VER units. This is essentially the ability to set production limits for VER generators in real time via the SO's SCADA system (i.e. curtailment) 12. As a direct consequence of the requirement that NBSO have the ability to issue direct control instructions,

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										VER generators must have the following SCADA system features: a. Ability to respond to MW limits sent by the SO through the SO's. b. Ability to hold the MW output to the limit established by the SO subject to the variability of the ambient conditions voltage control set point. c. Ability to open the Facility breaker at the point of common coupling 13. Section 6.11.1 and 6.17.1state that the NBSO has the authority to curtail VER production during periods of energy surplus. 14. Section 6.14 states that NBSO's SCADA system can send direct control signals. 15. Section 5.3.1 states that NBSO will make public their conventional, demand and VER forecasts available to all market participants. The time frames include daily for 5 days ahead (hourly), weekly for 28 days ahead (hourly), quarterly for 18 months (weekly), annually for 10 years (monthly). Section 6.7.7 indicates that potential curtailment information will also be provided by the SO as part of day-ahead or longer forecasts. 16. Section 5.4.15 modifies the capacity obligations for

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										VERs such that there is an allowance for month-by-month variability in their committed capacity which is typical for wind and solar generation. On a month-by-month basis a VER market participant may, before the start of the given month and within the capability period, increase, reduce or eliminate the capacity obligation for a VER. 17. Section 6.5.4 removes negative pricing bids for VERs during curtailment periods. It also ensures that the bid price for non-dispatchable units is set at zero where as non-dispatchable units must bid at a higher price. This ensures that non-dispatchable VER generation will be scheduled prior to dispatchable, conventional generation.
79	Market & Operational Framework For Wind Integration in Alberta AESO Recommendation Paper, September 2007	AESO 9/1/2007	X			X	X		X	Alberta has large wind resources with currently an excess of 500 MW of wind integrated into the grid and a strong interest in pursuing greater levels of wind penetration. AESO has recently undertaken a grid integration study and published two recommendation papers from the findings of the study in September 2007 and March 2009 titled “Market & Operational Framework for Wind Integration in Alberta" and (similarly) “Implementation of Market & Operational Framework for Wind Integration in Alberta”.

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										The papers claim that Alberta has adopted a leadership position in wind power development in Canada and has participated in cutting edge wind integration studies. The large size and generation mix of Alberta's electricity market and relatively small interconnection capability means Alberta has a limited ability to 'share' or dampen the wind power variability in the near term. According to the papers, AESO produced some of the first interconnection standards for wind in North America having delivered several cutting edge wind integration standards. They also launched a wind power forecasting project and created the "Market and Operational Framework" (MOF) for wind integration in Alberta in September of 2007. The purpose of the MOF is to ensure that if the AESO has access to an accurate (within some reasonable deviation) forecast of wind power, they can create operational plans using the following strategies: 1. Energy Market Merit Order (EMMO), 2. Regulating Reserves 3. Load/Supply Following Services and 4. Wind Power Management (WPM). The Energy Market Merit Order is described in the first

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										paper: "The Energy Market Merit Order (EMMO) is the primary mechanism by which the relative economic merit of supply offers are evaluated and dispatched to meet load requirements. With implementation of the Must Offer Must Comply rules, offers contained within the EMMO are price and volume certain two hours prior to the start of the delivery hour, which is referred to as T-2. At T-2, the ramping capability of the EMMO is also known. The EMMO can be dispatched by the system operator as often as is necessary in combination with the regulating reserves … to maintain supply demand balance." The wind integration study also indicated that adding more Regulating Reserve could help resolve smaller wind events. At AESO, Regulating Reserves are fast-response resources that are used in real time to maintain supply demand balance within the 20 minute timeframe. They are controlled directly by the Automatic Generation Control system (AGC). They must also be able to ramp to regulation range within 10 minutes. The study found that regulating reserves are the primary mechanism for load balancing of wind integration in the 10-min time frame.

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										The study of wind integration found that the 20 minute variability of net load of demand plus wind increased marginally over load-only profiles with increasing wind penetration suggesting that it could be reasonably managed with small increases in regulating reserves. The larger risk however comes from wind ramping events that come in the 20 minute to several hours time range. Load supply/following is similar to regulating reserves but is slower to respond and is generally used for the 20 minutes to hourly time frame and plays a large role when wind is ramping in the opposite direction of load. The phase II study also found that Regulating Reserve may need to be complimented with additional Load Following services for larger wind penetration scenarios. There may be scenarios however when the Energy Merit Market Order, Regulating Reserve, and Load Following do not allow the system to absorb all the available wind power and therefore wind power output must be curtailed. AESO is enforcing new standards of Wind Power Management where by wind power may be curtailed based on a number of possible scenarios including:

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										1. Forecast loss of wind with insufficient ancillary and/or ramping services. 2. Wind supply surplus conditions. 3. Insufficient ancillary services due to market conditions or emergency conditions. 4. Large unforeseen wind gusts. 5. Islanding conditions.
80	Implementation of Market & Operational Framework For Wind Integration in Alberta AESO Recommendation Paper, March 2010	AESO 3/1/2010	X			X	X		X	(same as #79)
81	Wind Integration: Preliminary Near Term Operational and Market Impact Studies Results	AESO 3/1/2010				X	X		X	a presentation by AESO for IRC was given on March of 2010 regarding the study (i.e. recommendation papers) and the market impact of wind integration in Alberta's grid operations. AESO indicated that if Energy Market Merit Order is

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	Alberta Electric System Operator Presentation to IRC									modified to be optimized with respect to ramp rate there will be an increase in price volatility. This is due to the fact that units would be dispatched more frequently but for shorter durations. More specifically units will be given preferential order based on their ramping ability rather than capacity, thus driving up price during up-ramps. During down-ramp events the price of energy will drop until it reaches 0$ per MWh which results in a curtailment signal and should also result in some self-mitigation by wind producers since they are price takers in the market. AESO suggested that if ancillary services are used instead there is less of an effect on price volatility. The presentation went on to suggest that larger penetrations of wind into the AESO grid would result in the increased possibility of supply surplus events (i.e. curtailment): • In the most extreme cases experiences by AESO in 2008,150 MW of over-supply was observed above min-by-min stability levels. • AESO expects that participants could manage $0 offers during periods of extreme surplus of energy to self-mitigate most of these events assuming they had the right signals (presumably SCADA based). • Without mitigation measures AESO anticipates increased

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										area control errors. Some mitigation strategies they suggested were: o Provide a wider range of regulating reserves in all hours o "Over-dispatching" the market merit order to create the maximum possible ramp rate. o Wind power management (which presumably implies curtailment policies and signaling events). • They went on to suggest that accurate wind power forecasting tools would be required to manage this complexity.
82	Generation Adequacy Assessment for Power Systems with Wind Turbine and Energy Storage IEEE 978-1-4244-6266-7/10	Ruimin Zheng, and Jin Zhong University of Hong Kong						X	X	Wind power has been considered as an environmental friendly electrical generation resource; however, the high wind power penetration can lead to high-risk levels in power system reliability. Energy storage system (ESS) is a promising means to smooth variations of wind power and improve the system reliability. Simulation models for assessing generation adequacies of power systems with wind power generation system (WPGS) and ESS are presented in this paper. The impacts of different wind power penetration levels on the reliability benefits from ESS are analyzed in the first case-study, when the WPGS is utilized to replace the conventional generators with same total rated power capacity. In the second case-

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										study, the WPGS and ESS are installed to meet the annual growth of load demand and maintain the generation adequacy levels. The Monte Carlo simulation is used to simulate the operation of generating units and ESS, considering the force outage rates (FOR) of generators and random fluctuations of wind speeds.
83	Optimal Placement of Hybrid PV-Wind Systems Using Genetic Algorithm IEEE 978-1-4244-6266-7/10	Mohammad A.S. Masoum Curtin University of Technology Seyed M. Mousavi Badejani and Mohsen Kalantar Iran University of Science and Technology Tehran, Iran							X	Genetic algorithms are proposed for optimal placement of hybrid PV-wind system (HPWS) and for determining the optimal ratio of wind/solar power contributions. The total capacity of HPWS is determined based on estimated annual power demand, average wind speed and sun radiation. Each PV and wind unit is defined based on real environmental conditions. To improve HPWS performance under different operating and environmental conditions, maximum power point tracking of PV units and blade angle pitch control of wind turbines are considered. For each candidate location, cost functions corresponding to PV, wind and battery units, as well as surplus produced power are defined and genetically minimized to determine the best location of HPWS. The proposed algorithm is used for optimal placement of a 1MVA hybrid PV-wind system in United States (considering 265 candidate locations) and to compute the optimal number of 40kW-PV

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										and 68.46kW-wind units.
84	Asymmetric Reserve Power Delivered by Large Wind Power Plants IEEE 978-1-4244-6266-7/10	Kristof De Vos, Simon De Rijcke and Johan Driesen ELECTA of the department electrical engineering of the K.U.Leuven (ESAT) Belgium					X			A stable and secure operation of the electricity grid is mainly achieved by contracting power generators to ancillary services in addition to their main commercial product, active power. Electricity from Renewable Energy Sources (RES-e) is today generally exempted from the participation in ancillary services. However, the increasing share integration of variable RES-e with a limited predictability has an impact on the demand and supply structure of these services. In this paper, the possibility of wind power participating in frequency control or delivering active power reserves as an ancillary service is investigated. Within this framework, technical, regulatory and economic aspects are examined and evaluated. As the specific details about the way ancillary services are contracted differ over Europe, a case study is done for the Belgian control zone. The consequence of offering an asymmetric reserve power, with only downward regulation,

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										is economically assessed.