Wind Integration Cost Calculation Variations And Other Regulatory Challenges

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About the Author

Rishi Garg joined the National Regulatory Research Institute in October 2012. He began his career as an attorney for the State of Illinois, serving as Policy Advisor to the Illinois Lieutenant Governor and then as Assistant Attorney General in the Public Utilities Bureau of the Illinois Office of the Attorney General. He later worked for the Natural Resources Defense Council's Project for a Sustainable Federal Energy Regulatory Commission Policy. Prior to joining NRRI, he was Assistant People's Counsel in the District of Columbia's Office of the People's Counsel. During his career, he has been involved in various energy-related stakeholder processes and submitted oral and written testimony before regulatory and legislative boards. Rishi received his BA from the University of Illinois and his JD from the University of Minnesota Law School. He is admitted to the bar in the State of Illinois and the District of Columbia.

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Executive Summary

This paper explores three interrelated regulatory matters related to the process of determining wind generation integration costs. First, this paper summarizes the new requirements placed upon public utility transmission providers by the Federal Energy Regulatory Commission (FERC) in Orders 764 and 764-A, "Integration of Variable Energy Resources." Second, the paper catalogues methodologies and cost figures determined from various state regulatory, public utility and federal processes that examine wind integration costs. Third, the paper takes a closer look at some of the current wind integration and related regulatory challenges faced by the Bonneville Power Administration (BPA).

Regarding FERC's Order 764 and 764-A reforms, this paper summarizes:

(1) the requirement to offer intra-hourly transmission scheduling to transmission customers at 15-minute intervals;
(2) the requirement that Variable Energy Resources (VER) interconnection customers provide meteorological and forced outage data for the purpose of power production forecasting; and,
(3) the guidance on development and evaluation of proposals to recover the costs of regulation reserves associated with VER integration.

The section concludes that FERC's approach to regulatory reform attempts to balance the need to accommodate new technologies with the recognition that transmission providers should receive full compensation for the transmission services provided. The section recommends that state regulatory commissions consider whether additional regulatory reforms, such as those discussed in FERC's Notice of Inquiry ("Integration of Variable Energy Resources," 130 FERC ¶61,053, January 21, 2010), could help further determine more accurate costs of integrating VERs into grid systems and whether to encourage the FERC to standardize such reforms in a formal rulemaking.

Regarding wind integration cost methodologies and figures, this paper reviews literature on wind integration cost drivers, summarizes wind integration cost calculation processes within six western U.S. service territories, and briefly describes wind integration cost treatment within organized wholesale electric markets and potential adoption of a western-region energy imbalance market (EIM). It concludes, in agreement with current literature, that variations in definitions, cost models, and the unique generation, transmission, and market circumstances of each service territory make meaningful integration cost study comparisons difficult.

The section recommends a more comprehensive study that examines the various cost models used in determining integration cost figures with the purpose of extracting metrics that lend themselves to meaningful comparisons across states, regions and service territories. The purpose of such a study would be to identify standards that could provide state regulatory authorities with a basis to evaluate wind integration cost figures that are placed before them for approval. Finally, the study would require collaboration among state commissions, generation companies, and public utilities and could result in state commission access to proprietary modeling software and training on interpreting their results.

Regarding current regulatory challenges facing BPA, this paper discusses (1) the complex procedural history that encompass a petition, filed by a coalition of wind generators and accepted by FERC, to declare certain wind-related management protocols in violation of the Federal Power Act (FPA); (2) attempts by BPA to reform curtailment protocols to achieve FPA compliance; and (3) BPA's petition requesting FERC Order 888 reciprocity status. The section concludes that the resolution of the various petitions currently before FERC and the 9th Circuit Court of Appeals will require balancing FPA requirements with federal Clean Water Act and other environmental mandates that BPA is subject to. Such a process could test the limits of FERC comparability principles if their adherence results in violations of environmental mandates. On the other hand, achievement of this balance could serve as a demonstration to the energy industry and regulatory community nationally of how a balancing authority (BA)[1] can design its tariffs to demonstrate reliable transmission services in an environmentally friendly manner, while adhering to FERC's comparability principles by providing transmission service in a manner that is not unduly discriminatory or preferential.

[1] A balancing authority is a responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time. A balancing authority area ("BAA") is the collection of generation, transmission, and loads within the metered boundaries of a balancing authority, which maintains load-resource balance within this area. See Energy & Environmental Economics (E3). (March 13, 2013). *PacifiCorp-ISO Energy Imbalance Market Benefits,* a Report for PacifiCorp and the California Independent System Operator, p. 5, fn. 1.

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I. Introduction

Wind integration cost calculation processes are as varied as the regions that have undertaken those calculations. The determination of wind integration costs is less concerned with the cost of the wind commodity than the costs of the various ancillary services required to accommodate wind resources.[2] Ancillary services are those services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of a balancing authority's transmission system in accordance with good utility practice.[3]

Ancillary services used to respond to generator variability are generally categorized as follows:

- Regulation generally deals with the random, minute-to-minute variability of loads and generation.
- Load-following typically deals with slower trends that extend from minutes to hours.
- Contingency reserves often encompass a series of reserves that must be maintained to provide fast and sustained response to a system emergency. This may include spinning, non-spinning, and supplemental reserves; ranging from seconds to hours.
- Unit commitment is the longer-term, often day-ahead process, the balancing authorities use to schedule generators based on forecasts of expected load and variable generation.[4]

Each ancillary service deployed by a transmission provider in response to the variability of transmission customers incurs real costs to the grid system.[5] Modeling these costs, their

[2] However, one NREL study indicates that based on the manner in which most current studies are conducted, a significant energy value component is often unintentionally imbedded into wind integration cost calculations. See Milligan, Michael and Brendan Kirby. (2009). *Calculating Wind Integration Costs: Separating Wind Energy Value from Integration Cost Impacts*, National Renewable Energy Laboratory, at 8 (2009 NREL Report).

[3] See Porter, K. S., Fink and B.M. Hodge, et al. (March 2013). *A Review of Variable Generation Integration Charges*, Exeter Associates and National Renewable Energy Laboratory at 5 (2013 NREL Report). (Citing North American Electric Reliability Corporation. (2012). *Glossary of Terms Used in NERC Reliability Standards*. www.nerc.com/files/Glossary_of_Terms.pdf.)

[4] See Milligan, Michael, Erik Ela, Bri-Mathias Hodge, et al. (2011). *Cost-Causation and Integration Cost Analysis for Variable Generation*, National Renewable Energy Laboratory.

[5] While the subject of this paper is wind integration costs, it is important to keep in mind that all transmission customers can cause system variability. See Vancko, Ellen, "The Great India Blackout – Could it Happen Here?," *ElectricityPolicy.com*, (stating that variability is not unique to renewable resources and must be properly managed to account for the unique characteristics of all generation types.) See also Regulatory Assistance Project. (2012). *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge*, a Report for the Western Governors' Association at 4. (2012 WGA Report) ("Integration is not an issue that is unique to renewable resources; conventional forms of generation also impose integration costs.") FERC's proposed definition of VER in the Order 764

proper allocation and methods to reduce them have all been the subjects of numerous regulatory proceedings, particularly as Variable Energy Resources ("VERs")[6] have claimed an increasing proportion of the transmission system. One result of such diverse proceedings is that a consistent, broadly applicable definition of "integration cost," as it pertains to VERs, is lacking. Rather, the unique characteristics of each service territory—its available generation and transmission resources, market characteristics, and many other factors combine to affect the location-specific costs of integrating VERs in any particular locality or region.

This contention is supported by a March 2013 report by the National Renewable Energy Laboratory (2013 NREL Report) which found significant differences in how VER integration studies are prepared in support of variable generation integration charges, including study methodology, assumptions, reserve definitions, and the data that is collected and utilized.[7] NREL noted that studies of VER integration charges "are at an early stage and *are more art than science*, as is often the case in electric utility ratemaking and its regulation."[8] Further, the report stated that the difficulty in calculating or measuring VER integration costs in a meaningful way arises because of challenges in defining what to compare and the complexity of the multiple interactions between generation resources as their output is varied to maintain reliability.[9]

Examples of definitional differences across utility service territories abound. For example, one utility used the term "Incremental Reserve Requirements" to indicate the need for additional reserves to maintain system reliability and security due to the variable output of wind generation; and the term "Imbalance Costs" to refer to the additional operating costs incurred due to the variable output of wind generation which may accrue from additional unit startups, incremental market interactions, operating thermal and hydro units off optimal levels, and forecast errors.[10]

Various authors of academic literature have defined "integration costs" differently. Examples include:

- an increase in power system operating costs (Milligan & Kirby 2009);
- the extra investment and operational cost of the non-wind part of the power system when wind power is integrated (Holttinen et al. 2011);

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proceedings, limiting the term to renewable resources, received scrutiny and is addressed in the body of this paper.

6 Importantly, this paper uses the term VER, which is defined more broadly than wind, in order to match the terminology used in much of the literature reviewed, as well as to match the terminology of the FERC's VER Orders. However, *this paper focuses predominantly on wind,* and references to VERs in this paper can be interpreted as such.

7 See Porter, *2013 NREL Report*, p. 6.

8 Ibid. (Emphasis added).

9 Ibid., p. 7.

10 See Coatney, Tom. (2003). "Modeling Wind Energy Integration Costs," Presentation by PacifiCorp to the Utility Wind Integration Group ("UWIG") Technical Wind Workshop, slide 5.

- comprising variability costs and uncertainty costs (Katzenstein &Apt 2012); and
- the marginal cost increase in the residual power system caused by VERs (Ueckerdt et al. 2012);[11]

An Electric Power Research Institute (EPRI) report characterized the cost to provide system flexibility to integrate wind resources as the additional costs induced by balancing the variability and uncertainty of wind, and is a function of the existing power system, plus any new investment required.[12]

One study defined the costs of variability as the combination of:

- Profile Costs – costs that occur because wind and solar do not generate electricity constantly;
- Balancing Costs – costs that arise because there are day-ahead forecast errors of VER generation; and
- Grid-Related Costs – costs that occur if VER capacity is located more distant from or closer to loads than an average conventional plant.[13]

Thus, wind integration costs can be characterized in numerous distinct ways and are often based upon local and regional factors that in many respects do not translate outside of the service territory. With this limitation in mind, this paper examines three interrelated regulatory topics that concern wind integration cost determinations, for the purpose of informing state regulatory commissions about improvements to the regulatory landscape as well as persistent challenges.

First, this paper summarizes the reforms promulgated by the FERC concerning grid integration of VERs in FERC Orders 764 and 764-A ("the VER Orders) issued June 22, 2012 and December 20, 2012, respectively. Second, the paper discusses six wind integration cost calculation proceedings undertaken by state and regional authorities in the West, comments briefly on corresponding practices within organized markets and notes consideration of a Western-region EIM. Third, the paper takes a closer look at concerns and challenges in the BPA service territory, both with respect to the FERC VER Order reforms and related jurisdictional and reliability matters. The paper concludes by offering guidance on what data the three items discussed, when taken together, can best offer state regulatory commissions.

Section II of this paper provides a brief overview of current wind penetration trends. **Section III** offers a summary of the VER Orders by discussing new requirements that they place

[11] See Hirth, Lion. (2012). *Integration Costs and the Value of Wind Power*, p. 3.

[12] See Electric Power Research Institute. (2011). *Impacts of Wind Generation* Integration, p.2. (EPRI Report).

[13] See Hirth, *Integration Costs*, p. 4. The author uses the term "variable renewable energy source ("vRES") but we have substituted the term VER to maintain internal consistency in this paper.

upon jurisdictional public utility transmission providers ("TPs").[14] **Section IV** examines recent processes that have taken place in six Western territories and catalogues the methods used to calculate wind integration costs. **Section V** provides a closer look at concerns and challenges faced by BPA including challenges to the VER Orders and additional regulatory matters that pertain to the region's integration of wind generation. Finally, **Section VI** concludes with recommendations for state regulatory commissions to consider when confronting wind integration cost and regulatory challenges.

The paper also includes four appendices:

- Appendix A provides definitions of certain ancillary services;
- Appendix B lists the state public utility commissions that intervened and filed comments at FERC in the Order 764 proceedings;
- Appendix C, by Dan Phelan, Research Assistant at NRRI, offers a discussion of current national and international wind cost and penetration trends; and
- Appendix D reproduces tables from utility wind integration studies for use as a reference to Section IV of this paper.

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[14] Though not all transmission providers are FERC-jurisdictional, the term "TP" is used throughout this paper to refer to FERC-jurisdictional public utility transmission providers. References to non FERC-jurisdictional entities, such as the Bonneville Power Administration, will be duly noted where made.

II. Trends in Wind Integration

A clear upward trend in wind penetration nationally is evidenced by the fact that new wind generating capacity accounted for 35% of all newly installed generating capacity from 2007-2010.[15] As of December 2011, nearly 12,000 MW of additional wind generating capacity had been brought online and another 8,320 MW of wind generating capacity was under construction.[16] The Energy Information Agency has forecasted that generation from wind power will nearly double between 2009 and 2035.[17] Further, the U.S. added 10,689 MW of wind power in 2012, more than any other energy resource.[18]

This recent and projected growth in wind power penetration is being facilitated in part by state and federal policies designed to encourage the expansion of VER generation.[19] As of May 2011, 30 states and the District of Columbia had in place a renewable portfolio standard (RPS) or goal.[20] In addition, the existing federal production tax credit (PTC) provides an inflation-adjusted credit for power produced from VERs and other renewable resources.[21] The PTC has provided a 10-year 2.1 cent/kWh credit (adjusted annually by the rate of inflation) for each kWh of electricity supplied by a qualifying renewable energy plant.[22] Other federal policies, including an investment tax credit, accelerated depreciation of certain renewable energy generation facilities, and loan guarantee programs, provide additional incentives to renewable generation facilities.[23]

A broader discussion of current trends in wind costs, viability, and penetration levels is provided in Appendix C to this paper. Driven in part by state and federal policies and, at an

[15] *Integration of Variable Energy Resources*, FERC Order 764, 139 FERC ¶61,246 (June 22, 2012) (FERC Order 764), ¶19. (Citing American Wind Energy Association ("AWEA"), *Wind Power Outlook 2011* (Apr. 2011)).

[16] Ibid., fn. 28 (Citing AWEA, *U.S. Wind Industry Fourth Quarter 2011 Market Report* (Jan. 2012)).

[17] Ibid. (Citing Annual Energy Outlook at 75, *available at* http://www.eia.gov/forecasts/archive/aeo11/pdf/0383(2011).pdf).

[18] See FERC Office of Energy Products. (2012). *Energy Infrastructure Update for December 2012.* (Available at: http://www.ferc.gov/legal/staff-reports/dec-2012-energy-infrastructure.pdf.)

[19] See FERC Order 764, fn. 28.

[20] Ibid., fn. 30. (Citing FERC, Div. of Energy Market Oversight, *Renewable Power and Energy Efficiency Market: Renewable Portfolio Standards* 1 (updated May 2011), *available at* http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-rps.pdf).

[21] Ibid. (Citing *Electricity Produced from Certain Renewable Resources*, 26 U.S.C. 45 (2007)).

[22] Joskow, Paul L. (2011). *Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies*. Alfred P. Sloan Foundation and MIT, Discussion Draft, fn. 7.

[23] See FERC Order 764, fn. 30.

increasing rate, by economic parity,[24] upward trends in wind resource integration have prompted FERC to undertake a series of transmission reforms, which are examined in the next section.

[24] As there is no fuel costs associated with wind, the price of wind power, excluding integration costs, is largely driven by turbine costs. Between 2003 and 2008, the cost of installing a wind turbine steadily increased to roughly $1,500/kW. Today, turbines are from a fifth to a third less expensive than they were at their height in 2008, but the cost of wind energy still reflects those higher-priced turbines. Still, wind power cost is approaching parity with the electric wholesale rate. Nationally, the lowest cost wind projects compete with wholesale rate electricity, but higher cost projects do not. See generally, Bolinger, M., & Wiser, R. (2011). *Understanding Trends in Wind Turbine Prices Over the Past Decade,* Lawrence Berkeley National Laboratory. Available at http://eetd.lbl.gov/ea/ems/reports/lbnl-5119e.pdf. See also Appendix C to this paper.

III. Background and Overview of the FERC VER Orders

In1996, FERC issued Order No. 888, which required all public utility TPs that own, control, or operate transmission facilities used in interstate commerce to have on file an open access, nondiscriminatory transmission tariff that contains minimum terms and conditions of nondiscriminatory service. The FERC also issued a *pro forma* Open Access Transmission Tariff (OATT) containing terms for scheduling transmission service and the provision of ancillary services.[25]

In issuing Order 764, "Integration of Variable Energy Resources," FERC concluded that reforms to current TP OATTS were required to ensure that transmission customers, particularly those who own VER generation, are not exposed to excessive or unduly discriminatory charges, and that TPs have the information needed to efficiently manage ancillary services costs.[26]

The VER Orders require each TP to (1) amend their OATTs to offer intra-hourly transmission scheduling to transmission customers at 15-minute intervals;[27] and (2) incorporate provisions into the *pro forma* Large Generator Interconnection Agreement ("LGIA")[28] requiring VER interconnection customers to provide meteorological and forced outage data to the TP for the purpose of power production forecasting. In addition, FERC provided guidance to TPs regarding the development and evaluation of proposals related to recovering the costs of regulation reserves associated with VER integration.[29]

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[25] See *Integration of Variable Energy Resources Notice of Proposed Rulemaking* (VER Integration NOPR), FERC Stats. & Regs. ¶ 32,664 (2010), ¶6. (Citing *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC Order No. 888, FERC Stats. & Regs. ¶ 31,036, at ¶31,682 (1996). (FERC Order 888). From time to time, FERC has undertaken rulemakings to reform its *pro forma* OATT. See http://www.ferc.gov/industries/electric/indus-act/oatt-reform/history.asp.

[26] See FERC Order 764, ¶1.

[27] Economic dispatch is the process of maximizing the output of the least-cost generating units in response to changing loads. Scheduling is the advance scheduling of injections of energy on the transmission grid. Sub-hourly dispatch refers to changing generator outputs at intervals less than an hour and intra-hour scheduling refers to changing transmission schedules at intervals less than an hour. Regulatory Assistance Project, *2012 WGA Report*, p.4.

[28] In FERC Order No. 2003 (2003), the FERC issued a single set of procedures—the Large Generator Interconnection Procedures ("LGIP")—and a single, uniformly applicable interconnection agreement - the Large Generator Interconnection Agreement ("LGIA")—for the interconnection of generation resources greater than 20 MW. See VER Integration NOPR at ¶7. In Order No. 2003-A (2004), the Commission explained that the interconnection requirements adopted in Order No. 2003 were based on the needs of traditional synchronous generators and that a different approach may be appropriate for generators relying on "newer technology." FERC thus exempted wind from certain requirements of the LGIA and, in Orders 661 and 661-A (2005), adopted a package of interconnection standards applicable to large wind generators for inclusion in Appendix G of the LGIA. See FERC Order 764, ¶8.

[29] See FERC Order 764, ¶¶'s 2-5.

The notion that hourly scheduling could cause a transmission customer to deliver more or less energy than scheduled, and in turn, could subject that customer to unjust and unreasonable imbalance penalties, reflects an important recognition by FERC that current transmission practices are out-dated and were developed at a time when virtually all generation on the system could be scheduled with relative precision.[30] FERC also considered it problematic that increasing VER penetration had prompted system operators to rely more on ancillary services, such as regulation reserves, to balance the variation in energy output from VERs.[31]

Taken together, these reforms indicate that FERC recognized while more ancillary services are required to accommodate increased wind penetration, regulatory reforms, rather than generator penalties, are an appropriate avenue to adapt to the new, VER-infused marketplace. In fact, FERC indicates that the Order 764 rules seek to reform operational protocols that present barriers to the integration of VERs and ensure that the cost of integrating new resources is not unnecessarily inflated by inappropriate systems and processes.[32]

A. Intra-hour scheduling reform[33]

FERC defined six ancillary services in Order No. 888:

(1) scheduling, system control and dispatch;

(2) reactive supply and voltage control from generation service;

(3) regulation and frequency response service;

(4) energy imbalance service;

(5) operating reserve – synchronized reserve service; and,

(6) operating reserve – supplemental reserve service.[34]

In addition, FERC adopted two *pro forma* OATT revisions in Order 890 (2007) - revised Schedule 4 for energy imbalances and new Schedule 9 for generator imbalances. FERC found that imbalance charges should provide appropriate incentives to keep schedules accurate without being excessive, and that consistency in imbalance charges, both between and among energy and

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30 Ibid.

31 *Integration of Variable Energy Resources Notice of Inquiry* (VER Integration NOI), 130 FERC ¶ 61,053 (2010), ¶18.

32 See VER Integration NOPR, ¶23.

33 There was notable debate on a number of issues related to the move to 15-minute schedules, including intentional schedule deviations, the adoption of consistent scheduling intervals, and others. This paper does not discuss proposals not ultimately adopted in the final rule. It provides a broad summary of the intra-hour scheduling rule without addressing each stakeholder proposal such as a review of NERC reliability standards and NAESB business practices or other issues such as high voltage direct current (HVDC) transmission lines, dynamic scheduling, and the geographic location of resources used to provide reserves. For a discussion of these matters, please see Order 764, ¶¶'s 146-153.

34 See FERC Order 888, ¶31,682.

generator imbalances, is preferable to the wide variety of imbalance provisions in place at the time. Further, FERC noted that all imbalances have the same net effect on the transmission system in that they require other generation to be ramped up or down to compensate for the imbalance.[35]

Schedule 3 of the *pro forma* OATT governs Regulation and Frequency Response Service and states that these services are necessary to provide for the continuous balancing of resources (generation and interchange[36]) with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load.[37]

In order to provide transmission customers the ability to mitigate Schedule 9 generator imbalance charges in situations when the transmission customer knows or believes that generation output will change within the hour, FERC adopted the intra-hour scheduling rule, enabling all transmission customers to submit transmission schedules at 15-minute intervals.[38]

Intra-hour scheduling is designed to reflect the variability of output in generation, more accurate power production forecasts, and other changes in load profiles and system conditions.[39] By moving from hourly to 15-minute scheduling intervals, the amount of imbalance energy for which the source balancing authority is potentially responsible can be reduced, leading to a corresponding reduction in the amount of capacity held to provide that energy and, in turn, lower reserve-related costs for the source balancing authority and ultimately consumers.[40] As an example, BPA has reduced its balancing reserves by 34% by moving from 60-minute to 30-minute schedules.[41]

This new rule should allow TPs, over time, to use fewer reserves to maintain overall system balance thereby purportedly reducing costs.[42] Reducing the amount of imbalance energy for which a balancing authority is potentially responsible and, in turn, lowering reserve-related costs could reduce regulation charges under Schedule 3 and imbalance changes under Schedule 4

[35] See *Preventing Undue Discrimination and Preference in Transmission Service*, (FERC Order 890), Consolidated Docket Nos. RM05-17-000 and RM05-25-000 (February 16, 2007), ¶72.

[36] Interchange refers to energy transfers that cross Balancing Authority boundaries.

[37] See Schedule 3 of *pro forma* OATT (Original Sheet No. 131).

[38] See FERC Order 764, ¶97.

[39] Ibid., ¶92.

[40] Ibid., ¶96.

[41] See Olsen, David. (2012). “Integrating Wind and Solar in the Western US,” Presentation for Energy Central Webcast, *Integrating Renewables into the Grid*, November 28, 2012, slide 9.

[42] See FERC Order 764, ¶95.

of the *pro forma* OATT.[43] *Over time, FERC envisions that implementation of intra-hour scheduling will allow TPs to rely more on planned scheduling and dispatch procedures, and less on reserves, to maintain overall system balance*.[44] This notion reflects a policy to balance the system by taking advantage of opportunities to increase system flexibility rather than an exclusively requiring the expenditure of large quantities of expensive resources to firm VERs.[45]

FERC acknowledged that implementation of intra-hour scheduling can result in a shift of responsibility for holding certain reserves from the source balancing authority to the sink authority for export transactions and recognized that scheduling at shorter intervals may result in the purchaser of energy having to manage more frequent changes in scheduled deliveries when compared to scheduling at hourly intervals.[46] In other words, under the new rule, the source BA would deliver generation to the sink BA at more frequent intervals requiring the sink to respond to generation injections more often and by potentially procuring additional reserves. However, FERC determined that this is an appropriate division of responsibility as within the hour, the source balancing authority will retain its responsibility of providing the energy needed for the VER to meet its schedule, while the purchaser (or sink) will take on the responsibility of managing more frequent deliveries of scheduled energy.[47]

In noting the broad applicability of the new scheduling rule, FERC stated that *every transmission customer* will have the ability to adjust its schedule at 15-minute intervals to reflect changing conditions including transmission customers that experience a within-hour forced outage or transmission customers taking delivery from energy constrained resources such as flow-limited hydro-electric generators, emission-limited thermal generators, and energy storage resources.[48]

Importantly, FERC affirmed the ability of TPs to submit alternative proposals that are consistent with or superior to the intra-hour scheduling requirements and required that TPs demonstrate on compliance how its proposal provides equivalent or greater opportunities for transmission customers to mitigate Schedule 9 generator imbalance charges, and for the TP to lower its reserve-related costs when compared to implementation of the intra-hour scheduling requirements.[49]

[43] See *Order on Rehearing and Clarification and Granting Motion for Extension of Time*, (Order 764-A), 141 FERC ¶ 61,232, December 20, 2012, ¶26.

[44] See FERC Order 764, ¶22. FERC affirmed that a variety of ancillary service costs could be avoided by the shift to intra-hour scheduling including reduced regulation charges under Schedule 3, imbalance charges under Schedule 4 and "any other ancillary service schedule" through which the TP recovers costs of capacity needed to provide generator imbalance service. See Order 764-A, ¶26.

[45] Olsen, *Integrating Wind*, slide 17.

[46] See FERC Order 764, ¶99.

[47] Ibid.

[48] Ibid., ¶94. FERC noted the example of Entergy who voluntarily adopted intra-hour transmission scheduling without the presence of substantial VERs in an effort to manage fluctuations in output from qualifying facilities on its system. Ibid.

[49] Ibid., ¶107.

Finally, the Commission retained a 20-minute prior notification requirement which is the time period needed by TPs to adequately evaluate, approve and implement transmission schedules, [50] and affirmed a TP's ability to recover any costs reasonably incurred to implement the intra-hour scheduling reforms.[51]

B. Data and forecasting reform[52]

FERC stated that VER power production forecasts are essential in managing the variability of VERs and that the use of these forecasting methodologies enhances economic efficiency and allows TPs to manage the operational affects of VERs on their transmission systems.[53] Detailed and timely power production forecasts are critical to reducing uncertainty regarding the expected level of VER power output at various points in time. By reducing uncertainty, power production forecasts give TPs an improved situational awareness of their transmission systems. These power production forecasting tools also provide TPs with the advanced knowledge of system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than managing the variability through the deployment of reserve services, such as regulation reserves.[54]

The accuracy of wind power forecasts is directly connected to the amount of balancing energy needed and hence the cost of wind power integration. Industry studies demonstrate the potential for significant benefits from the incorporation of power production forecasts into scheduling and unit commitment processes.[55] In WECC alone, NREL estimated the use of VER power production forecasts has the potential to reduce operating costs by up to 14% or $5 billion per year.[56] NERC has concluded that forecasting the output of variable generation is critical to bulk power system reliability in order to ensure that adequate resources are available for ancillary services and ramping requirements.[57]

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[50] Ibid., ¶118 and *pro forma* OATT §§ 13.8 and 14.6.

[51] Cost recovery is set pursuant to Schedule 1 of the TP's OATT which governs scheduling, system control and dispatch service. See *pro forma* OATT Original Sheet 132.

[52] This subsection addresses the forecasting and data-sharing reform broadly and does not address each additional proposed reform to the LGIA or Small Generator Interconnection Agreement ("SGIA").

[53] See VER Integration NOPR, ¶45. (citing NERC. 2010. Integration of Variable Generation Task Force, *Task 2.1 Report: Variable Generation Power Forecasting for Operations*, p. 5, *available at* http://www.nerc.com/docs/pc/ivgtf/Task2-1(5.20).pdf.

[54] Ibid.

[55] Ibid.

[56] See FERC Order 764, ¶172, (citing National Renewable Energy Laboratory, *Western Wind and Solar Integration Study* ES-18 (2010), *available at* http://www.nrel.gov/wind/systemsintegration/wwsis.html).

[57] Ibid., (citing NERC, *Accommodating High Levels of Variable Generation*, p. 54 (2009), *available at* http://www.nerc.com/files/IVGTF_Report_041609.pdf.)

FERC found that power production forecasting can be used by TPs to operate their systems and manage reserves more efficiently, and directed *new* VER interconnection customers to provide related data to TPs under certain defined circumstances.[58] FERC emphasized that changes to existing LGIAs with existing interconnection customers must be agreed-upon mutually or filed through Section 205 of the FPA because it would be unfair to unilaterally allow TPs to impose unexpected costs associated with data reporting on existing customers without making a showing that the specific data sought by the TP, and associated costs, are just and reasonable.[59]

The VER Orders require certain categories of meteorological data from VERs having wind or solar as their energy source.[60] Specifically, an interconnection customer with a VER having wind as the energy source must provide, at a minimum, site-specific meteorological data including temperature, wind speed, wind direction, and atmospheric pressure. An interconnection customer with a VER having solar as the energy source must provide, at a minimum, site-specific meteorological data including: temperature, atmospheric pressure, and irradiance (i.e., cloud cover).[61]

Ultimately, implementation of reporting requirements commensurate with the power production forecasting employed by the TP will, according to FERC, allow for more accurate commitment or de-commitment of resources providing reserves, ensuring that reserve-related charges imposed on customers remain just and reasonable and not unduly discriminatory or preferential.[62] Order 764 requires TPs to revise Article 8.4 of the LGIA to state that all requirements for meteorological and forced outage data must be consistent with the power production forecasting employed by the TP, if any, to manage reserve commitments.[63]

Importantly, FERC had originally proposed to require VER interconnection customers to report to the TP any forced outages that reduce the generating capability of the resource by 1 MW or more for 15 minutes or more.[64] However, FERC ultimately concluded that it is more appropriate for the TP and interconnection customer to negotiate the exact specifications of forced outage data to be provided, taking into account the size and configuration of the VER, its

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[58] Ibid., ¶171.

[59] Ibid., ¶195.

[60] California ISO, New York ISO, PJM, MISO and Xcel Energy stated that they either already have tariff language, business practice rules or other infrastructure governing wind power forecasting. See VER Integration NOPR, ¶¶'s 47-48.

[61] See FERC Order 764, ¶177.

[62] Ibid., ¶23. FERC stated that the current lack of meteorological and forced outage data reporting requirements in the *pro forma* LGIA may limit efforts by TPs to more efficiently manage operating costs associated with the integration of VERs interconnecting to their systems. Ibid., ¶173.

[63] Ibid., ¶¶174, 192-193.

[64] Ibid., ¶157. The Commission noted that provision of VER outage data at this level of granularity would allow a TP to ascertain the extent to which current VER power production is a result of unit availability as opposed to changing weather conditions. Ibid.

characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. Therefore, FERC did not impose any MW- or duration-based reporting requirement in the VER Orders.[65]

In addition, FERC proposed to modify the *pro forma* LGIA to include a new definition of VER defined as a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.[66]

Rejecting arguments to define VERs based upon a generation source's operational characteristics or level of storage, FERC adopted the proposed definition because it best met FERC's purpose to identify those resources that are required to provide to their TPs meteorological and forced outage data necessary to enable the TP to develop and deploy power production forecasting.[67] FERC noted further that it is the variability of the energy source, not the operating characteristics of the plant or nature of output, that are critical to identifying the set of resources that must be subject to the meteorological and forced outage data requirements adopted in Order 764.[68]

Finally, FERC noted that the Final Rule does not create an obligation for VER interconnection customers to provide meteorological and forced outage data in cases where the TP is not engaging in power production forecasting (i.e., where such forecasting is not yet warranted due to low penetration).[69] In addition, FERC declined to require TPs to share VER-related data with other entities such as a balancing authority area or the National Oceanic and Atmospheric Administration ("NOAA"), but strongly encouraged the voluntary sharing of data where appropriate.[70] FERC also declined to prescribe a single method of cost recovery for developing and implementing power production forecasting, since not all TPs will develop power production forecasting given regional differences in the types and penetration levels of VERs.[71]

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[65] Ibid., ¶181. The specific meteorological and forced outage data should be set forth in Appendix C of the LGIA. See FERC Order 764-A, ¶33.

[66] See VER Integration NOPR, ¶ 64. See also *pro forma* LGIA Article I. Certain stakeholders disagree with FERC's definition of VER, which is limited to renewable resources and excludes conventional resources. Public Interest Organizations ("PIOs") asserted that VERs and conventional generation are similarly situated in that they both impose uncertainty and variability costs upon the system. See *PIO Request for Rehearing of Order 764*, Docket No. RM10-11-000 (July 23, 2012), p.6. FERC stated that to the extent that a TP proposes to allocate to VERs their share of system variability costs, it must also allocate to all other generation resources their corresponding share of system variability costs. See FERC Order 764-A, ¶46 and FERC Order 764, ¶320.

[67] See FERC Order 764, ¶210.

[68] Ibid., ¶211.

[69] Ibid., ¶174.

[70] Ibid., ¶221.

[71] Ibid., ¶232.

C. Generator regulation service

Noting that in order to meet their obligations to offer generator imbalance service under Schedule 9, TPs must hold unloaded resources in reserve to respond to moment-to-moment variations attributable to generation, FERC proposed to establish a generic rate schedule (Schedule 10 - Generator Regulation and Frequency Response Service) through which TPs may recover the costs of providing this service.[72]

Regulation service, offered under Schedule 3 of the *pro forma* OATT, provides the capacity reserve necessary for the continuous balancing of resources (generation and interchange) with load to maintain a scheduled interconnection frequency of 60 cycles per second (60 Hz).[73] Energy imbalance service, offered under Schedule 4 of the *pro forma* OATT, accounts for hourly energy deviations between a transmission customer's scheduled delivery of energy and the actual energy used to serve load.[74]

Regulation service and energy imbalance service, while different in function, are complementary services through which TPs maintain their systems' balance and recover both the capacity (regulation service) and energy (energy imbalance service) costs of doing so from transmission customers on their systems.[75]

While the *pro forma* generator imbalance service provides a mechanism for TPs to recover the cost of providing the *energy* needed to manage hourly generator imbalances, it does not provide a mechanism for TPs to recover the costs of holding reserve *capacity* associated with providing generator imbalance energy.[76]

Proposed Schedule 10 would have provided a mechanism through which TPs could recover the costs of providing regulation reserves associated with the variability of generation resources both when they are serving load within the TPs balancing authority area and when they are exporting to load in other balancing authority areas.[77] FERC preliminarily found that clarifying the manner by which FERC-jurisdictional transmission providers may recover the costs associated with fulfilling their obligation to offer generator regulation service would remove barriers to the integration of VERs by eliminating FERC-jurisdictional transmission providers' uncertainty regarding cost recovery.[78]

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[72] Ibid., ¶240.

[73] Ibid., ¶235.

[74] Ibid., ¶236.

[75] Ibid., ¶237.

[76] Ibid., ¶239. While Order 890 did not create a new rate schedule to expressly recover these capacity costs, the Commission indicated that TPs could recover the costs of additional regulation reserves associated with providing imbalance service through a Section 205 filing. Ibid.

[77] Ibid., ¶241.

[78] Porter, *2013 NREL Report*, p.5.

However, in response to numerous comments urging flexibility in the design of capacity services needed to integrate VERs into transmission systems, FERC agreed that the proposed *pro forma* generator regulation service may not be the most efficient and economical service with which to integrate VERs.[79] Rather, FERC indicated that it would continue to evaluate proposals to recover capacity costs incurred to provide Schedule 9 generator imbalance service on a case-by-case basis[80] and instead offered guiding principles on calculating the impact of individual transmission customers on a TP's overall generation regulation reserve needs and their corresponding allocations.[81]

FERC listed its Order 764 guidance provisions as follows:

(1) TPs seeking to distinguish customers into classes for the purpose of requiring them to purchase or otherwise account for different quantities of generation regulating reserves should do so only to the extent that such classes and distinctions among classes are *reasonably related to operational similarities* and differences among those resources.[82]

(2) To the extent that a TP proposes to break customers into specific groups based on operational characteristics, those TPs should *provide detailed explanations* as to why such classifications are appropriate if and when they propose to allocate different generating regulation reserve obligations to different customer classes.[83]

(3) To the extent that a TP proposes to differentiate among customers (or customer classes) in determining their relative regulating reserve responsibilities, the TP must demonstrate that the *overall quantity of regulating reserve it requires of its transmission customers accounts for diversity benefits*[84] among all resources and loads, and the allocations to

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[79] See FERC Order 764, ¶268.

[80] FERC stated that individual cases are the appropriate place to evaluate the extent to which different customers may impose such a degree of variability or uncertainty on a transmission system that they merit different generator regulating rates. See FERC Order 764-A, ¶47.

[81] Ibid., ¶40. See also, FERC Order 764, ¶¶'s 317-323. This approach allows TPs to retain flexibility to propose capacity services that best respond to the needs of their customers. See FERC Order 764-A, ¶41.

[82] See FERC Order 764, ¶318.

[83] Ibid., ¶319.

[84] Diversity benefits result from the aggregation of the variations of all resources, such that one resource's negative deviation can offset some or all of another resource's positive deviation. FERC stated that when the transactions of two customers result in diversity benefits, it is incorrect to say that one customer is benefitting the other but not vice versa. Instead, diversity benefits would result from both transactions and sharing of these benefits among the customers would be reasonable. Ibid., fn. 290 (citing *Westar*, 130 FERC ¶ 61,215 at P 37). Weather events, such as droughts that may affect the required quantity of generator regulation reserves more or less during different parts of the year are examples of diversity events. See FERC Order 764-A, ¶53. Notably, the American Wind Energy Association ("AWEA") commented that diversity events ought to include the anomalous behavior of conventional generators and loads such as ramping to different outputs or schedule deviations caused by the behavior of a non-confirming industrial load. See AWEA Motion for Clarification or Rehearing, Docket No. RM10-11, (July 23, 2012), pp. 4-5.

individual customers (or customer classes) of their proportionate share is based on the operational characteristics of such customers (or customer classes).[85]

(4) Weather events such as droughts may affect the required quantity of generator regulating reserves that the TP must have in reserve, more or less, during one portion of the year versus another portion of the year. In such cases, *these diversity events, though perhaps characterized as anomalies, should be included in the data set* so that the quantity and costs of such reserves are more reflective of actual system operations.[86]

(5) In designing any proposals for generator regulation service charges, a TP should consider the *extent to which transmission customers are using intra-hour scheduling* in evaluating whether to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves.[87]

(6) While FERC reserves judgment as to the appropriate power-production forecasting requirements for a particular TP, *FERC expects that the implementation of power-production forecasting will be addressed in any proposal* to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves.[88]

In initially proposing the new Schedule 10 rate, FERC stated that, as with Schedule 3, the proposed Schedule 10 charge would be the product of two components: a per-unit rate for regulation reserve capacity, and a volumetric component for regulation reserve capacity.[89] FERC noted that the per-unit rate for service under the proposed Schedule 10 should be the same as the rate for service under the existing Schedule 3 because both schedules were designed to recover the costs of holding regulation reserve capacity to meet system variability.[90] Regarding the volumetric component, FERC proposed to provide each TP with the opportunity to justify a proposal to require all transmission customers who are delivering energy from VER generators:

(1) to purchase or otherwise account for the same volume of generator regulation reserves; or

[85] See FERC Order 764, ¶320.

[86] Ibid., ¶321.

[87] Ibid., ¶322.

[88] Ibid., ¶325.

[89] Ibid., ¶276.

[90] Ibid. Further, both schedules provide functionally equivalent services. Thus, FERC initially proposed to find it just and reasonable to use the same rate currently established in a TP's Schedule 3 when charging transmission customers under Schedule 10; and to require a demonstration that per-unit costs of regulation reserve capacity was somehow different when such capacity was utilized to address system variability associated with generator resources if TPs proposed to apply a different rate under Schedule 10. Ibid., ¶277.

(2) to purchase or otherwise account for a different volume of generator regulation reserves than it proposes to charge transmission customers delivering energy from other generating resources.[91]

An additional element of FERC's discarded Schedule 10 proposal required that TPs proposing the same volume of generator regulation reserves for all generators demonstrate that the volume of regulation reserves required of transmission customers delivering energy from generators located within its balancing authority area be commensurate with their proportionate effect on net system variability, taking account of diversity benefits; and that any proposal for different volumes of generator regulation reserves based on the generating resource be supported by data showing that VERs have a different per-unit impact on overall system variability than conventional generating units.[92]

Responding to concerns about the application of Schedule 10-type charges to VERs, FERC affirmed that the TP will be expected to reduce the costs of generator regulation service to the extent practicable and allocate such costs based on transmission customers' proportionate share of responsibility.[93] FERC stated further that the guidance is intended to provide a framework to assist TPs in developing proposals for generator regulation service, should they desire to do so. FERC stated that it did not intend the guidance to preclude a TP from making an alternative proposal under section 205 of the FPA; however, it provides guidance to TPs regarding the facts and circumstances that FERC may find relevant in evaluating such proposals.[94]

D. Section summary

FERC extended the deadline to comply with the VER Orders to November 12, 2013. The compliance process will afford TPs the opportunity to describe how their new tariff provisions will help reduce various ancillary services charges by adopting more flexible scheduling and better forecasting protocols, or for other TPs to demonstrate how their existing tariffs are superior to the new *pro forma* OATT. These reforms, over time, may enable sufficient system balancing capabilities such that Schedule 9 charges will be minimized and Schedule 10-type regulations charges may become rare, if not obsolete.

The impacts of these reforms on VER integration costs will become clearer after state regulatory commissions take up dockets investigating integration cost recovery proposals that have accounted for the cost impacts of the Order 764 reforms. Regulatory dockets, whether general rate cases, integrated resource planning dockets or reviews of utility-sponsored wind integration studies promise to offer the greatest insight into the local and regional effects of the Order 764 reforms and can potentially offer FERC guidance on additional reforms it should consider to further achieve more accurate VER integration costs.

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[91] Ibid., ¶278.

[92] Ibid., ¶280.

[93] See Order 764-A, ¶48.

[94] See Order 764, ¶333.

It is notable that FERC adopted regulatory reforms that better accommodate newer technologies such as VERs rather than proceeding in a manner that exclusively penalizes them with expensive firming charges to make up for their variability. Two statements in the Order 764 proceedings, noted above, highlight FERC's approach:

> over time, implementation of intra-hour scheduling also will allow public utility transmission providers to rely more on planned scheduling and dispatch procedures, and less on reserves, to maintain overall system balance;[95]

and

> these power production forecasting tools also provide TPs with the advanced knowledge of system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than managing the variability through the deployment of reserve services, such as regulation reserves.[96]

Order 764 represents a balanced approach that adopts regulatory reforms such as intra-hour scheduling and improved forecasting, but recognizes that TPs who provide ancillary services to respond to variability should be compensated by those responsible for their provision.

There are additional subject areas that may be ripe for regulatory reform, and which FERC contemplated in its January 2010 Notice of Inquiry, but that did not receive consideration in the proposed or final rule. Those subject areas include:

- Forward market structure and reliability commitment processes - VERs appear to participate in the day-ahead market on a limited basis, choosing instead to self-schedule the majority of their supply in the real-time energy markets (i.e., act as a price taker). Because day-ahead schedules are financially binding, there can be significant financial risk for VERs participating in the day-ahead market and not being able to meet these obligations in the real-time market. This may serve as a disincentive for VERs to participate in the day-ahead market.[97]

- Balancing authority area coordination and/or consolidation - Smaller balancing authorities may be unable to capture the benefits associated with VERs that are spread across a large and/or diverse geographical area and FERC seeks to explore whether increased coordination among balancing authorities has the potential to enlarge the base

[95] Ibid., ¶22.

[96] See VER NOPR, ¶45.

[97] See VER NOI, ¶26.

of generation and demand available to customers, thereby making variability more manageable and ultimately reducing overall costs.[98]

- Capacity market reforms – VERs are eligible to receive compensation for capacity services in most RTOs/ISOs. However, due to their operating characteristics and the capacity rating rules, which vary among RTOs/ISOs, VERs are eligible to offer only a portion of their nameplate capacity. The price paid for capacity services depends in part on the amount of available capacity. Additionally, resources that participate in capacity markets typically are required to offer capacity in the day-ahead market, which VERs often do not do.[99]

- Re-dispatch and curtailment practices necessary to accommodate VERs in real time – FERC requested comments on whether VERs may be curtailed too frequently in response to transmission congestion, minimum generation events and ramping events, because of the lack of clarity in curtailment protocols. [100]

State regulatory commissions are encouraged to consider further reforms in these areas that may more accurately identify and/or moderate VER integration costs, and to consider whether to encourage FERC to adopt those additional reforms through a formal rulemaking process.[101]

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[98] Ibid., ¶32.

[99] Ibid., ¶37.

[100] Ibid., ¶40.

[101] A compilation of "best practices" for VER integration is included in a recent PJM Report. See Exeter Associates, Inc., and GE Energy. (2012). *PJM Renewable Integration Study*, pp. 155-166 (see fn. 186, *infra.*) Best practices are also addressed in a comprehensive manner in the 2012 WGA Report prepared by the Regulatory Assistance Project. See Regulatory Assistance Project, *2012 WGA Report*.

IV. State Regulatory Approaches to Calculating Wind Integration Costs

This section explores different state and regional approaches to wind integration cost development by utilities and regulatory commissions. While there is no consistent wind integration cost calculation methodology among the states and regions examined, it is clear that local and regional cost development is guided significantly by the unique resource, market and infrastructure characteristics of each service territory. Rather than deciphering the various cost modeling techniques utilized to arrive at wind resource integration cost figures[102] – a worthwhile undertaking for future consideration that would require collaboration between regulatory commissions and public utilities – this section catalogues wind integration cost drivers and figures and broadly describes state and regional wind integration cost calculation methodologies.

A. A brief review of wind integration cost drivers and literature

According to the EPRI report referenced in the introduction to this paper, the degree of grid system flexibility, a metric based on a comprehensive set of factors, is a key driver in determining wind integration costs.[103] Further, according to a report by the National Conference of State Legislatures (NCSL), the size of electricity markets and load balancing areas play a significant role in the ease and cost of wind integration because larger markets have more resources to cost effectively balance energy demand and supply and offer a better variety of financial mechanisms, reducing system variability and wind integration costs respectively. [104]

According to NREL, wind integration generally causes a small increase in the amount of regulating capacity needed for system balance and a more substantial impact in the sub-hourly load following time frame.[105] NREL noted that the increase in variability that wind brings to the system has a cost on system operations, resulting from increased cycling from intermediate and possibly peaking units, along with an increase in the flexibility of reserves that are needed to manage the system.[106] Further, when thermal generating units cycle more often as a result of adding wind to the generating portfolio, there is typically a decrease in unit efficiency that arises

[102] The 2009 NREL Report criticized standard wind integration cost modeling techniques for containing a faulty differential energy value of a proxy daily flat block compared to wind energy, which is inadvertently included in the integration cost. Milligan, *Calculating Wind Integration Costs*, p.11.

[103] See EPRI Report, *Impacts of Wind Generation Integration*, p. 2. EPRI listed the following factors: wind penetration; variability of wind output for the system; location of wind resource relative to load; strength of transmission network (increased connection between regions reduces variability and uncertainty and increases the available flexible resources needed to balance wind); accuracy of the wind forecast; system stability requirements pertaining to additional need for voltage, frequency control, reactive power, and more; and the monitor and control system capabilities (supervisory control and data acquisition ("SCADA") of the individual wind plants.

[104] See National Conference of State Legislatures. (2009). *Integrating Wind Power into the Electric Grid*, p. 3. (NCLS Report). (Citing U.S. Department of Energy, *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply*, p. 92.)

[105] Milligan, *Calculating Wind Integration Costs*, pp. 1-2.

[106] Ibid.

as a result of the more frequent ramping, and because units may be operated at less efficient points on their heat rate curve.[107]

The practical impacts of wind integration cost studies are difficult to overstate. As one utility stated:

> When Public Service [Company of Colorado] evaluates new power supply options for its system, the total incremental integration cost determined using this study will be added to the bid or build price of wind resources to ensure that all costs associated with wind generation are represented and that wind is compared on an equivalent basis with other generation technologies.[108]
>
> Like total incremental wind integration costs, incremental wind curtailment and cycling costs will be added to the bid or build price of wind resources when evaluating wind against other power supply options.[109]

It is clear that such studies impact the types of resources that will be selected and dispatched to serve load and it is vital that utilities and regulatory commissions closely scrutinize study assumptions and results.

B. A review of wind integration cost calculation processes

As noted in the introduction to this paper, methodologies unique to individual balancing authorities impede meaningful interregional comparisons. Some of these regional variations include:

- methodologies and tools used to determine the rates charged for integrating wind.
- types of reserves or reserve impacts included in rates charged for integrating wind.
- variations in determining integration impacts and
- variations in generation forecasts.[110]

There is also a variety of means for determining the costs of ancillary services. However, according to NREL, all methods calculate wind integration costs by comparing total power system costs with and without wind generation.[111] Such simple comparisons of the with- and

[107] Ibid. The increase in cycling can cause wear and tear, which can be captured by quantifying operations and maintenance cost that is caused by the wind-induced cycling. Ibid.

[108] See Xcel, Inc. and EnerNex Corporation. (2011). *Public Service Company of Colorado 2GW and 3GW Wind Integration Cost Study*, p. 6. (PSCo Study).

[109] Ibid., p. 7.

[110] Porter, *2013 NREL Report*, p.7.

[111] Milligan, *Calculating Wind Integration Costs*, p.1.

without-wind costs are not sufficient, according to NREL, because the value of the wind energy itself is also included in this difference.[112] In order to remove the energy value bias and calculate only the wind integration cost, current methods substitute an energy proxy into the base case, but unfortunately, it is difficult to craft an energy schedule that can be placed into the base case that does not have significant capacity and/or differential energy values itself.[113]

With these VER integration cost calculation methodology limitations in mind, this paper next provides brief overviews of specific state and regional wind integration cost calculation processes in the American West.

1. Idaho Power Company

Idaho Power released its 2013 Wind Integration Study Report in February and stated that it had reached on-line wind generation totaling 678 MW of nameplate capacity.[114] The study investigated wind installed capacities of 800 MW, 1,000 MW and 1,200 MW and the study objectives were to determine:

- what are the costs of integrating wind generation on the company's system; and
- how much wind generation the company can accommodate without impacting reliability.[115]

Idaho Power defines 'integration cost" as the economic impact of wind generation variability and uncertainty on the utility company charged with accepting and delivering that energy.[116] The Company used an internally developed systems operations model to conduct the study.

Study results indicated that

- customer demand is a strong determinant of Idaho Power's ability to integrate wind, in that during low demand periods, the system of dispatchable resources

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112 Ibid.

113 Ibid.

114 See Idaho Power. (February 2013). *2013 Idaho Power Wind Integration Study Report*, p. 18. (Available at http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2013/windIntegrationStudy.pdf). Nameplate capacity is the maximum amount of electric energy that a generator can produce under specific conditions, as rated by the manufacturer. Generator nameplate capacity is usually expressed in kilovolt-amperes (kVA) and kilowatts (kW), as indicated on a nameplate that is physically attached to the generator. See *Glossary*, US Nuclear Regulatory Commission. Available at: http://www.nrc.gov/reading-rm/basic-ref/glossary/generator-nameplate-capacity.html.

115 Ibid., p. 12.

116 Porter, *2013 NREL Report*, p. 47. (Referring to a 2007 Idaho Power Wind Integration Study).

often cannot provide the balancing reserves needed to accommodate the wind and keep the system balanced, thereby requiring wind curtailment;[117] and

- the frequency of curtailments would accelerate beyond an 800 MW installed capacity level and that wind development beyond 800 MW is likely subject to considerable curtailment risk.[118]

The study revealed that an 800 MW penetration level results in costs of $8.06 for each MW integrated, but that the wind generators comprising the 678 MW of wind currently installed are assessed an integration cost of only $6.50.MWh (a stipulated cost agreed to in Case No. IPC-E-07-03, before the Idaho Public Utilities Commission).[119] In order to cover the $8.06/MWh integration cost associated with 800 MW of installed capacity, wind generators who integrate between the current and 800 MW penetration level would need to recognize integration costs of $16.70/MWh.[120] Generators between the 800 MW and 1000 MW levels would require an integration cost assessment of $33.42/MWh. Generators between the 1000 MW and 1200 MW levels would require integration cost assessments of $49.46/MWh.[121]

Wind Penetration Level	Integration Cost Assessment
678 – 800 MW	$16.70/MWh
800 – 1000 MW	$22.42/MWh
1000 – 1200 MW	$49.46/MWh

2. Portland General Electric Co.

On September 30, 2011, PGE released its Phase II Wind Integration Study indicating that its estimated self-integration costs are $11.04/MWh and within the range calculated by other utilities in the region; and that modeling assumptions reflect a potential 2014 state in which it

[117] See Idaho Power 2013 Wind Integration Study at 7. This statement suggests that there is a tension, in some instances, between efforts to promote wind energy and efforts to promote conservation.

[118] Ibid.

[119] Ibid., p. 8 and fn 1. Certain parties disagreed with Idaho Power's modeling assumptions. Idaho Power stated that the charges in the settlement agreement (which were capped at $6.50/MWh) and the amount from a revised estimate of $7.92/MWh were within reasonable ranges of the cost of integrating wind energy. The Renewable Coalition submitted testimony explaining why the $7.92/MWh estimate was too high, and stated that Idaho Power's conversion of wind speed data to wind generation data likely overestimated the variability that would be experienced by actual wind resources, leading to higher wind integration costs. See 2013 NREL Report at 49 (citing Dragoon, Ken (2007a), *Direct Testimony*, filed with the Idaho Public Utilities Commission. Case No. IPC-E-07-03. October 4, 2007).

[120] Ibid., p. 8.

[121] Ibid.

seeks to integrate up to 850 MW of wind (to meet the 2015 Oregon physical RPS requirement) using existing (by 2014) PGE resources and associated operating limitations.[122]

PGE used a mixed integer programming ("MIP")-based optimization model to calculate costs associated with integrating wind into the PGE system.[123] PGE measured the cost of wind integration as the savings in system operating costs that would result if wind placed no incremental requirements on system operations, and cost savings were conditional on the ability of a given set of generation resources to adjust for the variability and uncertainty of wind generation.[124]

The Phase II study considered four elements of wind integration costs:

- Day-Ahead uncertainty (resulting from Day-Ahead wind forecast error);
- Hour-Ahead uncertainty (resulting from Hour-Ahead wind forecast error);
- Load Following (generation used to follow wind trends within the hour); and
- Regulation (generation used to follow within-hour departures of wind from the wind generation schedule).[125]

Study results from two distinct modeling efforts were compiled in Tables 9 and 10 of the PGE study.[126] Both modeling efforts took the sum of four separate data components:

- Cost for day-ahead uncertainty (Identifier B)
- Cost for hour-ahead uncertainty (Identifier C)
- Cost for load following (Identifier D)
- Cost for regulation (Identifier E)

The first effort yielded a total cost of wind integration (2014) of $11.04/MWh and the second effort yielded a total cost of wind integration (2014) of $9.15/MWh.[127] The sum of the components (Identifiers B through E) did not equal the total (Identifier A) because the interactive effect of the components and resultant resource dispatch within the model will vary between the runs.[128]

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[122] See PGE and EnerNex. (2011). *PGE Wind Integration Study Phase II*, p. 2. Available at: http://www.uwig.org/PGE_Study/PGE_Phase%202_Wind_Integration_Report_9-30-11.pdf.

[123] Ibid., p. 8. The model is a "constrained optimization model" with an objective function to minimize total system operating costs given a set of operational constraints. Ibid., p. 33.

[124] Ibid., p. 16.

[125] Ibid., p. 34. Wind integration costs were considered in the aggregate and in each individual category. Ibid., p. 35.

[126] Ibid., pp. 47, 51. Tables 9 and 10 can be found in Appendix D of this paper.

[127] Ibid.

[128] Ibid., p. 46.

3. Puget Sound Energy

In June 2010, Puget Sound Energy ("PSE") proposed that a rate of $2.70/kW-month be levied upon wind generators.[129] The charge was determined by basing the incremental monthly cost per kW of capacity on a proxy natural gas peaking plant that PSE considered representative of the incremental market price of capacity needed to follow the intra-hour variability of wind generation.[130] PSE proposed to charge a wind facility based on their installed nameplate capacity.[131]

In June 2011 PSE proposed to update its cost of capacity for regulation service from $5.50/kW-month (set in 1998) to $12.39/kW-month, based on a revised cost of service study.[132] PSE also proposed to create a new category for VERs - purchasing regulation reserves at 16.77% of a resources point-to-point transmission service schedule for export out of the PSE balancing authority – resulting in a VER charge of $2.08/kW-month (16.77% of $12.39) for all exported energy from a wind facility within the PSE footprint.[133] A 2011 FERC Order reduced the capacity charge from $12.39/kW-month to $10.50/kW-month.[134]

On May 7 2012, the Washington Utilities and Transportation Commission ("UTC") held that PSE had properly relied on available historical data and modeling to forecast day-ahead and within-hour wind integration costs, and that this was a satisfactory basis upon which to include wind integration costs at the levels PSE proposed.[135] In reaching its decision, UTC noted that statutes requiring utilities to meet certain Renewable Portfolio Standards in the relatively near term have hastened the development and use of wind power in Washington, as elsewhere.[136]

In presenting its case before UTC, PSE described wind integration costs as follows:

> wind integration costs incurred by PSE—internally and through BPA—represent the costs of having to reserve capacity to balance wind generation. In essence, generation capacity that may have been dispatched, but for the presence of wind, is withheld from the energy market. Conversely, uneconomic generation that would not

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[129] Porter, *2013 NREL Report*, p. 67.

[130] Ibid.

[131] Ibid. For example, a 100-MW facility would pay $270,000 per month.

[132] Ibid., p. 68.

[133] Ibid.

[134] Ibid., p. 70.

[135] See *Washington Utilities and Transportation Commission, Order 08*, Consolidated Dockets UE-111048 and UE-111049, May 7, 2012, ¶252. UTC emphasized that in future cases it expects PSE to present more detail concerning the historical data and modeling upon which the Company forecast of wind integration costs depend. UTC also stated that it expects PSE to stay abreast of, and apply where cost-effective, more rigorous means to determine these costs as they develop in the industry. Ibid., ¶253.

[136] Ibid., ¶252.

> have been dispatched, but for the presence of wind, may be committed into the market.[137]

PSE's rate year power costs included both its internal cost of integrating wind resources and the wind integration costs it pays to BPA to manage the variable output of certain wind projects (charged as a Variable Energy Resource Balancing Service (VERBS) rate and a Generation Imbalance rate to PSE).[138] For wind generation within PSE's balancing area, PSE included costs associated with day-ahead scheduling deviations and within-hour wind variability.[139]

In allowing these costs, UTC noted that the accuracy of a Power Cost Adjustment (PCA) mechanism, whose purpose it is to capture significant unanticipated deviations from a power cost baseline, depended on UTC establishing an accurate baseline of power costs that included all reasonably anticipated, prudently incurred costs, such as PSE's wind integration costs.[140]

4. Bonneville Power Administration

BPA markets power from 31 federal hydropower plants and one nuclear plant that together totals approximately 23,000 MW of nameplate capacity.[141] The power plants and associated BPA-operated transmission system comprise the Federal Columbia River Power System (FCRPS) and BPA states that the ability of its hydro projects to accommodate increasing grid variability from wind energy is reaching its limits during times of high water/high wind and/or low load as well as during periods of low water.[142]

Since 2005, the total amount of installed wind generation in the BPA balancing authority area has increased from 325 MW to over 4,900 MW, and Bonneville expects to have 5,100 MW by 2013.[143] With a peak balancing authority area load of 10,500 MW and a minimum light load of 4,000 MW, wind penetration in the BPA balancing authority area is among the highest in the nation and as a result, the issues of flexibility adequacy, cost allocation and the division of labor between source and sink balancing authorities are of particular importance to BPA.[144] Further, in BPA's 2011-2012 base rate proceeding, the Record of Decision (ROD) noted that wind

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[137] Ibid., fn. 328 (citing PSE Initial Brief, ¶35).

[138] Ibid., ¶246 and fn. 329. The VERBS rate is discussed in Section V of this paper.

[139] Ibid. PSE relied on the AURORA model and an Ancillary Valuation Model to develop various elements of its VER integration costs. See id at ¶248.

[140] Ibid., ¶251.

[141] Porter, *2013 NREL Report*, p. 36.

[142] Ibid.

[143] See *BPA Request for Clarification or Rehearing*, Docket No. RM10-11-000, July 23, 2012, p. 1.

[144] Ibid., p. 2.

generation has increased by a factor of six over the past four years and that it was set to double again over the next two to three years.[145]

BPA defines its balancing services as:

- Regulating reserves—the capacity needed to provide for continuous balancing of generation and load;
- Following reserves—the capacity required to balance variations within the hour of actual load and generation from the forecasted load and generation; and
- Imbalance reserves—reserves needed due to differences between the average scheduled energy during the hour and the average actual energy during the hour.[146]

Balancing services include both incremental (*inc*) and decremental (*dec*) generation for each category. BPA develops the forecast for cumulative *inc* and *dec* generation required to maintain load-resource balance for the required reserve time periods.[147]

During BPA's prior rate proceeding (2008-2009), BPA recommended that the $19,124,320 collected as power rates to cover regulation and following service costs should be reallocated to wind generators.[148] Estimating that wind capacity in 2009 would be approximately 28,124,000 kW-months, BPA calculated a Wind Integration Rate (required to collect the target amount of revenue) of $0.68/kW-month applied to installed wind capacity.[149]

NREL compiled BPA's Wind Integration Rates from 2009, 2011 and 2013 into Table 10.[150] In 2009, BPA's wind integration rate was $0.68/kW-month, in 2010-2011 the rate was $1.29/kW-month and in 2012-2013, the wind integration rate was $1.23/kW-month.[151]

In BPA's 2012–2013 rate proceeding, BPA redefined its Wind Integration Rate as the VERBS rate, applied to operating wind and solar plants. Additionally, BPA created a Dispatchable Energy Resource Balancing Service (DERBS) rate that applied to all non-Federal dispatchable energy resources, i.e., thermal generation.[152]

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[145] See *BPA Wholesale Power and Transmission Rate Adjustment Proceeding* (BP-12) Administrator's Final Record of Decision ("ROD"), BP-12-A-02 (July 2011). BP-12 ROD (citing Mainzer *et al.*, BP-12-E-BPA-42, at 9-10.)

[146] Porter, *2013 NREL Report*, p. 37.

[147] Ibid.

[148] Ibid.

[149] Ibid.

[150] Ibid.

[151] Ibid. Table 10 can be found in Appendix D of this report.

[152] Porter, *2013 NREL Report*, p. 37. BPA has proposed updated base rates for 2014 and its base rate case is pending. See BP-14 Initial Rate Proposal, Power Rates Study, BP-14-E-BPA-01 (November 2012).

BPA established a Wind Integration Team (WIT) to undertake initiatives exploring technical solutions to address the challenge of balancing loads and resources to preserve system reliability while accommodating the rapid development of wind energy in the BPA balancing authority.[153] WIT developed operational and reliability protocols designed to maintain system reliability when wind variability exhausted the incremental (*inc*) and decremental (*dec*) balancing reserve capacity established on a planning basis.[154]

In addition, BPA proposed to develop a pilot project for FY 2012–2013 that would provide for the acquisition of *dec* balancing reserve capacity from non-Federal entities to replace the *dec* balancing reserve capacity procured from the FCRPS, thereby reducing VERBS costs.[155] BPA staff is evaluating the impacts of one contract to purchase *dec* balancing reserves from a non-Federal source and believes that it provides a foundation for expanding those purchases during the FY 2012–2013 rate period.[156]

BPA's balancing reserve forecast estimates the total amount of balancing services required and how much each resource contributes to the total amount. BPA then determines the cost of providing the required amounts of balancing services and allocates these costs to the relevant resources according to their contribution under four rates: regulating reserve, load-following reserve, DERBS, and VERBS.[157] For its 2012-2013 base rate case, BPA forecasted a total balancing reserve capacity requirement of 791 MW *inc* and 1,012 MW of *dec* of which 333 MW of *inc* and 346 MW of *dec* were assigned to load following and the remaining balancing reserve requirements were allocated to regulation, VERBS, and DERBS.[158]

5. Public Service Company of Colorado/Xcel

Public Service Company of Colorado ("PSCo") conducted a study to determine the costs of integrating 2,000 MW and 3,000 MW (nominal values) of wind energy into the Public Service electric system.[159] The Study also recast a previously performed 20% wind integration study using new inputs from the current study. This resulted in decreasing PSCo's maximum allowable system wind penetration from 1,440 MW to 1,414 MW under the 20% scenario.[160] The study analyzed and quantified the average wind integration costs associated with regulation, system operations and gas storage, and did *not* quantify wind integration costs associated with wind generation curtailment, electricity trading deficiencies due to wind uncertainty, or increased

[153] See BP-12 ROD at 10.

[154] Ibid. This is known as Dispatcher Standing Order 216 ("DSO 216") and is discussed in the next section.

[155] Ibid., pp. 221-222.

[156] Ibid.

[157] Porter, *2013 NREL Report*, p. 39.

[158] See BP-12 ROD, p. 41. VERBS is a combined service that includes regulation, following, and imbalance components. See BP-12 ROD (2011) (citing Mainzer *et al.*, BP-12-E-BPA-23, at 14).

[159] Xcel, *PSCo Study*, p. 6.

[160] Ibid., p. 10.

operating and maintenance costs at existing thermal units that may be called upon to ramp output levels over a broader range more often and with shorter notice.[161]

According to PSCo, the regulation cost arises from the intra-hour variability of wind resources that requires additional fast-responding regulation capacity to be available; the system operations cost arises from less than optimal operation of the electric system as the result of the uncertain nature of wind energy production; and the gas storage cost stems from inaccuracies in the amount of gas nominated each day for electric energy production caused by the uncertain nature of forecasting the wind.[162]

The PSCo Study presented its conclusions in a series of tables depicting the three components of wind integration costs noted above.[163] The average regulation costs for wind integration were $.10/MWh in the 20% scenario, $.14/MWh in the 2 GW scenario and .21/MWh in the 3 GW scenario. The average system operations costs for wind integration were $2.39/MWh for the 20% scenario, $3.40/MWh for the 2 GW scenario and $3.71/MWh for the 3 GW scenario. Finally, the average gas storage costs for wind integration were $.14/MWh for the 2 GW scenario and $.17/MWh for the 3 GW scenario.[164]

Each component was calculated by estimating the total annual integration costs for a given level of wind on the PSCo system and dividing by the total system annual wind energy. The resulting $/MWh value represents the *average* wind integration cost for the entire amount of wind energy on the system.[165] When PSCo uses wind integration costs for purposes of evaluating future power supply options, it will use the total *incremental* wind integration cost (the sum of the incremental wind integration cost for the three components divided by the incremental wind energy production).[166]

The Study used the Couger unit commitment and dispatch model to determine wind integration costs at three levels in order to develop individual commitment and economic dispatch plans within the model for every hour of the study year, which was the year 2018.[167] The Study determined that the average system operations wind integration cost was $3.40/MWh

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161 Ibid., p. 7. These items were analyzed in a corresponding study.

162 Ibid., pp. 7-8. According to PSCo, the average system operations wind integration cost is dependent on the cost of energy for the fossil-fueled resources in an electric operating company's generating resource portfolio as those resources constitute the majority of the resource portfolio, and the less-than-optimal operation of fossil-fueled resources (as the consequence of wind generation uncertainty) produces average system operations wind integration cost. Ibid., fn. 5.

163 Ibid., pp. 7-8. In these charts, the 20% figures correspond to the 1414 MW penetration level achieved in the rerun.

164 Ibid. The tables depicting these values can be found in Appendix D.

165 Ibid., p. 8.

166 Ibid.

167 Ibid., pp. 11 -12. The Cougar Model can both produce an optimal day-ahead generating unit commitment plan, and also dispatch the committed generating units of that plan in a least-cost manner to serve load for the electric system being represented. Ibid., p. 12.

at the 2 GW level of penetration and $3.71/MWh at the 3 GW level of wind.[168] However, the total *incremental* wind integration cost needed for additional wind should be determined by taking the difference between the total average integration costs determined for the 2 GW wind penetration level and any new level of wind penetration and dividing that figure by the incremental actual annual wind energy produced. This calculation produced a total incremental wind integration cost of $4.32/MWh.[169]

6. PacifiCorp

PacifiCorp completed a wind integration resource study in 2012 in order to estimate the operating reserves required to maintain system reliability and meet North American Electric Reliability Corporation ("NERC") control performance criteria.[170] The study resulted in an estimate of operating reserve volume and estimated cost of the operating reserves required to manage load and wind generation variation in PacifiCorp's Balancing Authority Areas.[171]

PacifiCorp used its Planning and Risk (PaR) production cost model to isolate the effect that additional reserve requirements due to wind generation have on overall system costs. This additional cost is attributed to the integration of wind generation resources and changes over time with changes in market prices for power and natural gas, changes in PacifiCorp's resource portfolio and potential changes in regional market design, such as an energy imbalance market.[172]

The study estimated the regulating margin requirement[173] based on load combined with wind variation and separately estimated the regulating margin requirement based solely on load variation.[174] The difference between these two calculations—with and without the estimated regulating margin required to manage wind variability and uncertainty—provided the amount of incremental operating reserves required to maintain system reliability due to the presence of wind generation in the PacifiCorp's BAAs.[175]

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[168] Ibid., p. 35.

[169] Ibid., Table 23.

[170] See *2013 PacifiCorp Integrated Resource Plan*. (April 30, 2013). Volume II, Appendix H to 2012 Wind Integration Resource Study, p. 84. PacifiCorp must provide sufficient operating reserves to comply with NERC Criteria BAL-007-1 and enough contingency reserves to comply with NERC Criteria BAL-002-0. Ibid., fn. 21, 22.

[171] Ibid.

[172] Ibid.

[173] Regulating margin is comprised of ramp reserve extracted directly from operational data, and regulation reserve which is estimated based on operational data. The study calculated regulating margin demand over two common operational timeframes: ten-minute intervals, called regulating; and one-hour intervals, called following. Ibid., p. 84.

[174] Ibid., p. 85.

[175] Ibid.

PacifiCorp provided Study results in Table H.1, depicting the average annual regulating margin (the regulating margin due to load separate from the regulating margin due to wind) and Table H.2, depicting the cost to integrate wind generation and including the incremental regulating margin reserves to manage intra-hour variances and the costs associated with day-ahead forecast variances that affect daily system balancing.[176] The load-only regulating margin was 394 MW and the incremental wind regulating margin was 185 for a combined regulating margin of 579 MW. The corresponding wind integration costs for 2012 included an hourly reserve cost of \$2.19/MWh and an inter-hour/system balancing cost of \$0.36/MWh for a total wind integration cost of \$2.55/MWh.[177]

While overall operating reserve levels are similar, this Study shows the estimated costs of these operating reserves are lower, and, according to PacifiCorp, the reduced cost is primarily driven by declining natural gas and power market prices.[178] The Study concludes that the effect of changing power and natural gas prices on the cost of wind integration is significant, even if the volume of wind being integrated does not change.[179] Further, second to hydro generation, natural gas generation is often used to meet the PacifiCorp's reserve requirements and manage variability and uncertainty in wind and retail load because gas-fired generation typically has less economic impact when used for reserves than coal-fired generation and has the operational flexibility to ramp up and down as the load and wind fluctuate.[180]

7. Subsection summary

It is clear that wind integration studies are developed using a diverse array of metrics that are often inconsistent across service territories. This diversity extends to wind penetration levels studied, types and costs of ancillary services considered, and types of cost models used. These variables in turn help to produce location-specific wind integration cost figures.

Company	**Penetration Level**	**Cost Model**	**Integration Cost**
Idaho Power	670-800 MWs 800-1000 MWs 1000-1200 MWs	Systems Operations Model (internally developed)	\$16.70/MWh \$22.42/MWh \$49.46/MWh
Portland Gas & Electric	850 MW	Mixed-Integer Programming (MIP)-based Optimization Model	\$11.04/MWh \$915/MWh
Puget Sound Energy		AURORA Model Ancillary Valuation Model	\$2.70/kW-month \$2.08/kW-month (reg. service for exports)

176 Ibid., pp. 85-86.

177 Ibid. Tables H.1 and H.2 can be found in Appendix D of this paper.

178 Ibid., p. 86.

179 Ibid.

180 Ibid. As natural gas prices have fallen, the costs of holding reserve capacity have correspondingly dropped even though the quantity of regulating margin requirement has increased. Ibid.

Bonneville Power Administration	5,100 MWs (approx.)		$1.23.kW-month
Public Service Company of Colorado	1140 MW 2000 MW 3000 MW	Couger Unit Commitment & Dispatch Model	$4.32/MWh
PacifiCorp	2126 MW	Planning & Risk (PaR) Production Cost Model	$2.55/MWh

The literature reviewed suggests that drivers of these diverse metrics include different resources available to provide regulation services, the location of those resources, and the flexibility and robustness of the grid. As discussed in the conclusion to this section, it may be worthwhile to take a closer look at the various models used to determine whether they provide any consistent metrics that can be compared across service territories. Even if such a comprehensive study were undertaken, however, it may be that the identification of consistent or "model" regulation cost inputs are elusive due to the host of factors subject to regional variations discussed above.

C. Organized market regions

In organized markets, reserves and other ancillary services are generally purchased at a single market clearing price in either a real-time, day-ahead or capacity market. This subsection briefly summarizes

- literature on the impacts of increased levels of wind generation on market clearing prices in organized markets; and
- RTO and other balancing authority treatment of imbalances related to VER integration

In 2010, SPP released a wind integration study prepared by Charles River Associates ("CRA").[181] A portion of the CRA report studied the impacts of 10% and 20% wind integration into the SPP region on SPP's day-ahead (or "Day 2") energy market clearing prices.[182] The day-ahead energy market clearing price is determined by the marginal unit, and CRA found that the higher penetration of wind and the transmission topology change necessary to accommodate wind additions affect which type of unit is on the margin.[183] CRA concluded that higher wind penetration does not necessarily lead to lower market clearing prices or result in a lower cost of energy for consumers, because the market clearing price is determined by the marginal units, not

[181] See Charles River Associates. (2004). *SPP WITF Wind Integration Study*.

[182] Ibid., p. 6-6.

[183] Ibid.

by infra-marginal[184] units like wind units, and the percentage of time that marginal resources (whether coal or gas) are on the margin shifts as wind integration levels change.[185]

In November 2012, PJM released a comprehensive Renewable Integration Study prepared by Exeter Associates and GE Energy and devoted a portion of the study to describe how different organized market operators and other balancing authorities treat energy imbalances from VER generators.[186] In brief, the study's findings were as follows:

BPA: BPA assesses persistent deviation penalties for positive and negative schedule deviations that exceed both 15% of the advance hourly schedule and 20 MW in an hour for three consecutive hours. VER generators that meet or beat a 30-minute persistence schedule are exempt from such penalties.[187]

CAISO: If a generator is participating in the Participating Intermittent Resource Program ("PIRP"), then hourly deviations are settled at a monthly weighted market-clearing price and accumulated for the monthly average of energy imbalances. If a variable generation resource does not participate in PIRP, then it is subject to 10-minute imbalance energy charges.[188]

ERCOT: All generation resources are settled in real-time based on their Real-Time Settlement Point Price ("RTSPP"). The settlement intervals are 15 minutes and the RTSPPs are calculated using the Nodal LMPs. Generators may be charged a penalty for deviating from their real-time base point instructions. For wind generators, penalties are determined by examining periods when they have been given an economic dispatch below their high dispatch limit (or capability) and during these periods, if a wind resource is generating more than 10% above its expected base point, it will be charged for the deviation based on real-time prices.[189]

ISO-New England: Energy deviations between real-time and day-ahead markets are also settled at the real-time LMP. Wind resources are exempt from a share of certain uplift costs that are allocated based on deviations.[190]

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184 A generating unit is infra-marginal if it is likely to be called on to supply power but unlikely to be decisive in determining the market price.

185 Ibid., p. 6-7.

186 Exeter Associates, *PJM Renewable Integration Study*.

187 Ibid., p. 14.

188 Ibid.

189 Ibid., pp. 13-14.

190 Ibid., p. 13.

MISO: Dispatchable Intermittent Resources ("DIRs") can be assessed Excessive or Deficient Energy Deployment Charges if an 8% tolerance band is exceeded for four or more consecutive 5-minute intervals within an hour. Both Intermittent Resources and DIRs are subject to Revenue Sufficiency Guarantee Charges - for positive scheduling deviations for DIRs for day-ahead schedules; and for positive and negative deviations for Intermittent Resources - though DIRs can receive real-time make-whole credits.[191]

NYISO: A VER generator that schedules day-ahead must buy or sell deviations at real-time LMPs. Up to 3,300 MW of installed wind and solar capacity is exempt from under-generation penalties when output differs from the real-time schedule during unconstrained operations.[192]

PJM: Balancing operating reserve charges are allocated to variable generation and other resources for deviations in real-time from day-ahead schedules. Generators will not be assessed balancing operating reserve charges if they follow PJM dispatch directions, and will also be eligible for operating reserve credits. A generator can decide not to follow PJM dispatch and will not be assessed balancing operating reserve charges if real-time output matches day-ahead schedules, but it will not be eligible for operating reserve credits. Differentials less than 5% or 5 MW incur no deviation charges.[193]

A complicating factor in the true assessment of wind integration costs in organized markets is the degree of market competitiveness and the impact of the lack of competition on clearing prices. For example, PJM's Independent Market Monitor ("IMM") declared PJM's regulation market "non-competitive" for the first three quarters of 2012 in the areas of market structure and market performance, and found market competitiveness to be indeterminate for the last quarter of 2012.[194]

D. A western regional energy imbalance market

Due to broad interest, a number of initiatives within the Western Interconnect have studied the potential benefits of adopting an energy imbalance market. An EIM is a mechanism that BAs and TPs could use to integrate higher penetrations of variable generation required to meet state renewable energy goals. The EIM is a centralized market mechanism that would enable dispatch of generation and transmission resources *across* balancing authority areas to resolve energy imbalances (or differences between generation and demand). In this way, the

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[191] Ibid., p. 14.

[192] Ibid.

[193] Ibid., pp. 12-13.

[194] See Monitoring Analytics. (March 14, 2013). *PJM State of the Market Report 2012*, pp. 265-266.

EIM would enable participants to manage transmission constraints and supply imbalance energy from the most cost-effective resources available in the region.[195]

A recent report prepared by Energy & Environmental Economics ("E3"), examining the benefits of an EIM between PacifiCorp and the California ISO, noted that adoption of an EIM could lead to more efficient interregional and intraregional dispatch, reduced flexibility reserve requirements in both regions and reduced renewable energy curtailment in the California ISO.[196]

A recent report by NREL stated that the economic dispatch of the EIM would operate every 5 minutes, allowing for a more economic balancing than would result if regulating resources were used for all imbalances inside the hour. Because part of the generation-load imbalance that needs to be addressed derives from the variability and uncertainty associated with wind and solar generation, an EIM would take advantage of the reduction in wind and solar generation variability that is achieved via the geographic diversity inherent across a wide area. An EIM could also allow a broader geographic range of generation resources to contribute to the economic balancing of generation and load.[197]

Further, as individual Western BAs currently manage energy imbalance and transmission congestion under their transmission tariffs, the energy supplied by the EIM would fulfill the imbalance settlement requirements of resources and loads, currently addressed in Schedules 4 and 9 of these tariffs (described in Section III of this paper), and replace them with market settlement rules.[198]

This brief introduction to current reports studying adoption of a Western regional EIM is provided to demonstrate that there may be options, short of adopting full organized market mechanisms, that could *more uniformly and transparently* establish wind integration costs in a manner that provides regulatory certainty and meets state and utility wind integration goals.

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[195] Regulatory Assistance Project, *2012 WGA Report*, p. 32.

[196] See E3, *PacifiCorp-ISO Energy Imbalance Market Benefits* Report. Notably, on June 28, 2013, FERC issued an Order accepting California ISO and PacifiCorp's EIM Implementation Agreement, finding its terms just and reasonable and not unduly discriminatory or preferential. The terms include a fixed implementation fee by PacifiCorp to CA ISO of $2.1 million based upon PacifiCorp's portion of the estimated $18.3 million CA ISO would incur if it were to configure an EIM to serve all BAAs in the Western Electricity Coordination Council ("WECC"). Further, CA ISO will develop the EIM through a stakeholder process and the agreement contemplates participation by other entities upon fulfillment of certain conditions. See Order Accepting Implementation Agreement, 43 FERC ¶61,298, June 28, 2013

[197] See Milligan, Michael, Clark, K., King, J., et al. (March 2013). *Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection*, National Renewable Energy Laboratory, p. vii. NREL notes that the EIM is intended to provide better generation-load balancing by being both big and fast and also that participation in the EIM would be voluntary. Ibid.

[198] See Regulatory Assistance Project, *2012 WGA Report*, p. 33. The EIM proposal would not establish an RTO or a consolidated regional network transmission tariff. The EIM governance documents could include provisions that would allow expansion of functions <u>only</u> with unanimous or supermajority agreement. While FERC would have jurisdiction to determine that EIM rates, terms and conditions are just and reasonable, that would not cause EIM participants to become jurisdictional themselves. Ibid.

However, this paper stops short of endorsing an EIM for the Western region as analysis of the costs and benefits of such an approach, still under consideration, is beyond the scope of this paper.

E. Section summary

As noted in the introduction to this paper, and as depicted in the VER integration cost tables presented in Appendix D of this paper, wind integration cost calculations are difficult undertakings in part because there are few if any metrics that lend themselves to meaningful comparisons across service territories, and thus states and regions are left to conduct wind integration cost studies based solely on the tools, proprietary models and market data available to them.

Comparisons between regions within and outside of organized markets add additional complexity. Take for example BPA's base rate proceeding to determine 2012-2013 base rates (discussed in Sections III and IV), in which the Record of Decision acknowledged the difficulty of comparing BPA's VERBS rate to wind integration rates across the country.[199] BPA staff explained that because there is no centralized energy or capacity market in the Pacific Northwest similar to the markets operated by ERCOT, MISO, NYISO, CAISO, PJM, and ISO-NE, BPA *must price capacity products and services based on the current tools and markets available in the region*.[200] Adoption of a Western regional EIM may alleviate these differences across certain regions, though the market's structure and viability is still under consideration.

A more comprehensive research project could attempt to shed light on the cost models used to calculate integration costs for the purpose of extracting usable metrics that can be compared against one another in a meaningful way. Such a project would require collaboration across the industry including regulatory commissions, power companies and public utilities. If done correctly, the study could result in the standardization of at least some metrics across states and regions, thereby providing state regulatory commissions a basis from which to evaluate integration cost figures placed before them for approval. In addition, such an effort could result in state commissions accessing proprietary computer models (respectful of confidentiality concerns) that drive the calculation of integration costs and training on how to use the models and interpret their results.

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[199] *BPA Wholesale Power and Transmission Rate Adjustment Proceeding* (BP-12) Administrator's Final Record of Decision ("ROD") (July 2011), p. 213.

[200] Ibid. (citing Mainzer et al., BP-12-E-BPA-42, at 34.) (Emphasis added). BPA staff explained that it is not comparable to look only at the hourly costs for regulation, spinning reserve, non-spinning reserve, and supplemental operating reserve and not discuss the export fees the organized markets charge to supply reserves for schedules to other balancing areas, which is similar to many of the costs BPA must recover in its VERBS rate. The critical need for capacity payments must also be considered to ensure that resources are constructed and available to supply the hourly markets for regulation, spinning reserve, non-spinning reserve, and supplemental operating reserve. Ibid., p. 214 (citing BPA staff's response to NWG at pp.34-35).

V. Bonneville Power Administration's Regulatory Challenges

Driven in part by its own success integrating large amounts of wind resources onto its grid system - BPA has over 4,700 MW of wind generation interconnected to its transmission system which marks the highest ratio of wind capacity to peak load (10,500 MW) of any balancing authority in the country[201] - BPA has had to address physical and jurisdictional consequences in a variety of federal and internal processes including:

- Base rate case proceedings – *Wholesale Power and Transmission Rate Adjustment Proceeding*, Administrator's Final Record of Decision ("ROD"), BP-12-A-02 (July 2011); BP-14 Initial Rate Proposal, Power Rates Study, BP-14-E-BPA-01 (November 2012) (*Pending)*.

- FERC proceedings examining BPA's Environmental Re-Dispatch Policy and Oversupply Management Protocol, emergency wind curtailment practices and safe harbor tariff/reciprocity concerns – FERC Docket Nos. NJ12-7-000; NJ12-13-000 and EL11-44-000; and

- Internal BPA Working Groups - Wind Integration Team (WIT) initiatives.[202]

Many of these matters are currently being contested, and this paper does not take a position on any petition or contested matter. Rather, this section describes the issues and indicates the potential impacts of their resolution; but first, this section provides a note on the complex procedural history of various interrelated petitions.

A. A procedural history overview

On June 13, 2011, a coalition of wind generators filed a complaint with FERC alleging that BPA had provided transmission service in an unduly discriminatory and preferential manner that favored its own generation at the expense of third party generators.[203] The petition challenged BPA's Environmental Re-dispatch Protocol (discussed in subsection B) alleging that BPA favored its own federal hydro-power generation by curtailing non-federal generation and appropriating firm transmission rights to satisfy the needs of the federal generation.[204]

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[201] See *BPA Request for Leave to Answer and Answer*, Docket No. NJ12-7-000, May 30, 2012, pp. 5-6. (Citing *Strategies and Decision Support Systems for Integrating Variable Energy Resources in Control Centers for Reliable Grid Operations* at 25, fig. 18, available at http://www1.eere.energy.gov/wind/pdfs/doe_wind_integration_report.pdf.)

[202] See BP-12 ROD, p. 197.

[203] See *Complaint and Petition for Order Under F.P.A §211A*, Iberdrola Renewable, Inc., et al. v. Bonneville Power Admin., Docket No. EL11-44-000, (June 13, 2011). The coalition included Horizon Wind Energy LLC, Invenergy Wind North America LLC, Iberdrola Renewables, Inc., NextEra Energy Resources, LLC and PacifiCorp. See also, Snyder, Stephen, J. (May 16, 2013). "Bonneville Wind Power Transmission v. FERC," *Infrastructure, an American Bar Association Publication*, **Vol. 51**, No. 1, p. 1.

[204] Ibid.

On December 7, 2011, FERC granted the wind generator coalition petition ruling that the Environmental Re-dispatch Protocol violated FPA §211A by offering non-comparable transmission services at rates that are unduly discriminatory or preferential.[205] FERC directed BPA to file a revised OATT "that will govern service provided by Bonneville in the future," and that satisfies FERC's directive under FPA §211A by providing comparable transmission service that is not unduly discriminatory or preferential.[206]

BPA responded by requesting rehearing of the December 2011 Order and by making a compliance filing on March 6, 2012 replacing its Environmental Re-dispatch Protocol with a new proposed Attachment P to its non-jurisdictional OATT called the Oversupply Management Protocol ("OMP") (discussed in subsection B),[207] which BPA claimed resolved the December 2011 Order's comparability concerns.

The FERC denied BPA's Rehearing Petition on December 20, 2012 stating that §211A of the FPA grants FERC broad authority *to require unregulated transmitting utilities to provide comparable transmission service*, and clarified its directive that BPA file revisions to its tariff to address FERC's comparability concerns.[208] On the same day, FERC issued an Order conditionally accepting BPA's OMP compliance filing but rejecting the OMP provisions related to cost allocation and requiring further compliance within 90 days that ensured comparability in the provision of BPA's transmission service.[209]

On February 25, 2013, BPA petitioned the 9th Circuit U.S. Court of Appeals for review of the December 7, 2011 and December 20, 2012 FERC Orders granting the wind coalition's petition and denying rehearing, respectively.[210] BPA also requested rehearing of the December 20, 2012 Order, and FERC indicated on February 19, 2013 that BPA's request required further consideration. On March 1, 2013, BPA filed a revised OMP and requested approval, and on April 19, 2013, BPA filed an Answer to Protests of its revised OMP.

Simultaneous to the wind coalition petition and BPA's OMP filings, BPA filed a Petition for Declaratory Order Granting Reciprocity Approval[211] in response to a 2009 FERC Order denying BPA's request for reciprocity.[212] The FERC found in its 2009 Order that BPA had not

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205 See *Order Granting Petition*, Docket No. EL11-44, December 7, 2011. See also, Snyder, *Bonneville Wind Power*, p. 1.

206 Ibid., ¶¶s 30, 78.

207 See *Compliance Filing of BPA*, Docket No. EL11-44, March 6, 2012.

208 See *Order Denying Rehearing*, Docket No. EL11-44-001, December 20, 2012 at ¶¶s 20, 46.

209 See *Order Conditionally Accepting Compliance*, Docket No. EL11-44-002, December 20, 2012, ¶46.

210 See *Petitions for Review of Orders by the Federal Energy Regulatory Commission*, BPA v. FERC (9th Circ. 2013.)

211 See *BPA Petition for Declaratory Order Granting Reciprocity Approval*, Docket No. NJ12-7, March 28, 2012.

212 See *Order on Petition for Declaratory Order*, Docket Nos. NJ09-1-000 and NJ07-8-000 (July 15, 2009). *Rehearing denied*, 135 FERC ¶61,023 (2011).

satisfactorily complied with Order No. 890 because its tariff did not contain all of the provisions of the Order No. 890 *pro forma* tariff, and refused to grant Bonneville's request for a finding that its tariff was an acceptable reciprocity tariff "until it incorporates into its tariff those provisions that it has not implemented along with certain other modifications…"[213]

Under the *pro forma* OATT, a non-public utility TP may satisfy the reciprocity condition by providing service under a tariff that has been approved by FERC under the voluntary "safe harbor" provision of the *pro forma* OATT. A non-public utility TP using this alternative submits a reciprocity tariff to FERC seeking a declaratory order that the proposed reciprocity tariff substantially conforms to or is superior to the *pro forma* OATT. The non-public utility TP then must offer service under its reciprocity tariff to any public utility TP whose transmission service the non-public utility TP seeks to use.[214]

However, the wind coalition complainants have asserted that FERC's Order granting their complaint requires BPA to file a jurisdictional OATT pursuant to FPA §211A.[215] FPA §211A, enacted as part of the Energy Policy Act of 2005, provides in relevant part that

> The Commission may, by rule or order, require an unregulated transmitting utility to provide transmission service: (1) at rates that are comparable to those that the unregulated utility charges itself; and (2) on term and conditions (not related to rates) that are comparable to those under which the unregulated utility provides transmission services to itself and that are not unduly discriminatory or preferential.[216]

While the wind coalition complainants have filed comments in response to the reciprocity request indicating that FERC should adopt BPA's proposed OATT as a jurisdictional tariff under FPA §211A, BPA has asserted that the reciprocity request should be handled as a matter distinct from the issues raised in the wind coalition complaint.[217] Notably, BPA's revised OMP compliance filing has been submitted in both the wind coalition docket (EL11-44) and the BPA Reciprocity Petition docket (NJ12-7).

As BPA noted in one of its many pleadings filed in interrelated petitions before the FERC,

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[213] Ibid., ¶11.

[214] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63.

[215] See *Protest of Complainants*, Docket No. EL11-44-006 and NJ12-7-001, March 26, 2013, p. 4.

[216] 16 U.S.C. §824j-1 (2006).

[217] See *BPA Request of Leave to Answer and Answer*, Docket No. NJ12-7-000, May 30, 2012, Ibid., pp. 4-5. According to BPA, Docket EL44-000 concerns a complaint under FPA §211A regarding a protocol curtailing wind generation "and has nothing to do with reciprocity." Ibid.

> This is an extremely complex case that raises factual, legal, biological, environmental and economic issues. The case has great significance in the Pacific Northwest, if not nationally.[218]

The manner in which FERC decides the reciprocity request and the revised OMP compliance filing could indicate how aggressively it intends to interpret and apply FPA §211A. In any case, the resolution of each proceeding, including the petitions for review before the 9th circuit, will impact all consumers in the BPA service territory and could have wide-reaching implications nationally. The following subsections will examine the substance of certain wind integration-related concerns implicated in the above-referenced dockets.

B. BPA environmental re-dispatch protocol and oversupply management protocol

In June 2010, BPA experienced an extreme high water/high generation event that made it very difficult to maintain load-generation balance and manage river flows without violating certain Clean Water Act requirements that limit the amount of voluntary spill at Federal Columbia River Power System (FCRPS) resources to protect fish listed under the Endangered Species Act from gas bubble trauma due to nitrogen gas saturation.[219]

Following the June 2010 event, BPA undertook an evaluation to determine how to manage such events in the future. During the June 2010 event, BPA offered to offset other generation in the region with zero-cost power from the FCRPS, because, compared to spilling water, water run through turbines results in reduced nitrogen gas super-saturation.[220] During past high water events, most generators in the region had accepted this displacement when BPA offered low-cost or free FCRPS power, but this did not occur during the June 2010 event because certain wind generators receive production tax credit and renewable energy credit for every megawatt hour they generate, and thus they had no economic incentive to limit their output when BPA faced an extreme high water event.[221]

The Environmental Re-dispatch Protocol called for taking all measures, short of paying negative prices,[222] to find load and reduce spill at FCRPS projects; followed by re-dispatching all

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[218] See *BPA Request for Leave to Answer and Answer*, Docket No. EL11-44-000 (August 15, 2011), p. 1.

[219] See BP-12 ROD, pp. 13-14.

[220] Ibid.

[221] Ibid.

[222] BPA prefers to utilize curtailment and dispatch protocols, rather than paying entities to take federal power through "negative pricing" to manage cases of over-generation. BPA has stated that if it were to pay negative prices to comply with the Endangered Species Act and the Clean Water Act during high runoff events, the cost burden would shift and would be narrowly focused on BPA preference customers; and BPA contends that those laws were not designed to place this cost burden on a narrow class of utility ratepayers. See *BPA Statement of Environmental Dispatch and Negative Pricing*, December 3, 2010, p. 2.

thermal generators down to their minimum generation levels necessary to maintain reliable operations; and, once these measures were taken, to re-dispatch wind generators by ordering the wind generator to decrease generation while BPA supplied replacement power from the FCRPS at zero cost.[223]

After FERC accepted the wind coalition petition for declaratory order and denied BPA's rehearing request (see subsection A), BPA filed its Oversupply Management Protocol ("OMP") which purported to resolve FERC's comparability concerns by providing free replacement power to serve the generators' loads, and compensating them for lost Production Tax Credits and Renewable Energy Credits and, for existing contracts executed prior to March 6, 2012, losses due to the failure to deliver renewable energy.[224]

Though BPA has proposed a revised OMP tariff that addresses the cost allocation concerns FERC identified in its December 20, 2012 Order,[225] a number of protesters still assert that the OMP is not comparable because it unilaterally curtails wind generation and takes their firm transmission to serve their customers with BPA's own hydro power.[226]

FERC acknowledged in its December 20, 2012 Order that Bonneville faces the burden of satisfying the obligations set forth in its statutes, as well as numerous other environmental rules and regulations, including those promulgated under the Endangered Species Act and the Clean Water Act.[227] FERC also rejected the notion that by directing Bonneville to provide comparable transmission service in accordance with section 211A, it was ignoring Bonneville's other statutory obligations and was requiring Bonneville to act in a manner that violates those governing statutes.[228] It remains to be seen, however, whether a protocol can be designed that accommodates the various environmental, economic and comparability requirements in a manner that maintains system reliability.

C. BPA Dispatcher Standing Order 216

According to BPA, Dispatcher Standing Order 216 ("DSO 216"), developed by WIT, is a reliability tool under which, when BPA's planned capacity reserves are depleted, BPA curtails

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[223] See id at 14. BPA defined that Environmental Dispatch Protocol as operational mechanism designed to protect system reliability and meet Clean Water Act requirements during high water events. Ibid., p. 198.

[224] See *BPA Request for Leave to Answer and Answer*, Docket EL11-44-000, (May 30, 2012), p. 51.

[225] FERC took issue with BPA's plan to allocate 50% of the displacement costs during oversupply events to wind generators. See *FERC Order Conditionally Accepting Compliance Filing*, Docket No. EL11-44-002, December 20, 2012, ¶45.

[226] See *Protest of Complainants* (Iberdrola Renewables, LLC, Pacificorp, NextEra Energy Resources, LLC, Invenergy Wind North America, LLC, EDP Renewables North America LLC, Docket Nos. EL11-44-006; NJ12-7-001, March 26, 2013.

[227] See *Order Denying Rehearing*, Docket No. EL11-44-001, (December 20, 2012), ¶31.

[228] Ibid., ¶32.

wind generation or wind schedules (depending on whether wind plants are over-generating or under-generating) to maintain reliability.[229] BPA has asserted that without DSO 216, reliability on its system would be seriously compromised.[230]

DSO 216 is triggered when the amount of balancing reserve capacity BPA has deployed reaches 90 percent of the amount forecast in its rate proceeding. When this happens, BPA issues a DSO 216 order which either directs the wind generators to limit their output in a *dec* event or cuts a portion of the wind generators' schedules to a set amount above the actual level of generation in an *inc* event.[231] The result of a DSO 216 *inc* curtailment is that a schedule is cut back during the hour and the load serving entity receiving that schedule must make some adjustment to make up for the schedule cut.[232]

BPA staff explained that DSO 216 is a necessary reliability and operational tool for establishing and enforcing a limit on the quantity of balancing reserve capacity provided for VERBS, because BPA cannot provide unlimited balancing reserves.[233] Because wind resources can have highly unpredictable demands for balancing service, and because providing a service that covers all wind tail events[234] would require a significant amount of balancing reserve capacity, system reliability cannot be maintained without a mechanism such as DSO 216 that ensures risk is managed when demands for balancing reserve capacity exceed the level of service that is planned and defined on a forecast basis.[235]

During extreme wind ramp events, the entire amount of balancing reserve capacity BPA holds can be used up within 10 minutes and according to BPA, without DSO 216, when wind generators have extreme scheduling errors, those errors could exhaust the entire amount of balancing reserve capacity that BPA makes available for variable energy resources, load, and dispatchable energy resources.[236]

According to BPA staff, DSO 216 is designed to curtail only those wind generators that are causing the depletion of reserves and to move those generators down closer to their schedule or curtail their schedules closer to the actual level of their generation.[237] When BPA exhausts the *inc* balancing reserve capacity it has set aside for all balancing purposes, including load

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[229] See *BPA Request for Leave to Answer and Answer*, Docket No. NJ12-7-000 (May 30, 2012), p. 4.

[230] See BP-12 ROD, p. 234 (citing Mainzer *et al*., BP-12-E-BPA-42, p. 19).

[231] Ibid., p. 12.

[232] Ibid.

[233] See BP-12 ROD, p. 233 (citing Mainzer *et al.*, BP-12-E-BPA-23, p. 31).

[234] Wind Tail Events are events where there are large imbalances between generation and load.

[235] Ibid., p. 234 (citing Mainzer *et al.*, BP-12-E-BPA-42, p. 19).

[236] Ibid. BPA staff adds that load and non-VER generators do not impose these extreme movements on the BPA system. Ibid.

[237] Ibid., p. 236.

balancing, BPA directs the wind generators that are scheduling more power than their actual generation to curtail the amount of their schedules to reflect their actual generation levels. Similarly, when BPA exhausts the *dec* balancing reserve capacity it has set aside for all balancing purposes, BPA directs the wind resources that are scheduling less power than their actual generation to reduce (feather) their generation to reflect their actual schedule.[238]

Some stakeholders have alleged that DSO 216 violates the *pro forma* OATT because when a TP curtails transmission customers in response to a reliability event, such curtailments must be made according to the level of transmission service a customer contracts for (i.e., non-firm transmission is curtailed prior to firm and/or network transmission service), and not based on distinctions pertaining to generator type.[239] They assert that DSO 216 requires involuntary curtailments of firm transmission service only for wind generators, in a manner that is not comparable to the treatment of Federal generation using firm transmission.[240]

Stakeholders have also stated that when BPA cuts schedules under DSO 216, adjacent BAs find themselves with an instant, unanticipated energy shortage in their systems, forcing them to scramble to deploy reserves to make the schedules whole and maintain balance in their footprint.[241]

BPA acknowledged that DSO 216 orders are only given to wind generators, but noted that it is wind generators that are driving the excessive use of balancing reserve capacity. BPA also asserted that undue discrimination requires that the TP is *unreasonably* applying different terms and conditions to customers that are similarly situated.[242] While concerns with DSO 216 are pending before FERC (they have been raised in EL11-44, NJ12-7 and the VER Order proceedings), it is notable that FERC has conditionally approved Southwest Power Pool's tariff amendment that would allow curtailment of currently non-dipatchable resources, including intermittent renewable resources, to relieve congestion.[243]

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[238] Ibid. (citing Mainzer *et al*., BP-12-E-BPA-23, p. 22.)

[239] See *Motion Requesting Clarification or, in the alternative, Rehearing of Iberdrola Renewables*, Docket No. RM10-11-001 (July 23, 2012), p. 3.

[240] Ibid., p. 5. The protest also claims that that DSO 216 curtails transmission customers in instances that are not in response to reliability events and not made according to the level of transmission service contracted for. Ibid., p. 7 and fn. 22, 23.

[241] *Request for Clarification or Rehearing of PowerEx Corp*, RM10-11-001 at 6, January 22, 2012. (Citing Protests and Comments of Complainants, p. 15, Docket No. NJ12-7-000, April 30, 2012.)

[242] See BP-12, ROD, p. 239 (citing *El Paso Natural Gas Co.*, 104 FERC ¶ 61,045, P 115 (2003) (emphasis added). According to BPA staff, in the case of application of DSO 216 the wind generators are not similarly situated to load and dispatchable generators, because the depletion of BPA's balancing reserve capacity is driven by the variability of the wind generators that are affected by the DSO 216 orders. Ibid.

[243] See Snyder, *Bonneville Wind Power Transmission v. FERC*, p. 4 (citing *Southwest Power Pool, Inc.* 140 FERC ¶61,225 (2012)).

D. Unilateral amendments to the FERC-jurisdictional Large Generator Interconnection Agreement (LGIA)

As noted in Section III.B above, FERC did not extend the Order 764 forecasting requirements to existing interconnection customers, reasoning that it would unfair to unilaterally allow TPs to impose unexpected costs associated with data reporting on existing transmission customers without making a showing that the specific data sought by the TP, and associated costs, are just and reasonable.[244] BPA called the ability to amend Appendix C of the LGIA unilaterally "essential" and stated that it may not have sought reciprocity safe harbor status with the Commission with this limitation. BPA also noted FERC's discussion of Article 9.3 of the LGIA in BPA's 2005 Safe Harbor Order,[245] as providing the TP a right to unilaterally amend Appendix C to include operational requirements.[246] BPA requested in the alternative, that the FERC clarify that the mutual agreement approach to changing data requirements does not apply to non-jurisdictional entities that have the unilateral right to amend Appendix C.[247]

FERC rejected BPA's request for clarification, stating that Order 764 does not apply to non-jurisdictional entities such as BPA unless such entities seek to qualify for or maintain safe harbor status. FERC stated that BPA could take the issue up, if it arises (i.e., if its customers do not agree with its reporting requirements) through a petition for declaratory order.[248]

As are many of the other issues discussed in this paper confronting BPA, the issue of unilateral amendments to Appendix C of the LGIA are tied in with BPA's status on reciprocity. This warrants a brief further discussion:

As a Federal power marketing administration, BPA is not subject to FERC jurisdiction or to the standards that apply to public utilities under the Federal Power Act. Non-jurisdictional entities can voluntarily file an OATT with the Commission to confirm that the tariff's terms and conditions substantially conform or are superior to the Commission's national model. This is called seeking reciprocity status.[249] However, it is unclear in what manner, if any, FERC will condition acceptance of a BPA OATT on adherence to FPA §211A, which extends FERC enforcement of comparability principles to unregulated public utilities.

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244 See Order 764, ¶195.

245 112 FERC ¶61,195 (2005)

246 See *Bonneville Request for Clarification or Rehearing*, RM10-11-000, July 23, 2012, pp. 10-11.

247 Ibid. Bonneville has over 4,900 of existing VER generation on its system and the inability to require such data could impede its ability to predict balancing requirements and undermine efforts to integrate additional VERs. Ibid.

248 See FERC Order 764-A, ¶¶36-39.

249 See BP-12 ROD, p. 10.

As noted earlier, FERC denied BPA safe harbor status subject to the agency making certain additions to and clarifications of its tariff in July 2009.[250] In April 2011, FERC issued an order denying rehearing and reiterating that to satisfy reciprocity requirements, BPA must revise its OATT as specified in the July 2009 Order.[251] BPA currently has a petition seeking reciprocity pending in Dockets NJ12-7 and NJ12-13, and will have to determine whether to proceed in light of the position FERC has taken in the VER Orders rejecting a TPs unilateral right to amend Appendix C of the LGIA.

E. Financial risk of reserve capacity procurement

In Order 764, FERC stated that the TP retains the risk and responsibility for inaccurate procurement of reserve requirements while the transmission customer retains the financial risk and responsibility for inaccurate schedules.[252] BPA claimed that VER customers should bear the risk of inaccurate reserve capacity procurement.[253] Since TPs are required to use power production forecasting to identify the necessary amount of reserves, if the data are wrong, the forecasts will be wrong, causing the TP to procure an incorrect amount of reserves.[254]

Therefore, BPA asserts that transmission customers should bear the costs of 1) excess reserves based on incorrect power production forecast and 2) short-term expensive purchases if too few reserves are acquired due to bad forecasts.[255]

In response, FERC stated that TP should maintain reserves sufficient to manage the aggregate variability caused by loads and resources on the system, but also recover the costs of providing these reserves – and allocate costs based on their responsibility for those costs.[256] FERC added that TPs can demonstrate that inaccurate data are leading to increased reserve costs and TPs should be able to recover those costs from the customer causing them.[257]

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[250] The Commission found that BPA's OATT was "acceptable for its reciprocity tariff with respect to the Transmission Planning requirements of Order 890," but also stated that BPA must amend its tariff to comply with the remaining requirements of Order 890 and that "[u]ntil Bonneville has amended its tariff in such a manner, it does not qualify for safe harbor treatment." See *Order Granting Clarification and Dismissing Rehearing, U.S. Dep't of Energy, Bonneville Power Admin*., 130 FERC ¶61,260, August 17, 2010, ¶4, fn. 2.

[251] See BP12 ROD at 11-12. BPA has filed Petitions for Declaratory Order Granting Reciprocity Status in cases pending before the FERC. See Docket Nos. NJ12-7-000, NJ12-13-000 and EL11-44-000.

[252] See Order 764 ¶331.

[253] See *Bonneville Request for Clarification or Rehearing*, RM10-11-000, July 23, 2012, p. 6.

[254] Ibid., p. 8.

[255] Ibid., pp. 8-9.

[256] See FERC Order 764-A, ¶69.

[257] Ibid., ¶70.

F. BPA curtailment practices

In Order 764, FERC stated that TPs must maintain sufficient capacity to provide Schedule 9 generator imbalance service, even though FERC has not adopted a generic generator regulation rate.[258] If the TP does not have sufficient reserves either because none exist or because they are fully subscribed, TP must attempt to procure alternatives.[259]

BPA responded that FERC should allow limiting the output of VERs that are over-generating to their schedules or curtailing the schedules of VER customers that are under-generating to their actual output.[260] BPA stated that if a TP is out of balancing reserve capacity, it can no longer absorb the difference between scheduled and actual output and it must take other steps or else risk reliability or other legal violations.[261]

FERC rejected BPA's request to curtail only VERs and not other transmission customers and stated that curtailments are required to be made on a non-discriminatory and comparable basis.[262] However, FERC did allow, in response to a request by PowerEx, that if a TP seeks to curtail a transmission customer's transmission service due to a lack of reserves, it would have to show that it had made the efforts specified in Order 890-A, i.e., that it attempted to procure alternative balancing resources, or if unavailable, it accepted use of dynamic scheduling[263] with a neighboring control area or allowed the transmission customer to self-supply the regulation service.[264]

FERC thus appears to suggest that curtailments by TPs are permissible in limited circumstances where there is a lack of reserves and when TPs follow the protocols established in Order 890-A. It is unclear whether this guidance would apply to DSO 216 which is an emergency tool for use in extreme reliability circumstances. Both Iberdrola and BPA agreed that DSO 216 is not an issue in the VER Order proceedings,[265] and if FERC grants rehearing requests

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[258] See FERC Order 764, ¶270.

[259] Ibid.

[260] See *Bonneville Request for Clarification or Rehearing*, RM10-11-000, July 23, 2012, p. 20.

[261] Ibid., p. 21.

[262] See Order 764-A, ¶94.

[263] Dynamic transfer refers to electronically transferring generation from the balancing authority area in which it physically resides to another balancing authority area in real-time. Such transfers allow generation to be located and controlled in a geographic location that is outside of the receiving balancing authority area. Dynamic transfer involves software, communications and agreements and requires the appropriate amount of firm, available transmission capacity between locations. Dynamic transfers facilitate energy exchanges between balancing authority areas and increase operational efficiency and flexibility. See Regulatory Assistance Project, *2012 WGA Report*, p. 5.

[264] See Order 764-A ,¶93 (citing Order 890-A, ¶290).

[265] See *Iberdrola Motion Requesting Clarification or Rehearing*, Docket No. RM10-11-001 (January 22, 2013), p. 4. See also, *BPA Motion for Leave to Answer and Answer*, Docket No. RM10-11-002 (February 7, 2013), p. 4.

of Order 764-A, FERC is likely to agree. The conflict between a TP's ability to curtail VERs during reliability events and a VER generator's right to be treated in a comparable fashion may persist until FERC clarifies the matter in a subsequent rulemaking.[266]

G. Section summary

As BPA continues to work towards resolution of the various challenges pertaining to it before the FERC and the 9th Circuit Court of Appeals, it is likely to engage in a process to determine the costs and benefits of continuing to pursue reciprocity amid the sacrifices it may be forced to make to attain it. The benefits of reciprocity include open access transmission service to transmission customers on comparable terms.[267] The requirements of reciprocity status include provision of any service to another TP that the nonpublic utility provides or is capable of providing on its system.[268]

However, if gaining reciprocity status also means sacrificing BPA's ability to curtail wind when it believes it to be necessary, or its ability to unilaterally amend the LGIA to ensure proper data is being provided to accurately predict balancing resource requirements, BPA may reconsider its reciprocity petition. BPA has already stated that it may be unable to operate reliably without DSO 216, even while DSO 216 has been raised as an issue in EL11-44-000 and NJ12-7-000. The Clean Water Act, Endangered Species Act and other environmental statutes to which BPA is subject prevent BPA from simply accommodating FERC comparability principles without first considering whether it will be out of compliance with its environmental obligations. For example, OMP is an emergency protocol designed to comply with environmental mandates and if BPA is unable to fashion the protocol to FERC's satisfaction, it may be forced to forego reciprocity. Resolution of this process may challenge the reach of FERC Order 890 and FPA §211A comparability principles when weighed against robust environmental and reliability mandates.

On the other hand, BPA and FERC may continue to work towards a solution that meets FERC comparability principles without violating other environmental statutory mandates. Perhaps this type of measured resolution would benefit from FERC or other interested parties offering guidance to BPA on how to achieve compliance on these multiple fronts. In any case,

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[266] On June 28, 2013, ISO New England issued a memo to stakeholders summarizing its curtailment practices and indicating the factors that contribute to the need to curtail wind resources as transmission constraints, interconnection choices and wind generator technologies. See Wilkinson, Eric. (2013). *Summary of Wind Power and Curtailment in New England*, ISO-New England, p. 2. Available at http://www.iso-ne.com/pubs/pubcomm/corr/2013/curtailment_summary_2013.pdf

[267] Reciprocity status helps ensure that transmission service is provided under an OATT that is clear, transparent, predictable and stable; helps ensure consistency with the OATTS of other TPs in the region; and helps facilitate transmission across interchanges, which is often required to deliver power from remote generation. See Pacific Northwest Investor Owned Utilities. (March 3, 2011). *Letter to BPA*, (available at http://transmission.bpa.gov/customer_forums/bpa_oatt/documents/bpa_reciprocity_letter.pdf).

[268] See Order 888-A, ¶30,286.

FERC and BPA appear to be working their way towards some middle ground, though there appears to be a long way to go.

Achieving that balance, where BPA regains reciprocity status and retains the curtailment and dispatch protocols it needs to operate the system within acceptable environmental and reliability limits could serve as a national demonstration, if not a national model, of how a balancing authority can operate in a manner that is reliable and environmentally responsible and that treats each transmission customer on a basis comparable to all other transmission customers.

VI. Conclusions and Recommendations

This paper examined three interrelated regulatory topics that concern VER integration cost determinations for the purpose of informing state regulatory commissions both about improvements to the regulatory landscape and persistent challenges.

First, this paper summarized FERC Orders 764 and 764-A and suggested that by adopting reforms that enable balancing of the grid through scheduling and dispatch procedures rather than exclusively though reserve services, while still providing guidance on cost recovery for ancillary transmission services provided, the FERC has taken a balanced approach towards VER integration cost mitigation.

The paper concludes that additional reforms, such as balancing area consolidation and re-dispatch and curtailment practice protocols, which were contemplated during the Notice of Inquiry proceeding, could further impact wind integration costs and suggests that state regulatory commissions consider whether to collectively encourage FERC to adopt further reforms through a formal rulemaking process.

Second, this paper examined six distinct Western U.S wind integration cost calculation processes, noting wind integration cost drivers identified in academic and industry literature, and cataloguing information on methodologies and cost figures. The paper concludes that due to regional differences in (often proprietary) models, resources, market structure and a host of other factors, meaningful evaluations and comparisons of VER integration cost data across service territory areas are difficult if not untenable.

The paper recommends that state regulatory commissions consider undertaking a more comprehensive analysis that would shed daylight on the various cost models used to develop wind integration costs for the purpose of identifying those metrics that do lend themselves to meaningful comparisons across service territories, and which could ultimately provide regulatory authorities with standards upon which to base evaluations of wind integration cost data sets that are placed before them for approval. The paper recommends a collaborative undertaking including state regulatory commissions, power companies and public utilities. Such an effort could result in state commissions accessing proprietary computer models (accounting for confidentiality concerns) that drive the calculation of integration costs and training on how to use the models and interpret their results.

Third, this paper examined wind integration related regulatory challenges currently faced by BPA. It described the procedural history of a successful petition to strike certain environmental and reliability-related protocols as violating the FPA; BPA’s responsive compliance filings and challenges to FERC Orders; and BPA’s concurrent request for reciprocity status. It also described five concerns impacting BPA’s wind integration practices: Environmental Dispatch/Oversupply Management Protocols, Dispatcher Standing Order 216, unilateral amendment to the LGIA, the financial risk of reserve capacity procurement, and BPA’s curtailment practices.

The paper concludes that the process that BPA undertakes to determine whether it can obtain reciprocity status while retaining its dispatch and curtailment protocols, as well as other practices it believes are required to maintain compliance with environmental statutes and operate its system reliably, if achieved, could serve as a national demonstration of how a balancing authority can operate in a manner that is reliable and environmentally responsible, and that treats each transmission customer on a basis comparable to all other transmission customers. On the other hand, the process may reveal the limitations of FERC Order 890 and FPA §211A comparability principles when weighed against equally robust environmental and reliability mandates.

Appendix A

A Description of Ancillary Services Used to Balance System Variability

Regulation – Fast, unpredictable variations in load occur in short (seconds to minutes) time frames, so energy generation must be ready for increases or decreases to meet the changes. Since variations in wind energy generally take place over longer times, wind power needs only minimal regulation. An automatic generation control system monitors load and generation and automatically balances the two by sending signals to power plants to increase or decrease their output.[269]

Regulation can be a significantly different service depending on the scheduling interval of the balancing authority. In areas with 5-minute energy scheduling, regulation is a fast service that deals with minute-to-minute variability. In areas that have only hourly scheduling, regulation is typically based on a longer interval (e.g., 90-minute service).[270]

Load Following – Energy demand and wind energy output vary more dramatically over time frames that extend from 10 minutes to several hours. The longer time frames cover the variation from low electricity consumption in the middle of the night to high consumption during the day. To balance energy production and consumption during this longer time frame, system operators deploy various types of generation to meet energy demand at the lowest cost.[271]

Unit Commitment – Some generators (including coal-fired power plants) require longer-term planning because they need anywhere from hours to days of preparation before they can generate power. System operators select which generators will be needed for each day's operation through the unit commitment process. They strive to ensure that adequate generation is available to reliably meet load at lowest cost.[272]

Reserves that are online and available to respond within 10 minutes are known as spinning reserves. Reserves with longer response times are referred to as non-spinning reserves.[273]

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[269] See NCLS Report, *Integrating Wind Power Into the Electric Grid*, p. 2.

[270] Porter, *2013 NREL Report*, fn 5.

[271] See NCLS Report, *Integrating Wind Power Into the Electric Grid*, p. 2.

[272] Ibid.

[273] Ibid., p. 3.

Appendix B

State Regulatory Commissions and Related Organizations in Order 764 Proceedings

Arizona Corporation Commission

California Public Utilities Commission

Massachusetts Department of Public Utilities

Montana Public Service Commission

National Association of State Utility Regulatory Commissioners (NARUC)

New England Conference of Public Utility Commissioners (NECPUC)

New Mexico Public Utility Commission

New York State Public Service Commission

Oregon Public Utilities Commission

Washington Utilities and Transportation Commission

Appendix C

Current Trends in Wind Cost, Viability, and Penetration Levels

By Daniel Phelan, Research Assistant, NRRI

Wind power is a variable resource, and must deal with uncertainty regarding its magnitude and frequency of generating capacity. The output of a turbine is determined by wind speed, which varies due to weather conditions. A turbine operator is therefore able to guarantee neither when his or her turbine will be active nor how much power the turbine will produce. Despite the challenges of variable generation, America added 10,689 MW of wind power in 2012, more than any other energy resource (Office of Energy Products, 2012). The U.S. Department of Energy (DOE)'s stated goal of 20% wind power by 2030 suggests that wind resources represent a growing piece of America's power grid (U.S. Department of Energy, 2008).

In describing this goal, the DOE addressed some challenges associated with wind power. These issues are primarily related to variability and transmission. To limit the negative impacts of variability, system operators must maintain reserve power. Aggregated wind power from a broad geographical area displays less variability, but a single turbine's output remains difficult to predict. Wind forecasts help estimate the output of wind turbines, and system controls further limit variability within a wind farm (North American Electric Reliability Corporation, 2009). The transmission difficulties related to wind power include reliability, voltage, and frequency. A variable-speed turbine is capable of responding to these needs, and system operators can take advantage of these turbines to improve system reliability. Technological advancements in turbine production allow for wind power to respond to the dynamic needs of power systems (U.S. Department of Energy, 2008).

Due to variability, wind will sometimes fail to meet demand, and at others exceed it. Advancements in wind forecasting techniques will allow system operators to better predict wind output, and operational techniques can limit the impact of variability. When wind falls short of demand, the grid must rely on other sources of energy for balancing purposes. The DOE points to energy spot market developments in the MISO, PJM, SPP, New York, and New England regions as beneficial to the further adoption of wind power, as these markets allow grid operators to economically balance load (U.S. Department of Energy, 2008). Demand-side response also helps mitigate shortages by encouraging customers to limit energy usage in times of high demand. In cases of extreme weather events, where wind output may exceed demand, turbines can utilize electricity storage methods or even shut down. Alternatively, this excess can be sold to other interconnected markets (Gul & Stenzel, 2005).

Cost Comparisons

Another barrier to wind integration is the cost of wind power. There are no fuel costs associated with wind, and the price of wind power is largely driven by turbine costs. Between 2003 and 2008, the cost of installing a wind turbine steadily increased to roughly $1,500/kW. Today, turbines are from a fifth to a third less expensive than they were at their height in 2008, but the cost of wind energy still reflects those higher-priced turbines (Bolinger & Wiser, 2011).

Many turbine projects being built today struck Power Purchase Agreements (PPAs) in 2008, and these PPAs are based on higher turbine production costs. PPAs made after 2008, however, tend to have lower power costs due to decreasing expenses. Regional differences also play a large role in the price of wind. In California, the state with the second highest installed wind power capacity, the average cost of wind power is much higher than the national average. Still, wind power cost is approaching parity with the electric wholesale rate. Nationally, the lowest cost wind projects compete with wholesale rate electricity, but higher cost projects do not (Wiser & Bolinger, 2011). While turbine costs and wind power costs exhibit downward trends, these prices hold great uncertainty due to the instability of the Production Tax Credit (PTC).

The status of the PTC plays a large role in American turbine financing. In years where the PTC has lapsed (2000, 2002, and 2004), wind installations have drastically decreased, never adding more than 500MW of capacity. This credit amounted to 2.2 cents per kWh in 2011, and the Recovery Act of 2010 has provided additional tax incentives for wind power. While these supporting policies are presently beneficial to the wind industry, they are not permanent. These incentives encourage immediate investment in wind power, but do not provide long-term security for turbine producers. Without these incentives, turbine installation stalls, and financing wind projects becomes more difficult (Wiser & Bolinger, 2011).

International Approaches

The U.S. remains one of the world leaders in wind integration despite wind’s economic and technological challenges. In 2012, China was the only country to add more wind power capacity than America, and these additions brought total installed capacity to 75,564 MW (Global Wind Energy Council, 2013). China’s installed wind capacity is the largest of any country, but does not reflect that energy market penetration of wind is low. China has seen a large growth in energy usage over the last decade, and the country primarily uses coal to meet that demand. China’s lagging transmission infrastructure represents the nation’s largest challenge to wind integration. Most of China's installed wind capacity is in the north, and interregional grid connections are minimal (Cheung, 2011). It is difficult for these turbines to provide other parts of the country with wind power. Without significant developments to their electrical grid, wind’s penetration capability is limited. While China is adding a large amount of wind power, the country's grid infrastructure favors coal power.

Wind turbines accounted for 26.5 % of Europe's power capacity additions in 2012 (Wilkes & Moccia, 2013). Germany has the most wind capacity of any European country, with 31,308 MW of installed capacity. European wind has spread rapidly over the short history of the twenty-first century. In 2000, wind power was centralized in three European countries: Germany, Spain, and Denmark. These countries held 85% of Europe’s wind power capacity; today they own just 18% of the total market (Wilkes & Moccia, 2013). Denmark remains exceptional, as 27.1% of its energy consumption is provided by wind. This is the highest level of wind penetration in the world, and Denmark has expressed a goal of 50% wind penetration by 2020. In order to combat the challenges of wind integration, Denmark has taken advantage of extensive interconnection with neighboring countries such as Norway, Sweden, and Finland. Denmark utilizes reserves located in neighboring countries and, in turn, provides these countries with excess wind power (Lund, Henrik; Hvelplund, Frede; et al., 2013).

Conclusion

With proper techniques and policy support, wind can be an economic and reliable source of power. However, operators should keep variability in mind and ensure the appropriate reserves are available. Grid improvements to infrastructure and interconnectedness will allow the further integration of wind power. The presence of wind power in America's power grid is growing, and is linked to policy decisions at both the state and federal level. American turbine production is strongly linked to incentives like Renewable Energy Credit (REC) programs and the PTC. These programs allow wind to compete on cost with other sources of electricity, or even mandate the purchase of renewable resources. With policy choices continuing to promote variable resources, grid operators will find it necessary to integrate higher levels of variable resources within their systems. Maintaining reserve power, increasing interconnection, and broad geographic aggregation of wind resources are some of the most important steps an operator can take to limit variability.

Appendix D
Wind Integration Cost Study Tables

I. Portland General Electric Company[274]

Table 9: Integration costs by component, year 2014

Identifier	Cost Saving For PGE	Run Delta Measures:	Cost/MWh ($2014)
A	RUN 7 – RUN 1	**Cost of Wind Integration** Cost for Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation	$11.04
B	RUN 6 – RUN 1	Cost for Day-Ahead Uncertainty	$3.44
C	RUN 3 – RUN 1	Cost for Hour-Ahead Uncertainty	$4.59
D	RUN 4 – RUN 1	Cost for Load Following	$1.03
E	RUN 5 – RUN 1	Cost for Regulation	$1.50

Table 10: Integration costs by component with two additional LMS100 SCCTs

Identifier	Cost Saving For PGE	Run Delta Measures:	Cost/MWh ($2014)
A	RUN 7 – RUN 1	**Cost of Wind Integration** Cost for Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation	$9.15
B	RUN 6 – RUN 1	Cost for Day-Ahead Uncertainty	$3.61
C	RUN 3 – RUN 1	Cost for Hour-Ahead Uncertainty	$2.86
D	RUN 4 – RUN 1	Cost for Load Following	$0.75
E	RUN 5 – RUN 1	Cost for Regulation	$0.98

274 See PGE, *PGE Wind Integration Study Phase II*, pp. 47, 51.

II. Bonneville Power Administration[275]

Table 10. BPA Wind Integration Rates

Year	Rate	Monthly Charge for a 100 MW Project
2009	$0.68 per kW-month	$68,000 per month
2010–2011	$1.29 per kW-month	$129,000 per month
2012–2013	Wind: $1.23 per kW-month Solar: $0.21 per kW-month	$123,000 per month $21,000 per month

Source: BPA:
2009 Wind Integration Rate Case Final Proposal, Final Record of Decision, June 2008.
2010 Wholesale Power and Transmission Rate Adjustment Proceeding (BPA-10) Administrator's Final Record of Decision, Appendix C, July 2009.
2012 Final Rate Proposal, Generation Inputs Study, July 2011.

III. Public Service Company of Colorado/Xcel[276]

Table 2: Average Regulation Wind Integration Cost

Wind Penetration Level	20%	2 GW	3 GW
Average Regulation Wind Integration Costs ($/MWh)	0.10	0.14	0.21

Table 3: Average System Operations Wind Integration Cost ($5.06/MMBtu gas price)

Wind Penetration Level	20%	2 GW	3 GW Scenario 2[3]
Average System Operations Wind Integration Cost ($/MWh)	2.39	3.40	3.71

Table 4: Average Gas Storage Wind Integration Cost ($5.06/MMBtu gas price)

Wind Penetration Level	2 GW	3 GW Scenario 2
Average Gas Storage Wind Integration Cost ($/MWH)	0.14	0.17

[275] Porter, *2013 NREL Report*, p. 37.

[276] Xcel, *Public Service Company of Colorado 2GW and 3GW Wind Integration Cost Study*, p. 8.

IV. PacifiCorp[277]

Table H.1 - Average Annual Regulating Margin Reserves, 2012 Wind Study (MW)

	West BAA	East BAA	Combined
Load-Only Regulating Margin	147	247	394
Incremental Wind Regulating Margin	54	131	185
Total Regulating Margin	202	378	579

Table H.2 - Wind Integration Cost (2012$ per MWh of Wind Generation)

Study	2010 Wind Integration Study	2012 Wind Integration Study
Wind Capacity Penetration	2046 MW	2126 MW, 2011 Operational Data
Tenor of Cost	3-year levelized, 2010$	1 year levelized, 2012$
Hourly Reserve ($/MWh)	$8.85	$2.19
Interhour/System Balancing ($/MWh)	$0.86	$0.36
Total Wind Integration ($/MWh)	$9.70	$2.55

277 *2013 PacifiCorp Integrated Resource Plan*, pp. 85-86.

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