A Review of Variable Generation Integration Charges

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List of Acronyms

ACE	area control error
AGC	automatic generation control
APS	Arizona Public Service
BA	balancing authority
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CAPEX	Capital Expansion Model
CPS2	Control Performance Standards
DERBS	Dispatchable Energy Resource Balancing Service
DOE	U.S. Department of Energy
EIS	energy imbalance service
ERP	electric resource plan
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
GOM	Generation Optimization Model
HYSIM	Hydro Simulation Model
IPC	Idaho Power Company
IPUC	Idaho Public Utilities Commission
IRP	integrated resource plan
ISD	incremental standard deviation
LMP	locational marginal price
LTAP	long-term acquisition plan
NAU	Northern Arizona University
NERC	North American Electric Reliability Corporation
NPPD	Nebraska Public Power District
NREL	National Renewable Energy Laboratory
NWP	numerical weather prediction
OATT	Open Access Transmission Tariff
PGE	Portland General Electric
PSE	Puget Sound Energy
PSCo	Public Service Company of Colorado
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic
QF	qualifying facility
REC	renewable energy credit
SAR	surrogate avoided resource
SCORE	Statistically Corrected Output from Record Extension
SPP	Southwest Power Pool
SPSC	State-Provincial Steering Committee
VER	variable energy resources
VERBS	Variable Energy Resource Balancing Service
WAPA	Western Area Power Administration
WACM	Western Area Colorado Missouri Balancing Authority
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association

WIEB	Western Interstate Energy Board
WIT	Wind Integration Team
WWSIS	Western Wind and Solar Integration Study

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Introduction

The growth of wind and solar generation in the United States, and the expectation of continued growth of these technologies, particularly in response to state statutory requirements such as renewable portfolio standards, dictates that the future electric power system will be operated in a somewhat different manner due to the increased variability and uncertainty relative to existing load and generation. A small number of balancing authorities (BAs) have attempted to determine an "integration cost" to account for these changes to their current operating practices.[1] A balancing authority is the 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, all focusing on ensuring that electricity can be reliably generated and delivered at the bulk power (i.e., wholesale) level (NERC 2012).

Some balancing authorities directly charge wind and solar generators for integration charges, whereas others, operated by electric utilities that also procure or build electric generation, add integration charges to projected costs of wind and solar in any integrated resource plans (IRPs) they may produce or in competitive solicitations for generation.

This project originated when the Western Interstate Energy Board's State-Provincial Steering Committee (SPSC) requested assistance from the U.S. Department of Energy (DOE) in compiling information on variable generation integration charges imposed by balancing authorities other than the California Independent System Operator (CAISO) in the Western electricity interconnection.[2] The SPSC is interested in creating a variable generation "dashboard" for the West that would show information on how wind and solar generation is being integrated into the electric grid by balancing authorities in the West, including integration charges, if applicable.

[1] The electric power industry has long dealt with the variability and uncertainty of both load and generation. Variability and uncertainty are addressed through ancillary service requirements, as required by FERC Order 888 to address unexpected short-term changes in generation and load; contingency reserves to ensure that electric reliability is maintained in the case of unexpected loss of generation or transmission; and capacity reserves or planning reserves to ensure that projected electric demand in the future is met through new generation, transmission, or demand-side management or demand response. Although actual practices differ considerably by state and by region, one common practice is that load pays for ancillary services, contingency reserves, and capacity or planning reserves. With integration charges or costs, the discussion among industry participants is whether the variability or uncertainty introduced by higher levels of variable generation is great enough that any additional costs attributed to meeting increased variability or uncertainty should be reflected, either through direct charges to variable generation or indirectly through integrated resource plans or competitive bidding solicitations. The purpose of this report is to summarize the integration charges in place to date, either directly or indirectly, and to compare and contrast the methodologies used to estimate those integration charges. This report does not take a position on whether, or how, integration charges should be defined, measured or assigned.

[2] The SPSC is organized and staffed by the Western Interstate Energy Board (WIEB), which is the "energy affiliate" of the Western Governors' Association (WGA). The SPSC is the result of a grant awarded by DOE in 2010 under the American Recovery and Reinvestment Act of 2009 to the WGA to, among other duties, enhance the states' capacity to effectively participate in interconnection-wide transmission planning being undertaken under a companion DOE grant to the Western Electricity Coordinating Council (WECC). These state participation activities under the DOE grant are occurring under the SPSC. Before the creation of the SPSC, similar functions were carried out by WIEB's Committee on Regional Electric Power Cooperation (CREPC), which still exists and functions together with the SPSC.

This report reviews the balancing authorities that have calculated variable generation integration charges and broadly compares and contrasts the methodologies they used to determine their specific integration charge. The practice of estimating variable generation integration costs is still evolving, although it has progressed significantly during the past decade (Milligan 2011). The practice has been a dynamic subject area, as there is disagreement within the industry as to the proper methodology that should be used. In short, there is no one generally accepted methodology to calculate variable generation integration costs.

The report also profiles each balancing authority we discussed and how it derives wind and solar integration charges. Two tables were compiled on the specifics of each wind and solar integration charge, showing integration rates that are directly charged to wind and solar generators and those that are factored into IRPs or solicitations for generation. The information was gathered through an extensive literature review, with individual sections sent to each balancing authority for review. Not all provided comments, and these are noted where applicable.

This report profiles 12 balancing authorities that have taken some action to account for variable generation impacts on their system. Seven impose integration charges on wind and/or solar generation, and six incorporate estimated integration costs in their resource planning or competitive solicitations for generation, or both.[3] PacifiCorp is listed in both categories, as Idaho allows PacifiCorp to deduct $6.50/MWh from avoided cost payments made to wind facilities that are registered as qualifying facilities under the Public Utility Regulatory Policies Act (PURPA). PacifiCorp also factors the estimated integration charges into its integrated resource planning process. All 12 balancing authorities estimate integration charges for wind; whereas only three estimate such charges for solar (Arizona Public Service [APS], Bonneville Power Administration [BPA], and Public Service Company of Colorado [PSCo]). Other than Westar, all of the balancing authorities profiled are located in the WECC area.[4] See Table 1.

[3] As this report was being finalized, we were notified of a wind integration service charge imposed by the Nebraska Public Power District (NPPD). The charge is $3.31/MWh for both regulation and supplemental reserves, $2.72/MWh for regulation reserves only (if supplemental reserves are self-supplied), or $0.59/MWh for supplemental reserves only (if regulation reserves are self-supplied). Due to limited information regarding the determination of NPPD's wind integration service charge, it will not be discussed in any further detail in this report.
[4] A map of the WECC balancing authorities can be found at www.wecc.biz/library/WECC%20Documents/Publications/WECC_BA_Map.pdf.

Table 1. How Balancing Authorities Profiled in This Report Incorporate Wind and Solar Integration Charges

Integration Charges Imposed on Wind and/or Solar Generation	Estimated Integration Costs Factored Into IRPs or Competitive Solicitations for Generation
Avista Corporation*	Arizona Public Service
Bonneville Power Administration	BC Hydro
Idaho Power*	NorthWestern Energy
PacifiCorp*	PacifiCorp
Puget Sound Energy**	Portland General Electric
Westar	Public Service Company of Colorado
Western Area Colorado Missouri Balancing Authority	

*Allowed by Idaho PUC to deduct integration charges from payments made to wind qualifying facilities under PURPA.
**Conditionally approved by the Federal Energy Regulatory Commission and now in settlement proceedings with interveners.

In general, variable generation integration costs are estimated by quantifying a certain set of system impacts. The system impacts analyzed by the balancing authorities reviewed in this report include different reserves such as regulation, load-following, and contingency reserves; unit commitment; and opportunity costs; among other impacts. How reserves are defined and used can vary significantly from region to region, and a multitude of terms are used to define comparable or similar reserves. A general description of these terms is provided below for reference:

- Regulation generally deals with the random, minute-to-minute variability of loads and generation (Milligan 2011).[5]
- Load-following typically deals with slower trends that extend from minutes to hours (Milligan 2011).
- 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 (Milligan 2011).
- Unit commitment is the longer-term, often day-ahead process, the balancing authority's use to schedule generators based on forecasts of expected load and variable generation (Milligan 2011).
- Opportunity costs—as used by BC Hydro for example—are the costs of forgoing low-price imports or high-price exports due to reserves being held to cover variable generation uncertainty.

[5] "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).

FERC Actions Related to Variable Generation Integration Charges

The Federal Energy Regulatory Commission (FERC) must approve all variable generation integration charges that are imposed by FERC-jurisdictional balancing authorities. Provided below is a summary of the guidelines set forth by FERC for proposing such a charge, and a chronological summary of how these guidelines were established. Notable among these guidelines are the subhourly scheduling and power production forecasting requirements, as described herein.

In November 2010, FERC issued a proposed rule that would require transmission providers to offer the option of scheduling transmission services at 15-minute intervals. In addition, the proposed rule would incorporate provisions into the *pro forma* Large Generator Interconnection Agreement that require generators using variable energy resources (VERs) to provide transmission owners with certain meteorological and forced outage data to support power production forecasting. Finally, FERC proposed to amend the *pro forma* Open Access Transmission Tariff (OATT)[6] to add a generic ancillary service rate schedule, Schedule 10—Generator Regulation and Frequency Response Service. Ancillary services refer to those services that are 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 (NERC 2012).

FERC sought to add a new rate schedule to the *pro forma* OATT that complements the generator imbalance service provided under Schedule 9 of the *pro forma* OATT. FERC stated that, to meet their obligations to offer generator imbalance service under Schedule 9, FERC-jurisdictional transmission providers must hold unloaded resources in reserve to respond to moment-to-moment variations attributable to generation. The proposed rule recognized this de-facto obligation and proposed to establish a generic rate schedule (Schedule 10) through which FERC-jurisdictional transmission providers may recover the costs of providing this service (FERC 2012b). 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.

However, FERC in its final rule (Order No. 764) ultimately declined to adopt a new Schedule 10, deciding to instead evaluate proposed charges on a case-by-case basis. FERC received numerous comments urging flexibility in the design of capacity services needed to integrate VERs into transmission systems, suggesting that the proposed *pro forma* generator regulation service may not be the most efficient and economical service with which to integrate VERs. FERC did, however, provide a framework for transmission providers to use as a guideline in developing such charges, and established some general principles to evaluate individual proposals, as described further below.

[6] The *pro forma* OATT refers to FERC's standardized transmission tariff that provides for open access transmission rights, as mandated by FERC in Order No. 888.

FERC will continue to evaluate proposals to recover capacity costs incurred to provide Schedule 9 generator imbalance service on a case-by-case basis. To provide guidance in the development of proposals for generator regulation services, FERC responded to individual commenter concerns regarding the design of a generator regulation service charge. The subsequent paragraphs provide an overview of the primary principles that FERC included in the final rule.

FERC stated that FERC-jurisdictional transmission providers may include opportunity costs for generator regulation service under certain circumstances. FERC also addressed the appropriate design of the volumetric component of a generator regulation service that would allow FERC-jurisdictional transmission providers to require different transmission customers (or generator classes) to purchase or otherwise account for different quantities of regulation reserves based on cost-causation principles. For instance, distinguishing customers into classes for the purpose of requiring them to purchase or otherwise account for different quantities of generation regulating reserves should be done only to the extent that such classes and distinctions among classes are reasonably related to operational similarities and differences among those resources.

To the extent a FERC-jurisdictional transmission provider proposes to break customers into specific groups based on operational characteristics, FERC expected FERC-jurisdictional transmission providers to 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.

If a FERC-jurisdictional transmission provider proposes to differentiate among customers (or customer classes) in determining their relative regulating reserve responsibilities, the FERC-jurisdictional transmission provider must demonstrate to FERC that the overall quantity of regulating reserve it requires of its transmission customers' accounts for diversity benefits among all resources and loads, and the allocations to individual customers (or customer classes) of their proportionate share is based on the operational characteristics of such customers (or customer classes).

FERC notes that weather events such as droughts may affect the required quantity of generator regulating reserves that the FERC-jurisdictional transmission provider must have in reserve more or less during one portion of the year versus another portion of the year. In such cases, FERC believed these 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.

In designing any proposals for generator regulation service charges, FERC stated that a FERC-jurisdictional transmission provider 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.

FERC noted that it recognizes that it is contentious to condition the allocation of different quantities of regulation reserves to different transmission customers on the FERC-jurisdictional transmission provider developing and deploying power production forecasting. Nevertheless, FERC stated that it expects 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. FERC further stated that FERC-jurisdictional transmission providers should make the results of any centralized forecast used by the FERC-jurisdictional transmission provider available through a secure information exchange to VER generators providing related data. In addition, FERC-jurisdictional transmission providers proposing to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves should explain in their proposals how forecasting results will be shared.

FERC declined to require transmission customers delivering from a VER to submit transmission schedules according to the FERC-jurisdictional transmission provider's forecast; asserting that requiring a transmission customer to submit transmission schedules for VER deliveries according to a centralized forecast would cloud the delineation between the obligations of the VER and the obligations of the FERC-jurisdictional transmission provider with respect to the provision of transmission service. FERC also specified that the FERC-jurisdictional transmission provider retains the risk and responsibility for inaccurate procurement of reserve requirements; whereas the transmission customer retains the financial risk and responsibility for inaccurate schedules.

Finally, FERC emphasized that these principles are intended to provide a framework to assist FERC-jurisdictional transmission providers in developing proposals for generator regulation service should they desire to do so. FERC also noted that it does not intend these guidelines to preclude a FERC-jurisdictional transmission provider from making an alternative proposal under section 205 of the Federal Power Act (FERC 2012b).

Report Findings

This report finds significant differences in how the studies are prepared in support of variable generation integration charges, including but not limited to study methodology, assumptions, reserve definitions, and the data that is collected and utilized. These findings indicate that integration studies in support of variable generation 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. Examples include the following:

- Differences in what each integration study is assessing (different reserves including regulation and load following, unit commitment, opportunity costs, contingency reserves, and impacts of variable generation on cycling of conventional generation units).
- Determining the integration impact of wind (comparing wind to a flat block or ideal generator; comparing load and net load; comparing reserve requirements with and without wind; comparing subhourly wind output to subhourly persistence wind forecasts; and applying ad hoc "wind integration" factors).
- Including or not including variable generation forecasts (mostly wind). Those that do include variable generation forecasts typically emphasize intra-day forecasts, not day-ahead forecasts.
- Restricting availability of reserves to a subset of available generation. A small number of integration cost studies limit the supply of reserves to an individual generator or subset of available generation. Not surprisingly, these studies typically find that the amount of available reserves becomes scarce as more variable generation is incorporated, as this

approach inflates the actual need for incremental reserves by ignoring the aggregation effects from geographically dispersed wind and solar generators.

These findings are supported by recent research that suggests that although it is easy in concept to define integration costs, it is very difficult in practice to calculate or measure integration costs in a meaningful way. This difficulty 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. In addition, the integration studies focus on whether increased operating reserves are needed for variable generation but do not consider other possible mechanisms such as demand response, considering future changes in generation mix, or implementing grid operating reforms such as virtually or physically expanding the size of the balancing authority and moving to shorter generator dispatch and transmission scheduling intervals (Milligan 2011). These observations are summarized in more detail below.

Methodologies and Tools for Determining Integration Rates Are Unique to Each Balancing Authority. Each balancing authority has a different resource mix (flexible versus inflexible), size of balancing area, access to ancillary services, and access to transmission with other balancing authorities. There are few commonalities and similarities to how each balancing authority estimates integration rates. Some examine multiple scenarios with different levels of geographic diversity for wind and different levels of water availability for hydro generation (BC Hydro). Some use combinations of optimization models, hydro-simulation models, and capital expansion models (BC Hydro); whereas others rely on a unit commitment or dispatch model that may be either off-the-shelf or developed internally (Avista, PSCo).

Types of Reserves or Reserve Impacts Included in Integration Rates. Balancing authorities include different reserves or system impacts as part of their integration rate (see Table 2). About half of the balancing authorities include load-following in estimated cost (BC Hydro, Portland General Electric [PGE] for both hour-ahead and intra-hour, APS, Avista, PacifiCorp, and BPA). A smaller number include contingency reserves (APS for solar, Avista, PacifiCorp, and PGE) and energy imbalances (BC Hydro, BPA, and PacifiCorp). Two balancing authorities include unit commitment impacts (APS and PSCo). BC Hydro incorporates opportunity costs from lost market transactions because of holding increased reserves with higher levels of wind capacity.[7] PSCo includes coal cycling, gas scheduling, and gas storage. Nearly every balancing authority includes regulation as part of the estimated integration cost, with five balancing authorities considering only regulation (Idaho Power Company [IPC], NorthWestern Energy, Puget Sound Energy [PSE], Westar, and Western Area Power Administration [WAPA]).

[7] In PacifiCorp's draft 2012 Wind Integration Resource Study, opportunity costs are defined as the value of a lost sale at a given generation station that must be backed down to meet reserve requirements.

Table 2. Components of Estimated Integration Costs

	Regulation	Load-Following	Contingency Reserves	Energy Imbalance	Unit Commitment Impacts	Opportunity Costs	Coal Cycling and Natural Gas Storage
APS	X	X	X		X		
Avista	X	X	X				
BC Hydro	X	X		X		X	
BPA	X	X		X			
Idaho Power	X						
NorthWestern	X						
PacifiCorp 2007, 2008			X	X			
PacifiCorp 2010	X	X	X	X			
PacifiCorp 2012	X	X	X	X	X		
PGE	X	X	X	X			
PSCo (Solar)					X		
PSCo (Wind)	X				X		X
PSE	X						
WACM	X						
Westar	X						

Determining Integration Impacts. Balancing authorities use a variety of methods for estimating the impact of integrating additional wind (see Table 3). Three balancing authorities (Idaho Power, PSCo, and PacifiCorp's 2010 IRP) compare wind with a flat block of energy. Note that PSCo divides the flat block into on-peak and off-peak for regulation. Three other balancing authorities (BC Hydro, APS, and Avista Corporation) compare wind with an ideal generator (i.e., a non-variable generator). Two balancing authorities (PacifiCorp in its 2007 IRP and PSCo for regulation) compare load with net load (load minus wind generation).

Other balancing authorities employed different techniques altogether. PGE estimated the impacts of wind integration by simulating scenarios with and without incremental reserve requirements for wind, with the cost of wind integration defined as the savings in system operating costs that would result if wind placed no incremental requirements on system operations. Westar tracks the changes in wind output from one 10-minute interval to the next from five wind projects in Westar's service territory. Westar also collects the difference in load from load forecasts; in generation between actual output and dispatch instructions; and in generators providing frequency response service, also as the difference between actual output and dispatch instructions. PSE used a methodology similar to Westar's but compared 10-minute wind output to hourly persistence forecasts for wind, load, and other generation. NorthWestern Energy applies an 18% "wind integration factor" to the amount of existing wind capacity to determine how much additional regulation is needed, without describing how the 18% was determined. WAPA's Western Area Colorado Missouri Balancing Authority (WACM) adds installed wind capacity to a rolling 12-month average of the system peak, then divides that sum by the annual revenue requirement necessary to provide regulation.

Table 3. Determination of Wind Integration Impacts

	Compare With Flat Block	Compare With Ideal Generator	Compare With Net Load	Other Methodology
APS		X		
Avista		X		
BC Hydro		X		
BPA				X
Idaho Power	X			
NorthWestern				X
PacifiCorp	X		X	
PGE				X
PSCo	X		X	
PSE				X
WACM				X
Westar				X

Variable Generation Forecasts. Similar to determining wind integration impacts, balancing authorities use a myriad of different approaches for wind forecasting, and most are focused on the intra-day timescale, not the day-ahead timescale. PSE, BPA, and PacifiCorp (2010 IRP) used various forms of persistence forecasting. BC Hydro, PGE, and PSCo used varying types of day-ahead forecasts. For wind, APS compares a perfect forecast with that of the simulated wind output produced by a contractor. Idaho Power used a function of simulated wind output ranging from 65 to 115 minutes before real-time. Avista assumed a range of wind forecasting errors from perfect forecast to 30% forecasting error. Three balancing authorities—NorthWestern Energy, Westar, and WACM—did not incorporate wind forecasting at all.

Most integration studies assume that wind forecasting errors follow a normal distribution and allow for the utilization of multiple standard deviations (usually two or three times standard deviation) to estimate the variability and uncertainty impacts of wind. More recent research suggests that for time ranges from 6 to 48 hours ahead, wind forecast errors associated with numerical weather prediction (NWP) models are normal, but errors associated from wind power are not normal. Instead, the errors are somewhat skewed and may have more pronounced peaks and longer tails than normal distributions. The wind power forecast error distributions can vary substantially depending on the size of the wind plant or balancing area, the forecasting method used, and the timescale that is measured. Not accurately estimating the distribution of wind power forecast errors can lead to either under- or over-estimating the frequency of large errors in wind power forecasting that in turn could raise system costs through under- or over-scheduling reserves, increased out-of-merit dispatch, and, possibly, events that could endanger system reliability (Hodge 2012).

Consideration of Solar. Only three utilities estimated solar integration costs, and all three made some approximations due to a lack of solar data and/or lack of experience with solar integration. APS contracted with Black & Veatch to conduct a solar integration cost study, which was released in November 2012. Black & Veatch utilized output and variability at existing Arizona solar facilities to estimate solar variability. However, for areas without actual data, Black &

Veatch made estimates using solar production modeling and statistical variability modeling. As adjusted by the sun's position in the sky, Black & Veatch used persistence forecasts to estimate the difference between predicted and actual solar output in 2020 and 2030. The solar integration costs were calculated based on the impact of incremental operating reserve costs and incremental system energy costs between load only and load and solar.

BPA assumed that solar would require only half as much balancing capability as wind because solar plants generate power only during the day. BPA also assumed a perfect forecast for solar and therefore did not include an energy imbalance component in the solar integration charge. BPA stated that it assumed perfect schedules for solar projects because it does not currently have enough solar projects scheduling on its system to provide data for scheduling accuracy.

PSCo used solar forecasting to estimate solar integration costs. The day-ahead solar forecasts compiled averaging solar insolation for that hour in a month (i.e., solar forecast for any day in May at 3 p.m. is the average insolation for 3 p.m. for every day in May). PSCo used its unit commitment and dispatch model to estimate the unit commitment impacts of solar but did not attempt to estimate solar integration costs due to additional regulation that may be needed, or the impacts of solar on gas supply or operations and maintenance on existing conventional generation plants.

Sources of Variable Generation Data. Five balancing authorities (APS, BC Hydro, Idaho Power, PGE, and PSCo) relied upon wind data created through mesoscale wind resource modeling. BPA, PSE, and Westar used historical wind data; whereas Avista used past wind speed data from one wind plant and anemometer readings from five sites and applied them to a wind turbine power curve. For its 2010 IRP, PacifiCorp relied on a combination of historical wind production data and the statistical relationship between pairs of sites to fill in data gaps.

Exclusion of Generation Plants. Various balancing authorities limited the available generating plants able to provide reserves or balancing services. Idaho Power limited the source of regulation to the Hells Canyon hydro project. PGE excluded some generation projects, asserting that they were not capable of providing reserves or balancing services. NorthWestern Energy limited its integration analysis toward determining how much additional regulation will need to be provided from a single natural gas plant. PSE used a portfolio of generation plants consisting of four coal units, four combined-cycle natural gas plants, the utility's share of hydro from the Columbia River, and two of its own hydro plants.

Consideration of Hydro. Balancing authorities also utilize different methods for forecasting hydro output and for scheduling hydro. BPA models the average of the top 120-hour peaking capacity based on the 1958 water year. As noted earlier, Idaho Power modeled only the operations of one hydro plant in its 2007 study with three different water years—1998 (good), 2000 (normal), and 2005 (poor). Avista also used three different water levels in its analysis (low, medium, and high). BC Hydro incorporated water data from 10 years and matched it up with simulated wind data from 1998 to 2006. The 10 water years (1964 to 1974) are considered representative of the full 60 years used in the hydro model, as they contain a range of water conditions including normal, dry, and wet water years. For determining the opportunity costs of lost market transactions, BC Hydro limited the ability to spill water at one hydro project, citing restrictions from water licenses, flood control, downstream user requirements, and the Columbia River Treaty.

Scenarios. Unlike variable generation integration studies, nearly every balancing authority profiled did not assess the effects of changes in resource mix over time, improvements in wind forecasting accuracy, changes in scheduling from hourly to subhourly, or expanding balancing area cooperation. Some balancing authorities evaluated different scenarios of increasing levels of wind or solar generation but largely assumed that the current scheduling practices, balancing area structure, and existing resource mix would stay intact. Exceptions include PSCo, which did multiple sensitivities ranging from varying gas costs, geographic diversity of wind projects, incremental pumped hydro storage, wind forecasting, demand response, and carbon prices, and PacifiCorp, which included carbon costs in its earlier wind integration analyses but not in their 2010 IRP.

Table 4 and Table 5 on the following pages summarize variable generation integration charges that are charged to variable generation, and variable generation integration rates that are incorporated into resource plans and/or competitive solicitations for generation. After these tables, profiles of each balancing authority that has set a variable generation integration rate are presented.

Table 4. Integration Charges and Methodologies by Balancing Authority

		Idaho Power Company	Avista Corporation	PacifiCorp
Total Average Load (MW)		1,680	1,096	9,431 (peak load for 2011)
Total Generation Capacity (MW)		3,276	1,791	10,597
Variable Generation Capacity (MW)	**Wind**	499	35	2,135
	Solar	0	0	9[i]
	Total	499	35	2,144
Percent of Variable Generation Exported		Unknown, but assumed to equal 0%[ii]	Unknown, but assumed to equal 0%[iii]	Unknown, but assumed to be small
Amount of Variable Integration Charge		8% of the published avoided-cost rate for wind qualifying facilities (QFs) under PURPA (capped at $6.50/MWh).	7% of the published avoided-cost rate for wind qualifying facilities under PURPA (capped at $6.50/MWh).	$6.50/MWh
Charge Assessed on		QF Wind Generators	QF Wind Generators	QF Wind Generators
Status of Charge		In effect since February 2008. Original eligibility cap of 10 MW was reduced to 100 kW, effective December 14, 2010.	In effect since February 2008. Original eligibility cap of 10 MW was reduced to 100 kW, effective December 14, 2010.	In effect since February 2008. Original eligibility cap of 10 MW was reduced to 100 kW, effective December 14, 2010.
Regulatory Background and Establishment of Current Wind Integration Charge		IPC's published avoided-cost rates are adjusted downward to reflect the company's estimate of the costs of integrating wind energy. Adjustments are applied in three tiers, increasing at higher levels of wind capacity. The integration charge is calculated as a percentage (7%, 8% or 9%) of the current 20-year, levelized, avoided-cost rate, and subject to a cap of $6.50/MWh. Between 2008 and 2012, non-levelized avoided cost rates vary between $59.17 and $66.82/MWh. Rates differ for light load and heavy load months. IPC's wind integration charge was established in February 2008 (Idaho Public Utilities Commission (IPUC) Order No. 30488, Case No. IPC-E-07-03), as the result of a Settlement Stipulation approved by IPUC. In February 2007, IPC submitted its wind integration study to the IPUC,	Avista's published avoided-cost rates are adjusted downward to reflect the company's estimate of the costs of integrating wind energy. Adjustments are applied in three tiers, increasing as total wind capacity in the system grows. The integration charge is calculated as a percentage (7%, 8% or 9%) of the current 20-year, levelized, avoided-cost rate, and subject to a cap of $6.50/MWh. Between 2008 and 2012, non-levelized avoided cost rates vary between $60.35 and $67.90/MWh. Rates differ for light load and heavy load months. Avista's wind integration charge was established in February 2008 (IPUC Order No. 30500, Case No. AVU-E-07-02), as the result of a Settlement Stipulation approved by IPUC. In April 2007, Avista submitted its wind integration study to the IPUC, proposing a charge of 12% of	PacifiCorp's published avoided-cost rates are reduced by $6.50/MWh to account for the costs of integrating wind energy. Between 2008 and 2012, the non-levelized avoided cost rates vary between $59.67 and $67.28/MWh. Note that rates differ for light load and heavy load months. The current wind integration charge was approved by the IPUC in March 2010 (Order No. 31021, Case No. PAC-E-09-07). In April 2007, PacifiCorp proposed a wind integration adjustment of $5.04/MWh to be applied as a decrement to the published avoided-cost rates payable to wind QFs, based on PacifiCorp's 2004 IRP (adjusted for inflation). In October 2007, PacifiCorp and the parties entered into a Settlement Stipulation, agreeing to an integration charge of $5.10/MWh, the estimate provided in PacifiCorp's 2007

	Idaho Power Company	Avista Corporation	PacifiCorp
	proposing a charge of $10.72/MWh. In October 2007, IPC presented an updated cost of $7.92/MWh for up to 600 MW of wind on its system. Also in October that year, IPC and the parties entered into the Settlement Stipulation, resulting in the current integration charge.	the published avoided-cost rate. In October 2007, Avista and the parties entered into the Settlement Stipulation, resulting in the current integration charge.	IRP. The rate of $5.10/MWh became effective in February 2008; however, PacifiCorp later requested that the IPUC allow a rate of $9.96/MWh. The IPUC denied that request, but allowed PacifiCorp to increase it to $6.50/MWh.
Methodology Used to Estimate Wind Integration Costs	IPC completed its initial wind integration study in February 2007. The study defines an integration cost as the economic impact of wind generation variability and uncertainty on the utility's system. IPC states that higher regulating reserves for various amounts of wind capacity constrain hydro operations at IPC's Hells Canyon Complex. As such, scenario-based modeling was used to estimate a range of costs. Main inputs include three different hydrologic conditions and four levels of wind integration (300, 600, 900, and 1,200 MW). The IPC study initially presented a wind integration cost of $10.72/MWh, which was the midpoint between costs associated with the then currently contracted 384 MW of wind capacity and the additional cost that would be incurred at a penetration level of 600 MW. After holding two public workshops, IPC revised six specific modeling assumptions, resulting in an estimated wind integration cost of $7.92/MWh at a penetration level of 600 MW. Among other things, the modeling revisions included greater geographic diversification of wind resources and a regressive forecasting	Avista's wind integration study was completed in March 2007. The study was prepared by the same group that prepared IPC's study (EnerNex Corporation), so the methodology used to estimate the cost of wind integration is similar. Four wind penetration levels (100, 200, 400, and 600 MW), along with three water level scenarios, were modeled. Total reserve obligations were estimated using historical utility data, and incremental regulation and load-following reserves were calculated by identifying the amount of reserves needed to meet load variability alone, then performing the same analysis but netting wind generation against load when performing the calculations. The results of Avista's study were estimated wind integration costs expressed in terms of a percentage of market prices. Avista's base case result was that the cost of integrating up to 400 MW of wind capacity was approximately 12% more than the cost of integrating other non-wind resources. Avista said they will apply the 7% discount as a starting point in negotiating contacts with larger wind projects.	PacifiCorp's most recent estimate of the cost to integrate wind energy is based on its 2010 Wind Integration Resource Study. Their estimate is based on the cost of incremental operating reserves and incremental system balancing costs required for wind integration. The amount of operating reserves required for different penetration levels of wind, and the estimated cost of holding those reserves on the system was modeled by PacifiCorp using existing operating reserve requirements for load and production data, subdivided into regulation and load following. The load data was the baseline case (zero wind generation) in each scenario, whereas coincident wind data was added in increasing levels of wind penetration capacity to gauge the change in operating reserves demand. The differences in system cost between the two simulations were divided by the total volume of wind generation in each scenario to derive the estimated operating reserve costs for wind integration. The majority of integration costs (i.e., about 90%) are associated with the incremental operating reserves; however, PacifiCorp also modeled the

	Idaho Power Company	Avista Corporation	PacifiCorp
Methodology Used to Estimate Wind Integration Costs	method, instead of persistence. IPC is updating the 2007 study and held a workshop in April 2012 to share the preliminary results and solicit feedback from interested parties.		incremental system balancing costs associated with wind integration. Similarly, the change in system costs between the two model simulations was used to isolate the wind integration cost due to system balancing. Note that PacifiCorp is currently in the process of updating the 2010 study. PacifiCorp most recently held a stakeholder meeting in May 2012, and currently expects to complete its updated wind integration study by fall 2012.

		Westar Energy	PSE	BPA
Total Average Load (MW)		5,549 (peak load)	2,570	6,200
Total Generation Capacity (MW)		7,100	3,000	18,400[iv]
Variable Generation Capacity (MW)	**Wind**	295	369	4,421
	Solar	0	0	13
	Total	295	369	4,434
Percent of Variable Generation Exported		Unknown	26%[v]	80%
Amount of Variable Integration Charge		3.47% * the amount of generating capacity within the Westar balancing area * (1, 2, 3, 4, or 5). 1. For yearly delivery, $53,358.74/MW 2. For monthly delivery, $4,446.56/MW 3. For weekly delivery, $1,026.13/MW 4. For daily delivery, $205.23/MW 5. For hourly delivery, $12.83/MW	$1.55/kW-month of transmission reservation capacity for generators with hourly scheduling intervals • 30% discount available for 30-minute scheduling intervals • 50% discount available for 15-minute scheduling intervals	Wind: $1.23 per kW-month Solar: $0.21 per kW-month
Charge Assessed on		Wind generation and other non-dispatchable resources that export power outside of Westar balancing area or to the SPP energy imbalance market	Exporting variable energy generators	All wind and solar generators
Status of Charge		In effect	In effect, but subject to refund pending FERC's final approval of the settlement agreement	In effect
Methodology Used to Estimate Wind Integration Costs		FERC approved Westar's request to impose a wind integration charge in March 2010. Westar's integration charge is an interim measure until SPP implements its locational marginal price (LMP)-based market in 2014. Westar uses a portfolio approach to assess different generator regulation charges for dispatchable and intermittent generation. The charge for dispatchable resources is calculated using 1.46% and the charge for non-exporting resources is calculated at 1.35%. For the wind integration charge, Westar used data from three	PSE compares historical scheduling and forecast data for wind generation to actual output to determine the regulation capacity needed to balance deviations in wind output within the hour. PSE then performs a portfolio analysis to account for any offsetting variability from load and dispatchable generation. Then, based on winds proportionate effect on system variability, PSE calculates the percentage of a customer's transmission schedule reservation that a transmission customer exporting energy outside of PSE's BA, needs to purchase to account	BPA calls its integration rate the Variable Energy Resource Balancing Service (VERBS) and determines the rate as part of its biannual rate cases. BPA first forecasts its total balancing reserve capacity quantity that will be needed during the two-year rate period. The model then allocates the total balancing reserves into incremental and decremental components of regulating reserves, following reserves, and imbalance reserves requirements for load, non-federal thermal generation (Dispatchable Energy Resource

	Westar Energy	PSE	BPA
Methodology Used to Estimate Wind Integration Costs	wind farms to create a single portfolio value for each 10-minute interval. Westar then compared the portfolio observation for each 10-minute interval to the previous interval to create values that represented the interval deviations. To calculate the regulation percentage, Westar uses two times the standard deviation of the portfolio deviations and divides it by the total nameplate capacity of all the wind sites. The current regulation percentage is 3.47% times the amount of generation and inside the Westar BA times the applicable charge. The amount of generation inside the BA is equal to nameplate capacity minus the amount of the generator capacity that the customer is self-supplying regulation for minus the amount of generating capacity that is supplying power to load inside the Westar BA. Westar updates the regulation requirement percentage annually.	for the variability of the wind resource. In its June 2011 FERC filing, PSE estimated that exporting wind customers need to purchase an amount of regulation equal to 16.77% of the transmission reserve capacity. In the same filing, PSE requested authority to increase its regulation service cost from $5.50/kW-month to $12.39/kW-month, therefore, 16.77% of that would be $2.08/kW-month. Note that PSE's proposed methodology is based on the Westar methodology recently approved by FERC. On October 20, 2011, FERC issued an order accepting and suspending PSE's filing for 5 months, and establishing a hearing and settlement procedure. In September 2012, PSE filed a Stipulation and Offer of Settlement for approval by FERC. The pending Settlement contains a 1.21% purchase obligation and a capacity charge of $10.50/kW-month in Schedule 3. The Schedule 13 generator regulation charge for VERs exporting energy outside PSE's BA is set at a "Base Rate" of $1.55/kW-month for non-dispatchable generators that submit schedules on an hourly basis. If a non-dispatchable generator is able to submit schedules in 30-minute intervals, the VER will receive a 30% discount. If a non-dispatchable generator is able to submit schedules in 15-minute intervals, the VER will receive a 50% discount. PSE indicated that the charges for regulation service are based on a black box, negotiated value, from an unspecified volumetric purchase	Balancing Service, or DERBS) and, variable generation, based on their contributions to total requirements. BPA estimates the cost of providing reserves under two cost categories—embedded costs and variable costs. Embedded cost is the revenue requirement needed by BPA's 10 largest hydro projects to provide all types of reserves. BPA calculates an embedded unit-cost, which for the 2012–2013 rate period was $6.69/kW-month. For the VERBS rate (as for the other rates), the unit cost is then multiplied by the incremental reserve requirement capacity amounts for the three VERBS components to estimate the total embedded costs. Variable costs consist of various losses associated with a loss of efficiency due to BPA needing to hold a sufficient amount of machine capability in a state of readiness to meet balancing needs. These losses are calculated for Stand Ready Costs and Deployment Costs using energy shift losses, efficiency losses, cycling and spill losses. Variable costs are similarly allocated amongst the various rate components. The total costs are then divided by the average estimated MW of wind capacity in the BPA area over the rate period to create the VERBS rate components. The VERBS rate is therefore is made up of three distinct components—regulation, following, and imbalance summed up to create the single VERBS rate of $1.23/kW-month. The solar rate is estimated to be half of the derived

	Westar Energy	PSE	BPA
Methodology Used to Estimate Wind Integration Costs		obligation for regulation service and a fixed capacity charge.	VERBS regulation and following components.

		WAPA's Colorado Missouri Balancing Authority
Total Average Load (MW)		Marketing area within WAPA that serves parts of Colorado, Wyoming, Missouri Nebraska and Kansas.
Total Generation Capacity (MW)		10,505 (for all of WAPA)
Variable Generation Capacity (MW)	**Wind**	1,030
	Solar	N/A
	Total	Assumed to be small
Percent of Variable Generation Exported		Unknown
Amount of Variable Integration Charge		1. Hourly, $0.000458/kW-hour 2. Daily, $0.011/kW-day 3. Weekly, $0.076/kW-week 4. Monthly, $0.331/kW-month
Charge Assessed on		Load and variable generation
Status of Charge		In place since 2006
Methodology Used to Estimate Wind Integration Costs		For variable generation within WAPA, nameplate capacity of variable generation added to rolling 12-month average of system peak. Total Annual Revenue Requirement for regulation service divided by this value to determine regulation service rate. Revenue requirement for regulation based on annual costs of plants providing regulation and costs of buying regulation on the wholesale market. WAPA no longer provides regulation and frequency response to variable generation being exported out of WAPA. Variable generation being exported out of WAPA must be dynamically scheduled or self-supply or receive regulation service from a third party.

[i] According to PacifiCorp's 2011 IRP, as of year-end 2010, PacifiCorp had 2,419 net metering customers throughout its six-state territory, generating more than 10,000 kW using solar, hydro, wind, and fuel cell technologies. About 92% of customer generators are solar-based; therefore Exeter has included 9 MW of solar generation in the table.
[ii] Wind exports are assumed to equal zero because Idaho Power purchases wind generation through power purchase agreements.
[iii] Wind exports are assumed to equal zero because Avista purchases wind generation through power purchase agreements.
[iv] The majority of BPA's capacity is hydro power and this figure represents the 2011 operating year sustained 1-hour peak capacity adjusted for average water conditions.
[v] According to PSE's FERC filing (*Revisions to Open Access Transmission Tariff*, Docket No. ER11-3735, June 6, 2011), PSE provides regulation service to one 96 MW facility exporting out of its BA and owns one 273 MW facility within its BA used to serve native load. Therefore, Exeter estimates that 26% of wind energy in PSE's BA is exported ((273+96)/96 = 0.26).

Table 5. Variable Integration Rates Incorporated in IRPs and/or Competition Solicitations for Generation

		PSCo (Wind Integration)	PacifiCorp	PGE
Average Load (MW)		3,878–4,340	9,431 (2011 peak load)	2011 winter: 2,612 2011 summer: 2,233
Total Generation Capacity (MW)		7,922	10,597	2,766
Variable Generation Capacity (MW)	**Wind**	1,768.5	2,135	450
	Solar	200	0	0
	Total	1,968.5	2,135	450
Percent of Variable Generation Exported		Assumed to be zero or very small	Assumed to be zero or very small	Small amount exported through the BPA-CAISO dynamic scheduling pilot
IRP/ERP/Competitive Solicitation		PSCo 2011 ERP	2011 IRP	2009 IRP (2011 Update)
Estimated Integration Cost		Total average wind integration cost excluding coal cycling estimated at $3.68/MWh at 2 GW of wind and $4.09/MWh at 3 GW of wind. Incremental integration cost excluding coal cycling estimated at $4.32/MWh for a 200 MW wind project added to a 2 GW wind portfolio at gas price of $5.06/MMBtu. Average coal cycling and curtailment costs estimated at $0.77/MWh with wind curtailment and $0.83/MWh with coal deep cycling (both at 2 GW of wind) and $1.03/MWh with wind curtailment and $1.08/MWh with coal deep cycling (both at 3 GW of wind).	$9.70/MWh (2010$)	$9.15/MWh (2014$, included in 2011 IRP update)
Incorporation Method		Incremental integration and coal cycling costs will be added to utility-build wind plant prices or bid prices from competitive suppliers for wind power. Value set to reflect differing integration costs as affected by natural gas prices and the amount of existing wind capacity.	Incorporated in resource expansion optimization modeling for comparing wind with other demand and supply resource options	Incorporated in resource plan modeling for comparing wind with other demand and supply resource options
		For wind integration costs without coal cycling, studied 2 GW and 3 GW by 2018 scenarios, with multiple sensitivities ranging from varying gas costs, geographic diversity of wind projects, incremental pumped hydro storage, carbon, wind forecasting, demand response, and carbon prices.	Defined wind integration costs as from increased operating reserves (regulation and load following, both up and down) and system balancing from day-ahead	Wind integration cost estimate represents PGE's estimated cost of using its own generating resources to integrate 850 MW (450 MW existing, 400 MW new) of wind by 2014. Additional reserves incorporated into model for hour-ahead uncertainty of wind; within-hour load following for wind; and generation resource requirements for

	PSCo (Wind Integration)	PacifiCorp	PGE
Methodology Used to Estimate Wind Integration Costs	Integration costs defined as including regulation, system operations and gas storage. Regulation amount determined through a comparative statistical analysis of net load and load, then multiplying by the regulation cost in PSCo's OATT ($6.740/kW-month, $80.88/kW-year). Cost then divided by predicted annual wind production for each scenario. Five-step process used for estimating system operation cost for wind integration. Step 1 is projecting day-ahead unit commitment plan every hour for 2018. Step 2 simulates serving daily load with actual load data and produces hourly system operating cost. For both of those steps, two proxies of hourly wind shapes used—flat block that distributes wind power evenly over each hour of the 24-hour period, and on/off peak proxy that distributes wind power over an on-peak block and an off-peak block. Step 3 has a new unit commitment with a day-ahead wind forecast, whereas Step 4 does economic dispatch with hourly wind profiles. Step 5 is calculating wind integration costs, which is the difference between the system production costs in Steps 2 (load dispatch) and Step 4 (load dispatch with wind), then dividing by annual wind energy production. Gas storage integration costs determined by the largest over- and under-nomination amounts for natural gas (to set demand charge) and total annual over- and under-nomination amounts (to set commodity charges). Demand and commodity charges totaled and the value that requires the greatest storage system demand used to estimate the average gas storage wind integration cost. For coal cycling, spreadsheet model developed with load forecast before and after a user-specified level of wind generation to derive the number and intensity of coal cycles. Cost per coal unit cycle derived from previous work done by Aptech Engineering for Xcel. Wind curtailment costs estimated by forecasts of coal	load and forecast errors. Uses four wind scenarios of 0; 425; 1,372 and 1,833 MW. Determine quantity of operating reserves needed at each scenario. For operating reserve costs, compared each wind profiles in each scenario with ideal wind profiles where wind generation is averaged across on- and off-peak blocks. System cost differences between the two divided by total wind generation. For system balancing costs, compare unit commitment costs with day-ahead load and wind forecasts with actual load and wind. Difference in system operating costs between actual wind profiles and with unit commitment adjusted to load and wind forecast error, divided by total wind generation.	within-hour regulation for wind. Subdivided integration costs into day-ahead uncertainty (for day-ahead wind forecast error); hour-ahead uncertainty (for hour-ahead wind forecast error); intra-hour load following; and within-hour changes of wind generation from wind schedules (regulation). Used constrained optimization model that accounts for three kinds of reserves: regulation, load-following, and contingency reserves. Model run in three stages corresponding to day-ahead, hour-ahead, and intra-hour; commitments made in prior stages carry through to the next stage as constraints. Total system operating costs at the third stage used in determining wind integration costs. Wind integration costs derived by running model with and without incremental reserve requirements for wind and dividing by total wind generation. Integration cost estimates affected by limited number of PGE generating plants that could provide reserves and that PGE's generation portfolio is short of total load requirements. Incorporating variable generation requires PGE generating resources to provide reserves rather than energy and increases PGE's reliance on wholesale market purchases. Earlier integration cost estimate of $11.04/MWh reduced with assumption that PGE would deploy new flexible thermal resources, i.e., two 100 MW GE LMS 100 simple cycle combustion turbines.

	PSCo (Wind Integration)	PacifiCorp	PGE
Methodology Used to Estimate Wind Integration Costs	prices, renewable energy credit (REC) prices and CO_2 emission costs. Generating resources selected to meet load forecast and number of coal cycles by unit was estimated. Wind curtailment costs also added. Model run twice, with and without wind, with cost difference representing cycling and wind curtailment costs.		

		NorthWestern Energy - Montana	PSCo (Solar Integration)	BC Hydro
Average Load (MW)		743	3,878-4,340	6,400
Total Generation Capacity (MW)		549	7,922	11,300
Variable Generation Capacity (MW)	**Wind**	141	1,768.5	246 in operation; 534 MW under contract
	Solar	0	200	0
	Total	141	1,968.5	780
Percent of Variable Generation Exported		Unknown	Assumed to be zero, or very small	None
IRP/ERP/Competitive Solicitation		2011 Electricity Supply Resource Procurement Plan	PSCo 2011 ERP	BC Hydro Wind Integration Study (value for the forthcoming 2012 IRP)
Estimated Integration Cost		\$11.28/MWh	Average solar integration costs ranged from \$1.25/MWh to \$6.06/MWh. Actual integration costs that PSCo will impose dependent on natural gas prices and amount of existing solar capacity.	\$10/MWh (for the 2012 IRP)
Incorporation Method		Value serves as a Wind Integration Pricing Signal, and is applied to wind in the electric supply portfolio	Incremental integration costs will be added to bid prices from competitive suppliers for solar capacity. Value set to reflect differing integration costs as affected by natural gas prices and the amount of existing solar capacity.	Wind integration cost included in evaluating generation bids and in comparing wind with other resources in long-term resource planning
Methodology Used to Estimate Wind or Solar Integration Costs		Applies 18% of installed wind capacity to regulation. Incremental regulation needs beyond load-only requirement of 60 MW assigned to wind. For 141 MW of wind online, 25 MW of additional regulation is estimated. 80% of costs of Dave Gates natural gas plant assigned to energy supply, and of that, about 14%	Solar integration charges estimated in 2009 study that focused on system dispatch inefficiencies from solar forecast errors. No integration costs estimated for solar from regulation, impacts on gas supply nominations, impacts on O&M on existing conventional generation units,	Wind integration cost considered the sum of variability cost, incremental operating reserves cost (regulation, load-following and imbalance reserve capacity), and day-ahead wind opportunity cost (opportunity cost for maintaining capacity to address day-ahead wind forecast error). Studied two years—2011 and 2021; three

	NorthWestern Energy - Montana	PSCo (Solar Integration)	BC Hydro
Methodology Used to Estimate Wind or Solar Integration Costs	($5.575 million) is assigned to wind. Integration cost is from wind's share of revenue requirement of natural gas plant divided by total wind generation.	transmission expansion costs or energy trading inefficiencies. Six scenarios were developed ranging from 200 to 800 MW of solar, with at least 200 MW coming from a solar thermal parabolic trough plant with four hours of thermal energy storage. Integration cost is determined by running a unit commitment model twice—once for day-ahead forecasted load and actual load, the second with day-ahead solar forecasts and actual solar generation. The difference in costs between the two model runs, divided by solar generation, is considered the solar integration cost. Average solar integration costs ranged from $1.25/MWh to $6.06/MWh, with integration costs roughly increasing at $1/MWh with each 100 MW of additional solar capacity. Solar day-ahead forecasts compiled averaging solar insolation for that hour in a month (i.e., solar forecast for any May day at 3 p.m. is the average insolation for 3 p.m. for every day in May).	wind penetration levels of 15%, 25%, and 35% and low-diversity and high-diversity wind. Incremental reserve requirements determined with statistical analysis of 10 years of historic 1-minute load data and simulated 1-minute wind data, with reserve requirements set at three standard deviations. Variability impacts estimated by difference between wind as an ideal generator and wind profiles. Optimization model used to estimate incremental reserve and variability costs for each wind scenario and water-wind year, with 10 water-wind years (not synchronous) studied. Day-ahead wind opportunity costs defined as the value of reduced trade opportunities in the 8- and 16-hour trading blocks to maintain flexibility in response to day-ahead wind forecast errors. System flexibility defined at three standard deviations (99.7%). Two methods modeled for flexibility—trade and generation schedule changes, and a combination of spilling water, wind curtailment and trade and generation schedule changes. Imbalance and load-following reserves allowed to be used for providing flexibility. Three water/wind years (normal, high and dry water years) modeled, with the opportunity cost of each determined on a daily basis. Most economical method on a daily basis is selected.

		APS (Wind Integration)	APS (Solar Integration)
Average Load (MW)		7,236 (peak load—all-time high)	7,236 (peak load—all-time high)
Total Generation Capacity (MW)		8,696	8,696
Variable Generation Capacity (MW)	**Wind**	289	289
	Solar	241	241
	Total	530	530
Percent of Variable Generation Exported		Assumed to be zero, or very small	Assumed to be zero, or very small
IRP/ERP/Competitive Solicitation		2012 IRP	Future IRP
Estimated Integration Cost		$3.25/MWh	Ranging from $1.53/MWh to $3.04/MWh, depending on the level of solar photovoltaic (PV) capacity on APS's system and the level of compliance with the North American Electric Reliability Corporation's (NERC) Control Performance Standards (CPS2). In a sensitivity analysis with higher gas prices and higher solar variability, solar integration costs were as high as $3.53/MWh.
Incorporation Method		Incorporated in resource plan modeling for comparing wind resources with other demand and supply resource options	Incorporated in resource plan modeling for comparing solar resources with other demand and supply resource options

	APS (Wind Integration)	APS (Solar Integration)
Methodology Used to Establish Wind or Solar Integration Cost Estimate	Estimated wind integration costs are based on a study performed at Northern Arizona University (NAU) under the direction of Dr. Tom Acker. Scenario-based modeling was used in the study, which examines four wind energy penetration levels (1%, 4%, 7%, and 10%) and three variations of geographic diversity (low, medium, and high). The 4% penetration level, along with the medium geographic diversity assumption, is used for the base case scenario. Wind integration costs are estimated by simulating APS system operation and planning for one typical year. Modeling was used to determine the operating costs for the system excluding the effects of wind variability and uncertainty, and comparing those results to a scenario which includes the operating costs for the system with wind (including the effects of its variability and uncertainty). Estimated wind integration costs are then deduced as the difference between the costs computed in the two simulations. The study year was selected as 2010. Historical load data for APS in 2004 was scaled to match the expected load and energy required in 2010, maintaining the hour-to-hour shape of the load and its correlation to the weather. A reasonable set of wind power plants in Arizona were simulated, using a mesoscale weather model, 2004 historical weather data, and a wind power prediction model. This provided wind power data that is time-synchronized with the load data, maintaining any correlation inherent between the two. APS will reevaluate these figures as renewable penetration increases and more experience is gained in dealing with the integration of intermittent or variable generation.	To comply with Arizona's Renewable Energy Standard, APS anticipates increasing solar PV resources on its system to 1,038 MW by 2020 and 1,669 MW by 2030. The APS Solar Study provides an estimate of the anticipated incremental cost to provide the reserve capacity and energy services necessary to integrate the projected levels of solar PV into the APS system during the 10-minute operating time frame. In addition to a base case scenario, the study included sensitivity cases with assumptions involving greater solar variability, higher gas prices, and varying levels of compliance with NERC's CPS2. Black & Veatch developed a spreadsheet model to calculate the variability of load and solar generation on a 10-minute time step throughout the year. Where available, Black & Veatch used output and variability at existing Arizona solar facilities to develop a deterministically-derived quantity of solar variability. For areas without actual data, estimated output was applied using solar production modeling and statistical variability modeling. Black & Veatch utilized a two-step methodology to calculate the reserve quantity and costs associated with integrating the anticipated levels of solar PV. The first step was to estimate the amount of incremental upward and downward regulating reserves required as a result of the forecasting errors from the solar PV penetration levels in each case. The second step involved modeling the cost impact to the system using production cost modeling software to estimate the system energy cost differential of providing the regulating energy margin.

APS

Background

APS does not directly assess an integration charge on VERs operating in its service territory. APS does, however, incorporate estimated variable generation integration costs in its resource planning model for comparing variable generation with other demand and supply resource options as part of its IRP. APS submitted its most recent IRP to the Arizona Corporation Commission in March 2012. As stated in the 2012 IRP, system integration costs may be incurred by the operation of some non-dispatchable resources, including wind and solar. At higher levels of wind and solar capacity, additional operating reserves may be needed on the rest of the system to effectively follow APS load and meet WECC reliability requirements (APS 2012a).

In APS's 2012 IRP, a system integration cost of $3.25/MWh was added to wind generation based on the results of APS's 2007 Wind Integration Cost Impact Study, discussed in further detail below (APS 2012a). Because solar generation in Arizona is more predictable than wind, APS assumed a lower integration cost for solar (without storage) of $2.50/MWh, per the WGA's Western Renewable Energy Zone Generation and Transmission Model (Black & Veatch 2009).

In the 2012 IRP, APS indicated that it would reevaluate these figures as renewable penetration increases and more experience is gained in dealing with the integration of variable generation (APS 2012a). APS noted that it was undertaking an effort to update its estimated cost of solar integration; and in November 2012, APS released its *Solar Photovoltaic (PV) Integration Cost Study*, prepared by Black & Veatch. Based on the level of solar integration and the assumptions used, estimated solar energy integration costs included in this study ranged from approximately $1.50/MWh to about $3.50/MWh (Black & Veatch 2012). An overview of the assumptions and methodology used in this study is provided at the end of this chapter.

Note that for the resource modeling used in its 2009 Resource Plan Report, APS included an estimated wind integration cost, also based on the results of the 2007 study prepared by NAU. APS did not incorporate an estimated integration cost for solar resources, but noted that in the future and at high penetration levels, it may be appropriate to include an integration cost for solar resources (APS 2009).

Wind Integration Costs

APS's wind integration study, *Final Report: Arizona Public Service Wind Integration Cost Impact Study* (NAU Report), was published in September 2007. The study effort was led by NAU on behalf of APS, and is the product of a joint effort between NAU, 3Tier, EnerNex, and APS, who all provided detailed analysis for the study. Tom Acker of NAU aggregated all of the analyses and wrote the final report. The objective of the study was to simulate APS system operation and planning for one typical year and estimate the incremental system costs for integrating wind generation. The basic methodology is summarized as follows:

- Determine the operating costs for the system, excluding the effects of wind variability and uncertainty
- Determine the operating costs for the system with wind, including the effects of variability and uncertainty

- Derive the integration costs as the difference between the costs computed in these two simulations (NAU 2007)

Assumptions

A range of wind energy penetration levels and geographic diversity in wind power production were considered, as shown in Table 6. All wind energy penetration levels listed refer to the expected APS energy production and peak load in 2010—the analysis year selected for the study. The 4% wind energy penetration level, with medium geographical diversity, was considered the "base case" in the study. Wind power plants were sited to achieve a prescribed level of geographic diversity (i.e., high, medium, or low), and to locate wind power plants at sites within the zones where adequate wind power potential existed as predicted by the wind simulation, which was conducted by 3TIER (NAU 2007).

Table 6. APS Wind Energy Penetration and Geographic Diversity

Wind Energy Scenarios		Installed Capacity (MW) by Geographic Diversity Level		
Energy Penetration Level (%)	**Penetration by Capacity (%)**	**High**	**Medium**	**Low**
1	1.5		108	
4	5.9	510	468	468
7	10.4		864	
10	14.8		1260	

Note: Scenarios that have no figure under "Installed Capacity" were not modeled as a part of this study.
Source: NAU, 2007.

Actual year 2004 hourly load data was employed in conjunction with simulated wind power production data over the same period. The study year was selected as 2010 so that the analysis could be conducted while retaining maximum certainty about the projected APS loads and generation resources. Thus, the 2004 actual loads were scaled up to the level expected in 2010 (NAU 2007).

In the NAU Report, integration costs are based on the incremental costs associated with unit commitment in the day-ahead and hour-ahead time frames, load-following within the hour, and regulation for minute-to-minute fluctuations. The modeling software utilized by APS at the time of the study would not permit any change in the actual wind that showed up during the day of operation from that which was forecast day ahead. The practical implication is that the actual wind (from the simulation) had to be used for the forecasted wind, and that the impact of different wind forecasts could not be directly investigated (e.g., a professional forecast versus a persistence forecast versus a perfect forecast, etc.). To account for uncertainty in the day-ahead wind forecast in the day-ahead optimization, the modeling software allowed a "firmness" factor to be applied to the wind energy. The firmness factor allows a fixed percentage from 0% to 100% of the forecasted wind generation for the day to be considered "firm" in the day-ahead optimization (NAU 2007).

The wind power simulation was conducted by 3TIER, using a mesoscale weather model employing 2004 historical weather data as an input to maintain a high correlation between the simulations and the actual weather. Wind speeds were simulated with 3TIER's mesoscale model for 1996 to 2006, with particular focus on 2003, 2004, and 2005. The time step of the mesoscale simulation was 10 minutes. This resolution in time was selected because it allows study of intra-hour wind variations, and could be easily modified for an hourly power system simulation. Using the output of the mesoscale modeling as an input, wind power plant output was computed using 3TIER's Statistically Corrected Output from Record Extension (SCORE) methodology (NAU 2007).

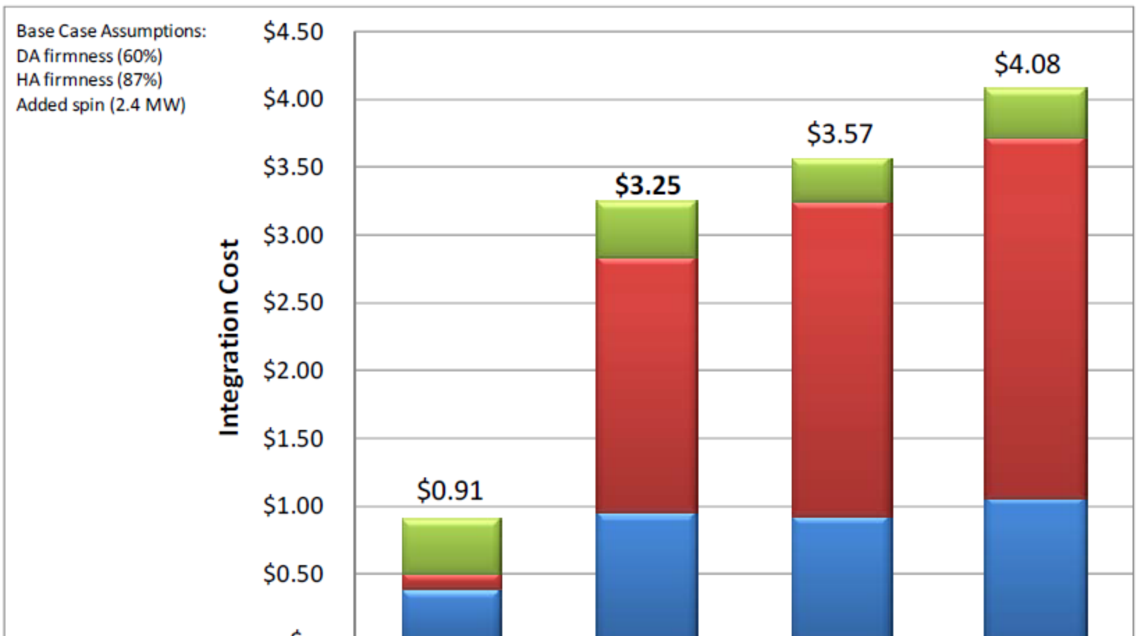
SCORE was developed specifically to predict the magnitude and variability of the output from a wind power plant. A GE 1.5-MW turbine with a 77-meter rotor diameter and 80-meter hub height was the reference turbine model employed in this simulation. The time step of the wind plant simulation was also 10 minutes (NAU 2007). Using the SCORE methodology, a wind power plant was composed of nine separate groupings of turbines, typically 36 MW per group of turbines (i.e., 24 turbines per group), allowing a maximum of 324 MW per site. This approach allowed wind power plants of varying sizes to be located at different sites, by choosing any number of groups of turbines. Strings of turbines were placed with a minimum spacing of four rotor diameters between turbines on the same string and a minimum spacing of 10 rotor diameters between the rows of turbines. Wind power output from 10 different sites were employed for the high geographic diversity case. For the medium-diversity cases, output from three sites centrally located in Arizona was utilized. For the low-diversity case, output from only two wind power plants was employed. Note that the 10-minute wind power output from the SCORE methodology was aggregated into hourly power sequences for each scenario for input into the APS power system model (NAU 2007).

Determination of Wind Integration Costs

The approach in conducting the APS integration study was to simulate system planning, operational activities, and decisions over the course of one typical year. In APS's case, this entailed running the modeling software, RTSim—the tool used by APS on a daily basis to model their system planning and operations, using an hourly time step. The simulation performs an optimal commitment of available generating units in the day-ahead time frame, ensuring there is adequate generation available to cover the next day's load, the variations in the load (e.g., ramps), and setting aside sufficient reserves. As the simulation proceeds into the day of operation, units that were committed for use during the day are re-optimized and recommitted on an economic basis in the hour-ahead timeframe when the expected load, generation, and wind is more certain. The units available during the hour (i.e., real-time) must follow the load swings within the hour and hour-to-hour (load following), as well as minute-to-minute fluctuations (regulation). After simulating the system operation for a year, an overall cost to run the system and meet the load is determined, including all market transactions (NAU 2007).

To assess the incremental cost to integrate the wind energy, the system operation was first simulated with some baseline set of resources that includes wind power, but in a way that attempted to remove the effect of its uncertainty and variability. This was done by assuming that wind power output was known perfectly in advance and that it added no variability to the control area, and where next-day load was the only uncertainty (NAU 2007). The system was then simulated again with the actual characteristics of wind energy, accounting for its uncertainty (inaccuracy in prediction) both day-ahead and hour-ahead, and accommodating for its variability, as predicted by the 3TIER modeling. The cost incurred during this simulation was then subtracted from the cost incurred with the baseline resources to estimate the overall integration costs (NAU 2007).

For the base case of 4% wind energy (medium diversity), the total integration cost was estimated at $3.25/MWh, varying from $0.91/MWh for 1% wind energy to $4.08/MWh for 10% wind energy (NAU 2007). Hour-ahead uncertainty, as employed by APS's modeling tool RTSim for in-the-day commitment of generating units, was the largest component of integration cost. This quantity is effectively a type of operating reserve (load following), and can be significant in magnitude relative to the other reserve amounts attributable to wind generation—see Figure 1 (NAU 2007).



Wind Energy Penetration	1%	4%	7%	10%
Within-hour Regulating	$0.40	$0.41	$0.31	$0.37
Hour-ahead Uncertainty	$0.11	$1.88	$2.32	$2.65
Day-ahead Uncertainty	$0.39	$0.95	$0.93	$1.06

Source: NAU, 2007

Figure 1. APS estimated wind integration costs

Solar Integration Costs

In its March 2012 IRP, APS incorporated a solar integration cost of $2.50/MWh in its resource planning model to compare solar resources with all other demand and supply resource options. APS's estimated solar integration cost is based on the WGA's Western Renewable Energy Zone Generation and Transmission Model. The integration cost assumptions provided in that model are $2.50/MWh for solar thermal and solar PV, and $0.00/MWh for solar thermal with storage.[8]

[8] APS includes a $0 integration cost for solar thermal with storage because there is no minute-by-minute variability because it operates with traditional steam turbine generators with voltage regulators and other traditional controls, thereby meeting WECC requirements.

According to the *Methodology and Assumptions* document that accompanies the model, these costs were provided as starting point assumptions and may be adjusted by the user (Black & Veatch 2009).

In November 2012, APS released the *Solar Photovoltaic (PV) Integration Cost Study* (APS Solar Study), prepared by Black & Veatch. The objective of the APS Solar Study was to estimate the incremental operating reserves, and the associated costs, necessary to integrate projected solar PV development in the APS service territory in the years 2020 and 2030 (Black & Veatch 2012).

To comply with Arizona's Renewable Energy Standard, APS anticipates increasing solar PV resources on its system to 1,038 MW by 2020 and 1,669 MW by 2030. The APS Solar Study provides an estimate of the anticipated incremental cost to provide the reserve capacity and energy services necessary to integrate the projected levels of solar PV into the APS system during the 10-minute operating time frame (Black and Veatch 2012). In addition to a base case scenario, Black & Veatch incorporated sensitivity cases with assumptions involving greater solar variability, higher gas prices, and varying levels of compliance with NERC's CPS2.

Load and Solar Assumptions

Black & Veatch developed a spreadsheet model to calculate the variability of load and solar generation on a 10-minute time step throughout the year. Load variability was developed by taking the APS projected load forecast for 2020 and 2030 and applying historic load variability to it, in order to forecast the 10-minute changes in load. A similar process was used to develop the solar variability estimates. First, hourly production estimates of solar output were developed for areas where APS envisions likely solar development in 2020 and 2030. A mix of solar PV generation technologies was modeled within these areas to reflect likely resource diversity. Where available, Black & Veatch used output and variability at existing Arizona solar facilities to develop a deterministically-derived quantity of solar variability. For areas without actual data, estimated output was applied using solar production modeling and statistical variability modeling. Persistence forecasts (adjusted for the sun's position) allowed Black & Veatch to develop a forecast of the difference between the predicted and actual output of the PV energy on the APS system in 2020 and 2030 (Black & Veatch 2012).

Because many of the prospective sites for new solar projects were unknown, Black & Veatch developed assumptions for likely development areas with the assistance of APS. For utility-scale solar plants, sites that are anticipated to host future solar projects were used to develop the solar resource profile. Undefined projects were divided amongst Phoenix, Yuma, Prescott, Gila Bend, and Palo Verde. These locations were picked because of their solar resource potential, transmission availability, likelihood for future development, and proximity to load. For distributed rooftop projects, 80% were located in the Phoenix metro area; the other 20% were evenly divided between Yuma, Flagstaff, and Prescott (Black & Veatch 2012).

Determination of Incremental Reserve Costs

Black & Veatch utilized a two-step methodology to determine the reserve quantity and costs associated with integrating the anticipated levels of solar PV. The first step was to estimate the amount of incremental upward and downward regulating reserves required due to solar forecasting errors from the solar PV penetration levels in each case. The second step involved modeling the cost impact using the ABB/Ventyx ProMod production cost modeling software to measure the energy cost differential of providing the needed amount of regulation (Black & Veatch 2012).

To identify the reserves required to integrate the expected level of solar development, Black & Veatch estimated the expected incremental area control error (ACE) violations, then calculated the operating reserves necessary to minimize the violations to comply with NERC's CPS2 and to conform to APS's current operating levels. Black & Veatch considered the reserve requirements and cost to achieve CPS2 compliance at the 90%, 95%, and 99% monthly levels (Black & Veatch 2012). To calculate reserve requirements for any given level of NERC's CPS2 compliance, Black & Veatch developed a spreadsheet model. The required input was forecasted hourly loads and 10-minute expected generation for the entire year. After the load and solar data were entered into the model, the number of CPS2 violations was calculated. Violations due to load only were first calculated, assuming perfect solar forecasting. After the solar forecast variability was added, the incremental reserves that was needed beyond what was required for load only during daylight hours was determined. The forecast error is then calculated as the net difference between the actual load and solar generation and the forecasted load and solar generation and represents the incremental operating reserve requirements needed for solar PV integration (Black & Veatch 2012).

The APS Solar Study focused on operating reserves that can respond to changes in system ACE in a 10-minute time frame to ensure reliable system operation. This includes spinning, non-spinning, and contingency reserves (see Table 7). APS expects that the GE LMS100 aero-derivative gas-fired peaking generator will be providing any additional needed reserve capacity. APS also stated that many of these units will be built within its planning horizon to accommodate future load growth and to provide firming-up capacity to compensate for variability of wind and solar generation. It is important to note that these units are already planned as future additions in APS's 2012 IRP, so their capacity costs have already been included in APS's system revenue requirements. Thus, it was assumed that there would be no additional capacity costs to provide the necessary regulation capacity in integrating solar energy generation into the APS system (Black & Veatch 2012).

Table 7. APS Operating Reserve Requirements

CURRENT APS OPERATING RESERVE REQUIREMENTS			REQUIREMENT	RESPONSE TIME
Operating Reserves	Regulating Reserves	Regulation Up	~1.5 percent of Load	Seconds
		Regulation Down	~1.5 percent of Load	Seconds
	Contingency Reserve	Spinning Reserves	The greater of N-1 *or* 7 percent of system thermal generation and 5 percent of hydro generation. At least 50 percent must be spinning reserve	Minutes to Hours
		Non-Spinning Reserve		Minutes to Hours

Source: Black & Veatch, *Solar Photovoltaic (PV) Integration Cost Study*, 2012.
Note: "N-1" is a NERC operation principle that requires that an electric system be capable of withstanding the loss of any individual component without experiencing unacceptable system conditions.

Energy costs were divided into the dispatch costs, reflecting changes in the system energy output to accommodate the solar PV, and spinning reserve costs, which represent the higher cost to commit resources to make sure that there are enough operating generating resources to meet dispatch requirements. Note that the cost to maintain reserve capacity was referred to as the spinning reserve cost in the APS Solar Study. Black & Veatch utilized production cost modeling to estimate the energy costs from supplying the incremental reserves. As noted earlier, incremental capacity costs were not included. Three production costs model runs were run for each scenario:

- Base Case with no incremental 10-minute reserve requirement
- Change Case #1: Increase load (in every hour when the solar PV is available) by the calculated amount of regulating reserve up, i.e., the amount of regulating reserve that can be dispatched upward
- Change Case #2: Decrease load (in every hour when the solar PV is available) by the calculated amount of regulating reserve down, i.e., the amount of regulation reserve that can be dispatched downward (Black & Veatch 2012)

The three production cost runs were intended to determine the system energy cost differential by relying upon all generating units that were available for 10-minute reserves. The production cost runs with varying loads are meant to estimate the cost of the incremental energy required for ramping up and ramping down the system. The system energy differential cost is the difference between system costs to move the system up netted out by the system cost savings of moving the system down using the new defined level of regulation reserves (Black & Veatch 2012). The base case net solar integration costs are presented below, in Table 8.

Table 8. APS's Estimated Solar Integration Costs

	2020			2030		
Solar MW	1,038			1,669		
Solar GWh	2,293			3,602		
CPS2 Compliance %	90%	95%	99%	90%	95%	99%
Incremental Spinning Reserves ($/MWh)	1.43	1.51	1.89	2.23	2.40	2.75
Incremental Energy Costs ($/MWh)	0.10	0.11	0.19	0.20	0.26	0.29
Solar Integration Costs ($/MWh)	1.53	1.62	2.08	2.43	2.67	3.04

Source: Black & Veatch, *Solar Photovoltaic (PV) Integration Cost Study*, 2012.

The sensitivity analysis revealed that the greater variability case did not have a significant impact on the estimated solar integration costs (i.e., less than $0.10/MWh). This is because the higher variability did not lead to a significantly greater amount of CPS2 violations. According to Black & Veatch, the high level of geographic diversity greatly smoothes out the generation profile and leads to some projects varying in the up direction; whereas others vary downward, eliminating some of the net impact (Black & Veatch 2012).

Higher gas prices had a more meaningful impact on the marginal energy and reserve costs, not surprisingly because the marginal generation resource is a natural gas-fired combustion turbine. Black & Veatch ran a sensitivity analysis that assumed a 30% increase in the price of natural gas. The marginal cost of integrating solar is lower than the 30% increase in the price of natural gas, with an approximate increase of 22% in 2020 and 15% in 2030 at a 99% CPS2 compliance level. The increases are about $0.25 to $0.50/MWh, depending on the time period and level of CPS2 compliance (Black & Veatch 2012).

BC Hydro

Background

BC Hydro began considering wind integration costs in a preliminary evaluation that was included in its 2008 long-term acquisition plan (LTAP). BC Hydro included a wind integration cost of $10/MWh in its 2008 LTAP analysis, and in its request for proposals for clean power that followed. In the 2008 assessment, BC Hydro determined the total wind integration cost as the sum of regulation and load-following reserve costs, and energy shift costs (i.e., the opportunity costs of forgoing low price imports or high price exports due to reserves being held to cover wind generation uncertainty). Scenarios were run at four levels of penetration (10%, 20%, 30%, and 40%), and with three aggregation scenarios, and analyzing the balancing reserve requirements at 2, 2.5, and 3 standard deviations. The Wind Integration Study included in BC Hydro's draft 2012 IRP builds on that previous examination. The draft 2012 IRP also proposes a wind integration cost of $10/MWh to be included in evaluating generation bids and in comparing wind with other generating resources in long-term resource planning. The value will be updated as future wind studies are conducted (BC Hydro 2012b; BC Hydro 2012a; Rucker 2012; and BC Hydro 2009).

Assumptions and Modeling

The Wind Integration Study examined multiple scenarios for the two fiscal years 2011 and 2021. Wind penetration was studied at three levels: 15% (approximately 1,500 MW), 25% (approximately 2,500 MW), and 35% (approximately 3,500 MW). In addition, scenarios with low-diversity and high-diversity wind were also examined, nested within the three penetration levels. Wind in the study was represented by a portfolio of theoretical wind projects that were identified in the May 2009 version of the BC Hydro Wind Data Study (DNV Global Energy Concepts, Inc. 2009). The wind integration costs ranged from $5/MWh to $19/MWh among the different scenarios. A cost of $10/MWh corresponded with the fiscal year 2011 economic dispatch, 15% scenario (BC Hydro 2012b; BC Hydro 2012a).

The study used three models to determine wind integration cost: the Generation Optimization Model (GOM), the Hydro Simulation Model (HYSIM), and the Capital Expansion Model (CAPEX). GOM, a deterministic, linear optimization model, was used to calculate the incremental operating reserve (regulation, load-following, and imbalance reserve capacity) costs, and to determine the day-ahead opportunity costs (opportunity cost for maintaining capacity to address day-ahead wind forecast errors). The HYSIM, a simulation model for the integrated BC

Hydro electric generation system with a monthly time step, was used to develop hydraulic boundary conditions (year-end and monthly target water levels) for GOM. CAPEX is a linear and mixed integer programming optimization model. This model is used by BC Hydro for economically dispatching resources over a planning time horizon. In the study, the CAPEX scenarios are synonymous with the low-diversity scenarios, because although not a direct intention of the model, these cases represent low-diversity levels of wind resources. High-diversity scenarios were determined by assuming wind projects were equally proportioned across specified regions of the province (Peace, Southern Interior, North Coast, and Vancouver Island) (BC Hydro 2012b).

Water data for the inflows used in the GOM modeling runs were based on 10 years (October 1964 to September 1974) representative of water conditions throughout the full 60 years of water data used in HYSIM. For statistical analysis of operating reserve requirements, the load data was synchronized with the wind data. Wind and water years could not be directly synchronized, however, due to problems with data availability and differences in the definition of a year (the wind data begins in August; whereas water years begin in October). Therefore, the water/wind year combinations shown below in Table 9 were used in the GOM modeling (BC Hydro 2012b).

Table 9. Water/Wind Year Combinations Used in the GOM Modeling

Water Year	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973
Wind Year	1998	1999	2000	2001	2002	2003	2004	2005	2006	2006

Source: BC Hydro. 2012b. *BC Hydro Draft Integrated Resource Plan 2012: Appendix 6E Wind Integration Study Phase II*. Draft. May 2012. Pg. 6E-22. www.bchydro.com/energy_in_bc/irp/document_centre/reports/draft_irp.html#chapters.

For the modeling of day-ahead impacts using GOM, however, wind data was limited by the availability of NWP forecasts. BC Hydro used NWP forecasts that corresponded to fiscal years 2006, 2007, and 2008. These years of wind forecast data were paired with the fiscal years 1969, 1970, and 1974 of water inflow data, representing normal, dry, and wet water conditions, respectively (BC Hydro 2012b).

The wind integration cost was modeled as the sum of the variability cost, the incremental operating reserves cost, and the day-ahead wind opportunity cost. The variability impacts were estimated by the difference between wind as an ideal generator and wind profiles. Energy was added in blocks of light load hours and heavy load hours. The blocks of energy from the ideal generator were equivalent to the total energy generated during each block based on the wind profiles. For calculation purposes, variability costs were included with operating reserve costs, because variability makes up only a small portion of the wind integration cost. GOM was used to estimate incremental reserve and variability costs for each wind scenario and water-wind year, with the 10 nonsynchronous water-wind years studied. The incremental operating reserve requirements were determined using statistical analysis of 10 years of historic 1-minute load data and simulated 1-minute wind data, with reserve requirements set at three standard deviations. The requirements are determined for load only and wind only, with requirements for load net wind determined by combining these with the root-sum-squares method [Total = $\{(\text{load value})^2 + (\text{wind value})^2\}^{1/2}$].

More specifically, to calculate the regulating reserves, the 1-minute averages of load and wind are calculated separately, and the 1-hour centered rolling averages of load and wind are calculated separately at each minute. Still executing wind and load calculations separately, the 1-hour centered rolling average is then subtracted from the 1-minute averages for each minute. Three standard deviations are used to determine the regulating reserve requirements. Finally, the root-sum-squares method is used, combining load and wind regulating reserve requirements by adding the squared load value with the squared wind value, then taking the square root of the resulting value. Similarly, the load-following reserve requirement is calculated by taking, for each minute, the clock hour actual average subtracted from the 1-hour centered rolling average for wind and load separately, including a 10-minute ramp—plus or minus five minutes—at the top of each hour, and using three standard deviations. The separate wind and load calculations are then combined using the root-sum-squares method. Comparably, imbalance reserve requirements are determined, calculating wind and load separately, by taking the clock hour average subtracted from the forecasted hourly average for each hour and again using three standard deviations. In calculations for wind, the study used persistence for the hour-ahead wind forecasts. The wind and load values are then combined using the root-sum-squares method.

Subtracting load requirements from the load net wind requirements results in the estimated incremental operating reserves for wind. After the incremental operating reserve requirements were estimated, the study used CAISO's ancillary service market prices as a basis to determine the opportunity cost of holding these reserves (BC Hydro 2012b and Rucker 2010).

In determining day-ahead opportunity costs, the study focuses on the day-ahead, but assumes 200 MW from the real-time market could be used to assist with wind integration. Day-ahead wind opportunity costs are defined as the value of reduced trade opportunities in the 8-hour light load hour and 16-hour heavy load hour trading blocks to maintain flexibility in response to day-ahead wind forecast errors. Three water/wind years were modeled, corresponding to normal, dry, and wet water conditions. The system flexibility required to deal with the day-ahead wind forecast error was defined at three standard deviations (99.7%).[9] Day-ahead wind forecast error was determined using numeric weather prediction wind forecasts.[10] Two methods of obtaining flexibility were considered, using the GOM: through trade and generation schedule changes, and through a combination of spilling water, wind curtailment, and trade and generation schedule changes. Spilling water was, however, limited to one facility (the Seven Mile plant), given water spilling restrictions at other BC Hydro facilities due to water licenses, flood control, downstream user requirements, and the Columbia River Treaty. Imbalance and load-following reserves were also allowed to be used for system flexibility. The opportunity cost was valued, for power trading schedule impacts, at energy market prices less transmission costs; for water spilling, as the BC Hydro water and storage value; and for wind curtailment, as the BC Hydro water and storage value plus the value of the REC that could have been attained from the wind generation. The opportunity cost of using these methods to manage wind forecast uncertainty is determined on a daily basis, with the resulting most economical method selected daily.

To determine the opportunity costs under an import scheduling framework[11], the maximum potential wind generation swing is determined as the maximum hourly wind forecast output less

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[9] As explained earlier, wind power forecast errors may not be normally distributed (Hodge 2012).

[10] NWP forecasts were determined in the May 2009 Wind Data Study: www.bchydro.com/etc/medialib/internet/documents/environment/winddata/pdf/wind_data_study_report_may1_2009.Par.0001.File.bch_wind_data_study_may1_09.pdf

[11] That is, the BC Hydro water and storage value is higher than the day-ahead market price.

any real-time market liquidity. The maximum hourly wind forecast output is the expected hourly wind forecast output plus the wind forecast error based on three standard deviations of confidence. Under an export scheduling framework,[12] opportunity costs are calculated as the expected minimum wind generation plus any real-time market liquidity. The expected minimum wind generation is determined as the expected hourly wind forecast output minus the wind forecast error based on three standard deviations. The difference between this value and the average forecasted wind generation for the time period reflects the hydro reserves that would be needed to accommodate wind variability. The day-ahead opportunity cost is calculated by taking the difference between the market price net transmission costs and the BC Hydro water and storage value, and then multiplying it by the magnitude of the trading block of the missed import/export. The resulting value is then divided by wind power generation (BC Hydro 2012b and Rucker 2010).

BPA

Background

BPA markets power from 31 federal hydropower plants and one nuclear plant that together total approximately 23,000 MW of nameplate capacity. The power plants and associated BPA-operated transmission system comprise the Federal Columbia River Power System (FCRPS). As of March 2012, BPA has more than 4,200 MW of wind power capacity connected to its balancing area, and predicts that amount could increase to almost 6,000 MW by 2013 (BPA 2012 and BPA 2011d).

BPA provides balancing services from 10 of the FCRPS hydro plants (the Big 10), which are controlled in real-time by BPA's automatic generation control (AGC), allowing them to respond automatically to changes in the BPA system.[13] The federal system dams are linked together in the Columbia River Basin. The availability of hydro system capacity is dependent on the amount of water currently in the Columbia River Basin, turbine availability (turbines need to be periodically taken out of service due to planned maintenance or experience unplanned outages), and operational objectives such as flood control; variable draft limits; water flow and operational limits related to fish, human safety, recreation, and Canadian Treaty operations.[14] BPA maintains that the ability of the Big 10 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.

BPA began examining the cost of integrating wind in 2007 during BPA's 2008–2009 rate proceeding to establish transmission and ancillary and control area service rates. During the proceeding, BPA introduced the Wind Integration—Within-Hour Balancing Service rate to take effect for BPA's 2009 rate year. The initial Wind Integration rate was the result of a settlement

[12] That is, the BC Hydro water and storage value is lower than the day-ahead market price.

[13] The Big 10 hydro plants are Grand Coulee, Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles, and Bonneville.

[14] Variable Draft Limits are period-by-period draft limits at Grand Coulee and Hungry Horse from January to March 31. These are planned limits to Firm Energy Load Carrying Capability generation to protect the ability to refill Grand Coulee and Hungry Horse to their April 10 elevation objectives with an 85% and 75% confidence, respectively. Source: BPA, U.S. Bureau of Reclamation, U.S. Army Corps of Engineers, *2012 Water Management Plan*, October 1, 2012.

between BPA and interveners and reallocated certain costs of reserves from BPA's power customers to wind generators. BPA recommended that $19,124,320 being collected as power rates to cover regulation and following service costs should be reallocated to wind generators. BPA estimated that wind capacity in 2009 would be approximately 28,124,000 kW-months; therefore, the Wind Integration rate required to collect the target amount of revenue was $0.68/kW-month applied to installed wind capacity (BPA 2009).

During the 2010–2011 rate proceeding and again for the 2012–2013 proceeding, BPA forecasted the revenue requirement for balancing service and allocated the costs across the participants.

Table 10 below shows the wind integration rates for the 2009 through 2011 and the 2012–2013 rate, along with the monthly cost for a typical 100-MW wind facility.

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.

For the 2012–2013 rate proceeding, BPA redefined the Wind Integration rate as the VERBS rate, and applied the rate to operating wind and solar plants. Additionally, BPA created a DERBS rate that applies to all non-Federal dispatchable energy resources (i.e., thermal generation) of 200 kW nameplate capacity and greater for deviations from scheduled generation amounts (BPA 2011b).

Assumptions

Balancing Reserve Requirement Forecast

BPA begins by forecasting the balancing reserve capacity quantity that will be required during the rate period. Balancing reserve capacity includes what is needed to provide the following, which are collectively referred to as balancing services:

- 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;
- Imbalance reserves—reserves needed due to differences between the average scheduled energy during the hour and the average actual energy during the hour.

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.

The balancing reserve capacity quantity forecast is based on 1-minute average data for a 24-month period for:

- Total wind, hydroelectric, federal thermal, and non-federal thermal generation;
- Total hydroelectric, federal thermal, and non-federal thermal schedules; and
- BPA balancing authority area load.

The historical data is used to develop forecasts for each of the above elements and is combined with a forecast of generation that is expected to come online during the rate case time period. For the 2012–2013 rate period, BPA used generation interconnection queue data to forecast generation capacity additions to the end of the rate period. Rather than instituting a hard cut-off regarding which projects in the queue would be included in the forecast, BPA evaluates certain factors to project the status of future projects during the rate period. These factors include where the project is in the interconnection study process; the status of the environmental review process and the projects permitting process; the grid upgrades that are required and how long it will take to complete them; information gained from discussions with the developer; and whether the developer has executed an interconnection agreement and committed to fund any necessary network upgrades. BPA then projects the amount of capacity that will be online between 2012 and 2013 (see Table 11).

Table 11. Forecast of Average Generation Capacity for the 2012–2013 Rate Period

Installed wind capacity	4,693 MW
Installed solar capacity	21 MW
Non-AGC controlled hydroelectric capacity	2,604 MW
Non-federal thermal capacity	5,784 MW
Federal thermal capacity	1,276 MW

Source: BPA, *2012 Final Rate Proposal, Generation Inputs Study*, July 2011.

The scheduling accuracy of wind generation is assumed to be equivalent to a 30-minute persistence measure. Therefore, the schedule for each wind facility for each hour is the 1-minute average of each wind facility's actual generation 30 minutes prior to the hour.

BPA forecasts overall balancing reserve by calculating the *inc* and *dec* requirements for each of the three reserve components (regulation, following, and imbalance). Using a percentile distribution, BPA discards the upper and lower 0.25% of values, leaving 99.5% of values that are used to produce a forecast of balancing reserve capacity that is needed to meet balancing requirements 99.5% of the time. BPA considers this method to be generally consistent with using three standard deviations to calculate requirements (BPA 2011b). Following the estimation of the total balancing reserves, BPA uses an incremental standard deviation (ISD) methodology to allocate the reserves to load, hydro generation, federal thermal generation, non-federal thermal generation, and wind generation, based on how each contributes to the joint regulation, following, and imbalance requirements. The ISD estimates how much the total balancing reserve capacity deviation changes given a 1-MW change in the load and/or generation standard deviation, while recognizing diversity between load and generation error signals. Essentially, ISD applies the same ratio of each element's contribution to the aggregate balancing reserve capacity requirement for each 24-hour period, to the total joint balancing reserve capacity requirement that includes diversity benefits (BPA 2011b).

The result of the modeling is as follows:

- Regulation *inc* and *dec* for load, hydro generation, federal thermal generation, non-federal thermal generation, and wind generation.
- Following *inc* and *dec* for load, hydro generation, federal thermal generation, non-federal thermal generation, and wind generation.
- Imbalance *inc* and *dec* for load, hydro generation, federal thermal generation, non-federal thermal generation, and wind generation.

The hydro and federal thermal generation requirements are assigned to load balancing; whereas the non-federal thermal generation and wind generation requirements are assigned to thermal and wind generation customers to derive the following rate components:

- Regulation Reserve Service = *inc* and *dec* regulation requirements for load, hydro generation, and federal thermal generation.
- Load-Following Reserve Service = *inc* and *dec* following requirements for load, hydro generation, and federal thermal generation plus *inc* and *dec* imbalance requirements for load, hydro generation, and federal thermal generation.
- DERBS = *inc* and *dec* regulation requirements for non-federal thermal generation plus *inc* and *dec* following requirements for non-federal thermal generation plus *inc* and *dec* imbalance requirements for non-federal thermal generation.
- VERBS = *inc* and *dec* regulation requirements for wind generation plus *inc* and *dec* following requirements for wind generation plus *inc* and *dec* imbalance requirements for wind generation. Additionally, solar generation balancing requirements are incorporated into the wind requirement. For the 2012–2013 rate period, BPA did not have adequate amounts of solar generation in its BA to create a solar forecast. BPA used data from the University of Oregon Solar Radiation Monitoring Laboratory to assess the regionally within-hour variability of solar energy. BPA assumes that the use of balancing services for solar will be similar to that required for wind generation, but because solar facilities produce power only during daylight hours (i.e., about half of the time) BPA believes solar will require only about half as much balancing capacity service as wind. Additionally, BPA assumed a perfect schedule for solar generation and, therefore, did not include an imbalance component.

Cost Allocation

The 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. BPA assigns cost responsibility for regulating reserves, DERBS, and VERBS (along with contingency reserves, both spinning and supplemental, collectively referred to as operating reserves), to BPA Transmission Services. For load-following reserves, BPA assigns cost responsibility to BPA Power Services, with load-following reserves calculated separately as part of the power rates revenue requirement.

For regulating reserve, DERBS, and VERBS, three categories of costs are estimated: embedded costs, direct assignment costs, and variable costs.

Embedded Costs

Embedded costs consist of the revenue requirement associated with the Big 10 hydro projects that provide BPA balancing services. BPA estimates the capacity available from the Big 10 projects by annually modeling the average of the top 120-hour sustained peaking capacity based on the 1958 water year, which represents average Columbia basin water conditions. This provides an annual average amount of sustained capacity available from the Big 10 for operational planning. The total estimated revenue requirement is divided by the average annual sustained capacity amount to estimate the embedded unit cost, which is then multiplied by the balancing reserve *inc* capacity quantity forecast for each resource, regulation, DERBS, and VERBS to derive the total embedded cost allocation for each. The embedded costs are only allocated based on forecast *inc* reserves. The embedded cost net revenue requirement of the Big 10 includes project-specific power-related costs, associated fish mitigation costs, administrative and general expenses, and three revenue credits not related to hydro operations.[15]

Direct Assignment Costs

Direct costs are assigned only to the VERBS rate and relate to costs incurred by BPA for specific wind integration projects. For the 2012–2013 rate period, BPA is proposing to assign to VERBS a portion of the costs associated with the Wind Integration Team (WIT) and the *Dec* Acquisition Pilot project. The WIT is an internal cross-agency initiative that arose from the 2009 settlement agreement. WIT's mission is to develop and implement methods to better integrate wind energy into the BPA grid. WIT funding is divided between Power Services and Transmission Services, with the Transmission Services portion directly assigned to the VERBS rate. The *Dec* Acquisition Pilot seeks to incorporate BPA purchases of *dec* reserves from non-federal generation sources that can reduce the amount of *dec* reserves that need to be supplied by the FCRPS units.

Variable Costs

Using the FCRPS system for balancing services requires BPA to hold a sufficient amount of machine capability in a state of readiness to meet balancing needs. This results in a loss of efficiency. BPA estimates the costs associated with efficiency losses under two categories as outlined in Table 12. Stand Ready Costs are costs associated with making a project capable of providing reserves and Deployment Costs are costs incurred when the system actually uses the reserve capability to respond when needed.

[15] Revenue credits include two non-operational components credited to Transmission Services from the Power Revenue Requirements Study. A third is a credit for costs associates with synchronous condensing, which is calculated individually and assigned to Transmission Services and so is credited to embedded costs to avoid double-counting. Synchronous condensers are controls that regulate voltage by absorbing or supplying reactive power as needed.

Table 12. Variable Cost Categories

Stand Ready Costs	Energy shift	The cost differential incurred by BPA when energy needs to be shifted from periods of high load/higher prices to periods of low load/lower prices to meet balancing energy needs.
	Efficiency loss	Each FCRPS project has a "most efficient" generation set-point based on the amount of water flow per MW. BPA incurs an efficiency loss when a facility needs to be moved off its most efficient generation point to meet balancing reserve capacity requirements.
	Cycling losses	Costs associated with the additional synchronization and ramping of units needed for to maintain the required amount of balancing capacity.
	Spill losses	Costs associated with the need to spill energy when river flows are high but BPA must maintain enough headroom to provide adequate *inc* reserve capability.
Deployment Costs	Response losses	Efficiency losses (as described above) associated with deploying committed units to provide balancing energy.
	Cycling losses	Cycling losses (as described above) associated with dispatching units to provide balancing energy.
	Spill losses	Spill losses that arise from BPA needing to reduce generation at a plant that would put it below water flow limits therefore, forcing the unit to spill water to maintain adequate downstream river flows.

Source: BPA, *2012 Final Rate Proposal, Generation Inputs Study*, July 2011.

BPA subdivides the total stand ready and deployment costs between regulation, variable generation balancing, dispatchable generation balancing, and a portion that gets assigned to load following.

BPA's 2012–2013 Rate Case

For the 2012–2013 rate case, BPA estimated the MW quantities associated with balancing services, and the annual revenue requirements. BPA conducted the modeling and cost estimation at a 99.5% level of service, adequate balancing capacity to provide balancing services for 99.5% of the required time. For the remaining time, BPA will curtail generation plants as required. BPA is forecasting a total balancing reserve capacity requirement of 791 MW *inc* and 1,012 MW of *dec*. Of the total reserve requirement, 333 MW of *inc* and 346 MW of *dec* was assigned to load following. The remaining balancing reserve requirement was allocated to regulation, VERBS, and DERBS. Table 13 provides BPA's forecast revenue requirements for regulation, VERBS, and DERBS.

Table 13. Revenue Forecast for BPA's 2012–2013 Rate Case for Regulation, VERBS, and DERBS

		2012–2013 Rate Years at a 99.5% Service Level	
Category		**Quantity**	**Annual Average Revenue ($)**
Regulating Reserves	Embedded cost	60 MW	4,816,800
	Variable cost	34 MW *inc* 35 MW *dec*	1,784,250
	Total		**6,601,050**
VERBS	Embedded cost	470 MW	37,731,600
	Direct assignment cost		8,214,701
	Variable cost	469 MW *inc* 623 MW *dec*	9,801,896
	Total		**55,748,197**
DERBS	Embedded cost	51 MW	4,094,280
	Variable cost	51 MW *inc* 81 MW *dec*	1,659,163
	Total		**5,753,443**
Total			**$68,102,690**

Source: BPA, *2012 Final Rate Proposal, Generation Inputs Study*, July 2011.

As noted earlier, the total cost of balancing services is allocated to different categories for each rate based on the balancing requirements for each service forecast in the balancing services capacity quantity forecast. BPA estimates the three different components for the VERBS individually. These components then account for:

- VERBS regulation—accounts for the moment-to-moment variability attributed to variable generation (as opposed to load and thermal generation changes).
- VERBS following—accounts for longer-duration within-hour variability attributed to variable generation.
- VERBS imbalance—accounts for the within-hour variability due to differences between the hourly scheduled amount and hourly average generation attributed to variable generation.

Table 14 summarizes the estimated rates calculated and implemented by BPA for the 2012–2013 rate period. VERBS charges to generators are based on the greater of the maximum 1-hour generation or the nameplate capacity of the wind or solar resource.

Table 14. 2012–2013 Rates for Regulation, VERBS, and DERBS

Rate	Estimated Costs ($000)	Average Annual Forecast (MW)	Rates
Regulation & Frequency Response			
Average annual costs	6,601		
Balancing authority area load forecast		5,682	
Rate (costs/load forecast)			0.13 mills/kWh
VERBS			
Regulation average annual costs	4,335		
Following average annual costs	20,610		
Imbalance average annual costs	30,804		
Total average annual costs	55,748		
Average installed resources		4,693	
Average customer supplied imbalance		1,393	
Regulation rate (costs/installed resources)			0.08 $/kW-mo
Following rate (costs/installed resources)			0.37 $/kW-mo
Imbalance rate (costs/installed resources)			0.78 $/kW-mo
Total VERBS rate			*1.23 $/kW-mo*
DERBS			
Annual average costs *inc*	4,576		
Annual average costs *dec*	1,177		
Total DERBS annual average costs	5,753		
Hourly rate *inc* (Cost/Annual deviation)			14.50 mill/kW/hr
Hourly rate *dec* (Cost/Annual deviation)			3.60 mill/kW/hr

Source: BPA, *2012 Final Rate Proposal, Generation Inputs Study*, July 2011.

The VERBS rate above is for the 99.5% service level and includes a reduction for BPA's estimate of the amount of customer supplied generation imbalance service that will be in place during the rate period. BPA has instituted a pilot program, Customer-Supplied Generation Imbalance, where wind generators can opt to self-supply a portion of their balancing reserve capacity. BPA accounted for wind generation balancing self-supply by reducing the amount of balancing reserve requirement allocated to wind generation by the amount of self-supply that was contracted by wind generators for the rate period.[16] As noted in Table 4, the average wind generation for the 2012–2013 rate period is forecast to be 4,693 MW. BPA forecasts the wind capacity that would self-supply balancing services at 1,393 MW; therefore, the imbalance component of the balancing reserve capacity requirement for variable generation was calculated using 3,300 MW of variable generation (wind capacity minus self-supply capacity) (BPA 2011b).

As discussed earlier, the balancing services requirement for solar is estimated to be about half what is needed for wind generation and the assumption of a perfect schedule for solar results in no imbalance component. The solar VERBS rate then is half of the regulation and following components of the wind VERBS rate, which results in a solar VERBS rate for 2012–2013 of $0.21/kW-month.

[16] BPA also provides Provisional Balancing Service. This service is offered to customers that (1) elected to self-supply but no longer are able to; or (2) had an estimated interconnection date beyond the rate period and, therefore, was not included in the study, but the project is completed earlier than estimated and goes into service during the rate period. Billing for provisional service is at the same VERBS rate.

Idaho Wind Integration Charges

Background

The Public Utility Regulatory Policies Act of 1978 (PURPA) provides the Idaho Public Utilities Commission (IPUC) with the jurisdiction to require Idaho's public utilities to offer power purchase contracts to QFs, including standard avoided cost purchase rates (published rates) for energy generated by QFs with a capacity of 10 MW or less. In February 2008, the IPUC issued three separate orders authorizing Idaho's three major public electric utilities to subtract a wind integration discount from the published rate for wind-powered QFs:

- Order No. 30488 for Idaho Power Company—Case No. IPC-E-07-03
- Order No. 30497 for PacifiCorp—Case No. PAC-E-07-07
- Order No. 30500 for Avista Corporation—Case No. AVU-E-07-02.

In essence, these discounts established a wind integration charge for the utilities to impose on QF wind generators (i.e., 10 MW or less) in Idaho. At the time these discounts were established, the parties involved acknowledged that the science of wind integration cost modeling was in its infancy. As such, the utility-specific wind integration charges are based on wind integration cost estimates that were submitted by each utility to the IPUC, subsequent negotiations between the relevant parties, and the settlement agreements accepted by the IPUC (IPUC 2008d).

The orders for Idaho Power[17] and Avista established a tiered-discount rate for wind QF payments (expressed in terms of a percentage of the published QF rate) that increases as more wind is added to the system, capped at a maximum of $6.50 per MWh. Table 15 summarizes the wind integration charges for Idaho Power and Avista, as established by the IPUC in February 2008.

Table 15. Summary of Wind Integration Discounts for Idaho Power and Avista

Utility Company	Wind Energy Penetration Level (MW)		
Wind Integration Discount (expressed as a percentage of the published QF rate)*	7%	8%	9%
Idaho Power Company	<300	301–500	>501
Avista Corporation	<199	200–299	>300

*The wind integration discounts for Idaho Power and Avista are capped at $6.50/MWh.
Note: The wind integration discount for PacifiCorp is a flat rate of $6.50/MWh.
Sources: Order No. 30488 (Idaho Power), Order No. 30500 (Avista), Order No. 31201 (PacifiCorp).

[17] Idaho Power provided limited comments to their draft profile. The company requested that we delete the background on PURPA implementation and wind projects in Idaho, but we felt it provided important context for the wind integration studies that Idaho Power and other utilities that serve load in Idaho have conducted.

The February 2008 IPUC order for PacifiCorp established a flat wind integration charge of \$5.10/MWh, as the IPUC reasoned that wind integration costs are lower in utility service areas with greater geographical diversity and larger control areas, which is the case with PacifiCorp (IPUC 2008d). In March 2010, the IPUC increased PacifiCorp's wind integration charge to \$6.50/MWh, but noted that there was still no consensus on the methodology used to calculate wind integration costs (IPUC 2010).

The three IPUC orders also eliminated the "90/110 performance band" from any new Firm Energy Sales Agreement for future wind-powered QFs. The performance band provision meant that when output was less than 90% of projections or more than 110% of projections, utilities could pay developers the usually smaller market-based rate rather than the published rate under PURPA. The IPUC reasoned that the wind integration discount rates account for the variability of wind, thus diminishing the need for a performance band for wind. In addition to the new wind integration charges, new wind-powered QFs were subject to a mechanical availability guarantee and a wind forecasting charge. Furthermore, the orders allowed utilities to amend existing wind-powered QF contracts to replace the performance band with a mechanical availability guarantee, should the wind-powered QFs also agree to fund their share of wind forecasting services and accept the wind integration charges. The mechanical availability guarantee requires wind-powered QFs to demonstrate monthly that except for scheduled maintenance and *force majeure* events, the QF is physically capable and available to generate at full output during 85% of the hours in the month. According to the orders, the cost of adding a wind-powered QF project to the wind forecasting service was attributed to the individual QF and shared equally between the utility and each wind-powered QF. The wind forecasting charges assigned to the wind-powered QF are subject to an annual cap set at 0.1% of the total energy payments the utility made to the QF (IPUC 2008a, 2008b, 2008c).

In November 2010, Idaho Power, Avista, and PacifiCorp filed a joint petition asking the IPUC to investigate a number of issues related to small-power projects that qualify for published rates under PURPA. The utilities requested that the eligibility cap on the size of projects that qualify for the published rate be reduced from 10 MW to 100 kW. The utilities contended that a rapidly expanding number of wind projects are having a profound price impact on customers and on transmission systems. The utilities argued that the small-power projects PURPA was originally intended to encourage are now developed by sophisticated large-scale wind companies that aggregate several projects within a mile apart from each other to fall under the 10 MW limit to qualify for the avoided-cost rate. When combined, these projects can total up to 100 MW or 150 MW interconnecting at one delivery point (IPUC 2011).

In February 2011, the IPUC issued an order retroactively reducing the eligibility cap for wind and solar projects to qualify for published rates from 10 MW to 100 kW, effective December 14, 2010. The 10 MW limit remains for non-wind and non-solar renewable projects. The IPUC stated the smaller size limit for wind and solar projects is temporary until a number of issues can be resolved (IPUC 2011, p. 40). However, in June 2011, the IPUC issued another order leaving the eligibility cap under which wind and solar projects can qualify for commission published rates at 100 kW. IPUC staff and other parties attempted to establish criteria that would allow the IPUC more discretion in determining whether a QF was truly a small project as anticipated by PURPA or a larger project that had disaggregated. The IPUC declined to adopt the criteria, maintaining that the potential would still remain for such criteria to be circumvented.

The IPUC asserted that it is more appropriate to first establish the just and reasonable avoided-cost rates before implementing procedures for obtaining such a rate (IPUC 2011).

In November 2011, the IPUC issued an order announcing the scheduling for a new docket, Case No. GNR-E-11-03, to review the terms of PURPA power purchase agreements including, but not limited to, the surrogate avoided resource (SAR) and IRP methodologies for calculating avoided cost rates. Direct testimony was filed in January 2012 and a settlement conference was held at the end of February 2012 (IPUC 2011, p. 42). Interested parties submitted rebuttal testimony at the end of June and the IPUC held three days of hearings in August 2012. The main issues addressed during the hearings included curtailments, renewable energy certificates, determination of avoided-cost rates, contract length, and delay damages/security (IPUC 2012).

In regard to the methodology used for determining avoided costs, Idaho Power proposed to replace the current SAR method with what it calls an "hourly incremental cost" methodology based on the highest-cost displaceable resource (e.g., a company-owned thermal plant or a long-term purchase contract). The hourly cost would be totaled each month to arrive at heavy-load and light-load pricing for each month of the contract term. The company stated that this more dynamic IRP method would more accurately reflect true avoided costs. Renewable developers, however, argued that Idaho Power is adopting a "short-run" avoided cost model and is arguing for shorter contract lengths to artificially deflate avoided cost rates. Renewable developers contend the hourly method is too complex and needs hourly updating and could allow the utilities to manipulate the results. Further, renewable developers asserted that the proposed method would not take into account the value of market sales of QF power during times of surplus and wrongly excludes potential carbon costs (IPUC 2012). Finally, Idaho Power also proposed a new tariff, Schedule 74, into the IPUC's PURPA case. This tariff would allow the utility to be relieved of its obligation to buy energy from QFs when the utility is operating only base-load resources during low-load hours (Fortnightly 2012).

Separately, in June 2012, Idaho Wind Partners filed a petition with FERC, asking the Commission to give guidance to the IPUC on the proper interpretation of a FERC regulation under Section 304(f) (*Petition for Declaratory Order*, FERC Docket EL12-74). Known as the "light loading" rule, Section 304(f) grants utilities an exemption from buying QF power if it ends up costing the utility more than it saves. This could occur when QF power is delivered during light load off-peak hours, forcing base-load plants off-line. Idaho Wind Partners assert that Section 304(f) doesn't apply if the QF has signed a contract with the utility that fixes the avoided cost rate in advance of power delivery, because the contract terms should already have taken such factors into account in setting the rate (Fortnightly 2012). In September 2012, FERC granted Idaho Wind's petition for a declaratory order, finding that Idaho Power's proposed Schedule 74 would be inconsistent with PURPA and FERC regulations (FERC 2012c).

Finally, in November 2012, FERC issued an order stating that it will take the IPUC to federal court for rejecting unexecuted QF contracts between wind generator Murphy Flat and Idaho Power. According to the order, FERC will argue that the utility was bound by the agreements even though it did not sign them by IPUC deadline of December 14, 2010. FERC stated that the phrase "legally enforceable obligation" is broader than simply a contract between an electric utility and a QF, and that the phrase can be used to prevent an electric utility from avoiding its

PURPA obligations by refusing to sign a contract, or delaying the signing of a contract, so that a later and lower avoided cost is applicable (FERC 2012h).

Meanwhile, in the state of Idaho, the IPUC has yet to issue a final order in its PURPA case. Consequently, the current utility-specific wind integration charges are based on wind integration cost estimates that were submitted by each utility to the IPUC, negotiations between the relevant parties, and the prior settlement agreements accepted by the IPUC. The subsequent sections of this chapter describe the methodologies used by each company to estimate the cost of integrating wind energy into their utility systems. Idaho Power published a wind integration study in 2007 and is in the process of revisiting its analysis. Avista also published a wind integration study in 2007. PacifiCorp included wind integration analyses and integration cost estimates in its IRPs in 2003, 2004, 2007, and 2008; and published a wind integration study in 2010. PacifiCorp is also in the process of revising its wind integration study.

Idaho Power Company

Idaho Power's 2007 Wind Integration Study

In February 2007, Idaho Power submitted its wind integration study to the IPUC, *Operational Impacts of Integrating Wind Generation into Idaho Power's Existing Resource Portfolio*; hereafter called the IPC Study. The IPC Study was prepared by EnerNex Corporation. The main objective was to estimate the quantifiable costs associated with integrating wind generation into Idaho Power's system. In the IPC Study, an integration cost is defined as the economic impact of wind generation variability and uncertainty on the utility company charged with accepting and delivering that energy.

Idaho Power asserted that the increased regulating reserves that must be maintained for wind generation have the effect of constraining hydro operations at Idaho Power's Hells Canyon Complex, so the objective of the IPC study was to estimate the economic cost of this effect (i.e., the analysis attempted to quantify the opportunity cost of constraining hydro reserves to integrate wind into Idaho Power's system). The IPC Study consisted of five main elements: gathering wind data and building wind generation profiles; gathering and analyzing current generation and load data without wind; analyzing combined wind and load data and determining operational changes; modeling operational changes to determine economic impacts; and evaluating the results.

The wind generation profiles were developed by WindLogics. The meteorological simulations used to produce wind speed data (which were converted to wind generation data) were based on the MM5 mesoscale model from the Pennsylvania State University / National Center for Atmospheric Research (IPC 2007a). To calculate hourly wind generation from the measured wind data, a turbine power curve was applied, in which wind speed was the independent variable and wind power was the dependent variable; the results were aggregated to hourly average values (IPC 2007a, Appendix A).

Idaho Power used the Synexus *Vista* Decision Support System (*Vista* DSS) to estimate the variation in regulating reserve requirements between a "flat wind case" and a "variable wind case." The daily cost estimate was calculated as the difference in the values of a case with a flat block of wind generation for a 24-hour period (e.g., a predictable and nonvariable resource) and another where the same amount of wind energy was delivered to the system, but exhibiting the variability and uncertainty of wind generation during that same 24-hour period. The wind integration cost per MWh was defined as the difference between the dollar value of the total annual generation from the flat wind case run valued at market, and that of the normal wind generation run also valued at market, divided by total wind energy production.

To account for seasonal variations in available hydroelectric resources, three different water condition years were used in the model: 1998 (good), 2000 (normal), and 2005 (poor). Four different levels of wind generation capacity were used: 300 MW, 600 MW, 900 MW, and 1,200 MW (IPC 2007a). The two *Vista* DSS runs referenced above were used to evaluate each wind penetration level for each water condition. The average wind integration cost over all three water condition years was used to estimate the cost at each penetration level (300 MW, 600 MW, 900 MW, and 1,200 MW).

The IPC study included an initial wind integration cost estimate of $10.72/MWh, which was the midpoint between costs associated with the then currently contracted 384 MW of wind capacity and the additional cost that would be incurred at a 20% penetration level (by capacity) of 600 MW. After holding two public workshops, Idaho Power submitted a report addendum to the IPUC on October 31, 2007, with a revised wind integration cost of $7.92/MWh (IPUC 2008a). There were six primary modeling adjustments that resulted in an overall decline in the estimated cost of integrating wind energy. These adjustments are described in the paragraphs below. Note that because the 1,200-MW penetration level was shown to be beyond Idaho Power's ability to integrate, the 1,200-MW penetration level was dropped from further consideration in the updated analysis.

First, the *Vista* DSS model included a built-in arbitrage opportunity that allowed it to select the lower price between the two electricity markets, Mid-Columbia and Palo Verde. In practice, these opportunities do occur on occasion, but a review of the modeling results indicated that this feature was utilized far too frequently and it was preferential toward the flat wind case over the variable wind case, so the arbitrage opportunity was eliminated from the model.

Furthermore, in the original study, regulating reserves were imposed by the *Vista* DSS model at a constant and bi-directional level. Model revisions, however, allowed for setting varying levels of regulation up and down on an hourly basis, with the ability to define dynamic reserves hourly.

Public comments regarding the IPC Study suggested that the original reserve estimation methodology in the study double-counted the amount of necessary reserves. In the original study, Idaho Power assumed that regulating reserves were necessary to cover variability in high-resolution (i.e., minute-to-minute) load and wind data, along with instantaneous 10-minute load and wind data. These two sources of variability were combined through a root-mean-square operation, not a straight arithmetic addition. However, public comments suggested that the instantaneous 10-minute data could also include a portion of the variability present in the high resolution data, and consequently regulating reserves calculated from both time series may reflect double counting. As such, the updated model removed high-resolution load and wind data, and based estimates on the amount of reserve necessary to address variability in the instantaneous 10-minute time frame for load and wind.

It was also suggested that the 24-hour flat wind case was biased because average wind generation during light-load hours in the synthetic wind time series exceeded average wind generation during the heavy-load hours, so the value of the flat wind case was favorably biased prior to consideration of any effects related to wind integration. To remove this bias from the model, the flat wind case was broken up into two blocks for each 24-hour period (one for light-load hours and one for heavy-load hours).

Additionally, 100 MW from the Elkhorn wind project in northeastern Oregon was included in the 300 MW scenario, and 100 MW from the Cotterel site in southern Idaho was removed to provide greater geographic diversification of the wind resource.

Finally, the wind forecasting methodology was changed from a persistence forecast taken at 65 minutes before the hour to a seasonal, autoregressive method. The updated wind forecasting process was simulated through the use of an autoregressive time-series model that expressed hourly average wind generation for an operating hour as a function of the six 10-minute readings occurring 65, 75, 85, 95, 105, and 115 minutes prior to the start of the operating hour (IPC 2007b).

Determination of Current Integration Charge

After the submission of the report addendum, Idaho Power and the Renewable Coalition (Renewable Northwest Project and the Northwest Energy Coalition) agreed to a settlement stipulation which resulted in the tiered integration charges presented in the beginning of this chapter (from Order No. 30488). The parties disagreed on the assumptions used in the modeling. Idaho Power stated that both the charges in the settlement agreement (which were capped at $6.50/MWh) and the amount from the revised estimate of $7.92/MWh were within reasonable ranges of the cost of integrating wind energy. The Renewable Coalition filed testimony in support of the settlement with an explanation of why the estimate of $7.92/MWh was too high. According to their testimony, 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. The Renewable Coalition also disputed the assumption that the Hells Canyon hydro facility was the only resource used to cover the reserve capacity needed for wind variability (Dragoon 2007a).

Idaho Power's 2012 Wind Integration Study

Idaho Power is developing an updated wind integration study to determine how much wind generation can be integrated into Idaho Power's electric system, and to refine the utility's estimate of the cost of integrating wind energy into its system (IPC 2012a).

Idaho Power held public workshops on March 16, 2012 and April 6, 2012, to review some of the basic study methodology and to present preliminary results of the analysis. During the April workshop, Idaho Power presented updated estimates of wind integration costs at various levels of system integration (IPC 2012b):

- $8.76/MWh at 800 MW of wind capacity
- $13.30/MWh at 1,000 MW of wind capacity
- $20.12/MWh at 1,200 MW of wind capacity

The methodology of the 2012 study is similar to that of the original IPC Study. The test year has been identified as 2017, wind capacity is being studied at three potential levels (800, 1,000, and

1,200 MW), and three different water conditions are being modeled. The analysis is being conducted by 3TIER and Plexos Solutions, and the schedule is unknown. Consistent with 2007 IPC Study, wind integration costs are estimated as the net-cost difference between the wind and non-wind cases divided by the total MWh of wind generation (IPC 2012a).

Avista Corporation

Avista's 2007 Wind Integration Study

In March 2007, Avista Corporation submitted its wind integration study to the IPUC, *Final Report: Avista Corporation Wind Integration Study*; hereinafter called the Avista Study. The Avista Study was also prepared by EnerNex Corporation. The Avista Study included the same definition of an integration cost that was used in the IPC Study, and the method used to calculate integration costs is similar to that of the IPC Study.

The wind generation model was based on data from Oregon State University's Energy Resources Research Laboratory. Historical data from five BPA anemometer sites as well as a wind plant in Vansycle, Oregon, were used as the reference data points. Wind speed data at each location was converted into wind energy generation at 10-minute intervals using a power curve from a 2.75 MW wind turbine model. The four wind generation scenarios used for the model were 100 MW, 200 MW, 400 MW, and 600 MW. Three water level scenarios (low, average, and high) were also developed.

A proprietary dispatch model (LP model), driven by a linear programming engine, was used to optimize operations of Avista's system. In the study, the LP model optimized a set of scenarios with wind energy, and another set without wind, where the wind energy is replaced by a non-variable resource. The differences between the two analyses (with and without wind) were used to identify the incremental reserve obligations required with wind. In the Avista Study, reserves included regulation, load-following, and spinning and non-spinning reserves. The integration costs were estimated by comparing operation costs from the with-wind scenarios to those where the same amount of energy was delivered by a non-variable resource. To calculate an estimate of the wind integration cost per MWh, the difference between the runs was divided by the total wind energy produced during the year. This process was completed for each wind penetration level, wind source, and water year.

Analogous to the IPC Study, the key wind integration cost driver was incremental reserves. The reserve obligations were estimated using historical utility data from 2002 through 2004. Specifically, regulation (up to 1 minute), load-following (1 minute to 1 hour), spinning and non-spinning operating reserves, and forecast errors are entered input in the Avista LP Model as constraints on system optimization. Incremental regulation and load-following reserves were calculated by identifying levels necessary to meet load variability alone, then performing the same analysis but netting wind generation against load when performing the calculations.

Avista ran its LP Model under various levels of wind forecasting error, from 0%, or perfect foresight, to 30%. Wind forecasting error was a significant focus of the Avista Study. Two-hour-ahead wind forecasts were compared to wind generation levels. Forecast error was calculated at the 95% confidence interval and carried across all hours in the up and down directions. In the study, Avista assumed forecast error would be met with spinning reserves.

The results of Avista's study were estimated wind integration costs expressed in terms of a percentage of market prices (because prices vary over time). Avista's base case result was that the cost of integrating up to 400 MW of wind capacity was approximately 12% more than the cost of integrating other non-wind resources (Avista 2007a).

Determination of Current Wind Integration Charge

Avista filed a petition with the IPUC requesting a wind integration discount of 12% of the published QF rate, applicable to wind-powered QFs. Avista stated that this figure represents the costs associated with the intra-hour variability of wind. When the wind-generated power is delivered on a firm hourly schedule, integration costs were approximately 6% in the Avista Study. Accordingly, if a wind-powered QF agreed to deliver on a firm hourly schedule, Avista proposed a wind integration discount of 6% of the published QF rate (Avista 2007b).

The Renewable Coalition (Renewable Northwest Project and Northwest Energy Coalition) and other parties submitted petitions to intervene, disputing the methodology used in the Avista Study. After formal and informal discussions and negotiations between the parties, the Renewable Coalition filed a *Motion for Approval of Settlement Stipulation* before the IPUC. Avista reviewed the Motion and supported the Settlement Stipulation (Renewable Coalition 2007). The settlement resulted in the tiered integration charges presented in the beginning of this chapter (from Order No. 30500).

The parties disagreed on the assumptions used in the modeling. Avista advised that both the charges in the settlement agreement (which do not exceed 9%) and the amount from its study (12%) were within reasonable ranges of the cost of integrating wind energy. The Renewable Coalition filed testimony in support of the settlement with an explanation as to why they believed Avista's cost estimate was too high (Renewable Coalition 2007). According to their testimony, the conversion from wind speed to wind generation in computer modeling is a complex and poorly understood issue. The Renewable Coalition stated that the resulting statistical characteristics of Avista's wind generation data indicated that the process used to produce the wind generation data likely overestimated the variability that would be experienced by wind resources. This was a considerable issue because wind integration costs are mainly dependent on wind generation variability. Another concern was Avista's method of computing reserve requirements. The Renewable Coalition stated that the total reserve requirements should be computed directly, or estimated as the square-root of the sum of the squares; whereas Avista maintained that its alternative approaches do not significantly change the result. Finally, the optimization algorithm used by Avista required that wind forecasts must be produced more than an hour in advance, and the Renewable Coalition stated that 20 to 30 minutes in advance should be sufficient (Dragoon 2007b).

PacifiCorp

The wind integration charges that the IPUC established for PacifiCorp[18] differ from the other two major utilities in Idaho. Instead of a tiered-discount rate, the IPUC authorized PacifiCorp to subtract a flat per-MWh charge from the published QF rate. Rather than submitting a wind integration study to the IPUC, PacifiCorp incorporated a wind integration analysis and integration cost estimate as part of its IRP. PacifiCorp's wind integration cost estimates have changed over

[18] PacifiCorp did not respond to requests to review this section.

time, based on varying model inputs and changing assumptions. Table 16 displays a chronological summary of PacifiCorp's estimated cost of integrating wind energy into the system.

Table 16. Chronological Summary of PacifiCorp Wind Integration Cost Estimate

Year and Source	Cost Estimate (per MWh)	Wind Capacity Level (MW)
2003 IRP—*Appendix L*	$5.50	1,000
2004 IRP—*Appendix J*	$4.64	1,000
2007 IRP—*Appendix J*	$5.10	2,000
2008 IRP—*Appendix F*	$9.96 to $11.85*	2,734
2010 Wind Integration Resource Study	$8.85 $9.70	1,372 1,833
2012 Wind Integration Resource Study (Draft Version)	$1.89	2,135
*This range is dependent upon the CO_2 tax level scenario used in the modeling.		

The subsequent sections describe the methodology used by PacifiCorp to estimate the cost of integrating wind resources into its system; starting with PacifiCorp's 2003 IRP and concluding with PacifiCorp's pending 2012 Wind Integration Resource Study. Note that PacifiCorp's most recent published wind integration cost estimates are from the 2010 Wind Integration Resource Study (the 2012 estimates were under stakeholder review and subject to change at the time of the publication of this document).

2003 IRP

In Appendix L of PacifiCorp's 2003 IRP, the estimated cost of wind integration was based on two factors: imbalance costs and incremental operating reserve requirements. Imbalance costs were calculated as the difference in system costs between firm contract delivery at constant rates over time, and an equivalent amount of energy from simulated wind resources. Wind generation fluctuated hourly based on available historical wind data. Using a three-year average, PacifiCorp calculated imbalance costs to be about $3.00/MWh for integrating 1,000 MW of wind capacity.

Incremental operating reserves were defined as the "resources that are available on short notice to provide additional power as needed" (PacifiCorp 2003). PacifiCorp assumed that intra-hour variability was insignificant, as experience to date had suggested that it resulted in no material cost issues. PacifiCorp did note, however, that this assumption was based only on observations of operations and it may change over time if the wind resource capacity was large enough or very centralized.

PacifiCorp's incremental reserve requirements were estimated by comparing loads with and without wind. This calculation was fairly straightforward. First, the standard deviation of hourly loads with wind for a year was calculated. Next, a new standard deviation was computed after subtracting out wind generation. The difference between the two standard deviations was taken as an estimate of the increased need for operating reserves (PacifiCorp 2003). The resulting estimate was a cost of $2.50/MWh for incremental reserve requirements. Combining the estimated imbalance cost and the cost of incremental reserves resulted in a total wind integration cost estimate of $5.50/MWh for integrating 1,000 MW of wind capacity.

2004 IRP

In Appendix J of the 2004 IRP, the imbalance cost estimate was not changed, but the cost of incremental reserve requirements were adjusted based on new and lower market prices, which was the only factor changed. The resulting estimate for integrating 1,000 MW of wind capacity was $4.64/MWh (PacifiCorp 2004).

2007 IRP

The estimated wind integration cost included in Appendix J of PacifiCorp's 2007 IRP was $5.10/MWh for integrating 2,000 MW of wind capacity. In the 2007 IRP, the same two cost components were used to estimate the cost of integrating wind energy: system balancing costs (i.e., imbalance costs) and incremental reserve requirements. System balancing costs were identified as the "difference in value between the energy delivered from wind resources compared to that delivered from less volatile resources." To calculate system balancing costs, PacifiCorp used the same methodology from the previous IRPs, which resulted in an estimate of approximately $4.00/MWh for 2,000 MW of wind capacity.

According to the 2007 IRP, incremental reserve requirements are based on the need for dynamic resources to be held in reserve, able to respond on a roughly 10-minute basis (PacifiCorp 2007c). For the 2007 analysis, PacifiCorp classified operating reserves into three categories based on purpose and characteristics: contingency reserves, regulating reserves, and load-following reserves. The need for contingency reserves, which are held for the purpose of responding to sudden equipment failures, was not expected to be affected by wind projects. Similarly, regulating reserves, which are held to respond to changes in system frequency over a period of a few seconds, did not appear to be to be significantly affected by wind energy. As such, incremental reserve requirements were based solely on load-following reserves, which were defined as "generation that can be brought on over a multiple-minute time period."

For incremental reserve requirements, the 2007 analysis was based on the hourly uncertainty in generation; whereas the 2003 and 2004 IRPs were based on the hourly variability of wind resources. The availability of hourly wind data from resources in PacifiCorp's service territory enabled the analysis to include proxy wind resources with realistic operating characteristics.

PacifiCorp revised its methodology to estimate the load-following reserve requirement based on the uncertainty in load for the next hour. In the IRP modeling, estimates of next-hour loads are made, and the model moves to bring on or back off resources as necessary to accommodate the expected change in loads. Knowing that the actual load of the next hour will likely be different than the forecast and that there will be deviations within the hour, operators hold additional resources ready to respond should they underestimate the need for resources. In essence, this methodology entailed establishing the necessary level of reserves to ensure that the deviation between forecast load and actual load in a given hour can be met 95% of the time.

The methodology was applied first to the system load with wind and then again to the system load net of wind generation. The difference between the two results represents the estimated incremental reserve requirement due to wind resources.. The resulting estimate was an incremental reserve requirement of 43 MW for 2,000 MW of wind capacity. The unit cost was calculated by dividing the total cost of additional reserves by the total wind energy, which resulted in $1.10/MWh of wind energy (PacifiCorp 2007c). System balancing costs combined with the cost of incremental reserve requirements resulted in the estimate of $5.10/MWh.

2008 IRP

In Appendix F of its 2008 IRP, PacifiCorp further refined its methodology of estimating wind integration cost. The same two cost categories were used but referred to as inter-hour (system balancing) and intra-hour (incremental reserve requirements) costs. Existing wind plant production data from October 2008 through April 2009 were used in the calculations, but the data was scaled up to reflect planned wind capacity additions to PacifiCorp's system. The intra-hour cost was calculated by estimating the MW quantity of reserves required as additional wind resources were added to the system. This was done by computing the deviation of hourly average wind generated energy from the historical hour-ahead wind generation forecast, and hourly wind generation.

The inter-hour cost calculation was split into day-ahead and hour-ahead. PacifiCorp assumed forecast imbalances were addressed in the day-ahead market. Using the hourly differences between long-term expected wind generation (i.e., prior energy expectations) and historical wind generation forecasts for the day-ahead horizon, the day-ahead system balancing costs were estimated. A similar method was used to calculate hour-ahead variation, but using the variance between the day-ahead wind forecast and the hour-ahead wind forecast. The specific hourly variance was applied to the corresponding hourly real-time price. The size of the variance determined the imbalance cost attributable to wind, which was the product of the hourly price and the corresponding variance percentage.

In its 2008 IRP, PacifiCorp estimated the overall wind integration cost to range from $9.96/MWh to $11.85/MWh, depending on which CO_2 tax level was utilized. The lower-bound estimate ($9.96/MWh) corresponded to an $8 CO_2 tax scenario, whereas the upper-bound estimate ($11.85/MWh) corresponded to a $45 CO_2 tax scenario (PacifiCorp 2008).

PacifiCorp's 2010 Wind Integration Resource Study

On September 1, 2010, PacifiCorp published its *2010 Wind Integration Resource Study* (PacifiCorp Study or 2010 analysis). The amount of operating reserves required for different levels of wind, and the estimated cost of holding those reserves on PacifiCorp's system was calculated using the Planning and Risk (PaR) model (PacifiCorp 2010a). The PaR model was also used to estimate the wind integration costs associated with system balancing (PacifiCorp 2010). Note that in the 2010 analysis, PacifiCorp assumed that there was no CO_2 tax.

Ten-minute interval load and wind data was used to estimate the amount of operating reserve, both up and down, needed to manage fluctuations in load and fluctuations in wind within PacifiCorp's balancing authority. The operating reserves were limited to spinning reserves and non-spinning reserves, which are needed for regulation, load-following, and contingency reserves. In the PacifiCorp study, regulation service refers to the operating reserve required to manage the variability of load and wind generation in 10-minute periods, and load-following service represents the operating reserve required to manage the variability as measured in hourly periods (PacifiCorp 2010b). Note that in PacifiCorp's study, contingency reserves were assumed to remain unchanged by wind generation. As used below, operating reserves encompass both regulation and load following.

To estimate the incremental operating reserves required for wind, PacifiCorp used existing operating reserve requirements for load and production data from 2007–2009, subdivided into regulation and load following. The 2007–2009 load data was the baseline case (zero wind generation) in each scenario, whereas coincident wind data, as observed (plus estimated wind data by the Brattle Group), was added in increasing levels of wind penetration capacity to gauge the change in operating reserves demand. The wind data set selected for the 2010 analysis contained gaps so PacifiCorp utilized the Brattle Group to simulate missing wind data. The methodology was based on using available wind data to estimate the missing wind data. The statistical relationships between pairs of sites were studied and those relationships were used to derive or estimate the wind output for periods that historical data were incomplete or missing (PacifiCorp 2010a).

In the PaR Model, the hourly wind forecast is done by persistence; applying the instantaneous sample of the wind generation output 20 minutes past the current hour to the next hour as a forecast and balancing the system to that point (PacifiCorp 2010b).

Two scenarios of 1,372 MW and 1,833 MW of wind were simulated in the PaR model to estimate the incremental operating reserve demand. The first simulation was based on a non-variable/flat resource and the second was based on wind profiles. The differences in system cost between the two simulations were divided by the total volume of wind generation in each scenario to derive the estimated operating reserve costs, i.e., regulation and load following (PacifiCorp 2010b).

Another set of PaR simulations was used to estimate the system balancing costs associated with wind integration. Two more PaR runs were used to simulate PacifiCorp's system operations. The first run determined the unit commitment of PacifiCorp's generation given the day-ahead forecast of wind and load, whereas the second simulation used that unit commitment, but dispatched units based on wind and load. The change in system costs between this second simulation and the original wind simulation (from the above paragraph) was used to isolate the wind integration cost due to system balancing (PacifiCorp 2010a).

In its 2010 analysis, PacifiCorp estimated that the cost of integrating 1,372 MW of wind capacity is $8.85/MWh and $9.70/MWh for 1,833 MW of wind capacity (PacifiCorp 2010b). Note that in the 2010 analysis, the vast majority of the wind integration costs were associated with incremental operating reserves (i.e., about 90%). PacifiCorp included the results of the 2010 analysis in its 2011 IRP.

PacifiCorp's 2012 Wind Integration Resource Study

PacifiCorp is in the process of completing an updated wind integration study. PacifiCorp is planning to publish the *2012 Wind Integration Resource Study* (2012 analysis) by late 2012, and include the results in the Company's 2013 IRP. PacifiCorp's proposed methodology is largely similar to the methodology used in its 2010 study—wind integration costs are to be estimated as the sum of the operating reserve costs and system balancing costs. PacifiCorp will use data from operations between 2007 and 2011; including 10-minute system load data, 10-minute average wind production data, and day-ahead load and wind forecast data (PacifiCorp 2012a).

Although the study methodology is similar to the previous analysis, the integration cost estimates included in the draft 2012 analysis are considerably lower than those in the 2010 analysis due to updated input assumptions. According to the draft version, the 2012 analysis reflects a significantly depressed commodity price environment than the 2010 analysis, which is the primary reason for the cost differential. 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. In the 2012 analysis, the value of reserves is considered the opportunity cost of a lost sale at a given generation station. This opportunity cost is the foregone margin (which is equal to the lost revenue from the wholesale sale) less the variable cost to run the generation plant at a higher level, which is primarily the cost of fuel. The PaR model showed that this sale would have been made had the unit not been backed down to provide the required reserves (PacifiCorp 1012b).

In addition, PacifiCorp included day-ahead load forecast error in the system balancing costs in the 2010 analysis, which should not have been attributed to wind resources according to the draft version of the 2012 analysis (PacifiCorp 2012b). In the draft 2012 analysis, PacifiCorp estimated that the cost of integrating 2,135 MW of wind capacity is \$1.89/MWh—\$0.36 attributable to system balancing, and \$1.52 for incremental operating reserves (PacifiCorp 2012b). Note that these results were under stakeholder review at the time of publication of this document, and are subject to change.

Determination of PacifiCorp's Wind Integration Charge in Idaho

The establishment of PacifiCorp's wind integration charge dates back to IPUC Case No. PAC-E-07-07 in 2007, in which PacifiCorp originally requested a wind integration charge of \$5.04/MWh. This cost is equivalent to the estimate from the 2004 IRP, \$4.64/MWh, adjusted for inflation to 2007 dollars (PacifiCorp 2007a). In October 2007, PacifiCorp and the Renewable Coalition filed a stipulated settlement asking the IPUC to approve a wind integration discount of \$5.10/MWh, citing the updated estimate in PacifiCorp's 2007 IRP (PacifiCorp 2007a). In February 2008, the IPUC agreed that the estimate of \$5.10/MWh was within a reasonable range, thus approving the settlement agreement and issuing Order No. 30497.

In September 2009, PacifiCorp requested the IPUC increase the applicable wind integration discount to \$9.96/MWh, citing the findings from a wind integration analysis in its 2008 IRP. The Renewable Northwest Project submitted comments to the IPUC in response to PacifiCorp's petition, arguing that the estimate from PacifiCorp's 2008 IRP was flawed. According to the Renewable Northwest Project, the most fundamental shortcoming was that the variability and uncertainty introduced by wind was considered separately from the variability and uncertainty attributed to load. Because the variability of load and the variability of wind are not correlated, the net variability of load and wind is less than the variability of load and wind individually. PacifiCorp did not respond to the Renewable Northwest Project's comments.

In March 2010, the IPUC stated that they continue to find that the costs of wind integration are real and greater than zero. The IPUC also acknowledged that there was not a consensus methodology for calculating wind integration costs. However, the IPUC found it reasonable to increase the integration charge from $5.10/MWh to $6.50/MWh (Order No. 31201), which was the maximum wind integration rate authorized for the other two major utilities in Idaho. The IPUC stated that the PacifiCorp case was not the appropriate forum to select a methodology for estimating wind integration discounts; the IRP process, however, was a more appropriate forum open to all stakeholders (IPUC 2010).

NorthWestern Energy – Montana

Background

NorthWestern Energy has applied to FERC to charge its retail supply customers to reflect the regulation demands of wind generation (FERC 2012e). NorthWestern's wind integration cost estimates are based on the Dave Gates Generating Station (DGGS) at Mill Creek, a 150-MW natural gas-fired generating unit in Montana (NorthWestern Energy 2011a and NorthWestern Energy 2011b). The plant is used to provide regulation service for NorthWestern Energy, and is therefore the basis for its regulation cost calculations.

NorthWestern contends that 60 MW is an appropriate amount of regulation capacity used by its traditional load, and 105 MW is necessary for regulation services for its total load. Therefore, NorthWestern proposed to allocate 60/105ths of the revenue requirement of DGGS to its wholesale and bundled retail customers under its Montana OATT Schedule 3—Regulation and Frequency Response Service; and 45/105ths solely to its retail supply customers to reflect the regulation demands of wind generation. Note that these allocations are based on a 12 coincident peak load. In addition, NorthWestern submitted two studies to FERC in support of its proposal: (1) the NorthWestern Energy Montana Wind Integration Study, which was part of NorthWestern's 2011 Electricity Supply Resource Procurement Plan; and (2) a study completed NorthWestern witnesses, Dr. Richard Tabors. Both studies utilize historical data from NorthWestern's balancing authority area to calculate regulation capacity needs (FERC 2012e).

The parties involved in the NorthWestern's rate case reached an impasse and were unable to come to a settlement agreement. There was disagreement among the interveners regarding both the numerator and the denominator proposed by NorthWestern. The Montana Large Customer Group (LCG) argued that the numerator should actually be 19 MW. Furthermore, LCG argued that the denominator should be based on the nameplate capacity of the DGGS, 150 MW, rather than NorthWestern's proposal of 105 MW. The Administrative Law Judge assigned to the case issued an Initial Decision in September 2012, finding portions of NorthWestern's application unjust and unreasonable, siding with the LCG for both the numerator and the denominator (FERC 2012e). As such, the proceeding will go through FERC's hearing process, including additional rounds of briefs before FERC issues a final order. The two studies NorthWestern submitted to FERC, and a study from LCG, are summarized below.

NorthWestern's Electricity Supply Resource Procurement Plan

For its 2011 Electricity Supply Resource Procurement Plan, NorthWestern Energy defined a wind integration price adder based on the DGGS natural gas power plant. As stated above, the plant is used to provide regulation service for NorthWestern Energy, and is therefore the basis for estimating regulation costs. The wind integration price adder represents how much net incremental regulation is going to be needed due to the variability of wind. The wind integration price adder is added to the cost of wind when evaluating supply options in NorthWestern Energy's procurement plan. To determine the wind integration price adder, a no-wind scenario with 60 MW of total regulation (42 MW allocated to energy supply) was analyzed and compared to a scenario including existing wind (141 MW), and an additional 25 MW of regulation (NorthWestern Energy 2011b).

The wind integration price adder is comprised of the costs of operating the Mill Creek facility above 60 MW, which has historically been the amount of regulation NorthWestern Energy has needed. These costs are adjusted for revenue credits from energy sales as a byproduct of regulation and distributed across wind projects in NorthWestern's electric supply portfolio. NorthWestern Energy determined that 25 MW of additional regulation will be needed in 2012 to accommodate the 141 MW of existing wind capacity by applying an 18% wind integration factor to the total wind capacity. NorthWestern Energy does not specify how they determined this value. The wind integration factor is the ratio of regulation per megawatt of wind capacity needed to meet reliability requirements. 80% of the costs of the Mill Creek facility are assigned to energy supply, and, of that, about 14% ($5.575 million) is assigned to wind. The integration cost was determined to be $11.28/MWh, which is wind's share of the costs of the Mill Creek facility, divided by the expected total wind generation (given a 40% capacity factor) (NorthWestern Energy 2011b).

Determination of Regulation Service Requirements[19]

In December 2011, NorthWestern submitted rebuttal testimony to FERC that included the study performed by Dr. Tabors (Tabors Study) analyzing the regulation service needs of NorthWestern. Using a six-step methodology, Dr. Tabors estimated NorthWestern's regulating capacity requirements for its traditional load:

- First, Dr. Tabors used 2009 1-minute ACE[20] data as a baseline for his analysis.
- Second, he subtracted on a minute-by-minute basis an estimate of the wind forecast uncertainty.
- Third, Dr. Tabors subtracted the amount of regulation that was actually procured from third party suppliers by NorthWestern on a minute-by-minute basis.
- Fourth, he averaged the 1-minute data into 10-minute blocks.
- Fifth, he aggregated the 10-minute blocks into calendar months to identify the maximum variation both up and down that is required.
- Finally, Dr. Tabors subtracted L10[21] values from both the up and down variability to arrive at regulation up and regulation down quantities (FERC 2012e).

[19] The determination of regulation service requirements is discussed in the body of this report only and is not included in the summary tables in the beginning of this report.
[20] ACE is defined as the instantaneous difference between a balancing authority's net actual and scheduled interchange, taking into account the effects of frequency bias and correcting for meter error (NERC 2012).
[21] L10 is a statistically derived value derived from NERC standards that reflects the maximum 10-minute deviation from ACE that is allowable. It is not necessary to perfectly drive ACE to zero, but rather ACE should be within the L10 value from zero.

Note that Dr. Tabors corrected an error in his analysis discovered by FERC staff. Initially, Dr. Tabors incorrectly associated a positive open loop ACE value with a need for regulation up capacity, as well as a negative open loop ACE value with a need for regulation down capacity. Using this methodology, Dr. Tabors analyzed NorthWestern's total capacity requirements for a range of NERC's CPS2 compliance targets. Ranging from the minimum CPS2 compliance level of 90% up to 98%, Dr. Tabors argued that NorthWestern would need between 52 MW and 101 MW of regulation capacity. Specifically, Dr. Tabors concluded that at a 92% compliance level NorthWestern would require 59 MW of regulation. For a CPS2 compliance level of 94%, Dr. Tabors explained that NorthWestern would require 67 MW of regulation capacity. Finally, to meet a 95% CPS2 compliance level, Dr. Tabors stated that NorthWestern requires 73 MW of regulation capacity (FERC 2012e).

LCG argued that 19 MW was a more appropriate numerator with a CPS2 compliance target of 95%. LCG witness James Dauphinais submitted a separate study to support this estimate, and LCG offered three critiques of Dr. Tabors' study. First, LCG argued that Dr. Tabors failed to eliminate regulation down capacity from the calculation of NorthWestern's non-wind integration capacity need, in accordance with FERC precedent. Second, LCG contended that Dr. Tabors failed to apply regulation limits to 1-minute open loop ACE values. Finally, LCG argued that Dr. Tabors erred by allocating the entire amount of diversity benefits between wind schedule deviations and non-wind schedule deviations to NorthWestern's wind integration regulation capacity need, when a cost-causation approach would produce more appropriate results (FERC 2012e). Mr. Dauphinais initially performed the seven steps to determine NorthWestern's regulation service requirement:

- First, for each 1-minute interval, he subtracted the non-wind balancing authority generation amount from the balancing authority load amount to get a net balancing authority load amount.
- Second, he converted these 1-minute instantaneous values to 10-minute average values.
- Third, he dropped the first and sixth 10-minute intervals for each hour to eliminate ramping periods between hourly schedule amounts.
- Fourth, for each hour, he calculated from the remaining 10-minute interval data the difference between the maximum 10-minute balancing authority net load amount for that hour and the minimum 10-minute balancing authority net load amount for that hour to get an hourly gross regulation service capacity amount for that hour.
- Fifth, for each month, he then sorted, from highest to lowest, the hourly gross regulation service capacity amounts.
- Sixth, he determined for each month the gross hourly regulation service capacity amount that would be necessary to cover 90% of the hours for that month.
- Lastly, he subtracted NorthWestern's L10 value of approximately 24 MW from the monthly 90th percentile gross regulation service capacity amounts (FERC 2012e).

Using this methodology, Mr. Dauphinais determined that NorthWestern's regulation capacity requirement should be 19 MW. Note that Mr. Dauphinais made the same correction noted above for the Tabors study, and made an additional modification based on feedback from a BPA witness. BPA argued (and LCG agreed) that Dr. Tabors incorrectly assigned all the diversity benefits to wind integration capacity need, which would necessarily result in an overstatement of the Schedule 3 rate. Instead, BPA advocated for an approach that allocates the benefit provided by diversity to NorthWestern's Schedule 3 customers (FERC 2012e).

PGE

Background

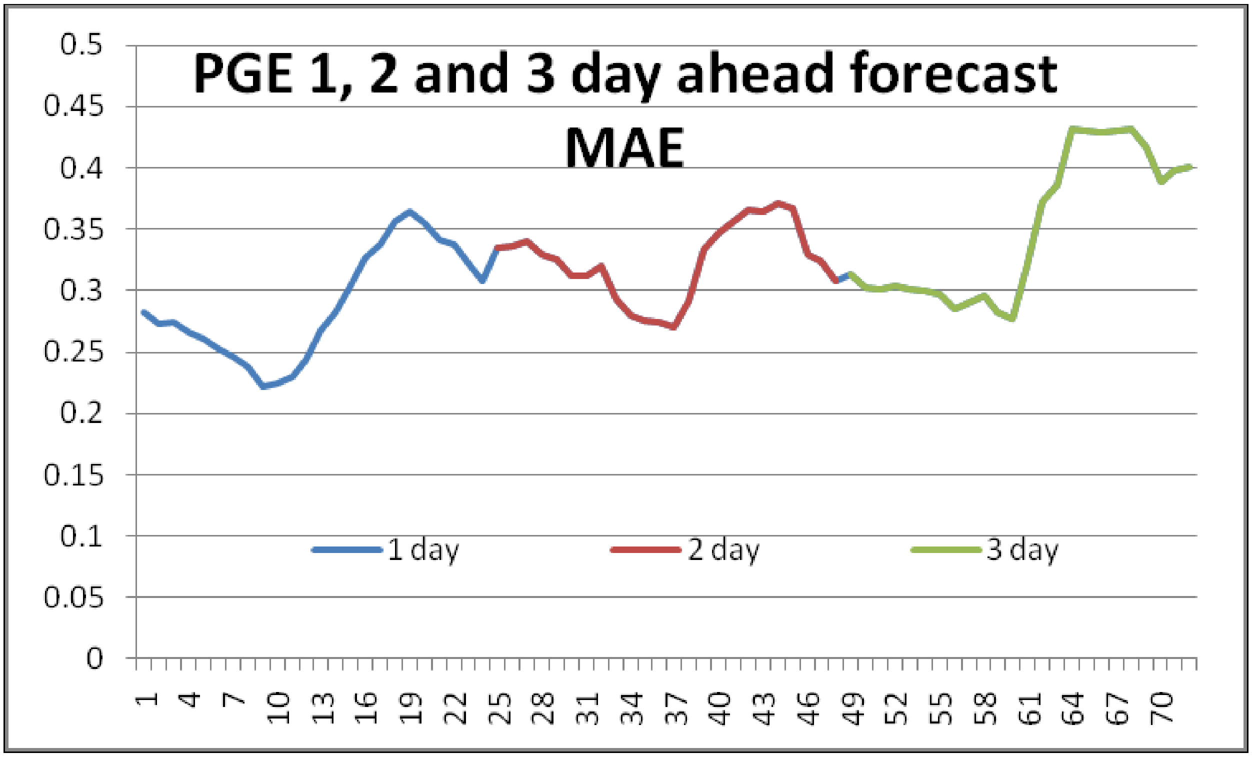
PGE[22] incorporates a wind integration cost into its resource plan modeling, as part of comparing wind resources with other demand and supply resource options. In 2007, PGE undertook Phase I of a wind integration study to estimate the wind forecasting costs associated with a PGE "self-integration" of wind generation (i.e., costs based on operations and constraints of PGE's owned generation and power purchases). In November 2010, the Oregon PUC directed PGE to assess wind integration costs in their IRP. As a result, in 2011, PGE reported that the wind integration cost would be decreased from $13.50/MWh in the 2009 IRP to $9.15/MWh (in 2014 dollars) for the next IRP (PGE 2011a; and Oregon Public Utilities Commission 2011).

Assumptions

The wind integration cost estimate of $9.15/MWh reflects PGE's estimated cost of using its own generating resources to integrate 450 MW of existing wind resources and 400 MW of new wind resources into PGE by 2014. Using the NREL Western Wind and Solar Integration Study (WWSIS) Resource Database, PGE developed wind power capacity factors and shapes. The database provided simulated wind power output at 10-minute intervals, and day ahead forecasts at one hour intervals. The 450 MW of existing wind are produced by Biglow Canyon Wind Farm, which was assumed to be self-integrated. The 400 MW of new wind generation were assumed to be located in the Columbia River Gorge.

PGE currently has an operational schedule that includes one-, two-, and three-day ahead forecasts for load and generation resources. Load and resource forecasts generated on Monday, Tuesday, and Wednesday each week provide one-day ahead forecasts; those generated on Thursday provide a day-ahead forecast for Friday and a two-day ahead forecast for Saturday; whereas forecasts generated on Friday yield a two-day ahead forecast for Sunday and a three-day ahead forecast for Monday. The WWSIS wind data provides a day-ahead forecast for every day. PGE supplemented the WWSIS data with historical hourly forecast data and corresponding generation data from 2007 to 2010 for the Biglow Canyon wind plant. The difference in timing between PGE's load and forecast schedules are meant that the forecast errors in the WWSIS data were not comparable to PGE's wind forecast errors for the two- and three-day ahead forecasts as shown in Figure 2.

[22] PGE did not respond to requests to review this section.



Source: PGE and EnerNex, 2011. PGE Wind Integration Study Phase II. September 30, 2011, pp. 14. www.uwig.org/PGE_Study/PGE_Phase%202_Wind_Integration_Report_9-30-11.pdf.

Figure 2. Mean absolute error for PGE wind forecasts of one, two, and three days ahead

PGE adjusted the forecast error in the NREL database forecasts without increasing the actual energy forecasted. Day ahead forecasts were not altered, but PGE increased the wind forecast error for two-day ahead forecasts by 14.1%, and by 24.1% for three-day ahead forecasts. In other words, the day-ahead forecasts were modified such that the forecast energy from the WWSIS data would not change, but the forecast error would increase to approximate the same increase in error as observed in PGE's historical (wind forecast and generation) data.

PGE is a "net short" utility, meaning total load in PGE exceeds the capacity of PGE's generation capacity. PGE relies upon market transactions to make up the difference. As a result, PGE states that only a limited number of PGE's generating plants can provide reserves, and several thermal units were not used as part of PGE's modeling. Additionally, scheduling in the Pacific Northwest is mostly done on an hourly basis. Changes in load and variable generation in real-time must therefore be compensated for with pre-scheduled generation, specifically set aside to manage generation changes within the hour. The model PGE used accounts for regulation, load-following, and contingency reserves (PGE and EnerNex 2011a).

The model estimates reserves for the hour-ahead uncertainty of wind; *within-hour* load following for wind; and generation resource requirements for within-hour regulation for wind. The study subdivided integration costs into day-ahead uncertainty (for day-ahead wind forecast error); hour-ahead uncertainty (for hour-ahead wind forecast errors); intra-hour load following; and within-hour changes of wind generation from wind schedules (regulation).

Modeling

To create a long-term forecast of wholesale electricity prices, PGE used the AURORAxmp Electric Market Model, which simulates electricity markets sorted by NERC area. It was also used to forecast 2014 hourly electric prices for the Pacific Northwest.

The primary model used by PGE to determine the wind integration estimate of $9.15/MWh, however, was an internally developed constrained optimization model, designed to minimize system operating costs under a given set of constraints that include plant dispatch requirements and system requirements (contingency reserves—spinning and non-spinning, regulation, load following, etc.) . The constrained optimization model is a mixed integer programming model that derives the estimated incremental operating costs of integrating wind. It was created using GAMS, Gurobi, and Microsoft Excel. The model optimizes dispatch and operations for one year—in this case, 2014. The model was run in three stages that corresponded to day-ahead, hour-ahead, and intra-hour, with commitments made in prior stages carrying through to the next stages as constraints. The total system operating costs at the third stage were used in determining wind integration costs.

The cost of wind integration was defined as the savings in system operating costs that would result if wind placed no incremental requirements on system operations. To that end, wind integration costs were derived by running the model with and without incremental reserve requirements for wind and dividing the resulting value by total wind generation.

Initially, the model produced an integration cost estimate of $11.04/MWh. This value was reduced to the $9.15/MWh value that will be used in PGE's next IRP when PGE assumed that it would deploy new flexible thermal resources—specifically, two 100-MW GE LMS 100 simple cycle combustion turbines (PGE and EnerNex 2011a).

PSCo – Wind

Background

Xcel Energy, doing business as PSCo, estimates wind integration and cycling costs when evaluating wind resources as part of PSCo's Electric Resource Plan and in comparing bids from wind generators in wind-only or all-source utility RFPs. PSCo also incorporates a solar integration cost, which is discussed in the next section. Cost values vary based on natural gas prices and the amount of existing wind capacity. PSCo has conducted three wind integration studies, with the most recent completed in August 2011. Xcel's prior studies examined 10%, 15%, and 20% wind penetration levels. However, Xcel asserts that previous integration studies based on percent wind penetration levels are no longer comparable due to growth in PSCo's peak load, which is the denominator in wind penetration percentage calculations. For this reason, PSCo opted to begin performing studies using installed nameplate wind capacity as their basis (Xcel Energy, Inc 2011a; and Xcel Energy, Inc. and EnerNex Corporation 2011).

Xcel's 2011 study estimated the average wind integration cost (excluding coal cycling) to be $3.68/MWh at 2 GW of wind, and $4.09/MWh at 3 GW of wind, given a base case gas price of $5.06/MMBtu and with an on/off peak proxy. Incremental integration costs (excluding coal cycling) are estimated to be $4.32/MWh for 200 MW of wind added to 2 GW of wind and a gas price of $5.06/MMBtu. The average coal cycling and curtailment costs are estimated to be

$0.77/MWh with wind curtailment and $0.83/MWh with coal deep cycling (both at 2 GW of wind) and $1.03/MWh with wind curtailment and $1.08/MWh with coal deep cycling (both at 3 GW of wind) (Xcel Energy, Inc. and EnerNex Corporation 2011; and Xcel Energy, Inc. 2011b).

Assumptions and Modeling: Wind Integration Charge

Wind integration costs were defined as including regulation, system operations (i.e., suboptimal unit commitment), and gas storage. PSCo uses incremental wind integration costs as an adder to wind generation costs in electric resource planning and in resource selection, whereas average wind integration costs are used as an input into the incremental wind integration cost calculations (Xcel Energy, Inc. and EnerNex Corporation 2011).

For wind integration costs without coal cycling, PSCo examined scenarios with 2 GW and 3 GW of wind by 2018, with multiple sensitivities ranging from varying gas costs, geographic diversity of wind projects, incremental pumped hydro storage, wind forecasting, demand response, and carbon prices. PSCo did not determine wind integration costs stemming from wind curtailment, trading inefficiencies because of wind's uncertainty, or higher operations and maintenance costs incurred by thermal units that are providing more flexibility to accommodate wind (Xcel Energy, Inc. and EnerNex Corporation 2011).

To estimate the wind integration costs (excluding coal cycling), PSCo used the Couger unit commitment and dispatch model to estimate the nominal values of integrating 2 GW and 3 GW of wind into PSCo. The Couger model creates an optimal plan for day-ahead unit commitment, and can dispatch committed generation at least-cost. In this case, the model was used to produce commitment and dispatch plans for every hour of the study year (2018). Incremental wind integration costs are determined as the sum of the incremental costs for regulation, system operations, and gas storage, divided by the incremental wind generation. Average wind integration costs are calculated by determining the total annual integration costs divided by total annual wind energy for each scenario (Xcel Energy, Inc., and EnerNex Corporation 2011).

To determine average regulation related to of wind integration, PSCo used a comparative statistical analysis of net load and load, which derived the required regulation capacities at varying levels of wind. This was then multiplied by the regulation cost in PSCo's transmission tariff ($6.740/kW-month, $80.88/kW-year). The cost was then divided by the predicted annual wind production for each scenario (Xcel Energy, Inc. and EnerNex Corporation 2011).

The average system operations costs were determined through a five-step process of Couger model runs. The first step involves projecting the day-ahead unit commitment plan every hour for 2018, whereas the second step simulates serving daily load with actual load data and produces an hourly system operating cost. Two proxies of hourly wind shapes were used to represent wind generation for both of these steps: a flat block that distributes wind power evenly over each hour of the 24 hour period, and an on/off peak proxy that distributes wind power over an on-peak block and an off-peak block. The third step has a new unit commitment with a day-ahead wind forecast, and the fourth step does economic dispatch with hourly wind profiles. The fifth and final step was to calculate the average system operations wind integration costs, which is the difference between the system production costs in the second step (load dispatch) and the fourth step (load dispatch with wind), then dividing by annual wind energy production (Xcel Energy, Inc. and EnerNex Corporation 2011).

The third part of the average wind integration cost, the average gas storage component, was determined based on projections of gas consumption developed from modeling in Couger. The largest over- and under-nominations of natural gas volumes were selected for a gas day and annually for a gas day. The largest of these values for a gas day was used to set the demand charge, whereas total annual amounts were used to set the commodity charge. The demand and commodity charges were totaled, and the value that required the greatest storage system demand was used in determining the average gas storage cost component of the average wind integration cost (Xcel Energy, Inc. and EnerNex Corporation 2011).

As discussed earlier, PSCo uses the incremental wind integration cost, not the average, for resource planning and selection. To determine the integration cost for any incremental generation above 2 GW of wind, the difference between the total average integration costs for 2 GW of wind and for the new level of wind must be determined, and then that value must be divided by the incremental annual wind generation. Table 17 shows an example of this calculation; in this case, for adding a 200 MW wind project to 2 GW of wind (Xcel Energy, Inc. and EnerNex Corporation 2011).

Table 17. Example Total Incremental Wind Integration Cost Calculation

Step	Value and (Calculation)	Result
	2,000 MW Calculation	
a	Total Actual Annual Wind Energy Assumption (MWh)	6,000,000
b	Average Regulation Wind Integration Cost ($/MWh)	0.14
c	Regulation Wind Integration Cost ($) (a*b)	840,000
d	Average System Operations Wind Integration Cost ($/MWh)	3.40
e	System Operations Wind Integration Cost (($) (a*d)	20,400,000
f	Average Gas Storage Wind Integration Cost ($/MWh)	0.14
g	Gas Storage Wind Integration Cost ($) (a*f)	840,000
h	Total Wind Integration Cost ($) (c + e + g)	22,080,000
	2,200 MW Calculation	
i	Capacity Addition Between 2,000 and 3,000 MW	1000
j	Capacity Factor of Added Wind Assumption	0.5
k	Amount of Added Wind Capacity Assumption (MW)	200
l	Hours in a Year	8,760
m	Total Actual Annual Wind Energy (MWh) (a + (j*k*l))	6,876,000
n	Average Regulation Wind Integration Cost at 3,000 MW ($/MWh)	0.21
o	Average Regulation Wind Integration Cost ($/MWh) (b + ((k/i)*(n-b)))	0.15
p	Regulation Wind Integration Cost ($/MWh) (m*o)	1,058,904
q	Average System Operations Wind Integration Cost at 3,000 MW ($/MWh)	3.71
r	Average System Operations Wind Integration Cost ($/MWh) (d + ((k/i)*(q-d)))	3.46
s	System Operations Wind Integration Cost ($) (m*r)	23,804,712
t	Average Gas Storage Wind Integration Cost at 3,000 MW ($/MWh)	0.17
u	Average Gas Storage Wind Integration Cost ($/MWh) (f+((k/i)*(t-f)))	0.15
v	Gas Storage Wind Integration Cost MW ($) (m*u)	1,003,896
w	Total Wind Integration Cost ($) (p+s+v)	25,867,512
	Total Incremental Wind Integration Cost Calculation	
x	Total Incremental Wind Integration Cost ($/MWh) ((w-h)/(m-a))	4.32

Source: Xcel Energy, Inc. and EnerNex Corporation 2011

Assumptions and Modeling: Coal Cycling Costs

The coal cycling costs that PSCo factors in when evaluating wind resources as part of PSCo's IRP, and in comparing bids from wind generators in wind-only or all-source utility RFPs, are determined separately from the wind integration costs. Xcel defines cycling costs as having both a plant cycling component and a wind curtailment component. As with wind integration costs, these values vary to reflect the amount of existing wind capacity, and Xcel's current assumptions with respect to load forecasts, fuel, and curtailment costs. Xcel plans to update the model and resulting values as needed to reflect any changes. PSCo evaluated two coal plant cycling protocol scenarios with 2 GW and 3 GW of wind by 2020. One scenario, considered the wind curtailment scenario, had coal plants cycle down to the economic minimum, or "shallow cycle," to allow for wind. Wind was then curtailed as needed. In the second scenario, "deep cycle," coal plants were cycled to their lower emergency minimum levels, with any excess wind beyond that curtailed as needed. The average costs are estimated to be $0.77/MWh with wind curtailment and $0.83/MWh with coal deep cycling (both at 2 GW of wind) and $1.03/MWh with wind curtailment and $1.08/MWh with coal deep cycling (both at 3 GW of wind). Incremental coal cycling costs are higher than average costs, with an additional 1 GW of wind capacity above the 2 GW level estimated at $2.18/MWh for the curtailment scenario, and $2.22/MWh for the deep cycle scenario (Xcel Energy, Inc. 2011a and Xcel Energy, Inc. 2011b).

To calculate these costs, PSCo only considered load-following cycles, excluding on/off cycling and AGC cycles for frequency regulation. PSCo also assumed perfect foresight of load and wind, and did not quantify the potential costs relating to wind curtailment during wind ramping events. To determine coal plant cycles attributable to wind, PSCo developed a spreadsheet model that used load forecasts before and after a user-specified level of wind generation. The cost per coal unit cycle was derived from previous work analyzing cycling costs at the Pawnee coal plant, done in 2008 by Aptech Engineering, which was used to ascertain costs at other PSCo units. Existing forecasts of coal prices, REC prices and CO_2 emission costs were used to determine wind curtailment costs. Generating resources were selected to meet the load forecast, the number of coal cycles by unit was estimated, and then the wind curtailment costs were added. The model was run twice, with and without wind, with the cost difference representing cycling and wind curtailment costs (Xcel Energy, Inc. 2011b).

PSCo – Solar

Background

In approving PSCo's 2007 Resource Plan in Docket No. 07A-447E, the Colorado Public Utilities Commission directed PSCo to examine solar integration costs. PSCo will add incremental solar integration costs to bid prices from competitive suppliers for solar capacity, and to solar costs as part of evaluating demand and generating resources in PSCo's electric resource planning. Average solar integration costs ranged from $1.25/MWh to $6.06/MWh, however the actual solar integration costs that PSCo will impose will vary depending on natural gas prices and the amount of existing solar capacity (Xcel Energy, Inc. and EnerNex Corporation 2009).

Assumptions and Modeling

The solar integration charges are estimated as determined in PSCo's most recent solar integration cost study performed in 2009 that focused on system dispatch inefficiencies from solar forecast errors. PSCo did not estimate solar integration costs from added regulation capacity, impacts on gas supply nominations, impacts on operations and maintenance on existing conventional generation units, transmission expansion costs or energy trading inefficiencies with higher levels of solar capacity. Six scenarios were developed ranging from 200 to 800 MW of solar, with at least 200 MW coming from a solar thermal parabolic trough plant with four hours of thermal energy storage (Xcel Energy, Inc. and EnerNex Corporation 2009).

The solar integration cost is determined by running the Couger unit commitment and dispatch model twice: once for day-ahead forecasted load and actual load, and then with day-ahead solar forecasts and solar generation. The difference in costs between the two model runs, divided by solar generation, is considered the solar integration cost. Average solar integration costs ranged from $1.25/MWh to $6.06/MWh, with integration costs roughly increasing at $1/MWh with each

100 MW of additional solar capacity. Solar day-ahead forecasts were compiled averaging solar insolation for that hour in a month (i.e., solar forecast for any day in May at 3 p.m. is the average insolation for 3 p.m. for every day in May) (Xcel Energy, Inc. and EnerNex Corporation 2009).

PSE

Background

PSE first petitioned FERC in June 2010 to institute a new ancillary service, termed Schedule 12, in PSE's OATT (PSE 2010a). PSE said the new ancillary service was intended to ensure there is enough capacity to follow and balance the within hour variability of wind generation, with costs being assigned to wind generators in PSE's balancing authority.

The first phase of PSE's Wild Horse wind facility went into service in 2006. PSE began supplying following capacity for the 229 MW project in late 2006 in addition to what PSE provided for load and other generating resources. Over the next few years, PSE received interconnection requests from third-parties for wind facilities that were to be located within its balancing authority area. Based on their experience providing balancing service for the Wild Horse wind facility, PSE expected their costs of providing balancing service to third-parties to exceed its existing rates under their OATT and undertook an effort to file for a new rate schedule to be added to their OATT. In spring 2008, PSE said demand for flexibility surpassed available supply, and the company had to purchase operating reserves in the short-term wholesale market. PSE noted demand was due to high water flows at several of PSE's hydro plants; environmental restrictions on some hydro plants that limited their production and operational flexibility; and limited flexible capacity from PSE's combined-cycle and combustion turbine plants (PSE 2010b).

In June 2010, PSE proposed a Schedule 12 rate of $2.70/kW-month to be levied upon wind generators, defined as the Following Capacity Fixed Charge (FCFC). The company determined this charge by setting the incremental monthly cost per kW of capacity based on a proxy natural gas peaking plant, defined as the Following Capacity Fixed Charge (FCAC), that it considered representative of the incremental market price of capacity needed to follow the intra-hour variability of wind generation. PSE assigned wind an 18.1% Following Cost Allocation Factor (FCAF). PSE proposed to charge a wind facility based on their installed nameplate capacity. For example, a 100-MW facility would pay $270,000 per month for Schedule 12 service.

In August 2010, FERC dismissed Puget's application without prejudice to Puget filing a new proposal. FERC agreed with PSE that "changing system conditions, such as an increasing amount of wind generation …, present unique challenges that may require novel solutions"(FERC 2010b). FERC explained, however, that proposals to FERC must address the problems they are intended to resolve, but PSE's proposal "… was not related to the actual, demonstrable costs incurred in providing service" (FERC 2010b). FERC noted that PSE supported its proposal for a proxy rate based on FERC's previous allowance of proxy rates in imposing generator imbalance charges under Order 890. However, FERC said that "while it will allow for the recovery of legitimate and verifiable opportunity costs," FERC will approve such proposals only if the recovery of opportunity costs will not contribute to the over-recovery of costs and that PSE has not shown that determining its opportunity costs through the use of a proxy generating unit will not result in the over-recovery of PSE's costs.

Following FERC's rejection of the proposed FCFC, PSE initiated discussions with FERC staff regarding a wind integration rate. In June 2011, PSE filed a new OATT amendment requesting authority to implement a wind integration rate for regulation and frequency response services for exporting wind generators (PSE 2011b). PSE proposed to update Schedule 3—Regulation and Frequency Response Service, and Schedule 13—Regulation and Frequency Response Service for Generators Selling Outside of Control Area. In the filing, PSE reiterated its need for additional regulation capacity related to variable generation in its balancing authority. PSE stated that it was currently providing regulation service to its own 273-MW Wild Horse facility (the 44-MW Phase 2 went into service in 2009) and Invenergy's 96-MW Vantage Wind facility, which went into service in late 2010 and exports all of its output to points outside of the PSE balancing authority area. Additionally, PSE noted that as of June 2011, another 377 MW of wind projects were in the PSE generation interconnection queue.

PSE's June 2011 proposal consisted of updating its cost of capacity for providing regulation service from the current value of $5.50/kW-month set in 1998, to $12.39/kW-month, based on a revised cost of service study. PSE also sought to update its Schedule 13 charges by creating a new category for VERs. The variable energy resource obligation for purchasing regulation reserves was proposed at 16.77% of a resources point-to-point transmission service schedule for export out of the PSE balancing authority. The variable energy resource charge would then be $2.08/kW-month (16.77% of $12.39) for all exported energy from a wind facility within the PSE footprint.

Assumptions

PSE's wind integration rate focuses purely on providing within-hour regulation service for the wind generators in its balancing authority. PSE's study used the 2010 4-second interval generation data for the full year for the Wild Horse facility and for from October to December for the Vantage Wind plant went into service October 4, 2010. The 4-second data was aggregated up to 10-minute interval data. In sum, the wind generation data set consisted of 10-minute generation data for the 273 MW Wild Horse plant from January 1, 2010 through October 3, 2010, and then the combined 369 MW of Wild Horse and Vantage Wind from October 4, 2010 through December 31, 2010.

PSE used 4-second 2010 load data and 4-second dispatchable generation plant data, both aggregated to 10-minutes. For the dispatchable generation, PSE chose six plants—the Colstrip coal facility units 1&2, the Goldendale and Sumas combined-cycle natural gas plants, and the Upper and Lower Baker hydroelectric units. For the forecast data sets, PSE created 60-minute before-the-hour persistence forecasts for wind generation, load, and the dispatchable generation units. Therefore the specific data sets used are:

- Hour-ahead forecasted 2010 load
- Hour-ahead forecasted 2010 wind generation
- Hour-ahead forecasted 2010 dispatchable generation from six plants
- 10-minute actual 2010 loads
- 10-minute actual 2010 wind generation
- 10-minute actual 2010 generation for the six representative dispatchable generation plants

- 2010 total monthly energy production for all dispatchable plants in the PSE balancing authority.

Determination of Regulation Reserve Charges

To calculate the variable energy resource rate, the following steps were performed:

1. Forecasted load was compared to actual load. PSE used a 95% confidence interval by taking the standard deviation of forecasted load versus actual load multiplied by two, resulting in a base within-the-hour regulation requirement of 71 MW.
2. The same computation was applied to forecasted wind versus actual wind resulting in a base within-the-hour regulation requirement of 77.8 MW.
3. The same computation for the representative dispatchable generation resulted in the following base within-the-hour regulation requirements—8.53 MW for coal plants, 7.53 MW for natural gas plants, and 1.99 MW for hydro plants.
4. Using the 10-minute deviations derived in steps 1 to 3, PSE determined the covariance pairs between each element. Then the square root of the sum of the five adjusted variances times two yielded the overall regulation requirement for PSE of 106.27 MW (Table 18).

Table 18. PSE Variable Energy Resource Rate Adjusted Variance Calculations

	Individual Std Dev (MW)	Covariance with PSE Load (MW)	Covariance with Wind Plants (MW)	Covariance with Coal Plants (MW)	Covariance with Hydro Plants (MW)	Covariance with CCCT / CT/Misc. (MW)	Adjusted Variance
PSE BAA Load	35.50		8.36	1.29	(0.99)	(2.57)	1,266.4
Wind Plants	38.90	8.36		(0.27)	0.25	1.27	1,522.8
Coal-Fired Steam Plants	4.27	1.29	(0.27)		0.09	0.58	19.9
Hydro Plants	0.99	(0.99)	0.25	0.09		0.08	0.4
CCCT/CT/Misc. Plants	3.77	(2.57)	1.27	0.58	0.08		13.5
					Total Adjusted Variance		2,823.1
					Total 2*Standard Deviation		106.27

Source: PSE FERC filing, *Prepared Direct Testimony of Lloyd C. Reed on Behalf of Puget Sound Energy, Inc.*, Docket No. ER11-3735, June 6, 2011.

5. To account for system diversity and allocate a portion of the diversity benefits to wind, PSE calculated a system benefit ratio at a 95% confidence interval of 0.637. The wind regulation requirement was adjusted to account for the diversity benefit, which yielded a total wind regulation requirement of 49.72 MW. This requirement was divided by the total MW of installed wind in the PSE balancing authority, which resulted in an intra-hour regulation allocation for wind of 16.77% (PSE 2011b). The same method resulted in a 1.21% purchase obligation for load and a 0.38% purchase obligation for dispatchable generation. However, the Schedule 3 and 13 purchase obligations are currently set at 2% and PSE did not request authority to change the regulation allocation for load and dispatchable generators at the time of June 2011 filing (FERC 2011).

Charges under Schedule 13 are determined via (1) reserved transmission, (2) purchase obligation, and (3) capacity rate. For exporting generators, the reserved transmission is their point-to-point firm transmission reservation capacity for exports outside the balancing authority. The purchase obligation as determined by the calculations outlined above were 16.77% for wind and 2% for dispatchable generators.

As noted earlier, the capacity rate was set at $5.50/kW-month and has not been changed since 1998. In the June 2011 FERC filing, PSE requested authority to change the capacity rate to $12.39/kW-month, based on a revised cost of service study. The cost of service study was conducted using the pool of resources used by PSE to provide balancing services in its balancing authority. This pool consists of PSE's share of Colstrip coal units 1 to 4; PSE's share of Mid-Columbia hydro; the Upper and Lower Baker hydro plants; and the Encogen, Goldendale, Mint Farm, and Sumas combined-cycle natural gas plants. PSE excluded its peaking units and run-of-river hydro units as PSE argued that the peaking plants are used for spinning reserves and the run-of-river hydro units do not have adequate dispatch flexibility (PSE 2011b).

The study estimated the weighted average cost of capacity of the pool using the net capability of each plant. The annual revenue requirement of each plant was divided by the net capability of each plant to get an annual capacity rate for each, which was divided by 12 to derive a $/kW-month value for each plant. The weighted average of the individual capacity rates yielded an overall capacity rate of $12.39/kW-month for balancing services (PSE 2011b).

PSE notes in its filing that the capacity available from its hydro facilities used to provide regulation service has been reduced in recent years. PSE's share of Mid-Columbia resources dropped to 720 MW in July 2012 and increased restrictions on the Baker river plants limit the ramping capability of the hydro plants. PSE is increasingly relying on its thermal units to provide regulation service (PSE 2011b).

Status of PSE's Integration Rate

On October 20, 2011, FERC issued an order accepting, but suspending, PSE's proposed tariff revisions and ordering settlement proceedings (FERC 2011). FERC suspended the proposed changes for five months to become effective January 5, 2012, but subject to refund, pending the outcome of settlement proceedings. At issue is the validity of the data sets that PSE used with respect to developing the 60-minute persistence forecast and how diversity benefits are determined. FERC also ordered PSE to revise the purchase obligation for load and dispatchable generation in the same way it is proposing to create the variable energy resource purchase obligation. Also to be examined is the cost of service methodology PSE used to derive the regulation capacity costs, particularly with respect to PSE's revenue requirement calculation and the return on equity.

On September 14, 2012, PSE submitted a Stipulation and Offer of Settlement (Settlement) for approval by FERC. The Settlement resolves the issues referenced in the above paragraph, and all parties in the proceeding either support or do not oppose the Settlement (FERC 2012d). According to the Settlement, Schedule 3 will be revised to reflect a 1.21% purchase obligation; consistent with the directive included in the October 2011 FERC order. In addition, the capacity charge included in Schedule 3 is proposed to be set at $10.50/kW-month, rather than $12.39/kW-month (PSE 2012a).

The Settlement includes more comprehensive revisions for Schedule 13. The Schedule 13 generator regulation charge for VERs exporting energy outside the PSE balancing authority will be set at a "Base Rate" of $1.55/kW-month. PSE indicates that this charge for regulation service is a black box, negotiated value. It is a composite charge that ultimately derives from a volumetric purchase obligation for regulation service and a fixed capacity charge. However, for the limited purpose of self-supplying regulation and frequency response service, a variable energy resource's volumetric purchase obligation is 15% of the generator's point-to-point transmission service reservation. The Schedule 13 regulation charge for dispatchable generators delivering outside of the PSE balancing authority is proposed to be set at $0.105/kW-month. PSE states that this charge is also a black box, negotiated charge that ultimately derives from an unspecified volumetric component and capacity rate (PSE 2012a).

The variable energy resource generator regulation charge is defined as a "Base Rate" because generators are eligible for specific discounts based upon certain scheduling practices. According to the revised Schedule 13 included in the Settlement, transmission customers purchasing service under PSE's Schedule 13 must submit, either manually or through a mutually agreeable automated process, transmission schedules derived from a T-30 persistence forecast for each hourly scheduling interval.[23] According to the proposal, a generator may receive a discount of 30% off the Base Rate charge in exchange for a commitment to submit a T-30 persistence schedule for each and every 30-minute scheduling interval. Furthermore, PSE will offer a discount of 50% off the Base Rate charge in exchange for a commitment to submit a T-25 persistence schedule for each and every 15-minute scheduling interval (PSE 2012a).[24]

On September 20, 2012, FERC authorized PSE to institute the proposed rates for Schedule 3 and Schedule 13, effective September 1, 2012, and remaining in effect pending FERC's approval of the Settlement (FERC 2012f). Shortly thereafter, in October 2012, FERC issued an order terminating the settlement judge procedures, noting that the Settlement was uncontested by all parties involved in the proceeding (FERC 2012g). As of the end of November 2012, FERC has not issued a final order regarding the Settlement.

Westar Energy

Background

Westar Energy[25] submitted its first FERC filing in June 2009, requesting authority to implement a new regulation charge for variable generation (Westar 2009). Westar is a utility in Kansas and is also a member of the Southwest Power Pool (SPP). The Westar balancing authority includes seven transmission owners and four different wholesale suppliers. Westar noted in the filing that there are several existing and proposed merchant generation projects that are/will be connected to the Westar grid or to a transmission operator in its balancing authority. Several of these generators requested to be a part of the Westar balancing authority, most recently wind facilities that connect to transmission operators other than Westar. As part of SPP, some ancillary services are recovered by SPP through SPP's OATT, but regulation service for grid operation within

[23] A T-30 persistence forecast consists of the average actual output of the generation facility between T-31 to T-30 minutes preceding the scheduling interval.
[24] T-25 persistence schedule consists of the average output of the generation facility between T-26 to T-25 minutes preceding the scheduling interval.
[25] Westar did not respond to requests to review this section.

Westar's balancing authority is largely Westar's responsibility, as is recovering the costs for it. Westar's OATT at the time recovered balancing authority ancillary service costs from merchant generators that serve load within Westar, but not from independent generators that export energy out of the Westar balancing authority.

Westar's filing sought authority to create a new agreement and a new Schedule 3A-Generator Regulation and Frequency Response Service for generators exporting energy out of the Westar balancing authority or into SPP's energy imbalance service (EIS) market. Generation that participates in the EIS is under functional control of SPP and provides imbalance service to the SPP region as a whole, i.e., it is not contracted to serve load in the Westar balancing authority. Westar's existing Schedule 3–Regulation and Frequency Response Service–for generation serving load within Westar remains unchanged. In its first filing, Westar proposed to impose a regulation purchase obligation of 1.35% on dispatchable generation exporting energy out of Westar's balancing authority, the same value as for load-serving generation under Schedule 3. For variable generation, Westar's charge was 7.8% of nameplate capacity (Westar 2009). FERC disagreed with the methodology Westar used to derive the 7.8% charge as it did not account for any reduction in regulation from decreased variability because of the geographic diversification of wind projects. FERC ordered Westar to revise its calculations. In January 2010, Westar submitted a revised methodology approved by FERC on March 18, 2010 (FERC 2010a).

Westar's current Schedule 3A purchase obligation, as set in March 2012, for variable generation is 3.47% of the amount of variable generating capacity within the Westar balancing area, multiplied by the current regulation rate as follows:

1. For Yearly delivery, $53,358.74/MW
2. For Monthly delivery, $ 4,446.56/MW
3. For Weekly delivery, $ 1,026.13/MW
4. For Daily delivery, $ 205.23/MW
5. For Hourly delivery, $ 12.83/MW

The above rates are the same as charged under Schedule 3 for within the Westar balancing authority load-serving generation and have not changed since the original Schedule 3A filing. The amount of generation inside Westar's balancing authority is equal to nameplate capacity, minus the amount of the generation capacity that the customer is self-supplying regulation for, minus the amount of generating capacity that is supplying power to load inside the Westar balancing authority. The charge is applicable to wind generation and other non-dispatchable resources that export power outside of Westar's balancing authority or to the SPP EIS market. As per FERC order, Westar submits an annual update and revised percentage of regulation purchase obligation requirements every March. Westar's regulation rate for variable generators is in effect only until SPP launches its new market design in March 2014, with day-ahead and ancillary service markets at locational marginal pricing.

Assumptions and Methodology

In June 2009, when Westar submitted its original filing, there was 382 MW of wind in the Westar balancing authority, 297 MW of which was Westar-owned or purchased by Westar under contract, and 85 MW of which was third-party wind generation, which was selling its output outside Westar's balancing authority or into the SPP EIS market. Westar noted that at the time, it was anticipating installing another 500 MW of wind over the next several years from a Westar RFP for wind. In addition, the SPP generation interconnection queue contained another 2,500 MW of wind projects seeking to interconnect in Westar's balancing authority (Westar 2009).

Westar's proposed Schedule 3A regulation charge was based on the following data and methodology:

- Westar used 10-minute interval data from three different wind facilities based in west, central and eastern Kansas.
- Westar calculated 10-minute changes in output by comparing each 10-minute interval to the one before.
- The regulation percentage is calculated as the standard deviation multiplied by two, divided by the total nameplate capacity of the wind facilities.

This methodology did not account for any diversity benefits from load and dispatchable generation and was deemed inadequate by FERC. Westar then submitted revised methodology that utilized a portfolio approach encompassing wind, load, generation providing regulation service within Westar, and generation in Westar controlled by SPP. Westar's revised methodology resulted in a wind regulation percentage of 4.04% for wind selling into the Westar balancing authority and 4.05% for exporting wind. FERC accepted this methodology and directed Westar to submit a compliance filing with the revised methodology for calculating an updated charge and to update the rate annually with new data.

Westar's latest update was submitted in March 2012 (Westar 2012a). Westar's methodology for calculating the regulation percentage obligation is as follows:

- The data set consists of 10-minute interval meter observations from Westar's Energy Management System for:
    - Westar Wind – three wind facilities either owned or contracted to Westar to serve load in Westar
    - Other Wind – two wind projects that export their energy or sell it to the SPP EIS market
    - Frequency – consists of deviations of generators that are providing regulation service, from dispatch instruction
    - Load – deviations of actual load from the load forecast
    - RBASE Generation – Generation in Westar's balancing authority controlled by SPP. The deviations are equal to the difference between observed values and dispatch instructions.[26]
- Wind deviations are equal to the difference between the output at the beginning of each 10-minute interval to the output at the end of each interval.

[26] Westar does not provide the time period for the data that was used, simply states it is 'during the study period'.

- Westar then calculates the correlation coefficients of each data set creating a correlation matrix.
- Westar then calculates the individual standard deviations and the variances, which are used to calculate covariances, the adjusted standard deviations, and the adjusted regulation requirement of each element in the portfolio at a 95% confidence interval (two standard deviations).
- The regulation percentage purchase obligation then becomes the regulation requirement divided by the nameplate capacity of each element.

This methodology is illustrated below in Figure 3.

As noted before, the reserve costs (1-5) are the same as was approved by FERC for Schedule 3 and represent the fixed costs associated with the generation resources that Westar is most likely to use for regulation service. These costs were developed as part of a settlement in FERC Docket No. ER05-925 (Westar 2009).

Step 1: Calculate Correlation of 10 minute deviations from expected levels for each class (unit less)

Classes of Deviation	Inside Wind	Outside Wind	Frequency	Gens on '13'	Load
Inside Wind	1				
Outside Wind	0.050	1			
Frequency	0.017	0.025	1		
RBASE Generation	0.014	0.027	0.079	1	
Load	-0.024	-0.035	-0.187	-0.202	1

Class of Deviation	Definition
Inside Wind	Westar owned wind
Outside Wind	All other wind in Westar's BA
Frequency	Deviation caused by frequency variation
Gens on '13' RBASE	Westar generation dispatched by SPP
Load	Deviation of load from SPP forecast

Step 2: Calculate the standard deviations and variances of the classes of 10 minute deviations and of a portfolio of all (summed) 10 minute deviations.

Classes of Deviation	StDev Contribution (MW)	Variance (MW^2)
Portfolio	65.8	4,334.57
Inside Wind	8.4	71.29
Outside Wind	10.7	115.18
Frequency	10.5	111.12
RBASE Generation	62.5	3,912.15
Load	28.7	824.41

Note

Note: After adjusting the classes of deviation, these standard deviations match.

Step 3: Using correlations in Step 1, calculate the covariance adjustment to be made to each class of deviation.
Step 4: Unadjusted Variance + Covariance Adjustments = Adjusted Variance. This adjustment makes these variances independent of each other.

Classes of Deviation	Unadjusted Variance (MW^2)	Covariance Adjustment (MW^2) 1	2	3	4	Regulation Requirement Adjusted Variance (MW^2)	StDev (MW)	Multiple*StDev (MW)
Inside Wind	71.29	4.5	1.5	7.3	-5.8	78.8	8.9	10.56
Outside Wind	115.18	4.5	2.9	18.1	-10.7	130.0	11.4	13.56
Frequency	111.12	1.5	2.9	52.0	-56.6	110.9	10.5	12.52
RBASE Generation	3912.15	7.3	18.1	52.0	-363.4	3626.1	60.2	71.59
Load	824.41	-5.8	-10.7	-56.6	-363.4	387.9	19.7	23.41
total variance (MW^2)	5034.15	Notice that the total variance of the classes				4333.8		
stdev (MW)	70.95	does not equal the portfolio variance yet.				65.8		131.6

Multiple
1.1888

Step 5: Calculate the Multiple needed to produce a value in J:29 that is two times the portfolio standard deviation. In this case, the Multiple is 1.1888

Note: the summed StDev of independent variables equals the StDev of the portfolio of independent variables.

Covariance Adjustment= Correlation(1,2)*StDev(1)*StDev(2)
where 1 and 2 are different classes of deviation

Regulation Element	calculated Regulation (MW)
Inside Wind	10.56
Outside Wind	13.56
Frequency	12.52
RBASE Generation	71.59
Load	23.41

Note: These are the same

Note: a Mutiple of 1.1888 demonstrates the benefit of portfolio diversification. In this case, each class of deviation only needs to contribute 1.1888 standard deviation megawatts to produce two standard deviation megawatts on the portfolio level.

Step 6: Calculate required regulation for All Wind (Inside + Outside) and Rbase Generation as a % of installed name plate capacity

Regulation Element	calculated Required Regulation (MW)	Installed Name Plate Capacity (MW)	Percentage Regulation Charge
All Wind	24.11	695	3.47%
RBASE Generation	71.59	4,919	1.46%

Source: Westar Energy, FERC filing, Westar Energy, Inc., Docket No. ER09-1273-000 Informational Filing, OATT, Schedule 3A, March 30, 2012.

Figure 3. Westar wind regulation rate calculation methodology

WACM

Background

In 2006, FERC approved Rate Schedule L-AS3 that implemented a rate for regulation and frequency response service for WACM (FERC 2006). WACM[27] was concerned that it would become the default Regulation Service provider for new variable generation plants, and would need additional regulation (WAPA 2006).

WACM's regulation and frequency service rates are assessed on both load and variable generation and are as follows (WAPA, Rocky Mountain Region 2011):

- Hourly: $0.000458/kW-hour
- Daily: $0.011/kW-day
- Weekly: $0.076/kW-week
- Monthly: $0.331/kW-month

The rates are effective from October 1, 2011, through September 30, 2016.

Assumptions and Determination of Charge

WACM does have some resources to provide Regulation Services, including Federal hydroelectric resources and non-federal thermal generation resources. The thermal resources, however, are not under WACM's control and are limited in their availability to provide regulation, as they generally operate at full capacity and are slow to respond to regulation requirements (WAPA 2006).

To derive their regulation and frequency service rates, WACM estimates the amount of regulation that is required by adding the installed capacity of variable generation to a rolling 12-month average of the system peak. The rate is calculated by dividing this value by the total annual revenue requirement. The revenue requirement for regulation is based on the annual costs of plants providing regulation and the costs of buying regulation on the wholesale market (WAPA 2006 and DOE Deputy Secretary 2006).

As of 2011, WACM no longer provides regulation and frequency response to variable generation being exported out of WACM. Any variable generation being exported out of WACM must be dynamically scheduled, self-supply regulation, or receive regulation service from a third party (WAPA, Rocky Mountain Region 2011).

[27] WAPA did not respond to requests to review this section.

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