ELLEN F. ROSENBLUM
Attorney General

MARY H. WILLIAMS
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

March 18, 2013

VIA E-MAIL AND U.S. MAIL

Attention: Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE, #215
P.O. Box 2148
Salem, OR 97301-2148
puc.filingcenter@state.or.us

Re: *In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Investigation into Qualifying Facility Contracting and Pricing*
PUC Docket No.: UM 1610
DOJ File No.: 330-030-GN0240-12

On behalf of the Oregon Department of Energy, enclosed for filing with the Commission in the above-captioned matter are an original and five copies of the response testimony and exhibits of Philip Carver, and response testimony of Tom Elliot and Kacia Brockman.

Sincerely,

Renee M France
Senior Assistant Attorney General
Natural Resources Section

RMF:mme/4062170
c: UM 1610 Service List (electronic copies only)

DOCKET NO. UM 1610
EXHIBIT: ODOE/100
WITNESS: PHILIP CARVER

Before the
PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Response testimony of Philip Carver

March 2013

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Phil Carver. I am a Senior Policy Analyst for the Oregon Department of Energy (ODOE). The business address is 625 Marion St. NE, Salem, Oregon 97301.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF YOUR EDUCATION AND EMPLOYMENT BACKGROUND.

A. I have a bachelor's degree in economics from the University of California-San Diego (1972) and a Ph.D. in natural resource and utility economics from the Johns Hopkins University (1978). From 1978 to 1980, I was an assistant professor at Dartmouth College. From 1980 until 2008, I worked for ODOE. During that time I testified in a number of Oregon Public Utility Commission (OPUC) dockets, including UM 1129. From November 2008 to July 2009, I was the lead OPUC staff on the Renewable Portfolio Standards rulemaking (AR 518). From May 2010 to December 2012, I was a half-time senior policy analyst with the OPUC. Since then I have worked half-time for ODOE as a senior policy analyst.

Q. WHAT IS THE PURPOSE OF YOUR OPENING TESTIMONY?

A. I will address issues 1A (method for calculating avoided cost prices), 4A (accounting for integration costs) and 4C (use of the seven FERC factors) together. I will also address issues 2A, 2B and 2C (definition and treatment of environmental attributes).

Q. WHAT IS YOUR RECOMMENDATION ON HOW AVOIDED COSTS SHOULD BE CALCULATED (ISSUE 1A)?

A. For both standard and non-standard contracts, I recommend the Commission retain the current method for standard avoided cost prices that uses wholesale power prices during the resource sufficiency period and, for the resource deficiency period, the cost of the next avoidable resource identified in the company's integrated resource plan (IRP). The only change the electric companies have recommended in this proceeding that I could support is applying an integration charge for certain wind projects, as discussed later in my testimony.

Q. WHY SHOULD THE CURRENT METHOD BE RETAINED?

A. The Commission adopted the current method described in Order No. 05-584 at 20-29 after an extensive investigation. The current method is a reasonable estimate of the value of Qualifying Facility (QF) power to retail customers. Electric companies have not provided evidence of fundamental changes in power operations or market dynamics to justify a change to a more complex modeling method.

Q. BUT WOULDN'T PACIFICORP'S OR IDAHO POWER'S PROPOSED METHOD PROVIDE A MORE ACCURATE ESTIMATE OF THE VALUE TO RETAIL CUSTOMERS?

A. No. For any hour of the resource sufficiency period, electric companies respond to the wholesale market price. This price is the value to the customers. When the electric company can make money selling into the market, it sells to capture this value. In an hour when the market price is lower than the company's incremental operating cost, it buys wholesale power. The only time it should not be buying or selling would be if the market price equals the variable cost for its next available unit. So during the sufficiency period, the current method of paying the wholesale price to the QF leaves the customers whole.

For the resource deficiency period, wholesale prices are expected to be less attractive to customers than the cost of a natural gas-fired combined-cycle combustion turbine (CCCT) or other firm resource. This attractiveness is based on a consideration of wholesale rate volatility and customers' needs for reliable service. For that time period the fully allocated cost of the deferred resource is the value of power to customers. During the deficiency period, customers would tend to be better off with the QF power. This is due to the overall risk reduction benefits of QF power as the electric company gains resource diversity and learns about lower carbon power sources that will be needed soon to address climate change. The complex models proposed by PacifiCorp and Idaho Power would not be fair and reasonable, as customers would pay a price to the QF that would be substantially below the value of the power. These issues were addressed in Order No. 05-584 and the Commission struck a fair balance. Nothing has changed to make that balance different, with the possible exception of significant additions of utility-owned and purchased wind generation, which I will discuss below.

Q. WHAT ABOUT PACIFICORP'S ARGUMENT THAT DURING AN HOUR IN THE RESOURCE DEFICIENCY PERIOD THE QF POWER MIGHT DISPLACE A COAL PLANT WITH LOWER OPERATING COSTS THAN A CCCT?

A. This argument is inconsistent with the concept adopted by the Commission in Order No. 05-584 at 20-29, which specifies that during the resource deficiency period it is the full cost of the new CCCT that is avoided. While the utility's incremental operating costs in a particular hour may be lower than the costs of a CCCT, market prices for power in a particular hour may be higher than the incremental CCCT operating costs. In such cases the value of the QF power would be the market price for power, not operating costs, consistent with the Commission's use of market power prices in the resource sufficiency period. Overall, the Commission struck a fair balance by using the full cost of a new CCCT as the avoided cost during the deficiency period.

Q. WOULD THERE BE SIGNIFICANT PROBLEMS FOR QFS IF UTILITIES WERE TO USE COMPLEX MODELS TO FORECAST AVOIDED COSTS?

A. Yes, the result would be opaque and harder to predict than the current method. The result would seriously hamper QF developers in getting projects designed and financed.

Q. HOW WOULD THE PROPOSED IRP METHODS HAMPER DEVELOPMENT OF QF RENEWABLE RESOURCES?

A. The development process occurs over several years even for small projects. Pages 12 to 16 of Exhibit 101 attached to ODOE's testimony show the kinds of issues that can extend the development of a small project to seven years or more. The remainder of Exhibit 101 details these issues. Large projects can face similar development timelines. It is in the latter stages of development that significant design costs are incurred. While some funds can be spent with little assurance of the price of the power, a project would not spend major sums without an initial analysis that shows the project has a reasonable prospect of economic viability when the contract is signed. Tom Elliott discusses this further in his testimony (Exhibit ODOE/200/Elliott/4-6). If an avoided cost update is likely to occur before project signing, as is common, the QF must make an educated guess about what avoided cost prices will be after the next update. It is possible to do that with the current method. With the modeling methods proposed by PacifiCorp and Idaho Power it would be virtually impossible, as I explain below.

Q. WHAT KIND OF CHANGES MIGHT LEAD A QF UNDER DEVELOPMENT TO UPDATE ITS ESTIMATE OF AVOIDED COST PRICES?

A. The date of resource deficiency and the natural gas price forecasts used to set current avoided cost prices are the key elements that affect avoided cost prices under the existing avoided cost method. Knowing changes in these two elements can allow a QF under development or its consultant to anticipate the direction of avoided cost rates after the next update and the likely magnitude of the change.

Q. WHERE MIGHT A QF UNDER DEVELOPMENT GET INFORMATION ABOUT THESE CHANGES TO ANTICIPATE THE DIRECTION OF UPDATED PRICES AND THE MAGNITUDE OF THE CHANGES?

A. Possible resource deficiency dates and tentative natural gas price forecasts are discussed in the informal public IRP process well before the utility files its final IRP with the Commission. This is well before the Commission considers acknowledgment of the IRP. A QF could also subscribe to a commercial natural gas price forecast or track a public one, such as the U.S. Energy Information Agency forecast. A QF might also buy a commercial forecast of Mid-Columbia wholesale power prices or use the forecast in the electric company's draft IRP, filed with the Commission shortly before the final IRP. A Northwest Power and Conservation Council price forecast released during the process also would be useful.

Q. WHY IS MAKING A FORECAST OF AVOIDED COST PRICES NOT POSSIBLE WITH THE ELECTRIC COMPANIES' PROPOSED IRP METHODS?

A. The proposed models are complex. Even if a QF understood the models, it would be very difficult to forecast the impact from changes in the resource deficiency date and natural gas price forecasts on the avoided costs derived from comparing two IRP model runs using a decremental analysis. Even a QF over 10 megawatts (MW) may not be able to afford to hire a consultant to run the proprietary and complex software the electric company uses for the proposed IRP modeling, and the QF may not have all of the information the electric company uses for its modeling, including proprietary information.

Q. BUT IF IT WERE DEMONSTRATED THAT USING A COMPLEX MODEL WERE MORE ACCURATE THAN THE CURRENT METHOD, SHOULD A MODELING APPROACH BE ADOPTED?

A. No. First, as discussed above, the modeled analyses of PacifiCorp and Idaho Power do not consider the value of potential wholesale power sales. Thus, they underestimate the value to customers. Even if complex models appropriately considered this value, there would need to be a sufficient increase in accuracy in setting avoided cost rates to justify making the process more difficult and less transparent for QFs. If the Commission determined that there is a substantial bias to the existing method, the Commission could retain the current method and require electric companies to apply an adjustment factor to correct any bias.

Q. DO YOU HAVE SPECIFIC CONCERNS ABOUT PACIFICORP'S PROPOSED METHOD TO CALCULATE AVOIDED COSTS?

A. Yes, I disagree with using only a few hundred hours to calculate the capacity credit for intermittent (variable energy) resources. This method ignores the reliability benefits outside this small fraction of hours in a year. These benefits to customers are real and should not be ignored. Customers lose service due to utility-owned generation or backbone transmission outages throughout the year. A better method is the Effective Load Carrying Capability (ELCC) method applied to all hours of the year. The annual ELCC method equates the annual system reliability of a system whether or not it has additional intermittent resources. PacifiCorp's proposed method does not provide equivalent reliability for the two scenarios.

Q. DO YOU ADVOCATE THAT THE ELCC METHOD BE USED TO EVALUATE THE NET PRICE PAID TO INTERMITTENT RESOURCES?

A. Only for resources over 10 MW consistent with the application of the seven factors of the FERC test, which I discuss below.

Q. DO YOU SUPPORT PACIFICORP'S PROPOSAL TO USE A SINGLE NORTHWEST HUB FOR POWER PRICES IN THE SUFFICIENCY PERIOD?

A. Yes, I support using just the Mid-Columbia hub during the sufficiency period. This change also seems to indicate that during the deficiency period the company should use the Stanfield natural gas hub, or some other hub (such as Opal), with an appropriate adder for firm gas transmission to Oregon for its natural gas price forecast, if it does not already do so.

In both cases the more local price hub would seem to best represent the costs that would be avoided by purchasing from the QF. The displaced operating cost in the deficiency period from an Oregon QF is more likely to be an Oregon resource. While the avoidable new CCCT might be built in Utah, avoided operations are distinct from avoiding the need to build a new CCCT.

PacifiCorp already operates a CCCT near Hermiston, Oregon. When a QF produces power, it reduces the need for power in Oregon. The reduced power operation most likely occurs at a CCCT and should occur at the CCCT with the more expensive fuel. Natural gas is generally more expensive at Stanfield than at Opal. Also, there is less likely to be a transmission constraint that would prevent using the QF power to displace an Oregon CCCT than to displace a Utah CCCT.

Q. PLEASE DESCRIBE HOW ELECTRIC COMPANIES SHOULD ADJUST THE NET PRICE PAID TO QFS BASED ON RENEWABLE RESOURCE CHARACTERISTICS. (ISSUES 4A AND 4C)

A. <u>For avoided costs under standard contracts</u> (resources 10 MW and smaller), the prices paid to wind resources should be reduced to account for the cost of regulating reserves that utilities incur associated with errors in wind forecasting and with variability before and within the hour, but only for wind resources in the contiguous area where utilities have major wind resources and have procedures for forecasting wind project output. For PacifiCorp and PGE, this area is just east of The Dalles. Standard contract QF wind projects outside this area should not be charged for integration. The benefits of geographic diversity are discussed on pp. 54-58 and pp. 61-67 of the June 2012 report from Western Governors' Association titled, "Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge," attached as Exhibit 102 to ODOE testimony.

One value for integration ($ per MWh) should be specified in each electric company's published avoided cost schedule. This charge against the avoided cost price should be based on the assumption that the electric company forecasts the output for the wind project. For these integration cost adjustments, and the adjustments discussed below, the Commission should hold periodic evidentiary proceedings to set the value for each utility. The values will likely vary among utilities.

Solar and base-load resources (geothermal, biomass and natural gas co-generation) should not incur an integration charge. Solar resources should not be charged for integration because their impact on net load variability is negligible at this time. None of the utilities in this docket attempts to forecast their solar generation on an hour-to-hour basis. If solar integration costs were material, they would do so.

For renewable avoided costs under standard contracts (resources 10 MW and smaller), the prices paid to wind generation should be reduced for integration costs only during the sufficiency period. If, as is currently the case, the resource used to set renewable avoided costs during the deficiency period is wind, avoided cost prices should not be adjusted for intermittency.

Solar and base-load renewable resources should not be charged for integration during the sufficiency period. During the deficiency period these resources should receive an integration credit because the integration costs they impose, if any, are negligible. In contrast, the wind resource used to set the renewable avoided cost during the deficiency period imposes integration costs.

For renewable resources larger than 10 MW, the prices paid should be adjusted for integration costs and the remainder of the seven FERC factors based on the characteristics of the renewable resource facility. As noted above, the capacity credit for solar and base-load renewable resources should be based on an annual ELCC analysis.

Q. SHOULD THERE BE DIFFERENT AVOIDED COST PRICES FOR DIFFERENT RENEWABLE GENERATION SOURCES? (ISSUE 2A)

A. My testimony on issue 4 addressed the question of price adjustments based on the generating characteristics for different types of resources. ODOE has no additional testimony on this issue at this time.

Q. HOW SHOULD ENVIRONMENTAL ATTRIBUTES BE DEFINED FOR PURPOSES OF PURPA TRANSACTIONS? (ISSUE 2B)

A. Environmental attributes should be defined in a manner consistent with Oregon's Renewable Portfolio Standard (RPS) statute and administrative rules, and with the Western Renewable Energy Generation Information System (WREGIS) tracking system.

OAR 330-160-0015(13) provides that, as part of a Renewable Energy Certificate (REC), the non-energy attributes are "a unique representation of the environmental, economic, and social benefits associated with the generation of electricity from renewable energy sources that produce Qualifying Electricity."

WREGIS, the designated tracking system for the Oregon RPS, defines Renewable and Environmental Attributes as: *Any and all credits, benefits, emissions reductions, offsets and allowances, howsoever entitled, attributable to the generation from the Generating Unit, and its avoided emission of pollutants. The avoided emissions referred to here are the emissions avoided by the generation of electricity by the Generating Unit, and therefore do not include the reduction in greenhouse gases (GHGs) associated with the reduction of solid waste or treatment benefits created by the utilization of biomass or biogas fuels. Avoided emissions may or may not have any value for complying with any local, state, provincial or federal GHG regulatory program. Although avoided emissions are included in the definition of a WREGIS Certificate, this definition does not create any right to use those avoided emissions to comply with any GHG regulatory program.*

The WREGIS definition also notes that: *Renewable and Environmental Attributes do not include (i) any energy, capacity, reliability or other power attributes from the Generating Unit, (ii) production tax credits associated with the construction or operation of the Generating Unit and other financial incentives in the form of credits, reductions or allowances associated with the Generating Unit that are applicable to a state, provincial or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to the seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used* *by the Generating Unit for compliance with local, state, provincial or federal operating and/or air quality permits.*

The proposal to use the WSPP Agreement definition of Environmental Attributes appears to be compatible with the conditions above. That definition is as follows:

"Environmental Attribute" means the following, unless a Tracking System is designated in the Confirmation, and such Tracking System defines "Environmental Attribute," in which case the Tracking System's definition of "Environmental Attribute" shall control: a characteristic concerning or affecting the environment created by or resulting from the generation of electric energy by a Renewable Energy Source, and which capable of measurement, verification, or calculation. The term does not include tax credits or other tax benefits under any law or other direct third-party subsidies for generation of electric energy by a Renewable Energy Source. The term includes "non-energy attributes" under Oregon law and "non-power attributes" under Washington law. By way of example, the term may include the following: avoided emissions of CO2 or other gases, or avoided water use (but not water or other rights or credits required under an Applicable Program to site and develop the Renewable Energy Facility itself).

In practice the use of the WSPP definition should incorporate both the Oregon RPS definition and the WREGIS tracking system definition. For that reason ODOE supports the proposal to use the WSPP definition and framework for environmental attributes.

One additional point is worth noting. The word “positive” in any definition of environmental attributes should be carefully considered. If the word is intended to represent “good things,” then the subjective nature of what is “good” is unclear. For example, emissions of pollutants are not considered a good thing (even if some portion is avoided). If the word “positive” is intended to mean non-zero or non-negative, that could be problematic. There are regulatory situations where it is important that the carbon attribute be retained as part of the environmental attributes, but the valuation of that attribute is in fact zero (as there are no avoided emissions of greenhouse gases in cases where a separate cap is in place within a jurisdiction with a cap-and-trade greenhouse gas system).

Q. SHOULD THE COMMISSION AMEND OAR 860-022-0075, WHICH SPECIFIES THAT THE NON-ENERGY ATTRIBUTES OF ENERGY GENERATED BY THE QF REMAIN WITH THE QF UNLESS DIFFERENT TREATMENT IS SPECIFIED BY CONTRACT? (ISSUE 2C)

A. There is no need to amend OAR 860-022-0075 to be consistent with Order No. 11-505. The order and the rule in question are already consistent. Order No. 11-505 provides clear direction as to when the non-energy attributes of energy from a QF would be transferred to the purchasing electricity company. This direction would be reflected in the purchase contract. Therefore, the qualifier in OAR 860-022-0075 allowing for the ownership of the non-energy attributes of energy generated by the QF to be determined by contract is sufficient to accommodate both the existing rule and Order No. 11-505.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

DOCKET NO. UM 1610
EXHIBIT: ODOE/101
WITNESS: PHILIP CARVER

Before the
PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Exhibit 101
Accompanying the response testimony of
Philip Carver

March 2013

Developing a Wind Energy Project in Massachusetts

Presentation to
Sustainable Wellesley
October 9, 2010
Donald S. McCauley

Disclaimer and Warning

- Views expressed are those of the Presenter and not of any other person or company.
- After 8 years tilting at windmills, Presenter can become a bit testy.

The Dream

Photo Simulation of Savoy Wind Power Project

About the Project:

Owner:	Minuteman Wind, LLC
Project Site:	West Hill, Savoy, MA
Turbines:	Clipper Windpower Liberty, 2.5MW, five turbines
Diameter:	96 m (315 ft)
Hub height:	80 m (262 ft)
Location:	42° 35.6' N 72° 58.3' W to 42° 36.1' N 72° 58.2' W

About the Photo:

Viewpoint:	Hawley Road
Angle of view:	38 degrees
Location:	42° 34.3' N 72° 59.6' W

Distance to nearest turbine: 1.88 miles (9941 ft.)
Apparent size and location of this turbine from this viewpoint is determined geometrically using EMD WindPro Software

Renewable Energy Research Laboratory

Department of Mechanical & Industrial Engineering
University of Massachusetts
160 Governor's Drive
Amherst, MA 01003-9265
413-545-4359
www.ceere.org/rerl
rerl@rerl.org

The Moral


HAUNTED FOREST
WITCH'S CASTLE
1 MILE
I'D TURN BACK IF I WERE YOU!
mike r. baker

Minuteman Wind Overview

- Created to develop small wind powered projects in New England.
- Minuteman's eight members have extensive experience in power generation development, electricity markets and renewable energy.
- Pursuing projects in Western and Central Massachusetts. Focused on Savoy Project.

Philosophy

- Minuteman Wind is committed to bringing renewable energy to New England.
- Wind energy is currently the most economic renewable energy resource.
- Minuteman Wind recognizes that development of wind powered electric generation in New England is especially challenging. Land use in New England consists of intensively developed urban areas, extensive scenic areas which support a large recreation economy, and many environmentally sensitive conservation areas. Further, New England lacks large areas of agricultural land where wind energy has been most successfully developed to date in the United States.
- Minuteman Wind believes that onshore wind energy development in New England needs to focus on small projects which are consistent with existing development and landscape in New England.

PART I - PROCESS

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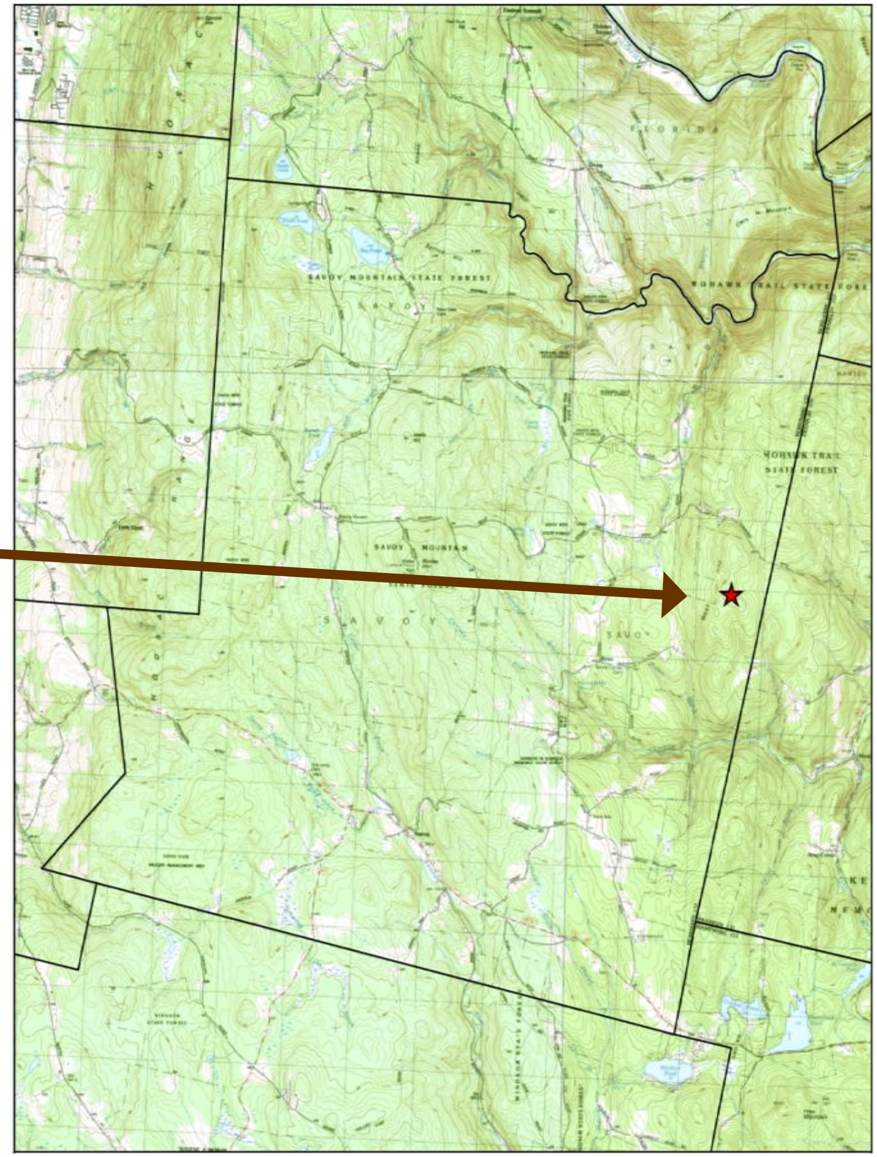
Project Summary

- 12.5 MW Project (five 2.5 MW turbines)
- Located on West Hill, Savoy, MA
- Privately owned forested land
- Limited environmental impacts
- Produce > 30,000 MWh per year (about the consumption of a small college)
- Received principal permits
- Looking to sell power & RECs

Project Location



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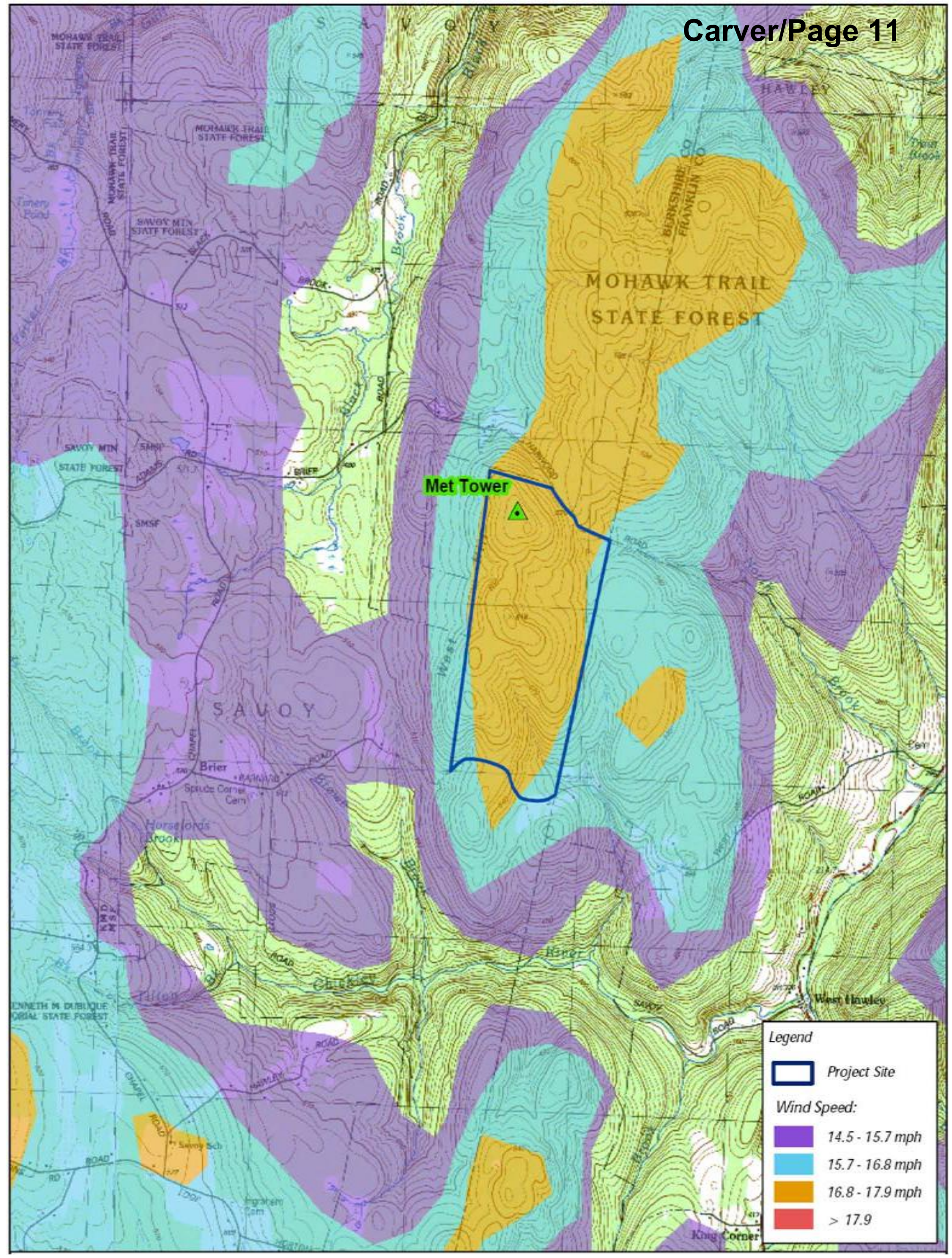
Renewable Energy Research Laboratory
Department of Mechanical & Industrial Engineering
University of Massachusetts
160 Governor's Drive
Amherst, MA 01003-9265
413-545-4359
www.ceere.org/rerl
rerl@rerl.org

Wind Resource Screening
(Source: AWST regional wind maps)



Development Timeline

- 2003
  - Identify Site
- 2004
  - Site Lease
  - Feasibility
  - Initial Funding
  - Meet with Town Officials

Development Timeline

- 2005
  - Wind Testing
  - Environmental Investigation
  - Site Design
  - Community Meetings
- 2006
  - Community Meetings (including opposition meeting)
  - Continued Wind Testing, Site Design and Environmental Investigation

Development Timeline

- 2007
  - Propose Wind Bylaw by calling Special Town Meeting
  - Many meetings with community and town officials
- 2008
  - STM adopts Wind Bylaw (joy!)
    - Key terms: Height, Setback, Surety, Consultants
  - Renew Site Lease
  - Start Permit Applications

Development Timeline

- 2009
  – ZBA quits, permit process aborted
  – Town government almost dissolves
  – DPU: Go Back to town
  – Reinitiate permit application
  – More meetings
  – State Environmental Review (MEPA)
    - More studies, more meetings

Development Timeline

- 2010
  - More studies
  - Green Communities Act RFP
  - EENF Certificate issued (joy!)
  - Special Permit issued (more joy!)
  - RFP canceled
  - New RFP

Issues

- Wind Data Collection and Analysis
- Turbine Evaluation
- Electrical Interconnection
  - Connect to 23 kV System at Site
  - Upgrade 23 kV Distribution Network vs. separate line
  - Maintain voltage standards
- Federal Aviation Administration

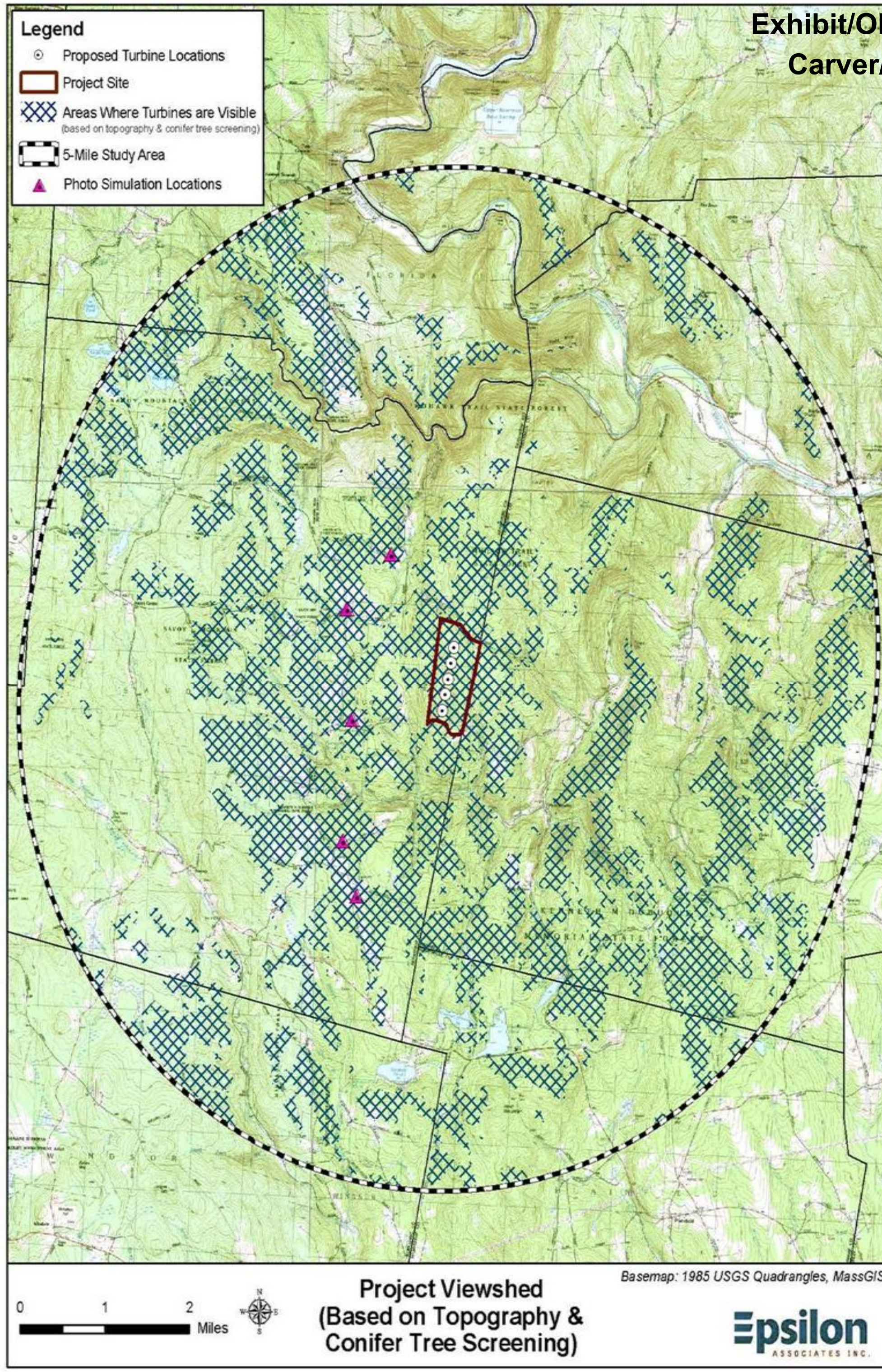
Issues

- Environmental Investigation
  - Wetlands Delineation
  - Avian Survey
  - Endangered Species
  - Sound Assessment
- Site Layout / Conceptual Design
- Equipment Delivery Analysis
  - Road Evaluation
- Geotechnical Investigation

Issues

- Cost:
  - Expensive area to build
    - Terrain
    - remote
  - No economies of scale
- Access
  - Town Roads
  - Rest of State

Visibility


Legend
Proposed Turbine Locations
Project Site
Areas Where Turbines are Visible
(based on topography & conifer tree screening)
5-Mile Study Area
Photo Simulation Locations
Basemap: 1985 USGS Quadrangles, MassGIS
0
1
2
Miles
Project Viewshed
(Based on Topography &
Conifer Tree Screening)
Epsilon
ASSOCIATES INC.

Inter-connection

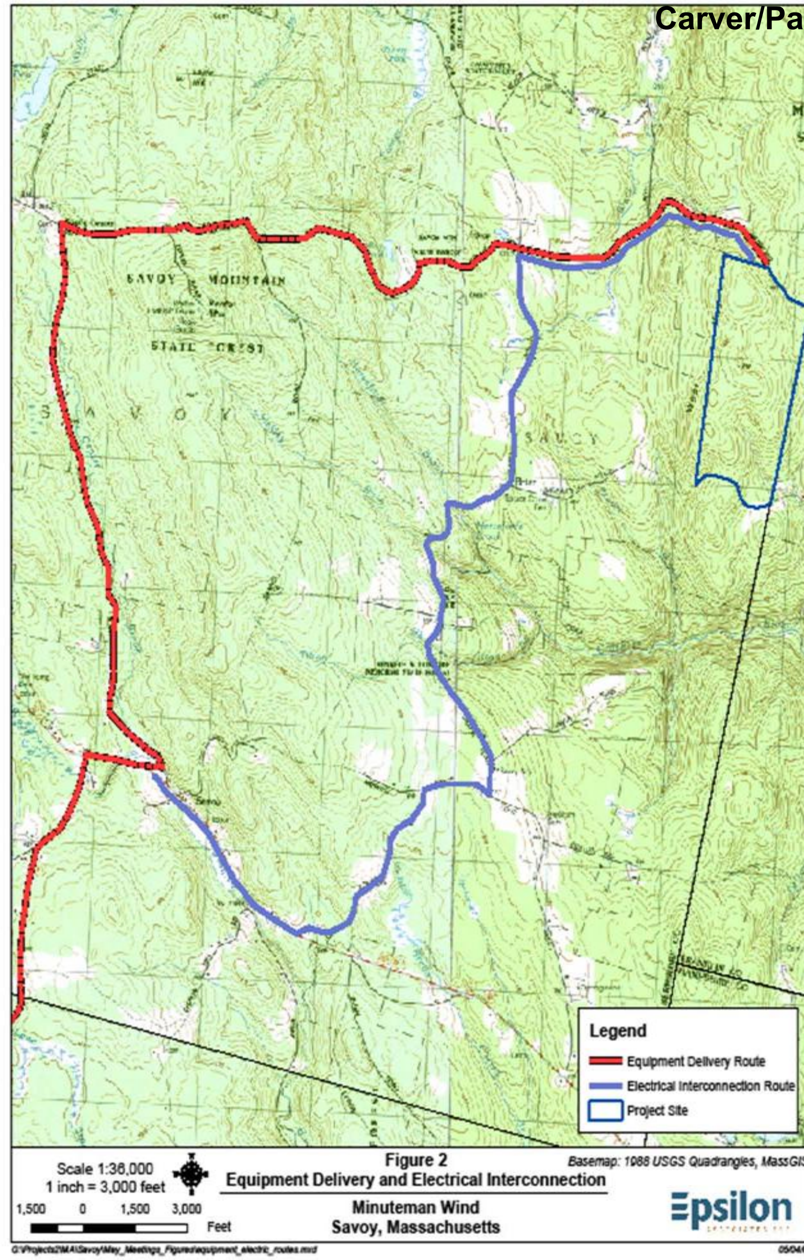
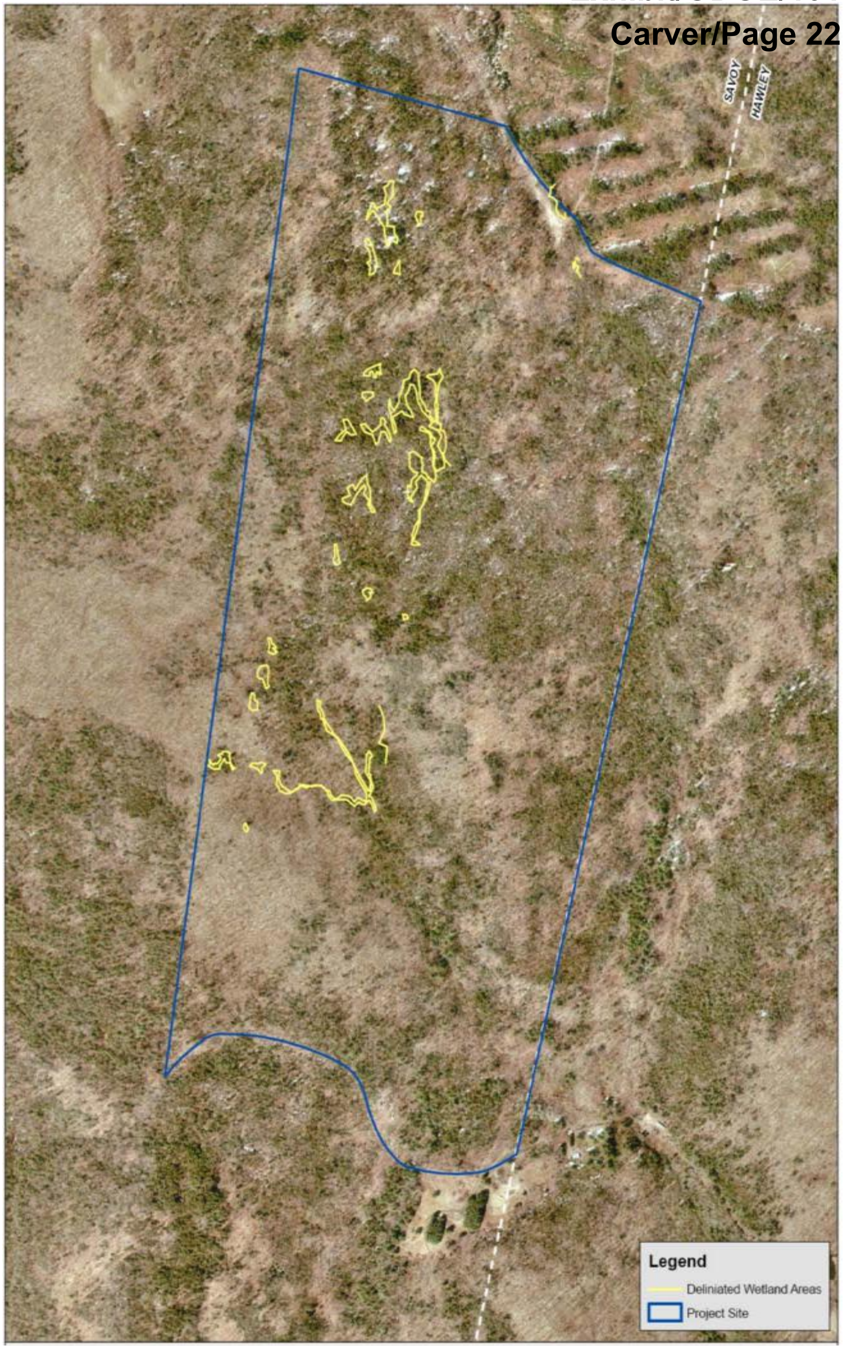
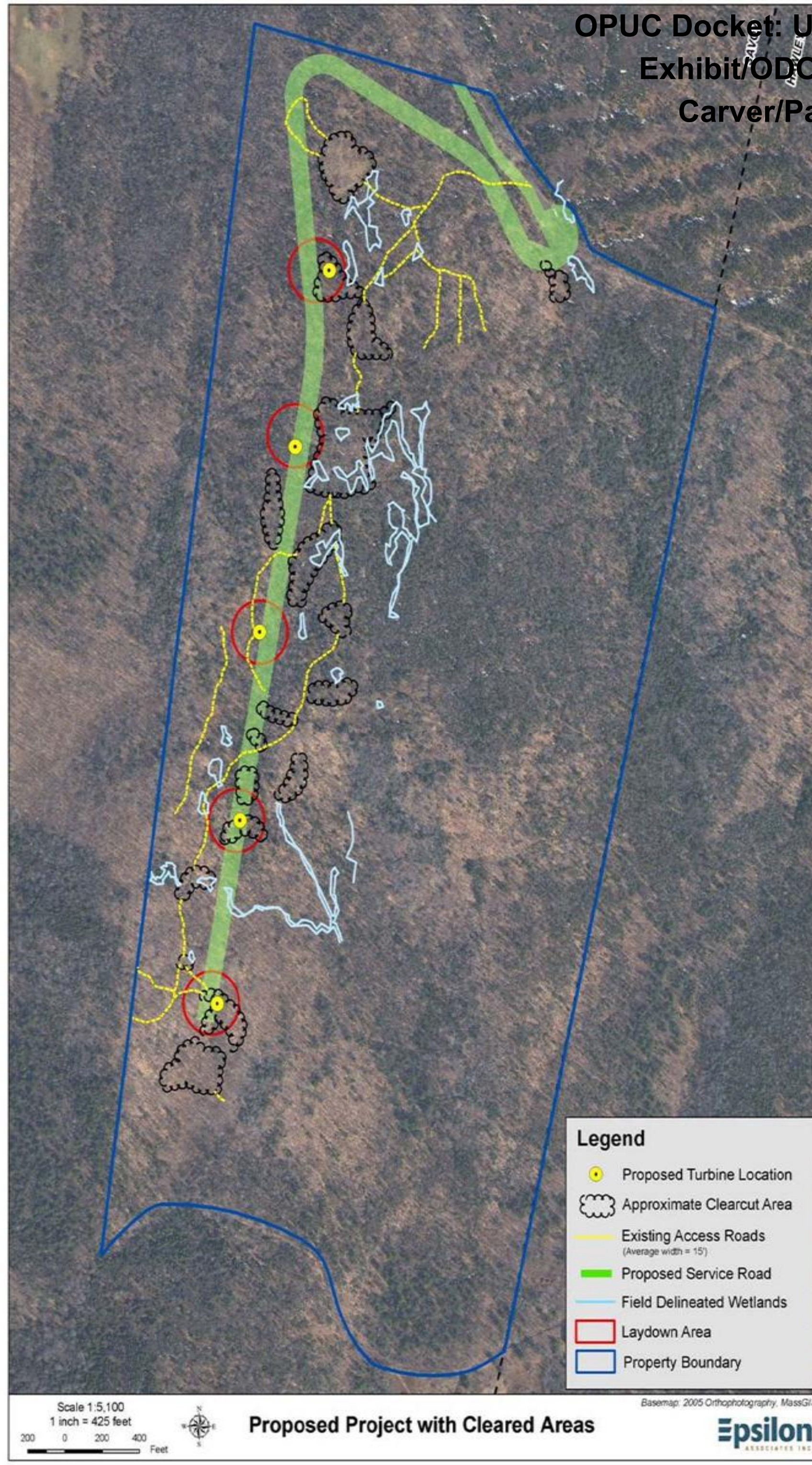


Figure 2
Equipment Delivery and Electrical Interconnection
Minuteman Wind
Savoy, Massachusetts

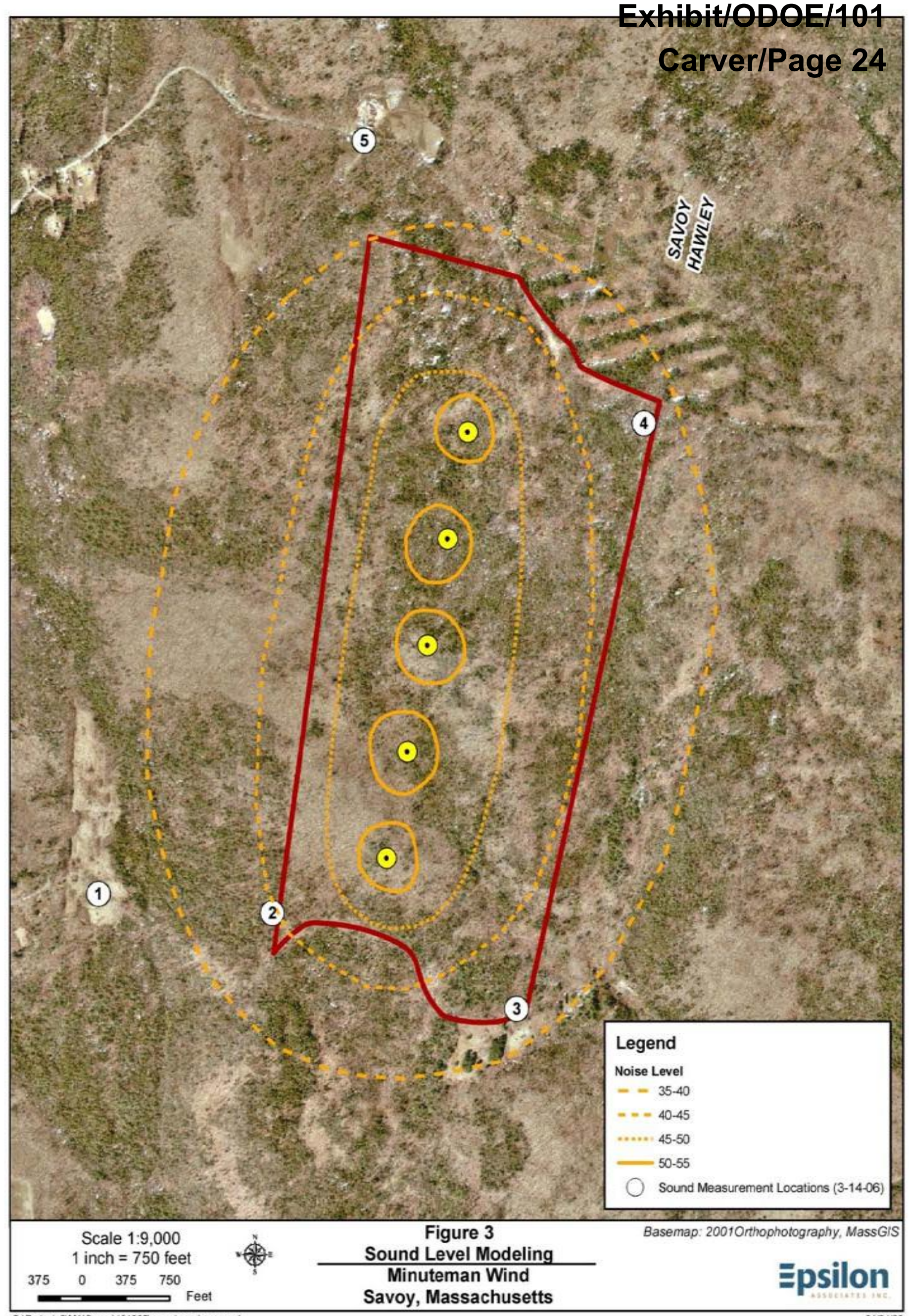
Wetlands Delineation



Site Layout


Legend
Proposed Turbine Location
Approximate Clearcut Area
Existing Access Roads
(Average width = 15')
Proposed Service Road
Field Delineated Wetlands
Laydown Area
Property Boundary
Scale 1:5,100
1 inch = 425 feet
200 0 200 400
Feet
Proposed Project with Cleared Areas
Basemap: 2005 Orthophotography, MassGIS
Epsilon

Noise Analysis



Key Issue - Zoning

- Need for enabling amendment to existing bylaws
  - Create a special permit process
- Sources of enabling bylaws
  - > 30 different Mass Town bylaws
  - Regional planning agencies
- Town Planning Board considering a competing bylaw
- Key Step – Mass DOER and EOEA developed Model Bylaw

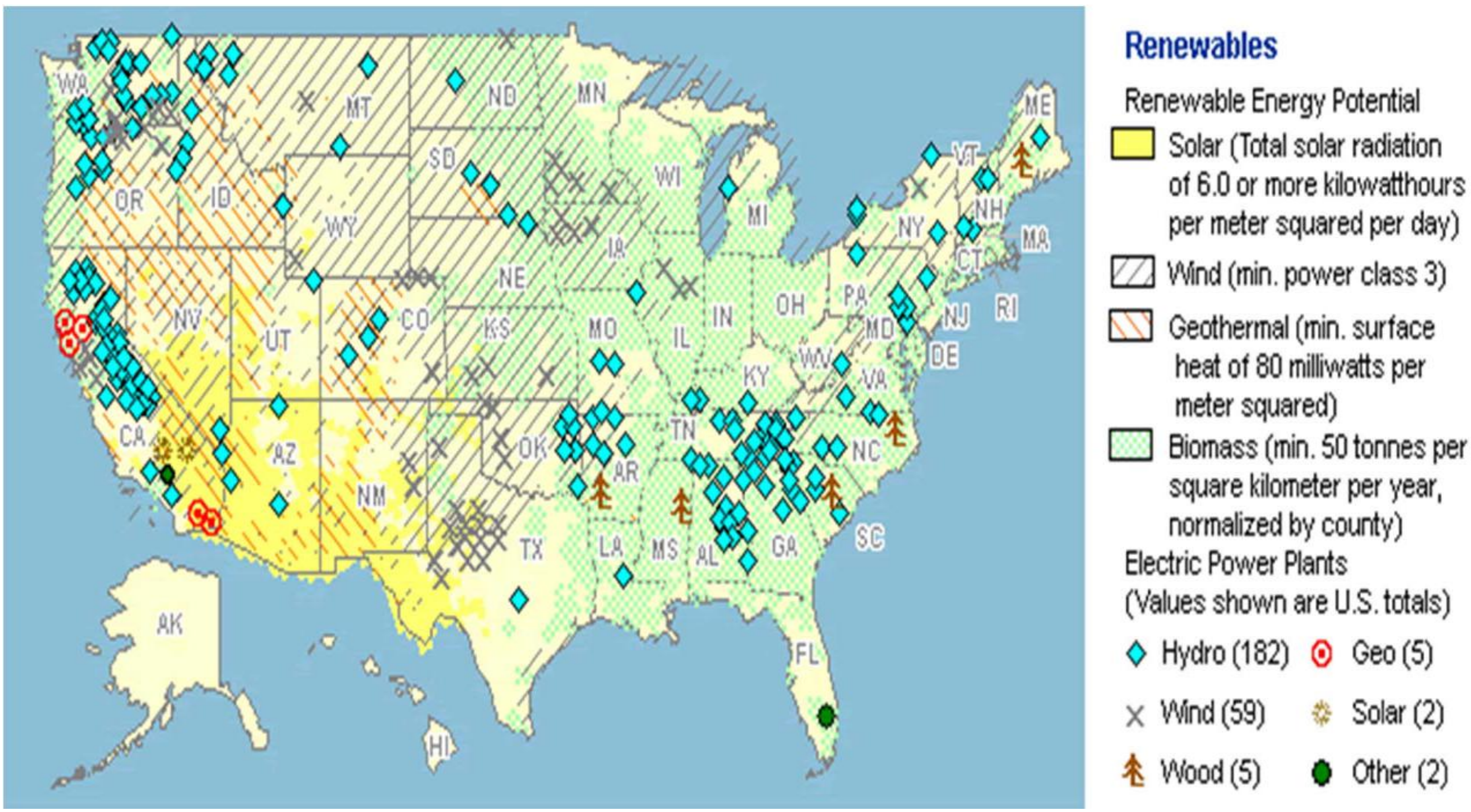
Consideration of Impacts

- Community Character
  - Visual Impact
  - Industrial facilities in agricultural/residential community
- Effect on Neighbors
  - Noise and Flicker
- Public Safety
  - Demands on Police and Fire Services
  - Traffic impacts
- Roads and Electric Distribution

Consideration of Benefits

- Environmental Benefit of Carbon-free electric generation
- Property Taxes
- Infrastructure Benefits
- Community Profile
  - "Our little town can show the way"

Renewable Energy Potential



PART II - ECONOMICS

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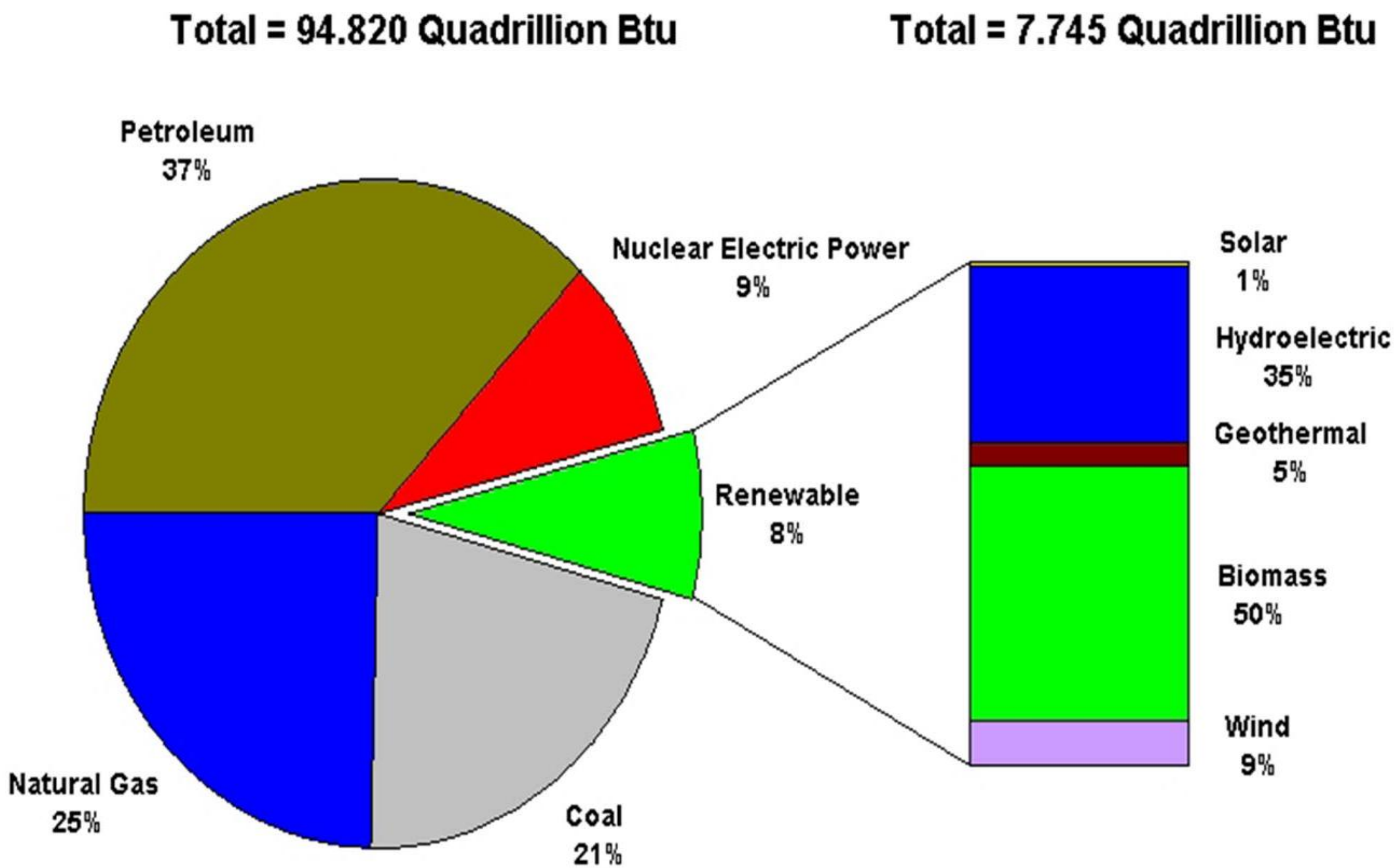
U.S. Renewable Energy Consumption in the Nation's Energy Supply, 2009



New England Energy Consumption

2009	GWh	% of Total
TOTAL GENERATION	119,437	94.2
Gas	38,163	30.1
Nuclear	36,231	28.6
Coal	12,945	10.2
Oil/Gas	12,487	9.8
Hydro: Run of River	4,244	3.3
Hydro: Pondage	4,110	3.2
Wood/Refuse	4,082	3.2
Refuse	2,504	2.0
Coal/Oil	1,613	1.3
Other*	784	.5

* Including 261 GWh of Wind, 256 GWh of Landfill gas and 1 GWh of Solar

Massachusetts Natural Gas Price Sold to Electric Power Consumers

Data 1: Massachusetts Natural Gas Price Sold to Electric Power Consumers (Dollars per Thousand Cubic Feet)

Sourcekey	N3045MA3

Date	Massachusetts Natural Gas Price Sold to Electric Power Consumers (Dollars per Thousand Cubic Feet)
1997	3.11
1998	2.78
1999	2.72
2000	4.6
2001	3.58
2002	3.6
2003	5.51
2004	6.61
2005	9.63
2006	7.45
2007	8.11
2008	10.43
2009	4.93

Renewable Energy Costs More

- Costs More
  - If wind & solar were cheaper, we would already use them
- Because they use diffuse energy sources
  - Requires much land and equipment to capture
  - By comparison, fossil fuels represent millions of years of concentrating solar energy
- Intermittent resources
  - Put stress on electric grid

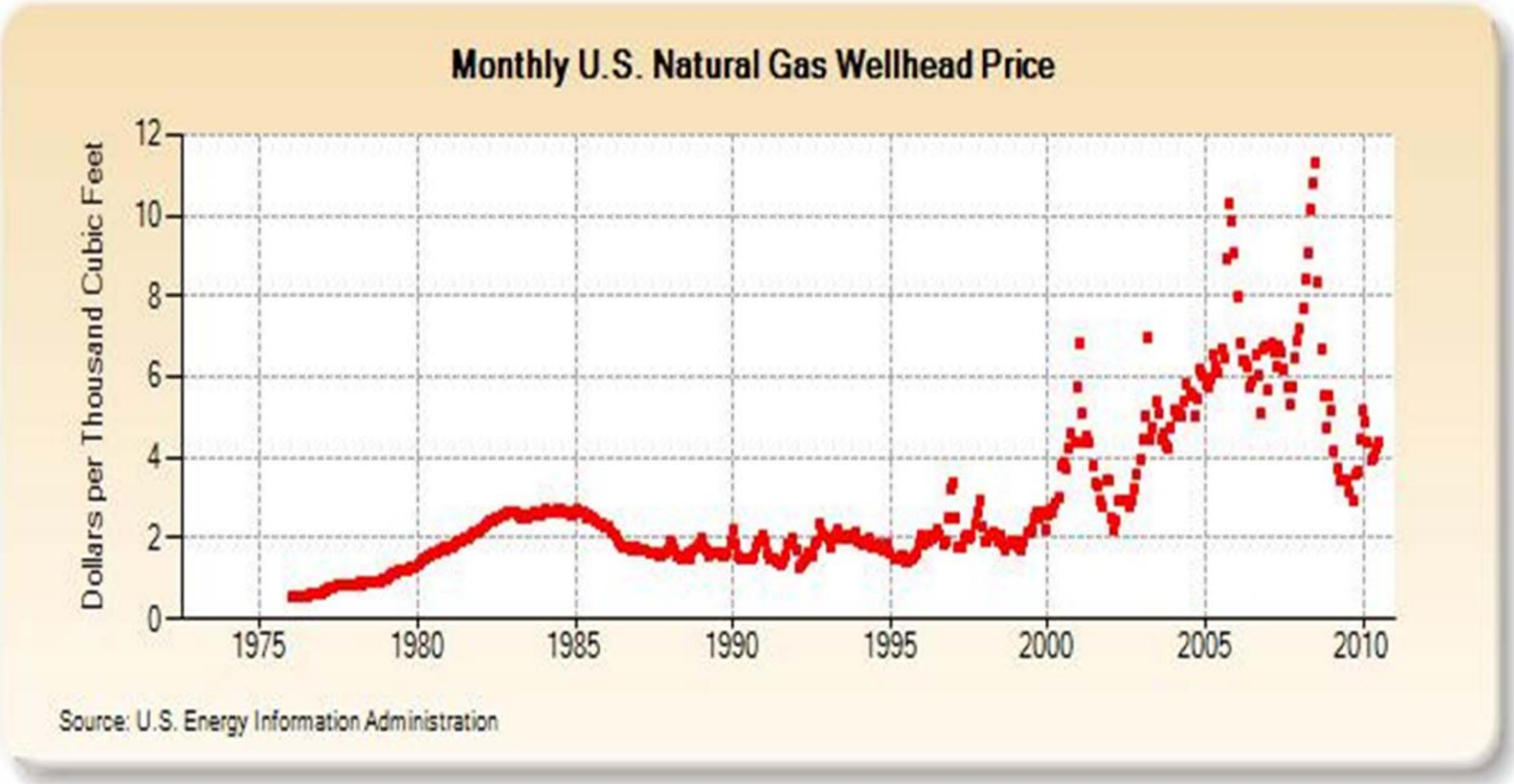
Comparative Costs

- BOTE* estimates (per kWh) of unsubsidized costs
  - Natural Gas fired – 6¢/at $5 gas
  - Great Plains Wind - 8¢
  - Offshore Wind - 19¢
  - Photovoltaic (PV) Solar - 30¢
- * this is a lawyer's guess; see an economist for economic advice
- Actual costs vary based on location, transmission and resource adequacy

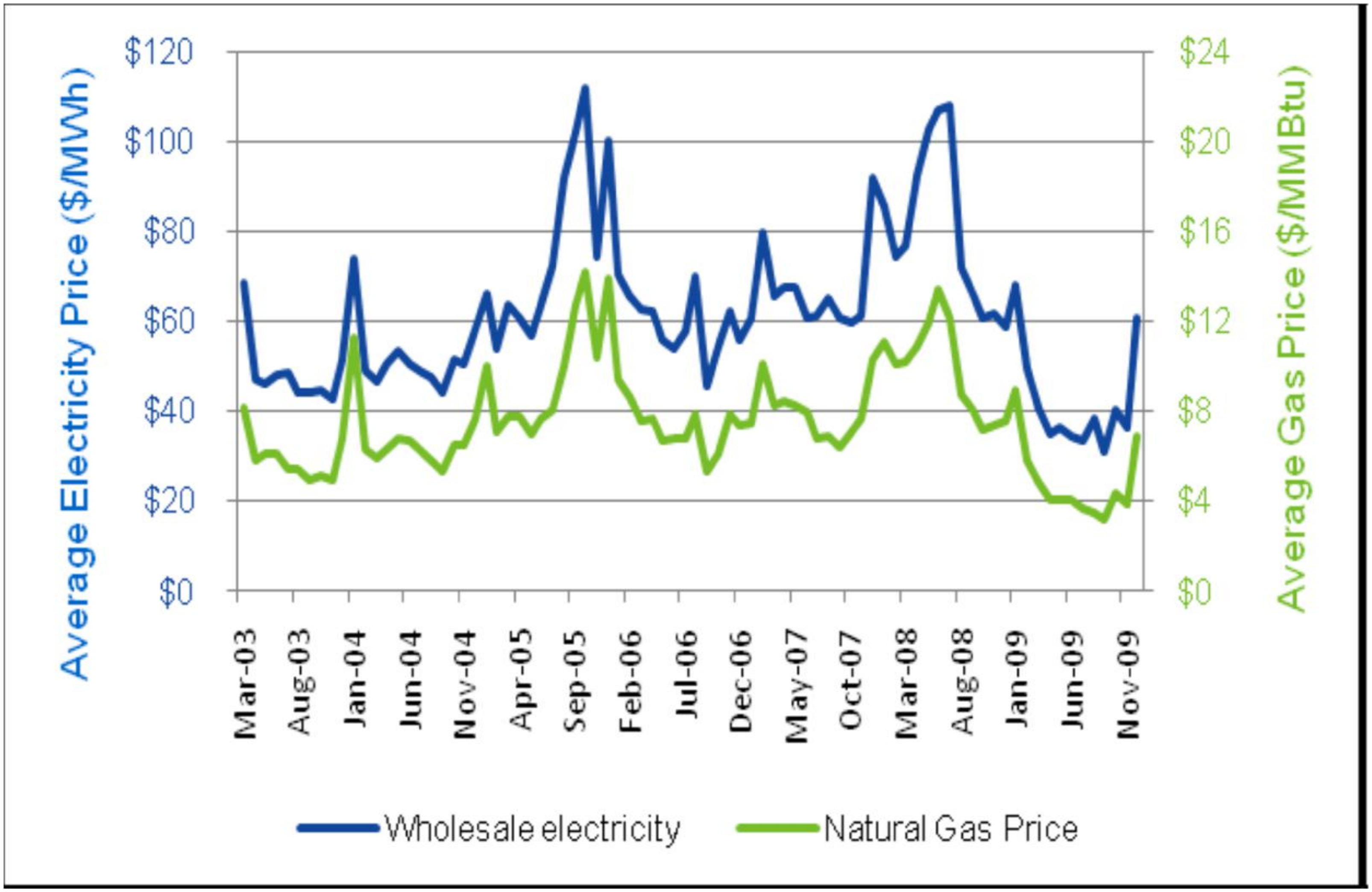
Achieving Parity

- Technological Advances
  - For Wind, this means even bigger machines
- Increasing Fossil Fuel prices
  - Gas prices are dramatically lower due to Fracking
- Imposing externality costs on fossil fuels
  - We can't even increase the gas tax to repair bridges

Monthly US Natural Gas Wellhead Price 1975 - 2010



Electricity Prices Track Natural Gas Prices



Average Natural Gas and Wholesale Electricity Prices in New England

Average Natural Gas and Wholesale Electricity Prices in New England
(2003 to 2009)

	Ave. natural gas price (MMbtu[1])	Ave. wholesale electricity price (MWh[2])
2003*	$5.88	$48.55
2004	$6.76	$52.08
2005	$9.70	$76.44
2006	$7.32	$59.69
2007	$7.96	$66.78
2008	$9.91	$80.54
2009	$4.77	$41.99
% Change 2008—2009	-52%	-48%

* Current wholesale market commenced March 2003

Bridging the Gap

- Grant Programs
- Net Metering
- Tax Benefits
  - Production Tax Credit
  - Investment Tax Credit
  - Depreciation
- Feed In Tariffs
- Renewable Portfolio Standards

Renewable Portfolio Standard

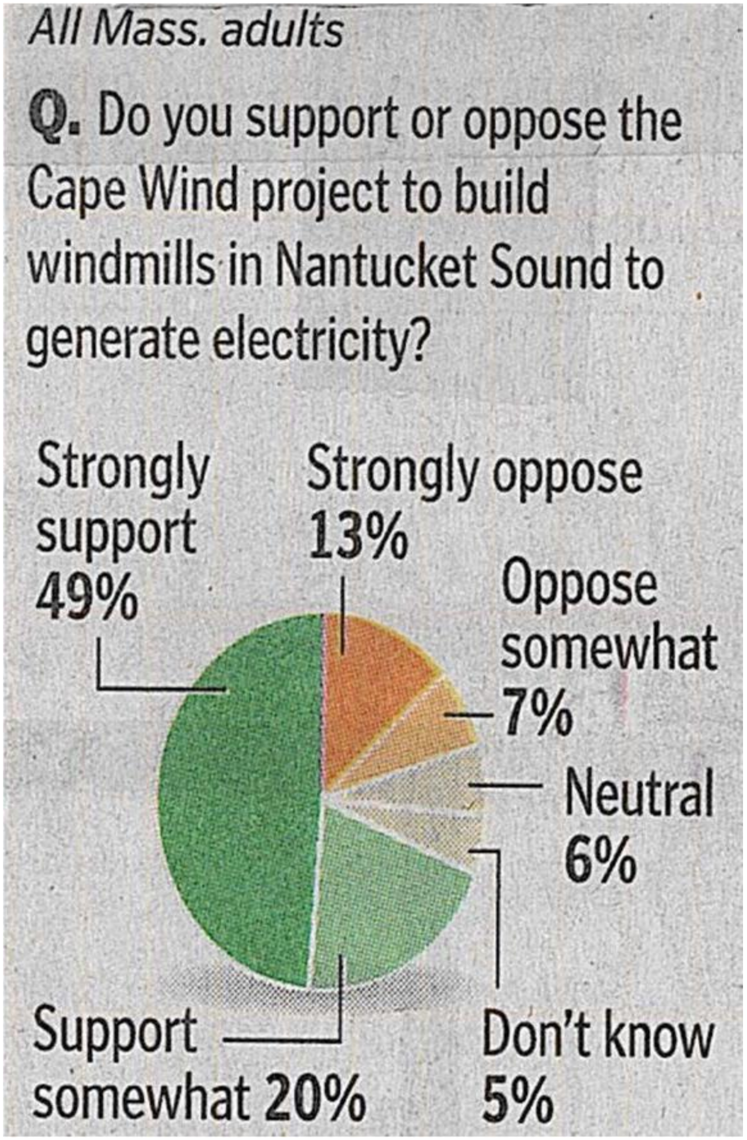
- Massachusetts requires Retail Suppliers to source an increasing percentage of their supply from renewable resources
  - 5.0% in 2010, increases 1.0% per year thereafter
- Alternative Compliance Payments
  - $60.92/MWh for 2010, escalating annually at CPI
- Political created, therefore lenders and investors are wary
- Best way of encouraging renewables
  - Spreads the cost on all users
  - Does not increase government deficits

Munis and the RPS

- Municipal light plants are exempt
- But if WMLP were not exempt, then (based on annual load of 250,000 MWh) WMLP need 12,500 MWh kWh of renewable resources in 2010
- Or would owe up to $750,000 for alternative compliance payments in 2010
- WMLP has contracted for 7,000 MWh per year from Spruce Mountain project in Maine commencing 2011
  - Excellent Progress
- Not yet at parity with NSTAR or National Grid customers

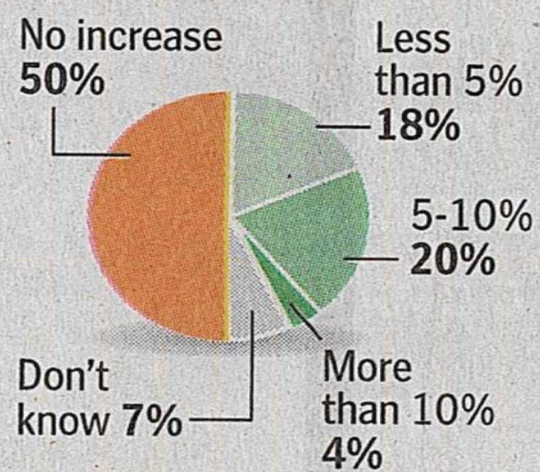
Will We Pay?

•


All Mass. adults
Q. Do you support or oppose the Cape Wind project to build windmills in Nantucket Sound to generate electricity?
Strongly support 49%
Strongly oppose 13%
Oppose somewhat 7%
Neutral 6%
Don't know 5%
Support somewhat 20%

Will We Pay?

Q. If electricity generated by the Cape Wind project costs more than electricity from traditional sources, would you be willing to pay more on your utility bill for electricity from Cape Wind?
IF YES: How much more would you be willing to pay?



SOURCE: Boston Globe poll conducted by the UNH Survey Center, Sept. 17-22. Margin of error is +/-4.3 percentage points for all adults and +/-4.5 percentage points for likely voters.

GLOBE STAFF

Final Thoughts

- Savoy may not be the best project
  - Other projects, especially out of state are cheaper
- However, much cheaper than Cape Wind
  - Will help economically struggling area
  - Develop a model for onshore wind projects
- But regardless of which projects are selected, will additional costs be accepted and how will they be allocated?

Questions?

Don McCauley

10 Speen Street

Framingham, MA 01701

508-665-5801

don@minutemanwind.com

DOCKET NO. UM 1610
EXHIBIT: ODOE/102
WITNESS: PHILIP CARVER

Before the
PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Exhibit 102
Accompanying the response testimony of
Philip Carver

March 2013

Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge

June 10, 2012
Western Governors' Association

The Integration Challenge

Prepared by Regulatory Assistance Project for Western Governors' Association. The preparation of this report was financed in part by funds provided by The Energy Foundation. The U.S. Department of Energy Office of Electricity Delivery and Energy Reliability supported the participation of the National Renewable Energy Laboratory.

Project Manager and Editor

Lisa Schwartz

Authors

Kevin Porter, Christina Mudd, Sari Fink and Jennifer Rogers – Exeter Associates
Lori Bird – National Renewable Energy Laboratory
Lisa Schwartz, Mike Hogan and Dave Lamont – Regulatory Assistance Project
Brendan Kirby – Consultant

Technical Committee

Laura Beane, Iberdrola
Ty Bettis, Portland General Electric
Steve Beuning, Public Service of Colorado
Daniel Brooks, Electric Power Research Institute
Ken Dragoon, Northwest Power and Conservation Council
Jack Ellis, consultant
Udi Helman, Brightsource
Gene Hinkle, GE Energy
David Hurlbut, National Renewable Energy Laboratory
Elliot Mainzer, Bonneville Power Administration
Michael Milligan, National Renewable Energy Laboratory
Andrew Mills, Lawrence Berkeley National Laboratory
Dave Olsen, Western Grid Group
Carol Opatrny, Opatrny Consulting, Inc.
Jim Price, California Independent System Operator
Jim Shetler, Sacramento Municipal Utility District
Charlie Smith, Utility Variable Generation Integration Group
Ryan Wiser, Lawrence Berkeley National Laboratory
Robert Zavadil, EnerNeX

Other Reviewers

Rich Bayless, Northern Tier Transmission Group
Ken Corum, Northwest Power and Conservation Council
Gene Danneman, Wind Wear LLC
Erik Ela, National Renewable Energy Laboratory
Jim Hansen, Northern Tier Transmission Group
Sharon Helms, Northern Tier Transmission Group
Eric King, Bonneville Power Administration
Chris Mensah-Bonsu, California Independent System Operator
Charlie Reinhold and Kristi Wallis, Joint Initiative

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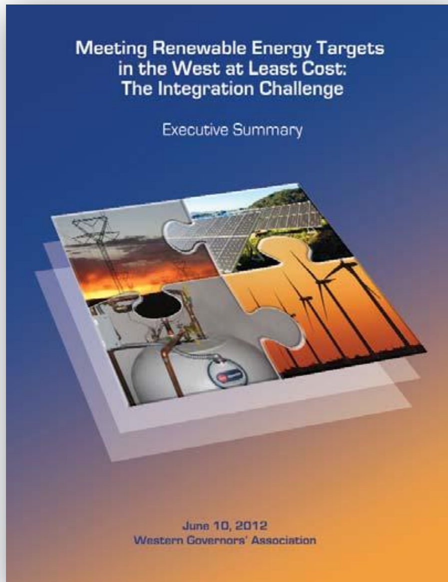
Western Governors' Association

Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge

Introduction

Clean, affordable energy is essential for continued growth of the economy in Western states. State laws and policies put in place in the last decade requiring energy suppliers to bring on-line large amounts of wind and solar generation have changed the traditional mix of "fuels" used for energy generation. By 2022, these policies are expected to more than double the amount of renewable resources in the Western U.S. compared to 2010.



Integrating these resources into a reliable and affordable power system will require an unprecedented level of cooperative action within the electric industry and between the industry and state, subregional and federal entities. Western Governors have encouraged utilities and transmission providers to reduce the cost of integrating renewable energy (see WGA Resolution 10-15). These efforts need to increase as wind and solar resources scale up to help power the Western economy in the future.

Western Governors can help accelerate these efforts by:

- Asking for regular reports from utilities and transmission providers serving their state on actions they are taking to put in place recommendations in this paper;
- Calling for an assessment from the state's utility regulators and energy office on whether an energy imbalance market and faster scheduling of energy and transmission could reduce ratepayer costs and, if so, what is needed to put these practices in place;
- Urging transmission providers and federal power marketing agencies to evaluate the cost and benefits of actions to increase transmission capacity and system flexibility and act on ones that look most promising;
- Directing state agencies to incorporate the recommendations in this report in state energy and transmission plans and economic development initiatives and requesting utilities and regulators to include the recommendations in requirements for utility resource plans and procurement;
- Asking utilities and state agencies to work collaboratively to inventory generating facilities and evaluate future flexibility options to integrate wind and solar resources; and
- Convening parties to discuss benefits to the region from least-cost delivery of wind and solar resources and to develop solutions to address institutional barriers.

The Western Governors' Association commissioned this report to explore ways to reduce costs to the region's electricity consumers for integrating wind and solar, identify barriers to adopting these measures and recommend possible state actions.

The Western U.S. power grid has existing flexibility in the system to cost-effectively integrate wind and solar resources but, as operated today, that flexibility is largely unused. Integration involves managing the variability (the range of expected electricity generation output) and uncertainty (when and how much that generation will change during the day) of energy resources.

Integration is not an issue that is unique to renewable resources; conventional forms of generation also impose integration costs. In fact, most of the measures described in the report would reduce costs and improve the reliability of the grid even if no wind or solar generation is added.

Other regions of the country have found ways to increase flexibility and efficiency from supply- and demand-side resources and transmission, although the West faces some unique challenges including:

- The Western Interconnection is a large area that includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of 14 Western states.
- It is organized into 37 balancing authorities that operate independent areas within an interconnected grid system.
- Energy and capacity are acquired primarily through utility-built projects and long-term bilateral agreements driven by utility resource plans and procurement processes.
- Outside of organized wholesale markets in Alberta and the California Independent System Operator (CAISO) footprint, subhourly energy transactions are limited.
- Energy is largely delivered on hourly schedules that are fixed shortly before the hour of delivery, with little (or no) ability to make changes.

Drawing from existing studies and experience to date, this report identifies operational and market tools as well as flexible demand- and supply-side resources that can be employed to reduce ratepayer costs for integrating wind and solar in the Western states. The following table provides a high-level overview of the costs and integration benefits for each of these approaches and indicates the level of certainty of these appraisals. The table also provides estimated timeframes for implementation. The remainder of the Executive Summary outlines these approaches and recommendations for states to consider.

Executive Summary

Assessment of Integration Actions

The following table takes a West-wide view of costs and integration benefits of actions described in this report and estimates implementation timeframe. Appendix A describes underlying assumptions. The extent to which any of these actions is undertaken, and therefore its costs and benefits, depend in part on the level of adoption of other actions. However, each action is treated independently here; there is no ranking of options against each other. Colors indicate confidence in the assessment of costs and integration of benefits: blue – high confidence, yellow – medium confidence, and orange – low confidence.

Option	Expected Cost of Implementation[1] (west-wide except where noted)	Expected Benefit for Integrating Variable Generation	Projected Timeframe in Implementing Option
Subhourly Dispatch and Intra-Hour Scheduling (non-standard, voluntary – not West-wide, 30-minute interval)	Low	Low	Short
Subhourly Dispatch and Intra-Hour Scheduling (standard, voluntary – not West-wide)[2]	Low to Medium	Low to Medium	Short
Subhourly Dispatch and Intra-Hour Scheduling (standard, required, West-wide)	Low to High	Medium to High	Medium
Dynamic Transfers (improved tools and operating procedures)	Low	Low to Medium	Short to Medium
Dynamic Transfers (equipment upgrades, including new transmission lines)	Medium to High	Medium to High	Medium to Long
Energy Imbalance Market (subregion only)	Medium to High	Medium	Medium
Energy Imbalance Market (West-wide)	Medium to High	High	Medium to Long
Improve Weather, Wind & Solar Forecasting	Medium	Medium to High	Short to Medium
Geographic Diversity (if using existing transmission)	Low to Medium	Low to Medium	Medium
Geographic Diversity (if new transmission needed)	High	Medium	Long
Reserves Management: Reserves Sharing	Low	Low to Medium	Short
Reserves Management: Dynamic Calculation	Low	Low to Medium	Short
Reserves Management: Using Contingency Reserves for Wind Events	Low to Medium	Low to Medium	Short to Medium
Reserves Management: Controlling Variable Generation (assuming requirements are prospective)	Low to Medium	Low to Medium	Medium to Long
Demand Response: Discretionary Demand	Low to Medium	Low to Medium	Short to Medium
Demand Response: Interruptible Demand	Low to Medium	Low to Medium	Short to Medium
Demand Response: Distributed Energy Storage Appliances	Low to Medium	Low to Medium	Short to Medium
Flexibility of Existing Plants—Minor Retrofits	Low to Medium	Low to Medium	Short to Medium
Flexibility of Existing Plants—Major Retrofits	Medium to High	Medium to High	Medium to Long
Flexibility for New Generating Plants	Low to High	Medium to High	Medium to Long

[1] Low - less than $10 million region-wide; medium - between $10 million and $100 million; high – more than $100 million.

[2] Ranges in costs and integration benefits reflect differences in scheduling intervals – 5 to 15 minutes vs. 30 minutes.

Summary of Integration Actions

Expand subhourly dispatch and intra-hour scheduling.

Economic dispatch is the process of maximizing the output of the least-cost generating units in response to changing loads. Scheduling is the advance scheduling of energy on the transmission grid.

Subhourly dispatch refers to changing generator outputs at intervals less than an hour. Intra-hour scheduling refers to changing transmission schedules at intervals less than an hour. In organized energy markets in the U.S., regional system operators dispatch generation at five minute intervals and coordinate transmission with dispatch.

While most transmission in the Western Interconnection is scheduled in hourly intervals, output from variable energy resources changes within the hour. Greater use of subhourly dispatch and intra-hour scheduling in the West's bilateral markets could allow generators to schedule their output over shorter intervals and closer to the scheduling period, effectively accessing existing generator flexibility that is not available to most of the West today. Among other benefits, this would facilitate a large reduction in the amount of regulation reserves needed with significant savings for consumers.

Barriers to achieving these savings in the West include the upfront cost to move from hourly to intra-hourly scheduling; inconsistent practices across areas where intra-hour scheduling is allowed today; the need to synchronize metering, control center operations and software; lack of coordination of intra-hour scheduling with financial settlements; and the lack of a formal, standard market for intra-hour energy transactions outside Alberta and the CAISO footprint.

Recommendations for states to consider:

- Encourage expansion of the Joint Initiative's intra-hour scheduling activities to shorter time intervals.
- Promote expansion of subhourly dispatch and intra-hour scheduling to all entities in the West.
- Foster standardization of intra-hour scheduling among Western balancing authorities, allowing updating of schedules within the hour.
- Evaluate the costs, benefits and impacts of extended pilots on the need for reserves, particularly for regulation.
- Commission an independent analysis of the estimated equipment and labor costs of transitioning to subhourly dispatch and intra-hour scheduling for all transmission providers in the West. Such an analysis also should estimate the benefits, including projected reductions in regulation and other reserve needs, especially for balancing authorities with large amounts of variable energy resources. In addition, the study should evaluate costs and benefits of intra-hour scheduling operations, such as:
  1. two 30-minute schedules both submitted at the top of the hour,
  2. one 30-minute schedule submitted at the top of the hour and another at the bottom of the hour,
  3. 15-minute scheduling and
  4. five-minute scheduling.
- Consider strategies for assisting smaller transmission providers to recover costs of transitioning to intra-hour scheduling, such as coordinated operations among multiple transmission providers or phasing in equipment and personnel upgrades over multiple years.
- Explore harmonized implementation of faster dispatch, scheduling, balancing and settlement across the Western Interconnection.
- Allow regulated utilities to recover costs for wind integration charges assessed by a third party at the lesser of the rate charged for intra-hour scheduling or hourly scheduling, if intra-hour scheduling is an available option. Grant cost recovery for software upgrades and additional staff necessary to accommodate intra-hour scheduling.

Facilitate dynamic transfers between balancing authorities

Dynamic transfer refers to electronically transferring generation from the balancing authority area in which it physically resides to another balancing authority area in real-time. Such transfers allow generation to be located and controlled in a geographic location that is outside of the receiving balancing authority area. Dynamic transfer involves software, communications and agreements and requires the appropriate amount of firm, available transmission capacity between locations.

Dynamic transfers facilitate energy exchanges between balancing authority areas and increase operational efficiency and flexibility. Using dynamic transfers, the within-hour variability and uncertainty of a wind or solar facility can be managed by the balancing authority where the energy is being used. Absent dynamic transfers, that responsibility remains with the balancing authority area where the facility interconnects, even if the plant schedules the power to be sold in another region. Dynamic transfers can result in greater geographic diversity of wind and solar facilities and reduced integration costs and imbalance charges.

For most transmission providers in the Western Interconnection, transmission slated for dynamic transfers must be held open for the maximum dynamic flow that could occur within the scheduling period, typically an hour. Thus, transmission slated for dynamic transfers could displace other potential fixed, hourly transactions on the line. While reservations can be updated in real-time to be used by other market participants, increased dynamic transfers may come at the expense of other uses of the line.

Dynamic transfers also increase intra-hour power and voltage fluctuations on the transmission system that can pose challenges for system operators. The impacts are more difficult to manage as more dynamic transfers have large and frequent ramps within the scheduling period. Lack of automation of some reliability functions is a barrier to increased use of dynamic transfers, as are concerns about the impact on transmission system operating limits.

Recommendations for states to consider:

- Complete transmission provider calculations of dynamic transfer limits to help identify which lines are most receptive, and which are most restrictive for dynamic transfers.
- Determine priority for transmission system improvements to alleviate restrictions on dynamic transfers considering locations for existing and potential renewable generation and balancing resources, and lines needed for dynamic transfers.
- Assess options and costs for additional transmission capacity and additional flexibility on transmission systems to facilitate more widespread use of dynamic transfers. For example, more flexible AC transmission systems can be "tuned" to operate more flexibly. Dynamic line ratings can increase utilization of existing transmission facilities. Also, the impact of lower transmission utilization factors due to dynamic transfers could be minimized through upgrades such as reactive power support and special protection systems.
- Explore use of ramping limits to increase the dynamic transfer capability of certain paths.
- Assess best approaches for integrating dynamic transfer limits into scheduling and operating practices and determine compensation issues.

- Conduct outreach and disseminate information to stakeholders on the implications of dynamic transfer limits and potential system impacts of dynamic scheduling in order to help identify solutions. Dynamic transfer limits may have implications for other mechanisms that can help integrate renewable resources, such as an energy imbalance market and flexible reserves.
- Automate reliability procedures such as voltage control and RAS arming to enable expanded use of dynamic transfers and increase the efficiency of system operations.
- Use near real-time data to calculate system operating limits to address concerns about potential violations of limits due to lack of current data. This could help mitigate restrictive dynamic transfer limits.
- Encourage balancing authorities to use dynamic transfers to aggregate balancing service across their footprints.

Implement an energy imbalance market (EIM)

As proposed for the Western U.S., an EIM is a centralized market mechanism to:

1. re-dispatch generation every five minutes to maintain load and resource balance, addressing generator schedule deviations and load forecast errors and
2. provide congestion management service by re-dispatching generation to relieve grid constraints.

An EIM would increase the efficiency and flexibility of system operations to integrate higher levels of wind and solar resources by enabling dispatch of generation and transmission resources across balancing authorities. That would harness the full diversity of load and generation in a broad geographic area to resolve energy imbalances. An EIM would optimize the dispatch of imbalance energy within transmission constraints, reducing operating costs and reserve needs and making more efficient use of the transmission system. In addition, an EIM would provide reliability benefits by coordinating balancing across the region, making more generation available to system operators.

Among the implementation barriers are upfront financing and accepting and adapting to a new operational practice. Other issues to be resolved include selection of a market operator, governance, a market monitor to prevent and mitigate potential market manipulation, coordination agreements with reserve sharing groups, seams agreements with non-participants and organized market areas, and uncertainty in the level of interest in participation.

Recommendations for states to consider:

- Undertake efforts to define the rates and terms for transmission service agreements for each transmission provider.
- Explore financing options to enable entities to defer some of the startup costs to future years and to better plan and budget for costs.
- Investigate the costs and benefits to ratepayers of regulated utilities participating in an EIM through public utility commission proceedings. Encourage publicly owned utilities to investigate costs and benefits of EIM participation for their consumers. Such evaluations should include potential reduction in integration costs, potential enhanced reliability, changes to compensation for transmission providers and impacts for customers, potential disadvantages of participation, and possible negative economic impacts for meeting renewable energy requirements in the absence of utility participation in an EIM.
- Examine mechanisms for preventing and mitigating potential market manipulation that could reduce benefits.
- Support continuing efforts to explore how governance of an EIM would work, including provisions that address concerns that an EIM could lead to the creation of an RTO.
- Determine the viability of an EIM if major balancing authorities do not participate.
- Provide encouragement and support for the Northwest Power Pool Market Assessment and Coordination Committee which has assembled 20 Western balancing authorities and several other participating utilities to fully evaluate the business case for an EIM.

- Support Western Interconnection-wide efforts to design a proposed EIM for the broadest possible geographic footprint.
- Establish a timeline for implementing the proposed EIM in the West.

Improve weather, wind and solar forecasting

Weather is a primary influence on all electric systems as it drives load demand, in addition to variable generation sources such as wind and solar. Hot days require more power generation to meet demand for cooling, while cold weather requires more generation to serve electric heating requirements. Thus, forecasting of variable generation should be viewed in the broader context of weather forecasting.

Variable generation forecasting uses weather observations, meteorological data, Numerical Weather Prediction models, and statistical analysis to generate estimates of wind and solar output to reduce system reserve needs. Such forecasting also helps grid operators monitor system conditions, schedule or de-commit fuel supplies and power plants in anticipation of changes in wind and solar generation, and prepare for extreme high and low levels of wind and solar output.

Key barriers to greater use of wind and solar forecasting are deficiencies in forecast accuracy, time required to implement forecasting processes including collection of necessary data, increased need to incorporate variable generation forecasts in day-ahead schedules and dispatch, and lack of updating schedules and dispatch with more accurate forecasts closer to real time. In addition, improvements in the foundational forecasts that variable generation forecasters rely upon will improve the quality and accuracy of variable generation forecasts. Improvements including more frequent measurements and observations, more measurements from the atmosphere, and more rapid refreshing of Numerical Weather Prediction models will improve variable generation forecasting as well as weather forecasting, which have broader benefits for the public, the aviation industry and other users of weather data.

Recommendations for states to consider:

- Support government and private industry efforts to improve the foundational models and data that are incorporated into variable generation forecasting models.
- Encourage the expanded use of variable generation forecasting by balancing authorities.
- Ask balancing authorities that already have implemented variable generation forecasting to study the feasibility and costs and benefits of improvements, such as using multiple forecasting providers or installing additional meteorological towers.
- Study the feasibility and costs and benefits of using variable generation forecasts for day-ahead unit commitments and schedules, including updating schedules closer to real time to take advantage of improved forecast accuracy.

- Consider the feasibility and costs and benefits of more regional variable generation forecasts involving multiple balancing authorities or exchange of forecasts among balancing authorities.
- Ask balancing authorities whether variable generation ramps are of concern now or are expected to be of concern in the future, whether any existing forecasting system adequately predicts ramps in variable generation, and the status of potential adoption of a ramp forecast for variable generation.

Take advantage of geographic diversity of resources

Over a large geographic area, and a corresponding large number of generating facilities, wind and solar projects are less correlated and have less variable output in aggregate. This reduces ramping of conventional generation for balancing, as well as forecasting errors and the need for balancing (not contingency) reserves.

Some regions in the U.S. have large balancing authority areas that naturally provide geographic diversity. Diversity also can be accessed through greater balancing authority cooperation, building transmission and optimized siting of wind and solar plants.

Siting these resources without regard to geographic diversity may have higher costs compared to projects sited to minimize transmission costs. However, if the resource sites are not of equal quality, more wind and solar capacity may be required to achieve the same generation output – at higher cost – compared to developing higher quality resources that are geographically concentrated.

Although the benefits of geographic diversity are generally recognized, there is insufficient information that quantifies the costs and benefits. Further, geographic diversity is typically not factored into transmission planning or resource planning and procurement processes. The question is whether reducing aggregate variability of variable generation through geographic diversity, with the resulting reductions in reserves requirements and wind and solar forecast errors, justifies initiatives such as transmission expansion. By itself, geographic diversity is probably insufficient to justify new or upgraded transmission lines but it may be an additional benefit. Regardless, the benefits of geographic diversity clearly support balancing authority area aggregation and greater cooperation across areas.

Recommendations for states to consider:

- Quantify the costs and benefits of geographic diversity in utility resource plans and procurement, subregional plans and Interconnection-wide plans. This includes, but is not limited to, siting wind and solar generation to minimize variability of aggregate output and better coincide with utility load profiles.
- Investigate the pros and cons of siting optimization software and whether it can be advantageously used in processes such as defining state and regional renewable energy zones and utility resource planning and procurement to reduce ramping of fossil-fuel generators and minimize reserve requirements.

- Support right-sizing of interstate lines that access renewable resources from regional renewable energy zones designated through a stakeholder-driven process in areas with low environmental conflicts, when it is projected that project benefits will exceed costs. Right-sizing lines means increasing project size, voltage, or both to account for credible future resource needs. Building some level of transmission in advance of need could avoid construction of a second line in the same corridor or minimize the need for additional transmission corridors, and associated environmental disruption, as well as the risk that transmission may not be available to deliver best resources identified in long-term planning.

Improve reserves management

Power system reserves are quantities of generation or demand that are available as needed to maintain electric service reliability. Contingency reserves are for unforeseen events, such as an unscheduled power plant outage. Balancing reserves are for day-to-day balancing of generation and demand.

Higher penetrations of wind and solar resources increase the variability and uncertainty of generation in the system, increasing the need for balancing reserves. These reserves can be managed more efficiently. First, reserve sharing can reduce the requirements of individual balancing authorities by averaging out short-term load and resource fluctuations across a broader area. Second, dynamically calculating regulation and load following reserves would take into account levels of renewable generation (for example, variability of wind plant output changes with output level), load on the system and other system conditions. Third, system operators can work with reliability entities to determine whether contingency reserves could be used for extreme events when wind output drops rapidly. Fourth, relatively modest limits and ramp rate controls for variable generation could significantly reduce the need to hold balancing reserves, at the cost of curtailing some output of renewable energy generation. Automatic generation control for down-regulation also may prove useful if variable generators are compensated for the service.

The first two of these approaches are more proven, while at least some aspects of the latter two approaches are less developed. Among the implementation barriers, additional research and implementation experience are needed in several areas.

Recommendations for states to consider:

- Equip more existing conventional generating facilities with automatic generation control. Experiment with automatic generation control for wind projects and evaluate the benefits to the system against compensating wind generators for lost output.
- Expand reserve-sharing activities such as ADI. Implementation costs are minimal and benefits may be substantial. In addition, ADI programs should consider expanding capacity limits.
- Request the WECC Variable Generation Subcommittee to analyze dynamic reserve methods to help with wind and solar integration.
- Ask balancing authorities to explore calculating reserve requirements on a dynamic basis to take into account the levels of wind and solar on the system and other system conditions.
- Perform statistical analysis to determine the benefits in reduced net reserves that result if balancing reserves for wind and contingency reserves can be at least partially shared. If results are positive, work with NERC and WECC to develop protocols allowing the use of contingency reserves for extreme wind ramping events.
- Develop coordinated or standardized rules for controlling variable generation that minimize economic impacts to wind and solar generators. Controls should be limited to situations where actions are needed to maintain system reliability or when accepting the variable generation leads to excessive costs.
- Consider different wholesale rate designs to encourage more sources of flexibility.

Retool demand response to complement variable supply

Where the fuel that drives a growing share of supply is beyond the control of system operators, as is the case with wind and solar energy, it is valuable to shift load up and down by controlling water heaters, chillers and other energy services. To realize significant integration benefits this must be done through either direct control of the load or pre-programmed responses to real-time prices.

Experience in some regions and results from studies suggest that demand response can be a key component of a low-cost system solution for integrating variable generation. Demand response also provides many other benefits, including increased customer control over bills, more efficient delivery of energy services and a more resilient power system.

Among the barriers, demand response programs that could help integrate variable generation are nascent, advanced metering infrastructure is not in place in many areas, better customer value propositions are needed, and strategies for measuring and verifying demand response must be improved.

Recommendations for states to consider:

- Consider demand response as part of a suite of measures designed and deployed to complement the reliable and cost-effective deployment of larger shares of variable energy resources.
- Further develop and test a range of value propositions to assess customer interest in direct load control and pricing event strategies that support variable generation, with frequent control of loads both up and down.
- Evaluate experience with program designs that pay consumers based on the value of the flexibility services they provide to system operators, with either direct control of selected loads or automated load responses programmed for customers according to their preferences.
- Consider the potential value of enabling demand response programs that can help integrate variable generation when evaluating utility proposals for advanced metering infrastructure.
- Particularly for real-time pricing based programs, cultivate strategies that earn consumer confidence in advanced metering infrastructure and pricing programs, including development of robust policies safeguarding consumer privacy and well-designed consumer education programs.
- Allow and encourage participation of third-party demand response aggregators to accelerate the development of new sources of responsive demand, new consumer value propositions and new service offerings. Address open-source access to demand response infrastructure, access to consumer information, and privacy and data security issues to enable third parties to offer demand response products and services.
- Allow demand response to compete on an equal footing with supply-side alternatives to provide the various services it is capable of delivering. Further, actively accommodate demand response in utility solicitations for capacity.
- Isolate and quantify costs of balancing services to make transparent the value of flexibility options such as demand response.
- Develop robust measurement and verification processes that recognize the unique characteristics of demand-side resources in ways that encourage, rather than discourage, wider participation.
- Examine ratemaking practices for features that discourage cost-effective demand response. Examples include demand charges that penalize (large) customers for higher peak demand levels when they shift load away from periods of limited energy supplies to periods of surplus, and revenue models that tie the utility's profits primarily to volume of energy sales.

Access greater flexibility in the dispatch of existing generating plants

Output control range, ramp rate and accuracy – along with minimum run times, off times and startup times – are the primary characteristics of generating plants that determine how nimbly they can be dispatched by the system operator to complement wind and solar resources. There are economic tradeoffs between plant efficiency, emissions, opportunity costs (the revenue lost when a generator foregoes energy production in order to provide flexibility), capital costs and maintenance expenses.

The best way to achieve the needed generator flexibility is to design and build it into the fleet, selecting technologies that are inherently flexible. Some plants can be retrofitted to increase flexibility by lowering minimum loads, reducing cycling costs and increasing ramp rates. Generators that can reduce output or shut down when wholesale market prices are lower than their operating costs can make more money than generators that have to continue operating at a loss.

Among the barriers to retrofitting plants are the fundamental limitations of the technology, uniqueness of each plant, cost and uncertain payback. The benefits of increasing existing plant flexibility may be comparatively small compared to other ways to reduce integration costs, such as larger balancing authorities and intra-hour scheduling. But the benefits are additive.

Recommendations for states to consider:

First, establish generator scheduling rules that do not block access to the flexibility capability that already exists. Subhourly energy scheduling has proven to be an effective method for maximizing the flexibility of the generation fleet. Second, perform balancing over as large a geographic area as possible. The larger the balancing area, the greater diversity benefit where random up and down movements of loads and variable generators cancel out. Third, design flexibility into each new generator by selecting technologies that are more flexible.

Fourth, retrofit existing generators to increase flexibility when this is practical and cost-effective:

- Analyze the potential for retrofitting existing, less flexible generating facilities. Evaluation on a plant-specific basis is required to determine what additional flexibility, if any, can be obtained through cost-effective modification. It may be possible to achieve faster start-ups, reduce minimum loads, increase ramp rates (up and down), or increase the ability to cycle the generator on and off, or off overnight, and at other times when it is not needed.
- Provide appropriate incentives to encourage generating plant owners to invest in increased flexibility.
- Consider establishing incentives or market options to encourage generators to make their operational flexibility available to system operators.

- Explore development of a flexible ramping ancillary service to take advantage of fast-response capabilities of some types of demand resources and generation.
- Require conventional generators to have frequency response capability or define frequency response as a service that generators can supply for compensation.
- Quantify cycling costs and identify strategies to minimize or avoid cycling.

Focus on flexibility for new generating plants

Traditionally, system operators relied on controlling output of power plants – dispatching them up and down – to follow highly predictable changes in electric loads. Generating plants were scheduled far in advance with only small adjustments in output required to follow changes in demand.

With an increasing share of supply from variable renewable energy resources, grid operators will no longer be able to control a significant portion of generation capacity. At the same time, renewable resources are among the most capital-intensive and lowest cost to operate. Once built, typically the least-cost approach is to run them as much as possible. Therefore, grid operators will need dispatchable generation with more flexible capabilities for following the less predictable "net load" – electricity load after accounting for energy from variable generation.

New dispatchable generation will need to frequently start and stop, change production to quickly ramp output up or down, and operate above and below standard utilization rates without significant loss in operating efficiency. Flexible resources that can meet increased system variability needs with high levels of wind and solar generation will enable more efficient system operation, increased utilization of zero variable-cost resources, and lower overall system operating costs.

A significant challenge is assessing how much flexible capacity already exists and how much will be needed – and when. Resource planning and procurement processes typically are not focused on flexible capability. New metrics and methods are needed to assess flexibility of resource portfolios and resource capabilities needed in the future.

Recommendations for states to consider:

- Retool the traditional approach to resource adequacy and planning analysis to reflect the economic benefit of flexibility service.
- Conduct a flexibility inventory of existing supply- and demand-side resources.
- Evaluate the need for flexible capacity at the utility, balancing authority, subregional and regional levels.
- Examine how utility resource planning and procurement practices evaluate long-term needs, benefits and costs of flexible capacity with increasing levels of variable renewable energy resources, including capabilities and limitations of analytical tools and metrics. Amend planning requirements or guidance to address these needs.
- Review recommendations of NERC's Integration of Variable Generation Task Force on potential metrics and analytical methods for assessing flexibility from conventional power plants for application in utility resource planning and procurement.
- Examine incentives and disincentives for utilities to invest in flexible supply- and demand-side resources, including those directed at resource adequacy, to meet the growing demand for flexibility services.
- Use competitive procurement processes to evaluate alternative capacity solutions, looking beyond minimum requirements for resource adequacy and analysis focused simply on cost per unit. Specify capabilities, not technologies and fuels, allowing the market to bring the most attractive options.
- Review air pollutant emissions rates allowed under state rules for impacts on procurement of flexible generation, with the aim of maintaining integrity of overall environmental goals.

Table of Contents

Acronyms

AESO – Alberta Electric System Operator
BPA – Bonneville Power Administration
CAISO – California Independent System Operator
DOE – U.S. Department of Energy
EIM – Energy imbalance market
FERC – Federal Energy Regulatory Commission
IRP – Integrated resource plan
ISO – Independent System Operator
kW – Kilowatt
kWh – Kilowatt-hour
LSE – Load-serving entity
MW – Megawatt
MWh – Megawatt-hour
NERC – North American Electric Reliability Corporation
OATT – Open Access Transmission Tariff
RPS – Renewable portfolio standards
RTO – Regional Transmission Operator
WAPA – Western Area Power Administration
WECC – Western Electricity Coordinating Council

Background

Renewable portfolio standards in place today will more than double the amount of renewable resources in the Western U.S. by 2022, compared to 2010.[1] States established these policies for a variety of reasons, from local economic development to environmental concerns, to greater fuel diversity and lower energy costs in the long run.

Wind and solar are the main resources utilities are tapping to meet these standards. Electric output from wind and solar generating plants varies over the day and by season due to the natural forces they rely on. Electric system operators (utilities, federal power marketing administrations and independent system operators) must balance variable generation along with other resources to meet electric loads reliably and affordably.

There is no universally agreed upon method to calculate the integration costs for wind and solar resources associated with their variability (the range of expected generation) and uncertainty (when and how much generation will change). Typically, operational integration studies use production cost tools to model a "base case" without these resources and compare it to one or more wind and solar cases to determine the impact on system fuel and operating costs, reserve requirements and operation of other generating plants. While the difference in total system costs between these cases can be calculated with reasonably high confidence, it is difficult to separate integration costs for wind and solar from the value of the energy produced. Further, conventional forms of generation also impose integration costs on the power system.[2,3] Identifying measures that result in overall lower integration costs for wind and solar is complicated by the challenge of quantifying integration costs under current and future operating practices.

Retail electric customers ultimately pay the costs of renewable (and other) resources and integrating them into the grid, whether they are utility-owned power plants or purchased power. Western utilities, transmission providers and subregional groups are testing and implementing a host of ways to reliably integrate renewable resources at lower cost.[4,5] These entities have significant advantages for managing

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[1] Heidi Pacini, Western Electricity Coordinating Council, "TEPPC 2022 Common Case – Conventional and Renewable Resource Assumptions," Feb. 10, 2011, http://www.wecc.biz/committees/BOD/TEPPC/20120106/default.aspx?InstanceID=1.

[2] Michael Milligan, Erik Ela, Bri-Mathias Hodge, Brendan Kirby (consultant) and Debra Lew, National Renewable Energy Laboratory (NREL); Charlton Clark, Jennifer DeCesaro and Kevin Lynn, U.S. Department of Energy (DOE), *Cost-Causation and Integration Cost Analysis for Variable Generation,* NREL Technical Report NREL/TP-5500-51860, http://www.nrel.gov/docs/fy11osti/51860.pdf.

[3] "Large generators impose contingency reserve requirements, block schedules increase regulation requirements, gas scheduling restrictions impose costs on other generators, nuclear plants increase cycling of other baseload generation, and hydro generators with dissolved gas limitations create minimum load reliability problems and increased costs for other generators." *Id.* at 34. For example, the proliferation of large, inflexible nuclear plants in the 1970s and 1980s prompted a raft of pumped storage projects to address ramping challenges.

[4] The Western Electricity Coordinating Council (WECC) is the regional entity designated by the North American Electric Reliability Corporation for coordinating and promoting bulk electric system reliability in the interconnection. WECC also coordinates the operating and planning activities of its members. A paper by WECC's Variable Generation Subcommittee outlines ways electricity markets could facilitate integration and voluntary efforts in the Western Interconnection: "Electricity Markets and Variable Generation Integration" (January 2011) and addendum (April 2012): http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/WECC%20Whitepaper%20-%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf and http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/2012%20Addendum%20-%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf.

[5] Cost savings in the power sector have wide ranging impacts on the economy as a whole. See Appendix B at end of this report, "Economic Impacts of Electric System Savings."

operational issues, compared to generators, using a portfolio approach to grid management. With wind and solar now beyond the infancy phase, much more can be done to integrate these resources at lower cost as they scale up under current policies and beyond.

Higher levels of variable generation require improved integration approaches, including new operational and market tools as well as flexible demand- and supply-side resources. Drawing from existing studies and experience to date, this report describes these approaches and status in the West, identifies barriers to adoption and gaps in understanding, and makes recommendations for consideration by Western states for further progress. The report focuses on ways to improve the operational integration of wind and solar into power system operations in the Western U.S. It does not address transmission expansion needs or costs or evaluate the contribution of wind and solar to resource adequacy.

The report is organized into nine chapters, each covering an action that holds significant promise for improving integration of renewable resources in the region:

1. Expand subhourly dispatch and intra-hour scheduling
2. Facilitate dynamic transfers between balancing authorities
3. Implement an energy imbalance market
4. Improve weather, wind and solar forecasting
5. Take advantage of geographic diversity of resources
6. Improve reserves management
7. Retool demand response to complement variable generation
8. Access greater flexibility in the dispatch of existing generating plants
9. Focus on flexibility for new generating plants

While any of these actions may be put in place independently of one another, all are important elements of a regional approach to low-cost integration. In addition, the extent to which any of these actions is undertaken, and therefore its costs and benefits, depends in part on the level of adoption of other actions. Further, many of these tools have important synergies (for example, forecasting, scheduling and reserves management). While this report is directed at large-scale wind and solar deployments, many of these recommended actions would improve integration of distributed generation. These measures would improve grid reliability as well, even if no wind or solar generation is added to the system.

A consistent theme running through the paper is the need for greater cooperation among utilities, states, subregions and federal entities to share resources, loads and transmission in order to take advantage of least-cost strategies to integrate renewable resources. The West has a strong tradition of collaboration on energy projects – consider the many jointly owned power plants and power lines in the region. Reserve-sharing groups and regional transmission expansion planning are other examples. And recently, the Northwest Power Pool (composed of 20 balancing authorities covering all or part of seven U.S. states and two Canadian provinces) established a Market Assessment and Coordination Committee to address the operational challenges of integrating variable generation, ranging from enhanced bilateral subhourly markets to a centralized energy imbalance market. Such coordination is the key, including efforts that extend Western Interconnection-wide.

Working together, Western states can help break down institutional barriers that stand in the way of a less costly, more reliable and cleaner power system for residents and businesses. Progress on measures described in this report should be reported regularly to states and regulators and analyzed for their efficacy.

Key electric industry terms are defined throughout the paper. Glossaries produced by the North American Electric Reliability Corporation (NERC)[6] and U.S. Department of Energy (DOE)[7] also may be useful.

[6] NERC, "Glossary of Terms Used in NERC Reliability Standards," updated Feb. 8, 2012, http://www.nerc.com/files/Glossary_of_Terms.pdf.

[7] U.S. Department of Energy, Energy Efficiency & Renewable Energy – Solar Energy Technologies Program, "Electric Market and Utility Operation Terminology," May 2011, www.solar.energy.gov/pdfs/50169.pdf.

Chapter 1. Expand Subhourly Dispatch and Scheduling*

Economic dispatch is the process of maximizing the output of the least-cost generating units in response to changing loads. *Scheduling* is the advance scheduling of energy on the transmission grid. Power system operators continuously manage both dispatch and scheduling to balance loads and resources.

Subhourly dispatch refers to changing generator outputs at intervals less than an hour, for example, every five minutes or every 30 minutes. Intra-hour scheduling refers to transmission customers changing their transmission schedules at intervals less than an hour. Greater use of subhourly dispatch and intra-hour scheduling in the West's bilateral markets could allow generators to schedule their output over shorter intervals and closer to the scheduling period, effectively accessing existing generator flexibility that is not available in most of the West today.

How Do Subhourly Dispatch and Intra-hour Scheduling Work?

The *pro forma* open access transmission tariff (OATT) under Federal Energy Regulatory Commission (FERC) Order 890 requires transmission customers to schedule firm point-to-point service on an hourly basis by 10 a.m. and non-firm transmission service by 2 p.m. the day before service is required, or in a reasonable time generally accepted by the region and consistently adhered to by the transmission provider. Schedules submitted after these times must be accommodated if practicable. Transmission providers have the discretion, but are not required, to accept schedule changes no later than 20 minutes before real-time (the actual hour of operations).[8] The *pro forma* tariff represents FERC's minimally accepted conditions. Individual transmission providers can petition FERC for deviations from the *pro forma* tariff as long as the deviations are comparable or superior to the *pro forma* tariff provisions.

Outside of Regional Transmission Organization (RTO)[9] areas, most transmission within balancing authority areas is through network transmission service; transmission between balancing authority areas ("interchange") is through firm or non-firm transmission service. (See text box, "Types of Transmission Service.")

Transmission in the West typically follows a set schedule for each hour, established an hour or more ahead of service. Because changes are allowed only for unanticipated events, changes in electricity demand within the hour cannot be met with changes in schedule. Therefore, transmission providers must carry enough reserves to cover the largest potential contingency during that hour, even if it is only for a short period of time. Intra-hour transmission scheduling would allow transmission providers to change schedules to better match load and hold lower amounts of reserves during the hour.

Most RTOs[10] dispatch generation within their footprint on a subhourly basis (at five minute intervals) and coordinate transmission scheduling with generation dispatch, instead of arranging them separately.

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* **Lead authors: Sari Fink and Kevin Porter, Exeter Associates; Lori Bird, National Renewable Energy Laboratory**

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

[9] An RTO is an independent organization that has functional control of transmission operations but does not own the underlying transmission assets. An RTO administers an OATT and may also operate day-ahead and real-time energy markets, ancillary service markets and capacity markets. There are seven RTOs in the U.S.: California Independent System Operator; Midwest Independent Transmission System Operator; Southwest Power Pool; Electric Reliability Council of Texas; PJM Interconnection; New York Independent System Operator; and Independent System Operator of New England.

[10] An exception is the Southwest Power Pool (SPP), which has a bilateral energy market and a regional OATT. SPP recently filed a petition with FERC to convert to a locational marginal pricing energy and ancillary services market by 2014.

Transactions *between* RTOs, or between an RTO and a generator outside the RTO footprint, generally are scheduled on an hourly basis. However, some regions have implemented intra-hour scheduling across balancing authority areas. For example, PJM and the Midwest Independent Transmission System Operator (Midwest ISO) have implemented intra-hour scheduling across their interties.[11] Other RTO areas are considering moving to intra-hour regional scheduling while weighing cost considerations.[12]

In 2010, FERC issued a Notice of Proposed Rulemaking (NOPR) for integration of variable energy resources (VERs).[13] Among other things, the proposed rules would require FERC-regulated transmission providers to offer all transmission customers the *option* to submit schedule changes in intervals of 15 minutes or less and to submit intra-hour schedules up to 15 minutes before the scheduling interval. Note that the proposed rules would not require intra-hour transmission schedules as the norm. Transmission providers would be free to offer scheduling at shorter intervals. FERC stated that this requirement, along with other reforms, is needed to "ensure that the services provided are not structured in an unduly discriminatory manner."[14]

FERC also preliminarily determined that the lack of 15 minute scheduling opportunities may be leading to higher generator imbalance charges for transmission customers and reserve costs for transmission providers. FERC states, "Accordingly, a public utility transmission provider may not require different volumes of generator regulation service from transmission customers delivering energy from VERs as opposed to conventional generators without implementing intra-hourly scheduling and power production forecasting as discussed in this Proposed Rule."[15] FERC acknowledged regional differences and sought additional comments on how to implement intra-hour scheduling and support efforts already underway.

[11] Transmission lines that link balancing authority areas.
[12] ISO/RTO Council, *Briefing Paper: Variable Energy Resources, System Operations and Wholesale Markets*, August 2011, http://www.isorto.org/atf/cf/%7b5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7d/IRC_VER-BRIEFING_PAPER-AUGUST_2011.PDF.
[13] FERC, 133 FERC ¶ 61,149, 18 CFR Part 35, *Integration of Variable Energy Resources*, Docket No. RM10-11-000, Nov. 18, 2010, http://www.ferc.gov/whats-new/comm-meet/2010/111810/E-1.pdf.
[14] *Id.* at 10.
[15] *Id.* at 75.

Types of Transmission Service

Traditionally, transmission providers have used firm transmission service. *Firm point-to-point transmission service* is available on an around-the-clock basis. *Non-firm transmission service* can only be used when transmission service is available and for periods ranging from one hour to one month, with adjustments to the schedule by the transmission provider as needed. Most wind generation that requires transmission from the point of interconnection to the point of delivery in another area relies on long-term firm transmission service contracts. *Network transmission*, another type of service, allows a load-serving customer such as a transmission-dependent utility to integrate load and generation resources over a certain area without having to make multiple firm transmission arrangements. FERC Order 888, issued in 1996, required all transmission providers to provide non-discriminatory transmission service.

FERC Order 890, issued in 2007, introduced *conditional firm transmission service*, which allows transmission schedules to be curtailed under certain limited conditions and during those few hours of the year when transmission service is projected to be unavailable. Conditional firm service was intended to alleviate the "all or nothing" situation associated with long-term firm transmission service. However, Order 890 defined the duration of conditional firm service contracts as two years, which has proved to be a limitation for wind developers seeking financing. Thus, while conditional firm transmission service has been added to OATTs in the West, the service has not been used to any great extent. An exception is Bonneville Power Administration (BPA), which has about 1,100 MW of conditional firm service agreements in place.[16]

Transmission services can be offered in increments less than an hour to complement wind integration. BPA recently removed the limitations on its intra-hour scheduling program and now allows all types of transmission services to be scheduled on the half-hour. Similarly, the Joint Initiative's[17] standards do not limit the type of transmission service that can use half-hour schedules, and the webExchange program (see next text box) allows scheduling changes for all types of transmission services.

Where Have Subhourly Dispatch and Intra-hour Scheduling Been Used?

In the Western Interconnection, only the Alberta Electric System Operator (AESO) and CAISO have fully implemented subhourly dispatch. CAISO dispatches resources within its balancing authority area that have submitted economic bids at five minute intervals in the real-time market. CAISO generally uses hourly scheduling at its interties into and out of its balancing authority area. However, CAISO dispatches dynamic transfers (dynamic schedules and pseudo-ties) of conventional resources (located outside of the CAISO balancing authority area) at five minute intervals similar to internal generation, and dispatches dynamic transfers of variable resources located outside of the CAISO footprint at five minute intervals to follow changes in their available output.

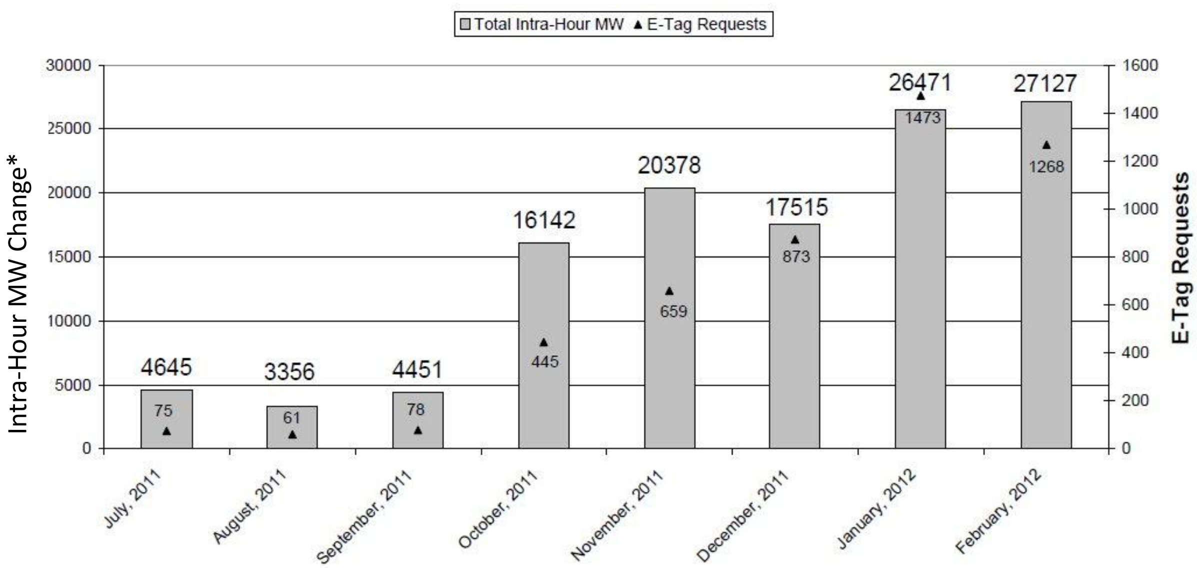
CAISO has a pilot program to test intra-hour scheduling over interties with BPA. Launched in October 2011, the pilot program allows energy from wind resources in the BPA balancing authority area to be scheduled into CAISO on the half-hour. Participants can update the second half of their hourly schedules either up or down, and BPA adjusts their schedules into CAISO accordingly. The pilot program will run

[16] Communication with Elliot Mainzer, BPA, March 31, 2012.
[17] Representatives from ColumbiaGrid, Northern Tier Transmission Group and WestConnect formed the Joint Initiative in 2008 to pursue projects that benefit from broader expertise and a more regional approach.

initially for one year and is limited to 400 megawatts (MW).[18] Both BPA and CAISO are hoping to expand the program over time. Dynamic transfers and intra-hour scheduling operate under CAISO's Dynamic Scheduling Protocol.[19]

BPA has conducted other intra-hour scheduling pilots in recent years. In December 2009, BPA began allowing wind generators to create new non-firm transmission schedules at the half-hour for exporting excess power. BPA later broadened the pilot to include non-firm schedules for non-wind exports along with imports, wheel-through schedules (where energy is transmitted through the BPA system but does not serve BPA customer utilities), and schedules within its balancing authority area. In September 2011, BPA removed the previous limitations on intra-hour scheduling changes and expanded the program to include firm schedules and allow decreases to any schedule. BPA has seen a substantial increase in use of intra-hour scheduling with the latest changes. More than 27 gigawatts of scheduling changes were requested in February 2012 alone (see Figure 1).[20]

Figure 1. BPA Intra-hour Scheduling Volume[21]



Under BPA's recently launched Committed Intra-hour Scheduling Pilot, participants routinely submit schedules every 30 minutes, instead of voluntarily submitting schedule changes as needed. The Committed Intra-hour Scheduling Pilot runs from October 2011 to September 2013 and is limited to 1,200 MW of capacity. Participants will receive a 34 percent reduction in their Variable Energy Resource Balancing Service rate,[22] equal to the reduction in need for balancing reserve that could be achieved by moving wind to half-hour scheduling (see Table 1). BPA anticipates that Committed Intra-Hour Scheduling will become much more broadly used in the future because it provides demonstrable

[18] BPA Business Practice: *CAISO Intra-Hour Scheduling Pilot Program, Version 1*, effective Nov. 11, 2011, http://transmission.bpa.gov/ts_business_practices/.
[19] See Dynamic Scheduling chapter.
[20] BPA Phase II & III Intra-Hour Report, Feb. 2, 2012, http://transmission.bpa.gov/wind/intra-hour/Phase_II_and_III_Intra-Hour_Report.pdf.
[21] BPA Phase II and III Intra-Hour Report, April 23, 2012, http://www.columbiagrid.org/ji-nttg-wc-documents.cfm.
[22] BPA Administrator's Final Record of Decision, 2012 Wholesale Power and Transmission Rate Adjustment Proceeding, July 2011, p. 462, http://www.test.bpa.gov/corporate/RateCase/2012/docs/BP-12-A-02.pdf.

balancing reserve savings and eliminates some of the double-carrying of capacity that takes place when variable energy resources are exported on a firm basis from one balancing authority area to another.

Table 1. Estimated Reduction in BPA Reserve Needs With Committed Intra-Hour Scheduling for Wind[23]

Installed Wind Capacity	60 Minute Scheduling		30 Minute Scheduling		Change in Reserves Needs	
TOTAL	INC	DEC	INC	DEC	INC	DEC
4,693 MW	620 MW	-856 MW	417 MW	-560 MW	202 MW (32.6%)	296 MW (34.6%)

Note: BPA's studies assume that only wind schedules move from a 30-minute persistence hourly schedule (30/60) to a 30-minute persistence half-hour schedule (30/30). The studies assume that load and all other generation (hydro and thermal) remain on hourly schedules.[24]

Participants in the Committed Intra-hour Scheduling Pilot must meet 30-minute persistence scheduling requirements but are exempt from persistent deviation penalties.[25] Portland General Electric and Snohomish PUD participate in the pilot. Portland General Electric submits 30 minute schedules for 450 MW of wind it operates within the BPA footprint; Snohomish PUD submits 30 minute schedules for 97 MW of wind. As a result, BPA will be able to reduce up-balancing reserves by 23 MW and down-balancing reserves by 34 MW.[26]

Joint Initiative

The Joint Initiative was formed in mid-2008 by representatives of ColumbiaGrid, the Northern Tier Transmission Group and WestConnect.[27] The Joint Initiative is a development forum where participants discuss matters such as standard business practices and procedures for intra-hour scheduling. Participation is voluntary and not intended as a move to intra-hour scheduling as a mandatory standard practice.[28] Actual intra-hour scheduling practices and requirements of participating transmission providers vary.

Goals of the Joint Initiative's intra-hour scheduling efforts are: (1) allow for within-hour schedule changes to address unanticipated generation patterns and (2) make better use of capacity within and between balancing authority areas through bilateral transactions with shorter scheduling timeframes. No limitations are placed on the type of transaction (import, export or wheel-through). The Joint Initiative is developing recommended intra-hour scheduling practices in two steps. Step 1 is intra-hour scheduling on the half hour for both new transactions and schedule adjustments. Step 2 is reviewing how Step 1 recommendations worked in practice and determining whether scheduling on a time interval shorter than 30 minutes would be beneficial and whether it is needed.

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[23] Data from Frank Puyleart, BPA, March 13, 2012.

[24] BPA defines 30-minute persistence scheduling as the generator's one minute average of actual generation 30 minutes prior to the scheduling interval. For example, the generator's schedule for 2:00 to 2:30 is the generator's actual average generation from 1:29 to 1:30. See "Schedule Accuracy Metrics" at http://transmission.bpa.gov/ts_business_practices/Content/7_Scheduling/Committed_IntraHour_Sch.htm.

[25] BPA Business Practice, *Committed Intra-Hour Scheduling, Version 2*, effective Dec. 20, 2011, http://transmission.bpa.gov/ts_business_practices/.

[26] BPA news release, "New pilot saves customers money and reduces BPA reserve requirements," Feb. 3, 2012.

[27] Currently, the Joint Initiative's projects include intra-hour scheduling; dynamic scheduling; using historic power flow ratings for transmission-constrained paths; and the Intra-Hour Transaction Accelerator Platform, discussed later in this chapter.

[28] Kristi Wallis, "Joint Initiative Update," presentation to the WECC Interchange and Accounting Subcommittee, Jan. 11, 2012, http://www.wecc.biz/committees/StandingCommittees/OC/ISAS/011912/default.aspx?InstanceID=1.

Currently, the following Western Interconnection transmission providers and balancing authorities outside of CAISO and AESO have implemented intra-hour scheduling: Avista, BPA, BC Hydro, Grant County PUD, Idaho Power Company, NorthWestern Energy, NV Energy, PacifiCorp, Portland General Electric, Public Service of Colorado, Public Service of New Mexico, Puget Sound Energy, Salt River Project, Seattle City Light, SW Transco, Tacoma Public Utilities and Western Area Power Administration (WAPA) - Rocky Mountain region. The majority of these providers have implemented the standardized practices developed by the Joint Initiative, although some offer additional flexibility (e.g., Puget Sound Energy) and others less flexibility (e.g., Public Service of New Mexico, Salt River Project, SW Transco and WAPA).

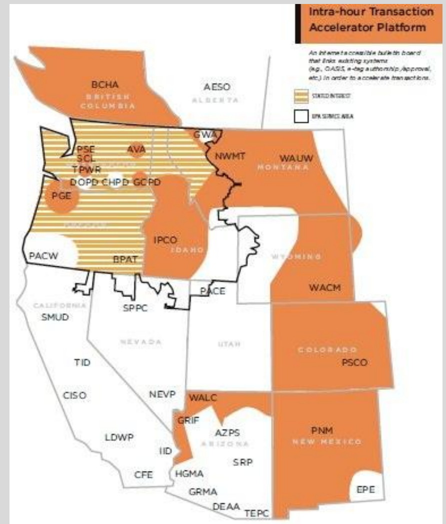
Intra-hour scheduling practices are not harmonized in the Western U.S. For example, some transmission providers allow only increases from hourly schedules, while others also allow decreases. In addition, some entities allow transmission customers to submit multiple schedules for the hour, for example, two 30-minute schedules, but no changes to those schedules during the hour. In other places in the U.S., transmission customers can change schedules every five minutes. Another key difference is whether intra-hour scheduling is voluntary or transmission customers are required to update their schedules at each interval. (See Table 2.) The lack of standardization between balancing authority areas limits the ability to use intra-hour scheduling and ultimately limits its potential value.

Table 2. Intra-Hour Scheduling Practices[29]

	When Locked Down?	When Activated?	Rolling?	Standard Protocols?	Bilateral or Market-wide?
Joint Initiative Transmission Providers and Balancing Authorities	15 minutes past the top of the hour	Any reason, although specifics differ by transmission provider/balancing authority	No	Yes	Bilateral
Western Standard Practice	Top of the hour	Focus on unusual events	No	No	Bilateral
Eastern RTO/ ISO Target Coordination	15 minute advance	Standard practice	Yes	Yes	Market-wide
Energy Imbalance Market	10 minute advance	Standard practice	Yes	Yes	Market-wide

[29] Adapted from Michael Milligan, "Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge," presentation to joint meeting of the State-Provincial Steering Committee and Committee for Regional Electric Power Cooperation, April 3, 2012. http://www.westgov.org/wieb/meetings/crepcsprg2012/briefing/present/l_schwartz.pdf.

Intra-Hour Transaction Accelerator Platform Project (I-TAP)[30]



The Joint Initiative established the I-TAP project to enable intra-hour trades and market flexibility through visibility, faster processing and scheduling of transactions. The resulting webExchange system is an electronic bulletin board for scheduling energy and capacity transactions and requests for transmission that went into service in November 2011. Instead of the traditional practice of phoning around to find market participants for bilateral trades, this transparent bulletin board allows all participants to see available bids and offers. The webExchange board is not a centralized market for energy; it simply facilitates a more efficient bilateral market.

WebExchange is primarily intended for current and next hour transactions, but participants can post a bid or offer of any duration. Potential buyers and sellers can indicate if they are willing to negotiate and can discuss price and non-price conditions by text message. Offers are anonymous until the parties choose to reveal their identities or transactions are finalized through bilateral contracts between buyer and seller. WebExchange displays available transmission capacity by transmission provider, which can be procured without going through individual OATT sites. Participants click once and webExchange automatically submits a transmission request and creates the e-Tags for the transaction.[31]

Participation in webExchange is voluntary and requires a subscription fee. As of January 2012, 16 utilities, one renewable energy generator and BPA subscribed to webExchange, with BPA the largest user.[32] Transactions began in November 2011. Enhancements are being considered, such as supporting a regional balancing capacity market through the same platform.[33]

Further implementation of intra-hour scheduling can be achieved through a FERC requirement applicable to all parties, a FERC requirement to offer the option of intra-hour scheduling, continued development of voluntary intra-hour scheduling initiatives, or voluntary changes to OATTs.

How Do Subhourly Dispatch and Intra-hour Scheduling Reduce Costs and Provide Other Benefits?

While most transmission in the Western Interconnection is scheduled in hourly intervals, output from variable energy resources changes within the hour. With few exceptions, interchange schedules between balancing authority areas in the West change only at the top of the hour, with a 20-minute

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[30] Unless otherwise indicated, information in this section is from Charles Reinhold, "Joint Initiative Update," presentation before the WECC Seams Issues Subcommittee, Feb. 2, 2012. Map courtesy of Northwest & Intermountain Power Producers Coalition.

[31] E-tags document the planned physical flow, transmission allocations and financial trading path of an energy schedule.

[32] Besides BPA, the subscribed participants are Avista, Eugene Water and Electric Board, Grant County PUD, Idaho Power, Iberdrola, NorthWestern, PacifiCorp, Portland General Electric, PowerEx, Public Service Company of New Mexico, Puget Sound Energy, Snohomish County PUD, Seattle City Light, Tacoma Power, Tri-State, Western Area Power Administration and Xcel Energy.

[33] BPA, "Traders Swap Electrons on New Online Platform," Dec. 8, 2011, http://www.bpa.gov/corporate/BPANews/ArticleTemplate.cfm?ArticleId=article-20111208-01.

ramping window (starting 10 minutes before the top of the hour) during which generation moves to its new output level. All deviations from the schedule must therefore be managed within each individual balancing authority area using its own regulating resources—generators on automatic generation control. These same units, representing only a small subset of all generators in the balancing authority area, must manage all of the variability of wind, solar and load that occurs between successive dispatches. Other generators, even if they are physically available to respond and more economic than the regulating units, are not allowed to respond because their schedules are set for the hour.

Subhourly economic dispatch as a standard practice, where generators are routinely dispatched at short time intervals, improves the efficiency of balancing. Subhourly dispatch enables other available generators that can economically respond to do so. In regions where all dispatch is subhourly (five-minute intervals is now standard practice in U.S. RTOs), the entire generation fleet can contribute to balancing the system. This significantly reduces movements of the regulating units and makes operation more efficient. In addition, having more flexible generators available to the balancing authority to manage variability means that more wind and solar can be integrated into reliable power systems operation.

As a complement, intra-hour transmission scheduling allows variable (and other) energy resources to schedule more accurately. In turn, system operators can optimize dispatch more frequently, reducing minute-to-minute deviations between load and generation and thus the amount of balancing energy and regulation reserves needed. System operators can instead access other types of reserves at lower cost rather than being forced to rely on regulation energy to meet imbalances. [34]

Integration Studies vs. Standard Practice in the West

Integration studies look at the costs and benefits of adding increasing levels of variable resources to a particular power system. Many of these studies assume that subhourly generator dispatch, transmission scheduling, balancing and settlement are implemented as standard practice on a system-wide basis. Therefore, information from these studies should be viewed with the understanding that most of the benefits are derived by moving to a mandatory intra-hour regime where generators are dispatched and transmission schedules are updated at shorter time intervals as a standard practice.

Current initiatives in the West treat subhourly generator dispatch and intra-hour transmission scheduling as separate topics. A system-wide regime including dispatch, scheduling, balancing and settlement – all implemented at the same shorter time interval – yields the maximum benefits.

Other benefits of intra-hour transmission scheduling as a standard practice include the ability to better manage generator imbalance penalties. Even in the absence of large amounts of wind and solar, scheduling flexibility helps generators mitigate imbalance penalties when a conventional generating plant that is selling energy off-system has an unexpected outage. More frequent scheduling also gives transmission providers more accurate information for operation and unit commitment, as well as for harmonizing information on known events (e.g., a unit tripping) with information in the transmission scheduling system. In addition, intra-hour scheduling allows more efficient use of available transmission

[34] Jennifer DeCesaro and Kevin Porter, *Wind Energy and Power System Operations: A Review of Wind Integration Studies to Date*, NREL/SR-550-47256, December 2009, http://www.nrel.gov/docs/fy10osti/47256.pdf.

capacity and enables operators to fully use the inherent flexibility of the existing generation fleet. That makes it easier to maintain system balance and reduces ancillary service needs.[35]

While intra-hour scheduling increases the cost of managing the system, the increased system efficiency and lower reserve requirements produce a net benefit.[36] As noted earlier, BPA calculated that a commitment to half-hour scheduling for wind would allow a 34 percent reduction in BPA's integration rate due to the reduction in reserves it would need to carry. BPA offers the reserve reduction only to those entities participating in the Committed Intra-hour Pilot where scheduling updates are mandatory. Implementing *optional* intra-hour scheduling alone is not likely to result in a persistent and significant reduction in overall reserve requirements.

Intra-hour transmission scheduling can be internal to a balancing authority area or across the interties (connections) between balancing authority areas. These interties often are constrained. Intra-hour scheduling across interties, particularly where transmission constraints exist, would enable more efficient integration of variable generation through faster and coordinated dispatch with neighboring balancing authority areas. The benefits of intra-hour scheduling between interties are greater with increasing levels of variable generation.[37]

Integration studies have found lower costs in areas with faster dispatch. Table 3 shows that integration costs in studies for RTO areas with five or 10 minute dispatch ranged from zero to about $4 per megawatt-hour (MWh), while areas with hourly dispatch had integration costs of about $8 to $9 per MWh. RTO areas have lower integration costs due, in part, to faster dispatch intervals and larger balancing authority areas, which provide access to more balancing resources.[38] Xcel Energy reports that in its balancing authority area in the Midwest ISO, wind increased from 400 MW to 1,200 MW without any change in the utility's flexibility reserves or regulation requirements because of five-minute dispatch.[39]

Table 3. Wind Integration Cost Studies: ISO/RTO Regions With Subhourly Dispatch vs. Bilateral Markets With Hourly Dispatch[40]

Study Date	Region	ISO or RTO?	Wind Capacity Penetration	Integration Cost: $/MWh of Wind Output	Energy Market Interval
3/05	NYISO	Yes	10%	Very low	5 minute
12/06	Minnesota/MISO	Yes	31%	$4.41	5 minute
2/07	GE/Pier/CAIAP*	Yes	33%	$0–$0.69	10 minute
3/07	Avista	No	30%	$8.84	1 hour
3/07	Idaho Power	No	30%	$7.92	1 hour

* The study assumed a renewable resources mix of two-thirds wind and one-third solar.

[35] Michael Milligan, Erik Ela, Bri-Mathias Hodge, Brendan Kirby (consultant) and Debra Lew (NREL); Charlton Clark, Jennifer DeCesaro and Kevin Lynn (DOE), *Cost-Causation and Integration Cost Analysis for Variable Generation*, NREL Technical Report NREL/TP-5500-51860, http://www.nrel.gov/docs/fy11osti/51860.pdf.
[36] Michael Milligan and Brendan Kirby, *Market Characteristics for Efficient Integration of Variable Generation in the Western Interconnection*, NREL Report, August 2010, http://www.nrel.gov/docs/fy10osti/48192.pdf.
[37] ISO/RTO Council, *Briefing Paper: Variable Energy Resources, System Operations and Wholesale Markets*, August 2011, http://www.isorto.org/atf/cf/%7b5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7d/IRC_VER-BRIEFING_PAPER-AUGUST_2011.PDF.
[38] ISO/RTO Council, *Increasing Renewable Resources: How ISOs and RTOs Are Helping Meet This Public Policy Objective,* Oct. 16, 2007, http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_Renewables_Report_101607_final.pdf.
[39] Communication with Stephen Beuning, Xcel Energy, April 16, 2012.
[40] Data source: ISO/RTO Council, 2007.

CAISO Integration Studies

In the West, the CAISO power system and wholesale markets will facilitate integration of the majority of in-state California wind and solar resources, as well as some portion of out-of-state resources scheduled to serve California load-serving entities. In a series of integration studies, CAISO has been evaluating operational requirements to support development of new wholesale market products and advise the California Public Utilities Commission (CPUC) in its long-term procurement planning process for regulated utilities and possible reforms of its resource adequacy program.

A study of the CAISO system under a 20 percent renewable portfolio standard (with approximately 6,700 MW of wind and 2,250 MW of solar), using a model of the California grid with fixed import-export balances based on a historical year, found that total procurement of regulation and load-following reserves would increase by 11 percent to 37 percent, depending on the season. However, both hourly and five-minute dispatch simulations suggested that for almost all hours of the year, the existing natural gas fleet in the CAISO footprint could provide the additional reserves and necessary operational flexibility. The simulations found some evidence of over-generation in spring months under high hydro conditions, which could be relieved by curtailment of inflexible imports (allowing for additional commitment of dispatchable gas plants to provide downward ramping).[41]

Subsequently, CAISO evaluated alternative CPUC renewable resource scenarios for a 33 percent renewable portfolio standard in 2020, modeled on a WECC-wide basis. These studies include some 17,000 MW to 18,000 MW of wind and solar resources serving California, with both in-state and out-of-state resources. Preliminary simulations generally found that integration of wind and solar at these levels is operationally feasible, although at least one sensitivity case suggested that additional flexible generation may be needed.[42] Follow-on analysis is examining further sensitivities on forecast errors, the application of stochastic planning methods, further consideration of reserve sharing with other balancing authority areas and other factors.

The Western Wind and Solar Integration Study[43] (Western study) reinforces the concept that subhourly dispatch and intra-hour scheduling greatly assist the integration of variable renewable generation. The study found dispatch and scheduling at shorter time intervals to be important for minimizing regulation requirements on the system. Figures 2 and 3 show that dispatching generation resources every five or 15 minutes, rather than every hour, substantially reduces the need to ramp generating units for regulation. Figure 3 shows that generation and load are more closely matched with five minute dispatch, reducing the burden on regulating units. Other integration studies internationally also support these findings.[44]

[41] CAISO, *Integration of Renewable Resources – Operational Requirements and Generation Fleet Capability at 20% RPS*, Aug. 31, 2010, http://www.caiso.com/Documents/Integration-RenewableResources-OperationalRequirementsandGenerationFleetCapabilityAt20PercRPS.pdf

[42] CAISO, "Track I Direct Testimony of Mark Rothleder on Behalf of the California Independent System Operator Corporation," Before the Public Utilities Commission of the State of California, Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, Rulemaking 10-05-006, submitted July 11, 2011.

[43] GE Energy, Western Wind and Solar Integration Study, prepared for National Renewable Energy Laboratory, May 2010, http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf.

[44] Corbus, D., D. Lew, G. Jordan, W. Winters, F. Van Hull, J. Manobianco and R. Zavadil, "Up with Wind: Studying the Integration and Transmission of Higher Levels of Wind Power," *IEEE Power and Energy*, 7(6): 36–46, November/December 2009.

Figure 2. Regulation Requirements With Hourly Dispatch[45]

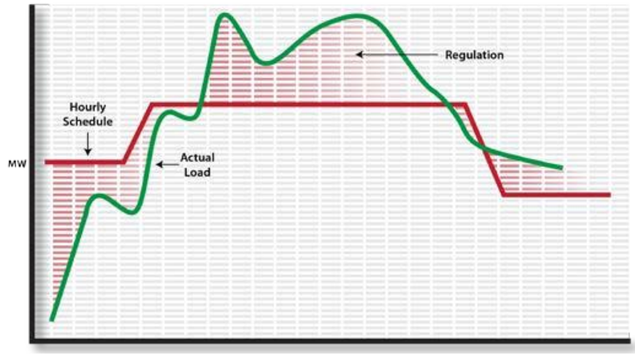
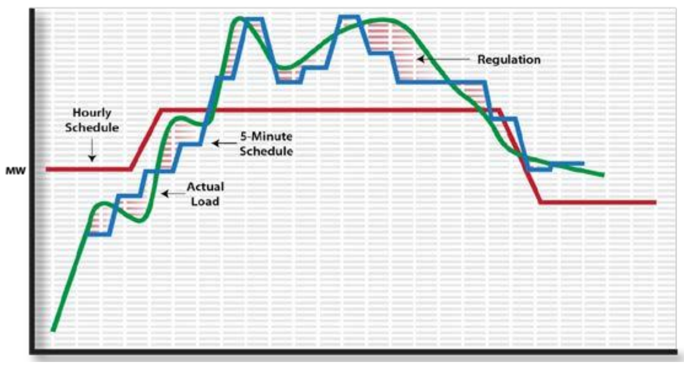


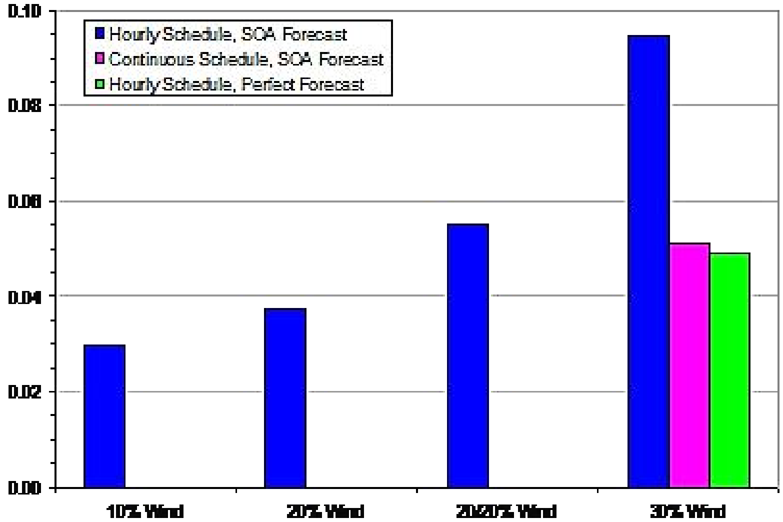
Figure 3. Reduced Regulation Requirements With Subhourly Dispatch[46]



Applying subhourly dispatch and intra-hour scheduling to the high wind/solar case in the Western study cut in half the amount of quick maneuvering of natural gas-fired combined-cycle plants, compared to hourly dispatch and scheduling (See Figure 4). In fact, the amount of fast maneuvering of combined-cycle plants was about the same in the 20 percent renewable energy case with *hourly* dispatch and scheduling and the 30 percent renewable energy case with *subhourly* dispatch and intra-hour scheduling. The study also found that hourly dispatch and scheduling has a greater impact on regulation requirements for the system than the variability caused by wind and solar resources.[47]

[45] National Renewable Energy Laboratory.
[46] *Id.*
[47] Western Wind and Solar Integration Study. The study simulated scheduling practices using seven-day scheduling, rather than the typical Western U.S. practice of five-day scheduling (e.g., Thursday schedules Friday/Saturday, Friday schedules Sunday/ Monday). Forecast error is higher for five-day scheduling, so a small amount of additional reserves may be needed than the study indicates.

Figure 4. Fast Maneuvering Duty of Combined-Cycle Units With Hourly Dispatch and Scheduling vs. Subhourly Dispatch and Intra-hour Scheduling[48]



A survey of grid operators from a variety of countries found that faster dispatch and scheduling leads to more efficient system operations and helps to manage variable wind generation. Respondents that work in areas with and without wholesale electric power markets indicated that frequent generation dispatch and scheduling are effective methods of managing variable renewable generation on the grid. Further, a number of grid operators are working to increase the scheduling frequency between balancing authority areas.[49]

[48] Western Wind and Solar Integration Study.
[49] Lawrence E. Jones, Alstom Grid Inc., *Strategies and Decision Support Systems for Integrating Variable Energy Resources in Control Systems for Reliable Operations: Global Best Practices, Examples of Excellence and Lessons Learned,* prepared for U.S. Department of Energy, December 2011, http://www1.eere.energy.gov/wind/pdfs/reliable_grid_operations.pdf.

Impact of Alternative Dispatch Intervals on Operating Reserve Requirements for Variable Generation[50]

A recent study examined the effects of shorter dispatch intervals and forecast lead times on regulation reserve requirements in the West. The study looked at the impacts on three cases:[51]

1. *Business as usual* (BAU), with each of the balancing authority areas today implementing the operational changes on its own
2. *Footprint*, with cooperation in distinct subregional planning areas – ColumbiaGrid, Northern Tier Transmission Group, WestConnect and British Columbia
3. *Regional*, in which the Western Interconnection is aggregated into a single balancing authority area

The researchers used data from the Western Wind and Solar Integration Study (Western study) and its “In Area” scenario, which assumes renewable portfolio standards are met by resources largely within each state. Further, researchers selected the Western study scenario with 30 percent wind energy in the WestConnect footprint and 20 percent wind energy in the remaining Western Interconnection (not including CAISO and AESO).

The study found that faster dispatch and shorter forecast lead times significantly reduced total regulation requirements regardless of coordination; in other words, a single balancing authority area can capture savings even in the absence of coordination with others. Further, less regulation reserve is needed under the footprint and regional cooperation scenarios, compared to the BAU scenario.

The accompanying chart shows that regulation requirements are reduced significantly under a shorter balancing energy dispatch schedule regardless of the level at which changes are implemented – individual balancing authority area, footprint-wide or Interconnection-wide.[52] For example, moving from a 60 minute dispatch to a 10 minute dispatch results in a 70 percent savings in regulation reserve.

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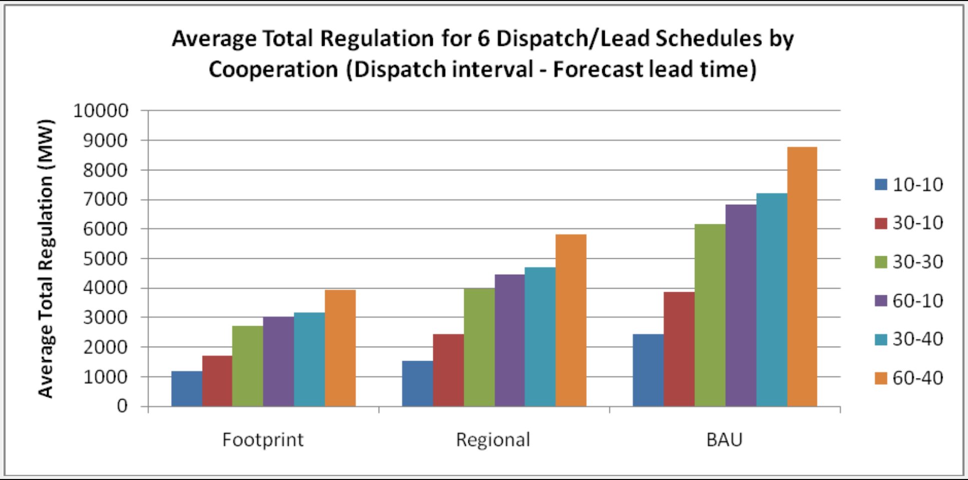
[50] Michael Milligan, Jack King, Brendan Kirby and Stephen Beuning, “The Impact of Alternative Dispatch Intervals on Operating Reserve Requirements for Variable Generation,” 10th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, Aarhus, Denmark, Oct. 25-26, 2011.
[51] California and Alberta were not modeled because organized energy markets and shorter dispatch intervals already are in place in these areas.
[52] In the legend on the right side of the chart, the first number is the dispatch interval, the second number is the lead time on the forecast, both in minutes.



What Are the Gaps in Understanding?

Gaps in our understanding of subhourly dispatch and intra-hour scheduling in the Western U.S. include the following:

- Costs for software development or additional manual controls have not been estimated.[53]
- Most balancing authorities have not evaluated the benefits.
- Inconsistencies in intra-hour scheduling procedures among balancing authorities have not been evaluated.
- No system is in place to make available to others transmission capacity that no longer needs to be set aside due to intra-hour scheduling.

What Are the Implementation Challenges?

Seams issues are among the obstacles to intra-hour scheduling. They include different scheduling intervals in different balancing authority areas and coordination of metering, control center operations and software. To reduce operational complexity and realize the full benefits of intra-hour scheduling, implementation would need to be standardized across the Western Interconnection. The lack of standardization in scheduling intervals, when schedules are locked down, allowed changes and other practices limits the ability to use intra-hourly scheduling and ultimately its value. Moreover, a commitment to use intra-hour scheduling is required, rather than simply the option to do so, to achieve significant efficiency gains.

Implementation costs are another obstacle. Transmission providers in the West have operated on hourly intervals since the grid was first built. Moving to subhourly dispatch and intra-hour transmission schedules would require new operating procedures, training, hardware and software upgrades, and additional personnel. For example, some parties estimate that transmission providers would be required to add five or six new employees each to handle the new procedures under FERC's proposed 15-minute scheduling.[54] Avista estimated that personnel additions alone would add approximately $1.2 million per year to operating costs and noted that for smaller transmission providers the additional costs could be

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[53] ISO/RTO Council, 2011.
[54] FERC filing: *Comments of the Pacific Northwest Parties*, March 2, 2011, Docket No. RM10-11, http://elibrary.ferc.gov/idmws/docket_sheet.asp.

prohibitive.[55] The amount of automation that is needed and the anticipated customer load (the number of customers using intra-hour scheduling) also would impact costs. Current experience with intra-hour scheduling pilots and initiatives indicates that moving to 30-minute transmission scheduling can be relatively low cost. However, implementing a shorter time interval is expected to be more costly.

Putting in place processes to increase scheduling frequency across interties requires substantial coordination across subregions. Current software may not be able to handle intra-hour scheduling across interties. In areas where grid operators perform control room functions using manual controls, there may be a functional limit to the frequency of scheduling while maintaining reliability.[56]

In comments to FERC on the NOPR for variable energy resources, several organizations raised concerns about the voluntary nature of the proposed rule on 15 minute transmission scheduling. They argued that integration studies estimating the benefits of intra-hour transmission scheduling assume implementation would be mandatory and bundled with subhourly dispatch, balancing and settlement. Expected benefits of intra-hour transmission scheduling could be significantly lower in the absence of these requirements.[57] *Optional* 15-minute transmission scheduling as a stand-alone product may not result in significant reductions in overall system reserve requirements. Further, if generators are still required to pay imbalance penalties based on their hourly schedules, even if they update their schedule on the quarter- or half-hour, there is little incentive to use intra-hour scheduling.

On the other hand, transmission providers asked FERC to allow the pilot programs and initiatives in the Western Interconnection to continue moving forward, without imposing a requirement to move to 15 minute scheduling. This would allow transmission providers to develop and implement solutions on their own and provide data on the costs and benefits of intra-hour scheduling.[58]

Another issue is that there is no formal, standard market for intra-hour energy in the West, although utilities can use tools such as webExchange to facilitate intra-hour bilateral trades. Such a market would allow utilities to help manage energy costs.

What Could Western States Do to Address Barriers?

Western states could take the following actions to further develop subhourly dispatch and intra-hour scheduling:

- Encourage expansion of the Joint Initiative's intra-hour scheduling practices to time intervals shorter than 30 minutes.
- Foster standardization of subhourly dispatch and intra-hour scheduling practices among all balancing authorities in the Western Interconnection.
- Evaluate the costs, benefits and impacts of extended pilots on the need for reserves, particularly for regulation.

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[55] FERC Filing: *Comments of Avista Corp.*, March 2, 2011, Docket No. RM10-11, http://elibrary.ferc.gov/idmws/docket_sheet.asp.

[56] ISO/RTO Council, 2011.

[57] Comments submitted to FERC Docket No. RM10-11: *Comments of the Pacific Northwest Parties*, March 2, 2011; *Comments of Avista Corp.*, March 2, 2011; *Comments of Idaho Power Company*, March 2, 2011; *Comments of Tacoma Power*, March 2, 2011, http://elibrary.ferc.gov/idmws/docket_sheet.asp.

[58] *Id.*

- Commission an independent analysis of the estimated equipment and labor costs of transitioning to subhourly dispatch and intra-hour scheduling for all transmission providers in the West. Such an analysis also should estimate the benefits, including projected reductions in regulation and other reserve needs, especially for balancing authorities with large amounts of variable energy resources. In addition, the study should evaluate costs and benefits of intra-hour scheduling operations, such as the following: 1) two 30-minute schedules both submitted at the top of the hour; 2) one 30-minute schedule submitted at the top of the hour and another 15 minutes past the top of the hour; 3) 20-minute scheduling; 4) 15-minute scheduling; and 5) five-minute scheduling.
- Consider strategies for assisting smaller transmission providers to recover costs of transitioning to intra-hour scheduling, such as coordinated operations among multiple transmission providers or phasing in equipment and personnel upgrades over multiple years.
- Explore harmonized implementation of faster dispatch, scheduling, balancing and settlement across the Western Interconnection.
- Allow regulated utilities to recover costs for wind integration charges assessed by a third party at the lesser of the rate charged for intra-hour scheduling or hourly scheduling, if intra-hour scheduling is an available option. Grant cost recovery for software upgrades and additional staff necessary to accommodate intra-hour scheduling.

Chapter 2. Facilitate Dynamic Transfers Between Balancing Authorities*

How Do Dynamic Transfers Work?

Dynamic transfer[59] refers to electronically transferring in real-time the control responsibility for generation from the balancing authority area in which the generator physically resides to another balancing authority area. Such transfers allow generation to be located and controlled in a geographic location that is outside of the receiving balancing authority area. Dynamic transfer involves software, communications and agreements that enable energy resources to be scheduled and used for balancing power demand in an area other than where the generating facility is sited.

Dynamic transfers require the appropriate amount of transmission capacity to be available between locations, as well as agreements between the source and sink balancing authorities.[60] Dynamic transfers also involve requirements for telemetry[61] to provide data, dynamic schedule coordination, system modeling, appropriate transmission service and contingency response.[62] In addition, dynamic scheduling requires available transmission capacity on the transmission path and, in some locations, firm transmission service between the balancing authority areas for the amount of energy to be transferred.

Dynamic transfers are used for a number of reasons. They can allow generators to meet real-time loads in another balancing authority area. Or transfers can enable generators to provide supplemental regulation to balance generation and load, or provide reserve sharing, for another balancing authority area.[63] Importantly for variable generation, dynamic transfers can transfer in real-time a designated portion or all of the output of a generator to another area so that it can be balanced and the variability managed by the authority in that area. For example, a wind generator in Montana could be dynamically transferred to California so that the generator would be balanced by resources in the larger CAISO balancing authority area.[64] Absent dynamic transfers, balancing responsibility remains with the balancing authority area where the facility interconnects, even if the plant schedules the power to be sold in another region. Dynamic transfers can help the Western U.S. use balancing resources for variable generation more efficiently, but they also raise significant challenges.

There are two primary methods for dynamic transfers:

1. *Dynamic scheduling* is commonly used for scheduling portions or all of the output of a power generator from one balancing authority area to another. Dynamic scheduling involves transferring metered generation data remotely and in real-time to another balancing authority area, where it is treated as a schedule in the area control error (ACE) calculation of the receiving

* **Lead author: Lori Bird, National Renewable Energy Laboratory**

[59] Dynamic transfer can be used for either generation or load. This chapter focuses on applications for generation, particularly from variable renewable energy resources.

[60] The source balancing authority is the physical location of the generator; the sink (or receiving) balancing authority is where the load it will serve is located.

[61] Telemetry is the process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations. *See* http://www.nerc.com/files/Glossary_of_Terms.pdf.

[62] NERC, *Dynamic Transfer Reference Guidelines*, June 2010, http://www.nerc.com/docs/oc/is/IS_Dynamic_Transfer_Guidelines_UPDATED_06-02-10.pdf.

[63] *Id.*

[64] Marcus Wood and Jennifer H. Martin, Stoel Rives, "New strategies for moving wind generation from high-wind areas to high-load areas," June 11, 2008, http://www.stoel.com/showarticle.aspx?Show=2974.

balancing authority.[65] ACE is a measure of whether the balancing authority area has enough generation to meet its own operational requirements, considering scheduled and actual flows of energy and scheduled and actual frequency.[66]

2. *Pseudo-ties* are commonly used for dynamically transferring generation across one or more balancing authority areas, but generally the source and sink are in the *same* balancing authority area.[67] The source is typically a balancing authority "bubble" that is located inside another balancing authority area but dynamically metered (via the pseudo-tie) to the sink balancing authority. The real-time generator output is accounted for as a tie-line flow in the ACE equation, but no physical tie actually exists. Pseudo-tie meter data do not appear in the interchange schedule and instead are used as actual metered energy values for interchange accounting.[68]

The primary differences between dynamic schedules and pseudo-ties involve:

- The operational control roles played by the two balancing authorities
- Treatment of the energy in ACE equations and interchange accounting
- Allocation of benefits from system frequency response provided by the generator following power system disturbance
- Which balancing authority area has control over the dispatch of the generator or a portion of it

In the ACE equation, dynamic schedules are accounted for as *scheduled* interchange of power, while pseudo-ties are accounted for as *actual* interchange of power.[69] Dynamic schedules can be used to achieve a real-time exchange of power in situations where scheduling in multi-hour blocks is insufficient. They can be used to meet regulating obligations, to provide power temporarily to meet reserve sharing agreements, or to exchange power to meet demand on a real-time basis.[70]

In contrast, pseudo-ties are generally used to represent interconnections from remotely located generation that is physically in one balancing authority area but "virtually" in the receiving area. Generators using a pseudo-tie are at locations where no direct physical connection exists between the generator and the receiving balancing authority area. The receiving balancing authority has operational and procedural responsibilities for the generator beyond those required for dynamic schedules, such as

[65] Balancing authorities use automatic generation control and perform ACE calculations to achieve generation/load balance. The calculation contains a number of components, including interchange tie line readings and load. ACE is typically calculated every four seconds based on real-time data. After the hour the actual metered generation or integrated energy transfer value appears in the source and sink balancing authorities' interchange schedules.

[66] Dynamic schedules require e-Tags that reference transmission entitlement in an amount that is greater than or equal to their maximum instantaneous energy quantities. The energy quantities in the e-Tags are adjusted after each hour to reflect the actual transfer amount. WECC is developing guidelines for use of E-tags with dynamic transfers. *See* http://www.wecc.biz/Standards/Development/WECC-0087/default.aspx.

[67] For additional information, see C. Loutan, C. Mensah-Bonsu and K. Hoffman, "Pseudo-Tie Generator Model Implementation for California ISO Operations and LMP Markets," *IEEE Transactions on Power Systems*, Vol. 26, No. 3, August 2011, http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=5617330.

[68] NERC, "Glossary of Terms Used in NERC Reliability Standards," updated Feb. 8, 2012, http://www.nerc.com/files/Glossary_of_Terms.pdf; NERC, *Dynamic Transfer White Paper*, April 2003, http://www.nerc.com/docs/oc/is/Dynamic_Transfer_White_Paper_Draft_4.pdf.

[69] NERC, June 2010.

[70] *Id.*

transmission and ancillary services and disturbance control standard recovery.[71] Table 1 summarizes the key differences between pseudo-tie and dynamically scheduled resources, using CAISO as an example.

Table 1. Comparison of Pseudo-Tie and Dynamically Scheduled Resources – CAISO[72]

#	Attributes	Pseudo-tie resource	Dynamically scheduled resource
1	Definition	A telemetered reading or value that is updated in real-time and used as a "virtual" tie-line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. *The integrated value is used as a metered MWh value for interchange* accounting purposes.	A telemetered reading or value that is updated in real-time and used as a schedule in the AGC/ACE equation and *the integrated value of which is treated as a schedule for interchange* accounting purposes. Commonly used for scheduling jointly owned generation to or from another BA area.
2	ACE equation	The dynamic transfer signal is incorporated in the *actual interchange* side of the ACE equation. The PTG energy from the pseudo tie to the designated physical BA area intertie points nets out to a zero MW value. Thus the PTG has no impact on the net scheduled interchange.	The dynamic transfer signal is incorporated in the *net scheduled interchange* (NSI) side of the ACE equation.
3	Frequency response	Any frequency response provided by the PTG following a disturbance counts towards the ISO (attaining) BA area frequency response obligation.	Any frequency response provided, following a disturbance counts towards the native BA area frequency response obligation.
4	Resource dispatch	ISO has real-time dispatch control over the entire resource output and is also able to dispatch it during system emergency conditions.	The ISO will have real time dispatch control over the dynamically scheduled portion of the unit(s) for system reliability purposes.
5	Market scheduling	Submits generation schedules.	Submits interchange schedules.
6	Market settlements	Balancing authority area service charges are handled like any other participating generation resource within the ISO.	BA area service charges are settled like any other interchange schedule.
7	Balancing authority area services	The ISO provides limited balancing authority services (e.g., operating reserves, outage coordination, station power, regulation and balancing energy).	The ISO does not provide balancing authority services.
8	Ancillary services	May contribute towards meeting the ISO BA area's AS requirements including regulation and participates in all AS markets.	Same
9	Intra-hour dispatch and interchange adjustments	Dynamic transfer automates intra-hour dispatch and interchange adjustments for operating reserves, hence no longer restricting energy and ancillary services to be pre-dispatched on an hourly basis.	Same
10	LMP market participation	Counts towards resource adequacy and participates in the ISO co-optimized energy and AS markets.	Same

The dynamic transfer method used for a specific operating arrangement may depend on the service to be provided, the capabilities of the system models and energy management system used by the balancing authorities, and who has responsibility for providing information on unit commitment and maintenance.[73]

[71] *Id.* The Disturbance Control Standard is designed to ensure the balancing authority is able to use its contingency reserve to balance resources and demand and return interconnection frequency within defined limits following a disturbance. Its activation is limited to the loss of supply. *See* http://www.nerc.com/page.php?cid=2%7C20.
[72] Loutan, Mensah-Bonsu and Hoffman.
[73] NERC, June 2010.

CAISO Dynamic Scheduling Protocol

CAISO allows resources to dynamically schedule energy on interties into and out of its balancing authority area under its Dynamic Scheduling Protocol. Previously, CAISO allowed dynamic scheduling only for imports. In November 2011, CAISO expanded its protocol to include exports and pseudo-ties and now allows four types of dynamic transfer transactions:[74]

1) Dynamic schedules of imports from resources into the CAISO balancing authority area
2) Dynamic schedules of exports from generating resources located in the CAISO balancing authority area
3) Pseudo-ties to the CAISO balancing authority area for generating resources in another balancing authority area (CAISO is the entity that receives the energy)
4) Pseudo-ties out of the CAISO balancing authority area for internal generating resources (another balancing authority area receives the energy)

Like imbalances for internal CAISO resources, dynamically scheduled intertie resources and pseudo-ties are cleared on a five-minute basis and settled on a 10-minute basis for energy; ancillary services are cleared and settled on a 15-minute basis. Dynamically scheduled conventional resources and pseudo-ties can deviate from their hourly schedule in response to CAISO dispatch instructions, and CAISO updates its dispatch of variable resources to track changes in their availability. In order to engage in dynamic scheduling, the resource's scheduling coordinator must execute a dynamic scheduling agreement, the host balancing authority must execute an operating agreement with CAISO, and transmission service must be arranged along the entire path of the resource from source to sink. Similar arrangements are required for pseudo-ties.

BPA's Dynamic Transfer Business Practices[75]

Resources can dynamically schedule into or out of BPA's balancing authority area by entering into a dynamic transfer agreement and executing dynamic transfer operating agreements with each balancing authority involved in the transfer. BPA may limit or freeze a dynamic transfer (including ramp rates) into, out of or through its balancing authority area for reliability reasons, even if no other transactions are curtailed. BPA has established limits for dynamic schedules and pseudo-ties based on transmission operating limits[76] within its balancing authority area:

- Dynamic transfer schedules over the California-Oregon Intertie are limited to 200 MW in aggregate from 6 a.m. to 10 p.m. every day and are limited to 550 MW from 10 p.m. to 6 a.m. every day.
- Dynamic schedules over the Northern Intertie are limited to 300 MW in aggregate.
- Dynamic transfers are not allowed over the DC Intertie at this time.

[74] CAISO, *Tariff Amendment to Modify Tariff Provisions Regarding Dynamic Transfers*, filing to FERC under Docket No. ER11-4161.
[75] BPA Business Practices, *Dynamic Transfer Operating and Scheduling Requirements, Version 2*, effective Feb. 22, 2012, http://transmission.bpa.gov/ts_business_practices/Content/7_Scheduling/Dynamic_Transfer_Op_Sched.htm.
[76] The value that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria, based upon certain operating criteria. *See* http://www.nerc.com/files/Glossary_of_Terms.pdf.

Where Have Dynamic Transfers Been Used?

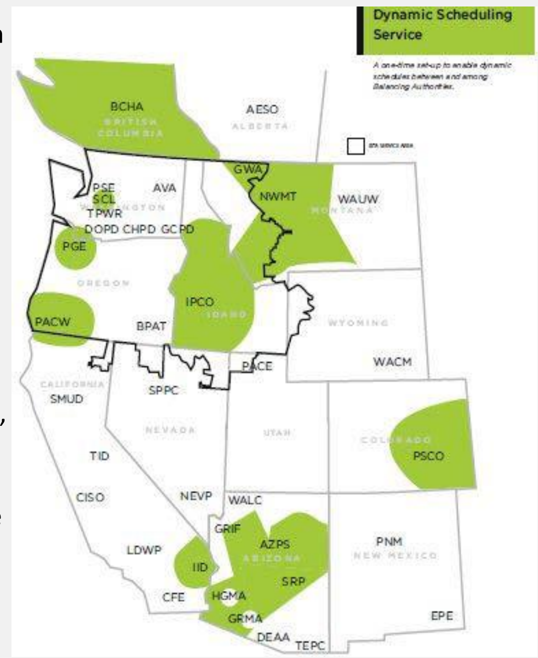
Dynamic transfers have been used for decades, but intra-hour variations in their dispatch have been relatively limited.[77] They can be used for large deliveries of generation over long distances. For example, a 1997 survey found that several utilities conducted dynamic transfers of generation of up to about 1,000 MW each.[78] There can be joint ownership of the energy output from a single physical generator for dynamic scheduling purposes. An example is the hydroelectric energy from the Hoover Dam that Southern California Edison and a number of municipal utilities schedule into California. Most historic dynamic transfers have involved relatively static transfers of power in which there are few fluctuations in power flow levels, in contrast to more recent transfers involving wind generation.

With the growth of wind generation in the Northwest in particular, the number of requests for dynamic transfers has increased in recent years.[79] Dynamically scheduled renewable resources are designated as one of the resource types eligible to meet California's renewable portfolio standards (RPS), so there may be increased interest in the use of dynamic schedules in the future.

Joint Initiative Dynamic Scheduling System[80]

The Joint Initiative created the Dynamic Scheduling System to simplify the process of entering into dynamic transfers in the West. The system allows wholesale electric commodities such as regulation (both down and up), load balancing and load following to be easily exchanged between industry participants.

The project was initiated in 2009 when parties agreed to fund and implement the web-based system.[81] As of October 2011, 18 entities had agreements in place to use the Dynamic Scheduling System: Arizona Public Service Company, BC Hydro, BPA, Grant County PUD, Idaho Power, Imperial Irrigation District, NaturEner USA, NorthWestern Energy, PacifiCorp, Portland General Electric, Powerex, Public Service of New Mexico, Puget Sound Energy, Seattle City Light, Salt River Project, Tri-State, WAPA and Xcel Energy.[82] The system is operational and participation will be able to grow with further testing and configuration, now underway.



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[77] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Dynamic Transfer Capability Task Force, Phase 1 Report*, March 16, 2011, http://www.columbiagrid.org/client/pdfs/DTCTFPhaseFullReport031611.pdf.
[78] E. Hirst and B. Kirby, "Dynamic Scheduling: The Forgotten Issue," *Public Utilities Fortnightly*, April 15, 1997, http://www.pur.com/pubs/2367.cfm.
[79] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Phase 1 Report*.
[80] Map courtesy of Northwest & Intermountain Power Producers Coalition.
[81] ColumbiaGrid, Northern Tier Transmission Group, WestConnect, Invitation to webDynamic Scheduling System/DSS Demonstration, Sept. 15, 2010. www.columbiagrid.org/download.cfm?DVID=1863.
[82] Sharon Helms, "Joint Initiatives Update," presentation to Committee for Regional Electric Power Cooperation and State-Provincial Steering Committee, Oct. 26, 2011.

The system is designed to simplify and speed up the process and reduce the cost of arranging dynamic transfers between balancing authority areas in the Western Interconnection. Participants can exchange dynamic schedules with one another for future short-term and long-term transactions of any size through a single set-up process. In addition, participants can enter into transactions with multiple parties simultaneously. The process reduces the time required to set up future dynamic transfers from months to minutes.

To establish transactions, participants create dynamic e-Tags. Use of e-Tags is standard practice and required for establishing interchange schedules of any type. Participating balancing authorities are informed that there is a virtual generating unit that their Energy Management System can control for the designated transaction period. The system limits dynamic schedules if there are transmission constraints or other reliability limits placed on the e-Tag.[83] Through the system, generating units that are dynamically transferring energy are responsive to automatic generation control signals.[84] After the hour, the aggregate signals for the hour are communicated automatically to participants through adjusted e-Tags. Participation in the system does not require any transmission tariff modification or changes in transmission service practices.[85]

The initial cost of developing the Dynamic Scheduling System was approximately $21,000 per participant (about $400,000 total). Ongoing operation and maintenance costs for existing functionality are approximately $8,000 per month. Participants also incur costs associated with modifying their own energy management systems to be able to interface with the Dynamic Scheduling System.[86] The benefit of a one-time set-up for unlimited future transactions is expected to substantially outweigh the system development cost and maintenance costs for participants going forward.

What Are the Expected Benefits of Dynamic Transfers?

Dynamic transfers facilitate energy and capacity exchanges between balancing authority areas and increase operational flexibility. They allow generators to sell services to entities other than the balancing authority in whose area they physically reside. Also, dynamic transfers enable generation owners with plants in several locations to aggregate output and sell it to a single buyer if transmission is available between all locations.[87] For example, in combination with firm transmission capacity, dynamic transfers allow wind plants in states without an RPS to sell to utilities or electricity markets in states with an RPS and allow the balancing authority in the RPS state to control and use the power to meet system needs. Further, the balancing authority area where the wind interconnects to the power system is not required to balance the variability and uncertainty of wind that it is not using to meet its loads.

Dynamic transfers also enable improved access to balancing resources for wind and solar projects, increasing system flexibility. Similarly, generators may dynamically schedule output to other balancing authority areas to reduce integration costs or imbalance charges.[88]

Dynamic transfers can result in greater geographic diversity for wind and solar facilities. As described elsewhere in this report, greater geographic diversity helps reduce output variability and makes the

[83] ColumbiaGrid, *et al.,* Sept. 15, 2010, www.columbiagrid.org/download.cfm?DVID=1863.
[84] Signals are sent using the Inter Control-Center Communications Protocol.
[85] ColumbiaGrid board meeting, April 15, 2009, www.columbiagrid.org/download.cfm?DVID=1219.
[86] Communication with Sharon Helms, March 9, 2012.
[87] Hirst and Kirby.
[88] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Phase 1 Report*.

variability easier to manage.[89] Dynamic transfers also may result in more efficient use of generating resources if they are transferred to areas with higher loads where the resources can operate more hours of the year. In addition, dynamic transfers can improve market opportunities and lower overall generation costs.[90]

However, even with the use of dynamic transfers, new transmission lines will be needed to accommodate variable energy resources from remote areas in order to access ancillary service capabilities of the sink balancing authority area. The Joint Initiative's Dynamic Scheduling System (see text box in this chapter) allows use of the transmission system to be maximized by enabling shorter duration dynamic schedules. Typical dynamic transfers require *long-term* firm transmission capability. The Dynamic Scheduling System allows use of the transmission system at certain times of the year or certain times of the day. While short-term firm transmission service is required, long-term firm transmission service is not.

A report by the Joint Initiative Infrastructure Strike Team estimated that the Dynamic Scheduling System could result in substantial savings to balancing authority areas by expanding access to regulating and load following resources through increased use of dynamic transfers. Conservatively assuming that 100 MW of additional regulation exchanges were transacted through the system at $3 per MWh (also conservative), the report estimated an annual value of $2.6 million in increased revenues or avoided costs.[91]

What Are the Implementation Challenges?

Firm transmission capacity is generally required to enter into a dynamic schedule, although CAISO only requires firm transmission for pseudo- ties and ancillary services. For most transmission providers in the Western Interconnection, transmission slated for dynamic transfers must be held open for the maximum dynamic flow that could occur within the scheduling period, typically an hour. (CAISO, however, allocates transmission for dynamic transfers in five-minute intervals, within available transfer capability.[92]) Thus, transmission slated for dynamic transfers could displace other potential fixed, hourly transactions on the line.[93] While reservations can be updated in real-time to be used by other market participants, increased dynamic transfers may come at the expense of other uses of the line.[94]

This is among the issues CAISO recently addressed in revisions to its dynamic transfer policies. CAISO allows dynamic schedules to use firm or non-firm transmission through other transmission systems, allows transmission service to be arranged on an hour-by-hour basis, and does not limit the delivery of dynamically transferred resources across its interties to fixed transmission reservations. (However, firm transmission is required for pseudo-ties and resources providing ancillary services.) CAISO requires a dynamically transferred resource to submit de-rates to its outage management system if it has not established a sufficient transmission reservation through other transmission systems, and will not be able to use additional transmission within the operating hour, to support dispatch up to its maximum

[89] H. Holttinen, *et al., Design and operation of power systems with large amounts of wind power*, IEA WIND Task 25, Phase one 2006-2008, VTT, http://www.vtt.fi/inf/pdf/tiedotteet/2009/T2493.pdf.
[90] ColumbiaGrid, April 15, 2009.
[91] ColumbiaGrid, Northern Tier Transmission Group and WestConnect, *Dynamic Scheduling System Business Case*, April 7, 2009.
[92] Available transfer capability is "[a] measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses." *See* http://www.nerc.com/files/Glossary_of_Terms.pdf.
[93] The reduction can be a ratio greater than one for one, creating a significant issue in scheduling protocols and priorities.
[94] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Phase 1 Report*.

available capacity. For management of its intertie capacity and internal transmission, CAISO dispatches resources in five-minute intervals within the available transfer capability.[95]

Dynamic transfers also increase intra-hour power and voltage fluctuations on the transmission system that can pose challenges for system operators. Historically, schedules on transmission paths between balancing authority areas were held constant during the scheduling period (hour). The transmission tuning was set for the expected flows at the start of the scheduling period. If a significant change in the flow occurred during the scheduling period, the system likely would be retuned or adjusted.

With a larger number of dynamic transfers that have large and more frequent ramps within the scheduling period, the impacts are more difficult to manage. If variations in flow from dynamic transfers are of a magnitude and frequency that exceed the ability of the system to be retuned (manually or automatically), or exceed the ability of system operators to recalculate and implement new system operating limits, reliability of the system is at risk. The greater number of manual actions required to address voltage control and remedial action schemes (RAS)[96] as a result of dynamic transfers may not be rapid enough or allow for accurate calculation of system operating limits for transmission paths.[97,98] The faster the signal moving across interchanges, the more it will run up against limits to RAS and switchgear.

Because of the difficulties in managing intra-hour power fluctuations and other potential effects on the power system, balancing authorities have studied whether there is a need to limit the quantity of dynamic transfers. Limits may be placed on the size of generation transfers that can be dynamically scheduled, the distance of the transfer, the number of control areas between the source and sink, and the number of schedules that can be accommodated.[99]

Lack of automation of some reliability functions is an issue with larger amounts of dynamically scheduled generation. In some cases operators manually arm and disarm RAS. This allows for higher transmission path ratings and optimal use of the transmission system. Under manual operation, RAS is deployed based on expected changes in power flows. Dynamic transfers can result in rapid fluctuations in power flows. For example, BPA found that before placing limits on dynamic transfers, power flows were changing more rapidly than the system operators could manually control the RAS.[100]

Another concern is the difficulty in using manual methods for voltage control, such as switching transmission lines in and out of service, switching reactive power sources (including shunt and series capacitors, line reactors and distribution capacitors), and changing generation patterns to ensure there is sufficient dynamic reactive power[101] to address contingencies. In high load conditions, where voltage

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[95] Changes will be implemented in Spring 2013 to allow dynamic transfers of intermittent resources to bid for transmission reservations in the day-ahead market and hour-ahead scheduling process, but these transmission reservations will not limit the dispatch of other dynamic transfers by 5-minute intervals within the operating hour. The process may alleviate issues surrounding unnecessary congestion and limited transmission access.

[96] RAS are designed to trip generation to maintain system reliability in the event of loss of transmission.

[97] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Phase 1 Report*.

[98] K. Clark, R. D'Aquila, M. McDonald, N. Miller and M. Shao, GE Energy, Final report on Impact of Dynamic Schedules on Interfaces, Version 3, Jan. 6, 2011, http://www.caiso.com/Documents/FinalReport-Impact-DynamicSchedulesonInterfaces-PreparedbyGE.pdf.

[99] Hirst and Kirby.

[100] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Phase 1 Report*.

[101] "Dynamic reactive power is produced from equipment that can quickly change the Mvar level independent of the voltage level. Thus, the equipment can increase its reactive power production level when voltage drops and prevent a voltage collapse.

is sensitive to power flows, operators may need to take frequent steps to address voltage levels. For example, the Northern Intertie experienced substantial fluctuations in voltage as a result of rapid changes in power flows from dynamic transfers, causing operators to repeatedly take action. Dynamic transfer limits were introduced as a result.[102]

Dynamic transfers also can impede the accurate calculation of system operating limits on transmission paths, if resulting flow variations are large and occur more quickly than the system can be retuned and new limits calculated. If limits are not accurately calculated, flows could actually exceed limits and create a reliability concern. To prevent a possible reliability risk of exceeding system operating limits, operators may choose to conservatively use a lower system operating limit which would result in less than full utilization of transmission capacity.[103]

Transmission limits must be designed to reliably perform and meet acceptable service standards in the event of an unplanned outage. Maximum capacity limits typically are calculated with all capacitor banks in service and RAS appropriately armed. However, if resulting flows from schedules for the period are predicted to be much lower than maximum, capacitors may have to be switched out, RAS adjusted and the transmission system retuned to avoid exceeding voltage limits. With the capacitor banks out, the system operating limit of the path is likely lower than the maximum. Dynamic transfers also pose possible impacts to transmission equipment, including wear and tear on equipment from increased switching.[104]

In addition, if the system is not designed for increasing fluctuations in power flows, dynamic transfers could reduce the quality of power delivered to retail customers. Swings in power flow can affect voltage levels or lead to frequency deviations.[105] Other concerns with greater use of dynamic scheduling relate to contingency actions that may need to be taken in the unlikely event that telemetry or data communications fail.[106]

What Are the Gaps in Understanding and Unresolved Issues?

Whether dynamic transfer limits are required and, if so, how to calculate them are not settled issues. Some system operators have determined that limits are needed to maintain system reliability while others have not. Studies by BPA, CAISO and Powertech Lab on dynamic transfer limits have all found voltage changes at critical interconnection points to be important for determining limits to dynamic transfers.[107] While the CAISO study found voltage changes to be one source of potential limits on dynamic transfers, it concluded that no limits other than operational transfer capability are required on dynamically scheduled variable generation when the maximum variations are allowed at each major

Static var compensators, synchronous condensers and generators provide dynamic reactive power." FERC Staff Report, *Principles for Efficient and Reliable Reactive Power Supply and Consumption*, 2005, http://www.ferc.gov/eventcalendar/files/20050310144430-02-04-05-reactive-power.pdf.

[102] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Phase 1 Report*.

[103] *Id.*

[104] For examples see Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Dynamic Transfer Capability Task Force, Phase 3 Report,* July 2011, http://columbiagrid.org/client/pdfs/DTCTFPhase3Report(Final-12.21.2011%20).pdf.

[105] Rich Bayless, "Integration of Intermittent Energy Into the Grid: Are Dynamic Transfer Capability Limits Needed?" presentation to Committee for Regional Electric Power Cooperation and State-Provincial Steering Committee, Oct. 26, 2011.

[106] Hirst and Kirby.

[107] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Phase 1 Report*.[108] Clark, *et al.*

CAISO interface.[108] BPA, however, has instituted dynamic transfer limits on interties. Others argue that as long as transmission paths are operated below their system operating limit, no limits are required on dynamic transfers, particularly because fluctuations occur over the course of minutes compared to contingency events which take place in seconds.[109]

In October 2010, the Joint Initiative's Wind Integration Study Team developed a task force of technical staff from the Northwest and California to explore dynamic transfer limits. The Task Force concluded that it was necessary to calculate these limits for flowgates and named them "transfer variability limits." The Task Force completed its work in three phases. The first phase defined issues related to the potential need for transfer variability limits.[110] The second phase involved developing a methodology for calculating limits that transmission providers could apply to lines.[111] The third phase refined the transfer variability limit methodology developed in Phase 2, considered possible system improvements to increase transfer limits, and identified additional issues raised during the work of the Task Force.[112]

While transfer variability limits are system-specific and a function of the types of reactive devices and automation employed on a transmission provider's system, more standardized methods of determining limits can help reduce variation in calculating these limits. Calculations of limits may differ based on operator perspectives on acceptable risk, how they manage dynamic transfers, and tolerances for wear and tear on equipment. If two balancing authorities that share a transmission line have different limits on dynamic transfers, the strictest limit would prevail. A standardized method for determining limits may lead to greater consistency in limits developed by adjacent balancing authority areas that share transmission paths, although some differences may persist due to operator perspectives.[113]

The Task Force found that additional work is needed to develop and coordinate commercial practices related to the use of dynamic transfers. Once a transfer variability limit is established for a flowgate, affected transmission providers will need to determine how to allocate the transfer capability to resources that want to use dynamic transfers. Some standardization of allocation methods may be desirable, particularly if multiple transmission providers operate on a particular flowgate. In addition, transmission providers will need to determine if it is necessary to conduct real-time monitoring of variable transfers across individual flowgates.[114]

Another issue to be resolved is how to address potential increases in operation and maintenance costs that may result from increased dynamic transfers and any capital improvements on a given path to expand transfer variability limits. The Task Force developed a list of potential options for increasing transfer variability limits, including relative costs and implementation time required (see Table 2). How costs of improvements would be allocated across transmission providers on a particular path also remains to be determined.[115]

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[108] Clark, *et al.*
[109] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Phase 1 Report*.
[110] *Id.*
[111] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Dynamic Transfer Capability Task Force, Phase 2 Report*, July 2011, https://www.columbiagrid.org/DTCTF-overview.cfm.
[112] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Dynamic Transfer Capability Task Force, Phase 3 Report*, July 2011, http://columbiagrid.org/client/pdfs/DTCTFPhase3Report(Final-12.21.2011%20).pdf.
[113] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Phase 1 and Phase 3 reports*.
[114] *Id.*
[115] *Id.*

Table 2. Options for Enhancing Transfer Variability Limits[116]

Upgrade Option to Enhance Transfer Variability Limit	**Relative Cost:** Low < $10M; High > $100M	**Relative Time to Implement:** Short < 2 years; Long >10 years
Revise assumptions and/or criteria	Low	Short
Incorporate variable resource characteristics	Low	Short
Automate reactive voltage control	Low	Short
Improved tools for system operations	Low	Short to Medium
Operational procedures	Low	Short to Medium
Constrain ramp rates	Low	Short to Medium
Increase staffing Levels	Low-Medium	Short to Medium
Automate RAS	Medium	Medium-Long
Higher duty switching devices	Medium	Medium-Long
SVC	Medium	Medium-Long
STATCOMs	Medium	Medium-Long
Series compensation	Medium	Medium-Long
FACTS	Medium-High	Medium-Long
Phase shifting transformers	Medium-High	Medium-Long
Transmission lines	High	Long

What Could Western States Do to Support Dynamic Transfers?

Western states could encourage the following activities to support dynamic transfers:

- Complete transmission provider calculations of dynamic transfer limits to help identify which lines are most receptive, and which are most restrictive for dynamic transfers.
- Determine priority for transmission system improvements to alleviate restrictions on dynamic transfers considering locations for existing and potential renewable generation and balancing resources, and lines needed for dynamic transfers.
- Assess options and costs for additional transmission capacity and additional flexibility on transmission systems to facilitate more widespread use of dynamic transfers. For example, more flexible AC transmission systems can be "tuned" to operate more flexibly. Dynamic line ratings can increase utilization of existing transmission facilities. Also, the impact of lower transmission utilization factors due to dynamic transfers could be minimized through upgrades such as reactive power support and special protection systems.[117]
- Explore use of ramping limits to increase the dynamic transfer capability of certain paths.
- Assess best approaches for integrating dynamic transfer limits into scheduling and operating practices and determine compensation issues.

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[116] Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team, *Phase 3 Report*.
[117] Bayless.

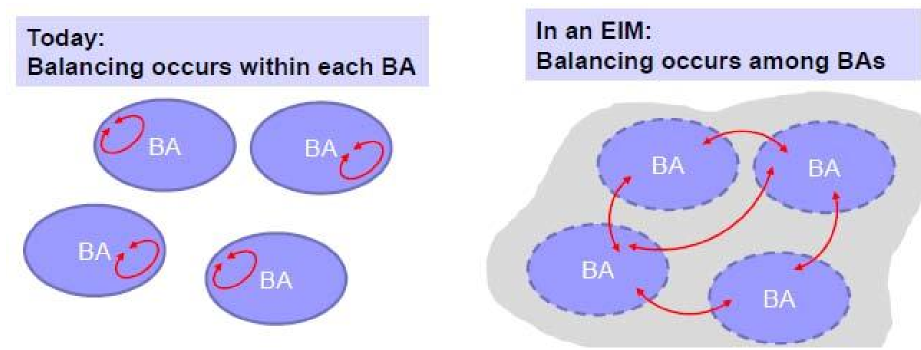
- Conduct outreach and disseminate information to stakeholders on the implications of dynamic transfer limits and potential system impacts of dynamic scheduling in order to help identify solutions. Dynamic transfer limits may have implications for other mechanisms that can help integrate renewable resources, such as an energy imbalance market and flexible reserves.
- Automate reliability procedures such as voltage control and RAS arming to enable expanded use of dynamic transfers and increase the efficiency of system operations.
- Use near real-time data to calculate system operating limits to address concerns about potential violations of limits due to lack of current data. This could help mitigate restrictive dynamic transfer limits.
- Encourage balancing authorities to use dynamic transfers to aggregate balancing service across their footprints.

Chapter 3. Implement an Energy Imbalance Market*

How Does an Energy Imbalance Market Work?

An Energy Imbalance Market (EIM) has been proposed for the Western Interconnection as a mechanism that balancing authorities and transmission providers could use to integrate higher penetrations of variable generation required to meet state renewable energy goals. The EIM is a centralized market mechanism that would enable dispatch of generation and transmission resources *across* balancing authority areas (BAs) to resolve energy imbalances – differences between generation and demand (see Figure 1). In this way, the EIM would enable participants to manage transmission constraints and supply imbalance energy from the most cost-effective resources available in the region.

Figure 1. An EIM Expands the Pool of Resources to Balance Wind and Solar Generation[118]



The EIM would optimize the dispatch of imbalance energy by incorporating real-time information on generation capabilities and transmission constraints using nodal locational pricing.[119] Participation in the EIM would be voluntary for balancing authorities and transmission providers. The benefits would depend on the level of participation.[120]

The EIM optimizes energy dispatch from offered resources and settles imbalance transactions through an organized market, rather than bilateral transactions, as is the current practice. However, the EIM would not eliminate bilateral energy transactions; rather, it would supplement them.[121] Each hour, initial operating conditions would still be based on traditional bilateral transactions.

The EIM is a real-time energy-only market that recognizes existing bilateral transmission delivery rights while automating intra-hour economic dispatch. In the EIM, energy imbalance is defined as the difference between scheduled and actual energy, at both generation and load settlement locations. Generators and loads pay or receive payment based on the difference between scheduled and actual

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* **Lead author: Lori Bird, National Renewable Energy Laboratory**

[118] Steve Beuning, Xcel Energy, "What Is an Energy Imbalance Market?" presentation for Crossroads Webinar Series, Jan. 28, 2011.

[119] "Nodal pricing is a method in which market prices are calculated for a number of locations on the transmission network (nodes) that represent physical locations on the system. These locations can include both generators and loads. The price at each node represents the incremental cost of serving one additional megawatt of load at that location subject to system constraints." David Godfrey, WECC, *Committee Report: Efficient Dispatch Toolkit Steering Committee*, Sept. 9, 2011, p. 36.

[120] WECC staff, WECC Efficient Dispatch Toolkit Cost-Benefit Analysis (revised), Oct. 11, 2011, http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf.

[121] *Id.*

energy delivered. The proposed EIM is designed specifically to: 1) provide balancing service by re-dispatching generation every five minutes to maintain balance between generation and demand, addressing generator schedule deviations and load forecast errors and 2) provide congestion management service by re-dispatching generation to relieve overloaded constraints on the grid.[122,123]

To balance the system, the EIM would use security-constrained economic dispatch, an algorithm used in centralized wholesale markets, to dispatch the least-cost resources available in the system given reliability constraints. The EIM would run the security-constrained economic dispatch every five minutes to determine the most economic dispatch of resources across the market footprint based on offers from individual power plants and deliverability information from the energy management system, and to calculate nodal locational prices used for settlements. Price information would be public and provide signals to generators about the need for energy in specific locations.[124]

Within the WECC footprint, individual balancing authorities manage energy imbalance and transmission congestion under their transmission tariffs. The energy supplied by the EIM would fulfill the imbalance settlement requirements of resources and loads, currently addressed in Schedules 4 and 9 of these tariffs.[125] The EIM eliminates the *pro forma* tariff concept of imbalance penalty bands, replacing it with market settlement rules.[126] The scheduled value of offered resources may be adjusted through the operating hour based on dispatch instructions from the market.

The EIM would accommodate existing contingency reserve sharing groups in the region. To ensure that the contingency reserves are accounted for appropriately in system operations, reserve sharing groups would need to coordinate with the market operator. Together, they would ensure that sufficient reserves are available and have transmission access to cover sudden unplanned loss of generation resources.

An EIM would not be a full wholesale energy market. It would not include a day-ahead market, coordinated unit commitment, financial transmission rights or an ancillary services market. Also, an EIM would not eliminate existing transmission arrangements. Under an EIM, entities may continue current practices for obtaining transmission service, such as reserving and entering into long-term contracts for firm point-to-point and network transmission service.[127]

The EIM proposal would not establish an RTO or a consolidated regional network transmission tariff. The EIM governance documents could include provisions that would allow expansion of functions only with unanimous or supermajority agreement. While FERC would have jurisdiction to determine that EIM rates, terms and conditions are just and reasonable, that would not cause EIM participants to become jurisdictional themselves.[128] To avoid RTO characteristics or status, the EIM should not provide

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[122] M. Milligan, J. King, J., B. Kirby, and S. Beuning, *Impact of Alternative Dispatch Intervals on Operating Reserve Requirements for Variable Generation*, NREL Report No. CP-5500-52506, October 2011.
[123] WECC Efficient Dispatch Toolkit Steering Committee, *WECC White Paper Energy Imbalance Market Functional Specification*, Sept. 8, 2011, http://www.wecc.biz/committees/BOD/09212011/Lists/Minutes/1/12a%20EIM%20Functional%20Specification.pdf.
[124] WECC staff, Oct. 11, 2011.
[125] Western Interstate Energy Board, *White Paper: New Tools for Integrating Variable Energy Generation Within the Western Interconnection*, January 2011. http://www.westgov.org/EIMcr/documents/eim-hli.pdf.
[126] Communication with Steve Beuning, Xcel Energy, Feb. 24, 2012.
[127] WECC staff, Oct. 11, 2011.
[128] Arnold Podgorsky, "EIM FERC Jurisdiction and Governance – Concepts: A WSPP Perspective," presentation to PUC EIM Group, State-Provincial Steering Committee, April 10, 2012, http://www.westgov.org/PUCeim/webinars/04-10-12/04-10-

transmission service or control transmission facilities owned by others and should not have an OATT. Participating transmission providers would retain their own OATTs with modifications to integrate their activities with the EIM. Each transmission owner could add an EIM transmission service and rate to its OATT that conforms to a common, agreed upon approach requiring FERC approval.[129]

The EIM would be operated by an independent entity with the responsibility of accounting for and financially settling all energy imbalances. Market design considerations include the governance structures, market operator and development of technical designs. Concerns have been raised that market manipulation could lead to costs outweighing potential benefits of an EIM.[130] A market monitor would be needed to ensure that no abusive scheduling or market manipulation practices occur.

Enhanced Curtailment Calculator

WECC has proposed to develop an Enhanced Curtailment Calculator to calculate curtailment responsibility on transfer paths in the region, potentially including all rated paths and some currently unrated paths. Currently, WECC only calculates curtailment responsibility on six designated "Qualified Transfer Paths" which have been deemed qualified for unscheduled flow mitigation. The current tool is updated twice per year and assumes all transmission facilities are in-service. The development of the Enhanced Curtailment Calculator would allow near real-time updates of transmission system data to include actual outages and a more detailed model of the physical transmission system.

The Enhanced Curtailment Calculator is a reliability tool that can be developed and implemented independently of the EIM, but it can provide important transmission system data to support EIM operation. It would serve as a seams coordination tool with other markets (CAISO and AESO) and any non-market areas in the region to determine curtailment responsibilities.[131]

How Would an EIM Reduce Costs and Provide Other Benefits?

An EIM would provide a number of benefits of organized markets over current initiatives, without creating a full wholesale market system. In fact, initial results from a recent analysis by ColumbiaGrid found that the Joint Initiative products provide only 10 percent to 17 percent of estimated EIM benefits.[132]

An EIM would increase the efficiency and flexibility of system operations to enable utilities in the West to integrate higher levels of variable renewable energy resources. It would optimize the dispatch of energy given transmission constraints, which is expected to reduce operating costs and make more efficient use of the transmission system. Such efficiencies are expected because the EIM would

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12WSPPferc-gov.pdf. "Exempt entity's participation in EIM would not cause loss of exemption or otherwise subject Exempt's rates to FERC review, subject to a wrinkle: FERC will "review rates, revenue requirements, and costs . . . only if they *affect* the rates charged by jurisdictional Participants . . . ." *West Connect,* 124 FERC 61,240 (2008). The WSPP's general counsel concludes: "Because EIM rates are market-based and, absent market power, would be inherently just and reasonable, there is no need to examine Exempt rates to assure that EIM rates are just and reasonable." (Slides 5-7)

[129] *Id.*, slide 10.

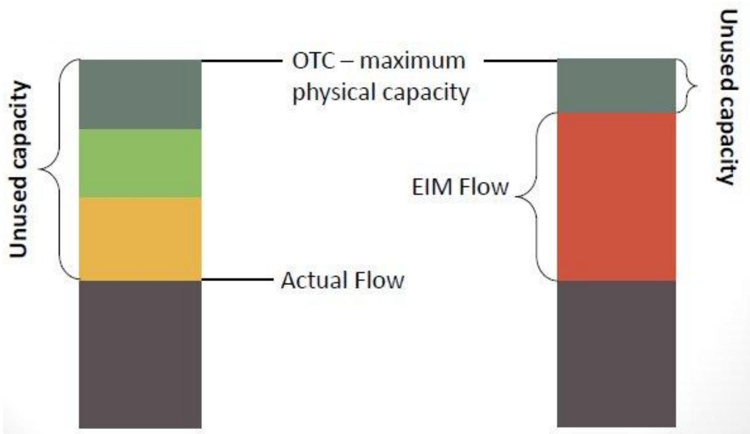
[130] Kenneth Rose, "An Economist's Viewpoint: What Should Be Included in a Comparative Analysis of Costs and Benefits of an EIM," presentation to the WECC Board of Directors meeting, March 15, 2012.

[131] WECC Efficient Dispatch Toolkit Steering Committee, Sept. 8, 2011.

[132] Patrick Damiano, ColumbiaGrid Members' EIM Analysis Work Group, "Draft Phase I Findings and Results," presentation on March 14, 2012, slide 35.

determine transmission availability based on real-time flows of energy, rather than reserved transfer capability on scheduled transmission paths.[133] See Figure 2.

Figure 2. An EIM Makes Better Use of Transmission Capacity[134]



The EIM would enable re-dispatch of resources to maximize the use of the transmission system, enabling the operator to use a larger pool of resources to manage imbalances than is currently available. The transmission system could be operated more efficiently because the availability of transmission service would be based on actual real-time power flows, rather than on reserved capability on scheduled transmission paths. Traditionally, transmission service has been provided assuming worst-case flow impacts on the grid, but the EIM would use information on actual flows to evaluate delivery impacts.[135]

An EIM also would provide reliability benefits by coordinating balancing across the region.[136] Coordination across a larger area can reduce the per-unit variability of wind and solar generators, because weather patterns are less correlated over a wider area. Also, forecasting errors decrease over a larger geographic area. In turn, this netting of variability across a larger area reduces the variability that fossil generators would need to counterbalance. By reducing the steepness of ramps and the number of times that fossil units need to be cycled on and off, the efficiency of operations is increased and the wear-and-tear on the fossil plants is reduced.[137] Further, by enabling surplus generation in one region to be netted against deficits in another region, an EIM leads to lower aggregate deviations. The smaller deviations will enable balancing authority areas to carry fewer flexibility reserves than are currently needed, reducing cost to consumers, though an EIM will not reduce reserves needed for contingencies.

Operators manage the variability of variable generation minus the load, referred to as the "net load." Currently, most balancing authorities manage net load with reserve capacity that can respond to

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133 *Id.*

134 Victoria Ravenscroft, "Energy Imbalance Market," presentation to Colorado Public Utilities Commission, March 7, 2012. OTC-operating transfer capability limit.

135 Transmission availability in real-time would no longer be determined by reservation of Available Transfer Capability on scheduled transmission paths that are posted on the Open Access Same-Time Information System. *See* http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf.

136 However, some utilities have expressed concerned that an EIM could negatively affect reliability because the grid would be operated closer to operating limits.

137 See the geographic diversity and forecasting chapters for more information.

automatic generation control to correct supply and demand imbalances. Under the EIM, the system operator will reset the operating levels of participating generators every five minutes, reducing the amount of deviations that need to be addressed by expensive regulation reserves. Fast market operations also enable regulating units to be run at more optimal levels.[138] In addition, the amount of local generation needed to handle variability would be reduced. The market signal provided through the EIM would enable the most cost-effective available generators anywhere in the participating region to respond.

An EIM would create an automated and transparent system for acquiring imbalance energy resources. Balancing authorities use both on-system and off-system resources to manage net load deviations. Off-system resources can be particularly important for extreme wind and solar ramp events. Today, system operators use manual processes to identify trading partners and to reserve and schedule available transmission service. These processes can be time consuming and provide limited choices. An EIM, in contrast, would enable participants to choose from the most cost-effective available resource bids to provide imbalance energy under real-time system conditions, reducing the probability that renewable resources will be curtailed. Instead of curtailing wind, for example, an EIM will enable more wind energy to be delivered to consumers at a lower price. Reduced ramping will save generation and transmission entities fuel costs, with the savings passed along to customers.

Benefits of an EIM in the Southwest Power Pool

The Southwest Power Pool (SPP) Energy Imbalance Service Market has been operating since 2007. An analysis conducted for SPP found that the trade benefits of the SPP Energy Imbalance Service Market were $103 million for the first year of operation. The benefits of operation were about 20 percent higher than expected based on a 2005 cost-benefit study, primarily due to higher natural gas costs than predicted.[139] SPP estimates that the production cost benefits have exceeded $100 million annually since operation.[140]

Some 82 percent of generation was voluntarily offered for dispatch in SPP's Energy Imbalance Service Market over the past year. Of the remaining resources, only 2 percent was self-dispatched; the rest are non-dispatchable, including nuclear and intermittent resources.[141]

WECC contracted with Energy and Environmental Economics, Inc. (E3) to estimate operational savings that would result from an EIM. Compared to a benchmark case, the study estimated that annual system benefits would have been $50.3 million in 2006, and projected annual benefits of $141 million in 2020.[142] The 2020 savings estimate consisted of two major components: 1) dispatch-related savings (representing $42 million of the $141 million in savings) resulting from removal of barriers to trade between zones in the West including pancaked transmission service rates and losses and other

[138] Michael Milligan and Brendan Kirby, *Market Characteristics for Efficient Integration of Variable Generation in the Western Interconnection*. NREL Report TP-550-48192, August 2010, http://www.nrel.gov/docs/fy10osti/48192.pdf.
[139] SPP, Board of Directors/Members Committee Meeting & Special Meeting of Members, April 22, 2008, http://www.spp.org/publications/BOD042208.pdf.
[140] Communication with Richard Dillon, SPP, Feb. 29, 2012.
[141] SPP Market Monitoring Unit, *Monthly State of the Market Report – March 2012*, published April 16, 2012, page 16, http://www.spp.org/publications/SPP%20MSOM%20Report%20201203.pdf.
[142] WECC staff, Oct. 11, 2011.

inefficiencies and 2) savings related to reduced need for flexibility reserves[143] and access to more cost-effective flexibility reserves throughout the region (representing nearly $100 million of the $141 million in savings).[144] The study also examined scenarios such as a limited number of entities participating in an EIM, cases at various natural gas prices, and cases with specified operational characteristics such as reserve sharing, coordination and more efficient unit commitment.

Recent studies by the National Renewable Energy Laboratory (NREL) also estimated the potential benefits of a regional EIM. One analysis[145] examined the following impacts of an EIM for a scenario assuming 30 percent wind penetration based on data from the Western Wind and Solar Integration Study (Western study):[146]

1) Effects on operating reserves
2) Reduction in ramping requirements resulting from a larger operating footprint
3) Impact of faster scheduling on operating reserves
4) Role of coordinated planning

Assuming full regional participation in an EIM, the NREL study found that average reserve levels decrease by 51 percent to 54 percent, depending on the type of reserve. Reductions in maximum reserve levels range from 58 percent to 67 percent, also depending on reserve type. With partial regional implementation of an EIM, the study found smaller but significant savings in reserves, including a 32 percent to 41 percent reduction in average reserve levels and a 42 percent to 46 percent reduction in maximum reserve levels.[147] Reduction in reserve requirements lower costs for participants and ultimately consumers.

In its most recent analysis, NREL estimated the potential cost savings from reductions in reserve needs with an EIM. Scenarios include several levels of wind and solar penetration in the West, relying on data from the Western study as well as solar data developed by NREL for studies overseen by WECC's Transmission Expansion Planning Policy Committee (TEPPC).[148] The analysis shows significant cost savings from sharing of reserves, with benefits dependent on the level of participation in the EIM. For a scenario of 8 percent wind and 3 percent solar penetration in the Western Interconnection, based on the TEPPC 2020 Common Case, the study found that maximum reductions in reserve requirements ranged from 42 percent for regulation reserves to 56 percent for both spinning and non-spinning reserves. Applying general reserve pricing to these reductions, the study estimated cost savings of approximately $103 million per year for full implementation of the EIM in the Western Interconnection (excluding only the CAISO and AESO market areas). Benefits are estimated to fall to approximately $77

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[143] Flexibility reserves are dispatchable thermal and hydro resources required to balance the system with higher penetrations of wind and solar.

[144] Energy and Environmental Economics, Inc., *WECC EDT Phase 2 EIM Benefits Analysis & Results*, prepared for WECC, October 2011 (revised), http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf

[145] J. King, B. Kirby, M. Milligan and S. Beuning, *Flexibility Reserve Reductions From an Energy Imbalance Market With High Levels of Wind Energy in the Western Interconnection*, NREL Report No. TP-5500-52330, October 2011, http://www.nrel.gov/docs/fy12osti/52330.pdf.

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

[147] J. King, *et al.,* 2011.

[148] J. King, B. Kirby, M. Milligan and S. Beuning, *Operating Reserve Reductions From a Proposed Energy Imbalance Service With Wind and Solar Generation in the Western Interconnection*, forthcoming.

million per year if the EIM footprint excludes the federal Power Marketing Agencies in the West – BPA and WAPA.[149]

Applying this same methodology to a higher penetration of wind energy in the West – 30 percent annual wind energy penetration – NREL estimates that the benefits of reserve reductions are approximately $221 million per year if the EIM is implemented across the entire Western Interconnection, excluding only CAISO and AESO. If instead the EIM is implemented without the participation of BPA and WAPA, the reserve reduction benefits fall to approximately $144 million per year.[150]

What Is the Cost of Implementing an EIM?

An important consideration for potential participants is startup and ongoing costs. To estimate the cost of implementing an EIM, WECC engaged Utilicast to conduct an analysis of costs for the market operator and additional costs to market participants. The study estimated high and low values for each cost category to reflect uncertainty in the design and selection of market operator and then summed the high and low values to create an overall range. Therefore, the overall low values may be lower than expected and the high values may be higher than expected. The study examined two potential footprints for the EIM: 1) the entire Western Interconnection except for CAISO and AESO and 2) a footprint further excluding WAPA, BC Hydro, BPA and all balancing authorities embedded within BPA.[151]

Assuming all balancing authorities outside of CAISO and AESO participate in the EIM, the startup cost for a market operator ranged from $25.6 million to $220.2 million and annual operating costs from $33.9 million to $128.9 million. The total cost to market participants was estimated to include a startup cost of $41.31 million to $120.02 million and annual operating costs of $46.46 million to $131.51 million. The cost estimates include a portion of the cost of the proposed Enhanced Curtailment Calculator, although those costs represent a relatively small fraction of the total estimate.[152] Altogether, the overall startup costs would be $66.91 million to $340.22 million and the operating cost would be $80.36 million to $260.41 million.

The 10-year Net Present Value (NPV) of the costs are $657 million to $2,239 million, compared to the 10-year NPV of the benefits from the E3 study of $989 million to $1,598 million (2010 dollars).[153] Thus the estimated net benefit ranges from positive to negative depending upon the assumptions.

To narrow the range of costs, WECC commissioned a study to determine the costs of implementing an EIM with WECC as the market operator. The study found that startup costs for an EIM with WECC as the market operator would range from $42.2 million to $114.0 million, with operating costs ranging from

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[149] DOE Secretary Chu acknowledged WAPA's support of the EIM in his March 16, 2012, memo to Power Marketing Administrators, http://energy.gov/downloads/memorandum-secretary-chu-power-marketing-administrations-role-march-16-2012.
[150] J. King, *et al.,* forthcoming.
[151] WECC Staff, Oct. 11, 2011, http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf.
[152] The start-up cost range for the Enhanced Curtailment Calculator was $0.3 million to $0.4 million. The operational cost range for the tool was $0.1 million to $0.2 million.
[153] Utilicast LLC, *Efficient Dispatch Toolkit Cost Analysis*, prepared for WECC and the Efficient Dispatch Toolkit Steering Committee, April 2011, http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf.

$50.0 to $95.7 million annually.[154] The net present value of costs of the EIM operated by WECC was estimated to range from $818 million to $1,959 million over 10 years.[155]

For comparison, the SPP Energy Imbalance Service Market, which began operation in 2007, required capital expenditures of $35 million for the vendor and hardware costs, not including labor or the costs associated with other preliminary work conducted prior to the full implementation of the systems.[156]

Recently, both SPP and CAISO submitted cost estimates for implementing an EIM in the Western Interconnection to the PUC EIM Group (a group of Western state utility commissioners interested in further evaluating the costs and benefits of an EIM and the resulting effect on rates). SPP estimated startup costs of $64.4 million with ongoing costs in the first two years of about $28 million annually.[157] CAISO estimated that the cost to join would involve a one-time charge of about "$0.03 per MWh times the annual net energy load reported to WECC for 2009."[158] In addition, there would be additional ongoing charges for participants of the EIM including: 1) $0.19 per MWh participating in the EIM, which reflects the cost of accessing CAISO market services and operating systems; 2) $1,000 per month for each scheduling coordinator; 3) $0.005 per bid segment; and 4) telecommunications charges that vary by participant from $3,000 to $100,000 for installation and roughly $500 annually per month thereafter.[159]

What Are the Implementation Challenges?

While detailed market specifications of a proposed EIM have been prepared, a number of operational issues would need to be resolved for an EIM to be implemented including the following:

1) *Determining the market operator, governance structure and market monitor.* While many technical details of market operation have been developed and proposed, questions remain regarding who should operate the EIM as well as the nature of the governing board and how it would interact with the market operator. An important issue is how to develop the governance structure to ensure that the EIM would not become an RTO and market functions would not be expanded without widespread agreement among participants. Also important are further details on a market monitor to ensure a market design and oversight that would prevent manipulation. These issues could be addressed through provisions in the governance documents. Potential governance structures are addressed in a recent Western Systems Power Pool draft discussion paper.[160]
2) *Establishing appropriate tariffs to enable implementation of the EIM.* Changes to participating transmission providers' tariffs would address such issues as energy imbalance settlements, imputed transmission service, and replacement of Schedules 4 and 9 of the participating transmission providers' tariffs.

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[154] Note that the low end of the start-up cost range for the WECC-operated market is higher than the original low-end estimate for an EIM without a specified market operator.
[155] WECC staff, Sept. 8, 2011, http://www.wecc.biz/committees/BOD/09212011/Lists/Minutes/1/13%20EDT%20Analysis%20-%20Risk,%20Governance,%20and%20Cost.pdf.
[156] Communication with Richard Dillon, SPP, Feb. 29, 2012.
[157] Southwest Power Pool, EIM Estimate for Western Interconnection, March 30, 2012, http://www.westgov.org/PUCeim/documents/fnl-SPPEIMce.pdf.
[158] California ISO, CAISO Response to Request from PUC-EIM Task Force, March 29, 2012, p. 5, http://www.westgov.org/PUCeim/documents/CAISOcewa.pdf.
[159] California ISO, 2012.
[160] Wright and Talisman and Western Systems Power Pool, *Corporate Structure and Governance of Western Energy Imbalance Market*, Draft March 27, 2012, http://www.westgov.org/wieb/meetings/crepcsprg2012/briefing/EIMgovernance.pdf.

3) *Developing operating procedures to coordinate with contingency reserve sharing groups.* Under an EIM, the market operator and reserve sharing groups must coordinate to ensure that contingency reserves are fully accounted for in system operations.
4) *Establishing seams coordination agreements with non-participants and CAISO.* To ensure grid reliability, congestion management responsibility between the EIM operator and non-EIM entities must be allocated. Many balancing authorities in the Western Interconnection do not yet have a broad situational awareness of flows on the regional grid and may require additional tools. Only one-third of the balancing authority areas in the Western Interconnection have solving state-estimator software capability that provides more accurate measurement of megawatts and voltages than can be obtained from regular meter equipment. State estimators can supply information to other programs that optimize dispatch economics and evaluate potential reliability impacts. The EIM would use its state estimator capability for security-constrained economic dispatch to address imbalances and provide congestion management.[161] Agreements addressing market seams issues have been established in other parts of the country, such as MISO and PJM,[162] which could provide a model for EIM agreements. CAISO has developed a straw proposal for addressing seams issues with the EIM.[163] Many transmission paths in the Western Interconnection use a rated-path method, which may help in the coordination of seams agreements for transmission rights allocation.
5) *Determining whether the EIM operator can use WECC state estimator data for input to its security-constrained economic dispatch software.* Some parties in the WECC do not consider it appropriate for a market operator to have access to WECC-solved state estimator output data. If the data are not provided to the EIM operator, the costs to develop the EIM could increase.
6) *Determining how an EIM would be financed or how participants would pay for system startup costs as well as costs associated with upgrading systems to share data and participate in the EIM.* Financing startup costs would help address challenges related to using existing budgets to pay for system upgrades. Participants may not have sufficient budgets to support in a timely manner the upgrades needed to implement the EIM initially. Some form of financing may be necessary to enable participants to spread startup costs across future years. For example, the Midwest ISO used bond financing to fund market startup costs.
7) *Assessing sufficiency of participation level.* The EIM will be voluntary for balancing authorities and transmission providers. Some entities may choose not to participate. It is unclear how broad participation must be to make the EIM economically feasible, although studies that estimate benefits for several scenarios of participation indicate the relative magnitude of these effects.
8) *Providing training on new operating tools and procedures.*
   a. Grid operators would need to become familiar with new tools and procedures. This would require training of operators and key utility personnel to enable them to operate the system effectively in the balancing market.
   b. Transmission providers would need to adapt to new tools and operating practices because congestion management practices would be different under an EIM.

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[161] Communication with Steve Beuning, Xcel Energy, March 23, 2012.
[162] WECC Staff, Oct. 11, 2011.
[163] In 2010, CAISO examined the seams coordination mechanisms that are used and under development in the Eastern Interconnection and how they could be applicable in the Western Interconnection. CAISO proposed two mechanisms for CAISO and EIM: 1) dynamic transfers for coordinated market clearing and 2) reciprocal recognition of transmission constraints when needed for congestion management. CAISO, *WECC Consideration of Efficient Dispatch Toolkit, and Potential Market-to-Market Coordination*, November 2010, http://www.wecc.biz/committees/StandingCommittees/MIC/SIS/SIS111510/Lists/Exhibits/1/WECC_SIS_EIM_MarketCoordination_20101109_final.doc.

c. In RTO regions, the market dispatch use of the transmission system is provided without additional charge or reservation under the regional network transmission tariff. In an EIM for the Western U.S., transmission providers would establish an intra-hour transmission product charge for EIM-related market dispatch transactions. The EIM transmission providers and market participants would need to be trained to fully understand this aspect of the market.[164]

What Could Western States Do to Address Unresolved Issues for an EIM?

Public utility commission involvement in EIM discussions and planning is critical to ensure that issues are vetted with regulators prior to any filings at FERC. The PUC EIM Group, formed in November 2011, includes commissioners from all Western Interconnection states. The group has commissioned study work on the costs and benefits of a potential EIM and held a number of webinars.[165] Beyond that, Western states could encourage the following actions to address unresolved issues:

- Undertake efforts to define the rates and terms for transmission service agreements for each transmission provider.
- Explore financing options to enable entities to defer some of the startup costs to future years and to better plan and budget for costs.
- Investigate the costs and benefits to ratepayers of regulated utilities participating in an EIM through public utility commission proceedings. Encourage publicly owned utilities to investigate costs and benefits of EIM participation for their consumers. Such evaluations should include potential reduction in integration costs, potential enhanced reliability, changes to compensation for transmission providers and impacts for customers, potential disadvantages of participation, and possible negative economic impacts for meeting renewable energy requirements in the absence of utility participation in an EIM.
- Examine mechanisms for preventing and mitigating potential market manipulation that could reduce benefits.
- Support continuing efforts to explore how governance of an EIM would work, including provisions that address concerns that an EIM could lead to the creation of an RTO.
- Determine the viability of an EIM if major balancing authorities do not participate.
- Provide encouragement and support for the Northwest Power Pool Market Assessment and Coordination Committee which has assembled 20 Western balancing authorities and several other participating utilities to fully evaluate the business case for an EIM.
- Support Western Interconnection-wide efforts to design a proposed EIM for the broadest possible geographic footprint.
- Establish a timeline for implementing the proposed EIM in the West.

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[164] WECC Efficient Dispatch Toolkit Steering Committee, Sept. 8, 2011, http://www.wecc.biz/committees/BOD/09212011/Lists/Minutes/1/12a%20EIM%20Functional%20Specification.pdf.
[165] See the PUC EIM Group website at http://www.westgov.org/PUCeim/index.htm.

Chapter 4. Improve Weather, Wind and Solar Forecasting*

How Does Forecasting Work?

Grid operators continuously balance supply and demand to maintain electric service reliability. An important part of a grid operator's responsibility is to manage variability (the range of expected load and generation) and uncertainty (when and how much load and generation will change) as demand for electricity changes from seconds to minutes, hourly and daily, due to weather and other factors.[166] Further, generating facilities may be unavailable due to scheduled maintenance, unscheduled outages or fuel supply constraints.[167]

Weather is a primary influence on all electric systems as it drives load demand, in addition to variable generation sources such as wind and solar. Hot days require more power generation to meet demand for cooling, while cold weather requires more generation to serve electric heating requirements. Thus, forecasting of variable generation should be viewed in the broader context of weather forecasting. Improvements in weather forecasting will benefit consumers not only for improving forecasts of variable generation but for more accurately predicting loads and preparing for extreme events such as large storms or extended periods of hot or cold weather.

At high penetration levels, variable energy resources such as wind and solar add to variability and uncertainty.[168] It is widely acknowledged that forecasting generation from variable energy resources is essential as their levels increase.[169] Several studies assessing the feasibility of integrating wind and solar resources conclude that forecasting their output will help lower the amount of needed system reserves – generation or demand that must be available to react to unexpected events, such as higher load than forecasted or a forced outage of a generation plant, and maintain electric service reliability – reducing cost to consumers.

Variable generation forecasting also helps grid operators monitor system conditions (sometimes referred to as "situational awareness"), schedule or de-commit other power plants in anticipation of large changes in wind and solar generation ("ramps"), and prepare for extreme high and low levels of wind and solar output.[170]

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* **Lead author: Kevin Porter, Exeter Associates**

[166] J. Charles Smith, "Solar and Wind Forecasting: Achieving a 33% Solution," presentation before the California Energy Commission Workshop on Forecasting, Dec. 16, 2011, http://www.energy.ca.gov/research/notices/2011-12-16_workshop/presentations/05_UVIG-Smith.pdf.

[167] This chapter is focused on the implementation and use of variable generation forecasting by balancing authorities. Other market participants such as power marketers and independent power producers also may benefit from improved variable generation forecasting.

[168] In addition to wind and solar generation, variable generation also includes technologies such as run-of-river hydro and emerging technologies such as wave power. Weather drives variability of all of these resources. Because weather also drives demand for electricity, forecasting for generation and load should be viewed together.

[169] See North American Electric Reliability Corporation (NERC), *Accommodating High Levels of Variable Generation*, April 2009, http://www.uwig.org/IVGTF_Report_041609.pdf; GE and National Renewable Energy Laboratory, *Western Wind and Solar Integration Study*, May 2010, http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf; and Lawrence E. Jones, U.S. Department of Energy and Alstom Grid, *Strategies and Decision Support Systems for Integrating Variable Energy Resources in Control Centers for Reliable Grid Operations*, December 2011, http://www1.eere.energy.gov/wind/pdfs/doe_wind_integration_report.pdf.

[170] NERC, May 2010.

How Variable Generation Forecasts Are Assembled

Variable generation forecasts are prepared with a combination of data from large-scale numerical weather prediction (NWP) models maintained by public meteorological agencies and meteorological and generation data from individual wind and solar plants. An NWP model is a computer simulation of the atmosphere and the physical processes that affect the atmosphere. The simulations incorporate mathematical formulas that are part of computer programs. These programs are fed into computer runs to simulate the future state of the atmosphere. The NWP models use weather observations from thousands of sources, such as weather stations at airports and other locations, radar systems, aircraft and satellites, collected by national weather services such as the National Oceanic and Atmospheric Administration (NOAA). These organizations share data worldwide, contributing to an international snapshot of current weather conditions that are essential for creating weather forecasts.

The quality of the output from NWP models depends on both the quality of the input data (the current knowledge of the state of the atmosphere) and how well the model represents physical interactions in the atmosphere.[171] The modeling results are limited by the spatial resolution of the modeling grid and how well the physical interactions in the atmosphere are represented in the model.[172] In other words, if the spatial resolution in the model is 10 kilometers, terrain differences smaller than 10 kilometers will likely not be reflected in the model.

Weather is often thought of horizontally, such as weather fronts moving from one part of the country to the other. However, weather also is affected by vertical phenomena. For example, the diurnal pattern of wind is caused by variations in the vertical profile of temperatures. However, most weather observation stations are located at 10 meters or less above ground level and near urban areas, while the hub heights of wind turbines are about 100 meters in elevation and are not located near urban areas.[173] Also, NWP models were developed for general weather forecasting applications such as aviation, agriculture and public safety, not for wind and solar forecasting.[174]

As a result, companies that forecast wind and solar generation supplement the NWP models with more local meteorological and generation observations and refresh data more frequently. Forecasting companies also supplement the NWP models with statistical models and techniques. The statistical models establish a relationship between predictor (input) and forecast (output) variables, based on a training sample of historical data. (Statistical models can learn from experience without having to model the supporting physical and atmospheric relationships.) The typical approach is to rely upon output from the NWP models and measured data from the wind or solar plant to forecast the output (power production, wind speeds, etc.) at the location of the plant. The statistical models help represent the effects of local terrain and other geographic details that cannot be realistically represented in the NWP models. But because statistical models need to learn from historical examples, the models generally predict typical events more successfully than rare events, unless the models are specifically designed for predicting such events and are trained on a sample that includes them.

[171] Mark Ahlstrom, James Blatchford, Matthew Davis, Jacques Duchesne, David Edelson, Ulrich Focken, Debra Lew, Clyde Loutan, David Maggio, Melinda Marquis, Michael McMullen, Keith Parks, Ken Schuyler, Justin Sharp and David Souder, "Atmospheric Pressure: Weather, Wind Forecasting and Energy Market Operations," *IEEE Power & Energy Magazine*, November/December 2011.
[172] NERC, May 2010.
[173] American Wind Energy Association, *Policy Positions on Wind Power Forecasting*, January 2012 draft.
[174] Ahlstrom, *et al.,* November/December 2011.

Solar Forecasting: The adoption of solar forecasting is not as far along as wind because the growth in solar capacity is relatively new and the contribution of solar power is relatively small, although growing rapidly. The ease of solar forecasting depends on the amount of solar radiation that reaches the surface and can be measured. That, in turn, depends on clouds (the depth of clouds, or the concentration of water and ice in clouds), the amount of water vapor and the quantity of aerosols. Hour-ahead forecasts for solar photovoltaic (PV) systems rely on statistical models that use time series of on-site insolation measurements, off-site measurements of clouds and solar insolation, [175] and satellite images of water vapor channels that might interfere with solar radiation. Day-ahead solar PV forecasts use physics-based models, with forecasts of transmissivity[176] as the major variable.

Once the sun has risen, clouds are the main factor in the variability of solar plant generation and the uncertainty of the solar power forecast. In the short-term, some clouds are fairly stable and move with the winds at the same level. Sky imagers near solar plants can be used to detect approaching clouds and estimate the potential impact on solar plant generation. Satellite images can be used to estimate the direction and speed of approaching clouds over the next few hours and predict their future movement and impact on solar plant production. Over longer periods, NWP models are necessary to model cloud changes as they change shape, increase their size and break apart.[177]

It appears that solar output will have different forecasting challenges than wind. Good solar sites have low cloudiness, and forecast errors for solar are small if clouds are not a major factor. However, partly cloudy days are more challenging for solar forecasting. In contrast, good wind sites have high wind speeds, which lead to high variability. In addition, satellites provide frequent, high resolution cloud data, which helps short-term solar forecasts.[178] There is no such tool available for short-term wind forecasting, although DOE and NOAA selected two companies to formulate such a forecast.[179]

Types of Forecasts

- *Weather and Situational Awareness Forecasts* provide alerts on severe weather in real-time to allow grid operators to respond to high wind or other types of events.
- *Hours-ahead or Intra-day Forecasts* are short-term forecasts that span the next several hours (usually six to eight hours) and provide subhourly forecasts (such as five to 10 minutes ahead) that are updated frequently – at least hourly, and often much faster than that, such as every 10 minutes. These forecasts allow grid operators to anticipate possible changes in variable generation and identify and prepare any additional reserves that may be needed to maintain grid reliability.
- *Next-day Forecasts* typically provide hourly variable generation forecasts for the next few days and are updated every six to 12 hours. Along with other inputs such as electricity demand forecasts, grid operators use next-day variable generation forecasts to determine if sufficient generation is available to meet projected load and for scheduling fuel purchases and deliveries, particularly for power systems with significant natural gas generation.

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[175] Solar insolation is a measure of solar radiation energy received on a given surface area at a given time, generally expressed in watt-hours per square meter or, in the case of photovoltaics, kilowatt-hours per year per kilowatt peak rating.
[176] Solar transmissivity is the percent of incident solar radiation that is transmitted. The lower the number, the less solar radiation transmitted.
[177] NERC, May 2010.
[178] Andrew Mills and Ryan Wiser, Ernest Orlando Lawrence Berkeley National Laboratory, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power*, 2010, http://eetd.lbl.gov/EA/EMP/reports/lbnl-3884e.pdf.
[179] National Oceanic and Atmospheric Administration, *DOE-NOAA-Private Sector Wind Forecast Improvement Project*, http://www.esrl.noaa.gov/psd/psd3/wfip/.

- *Nodal Forecasts* are hourly forecasts of expected variable generation production aggregated for each transmission delivery point (or node). These forecasts allow grid operators to factor forecasted variable energy generation into estimates of transmission congestion for each delivery point.

No single forecast is adequate for all applications. So increasingly, grid operators are using more than one wind forecast – either multiple forecasts from different models (provided by a single company or several companies) or multiple forecasts from the same model and vendor, with small changes in the initial conditions of the model. Such "ensemble forecasts" can be weighed to reflect past performance or to focus on particular weather situations. Ensemble forecasting requires considerable computational resources and care in designing the model conditions, but successful implementation provides valuable insights into the uncertainty of the forecasts.

Separate forecasts for predicting large ramps in variable generation also may be needed. Ramps are generally defined as large changes in load or generation, either up or down, over a defined time period. Unexpected ramps from variable generation, such as from a large weather front, can affect the grid operator's ability to maintain reliability and ensure adequate reserves are available to cover ramps.[180] AESO, Arizona Public Service and the Electric Reliability Council of Texas (ERCOT) use separate variable generation ramp forecasts in addition to wind power forecasts. Other grid operators are considering using ramp forecasts.

While variable generation forecasts are generally optimized to minimize forecast errors, a forecast tuned for ramps is designed to predict rare events. Ramps can result from multiple meteorological features that are highly localized or from weather events that are difficult to detect. Because of the significant uncertainty in predicting the timing and magnitude of ramps, results are presented probabilistically.[181] The intent is to identify potential ramp events and when additional reserves or flexibility in dispatching generators may be warranted to maintain system reliability.

The state of the power grid determines whether a variable generation ramp event poses a reliability risk. Variable generation that is ramping up is easier to manage when load is increasing than when load is declining.[182]

There is no industry consensus on the definition of a variable generation ramp event. The number of ramp events differs significantly based on the time period used to define a ramp. Many more ramps will occur over a time period of 60 minutes as compared to 30 minutes. The variance between two time intervals can be significant, with ramp predictions ranging from 50 to 1,000 ramp events per year, depending on the time interval used.[183]

[180] NERC, May 2010.
[181] In general, ramp forecasts are thought of as separate from standard variable generation forecasts. However, standard forecasts can be modified to penalize forecast error more heavily during ramping events. That, in turn, would prioritize ramping events in tuning and adjusting the variable generation forecast.
[182] NERC, May 2010.
[183] Ahlstrom, *et al.* November/December 2011.

Performance of Variable Generation Forecasts: Table 1 presents general wind forecast errors by Mean Absolute Error (MAE)[184] for hour-ahead and day-ahead forecasts, by individual wind plant and for all wind plants in a large region, as well as forecast errors by energy and by capacity. The table presents two important findings: 1) forecast errors for a single wind plant are larger than for multiple wind plants in a region and 2) forecast errors are smaller the closer to the time generation serves demand.

Table 1. Average Wind Forecast Error by Time Frame[185]

	Forecast Error	
	Single Plant	**Region**
Hour-Ahead		
Energy (% Actual)	10 – 15%	6 – 11%
Capacity (% Rated)	4 – 6 %	3 – 6 %
Day-Ahead		
Hourly Energy (% Actual)	25 – 30%	15 – 18%
Hourly Capacity (% Rated)	10 – 12%	6 – 8%

Forecasting for solar and wind is quite new, compared to forecasting load. Day-ahead forecast errors in predicting load are considerably lower, ranging from about 1 percent to 3 percent.[186] While improvements in forecasting variable generation are expected through advances in computing performance and capability, research and development, and learning by users, the practice already is useful to grid operators. For example, day-ahead forecasts for wind power generally provide a good estimate of the amount of wind energy expected and a general sense of timing and magnitude of when that energy will be available, allowing grid operators to take advance action to preserve grid reliability.[187] Continuing use of and improvements in variable generation forecasting will give balancing authorities more confidence in the forecasts over time and allow balancing authorities to hold lower levels of reserves.

Where Is Variable Generation Forecasting Used?

Every RTO in the U.S. already uses variable generation forecasting or plans to implement the practice in 2012. CAISO was the first to do so, in June 2004. In the Western U.S., at least 11 balancing authorities (including CAISO) are engaged in variable generation forecasting, encompassing over 80 percent of the wind capacity in the region (see Table 2). Most of these balancing authorities adopted variable generation forecasting recently – in 2008 or later. [188] With increasing numbers of wind and solar

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[184] The Mean Absolute Error takes the absolute values of the individual wind forecast errors divided by the predicted or reference value. Another measure, the Root Mean Square Error (RMSE), involves obtaining the total square error first, dividing by the total number of individual errors, and then taking the square root.
[185] J. Charles Smith, Dec. 16, 2011.
[186] Debra Lew, Michael Milligan, Gary Jordan and Dick Piwko, *The Value of Wind Power Forecasting*, conference paper for the American Meteorological Society Annual Meeting, Jan. 26, 2011, http://www.nrel.gov/wind/systemsintegration/pdfs/2011/lew_value_wind_forecasting.pdf.
[187] NERC, May 2010.
[188] Kevin Porter and Jennifer Rogers, *A Survey of Variable Generation Forecasting in the West*, prepared for National Renewable Energy Laboratory, forthcoming.

facilities, more balancing authorities will implement variable generation forecasting in the future. Most balancing authorities and RTOs pay for the variable generation forecasts, although the AESO, CAISO, the Independent Electric System Operator of Ontario, and the New York ISO all assign some or all of the forecasting costs to variable generators.

Table 2. Balancing Authorities in the Western U.S. That Forecast Variable Generation[189]

Balancing Authority	Average Load[1] (MW)	Wind Capacity in Balancing Authority (MW)	Solar Capacity in Balancing Authority (MW)
Alberta Electric System Operator	8,400	865	0
Arizona Public Service (APS)	2,939-4,650	205[2]	61.9
Bonneville Power Administration	6,000	4,400	<1
California Independent System Operator	26,525	3,598	498
Glacier Wind	NA	210	0
Idaho Power Company	1,800	485	0
Northwestern Energy	1,805	138.59	0
Sacramento Municipal Utility District	3,280	0	35
Southern California Edison (SCE)	23,303[3]	[4]	[4]
Turlock Irrigation District	245-336	0[5]	2
Xcel Energy - Public Service of Colorado (PSCo)[6]	3,878-4,340	1,484	200
TOTAL	75,965-84,525	10,773.59	797.9

1 Unless otherwise Indicated.
2 190 MW is dynamically transferred from Public Service of New Mexico; another 15 MW is transferred out of APS to Salt River Project.
3 Represents all-time peak.
4 SCE has 2,057 MW of wind capacity and 383 MW of solar capacity, included in the figures for CAISO.
5 Owns a wind project in BPA's service area.
6 Data are for PSCO's service territory.

How Does Forecasting Reduce Costs?

Several studies assessing the feasibility of integrating large amounts of wind have shown that using day-ahead, state-of-the-art variable generation forecasts to schedule and dispatch generating plants can significantly improve grid operations and reduce total operating costs. Without variable generation forecasts, grid operators may schedule and dispatch other power plants too much or too little. Using variable generation forecasts, grid operators can schedule and operate other generating capacity efficiently, reducing fuel consumption, operation and maintenance costs, and emissions as compared to simply letting variable generation "show up."[190] Grid operators also may use variable generation forecasts to determine how much natural gas will be needed on a day-ahead basis. Without such

189 Data from Kevin Porter and Jennifer Rogers, *Survey of Variable Generation Forecasting in the West*, National Renewable Energy Laboratory, April 2012, http://www.nrel.gov/docs/fy12osti/54457.pdf, except BPA's wind capacity and average load in the CAISO, provided by those entities.
190 *Id.*

forecasts, grid operators may under-schedule or over-schedule the amount of natural gas they need day-ahead.

As forecasting errors are reduced, wind and solar can be predicted with more confidence and fewer reserves will be needed to accommodate forecast errors, reducing integration costs.

Compiling data from several wind integration studies, Table 3 shows that using wind forecasting in day-ahead schedules can reduce operating costs by an estimated $20 million to $510 million per year, depending on the region and amount wind relative to peak load. Estimated savings are higher with higher levels of wind capacity. If wind output could be perfectly forecasted, the estimated increase in savings is estimated at only $10 million (as compared to $510 million) to $60 million (as compared to $180 million), illustrating that current state-of-the-art forecasts are likely to achieve most of the economic benefits possible.[191]

Table 3. Projected Impact of Wind Forecasts on Grid Operating Costs[192]

			Projected Annual Operating Cost Savings	
	Peak Load	**Wind Generation**	**State-of-Art Forecast vs. No Forecast**	**Additional Savings From Perfect Forecast vs. State of Art Forecast**
California	64 GW	7.5 GW	$ 68 M	$19 M
	64 GW	12.5 GW	160 M	38 M
New York	33 GW	3.3 GW	95 M	25 M
Texas	65 GW	5.0 GW	20 M	20 M
	65 GW	10.0 GW	180 M	60 M
	65 GW	15.0 GW	510 M	10 M

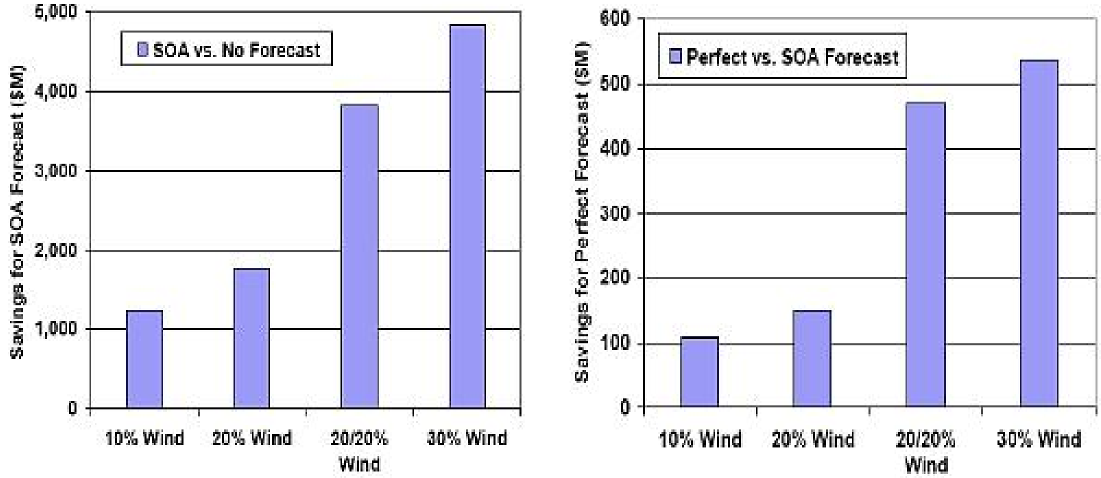
The Western Wind and Solar Integration Study (Western study) found similar benefits, determining that at 35 percent wind and solar penetration, the use of day-ahead variable generation forecasting in scheduling and dispatching generators would reduce annual operating costs in the WECC region by up to $5 billion annually, or $12 to $17 per MWh of renewable energy. The study estimated that perfect forecasts would reduce operating costs in WECC by another $500 million, or another $1 to $2 per MWh

[191] Richard Piwko, GE Energy, "The Value of Wind Power Forecasting," Utility Wind Integration Group workshop on wind forecasting applications for utility planning and operations, Feb. 18-19, 2009. The grid operators in this table have subhourly energy markets and large balancing areas. As described elsewhere in the paper, these strategies are helpful in integrating variable generation. Benefits of wind and solar forecasting in regions that do not have large balancing areas and subhourly markets will be smaller, although still significant.

[192] *Ibid.*

of renewable energy – another indication that using today's state-of-the-art forecasts reaps most of the potential benefits.[193]

Figure 1. Value of Forecasting — Western Wind and Solar Integration Study[194]



Wind Forecasting Reduces Costs for Xcel Energy

Xcel Energy uses wind forecasting for its Northern States Power-Minnesota (NSP-MN) subsidiary that operates in the Midwest ISO day-ahead market; Public Service Company of Colorado (PSCo), a balancing authority in the Western Interconnection; and Southwestern Public Service Company (SPS), which operates in the Southwest Power Pool (SPP) energy imbalance market. Xcel Energy has reduced wind forecast errors as it has gained experience with wind forecasting and added new capabilities such as intra-day unit commitment.

For NSP-MN, Xcel Energy reduced Mean Average Percentage Errors from 15.7 percent to 12.2 percent between 2009 and 2010, resulting in $2.5 million in annual savings. Xcel Energy also found annual savings from improved wind forecasting of $3.1 million for PSCo and $400,000 for SPS. On a "value per 1 percent improvement" in forecasting, Xcel Energy estimated $830,000 for PSCo, $722,000 for NSP-MN, and $175,000 for SPP.

Xcel Energy attributes these large variations in savings to several factors. First, NSP-MN operates within Midwest ISO's day-ahead and five-minute markets and has access to a large balancing area and ancillary services markets, reducing the cost and system impact of variable generation forecasting errors. Interchanges between PSCo and neighboring balancing authorities are hourly, not subhourly, but PSCo operates significant levels of flexible natural gas-fired generation. SPS, in contrast, has more inflexible generating plants, so better forecasts are not as useful because the plants cannot respond in sufficient time.[195]

[193] GE Energy, *Western Wind and Solar Integration Study*, prepared for National Renewable Energy Laboratory, May 2010, http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf.
[194] *Ibid.*
[195] Ahlstrom, *et al.,* November/December 2011.

What Are the Gaps in Understanding?

The quality of the observational data that serve as the foundation for initializing the NWP models contributes to the accuracy of the variable generation forecasts. Weather prediction is complex and driven by several factors that may interact non-linearly. Small errors in the foundational models can increase rapidly over time, contributing to inaccuracies in variable generation forecasts. Higher quality forecasts will require more frequent measurements and measurements from a larger area of the atmosphere. More rapid refreshing of the NWP models and increasing their geographic coverage also will improve variable generation forecasts but will require more high-performance computing capabilities.

The scope and cost of such activities will require public-private cooperation and partnerships, as well as policy and financial support among policymakers. However, such improvements in foundational models would likely result in public benefits over and above improved variable generation forecasting, such as improved accuracy of weather forecasting that could benefit the public, the aviation industry and other users of weather data. Improved accuracy of weather forecasting will also help utilities to improve load forecasts, and to improve prediction of effective and disruptive weather events. DOE, NOAA, forecasting vendors, grid operators, and university and government research groups are collaborating on a project, with results due by the end of 2012, to determine the value of high-resolution rapid-refresh weather forecasting models and additional observations.[196] In addition, the wind industry, government agencies, and forecasting vendors are defining data-sharing methods that could facilitate industry sharing of local meteorological measurements and wind data at turbine hub height with government agencies such as NOAA to improve the foundational forecasts while protecting the confidentiality of the source data.[197]

What Are the Implementation Challenges?

Following are challenges for variable generation forecasting:

Accuracy and Interpretation of the Forecast – With years of experience forecasting load, forecast errors now range from 1 percent to 3 percent. Variable generation forecasts are not nearly this accurate. As a result, some balancing authorities in the West report that while wind forecasting is helpful, they interpret it with caution or discount it.[198] Variable generation forecasts provide value in predicting the patterns and profiles in energy production, if not the actual timing (a common error in wind forecasting). Improving the foundational meteorological data in the NWP models could play an important role in improving both wind and solar forecasts.

Implementation Time – Western U.S. balancing authorities that use variable generation forecasting report that it takes time to implement a forecasting system. Data collection methods and communication infrastructure must be established between wind and solar projects, the balancing authority and the forecasting company.[199] In addition, the forecasting model ideally should be trained with historical variable generation production. For these reasons, balancing authorities recommend starting variable generation forecasting early.

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[196] Ahlstrom, *et al.*, November/December 2011.
[197] *See* American Wind Energy Association, January 2012 draft.
[198] Porter and Rogers.
[199] *Id.*

Data – Data are needed to train and improve variable generation forecasts. But collecting and using more data has costs and may result in a more complex and cumbersome forecast. There may be diminishing returns as the data become more granular and are obtained closer to real time. In addition, some forecast providers optimize forecasts to power production and do not require wind speed data, while other forecast providers want meteorological, wind speed, temperature and barometer data. There also may be proprietary concerns, as variable generation forecasting companies add their own observations and results from statistical and modeling techniques to the NWP models and likely are not willing to share that information without non-disclosure agreements.

Size of Balancing Area – Larger balancing areas, either virtually or physically, smooth the variability of wind and solar output through geographic diversity. In turn, that reduces forecasting errors. Generally, forecast errors can be reduced 30 percent to 50 percent by aggregating multiple wind plants as compared to wind forecast errors of individual or geographically concentrated plants. Table 4 shows that forecast accuracy increases for forecasts that cover larger regions. In this example, the Mean Absolute Error (MAE) and Root Mean Square Error (RMSE) are less when measured WestConnect-wide (labeled "FP," or footprint, in the table) and for all of WECC, rather than for an individual state.

Table 4. Variable Generation Forecast Errors by Area, 30 Percent Renewable Energy Scenario Western Wind and Solar Integration Study[200]

	Installed MW	**MAE MW**	MAE %	**RMSE MW**	RMSE %	**Max Neg Err MW**	Max Neg Err %	**Max Pos Err MW**	Max Pos Err %
AZ	7,710	**934**	12.1%	**1,333**	17.3%	**-6,909**	-89.6%	**5,357**	69.5%
CE	4,650	**570**	12.3%	**756**	16.3%	**-3,102**	-66.7%	**3,471**	74.6%
CW	570	**92**	16.2%	**128**	22.5%	**-489**	-85.8%	**475**	83.4%
NM	2,970	**450**	15.1%	**620**	20.9%	**-2,450**	-82.5%	**2,233**	75.2%
NV	3,450	**426**	12.4%	**612**	17.7%	**-3,048**	-88.4%	**2,144**	62.1%
WY	7,410	**1,018**	13.7%	**1,380**	18.6%	**-5,591**	-75.5%	**5,707**	77.0%
FP	26,760	**2,059**	7.7%	**2,694**	10.1%	**-11,515**	-43.0%	**11,771**	44.0%
WECC	72,210	**4,667**	6.5%	**6,012**	8.3%	**-30,934**	-42.8%	**19,337**	26.8%

Shorter Scheduling Intervals – Shorter scheduling intervals and updating forecasts throughout the day improve forecasting accuracy because forecast errors decrease closer to the time generation is dispatched to meet load. However, to meet day-ahead scheduling requirements, NWP models begin running several hours before day-ahead schedules are due. For day-ahead schedules due at noon, for example, the NWP models begin running at midnight, using observations from the day before. Figure 2 illustrates that forecast preparation starts 48 hours before the day-ahead market closes, and if scheduling of generation and dispatch is done before weekends and holidays, the forecasts can be several days old.

[200] GE Energy.

Figure 2. Typical Schedule for Wind Power Forecasts and Day-Ahead Scheduling[201]

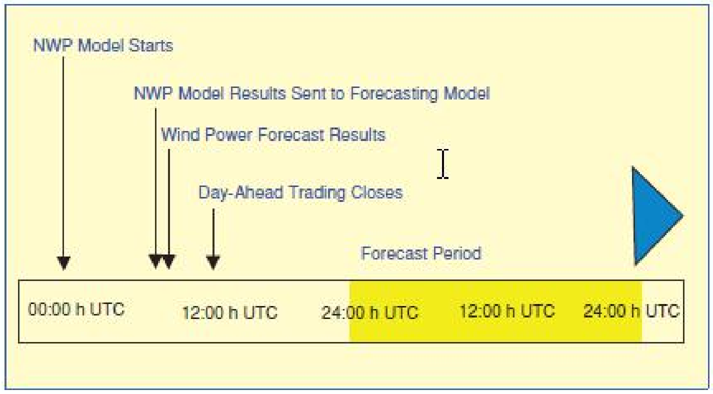
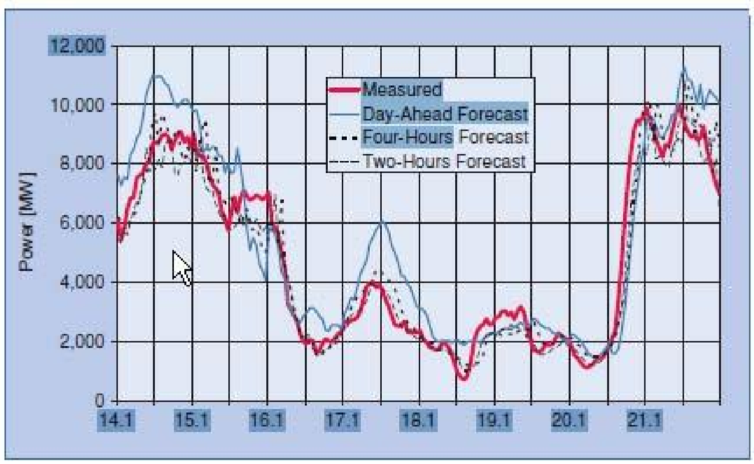


Figure 3 shows the difference in actual wind generation compared to forecasts two hours ahead, four hours ahead and day ahead in Germany. As illustrated, wind forecasts closer to real-time tend to be closer to actual measured wind production. Running intra-day unit commitment algorithms, in addition to day-ahead unit commitment, and using the results to inform forecasts – or using a more stochastic approach to unit commitment with frequent rolling updates – may be useful strategies for taking advantage of short-term forecasts of variable generation.[202]

Figure 3. Comparing Intra-Day and Day-Ahead Wind Power Forecasts in Germany[203]



Incorporating Variable Energy Forecasts in Schedules and Dispatch – Despite benefits reported in multiple studies, variable generation forecasting generally is not used for day-ahead dispatch and scheduling in the West. Instead, most balancing authorities use the forecasts for intra-day unit commitment (ensuring that sufficient generation is available to meet load during the day, as opposed to

[201] Bernhard Ernst, Brett Oakleaf, Mark L. Ahlstrom, Matthias Lange, Corinna Moehrlen, Bernhard Lange, Ulrich Focken and Kurt Rohrig, "Predicting the Wind," *IEEE Power and Energy Magazine*, November/December 2007, pp. 79-89.
[202] Peter Meibom, Helge V. Larsen, Rudiger Barth, Heike Brand, Aidan Tuohy and Erik Ela, *Advanced Unit Commitment Strategies in the United States Eastern Interconnection*, National Renewable Energy Laboratory, August 2011, http://www.nrel.gov/docs/fy11osti/49988.pdf.
[203] Ernst, *et al.*

day ahead). The economic and reliability gains from using variable generation forecasts can be realized only if they are integrated with day-ahead schedules and dispatch. Sufficient generation and demand resources will have to be scheduled to account for the increased uncertainty around the variable generation forecast as compared to load alone. The forecast error also may be reflected in the day-ahead commitment schedule, and cost responsibility for deviations from the forecast must be considered. Nevertheless, the value of incorporating the variable generation forecast into day-ahead scheduling is significant.

What Could Western States Do to Encourage Use of Variable Generation Forecasting?

Western states could take the following actions to encourage improvements in wind and solar forecasting and increase its use:

- Support government and private industry efforts to improve the foundational models and data that are incorporated into variable generation forecasting models.
- Encourage the expanded use of variable generation forecasting by balancing authorities.
- Ask balancing authorities that already have implemented variable generation forecasting to study the feasibility and costs and benefits of improvements, such as using multiple forecasting providers or installing additional meteorological towers.
- Study the feasibility and costs and benefits of using variable generation forecasts for day-ahead unit commitments and schedules, including updating schedules closer to real time to take advantage of improved forecast accuracy.
- Consider the feasibility and costs and benefits of more regional variable generation forecasts involving multiple balancing authorities or exchange of forecasts among balancing authorities.
- Ask balancing authorities whether variable generation ramps are of concern now or are expected to be of concern in the future, whether any existing forecasting system adequately predicts ramps in variable generation, and the status of potential adoption of a ramp forecast for variable generation.

Chapter 5. Take Advantage of Geographic Diversity of Resources[*]

How Does Geographic Diversity Work?

The quality of wind and solar resources is not uniformly distributed. Over a large geographic area – and a corresponding large number of wind and solar generating facilities – the percentage change in total output is reduced. Uncertainty in wind and solar forecasting also is reduced through this "portfolio effect" because there are fewer random forecast errors and individual forecast errors are more likely to be averaged or cancelled out.

In addition, wind or solar projects that are concentrated geographically tend to have highly correlated output and thus may have hourly imbalances (unexpected changes from hourly energy schedules) in the same direction as one another. Wind and solar projects that are geographically diverse have less correlated output, as well as less variable output in aggregate. Geographically diverse projects can help reduce hourly variability, reducing the need for reserves and decreasing the likelihood of large ramps in variable generation.

Some regions in the U.S. have large balancing authority areas that naturally provide geographic diversity. Geographic diversity also can be accessed through balancing authority cooperation, transmission expansion and optimized siting of wind and solar plants.

The benefits of geographic diversity have long been observed with load. For example, a utility's *aggregated* residential load is smoother than *individual* household loads, because individual loads are not correlated minute to minute. It also is well known that aggregating total electricity demand over wide regions decreases load variability and balancing reserve requirements.[204]

Several studies have established that a larger geographic area helps smooth output of variable energy resources significantly. For example, the Western Wind and Solar Integration Study (Western Study) found that large geographic areas mitigate changes in net load due to changes in wind and solar generation output. Figure 1 illustrates this concept. The figure shows results from the "In-Area" scenario, where 10 percent to 30 percent of the energy is from wind and 1 percent to 5 percent of the energy is from a combination of concentrating solar power (CSP) and photovoltaic (PV) systems. For the most part, this scenario constrains wind and solar plants to locations within each state to meet its renewable energy targets. The figure compares the results to the other two scenarios in the study, where wind and solar resources are spread throughout the five-state WestConnect footprint or the entire WECC region.

Figure 1 shows the percentage increase in variability, measured by the standard deviations of hourly changes in "net load" (electricity load minus production from wind and solar), as the penetration of wind and solar increases. The three areas that are smaller geographically (Colorado West, Wyoming and New Mexico) exhibit the largest increase in variability. Colorado West, for instance, would experience changes in variability estimated at more than 100 percent at 30 percent penetration of wind and solar, while variability in Wyoming would be 87 percent higher than variability from electricity demand alone.

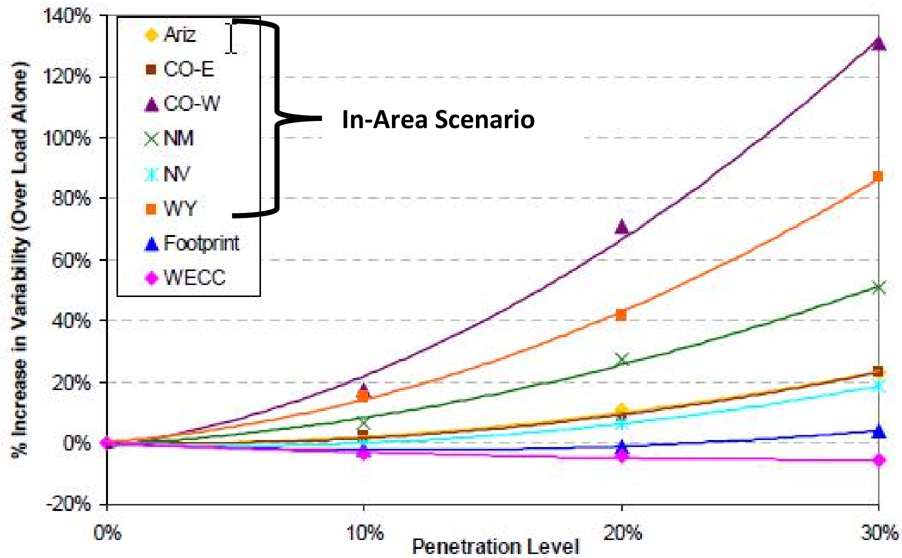
[*] **Lead author: Kevin Porter, Exeter Associates**

[204] In fact, these benefits were among the primary reasons for the formation of "tight" power pools in the Northeast before they evolved into regional transmission organizations. See Massachusetts Institute of Technology, *The Future of the Electric Grid*, 2011, http://web.mit.edu/mitei/research/studies/the-electric-grid-2011.shtml#report.

However, the growth in variability drops sharply as geographic area increases. At the WestConnect level (labeled "Footprint" in the figure), net load variability is 4 percent higher at the 30 percent penetration level compared to load alone. And WECC-wide, net load variability is actually *lower* than variability with load alone.

Overall, geographic diversity helps reduce the impact of extreme wind and solar events on net load variability and corresponding system balancing requirements. The variability for each Western study scenario more than doubles for certain states, but the increase in variability at the WestConnect footprint and WECC levels is much smaller.[205]

Figure 1. Percent Increase in Variability for In-Area Scenario – Western Wind and Solar Integration Study[206]



The WECC Variable Generation Subcommittee initiated a study in February 2010 to analyze the benefits of cooperation among the balancing authorities in the Western Interconnection. To determine the largest potential benefit that could be expected if balancing authorities engaged in cooperation, the study examined production cost savings and balancing reserves savings that would result from consolidation of balancing authorities in the Western Interconnection. The study found that consolidation resulted in roughly 1 percent to 2 percent annual reduction in thermal production cost and approximately 50 percent reduction in load following and regulation reserve requirements (in terms of capacity and ramp rates, compared to the sum of the individual balancing authority reserve requirements that need to be carried under the current structure).[207]

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[205] *Id.*

[206] GE Energy, *Western Wind and Solar Integration Study*, prepared for National Renewable Energy Laboratory, February 2010, http://www.nrel.gov/wind/systemsintegration/wwsis.html.

[207] Western Electricity Coordinating Council Variable Generation Subcommittee, "Electricity Markets and Variable Generation Integration, 2012 Addendum," April 12, 2012, http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/2012%20Addendum%20-%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf.

A wind integration study performed in 2007 for Arizona Public Service found that increased geographic diversity also can help ease ramps from wind plants. Hourly ramp events greater than 10 percent of nameplate capacity occurred roughly 15 percent of the time for individual plants, but only about 5 percent of the time over a geographically diverse set of generation. As Table 1 shows, the study also found that geographic diversity reduced 10 minute ramps. Roughly 70 percent to 80 percent of ramps for individual wind plants were less than 2 percent of their rated capacity, with the remaining ramps between 2 percent and 10 percent of their rated capacity. (Less than 1 percent of the ramps involved more than 10 percent of the individual plant's capacity.) The combined output, however, illustrates the effects of geographic diversity. Nearly 90 percent of ramps involved less than 2 percent of the total wind capacity simulated in the study, and a miniscule fraction of ramps were above 10 percent of the total wind capacity. This reduction stems from the uncorrelated nature of wind fluctuations from site to site.[208]

Table 1. Distribution of 10 Minute Ramps, Sorted by Wind Power Plant and Grouped in Percentages of Rated Capacity – Arizona Public Service Wind Integration Study[209]

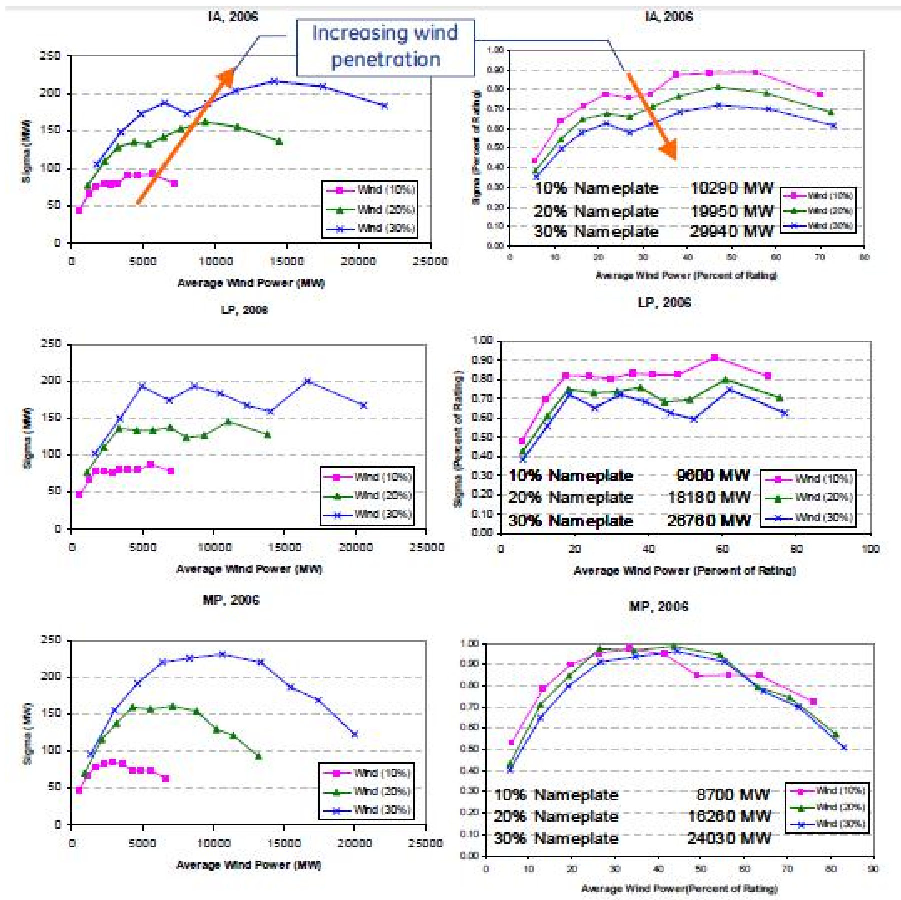
	Wind Power Plant	Ramps outside the ±10% of rated capacity range		Ramps in ±2% to ±10% of rated capacity range		Ramps inside the ±2% of rated capacity range	
		Count	%	Count	%	Count	%
West/APA Zone	Anderson	3,568	0.62	112,259	19.39	463,053	79.99
	Aubrey Cliffs	4,112	0.71	176,923	30.56	397,845	68.73
	Bullhead	4,372	0.76	120,973	20.90	453,535	78.35
	Cottonwood	3,444	0.60	115,433	19.94	460,003	79.46
	Gray Mountain	5,119	0.89	155,607	26.88	418,154	72.24
	Combined Output	**223**	**0.04**	**59,485**	**10.28**	**519,172**	**89.69**
East/APS Zone	Greer	1,996	0.34	100,939	17.44	475,945	82.22
	Hay	4,902	0.85	113,222	19.56	460,756	79.59
	Pinedale	3,344	0.58	116,744	20.17	458,792	79.26
	Springerville	5,040	0.87	135,932	23.48	437,908	75.65
	Young	2,222	0.38	114,930	19.85	461,728	79.76
	Combined Output	**298**	**0.04**	**63,750**	**11.01**	**514,832**	**88.94**

Figure 2 is another illustration of the impact of geographic diversity, also from the Western study. In the charts on the left side, the Y axis shows the standard deviation of hourly changes in wind generation, and the X axis shows average levels of wind capacity. In addition to the In-Area (IA) Scenario described above, the Mega Project (MP) Scenario used the best available wind and solar resources within the study footprint and included new long distance transmission to deliver wind and solar generation to load. The Local Priority (LP) Scenario is an intermediate scenario between the In-Area and Mega Projects Scenario, with a more modest addition of new transmission. Hourly changes in the variability of wind generation increase as wind capacity is added in both the In-Area and Local Priority scenarios (top two charts on the left), although it flattens out at 5,000 MW of wind capacity. The results are strikingly different for the Mega Project scenario (bottom chart on the left), where large wind projects are concentrated in smaller geographic areas. Wind variability peaks at the mid-power range, comparable to the power curve of a single wind plant which rises sharply before dropping off.

[208] Northern Arizona University, *Final Report: Arizona Public Service Wind Integration Cost Impact Study*, prepared for Arizona Public Service Company, September 2007, http://www.uwig.org/APS_Wind_Integration_Study_Final9-07.pdf.
[209] *Id.*

The right side of Figure 2 shows net load variability, normalized by the installed wind capacity. For the In-Area and Local Priority scenarios, the normalized variability of net load decreases with higher wind and solar penetration because of increased geographic diversity as more wind capacity is added. In contrast, the Mega Project scenario is more comparable to the ramping up and down of a single wind project because most wind capacity is added in a relatively small geographic area. Overall, Figure 2 illustrates that there is less wind variability (normalized to wind capacity) at higher wind penetration levels due to geographic diversity.[210]

Figure 2. 10 Minute Variability for Wind and Net Load – Western Wind and Solar Integration Study[211]



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[210] GE Energy.
[211] *Id.*

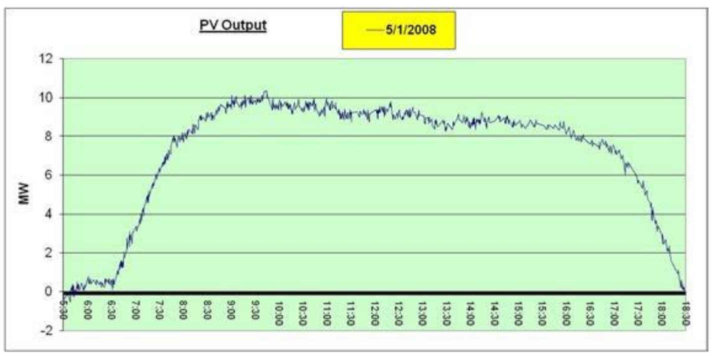
Ramping Requirements

Grid operators must keep the power grid in balance to maintain reliability and ensure compliance with NERC requirements. With higher levels of variable generation, grid operators will need to estimate ramping requirements for conventional generation and determine whether they have sufficient capability to handle those ramps.[212] Options include short-term system sales or purchases, backing down other generation during up-ramps, accessing generation during down-ramps, using demand response and curtailing wind output.[213] Because wind ramps tend to be relatively slow moving and occur over several hours, a 30-minute ancillary service would be sufficient to manage wind ramp events. Such a service would likely be less costly than regulation or spinning reserves because the resources providing the service would not need to be on-line and always available, as is the case with regulation and spinning reserves.[214] Continuing improvements in variable generation forecasting also will help identify and prepare for variable generation ramp events.

Variability of Solar PV Systems

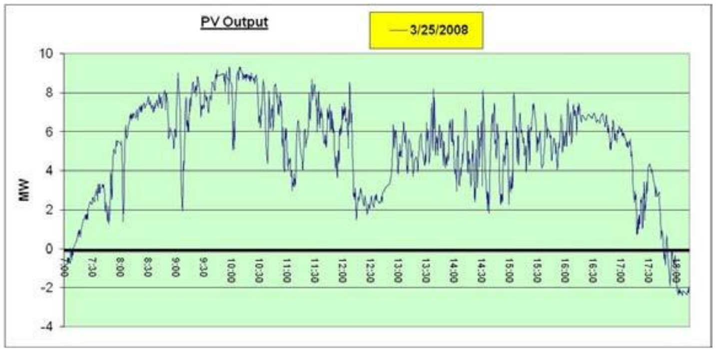
Similar to wind, variability of output from solar PV systems can be significant at a single site,[215] with variations in output of +/- 50 percent in a 30 second to 90 second timeframe and +/- 70 percent in a five minute to 10 minute timeframe. Figures 4 and 5 depict this phenomenon for a PV system in Nevada.

Figure 2. Solar Photovoltaic Plant Output on a Sunny Day at a Nevada Site[216]



[212] Ken Dragoon, *Valuing Wind Generation on Integrated Power Systems*, Elsevier, 2010.
[213] Northwest Power and Conservation Council, *The Northwest Wind Integration Action Plan*, 2007, http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf.
[214] ISO/RTO Council, *Comments of the ISO/RTO Council in Response to the Federal Energy Regulatory Commission's Notice of Inquiry Seeking Public Comment on the Integration of Variable Energy Resources*, 2010, http://www.isorto.org/site/c.jhKQIZPBImE/b.4344503/k.83C1/FERC_Filings.htm.
[215] With the exception of the Western study, discussion of solar in this chapter focuses entirely on solar PV systems. However, geographic diversity also applies to concentrating solar plants (CSP). CSP has substantial thermal inertia due to thermal storage in its working fluid which helps smooth the effects of short-term variations in solar radiation. Thermal inertia also can be enhanced through the storage of additional heated fluid. Thermal storage and an increased size in the solar collector field further smooth plant output due to passing clouds and allow for extended plant operations into or through the night. See Intergovernmental Panel on Climate Change, *Renewable Energy Sources and Climate Change Mitigation*, "Integration of Renewable Energy Into Present and Future Energy Systems," 2011, http://srren.ipcc-wg3.de/report/IPCC_SRREN_Ch08.pdf.
[216] NERC, *Accommodating High Levels of Variable Generation,* April 2009, http://www.uwig.org/IVGTF_Report_041609.pdf.

Figure 3. Solar Photovoltaic Plant Output on a Partly Cloudy Day at a Nevada Site[217]



Estimating short-term variability for solar includes predictable and unpredictable elements. The predictable portion is caused by the changing position of the sun throughout the day and is typically not noticeable for very short intervals (seconds to minutes), but may become more pronounced when the time interval extends beyond tens of minutes, particularly near sunrise and sunset.[218] Non-predictable solar variability is caused by the motion and formation of clouds. A cloud passing in front of the sun may cause a small PV project to move from full production to no production to full production in seconds. The time for a cloud to shade the entire PV system is contingent on system size, cloud speed and cloud height. A 100 MW PV plant will be shaded for minutes, not seconds. Changes in PV production from clouds are not uniform. Clouds may affect one part of a plant before another, or affect only one part of the plant and not the other.

A study that evaluated historical solar PV variability research and analyzed solar resource data found that changes in solar insolation[219] at individual sites can be significant, with changes in insolation exceeding 60 percent of the clear sky (cloudless) insolation. With the influence of geographic diversity, the large changes in PV solar output are reduced. Aggregating variability from 100 PV solar sites, nearly all changes in solar insolation in 15 minute intervals or less would be no greater than 10 percent of the clear sky output. The study also determined that for similarly located PV and wind plants, solar PV variability is slightly greater than wind, particularly during time scales of between five minutes and 15 minutes. The distance required to smooth variability on these time scales is slightly less for PV than for wind.[220] Other studies suggest that correlation of changes in output between two solar sites is a function of distance, time scale and cloud speed.[221]

Figures 6 and 7 depict the difference in variability in solar irradiance[222] between a single site and multiple sites. Figure 6 shows the variability for one day of solar irradiance from a single site in Napa,

[217] *Id.*
[218] R. Perez and T. Hoff, "Solar Resource Variability: Myths and Facts," *Solar Today*, August 2011, http://cleanpower.com/Content/Documents/research/capacityvaluation/Solar%20Resource%20Variability%20-%20Myths%20and%20Facts.pdf.
[219] Solar power density (in Watts per square meter) on a particular surface.
[220] Andrew Mills and Ryan Wiser, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power*, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-3884E, September 2010, http://eetd.lbl.gov/ea/emp/reports/lbnl-3884e.pdf.
[221] Solar forecasting companies estimate cloud speed. Cloud speed also can be estimated from satellite-derived irradiance forecasts available from web sites such as Solar Anywhere. See Perez and Hoff.
[222] The direct, diffuse and reflected solar radiation that strikes a surface usually expressed in kilowatts per square meter. Irradiance multiplied by time equals insolation. See http://www1.eere.energy.gov/solar/solar_glossary.html#I.

Calif.[223] Figure 7 shows solar irradiance data from 25 locations in this area rather than a single location. Short-term solar variability is clearly smoother for multiple sites than for a single solar site. In addition, data from existing PV sites in Germany indicate that five minute ramps (in normalized PV power) at a single site may exceed +/-50 percent, while five minute ramps (in normalized PV power) from 100 PV sites spread throughout the country never exceed +/-5 percent.

Figure 4. 10-Second Solar Irradiance for One Day at Single Site in Napa, Calif.[224]

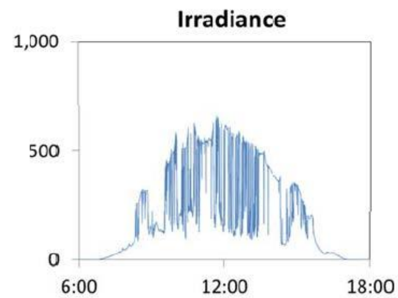
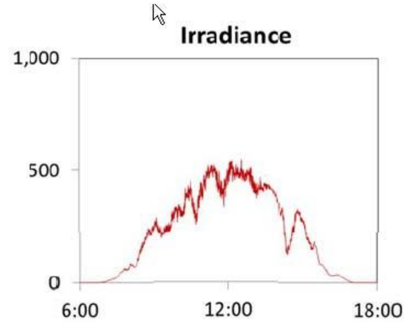


Figure 5. 10-Second Solar Irradiance for One Day at 25 Sites in Napa, Calif.[225]

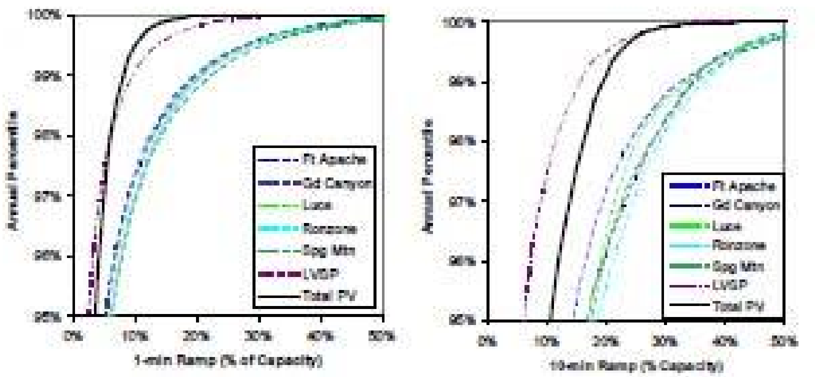


Geographic diversity can also occur *within* solar PV plants. The larger the plant, the greater the flattening effect on output. Several studies indicate significant smoothing in output across PV plants. Analysis of several time-synchronized solar insolation measurements in the Great Plains (six PV plants in Las Vegas, four PV plants in Arizona and two PV plants in Colorado) suggests smoothing occurs on longer time scales between PV plants than within each PV plant. Specifically, aggregating six PV plants in Las Vegas smoothed ramps at one minute, 10 minute and 60 minute intervals, with the greatest flattening for one minute and 10 minute ramps (see Figure 8).[226]

[223] Perez and Hoff.
[224] *Id.*
[225] *Id.*
[226] A. Mills, M. Ahlstrom, M. Brower, A. Ellis, R. George, T. Hoff, B. Kroposki, C. Lenox, N. Miller, J. Stein and Y. Wan, *Understanding Variability and Uncertainty of Photovoltaics for Integration With the Electric Power System*, Ernest Orlando Lawrence Berkeley National Laboratory, 2009, http://eetd.lbl.gov/ea/emp/reports/lbnl-2855e.pdf.

The general conclusion from research into solar variability is that with sufficient geographic diversity, the subhourly variability resulting from passing clouds can be decreased.[227]

Figure 6. One Minute and 10 Minute Ramps for Six PV Plants in Las Vegas[228]



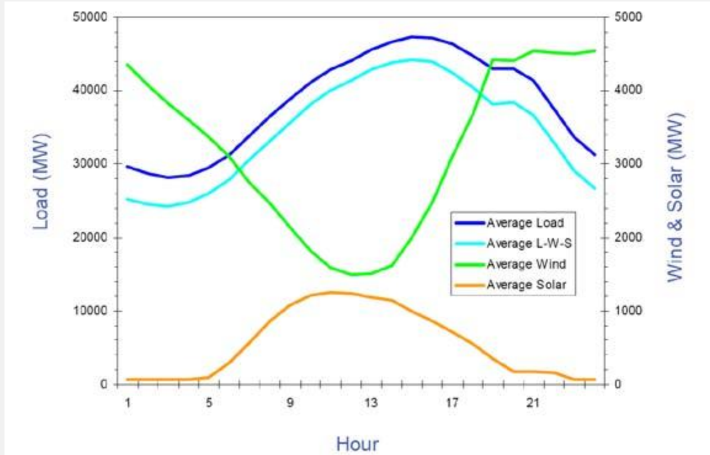
Benefits of Renewable Resource Diversity

Generation from different renewable energy technologies is typically not well correlated. Systems with a diverse range of renewable energy technologies will have smoother aggregate output and less overall variability and uncertainty.

The California Energy Commission's Intermittency Analysis Project found that aggregate solar and wind profiles in the state coincide well with load profiles. As shown in the graph, the reason is that the wind and solar profiles in the study have opposite — and therefore complementary — profiles. Wind generation tends to produce more energy during the off-peak load hours at night, while solar generation occurs during peak load hours during the day, when wind power is usually less available. The figure shows that the net load profile matches closely with the actual load profile.[229]

[227] When ramps over a particular time scale are uncorrelated between all (*N)* plants, the aggregate variability is expected to scale with $1/\sqrt{N}$ relative to the variability of a single point. For example, the aggregate variability of 400 PV plants should be about 5 percent of the variability if all of the same plants were at one location (1/√400). *Id.*
[228] *Id.*
[229] Xinggang Bai, Kara Clark, Gary A. Jordan, Nicholas W. Miller and Richard J. Piwko, *Intermittency Analysis Project – Appendix B: Impact of Intermittent Generation on Operation of California Power Grid*, California Energy Commission, CEC-500-2007-081-APB, July 2007, http://www.uwig.org/CEC-500-2007-081-APB.pdf.

Projected California Average Wind and Solar Output and Net Demand, July 2003[230]



Other studies have found similar results:[231]

- One study found a higher capacity credit for hydro when using wind power to conserve water stored in the reservoir. If wind generation and water flows are not correlated, the combination of wind and hydro power can decrease the risk of energy shortfalls in a hydro-dominated system.
- Studies have found the potential for reducing variability in combining wind and wave energy in Scotland, Ireland and California.
- Another study found similar benefits of combining wind, wave and solar power in Denmark, reporting that the different fluctuation patterns of the assortment of renewable resources could be mixed in optimal combinations to minimize excess generation. The optimal combinations change depending on how much of the electricity generation came from renewable resources. For example, the study found the optimized combination included 50 percent onshore wind, 40 percent solar PV, and 10 percent wave power when renewable energy comprised less than 20 percent of demand. But when renewable energy made up more than 80 percent of demand, the optimal mix was 50 percent onshore wind power, 20 percent solar photovoltaic and 30 percent wave power.

What portion of the benefits identified in these studies is due to geographic diversity rather than resource/technology diversity is unclear. Also, new transmission may be necessary to unlock the benefits of either one. Balancing authorities may prefer to deal with more integration challenges from geographically concentrated wind and solar plants than to incur the capital expense and risk of building new transmission. In addition, technology diversity benefits often are site-specific. The combination of wind and solar may not be negatively correlated as was shown in the California study. In Ireland, for example, wind generation tends to peak in the late afternoon and is more correlated with solar production. Further, as with geographic diversity, the costs and benefits of diversifying the renewable energy resource mix should be compared to the costs and benefits of a less diverse, but higher capacity factor, renewable resource mix.[232]

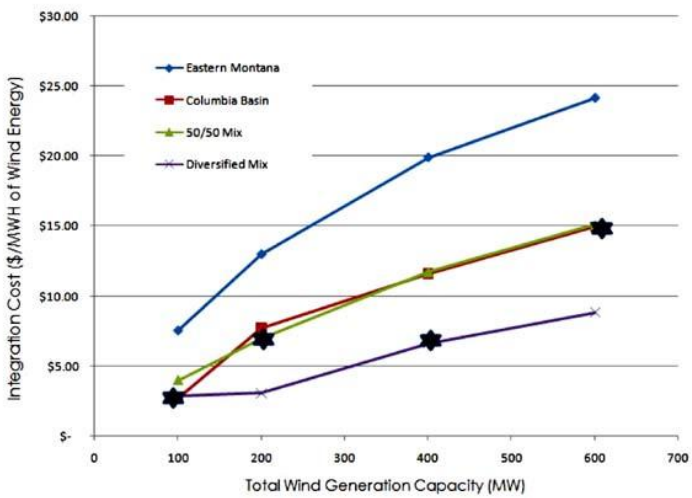
[230] *Id.*
[231] H. Lund, "Large-Scale Integration of Optimal Combinations of PV, Wind and Wave Power Into the Electricity Supply," *Renewable Energy*, 2006, 31(4), pp. 503-515, doi:10.1016/j.renene.2005.04.008.
[232] IPCC, *Renewable Energy Sources and Climate Change Mitigation: Special Report of the Intergovernmental Panel on Climate Change*, 2012, Prepared by Working Group III of the Intergovernmental Panel on Climate Change [O. Edenhofer, R. Pichs-

How Does Geographic Diversity Reduce Costs?

The beneficial impact of geographic diversity on variable generation depends on the amount of wind and solar generation relative to electricity demand, the variability of load alone, the size of the geographic footprint over which variable generation can be spread, and the level of diversity of the wind and solar resources.[233]

All other things being equal, a geographically diversified portfolio of wind or solar resources (or both) will reduce the costs of integrating variable generation. This is because aggregate generation output will be less variable, leading to reduced wind and solar forecast errors and reduced need for reserves. Figure 9 shows that according to one study, integration costs decreased with increased geographic diversity even as wind generation increased from 10 percent to 20 percent. In contrast, wind integration costs were higher for the less geographically diversified scenario (Eastern Montana). The wind integration costs for this study included costs for higher levels of regulation and load following reserves and costs due to wind forecast errors for higher wind scenarios, compared to a base case scenario.[234]

Figure 9. Effects of Geographic Dispersion of Wind Plants on the Integration Cost of Wind – Avista 2007 Wind Integration Study[235]



A wind integration study for NorthWestern Energy also found that geographic diversity helps decrease the need for regulation reserves, compared to no or limited geographic diversity. The study examined the incremental regulation service that would be required by the addition of 50 MW of wind power in the balancing authority area. The study found that a 50 MW wind plant added to a site near the largest existing wind project would require 21 MW of incremental regulation service, while adding the 50 MW plant approximately 200 miles away from the existing project would require only 5 MW of incremental

Madruga, Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, T. Zwickel, P. Eickemeier, G. Hansen, S. Schlömer, C. von Stechow (eds)], Cambridge University Press, p. 634, http://srren.ipcc-wg3.de/report/IPCC_SRREN_Full_Report.pdf.

[233] EnerNex Corporation, *Eastern Wind Integration and Transmission Study*, February 2011, http://www.nrel.gov/wind/systemsintegration/ewits.html.

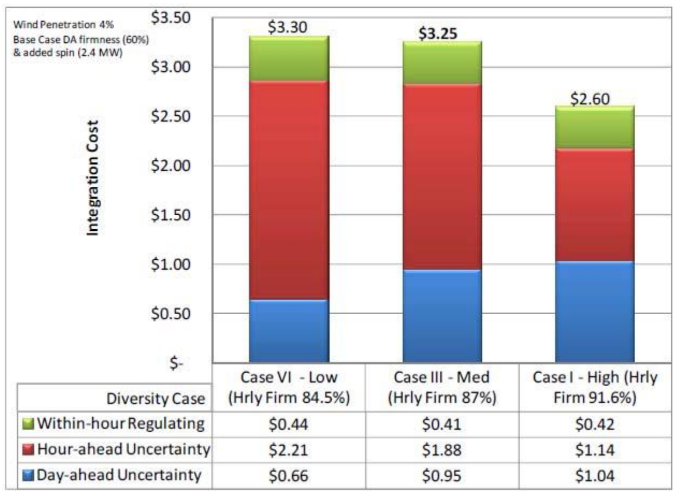
[234] EnerNex Corporation, *Avista Corporation Wind Integration Study*, March 2007, http://www.uwig.org/AvistaWindIntegrationStudy.pdf.

[235] *Id.*

regulation service. Further, the study found a *negative* incremental regulation demand (in other words, less regulation was needed after adding wind compared to not adding wind) if four 10 MW wind plants and four 2.5 MW wind plants were spread across the balancing authority area instead of adding a single 50 MW wind plant.[236]

A wind integration study for Arizona Public Service also found that reduced variation in aggregate wind energy production due to geographic diversity would reduce integration costs. The study examined three levels of geographic diversity at 4 percent wind energy penetration: 1) low geographic diversity with output from only two plants; 2) medium geographic diversity with output from three centrally-located plants (the "base case" scenario); and 3) high geographic diversity with output from plants at 10 sites. Integration costs decreased with increasing geographic diversity: $3.30/MWh for the low geographic diversity scenario, $3.25/MWh for the medium diversity scenario and $2.60/MWh for the high geographic diversity scenario. Figure 10 illustrates the sensitivity of integration costs to geographic diversity.[237]

Figure 10. Sensitivity of Integration Costs to Geographic Diversity of Wind Energy – Base Case[238]



Diversity Case	Case VI - Low (Hrly Firm 84.5%)	Case III - Med (Hrly Firm 87%)	Case I - High (Hrly Firm 91.6%)
Within-hour Regulating	$0.44	$0.41	$0.42
Hour-ahead Uncertainty	$2.21	$1.88	$1.14
Day-ahead Uncertainty	$0.66	$0.95	$1.04

What Are the Gaps in Understanding?

Although the benefits of geographic diversity are generally recognized, there is insufficient information that quantifies the costs and benefits. Further, geographic diversity is typically not factored into transmission planning or resource planning and procurement processes. The question is whether reducing aggregate variability of variable generation through geographic diversity, with the resulting reductions in reserves requirements and wind and solar forecast errors, justifies initiatives such as transmission expansion. By itself, geographic diversity is probably insufficient to justify new or upgraded transmission lines but it may be an additional benefit. Another benefit with transmission expansion is that the capacity value of wind may increase. The Eastern Wind Integration and Transmission Study found that the capacity value of wind ranged from 16.0 percent to 30.5 percent with the existing

[236] GENIVAR, *Northwestern Energy Montana Wind Integration Study,* prepared for NorthWestern Energy, June 1, 2011, http://www.uwig.org/NWE_WindIntegraionStudy_FinalReport_V1_20110606.pdf.
[237] Northern Arizona University.
[238] *Id.*

transmission system, and from 24.1 percent to 32.8 percent with a transmission overlay.[239] Regardless, the benefits of geographic diversity clearly support balancing authority area aggregation and greater cooperation between balancing authority areas through such measures as dynamic transfers.[240]

Siting optimization tools are advancing in development. They may be used to select wind and solar sites that maximize energy production and match utility load profiles, minimizing balancing reserve requirements and enabling variable generation to help meet those requirements. These tools also should account for any necessary transmission expansion. If fully developed, siting optimization tools could affect how renewable energy zones are identified and prioritized and be useful in utility resource planning and procurement.

Tools for Optimizing Geographic Diversity

Software under development includes Northup Grumman's Maximizing and Optimizing Renewable Energy (MORE) Power tool, which uses a stochastic optimization algorithm to compute the most advantageous locations in a region for renewable resources in order to minimize generation variability and maximize energy production. Using the MORE Power tool in an optimization model, the state of Montana compared typical placement of wind projects versus optimizing sites, both in-state. Results showed that optimized placement increased production of useable energy 58 percent, and significant ramping events occurred three times less, compared to current project placement.[241] The model, however, does not consider the impacts of capital (installation) costs or operational costs (energy revenues) in its optimization calculation. Therefore, to identify the economics of the model outputs, the results would need to be run through a production simulation model and capital cost model.[242]

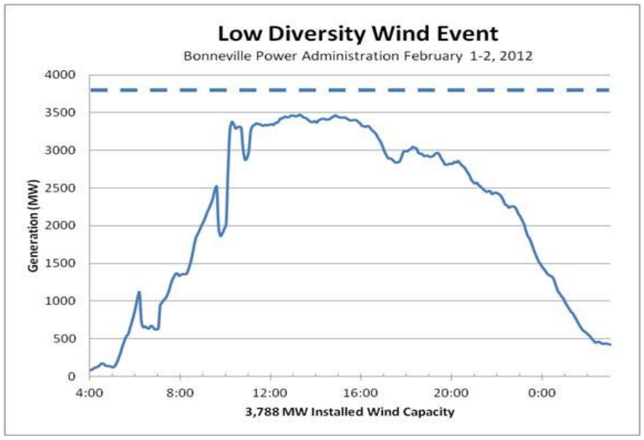
What Are the Implementation Challenges?

There are limits to accessing geographic diversity. First, lack of available transmission capacity may lead to concentrations of wind and solar plants, reducing or eliminating the potential for geographic diversity. In these regions, wind output becomes more correlated and less variable, and aggregate wind output becomes more volatile, similar to the output of a single wind turbine. Related, increasing spacing between solar or wind plants may require additional transmission capacity and incur higher transmission losses.[243] In addition, geographic diversity of wind and solar plants in a small balancing authority area is limited by its boundaries, unless variable generation from another area is transferred in through dynamic scheduling.[244]

[239] EnerNex Corporation, *Eastern Wind Integration and Transmission Study*, February 2011, http://www.nrel.gov/wind/systemsintegration/ewits.html.
[240] ColumbiaGrid and BPA are exploring a concept known as Variable Energy Resource Diversity Interchange (VERDI) which would operate much like ACE Diversity Interchange (described in Chapter 6 of this report), but focus on netting offsetting changes in variable generation between balancing authority areas.
[241] "A Value Statement to the State and Provincial Steering Committee Quantifying the Benefits to the Electrical Grid of Geospatially Dispersed Renewable Generation: A Proposal to Conduct a Study of Optimized Locations for Renewable Energy Generation as Part of RTEP," presented to the Committee on Regional Electric Power Cooperation and State-Provincial Steering Committee, Oct. 10, 2011, http://www.westgov.org/wieb/webinars/2011/October10/t_kaiserski.pdf.
[242] Michael Moore (NREL) and Brad Nickell (WECC), memo to State-Provincial Steering Committee Optimization Tool Work Group, March 9, 2012.
[243] Conversely, distributed (largely rooftop) solar PV inherently is more geographically diverse. *See* Mills and Wiser.
[244] Dynamic scheduling is addressed in another chapter in this paper.

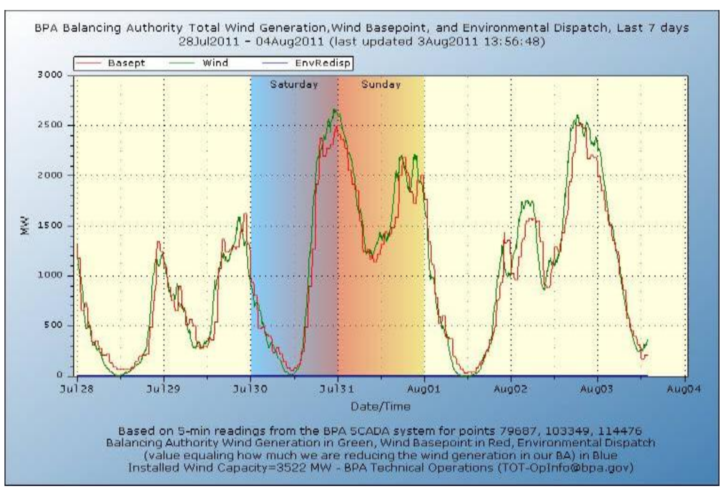
BPA's service area is an example of wind development concentrating around available transmission. As of April 2012, BPA had 4,400 MW of wind capacity in its service area,[245] and the agency projects to have as much as 6,000 MW of wind capacity by the end of 2013.[246] Figure 11 provides a recent example of a ramping event. Wind generation increased by 1,410 MW over a 40 minute span, representing over 37 percent of installed wind capacity in BPA.

Figure 11. Recent Wind Event on BPA's System[247]



Such rapid rises in wind production over a short period of time are relatively unusual, but they must be managed with sufficient balancing capacity. Figure 12 provides a more typical example, where wind ramps over a period of several hours. The graph shows five-minute wind production data from BPA between July 28 and Aug. 4, 2011.

Figure 12. Wind Generation in BPA's Balancing Authority[248]



[245] Bonneville Power Administration, *Wind Generation Capacity in the BPA Balancing Authority Area*, http://transmission.bpa.gov/Business/Operations/Wind/WIND_InstalledCapacity_Plot.pdf.
[246] Bonneville Power Administration, "Wind Power," http://www.bpa.gov/corporate/WindPower/index.cfm.
[247] Bonneville Power Administration, Wind Generation & Total Load in the BPA Balancing Authority, http://transmission.bpa.gov/Business/Operations/Wind/default.aspx.
[248] Courtesy of Eric King, BPA.

There also may be trade-offs in accessing geographic diversity. To the extent wind and solar sites are not of equal quality, more variable generation capacity may be required to realize the same generation output, at presumably higher cost of generating energy, compared to developing higher quality resources that are geographically concentrated.

In the Arizona study described earlier, the amount of wind capacity varied across the three geographic diversity cases. To reach higher levels of geographic diversity, some of the wind capacity from higher producing sites was replaced with lower producing sites. To make up for the reduced capacity factor of the lower quality sites, more capacity was required in the high geographic diversity case to achieve the same level of wind energy (4 percent). The low and medium geographic diversity cases required 468 MW of wind, while the high geographic diversity case required 510 MW of wind.[249,250]

What Could Western States Do to Encourage More Geographic Diversity of Renewable Resources?

Geographic diversity can help smooth the variability of wind and solar generation, thereby improving wind and solar forecasting and reducing reserve needs. Proactively accessing the benefits of geographic diversity, however, may require more generation capacity (at lower capacity factors) to be developed than in areas with higher quality but more concentrated wind and solar resources. The costs and benefits of proactively encouraging geographic diversity will likely be region-specific. Meantime, the region can capture some of the benefits of geographic diversity through cooperative efforts such as dynamic transfers and balancing authority area consolidation and coordination.

Western states could encourage the following actions toward improving geographic diversity of renewable resources in the region:

- Quantify the costs and benefits of geographic diversity in utility resource plans and procurement, subregional plans and Interconnection-wide plans. This includes, but is not limited to, siting wind and solar generation to minimize variability of aggregate output and better coincide with utility load profiles.
- Investigate the pros and cons of siting optimization software and whether it can be advantageously used in processes such as defining state and regional renewable energy zones and utility resource planning and procurement to reduce ramping of fossil-fuel generators and minimize reserve requirements.
- Support right-sizing of interstate lines that access renewable resources from regional renewable energy zones designated through a stakeholder-driven process in areas with low environmental conflicts, when it is projected that project benefits will exceed costs. Right-sizing lines means increasing project size, voltage or both to account for credible future resource needs. Building some level of transmission in advance of need could avoid construction of a second line in the same corridor or minimize the need for additional transmission corridors, and associated environmental disruption, as well as the risk that transmission may not be available to deliver best resources identified in long-term planning.

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[249] *Id.*

[250] A rough calculation of the cost of the additional wind capacity that is needed for the high geographic diversity case is $9.6/MWh (42 MW * $2,000/kW * 1,000 kW/MW * 15 percent/yr = $12,600,000/yr, divided by 1,314,000 MWh per year [510 MW wind plant with a capacity factor of 30 percent]). The federal production tax credit and other tax benefits were not factored into this estimate. Estimate courtesy of Andrew Mills, Lawrence Berkeley National Laboratory.

Chapter 6. Improve Reserves Management*

Power system reserves are quantities of generation or demand that are available as needed to maintain electric service reliability. Contingency reserves are required to maintain the reliability of the electric system in the case of an unforeseen event, such as a power plant outage. Balancing reserves are needed to balance generation and demand. While rules specify how much contingency reserves are required, there are no specific requirements for the amount of balancing reserves needed. Balancing authorities must schedule balancing reserves necessary to meet performance standards.

Higher penetrations of wind and solar resources increase the variability and uncertainty of the net load served by the system, increasing the need for balancing reserves.[251] The overall need for balancing reserves can be reduced through operational mechanisms to manage reserves more efficiently. This chapter covers operational changes that can minimize the amount of reserves needed to integrate variable generation while maintaining system reliability.

Key Types of Reserves[252]

Contingency reserves are required to maintain system reliability in the case of a significant system failure, such as a transmission line outage or sudden loss of a large generating resource. There are various methods for determining the amount of contingency reserves needed. One method sets the contingency reserve requirement equal to the largest credible outage on the system – for example, a large generator or transmission line that could potentially fail. Generating units slated to provide contingency reserve need to quickly restore system frequency and produce replacement power. In many parts of the U.S., utilities pool their individual contingency reserve obligations to reduce total capacity requirements through reserve-sharing groups.

Balancing reserves can be divided into regulating and load following categories:

Regulation reserves balance the momentary fluctuations in generation and load and deviations from forecasts. In larger power systems, regulation reserves are typically provided by generators that can respond to automatic generation control signals from the system operator to ensure that the frequency is maintained at its nominal level and that the area control error (ACE), a measure of the overall imbalance on the system, is within an acceptable range.

Load-following reserves are similar to regulation reserves but are used to respond to changes on a slower time scale – tens of minutes to hours. These reserves are used to address expected imbalances as a result of predicted changes in near term load and generation. For example, loads generally follow somewhat predictable patterns throughout the day, but load forecasts are never completely accurate. Dedicated load-following reserves address rapid increases in load that cannot be met by slower-ramping base-load units.

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* **Lead author: Lori Bird, National Renewable Energy Laboratory**

[251] Importantly, however, the system needs no more peaking capacity resources than it would without variable generation (except in the case of reserves needed to meet hourly export schedules). *See* Brendan Kirby and Michael Milligan, *Capacity Requirements to Support Inter-Balancing Area Wind Delivery,* NREL Technical Report, NREL/TP-550-46274, July 2009, http://www.nrel.gov/docs/fy09osti/46274.pdf.

[252] E. Ela, M. Milligan and B. Kirby, *Operating Reserves and Variable Generation*, NREL Technical Report NREL/TP-5500-51978, August 2011, http://www.nrel.gov/docs/fy11osti/51978.pdf.

Wind generation primarily increases the need for load-following reserves because most of the added variability and uncertainty is in the minutes-to-hours timeframe. Minute-to-minute fluctuations generally smooth out with a large number of wind turbines that are spread geographically.[253] In addition to the sheer quantity of reserve requirement, variable resources can increase the need for system flexibility – for example, generating units with fast ramp rates. However, variability can be reduced if variable generators are geographically dispersed and if system operators use improved forecasting.

Solar generation tends to have greater minute-to-minute variability due to the effects of cloud cover on generation. However, in power systems where load peaks summer afternoons, the daily and seasonal patterns of the sun are highly predictable and coincident with system peaks. The regulation reserve requirement does not increase linearly for large solar systems, because momentary fluctuations in output due to cloud cover rapidly average out over large or diverse facilities. However, large amounts of distributed solar generating units can make load forecasting more challenging due to the additional uncertainty in timing of load.[254]

Options for Minimizing Reserve Requirements: How Do They Work? Where Have They Been Used?

Mechanisms for reducing overall reserve requirements include reserve sharing, dynamically calculating reserves, using contingency reserves for wind events and controlling variable generation. The first two of these approaches are more proven, while at least some aspects of the latter two approaches are less developed.

1. *Reserve sharing* – Mechanisms to facilitate reserve sharing can reduce the individual reserve requirements of the system by averaging out short-term load and resource fluctuations across balancing authority areas.[255]

   A group of Western transmission providers and customers has implemented a program called the ACE Diversity Interchange (ADI) as a reliability tool to reduce control burden, which also reduces sensitivity to non-dispatchable resource output and improves control performance. An additional benefit of the ADI tool is sharing momentary regulation reserve requirements. ADI increases efficiencies in the system by taking advantage of the fact that some balancing authority areas may have a positive momentary imbalance (generation exceeds load) at the same time that others have a negative momentary imbalance (generation is less than load). By enabling balancing authority areas to net these surpluses and deficits, the entire system can gain efficiencies by sharing regulation reserves.

   The ADI program pools the control errors of participating balancing authorities. While it does not currently affect a balancing authority's reserve requirements because the system is voluntary and participants can opt out at any time, it allows sharing of regulation reserves on a momentary basis and reduces wear and tear on regulating units. The ADI tool used in the Western Interconnection

[253] NERC, *Accommodating High Levels of Variable Generation*, April 2009, http://www.nerc.com/files/IVGTF_Report_041609.pdf.

[254] See the forecasting and geographic diversity chapters in this paper for more information.

[255] Several reserve sharing groups are already established in the West, including the Northwest Power Pool, Rocky Mountain Power Pool, WAPA, and Public Service Company of Colorado and Desert Southwest. While these groups help to minimize the total capacity needed to supply contingency reserves, reserve sharing does not represent a fully optimized method of pooling reserves because the process is not responsive to changing system conditions. None of these groups have the ability to share regulation or load-following reserves.

currently limits instantaneous benefits to ±30 MW to ensure that no system reliability issues arise.[256]

ADI has been used in a variety of locations in the U.S. since the mid-1980s, by balancing authorities in the Southwest Power Pool, Midwest ISO, Northwest, and Mid-Continent Power Pool, where it originated.[257] Several balancing authority areas in Europe have implemented a system similar to ADI.[258]

The Western ADI system was implemented in just six months and began operation in 2007. The cost to maintain the ADI tool in 2012 is less than $200,000, which is equally shared among participants. Current participants include Arizona Public Service, BC Hydro and Power Authority, Glacier Wind (NaturEner Power Watch), Idaho Power Company, NorthWestern Energy, Puget Sound Energy and Salt River Project.[259]

Among its benefits, ADI is easy to implement, low cost, and results in less wear and tear on generating units because there are fewer adjustments to output levels. ADI also results in improved compliance with NERC performance control standards. In addition, it leads to fewer generators operating out of economic merit order. A recent NERC review of ADI found that its implementation has not had adverse impacts on reliability. NERC has essentially endorsed the use of ADI, recommending that the ADI white paper be converted to a reference document and added to the NERC Operating Manual.[260]

Other mechanisms to enable reserve sharing or reduce reserve requirements are discussed elsewhere in this report. For example, an energy imbalance market, such as the one operated by the Southwest Power Pool and as proposed for the Western Interconnection, would create a regional market for imbalance energy and reduce the need for balancing reserves in the market footprint. Subhourly dispatch and intra-hour scheduling also reduce reserve requirements.

2. *Dynamic calculation of reserve requirements* – Dynamically calculating regulation and load following reserve requirements, taking into account the levels of variable generation and load on the system, is another method of minimizing reserve needs. Because the variability of wind and solar generation, and net load, changes by generating output level, reserve levels can be set based on these variables.[261,262] The value of dynamically establishing reserve requirements becomes more significant at higher penetrations of variable generation.

   Today, reserve requirements are often set at static levels. Some system operators adjust reserve requirements hourly for load conditions, but not based on forecasted variable generation. A number of studies have suggested that changing reserve levels based on system conditions may improve

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256 Communication with Carol Opatrny, Opatrny Consulting, Inc., March 15, 2012.
257 Don Bradley, "ACE Diversity Interchange," presentation by NERC to Operating Committee, March 6, 2011.
258 André Estermann, "European Integration of Balancing Markets: Projects and Current Research," presented at the Utility Wind Integration Workshop on Market Design and Operation With Variable Renewables, June 2011.
259 Communication with Carol Opatrny.
260 NERC ACE Diversity Interchange Task Force, *Draft: ACE Diversity Interchange White Paper*, March 6, 2012.
261 NERC Integration of Variable Generation Task Force, Task 2.4 report, *Operating Practices, Procedures, and Tools*, March 2011, http://www.nerc.com/docs/pc/ivgtf/IVGTF2-4CleanBK(11.22).pdf.
262 The need to hold balancing reserves for load changes through time as well. For example, balancing requirements are highest during morning and evening ramps when loads are changing rapidly, versus the middle of the night and other hours when loads are not changing much through time. Some balancing authorities take advantage of this fact while others do not.

efficiency and reliability.[263,264] Reserve requirements could vary based on factors such as the load forecast, the variable generation forecast, net load variability forecast, the confidence in forecasts, and possibly information on the expected behavior of conventional generation.[265] For example, if wind is generating at its peak level, grid operators do not need to be concerned about the levels rising. Conversely, if wind generation is at its minimum level (zero), grid operators do not need to worry about reductions in wind output. The probability of movements up and down also can be taken into account in determining reserve requirements.

Many, but not all, wind energy ramps occur slowly and are more likely to be predicted closer to real-time operations. The ability to forecast these events means that system operators can be more certain of operating conditions, which can reduce the need to hold reserves. This pertains particularly to load-following reserves, which are most affected by wind generation.[266]

The ability to optimize reserves on a short-term basis is in some ways a function of the resource base available to a particular balancing authority. Thermal systems may have more flexibility to establish reserve levels on a shorter-term basis than large, interconnected hydro systems in which decisions in one hour affect operating conditions and water supply in subsequent hours.

There is some experience with adjusting reserve requirements based on system conditions. For example, ERCOT has a semi-dynamic method of calculating reserves. The regulation reserve and non-spinning reserve requirement depend on the amount of wind on the system, among other factors.[267]

3. *Using contingency reserves for wind events* – Another potential mechanism for reducing balancing reserves for variable generation is to use contingency reserves for extreme events in which large amounts of variable generation become rapidly unavailable. Today, although contingency reserves can be called on for wind over-speed events, load-following reserves are used for events when wind generation rapidly declines due to falling wind speeds. Large loss of wind generation occurs more slowly than system contingency events, such as an unscheduled outage of a conventional power plant. In addition, loss of variable generation output can be more easily predicted.[268]

   According to NERC, it may be desirable to assess whether large wind ramp events should be treated as contingencies because use of contingency reserves could reduce costs and increase reliability.[269] Some system operators are studying the concept of using contingency reserves for extreme wind events, including the Midwest ISO.[270] A statistical analysis is required to determine the benefits in

[263] E. Ela, B. Kirby, E. Lannoye, M. Milligan, D. Flynn, B. Zavadil and M. O'Malley, *Evolution of Operating Reserve Determination in Wind Power Integration Studies*, NREL Report No. CP-5500-49100, http://www.nrel.gov/docs/fy11osti/49100.pdf.
[264] Ela, Milligan and Kirby.
[265] Ela, Kirby, Lannoye, Milligan, Flynn, Zavadil and O'Malley.
[266] *Id.*
[267] ERCOT, *ERCOT Methodologies for Determining Ancillary Service Requirements*, 2010, http://www.ercot.com/content/mktinfo/services/kd/2010%20Methodologies%20for%20Determining%20AS%20Requirements.pdf.
[268] Ela, Milligan and Kirby.
[269] NERC IVGTF Task 2.4 report.
[270] ISO/RTO Council, *Briefing Paper: Variable Energy Resources, System Operations and Wholesale Markets*, August 2011, http://www.isorto.org/atf/cf/%7b5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7d/IRC_VER-BRIEFING_PAPER-AUGUST_2011.PDF.

reduced net reserves that result if reserves for wind and contingency reserves can be at least partially shared.

A recent NERC report notes that there are situations in which the loss of wind generation is similar to the loss of conventional units, such as when wind plants are tripped at their point of interconnection. Further, if the power system is in a state of emergency and the loss of variable generation exacerbates that condition, it makes sense to use contingency reserves to maintain system reliability. Wind cutouts due to high wind events qualify as contingency events in some regions. NERC recommends that regions or reserve sharing groups permit the use of contingency reserves under "imbalance energy circumstances made more likely with the increasing penetration of renewables."[271] This is an important issue that requires additional research and discussion. There is little agreement within industry at this point on how, and to what extent, to extend the definition of qualifying contingencies for wind generation.

4. *Controlling variable generation* – Relatively modest limits on wind turbine operations could significantly reduce the need to hold balancing reserves. Reserve levels are set to accommodate lower probability, large, rapid and unexpected changes in wind output, especially when turbines across a balancing authority area create energy imbalances in the same direction (actual generation all higher or all lower than forecast).

   Fortunately, wind ramps that are balancing authority area-wide tend to be associated with large-scale weather events that are more easily predicted than local variability for individual wind sites. Selectively imposing ramping limits when large-scale weather events are forecast may significantly reduce balancing reserve requirements at a relatively modest cost of some lost wind generation during relatively infrequent ramping events.

   In addition, wind turbines can be designed to respond to automatic generation control signals to provide regulation service on a minute-to-minute basis. Plant operators can pitch wind turbine blades quickly to provide second-to-second control. In fact, the speed of blade pitch controls can be faster than fuel and steam turbine controls in thermal power plants, so regulation service from wind turbines can be higher quality.[272] Solar units also can provide response fast enough for regulation and stability response. Inverters used in solar plants allow for cycle-to-cycle controls.[273]

   FERC is exploring ways to promote regulation and flexibility products. Faster and more accurate regulation sources could receive a higher payment. Currently, bilateral markets and transmission tariffs do not make distinctions based on these factors.

   However, supplying regulation from wind and solar generators would require the units to operate below full capacity to be able to ramp up, foregoing low-cost and clean generation. And because wind and solar generators have no fuel costs, it generally is uneconomic to use them for down-ramping compared to thermal units, which save fuel when providing this service. Instead, wind and

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[271] NERC, *Special Report: Ancillary Service and Balancing Authority Areas Solutions to Integrate Variable Generation*, March 2011, p. 18, http://www.nerc.com/files/IVGTF2-3.pdf.
[272] B. Kirby, M. Milligan and E. Ela, *Providing Minute-to-Minute Regulation From Wind Plants*, National Renewable Energy Laboratory, October 2010, http://www.nrel.gov/docs/fy11osti/48971.pdf.
[273] NERC, *Special Report: Ancillary Service and Balancing Authority Areas Solutions to Integrate Variable Generation*, March 2011.

solar generators lose the opportunity to generate electricity.[274] However, down-regulation from wind can be economically attractive to the system at minimum load periods.[275]

Wind turbines in Denmark provide regulation service on a regular basis, and Quebec is testing this practice.[276] For wind and solar generators to provide regulation service, ancillary service markets or other compensation mechanisms must be in place.

Ramp rate controls on wind and solar plants are another tool. Controlling large ramps from increases in wind or solar plant output does not greatly affect the economics of variable generating plants. The primary costs of implementing ramp rate controls are the curtailed generation from variable generation and the costs associated with the communications and control equipment. Ramp rate controls have been used in ERCOT, Ireland, Germany and Hawaii.[277]

How Would Improving Reserves Management Reduce Costs and Provide Other Benefits?

Reducing the need for reserves through better management can result in substantial operational cost reductions, resulting in savings to consumers. For example, the Western Wind and Solar Integration Study[278] (Western study) calculated benefits of reserve sharing and other forms of balancing authority cooperation, such as the ACE diversity interchange, an energy imbalance market and dynamic scheduling.

The Western study found that balancing authority cooperation can lead to operating cost savings because reserves can be pooled. To estimate the savings, the Western study performed a sensitivity analysis modeling the Western Interconnection as five large regions instead of a system designed to approximate today's 37 balancing authority areas. In the 10 percent renewable energy penetration scenario, the analysis found $1.7 billion (2009$) in operating cost savings region-wide as a result of larger balancing areas. Overall, the study found that significant savings can be gained from reserve sharing over larger regions with or without renewable resources on the system.

The Western study also found, assuming full balancing authority coordination in WestConnect, that the presence of renewable resources on the system can free up conventional generators to provide up-reserves. Generally, reserves required to accommodate wind and solar can be supplied by existing natural gas plants that are backed down. The Western study found that with 30 percent penetration of wind and solar, net load variability increases and average reserve requirements to address variability doubles. However, thermal units are backed down because it can be more cost-effective to do so than to take them offline. As a result, the Western study cases with wind and solar had *more* up-reserves available to the system. Thus, the study found that there was no need to commit additional reserves to cover variability resulting from increased wind and solar in the study footprint.

[274] In jurisdictions with renewable portfolio standards, qualifying renewable resources may receive substantial contract payments from load-serving entities. The loss of that revenue, as well as foregone federal production tax credits, would exceed the regulation capacity payments variable generators could receive for providing down regulation, so they would be unlikely to bid to provide ancillary services. In the future, on-site energy storage could make this option more viable.
[275] NERC Task 2.4 report.
[276] *Id.*
[277] *Id.*
[278] GE Energy, *Western Wind and Solar Integration Study*, prepared for National Renewable Energy Laboratory, May 2010, http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf.

What Are the Gaps in Understanding and Implementation Challenges?

Following are key gaps and challenges for improving reserves management:

- Methods to dynamically calculate reserve requirements are new and experience is limited. Additional work is needed to determine how to adjust reserve levels more frequently, while maintaining system reliability.
- Variable generation would need sufficient compensation to curtail output in order to provide regulation reserves.
- Additional research and implementation experience may be required to evaluate how contingency reserves could support the volatility of wind generation and determine if the use of contingency reserves for large wind ramping events would compromise system reliability.
- The value of selective ramp limits on variable generators needs to be calculated and offered as an option to generators seeking to reduce their integration costs.

What Can Western States Do to Encourage Better Reserves Management?

Western states could encourage the following activities to achieve better reserves management:

- Equip more existing conventional generating facilities with automatic generation control. Experiment with automatic generation control for wind projects and evaluate the benefits to the system against compensating wind generators for lost output.
- Expand reserve-sharing activities such as ADI. Implementation costs are minimal and benefits may be substantial. In addition, ADI programs should consider expanding capacity limits.
- Request the WECC Variable Generation Subcommittee to analyze dynamic reserve methods to help with wind and solar integration.
- Ask balancing authorities to explore calculating reserve requirements on a dynamic basis to take into account the levels of wind and solar on the system and other system conditions.
- Perform statistical analysis to determine the benefits in reduced net reserves that result if balancing reserves for wind and contingency reserves can be at least partially shared. If results are positive, work with NERC and WECC to develop protocols allowing the use of contingency reserves for extreme wind ramping events.
- Develop coordinated or standardized rules for controlling variable generation that minimize economic impacts to wind and solar generators. Controls should be limited to situations where actions are needed to maintain system reliability or when accepting the variable generation leads to excessive costs.[279]
- Consider different wholesale rate designs to encourage more sources of flexibility.

[279] NERC Task 2.4 report.

Chapter 7. Retool Demand Response to Complement Variable Generation*

Within the realm of demand-side management, demand response is distinct from conservation or energy efficiency.[280] Demand response has traditionally referred to short-term reductions in demand in response to temporary shortages of energy. Yet the value of demand response in reliably and cost-effectively integrating variable renewable energy resources dramatically transcends its traditional role.

Electricity and natural gas suppliers have always solicited consumers willing to forego service under prescribed system events in return for compensation in some form, called "interruptible load." This is a blunt and often disruptive form of demand response used during power system emergencies and where it is a cost-effective alternative to investing in the infrastructure necessary to serve the last increment of load experienced very few hours a year, during periods of maximum demand on the system. If used sparingly, this approach to demand response can be useful in a system where nearly all generating resources are typically available[281] when and as needed to serve demand, and where *demand* is presumed to be largely beyond the control of system operators.

Where the *availability of supply* is increasingly beyond the control of operators, as is the case with variable energy resources,[282] the presumption that demand is virtually uncontrollable presents a different set of challenges. Periods of energy shortfall – with price spikes, service interruptions or both – may be more frequent and not necessarily associated with peak demand.[283] At the same time, periods of energy surplus will increase, with very low (or even negative) prices and curtailment of least-cost resources.[284] This in turn increases the value of opportunities to shift load in a predictable and repeatable fashion from one time of day to another, and in a related function to ramp load up and down as an alternative to more costly measures – in a manner and on terms acceptable to the consumer, with minimum disruption to delivery of energy services.[285]

The plummeting cost and exploding functionality of information, communication and control technologies are opening new demand response possibilities for managing variable generation at lower cost than alternatives like grid-scale energy storage. However, the value of responsive demand in this expanded role relies on the ability to deploy it much more frequently and in both directions – reducing and increasing demand in concert with variable generation and system conditions. In turn, this requires innovative new value propositions for consumers. This chapter surveys the untapped potential of cost-effective demand response for integrating variable generation, identifies remaining barriers to its widespread deployment, and makes recommendations for addressing them.

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* **Lead author: Mike Hogan, Regulatory Assistance Project**

[280] The North American Electric Reliability Council (NERC) categorizes demand-side resources at http://www.nerc.com/page.php?cid=4|53|56.

[281] "Available" is used here in the technical sense that the resource is physically capable of operating and has access to the primary energy source required to operate it.

[282] Use of automatic generation control for wind plants is discussed in chapters 6 and 8.

[283] In ERCOT, with 8.5 percent of 2011 supply coming from wind, 21 "load resource deployments" have occurred since April 2006; 15 were outside of the summer peak season and eight of those occurred between 8 p.m. and 8 a.m.

[284] The Pacific Northwest had its first high-profile encounter with this phenomenon in the spring of 2011 during a period of extreme hydro production, in tandem with increasing wind production. Denmark, however, has managed this issue on a regular basis for more than a decade.

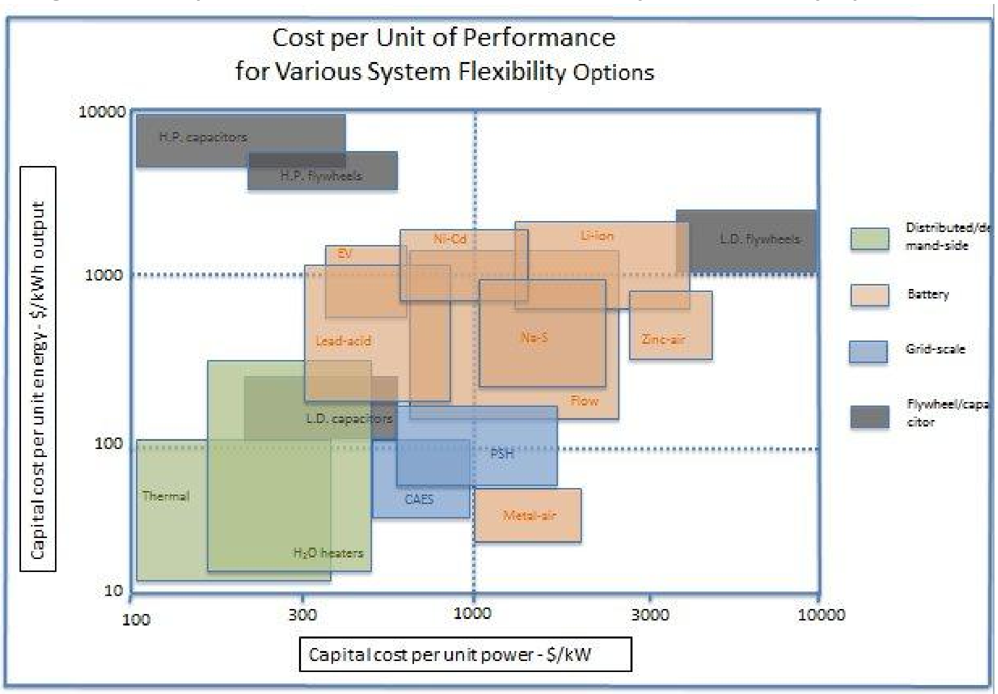
[285] The U.S. Energy Information Administration, in its most recent *Electric Power Annual* released in November 2011 (http://205.254.135.7/electricity/annual/), continues to measure "demand-side management" only in terms of peak load reduction, even as NERC has begun to track the many other services demand response increasingly provides (http://www.nerc.com/page.php?cid=4|53|56).

How Does Demand Response Reduce Costs?

Implementation of measures addressed elsewhere in this report, including various forms of balancing authority cooperation, shorter scheduling intervals and better forecasting, can dramatically reduce the need for additional integration strategies such as demand response. Where additional measures are necessary, however, demand response appears to offer a low-cost system solution.

A number of programs are underway to demonstrate the functionality and cost of the most promising demand response strategies. Meantime, recent studies provide indicative cost comparisons to other approaches, such as battery technologies, pumped storage hydro and compressed air storage. Figure 1 captures analysis by Sandia National Laboratories and the Electric Power Research Institute on cost and performance for a range of flexibility options available to system operators.

Figure 1. Cost per Unit of Performance for Various System Flexibility Options[286]



The demand response strategies discussed in this chapter are on average about 10 percent to 30 percent of the cost of grid-scale options – pumped storage hydro and compressed air storage – for roughly comparable performance. These demand response strategies are even more competitive compared to currently available batteries and strategies for specialized tasks such as frequency response. Some of these alternatives may well see dramatic improvement in coming decades, but broadly speaking demand response provides a compelling consumer benefit that is accessible with proven technology.

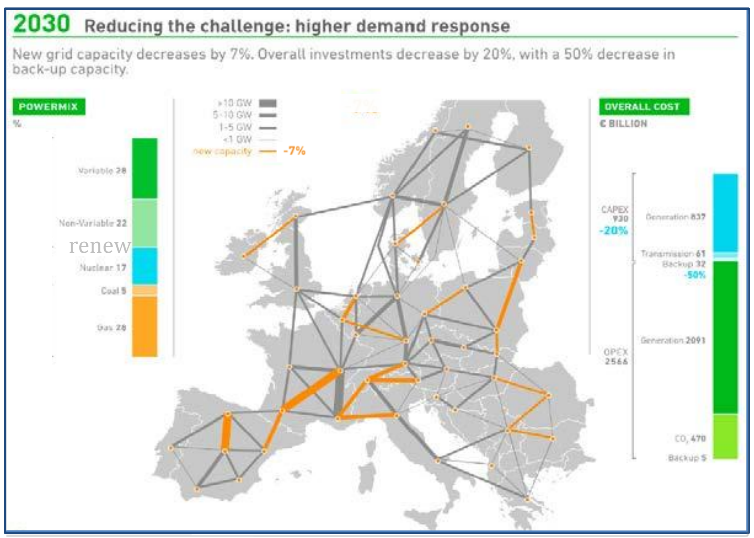
Another dimension of consumer cost savings has to do with the deployment of any of these strategies at all, versus balancing the system by "brute force" – keeping a significant quantity of generating capacity

[286] Based on information from http://www.electricitystorage.org/technology/storage_technologies/technology_comparison and data compiled by Ecofys in BPA Technology Initiative #220.

in reserve, ramping it as necessary to address under-supply situations, and curtailing capital-intensive, low-marginal cost nuclear and variable energy resources to address over-supply situations. Of course the brute force option seems expensive, but are the demand response strategies described here less expensive? In the Western Wind and Solar Integration Study, the estimated benefits of using demand response instead of spinning reserves from thermal generators in high wind scenarios was on the order of $310,000 to 450,000 per MW per year.[287] In high wind scenarios in ERCOT, the benefit of using real-time pricing for all customers to help balance the system was estimated to be $6 to $10 per MWh of wind generation.[288]

A widely respected study recently completed for the European grid provides further insight. Figure 2 shows the difference in system investment required between two scenarios with high penetrations of variable energy resources – one in which demand is treated more or less as it is today, and the other where 10 percent of the aggregate demand in the course of a day is assumed to be "moveable" from periods where supply is less available to periods where it is more available. The result is less need for backup capacity, less need for curtailment of least-cost resources like wind and solar, and less need for transmission, all leading to a net reduction in investment needs of more than 20 percent over the next 15 to 20 years.[289] If these types of investment savings can be captured and passed through to retail customers, the benefits to consumers should be significant.

Figure 2. Effect of Demand Response on Future Investments in Resource and Transmission in the European Union[290]



287 *See* Peter Cappers, Andrew Mills, Charles Goldman, Ryan Wiser and Joseph H. Eto, Lawrence Berkeley National Laboratory, *Mass Market Demand Response and Variable Generation Integration Issues: A Scoping Study*, October 2011, http://eetd.lbl.gov/ea/ems/sg-pubs.html (citing GE Energy, *Western Wind and Integration Study*).
288 Ramteen Sioshansi and Walter Short, "Evaluating the Impacts of Real-Time Pricing on the Usage of Wind Generation," *Power Systems, IEEE Transactions on Power Systems*, 24 (2): 516–524, May 2009.
289 McKinsey & Co., KEMA, Imperial College London and European Climate Foundation, *Power Perspectives 2030: On the road to a decarbonized power sector*, October 2011, http://www.roadmap2050.eu/pp2030.
290 *Id.*

What Are Other Benefits of Demand Response?

Deployment of demand response strategies that mitigate the cost of reliably integrating variable generation is likely to produce collateral benefits as well. These include:

- Affordable access for more customers to an expanded array of energy services
- An enhanced sense of consumer empowerment in the face of rising energy costs
- Increased efficiency in the delivery of energy services
- Non-exportable skilled craft and IT employment in deploying and managing demand response systems
- A more distributed electric system better able to absorb unexpected disruptions
- Reduced need for construction of large-scale infrastructure and reduction of associated impacts
- A more rapid, secure transition to a less polluting, domestic and non-depletable energy supply

Sources of Demand Response as a Balancing Resource

The potential to expand demand response as a resource for balancing services exists across all customer classes, from the largest industrial consumer to individual households. The nature of their loads, the scope of untapped demand response potential, and the means for accessing it vary and can be grouped into three categories:[291]

Large industrial customers
Historically most demand response has come from large industrial customers with electricity-intensive processes.[292] These customers typically have some discretion over when they run certain processes within a day, and they are more likely to have the infrastructure, expertise and resources needed to contract with vendors for demand response services. While the large average size of these interruptible loads offers logistical and administrative advantages, they have historically not been well matched for day-to-day balancing operations. That's because they tend to be geographically concentrated, many of the processes are typically on or off (rather than adjustable), and there are usually strict limits on the number of times they can be called on for responsive demand.[293] Facilities may include operations with smaller loads similar to those described below for commercial customers, but most of this potential remains untapped and for the same reasons.

Commercial, small industrial and government customers
These nonresidential customers are typically smaller and less electricity-intensive than large industrial customers and therefore more challenging to access. However, in the aggregate they represent significant demand responsive potential.[294] They tend to be more business savvy than residential consumers though usually not at the same level of sophistication as large industrial customers and with fewer resources – technical, financial and legal. While these nonresidential customers normally have fewer options than large industrial customers for shifting demand, they may have loads that can be modulated over short periods of time, such as variable-speed drives, area lighting and space

[291] For a quantitative breakdown of these customer classes, see http://www.electripedia.info/consumers.asp.
[292] Federal Energy Regulatory Commission (FERC) Staff Report, "A National Assessment of Demand Response Potential," prepared by The Brattle Group, Freeman, Sullivan & Co. and Global Energy Partners LLC, June 2009, http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.
[293] Encouraging recent exceptions include ALCOA providing regulation services to MISO from their Warrick, Ind., facility and ERCOT deriving 50 percent of spinning reserves from a handful of industrial and commercial customers.
[294] FERC, June 2009.

conditioning. In many cases, they also have loads such as commercial chillers or medium-heat processes that are well suited to thermal energy storage applications.

Due to the size and nature of the individual loads, they are often a good fit for day-to-day balancing operations. Yet much of this potential remains untapped due to historical logistical, administrative and regulatory barriers. Technology is rapidly reducing the logistical and administrative barriers by reducing the cost and increasing the functionality of real-time automated control of smaller loads in ways that have little or no perceptible impact on the quality of energy services, and entrepreneurs are beginning to innovate ways to access this potential.[295] However, in many jurisdictions regulatory barriers and resistance from electricity suppliers remain obstacles.[296]

Residential customers
Residential customers are the largest untapped pool of demand response potential.[297] Broadly speaking they are highly diffuse; vary widely in their levels and patterns of consumption; have low response to electricity prices; lack information, time and specialized expertise; face financing constraints; and in organized markets do not have the same access to wholesale markets as large customers. Due to technical constraints and regulatory practices for retail pricing, household consumption of energy services has historically been largely divorced from conditions on the power grid at any given time.

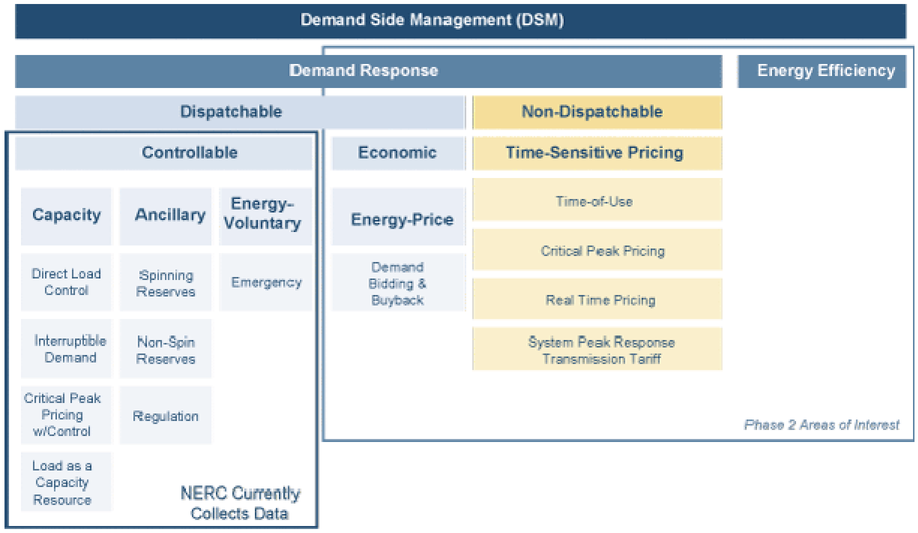
Some of the largest loads with the greatest demand response potential, such as water heating and refrigeration, are non-seasonal uses and are therefore well placed to provide balancing services. Electric vehicles hold great potential for flexible loads and storage services but broad commercial application is many years away. The residential sector offers a rich vein of potential today even without electric vehicles and at a fraction of the cost of other alternatives for expanding balancing services for the grid. Accessing that potential, however, will require a reconsideration of the potential uses of demand response, how to expose the relative value of demand response to all concerned, who has access to the market, what it will take to gain consumer acceptance, and how individual households can expect to be compensated for providing services that may in the first instance be of value only to grid operators but that in the end benefit all consumers.

What Services Can Demand Response Provide?

The role of demand response has historically been limited largely to blocks of electricity demand that can be interrupted at times of peak system load. As the share of production from variable sources rises, and the cost of shaping demand in real time with little or no perceptible degradation in energy services falls, a broader suite of demand-shaping options comes into play. Figure 3 illustrates the widening array of services demand response is beginning to provide system operators.

[295] See http://www.enbala.com/video.html for an instructive example.
[296] FERC, June 2009.
[297] See FERC Staff Report, *Assessment of Demand Response and Advanced Metering*, September 2009, http://www.ferc.gov/legal/staff-reports/sep-09-demand-response.pdf.

Figure 3. NERC's Classification of Demand Response Services[298]



NERC explains the expanded role of demand response:[299]

> In addition to its ability to target peak demand growth, communications technologies have made the resource more dispatchable than ever before, in many cases available to operators in a matter of minutes.
>
> In fact, demand response is increasingly being classified as non-spinning reserves and used as "ancillary services" by many utilities…. Use of demand response as spinning reserves indicates that operators are beginning to count on the resource with more certainty and that the programs are available to operators within strictly defined time-windows.

These are no longer emergency functions but normal, day-to-day balancing services requiring high reliability, fine control and response times running from seconds to hours. Providing these services also requires demand to be able to ramp down *and* up as needed. In addition, with greatly increased frequency of use it is important to distinguish between demand for electricity and demand for the associated energy services, such as space heating, water heating and air-conditioning. Further, non-seasonal loads are clearly preferred.

Three broad categories of loads are capable of delivering these kinds of services day in and day out without noticeably inconveniencing customers – the common denominator in each case that the consumption of electricity can be separated in time from the consumption of the energy service:

1. *Discretionary demand*, where the timing of the load is flexible within a given period of time. Large industrial loads historically tapped for peak-shaving services fall into this category.

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[298] See http://www.nerc.com/page.php?cid=4|53|56.
[299] *Id.*

Another example is water utilities with the flexibility to run pumping operations selectively within a 24-hour period.

2. *Demand that can be temporarily reduced or interrupted* – This category includes loads where the delivery of electricity can be reduced or interrupted for limited periods of time without noticeably degrading energy services. One example is refrigeration where individual compressor motors can be turned on and off for short periods of time with no noticeable impact.
3. *Distributed energy storage appliances* – This category primarily uses thermal energy storage to allow the timing of electricity delivery to be decoupled from the delivery of the associated energy service. An example is electric water heaters, where surplus electricity can be stored as higher temperature water – above normal set-points – to be mixed later with colder water to deliver the same quality and quantity of energy services (in this case, hot water) without interruption. This time-shifting service is normally associated with more expensive supply-side storage resources like pumped hydro or nascent compressed air storage technologies. But demand-side applications like electric water heaters are right at the load and use well-proven, low-cost technology.

How Will Demand Response Be Delivered and Who Will Make It Available?

An expanded role for demand response has the potential to reduce considerably the cost of integrating large amounts of variable generation while safeguarding reliability. The key lies in empowering demand to be more responsive in real time to changes in the supply of energy, upending the increasingly outdated assumption that supply must always respond in real time to changes in demand for energy services.

How Will Demand Response Balancing Services Be Delivered?

There are two basic ways for system operators to get the desired response from demand: an active response on the part of the customer to a signal originating from the grid, or direct control of designated loads on the customer's premises as needed (within agreed-upon constraints). In either case three key factors must be addressed: 1) for demand response to provide a real alternative on a par with supply-side measures it must be dispatchable (controllable) by system operators to a comparable degree of reliability, 2) the customer must retain final say over when and how the load responds and 3) the customer must be fairly compensated for the value provided.

Price can serve as a signal to customers of the need for a particular balancing response and as a measure of the value of the service actually provided, and allowing customers to respond to price clearly satisfies the need for customer control. However, it raises questions about how much control the system operator can exercise to obtain the needed services. Are the pricing structures dynamic enough, and can or will customers respond quickly enough – with or without the help of automated technology – to meet the needs of system operator?

Direct load control by system operators can solve this dispatchability issue and is increasingly practical for much smaller and more diffuse loads than in the past. Under these arrangements, customers grant system operators (or intermediaries) direct control over selected loads, though they retain final say over what loads can be controlled and how, and price can still be used as a yardstick for value. However, despite decades of utilities cycling air conditioners in homes and small businesses for peak demand reductions, for example, the prospect of granting the utility or grid operator direct access to customers' appliances or equipment may raise concerns about privacy and control. (In the age of Facebook and

Google this may not be as much of an issue, especially if customers can choose their own third-party demand response service.)

Fortunately, it appears feasible to access the highest-value potential applications by combining the best of both approaches. Recent studies indicate that the response time horizon for balancing issues raised by high levels of variable generation is in the range of tens of minutes to 12 hours.[300] Real-time pricing and direct load control programs are dynamic enough to work throughout this timeframe, though other forms of time-varying pricing are not.[301] Direct load control programs are preferred to real-time pricing in the seconds-to-minutes timeframe, but no material increase in the need for such fast response service is expected from integrating large shares of variable generation.

Real-time pricing for large industrial customers is in wide use. It can address the relevant timeframe and may avoid the privacy and control issues raised by direct load control. But the complexity and frequency of the response envisioned will quickly exceed the tolerance of all but the most dedicated in other customer segments.

For households and small businesses, the response must be as invisible as possible to the consumer, a criterion that is increasingly feasible but that makes the response mechanism more complex. Further, while a demand response service may be of good value to the system operator compared to alternatives, it may not warrant a price signal severe enough to elicit an active response from the customer. For example, a given demand-based two-hour ramping response that is less costly than supply-side options may translate into a price difference of only tenths of a cent per kilowatt-hour when spread across all customers – not the kind of savings that have traditionally moved most consumers to take notice. Further, the value per kilowatt-hour is much greater if applied to, say, the 20 percent of customers able, willing and needed to achieve the required ramp.

The objectives for real-time pricing are to preserve customer control, while at the same time causing minimal inconvenience in both the setting of the response and its effect on the customer. For these reasons, a "set it and forget it" model is critical to the success of real-time pricing-based programs as a system balancing tool.[302] The real-time pricing model that is appropriate for integrating variable generation therefore approximates in important ways the direct load control model.

Price remains the primary yardstick for value in both models, and compensation could be provided through a read-out in the customer's utility bill of the various prices paid per kilowatt-hour and when. It is possible, however, to imagine other ways to make participation both convenient as well as financially rewarding, particularly for residential and small commercial customers.[303] One such approach might involve a menu of fees paid to the consumer depending on which services, and in what quantity, the consumer has agreed to provide – in essence, a demand charge flowing to the customer rather than the other way around. Whatever approach is taken, the objective is to maximize cost-effective demand response by keeping the value proposition simple and attractive.

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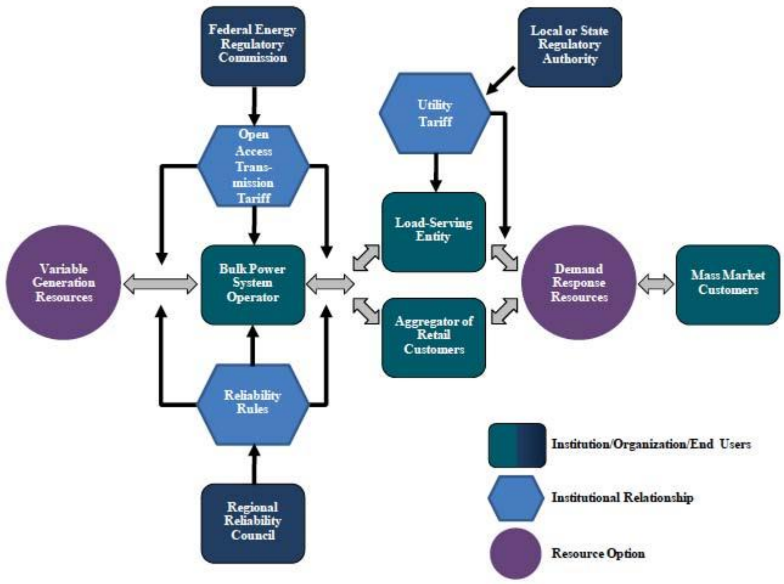
[300] GE Energy, Western Wind and Solar Integration Study, prepared for National Renewable Energy Laboratory, May 2010, http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf; NERC Integration of Variable Generation Task Force, *Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation*, March 2011, http://www.nerc.com/files/IVGTF2-3.pdf.
[301] Cappers, *et al.*
[302] *Id*.
[303] For example, a number of electricity co-operatives offer free electric water heaters to their customers in return for the right to use them as embedded thermal energy storage devices. A good example is St. Croix Electric in Wisconsin.

Who Will Deliver Demand Response Balancing Services?
Figure 4 shows numerous stakeholders all along the value chain (as illustrated, with a specific focus on residential and small nonresidential customers), each of whom will have a hand in either enabling or inhibiting development of demand response balancing resources. Of particular interest are stakeholders who will act at the customer interface to turn demand response into a practical resource that system operators can call upon to balance variable generation.

Figure 4. Organizations and Institutions That Influence the Relationship Between Variable Generation and Demand Response Resources[304]



Large industrial customers typically work directly with the load-serving entities (including utilities) or the system operator when providing demand response services, although some industrial customers work with intermediaries. As participation in demand response expands, particularly among residential and small commercial customers, there are compelling reasons to consider a larger role for non-utility entities as intermediaries. Much of the untapped potential will require incremental investment at customer premises, which can be procured and financed more efficiently at scale. Scale, accountability and enforceability are needed for demand response to become a practical, reliable balancing resource. Further, tapping the full potential of demand response in the residential and small commercial segments requires applying advances in information, communication and control technologies to take advantage of the diversity and granularity of loads.

Third-party aggregators of retail customers have emerged in recent years as a viable alternative, opening up the possibility of multiple demand aggregation and activation strategies.[305] These entities contract with a large number of dispersed customers to install load management devices on premises, enabling enhanced real-time responses that are aggregated into the kind of large-scale, distributed, controllable and accountable system balancing resources valued by system operators.

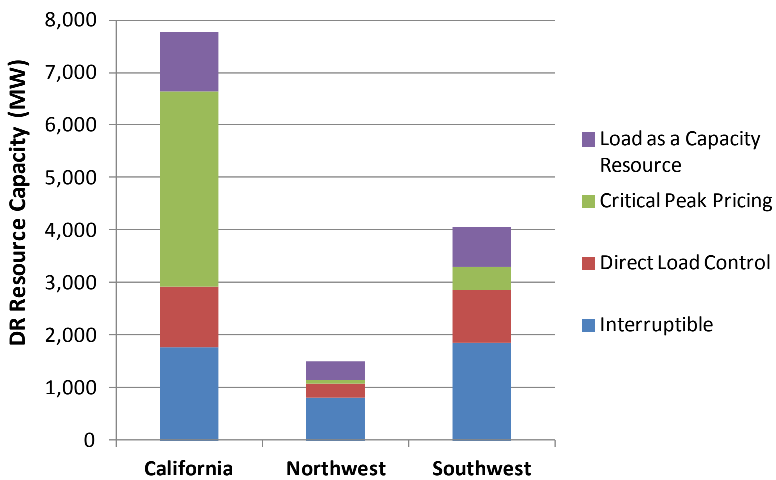
[304] Cappers, *et al.*
[305] *Id.*

Competition at the consumer interface drives far more rapid innovation and value creation than is possible when access to control of customer loads is restricted to a single entity. When it comes to providing electricity, there is reasonable disagreement over whether the possible benefits of competition outweigh the costs and risks. In the case of demand response, however, because the primary objective is to change the shape of demand and all of the action takes place on the customer premises ("behind the meter"),[306] lack of competition simply leads to disempowered customers, stifled innovation and wasted cost-saving opportunities.

What Is the Potential Size of the Demand Response Balancing Resource?

The potential size of the demand response balancing resource is difficult to assess with confidence for several reasons, including the need to better understand implementation costs and the degree to which system flexibility will be provided through other means, including those described elsewhere in this report. Figure 5 presents one measure of the potential scope for cost-effective demand response, referring only to its role in shaving peak demand.

Figure 5. Demand Response Resources in 2022 in "High DSM Case"[307]



[306] Expanding the role of demand response will drive changes in the distribution system as well, but the scope of these activities is unaffected by the type of entity providing demand response for the customer.
[307] Galen Barbose, "Utility DSM in the West: Current Targets and Cost-Effective Potential," *Western Clean Energy Advocates meeting*, April 12, 2012.

Proofs of Concept

The proposition that demand response can deliver cost-effective dynamic grid reliability services, particularly those most valuable in integrating variable generation, is already being tested in various places. The following is a representative sampling:

Balancing French Nuclear Plants
What may be the longest duration proof of concept are measures that EdF, the state-owned French utility, has used for decades to operate its system with 80 percent of electricity produced by relatively inflexible nuclear plants. Given the normal variability of demand for energy services by its customers, EdF faces frequent oversupply challenges. To avoid as much as possible the high cost of turning down nuclear plants, EdF has employed strategies such as investment in a distributed system of electric water heaters with highly efficient thermal storage tanks. Excess electric production by the nuclear fleet is diverted to heat water that is stored and used to deliver steady supplies of thermal energy for various local uses.[308]

ERCOT
Demand resources currently participate in ERCOT's regulation, responsive (spinning) reserves and non-spinning reserves markets, as well as programs like Emergency Interruptible Load.[309] Participation is limited by several factors including required metering and telemetry infrastructure, currently in place for only a handful of industrial and large commercial customers. Yet ERCOT already gets 50 percent of its spinning reserves from demand response – the maximum currently allowed. In total, demand response from 189 customers provides 2,400 MW of ancillary services capacity (about 4 percent of ERCOT's peak load), half of which is provided by 10 large industrial customers. A pilot for mass-market customer participation in ERCOT's demand response markets through aggregation is planned for summer 2012.

BPA Technology Innovation Project
One of the most interesting demand response pilots for balancing variable generation is currently underway at nine BPA customer utilities. The research team is trialing the use of new and existing water heaters, space heating, and cold storage systems as distributed energy storage devices to provide load-following (10- to 90-minute load ramps both up and down), which has been identified as the most pressing challenge presented by the growth in variable generation in BPA's footprint.

Denmark's EcoGrid Project
Denmark's challenge is a combination of a large wind fleet (about 20 percent of its annual energy production is from wind) and a large number of district heating plants that produce electricity and steam. Wind plants, with near-zero production cost, are treated as must-run facilities. The district heating plants operate primarily to supply heat to homes and businesses. Therefore, the supply of electricity in Denmark ramps up and down with no particular correlation to fluctuations in demand. The country is blessed with a neighboring power system that is nearly all hydro and currently has enough interconnection capacity with the neighboring system to manage these cycles. But as the country seeks to expand wind generation to 50 percent of production this will no longer suffice, so a program is in development to expand demand response (including increased use of electric heat pumps) and increase

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[308] See, for example, S.D. Thomas, *The Realities of Nuclear Power*, 1988, chapter 8.
[309] Jay W. Zarnikau, "Demand participation in the restructured Electric Reliability Council of Texas market," 2009, *Energy* 35 (2010) 1536–1543, http://www.frontierassoc.com/files/DemandParticipation.pdf.

the capacity of thermal energy storage associated with the country's district heating systems. Denmark also is developing "microgrids"[310] that tie various electricity loads to the availability of energy.[311]

GridMobility Pilot at Mason County PUD #3
A pilot involving 100 residential customers of Mason County (Wash.) Public Utility District #3 is testing a technology that uses water heaters to store energy when variable generators are producing power, while delivering steady hot water service to the customer. A crucial difference with the BPA project described above is that load is responding here specifically to increases and decreases in variable energy production rather than to overall system balancing requirements.

What Are the Gaps in Current Understanding?

Gaps in our understanding of demand response for integrating variable generation include more definitive information in the following areas:

- Implementation costs, including distribution system impacts and programmatic costs
- Effectiveness of various business models for eliciting a utility's interest in aggressively pursuing demand response
- Measurement and verification and duration of savings
- Effectiveness of various consumer education programs and marketing approaches for customer participation
- Data security protections

In addition, at higher penetration levels of distributed renewable generation, the need for and use of demand response for distribution system integration and balancing will increase. This in turn will result in "competition" between load-serving entities and grid operators for demand response resources. Understanding how this situation may evolve is important for identifying the role that demand response can play in integration of renewable resources at the transmission level.

What Are the Implementation Barriers?

Following are barriers to deploying demand response to help integrate variable generation:

- Demand response programs have generally been developed with little or no connection to deployment of renewable generation.
- Direct load control and pricing event strategies that support variable generation are still in the development stage.
- WECC reliability rules do not allow for demand response to provide regulation or spinning reserves.
- Better customer value propositions for demand response are required. Among pricing options, for example, real-time pricing has the greatest potential for integrating variable generation. But

[310] Microgrids are intentional islands of distributed resources and loads that disconnect automatically when the local grid is down and automatically resynchronize to the grid when conditions return to normal.
[311] See EcoGrid.dk Phase I Summary Report, http://www.energinet.dk/EN/FORSKNING/Energinet-dks-forskning-og-udvikling/EcoGrid/Sider/default.aspx. In particular see WP4 and WP5, as well as a description of the large-scale pilot project at Bornholm at www.eu-ecogrid.net/images/Documents/EcoGrid%20EU%20-%20Guide%20to%20the%20large-scale%20project.pdf.

it must be made available to consumers in ways that are simple, convenient, equitable and financially compelling.

- Advanced metering infrastructure with two-way communication and automated controls is not available in many jurisdictions. Such infrastructure is essential for price-driven demand response. It is less important for direct load control.
- In vertically integrated power markets it may be difficult to isolate the costs actually incurred for certain ancillary services, such as regulation and supplemental operating reserves, which are rolled into rates, creating a challenging business model for the pursuit of demand response.
- To realize its full potential, demand response must be as measureable, verifiable and long-lived as the supply-side alternatives it would displace.

What Can Western States Do to Encourage Demand Response as a Balancing Resource?

There is a common misconception that, absent major breakthroughs in energy storage technologies, integration of high levels of variable generation will be prohibitively expensive or a threat to reliability. This misconception rests on the assumption that we do nothing about the low-cost options readily available to us.[312] A new approach to demand response is one such option.

Western states could encourage the following activities to access the substantial untapped demand response potential among residential and small commercial customers:[313]

- Consider demand response as part of a suite of measures designed and deployed to complement the reliable and cost-effective deployment of larger shares of variable energy resources.
- Further develop and test a range of value propositions to assess customer interest in direct load control and pricing event strategies that support variable generation, with frequent control of loads both up and down.
- Evaluate experience with program designs that pay consumers based on the value of the flexibility services they provide to system operators, with either direct control of selected loads or automated load responses programmed for customers according to their preferences.
- Consider the potential value of enabling demand response programs that can help integrate variable generation when evaluating utility proposals for advanced metering infrastructure.
- Cultivate strategies that earn consumer confidence in advanced metering infrastructure and pricing programs, including development of robust policies safeguarding consumer privacy and well-designed consumer education programs.
- Allow and encourage participation of third-party demand response aggregators to accelerate the development of new sources of responsive demand, new consumer value propositions and new service offerings. Address open-source access to demand response infrastructure, access to consumer information, and privacy and data security issues to enable third parties to offer demand response products and services.

[312] Several recent studies reached the conclusion that if a portfolio of readily available measures is adopted, including load as a balancing resource, variable renewable resources of 30 percent or more of total supply can be integrated reliably and cost effectively with little or no investment in additional utility-scale storage. See, for example, GE Energy, *Western Wind and Integration Study*; McKinsey, KEMA, Imperial College London and European Climate Foundation, *Roadmap 2050: A practical guide to a prosperous, low-carbon Europe*, April 2010, www.roadmap2050.eu/.

[313] See FERC, June 2009, and Cappers, *et al.* for more information on the challenges facing expanded deployment of demand response and possible actions.

- Allow demand response to compete on an equal footing with supply-side alternatives to provide the various services it is capable of delivering. Further, actively accommodate demand response in utility solicitations for capacity.
- Isolate and quantify costs of balancing services to make transparent the value of flexibility options such as demand response.
- Develop robust measurement and verification processes that recognize the unique characteristics of demand-side resources in ways that encourage, rather than discourage, wider participation.
- Examine ratemaking practices for features that discourage cost-effective demand response. Examples include demand charges that penalize (large) customers for higher peak demand levels when they shift load away from periods of limited energy supplies to periods of surplus, and revenue models that tie the utility's profits primarily to volume of energy sales.[314]

[314] Regulatory Assistance Project, *Revenue Regulation and Decoupling: A Guide to Theory and Application,* June 2011, http://raponline.org/docs/RAP_RevenueRegulationandDecoupling_2011_04_30.pdf.

Chapter 8. Access Greater Flexibility in the Dispatch of Existing Generating Plants[*]

Output control range, ramp rate and accuracy – along with minimum run times, off times and startup times – are the primary characteristics of generating plants that determine how nimbly they can be dispatched (controlled) by the system operator to complement variable wind and solar resources. Additional factors influence the cost of getting the flexibility needed. Operating practices described elsewhere in this paper, such as dispatch interval, greatly influence the ability of system operators to access the flexibility that already exists in the existing generating fleet.[315]

Some flexibility characteristics are inherent to the generation technology, others can be adjusted when a new plant is designed, and some are influenced by how the plant is operated. Some existing plants can be retrofitted to increase flexibility by lowering minimum loads, reducing cycling costs and increasing ramp rates. Increasing generator flexibility involves economic tradeoffs between plant efficiency, opportunity costs (the revenue lost when a generator foregoes energy production in order to provide flexibility), capital costs and maintenance expenses.

Interest in increased flexibility from existing generators is motivated by more than improving integration of variable generation. First, system operators must maintain compliance with NERC reliability standards to avoid possible fines of up to $1 million per day. Second, generators that can reduce output or shut down when wholesale market prices are lower than their operating costs make more money than generators that have to continue operating at a loss when wholesale prices are low.

This chapter examines differences in flexibility between generation technologies and ways to acquire and value generator flexibility. It also examines concerns and costs associated with increased cycling of generators, although there are causes of increased cycling besides more variable generation, such as block schedules and adding new baseload generation. At the end of the chapter is a guide to characteristics associated with power plant flexibility, defining many of the terms used here. Chapter 9 discusses flexibility issues further, from the perspective of planning for and acquiring new resources.

How Does Flexibility Work for Various Generation Technologies?

While flexibility of individual generators varies significantly, the type of generation technology is a key factor in differing flexibility capabilities:[316]

Coal-Fired Steam Plants[317] **–** Coal-fired generators burn fuel in a boiler to create steam that drives a turbine to power the electric generator. These large, complex plants, with many subsystems to control emissions and handle fuel, are typically built to run 24/7 and therefore have limited flexibility. Generator size ranges from 20 MW to 1,200 MW, but modern units are typically 600 MW to 1,000 MW. Ramp rates are low, typically 10 MW/minute. Minimum loads are high, often 40 percent or greater. Coal-fired generators do not follow automatic generation control commands with high precision. Cycling costs can be high due to thermal stress-based damage, depending on the plant design. Fuel costs are low and efficiencies are reasonably high resulting in low production cost.

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[*] **Lead authors: Brendan Kirby, consultant; Jennifer Rogers, Exeter Associates**

[315] Another example is virtual or physical balancing authority area consolidation. The ramping capability of the combined balancing authorities adds linearly, while the need for ramping adds less than linearly.

[316] Flexibility in fuel supply contracts also is important to avoid must-run conditions due to fuel storage limits.

[317] Natural gas and oil-fired *steam* plants are rarely used due to their high operating cost.

Nuclear Plants – Like coal plants, nuclear plants use fuel (in this case, uranium) to create steam that drives a turbine to power the electric generator. They are inherently less flexible than coal plants. Their energy production cost (excluding capital costs to build the plant) is lower than for coal plants, so there is less economic incentive to provide flexibility. Licensing restrictions further reduce available flexibility.

Combustion Turbines – Combustion turbines burn natural gas or oil in the engine to create a hot gas. The gas drives a turbine to run a compressor that keeps the engine operating and powers a generator. Individual turbines range in size from 5 MW to 250 MW. Minimum load is typically 25 percent to 35 percent, though some older turbines or emissions-limited turbines have much higher minimum loads. Industrial turbines (combustion turbines specifically designed for electric power production) can take an hour to start, but some aero-derivative turbines (combustion turbines based on aircraft turbine designs) can start in 10 minutes or less. Ramp rates are typically high with the ability to ramp over the full operating range in less than 10 minutes. Cycling costs are significantly lower than for coal plants. Efficiencies are typically about 40 percent. Depending on fuel prices, energy production costs are typically higher than for coal plants. Combustion turbines are now being designed with fast (under 10 minutes) starting capabilities, fast ramping, good partial heat rate and low cycling costs.

Combined Cycle Plants – Combined cycle plants use the exhaust heat from one or two combustion turbines to create steam that drives a steam turbine and an electric generator. Efficiencies over 60 percent are achievable. Ramp rates are better than coal plants but slower than a combustion turbine. Older plants often were designed to maximize efficiency while sacrificing flexibility. Newer plants typically have increased flexibility with typical minimum loads of about 35 percent. Compared to combustion turbines, cycling costs are higher and start times are longer, ranging from an hour to several hours.

Internal Combustion Engines – Internal combustion engines are making a comeback for utility scale generation because they are very flexible. Typically natural gas-fired, modern plants are designed to operate for thousands of hours a year. They usually are more efficient than combustion turbines (but less efficient than combined cycle plants), with very good efficiency at less than maximum power. Start times and ramp rates can be extremely fast, going from off-line to full load in under five minutes when in hot standby mode with zero cycling costs. Plants are typically composed of multiple engine generators and range in size from 1 MW to 400 MW. There are currently more than 1,700 MW of engine-driven generating plants from one manufacturer alone.

Hydro – Run-of-river hydro output varies depending on natural forces and inherently has little flexibility. Conversely, reservoir-based hydro inherently has nearly ideal flexibility. Most reservoir-based hydro is energy limited, meaning the generators cannot be operated at full power all of the time because there is not enough incoming water to keep the reservoir full. Instead, operation is scheduled to maximize energy value. However, the plants also can be used for flexibility, responding to system operators' instructions. Ramp rates are typically very fast and accurate, often with no significant start time, no minimum run time, no minimum off time and zero cycling costs. Minimum load depends on the turbine and plant design but is often 50 percent or better. While the turbines and generators themselves are very flexible, hydro plant flexibility can be significantly reduced by minimum and maximum flow requirements, ramp rate limits, and prohibitions on plant cycling intended to protect fish.

Pumped Storage – Pumped storage plants pump water from a lower reservoir to an upper reservoir so the water is available to flow back downhill and generate electricity during advantageous periods. Pumped storage plants are an excellent source of flexibility. Most were built in the 1970s and 1980s to arbitrage the difference in energy costs between night and day, with coal and nuclear plants typically on the margin (the next generator to be moved up or down in response to increased or decreased demand for electric power) at night, and natural gas and oil plants on the margin during the day. The 80 percent (typical) efficiency of pumped storage plants made storing nighttime energy for use during the following day attractive. With natural gas-fired generation now on the margin much of the time, such arbitrage is less attractive. Instead, existing pumped storage plants are increasingly used (and new pumped storage plants are increasingly designed) to provide ancillary services where such flexibility is explicitly valued. Similar to hydro, minimum loads for pumped storage facilities are often around 50 percent while generating. Typically, such plants have no ability to regulate pumping rates and, therefore, energy usage. New plant designs are seeking to maximize flexibility with variable speed drives and advanced turbine designs. Much lower minimum generation levels, and power control while pumping, can increase plant flexibility while pumping and generating.

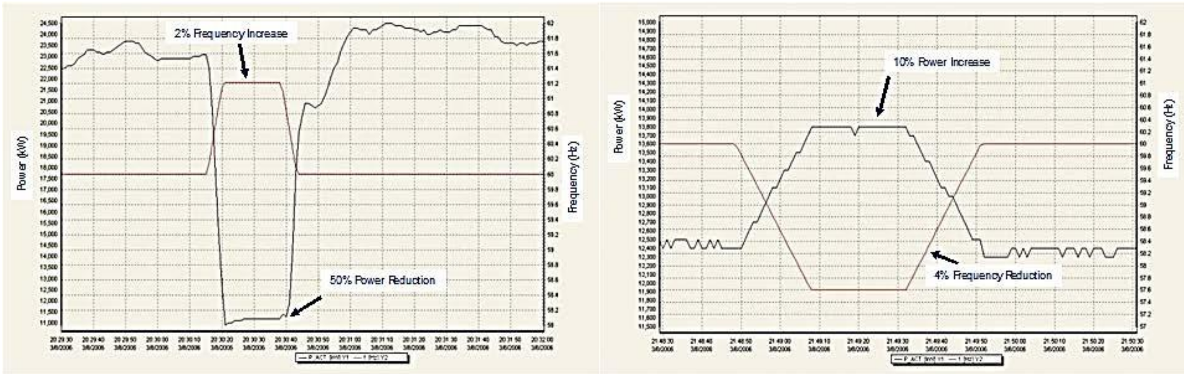
Geothermal – Geothermal plants use the geologic heat of the earth to create steam that drives a turbine and a generator. Limitations of steam chemistry coupled with low incremental energy cost – and thus little incentive to reduce operation – tend to make these plants inflexible.

Wind – Modern wind plants can be designed to provide flexibility and control. While the generator cannot provide more power than the wind is currently making available (at least not for more than a few seconds), generation can be controlled down at any time. While wind energy has zero production cost, down-control of wind plants can be attractive when there are no other viable alternatives – that is, when there are no other generators capable of reducing output, responsive loads capable of increasing output, or storage devices capable of responding.

Figure 1 shows results from a commissioning test of a wind plant in Quebec. The plant is responding to changes in system frequency very accurately and quickly. The left hand plot shows the wind plant reducing output when frequency rises above 60 Hertz (Hz). The right hand plot shows the wind plant increasing output when frequency drops below 60 Hz. The wind plant must be curtailed in advance of the time the system operator needs upward control in order to have upward response capability.[318] Wind plants also can provide stability response and synthetic inertia (very fast, within cycles – 1/60th of a second – response required to avoid large blackouts).[319]

[318] N. Miller, K. Clark and M. Shao, *Frequency Responsive Wind Plant Controls: Impacts on Grid Performance*, IEEE General Power Meeting, July 2011.
[319] *Id.*

Figure 1. Wind Plants Can Provide Fast and Accurate Upward and Downward Control[320]



Solar Photovoltaic – Like wind generators, the energy source for solar photovoltaic (PV) generators is variable and free. While the PV generator cannot provide more power than the sun is currently making available, generation can be controlled down at any time. PV plants are electronically controlled so response can be fast and accurate. As with wind, PV can provide downward control (reduced output) at any time but to provide upward control (increased output) the plant must be curtailed in advance. As with wind, obtaining upward control is expensive. Distributed PV systems theoretically can provide the same response capabilities as centralized PV units. However, the cost of communicating the system operator's control signals to each distributed PV panel is currently prohibitive. Also, interconnection standards typically prohibit PV panels from providing response.

Concentrating Solar – Concentrating solar power plants use mirrors to focus sunlight in order to create steam. The steam drives a turbine and powers a conventional rotating generator that is directly connected to the grid (in other words, not through power electronics). The flexibility of these plants is similar to fossil-fueled steam power plants but, like wind, giving up the "free fuel" makes this flexibility expensive. Concentrating solar power plants can be equipped with thermal storage. There are several such plants in operation in Spain and under construction in the Western U.S. Depending on the plant design, thermal storage allows the plant electrical power to be reduced during daylight hours without spilling the sunlight or simply stored for dispatch as energy or ancillary services in subsequent hours. Generally, thermal losses on the storage systems are low, allowing the plant operator to retain the stored energy overnight or into the next operating day.

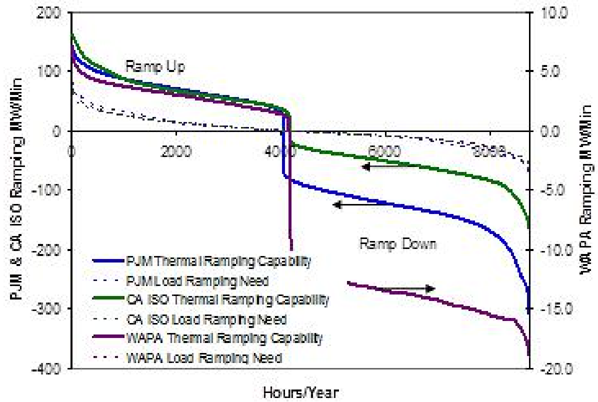
How Can System Operators Access Flexibility Within the Existing Generation Fleet?

The power system must balance aggregate load with aggregate generation, instantaneously and continuously, by ramping generators (and fast-responding loads) up and down. Total flexibility capability tends to increase linearly with size of the balancing authority area.[321] However, the variability of individual loads and generators typically is not perfectly correlated, so total flexibility requirements tend to increase less than linearly with size of the balancing area. Taken together, these trends mean larger regions inherently have more flexible resources available relative to total or net variability. Figure 2 illustrates generation ramping capabilities and load ramping requirements for three areas.

[320] *Id.*

[321] Total flexibility that is potentially available to provide balancing is the sum of flexibility capabilities of individual generators and responsive loads in a given area.

Figure 2. Thermal Ramping Capabilities Typically Exceed Net Load Ramping Requirements[322]



WAPA's Rocky Mountain balancing authority area is significantly smaller than the PJM and CAISO footprints, with lower ramping capabilities and needs. Consequently, the PJM and CAISO curves (left side of the graph) use a different scale than the WAPA curve (right side). Load ramping requirements of all three balancing authority areas have similar shapes. Thermal generation ramp-up capabilities also are similar. Ramp-down capabilities show greater differences between balancing authority areas. CAISO tends to operate with far more generators partially loaded many hours of the year. Generators are poised to move up or down, and the generation ramping capabilities curves are fairly symmetric. WAPA and PJM have more base-load coal-fired generators that tend to operate closer to full load.

Thermal generators in these systems have more ramp-down capability than ramp-up capability. Still, thermal ramping capability exceeds load-ramping requirements. That is, the thermal generators have ample physical ramping capability to meet the flexibility needs of the total system load.[323]

Administrative rules, such as only allowing changes in generator schedules every 30 minutes or every hour rather than every five minutes, mean that the full flexibility that generators are physically capable of providing is unavailable to the system operator for balancing. It is this scheduling practice, more than physical limitations of the generators, which reduces balancing flexibility.[324] Assuring that the system operator has access to the full ramping capability that is physically available from all of the generators throughout the region is important for assuring system reliability and reducing wind and solar integration costs. Hourly scheduling rules, for example, increase integration costs compared to subhourly scheduling.[325]

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[322] B. Kirby and M. Milligan, *A Method and Case Study for Estimating The Ramping Capability of a Control Area or Balancing Authority and Implications for Moderate or High Wind Penetration*, American Wind Energy Association, WindPower, May 2005.
[323] Hydro generators, which were not included in the study due to unavailable data, add additional physical ramping capability.
[324] Kirby and Milligan, 2005.
[325] Kirby and Milligan, 2005; Federal Energy Regulatory Commission, *Order Accepting and Suspending Proposed Tariff Changes and Establishing Hearing and Settlement Judge Procedures: California Independent System Operator Corporation Docket No. ER12-50-000*, Dec. 12, 2011.

CAISO Flexible Ramping Constraint

While most balancing authority areas typically have sufficient ramping capability available, CAISO has recently experienced insufficient ramping capability and expects this to become more common with increasing generation from variable energy resources. The shortage is caused by several factors including resources shutting down without sufficient notice, errors in variable generation forecasts, sudden changes in expected deliveries, contingencies, high hydro runoff, and interties tagging and delivering less than awarded in the hour-ahead scheduling process. The flexibility shortage is most prominent during the morning and evening ramps as load increases.

In response, CAISO took an initial step toward establishing a new following (ramping) ancillary service. As approved by FERC, CAISO identifies a Flexible Ramping Constraint and compensates generators and loads when it schedules them to alleviate the constraint. A stakeholder initiative, Renewable Integration Market and Product Review Phase 2, is developing a more complete market-based solution with a new flexible ramping ancillary service and bid-based pricing.

The tariff amendment allows CAISO to procure upward ramping capability from "committed, flexible generation resources and proxy demand response resources that are not designated to provide regulation or contingent operating reserves, and whose upward ramping capability is not committed for load forecast needs."[326] CAISO determines how much flexibility is required between 15-minute real-time unit commitment and five-minute real-time dispatch. The flexibility requirement is then applied to hour-ahead scheduling, short term unit commitment and real-time dispatch. If CAISO determines additional up-ramp capability is required, CAISO removes designated generation and responsive load from energy markets, ancillary service markets, or both so that these resources are available for ramping.

Compensation under the initial program is based on the opportunity cost of the marginal Flexible Ramping provider. If, for example, the spinning reserve price is $5/MWh and the marginal resource bid $3/MWh to supply spinning reserve, the payment to all Flexible Ramping providers for that interval would be the $2/MWh lost opportunity cost. If the marginal resource bid for spinning reserve is $7/MWh, there would be no compensation for supplying Flexible Ramping because the resources would not have been selected to supply spinning reserve.[327] Compensation is among the issues FERC is reviewing.

If the amount of reserves decreases between the 15-minute unit commitment and the five-minute real-time dispatch, the reserves may be released to participate and set prices in the real-time dispatch. Flexible Ramping costs will be allocated to load, as are the costs for other ancillary services. CAISO found that 80 percent of the load-following requirements are attributable to loads and 20 percent are attributable to wind and solar variations. The wind and solar contribution will rise with higher penetrations of variable energy resources. Cost allocation is the other issue FERC set for rehearing.

During times when the power system inherently has sufficient ramping reserves available, as is most often the case, there is no cost for ramping reserves. This is a feature that is common to most ancillary service markets (contingency reserve prices often are near zero at night, for example) and will presumably carry over to a full ramping ancillary service in CAISO and in other market areas.

[326] *Id.* at 2.
[327] Assuming the resource incurred a $3/MW-hr cost to provide spinning reserve (the bid price of the marginal unit), the resource may not be appropriately compensated under this scheme.

How Can Generating Plant Retrofits Increase Flexibility?

The best way to obtain generator flexibility is to design and build it into the generation fleet by selecting technologies that are inherently flexible. Retrofitting existing generators to increase flexibility is possible in some cases but extensive modification may be impractical.[328]

Most coal-fired plants were intended to serve as base-load generation, operating at fairly constant, high capacity levels with infrequent cycling due to the historically low cost of coal relative to other energy sources. Generally, base-load coal plants were designed with minimum operating levels of 45 percent to 50 percent of their design capacities, though modern plants are being designed with a minimum operating level of 35 percent.[329]

Coal- and natural gas-fired thermal steam plants are slow to respond to changes in operation due to the high amount of thermal inertia in the boiler, steam turbine and auxiliaries. Increased cycling of base-load designed coal plants without retrofitting results in higher costs and a shortened lifespan,[330] as is discussed elsewhere in this chapter. Incorporating methods to reduce wear and tear costs can increase the plant's load-following capability (ramp rate up and down, lower minimum reliable load and faster startup capability). These approaches also minimize, but do not eliminate, increased operation and maintenance costs, reliability issues, and effects on component and plant-life time span.

Following are methods that plant operators can use to reduce cycling-related wear and tear costs: [331]

1. Increase preventative and corrective maintenance to address increased wear and tear damage under different unit missions and life cycle analysis
   a. Critical Component Failure Modes Effects Analysis (fatigue, thermal shock, creep, oxidation, differential expansion, depositions, corrosion product migration)
   b. Root Cause Analysis of failed components
   c. Condition Assessment
   d. Monitor cumulative damage

2. Change operating procedures to minimize the thermal, corrosion and mechanical cycle damage
   a. Start-ups
   b. Ramping to load
   c. Load changes
   d. Shutdowns
   e. Shutdown protection (lay-up)

3. Upgrade equipment to reduce wear and tear damage and reduce repair costs
   a. Remote controls for vents and drains
   b. Turbine bypass

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[328] Jimmy Lindsay and Ken Dragoon, *Summary Report on Coal Plant Dynamic Performance Capability*, Renewable Northwest Project, Aug. 16, 2010, http://rnp.org/sites/default/files/pdfs/RNP%20Coal%20Report%2010Aug16.pdf.
[329] J. Nicolas Puga, "The Importance of Combined Cycle Generating Plants in Integrating Large Levels of Wind Power Generation," *The Electricity Journal*, August/September 2010, Vol. 23, Issue 7, http://www.bateswhite.com/media/pnc/4/media.344.pdf.
[330] Eugene Danneman and Stephen Beuning, *Wind Integration – System and Generation Issues*, ASME, Power2010-27128, July 2010, http://www.energy-tech.com/article.cfm?id=31202.
[331] *Id.*

c. Economizer recirculation
d. Higher grade metal alloys
e. Upgraded digital control systems and actuators
f. Flexible pressure part design and connections
g. Water chemistry monitors
h. Metal thermocouples

There is no overarching solution for retrofitting coal plants. Cycling is plant-specific, making generalizations difficult.[332]

HECO Plant Retrofits

Hawaiian Electric Company (HECO) is in the planning and budgeting phase of retrofitting eight of its fossil-fuel units at two generating facilities (in this case, oil-fired units) to increase flexibility. The units were commissioned in the early to mid-1970s, designed to run as base-load units. They range in capacity from about 79 MW to 130 MW each. The retrofit project will increase the utility's ability to accept more energy from variable renewable resources.

Through the retrofit, HECO aims to reduce the combined minimum load of the units from about 330 MW to approximately 170 MW. HECO also aims to improve upward ramp rates from 2.5 percent per minute to 5.5 percent per minute. HECO intends to generally rely on wind controls to limit their up-ramps to reduce the need for downward ramping of the oil-fired plants. The retrofit will likely involve new equipment and equipment replacement and redesign, although specific changes are yet to be determined. The project is scheduled for completion by 2018, to coincide with the timing of a scheduled request for proposals of 200 MW of renewable energy.[333]

Natural gas-fired steam thermal plants are generally more flexible than coal plants prior to any retrofit, although they are still subject to constraints and incur costs from increased cycling. Combined-cycle gas turbine (CCGT) plants are limited by system warm-up times, permissible steam turbine pressure and temperature transients, and heat recovery steam generator time to reach the required conditions.

However, CCGT plants can be modified to avoid some of the limiting constraints. Siemens, for example, offers an upgrade package that includes improvements such as modified temperature controls, modifications to the steam turbine controller, and new balance of plant system signals.[334]

Iberdrola upgraded its Klamath Cogeneration Plant in 2009 in part to improve heat rate, service duration and load response capability, particularly during cold weather. Automated generation control was added later, as well as customized communications infrastructure between the company's trading department and wind power control center. While the heat rate upgrade required changes to hardware, the modifications for load-following were primarily electronic in nature. Cumulatively, the upgrades improved the ability to respond to fluctuations in output from the portion of the company's wind generation portfolio participating in BPA's pilot program for self-supplying reserves.[335]

[332] Lindsay and Dragoon.
[333] Communication with Dean Arakawa, Hawaiian Electric Company, March 13, 2012; Hawaiian Electric Company, "Generating Unit Enhancements," Utility Wind Integration Group 2010 Fall Technical Workshop, slides.
[334] Puga.
[335] Communication with Michael Roberts, Iberdrola, March 16, 2012.

By retrofitting, some CCGTs have achieved greater than 50 percent reductions in start-up times after overnight shutdowns.[336] Table 1 compares capacity and flexibility from an existing CCGT, an upgraded (retrofitted) CCGT and an entirely new CCGT.

Table 1. Calpine (CPN) Comparative Incremental Flexibility and Capacity[337]

		CPN CCGT (today)	CPN CCGT (upgrade)	New generation CCGT
Capacity	[1]	550	600	625
Fullload heat rate	[2]	7.0	6.85	6.6
Warm start	[3]	90	30-60	30
Cold start	[4]	240	90	30
Ramp rate	[5]	10-12	20-25	30

Notes:
[1] MW (2x1)
[2] MMBtu/MW HHV (2x1)
[3] Minutes to achieve Pmin (1x1)
[4] Minutes to achieve Pmin (1x1)
[5] MW/minute per engine between Pmin and Pmax

The benefits of retrofitting plants may be comparatively small even in aggregate compared to other means of improving integration of variable generation, such as larger balancing authority areas and subhourly scheduling. However, the benefits are additive – retrofitting existing generating plants along with implementing other mechanisms described in this paper enhances the ability to integrate large amounts of variable generation.[338]

How Does Cycling Affect Generating Plants?

Concerns have been expressed that adding more variable generation will increase cycling of coal and natural gas plants – turning on and off or ramping from one power level to another to follow changes in net load. Most of the wind integration studies conducted to date have not fully accounted for the full impact or costs of increased cycling and "wear and tear" on fossil units, in large part because specific studies to estimate such costs are confidential.[339]

Generators differ dramatically in the costs they incur when they cycle. Costs result primarily from the thermal stresses the equipment is exposed to in changing operating modes. These same stresses account for the minimum start time, minimum run time and minimum off time. Hydro units typically have low cycling costs, as do some internal combustion engine-driven plants and specially designed combustion turbines. Combined cycle generators and many combustion turbines have higher cycling costs.

Coal-fired steam plants typically have the highest cycling costs. Coal plant designs were often optimized to maximize efficiency when operating at constant power output, with less consideration given to

[336] *Id.*
[337] Calpine, "Preserving Existing Generation to Satisfy Renewable Integration Requirements," Dec. 8, 2011.
[338] Communication with Richard Piwko, GE Energy, Feb. 29, 2012.
[339] Debra Lew, Greg Brinkman, Michael Milligan, Steve Lefton and Dick Piwko, "How Does Wind Affect Coal? Cycling, Emissions and Costs," presentation at Windpower, May 25, 2011, http://www.nrel.gov/docs/fy11osti/51579.pdf.

cycling costs. The existing coal fleet includes few units designed specifically for flexible operations.[340] Operational factors associated with cycling have the following influences on coal-fired generating assets:

- Increased damage to the boiler, turbine and other components exposed to high temperatures
- Increased wear and tear on balance of plant components
- Decreased thermal efficiency at low load
- Increased fuel costs due to more frequent unit starts
- Difficulties in maintaining optimum steam chemistry
- Potential for catalyst fouling in NOx control equipment
- Increased risk of human error in plant operations

The additional wear on plant components requires increased spending on preventive and corrective maintenance. This is challenging to plants that are lower in the dispatch stack (called on less often to operate) and therefore receive less revenue. Operator training on rate of change and thermal limits, and improved outage scheduling during periods of forecasted high renewable energy production, can help mitigate cycling impacts.[341]

Cycling Cost Example

A typical 600 MW coal plant might produce electricity for $20/MWh (fuel plus variable overhead and maintenance costs). The plant can operate around the clock if the average wholesale price exceeds $20/MWh. The plant has an economic incentive to cycle if the difference between daytime and nighttime prices is sufficient.

Say it costs $63,000 to cycle the plant off overnight.[342] Average wholesale power prices have to drop below $6.88/MWh for eight hours overnight in order for cycling the plant off to cost less than keeping the plant operating [$20/MWh - $63,000/(600 MW * 8 hrs)]. If the plant cycles, daytime prices must average above $26.56/MWh to keep the plant viable [$20/MWh + ($63,000/9,600 * 16 hrs)].[343]

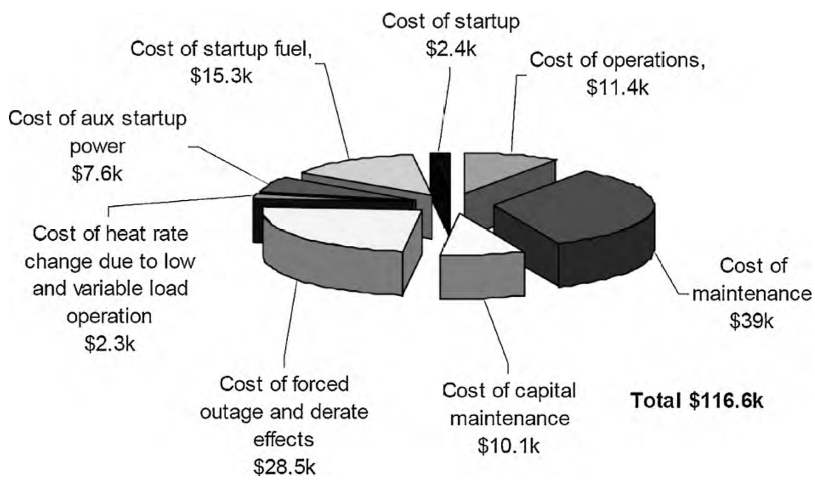
Cycling for longer periods of time incurs higher costs. If the coal plant is turned off for less than 12 hours (as in the daily cycling example in the text box), it incurs “hot start” cycling costs (the boiler and turbine are still at relatively high temperatures). If it turns off for more than 72 hours, it incurs “cold start” cycling costs (the boiler and turbine have cooled down over the three days), which might be as high as $161,000 for a 600 MW plant. Weekly cycling might shut the plant down at 10 p.m. on Friday and restart it at 6 a.m. on Monday for a 56-hour shutdown. Using cold start costs as a rough approximation, it would be less expensive to cycle the plant than keep it operating all weekend if the weekend average wholesale price for electricity dropped below $15.21/MWh [$20/MWh - $161,000/(600 MW * 56 hrs)]. Wholesale prices during the rest of the week would have to average above $22.40/MWh to keep the plant viable.

[340] S. Hesler, *Impact of Cycling on Coal-Fired Power Generating Assets*, prepared for Electric Power Research Institute (EPRI), April 2011.
[341] Communication with Stephen Beuning, Xcel Energy, April 20, 2012.
[342] S. Lefton, *Power Plant Asset Management Cost Analysis and Cost-Based Power Plant Asset Management – Thermal Power Plant Cycling Costs*, Utility Wind Integration Group, Technical Workshop, April 2011.
[343] Even in non-organized markets as in most of the Western U.S., utilities dispatch plants based on marginal cost and market prices.

Recent studies identified the typical unit cost per shutdown-start cycle of coal-fired plants as ranging from $3,000 to $100,000 for small drum units and from $15,000 to $500,000 for large supercritical units, compared to $300 to $80,000 for simple-cycle natural gas turbine units.[344]

A study for Xcel Energy using historical operations and financial data for a 30-year-old, 500 MW base-load coal plant determined an overall per-cycle cost (based on a weighted average of hot, warm and cold starts) of $116,600 (2008$).[345] The typical costs for the plant range from $153,000 to $201,000 per cold-start cycle and from $82,000 to $110,000 for a hot start.[346] As shown in Figure 3, fixed and variable operation and maintenance (O&M) costs to repair wear and tear and for forced outage replacement energy were predominant.[347]

Figure 3. Illustrative Shutdown-Start per Cycle Cost of a 30-Year-Old 500 MW Coal-Fired Steam Plant[348]



Higher penetrations of variable renewable energy resources are increasing cycling of other power plants, but they are not the only cause. In fact, Xcel Energy reports that for its Pawnee plant, only 15 percent of the cycling is due to wind.[349] Daily block schedule transactions – large amounts of capacity scheduled day-ahead for stretches of up to 16 hours – are convenient for energy traders but they do not correspond to the physical requirements of the power system.

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[344] Steven A. Lefton, Philip M. Besuner, G. Paul Grimsrud and Todd A. Kuntz, Intertek-APTECH, *Experience in Cost Analysis of Cycling Power Plants in North America and Europe,* TP133.

[345] Per-start cycling costs vary by plant. Costs are dependent on several factors including unit design (tolerance) for cycling, age of unit, fuel costs, forced outage replacement energy costs, maintenance history, and practices and operating practices. In addition, the cost per start changes with time. There is an early period when latent damage induced with each start causes no increase in forced outages. After a period of time, the latent damage catches up and causes critical component failures. A sharp increase occurs in forced outages after a couple years of intermittent duty if no improvements are made.

[346] Dwight Agan, Philip Besuner, G. Paul Grimsrud and Steven Lefton, *Cost of Cycling Analysis for Pawnee Station Unit 1 Phase 1: Top-Down Analysis,* Aptech Engineering Services, prepared for Xcel Energy, AES 08116940-2-1pr, November 2008, http://www.google.com/url?q=https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document%3Fp_dms_document_id%3D79884&ei=TkZuT5GCCuWliQKXicS6BQ&sa=X&oi=unauthorizedredirect&ct=targetlink&ust=1332628822166117&usg=AFQjCNF642QNgm61tftrSWbGS8UOOrBp4w.

[347] Puga.

[348] *Id.*

[349] “Driving Unit Flexibility With Wind Induced Cycling Costs,” presentation to the Utility Wind Integration Group 2010 Fall Technical Workshop, Oct. 14-15, 2010.

Figure 4 shows a typical daily load pattern. In this example, daily block energy transactions are supplying 4,000 MW of energy during peak hours. Though the energy is scheduled well in advance and delivery follows the schedule perfectly, the block transactions only approximately match the power system's load requirements and force remaining generators to cycle dramatically twice a day at both the start and the end of the transaction.

Figure 4. Daily Block Schedules Increase the Cycling Requirements for Other Generators[350]

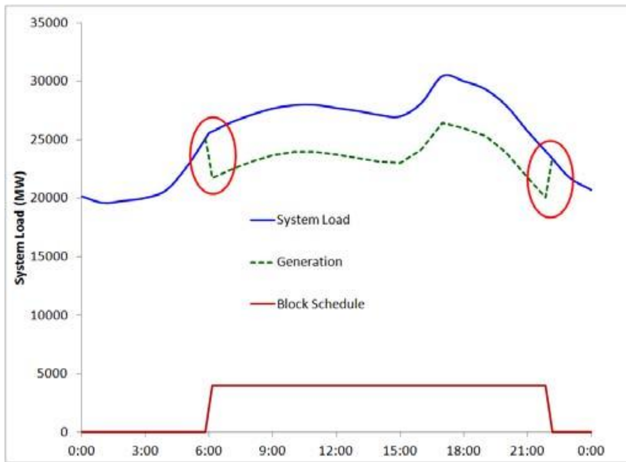
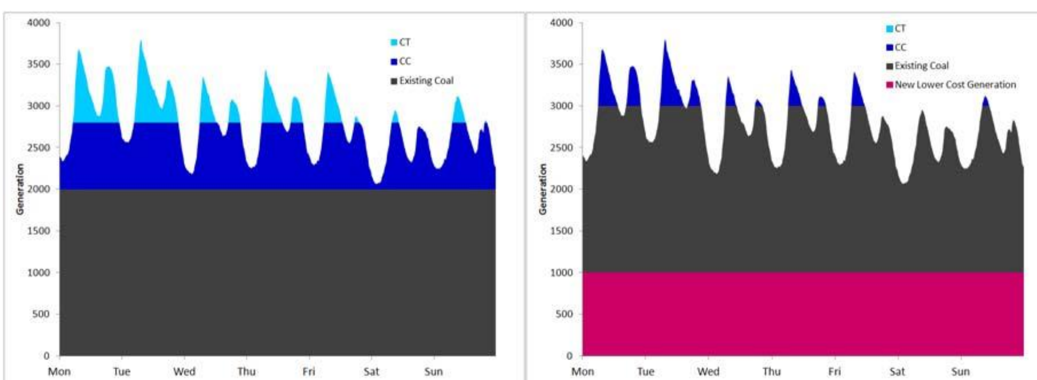


Figure 5 shows that adding a new, lower cost baseload generator also can cause increased cycling of existing generators. The chart on the left shows coal generation providing flat output for the week. Combined-cycle plants and combustion turbines cycle daily and follow the load ramps. The chart on the right shows that adding a lower-cost baseload generator forces the existing coal plants to cycle and displaces the natural gas generation.[351]

Figure 5. Addition of Lower Cost Generation Can Force Increased Cycling of Existing Generation



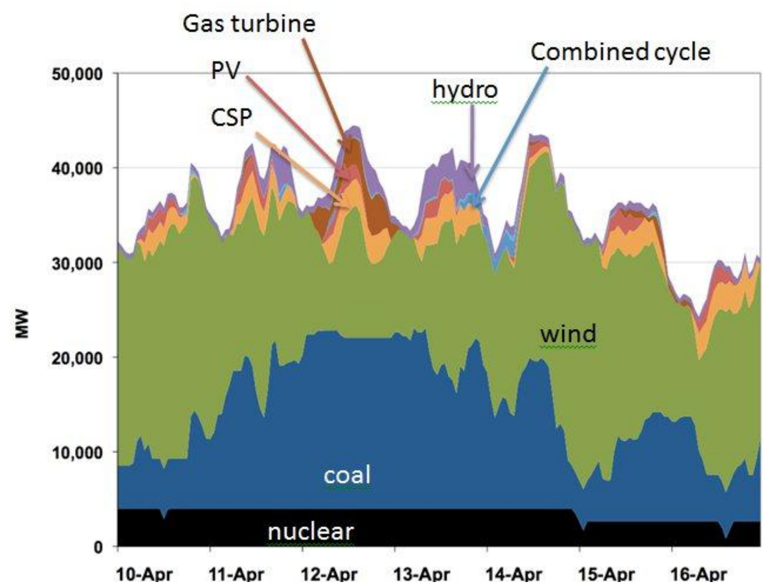
Regardless of the cause of cycling, cycling costs change the relative economics of various generation technologies. Weekly cycling is typically more economically attractive than daily cycling even though the

[350] Milligan, *et al.,* November 2011.
[351] *Id.*

cost per cycle is higher due to the larger thermal stresses on the power plant. The impacts of cycling costs tend to reduce coal's competitive advantage compared with other technologies that have lower or zero cycling costs.

The National Renewable Energy Laboratory's (NREL's) Western Wind and Solar Integration Study (Western Study) simulated the impact of up to 35 percent wind and solar on conventional generators and the grid using wind, solar (actual and simulated data from mesoscale models) and load data from 2004 through 2006. Figure 6 illustrates the most variable week of all three years and shows extensive cycling by coal plants.

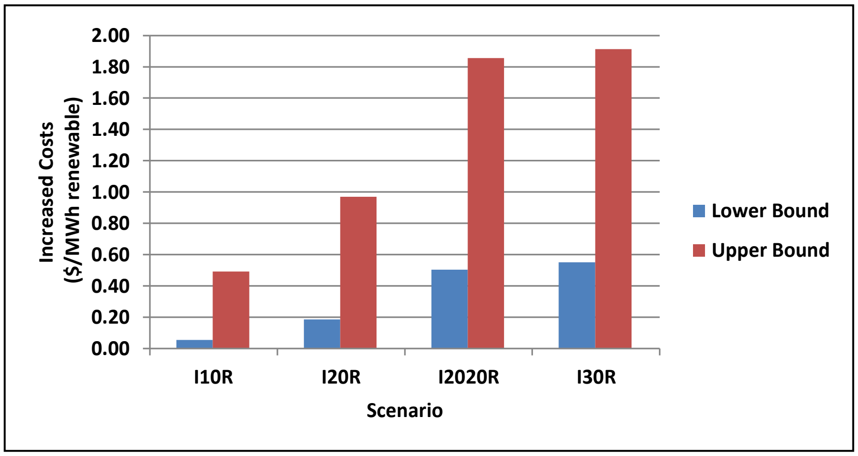
Figure 6. Week of High Variable Generation Output – Western Wind and Solar Integration Study[352]



A second phase of the Western Study is examining the cycling and ramping costs incurred by fossil-fueled generators in systems with high levels of variable generation, as well as the associated emissions impacts. Researchers examined data from 400 coal and natural gas plants on the costs of hot, warm and cold starts; costs of ramping down to minimum output; impacts on forced outage rates; and long-term heat degradation. They then applied upper and lower bound estimates of wear and tear costs and re-ran the production cost model used for the study, incorporating the wear and tear costs. As shown in Figure 7, the study found that the upper bound of increased cycling costs ranges from roughly $0.50/MWh of renewable resources produced (for the lowest renewable energy penetration scenario) to just under $2.00/MWh of renewable resources produced (for the highest penetration scenario). At $2.00/MWh of renewable resources produced, cycling costs translate into a 2.4 percent reduction in the value of the renewable resources.[353]

[352] GE Energy, *Western Wind and Solar Integration Study*, prepared for National Renewable Energy Laboratory, May 2010, http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf
[353] Debbie Lew, Greg Brinkman, Steve Lefton, Nikhil Kumar, Gary Jordan and Sundar Venkataraman, "Impacts of Wind and Solar on Conventional Generation," presentation to the Utility Wind Integration Group (UWIG), April 25, 2012.

Figure 7. Cycling Costs Due to Renewable Resources[354]



NREL determined the emissions impacts of cycling using 2008 hourly emission measurements from the majority of fossil fuel plants in the U.S. NREL then estimated WECC-wide average NO_x and CO_2 emission rates for start-up, ramping and partial loading and re-ran the production cost model used in the first phase of the Western Study. As indicated in Table 2, NREL found a decrease in NO_x emissions for part loading, offset partly but not entirely by higher emissions at start-up and ramping. CO_2 emissions increase but not significantly. NREL will re-run the production cost model using unit-specific emission rates, with results expected in late 2012.[355]

Table 2. NO_x and CO_2 Emissions – Western Wind and Solar Integration Study[356]

	NO_x (lbs/MWh)	CO_2 (tons/MWh)
Assuming flat emission curves	0.422	0.499
+considering part-load emission rates	+0.031 (+7.3%)	-0.006 (-1.3%)
+considering startup emissions	-0.006 (-1.3%)	-0.001 (-0.3%)
+considering ramping emissions	-0.011 (-2.7%)	-0.001 (-0.2%)
Total	0.436 (3.3%)	0.490 (-1.7%)

What Are the Gaps in Understanding?

As we discuss further in Chapter 9, there are no well-developed definitions for flexibility, or metrics or models for measuring existing flexibility and future flexibility needs. Further, those needs depend on the

[354] *Id.*
[355] Greg Brinkman, "Emission Impact of Fossil Fuel Unit Cycling," presentation to UWIG User Group Meeting, Oct. 12, 2011, http://wind.nrel.gov/public/WWIS/Emissions.pdf.
[356 356] Lew, *et al.*

institutional framework that is in place. If the operational and market tools described earlier in this report are further developed in the Western U.S., less physical flexibility will be needed.

Flexibility capabilities and cycling costs for existing generating facilities vary significantly between generation technologies and among individual generators using the same technology. Differences between technologies are reasonably well understood but differences between individual generators often are not well known. This is mostly because the damage caused by cycling fuel-burning generators results from thermal stress (temperatures increasing and decreasing unevenly) and accumulates over time. To avoid potentially catastrophic damage, plant designers impose minimum run times and minimum down times for plant operation to allow sufficient time for the plant to reach thermal equilibrium (time required for temperatures to even out).[357]

Several engineering consulting firms suggest that start-up costs have been dramatically underestimated by utilities.[358] Others find that many plants, regardless of their original design, have adopted two-shift operation (operating 10 to 15 hours per day and shutting down for the remaining nine to 14 hours) to meet the demands of competitive markets. Studies of two-shifting operation have suggested that the original equipment manufacturer guidelines are very conservative and their suggested minimum down times can generally be halved allowing for two-shift schedules.[359] Plant-specific analysis is required to determine what equipment and operation modifications are cost-effective for increasing flexibility.

What Are the Implementation Challenges?

Increasing the flexibility of existing generators is challenging because of fundamental limitations of the installed technology and unique differences between each plant. Coal plants, for example, may contribute to meeting a changing net demand by increasing or decreasing generation, but the rate of that change is limited by a set of physical and economic factors. The enormous thermal mass of the boiler and steam generator attenuate the response to changes in fuel feed rates. Minutes pass before fuel adjustments affect steam mass flows, and hence turbine and generator output. Engineers use an array of alternative techniques to allow coal-units to respond faster. The maximum ramping rate is specific to plant design and also is a function of plant capacity. Generally, coal-fired units become less responsive as they approach minimum generation levels.[360]

A plant's minimum generation is one of the most significant parameters for dynamic performance. Operating at low generation is associated with several negative impacts including poor power control, poor environmental control performance, problematic air-flow limitations and lower efficiency. Further, at low load, boiler burners lose flame stability and costly supplementary firing may be required. Minimum generation is defined as the lowest safe and reliable plant operation without use of supplementary firing units, and for coal units is typically 35 percent to 40 percent of full load capacity.[361]

A survey conducted by EPRI in 1998 demonstrated that while minimum load potential is unique to each plant it could be decreased from an average of 38 percent to 30 percent for the 18 plants studied through some cost-effective combination of unit master control, feed-water and boiler control, turbine

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[357] Lindsay and Dragoon.
[358] S. Lefton and P. Besuner, "The Cost of Cycling Coal Fired Power Plants," *Coal Power Magazine*, Winter 2006, http://www.aptecheng.com/corporate/CurrentEvents/100_CoalPowerWinterMag16-20.pdf.
[359] Lindsay and Dragoon.
[360] *Id.*
[361] *Id.*

enhancement retrofits, or a combination of these approaches.[362] This represents a significant, but limited, opportunity to obtain greater flexibility.

Coal plant ramp rates represent a similar opportunity for potential improvement. Various sources indicate that coal plant ramp rates should range from 3 percent to 8 percent of plant maximum power per minute, depending on the plant technology.[363] A 1982 EPRI survey found that *actual* coal plant maximum ramp rates ranged from 2 percent to 4.3 percent. Analysis of a specific coal plant found that it was able to improve its ramp rate by 300 percent with simple sensor and control retrofits, but the final ramp rate was still only 3 percent per minute.[364]

For wind plants, the ability to retrofit them to provide automatic generation control, frequency response and synthetic inertia depends on the design of the individual turbines themselves and the plant control system. In some cases, retrofits can be cost-effective. For example, all of the new wind plants Xcel Energy acquires must be able to provide set-point capability. Xcel Energy is retrofitting 19 existing wind plants to add automatic generation control, primarily in the Midwest ISO. This has reduced curtailments of Xcel's wind projects because system operators have more confidence in maintaining system balance with operation of wind plants that have automatic generation control.[365]

What Could Western States Do to Improve the Flexibility of the Generating Fleet?

Generating fleet flexibility can be enhanced four ways. First, establish generator scheduling rules that do not block access to the flexibility capability that already exists. Subhourly energy scheduling, especially five minute scheduling, has proven to be an effective method for maximizing the flexibility of the generation fleet. Second, perform balancing over as large a geographic areas as possible. The larger the balancing area, the greater diversity benefit where random up and down movements of loads and variable generators cancel out. Third, design flexibility into each new generator by selecting technologies that are more flexible. Fourth, retrofit existing generators to increase flexibility when this is practical and cost-effective.

The first three methods are addressed elsewhere in this report and the related recommendations are not repeated here. [366] Beyond those recommendations, Western states could consider the following steps to increase generator flexibility:

- Analyze the potential for retrofitting existing, less flexible generating facilities. Evaluation on a plant-specific basis is required to determine what additional flexibility, if any, can be obtained through cost-effective modification. It may be possible to achieve faster start-ups, reduce minimum loads, increase ramp rates (up and down), or increase the ability to cycle the generator on and off, or off overnight, and at other times when it is not needed.
- Provide appropriate incentives to encourage generating plant owners to invest in increased flexibility.

[362] EPRI, *Low Load/Low Air Flow Optimum Control Applications*, TR-111541, 1998, http://mydocs.epri.com/docs/public/TR-111541.pdf.
[363] Lindsay and Dragoon.
[364] F.H. Fenton, "Survey of Cyclic Load Capabilities of Fossil-Steam, Generating Units," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-101, No. 6, June 1982.
[365] Comments by Stephen Beuning, Xcel Energy, to State-Provincial Steering Committee, April 3, 2012.
[366] Several of the recommendations in Chapter 9, for new flexible capacity, are relevant here.

- Consider establishing incentives or market options to encourage generators to make their operational flexibility available to system operators.
- Explore development of a flexible ramping ancillary service to take advantage of fast-response capabilities of some types of demand resources and generation.
- Require conventional generators to have frequency response capability or define frequency response as a service that generators can supply for compensation.
- Quantify cycling costs and identify strategies to minimize or avoid cycling.

Generator Flexibility Characteristics

Minimum Power (MW): The minimum power level at which the plant can sustain operations is an important factor in its flexible operation. Minimum power also represents a cost of flexibility. The power system must accommodate the generator's minimum power level in order to gain access to its control range. Consider two generators with a 300 MW of control range. One is a 500 MW power plant with a minimum power of 200 MW and the other is a 1,200 MW power plant with a minimum power of 900 MW. The first plant provides 300 MW of control range with 700 MW less minimum power burden than the second plant. This can be important if the grid is experiencing minimum load problems and curtailing wind, solar, or hydro generation instead of fossil-fuel plants with higher variable costs.

Maximum Power (MW): Maximum power, or the rated power output of the generator, does not directly affect the flexibility of the plant, but it affects the grid's need for flexibility. That's because contingency reserves must be held to cover the possible sudden failure of the largest generator (or transmission line) on the grid, so higher maximum power levels increase the need for contingency reserves.

Control Range (MW): This is one of the primary flexibility characteristics the power system operator is seeking. Control range is the range over which the power plant can be operated from minimum power to maximum power. Control range is used to counter the aggregate variability of wind and solar generation and system load.

Ramp Speed (MW/minute): Ramp speed is the flexibility characteristic the system operator requires to follow net load (load minus variable resource output) and integrate variable renewable resources. Ramp speed determines how quickly generators can be moved from one output level to another and is measured in megawatts per minute. Some ancillary services – services that assist the grid operator in maintaining system balance – are defined based on the amount of control range required as well as the ability of the generator (or responsive load) to provide control response within a specified amount of time. Spinning reserve, for example, is defined as a 10-minute service. So a generator with a 5 MW/minute ramp rate could only supply 50 MW of spinning reserve (5 MW/minute times 10 minutes) even if it had hundreds of MW of control range available.

Frequency Response: Frequency response is the ability of the generator to sense grid frequency and use frequency responsive controls ("governors") to quickly respond autonomously if frequency moves outside a specified range. Grid frequency drops suddenly if a major power plant fails, for example. To make up for the loss in generation, other power plants must immediately increase output, loads must decrease, or both. There is no time to wait for the system operator to issue commands. Autonomous governor response is distinct from automatic generation control. Both are automatic, but automatic generation control facilitates the system operator's centralized control of the generator, while governor control facilitates the autonomous response of the generator directly to the change in grid frequency. Both types of control are required for grid reliability. All types of generators, including wind and solar plants, can be equipped with governors.

Inertia: Inertia, the tendency for a body in motion to stay in motion, comes from the rotating mass of generators and motor loads. This provides a response to the sudden loss of a large power plant that is even faster than governors provide frequency response. The more inertia the power system has, the slower frequency declines and the easier it is for frequency responsive generators, loads, storage devices, under-frequency load shedding systems, and spinning reserves to recover from the sudden power plant failure. Inertia is an inherent characteristic of conventional generators and varies by generation technology. Power systems have typically been designed around the generator inertia rather than inertia requirements dictating the generation technology choice. Stability concerns could arise if large amounts of electronically coupled generators (generators that have power electronics that connect them to the grid such as solar PV and most new wind turbines) that have no inherent inertia displace high-inertia generators like coal- and natural gas-fired plants and hydro plants. Modern wind plants can use computer controls and their power electronics to respond rapidly to sudden frequency changes to create “synthetic inertia” if this is required to maintain grid stability. Other sources (storage) also may be required to maintain power system reliability.

Start Time: Generators differ dramatically in the amount of time required to start up, synchronize to the grid and ramp to full load. Some hydro plants, internal combustion engine generators and combustion turbines can start and load within minutes. Depending on whether they are hot, warm or cold (which itself depends on how long the power plant has been turned off with no fire in the boiler), large coal plants can take 24 to 72 hours to reach minimum load. Other technologies such as combined cycle plants and many combustion turbines can take an hour or more to do so. Start times can be reduced, at some cost, with operating modes. Some internal combustion engine generators can use warm water to keep the engine jackets warm, start in one minute, and fully load within five minutes. Some hydro generators can remain synchronized to the grid with their turbines spinning in air if very fast starting and loading is required.

Minimum Run Time and Off Time: Many generators must operate for a minimum amount of time once started – and remain off for a minimum amount of time once stopped – in order to alleviate thermal stresses and avoid damaging the generator. The minimum run and off times are longest for large coal-fired steam generators and shortest for hydro generators.

Fuel Scheduling: Fuel scheduling constraints can limit access to generators’ physical flexibility. A combustion turbine, for example, may be physically capable of rapidly starting and operating over a wide power range. But if it burns natural gas there may be restrictions on when the gas can be scheduled and the rate at which it may be consumed. Gas is typically nominated (scheduled) day-ahead, reducing flexibility. This problem is compounded on weekends when schedules are set on Friday for operations on Saturday, Sunday and Monday. These gas scheduling constraints represent a significant integration cost — added expense or limitation – that is not based on limitations in the physical capabilities of the gas generator itself. Plants with on-site fuel supplies (coal, uranium, oil) are typically not limited by fuel scheduling limitations and can access the full physical capabilities of the generator.[367]

[367] M. Milligan, E. Ela, B. Hodge, D. Lew, B. Kirby, C. Clark, J. DeCesaro and K. Lynn, “Integration of Variable Generation, Cost-Causation, and Integration Costs,” *Electricity Journal*, November 2011.

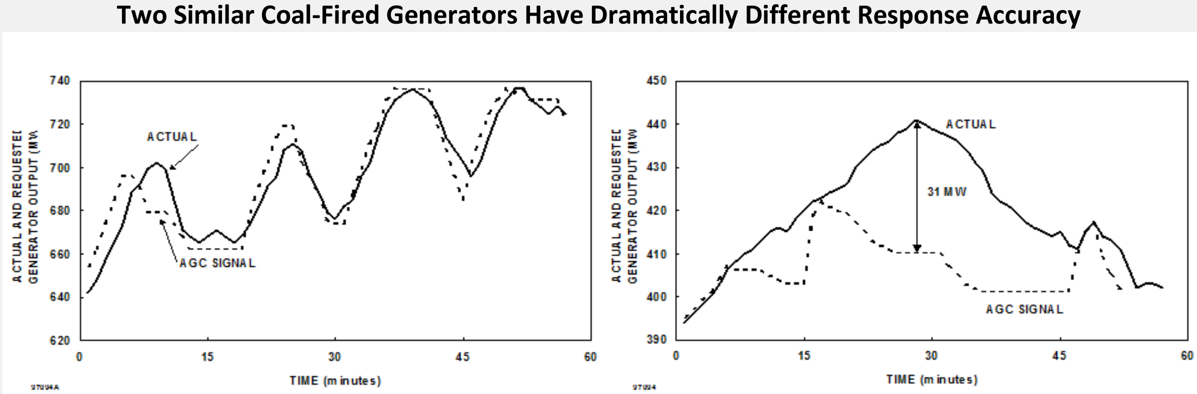
Emissions Limits: Some generators are not allowed to operate over their full control range because they have higher emissions rates at certain operating points. This typically increases the minimum power level at which they are allowed to operate. It may also reduce the allowable ramp rate.

Energy Production Cost: Generators with a low energy production cost are dispatched to operate before higher cost generators. Consider the case of two generators, one that costs $10/MWh to run and is equipped with response capability (control range, ramp speed) and the other without such capability that costs $50/MWh. If the less costly generator must reduce energy production to follow system operator commands, because the more expensive generator does not have the needed flexibility, there is a $40/MWh "lost opportunity cost." Expanding response capability throughout the generating fleet can reduce flexibility costs overall.

Efficiency: Many generators are most efficient when operating near their full rated output. Efficiency often declines as generator output drops. Consequently there is an efficiency penalty cost associated with operating a generator throughout its control range in response to net load. There may be an additional efficiency penalty when a generator is configured to provide greater flexibility. Large steam generators, for example, can be operated in sliding pressure or "valves wide open" mode to maximize efficiency. Generator output is controlled by adjusting the amount of fuel delivered to the boiler. Control is slow and inaccurate, however. If faster and more accurate control is required the plant must operate with the steam throttle valve partially closed, reducing plant efficiency.

Response Accuracy: Many generation technologies respond accurately to control signals, within the limitations of their control range and ramp speed. Hydro generators and modern wind generators are usually particularly accurate. Large coal-fired steam plants are more complex to control and often have less accurate response, as shown in the figure. Inaccurate generator response increases the total amount of system response capacity needed because the system operator calls on other resources to compensate for the response error.[368]

Two Similar Coal-Fired Generators Have Dramatically Different Response Accuracy



[368] E. Hirst and B. Kirby, *Ancillary-Service Details: Regulation, Load Following, and Generator Response*, Oak Ridge National Laboratory, ORNL/CON-433, September 1996.

Chapter 9. Focus on Flexibility for New Generating Plants*

Electric power systems were designed to meet fluctuations in electricity demand which have highly predictable hourly, daily, weekly and seasonal patterns. Traditionally, system operators relied on controlling output of power plants – dispatching them up and down – to follow highly predictable changes in electric loads. Generating plants were scheduled far in advance with only small adjustments in output required to follow changes in demand.

With an increasing share of supply from variable renewable energy resources, grid operators will no longer be able to control a significant portion of generation capacity. At the same time, renewable resources are among the most capital-intensive and lowest cost to operate. Once built, typically the least-cost approach is to run them as much as possible. Therefore, grid operators will need dispatchable generation with more flexible capabilities for following the less predictable "net load" – electricity load after accounting for energy from variable generation.[369]

New dispatchable generation will need to frequently start and stop, change production to quickly ramp output up or down, and operate above and below standard utilization rates without significant loss in operating efficiency. This chapter addresses changes needed in resource planning and procurement frameworks, currently driven by traditional resource adequacy constructs, to deliver the most cost-effective mix of resources in the future. Other means of accessing greater flexibility, such as subhourly dispatch and intra-hour scheduling, an energy imbalance market and reserve sharing, are discussed in other chapters of this report.

What Is Resource Adequacy?

Resource adequacy is the ability of an electrical system to meet the total energy and demand requirements at all times, taking into account scheduled and reasonably expected unscheduled outages of system devices.[370] The utility industry traditionally bases its resource adequacy requirements on the 1-in-10 standard for Loss of Load Expectation. In other words, the expected number of days that available generating capacity is insufficient to meet daily peak demand (load) is no more than one day in 10 years. This 1-in-10 standard is the primary force behind reserve margins and installed capacity requirements.

Figure 1 depicts three ways that flexible, dispatchable generating resources will be required to help maintain reliability and optimize the electric system with increasing levels of variable renewable energy generation:

1. *Periods of high loads and low renewable energy output* – Providing additional generating resources to efficiently meet demand
2. *Periods of low load and high renewable energy output* – Accommodating low-cost renewable generation by reducing output
3. *Moment to moment variations due to the variable nature of renewable resources*

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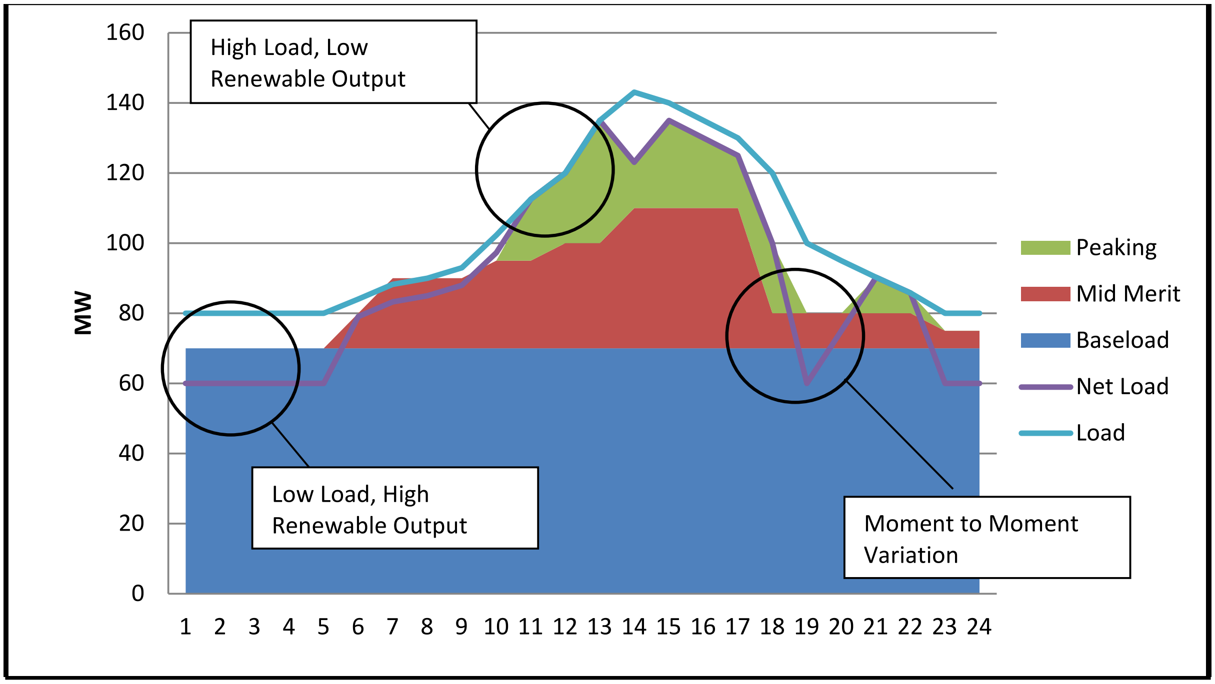
* **Lead author: Christina Mudd, Exeter Associates**

[369] Simon Skillings and Meg Gottstein, "Beyond Capacity Markets – Delivering Capability Resources to Europe's Decarbonised Power System," March 26, 2012, accepted for publication by IEEE, http://www.raponline.org/document/download/id/4854.

[370] K. Carden, N. Wintermantel and J. Pfeifenberger, *The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On*, National Regulatory Research Institute, April 2011, http://nrrionline.org/index.php?main_page=product_music_info&cPath=62&products_id=221.

Figure 1. Need for Operational Flexibility – Sample Day[371]



Renewable output is represented as the difference between load and net load.

How Does Flexible Capacity Work?

Utilities call on conventional resources (base load, mid-merit and peaking resources) to provide firm capacity and load-following services. Table 1 summarizes the operating characteristics of these resources, described in greater detail in Chapter 8.

Analysis undertaken as part of the Grid Integration of Variable Renewables (GIVAR) project in Europe demonstrates that a significant amount of flexible capacity already exists within the current electric power supply system when considering the technical capabilities of installed plants.[372] According to the analysis, existing flexible capacity within the nations studied is capable of supporting renewable energy penetrations of between 19 percent and 63 percent, with the Western Interconnection of the U.S. able to accommodate 45 percent renewable energy with existing flexibility.[373] However, the report notes that transmission expansion and enhancements and economic incentives may be required to realize the benefits of this flexibility.

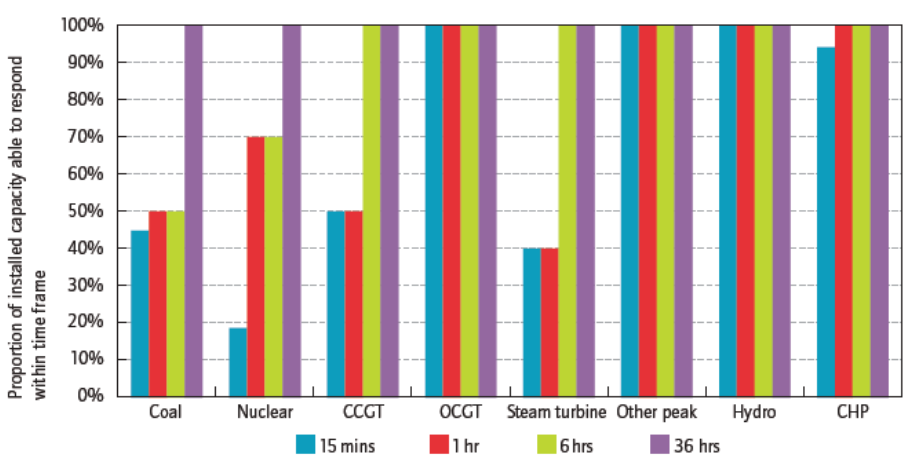
[371] Christina R. Mudd, Exeter Associates, Inc., March 2012.
[372] Although a plant may be technically able to ramp its production up and down, that does not mean it makes economic sense to do so. More frequent start-ups, shut-downs, and ramping increase wear and tear on the plant, posing additional costs and reducing profitability.
[373] International Energy Agency, *Harnessing Variable Renewables: A Guide to the Balancing Challenge,* 2011, http://www.iea.org/w/bookshop/add.aspx?id=405.

Table 1. Characteristics of Conventional Power Plants[374]

	Typical Utilization Rate (operating hours /year)	Capital Costs	Per Unit Output and Operating Costs	Flexibility Rating	Typical Fuels and Technologies
Baseload Plant	>80%	High	Low	Low flexibility, 24 to 72 hours to start and stop, efficiency losses at low utilization	Nuclear, Coal-Fired Steam
Mid-Merit Plant	30-60%	Medium	Medium	Moderate flexibility 10 minutes to ramp up and down production	Natural Gas Combined Cycle and Combustion Turbines
Peaking Plant	<10%	Low	High	Start times and ramp rates are fast	Diesel, Oil, and Natural Gas Reciprocating Engines, Internal Combustion Engines

Figure 2 shows the GIVAR assessment of dispatchable generation in the Western Interconnection with flexibility measured in ramp rates, the time it takes power plants to respond. Table 2 summarizes the flexible resources in the Western Interconnection identified through the GIVAR analysis.

Figure 2. Technical Flexibility of Dispatchable Plants (Western U.S. in 2017)[375]



[374] Based in part on information from J. Klimstra and M. Hotakainen, *Smart Power Generation: The Future of Electricity Production,* Arkmedia, Vassa, 2011.
[375] International Energy Agency.

Table 2. Technical Flexible Resources From Dispatchable Power Plants in the Western U.S. (2017)[376]

Flexible Resource in	Maximum Ramp-Up Capability (MW)	Maximum Down-Ramp Capability (MW)
15 min	85,198	50,676
1 hr	97,900	61,451
6 hr	150,846	127,059
36 hr	179,285	159,216

Note: The GIVAR study examined installed generation expected in 2017 based on data compiled for the Western Wind and Solar Integration Study.

Capabilities of Flexible Power Plants[377]

- Fast starting
- Fast ramping up and down of load
- High fuel efficiency in a wide range
- Fuel flexibility
- Minimum maintenance outage time
- Starting and stopping not affecting maintenance
- Remote control of output (frequency regulation)
- Black start capability
- Short building time
- Low spatial impact
- Easy adaptable capacity
- Low sensitivity to ambient conditions
- Minimum water use
- Low capital expenditure

How Could Flexible Capacity Be Procured?

There are four main mechanisms in the U.S. through which utilities or system operators currently secure capacity resources, though the focus typically is not on flexibility:[378]

1. *Utility Resource Planning and Procurement.* Most Western states require jurisdictional utilities to conduct long-term integrated resource planning to establish a preferred portfolio of resources under a variety of forward-looking scenarios. The plans use modeling simulations that focus on the quantity and timing of supply- and demand-side resources and transmission required to meet demand under these scenarios. Some utilities use relatively simple econometric models; others use more complicated system optimization and dispatch models. Resource plans take into account variables such as fuel prices, electric market prices, resource operation and dispatch, and environmental impacts. Regulators typically require utilities to consider need, cost, risk and uncertainty. Aside from meeting energy efficiency goals and renewable portfolio standards, resource needs are typically driven by capacity requirements, rather than energy needs.

[376] *Id.*
[377] Klimstra and Hotakainen.
[378] S. Newell, K. Spees and A. Schumacher, *A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs,* The Brattle Group, September 2009.

Depending on the state, the electric utility regulator may acknowledge or approve the resource plan, particularly the proposed near-term action plan to acquire the resources and transmission that are part of the preferred portfolio. Regulations may require that utilities use competitive solicitations for generating resources to compare merchant developer options with utility self-build (or turnkey) options – either as part of resource planning or in a separate procurement process.

2. *Forward Capacity Markets and Auctions.* In some restructured electricity markets, a regional system operator establishes resource adequacy requirements and runs a competitive auction several years ahead of need to procure capacity resources. For example, PJM and ISO New England operate annual auctions three years before the delivery period to acquire incremental supply- and demand-side resources to meet load forecasts. Load-serving entities (LSEs) are still individually responsible for meeting their customers' peak loads, and they must demonstrate they will have sufficient capacity to meet their peak loads (plus required reserves) several years into the future. LSEs have the option to meet resource adequacy requirements through bilateral contracting or LSE-owned generation (referred to as "self-supplied" or "self-scheduled" resources). However, the system operator procures any residual needed capacity through the auction and assigns cost responsibility to LSEs. LSEs must offer all existing capacity into the auction, along with new demand- or supply-side capacity offerings, with certain exceptions.[379]

   The forward capacity markets in use in PJM and ISO New England are not a good fit for Western states that do not operate in markets with regional system operators. Further, these capacity markets are not designed to provide the optimal mix of resources for the future. However, the markets provide useful lessons, particularly with respect to using demand response as a capacity resource.[380]

Demand Response Is a Flexibility Resource[381]

In addition to flexible generating plants, flexible capacity includes a wide range of technologies and resources, including demand response. Through short-term customer responsiveness, demand-side resources can be dispatched to provide energy, capacity, synchronized reserve and regulation service. Forward capacity markets have acquired a significant amount of demand response, as have ancillary services markets. Demand response makes up 9 percent of total capacity resources for both ISO New England and PJM for the 2014/2015 delivery year. Both ERCOT and Midwest ISO use dispatchable, controllable load to provide frequency generation service. Using load as a resource for balancing variable generation is described in the chapter on demand response.

3. *Resource Adequacy Requirement With Regulatory Backstop for Planning and Procurement.* Some jurisdictions with restructured markets have resource adequacy requirements but do not have a centralized forward capacity market. For example, the California Public Utilities Commission established resource adequacy obligations for all LSEs under its jurisdiction, including investor-

[379] Meg Gottstein and Lisa Schwartz, "The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects," The Regulatory Assistance Project, May 2010, http://www.raponline.org/document/download/id/91.
[380] *Id.*
[381] *2014/2015 RPM Base Residual Auction Results,* http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx, and *Forward Capacity Auction 2014-2015 Total Flows Diagram*, Sept. 20, 2011, http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp15/fca15/index.html.

owned utilities, energy service providers and community choice aggregators. Each LSE is required to demonstrate to the Commission that it has procured under bilateral contracts sufficient capacity resources, including reserves, to serve its local capacity requirements on an annual basis as well as its residual aggregate system load on a monthly basis. Both the Commission and CAISO review the LSE's resource supply plans to determine whether they will meet these local and system resource adequacy requirements. CAISO established a backstop capacity procurement mechanism to acquire and allocate costs for capacity in the event that an LSE fails to meet its resource adequacy requirements or a generator or supplier fails to meet its scheduled delivery, or that system conditions otherwise merit commitment of generation that does not have a resource adequacy contract.

4. *Voluntary Capacity Markets and Regional Pooling.* A voluntary capacity market might operate as a bulletin board where a regional administrator matches buyers and sellers of capacity resources. Another option is a facilitated, voluntary auction. For example, the Midwest ISO requires LSEs to demonstrate that they have sufficient resources to meet their forecasted load and reserve margin for the month ahead.[382] The Midwest ISO operates a voluntary capacity auction prior to the start of each month to enable LSEs to acquire any additional capacity needed.

   In the West, the Joint Initiative is considering how a flexible reserve product might be established to provide additional ramping capabilities in the region. One option is a new category of non-contingency "flexible reserves" with a 30-minute ramp capability that could address net variability in renewable resources, load and interchange between balancing authority areas.[383] Some utilities already have a target level of flexible capacity resources to support ramping events.[384] A regional pool for flexible reserves would require less reserve capacity than the sum of such reserves for individual balancing authority areas due to geographic and resource diversity.

How Is the Region Addressing Flexible Capacity?

The products and services provided by flexible capacity resources, such as ancillary services and imbalance reserves, are not new. Utilities already use the quick ramping ability of natural gas plants to balance wind and solar resources. Some Western utilities, however, are concerned that the current fleet of natural gas plants may be insufficient for balancing higher penetrations of renewable resources and are considering how to better incorporate flexible capabilities in integrated resource planning.[385]

Utility resource planners consider capacity requirements 20 years or more in the future. State and federal environmental and energy policies also have long time horizons. Planning to meet flexible capacity needs will better prepare utilities and system operators to manage the grid with higher penetrations of variable generation.

[382] MISO is considering changes to its capacity market including requiring LSEs to demonstrate resource adequacy one year in advance.
[383] *Flex Reserves Discussion,* Joint Initiatives Meeting, Jan. 21, 2012, http://www.columbiagrid.org/ji-nttg-wc-documents.cfm.
[384] For example, Public Service of Colorado has a target for flexible reserves based on a history of worst 30-minute ramping impacts. The resource target is not a standards-based obligation like contingency reserve. Instead, it is based on current and forecasted wind portfolio operating points.
[385] Lisa Schwartz, *et al.,* Regulatory Assistance Project, *Renewable Resources and Transmission in the West: Interviews on the Western Renewable Energy Zones Initiative,* prepared for Western Governors' Association, March 2012, http://www.westgov.org/component/joomdoc/doc_download/1555-wrez-3-full-report-2012.

Utility resource plans and wind integration studies are beginning to recognize the need for flexible capacity. For example, PacifiCorp recently revised its 2011 resource plan to add an action item to study grid flexibility, including the following elements: [386]

- Definition and metrics for measuring flexibility for all types of resources
- An inventory of flexibility needs and capability of existing assets to meet them
- A projection of flexibility needs to successfully integrate additional variable renewable energy resources
- A comparison of benefits and costs of obtaining flexibility from a range of flexibility resources

Resource planning tools and models are not designed to measure the optimization and efficiency of a power system. For example, operating and maintenance costs are typically established as fixed costs in resource planning and production cost models. However, they vary greatly based on plant operations and in particular with increased cycling and starts and stops. Further, wind and solar integration studies attempting to measure the cost of balancing variable generation often are conducted separately from the resource planning process.[387]

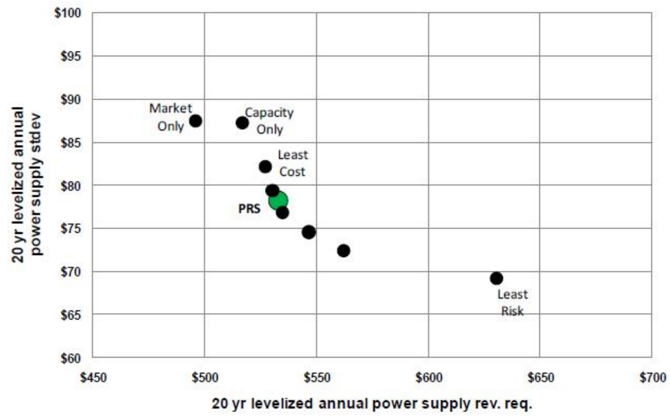
Avista's 2011 resource plan selected a "Preferred Resource Strategy" with a mixture of natural gas-fired simple- and combined-cycle plants in anticipation of a growing need for system flexibility to integrate variable resources. As part of its resource planning process, Avista incorporated an "Efficient Frontier" analysis. Such an analysis defines the least-cost resource portfolio at each specified level of risk tolerance (such as the average value for the worst 10 percent of outcomes). The Efficient Frontier is not designed to analyze the need for flexible capacity, but it does present one view of optimization of cost and risk. Figure 3 shows how Avista's selected portfolio mix fits along the Efficient Frontier.[388]

[386] PacifiCorp, *Revised 2011 Integrated Resource Plan Action Plan*, Oregon Public Utility Commission Docket No. LC 52, Jan. 9, 2012, http://edocs.puc.state.or.us/efdocs/HAS/lc52has113145.pdf.

[387] For example, Idaho Power (which serves primarily Idaho customers as well as a small portion of Oregon) recommended that wind integration studies, which are highly technical and focused on system operation, be addressed separately from the resource planning process. In response, Oregon Public Utility Commission staff recommended in part that the company's next wind integration study look for ways in which diversity and flexible balancing resources could lower the cost of integrating variable resources. Oregon Public Utility Commission Staff Report on Idaho Power's 2011 Integrated Resource Plan, Docket No. LC 53, Jan. 24, 2012, http://www.puc.state.or.us/PUC/meetings/pmemos/2012/021412/reg3.pdf.

[388] Avista's resource plan "splits natural gas-fired generation between simple- and combined-cycle plants in anticipation of a growing need for system flexibility to integrate variable resources." *Avista 2011 Electric Integrated Resource Plan,* Aug. 31, 2011, p. 8-1, http://www.avistautilities.com/inside/resources/irp/electric/Pages/default.aspx.

Figure 3. Avista Efficient Frontier[389]



In its 2011 Energy Resource Plan, Public Service Company of Colorado focused on three areas of potential need: 1) generation capacity to meet reserve margins, 2) renewable energy to meet the state Renewable Energy Standard and 3) flexible generation resources for integrating renewable resources. The plan looks out over a 40-year study period and develops a strategy for a seven-year resource acquisition period. The utility analyzed the need for flexible generation (power plants that can ramp generation or be brought on-line within a 30-minute timeframe) to help maintain the balance between generation and load.[390] The utility found that it does not need to acquire additional flexible generation resources within the seven-year resource acquisition period ending in 2018.[391]

Flexible Capacity in the CAISO Footprint[392]

CAISO is proposing two new resource adequacy backstop mechanisms to ensure sufficient quantities of flexible capacity in the future:

- *Risk of Retirement* – Under this approach, CAISO would assess flexible and local capacity at risk of retirement with one year or less remaining under a Resource Adequacy contract. Resources needed within five years would be eligible to receive a minimum revenue guarantee to cover the cost of flexible resources procured under the Flexible Capacity Backstop mechanism.
- *Flexible Capacity Backstop* – Under this mechanism, CAISO would make up for deficiencies in LSEs' procurement of flexible capacity resources. CAISO would establish minimum flexible capacity requirements for Local Regulatory Authorities (e.g., the California Public Utilities Commission), apportioned to each LSE. CAISO would procure flexible capacity as needed if LSEs procure insufficient flexible capacity, with costs allocated to LSEs on a load-ratio share based on the amount short. Generators can elect to offer their resources for the program.

[389] *Avista*, p. 8-15.
[390] Spinning reserves were not considered as part of the 30-minute pool of resources available to manage wind ramp-downs. In addition, the assessment did not address the role that demand response might play in meeting flexibility requirements.
[391] Public Service Company of Colorado, *2011 Electric Resource Plan, Volume I*, Oct. 31, 2011, p. 1-30, http://www.xcelenergy.com/About_Us/Rates_&_Regulations/Resource_Plans/PSCo_2011_Electric_Resource_Plan.
[392] CAISO, *Flexible Capacity Procurement: Market and Infrastructure Policy Straw Proposal*, March 7, 2012, http://www.caiso.com/Documents/StrawProposal-FlexibleCapacityProcurement.pdf.

The following table shows the types of flexible resources that will be eligible for the proposed CAISO programs. Excluded are base-load resources, intermittent (variable) resources, and hourly intertie resources that are not dynamically scheduled.

Eligible Flexible Resources for Proposed CAISO Resource Adequacy Backstop Mechanisms[393]

Maximum Ramping	Load Following	Regulation
Maximum Continuous Ramping for the Month	15-Minute Ramping	1-Minute Ramping
Requirement determined by longest continuous ramp • MW of ramp possible during longest continuous ramping period	Requirement is the 15-minute ramping capacity need	Requirement is the need for regulation expressed in ramp rate of MW/min
Units must respond to ISO dispatch instructions. Renewable generation, base load units, and units that self-schedule are not eligible.	Unit must respond to ISO dispatch instructions.	Units must be regulation certified
Each resource's contribution is ramping capacity over the time period: • Pmax – Pmin if the unit cannot start quick enough • Pmax if the unit starts and reaches Pmax during the ramp interval (example - if longest ramp interval is 5 hours for the month, a resource that starts and gets to its maximum output in less than 5 hours can count its Pmax toward maximum ramping requirements)	Each resource's contribution is the minimum of: • Pmax-Pmin • Ramp Rate(/minute) * 15minutes • Ramp Rate based on the MW weighted average ramp-rate of the resource for a resource with different ramp-rates for different operating ranges(i.e., use the megawatt size of the operating zone to weight the ramp rate for that zone).	Ramp rate based on the MW weighted average ramp rate of the resource for the operating ranges where it can provide regulation.

How Does Flexible Capacity Reduce Costs and Provide Other Benefits?

Resource adequacy is driven by load forecasts and energy demand. Variable energy resources do not add to demand requirements, and thus the integration of renewable resources does not increase the overall capacity requirement of a system. The same flexible capacity used to smooth output of variable resources can be used to meet peak load requirements, and the peak load will remain the same with or without wind and solar resources.

While flexible capacity resources may cost more than other capacity resources, optimization of the electric power system as a whole should reduce costs in the long-run. First, acquiring the best mix of resources, including those that complement wind and solar, will lead to more efficient system operation. Flexible, dispatchable resources that ramp up and down as needed to fill in around renewable energy production will allow increased utilization of low-cost energy.

393 *Id.*

Second, capacity resources that are designed to be flexible will provide these services at a lower cost than thermal plants that lose efficiency at lower utilization rates and have increased operating costs as a result of frequent start and stops. When thermal plants are operated at partial loads during periods of high variable generation output and low loads, fuel efficiency decreases and emissions increase, offsetting some of the benefits associated with renewable energy generation. Maximizing the benefits of renewable resources requires adaptation of thermal plants to meet new operating requirements.[394]

Power Perspectives 2030, a study of the feasibility of Europe's plan to reduce overall greenhouse gas emissions 80 percent by 2050, found that a more flexible portfolio of non-renewable supply resources is a key component of an economic long-term solution. While some of this increased flexibility will come from an increase in the number of back-up generators with very low levels of utilization, the study found that more efficient options such as flexible gas-fired combined cycle plants can continue to realize annual load factors comparable to what they see today – though with more erratic day-to-day operating profiles – and should therefore constitute the core of the non-renewable supply portfolio. Together with more responsive demand, expanded transmission systems and larger balancing areas, more flexible generating resources are needed to optimize production and consumption. Essentially what is needed is a portfolio of "flexible base-load" supply resources capable of matching net load – with its shrinking share of round-the-clock demand – without compromising efficiency.[395]

What Are the Gaps in Understanding?

Information Gap. The principal gap is understanding how much more flexible capacity will be needed and when. The answer depends on how much variable generation will be developed, how much balancing authority cooperation and aggregation will occur, how much flexibility will result from operational changes such as improved forecasting, dispatch and scheduling practices, how much transmission reinforcement will be in place, and therefore how much residual flexibility will be needed from demand response and power plants. In addition, costs and benefits of flexible vs. inflexible resource portfolios are not well understood. What we do know is that flexible capacity resources will increase operating capabilities so that a variety of approaches can be employed, reducing cost and risk.

Gaps in Analytical Approach and Tools. To fully understand the need for and benefit of flexible capacity, it is necessary to analyze the volatility attributed to renewable resources in power supply models and the effects of cycling conventional power plants. Accurately modeling variable generation requires hourly and intra-hourly generation profiles. For example, the common modeling practice by utility resource planners is to create a single wind generation shape that represents the aggregate of all wind resources in each load area. This shape is smoother than it would be for individual wind plants, representing the diversity that a large number of wind farms located across a zone would create. While this simplified methodology works well for forecasting electricity prices across a large market and evaluating the need for capacity resources, it does not accurately represent the volatility of specific wind resources and the minute to minute system requirements required to integrate variable resources. Further, resource planning studies typically rely on hourly data, whereas variations in subhourly variable generation profiles may establish a need for resources with shorter ramp rates.

[394] MIT Energy Initiative, *Managing Large-Scale Penetration of Intermittent Renewables,* April 20, 2011, p. 3, http://web.mit.edu/mitei/research/reports/intermittent-renewables-full.pdf.
[395] *Power Perspectives 2030*.

Other analytical gaps in resource planning include metrics and methods for assessing flexibility of resource portfolios. NERC's Integration of Variable Generation Task Force is developing guidance on this issue for system planners.[396]

Modeling Limitations: Public Service of Colorado's Experience

Public Service of Colorado uses both the Strategist and ProSym models in the development of its long-term resource plans. Strategist is a capacity expansion model that determines the most cost-effective mix of generation resources that can be integrated with a utility's existing system to serve future customer demand for electricity. ProSym is a least-cost, chronological dispatch-and-commit model that simulates resources to meet projected demand and forecasts future production costs. While these models capture the reduction in coal generation backed down to accommodate wind generation, they do not have the ability to track and report the number of times a coal unit is cycled as a result of wind generation or assign a cost for each cycle. The utility attempted to analyze and capture these costs in separate spreadsheet models. While this approach will help to assign costs to cycling, it does not allow for resource selections or operating strategies that minimize cycling because the costs are not embedded in the model.

Technology and System Advancements. Advancements in both supply- and demand-side technologies and smart grid systems will change resource needs over time in an increasingly dynamic electric system. But the timing and extent of changes in real time operations and resource optimization are unknown. Utilities are making incremental improvements in long term planning to account for these innovations.

Resource Procurement Process Not Capability Based. Utilities comparing third-party bids and self-build capacity options in competitive solicitations may evaluate alternatives without sufficient consideration of the costs and benefits of flexibility that may be needed with higher levels of variable generation. New criteria and methods are needed to evaluate flexible capabilities of resource options. For example, Portland General Electric's proposed solicitation for power supply resources includes a request for flexible capacity resources that will allow for dynamic automated generation control and the right to schedule daily, hourly and subhourly in exchange for a capacity and energy fee. In addition to economic dispatch costs (calculated as the ratio of the bid's projected total cost per megawatt-hour to forecast market prices), price evaluation for flexible capacity resources will include forecasted reliability-based dispatch costs for following expected load and wind deviations.[397]

What Are the Implementation Challenges?

Acquisition of new capacity is the result of a long, detailed process driven in most Western states by utility resource plans. Typically, regulated utilities do not receive pre-approval by state regulators for

[396] Eamonn Lannoye, Michael Milligan, John Adams, Aidan Tuohy, Hugo Chandler, Damian Flynn and Mark O'Malley, "Integration of Variable Generation: Capacity Value and Evaluation of Flexibility," prepared for NERC's Integration of Variable Generation Task Force, 2010, http://www.nerc.com/docs/pc/ivgtf/IVGTF%20PES%20PAPER%20V6.pdf; North American Electric Reliability Corporation, *NERC IVGTF Task 2.4 Report Operating Practices, Procedures, and Tools*, March 2011, http://www.nerc.com/docs/pc/ivgtf/ivgtf2-4.pdf.

[397] The utility "…is seeking to acquire new resources that will fill the dual function of providing capacity to maintain supply reliability during peak demand periods and other contingencies, while also providing needed flexibility to address variable load requirements and increasing levels of intermittent energy resources." Portland General Electric, *Final Draft Request for Proposals for Power Supply Resources*, Oregon Public Utility Commission Docket No. UM 1535, Jan. 25, 2012, pp. 1, 29-30, http://edocs.puc.state.or.us/efdocs/HAH/um1535hah14104.pdf.

resource additions. Instead, decisions regarding prudence and cost recovery are decided in a rate case. Utilities selecting a higher cost alternative in order to acquire flexible capacity, rather than simply meeting peak megawatt requirements, may risk cost disallowance if state policies and regulations do not recognize flexible resource needs.

As discussed above, a significant challenge facing utilities, system operators and regulators is assessing how much flexible capacity exists and how much will be needed – and when. If existing resources are able to meet current loads, plans to acquire flexible generation are put on hold until such time as additional capacity is required for resource adequacy. Further, advanced technologies with more flexible operating parameters may not be cost-effective based on current system requirements.

Transition Issues

Calpine's 542 MW natural gas-fired Sutter plant in California, which came on-line in 2001, may be an example of having flexible capabilities at a time where the need for flexibility jeopardized the continued operation of the facility. Demand for electricity has fallen in California and, as a result, the Sutter Energy Center is operating without a contract during a period of extremely low electricity prices. CAISO estimates that the plant and its flexibility will be needed by 2017. But that does not address cost recovery today.[398] The CPUC recently ordered utilities to negotiate a contract with the plant.

State air quality regulations also may pose a barrier. Emissions rates for power plants may restrict or prohibit fast-ramping generators.

What Could Western States Do to Encourage a Focus on Flexible Capacity?

Western states could consider the following steps to enable the appropriate mix of resources in the future:

- Retool the traditional approach to resource adequacy and planning analysis to reflect the economic benefit of flexibility service.
- Conduct a flexibility inventory of existing supply- and demand-side resources.[399]
- Evaluate the need for flexible capacity at the utility, balancing authority, subregional and regional levels.
- Examine how utility resource planning and procurement practices evaluate long-term needs, benefits, and costs of flexible capacity with increasing levels of variable renewable energy resources, including capabilities and limitations of analytical tools and metrics. Amend planning requirements or guidance to address these needs.
- Review recommendations of NERC's Integration of Variable Generation Task Force on potential metrics and analytical methods for assessing flexibility from conventional power plants for application in utility resource planning and procurement.
- Examine incentives and disincentives for utilities to invest in flexible supply- and demand-side resources, including those directed at resource adequacy, to meet the growing demand for flexibility services.
- Use competitive procurement processes to evaluate alternative capacity solutions, looking beyond minimum requirements for resource adequacy and analysis focused simply on cost per

[398] "Sutter, Gas Meters Spark Debate," *California Energy Markets,* No. 1168, Feb. 17, 2012.
[399] See chapters on demand response and flexibility of existing plants.

unit. Specify capabilities, not technologies and fuels, allowing the market to bring the most attractive options.

- Review air pollutant emissions rates allowed under state rules for impacts on procurement of flexible generation, with the aim of maintaining integrity of overall environmental goals.

Appendix A. Assumptions for Assessment of Integration Actions*

The table in the Executive Summary assessing integration actions described in this report includes three columns:

- *Expected West-Wide Cost of Implementation*: This is an estimate of the implementation costs for the entire Western Interconnection (or, where specified, for a subregion), to the extent such information is available. Cost information is from secondary sources cited in the report. Otherwise, it is subject to the authors' judgment. Less than $10 million region-wide is "low" cost; between $10 million and $100 million is "medium" cost; and more than $100 million is "high" cost. We provide a level of confidence in the estimate. Blue shading is for high confidence, yellow for medium confidence and orange for low confidence.
- *Expected Benefit for Integrating Variable Generation*: The authors judged the benefit of each option for integrating variable generation based on one or more of the following factors: ability to integrate more variable generation, increased ease of integrating variable generation and reduction of reserve requirements. We provide a level of confidence in the estimate. Blue shading is for high confidence, yellow for medium confidence and orange for low confidence.
- *Projected Timeframe in Implementing Option*: Primarily based on the authors' judgment, we used any available information on implementation time. "Short" is less than two years, "medium" is two to five years, and "long" is more than five years.

Caution should be used in drawing conclusions from this table and underlying assumptions. Availability and quality of information are inconsistent. Assigned rankings should be viewed broadly, from a regional perspective. Individual projects will have specific cost, integration, implementation and cost-effectiveness impacts.

Subhourly Dispatch and Intra-Hour Scheduling

This category covers three options: voluntary, non-standard 30-minute scheduling (the existing situation in the West); voluntary 5-minute to 30-minute scheduling with standard definitions and standard terms and conditions; and mandatory 5-minute to 30-minute scheduling across the West with standard terms and conditions.

Because the first option (voluntary, non-standard, 30-minute scheduling) is the present situation in the West, and the cost for current 30-minute scheduling is reportedly low, it is assigned a low cost with high confidence (green). Particularly with the lack of standardization, we assigned it a low integration benefit with high confidence. Implementation time for additional balancing authorities to adopt this practice is short.

The second option (voluntary but with standard definitions and standard terms and conditions) has a range of low to medium cost and integration benefit, depending on the scheduling interval, with medium benefit achieved only if a significant number of balancing authorities adopt subhourly dispatch and intra-hourly scheduling with standard scheduling provisions. Because of uncertainty about how many balancing authorities may adopt this option, we assigned a medium level of confidence (yellow) for both cost and integration benefits. We assumed a short implementation time (two years or less) to adopt standard definitions, terms and conditions.

* **Lead author: Kevin Porter, Exeter Associates**

For the third option (mandatory across the West with standard terms and conditions), a low to high cost is assumed, with low for 30-minute scheduling and high based on Avista's estimate for complying with FERC's proposed 15-minute scheduling provision. We also assumed a higher benefit for integration of variable generation (medium to high) and a longer implementation period (medium), compared to voluntary intra-hour scheduling. Because the costs for 15-minute scheduling are based on an estimate from only one balancing authority, we assigned a medium confidence level. We also assigned a medium confidence level for integration benefits because the effects depend on the scheduling interval adopted.

Dynamic Transfers

This section of the table includes two options: 1) improved tools and operating procedures and 2) equipment upgrades, including new transmission lines and system voltage control devices. We used estimates from the Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team for implementation costs and timing. Generally, we assumed that actions not requiring additional staffing had low cost and low to medium implementation time, with an integration benefit of low to medium. We ranked actions requiring new equipment or transmission as medium to high cost and implementation time, but with a higher benefit for integrating variable generation. We have high in our cost assessment for both options, given available information from the Northern Tier Transmission Group and ColumbiaGrid Wind Integration Study Team. We assigned a medium confidence level for integration benefits for both implementation options.

Energy Imbalance Market (EIM)

We divided this section of the table into a subregion-only EIM and a West-wide EIM. Costs for both were rated medium to high – set-up costs are not that different. We assumed the integration benefits and the implementation time would be medium for a subregion-only EIM. For the West-wide EIM, we view integration benefits as high and assigned a medium to long timeframe for implementation, with the assumption that not all balancing authorities that ultimately participate will sign up initially. (The high benefit ranking assumes robust participation.) As noted in the EIM chapter, 82 percent of generation was voluntarily offered for dispatch in Southwest Power Pool's Energy Imbalance Service market over the past year. Of the remaining resources, only 2 percent was self-dispatched; the rest are non-dispatchable, including nuclear and intermittent resources.

We have high confidence in our cost assessment for both the subregional and West-wide EIM. While previous analyses suggested a wide variation in costs depending on assumptions, the Southwest Power Pool and California ISO recently provided cost bids for market operator, reducing uncertainty. Our confidence in the integration benefits is medium, in part because it is not clear how many balancing authorities will participate in either a subregional or West-wide EIM at least initially. An NREL study with results due in May 2012 will provide more information on reserve and dispatch benefits. Confidence in integration benefits could increase based on the results of the study.

Improve Weather, Wind and Solar Forecasting

A wide range of costs can be assigned for forecasting. A rudimentary, persistence-based forecast can be implemented at very little cost, but that will be inadequate for making longer-term forecasts and for forecasting variable generation ramps. Using third-party forecasting, adding specialized forecasts such as ramps, or developing an internal robust forecast will cost more. We assumed that balancing authorities would enlist a third party to do variable generation forecasting but without specialized forecasting tools such as separate ramp forecasts, so we assumed a medium cost with a medium level of confidence. We assigned a medium to high benefit for integrating variable generation, with a high confidence level, based on multiple integration studies that have emphasized the importance of forecasting. We rated implementation time as short to medium. Forecasting can be implemented quickly but it takes time to train the forecasting model and resolve data gathering and other implementation issues.

Geographic Diversity

Geographic diversity is divided into two categories: 1) additional geographic diversity that can be captured without transmission expansion and 2) new transmission is constructed to take advantage of geographic diversity.

We assigned geographic diversity without transmission expansion low to medium costs, with a medium designation for scenarios where additional development of lower quality variable energy resources is developed to achieve the same level of generation output from higher quality, but geographically concentrated, resources. We are confident in our assessment of cost. We assigned a low to medium rating for the integration benefits for geographic diversity absent transmission expansion – in other words, to capture diversity within a balancing authority area – with a medium level of confidence, as the benefits depend on the ability to access geographically diverse resources. Avista's wind integration report described in Chapter 5 suggests that not all wind resources that would result in geographic diversity can be developed because of transmission constraints and public opposition to environmentally sensitive areas. Implementation time is ranked as medium, recognizing that efforts to access geographic diversity, such as ensuring that new generation project development is geographically diverse, may take time to implement.

Transmission developed to access geographic diversity is designated as high cost with high confidence, and integration benefits are medium with high confidence. The benefit of geographic diversity increases with higher levels of variable generation, but at a decreasing rate with penetration. The time for implementation is long because of the time required to permit and build transmission.

Reserves Management

Reserves management options are divided into four categories: reserves sharing, dynamic calculation, using contingency reserves for wind events, and controlling variable generation. For reserves sharing, we mostly based our estimates on the experience with the ACE Diversity Interchange (ADI), as described in Chapter 6. (As the report notes, an energy imbalance market mitigates reserve obligations through a form of reserve sharing, with simultaneous netting of resource variability in economic dispatch.) Again based on ADI, we assumed a low cost (with a high confidence level) and a short implementation time, because ADI took only six months to implement through dynamic schedules. The ADI tool limits instantaneous benefits to ±30 MW for each participating balancing authority area because the tool has no means to evaluate and anticipate transmission flow impacts associated with the allowed increased inadvertent interchange swaps. We therefore designated integration benefits as low to medium, with a high level of confidence. Our benefits assessment could be raised to medium if the limitation is removed, but removing the cap on transmission flow impacts without any tools to evaluation reliability implications also may pose a drawback.[400]

For dynamic calculation of regulation and load following reserves, we assigned the same ranking as we used for reserves sharing. Several factors can be examined in dynamically setting reserve requirements, including the load forecast, the variable generation forecast, net load variability forecast, the confidence in forecasts, information on the expected behavior of conventional generation, and variable generation output. However, it appears that dynamic calculation of reserves requires simple to moderate changes in operating practice. That suggests the cost would be low and the implementation time short. Our estimate of integration benefit is low to medium. We have high confidence in our cost assessment and medium confidence in our benefit assessment.

Regarding use of contingency reserves for wind events, we assigned a low to medium cost. Medium represents cases where additional contingency reserves may need to be procured to address wind events that exceed required timeframes for restoring reserves. The confidence level for our cost assessment is medium because of uncertainty over additional contingency reserves that may be needed. That also influences our estimate of implementation time, so we assumed a medium timeframe if additional contingency reserves have to be obtained and short if not. Integration benefits were considered to be low to medium, with the expectation that contingency reserves would not be called on often for wind events. We assigned a high confidence level for integration benefit, given NERC's statement that using contingency reserves for large wind ramp events could reduce costs and increase reliability.

For controlling variable generation, we assumed requirements are prospective and would apply only to new variable generators. We therefore assumed a cost of low to medium, with a medium confidence level. Our projection for cost does not include revenue losses to variable generators from operating below full output to provide regulation. Because the requirement is assumed to be prospective, we view the integration benefit as low to medium, with a medium confidence level, as it will take time to be fully implemented. We estimate a medium to long implementation time for ramp rate operating limits, reflecting the assumption that requirements would be prospective and it would take time for them to be fully phased in.

Demand Response

Demand response options are divided into discretionary demand, interruptible demand and distributed energy storage appliances.

Cost and integration benefits for discretionary demand are assumed to be low to medium, with low ascribed to large industrial loads already providing demand response and medium for water utilities for running pumping operations selectively. We assume a short to medium implementation time, with short for more fully utilizing existing demand response resources beyond peak shaving and medium for expanding discretionary demand response programs to additional customers.

[400] A Reliability-Based Control field trial also is underway in the Western Interconnection. It provides similar benefits to balancing authority areas as ADI under normal system operations, but reduces the allowed exchanges during periods where system frequency is adversely impacted by the exchange. The ADI program lacks this feature of linking exchanges to the reliability attribute of system frequency.

We gave the same assignments for costs, integration benefits and implementation timeframe for interruptible demand, with a low cost rating for tapping demand response from existing program participants more frequently and medium for accessing additional customers.

Distributed energy storage appliances include electric water heaters and other appliances that can time-shift demand. We used the same assignments of low to medium for cost and integration benefit and short to medium for implementation time. We assumed the cost will be medium for wide-scale roll-out and low for more targeted applications. We assumed implementation time typically will be short, although it could be medium for a large-scale roll-out and for some equipment applications.

Our confidence level for cost and integration benefits for all demand response categories is medium. Some applications are site-specific, and the use of demand response for integrating variable energy generation is not yet widely practiced.

Flexibility of Existing Plants

We divided this category into two parts – minor retrofits and major retrofits. Minor retrofits were considered to be electronic changes, revised balance of plant system signals, and modifications to temperature controls and the steam turbine controller. Major retrofits were defined as major equipment replacement, installation of new equipment and equipment redesign.

It is difficult to estimate the potential cost, integration benefits and implementation timetable for adding flexibility to existing plants. The costs are unique to individual plants, and modifications are a plant-by-plant decision. We assumed the cost of minor retrofits from a regional perspective will be low if only a few plants undertake such retrofits and medium if more plants make minor retrofits. Integration benefits are projected to be low to medium, depending on the scope of the retrofits and how many generating plants undertake them. Our confidence in both cost and integration benefit is low (orange) because of uncertainties about the scope and number of retrofits that may be undertaken. We assume minor retrofits could be implemented in a short to medium timeframe.

Major retrofits are capital-intensive, so cost is rated medium to high. We also rated integration benefits medium to high, as more flexibility is presumed to be made available from major retrofits. But because retrofits are plant-specific and there is uncertainty about how many major retrofits may be performed, our confidence in these estimates is low. Implementation time is assumed to be medium to long.

Flexibility for New Generating Plants

Cost may be low if generating plants are being built anyway to maintain reliability – and load-serving entities are simply choosing a more flexible plant option – or they may be high if plants are being built solely for flexibility. We assume there will be a mix of both, so we assigned a ranking for cost of low to high with a high level of confidence.

We view integration benefits as ranging from medium to high, depending on what types of generating plants are developed and how many. While flexibility options for new generating plants already are increasing and some load-serving entities are beginning to consider flexibility in resource planning and acquisition, uncertainties remain regarding how many flexible generating plants will be built, and when. The implementation timeframe for building new, flexible generating plants – assumed to be natural gas-fired – is medium to long.

Appendix B. Economic Impacts of Electric System Savings*

Reducing the cost of integrating renewable resources will keep down electricity costs. As explained below, cost-effective improvements in the electric system fundamentally lower the cost to serve consumers and have a positive effect on the region's economy. Reducing integration costs also will help mitigate concerns about high penetrations of variable resources that could dampen renewable energy development overall, with its own economic consequences for the region.

The economic impacts of any new activity depend on how it affects industries and consumers in the geographic area of interest. Economic impacts of cost-effective transmission system improvements, for example, result from both the direct activity as well as from changes in disposable income for households and businesses due to changes in costs for electric service. Impacts are of two general types:

1. Income based impacts from increased consumer spending, as well as higher employment and improved business competitiveness, as a result of lower electric costs

2. System improvement-related impacts,[401] including:
   - *Direct* economic effects (e.g., spending on goods and services at a work site or buying new equipment)
   - *Multiplier* effects, including spending on supporting goods and services by firms engaged in the direct activity ("*indirect*" impacts) and workers spending their wages in the local economy ("*induced*" impacts)

Most economic impact studies focus on estimating the direct, indirect, and induced jobs stemming from the construction of a facility where the costs and benefits of the operation are borne by a private developer. However, where electric ratepayers ultimately pay the costs and receive the benefits of an investment, these studies typically leave out what is often a substantial short-term set of impacts – those associated with increased or decreased disposable income resulting from changes in electric system costs. It is often these income based impacts, achieved through cost-saving improvements to the electric system, which have the greatest impact on jobs.

While job impacts for the region as a whole may be positive, there likely will be regions that gain more than others and some that may lose. As the region makes a transition to higher levels of renewable resources, employment in supplying and operating traditional forms of generation may decrease. Similarly, cost-effective investments in innovative technology in the power sector may result in displaced demand for other services. This "creative destruction" process can result in job migration, but on average the cost savings will have positive economic impacts. In addition, renewable resource development, including transmission improvements to deliver energy to load centers, may disproportionately direct development to some regions more than others. The region as a whole will benefit economically from cost-effective investments in electric infrastructure. However, that benefit may not be uniformly dispersed.

Job creation can be reported as either jobs created per million dollars of ratepayer *savings* or million dollars of *expenditures*. A job is one full-time equivalent (FTE) of employment.

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* **Lead author, David Lamont, Regulatory Assistance Project**

[401] Here, system improvements represent a range of activities, from transmission expansion to software upgrades to implement changes in system operations.

Income-Based Impacts

Additional jobs are created through lower electricity bills that result from *cost-effective* electric system improvements. Such investments fundamentally lower the cost to serve consumers in the region. Ratepayer savings enable increased spending on other goods and services within the region, leading to an expanded economy and more jobs. Lower electric costs for businesses allow them to expand. The total job impact of a cost-effective investment in the electric sector is the sum of system improvement-related jobs plus those created as a result of consumer savings.

In order to capture the impact of lower electric bills on jobs, some studies have analyzed the *net savings* of electric system investments. For example, a study for the proposed Champlain Cable – a transmission cable from Quebec to New York City – estimated that installation of the cable would provide $650 million of power savings for New York City and 2,400 job-years created as a result. This works out to 3.7 job-years per million dollars of power cost savings over the first 10 years of operation of the cable.[402] Using a similar approach, an analysis for the State of Vermont showed that 5.5 jobs were created for each million dollars of savings in the electric sector from energy efficiency programs – a more labor-intensive and local activity than transmission construction.[403]

Conversely, the State of Connecticut evaluated a program to improve the reliability of its transmission system and found that paying for such improvements would result in the loss of an average of about six jobs per million dollars of expenditures during the phase-in portion of the project, but ultimately would result in positive employment impacts.[404] Studies on the economic impacts of investments in energy efficiency have estimated a direct job impact of between three and 10 job-years per million dollars of program expenditures.[405]

System Improvement-Related Impacts

The amount of material sourced within the region is an important variable in the number of local jobs created by the proposed activity. For example, transmission construction in an industrialized state that manufactures components used in such projects would likely create more in-state jobs than the same project in a less industrialized state. Similarly, a software design project by a local firm would create more local jobs.

The following table is excerpted from a recent survey and analysis of construction-related jobs associated with various transmission projects.[406] The range of estimated job impacts is considerable – from two to 18 job-years of employment per million dollars of expenditures. Most of these impacts are

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[402] *See* http://www.chpexpress.com/docs/Analysis-of-the-Macroeconomic-Impacts-of-the-Proposed-CHPE-Project.pdf.
[403] Communication with George Nagle, economist, Vermont Department of Public Service, March 15, 2012.
[404] Regional Economic Models, Inc., *Measuring the Impact of Improved Electricity Distribution in Connecticut*, prepared for Connecticut Light & Power, July 2007, http://www.remi.com/download/publications/energy/Final_Report-Measuring_the_Economic_Impact_of_Improved_Electricity_Distribution_in_Connecticut.pdf.
[405] Optimal Energy and Synapse Energy Economics, *Economic Impacts of Energy Efficiency in Vermont - Final Report,* prepared for Vermont Department of Public Service, Aug. 17, 2011, http://legislature.idaho.gov/sessioninfo/2011/interim/energy_public_optimal.pdf.
[406] Brattle Group*, Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, prepared for Working Group for Investment in Reliable and Economic Electric Systems, May 2011, http://www.wiresgroup.com/images/Brattle-WIRES_Jobs_Study_May2011.pdf. See the report for details on each project.

associated with the construction phase of the project. The study showed, on average, that each million dollars of transmission investment supported just under four job-years of direct employment and about seven job-years of total local employment.[407]

Summary of Recent Studies on Employment and Economic Impacts of Transmission Investments[408]

Study Sponsor	State(s) / Region	Total Transmission Capital Cost ($ million)	% Local Spending	FTE-Years of Employment Per $ Million Direct	Total
AltaLink	Alberta	$6,109*	75%	5	7
ATC LLC 138 kV	WI	$16	46%	NA	5
ATC LLC 345 kV	WI	$321	100%	NA	8
CapX2020	MN, ND, SD, WI	$1,773	100%	7	13
Central Maine	ME	$1,543	81%	4	6
Montana L&I in State	MN	$3,137	11%	1	2
Montana L&I out of State	MN	$1,263	33%	2	5
Montana L&I combined	MN	$4,401	17%	2	3
Perryman Group	TX	$5,000	100%	NA	18
SD Wind Energy Assn	SD	$169	25%	1	3
SPP Group 1 Low in-region	SPP	$1,282	47%	4	7
SPP Group 1 High in-region	SPP	$1,282	74%	5	8
SPP Group 2 Low in-region	SPP	$1,136	47%	4	7
SPP Group 2 High in-region	SPP	$1,136	73%	5	8
Wyoming Infrastructure	WY	$4,150	33%	5	5
			Average	**4**	**7**

*Canadian dollars

[407] While this study was focused on the poles and wires type of construction activity, it is being used here to represent a proxy for employment benefits from any type of investment in grid infrastructure.
[408] Brattle Group.

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WITNESS: TOM ELLIOTT

Before the
PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Response testimony of Tom Elliott

March 2013

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Tom Elliott. I am the Energy Analyst for the Small Scale Energy Loan Program (Loan Program) at the Oregon Department of Energy. The business address is 625 Marion St. NE, Salem, Oregon.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF YOUR EDUCATION AND EMPLOYMENT BACKGROUND.

A. I received a BS in Accounting from the University of Colorado, Boulder in 1980, an MBA from UC Berkeley in marketing and finance in 1985, and an AAS in Energy Management from Lane Community College in Eugene in 2008. Prior work experience includes financial and business analysis for Hewlett Packard. Since 2008, I have been the energy analyst for the Loan Program where among other duties I assess the technical and economic viability of loan applicants' proposed projects.

Q. WHAT IS THE PURPOSE OF THIS OPENING TESTIMONY?

A. I will address issues 5A (power purchase agreement (PPA) standard contract eligibility cap), 6E (how should contracts address mechanical availability) and 6I (appropriate contract term).

Q. WHAT EXPERIENCE DOES THE SMALL SCALE ENERGY LOAN PROGRAM HAVE IN FINANCING QUALIFYING FACILITY (QF) PROJECTS?

A. Since its beginning in 1980, the Loan Program has financed 27 QF projects representing a total of 92 megawatts (MW) of capacity.

Q. WHAT SIZES OF QF PROJECTS HAS THE LOAN PROGRAM FINANCED?

A. From 1980 through 2005, the projects ranged from 20 kilowatts (kW) to 19.6 MW. From 2006 on they have ranged in size from 750 kW to 9.0 MW.

Q. SHOULD THE COMMISSION CHANGE THE 10 MW CAP FOR THE STANDARD (PPA) CONTRACT? WHY OR WHY NOT? (ISSUE 5A)

A. No. The cap should remain at 10 MW. The additional transaction costs that the QF developers must fund along with other uncertainties related to moving from standard to negotiated PPA contracts would likely impede QFs' ability to finance their projects.

Q. WHY DO YOU BELIEVE TRANSACTION COSTS FOR QF DEVELOPERS WOULD RISE?

A. During the last few months, the Loan Program has asked QF developers that have received recent loans for projects with standard contracts what impact negotiating the PPA would have had for them. They all said that they would have needed attorneys experienced in energy development and PPA negotiations to assist them in negotiating the PPA. One developer suggested it would be "crazy" to negotiate a PPA without an attorney. Additionally, at least until the Loan Program gained more experience financing QFs with negotiated PPAs, we would not begin serious financing discussions for a QF project with a PPA that was negotiated without the assistance of an attorney. Currently the Loan Program is comfortable with the standard PPA contract. The Loan Program does not require outside or third party assistance to review them, in part because they are non-negotiable. That being said there are clauses in the current standard PPA contracts that the Loan Program would prefer be stricken or changed – e.g., mechanical availability requirements resulting in contract termination (to be addressed in my testimony on issue 6E).

Q. WOULD THE LOAN PROGRAM INCUR ANY ADDITIONAL COSTS TO REVIEW A NEGOTIATED PPA CONTRACT?

A. At least until we had more experience with reviewing negotiated PPAs, the Loan Program would require outside expertise (technical consultants and legal advice) to review a negotiated PPA. We would want to understand the entirety of the contract and have assistance reviewing all potential clauses that may affect a QF's ongoing ability to generate and be paid for power delivered to the electric company. Those Loan Program costs would be passed on to the QF seeking a loan.

Q. HOW MUCH WOULD THE ADDITIONAL TRANSACTION FEES BE FOR THE QF?

A. It is difficult to speculate how much the total additional transaction costs would be for a QF. The total is likely to vary depending on the energy resource and contractual issues. The indirect costs to the QF for the Loan Program's technical consultant and legal reviews passed on to the QF may range from $5,000 to $10,000, an amount similar to the total costs the Loan Program passes on to the QF for Department of Justice assistance in negotiating and finalizing the loan contract with the QF.

Regarding the QF's additional transaction cost of negotiating the PPA with the electric company, the QF developer we talked with that had the most experience developing and financing energy projects estimated the legal bill for negotiations with the electric company might be $100,000 or more. Another developer estimated that an attorney with the right experience and expertise would likely charge $250 to $500 an hour.

Q. HOW ELSE WOULD THE FINANCING PROCESS CHANGE IF THE QF MUST NEGOTIATE THE PPA RATHER THAN USE THE STANDARD OFFER CONTRACT?

A. If the QFs have to negotiate the PPA, there may be delays in the project development. They will certainly need to commit more time and resources. Currently the Loan Program considers the standard offer contracts bankable (acceptable to institutional lenders for financing). With negotiated contracts the Loan Program and other lenders will need to review each contract closely to determine its bankability. The Loan Program will not be able to review and analyze a QF application until we have a final draft (or near final draft) PPA. These PPAs will need final avoided cost prices and details of significant terms for operation and power delivery.

Q. WHY IS IT IMPORTANT FOR THE QF TO HAVE TERM FINANCING LINED UP WITH THE LOAN PROGRAM OR ANOTHER LENDER?

A. The QF needs to have term financing in place before it can get its construction financing that will need to be in place before the QF orders equipment and executes construction and other contracts.

Q. WHY DOES THE LOAN PROGRAM NEED CERTAINTY OF THE NEGOTIATED PPA?

A. Among other considerations, the Loan Program needs a reliable price for power deliveries over the life of the contract so we can meaningfully assess the *pro forma* revenue forecasts. In addition to price, the Loan Program also needs the certainty of other key clauses such as mechanical availability or power delivery requirements that could result in termination. Causes for PPA termination affect the Loan Program's determination of a QF project's long term financial viability.

Q. WHY IS THE QF'S REVENUE FORECAST SO IMPORTANT? HOW WOULD AN UNCERTAIN PPA PRICE AFFECT THE LOAN AMOUNT?

A. The Loan Program relies on the QF's generation revenue, after deducting operating and other expenses, to repay the loan. If the PPA prices are uncertain during the loan underwriting process, the Loan Program will use a conservative, lower PPA price estimate. This lower estimate may cause the loan request to be denied entirely or, more likely, may reduce the amount that the Loan Program is willing to commit to lending to the QF. This means the QF developer would have to add additional equity it may not have or not want to add due to insufficient returns necessary for the QF to proceed with its project.

Q. WHAT IS THE NET EFFECT? DOES THIS MEAN THAT FEWER QF PROJECTS WOULD BE DEVELOPED?

A. Yes, I believe that is likely. Lowering the cap for standard contracts would cause the QFs that use the Loan Program to incur significant upfront legal fees to negotiate a PPA early in the process to determine if they even have a viable project, and that may deter some potential project developers altogether. One of our recent QF borrowers told us that not having a standard contract would have likely killed his project. Some QF projects may be able to absorb the higher transaction costs along with other soft costs, while it might be the proverbial last straw for others. The QFs will need to negotiate their PPAs early in the project development and financing process. Remaining uncertainty related to price may result in a reduced loan commitment amount. This factor alone, or combined with the other factors, would likely lead to fewer QF projects. As a result, retail customers would lose the net benefit of additional QF generation including resource diversity and hedging against uncertainties related to natural gas prices and federal policies on regulation or taxation of greenhouse gases.

Q. WHAT IS YOUR PRIMARY CONCERN RELATED TO HOW CONTRACTS ADDRESS MECHANICAL AVAILABILITY? (ISSUE 6E)

A. Potential termination of a PPA for missing a mechanical availability requirement is unnecessarily harsh, and makes future loans with that clause in the PPA too risky for the Loan Program to finance. The Commission should require that QF contract penalties be in proportion to likely damages to an electric company. These contracts should include provisions for notice of non-compliance, and opportunity to remedy before penalties are incurred. Such terms could protect the electric company, and be considered financeable by the Loan Program.

Q. DURING RESOURCE PLANNING, HOW CAN THE ELECTRIC COMPANY BE REASSURED THAT QFS WILL GENERATE AND DELIVER POWER WITHOUT SEVERE PENALTIES FOR BEING UNAVAILABLE?

A. The QF has every incentive to keep its equipment maintained, operational and ready to generate electricity when the renewable resource is available. During due diligence, the Loan Program carefully reviews the QF's equipment warranties, operations and maintenance (O&M) processes and procedures, and the O&M providers' experience and response times. The Loan Program requires a separate repair and replacement loan reserve to ensure that funds are available for unexpected significant repairs. As stated earlier, the Loan Program depends on the generation revenue as the foundation for loan repayment. Therefore the Loan Program would look to the PPA terms to allow and encourage the QF to remedy mechanical outages and restore the system to full operation rather than risking contract termination altogether. The Loan Program will not make a loan until it is satisfied that the generation revenue forecasts are bankable, and that those same revenues will be available throughout the loan term.

Q. WHAT'S DIFFERENT BETWEEN A SMALL QF VS. A LARGE WIND PARK THAT WOULD CAUSE MISSED MECHANICAL AVAILABILITY TARGETS?

A. The Loan Program believes there are circumstances where a small wind QF may, through no fault or its own or with no ability to control, face a situation where multiple wind turbines are down for an extended period. A small QF may have only a half dozen turbines, so the average calculated mechanical availability percentage for a contract period can be pulled down with only a few turbines out for an extended period. If spare parts are not readily available, particularly for older turbines, an extended outage might occur. A small QF will likely have a slower response time for turbine faults than a large wind park. A large wind generation operation will have 24/7 monitoring with an onsite (or local) maintenance team to respond immediately to unscheduled maintenance events. A small QF may also experience delay when calling in outside expertise that the large operation has on staff or on call. All things being equal, small QFs are more likely to be at the end of the queue for spare parts and recall fixes if competing with large, commercial scale wind farms for the same limited maintenance resources. As such, lower mechanical availabilities for small QFs than what is expected for large scale installations may be appropriate to meet the goals of the state's PURPA policy (ORS 758.500 *et seq*.) and community-based renewable energy project goals (ORS 469A.210).

Q. SHOULD THE ANNUAL MEASUREMENT PERIOD FOR MECHANICAL AVAILABILITY BE CHANGED TO MONTHLY?

A. No. Only Idaho Power proposes to change from annual to monthly. The Loan Program believes monthly measurement would disadvantage small QFs unnecessarily. A small outage could represent a large percentage of a small QF's capacity and may cause the QF to miss a monthly mechanical availability target, without having a major impact on the electric company. Additionally, monthly measurement and reporting would require more administrative work than annual reporting.

Q. WHAT IS YOUR POSITION REGARDING THE MECHANICAL AVAILABILITY PERCENTAGE? SHOULD PLANNED OUTAGES BE TREATED DIFFERENTLY? HOW MANY HOURS OF PLANNED MAINTENANCE SHOULD THERE BE? CAN YOU COMMENT ON THE ELECTRIC COMPANIES' TESTIMONY REGARDING NOTIFICATION FOR SCHEDULED MAINTENANCE?

A. ODOE understands the electric companies' need to plan their resources in part based on QFs' ability to reliably generate and deliver power. Procedures also are needed to plan for known, scheduled maintenance. Reasonable notice provisions seem applicable. Rather than comment on the details of the various proposals, I believe reasonable compromises can be made that meet the electric companies' needs while not unduly burdening the small QFs. Overly stringent requirements with default penalties including PPA termination will likely result in QFs projects being non-financeable.

Q. WHAT WERE THE TERMS OF THE LOANS (CONTRACT LENGTHS) FOR THE QFS THAT THE LOAN PROGRAM FINANCED?

A. From 1980 through 2005, the Loan Program financed 16 QFs for terms between 20 and 25 years, three QFs for shorter terms, and two QFs for terms up to 30 years. From 2006 to present, the Loan Program has financed five projects for between 15 and 20 years and one project (largely self-financed) for five years.

Q. WHAT IS THE YOUR RECOMMENDATION REGARDING THE APPROPRIATE CONTRACT TERM AND DURATION OF THE FIXED PRICE PORTION? (ISSUE 6I)

A. I recommend continuing the current standard contract length of up to 20 years, and maintaining the first 15 years having a fixed price.

Q. HOW WOULD SHORTENING THE STANDARD CONTRACT TERM AFFECT QF FINANCING?

A. The Loan Program requires that any QF seeking financing have an executed PPA before any funds are disbursed on the loan. The term of the loan or repayment period must not exceed the PPA term. If the PPA term is reduced for instance to 10 years, the Loan Program would require the loan term to also be 10 years or less.

Q. WHAT WOULD A SHORTER PPA TERM MEAN FOR THE QF?

A. For the same amount borrowed, the QF's monthly loan payments would be significantly higher to pay off the loan in a shorter time period.

Q. COULDN'T THE QF JUST PAY MORE EACH MONTH?

A. No. The monthly loan repayments are typically "maxed out" – there isn't any more additional underlying generation revenue (less operating and other expenses) available to repay the loan. If the PPA term and loan term were shortened, the Loan Program would have to reduce the total amount of the loan back to a point where the loan payments were affordable based on the underlying project generation revenue.

Q. WHAT WOULD THAT DO TO POTENTIAL QFS?

A. QF developers would likely not go forward with their projects because they either lack capital to increase their equity share to make up for the amount they intended to borrow, or they would be unwilling to do so because their return on the invested capital would not be worth the risks and total effort required to bring a QF project to fruition.

Q. HOW WOULD REDUCING THE FIXED PRICE PORTION OF THE CONTRACT AFFECT QF FINANCING?

A. The Loan Program would shift all or a larger portion of loan repayment to the beginning of the loan to coincide with the fixed portion. That would result in the monthly payments needing to be higher during that period. But for the same reasons mentioned above, the Loan Program would need to reduce the total amount of the loan to the QF to bring it back in line with the underlying generation revenue. Again this shift may result in QFs not moving forward with projects.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

DOCKET NO. UM 1610
EXHIBIT: ODOE/300
WITNESS: KACIA BROCKMAN

Before the
PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Response testimony of Kacia Brockman

March 2013

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Kacia Brockman. I am a Policy Analyst for the Planning, Policy and Technical Analysis Division within Oregon Department of Energy. The business address is 625 Marion St. NE, Salem, Oregon.

Q: PLEASE PROVIDE A BRIEF DESCRIPTION OF YOUR EDUCATION AND EMPLOYMENT BACKGROUND

A. I received a BS in Engineering Physics from the University of Colorado in 1991. From 1991 until 2001 I worked as a network engineer designing least cost/least risk infrastructure upgrades to wireless telecommunications networks. From 2003 until 2013 I worked for Energy Trust of Oregon designing and implementing an incentive program to encourage development of solar electric generation projects by removing market barriers. In February 2013, I began working at Oregon Department of Energy, where I specialize in rules administration and regulatory affairs.

Q. WHAT IS THE PURPOSE OF THIS OPENING TESTIMONY?

A. I will address issues 3A, 3D and 3E (schedule of avoided cost updates) and issue 5D (selling Renewable Energy Certificates (RECs) out of state.)

Q: WHAT ARE ODOE'S INTERESTS REGARDING THE FREQUENCY OF AVOIDED COST UPDATES? (ISSUES 3A, 3D AND 3E)

A: ORS 758.500, *et seq*., states in part:

> (2) It is the goal of Oregon to:
>
> (a) Promote the development of a diverse array of permanently sustainable energy resources using the public and private sectors

> to the highest degree possible; and
>
> (b) Insure that rates for purchases by an electric utility from, and rates for sales to, a qualifying facility shall over the term of a contract be just and reasonable to the electric consumers of the electric utility, the qualifying facility and in the public interest.
>
> (3) It is, therefore, the policy of the State of Oregon to:
>
> (a) Increase the marketability of electric energy produced by qualifying facilities located throughout the state for the benefit of Oregon's citizens; and
>
> (b) Create a settled and uniform institutional climate for the qualifying facilities in Oregon.

ODOE encourages the development of QF projects in part by providing loans through the State Energy Loan Program and grants through the Renewable Energy Development Grant Program. Based on our experience reviewing project applications in those programs, and our understanding of incentive programs operated by the Energy Trust of Oregon for small renewable resource projects, we know that a QF project is most likely to succeed when the project has certainty about the power purchase price for which it is eligible. To achieve that certainty, changes to the avoided cost rates should be made on a predictable schedule, using a transparent and consistent methodology and with sufficient time and opportunity for stakeholder engagement.

Q: SHOULD THE COMMISSION REVISE THE CURRENT SCHEDULE OF UPDATES – AT LEAST EVERY TWO YEARS AND WITHIN 30 DAYS OF

ACKNOWLEDGEMENT OF THE UTILITY'S INTEGRATED RESOURCE PLAN (IRP)? (ISSUE 3A)

A: The current methodology of regularly scheduled avoided cost filings on a date certain, plus avoided cost filings 30 days after each IRP acknowledgement order, should be retained. However, ODOE supports increasing the frequency of regularly scheduled avoided cost filings from every two years to every year. The date of resource deficiency should be updated only if the Commission has issued an order updating the date, such as in an IRP acknowledgement order.

Q: ODOE SUPPORTED AVOIDED COST FILINGS EVERY TWO YEARS IN DOCKET UM 1129. WHY HAS ODOE CHANGED ITS POSITION?

A: In Order No. 05-584, the Commission stated its goal to accurately assess avoided costs on an ongoing basis. To achieve that goal, the Commission allowed for unscheduled avoided cost updates between the regular two-year filings. The potential for unscheduled updates has created uncertainty about potential project revenues, making it difficult for QFs under development to secure necessary financing. ODOE believes that increasing the frequency of the regularly scheduled avoided cost price updates from two years to one year would: (1) allow the electric companies to maintain accurate avoided cost rates based on up-to-date forward electricity and natural gas prices and (2) add certainty for the QFs by reducing the likelihood of unscheduled avoided costs updates. The regular filing process should include an evidentiary process of fixed duration sufficient to allow for stakeholder engagement.

Q: TO WHAT EXTENT CAN DATA FROM IRPS THAT ARE IN THE LATE STATES OF REVIEW AND WHOSE ACKNOWLEDGEMENT IS PENDING BE FACTORED INTO THE CALCULATION OF AVOIDED COST PRICES? (ISSUE 3D)

A: If, by chance, the dates for the utility's regular avoided cost update and its IRP acknowledgement fall close to each other, the Commission should issue an order to skip the regularly scheduled filing and rely on the IRP-triggered filing, as it did in Order No. 07-428.

Q: ARE THERE CIRCUMSTANCES UNDER WHICH THE RENEWABLE PORTFOLIO STANDARD (RPS) IMPLEMENTATION PLAN SHOULD BE USED IN LIEU OF THE ACKNOWLEDGED IRP FOR PURPOSES OF DETERMINING RENEWABLE RESOURCE SUFFICIENCY? (ISSUE 3E)

A: Generally, no. The IRP acknowledgement orders are the best tool for determining the dates of resource sufficiency and deficiency. The IRP process allows time to fully explore the evidentiary issues. In contrast, the rules under OAR 860-083-400(8)(a) provide Commission staff and interested persons only 45 calendar days after an RPS implementation plan is filed to file written comments. In addition, OAR 860-083-0400 (4)-(6) indicates that the RPS implementation plan should be consistent, to the extent possible, with the most recently acknowledged IRP. Still, the Commission should retain discretion to update the renewable resource deficiency date in its acknowledgement order for the RPS implementation plan based on the facts at the time. Such an order updating the renewable resource deficiency date would trigger an update to the renewable avoided cost prices.

Q: CAN A QF RECEIVE OREGON'S RENEWABLE RESOURCE AVOIDED COST RATE IF THE QF OWNER WILL SELL RECS IN ANOTHER STATE? (ISSUE 5D)

A: Yes. Consistent with Order No. 11-505, a QF receiving the renewable resource avoided cost rate owns the RECs generated during the electric company's resource sufficiency period, when the QF is receiving the market price for the energy. During the QF's REC ownership period, the QF's options to transfer RECs to another party should not be limited. QFs cannot sell RECs to another state during the electric company's renewable resource deficiency period, in which the QF receives the renewable resource avoided cost rate and the QF transfers 100% of the RECs to the electric company.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hearby certify that on March 18, 2013, I served the foregoing response testimonies and exhibits in Docket UM 1610 upon all parties of record in this proceeding by electronic mail only as all parties have waived paper service.

OPUC Dockets
Citizens' Utility Board of Oregon
610 SW Broadway, Ste. 400
Portland, OR 97205
dockets@oregoncub.org

Oregon Dockets
Pacificorp, dba Pacific Power
825 NE Multnomah Street, Ste. 2000
Portland OR 97232
oregondockets@pacificorp.com

Regulatory Dockets
Idaho Power Company
PO Box 70
Boise ID 83707-0070
dockets@idahopower.com

RNP Dockets
Renewable Northwest Project
421 SW 6th Ave., Suite. 1125
Portland OR 97204
dockets@rnp.org

Paul D. Ackerman **(C)**
Exelon Business Servies company, LLC
100 Constellation Way Ste. 500C
Baltimore, MD 21202
paul.ackerman@constellation.com

Gregory M. Adams **(C)**
Richardson & O'Leary
PO Box 7218
Boise ID 83702
greg@richardsonandoleary.com

Daren Anderson
Northwest Energy Systems Company LLC
1800 NE 8th St., Ste. 320
Bellevue, WA 98004-1600
da@thenescogroup.com

Brittany Andrus **(C)**
Public Utility Commission of Oregon
PO Box 2148
Salem OR 97308-2148
brittany.andrus@state.or.us

Stephanie S. Andrus **(C)**
PUC Staff--Department of Justice
Business Activities Section
1162 Court St NE
Salem OR 97301-4096
stephanie.andrus@state.or.us

Adam Bless **(C)**
Public Utility Commission of Oregon
PO Box 2148
Salem OR 97308-2148
adam.bless@state.or.us

James Birkelund **(C)**
Small Business Utility Advocates
548 Market St. Ste. 11200
San Fransisco, CA 94104
james@utilityadvocates.org

Peter P. Blood
Columbia Energy Partners LLC
317 Columbia St.
Vancouver, WA 98660
pblood@columbiaenergypartners.com

Kacia Brockman **(C)**
Oregon Department of Energy
625 Marion St. NE
Salem, OR 97301
kacia.brockman@state.or.us

Will K. Carey
Annala, Carey, Baker, et al., PC
Po Box 325
Hood River, OR 97031
wcarey@hoodriverattorneys.com

Randy Dahlgren **(C)**
Portland General Electric
121 SW Salmon St. - 1WTC0702
Portland OR 97204
pge.opuc.filings@pgn.com

R. Bryce Dalley
Pacific Power
825 NE Multnomah St., Suite 2000
Portland OR 97232
bryce.dalley@pacificorp.com

Melinda J. Davison **(C)**
Davison Van Cleave PC
333 SW Taylor, Suite 400
Portland OR 97204
mjd@dvclaw.com
mail@dvclaw.com

Megan Walseth Decker **(C)**
Renewable Northwest Project
421 SW 6th Ave #1125
Portland OR 97204-1629
megan@rnp.org

Bill Eddie **(C)**
One Energy Renewables
206 NR 28th Avenue
Portland OR 97232
bill@oneenergyrenewables.com

Loyd Fery
11022 Rainwater Lane SE
Aumsville, OR 97325
dlchain@wvi.com

J. Richard George **(C)**
Portland General Electric Company
121 SW Salmon St. 1WTC1301
Portland OR 97204
richard.george@pgn.com

John Harvey **(C)**
Exelon Wind LLC
4601 Westown Parkway, Ste. 300
West Des Moines, IA 50266
john.harvey@exeloncorp.com

Diane Henkels **(C)**
Cleantech Law Partners PC
6228 SW Hood
Portland OR 97239
dhenkels@actionnet.net

Robert Jenks **(C)**
Citizens' Utility Board of Oregon
610 SW Broadway, Ste. 400
Portland, OR 97205
bob@oregoncub.org

Kenneth Kaufmann **(C)**
Lovinger Kaufmann LLP
825 NE Multnomah Ste. 925
Portland, OR 97232-2150
kaufmann@lklaw.com

Matt Krumenauer **(C)**
Oregon Department of Energy
625 Marion St NE
Salem OR 97301
matt.krumenauer@state.or.us

David A. Lokting
Stoll Berne
209 SW Oak Street, Suite 500
Portland, OR 97204
dlokting@stollberne.com

Richard Lorenz **(C)**
Cable Huston Benedict Haagensen & Lloyd LLP
1001 SW Fifth Ave. – Ste. 2000
Portland, OR 97204-1136
rlorenz@cablehuston.com

Jeffrey S. Lovinger **(C)**
Lovinger Kaufmann LLP
825 NE Multnomah Ste. 925
Portland, OR 97232-2150
lovinger@lklaw.com

Adam Lowney
McDowell Rackner & Givson PC
419 SW 11th ave., Ste. 400
Portland, OR 97205
adam@mcd-law.com

John Lowe
Renewable Energy Coalition
12050 SW Tremont Street
Portland OR 97225-5430
jravenesanmarcos@yahoo.com

Mike McArthur
Association of OR Counties
PO Box 12729
Salem,OR 97309
mmcarthur@aocweb.org

G. Catroina McCracken **(C)**
Citizens' Utility Board of Oregon
610 SW Broadway, Ste. 400
Portland, OR 97205
catriona@oregoncub.org

Glenn Montgomery
Oregon Solar Energy Industries Association
PO Box 14927
Portland OR 97293
glenn@oseia.org

Thomas H. Nelson
PO Box 1211
Welches OR 97067-1211
nelson@thnelson.com

Kathleen Newman
Oregonians for Renewable Energy Policy
1553 NR Greensword Dr.
Hillsboro OR 97214
kathleenoipl@frontier.com
k.a.newman@frontier.com

Mark Pete Pengilly
PO Box 10221
Portland OR 97296
mpengilly@gmail.com

Elaine Prause
Energy Trust of Oregon
421 SW Oak St. #300
Portland, OR 97204-1817
elaine.prause@energytrust.org

Lisa F. Rackner
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland OR 97205
dockets@mcd-law.com

Peter J. Richardson **(C)**
Richardson & O'Leary PLLC
PO Box 7218
Boise ID 83707
peter@richardsonandoleary.com

Toni Roush
Roush Hydro Inc.
355 E Water
Stayton, OR 97383
tmroush@wvi.com

Irion A. Sanger **(C)**
Davison Van Cleve
333 SW Taylor - Suite 400
Portland OR 97204
ias@dvclaw.com

Donald W. Schoenbeck **(C)**
Regulatory & Cogeneration Services, Inc.
900 Washington Street, Suite 780
Vancouver WA 98660-3455
dws@r-c-s-inc.com

John W. Stephens **(C)**
Esler Stephens & Buckley
888 SW Fifth Ave Suite 700
Portland OR 97204-2021
stephens@eslerstephens.com
mec@eslerstephens.com

David Tooze
City of Portland – Planning & Sustainabiliy
1900 SW 4th Ste. 7100
Portland, OR 97201
david.tooze@portlandoregon.gov

S. Bradley Van Cleve **(C)**
Davison Van Cleve PC
333 SW Taylor - Suite 400
Portland OR 97204
bvc@dvclaw.com

John M. Volkman
Energy Trust of Oregon
421 SW Oak St. #300
Portland, OR 97204
john.volkman@energytrust.org

Donovan E. Walker
Idaho Power Company
PO Box 70
Boise ID 83707-0070
dwalker@idahopower.com

Mary Wiencke
Pacific Power
825 NE Multnomah St, Suite 1800
Portland OR 97232-2149
mary.wiencke@pacificorp.com

(C)=Confidential

Renee M. France
Senior Assistant Attorney General
Natural Resources Section