Enabling the Widespread Adoption of Wind Energy in the West: The Case for Transmission, Operations and Market Reforms

Jenifer E. Gardner
Ronald L. Lehr
October 19, 2011

I. Introduction

"In extensive consultations over the past year – with more than 100 organizations and government agencies – on how to transform the nation's electric power system to deliver clean energy, improve energy security, and address global climate change, improved electric system planning emerged as the single most important issue."
– Reid Detchon, Executive Director of the Energy Future Coalition.[1]

The benefits of renewable energy have been touted for decades. Wind energy development, in particular, has increased dramatically over the past ten years. In 2009 alone, nearly 10,000 megawatts ("MW") of wind power was installed, bringing the total installed wind capacity in the United States to over 35,000 MW – representing a nearly twelve-fold increase since 2000.[2] Last year, despite a stagnant economy, cumulative wind power capacity grew by 15 percent, bringing the U.S. total to more than 40,000 MW.[3] Wind and other renewable energy sources have enormous potential to not only reduce dependence on fossil fuels, but to reduce overall carbon emissions. Yet, despite the inherent benefits of wind power, it is a variable and uncertain generation resource – in other words, the wind is not always blowing. As a result, some have raised concerns regarding the reliability of electric grids[4] that derive a large fraction of their energy from wind.[5] Others have taken issue with the costs of reliably integrating large amounts of variable generation into electric grid operations.[6]

This paper begins by briefly recounting the background of electricity development generally, and then more specifically, recites some history of transmission development in the United States. Next, it provides an overview of

---

[1] Press Release, Energy Future Coalition, Groundbreaking Coalition Formed to Improve Planning Process for the Eastern Electric Grid, September 18, 2009 (available at: http://www.energyfuturecoalition.org/files/webfmuploads/Transmission%20STEPP%20Press%20Release%2009.18.09.pdf).
[2] K. Porter and J. Rogers, Status of Centralized Wind Power Forecasting in North America (2010).
[3] U.S. Department of Energy, 2010 Wind Technologies Market Report, Executive Summary (2011).
[4] This paper will refer to both the "grid" and "grids" throughout. When discussing "grid," the reference is to the entire United States electric grid – comprised of three primary interconnections (Eastern Interconnection, Western Interconnection and ERCOT). When using "grids," the reference is to the multiple individual grids (usually on a regional basis) that comprise the entire United States electric grid. For a map depicting these different grids, please refer to Appendix I.
[5] Paul Denholm et al., The Role of Energy Storage with Renewable Electricity Generation (2010).
[6] *Id.*

electricity transmission as it exists today and several of the more salient challenges facing current electric grid operations as they incorporate more renewable energy. Next, this paper discusses operations and integration methods currently in place in U.S. electricity markets and concludes by proposing transmission, operations and market reforms for enabling widespread adoption of wind energy in the West.

II. BACKGROUND

A. The Beginnings of Electricity – Transmission and State Regulation

The 19th century inventors who first began harnessing electric power did so by locating generation next to load[7] – at first for lighting, then later for machinery and other electric equipment.[8] These early systems were modeled after Thomas Edison's 1882 Pearl Street Station[9] and delivered electricity over copper lines using direct current ("DC").[10] However technologically advanced these early approaches were for their time, they were incredibly inefficient – so much so that most power plants had to be located less than a mile from load.

By the 1890s, other inventors began refining Edison's form of electric power distribution. The most important new development of that time was high-voltage power transmission lines using alternating current ("AC").[11] Alternating current allowed power lines to transmit power over much longer distances than Edison's DC system.[12] In 1896, George Westinghouse utilized AC technology to build an 11,000 volt AC line connecting a hydroelectric generating station at Niagara Falls to Buffalo, New York – 20 miles away.[13] From that point forward, voltage of new transmission lines grew rapidly.[14]

---

[7] "Load" refers to the amount of power required by consumers and is synonymous with demand. MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 61 (2004). For a glossary of terms (such as "load") relevant to this paper's discussion of electricity transmission, please refer to Appendix L.

[8] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 2 (2004).

[9] Pearl Street Station was the first central power station in the United States. It was located at 255-257 Pearl Street in Manhattan on a site measuring only 50 by 100 feet. It began with one direct current generator and started generating electricity on September 4, 1882, serving an initial load of 400 lamps and 85 customers. By 1884, Pearl Street was serving a load of 10,164 lamps and 508 customers. MATTHEW JOSEPHSON, EDISON 255 (McGraw Hill 1959).

[10] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 2 (2004).

[11] *Id.*

[12] *Id.*

[13] It was Westinghouse's Niagara Falls hydroelectric development that marked the beginning of the practice of placing generating stations far from demand centers. The Niagara Falls development set a contemporary standard for generator size and was the first large system supplying electricity from one circuit for multiple end uses (i.e. railway, lighting, power). Robert Schnapp, History of the U.S. Electric Power Industry, 1882-1991, http://www.eia.doe.gov/cneaf/electricity/ page/ electric_kid/ append_a.html (last visited December 15, 2010).

[14] See Appendix A – "Common Voltages on Today's Transmission Lines" to see how transmission line voltages have varied over time – from 1896 to today.

The more capable AC transmission system further spurred the industry to build larger generators to serve ever-growing loads and populations.[15] With economies of scale,[16] electric industry economics began to favor larger companies rather than the multiple small power plants and local distribution systems established during the 1880s and 1890s using Edison's DC system.[17] These trends resulted in the first electric monopolies – a business organization form that continued to thrive through the first quarter of the 20th century.[18]

State governments reacted to the new growth of expanding monopolistic electric firms by extending the jurisdiction of their regulatory commissions to electric companies.[19] Georgia, New York and Wisconsin set the trend in 1907 when their state legislatures enacted laws setting up a state regulatory system.[20] By 1914, 43 states had regulatory commissions with oversight powers over electric utilities.[21]

The electric industry continued its path toward greater consolidation and by the late 1920s, the 16 largest electric power holding companies controlled over 75 percent of all U.S. electricity generation.[22] However, because these holding companies crossed state lines, they generally were exempt from state commission jurisdiction.[23] As a result, many in the industry felt that federal regulation was necessary.[24] A 1927 United States Supreme Court decision concurred, holding that electricity was an interstate commodity subject to both state and federal regulation.[25]

B. Federal Regulation over the Electric Power Industry Begins

The federal government became a regulator of utility companies beginning in the 1930s. The period between 1933 and 1950 in the United States was characterized not only by an increase in federal regulation, but also by continued

---

[15] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 2 (2004).
[16] "Economies of scale" refers to reductions in unit cost as the size of a facility and the usage levels of other inputs increase. One of the common sources of economies of scale is through long-term purchase agreements (i.e. bulk buying of materials, including electricity generation). Arthur Sullivan & Steven M. Sheffrin, Economics: Principles in Action, http://www.pearsonschool.com (last visited December 16, 2010).
[17] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 3 (2004).
[18] *Id.*
[19] State regulatory commissions, now typically in the form of public utility commissions, originally only had jurisdiction over railroads. However, once electric monopolies began to form, they reacted quickly to expand their jurisdiction to electric utilities. MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 3 (2004).
[20] Robert Schnapp, History of the U.S. Electric Power Industry, 1882-1991, http://www.eia.doe.gov/cneaf/electricity/page/electric_kid/append_a.html (last visited December 15, 2010).
[21] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 3 (2004).
[22] Robert Schnapp, History of the U.S. Electric Power Industry, 1882-1991, http://www.eia.doe.gov/cneaf/electricity/page/electric_kid/append_a.html (last visited December 15, 2010).
[23] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 3 (2004).
[24] *Id.*
[25] Public Utility Commission of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83, 89 (1927).

growth in the industry, increased consolidation and interconnection, and increasing economies of scale.[26] The following discussion outlines and discusses some of the key legislation enacted during and since that time.

1. The Public Utility Holding Company Act of 1935

The Public Utility Holding Company Act of 1935 ("PUHCA") was the first major federal regulation over the electric power industry.[27] PUHCA limited the geographical scope and corporate structure of utility holding companies.[28] More specifically, PUHCA is credited with creating vertically integrated utilities (owning both power plants and power lines) in monopoly service areas.[29]

2. The Federal Power Act of 1935

The Federal Power Act of 1935 gave the Federal Power Commission jurisdiction over wholesale power sales[30] and the transmission of electric power.[31] Today, the Federal Power Commission is known as the Federal Energy Regulatory Commission ("FERC").[32] Under the Federal Power Act, states retained jurisdiction over retail rates, generation and transmission siting, and franchised distribution areas.[33] This combination of federal and state regulation over the industry remained in effect – and in the same form – for nearly 50 years.[34]

3. The Public Utility Regulatory Policies Act of 1978

Following an exponential growth in high-megawatt power plants and high-voltage transmission lines, as well as the addition of transcontinental natural gas

[26] Robert Schnapp, History of the U.S. Electric Power Industry, 1882-1991, http://www.eia.doe.gov/cneaf/electricity/page/electric_kid/append_a.html (last visited December 15, 2010).
[27] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 3 (2004).
[28] *Id.*
[29] A horizontally integrated utility differs from a vertically integrated utility in that it is comprised of holding companies with separate generation, transmission, distribution, and service subsidiaries. Willis Group Holdings, Who Needs Coverage, www.willis.com/Client_Solutions/Industries/Utilities/Who Needs Coverage/ (last visited March 16, 2011).
[30] A "wholesale" electricity sale occurs when the price of electricity generation is sold to another utility or to a power marketer or trader, to be ultimately resold as "retail sales" to end users, such as businesses and residential consumers. Lynn Hargis, The Federal Power Act: What is it? What do I care?, http://www.publiccitizen.org/documents/Federal%20Power%20Act%20Factsheet.pdf (last visited December 15, 2010).
[31] Federal Power Act, 16 U.S.C. §§ 791 et seq.
[32] Lisa G. Dowden, *The RTO In Your Future: What Should Your Clients Know?,* 16-SPG Nat. Resources & Env't 247 (2002).
[33] A "franchised distribution area" describes an area owned by a distribution company over which power is delivered to the grid, or where utilities are given rights (usually by municipalities) to deliver electricity and use utility easements within that area. Uniongas.com, Resources, http://www.uniongas.com/storagetransportation/resources/additionalinfo/glossary.asp#F (last visited March 29, 2011).
[34] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 3 (2004).

pipelines, the power system that had begun as fundamentally local was now interstate.[35] In the wake of this rapid industry growth, the Public Utility Regulatory Policies Act of 1978 ("PURPA") was enacted.[36] PURPA was considered groundbreaking legislation in that it required utilities, for the first time, to buy power from companies that were not themselves utilities.[37] As a result, PURPA created a new industry of nonutility power generators. Its importance to transmission policy cannot be overstated in that PURPA also required that nonutility generators be given access to transmission systems in order to deliver their power to grids.[38]

4. <u>The Energy Policy Act of 1992</u>

In an era during which the United States experienced growing concern about the nation's dependence on imported fuels, Congress passed the Energy Policy Act of 1992 ("EPAct 1992").[39] EPAct 1992 required that the now well-established competitive generators, as well as any other utility, be given access to utilities' transmission grids on rates and terms that were comparable to those that utilities would charge and require of themselves.[40] Access to grids became indispensable to growing wholesale power markets because greater access increased the ability of nonutility power generators to use transmission systems to send power to purchasers at fair and predictable rates and terms.[41] Since the mid-1990s, FERC has issued several orders to implement the goals of EPAct 1992, including Orders 888, 889, 2000, and 2003-A.

a. <u>FERC Order 888</u>

Enacted in 1996, FERC Order 888 detailed how transmission owners should charge for use of their lines and the terms under which they should give others access to their lines.[42] The order also required utilities to functionally unbundle their transmission and generation businesses and to follow a corporate code of conduct.[43] FERC hoped that this separation – referred to as "open transmission access" – would

---

[35] In 1948, for example, only two power plants exceeding 500 MW existed in the United States. By 1972, 122 such plants were in existence. The number of miles of high-voltage transmission lines, essentially non-existent in the 1950s, more than tripled to over 60,000 circuit miles in the 1960s. MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 4 (2004).
[36] *Id.*
[37] Before PURPA, only utilities could own and operate electric generating plants. After PURPA, utilities were required to buy power from independent companies that could produce power for less than what it would have cost the utility to generate the power – known as the "avoided cost." Public Utility Regulatory Policy Act (PURPA), http://www.usca.org (last visited July 22, 2011).
[38] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 4-5 (2004).
[39] *Id.* at 5.
[40] *Id.*
[41] *Id.*
[42] Miles Keogh, FERC Order 890: What Does It Mean For the West?, http://www.nationalwind.org/assets/publications/ferc890.pdf (last visited October 12, 2011).
[43] EnergyVortex.com, Energy Dictionary, http://www.energyvortex.com/energydictionary/ferc_order_888.html (last visited December 15, 2010).

make it impossible for the transmission business to give its own power plants preferential access to transmission lines.[44] Since utilities under regulation make money by investing in equity (mainly in power plants), they have incentive to use their monopoly control of transmission to "fence out" competitive generators – a result FERC has tried to prevent through enactment of Order 888 and its progeny.[45]

b. FERC Order 889

FERC Order 889, also enacted in 1996, created an online system – "OASIS"[46] – through which transmission owners were required to post available capacity on their lines.[47] Competing companies that wanted to use available capacity on utility-owned lines to transport power could access the available capacity through the OASIS system.[48] Order 889 further prohibited utilities from communicating market information in any way that would prevent access to this information by potential competitors.[49]

c. FERC Order 2000

FERC Order 2000, enacted in 1999, represented a push for transmission-owning utilities to form regional transmission organizations ("RTOs").[50] FERC did not require utilities to join RTOs; rather, it encouraged utilities to form these organized markets and required the following minimum characteristics of all RTOs:

1. *Independence.* RTOs must be independent of market participants;
2. *Scope and Regional Configuration.* RTOs must serve a region of sufficient scope and configuration to permit each RTO to effectively perform its functions;
3. *Operational Authority.* The RTO must coordinate security for its region; and
4. *Short-term Reliability Authority.* The RTO must have

[44] THE HONORABLE SPENCER ABRAHAM, SECRETARY OF ENERGY, NATIONAL TRANSMISSION GRID STUDY 2 (2002).
[45] Address by Anne K. Bingaman, Assistant Attorney General, U.S. Department of Justice, Remarks Before the American Bar Association's Public Utility, Communications and Transportation Law Section (April 20, 1995).
[46] "OASIS" stands for "Open Access Same Time Information Systems." Sheila S. Hollis, *The Electric Industry Opportunities and Impacts for Resource Producers, Power Generators, Marketers, and Consumers,* Rocky Mountain Mineral Law Special Institute, 42B Special Institute, Chap. 13 (1996).
[47] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 5 (2004).
[48] *Id.*
[49] EnergyVortex.com, Energy Dictionary, http://www.energyvortex.com/energydictionary/ferc_order_888.html (last visited December 15, 2010).
[50] This paper will refer to both RTOs and ISOs ("Independent System Operators"). For all intents and purposes, RSOs and ISOs are both competitive regional wholesale electricity markets with virtually the same structure. The only difference is that an RTO is a FERC-created entity that must comply with specific FERC standards not applicable to ISOs. Lisa G. Dowden, *The RTO In Your Future: What Should You Know?,* 16 SPG Nat. Resources & Env't 247 (2002).

> exclusive authority for maintaining short-term reliability of the grid it operates.[51]

FERC additionally assigned these organizations the responsibility of developing regional transmission plans and pricing structures that would promote competition in wholesale power markets.[52]

d. FERC Order 2003-A

In 2004, FERC issued Order 2003-A, requiring transmission owners to interconnect new generators of less than 20 MW to their grid.[53] The order required transmission owners to connect these small generators under standard terms and conditions and to follow both a specified process and timeline for interconnection.[54] In circumstances where new power plants would add new stresses to power grids, requiring transmission upgrades, Order 2003-A further outlined which party would be required to pay for the upgrades.[55]

5. The Energy Policy Act of 2005

Following the Energy Policy Act of 1992 and related FERC orders was the Energy Policy Act of 2005 ("EPAct 2005"). EPAct 2005 was enacted with three specific FERC-related public policy goals in mind: (1) it reaffirmed a national commitment to wholesale power market competition; (2) it strengthened FERC's regulatory tools by recognizing that effective regulation is necessary to protect consumers and to ensure fair competition; and (3) it provided for the development of a stronger energy infrastructure.[56]

More specifically, EPAct 2005 gave FERC rulemaking authority in order to prevent market manipulation in wholesale power markets, transmission services, and transportation services.[57] Additionally, FERC was granted the authority to

---

[51] THE HONORABLE SPENCER ABRAHAM, SECRETARY OF ENERGY, NATIONAL TRANSMISSION GRID STUDY 24 (2002). For a more in-depth discussion of RTOs, *see infra* Section IV.B.3.a. – "Regional Transmission Organizations."

[52] Generally speaking, a "wholesale power market" exists where the purchase and sale of electricity is from generators to resellers (that then sell to retail customers), including the ancillary services needed to maintain reliability and power quality at the transmission level. MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 67 (2004).

[53] *Id.*

[54] *Id.*

[55] A detailed discussion of how these upgrade costs are allocated is outside the scope of this paper. For more detailed information on FERC Order 2003-A, *see Standardization of Generator Interconnection Agreements and Procedures: Order on Rehearing Before the Federal Regulatory Commission,* Docket No. RM02-1-001; Order No. 2003-A (March 5, 2004).

[56] Federal Energy Regulatory Commission, Fact Sheet – Energy Policy Act of 2005, http://www.ferc.gov/legal/fed-sta/epact-fact-sheet.pdf (last visited October 12, 2011).

[57] *Id.*

oversee mandatory reliability standards governing the U.S. electric grid.[58] Under this authority, FERC required transmission organizations with organized electricity markets to make long-term firm transmission rights[59] available to load-serving entities.[60]

6. Subsequent FERC Orders

Following the enactment of EPAct 1992 and its related FERC orders, as well as the enactment of EPAct 2005, FERC issued a number of subsequent orders specifically focused on transmission planning. Two of the more recent and pertinent of those orders are discussed in further detail below.

a. FERC Order 890

Issued in 2007, FERC Order 890 required public utility transmission providers to participate in an "open transmission planning process" at both the local and regional level.[61] The goals behind FERC Order 890 were increasing coordination between neighboring transmission providers and interconnected systems, state authorities, and other stakeholders; as well as ensuring greater accessibility and availability of transmission-related data.[62] FERC further characterized this "open transmission planning process" with the following nine transmission planning principles:

1. Coordination;
2. Openness;
3. Transparency;
4. Information Exchange;
5. Comparability;
6. Dispute Resolution;
7. Regional Participation;
8. Transmission Congestion Studies; and
9. Cost Allocation.[63]

---

[58] Federal Energy Management Program – Energy Policy Act of 2005, http://www1.eere.energy.gov/femp/regulations/epacy2005.html (last visited January 18, 2011).
[59] "Firm transmission rights" refers to long term supply arrangements – i.e., agreements to provide long term transmission service under pricing arrangements that hedge congestion cost risks sometimes faced in organized markets. Joseph T. Keller, Federal Energy Regulatory Commission February 2, 2006 Commission Meeting, http://apps.
americanbar.org (last visited March 26, 2011).
[60] This was done in order to support long-term power service agreements for load-serving entities without exposure to transmission congestion-related cost risks. Federal Energy Regulatory Commission, Fact Sheet – Energy Policy Act of 2005, http://www.ferc.gov/ (last visited January 18, 2011).
[61] Miles Keogh, FERC Order 890: What Does It Mean For the West?, http://www.nationalwind.org/assets/publications/ferc890.pdf (last visited October 12, 2011).
[62] *Id.*
[63] *Id.*

b. FERC Order 1000

On July 21, 2011, FERC issued Order 1000 as a follow-up to the transmission planning principles outlined in Order 890.[64] The goals of Order 1000 include the continued reformation of the transmission planning process and cost allocation requirements to ensure that consumers are receiving just and reasonable rates, in addition to the implementation of a "beneficiary pays" principle to properly direct cost allocation for future transmission investment.[65] Included in the order are the following three requirements for transmission planning:

1. Each public utility transmission must participate in the regional transmission planning process in order to produce a single regional transmission plan that satisfies the principles under Order 890;
2. Each transmission planning process at the local and regional level must consider transmission needs driven by federal or state laws or regulations; and
3. Public utility transmission providers in neighboring transmission planning regions must coordinate concerning more efficient or cost-effective solutions.[66]

In addition to the three aforementioned requirements for transmission planning, Order 1000 also sets forth the following three requirements for transmission cost allocation:

1. Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities that satisfies the six regional cost allocation principles;[67]

---

[64] Although FERC Order 1000 was issued July 22, 2011, it did not become effective until October 11, 2011. FERC.gov, FERC Transmission Planning, Cost Allocation Reforms to Benefit Consumers, http://www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6.asp (last visited October 11, 2011); Hannah Northey, Energy Policy: FERC Approves Sweeping Overhaul of Transmission Rules, http://www.eenews.net (last visited October 11, 2011).

[65] The "beneficiary pays" principle states that beneficiaries of new transmission investment should pay for that investment and commentators have considered it the "core" of Order 1000. Peter Behr, FERC's New Grid Policy Gives a Major Push to Renewable Energy Projects, http://eenews.net (last visited July 22, 2011).

[66] 18 C.F.R. § 136.35 (2011).

[67] The six regional cost allocation principles include: (1) cost allocated in a way that is roughly commensurate with benefits; (2) no involuntary allocation of costs to non-beneficiaries; (3) benefit to cost threshold ratio (i.e., the ratio must not be so high that facilities with significant net positive benefits are excluded from cost allocation); (4) allocation to be solely within transmission planning region(s) unless those outside voluntarily assume costs; (5) transparent method for determining benefits and identifying beneficiaries; and (6) different methods for different types of facilities (e.g.,

2. Public utility transmission providers in neighboring planning regions must have a common interregional cost allocation method for new interregional transmission facilities that satisfies the six regional cost allocation principles; and
3. Participant funding of new transmission facilities is permitted but not as part of the regional or interregional cost allocation method.[68]

C. Today's Transmission System

The U.S. transmission system today exists as an interconnected network with more than 150,000 miles of high-voltage transmission lines that transport electricity from generators to consumers.[69] This system is comprised of three major electric power systems that are only weakly connected with one another: the Eastern Interconnection, the Western Interconnection and the Electric Reliability Council of Texas ("ERCOT").[70] While this network performs well most of the time, weaknesses do emerge.[71] On rare occasions, the stresses on these networks become so intense that they break down, causing blackouts such as the one that shut down the power system in the Northeast and Midwest United States on August 14, 2003.[72]

Given these weaknesses, today's transmission debate focuses on how best to use a combination of technology and policy to strengthen weak network sections, as well as how best to incorporate renewable sources of energy onto the grid. To accomplish these goals, physical networks may require new lines and other investments. Similarly, the institutions that govern transmission will require changes in order to support desired physical grid changes. In the end, power systems will need to respond to increasing demands through physical grid expansion (using a combination of new technology, new generation, and energy efficiency), as well as operational and market reforms.

---

transmission built for reliability reasons v. transmission built for economic reasons). 18 C.F.R. § 136.35 (2011).

[68] 18 C.F.R. § 136.35 (2011).

[69] THE HONORABLE SPENCER ABRAHAM, SECRETARY OF ENERGY, NATIONAL TRANSMISSION GRID STUDY 2 (2002). For a table depicting the size and characteristics of today's transmission system, please refer to Appendix B.

[70] *Id.* For a map of these interconnected power systems, please refer to Appendix I.

[71] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 6 (2004).

[72] The 2003 blackout was triggered by one high-voltage line in northern Ohio that brushed against a grouping of overgrown trees and shut down. Normally, this failure would have triggered an alarm, but the alarm system failed. The subsequent "domino effect" resulted in a series of additional line failures throughout southeastern Canada and eight northeastern states. In total, 50 million Americans lost power for up to two days in what has been called the biggest blackout in North American history. In the wake of the blackout, Congress enacted the Energy Policy Act of 2005, which expanded the role of FERC by requiring it to solicit, approve and enforce new reliability standards from NERC, the North American Electricity Reliability Corporation. JR Minkel, *The 2003 Northeast Blackout – Five Years Later,* SCIENTIFIC AMERICAN, Aug. 13, 2008, http://www.scientificamerican.com/article.cfm?id=2003-blackout-five-years-later (last visited June 1, 2011).

III. Transmission

A. Overview

Lack of cost-effective transmission remains the single greatest impediment to the rapid development of utility-scale renewable energy in the United States.[73] Over 145,000 MW of renewable energy is projected to be added to the North American grid over the next ten years – if only half of that comes into service, it will still account for a 350 percent increase in renewables over what existed in 2008.[74] Thus, the need for transmission upgrades and improvements cannot be understated.[75] Ideally, a strong and cost-effective transmission system successfully:

1. Improves the reliability of the electric power system;
2. Gives electricity customers flexibility to diversify the mix of fuels that produce their electricity;
3. Improves industry cost structures by giving low-cost power plants access to high-cost power markets; and
4. Enables competition among power plants by giving more plants access to more markets.[76]

There are two primary obstacles inhibiting not only the development of a strong and cost-effective U.S. transmission system, but also the widespread transmission of energy from renewable sources like wind. First there is the "chicken-and-egg" conundrum: renewable energy developers do not always have the financial capability to support large-scale transmission investment, yet transmission is often not built because it is not clear that renewable energy projects will actually be developed to use the transmission.[77] Second, although renewable energy developers can build wind and other renewable energy projects in as little as two or three years, transmission is not always available to transport energy produced from those projects to the high demand areas.[78] To overcome these obstacles, the challenges of

---

[73] Resource procurement drives transmission development. When resources are not being added to grids, transmission is not being built. Yet, sometimes resources are not added because the required transmission is not yet being built – hence, the "chicken and egg" problem so commonly associated with U.S. transmission development (and further discussed in this section). WESTERN RENEWABLE ENERGY ZONES – PHASE 1 REPORT 3 (2009).

[74] NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, ACCOMMODATING HIGH LEVELS OF VARIABLE GENERATION, EXECUTIVE SUMMARY (2009).

[75] For a more detailed discussion on transmission technologies being considered and those already in use to increase the effectiveness of already-available transmission, *see* Jeff Hein et al., *Methods to Increase Existing Transmission Capacity – a Technology Assessment and Application Guide*, Presented to CREPC and SPSC (October 19, 2011) (available at:f http://www.westgov.org/wieb/webinars/2011/October19/10-19-11taag.pdf).

[76] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 8 (2004).

[77] Kevin Porter, *New Transmission Initiatives for Renewable Energy and Some Thoughts on Wind Integration,* Remarks at the NARUC Winter Meetings (February 17, 2008).

[78] NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, LONG-TERM RELIABILITY ASSESSMENT 2009-2018 26 (2009).

renewable energy transmission must be analyzed before possible solutions can be proffered.

B. Challenges

1. Renewables are a "Location-Constrained" Resource

States in the West and Midwest possess the greatest potential for wind development in the United States.[79] The West in particular enjoys an abundance of not only wind, but also solar and geothermal resources, while simultaneously facing a unique challenge: the best sources of renewables are often located far from loads. Unfortunately for wind developers, the cost of transmission facilities for wind developments are often higher than for conventional energy plants that can locate nearer transmission facilities and system loads.[80] This is so because the power of wind is directly proportional to wind speed and therefore, the best wind economics result where the most powerful wind resources are "tapped" – typically in areas remote from major population centers.[81]

2. Flexibility of the Existing Grid

Today's electric grids operate in response to fluctuating loads and are therefore inherently flexible in terms of incorporating a variety of energy sources. Electric system operators play a key role in this flexibility by ensuring that a balance between generation and demand always exists in their respective control areas.[82] However, since demand fluctuates mostly in response to weather, as system operators continue to integrate wind, they will confront additional uncertainty on the generation side due to wind's inherent variability.[83] This, in turn, significantly increases the demands placed on operators to manage the generation and load balancing process. To the extent that they find themselves controlling systems with

---

[79] For a map and table depicting state-by-state wind resource potential in the United States, *see* United States Department of Energy, "80-Meter Wind Maps and Wind Resource Potential," http://www. windpoweringamerica.gov/wind_maps.asp (last visited October 18, 2011).
[80] Darrel Blakeway & Carol Brotman White, *Tapping the Power of Wind: FERC Initiatives to Facilitate Transmission of Wind Power,* 26 Energy L.J. 393, 401 (2005).
[81] *Id.*
[82] "Control area" refers to an electric power system in which operators match loads to resources within the system, maintain scheduled interchange between their control areas and neighboring control areas, maintain frequency within reasonable limits, and provide sufficient generation capacity to maintain operating reserves. In the West, these "control areas" are called "balancing authority areas" ("BAAs") and are controlled by balancing authorities ("BAs") – *see infra* Section IV.3.B. "Balancing Authorities/Balancing Authority Areas." MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 60 (2004); Dr. Johannes Teyessen & Martin Fuchs, WIND REPORT 2005, E.ON Energie (2005).
[83] Wind is considered "variable" because the wind is not always blowing but rather, fluctuates depending on weather patterns. Dr. Johannes Teyessen & Martin Fuchs, WIND REPORT 2005, E.ON Energie (2005).

sufficient flexibility to incorporate variable resources like wind, system operators will be able to significantly lower the costs associated with such integration.[84]

3. Need for Grid Expansion

The process to plan and build new transmission lines is often long and at times, may involve controversy.[85] However, benefits of new transmission infrastructure are hard to ignore – increased energy transmission availability for an ever-growing energy dependent American society, increased competition among generation sources leading to lower energy prices, and increased reliability of the overall transmission system.[86]

Despite the benefits inherent in expanded transmission infrastructure, obtaining the necessary approvals for transmission investment and construction is difficult.[87] Once the decision to develop transmission has been made and the necessary approvals have been obtained, who pays for transmission costs must then be determined. Although the presumption is that new transmission is expensive, when viewed in terms of its potential to reduce generation costs, it is relatively inexpensive. For example, a utility's ability to access lower-cost generation can more than make up for the investment in new transmission lines required to access that generation.[88] The following scenario from Colorado is a prime example of one common debate regarding who pays for these transmission upgrades:

> When power developer GE Wind built a 164 MW wind farm in southern Colorado, Xcel Energy, a regulated utility, and GE Wind, engaged in a detailed discussion about who should pay

---

[84] *See* Utility Wind Integration Group's website at www.uwig.org for additional information about wind integration studies and costs. Generally, wind integration studies find that integration costs are relatively modest at about ten percent or less of contract values for wind power. *See also* Kevin Porter, *New Transmission Initiatives for Renewable Energy and Some Thoughts on Wind Integration,* Remarks at the NARUC Winter Meetings (February 17, 2008).

[85] Controversy can range from environmental concerns – particularly when building on federal lands – as well as "NIMBY" (Not in My Backyard) concerns from the local community where added transmission lines may be viewed as unsightly and therefore undesirable. MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 11 (2004).

[86] Darrell Blakeway & Carol Brotman White, *Tapping the Power of Wind: FERC Initiatives to Facilitate Transmission of Wind Power,* 26 Energy L.J. 393, 401 (2005).

[87] For a chart depicting the typical capital costs for electric transmission lines, see Appendix C.

[88] Transmission usually only represents five to ten percent of retail energy dollars, while generation can represent as much as 50 to 60 percent. So, even large dollar transmission investments can pay consumers back relatively quickly where lower cost generation is enabled and replaces higher cost, or higher risk, power. Factors that impact the costs of new transmission include terrain and development (e.g. mountainous terrain and developed land is more expensive to build over than flat terrain and ranch or farmland); the need to acquire rights-of-way (as compared with upgrading lines on existing rights-of-way); costs of upgrading substations and interconnecting with existing grids; and the possibility of installing cost-effective new grid control technologies. Ravi K. Aggarwal, MBA, *Regional Transmission Adequacy Guidelines – RRG Briefing,* Remarks at the RTAG Steering Committee & Technical Workgroup Meetings (April 29, 2005).

> for what parts of the transmission system. The wind farm was 40 miles from Xcel Energy's power grid and, as a result, someone needed to build a new power line to feed the wind power into the grid. At the same time, Xcel Energy identified several improvements to its power grid that it felt were [necessary.][89]

Thus, the debate in this Colorado example (and elsewhere in the country), revolves around who should pay for what part of upgrades to transmission systems.[90] Examples of typical cost allocation methods include "pure participant" funding and "socialization" of costs. In the Colorado example, a pure "participant funding" process would require GE Wind to pay for all upgrades in exchange for valuable transmission rights or credits for future transmission service.[91] By contrast, broader cost recovery for transmission – i.e. "socialization" of the costs – would have Xcel Energy, and by extension its ratepayers, pay for all new lines and upgrades to its transmission system.[92]

In practice, most of the United States has adopted or is considering some form of cost recovery that combines participant funding and socialization in order to broadly spread some costs to consumers.[93] For instance, in the Colorado example, GE Wind ultimately paid to build the power line to connect its wind farm to the grid, while Xcel Energy paid to upgrade other parts of their transmission system.[94] Additionally, both Southwest Power Pool ("SPP") and Midwest Independent Transmission System Operator ("MISO") have filed requests at FERC for regional cost allocation mechanisms that broadly allocate costs of regionally beneficial projects. MISO allocates "multi-value projects"[95] in this manner, while SPP has created a "highway/byway"[96] approach in which costs for larger transmission facilities are allocated regionally.[97]

---

[89] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 22 (2004).
[90] *Id.*
[91] Bruce Edelston, *Participant Funding: The Se Trans Proposal,* Presentation to HEPG (December 11, 2003).
[92] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 22 (2004).
[93] *Id.* at 25.
[94] *Id.* at 23.
[95] Multi-value projects ("MVPs") are a new class of regional transmission expansion projects and include network upgrades that meet at least one of three criteria: (1) transmission projects developed to enable the reliable delivery of energy in support of a public policy mandate (such as a state RPS); (2) transmission projects that provide multiple types of economic value across multiple pricing zones; and (3) transmission projects that address at least one transmission issue that is driven by a compliance requirement with a NERC or regional entity standard. Leonard.com, Energy Alert: New Transmission Costs Could Shift from Generators to Users of Electricity, http://leonard.com (last visited July 8, 2011).
[96] SPP's highway/byway approach focuses on SPP's region as a whole and allocates costs according to the voltage of the new transmission facilities: (1) costs of facilities operating at 300 kilovolts ("kV") and above are allocated 100% across the entire SPP region using postage stamp pricing; (2) costs of facilities operating above 100 kV and below 300 kV are allocated one-third on a regional postage stamp basis and two-thirds to the actual zone where the facilities are located; and (3) costs of facilities

FERC Order 1000, issued July 21, 2011 and effective October 11, 2011, has focused on settling the transmission cost allocation debate once and for all.[98] Order 1000 sets forth the "beneficiary pays" principle, allocating costs for new transmission facilities to the beneficiaries of those facilities rather than socializing those costs on a regional or national basis.[99] The order further allows the "participant funding" method to be used for new transmission facilities – so long as it is not used as the regional or interregional cost allocation method.[100] However, as industry continues to grapple with the requirements and impacts of the order, only time will tell if FERC's latest mandate truly resolves the transmission cost allocation debate.[101]

C. Studies Supporting the Case for Transmission Rebuild

Numerous studies and initiatives have been conducted to support the notion that new transmission construction is essential to enable variable wind resources to reach markets. An important assumption is that the economic questions addressed by these studies stem from one key notion: costs are in the eye of the beholder and therefore, the costs of one option must always be compared to other options. While agreement upon what generation or transmission actually "costs" is hard to reach, more can be gained through a comparison of various costs. For instance, a major source of uncertainty concerning the cost of generation is its dependence on future fuel cost projections, which historically, have often been wrong.[102]

---

operating at or under 100 kV are allocated fully to the zone in which the facilities are located. Climateandenergy.org, FERC Approves SPP Highway/Byway Cost Allocation Plan for High Voltage Transmission Lines, http://blog.climateandenergy.org (last visited July 19, 2011).

[97] The costs of MISO's MVPs are allocated to all load within MISO as well as to exports to users outside of MISO. Leonard.com, Energy Alert: New Transmission Costs Could Shift from Generators to Users of Electricity, http://leonard.com (last visited July 8, 2011). FERC approved MISO's MVP proposal on December 16, 2010. Press Release, FERC, FERC Removes Barriers to Development of Needed Transmission in Midwest Region (December 16, 2010) (available at http://www.ferc.gov). SPP's highway/byway cost allocation plan was approved by FERC on June 17, 2010. Department of Energy, FERC Proposes New Transmission Planning and Cost Sharing, http://apps1.eere.energy.gov /news/news-detail.cfm/news-id=16117?print (last visited July 8, 2011).

[98] For a more detailed discussion of FERC Order 1000, *see supra* Section II.B.6.b. "FERC Order 1000."

[99] FERC.gov, FERC Transmission Planning, Cost Allocation Reforms to Benefit Consumers, http:// www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6.asp (last visited July 22, 2011); Peter Behr, FERC's New Grid Policy Gives a Major Push to Renewable Energy Projects, http:// www.eenews.net (last visited July 22, 2011). For a more detailed discussion of FERC Order 1000, *see supra* Section II.B.6.b. "FERC Order 1000."

[100] *Id.*

[101] Shifra Mincer, FERC Order 1000 Draws More Complaints, http://energy.aol.com/2011/08/24 /ferc-order-1000-draws-more-complaints/ (last visited October 11, 2011).

[102] More specifically, where fuel prices are projected too high, consumers typically invest more than economically efficient amounts in alternatives, such as additional efficiency measures or more renewable energy. On the other hand, where fuel prices are projected too low, consumers are placed at direct risk of fuel price spikes and in this scenario, consumers have *not* invested in adequate alternatives, so they pay higher than anticipated fuel costs, or fail to pay altogether and are simply cut off by their utility provider. RYAN WISER ET AL., EASING THE NATURAL GAS CRISIS: REDUCING NATURAL GAS PRICES THROUGH INCREASED DEPLOYMENT OF RENEWABLE ENERGY AND ENERGY EFFICIENCY, LBNL-56756 (2005) (available at: http://eetd.lbl.gov/EA/EMP).

In response to these cost debates and future fuel price uncertainties, the most recent of these transmission-related studies and initiatives have been performed in order to encourage the development of the West's vast renewable energy portfolio. Only two such organizations with transmission-relevant responsibilities exist at the Western Interconnection level – the Western Electricity Coordinating Council ("WECC")[103] and the Western Governors' Association ("WGA"),[104] including the WGA's energy arm, the Western Interstate Energy Board ("WIEB").[105] In addition to the regional work conducted by WECC and WGA, several states have carried out their own studies and prepared reports that add to current Western transmission considerations. A discussion of some of the highlights of this work follows.

1. Western Governors' Association "Clean and Diversified Energy Advisory Committee" ("CDEAC") Report

The 2006 CDEAC Report to the Western Governors' Association was commissioned in order to identify obstacles and propose solutions necessary to accomplish the following three goals for the West: (1) develop an additional 30,000 MW of clean energy by 2015 from both traditional and renewable energy sources; (2) achieve a 20 percent increase in energy efficiency by 2020; and (3) ensure a reliable and secure transmission grid for the next 25 years.[106] In order to achieve these goals, the report proposes recommendations on a federal, regional and state basis. The following are the report's federal recommendations, to FERC, encouraging FERC to change its transmission policies in order to:

1. Eliminate pancaked rates (i.e. fees imposed on transmission customers contracting for service across multiple control areas) in the transmission system;
2. Promote balancing authority area ("BAA")[107] consolidation on a case-by-case basis, where analysis finds that benefits exceed the costs and there are no significant adverse impacts on reliability; and
3. Encourage congestion management systems that allow access to least-cost generation within NERC reliability constraints.[108]

---

[103] For more information, *see* www.wecc.biz.
[104] For more information, *see* www.westgov.org.
[105] For more information, *see* www.westgov.org/wieb/.
[106] CLEAN AND DIVERSIFIED ENERGY ADVISORY COMMITTEE TO THE WESTERN GOVERNORS, CLEAN ENERGY, A STRONG ECONOMY AND A HEALTHY ENVIRONMENT, PREFACE (2006).
[107] A balancing authority area ("BAA") is a control area. The balancing authority ("BA") is the entity that is in control of the BAA. For instance, the Western Area Power Administration ("WAPA") is the BA in charge of energy balancing for three separate BAAs in the Western Interconnection: WACM, WAUW and WALC. For a more detailed discussion of BAs and BAAs, *see infra* Section IV.3.B. "Balancing Authorities/Balancing Authority Areas."
[108] *Id.*

The following are the report's regional recommendations, to the Western Governors, to promote state and regional policies in collaboration with state legislatures in order to:

1. Ensure available resources – both funding and staff time – to enable state participation in regional transmission planning;
2. Encourage the electric power industry to make the existing proactive, transparent interconnection-wide and sub-regional transmission planning process a priority;
3. Review, and if necessary, amend state laws to require PUCs and public power boards to consider regional transmission needs;
4. Bring together stakeholders and forge solutions to regional transmission needs, cost allocation and siting where Regional Transmission Organizations ("RTOs") or Independent System Operators ("ISOs") do not exist, and ensure state participation in such activities by existing RTOs/ISOs;[109]
5. Urge transmission operators to develop workable agreements at seams between ISO and non-ISO systems to enable effective grid operations; and
6. Evaluate the option of creating a regional siting agency to encourage consistent siting processes.[110]

The following are the report's state recommendations, to state public utility commissions, necessary to adopt policies and promote transmission-friendly legislation:

1. For states with mandatory renewable portfolio standards ("RPSs")[111], regulatory commissions should make public interest findings associated with cost-effective transmission projects that will enable states to attain energy policy goals;
2. Expand transmission in advance of generation to enable the modular development of location-constrained resources to meet state RPS goals in a cost-effective manner; and
3. Coordinate a multi-state review of transmission projects by developing common principles for cost allocation and cost recovery, and adopt a common Western procedural process

---

[109] For a more in-depth discussion of RTOs and ISOs *see infra* Section IV.B.3. – "Market Structures."
[110] CLEAN AND DIVERSIFIED ENERGY ADVISORY COMMITTEE TO THE WESTERN GOVERNORS, CLEAN ENERGY, A STRONG ECONOMY AND A HEALTHY ENVIRONMENT 20-21 (2006).
[111] A renewable portfolio standard, or "RPS," usually comes in the form of a state mandate requiring certain in-state utilities to generate a specified percentage of their energy from renewable energy resources. For more information on state-by-state RPS requirements, *see* http://www.dsireusa.org/rpsdata/index.cfm.

that would identify and coordinate the applications, forms, analyses and deadlines.[112]

2. Western Renewable Energy Zones Initiative

To complete the 2009 Western Renewable Energy Zones ("WREZ") report, the Western Governors' Association collaborated with a broad range of stakeholders, including the U.S. Department of Energy, the U.S. Department of the Interior, the U.S. Department of Agriculture, and the Federal Energy Regulatory Commission ("FERC").[113] The WREZ project followed ratification of the earlier CDEAC report and represented a more refined effort, aimed at identifying the best renewable resources in the West and the transmission necessary to bring those resources to market. In so doing, the 2009 WREZ report identified "Western Renewable Energy Zones" – i.e. those areas throughout the Western Interconnection[114] that contain the greatest potential for large scale development of renewable resources, combined with low environmental impacts.[115] The report concludes by identifying transmission strategies necessary to facilitate development of high-voltage transmission to transport renewable energy from identified renewable energy zones to load centers.[116] The WREZ report recommends:

1. Close coordination amongst resource planners, transmission providers, sub-regional and interconnection-wide transmission planners, transmission developers, federal land use agencies, renewable developers, state/provincial and federal regulators, and environmental organizations;
2. Transmission right-of-way or corridor siting necessary for the timely development and delivery of renewable energy resources to market, as well as for protection of lands and wildlife resources;
3. Aggregating the demand for renewable energy to stimulate development of commercial renewable generation and supporting transmission projects;
4. Identifying the political and regulatory obstacles to permitting and construction of cross-jurisdictional transmission lines and renewable energy projects, as well as addressing any barriers to coordinated purchasing by load-serving entities; and
5. Identifying cost allocation issues and opportunities to streamline and coordinate inter-jurisdictional permitting

[112] CLEAN AND DIVERSIFIED ENERGY ADVISORY COMMITTEE TO THE WESTERN GOVERNORS, CLEAN ENERGY, A STRONG ECONOMY AND A HEALTHY ENVIRONMENT 20-21 (2006).
[113] WESTERN RENEWABLE ENERGY ZONES – PHASE 1 REPORT 2 (2009).
[114] For a map depicting the Western Interconnection, please refer to Appendix G.
[115] WESTERN RENEWABLE ENERGY ZONES – PHASE 1 REPORT 2 (2009).
[116] *Id.*

processes by facilitating collaboration among private sector actors and regulators.[117]

3. NREL Western Wind and Solar Integration Study

The National Renewable Energy Laboratory's ("NREL's") Western Wind and Solar Integration Study focused its investigation on the operational impacts of up to 35 percent energy penetration of wind, solar photovoltaic ("PV"), and concentrating solar power ("CSP")[118] on power systems operated by the WestConnect[119] group of utilities in Arizona, Colorado, Nevada, New Mexico and Wyoming.[120] The study took place over a period of two and a half years, led by a team of researchers in wind power, solar power and utility operations, with oversight from technical experts in each of these fields.[121]

NREL's study concluded that it is operationally feasible for WestConnect to accommodate 30 percent wind and five percent solar energy penetration, assuming the following changes to current practice could be made over time:

1. Substantially increase BA operation or consolidation;
2. Increase use of sub-hourly scheduling for generation and interchanges;
3. Increase utilization of transmission;
4. Enable coordinated commitment and economic dispatch of generation over wider regions;
5. Incorporate state-of-the-art wind and solar forecasts in unit commitment and grid operations;
6. Increase flexibility of dispatchable generation[122] where appropriate;
7. Commit additional operating reserves[123] as appropriate;

---

117 WESTERN RENEWABLE ENERGY ZONES – PHASE 1 REPORT 19 (2009).
118 PV devices – commonly known as solar cells – convert sunlight directly into electrical energy. By contrast, CSP technologies use mirrors to reflect and concentrate sunlight onto receivers that collect solar energy and convert it to heat. This heat – or thermal energy – can then be used to produce electricity via a steam turbine or heat engine that drives a generator. For more information on the differences between PV and CSP, *see* http://www.eere.energy.gov/basics/ renewable_energy/ solar.html.
119 For a map depicting the area covered by the WestConnect group of utilities, please refer to Appendix D.
120 NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY, EXECUTIVE SUMMARY (2010).
121 *Id.*
122 "Dispatchable generation" refers to sources of electricity that can be dispatched at the request of power grid operators – i.e., those that can be turned on or off upon demand. A common example of dispatchable generation is a hydroelectric power plant, which can be easily powered up or down. Jim McIntosh and Warren Frost, *Wind Generation Integration*, Remarks at the NERC MRC Meeting (May 6, 2008).
123 "Operating reserves" refers to "extra generation available to serve load in case there is an unplanned event such as loss of generation." Eric Hirst and Brendan Kirby, Technical and Market

8. Build additional transmission as appropriate to accommodate renewable energy expansion;
9. Target new or existing demand response programs ("load participation") to accommodate increased variability; and
10. Require wind plants to provide "down reserves."[124]

To reach the 35 percent renewable penetration amounts and continue to operate the electric system with adequate reliability, the study results further found that regional coordination is required.[125] Additionally, although the power system is designed to balance generation and load, with wind and solar added in large amounts, the system must be able to handle *net* load variability (i.e. combined statistical load with wind and solar variability).[126] This variability can be considerable during certain parts of the year.[127] To handle this variability, the study further recommends:

1. Increase BA cooperation to better accommodate net load variability;
2. WECC can save $2 billion by holding spinning reserves[128] as five large regions (i.e. BA cooperation) rather than many smaller zones – cost savings result because resources are pooled;
3. Sub-hourly scheduling, as opposed to hourly scheduling, can substantially reduce "maneuvering duty" imposed on units providing load following – resulting in plant efficiency improvements and reductions in operations and management costs;
4. Integrating day ahead wind and solar forecasts into the unit commitment process is essential to mitigate uncertainty in forecasts of wind and solar generation;
5. Sufficient intra-area transmission within each state or transmission area for renewable energy generation to access load or bulk transmission is needed; and

---

Issues for Operating Reserves, http://www.ornl.gov/sci/btc/Restructuring/Operating_Reserves.pdf (last visited March 26, 2011).

[124] NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY, EXECUTIVE SUMMARY (2010). A "down reserve" is a type of spinning reserve that can decrease its actual operating level automatically when needed by the system operator. For more information on down reserves, *see* http://www.ferc.gov/EventCalendar/Files/20100629180718-ER10-500-000.pdf.

[125] *Id.*

[126] *Id.*

[127] For two different graphs depicting these kinds of seasonal changes and how the variable nature of renewables – like wind – can affect an operator's ability to combat these changes, please refer to Appendix E.

[128] "Spinning reserves" refers to electric generating units connected to the system that can automatically respond to frequency deviations and operate when needed. MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 65 (2004).

6. Ensure (or increase, where needed) system flexibility to accommodate increased renewable generation.[129]

4. Colorado Governor's Energy Office REDI Report

In 2009, the Colorado Governor's Energy Office ("GEO") released the REDI ("Renewable Energy Development Infrastructure") Report, identifying obstacles and proposing solutions for connecting Colorado's renewable resources to its markets. More specifically, the study examined how Colorado's electricity sector could reduce its CO_2 emissions by 20 percent by 2020 from its 2005 levels – referred to as the "20 x 20 goal."[130] The report ultimately finds that if the state's electricity sector is to meet the 20 x 20 goal, the following steps must first be taken:

1. Greatly increase investment in demand-side resources (i.e. energy efficiency, demand-side management, demand response, and conservation);
2. Greatly increase investment in renewable energy development, particularly utility-scale wind and solar generation;
3. Accelerate construction of high-voltage electric power transmission to deliver renewable energy from Colorado's renewable resource generation development areas to the state's major load centers;
4. Strategically use natural gas-fired power generation to provide needed new power to the grid and to integrate variable renewable resources;
5. Consider decreasing the utilization factor of coal-fired generation and consider early retirement of the oldest and least efficient of the state's coal-fired generating stations;
6. Increase coordination among the interested parties who plan new generation and transmission; and
7. Move to a single regional BA rather than many smaller and separate BAs.[131]

5. Colorado Governor's Energy Office STAR Report

Following its 2009 REDI Report, in 2010 the Colorado GEO released its STAR ("Strategic Transmission and Renewables") Report. The STAR Report was designed to not only elaborate on REDI's findings, but also to identify ways in which to transform Colorado's electricity sector to meet the Colorado Climate Action Plan's

---

[129] NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY, EXECUTIVE SUMMARY (2010).
[130] COLORADO GOVERNOR'S ENERGY OFFICE, CONNECTING COLORADO'S RENEWABLE RESOURCES TO THE MARKETS IN A CARBON-CONSTRAINED ELECTRICITY SECTOR 6 (2009).
[131] *Id.* at 6-7.

("CAP's")[132] goal of reducing the state electricity sector's CO_2 emissions by 80 percent by 2050 from 2005 levels.[133] The report identifies the following measures needed to meet the state's "80 by 2050" goal and to increase the integration of renewable energy into Colorado's electric grid:

1. The development of substantial new high-voltage transmission infrastructure to address congested and under-sized existing transmission;
2. Use of strategic planning amongst Colorado's utilities and regulators to plan future transmission expansion;
3. Improvements in the state's current legal structure for permitting and siting transmission in order to speed up the necessary transmission expansion process;
4. Increased cooperation between the state's transmission-owning utilities and regional and national stakeholders to adopt new methods to integrate renewable energy;
5. Consideration of the rules and regulations necessary to allow Independent Transmission Companies ("ITCs")[134] to operate in Colorado in order to increase competition; and
6. Physical or virtual consolidation of Colorado's two BAs– Western Area Power Administration and Public Service Company of Colorado – to reduce costs associated with the renewable energy integration process.[135]

6. Tehachapi Study Group

The Tehachapi Study Group's two reports, released in 2006 and 2007, were completed in response to California's Renewables Portfolio Standard ("RPS")[136], in order "to develop a comprehensive transmission development plan for the phased expansion of transmission capacity in the Tehachapi area."[137] Once completed, the

[132] The 2007 Colorado Climate Action Plan – "CAP" – sets out a number of measures that Colorado can take in order to reduce CO_2 emissions 20 percent by 2020 and 80 percent by 2050, with detailed discussions on renewable energy, energy efficiency, hybrid and other "clean" automobiles, and recycling and waste reduction. GOVERNOR BILL RITTER, JR., COLORADO CLIMATE ACTION PLAN: A STRATEGY TO ADDRESS GLOBAL WARMING 3 (2007).

[133] COLORADO GOVERNOR'S ENERGY OFFICE, STAR: A VISION OF COLORADO'S ELECTRIC POWER SECTOR IN THE YEAR 2050 1 (2010).

[134] ITCs are relatively new to the electricity transmission market but are beginning to have an ever-increasing role in transmission expansion and modernization in the U.S. ITCs prefer to work in and with states with statutory and regulatory structures that are friendly to ITCs. *Id.* at 7.

[135] *Id.* at 1-7.

[136] California's RPS was recently amended to reflect a goal of 33 percent renewables by 2020. For more information on California's RPS, *see* CA.gov, Renewables Portfolio Standards (RPS) Proceeding – Docket # 03-RPS-1078, http://www.energy.ca.gov/portfolio/index.html (last visited July 22, 2011).

[137] The Tehachapi Study Group's work was integrated into the California ISO's annual transmission plans and California's Renewable Energy Transmission Initiative beginning in 2007. THE TEHACHAPI RENEWABLE TRANSMISSION PROJECT: GREENING THE GRID (2010); Western Grid Group, "Transmission to

Tehachapi project will consist of more than 250 miles of new and upgraded high-voltage transmission facilities.[138] The report recommends the following in order to accomplish efficient and effective transmission construction necessary for renewable energy development needed to satisfy the state's RPS:

1. Minimize costs and environmental impacts by constructing primarily in existing rights-of-way, with existing facilities either being replaced or upgraded; and
2. Facilitate coordination with federal, state, and local agencies, as well as with communities impacted by the project to seek input, address concerns, secure all necessary approvals, and expedite construction of the project.[139]

IV. OPERATIONS AND MARKET STRUCTURES

A. Overview

In terms of operations, and in order to meet the ever-changing demand for energy, utilities build and operate a variety of power plant types. "Baseload" plants are used to meet the large constant demand for electricity and are usually nuclear or coal-fired plants, but can also include hydroelectric plants (particularly in the Northwestern United States). Utilities try to run these plants at full output as much as possible.[140] In contrast, variation in load is typically met with "load following" or "cycling" plants.[141] These units are typically hydroelectric generators or plants fueled with natural gas or oil.[142] Load following units are further categorized as "intermediate load plants," which are used to meet most of the day-to-day variable demand; and "peaking units," which meet the peak demand and often run less than a few hundred hours per year.[143]

Renewables, typically used to meet intermediate load, are "must run, must take" in that their operating costs are very low, and thus, once the capital is deployed, it makes economic sense to take all of their production.[144] Old, smaller coal plants and natural gas generators are also used for intermediate load, but by contrast, are

---

Access and Deliver Tehachapi Wind and Solar Power," http://www.westerngrid.net/2011/ 02/ transmission-to-access-and-deliver-tehachapi-wind-and-solar-power/ (last visited October 18, 2011).

[138] The project will extend from Eastern Kern County to the city of Ontario in San Bernardino County, passing through portions of the Antelope Valley, the Angeles National Forest, the San Gabriel Valley and the Western Inland Empire. THE TEHACHAPI RENEWABLE TRANSMISSION PROJECT: GREENING THE GRID (2010).

[139] *Id.*

[140] PAUL DENHOLM ET AL., THE ROLE OF ENERGY STORAGE WITH RENEWABLE ELECTRICITY GENERATION (2010). For a map depicting WECC's footprint, please refer to Appendix I.

[141] *Id.*

[142] *Id.*

[143] *Id.*

[144] Staff of the California Public Utilities Commission, Remarks at the CAISO July 16 Stakeholder Meeting (July 30, 2010).

more expensive to run. Finally, smaller hydroelectric and pumped storage units are typically the most expensive to operate and their use is therefore limited to meeting peak load.[145]

Along with meeting predictable changes in demand that occur on a daily, weekly and seasonal basis, utilities must also keep additional plants available to meet unforeseen increases in demand, losses of conventional plants and transmission lines, and other contingencies.[146] This class of responsive reserves is often referred to as "operating" or "contingency" reserves[147] and includes meeting frequency regulation (i.e., the ability to respond to small, random fluctuations in normal load), load forecasting errors (i.e., the ability to respond to a greater or less-than-predicted change in demand), and contingencies (i.e., the ability to respond to an unscheduled power plant or transmission line outage).[148]

In addition to impacting plant operations generally, the variable nature of renewable sources of energy – namely wind – also affects the operation of existing power plants in three primary operating timeframes: (1) regulation; (2) load following; and (3) unit commitment.[149]

1. Regulation

"Regulation" refers to changes in generation requirements, usually in response to load fluctuations, occurring in short time frames (i.e., seconds to minutes).[150] Regulation is provided by an automated system – automatic generation control ("AGC") – that provides generation ramping in response to short-term "mismatches" between generation and load.[151] These mismatches are generally increased when variable sources of renewable energy are integrated into the electric grid.

2. Load Following

"Load following" refers to generation changes resulting from more long-term (i.e., hourly) ramping requirements related to changes in loads.[152] It can also be impacted by wind deployment. Load following differs from regulation in three

---

[145] Staff of the California Public Utilities Commission, Remarks at the CAISO July 16 Stakeholder Meeting (July 30, 2010).
[146] PAUL DENHOLM ET AL., THE ROLE OF ENERGY STORAGE WITH RENEWABLE ELECTRICITY GENERATION (2010).
[147] "Operating reserves" are primarily capacity services (i.e., the ability to provide energy on demand) as opposed to actual energy services. JIANXUE WANG ET AL., OPERATING RESERVE MODEL IN THE POWER MARKET, IEEE TRANSACTIONS ON POWER SYSTEMS (2005).
[148] PAUL DENHOLM ET AL., THE ROLE OF ENERGY STORAGE WITH RENEWABLE ELECTRICITY GENERATION (2010).
[149] *Id.* For a graph depicting the different measures of unit commitment, please refer to Appendix K.
[150] *Id.*
[151] BRENDAN KIRBY AND ERIC HIRST, GENERATOR RESPONSE TO INTRAHOUR LOAD FLUCTUATIONS 3 (2002).
[152] Load following is most typically seen during the morning load peak and evening load drop timeframes. MICHAEL MILLIGAN ET AL., COMBINING BALANCING AREAS' VARIABILITY: IMPACTS ON WIND INTEGRATION IN THE WESTERN INTERCONNECTION 3 (2010).

important respects: (1) it occurs over longer time intervals (minutes to hours as opposed to seconds to minutes); (2) load following requirements of individual customers are highly correlated with one another, whereas regulation patterns are highly uncorrelated; and (3) load following changes are often predictable and have similar day-to-day patterns, whereas regulation patterns do not.[153] Just as with regulation, the integration of a variable resource such as wind to the grid will, in most cases, increase load following costs.[154]

3. Unit Commitment

"Unit commitment" refers to longer-term decisions to commit generation units to service from days to weeks ahead.[155] The purpose of unit commitment is to determine the least-cost mix of generation to have available at each interval for the next several days.[156] Increased costs can result from having a suboptimal mix of units online because of errors in unit commitments. These errors can follow from a number of causes, including weather forecasts, wind-specific forecasts, and an inability to access planned generation due to unscheduled outages.[157] Therefore, selecting generators for the least-cost energy supply is the primary consideration in unit commitment, but the unit commitment process must also ensure that the selected mix has enough ramping capability[158] to meet the BA's needs each hour.[159] Adding a variable energy resource like wind complicates the unit commitment process in that energy requirements, ramping requirements, and forecast errors all change.

B. Challenges

1. Reliability Issues

Electric system reliability is often described in two different terms: (1) adequacy; and (2) security.[160] "Adequacy" is the ability of the electric system to

---

[153] ERIC HIRST AND BRENDAN KIRBY, MEASURING GENERATOR PERFORMANCE IN PROVIDING REGULATION AND LOAD-FOLLOWING ANCILLARY SERVICES 1 (2001).
[154] *Id.*
[155] M. MILLIGAN AND B. KIRBY, IMPACT OF BALANCING AREAS SIZE, OBLIGATION SHARING, AND RAMPING CAPABILITY ON WIND INTEGRATION 35 (2007).
[156] *Id.*
[157] PAUL DENHOLM ET AL., THE ROLE OF ENERGY STORAGE WITH RENEWABLE ELECTRICITY GENERATION (2010).
[158] "Ramping capability" is explained in the following scenario: During a wind *down-ramp,* an operator must compensate for the loss of generation by calling on responsive loads to change their demand levels, ramping up other on-line generation, or by starting up a unit that is currently off-line. Conversely, during a wind *up-ramp*, an operator must compensate by ramping down units, shutting them off, or in some instances, curtailing the high-producing wind altogether. For more information on wind power and ramping requirements, *see* ERIK ELA AND JASON KEMPER, WIND PLANT RAMPING BEHAVIOR (2009) (available at: http://www.nrel.gov/docs /fy10osti/46938.pdf).
[159] PAUL DENHOLM ET AL., THE ROLE OF ENERGY STORAGE WITH RENEWABLE ELECTRICITY GENERATION (2010).
[160] MAURICIO CEPEDA, ET AL., GENERATION ADEQUACY AND TRANSMISSION INTERCONNECTION IN REGIONAL ELECTRICITY MARKETS 3 (2008).

supply the electrical demand and energy requirements of customers at all times, taking into account scheduled and unscheduled outages of power lines and power plants.[161] "Security" is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities such as a power plant or a power line.[162] The North American Electric Reliability Council ("NERC") is the federal entity charged with setting adequacy and reliability standards for U.S. utility facility owners and operators.[163]

Issues of both adequacy and security arise when integration of renewables to the grid is considered. The power system today is designed to handle tremendous variability in loads.[164] Renewables exacerbate that variability. For example, wind generation today cannot be controlled and scheduled with a high degree of accuracy – stated another way, operators can reduce wind generation when the wind is blowing too much, but cannot produce more wind generation when the wind fails to blow.[165]

Keeping wind's inherent variability in mind, the initial goal is to manage net system variability and net system uncertainty because when load and generation are combined, they produce less overall variability than when each is considered alone. Furthermore, combined or net variability is what NERC's mandatory reliability criteria require – not control of variability of a particular form of generation like wind, solar and other renewables.[166] Thus, the system operator must be able to

---

[161] MAURICIO CEPEDA, ET AL., GENERATION ADEQUACY AND TRANSMISSION INTERCONNECTION IN REGIONAL ELECTRICITY MARKETS 3 (2008).
[162] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 7 (2004). (citing RICHARD SEDANO, DIMENSIONS OF RELIABILITY: ELECTRIC SYSTEM RELIABILITY FOR ELECTED OFFICIALS (Montpelier: National Council on Electric Policy, 2001)).
[163]NERC is the FERC-appointed entity that sets technical reliability requirements for all electric systems. For example, two of NERC's reliability indicators are Control Performance Standards 1 and 2 ("CPS 1 and 2"). These criteria assess characteristics of a control area's "area control error" or "ACE." Their purpose is to indicate whether a control area's generation is adequately controlled to make interchanges (i.e., the exchange of electric power between control areas), meet its schedules, and sustain interconnection frequency support obligations. Nasser Jaleeli & Louis S. VanSlyck, *NERC's New Control Performance Standards,* IEEE TRANSACTIONS ON POWER SYSTEMS, Aug. 3, 1999, at 1092. ACE is further discussed later in this paper – *see infra* Section IV.B.4.b – "Ace Diversity Interchange."
[164] Kevin Porter, *New Transmission Initiatives for Renewable Energy and Some Thoughts on Wind Integration,* Remarks at the NARUC Winter Meetings (February 17, 2008).
[165] While a generator cannot make the wind blow when needed, as additional wind farms are connected through Automatic Generation Control ("AGC") – an automatic system that dispatches generation to meet changes required in the regulation and load following time frames – wind operators will be able to "ramp" wind farms up to available wind resource levels by using the present ability to ramp wind down. Further, operators currently have the ability to curtail wind power when necessary. SIXTH NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN – CHAPTER 12: CAPACITY AND FLEXIBILITY RESOURCES 12-3 (2010).
[166] Kevin Porter, *New Transmission Initiatives for Renewable Energy and Some Thoughts on Wind Integration,* Remarks at the NARUC Winter Meetings (February 17, 2008).

balance the total of loads and resources while continuing to meet reliability standards.[167]

2. <u>Transmission Rates and Pricing</u>

If a utility makes up-front investments in transmission lines, it generally has the right to recover its investments through utility rates.[168] The rates that utilities can charge others to use their transmission lines are regulated by FERC.[169] Recently, through Order 2000, FERC asked the industry players – most notably, transmission owners – to establish RTOs.[170] Where RTOs exist, the RTO and transmission owners in the area decide who prepares and submits transmission rates to FERC for approval.[171]

Industry experts typically describe four methods for setting transmission rates: (1) pancaked rates; (2) postage stamp pricing; (3) license plate pricing; and (4) distance-sensitive pricing.[172] Each method attempts to establish a fair and accurate means for users of a power system to pay transmission system owners for use of their transmission lines.[173] "Users" of a power system include companies that generate electricity and use lines to ship power to their customers.[174] A brief discussion of these varying methods for setting transmission rates follows.

<u>Pancaked rates</u>. Pancaked rates are paid when power under contract traverses more than one power system and where each system charges its full rate to provide transmission service.[175] This method of pricing for a regional transmission system is expensive and tends to discourage companies from sending power over long distances and through several transmission systems, regardless of the value of transactions to consumers.[176]

<u>Postage stamp pricing</u>. Postage stamp pricing for purposes of pricing transmission across transmission lines is similar to that of actual postage stamp pricing. [177] The per-unit fee to use the transmission system within a single zone is the

---

[167] Kevin Porter, *New Transmission Initiatives for Renewable Energy and Some Thoughts on Wind Integration,* Remarks at the NARUC Winter Meetings (February 17, 2008). For a brief description of two of these reliability standards – CPS 1 and CPS2 – *see supra* note 162.
[168] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 24 (2004).
[169] *Id.*
[170] THE HONORABLE SPENCER ABRAHAM, SECRETARY OF ENERGY, NATIONAL TRANSMISSION GRID STUDY 24-25 (2002). For a more detailed description of RTOs, *see infra* Section IV.B.3 – "Market Structures."
[171] *Id.*
[172] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 24-25 (2004).
[173] *Id.*
[174] *Id.*
[175] EnergyBuyer.org, Glossary of Energy Market Terms, http://www.energybuyer.org/glossaryLM.htm (last visited December 15, 2010).
[176] SCOTT HEMPLING, ESQ., POSTAGE STAMP PRICING: THE SEVENTH CIRCUIT REVERSES FERC 2 (2009).
[177] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 24 (2004).

same, whether the power is contracted to move 100 feet or 100 miles.[178] Companies located in less densely populated areas and in higher cost areas tend to favor postage stamp pricing over the alternative of license plate pricing. [179]

License plate pricing. Some parts of the transmission system – such as North and South Dakota – are expensive to serve because they have small, isolated populations that require long distance transmission lines.[180] Other parts of the system – such as NStar of Boston, Massachusetts – have much less extensive transmission systems that cover only short distances and serve dense populations, resulting in much lower costs.[181] License plate pricing occurs when companies that use the transmission grid pay different prices based on costs at points at which power is delivered into their area.[182] The license plate metaphor applies because each company pays a fee to obtain access to the transmission system and can use any part of the system after paying that fee.[183] The companies based in low-cost areas tend to favor this approach.[184]

Distance-sensitive pricing. Distance-sensitive pricing is dependent upon the cost of moving power over varying distances.[185] For example, users that contract to use the transmission system for 10 miles would pay less than those that use it for 100 miles.[186] Distance-sensitive rates tend to discourage investments in long distance transmission. As a result, distance-sensitive pricing may be a barrier to free-flowing wholesale power competition.[187]

3. Market Structures

Most of the electricity generated in the United States today is managed in competitive markets through RTOs or ISOs.[188] RTOs and ISOs are typically referred to as "wholesale electricity markets" and dominate the field of U.S. electricity

---

[178] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 24 (2004).
[179] *Id.*
[180] *Id.* at 24-25.
[181] *Id.* at 25.
[182] SCOTT HEMPLING, ESQ., POSTAGE STAMP PRICING: THE SEVENTH CIRCUIT REVERSES FERC 2 (2009).
[183] *Id.*
[184] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 25 (2004).
[185] Sheila S. Hollis, *The Electric Industry Opportunities and Impacts for Resource Producers, Power Generators, Marketers, and Consumers,* Rocky Mountain Mineral Law Special Institute, 42B Special Institute, Chap. 13 (1996).
[186] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 25 (2004).
[187] *Id.*
[188] For all intents and purposes, RTOs and ISOs are both competitive regional wholesale electricity markets with virtually the same structure. The only difference is that an RTO is a FERC-created entity that must comply with specific FERC standards not applicable to ISOs. Lisa G. Dowden, *The RTO In Your Future: What Should You Know?,* 16SPG Nat. Resources & Env't 247 (2002). For further discussion on RTOs and ISOs, *see infra* Section II.B.4.c.–"FERC Order 2000" and *see supra* Section IV.B.3.a. – "Regional Transmission Organizations." For a map depicting the current ISO/RTO markets in the United States and Canada, please refer to Appendix F.

generation.[189] In fact, the only exceptions to this structure exist in the western and southeastern United States, with both regions instead relying upon investor-owned or publicly-owned utility control areas.[190] These control areas, also referred to as balancing areas or balancing authority areas ("BAAs"), are controlled by balancing authorities ("BAs"). The utilities or public authorities that act as BAs in these areas are entrusted with managing generation supply and demand within their own jurisdictional boundaries and interchanging power with adjacent BAAs as needed.[191]

a. Regional Transmission Organizations

An RTO or ISO is an entity that operates the transmission assets of numerous utilities in a region.[192] One of the most notable traits of an RTO is its size – RTOs cover large regions rather than the smaller in-state areas typically covered by balancing authorities. Ideally, an RTO is independent of any market participant, provides fair and open access to its grid for any market participant desiring to engage in transactions, and impartially allocates transmission capacity in the event of a transmission constraint.[193] According to FERC, "RTOs are the platform upon which our expectations of the substantial generation cost savings to American [utility] customers are based."[194]

In Orders 2000 and 2000A, FERC outlined minimum functions and characteristics that all RTOs must fulfill.[195] In order to obtain FERC approval, an RTO must possess four minimum characteristics and perform eight minimum functions.[196] The eight minimum functions that an RTO must perform include:

1. Tariff administration and design;
2. Congestion management;
3. Parallel path flow;
4. Ancillary services;[197]

---

189 THE HONORABLE SPENCER ABRAHAM, SECRETARY OF ENERGY, NATIONAL TRANSMISSION GRID STUDY 24 (2002).
190 The states in the West that do not use an RTO or ISO structure and instead rely on the balancing authority structure include: Arizona, some parts of California, Colorado, Idaho, Montana, Nebraska, Nevada, most of New Mexico, Oregon, most of South Dakota, Utah, Washington, and Wyoming.
191 SCOTTMADDEN, INC., EMERGING REGIONAL ELECTRICITY MARKET ISSUES 2 (2009). For a map depicting the current balancing authorities in the West, please refer to Appendix G.
192 For a map depicting the current ISO/RTO markets in the United States and Canada, please refer to Appendix F.
193 *Id.*
194 New York Independent System Operator, Inc., 96 F.E.R.C. P 61, 059 (2001).
195 Lisa G. Dowden, *The RTO In Your Future: What Should You Know?,* 16SPG Nat. Resources & Env't 247, 249 (2002).
196 The four minimum characteristics were previously discussed – *see supra* Section II.B.4.c."FERC Order 2000."
197 Ancillary services are those necessary to support the transmission of electric energy from resources to loads, while maintaining reliable operation of the transmission system. Examples include spinning reserve, supplemental reserve, reactive power, regulation and frequency response, and energy imbalance. FEDERAL ENERGY REGULATORY COMMISSION, REPORT ON OUTAGES AND CURTAILMENTS DURING THE SOUTHWEST COLD WEATHER EVENT OF FEBRUARY 1-5, 2011 19 (2011).

5. OASIS and total transmission capability and available transmission capability determinations;
6. Market monitoring;
7. Planning and expansion; and
8. Interregional coordination.[198]

RTOs and ISOs cover many regions of the United States, with two-thirds of the country's economic activity occurring within their boundaries.[199] Current organized markets in the United States include:

1. ISO New England;
2. New York ISO;
3. PJM (Mid-Atlantic and a portion of the Midwest);
4. Midwest ISO;
5. Southwest Power Pool;
6. ERCOT (most of Texas); and
7. California ISO.[200]

b. Balancing Authorities/Balancing Authority Areas

In contrast to the RTOs and ISOs commonplace to the East, Midwest and California, the West is organized into balancing authorities that bear the ultimate responsibility of operating the system reliably.[201] Each generator and load is in one, and only one, balancing authority area.[202] To date, there are 38 BAs in the Western Interconnection.[203] Each BA is responsible for controlling the energy in-flows and out-flows of its BAA, by:

---

[198] Lisa G. Dowden, *The RTO In Your Future: What Should You Know?,* 16-SPG Nat. Resources & Env't 247, 249 (2002).

[199] *What Are RTOs and Organized Markets?,* ELECTRIC POWER SUPPLY ASSOCIATION, 2010, http://www.epsa.org/industry/primer/?fa=rto.

[200] *Id.* For a map depicting the current ISO/RTO markets in the United States, please refer to Appendix F.

[201] "Balancing authority" ("BA") is NERC terminology for the entity that is responsible for reliability services within a particular balancing area. "Balancing authority area" ("BAA") is used to describe the portion of the electrical system for which the balancing authority is responsible. SIXTH NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN – CHAPTER 12: CAPACITY AND FLEXIBILITY RESOURCES 12-5 (2010).

[202] *Id.*

[203] Western Governors' Association, Map of Current Western Interconnection Balancing Authorities, http://www.westgov.org/wirab/meetings/sprg2011/briefing/m_maher.pdf (last visited June 13, 2011). NERC recently approved a 38th balancing authority for the Western Interconnection – Red Mesa. For more information on Red Mesa, *see* http://www.wecc.biz/committees/BOD/12082010/Lists/Minutes/1/ Red%20Mesa% 20Final%20Report%20For%20Approval.pdf (last visited June 1, 2011). For a map depicting the 38 balancing authorities in the Western Interconnection, please refer to Appendix G.

1. continuously balancing load and resources;
2. contributing to maintaining the frequency of the interconnection at its required level (as specified by CPS 1 and 2)[204];
3. monitoring and managing transmission power flow on the lines in its own area so they stay within system reliability limits;
4. maintaining system voltages within required limits; and
5. dealing with generation or transmission outages as they occur.[205]

Operators in a BAA must balance load and resources and keep track of imports and exports, all while load is continuously changing. Balancing authorities do this by operating in a basic time frame of one hour, every hour of the day.[206] The basic test of success in this balancing is known as "area control error" ("ACE").[207] ACE is a measurement, calculated every four seconds, of imbalance between load and generation within a BAA, taking into account previously planned imports and exports of electricity and the frequency of the interconnection.[208] ACE is designed to minimize what are called "frequency excursions" – i.e. spikes and dips in frequency measurement. The effect of wind and other variable generation on the balancing authority's ability to balance generation and load has raised operator concerns regarding the costs of maintaining ACE within required restraints.[209]

4. Market Tools

The following market tools are most accurately described as "balancing tools" – i.e., they are designed to enhance the reliability and efficiency of balancing load and generation as variable generation increases in the West. WECC's Efficient Dispatch Toolkit is still in the study phase as WECC continues its analysis of a high-level market design for implementing these tools in WECC's footprint in the Western

---

[204] For a more detailed discussion of CPS 1 and 2, *see supra* note 163.
[205] SIXTH NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN – CHAPTER 12: CAPACITY AND FLEXIBILITY RESOURCES 12-5 (2010).
[206] *Id.*
[207] *Id.*
[208] The ideal ACE measurement is zero. SIXTH NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN – CHAPTER 12: CAPACITY AND FLEXIBILITY RESOURCES 12-6 (2010).
[209] For instance, because variable generation is less easily controlled, response capacity must be increased – the more uncertain the level of output, the more response capacity must be carried by the operator in order to comply with ACE requirements. Generally speaking, the higher the capacity requirement, the higher the costs. For a more in-depth discussion of system operator concerns regarding integrating renewables, *see* JACK ELLIS ET AL., WHITEPAPER: ELECTRICITY MARKETS AND VARIABLE GENERATION INTEGRATION 7-29 (2011) and YV MAKAROV ET AL., ANALYSIS METHODOLOGY FOR BALANCING AUTHORITY COOPERATION IN HIGH PENETRATION OF VARIABLE GENERATION 3.1-3.22 (2010).

Interconnection.[210] The ACE Diversity Interchange is also in the study phase, with the second phase of that study currently in progress.[211]

a. WECC's Efficient Dispatch Toolkit

The Western Electricity Coordinating Council's ("WECC's") Efficient Dispatch Toolkit ("EDT") is a proposal comprised of two "tools:" (1) the Enhanced Curtailment Calculator ("ECC"); and (2) the Energy Imbalance Market ("EIM").[212] The goal behind implementation of the EDT is to provide for an increased use of transmission facilities in the West, resulting in lower costs for both renewable energy integration and energy supply for balancing market participants.[213]

The ECC is a seams coordination tool[214] used to manage power flow impacts across all seams between balancing authorities within the WECC footprint.[215] The ECC would be used to coordinate curtailments for reliability in order to manage congestion on WECC transmission paths.[216] Currently curtailments are performed by webSAS – "web Security Analysis System" – which serves as an Internet-based application used by WECC to analyze, initiate, communicate, and provide compliance reports related to transmission path usage and congestion.[217] The ECC would improve upon webSAS by including a wider range of transmission paths and more granular models of topology.[218] Although ideally the ECC and EIM would operate together, the ECC can be developed and implemented independently of the EIM.[219]

---

[210] For a map depicting WECC's footprint, please refer to Appendix J.

[211] The first phase used ADI in the following participating control areas: Idaho Power Company, NorthWestern Energy, PacifiCorp – East, and PacifiCorp – West. The second phase is using ADI in the following participating control areas: Arizona Power, Bonneville Power Administration, British Columbia Transmission Corporation, Idaho power Company, NaturEner, PS New Mexico, Nevada Power, NorthWestern Energy, PacifiCorp – East, PacifiCorp – West, Puget Sound Energy, Salt River Project, Seattle City Light, Sierra Pacific, Tucson Electric, and PS Colorado (Xcel). ACE Diversity Interchange: Overview and Update, Remarks at the WECC Meetings in Marina Del Ray, CA (Oct. 30, 2008) (slides available at http://www.wecc.biz).

[212] WESTERN INTERSTATE ENERGY BOARD, NEW TOOLS FOR INTEGRATING VARIABLE ENERGY GENERATION WITHIN THE WESTERN INTERCONNECTION (2011), http://www.westgov.org/EIMcr/documents/eim-hli.pdf (last visited March 28, 2011).

[213] *Id.*

[214] A "seams coordination tool" refers to two primary concepts: (1) ensuring reliability by managing congested paths in a coordinated manner; and (2) ensuring equitable treatment for all customers and transmission service providers. Because each control area's dispatch has an impact on other neighboring control areas' facilities, seams coordination ideally enables neighboring control areas (i.e. balancing authorities) to coordinate their congestion on a larger scale, reducing the number of congested paths. Overview: Seams Coordination Process, http://wecc.biz (enter "seams" in search box) (last visited March 28, 2011).

[215] *Id.*

[216] Michelle Mizumori, Remarks at the WestConnect EIS Work Group (October 28, 2010) (slides available at http://www.wecc.biz).

[217] Unscheduled Flow (USF) FAQ, http://wecc.biz (enter "USF FAQ" in search box) (last visited July 26, 2011).

[218] The reference to "more granular models of topology" simply refers to more detailed mapping capabilities inherent in the ECC over webSAS. Michelle Mizumori, "Review of EDT and Cost Benefit

The EIM would supply both energy imbalance and congestion management services for those portions of the WECC not within the footprint of the Alberta and California ISOs.[220] More specifically, the EIM would allow balancing authorities in the West to supply energy imbalance and to manage transmission constraints across BA borders, rather than only within BAs (as is the current practice).[221] Participation in the EIM would be voluntary on either a BA- or transmission service provider-basis.[222] An EIM would differ from other market structures (i.e., RTOs and ISOs) in that it would not use a consolidated regional tariff, it would be a real time energy-only market, and it would not include unit commitment.[223]

Separate cost and benefit studies on the EIM were released in June and July 2011.[224] Utilicast performed the cost study for the EIM and looked at a number of cost types, including software, hardware, infrastructure, staff and overhead, and also ran a "high cost" and "low cost" scenario.[225] Utilicast additionally used two different "footprint" sizes, resulting in a total of four different cost scenarios (a "high" and "low" for each footprint).[226] The results were: $251.53 million in costs for a high cost/Footprint 1 scenario; $148.3 million in costs for a high cost/Footprint 2 scenario; $87.77 million in costs for a low cost/Footprint 1 scenario; and $51.79 million in costs for a low cost/Footprint 2 scenario.[227] Because the Utilicast study is not BA-specific and instead, analyzes costs based on two varying footprint sizes

---

Analysis Process," Remarks at the Efficient Dispatch Toolkit Technical Session (June 22, 2011) (slides available at http://www.wecc.biz).

[219] WESTERN INTERSTATE ENERGY BOARD, NEW TOOLS FOR INTEGRATING VARIABLE ENERGY GENERATION WITHIN THE WESTERN INTERCONNECTION (2011), http://www.westgov.org/EIMcr/documents/eim-hli.pdf (last visited March 28, 2011).

[220] *Id.*

[221] *Id.*

[222] *Id.*

[223] For a more detailed discussion pertaining to the difference between an EIM and an RTO/ISO, *see* WESTERN ELECTRICITY COORDINATING COUNCIL, WHITE PAPER: ENERGY IMBALANCE MARKET FUNCTIONAL SPECIFICATION (2011), http://www.wecc.biz/committees/BOD/09212011/Lists/Minutes/1/12a%20EIM%20Functional%20Specification.pdf (last visited October 11, 2011).

[224] To access these benefit and cost studies, *see* http://www.wecc.biz/comittees/EDT/EDT%20Results/Forms/AllItems.aspx.

[225] One of the primary differences between the "high cost" and "low cost" scenarios is the entity serving as the market operator for purposes of the EIM. If WECC serves as the market operator, costs are greatly reduced – hence, the "low cost" scenario. However, if an outside entity is chosen instead to serve as the market operator, costs are greatly increased – hence, the "high cost" scenario. David Luedtke, "Efficient Dispatch Toolkit Cost Analysis," Remarks at WECC Board of Directors Meeting (June 22, 2011).

[226] "Footprint 1" excludes CAISO and Alberta. "Footprint 2" excludes CAISO, Alberta, British Columbia, Bonneville Power Administration ("BPA"), WAPA ("Western Area Power Administration") and embedded Northwest BAs (within BPA's footprint). David Luedtke, "Efficient Dispatch Toolkit Cost Analysis," Remarks at WECC Board of Directors Meeting (June 22, 2011). For a map depicting all 38 Western Interconnection balancing authorities, please refer to Appendix G.

[227] David Luedtke, "Efficient Dispatch Toolkit Cost Analysis," Remarks at WECC Board of Directors Meeting (June 22, 2011).

(resulting in aggregate market participant costs), WECC developed a "BA Roadmap" to help each BA calculate their individual costs of joining an EIM.[228]

Energy & Environmental Economics, Inc. ("E3") performed the benefit study for the EIM. E3 found benefits resulting from an EIM in three important areas: (1) more efficient generator dispatch; (2) more efficient clearing of energy imbalances; and (3) reduced flexibility reserve requirements.[229] In its original study, E3 concluded that in the year 2020, savings under an EIM would total $175 million, with $117 million related to "flexibility reserves" (i.e. reduced ramp rate requirements[230]) and $57 million related to improved dispatch (from lowering inter-zonal hurdle rates[231]).[232] One of the key findings of E3's study was that benefits are sensitive to assumptions surrounding BA participation levels – i.e., generally, the larger the footprint, the greater the benefits of an EIM.[233]

However, on October 10, 2011, E3 notified WECC that its original model runs failed to adequately consider full monthly maximum output of hydroelectric units toward reserve requirements, resulting in inflated benefits for its initial EIM analysis.[234] After making the necessary corrections to its model runs, EIM released the updated results on October 12, 2011.[235] As a result of the new hydro inputs, the benefits of the EIM were slightly reduced: the total benefits of an EIM were reduced to $141 million (down from $175 million), and the range of savings (depending on the size of the footprint) was also reduced – $141 to $233 million (down from $165

---

[228] Although WECC has completed its own analysis for determining individual BA costs pertaining to implementation of the EIM, various BAs in the Western Interconnection are still in the process of conducting their own, individual analyses. For WECC's own analysis *see* http://www.wecc.biz/committees/EDT.

[229] *Id.*

[230] "Flexibility reserves" are dispatchable resources (thermal or hydro) that are required to ensure reliable operations under high penetration of renewables (i.e., wind and solar) and are characterized by increased ramping requirements. An EIM results in cost savings through flexibility reserves because fewer reserves are needed across a larger "virtual" footprint – something an EIM creates. Arne Olson, et. al, "WECC Energy Imbalance Market Benefit Study," Remarks at WECC Board of Directors Meeting, June 22, 2011.

[231] A "hurdle rate" is a price adder, in $/MWh, that production simulation models (like the model used in E3's study) use to inhibit trade between zones. Ideally, a hurdle rate reflects a real-life impediment to trade, and includes: (1) point-to-point transmission rates across interfaces; (2) pancaked losses; (3) inefficiencies due to illiquid markets; and (4) need to use resources to serve native load. Arne Olson, et. al, "WECC Energy Imbalance Market Benefit Study," Remarks at WECC Board of Directors Meeting, June 22, 2011.

[232] *Id.*

[233] *Id.*

[234] Letter from Arne Olson, Partner, Energy & Environmental Economics, Inc., to Mark W. Maher, Chief Executive Officer, Western Electricity Coordinating Council (October 10, 2011) (on file with author).

[235] WESTERN ELECTRICITY COORDINATING COUNCIL, WHITE PAPER: WECC EFFICIENT DISPATCH TOOLKIT COST-BENEFIT ANALYSIS (REVISED) (2011), http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf.

to $248 million).[236] Despite E3's qualitative analysis, efforts remain underway in the Western Interconnection to quantify the reliability benefits of an EIM on an individual BA-by-BA level.

b. ACE Diversity Interchange

ACE Diversity Interchange ("ADI") is a form of dynamic scheduling[237] that pools the Area Control Errors ("ACE") among different balancing authorities in order to take advantage of control error diversity (i.e. momentary imbalances of generation and load).[238] The premise of ADI is that when multiple balancing authorities pool their ACE responsibilities, they are able to:

1. reduce control burden on individual BAs through the ADI "equal share" allocation method[239];
2. reduce generator movement;
3. reduce sensitivity to variable resource output; and
4. improve compliance with CPS 1 and 2 reliability standards.[240]

As the ADI study is still in progress in the Western Interconnection, no ADI results are yet available. However, the Southwest Power Pool ("SPP") conducted a similar ADI simulation using ten BAs within its own footprint. The SPP simulation was performed during December 2007, April 2008 and August 2008, and produced positive results in the form of overall lower ACE values for the SPP.[241]

---

[236] As a result of the added hydro inputs (applied toward reserve requirements), the costs for the Benchmark Case (i.e., where no EIM was used) were reduced, thereby resulting in lower EIM production cost savings. *Id.*

[237] "Dynamic scheduling" is a mechanism that enables generation in one balancing authority to be transferred into another balancing authority for the ACE calculations of the two areas. YV MAKAROV ET AL., ANALYSIS METHODOLOGY FOR BALANCING AUTHORITY COOPERATION IN HIGH PENETRATION OF VARIABLE GENERATION ix (2010).

[238] Oatioasis.com, ACE Diversity Interchange, http://www.oatioasis.com/NWMT/NWMTdocs/ADI_webposting_040107.pdf (last visited March 28, 2011).

[239] The ADI "equal share" allocation method is outside the scope of this paper, but generally, refers to the following methodology: (1) determine the ADI limit; (2) compare raw ACE measurements; (3) calculate net ACE measurement; (4) determine majority and minority groups; (5) majority groups' aggregated ACE is used to "zero out" the minority groups' individual ACE measurements; and (6) minority groups' aggregated ACE is applied in equal shares to the majority groups' individual ACEs to the extent possible (but with no sign change allowed). For further discussion on the ADI "equal share" allocation method, *see* ACE Diversity Interchange: Overview and Update, Remarks at the WECC Meetings in Marina Del Ray, CA (Oct. 30, 2008) (slides available at http://www.wecc.biz).

[240] ACE Diversity Interchange: Overview and Update, Remarks at the WECC Meetings in Marina Del Ray, CA (Oct. 30, 2008) (slides available at http://www.wecc.biz).

[241] For more information on SPP's ADI simulation, *see* spp.org (last visited May 20, 2011).

Table:
Raw ACE and ADI-adjusted ACE for SPP[242]

	Dec. 2007	Apr. 2008	Aug. 2008
Raw ACE	14.2	14.7	17.6
ADI ACE	7.5	7.5	8.9

5. Forecasting Methods

As of 2010, total U.S. installed wind capacity was over 40,000 MW.[243] At increasing levels of wind penetration, uncertainty surrounding the amount of wind that can be expected becomes increasingly problematic. On the one hand, increased amounts of wind can add variability specifically to the operator's considerations and decision-making. On the other, increasing amounts of wind reduces overall variability as the diversity of wind plant locations smoothes out the overall variability of the total wind in operation. In addition to variability considerations, there are increased costs associated with having excess units online, as well as from reduced unit efficiency.[244] Improved wind forecasting can help reduce these costs.[245] Other benefits that accompany improved wind forecasting include:

1. reduced imbalance charges and penalties;
2. competitive knowledge advantage in real-time and day-ahead energy market trading;
3. more efficient project construction, operations, and maintenance planning; and
4. reduction in the occurrence or length of curtailments, resulting in cost savings.[246]

a. Centralized v. Decentralized Forecasting

Discussions about wind forecasting methods often center upon whether forecasts should be centralized or decentralized. Each has benefits as well as

[242] "Raw" ACE is the absolute average ACE of the 10 BAs for the month. "ADI" ACE is the absolute average of the ADI-adjusted ACE of the 10 BAs for the month. The ACE values depicted in the table are premised on the idea that an ideal ACE measurement is "0." Note that the combined ACE values result in lower ACE measurements, bringing those values closer to "0" than they would be alone. For more information on ACE, *see supra* Section IV.B.3.b. "Balancing Authorities/Balancing Authority Areas." For more information on SPP's ADI simulation, *see* spp.org (last visited May 20, 2011).
[243] U.S. DEPARTMENT OF ENERGY, 2010 WIND TECHNOLOGIES MARKET REPORT, EXECUTIVE SUMMARY (2010).
[244] *Id.*
[245] A sample of various wind integration studies estimate the potential annual operating cost savings from using wind forecasting in the day ahead market range from $20 million to $510 million. A perfect forecast could add between $10 and $60 million more in savings. K. PORTER AND J. ROGERS, STATUS OF CENTRALIZED WIND POWER FORECASTING IN NORTH AMERICA (2010).
[246] Jeff Lerner et al., The Importance of Wind Forecasting (April 2009), http://renewableenergy focus.com /view/1379/the-importance-of-wind-forecasting-/ (last visited March 17, 2011).

drawbacks. Centralized forecasting refers to one forecast supplier providing forecasts for all wind power facilities in a specified geographic area (comprised of a utility service area, a balancing authority area, or an RTO/ISO).[247] Decentralized forecasting refers to one or more forecast suppliers providing individual and independent forecasts on a wind farm-by-wind farm basis.[248]

Centralized forecasts are typically owned or contracted by the grid operator and have certain advantages over decentralized forecasts, including:

1. use of a consistent wind power forecasting approach;
2. improved grid operator access to wind generation data;
3. ease of setting and enforcing standards; and
4. possible utilization of economies of scale[249] in order to reduce the cost of forecasting for each individual system operation.[250]

In contrast, decentralized forecasts are supplied individually by wind projects and have certain advantages over their centralized counterparts:

1. no external funding needed;
2. standards can be set more easily;
3. use tends to lead to greater competition among forecast providers; and
4. possibility of improved forecasting accuracy at individual wind facilities.[251]

Despite the advantages of both forecasting methods, each also suffers from disadvantages. For instance, while centralized forecasts offer consistency and operator ease of access to wind generation data, they also suffer from the following disadvantages:

1. because centralized forecasts are based on a single forecasting methodology, the more "consistent" result may be consistently wrong;

---

[247] NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, NERC IVGTF TASK 2.4 REPORT: OPERATING PRACTICES, PROCEDURES, AND TOOLS 24-38 (2011).
[248] *Id.*
[249] "Economies of scale" is a theory of the relationship between the scale of use of a properly chosen combination of all productive services and the rate of output of the enterprise. So, in this sense, economies of scale refers to the ability of a centralized wind forecast to benefit from the analysis of all productive wind forecasts within the relevant balancing area, RTO or ISO. George J. Stigler, *The Economies of Scale,* 1 J.L. & Econ. 54 (1958).
[250] K. PORTER AND J. ROGERS, STATUS OF CENTRALIZED WIND POWER FORECASTING IN NORTH AMERICA (2010).
[251] Michael Brower, Wind Energy Forecasting, Presentation on behalf of AWS Truepower (January 2011)(slides available at http://web.mit.edu/windweek/Presentations/Brower_MIT_Wind_Workshop.pdf).

2. single forecasting methods may lead to a bias for certain weather conditions or events, possibly leading to large system errors;
3. when a single central wind forecast is in place, competition and the ability to compare alternative results may be reduced or altogether lost; and
4. few centralized systems use ramp forecasting to predict sudden "ramps" in wind power, increasing the likelihood of forecast errors.[252]

Additionally, while decentralized forecasting methods may be easier to operate and offer more flexibility than centralized forecasting methods, the following disadvantages still exist:

1. enforcement of standards will be exceedingly difficult on a wind farm-by-wind farm basis;
2. forecasting accuracy is improved only on an individual wind facility basis, but not over a larger region (i.e. utility service areas, balancing areas, RTOs and ISOs); and
3. forecasting costs can prove more expensive because of a lack of economies of scale.[253]

b. Ensemble Forecasting

Ensemble forecasting describes forecasting methods that test the simultaneous use of multiple forecasting methodologies within the same meteorological zone in order to determine the best forecasting tools to apply to different situations.[254] By employing an ensemble of wind forecasts, forecast errors can be reduced, as the forecast errors from individual wind forecasting models tend to cancel out.[255] Ensemble forecasting embodies the idea that certain forecasting models are more appropriate for certain weather events – for example, a situational awareness wind forecast is used in real-time for severe weather events; hour-ahead wind forecasting applies updates to generate forecasts as frequently as five minutes and is helpful in determining if there is sufficient flexibility in the system beyond the five-minute dispatch time horizon; and day-ahead wind forecasts are typically used in reliability planning.[256]

[252] K. PORTER AND J. ROGERS, STATUS OF CENTRALIZED WIND POWER FORECASTING IN NORTH AMERICA (2010).
[253] Michael Brower, Wind Energy Forecasting, Presentation on behalf of AWS Truepower (January 2011)(available at: http://web.mit.edu/windweek/Presentations/Brower_MIT_Wind_Workshop.pdf).
[254] *Id.*
[255] K. PORTER AND J. ROGERS, STATUS OF CENTRALIZED WIND POWER FORECASTING IN NORTH AMERICA (2010).
[256] *Id.*

c. Case Studies of Spain and Germany:
Central Clearinghouses, Clustering Analyses, Ensemble Forecasting and Forecasting Over Larger Geographic Areas

An analysis of two countries – Spain and Germany – with superior wind forecasting to that of the United States is helpful in determining how to improve U.S. wind forecasting. Both countries employ a number of forecasting methods to improve forecasting accuracy within their boundaries, including the use of central clearinghouses, clustering analyses, ensemble forecasting, and forecasting over larger geographic regions.

The case of Spain. Spain's electricity regulatory authority, Red Eléctrica De España ("REE") uses an internal forecast for each of the county's wind "parks," known as "SIPREÓLICO."[257] SIPREÓLICO uses the following techniques in order to improve wind forecasting within the country:

1. total hourly forecast for the next ten days (updated hourly);
2. hourly forecasts for the next 48 hours by region or transmission system node (updated every 15 minutes); and
3. hourly random forecast of total production.[258]

As a result of these measures, Spain has noticed a reduction in forecast errors and a lesser need for reserves to cover those errors.[259] Additionally, Spain's centralized control center – Control Center for Renewable Energies ("CECRE") – aids in the accuracy of wind forecasting by conducting wind analysis in real time and, when adjustments are needed, calculating wind generation set points for the country's wind parks to follow within a 15-minute time frame.[260]

The case of Germany. Germany, like Spain, also possesses excellent wind forecasting. Germany utilizes the following measures in order to ensure the highest possible accuracy in wind forecasting:

1. day-ahead equalization;
2. 15-minute schedules within control areas;
3. scheduled exchanges with other control areas based on one-hour intervals;
4. bilateral trades that can be based on 15-minute intervals; and
5. forecasting over larger geographic areas.[261]

---

[257] Jorge Hidalgo López, Electrical Control Centre Department., Wind Development and Integration Issues and Solutions, Remarks Before the Northwest Wind Integration Forum (July 29-30, 2010).
[258] *Id.*
[259] *Id.*
[260] *Id.*
[261] Regarding forecasting over larger geographic regions, the German forecasting study indicated that wind power forecasting error is reduced significantly when forecasted wind output from all four

Germany, like Spain, also has a central entity – TSO Security Cooperation – entrusted with coordination of wind onto the grid in order to avoid transmission congestion.[262] Additionally, Germany's use of day-ahead forecasting makes it possible to balance out differences between supply and forecast values through appropriate trades.[263]Also important to Germany's wind forecasting is its use of ensemble methods that combine five or more forecasting systems to determine the most accurate wind forecast.[264]

V. CONCLUSIONS AND RECOMMENDATIONS

A. The Case for Regional Transmission

In order to overcome the challenges and obstacles currently facing the incorporation of renewable energy sources like wind to the electric grid, there are a number of possible transmission-specific solutions that may be implemented. While transmission expansion is an important consideration, other solutions exist that may be able to postpone or reduce needed expansion, including increased coordination among state, regional and federal entities, and a streamlined approach to siting.

1. Increased Coordination Among Relevant Parties

Every study examining transmission analyzed in this paper – the WREZ Report, the NREL Western Wind and Solar Integration Study, the Western Governors' Association CDEAC Report, the Colorado Governor's Energy Office REDI and STAR Reports, and the Tehachapi Study Group – discussed the importance of increased coordination and cooperation amongst relevant parties. More specifically, relevant parties in terms of renewable energy projects and transmission integration include:

1. resource planners;
2. sub-regional and interconnection-wide transmission planners;
3. transmission developers;

---

regions of Germany is compared with output from just a single region. In general, there can be a 30 to 50 percent reduction in forecasting error that results from aggregation and geographic dispersion of wind power, as compared with the error of individual or geographically concentrated wind plants. Dr. Yuri Makarov, German Approach and Experience with Integrating Large Amounts of Wind Energy into a Power System, Remarks to the Northwest Wind Integration Forum (July 29-30, 2010); Dr. Johannes Teyessen & Martin Fuchs, WIND REPORT 2005, E.ON Energie (2005).

262 *Id.*

263 Under Germany's 2004 Renewable Energies Act ("EEG"), all electricity traders who supply consumers in Germany must cover a specific proportion of their sales with electricity that is promoted under the Act (i.e. wind power). The conversion of the actual wind power generation into safe supplies by the transmission system operators is called "EEG equalization." If the forecast is *higher* than the EEG supply, then the difference for the hour in question on the following day is sold. If the forecast value for the hour in question is *below* the value of the EEG to the traders, then the difference is bought. Dr. Johannes Teyessen & Martin Fuchs, WIND REPORT 2005, E.ON Energie (2005).

264 K. PORTER AND J. ROGERS, STATUS OF CENTRALIZED WIND POWER FORECASTING IN NORTH AMERICA (2010).

4. federal land use agencies;
5. renewable energy developers;
6. state, provincial and federal regulators;
7. balancing authorities; and
8. environmental organizations.

Such coordination will not only assist in the efficient completion of a new renewable energy project, but will help to identify any political or regulatory obstacles to permitting and construction of any new transmission lines – particularly those that will cross over multiple jurisdictions. Regulatory obstacles are especially common in the West, where a vast majority of all federal lands are located.[265]

2. Construction of New Transmission

The reality of present transmission systems in the United States is that while they may reach maximum capacity only a few times per year, a lack of timely data and simultaneous prevalence of ambiguous data on actual flows plagues transmission operators – particularly in the West. This results in inefficient use of existing transmission lines. Additionally, the West is the fastest growing region in the United States, requiring an increasing amount of generation resources – including renewable resources – that need to connect to the grid.[266] Although recent studies indicate that it may be possible to make more effective and efficient use of existing transmission lines, ultimately, without construction of new lines, it will become increasingly difficult to get significant new wind resources online using the best resources with the lowest costs.[267]

By using a "participant funding" method that also spreads some cost to utility consumers (as utilized by GE Wind and Xcel Energy in Colorado), or by spreading regional costs to regional beneficiaries (as MISO and SPP have done), costs for new transmission can be fairly divided and shared.[268] Of course, given the mandates of

[265] Most of the federal lands in the United States are located in the western states of Washington, Oregon, California, Nevada, Idaho, Montana, Wyoming, Colorado, New Mexico, Arizona and Utah. Alaska also contains a large quantity of federal lands. New construction over federal lands can prove particular difficult in that it requires the approval of the appropriate federal agency – usually the Bureau of Land Management ("BLM"). For instance, such approval will more likely than not include the satisfaction of the National Environmental Policy Act's ("NEPA") standards and requirements. PublicLands.org, Public Lands Information Center, http://www.publiclands.org/home.php (last visited December 16, 2010).

[266] CLEAN AND DIVERSIFIED ENERGY ADVISORY COMMITTEE TO THE WESTERN GOVERNORS, CLEAN ENERGY, A STRONG ECONOMY AND A HEALTHY ENVIRONMENT 1 (2006).

[267] *See* Teresa Hansen, Power Flow Electronics Help Solve Transmission Line Load Problems, http://www.elp.com (type "Power Flow Electronics Help Solve Transmission Line Load Problems" into search box) (last visited March 17, 2011); *see also* NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY 17 (2010).

[268] For a detailed discussion on the "participant funding method" used by GE Wind and Xcel Energy in Colorado, *see supra* Section III.B.3."Need for Grid Expansion."

FERC's most recent order, Order 1000, any regional cost allocation method will have to follow the "beneficiary pays" principle.[269]

Additionally, cooperation among relevant parties, as discussed above, is crucial to facilitating two kinds of decision-making that support new transmission construction: (1) investment "due diligence" decisions; and (2) public sector approval decisions. In investment due diligence decision-making, risks that could delay or frustrate returns on investment are identified, analyzed and incorporated into investment decisions.[270] By contrast, public sector approval decision-making rests on the quality of factual information presented in trial-type hearings.[271] In both cases, the elements of good system planning, based on broad stakeholder participation that reveals and resolves various perspectives, can provide the information needed by the relevant parties for sound investment in new transmission.[272]

3. Creation of a Single State Entity for Siting Authority

In some western states, several different governmental entities have responsibility to approve transmission siting proposals. As a result, no single entity balances all facets of the project to determine its net positive or negative contributions to the public interest and applicants often are required to submit separate applications to acquire permits from multiple agencies.[273] By assigning siting authority to one agency – such as the state public utility commission or state environmental agency – the confusion and time-consuming effects of having multiple governmental entities in charge of siting approval can be greatly reduced.[274] Furthermore, creation of a single state entity for siting authority can facilitate construction of new transmission lines by streamlining siting approval processes for new renewable energy projects that require new transmission.

---

[269] For further discussion on the requirements of Order 1000 in terms of the "beneficiary pays" principle, *see supra* note 65.

[270] JACK CASAZZA & FRANK DELEA, UNDERSTANDING ELECTRIC POWER SYSTEMS: AN OVERVIEW OF THE TECHNOLOGY, THE MARKETPLACE, AND GOVERNMENT REGULATIONS 200-211 (2010).

[271] Public sector decision-making takes place within federal agencies, state utility commissions, and state and local land use jurisdictions. The trial-type hearings that support public decision-making include evidence that is often presented in expert witness testimony that is subjected to discovery, cross-examination on a public record, and counter-testimony filed by antagonist experts. DORA: Public Utilities Commission, http://www.dora.state.co.us/puc/aboutpuc.htm (last visited March 28, 2011).

[272] "Good system planning" includes testing all generation options against each other, evaluating external costs and risks, and considering demand side alternatives in order to determine the need for transmission. *See* Western Grid Group, Public Interest Principles for Electric System Planning, http://www.westerngrid.net/public-interest-principles-for-electric-system-planning/ (last visited April 3, 2011).

[273] MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 40 (2004).

[274] *Id.*

B. The Case for Regional Planning
(Markets and Operations)

In addition to increased coordination, siting reforms and shared cost recovery mechanisms, changes will need to be made to existing operations and market structures. These changes will be in the form of regional planning and ideally, when combined with transmission reforms, will make overall incorporation of renewables to the current energy mix more efficient and cost-effective.

1. Creation of a Single Regional Balancing Authority Area, Balancing Authority Consolidation and "Virtual" Consolidation

Creation of a single regional balancing area and cooperation within that balancing area offers three key benefits:

1. aggregating diverse renewable resources over larger geographic areas reduces overall variability of those renewables;
2. aggregating loads reduces overall load variability; and
3. aggregating the non-renewable balance of generation provides access to more balancing (and more flexible) resources.[275]

Thus, creation of a single BAA (controlled by a single BA) – as opposed to numerous smaller BAAs – creates a larger region in which to balance the variability characteristics of renewable resources of energy and, in turn, can result in savings through the pooling of energy reserves.[276] Further, consolidation of multiple areas into just a few, or the virtual consolidation of certain balancing authority functions (e.g. scheduling, access to ancillary services, reporting reliability), can have the same net benefits and may serve as initial steps towards phasing into a single, large balancing authority area in the future.

However, expecting 38 individual balancing authorities to consolidate into one in the West may prove challenging and thus, consolidation and cooperation among the 38 may be more realistic and helpful – at least in the near term. Increasing BAA cooperation and size is important not only to transmission, but to operations necessary to facilitate the addition of wind and other renewables to the electric grid. Further, in the Western U.S., where an ISO is found only in California,[277] it is much easier to simply expand already-existent BAAs or add voluntary coordination features (or both) rather than switch over to an entirely new system of organization.

---

[275] NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY 17 (2010).
[276] According to NREL's Western Wind and Solar Integration Study, there are significant savings from sharing reserves over larger regions, irrespective of the renewables on the system. NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY 17-19 (2010).
[277] An ISO also exists in Alberta, Canada and is included in the Western Interconnection footprint. For a map depicting the ISO/RTO markets in the U.S. and Canada, please refer to Appendix F.

As previously discussed, by increasing the size of a BAA, as well as increasing cooperation among different BAs, numerous benefits can be realized.[278]

More specifically, the probability that excess ramping capacity is available increases as the BAA increases in size.[279] This can be accomplished by combining BAAs or by facilitating sub-hourly transactions between individual BAs.[280] And, while the unit commitment problem is numerically more complex in a large BAA because of the larger number of generators, economic commitment solutions are more robust, less volatile, and lower cost because each individual generator comprises a smaller percentage of total system requirements.[281] In reference to cost, specifically, use of postage stamp pricing and license plate pricing within these larger BAAs will be preferred to pancaked rates and distance-sensitive pricing, which make electricity transmitted over longer distances more expensive.

Load and wind forecasts are more accurate for larger balancing authority areas, as well.[282] Further, increasing the effective size of these control areas – either through consolidation or through sharing of balancing obligations – will reduce the costs of wind integration.[283] Finally, from an operational perspective, balancing authority cooperation can lead to cost savings because resources can be pooled.[284]

2. Improved Forecasting

While there are advantages and disadvantages to both centralized and decentralized wind forecasting, a centralized forecasting method that is used in combination with other forecasting techniques offers the best chance for accurate forecasting over a larger geographic area. Such a notion is especially critical when considering BA cooperation and BAA consolidation in the West. In addition, certain other forecasting techniques, borrowed from the successes seen in Spain and Germany, should be implemented to increase accuracy of centralized wind forecasting – more specifically: (1) establishment of a central clearinghouse; (2) use of a clustering analysis and control protocols; (3) use of ensemble forecasting; and (4) forecasting over larger geographic areas.

---

[278] NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY: EXECUTIVE SUMMARY ES-15 (2010). For a table depicting the inherent benefits of utilizing a larger balancing area, as well as a graph depicting the reduced-variability benefit arising from aggregating smaller transmission areas into a larger balancing area, please refer to Appendix H.
[279] M. MILLIGAN & B. KIRBY, IMPACT OF BALANCING AREA SIZE, OBLIGATION SHARING, AND RAMPING CAPABILITY ON WIND INTEGRATION 29 (2007).
[280] *Id.*
[281] *Id.*
[282] *Id.*
[283] *Id.*
[284] NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY: EXECUTIVE SUMMARY ES-16 (2010).

First, a central clearinghouse needs to be established in order to perform all wind forecasting within the same interconnection.[285] State PUCs should adopt a common regulatory requirement for utilities and wind plant operators to provide their forecast data to the clearinghouse. Additionally, the central clearinghouse will be vital in recordkeeping and archiving forecast data, ultimately enabling the clearinghouse to evaluate potential improvements in forecasts and evaluate timing and impacts of forecast errors.

Second, a clustering analysis should be used in order to identify which wind plants are likely to affect which conventional units with respect to day-ahead unit commitment, intra-hour balancing, and regulation.[286] In so doing, geographic groupings of wind plants and conventional units could be served by a single wind forecast. Additionally, control protocols should be used in order to develop model protocols by which a balancing authority can use a centralized zonal wind forecast to conduct reliability unit commitment, manage congestion, and determine a wind plant's hourly operating set points.[287]

Third, ensemble forecasting should be used to take advantage of the best forecasting tools for differing weather situations.[288] Being able to "pick and choose" the best forecasting tool based on the particular weather pattern (e.g., situational awareness forecasting for severe weather events) will result in a reduction of forecasting errors and will thus improve the accuracy of wind forecasting.[289] Since forecasting is changing and improving rapidly, programs of continuous training and improvement should accompany implementation of more sophisticated forecasting across wind, solar and temperature forecasting for gas nominations and scheduling.

Lastly, forecasting should be conducted over larger geographic areas in order to reduce aggregate forecasting error.[290] Because there can be a 30 to 50 percent reduction in forecasting error directly resulting from aggregation and geographic dispersion of wind power, wind forecasting over a larger region has a substantial impact on improving forecasting accuracy.[291] Finally, when forecasting is more accurate based on forecasting in a larger region, power system operators can often more accurately predict and plan for *future* changes in wind generation.[292]

---

[285] Michael Milligan and David Hurlbut, Supply Curve of Policy Options for Integrating Variable Generation: Forecasting, Remarks to CREPC (September 14, 2010).
[286] *Id.*
[287] *Id.*
[288] *Id.*
[289] K. PORTER AND J. ROGERS, STATUS OF CENTRALIZED WIND POWER FORECASTING IN NORTH AMERICA (2010).
[290] For a depiction of forecast error and uncertainty and how forecasts are more accurate when they are aggregated to include a large number of geographical areas rather than a single plant, please see Appendix H.
[291] C. Finley et al., Development and Implementation of an Integrated Utility-Wide Wind Forecast System, remarks to the UWIG Forecasting Workshop (2008).
[292] NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IVGTF TASK 2.1 REPORT: VARIABLE GENERATION POWER FORECASTING FOR OPERATIONS (2010).

3. Faster Scheduling

The economic and reliability gains from using wind power forecasting can only be realized if wind power forecasts are coupled with day-ahead schedules.[293] Additionally, moving to a ten-minute scheduling window instead of the current whole-hour scheduling would help maintain the host balancing authority's ACE by allowing it to bring in generation from other balancing authorities.[294]

The current practice of scheduling both generation and interstate exchange of electricity only once each hour has a significant impact on regulation duty.[295] At high penetration levels, such hourly scheduling changes can use most, if not all, of the available regulation capability to compensate for ACE ramps.[296] This results in no remaining regulation capability needed for any sub-hourly variability.[297]

4. Utilization of Market Balancing Tools

Market balancing tools offer operators enhanced ability to balance load and generation – a task that becomes more difficult as increased variable renewable generation is added to the grid. By taking advantage of the ECC, EIM or ADI (or all three), balancing load and generation becomes not only easier, but also more efficient. While WECC is still in the process of analyzing the potential impacts of an ECC and EIM in the Western Interconnection, ADI is currently being used by 16 "participating control areas" in the West.[298] Initial studies indicate that use of ADI in these control areas has already improved compliance with reliability standards by increasing net compliance with CPS 1 and reducing net violations of CPS 2.[299]

C. Conclusion

In order to most effectively facilitate the addition of renewable sources of energy – more specifically, wind – to the electric grid in the West, changes to the transmission system, as well as the operations system, must be made. This will require the implementation of measures related to regional transmission, in the form of:

---

[293] NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IVGTF TASK 2.1 REPORT: VARIABLE GENERATION POWER FORECASTING FOR OPERATIONS (2010).
[294] SIXTH NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN – CHAPTER 12: CAPACITY AND FLEXIBILITY RESOURCES 12-13 (2010).
[295] NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY: EXECUTIVE SUMMARY ES-17 (2010).
[296] *Id.*
[297] *Id.*
[298] For more information on ADI's footprint in the Western Interconnection, *see* ACE Diversity Interchange: Overview and Update, Remarks at the WECC Meetings in Marina Del Ray, CA (Oct. 30, 2008) (slides available at http://www.wecc.biz).
[299] For more information regarding these study results, *see id.*

1. increased coordination among relevant parties;
2. construction of new transmission lines; and
3. creation of single state entities for siting authority.

This will further require the implementation of measures related to regional markets and operations, in the form of:

1. increased balancing authority cooperation and increased balancing authority area size;
2. improved forecasting;
3. faster scheduling; and
4. utilization of market balancing tools.

Combined, these measures should not only increase the future development of wind and other renewable sources of energy in the West, but should aid in the effective and efficient incorporation of those resources to the electric grid.

APPENDIX A

New Transmission Line Voltages During Electrification of the United States

Date	Typical Voltage
1896	11,000
1900	60,000
1912	150,000
1930	240,000
1950	345,000
1960	500,000
1970	745,000
Today	Up to 800,000

Due to the significant U.S.-wide transmission construction that took place beginning in the early 1950s and throughout the 1970s, in addition to the increased efficiency of newer lines, by the late 1970s, significant new construction was no longer needed. However, with increased population growth (and thus demand growth) in recent years, and because of the increased use of renewable energy, demand for new transmission is once again on the rise.

Source: MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 2 (2004) (citing Smithsonian Institution, 2002); BOB SHIVELY AND JOHN FERRARE, UNDERSTANDING TODAY'S ELECTRICITY BUSINESS 63 (2010).

APPENDIX B

Miles of High Voltage Transmission Lines in the United States

Voltage	Miles of Transmission Line
AC	**AC**
230 kV	76,762
346 kV	49,250
500 kV	26,038
765 kV	2,453
TOTAL AC	154,503
DC	**DC**
250-300 kV	930
400 kV	852
450 kV	192
500 kV	1,333
TOTAL DC	3,307
Total AC/DC	**157,810**

Source: MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 6 (2004) (National Transmission Grid Study, U.S. DOE, May 2002).

APPENDIX C

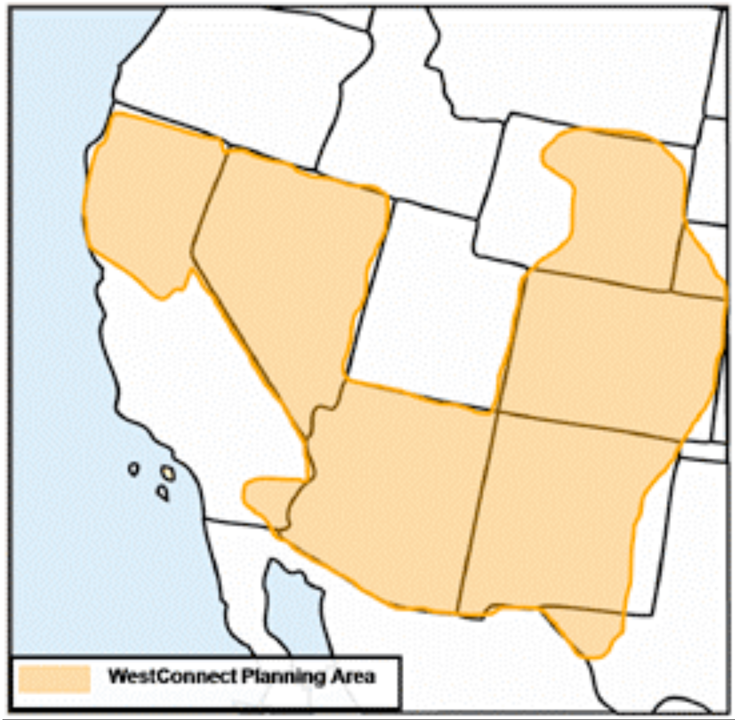
Typical Capital Costs for Electric Transmission Lines, by Voltage

Transmission Facility	Typical Capital Cost
New 345 kilovolt (kV) single circuit line	$915,000 per mile
New 345 kV double circuit line	$1.71 million per mile
New 138 kV single circuit line	$390,000 per mile
New 138 kV double circuit line	$540,000 per mile
New 69 kV single circuit line	$285,000 per mile
New 69 kV double circuit line	$380,000 per mile
Single circuit underground lines	Approximately four times the cost of above-ground single circuit lines
Rebuild/Upgrade 69 kV line to 138 kV line	$400,000 per mile

Higher transmission voltages of 500 kV and 765 kV are becoming more common in the United States. These are far more expensive to install than the voltage lines delineated in the above table – costs range from $1 million per mile and higher.

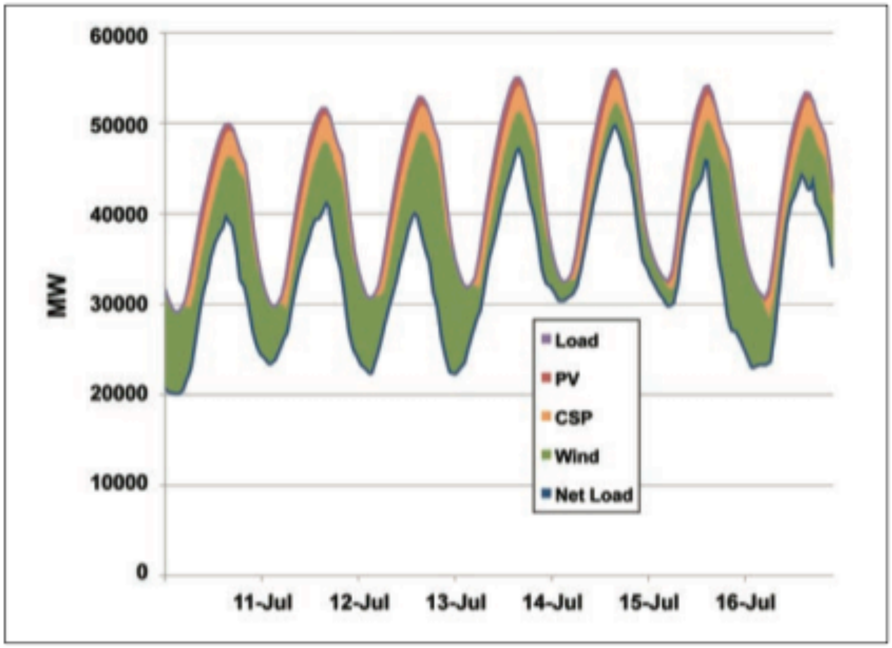
Source: MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 15 (2004)(citing American Transmission Company, *10-Year Transmission Assessment,* September 2003).

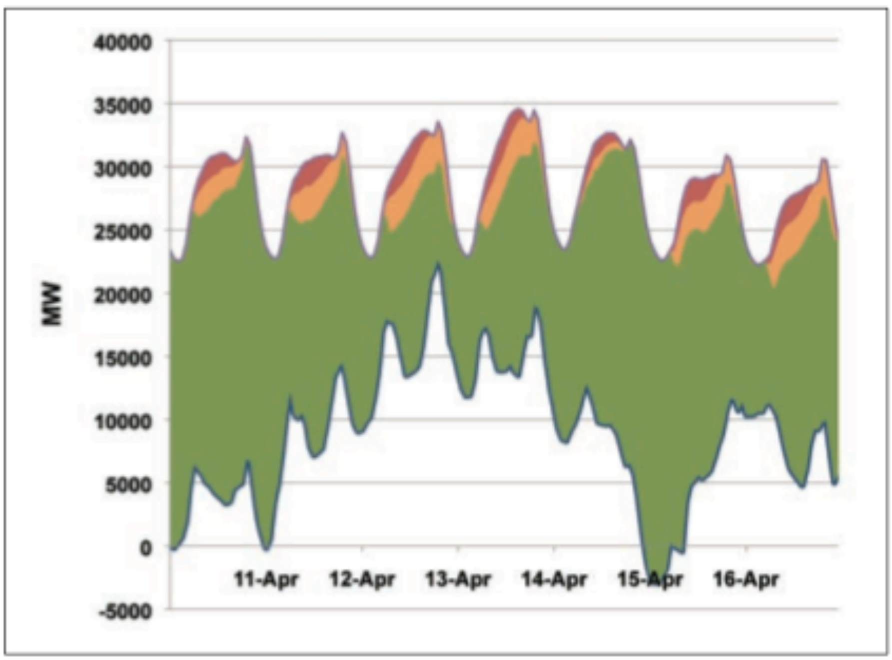
Appendix D



Source: About WestConnect, http://www.westconnect.com/aboutwc.php (last visited October 18, 2010).

APPENDIX E





Graphs depicting the load, wind, solar and net load profiles for 30% renewables integration during two selected weeks in July and April. In the July week (top graph), the net load (blue line at bottom edge) is not significantly impacted by wind and solar variation. However, in the April week (bottom graph), the high, variable wind output dominates the net load, especially during low load hours, leading to several hours of negative net load during the week.

Source: NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY: EXECUTIVE SUMMARY ES-11-12 (2010).

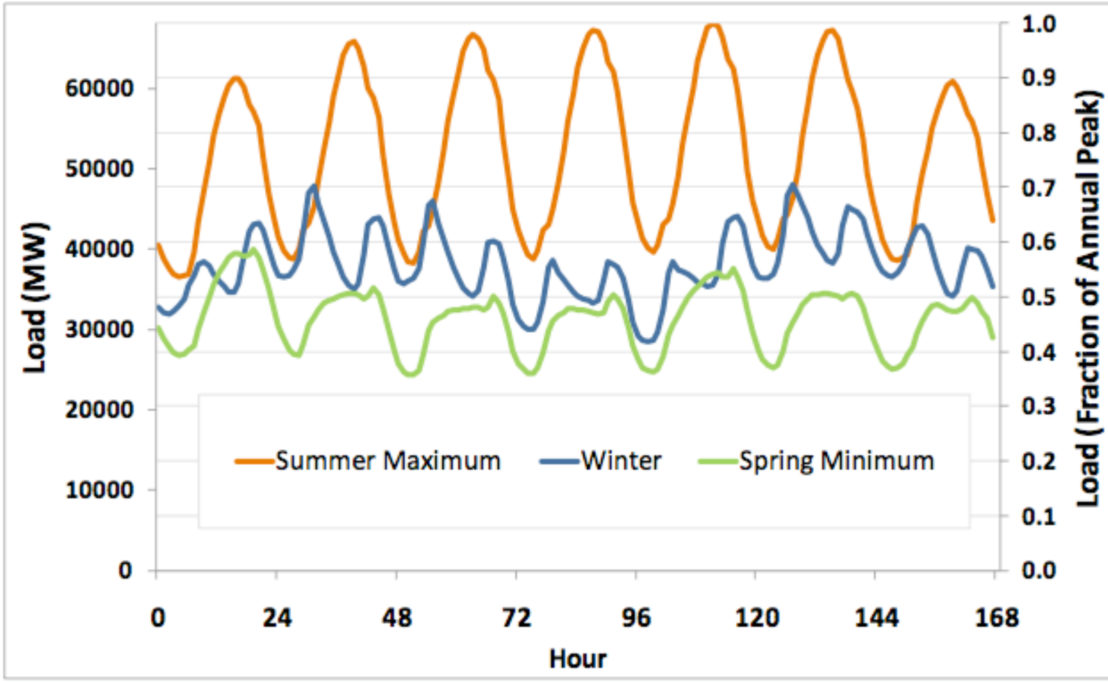
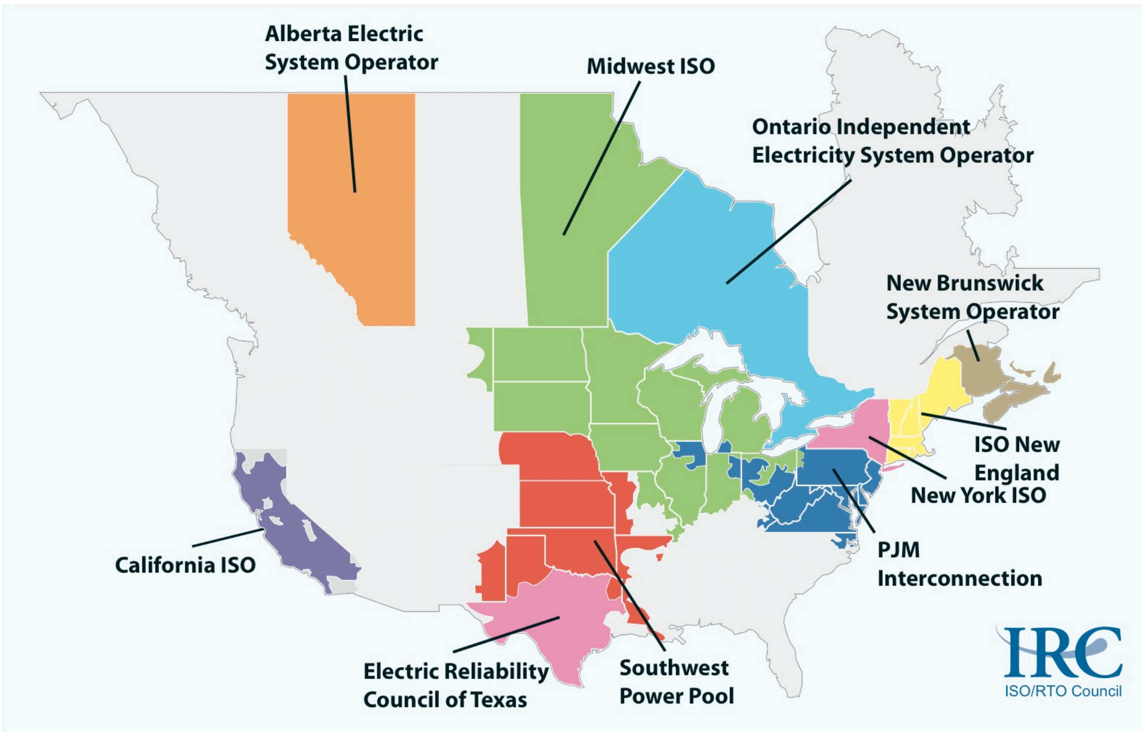


Figure 2.1. Hourly loads from ERCOT 2005

This table shows the electricity demand patterns for three weeks for the Electric Reliability Council of Texas ("ERCOT") grid during 2005. Many of the general trends shown in the demand patterns here are common throughout the country.

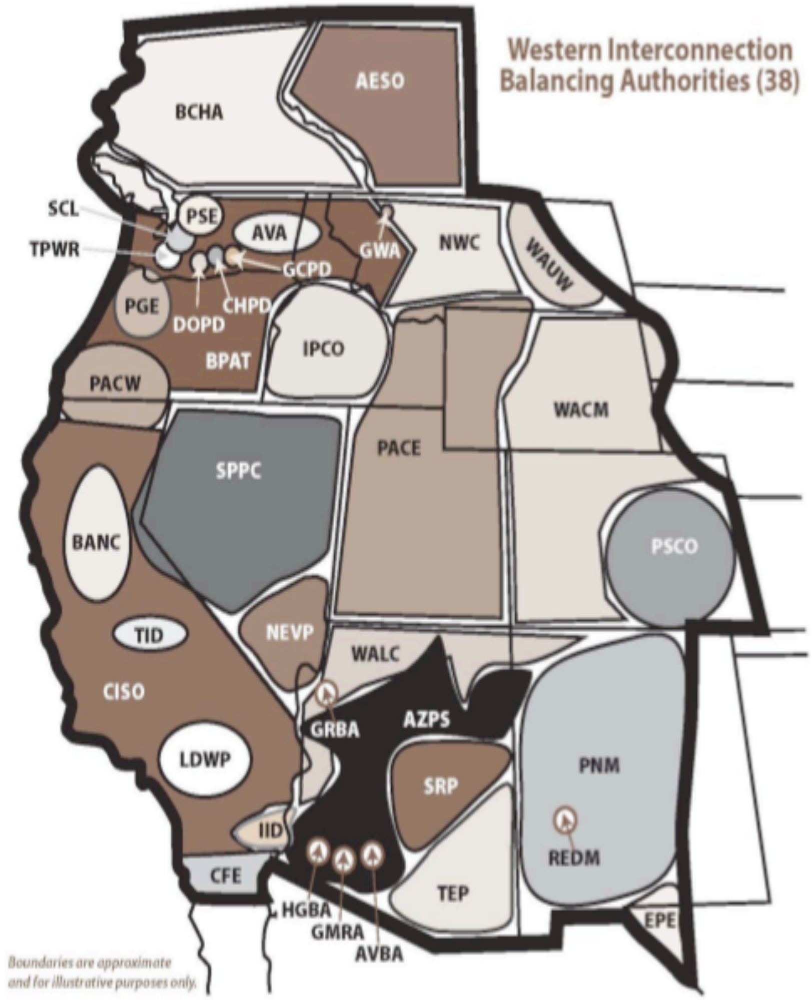
Source: PAUL DENHOLM ET AL., THE ROLE OF ENERGY STORAGE WITH RENEWABLE ELECTRICITY GENERATION (2010).

APPENDIX F



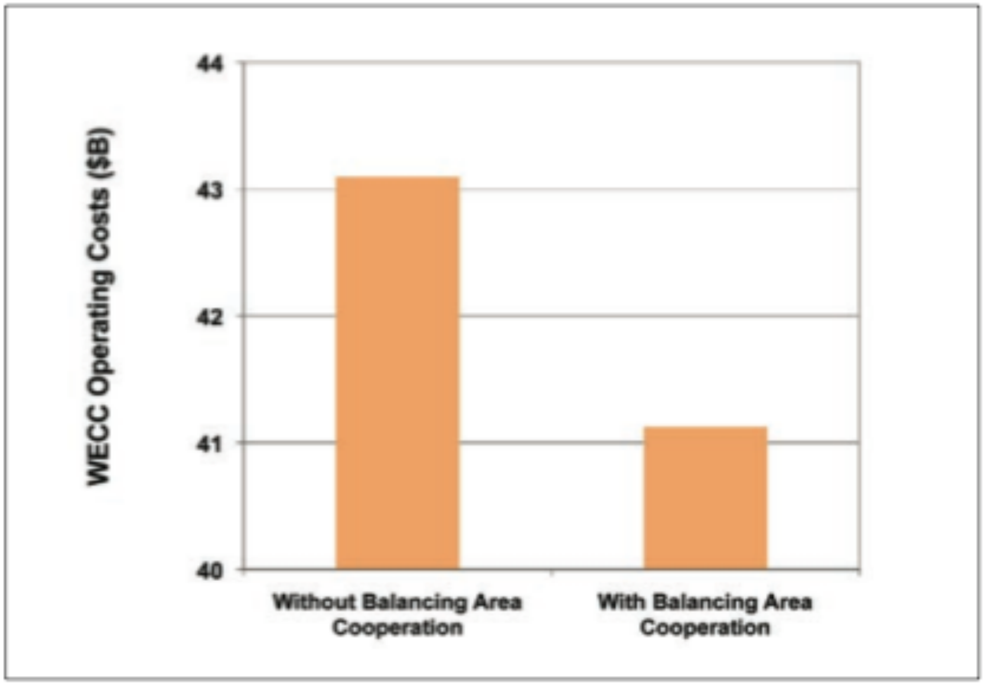
Source: ISO RTO Operating Regions, http://www.isorto.org/site/c.jhKQIZPBImE/b.2604471/k.B14E/Map.htm (last visited October 18, 2010).

APPENDIX G



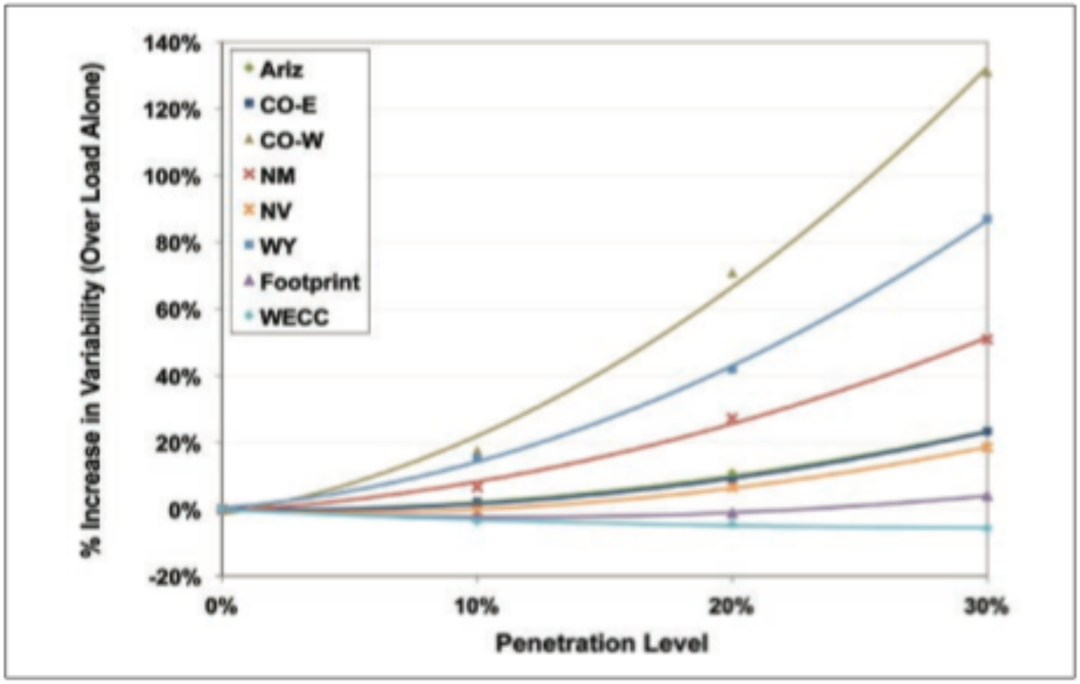
Source: Western Governors' Association, Map of Current Western Interconnection Balancing Authorities, http://www.westgov.org/wirab/meetings/sprg2011/briefing/m_maher.pdf (last visited June 13, 2011).

<u>**APPENDIX H**</u>



WECC can save $2 billion by holding spinning reserves as five large regions (right) rather than many smaller ones (left).

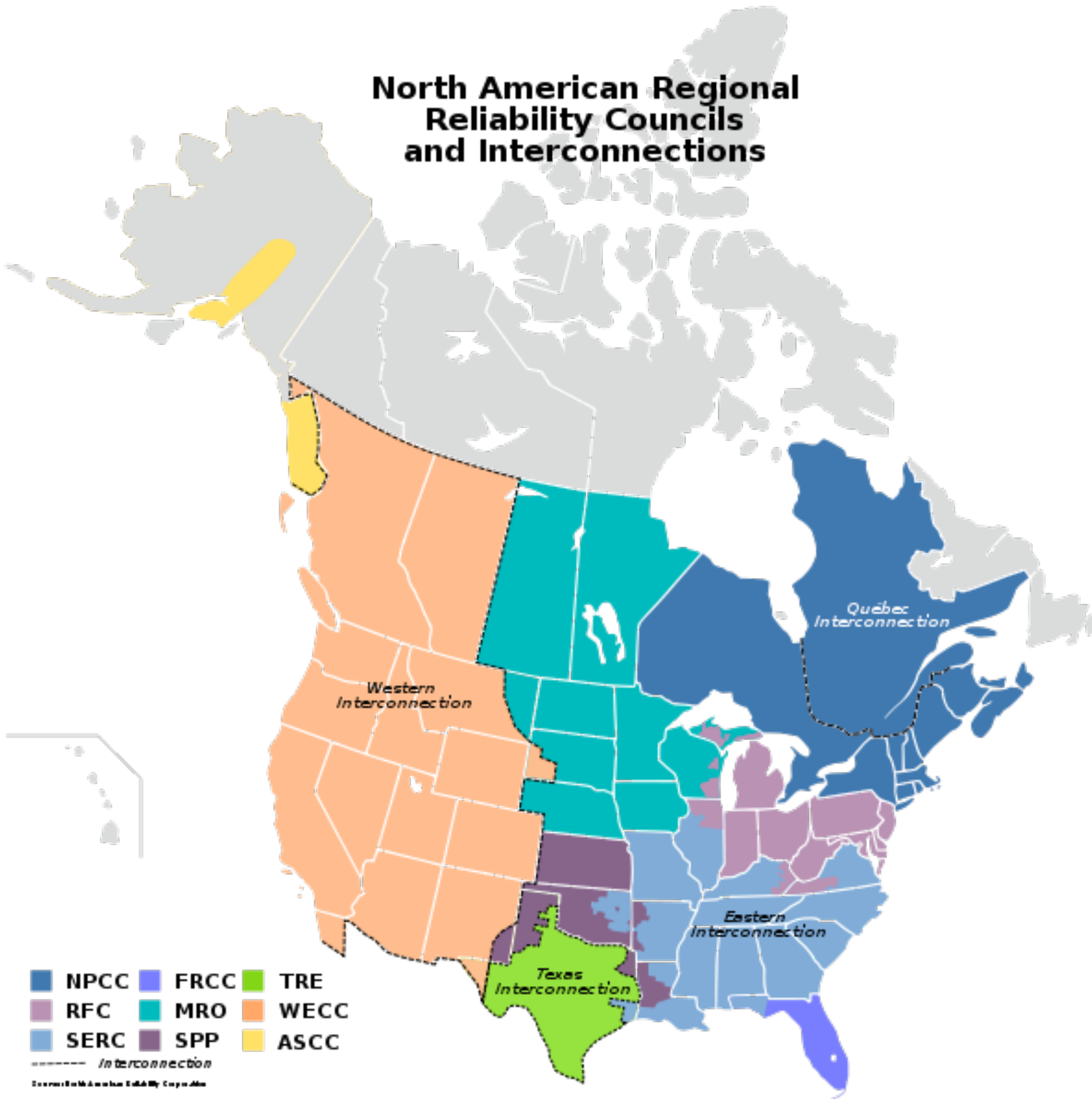
Source: NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY: EXECUTIVE SUMMARY ES-16 (2010).



The variability of the net load increases with increasing renewable energy penetration. However, aggregating several transmission areas over the WestConnect footprint results in reduced variability.

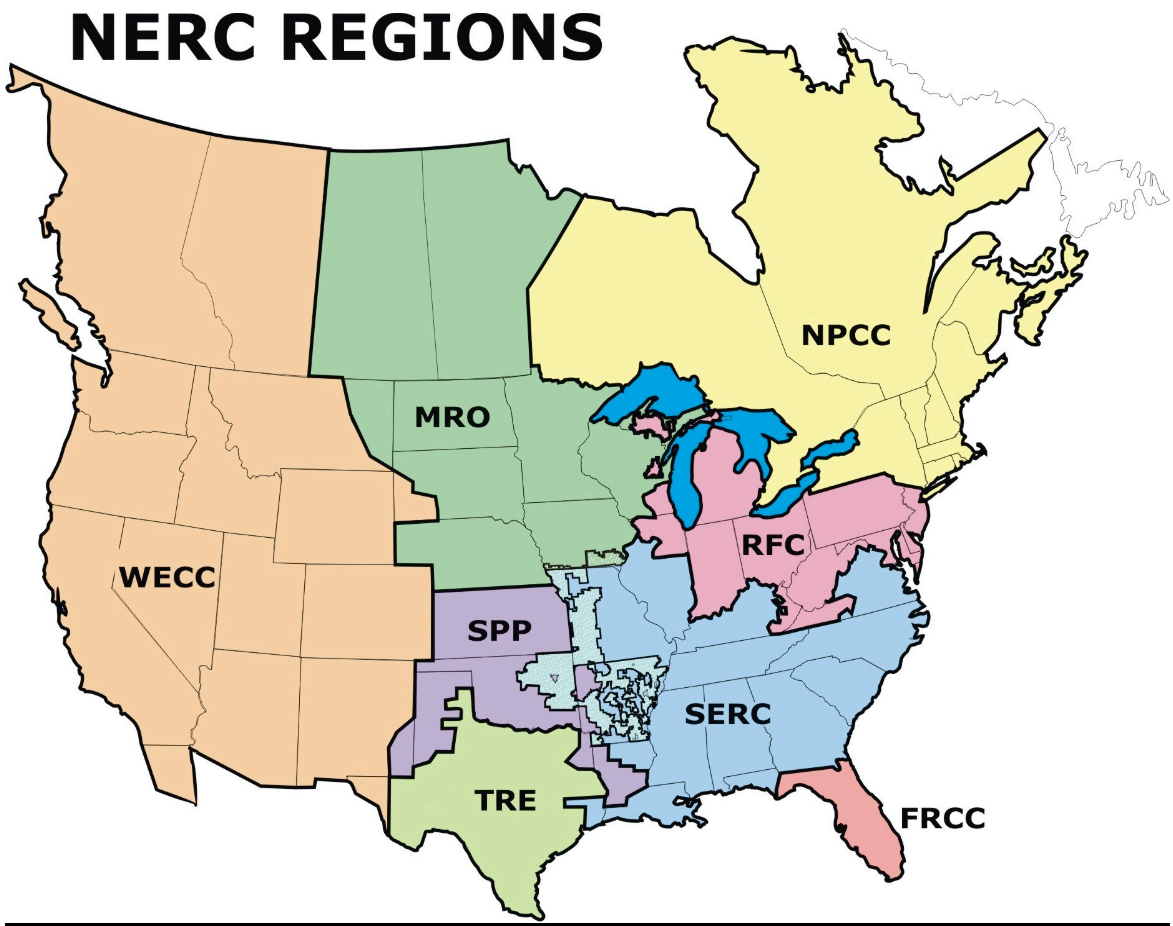
Source: NATIONAL RENEWABLE ENERGY LABORATORY, WESTERN WIND AND SOLAR INTEGRATION STUDY: EXECUTIVE SUMMARY ES-16 (2010).

APPENDIX I



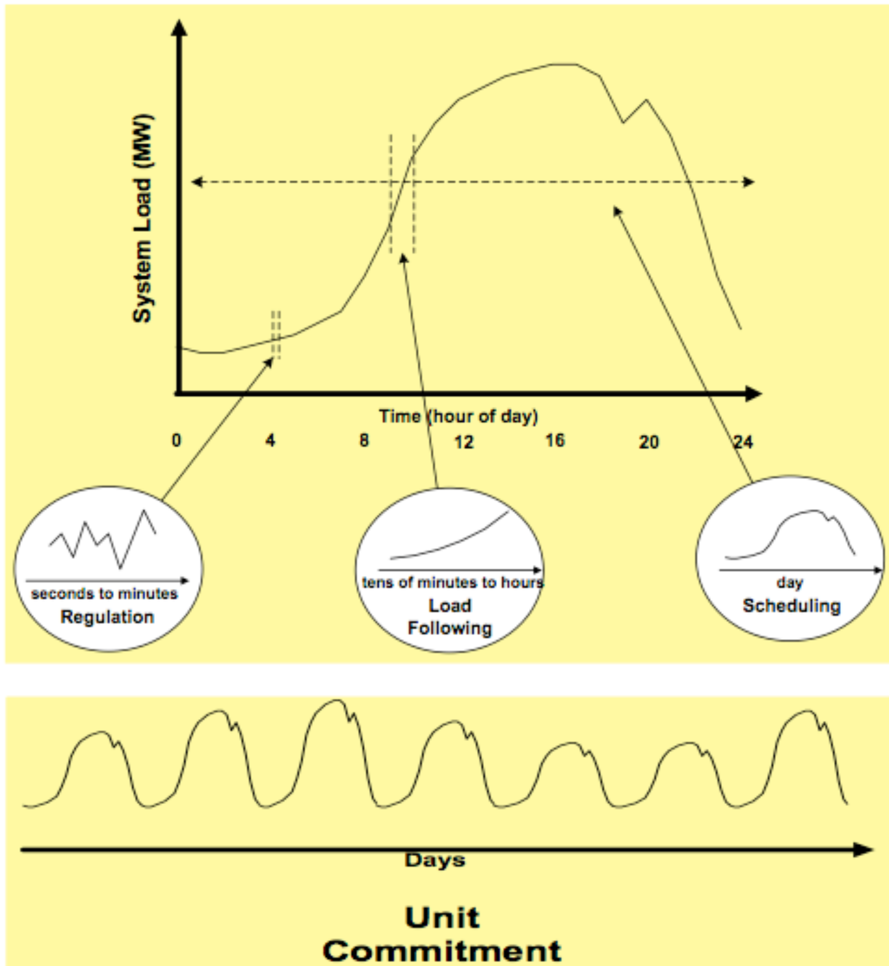
Source: North American Electric Reliability Corporation, Map of Regional Reliability Councils and Interconnections, www.nerc.com/ (last visited December 16, 2010).

APPENDIX J



Source: North American Electric Reliability Corporation, Regional Entities, www.nerc.com/ (last visited March 29, 2011).

APPENDIX K



Source: ERIK ELA AND JASON KEMPER, WIND PLANT RAMPING BEHAVIOR: TECHNICAL REPORT FOR NREL (2009)(available at: http://www.nrel.gov/wind/systemsintegration/pdfs/2009/ela_wind_ plant_ramping.pdf).

APPENDIX L

GLOSSARY

Alternating Current ("AC"): An electric current that reverses its direction of flow periodically; AC is wave of electrons that flow back and forth through a wire.

Ancillary Services: Services necessary to support the transmission of electric energy from resources to loads, while maintaining reliable operation of the transmission system. Examples include spinning reserve, supplemental reserve, reactive power, regulation and frequency response, and energy imbalance.

Base: Generation designed to operate around the clock at varying dispatch levels.

Blackout: Emergency loss of electricity due to the failure of generation, transmission or distribution.

Congestion: Transmission paths that are constrained – may limit power transactions because of insufficient capacity. Congestion can be relieved by increasing generation or by reducing load.

Control Area: Electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Curtailment: A reduction in the scheduled capacity or energy delivery due to a transmission constraint.

Cycling: Generation designated to operate as dispatched to cycle up and down on hourly or sub-hourly basis to compensate for other generation varying units.

Demand: The amount of power consumers require at a particular time. Demand is synonymous with load. System demand is measured in megawatts.

Demand Response: Deliberate intervention by a utility in the marketplace to influence demand for electric power or shift the demand to different times to capture cost savings.

Direct Current ("DC"): Electricity flowing continuously in one direction; the constant flow of electrons in a wire.

Dispatch: The physical inclusion of a generator's output onto the transmission grid by an authorized scheduling utility.

Distributed Generation: Electric generation that feeds into the distribution grid, rather than the bulk transmission grid, whether on the utility side of the meter, or on the customer side.

Federal Energy Regulatory Commission ("FERC"): A federal agency created in 1977 to regulate, among other things, interstate wholesale sales and transportation of gas and electricity at "just and reasonable" rates.

Firm Transmission: Transmission service that may not be interrupted for any reason except during an emergency when continued delivery of power is not possible.

Grid: Layout of the transmission system; a network of transmission lines and the associated substations and other equipment required to move power.

High Voltage Lines: Used to transmit power between utilities, as opposed to "low" voltage lines that deliver power to homes and most businesses.

Independent System Operator ("ISO"): Entity that controls and administers nondiscriminatory access to electric transmission in a single region or across several systems, independent from the owners of the facilities.

Interchange (or Transfer): The exchange of electric power between control areas.

Interconnection: A specific connection between one utility and another.

kW, MW, GW: Electrical power generated or consumed: 1 kilowatt (kW) = 1,000 watts; 1 megawatt (MW) = 1,000 kW; and 1 gigawatt (GW) = 1,000 MW = 1 million kW = 1 billion watts.

Load: The amount of power demanded by consumers. It is synonymous with demand.

Load Balancing: Meeting fluctuations in demand or matching generation to load to keep the electrical system in balance.

Load Forecast: An attempt to determine energy consumption at a future point in time.

Load Shifting: Shifting load from peak to off-peak periods, including use of storage water heating, storage space heating, cool storage, and customer load shifts.

Network: A system of transmission or distribution lines cross-connected to permit multiple suppliers to enter the system.

Nonfirm Transmission: Transmission service that may be interrupted in favor of firm transmission schedules or for other reasons.

North American Electric Reliability Council ("NERC"): Formed in 1968 to promote the reliability of generation and transmission in the electric utility industry. Consists of 10 regional reliability councils and one affiliate encompassing all of the electric systems in the U.S., Canada and northern parts of Baja, Mexico.

OASIS: Open-Access Same-Time Information System; an electronic posting system for transmission access data that allows all transmission customers to view the data simultaneously.

Outage: Removal of generating capacity from service, either forced or scheduled.

Pancaked Rates: Fees that are tacked on as electricity flows through a number of transmission systems.

Peak Demand: The maximum (usually hourly) demand of all customer demands plus losses. Usually expressed in MW.

Peaking: Generation designated to operate as dispatched during peak hours.

Performance-Based Regulations: Rates designed to encourage market responsiveness. They can be automatically adjusted from an initial cost-of-service rate based on a company's performance. Performance indicators generally reflect consumer and societal values.

Point of Delivery: The physical point of connection between the transmission provider and a utility. Power is metered here to determine the cost of transmission service.

Postage Stamp Rates: Flat rates charged for transmission service without regard to distance.

Power Pool: Two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs.

Real Time Pricing: Time-of-day pricing in which customers receive frequent signals on the cost of consuming electricity at that moment.

Regional Transmission Organization ("RTO"): An independent regional transmission operator and service provider that meets certain criteria, including those related to independence and market size, established by FERC Order 2000.

Reliability Practices: The methods of implementing policies and standards designed to ensure adequacy and security of the interconnected electric transmission system in accordance with applicable reliability criteria (i.e. NERC, local regional entity criteria).

Reliability: Term used to describe a utility's ability to deliver an uninterrupted stream of energy to its customers and how well the utility's system can handle an unexpected shock that may affect generation, transmission or distribution service.

Reserved Capacity: The maximum amount of capacity and energy that the transmission provider agrees to transmit for the transmission customer over the transmission provider's transmission system between the point(s) of receipt and the point(s) of delivery.

Renewable Energy Resources: Energy resources that are naturally replenishing in a relatively short period of time, such as solar, wind, geothermal, biomass and hydropower.

Schedule: An agreed-upon transaction size (MW), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the contracting parties and the control area(s) involved in the transaction.

Spinning Reserve: Electric generating units connected to the system that can automatically respond to frequency deviations and operate when needed.

Total Transmission Capability: The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner at a given time.

Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. Generally expressed in MW. In this context, "area" may be an individual electric system, power pool, control area, subregion or NERC region, or a portion of any of those.

Transmission: The process of transporting wholesale electric energy at high voltages from a supply source to utilities.

Transmission Provider: The public utility (or its designated agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service.

Transmission System: The facilities owned, controlled, or operated by the transmission provider that are used to provide transmission service.

Vertical Integration: Refers to the traditional electric utility structure, whereby a company has direct control over its transmission, distribution and generation facilities and can offer a full range of power services.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (that sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Source: MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 59-67 (2004).