Legal, Technical, and Economic Challenges in Integrating Renewable Power Generation Into the Electricity Grid

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I. INTRODUCTION

Concern about climate change and other environmental impacts of traditional power generating sources (e.g., natural gas, coal, nuclear, and hydropower) have led both states and the federal government to adopt aggressive policies over the last decade to promote the development of renewable sources of electric generation. These generating sources include wind, solar, geothermal, biomass, small hydro, and landfill gas, among others. President Obama has called for a Clean Energy Standard (CES)[1] that would double the fraction of America's generation from less carbon-intensive generating sources, as well as the 2009 American Recovery

1. President Obama called for a national Clean Energy Standard (CES) to meet 80% of the nation's energy demands through "clean" energy sources in his state of the union speeches in 2011 and 2012. Obama's CES would define qualifying "clean" energy sources different than most state renewable energy standards, however. Nat Keohane, *A Clean Energy Standard for America*, THE WHITE HOUSE BLOG (Mar. 2, 2012, 10:22 AM), http://www.whitehouse.gov/blog/2012/03/02/clean-energy-standard-america.

and Reinvestment Act (ARRA) that expanded both tax incentives for project development and federal investments or loan guarantees for renewable technologies.[2] Former Interior Secretary Ken Salazar also promoted accelerated renewable project development on federal lands under the Energy Policy Act of 2005 (EPAct)[3] and ARRA by developing a "fast-track" process to permit projects under the tight ARRA timelines.[4] Congress has failed to adopt comprehensive climate legislation, but the Executive branch has taken its existing authority and expansively used it to act where Congress has not.[5]

The states have also been aggressive in promoting renewable energy, most significantly by adopting Renewable Portfolio Standards (RPSs) that call for a specified fraction of each electric utility's annual demand to be met from a specified set of renewable generating sources.[6] Each state has its own RPS target and qualifying criteria, but California has been the most aggressive. The California RPS has driven renewables development—and increased pressure to build the transmission lines necessary to move that power from resource-rich regions to the demand centers in California—throughout the West. The California RPS standard, which was originally set at 20% by 2020 in 2002[7] and then expanded to

2. *See generally* American Recovery and Reinvestment Act of 2009, 42 U.S.C. § 16516(a) (Supp. III 2009).

3. Energy Policy Act of 2005, Pub. L. 109-58, 119 Stat. 594 (codified in scattered sections of 26 U.S.C. and 42 U.S.C.).

4. Siobhan McIntyre & Timothy P. Duane, *Water, Work, Wildlife, and Wilderness: The Collaborative Federal Public Lands Planning Framework for Utility-Scale Solar Energy Development in the Desert Southwest*, 41 ENVTL. L. 1093 (2011).

5. The Supreme Court determined that carbon dioxide is a "pollutant" under the Clean Air Act (CAA) in *Massachusetts v. EPA*, 549 U.S. 497 (2007), leading the U.S. Environmental Protection Agency (EPA) to make a required endangerment finding under the CAA in 2009. Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496, 66,497 (Dec. 15, 2009). The EPA then adopted a series of regulations on carbon dioxide that have been upheld by the D.C. Circuit Court of Appeals in *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102, 120 (D.C. Cir. 2012).

6. The outstanding "Database of State Incentives for Renewables & Efficiency," developed and maintained by the North Carolina Solar Center for the U.S. Department of Energy, offers a series of tables and maps summarizing a wide array of state-level programs. For a list of the states and utilities with RPS targets see U.S. Dept. of Energy, *Rules, Regulations & Policies for Renewable Energy*, DATABASE OF STATE INCENTIVES FOR RENEWABLES & EFFICIENCY col. 2 (RPS), http://www.dsireusa.org/summarytables/rrpre.cfm (last visited Dec. 20, 2012).

7. CAL. PUB. UTIL. CODE § 399.11(a) (West 2004).

33% by Executive Order in 2008,[8] was expanded statutorily to 33% of California's annual electricity demand by 2020 with the passage of SB 2(1x) in 2011.[9] The new RPS requirements now apply to municipal utilities like the Los Angeles Department of Water and Power (LADWP). California's RPS and the state's implementation of the California Global Warming Solutions Act of 2006 (AB 32) through a cap-and-trade emissions standard are reordering the generation resource mix throughout the West.

The result has been a dramatic increase in renewables and a policy debate over how best to integrate the variable generation output of renewables into the existing grid. The California Independent System Operator (CAISO), which operates the California grid, estimates that 2,500 megawatts (MW) of new renewable generation will come on-line in 2012 alone—nearly doubling the total of 2,871 MW that was added to the grid from 2003-2011. The slope of the increase is also growing, with 15-20 GW expected to be added by 2020.[10] California policy-makers have also indicated that they may further increase the RPS goal to 40% of California's power from renewables by 2025.[11]

The Bonneville Power Administration (BPA) has also experienced exponential increases in renewable generation, going from 250 MW in June 2005 to 2,500 MW by December 2009 and then up to 4,711 MW by May 2012.[12] Wind generation on the BPA system actually exceeded

8. Cal. Exec. Order S-14-08 (Nov. 17, 2008), *available at* http://gov.ca.gov/news.php?id=11072. For a summary of the history of California's RPS see McIntyre & Duane, *supra* note 4, at 1102–03.

9. S.B. 2, 2011-2012, Reg. Sess. §§ 1, 4 (Cal. 2011), *available at* http://leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf. The bill was introduced February 1, 2011; passed the Senate on February 25, 2011; passed the Assembly on March 15, 2011; and was signed into law by Governor Brown on April 12, 2011. Cal. Legislative Counsel, *Complete Bill History: S.B. No. 2 (1st Ex. Sess.)*, OFFICIAL CAL. LEGISLATIVE INFO., http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/ sbx1_2_bill_20110412_history.html (last visited Nov. 12, 2011).

10. Mark Rothleder, CAISO Executive Director, Market Analysis and Development, Presentation to the Environmental Law Conference at Yosemite (Oct. 27, 2012).

11. *See* Mark Z. Jacobson & Mark A. Delucchi, *A Path To Sustainable Energy by 2030*, SCI. AM., Nov. 2009. California Governor Jerry Brown has stated that "while reaching a 33% renewables portfolio standard will be an important milestone, it is really just a starting point—a floor, not a ceiling. Our state has enormous renewable resource potential. I would like to see us pursue even more far-reaching targets. With the amount of renewable resources coming on-line, and prices dropping, I think 40%, at reasonable cost, is well within our grasp in the near future," in his SB 2 (1x) signing statement on April 12, 2011. Letter from Jerry Brown, Governor, Cal., to Members of the Cal. State S. (Apr. 12, 2011), *available at* http://gov.ca.gov/docs/SBX1_0002_Signing_Message.pdf.

12. Bonneville Power Admin., *Wind Generation Capacity in the BPA Balancing Authority Area*, BPA–TRANSMISSION SERV., http://transmission.bpa.gov/business/operations/wind/WIND_InstalledCapacity_Plot.pdf (last visited Dec. 20, 2012).

hydro generation for the first time in October 2012.[13] The majority of the wind generation in BPA's balancing authority area (BA) produces power for sale to California and much of it is generated during times of high hydropower production within the BPA BA. Managing the transmission demands of wind in the BPA BA for export to California has therefore become a challenge that has erupted in legal conflicts between BPA and wind generators before the Federal Energy Regulatory Commission (FERC). These types of conflicts will likely become more prevalent unless significant policy changes and new institutional innovations address the sources of these conflicts.

Policy conflicts before FERC over renewables integration led the Commission to adopt Order No. 764 on the Integration of Variable Energy Resources (VER) in June 2012, to take effect in June 2013.[14] The BPA wind dispute continues, however, and CAISO anticipates similar conflicts on its system in the future due to a variety of other factors affecting the existing generation mix. Understanding the sources of conflict in the BPA wind dispute—as well as the limits of FERC's Order No. 764 to address the underlying causes of the conflict—is therefore essential to develop effective policies and institutional innovation to reduce such conflict. Some observers argue for even higher levels of renewable generation in the resource mix in order to meet climate change mitigation goals, and some European countries have already adopted policies to make such a transition to a renewables-dominated generating system.[15] We will not achieve a robust, reliable, and resilient electrical system with high levels of renewable generation unless we address the institutional impediments to integration.

This Article addresses the legal, technical, and economic challenges of integrating high levels of renewable power generation into electrical grid system operation. Part II shows that the primary integration challenge is

13. Associated Press, *Wind power briefly exceeds NW hydro power*, MAIL TRIBUNE (Oct. 25, 2012), http://www.mailtribune.com/apps/pbcs.dll/article?AID=/20121025/BIZ/210250319.

14. Integration of Variable Energy Resources, 141 F.E.R.C. ¶ 61,246 (June 22, 2012) (to be codified at 18 C.F.R. pt. 35); *see also* News Release, Fed. Energy Regulatory Comm'n, FERC Approves Final Rule to Integrate Variable Energy Resources, (June 21, 2012), *available at* http://www.ferc.gov/media/news-releases/ 2012/2012-2/06-21-12-E-3.asp. *See generally* FED. ENERGY REGULATORY COMM'N, INTEGRATION OF VARIABLE ENERGY RESOURCES, Docket No. RM10-11-000, 139 FERC 61246 (2012).

15. Lesley McAllister, *Overallocation and Reform in the EU ETS*, ENVIRONMENTAL LAW PROF BLOG (July 26, 2011), http://lawprofessors.typepad.com/environmental_law/2011/07/overallocation-and-reform-in-the-eu-ets.html.

reducing the total costs of integration and allocating the costs of integration in a hybrid regulatory structure, which presents different institutional impediments than traditional cost-of-service ratemaking or rate-of-return regulation. We demonstrate that the primary impediment to improved integration is a failure to make the critical policy choice about how such costs will be allocated. Part III describes and analyzes the BPA-wind dispute in order to evaluate the adequacy of the existing legal regime to address this policy issue. Part IV describes and analyzes a suite of strategies proposed by the Western Governors' Association (WGA) to reduce the cost of integrating renewable generation. Finally, Part V demonstrates that FERC Order No. 764 is only a first step toward improved integration because it does not address the fundamental policy decision regarding the distribution of integration costs and methods for cost recovery. We then offer recommendations for action by FERC, state regulators, state legislatures, and Congress to promote improved integration of renewable generation.

Throughout the Article, we distinguish between four distinct (but interrelated) integration problems: (1) the technical challenges of integrating variability; (2) the economic costs of integrating variability; (3) the policy choice regarding distribution of integration costs; and (4) the legal framework for implementing that policy. Proper analysis of the technical, economic, and legal issues depends on the critical policy choice regarding cost allocation. Resolution of the cost allocation policy decision is therefore essential to development of a new institutional structure that will promote high levels of renewable generation.

II. THE CHALLENGE OF COST ALLOCATION IN A HYBRID REGULATORY STRUCTURE

A. The Integration of Variable Generating Resources is Not a New Problem

The electric utility industry has faced the challenge of variable resource integration since its inception: both demand and supply sources vary over time and with uncertainty, so maintaining system reliability has always required both technical modifications to the electrical grid as well as economic expenditures to maintain overall grid reliability. *All* electrical generating resources are variable, intermittent, uncertain, or unpredictable to some degree: renewables differ primarily in the temporal scale of their output variability. But *every* new power plant, transmission line, or load—regardless of generation type—affects power system operations and therefore requires integration through technical modifications with economic consequences by altering how other resources in the portfolio are operated.

We do not mean to suggest by this, however, that integration is not a significant challenge. The specific characteristics of variability, intermittency, and uncertainty associated with the generating output of modern renewable generation technologies present a significant technical challenge to maintain system reliability. Moreover, the economic costs of integration may be significant with high levels of penetration by renewables as a fraction of the generating resource mix. But it is instructive to consider how the variability, intermittency, and uncertainty associated with traditional generating technologies (i.e., those that do not generally qualify under state RPS mandates today) have been dealt with historically in order to determine how best to address the modern challenge of integrating renewables into a reliable grid. We shall demonstrate here that variability, intermittency, and uncertainty are inherent characteristics of the electrical grid and that the primary impediment to renewables integration is one of cost allocation.

Consider an ideal case: The exact same level of demand is maintained for all hours of the year (regardless of weather, day of the week, or time of day) and that demand is met by a single generator that has 100% reliable output to precisely match the demand level. Both demand and supply are invariable in this ideal example. But this ideal quickly turns into a case of variable generation as soon as the presumption of 100% reliability is altered. Even with 99% reliability, the generator's output is now variable. Moreover, the fact that the generator is sized to exactly match the demand means that all of the load must be shed (i.e., must lose power) during the one percent of the time (i.e., 87.6 hours per year) that the generator is unavailable. This level of lost power would be nearly forty times more hours than the industry standard, which is for a loss of load probability (LOLP) of just one day in ten years (2.4 hours per year).[16] Utility planners, therefore, strive to provide reliable power for 87,576 out of every 87,600 hours—whether the outage is caused by the failure of a generator, a downed transmission line, or problems with the distribution system.

The system planner can improve reliability by building more, smaller units. Assume that the overall demand is 1000 MW in our example and

16. *See* EDWARD KAHN, ELECTRIC UTILITY PLANNING & REGULATION (Am. Council for an Energy-Efficient Economy, 1988).

that the least-cost power plant (ignoring the consequences of it being out of service for either routine maintenance or a forced outage) is a single 1000 MW plant that produces power at 10.0 cents per kilowatt-hour (kWh). Assume that a 500 MW plant costs 10% more per kWh than a 1000 MW plant, a 250 MW plant costs another 10% more, and a 100 MW plant costs 10% more still. The cost of outages is real and significant, so the system planner wants to reduce the likelihood of any one customer losing power to only nine hours per year (i.e., to just one-tenth the current likelihood, but still nearly four times the industry reliability target). The system planner will therefore invest in higher-cost resources in order to reduce total system costs—including customers' costs of outages—by building several smaller plants rather than the single large plant. Moreover, the system planner will overbuild capacity to improve reliability. The resulting portfolio of generators may include one 500 MW plant, a 250 MW plant, and four 100 MW plants (for a total of 1150 MW of capacity, allowing a 15% "reserve margin" over demand). Some customers will still lose power when a plant goes out, but rolling blackouts can minimize the impact. The total cost of such a generation mix would be about 26% higher than if only the single, "least cost" 1000 MW generator had been built. But customers are willing to pay a premium of 12.6 cents per kWh rather than 10.0 cents per kWh for the benefit of reliability.

We can extend the example further by accounting for the risk of transmission outages. Assuming that the generators are not distributed among the customers directly at the site of customer load, the power must be transmitted from the generators to customers. Having all the power transmitted on the same transmission line would expose the entire system to an outage risk due to storms, technical failures, or even sabotage. Therefore, the system planner will choose to locate the power plants in different locations in order to geographically diversify that vulnerability. This may also increase system costs, by way of more, smaller, and less efficient transmission lines, as well as reduced economies of scale related to the common needs of the power plants (e.g., natural gas supply pipelines, access to coal mines). Once again, those higher system integration costs are worth it for reliability.

But this analysis has focused only on the supply side of the equation; let us make customer demand a bit more realistic. Now assume that demand varies dramatically annually, by day of the week and by hour of the day—but such variation is not perfectly predictable and reacts in response to weather conditions, the shopping season, and whether or not the Super Bowl is on TV on a given day. Moreover, let's assume there are just ten customers: a 500 MW peak-demand customer, a 200 MW customer, two 100 MW customers, four 50 MW customers, and two 25

MW customers. That adds up to a potential peak demand of 1150 MW, but the customers do not all demand their peak demand at the same time. Therefore, the peak demand for the overall system is only 1000 MW on the hottest days. The diversity of customer loads works to the advantage of the system planner in the same way that geographic diversity reduces the risk of outages. The planner need not build as many power plants as would be necessary to meet the sum total of each customer's demand. But the timing of customer additions would affect how the system planner could best achieve a least-cost resource mix that meets reliability standards.

The particular combination of customer demand presents an even more complex problem for planning, however, and it may require the system planner to diversify the generation mix even further. This is because overall system demand now has the potential to vary even more dramatically: as one customer turns the power off, another may turn it on—but, when the first turns it back on, the overall demand may suddenly go up. The system planner now needs generators that can vary their output to match the load. The generation mix will therefore be altered further to include different types of power plants. Some will be "baseload" (operating all the time; typically the lowest-cost power plants), while others will have more flexibility to vary output with changing customer loads (at a higher cost per unit of output). This variability in customer demand imposes a significant integration cost on the system. Moreover, the cost of such integration will be greatest for those customers that vary their load the most compared to the pattern of variation in the overall system load. Conversely, the cost of integrating customers whose demand co-varies negatively with variation in the overall system load may actually be negative (i.e., total system costs are *reduced* by having them as customers).

Several important principles emerge from this relatively simple example. First, the timing of when a resource is added to the system affects how one calculates both the benefits and the costs of that resource. Second, integration of multiple resources increases system costs but also generally increases reliability by reducing the system's vulnerability to the loss of any single generator. Third, both generators and customers impose integration costs on the system—and those integration costs may actually be *negative* if the generators or the load vary their output and demand so as to allow more efficient generators to meet the system load when it would otherwise be vulnerable to disruption. Finally, geographic diversity in both loads and resources can reduce overall system costs. Larger utilities with more diverse loads and generating resources will generally be able to meet demand more reliably for less cost than smaller utilities without such diversity. This is known as the portfolio effect. The value or cost of each additional generator or load is a function of how that generator or load *co-varies* with the system portfolio's costs; the individual generator or load's variability is *not* the most important determinant of cost.[17] Equally important, blanket statements about the cost (or benefits) of variability are generally unreliable: the cost or benefit of a given generator or customer's variability depends on the characteristics of the specific resource mix and customer demand patterns for a given balancing area.

The real world of utility planning today is infinitely more complex than our simple example, which is based on a system where there is a central system planner rather than a set of market mechanisms to induce behavior by generators and customers—and which involves very few generators and customers operating over very coarse time scales.[18] The technical complexity alone of the modern electric grid requires the simultaneous, instantaneous satisfaction of millions of customers' demand across thousands of miles of geography from hundreds of generating sources over thousands of miles of transmission lines and tens of thousands of miles of distribution lines. Given its complexity, it is a marvel of modern engineering brilliance that the electrical system does not go down every day.[19]

That complexity also means it is extremely difficult to calculate the true cost or value of integrating a given generating resource or customer into the electrical grid. And when it is difficult to calculate something, there will likely be a lot of different technical rationales for calculating it a particular way—usually in a way that will push the costs of integration onto a party other than the party proposing a particular method of calculating those costs of integration. Thus it is not surprising that integration cost estimates vary widely and that the basis for calculating those costs is a highly contested subject today. Yet, there was no dispute

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17. Timothy P. Duane, The Risk-Adjusted Cost Evaluation of Electric Resource Alternatives (June 1989) (Ph.D. Dissertation, Stanford University) (on file with author).

18. *See* KAHN, *supra* note 16.

19. Electricity has different technological characteristics than other complex technical systems like air transportation. David Marcus has said that it would be comparable to having a deregulated airline system where, any time a flight was delayed for a single minute, every other airplane flying at the time of the delay would simultaneously drop out of the sky. Timothy P. Duane, *Regulation's Rationale: Learning from the California Energy Crisis*, 19 YALE J. ON REG. 471, 490 (2002).

about how to calculate integration costs under cost-of-service ratemaking and the rate-of-return regulatory structure.

B. Historic Cost-of-Service Regulatory Structure Internalized Costs of Integration

How did we as a society overcome the problem of integration? How did we manage to develop a grid with the proper mix of generating resource diversity, operating flexibility, aggregate demand diversity, and overall costs that are low enough to continually fuel growth in electricity demand that is disproportional to overall energy demand growth? What were the institutional arrangements that allowed the system to be built?

The answer, until the past fifteen years or so, was cost-of-service ratemaking or rate-of-return regulation based upon cost-of-service. Integration costs were internalized through the structure of vertical electric utility integration (i.e., generation, transmission, and distribution provided by a single entity with a geographic monopoly and obligation to provide service to all customers within a geographic area). The integration costs were recovered from all ratepayers either through rate-of-return regulation by a state regulatory commission (based on the cost-of-service) or passing cost-of-service through to customers via public utilities.[20] It is therefore instructive to review how that system addressed integration costs before renewables generated the recent controversy over such costs.

As we have suggested above, electrical utilities have traditionally planned for and invested in generation and transmission resources based upon two primary principles and therefore evaluative criteria: (1) to maintain system reliability in order to have no more than a specified likelihood of outages for individual customers, and (2) to minimize the total system cost to achieve that level of reliability. Under cost-of-service ratemaking or rate-of-return regulation, the utility would allocate the total system costs across all of its ratepayers based on some combination of fixed charges (e.g., a monthly bill tied to some fixed set of costs that need to be recovered from ratepayers) and variable charges (e.g., based upon the amount of kWh consumed in a given month). Moreover, the variable charge typically increases as a function of consumption levels. For example,

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20. *See* RICHARD F. HIRSH, POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM (1999); *see generally* KAHN, *supra* note 16; Duane, *supra* note 19.

there is a "block" of usage at a relatively low rate, then another block at a higher rate, and then additional blocks at even higher rates. The reason for this increasing block rate system is that higher demand generally requires higher-cost resources to be dispatched—typically infrequently—in order to meet all of the demand. Finally, there are sometimes cross-class subsidies among different classes of ratepayers (e.g., commercial and industrial customers may subsidize residential customers). These cross-class subsidies persist for two very different reasons: (1) universal access to electrical service is an important public policy goal,[21] and (2) the politics of increasing residential rates make it very difficult to charge residential customers the full cost of serving their demand. Residential customers vote and public utilities commissions are appointed by the Governor of a given state, so most commissioners are politically sensitive.

There are several important features to note under this traditional system. First, when determining whether or not to add a generating resource, the critical question is simply whether or not the *total system costs* are lower with that incremental addition compared to any alternative addition of a different generation or transmission resource. This means that the integration costs associated with the new generating resource are never calculated; instead, they are presumed to be system costs if the resource is the least-cost addition. Second, the impact of a new customer's demand (or the variability in a customer's demand) on total system costs is never calculated and that customer is never directly charged for any increases in system costs (nor is the customer credited for any decreases in system costs). Instead, *all* customers bear the increased costs of any changes in load—be it due to the addition of new customers or through changes in existing customers' loads. Rates may indirectly be higher for the new customer if that customer consumes a lot of electricity, but those higher rates will also be borne by all of the existing customers.

Utilities nevertheless worry about these integration costs, which could significantly increase total system costs and, therefore, rates, if they get too high. Moreover, utilities indirectly account for the integration costs when calculating the total system costs of various possible resource additions: if one relatively low-cost generating resource imposes high integration costs on the system, another higher-cost generating resource (or transmission investment) with lower integration costs may lead to lower total system costs. In such cases, the latter (low integration cost) resource will be added to the resource mix ahead of the former (high

21. Federal establishment of the Rural Electrification Administration and Tennessee Valley Authority—along with the Western Area Power Administration and Bonneville Power Administration to market low-cost hydropower from federal projects at preferential rates to publicly-owned utilities—reflect this policy goal.

integration cost) resource. Notably, though, the analysis always focuses on the impact of a resource on the total system costs—rather than the integration costs of an individual generating resource *per se*. The reason is that utilities recover their total system costs (including, for investor-owned utilities subject to state rate-of-return regulation, a reasonable rate of return on invested capital) regardless of a given resource's or customer's integration costs. Integration costs are just another cost of doing business that can be passed through to customers.

Some traditional non-renewable generating resources have imposed significant integration costs, and utilities have dealt with them by making co-investments in either other generating resources or transmission resources to reduce total system costs. The Diablo Canyon nuclear power plant is an illustrative example. Because the addition of Diablo Canyon alone would result in significant "overgeneration" during most off-peak periods and cause significant operational problems in the transmission system, Pacific Gas & Electric Company (PG&E) built the Helms Pumped Storage hydroelectric project to complement Diablo Canyon. Helms then used Diablo Canyon's "excess" generation during off-peak periods to pump water back uphill from Wishon reservoir to Courtright reservoir. Net generation from the Helms plant was negative, meaning that it took more power to pump the water uphill than was generated by the plant on a daily and annual basis. But the "cost" of the electricity used to pump the water uphill was actually negative, because it reduced Diablo Canyon's integration costs. The pumped storage hydro could then run downhill again during peak periods to produce higher-value power when Diablo Canyon could not increase its own output. Neither Diablo Canyon nor Helms was as cost-effective alone as they were together; when considered as a package, their complementary profiles reduced integration costs.

Such complementary relationships between resources depend upon the particular demand patterns (both temporally and spatially), generating resource mix profile (including the likelihood and magnitude of generating unit outages), and cost structure of the individual utility in question (e.g., high fixed costs versus high variable fuel costs). As noted above, the benefits of aggregation and diversification across both loads and generating resources have generally led to larger utilities in order to reduce the total system costs of maintaining desired reliability. But even these larger utilities could be more reliable or reduce their total system costs by contracting for some power with other utilities, so significant transmission investments have been made to link utilities to take advantage of greater diversity.

California and the Pacific Northwest are an excellent example. California utilities have historically been summer-peaking, primarily due to air conditioning and irrigation pumping in the hotter California climate, while Pacific Northwest utilities historically had winter peak demand due to the extensive penetration of electric heating, which was much greater in the region due to the relatively low cost of federal hydropower.[22] Moreover, California's generating system was capacity constrained but it had the ability to produce a great deal of energy during the winter without threatening its ability to meet peak demands during the summer. In contrast, the Pacific Northwest's system was energy constrained, because it could produce only as much power as the total amount of water behind its system of dams. Capacity was less of an issue for the Pacific Northwest, which could generate capacity in the summer to help meet California's peak demand—in exchange for California providing energy in the winter. It was a match made in generation planning heaven, so the California and Pacific Northwest utilities invested in significant transmission systems to allow the exchanges to take place.[23] Each region, and each individual utility involved in the trade, was able to reduce its total system costs by investing in transmission and contracting to buy power from others rather than building and operating more of its own generation.

Each utility was also able to recover the costs of its investments in transmission based on the security of cost-of-service ratemaking or rate-of-return regulation. The investor-owned utilities simply had to show their respective state public utilities commissions that those investments were prudent (i.e., resulted in lower total system costs compared to the alternatives); the public utilities had to convince the voters who elected them that there was no less expensive alternative that would maintain reliability. The latter was easier for California's municipal utilities than many of the public utilities in the Pacific Northwest, however, because most modern investments in either generation or transmission have

22. *See* Jolanka V. Fisher & Timothy P. Duane, *Trends in Electricity Consumption, Peak Demand, and Generating Capacity in California and the Western Grid* 2 (Univ. of Cal. Energy Inst., Working Paper No. PWP-085, 2001), *available at* http://www.ucei.berkeley.edu/PDF/pwp085.pdf.

23. Design of those transmission resources therefore also reflected the particular needs of the two regions and the timing of when they each found it advantageous to exchange power for energy—which is a different set of operating conditions than those transmission lines are now expected to meet. Not surprisingly, then, the transmission system design and investment that would optimize the export of wind power to California would be different.

increased overall costs more significantly compared to the historically low-cost federal hydropower that the region may have come to take for granted. But BPA—the federal marketing agent for the Federal Columbia River Power System (FCRPS)—was assured that it could recover its costs of operation through regular cost-of-service rate cases.[24]

BPA's extensive reliance on low-cost hydropower has nevertheless meant a great deal of uncertainty and variability in BPA's generation output—even before the addition of significant new wind generation. According to BPA, "BPA's weather-dependent hydro resources create high supply uncertainty for power planning and marketing activities."[25] This high supply uncertainty is "due to the unpredictability of water supply volumes and runoff timing within a given year and from year to year."[26] The FCRPS has relatively limited storage, making hydropower an intermittent, variable, and uncertain resource that creates integration costs. Moreover, hydropower is a resource that generates significant environmental costs and is thus subject to stricter environmental regulatory constraints than other resources. The FCRPS faces severe operating limits under the federal Endangered Species Act (ESA) and Clean Water Act (CWA) to reduce Total Dissolved Gas (TDG) downstream of its dams to protect salmon species.[27] Higher TDG levels are associated with higher salmon mortality and TDG levels are higher if BPA "spills" too much water over its dams rather than through its turbines.[28] Therefore,

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24. BPA conducts its own rate case, like a municipal or other publicly-owned utility, but it must also get approval of its final rate decisions from FERC. Bonneville Power Admin., *Rate Cases*, BONNEVILLE POWER ADMIN., http://www.bpa.gov/Finance/RateCases/Pages/default.aspx (last visited Dec. 19, 2012).

25. BONNEVILLE POWER ADMIN., BPA STRATEGIC DIRECTION 5 (Mar. 2012) [hereinafter BPA STRATEGIC DIRECTION].

26. *Id*. at 20.

27. Total Maximum Daily Loads (TMDLs) have been established for TDG levels under the federal Clean Water Act (CWA), and the impact of any violation of those TDG levels may jeopardize the viability and recovery of various salmon species listed as threatened or endangered under the Endangered Species Act (ESA). Salmon recovery and hydropower development and operation have a complex legal relationship in the Pacific Northwest that is beyond the scope of this Article. Both the ESA and CWA are constraints on the FCRPS.

28. See PAUL J. PICKETT, HELEN RUEDA & MIKE HEROLD, TOTAL MAXIMUM DAILY LOAD FOR TOTAL DISSOLVED GAS IN THE MID-COLUMBIA RIVER AND LAKE ROOSEVELT SUBMITTAL REPORT (June 2004), *available at* https://fortress.wa.gov/ecy/publications/summarypages/0403002.html for background information on the TDG issue. See K. E. MCGRATH, E. M. DAWLEY & D. R. GEIS, TOTAL DISSOLVED GAS EFFECTS N FISHES OF THE LOWER COLUMBIA RIVER (June 2006), *available at* http://www.pnl.gov/main/

BPA must sometimes generate power even when that hydropower is not needed because other system resources are otherwise able to meet the demand.

Of course, it might be the other way around—those other system resources are not needed at times when BPA must generate power to avoid spilling water that could increase TDG levels. What is striking about the traditional system of cost recovery is that it would not matter which is the correct way to characterize the situation: under the traditional system, whichever approach would reduce total system costs would be the basis for dispatching the individual generating resources in the system. Additionally, if investing in new generation or transmission could reduce total system costs even further, BPA would be assured of recovering those costs and would have incentives to make such investments. The distribution of costs did not affect dispatch, investment, or cost recovery. Instead, all of the costs were internalized to allow minimization of total system costs.

Under such a scenario, there would be no conflict over a dispatch decision by BPA to curtail one generator rather than another. And BPA would consider *all* of the opportunity costs associated with its curtailment decision if it owned all of the resources that might be subject to curtailment.[29] But that is *not* the regulatory or incentive structure we have today. And that is the primary source of the conflict over integration costs: who should pay them. We show in Part III that this is the heart of the BPA-wind dispute.

C. Hybrid Regulatory Structure Shifts Cost Burdens Without Clear Policy Choice

The new world that BPA and wind generators operate in today is one with a hybrid regulatory structure: some entities continue to operate under a cost-of-service ratemaking or rate-of-return regulatory system while others operate under a "market rate" system where their investments are neither subject to regulatory scrutiny for prudency nor guaranteed a positive return on investment or even recovery of investment capital. The market for these entities enforces prudency, and their rate of return is determined by the net income after costs have been deducted from revenues. Reducing costs, therefore, translates directly into an enhanced bottom line and return on investment. For entities like BPA, however,

publications/external/technical_reports/PNNL-15525.pdf for a technical analysis of how TDG levels affect salmon on the lower Columbia River.

29. These opportunity costs include all of the net costs after all of the revenues and taxes have been accounted for.

the costs of integration must be allocated across their customers if the costs are not borne by the entities selling power to BPA or seeking to utilize BPA's transmission services to sell the power to California or other customers.

This arrangement is not unique to BPA. Most utilities continue to recover the costs of their transmission system through a hybrid regulatory structure that includes some component of either cost-of-service ratemaking or rate-of-return regulation coupled with market transactions for transmission services. Moreover, many other generators also continue to recover their costs through traditional cost-of-service ratemaking or rate-of-return regulation. Renewables generate revenue through various revenue streams. In contrast, most renewable generators are not assured cost recovery and must recover their investments through a combination of three revenue streams: (1) from electricity sales through either Power Purchase Agreements (PPAs) or spot market transactions; (2) from the sale of Renewable Energy Certificates (RECs) that can be used by the purchasing utility to meet a state RPS; and (3) from Production Tax Credit (PTC) income through the generation and sale of qualifying power.[30] Renewable generators are not only in the business of generating energy; they also sell RECs and PTCs to tax equity investors to generate revenue.

RPS design is an important factor structuring the market for renewables generation. In general, an RPS typically specifies both the characteristics of generating resources whose output qualifies as meeting the RPS[31] and a minimum fraction of annual consumption that the purchasing utility (called a load-serving entity [LSE] under California's RPS) must certify it has purchased. As noted above, California's RPS target is now 33% of total annual consumption (in kWh) by 2017-2020 for each LSE. The California RPS also has intermediate targets of 20% in 2011-2013 and

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30. For a history of the PTC, see Timothy P. Duane, *Greening the Grid: Implementing Climate Change Policy Through Energy Efficiency, Renewable Portfolio Standards, and Strategic Transmission System Investments*, 34 VT. L. REV. 711, 762 n.201 (2010). The PTC expired on December 31, 2012 but was extended the next day by Congress on January 1, 2013 in the "fiscal cliff" legislation for any projects that start construction by the end of 2013. *See* Am. Wind Energy Ass'n, Congress Extends Wind Energy Tax Credits For Projects That Start in 2013, AM. WIND ENERGY ASS'N (Jan. 1, 2013), http://www.awea.org/newsroom/pressreleases/congressextendswindptc.cfm.

31. Typical examples of qualifying technologies include wind, solar, biomass, geothermal, tidal, wave, hydropower smaller than a particular size or built since a particular year. Some RPSs do not allow municipal solid waste [MSW] to qualify, however, unless it is for landfill gas recovery, including full methane capture.

25% in 2014-2016.[32] Only about 14% of California's overall consumption met the RPS standard in 2011, but the six largest utilities in the state had consumption ranging from 16% to 22% that was generated by renewables.[33] Each utility is unique, so both the temporal and spatial variability of load and the rest of each utility's generation resource mix are quite different.[34] Therefore, both the value of each kWh produced by these renewables and the impact of each generating plant's output on total system costs vary as a function of each specific utility's load and resource mix—together with the transmission system through which the power must be transmitted from the generator to the load. It is therefore impossible to make a generic statement about either the cost or the value of renewable generation under the RPS.

Yet the RPS itself treats every kWh generated by a qualifying renewable generator as equal in value: the RPS only counts kWh, so other generating characteristics (e.g., timing of output by season or diurnally, geographic location, reliability and match with load curve) are not explicitly valued. It is comparable to developing an Organic Food Standard (OFS) that values only calories: if 33% of one's annual calories need to come from organic sources, however, it is highly likely that the least-cost organic calories would be purchased to meet the OFS. Those calories are likely to come primarily from carbohydrates, which could lead to a less balanced diet than that which existed before adoption of the OFS. The result could then be a less healthy diet and higher costs to supplement dietary deficiencies. A crude RPS is like this, and it can create incentives without regard for either the portfolio value of the renewable generation or the costs of integrating those renewables into the system. In other words, total system costs may be higher than with an alternative set of renewable generators—even if those alternative generators cost more per kWh of output.

The regulatory entities implementing the California RPS have begun to recognize this problem. There are ongoing efforts to improve the resource procurement process so as to recognize a multitude of benefits provided by renewables.[35] This will be especially important as the rapid

32. S.B. 2, *supra* note 9.

33. San Diego Gas & Electric (SDG&E): 16%; Southern California Edison (SCE): 19%; Los Angeles Department of Water and Power (LADWP): 19%; Pacific Gas & Electric (PG&E): 19%; Sacramento Municipal Utility District (SMUD): 22% (these figures are based on the individual "Power Content Label" produced by each utility; 2012 data was unavailable at press time; the state total includes smaller utilities and is only 14%).

34. LADWP generated 41% of its power from coal, for example, while SMUD produced 29% of its power from large hydropower; nuclear shares ranged from 0-24% while large hydropower shares ranged from 0-29%.

35. S.B. 2(1x) gives the CPUC the discretion to incorporate these factors, and CPUC procedures are attempting to address these factors through a "least-cost, best-fit"

RPS ramp-up occurs up until 2020. There is a clear need to create incentives for providing integration services and to diversify the portfolio of generating resources—both in terms of technology and geography—in order to develop a robust, reliable, least-cost system with high levels of renewables.

There is potential to develop such a diversified portfolio of renewables. Illustrative output by renewables into the CAISO on a single day shows how different types of renewables generate power at different times that can complement both each other and demand. Geothermal, biomass, biogas, and small hydro generation are relatively steady (with some ramping capability by hydro in response to peak demand and higher prices) on a daily basis—though the small hydro faces greater inter-annual and seasonal variation—while solar rises with the sun on a predictable basis and goes down as the sun goes down. Wind is the most unpredictable, but our ability to predict it increases considerably (while the variability associated with its total output decreases) as both the number of wind turbines and the geographic scale of their generation increase. Simulations of output in the Pacific Northwest show that wave or tidal power can also be incorporated into the generation resource mix to provide power output that does not co-vary with the rest of the portfolio, decreasing uncertainty and variability of generation from the overall portfolio.[36] Wave or tidal power is also more predictable than wind.

But we do not generally pay renewable generators for these system or portfolio benefits; instead, they must compete with each other to be the least-cost bidder to win a PPA under the RPS.[37] Carbohydrates usually win if you are unwilling to pay a premium for the benefits of protein; that is also the case in competitive bidding for RECs and for PPAs under the RPS. The result is a lot of wind—because it is generally a more mature technology and, therefore, a lower cost than most other renewables—in

procurement system. *See* Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, R1005006 (Cal. Pub. Util. Comm'n May 6, 2010). The actual RPS is measured only in kWh, though, without regard to whether the kWh are "carbohydrates" or "protein."

36. Douglas A. Halamay et al., *Reserve Requirement Impacts of Large-Scale Integration of Wind, Solar, and Ocean Wave Power Generation*, 2 IEEE TRANSACTIONS ON SUSTAINABLE ENERGY 321, 321–22 (2011).

37. There is a tension between "least cost" and "best fit" in procurement policies, and a focus on minimizing the cost of renewables procurement has generally been at the expense of getting the "best fit" in the generating portfolio; also, note that markets do not now generally compensate for these non-commodity system benefits.

the places with the highest wind potential—because that is how individual project developers can generate power and RECs at the lowest cost. "Current wind projects," notes the BPA, "are heavily concentrated in the Columbia River Plateau . . . in part because there are insufficient incentives in place to diversify the geographic siting of wind projects."[38] The Columbia Gorge offers a tremendous wind resource in the Pacific Northwest, which means that wind generation patterns in the region are highly correlated. That high correlation translates into high coincident demand for BPA's transmission services to export the region's wind to California to garner the highest total revenue due to higher prices for the power itself or the RECs to meet California's RPS. Unfortunately, much of the Columbia Gorge wind blows during high spring runoff periods. The result is a direct conflict for transmission capacity between hydropower, primarily intended for sale to BPA's preference customers, who are primarily public utilities, and wind, intended for sale to California utilities—although REC sales to California LSE's to meet the California RPS and tax income from the PTC are also critical sources of revenue for wind developers and operators.

Legal conflicts over integration reflect a failure to make clear policy choices about cost allocation under our hybrid regulatory structure. The BPA-wind dispute illustrates the limits of the existing legal regime to resolve the cost allocation conflict in a way that will assure both cost recovery and predictability for utilities and generators without that policy choice.

III. Wind, Water, and the Bonneville Power Administration

In this Part, we describe and analyze the BPA-wind legal dispute before FERC and demonstrate that the hybrid regulatory structure under which that dispute is being resolved has not yet addressed the critical policy choice regarding how to allocate integration costs. The BPA-wind dispute is the most prominent example to date of a legal conflict over integration costs, but similar disputes are likely to arise on an *ad hoc* basis until FERC establishes clear policies to reduce integration costs and to allocate those costs among generators, transmission providers, and ratepayers. Part IV summarizes strategies to reduce integration costs and Part V recommends cost allocation principles.

In June 2011, a group of wind-facility owners filed a petition against the BPA, alleging that the BPA's redispatch policy, based on Dispatch

38. BPA Strategic Direction, *supra* note 25, at 20.

Standing Order 216 (DSO 216),[39] was unduly discriminatory against wind generators in favor of federal hydropower generators and their customers.[40] FERC, having determined that transmission policy—not generation policy—was at the heart of this dispute, held that DSO 216 violated section 211A of the Federal Power Act (FPA)[41] because it resulted in noncomparable transmission service.[42] DSO 216 unfairly treated nonfederal wind generators by interrupting their customers' point-to-point transmission service during high-volume runoff events without causing similar interruptions to firm transmission service held by federal hydropower generators.[43]

While FERC directed the BPA to revise its policy to resolve the comparability issues with its transmission service, the Commission declined to "specify the precise terms and conditions" that this revised policy should contain to comply with section 211A.[44] As a result, the BPA

39. Bonneville Power Admin., *DSO 216 Overview & Requirements*, BPA-TRANSMISSION SERVICES, http://transmission.bpa.gov/wind/op_controls/dso216_overview_requirements.pdf (last updated Nov. 29, 2011) [hereinafter *DSO 216 Overview*]. Please note that the BPA provides DSOs only to dispatchers and wind operators. *See* Bonneville Power Admin., *Requesting DSO 216*, BPA-TRANSMISSION SERVICES (Nov. 2, 2009), http://transmission.bpa.gov/wind/op_controls/requesting_dso_ 216.pdf.

40. Iberdrola Renewables, Inc. v. Bonneville Power Admin., 137 F.E.R.C. ¶ 61,185, at para. 1 (Dec. 7, 2011) (Order Granting Petition).

41. *Id*. at paras. 32–35. Specifically, section 211A reads:

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

16 U.S.C. § 824j-1(b) (2005).

42. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at paras. 63–64.

43. *Id*. at para. 62.

44. *Id*. at para. 65. Specifically, FERC stated:

> While we will not specify the precise terms and conditions that must be set forth in Bonneville's OATT in order to remedy the non-comparable services . . . , pursuant to section 211A Bonneville must address the comparability concerns . . . As we noted above, the Commission appreciates that Bonneville must reconcile the obligations set forth in its organic statutes with numerous rules and regulations, including those under the Endangered Species Act and the Clean Water Act. As directed in this order, Bonneville also must reconcile the provision of comparable service that is not unduly discriminatory or preferential with its organic statutes.

Id.

submitted to FERC its Oversupply Management Protocol (OMP),[45] along with a revised Open Access Transmission Tariff (OATT), in March 2012. The BPA's revised policy only renewed the debate.[46]

In this Part, we provide an analysis of the parties' legal issues and arguments, tracing this dispute from its origin with the BPA's issuance of DSO 216 to the OMP in March 2012. While the wind industry's dispute with the BPA is legally unique, as will be discussed herein, we nonetheless seek to identify critical issues that impact a redispatch policy generally—which can then serve as a lens through which we might analyze redispatch and transmission concerns more generally to develop policies that reduce both the cost of, and conflict over, renewables integration. We demonstrate that existing law is inadequate to resolve the legal dispute unless the policy choice on cost allocation is made explicitly.

A. FERC's Transmission Policy

Before embarking on our description and analysis of the legal dispute between Pacific Northwest wind generators and the BPA, it is important to highlight key FERC Orders that impact the transmission policies of providers like the BPA, the CAISO, and Regional Transmission Organizations (RTOs).[47] In April 1996, FERC issued Order No. 888, establishing, among other things, the "open access" rule that requires transmission owners to offer nondiscriminatory, comparable transmission service to all service customers.[48] Approximately one year later, the Commission issued Order No. 888-A, which set forth guidelines on implementing this open access rule—including the use of the Open Access Same-Time Information System, or OASIS.[49] Order No. 888-A is often

45. *See* BONNEVILLE POWER ADMIN., OVERSUPPLY MANAGEMENT PROTOCOL, VERSION 2 (2012) (Superceded by Version 3, effective Apr. 2, 2013), *available at* http:// transmission. bpa.gov/ts_business_practices/Content/Archive/Oversupply_mgt_protocol_archive.htm [hereinafter OMP]. This discussion refers to Version 2 (2012); Version 3 was released as this Article was going to press and was therefore unavailable for analysis. All of the proceedings before FERC discussed here were regarding Version 2.

46. *See* Protest of Complainants, Iberdola Renewables, Inc. v. Bonneville Power Admin., (F.E.R.C. 2013) (Docket No. EL11-44-002); Response of the Bonneville Power Administration, Iberdola Renewables Inc. v. Bonneville Power Admin., (F.E.R.C. 2013) (Docket No. EL11-44-002) [hereinafter BPA's Response to comments].

47. The BPA is neither an ISO nor an RTO and has resisted establishment of either in the Pacific Northwest.

48. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, 61 Fed. Reg. 21,540 (May 10, 1996) (codified at 18 C.F.R. pts. 35, 385).

49. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, 62 Fed. Reg. 12,274 (Mar. 14, 1997) (codified at 18 C.F.R. pt. 35).

referred to as the *pro forma* OATT.[50] In 2007, FERC reformed its transmission policy to strengthen this *pro forma* OATT so that the Commission could more effectively address undue discrimination and facilitate its enforcement and regulation of transmission grid operations.[51]

FERC has continued to amend its open access transmission policy over time,[52] most recently in ways that directly connect to the BPA dispute. For example, in October 2010, FERC issued a clarification order[53] confirming that California "has a wide degree of latitude in setting avoided cost" and "can utilize a multi-tiered avoided cost rate structure" that would be consistent with the avoided-cost requirements under section 210 of Public Utility Regulatory Policies Act[54]—including any inclusion of the state's procurement obligations in its calculation of avoided cost.[55] In 2010, the tension between high-volume runoff and the variability of wind generation had reached its peak, and the BPA launched a project to reconcile competing costs.[56] That project gave way to DSO 216, which the BPA utilized in its redispatch policy during high-volume runoff.[57]

However, in July 2011, FERC issued Order No. 1000.[58] Order No. 1000 amended the open access transmission policy by requiring transmission providers to develop region-wide policies that consider how both federal

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50. *See, e.g.*, *Iberdrola*, 137 F.E.R.C. ¶ 61,185 at para. 3.

51. Preventing Undue Discrimination and Preference in Transmission Service, 72 Fed. Reg. 12,266 (Mar. 15, 2007) (codified at 18 C.F.R. pts. 35, 37).

52. FERC's amendments to the open access transmission policy include Orders 888, 889, and 890. FERC introduced a "pro forma OATT" under Order 888, which is one element in the wind industry's position in this dispute. Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 62 Fed. Reg. 12274-01 (Mar. 14, 1997) (codified at 18 C.F.R. pt. 35); *see also Iberdrola*, 137 F.E.R.C. ¶ 61,185 at paras. 3, 21.

53. FERC Order Granting Clarification and Dismissing Rehearing, 133 F.E.R.C. ¶ 61,059 (2010).

54. 16 U.S.C. § 824a-3 (2005).

55. CAL. PUB. UTILS. COMM'N, LEGAL SUMMARY OF THE THREE FEDERAL ENERGY REGULATORY COMMISSION (FERC) ORDERS RELATED TO THE COMBINED HEAT AND POWER FEED-IN TARIFF PROGRAM, http://www.cpuc.ca.gov/NR/rdonlyres/37527239-30C5-403D-91FF-3CCBE2AFCAB8/0/LegalSummaryofFERCCHPFiT.pdf (last visited Sept. 19, 2012).

56. *See DSO 216 Overview*, *supra* note 39, at 1.

57. *See id*.

58. For a quick guide to the key requirements under FERC Order 1000, see FED. ENERGY REGULATORY COMM'N, FED. ENERGY REGULATORY COMM'N FACTS (July 21, 2011), *available at* http://www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6-factsheet.pdf.

and state public policy affects transmission needs.[59] Energy experts believed Order No. 1000 would enable the national grid to evolve to meet the increasing transmission demand from renewable energy.[60] Furthermore, some scholars suggest that Order No. 1000 could mark a shift toward comprehensive transmission strategies that involve thoughtful consideration of how transmission demand is affected by energy efficiency, demand response, and demand reduction.[61] A month after FERC issued Order No. 1000, a group of wind generators in the Pacific Northwest filed a petition with FERC against the BPA's redispatch policy.[62]

Most recently, in June 2012, FERC approved Order No. 764, effective June 2013, to improve VER integration.[63] While this rule will impact the several aspects of transmission service for variable-energy generators, Order No. 764 (discussed in Part V below) does not directly address either the BPA's curtailment authority or cost allocation of renewables integration. The prospect of continued conflicts before FERC between BPA and wind generators is therefore high despite Order No. 764.

B. Factual Background: Hydropower, High-Volume Runoff, and Wind

The BPA is not a public utility; it is a nonprofit organization described as a "federal power marketing agency,"[64] that markets power in the Pacific Northwest from federal sources, namely hydropower, as well as nonfederal sources, primarily wind at this time.[65] The BPA's task as a transmission service provider is to ensure that the Pacific Northwest has a system that adequately integrates and transmits affordable power from both federal and nonfederal generation sources while maintaining electrical reliability and stability.[66] In addition to this goal, however, the BPA must mitigate the FCRPS impact on fish and wildlife in the Pacific

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59. Shelley Welton & Michael B. Gerrard, Comment, *FERC Order 1000 as a New Tool for Promoting Energy Efficiency and Demand Response*, 42 ENVTL. L. REP. NEWS & ANALYSIS 11025 (2012).

60. *See id*.

61. *Id*. (discussing how Order 1000 could serve as opportunity for transmission planning that better matches current and evolving demands on national grid).

62. *Iberdrola*, 137 F.E.R.C. ¶ 61,185 at para. 1.

63. *See DSO 216 Overview, supra* note 39.

64. *Iberdrola*, 137 F.E.R.C. ¶ 61,185 at para. 2.

65. Bonneville Power Admin., *2011 BPA Facts*, BONNEVILLE POWER ADMIN., http://www.bpa.gov/corporate/about_BPA/Facts/FactDocs/BPA_Facts_2011.pdf (last visited Sept. 21, 2012). The BPA markets wholesale power from 31 federal hydroelectric sources, as well as a few nonfederal electric sources—specifically, wind. *Id*. The BPA's service area includes Idaho, Oregon, Washington, parts of Montana, California, Nevada, Utah, and Wyoming. *Id*.

66. Bonneville Power Admin., *Mission Vision Values*, BONNEVILLE POWER ADMIN., http://www.bpa.gov/corporate/About_BPA/ (last visited Sept. 21, 2012).

Northwest.[67] While many statutes impose obligations on the BPA, including environmental concerns that are relevant to public utilities as well, the intersection of these two basic goals—reliable, integrated service and mitigation of impact on salmon—are at the heart of the current dispute.[68]

A few years ago, the BPA sought to address the effect of variable-energy resources, namely, wind, on its ability to meet its goal of reliable, integrated transmission service—especially given the ever-increasing wind capacity in its service territory.[69] Therefore, the BPA issued DSO 216,[70] the mechanics of which are as follows. When a wind plant is actually generating more than allotted under its transmission schedule, the BPA must offset such over-generation by decreasing federal generation.[71] In such circumstances, DSO 216 enabled the BPA to place "generation output limits" on the over-generating wind plant, relative to its schedule, and require the plant to lower its generation accordingly or face penalties.[72] But when a wind plant is actually generating less than its transmission schedule, the BPA must increase federal generation to make up the difference.[73] In such circumstances, DSO 216 enabled the BPA to automatically curtail the transmission schedule for the under-generating wind plant, relative to its actual generation, for the remainder of the operating hour.[74]

67. *Id*.
68. While the wind industry has repeatedly questioned whether the BPA is truly concerned about its environmental obligations, as opposed to a desire to shift costs of operation to nonfederal generation in favor of federal hydropower customers, the BPA cites multiple statutes as sources of its obligations. *Iberdrola*, 137 F.E.R.C. ¶ 61,185 at paras. 22, 24. These include the Northwest Power Act, 16 U.S.C. § 839, the Federal Columbia River Transmission System Act, 16 U.S.C. § 838, the Pacific Northwest Power Preference Act, 16 U.S.C. § 837, the Bonneville Project Act, 16 U.S.C. § 832, the Clean Water Act, 33 U.S.C. § 1341, and the Endangered Species Act, 16 U.S.C. § 1536. *Id*. According to BPA, "[s]everal commenters noted that Oregon and Washington have different TDG standards" and "suggested BPA should seek to change Washington's standard to conform with Oregon's. This would allow river operators to spill more water." BONNEVILLE POWER ADMIN., BPA AND FISH PASSAGE CENTER STUDY EFFECTS OF CHANGING TOTAL DISSOLVED GAS STANDARDS 1 (2011). However, "BPA concluded from these studies that a change in the dissolved gas standard would produce a modest reduction in overgeneration spill." *Id*. *at 2*.
69. *See DSO 216 Overview*, *supra* note 39.
70. *Id*.
71. *Id*. § II(B)(1).
72. *Id*. § II(C)(1).
73. *Id*. § II(B)(2).
74. *Id*. § II(C)(2).

In 2010 and 2011, however, the tension between the BPA's goals of reliable, integrated transmission and mitigation of environmental impact reached an all-time high, ultimately due to high-volume runoff from melting snowpack but exacerbated by variable wind generation.[75] While in the past the BPA has addressed high-volume runoff by providing low-cost federal hydropower to its customers, spring 2011 proved to be the fourth highest runoff since 1929.[76] Having determined that providing low-cost or negative-cost hydropower to its customers during high-water runoff was not a sustainable strategy, the BPA announced that it would curtail nonfederal generation as needed, pursuant to protocol under DSO 216.[77] In doing so, the BPA's curtailment would be automatic, unilateral, and—most importantly—uncompensated.[78]

C. Round 1: Dispute over DSO 216

During the spring of 2011, the BPA unilaterally curtailed 97,577 megawatt hours (MWh) of wind generation to deal with high-water runoff.[79] On June 13, 2011, a group of wind-facility owners responded,

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75. Bruce W. Radford, *Bonneville's Balancing Act*, 149 PUB. UTIL. FORT., no. 9, 2011 at 24, 25. As Radford effectively describes the phenomenon, increased spillway discharge creates dangerous levels of dissolved gas and bubble trauma that can fatally injure native fish. *Id*. at 24. Already having to reduce its generation due to increased spillway discharges, federal hydropower was further reduced due to its displacement by wind generation. *Id*. The lack of variable fuel costs, as well as the demand for tax credits and renewable energy certificates, makes the wind industry unlikely to voluntarily curtail generation. *Id*.

76. *Id*. at 25–26.

77. *Id*. at 26; *see also* DSO 216 Overview, *supra* note 39.

78. Radford provides a sufficient analysis of the BPA's announcement:

> Under this new regime, developed through a stakeholder process that began after the spring 2010 runoff pushed resources to the limit, BPA announced that, if necessary to avoid harmful spill and satisfy its statutory obligations—to preserve fish and wildlife, to market low-cost hydropower to state and municipal preference customers, and to operate and recover costs in a businesslike fashion—it wouldn't agree to accept a negative price in order to over-generate and divert water through dam turbines. That is, it wouldn't agree to pay customers, as the market otherwise would dictate, for the privilege of running its turbines to avoid harmful spill when to do so would produce output in excess of the actual hydropower load requirement. Rather, it would simply curtail non-federal generation as needed—thermal plants first, followed by wind—and replace that power with its own turbine-generated FCRPS output, and send it to the would-be thermal and wind off-takers, using the same transmission capacity and schedule rights owned by the curtailed thermal and wind plants. And BPA under this policy wouldn't consent to pay a negative price, nor would it compensate curtailed wind generators for lost PTCs and RECs.

Radford, *supra* note 75, at 26.

79. *Iberdrola,* 137 F.E.R.C. ¶ 61,185, at para. 63, n.99; *see also* Radford, *supra* note 75, at 27. For statistics of the BPA's limit and curtailment events in 2011 and 2012,

filing a petition with FERC that alleged the BPA "[used] its transmission market power to curtail wind generators in an unduly discriminatory manner in order to protect its preferred power customer base from costs it does not consider socially optimal."[80] On December 7, 2011, the Commission declined to rule on the BPA's 2011 wind curtailment actions, but it ordered the BPA to revise its transmission policy such that, moving forward, transmission service is not unduly discriminatory or preferential in violation of section 211A of the FPA.[81] This section will outline the legal issues and arguments, including FERC's jurisdictional authority, noncomparability analysis under the FPA, and its short analyses of the parties' interconnection agreements and e-tag issues.

1. FERC Jurisdiction: Shifting Focus From Past Conduct to Prospective Policy

Before FERC could analyze the merits of the dispute, it had to address the BPA's initial position that the Ninth Circuit Court of Appeals, not FERC, had jurisdiction over the matter.[82] Specifically, the BPA argued that the Ninth Circuit had exclusive jurisdiction over challenges to the redispatch policy, which constituted a "final action" under the Northwest Power Act.[83] While the term "final action" is not defined under that statute, the BPA provided two arguments that its policy constituted such. First, the redispatch policy is the result of the BPA's completed decision-making process and directly affects the generators party to this dispute.[84] Alternatively, the policy represents final action under the

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see BONNEVILLE POWER ADMIN., BAPT OPERATIONAL ANALYSIS DSO216 REPORT (2012), *available at* http://transmission.bpa.gov/wind/op_controls/FY_2012_Q1_Q2_Q3_Q4_DSO216_Event_Report.pdf.

80. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 1.

81. *Id*. at paras. 63, 65.

82. *Id*. at paras. 19, 22. Specifically, the BPA had filed a motion with FERC to hold the matter in abeyance pending the Ninth Circuit's review of a motion that had been filed by joint intervenors. *Id*. at para. 18. While it appears that wind proponents had filed the motion with the Ninth Circuit as a secondary strategy to the FERC petition, the BPA likely believed that a Ninth Circuit ruling based on the Northwest Power Act would have been more favorable than a FERC ruling under the FPA.

83. *Id*. at para. 22; 16 U.S.C. § 839f(e)(5) (2012).

84. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 23 (citing Bennett v. Spears, 520 U.S. 154 (1997) (setting standard for defining "final action" for purposes of establishing jurisdictional authority over an agency)).

Ninth Circuit's "true nature" test because the BPA's conduct reflects its statutory authority and concomitant statutory obligations.[85]

On the other hand, the wind generators argued that FERC's authority under section 211A of the FPA is not subordinate to or limited by the BPA's enabling statutes and that section 211A could be applied without conflict.[86] With respect to "final action," the wind generators argued that the BPA's policy was not mandated by the Northwest Power Act, and that the statute was not the source of their grievance—which was firmly rooted in the FPA's discriminatory restrictions.[87]

FERC ultimately exerted its jurisdictional authority over the dispute under section 211A of the FPA, but, in doing so, the Commission surrendered an ability to determine whether the BPA's past curtailment of wind was legally prohibited.[88] Section 211A authorizes FERC to require the BPA, by rule or order, to provide transmission services that are comparable and not unduly discriminatory or preferential to services that it charges and provides to itself.[89] By interpreting this provision as authorizing the Commission to take *prospective* action, requiring the BPA to file a revised tariff governing future services, FERC expressly declined to *retroactively* determine whether past wind curtailment was prohibited under the BPA's enabling statutes—avoiding the question of "final action" that may trigger Ninth Circuit jurisdiction.[90] In other words, the fundamental jurisdictional issue may be responsible, at least in part, for the lack of guidance in the Commission's ruling on whether the BPA could continue to unilaterally curtail nonfederal generation during high-volume runoff events.[91] The Commission must first address the policy

85. *Id*. at para. 24 (citing M-S-R Pub. Power Agency v. Bonneville Power Admin., 297 F.3d 833, 840 (9th Cir. 2002)); *see also* BPA STRATEGIC DIRECTION *supra* note 28, at 21 (listing multiple statutory obligations under which BPA operates).

86. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 20. "According to Petitioners, a directive under section 211A would simply add another comparability standard for terms and conditions of Bonneville's transmission service . . . Petitioners also assert that the Commission can act under section 211A without interfering with Bonneville's environmental obligations." *Id*.

87. *Id*. at para. 29.

88. *Id*. at para. 30. The Commission's rationale as to why section 211A applies to this dispute, and its analysis under section 211A, will be discussed in the following section.

89. 16 U.S.C. § 824j-1(b).

90. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 30. "To the extent Bonneville's past actions are subject to judicial review by the Ninth Circuit Court of Appeals, such review does not limit the Commission's prospective exercise of authority in this proceeding under section 211A of the FPA." *Id*.

91. There could also be policy concerns driving FERC's decision not to analyze the appropriateness of the BPA's past curtailment, including the impact of setting a national curtailment standard under section 211A, as opposed to letting a unique transmission provider find its own resolution to the issue. But this Article explores FERC's

question of how to allocate integration costs before it can rule on the validity of BPA's curtailment actions; otherwise, a ruling on those actions is a *de facto* policy choice on allocation.

2. Section 211A: At the Heart of Generation Curtailment is a Right to Transmission

FERC firmly stated that its jurisdictional authority to grant relief in the present dispute stemmed from section 211A of the FPA.[92] In determining that the dispute fit squarely under its section 211A authority, the Commission described the dispute as one of transmission—not generation.[93] Specifically, the Commission stated:

> As Congress has recognized, open access is a fundamental tenet of electricity markets. Clear and firm principles on open access give industry the confidence to invest in new generation resources and support the construction of associated transmission necessary to meet future needs . . . [W]e recognize the dilemma that Bonneville faces in having to navigate among many competing obligations, . . . [but the redispatch policy] results in Bonneville providing transmission service to others on terms and conditions that are not comparable to those it provides itself. For these reasons, we find it appropriate to act under FPA section 211A.[94]

Thus, FERC agreed with the wind generators that this dispute, while involving the curtailment of generation, fundamentally presented an issue of transmission rights.[95] Wind-facility owners had argued that a curtailment policy enabling the BPA to substitute its federal hydropower for wind—and other nonfederal generation—whenever it unilaterally deems it necessary is noncomparable because it prefers federal generation over nonfederal.[96] But the BPA submitted at least five distinct arguments in defense of its redispatch policy. Below is a summary of BPA's main arguments, presented in response to key wind industry arguments.[97]

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determinations on two other issues, which appear to presume the BPA's ability to unilaterally curtail—so long as such curtailment is comparable.

92. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 30. Since FERC would apply and grant relief under section 211A in this matter, the Commission declined to address the wind generators' alternative claims, under sections 210 and 212 of the FPA, that it compel the BPA to adhere to the terms of its interconnection agreements. *Id.* at paras. 9, 31.

93. *Id*. at paras. 32, 62–64.

94. *Id*. at paras. 32–33.

95. *Id*. at paras. 62–64.

96. *Id*. at para. 61.

97. Please note that, given the focus on the BPA's distinct arguments in defense of its redispatch policy, this summary reorders the FERC's listing of party arguments.

First, wind generators had asserted that the BPA's redispatch policy squarely affected their transmission rights because the redispatch policy curtailed competing nonfederal generators and used their service to delivery federal hydropower to the load.[98] "[The BPA] does not compensate curtailed wind generators for its appropriation of their right to serve their customers or for the use of the firm transmission rights reserved for curtailed wind generators' output."[99] In response, the BPA argued that its policy does not affect transmission rights because it does not deprive wind generators of transmission access in violation of their interconnection agreements; rather, it only limits the ability of a wind facility that is interconnected to the FCRPS to *generate*.[100] The BPA and its proponents argued that no section 211A claim should be sustained because the transmission schedules are honored: nonfederal energy customers still receive energy after curtailment—it is just power generated by federal hydropower rather than power generated by the contracted source of generation.[101]

Second, wind generators had alleged that, while the BPA delivers federal hydropower to match the curtailed wind facility's schedule and to meet the wind customers' needs, the energy product becomes ineligible for California's renewable portfolio standard requirements, resulting in economic loss.[102] While the BPA maintained its initial position that section 211A is inapplicable, it alternatively argued that its policy does not violate comparability and is, therefore, not unduly discriminatory.[103] Since the BPA does not usurp wind energy for its own use but rather substitutes federal hydropower in its daily management of transmission service, wind's resultant loss in revenue or tax credits should not render the redispatch policy non-comparable.[104] Furthermore, the BPA pointed to a prior FERC ruling to argue that such an economic consequence is irrelevant to a determination of comparability where the transmission terms are otherwise equally applied to federal and nonfederal generators.[105]

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98. *Id*. at para. 36.
99. *Id*.
100. *Id*. at paras. 36, 45 (emphasis added).
101. *Id*. at para. 45. NRECA was one of the parties advocating this position in comments before FERC.
102. *Id*. at para. 49.
103. *Id*. at para. 41.
104. *Id*.
105. *Id*. (citing Bonneville Power Admin. v. Puget Sound Energy, Inc., 125 F.E.R.C. ¶ 61,273 (2008)). In this 2008 ruling, FERC confirmed that comparability depends on whether a transmission provider treats affiliated and nonaffiliated generators on a comparable basis—an inquiry "unaffected by whether the opportunity of the generators, either affiliated or unaffiliated, to recover their lost revenue is [sic] through Commission-jurisdictional rates or non-jurisdictional rates." *Puget Sound Energy, Inc*., 125 FERC at 62,315–16. But, in that case, both affiliated and nonaffiliated generators were similarly

Third, wind generators had identified alternative solutions for managing high-volume runoff, including "entering into storage arrangements with entities in British Columbia, entering into agreements with regional investor-owned utilities for displacement of thermal and non-thermal generation outside Bonneville's balancing authority area and paying some degree of negative prices to induce owners of generators in the area, including wind generators, to back down generation."[106] In response, the BPA argued that a directive to revise its redispatch policy under section 211A would compromise its compliance with its myriad statutory obligations, which compelled its implementation of a curtailment policy in the first place: "[C]urtailments are necessary for Bonneville to manage its hydro facilities during high water events, to ensure reliability, and to ensure that Bonneville meets its Clean Water Act and Endangered Species obligations and other statutory responsibilities under the Northwest Power Act."[107]

Fourth, wind generators had argued that FERC consistently characterizes the *pro forma* OATT as the "minimum terms and conditions of non-discriminatory service," such that the BPA's deviations should be dispositive of noncomparable service unless FERC permitted the deviation.[108] In response, the BPA argued that, as an unregulated transmitting utility, it is not required to adopt the *pro forma* OATT—and section 211A does not authorize the Commission to require such adoption.[109]

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affected by the BPA's policy for deadband reactive power service; the nonaffiliates' noncomparability argument focused on the BPA's ability to subsidize its costs by raising rates of captive customers—something nonaffiliates could not do without risking sales revenue. *Id*. at 62,314. FERC held that, because both affiliates and nonaffiliates must recover their losses in some way, the policy was comparable. *Id*. at 62,315.

In the current dispute, only nonfederal wind generators claim an economic loss due to the BPA's redispatch policy; federal hydropower is not curtailed at all but instead substitutes its energy for wind customers. FERC characterized this as an interruption in transmission service that is not comparably incurred by both federal and nonfederal generators. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 62. But perhaps its 2008 ruling could also be distinguished on grounds that the BPA's current redispatch policy involves unilateral curtailment *and* one-sided economic loss.

106. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 39.

107. *Id*. at para. 42. FERC ultimately bought this argument, but only in the sense that the BPA, not FERC, must decide how best to balance these competing obligations—including comparable service—in its revised policy. *Id*. at para. 64.

108. *Id*. at para. 37.

109. *Id*. at para. 43. FERC seemed to buy this argument as well, by placing the onus on the BPA to decide how best to balance its statutory obligations with the section 211A requirement of comparable service. *Id*. at para. 65. However, the Commission did

Fifth, wind generators had argued that the BPA's refusal to pay low-cost or negative prices inappropriately shifted the burden of hydropower over-generation onto the wind industry by way of a policy that sought primarily to "protect its preference power customers from increased costs," rather than to mitigate environmental impact.[110] According to the wind industry, the BPA's willingness to offer negative-price hydropower would allow wind generators to independently decide when to curtail—which would be based in part on each facility's specific tax credit and revenue concerns.[111] Furthermore, there is a growing concern that the BPA's policy would "impose a chilling effect on wind industry development" as potential generators begin to fear that the BPA can unilaterally curtail generation and amend interconnection agreements.[112] In response, the BPA asserted that payment of low-cost or negative prices for hydropower would "jeopardize" its statutory obligations to the U.S. Treasury, "jeopardize" its statutory obligation to provide lowest possible rates, and "inappropriately transfer the costs of wind development incentives to customers who do not benefit from [wind power]."[113] It is not coincidental in this dispute that most of the wind serves California load and has been developed specifically in response to California's aggressive RPS policies.

In the end, FERC ruled that the BPA's redispatch policy resulted in noncomparable service, justifying its exercise of section 211A authority, because the policy unfairly treated nonfederal generators by interrupting their customers' point-to-point service without comparable interruptions

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identify adoption of the *pro forma* OATT as one option available to the BPA. *Id*. at para. 65, n.101.

110. *Id*. at para. 8. Pursuant to this argument, the BPA must address its multiple goals of cheap power, integrated transmission, and mitigation of environmental impact by "modern-day market precepts—which, under certain conditions of stream-flow dynamics and electric supply and demand, might imply a zero or even negative price for its hydro output." Radford, *supra* note 75, at 24.

111. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 40. Of course, a wind generator, with no variable fuel costs, arguably has little-to-no incentive to voluntarily ramp down or go off-line when faced with the potential loss in tax credits and renewable energy certificates. *See* Radford, *supra* note 75, at 25. But perhaps the wind industry's point here was that, in terms of production-forecasting and interconnection negotiations, federal and nonfederal generators could proactively compromise instead of a transmission provider's retroactive, unilateral curtailment.

112. Radford, *supra* note 75, at 28 (noting that owners of Shepherds Flat Wind Farm were among those voicing concerns of chilling effect).

113. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 44. The BPA apparently also argued that continued payment of hydropower at negative prices could produce the "converse of the California power crisis seen a decade ago." Radford, *supra* note 75, at 30 ("CAISO was forced to offer sky-high prices to keep the lights on . . . Just as the ISO purchased power at any price to avoid blackouts, Bonneville could be forced to pay any negative price to avoid spill."). *See generally* Timothy P. Duane, *Regulation's Rationale: Learning from the California Energy Crisis*, 19 YALE J. ON REG. 471 (2002) (providing a detailed discussion of the California electricity crisis and its consequences).

to service held by federal hydropower generators.[114] The Commission was convinced by the wind-facility owners' evidence of the business, commercial, and economic impacts of the BPA's policy.[115] The Commission initially cited $50 million in potential lost tax credits and energy certificates,[116] but later estimated that the total cost to wind generators was more likely to be as low as $2.15 million.[117] FERC also found harm to load-serving entities that were rendered ineligible to satisfy state renewable portfolio standard requirements as a result of curtailment.[118]

FERC ordered the BPA to file a revised tariff within ninety days of its ruling to address the comparability concerns, but the Commission declined to specify the "precise terms and conditions" that the BPA's revised OATT must include to remedy the non-comparable service caused by its

114. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 62.
115. *Id*. at para. 63.
116. *Id*.
117. *Id*. at para. 63, n.99. The BPA apparently first noted the $50 million figure in its final record of decision, and this figure was based on peer review studies that assumed a combined REC/PTC value of $38/MWh. BONNEVILLE POWER ADMIN., BPA'S INTERIM ENVIRONMENTAL REDISPATCH AND NEGATIVE PRICING POLICIES, ADMINISTRATOR'S FINAL RECORD OF DECISION 29 (May 2011), *available at* http://www.bpa.gov/news/pubs/RecordsofDecision/rod-20110513-Interim-Environmental-Redispatch-and-Negative-Pricing-Policies.pdf [*hereinafter* FINAL ROD]. In their FERC petition, the wind-facility owners cited the Final ROD's $50 million figure, arguing that they could not otherwise accurately estimate the financial cost of the BPA's policy. Complaint & Petition for Order Under Federal Power Act Section 211A against Bonneville Power Admin. Requesting Fast Track Processing at 4, 66, Iberdola Renewables Inc. v. Bonneville Power Admin. (F.E.R.C. 2011), *available at* http://www.bpa.gov/Projects/Initiatives/Oversupply/Oversupply Documents/OtherDocs/2011-06-13_ ComplaintAgainstBPA.pdf. However, in footnote 99 of its 2011 ruling, FERC noted:

> Other evidence suggests that the actual loss in 2011 may have been much lower. Bonneville has indicated that the value of applicable RECs is $16/MWh and the value of PTCs is $37/MWh and that, because only 29 percent of the wind fleet receives PTCs, the weighted average value of PTCs and RECs is $22/MWh . . . Since the Petition was filed, we have learned that, between May 18 [sic] and July 10, 2011, Bonneville invoked its [policy] to redispatch a total of 97,577 MWh of wind generation, which equals 5.4 percent of the 1,760,905 MWh of power produced by wind generators in the Bonneville Balancing Authority Area during this same period. Based on this information, we estimate that the [policy] resulted in, for 2011, a $2.15 million loss in RECs and PTCs to wind resources.

Iberdrola, 137 F.E.R.C. ¶ 61,185, at para. 63, n. 99.

118. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 63. Interestingly, after listing the multiple economic consequences of the BPA's redispatch policy, the Commission stated that the wind-facility owners had demonstrated—"[r]egardless of the magnitude of the loss"—that the BPA's policy caused noncomparable transmission service. *Id*.

redispatch policy.[119] Furthermore, the Commission declined to address whether the appropriate resolution to the high-volume runoff problem is for the BPA to pay negative hydropower prices.[120] The BPA is subject to a myriad of statutory obligations, which FERC confirmed included an obligation to provide comparable transmission service that is not unduly discriminatory pursuant to section 211A.[121] But *how* the BPA's OATT should "reconcile" these "numerous rules and regulations" is a question that FERC left for the BPA to answer.[122] But leaving that question to the transmission provider is problematic when that provider does not own all of the generating resources that it manages; the transmission provider is then in a position to make a cost allocation decision that favors its own interests over other parties' interests.

3. Interconnection Agreements and E-Tags

Aside from its primary determination that the BPA's redispatch policy results in non-comparable transmission service in violation of section 211A, FERC also determined two other issues: whether the BPA can rely on provisions in its interconnection agreements to unilaterally curtail wind during high-volume runoff,[123] and whether the BPA must update e-tags when it does curtail wind.[124]

With respect to the parties' interconnection agreements, the Commission rejected the BPA's claims that certain contractual provisions supported its use of the redispatch policy.[125] FERC determined that any service

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119. *Id*. at para. 65.
120. *Id*.
121. *Id*.
122. *See id*.
123. *Id*. at para. 68.
124. *Id*. at para. 74, 76. E-tags are the verification tool used to track energy generated from renewable sources from production until consumption in order to ensure that the renewable energy credits associated with that energy are not sold more than once for purposes of complying with an RPS.
125. *Id*. at para. 73. The wind generators had argued that, while the parties' agreements contained force majeure clauses, the BPA failed to demonstrate that high-volume runoff constituted an emergency supporting use of the redispatch policy, which effectively unilaterally modified executed agreements. *Id*. at para. 71 (citing Article 16.1.1, Force Majeure, of interconnection agreements). Furthermore, they argued that the BPA was precluded from unilateral, uncompensated curtailment by its contractual obligations to perform in accordance with applicable laws, regulations, reliability standards, and "Good Utility Practice." *Id*. at para. 67 (citing Article 4.3, Performance Standards, of interconnection agreements). In addition to arguing that force majeure indeed supports its redispatch policy, the BPA cited another provision that authorized it to "'interrupt or reduce deliveries if such delivery of electricity could adversely affect [its] ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System' and where required by 'Good Utility Practice.'" *Id*. at para. 72 (citing Articles 16.1.1 and 9.7.2 of interconnection agreements).

interruptions authorized by the agreements must be performed according to "Good Utility Practice," which necessarily includes compliance with applicable statutory obligations—including providing comparable transmission service under section 211A.[126] With respect to force majeure, FERC again set aside the BPA's past curtailment, ruling only that the BPA cannot rely on force majeure in the future unless it could demonstrate that circumstances squarely fall within that provision[127] and that its curtailment no longer causes the non-comparable service struck down by this ruling.[128] Notably, albeit in a footnote, FERC questioned whether force majeure could ever be available to high-volume runoff when the BPA predicts a "one-in-three chance of flows at least as high as those of early June 2010 occurring in any year and lasting for one month or more."[129]

With respect to e-tags, the Commission acknowledged the wind industry's concerns that the BPA's failure to update e-tags upon curtailment resulted in inconsistent grid flow patterns and impacted the wind generators' accounting of environmental credits.[130] FERC also acknowledged the wind industry's request for additional time to collaborate with the BPA and other stakeholders on a "constructive resolution" to the e-tag issue.[131] Nonetheless, FERC instructed the BPA to update e-tags "to the extent that [it] changes the source of a point-to-point transaction (e.g., substituting hydropower for wind power)."[132]

Although the Commission did not address whether a transmission provider may appropriately choose curtailment instead of negative pricing to resolve over-generation concerns in its non-comparability determination, its determinations on the issues of interconnection agreements and e-tags provide some insight on this key question. For example, by tying the choice of unilateral curtailment of generation to the performance standards in the interconnection agreements, and then confirming that such standards

126. *Iberdrola*, 137 F.E.R.C. ¶ 61,185, at para. 73.
127. *Id.* Article 16.1.1 defines force majeure as "'any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control.'" *Id.*
128. *Id.*
129. *Id.* at para. 73, n. 110 (citing BPA's Answer).
130. *Id.* at para. 74 (Wind industry proponents had argued that the BPA's failure to update e-tags when it curtailed wind could create "false signals" that created reliability concerns and impacted "proper accounting for environmental credits.").
131. *Id.* at para. 75.
132. *Id.* at para. 76.

inherently include comparable service, FERC attaches a consequence to the policy choice that remains the BPA's to make: if you choose curtailment, it must be comparably implemented. The question is then whether reimbursement for displacement is, indeed, comparable service in times of curtailment.

D. Round 2: The Oversupply Management Protocol (OMP)

In March 2012, the BPA complied with the FERC's ruling by revising its redispatch policy to the "Oversupply Management Protocol" ("OMP").[133] Under the OMP, the BPA would continue to unilaterally curtail nonfederal generation during high-volume runoff, but it would now compensate the wind-facility owners for lost tax credits and REC revenues.[134] This section discusses the OMP protocol and the wind generators' most recent FERC petition, focusing on new arguments brought in the wake of the rejected redispatch policy.

1. Unilateral Curtailment by Another Name?

Under BPA's policy, all participating facilities with a nameplate generating capacity of three megawatts or greater are subject to the OMP.[135] Generators that wish to be reimbursed for displacement costs—i.e., wind facilities seeking compensation for lost tax credits and revenues due to curtailment during high-volume runoff—must affirmatively opt in and provide, in advance, fact-specific displacement cost data.[136] Generators that do not opt in "will be displaced at $0 and will not be subject to cost allocation."[137] Additionally, the BPA will assume a displacement cost of $0 for generators that fail to submit displacement cost information specific to each facility.[138] Those determined to be zero-cost appear to be the BPA's "voluntary" generators, first in line for displacement.[139] Generators have been locked into their election as of April 4, 2012.[140]

133. *OMP*, *supra* note 45, at 1. According to version 2 of the OMP, the protocol became effective on March 31, 2012, and terminated on March 30, 2013. *Id*. Version 3 of the OMP was released on April 2, 2013 as this Article went to press, so Version 3 was unavailable in time for any analysis or discussion here.

134. *Id*. at 4

135. *Id*. at 1.

136. *Id*. at 1–2.

137. *Id*. at 2.

138. *Id*.

139. *See id*. at 2, 4.

140. *Id*. at 2. The BPA also offers generators the opportunity to make advance arrangements that would waive "In-Kind Real Power Loss Return obligations to reduce spill." *Id*. at 2–3.

The OMP utilizes a least-cost displacement regime, wherein over-generating non-variable energy resources are first subject to reduction and, only if further reduction is required, over-generating variable-energy resources (i.e., wind) will then be subject to reduction.[141] Thus, in the event of high-volume runoff, the BPA would first invoke mitigation measures to ensure federal hydropower generation minimizes its environmental impact.[142] If such measures require nonfederal reduction (i.e., curtailment), the BPA will approach non-federal generating resources to make advance displacement offers.[143] First, it will approach thermal generators.[144] The BPA will not approach wind generators unless further reduction is needed, and, at that time, it would first approach those wind facilities that require the least cost to displace.[145]

2. *The Debate Renewed*

Shortly after the BPA issued the OMP, the wind generators filed another petition with FERC, requesting an interim order precluding the BPA from implementing the OMP until the Commission has issued a determination on the merits.[146] The wind generators argue that the BPA failed to comply with the Commission's 2011 ruling, because the OMP

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141. *Id*. at 2. Radford provides a helpful summary:

> Bonneville would assign a zero displacement cost to thermal units, but allow them to satisfy minimum run and ramping requirements. With curtailments of non-federal resources occurring in least-cost sequence, BPA would displace thermal units first, before forcing wind power off the system so as to create unserved load as a market for its surplus hydropower.

Bruce W. Radford, *It's the Money, Not the Fish*, 150 PUB. UTIL. FORT., no. 7, 2012 at 24, 25. And, with respect to wind power curtailment, "BPA would first curtail those wind plants needing the least amount of compensation to be made whole." *Id*. at 24.

142. *OMP*, *supra* note 45, at 2.

143. *Id*.

144. *Id*. at 4.

145. *Id*. In other words, the BPA would first displace those wind generators who opted out or failed to submit displacement cost data—the "voluntary" generators who can be displaced at zero-cost to the BPA (but *not* zero-cost to the wind generators). Voluntary displacers who fail to reduce generation in compliance with the OMP would be subject to penalties. *Id*. at 5.

146. Protest & Limited Motion for Expedited Order Staying Implementation of Tariff Amendment of Nw. & Intermountain Power Prod. Coalition & Transalta Energy Mktg., Iberdrola Renewables, Inc. v. Bonneville Power Admin., (F.E.R.C. 2012) (Docket No. EL11-44-002), *available at* http://www.nippc.org/upload/ Comments%20on%20BPA's %20OMP%20proposal%20032712.pdf (last visited Sept. 29, 2012) [hereinafter *2012 Petition*].

is not a complete OATT[147] and because it otherwise fails to provide comparable transmission service that is not unduly discriminatory under section 211A.[148] The 2012 petition argues that the BPA should instead manage its oversupply by selling federal hydropower at prices sufficient to induce other generators to voluntarily displace generation—via "FPS-12, Firm Power Products and Services Rate,"[149] which the wind generators argue can achieve the same environmental protection as the OMP but without the cost protection of federal hydropower.[150]

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147. For the wind generators' arguments in this regard, see *id*. at 9–14. This section will focus on comparability.

148. *Id*. at 1. While FERC at one time ordered the BPA to file "tariff revisions," the Commission had in other sections noted that this should be a revised OATT, s*ee Iberdrola*, 137 F.E.R.C. ¶ 61,185, at paras. 66, 78. But the wind industry notably characterizes the FERC's ruling as *precluding* the BPA from displacing nonfederal generation with federal hydropower during over-generation events. *2012 Petition*, *supra* note 146, at 1. The 2011 ruling could also be read as instructing the BPA to ensure that, if it chooses curtailment, such protocol is *comparable* for federal and nonfederal generating sources. The wind industry's argument being, then, that the OMP is non-comparable because its least-cost displacement regime does not apply to federal generators—displacement is still a one-way street.

The wind generators also argue that the BPA's compliance filing must be rejected because the BPA failed to obtain a FERC declaratory order that the OMP is just, reasonable, and not unduly discriminatory or preferential, pursuant to a regulation applicable to the BPA's existing tariff. *2012 Petition*, *supra* note 146, at 27–28 (citing 18 CFR § 35.28(e)).

149. *2012 Petition*, *supra* note 146, at 1–2. The FPS-12 allows for a "flexible rate": "[d]emand and/or energy charges shall be as specified by BPA or as mutually agreed by BPA and the Customer. . . . " *Id.* at Att. A.

150. *Id*. at 4. Specifically, the wind generators argue:

> This is the heart of the matter: the negative pricing flexibility in Bonneville's FPS-12 Rate can produce the same protection of fish and reliability as the Oversupply Management Protocol, but it might result in higher negative prices paid to non-Federal generators. Bonneville apparently rejects competitive power markets. Bonneville's dislike for the existing solution, however, does not render the solution unworkable. It is simply not appropriate for Bonneville to ignore the Commission's directive, and implement a new (and clearly non-comparable) transmission regime, prior to the Commission's opportunity to vet the issues, just because Bonneville finds the remaining alternatives distasteful.

Id. The BPA had argued:

> Bonneville does not believe paying negative prices to moderate TDG [Total Dissolved Gas] levels will result in a well functioning market. . . . Bonneville needs to generate power in order to moderate TDG levels and cannot make a rational economic choice whether or not to accept any particular price for its power. As a result, marketers will be able to charge any price for accepting Bonneville's power. In addition, thermal generators will likely hold out for negatively priced power once Bonneville begins paying negative prices. Bonneville does not believe other entities should be allowed to profit in this manner at Bonneville's expense when Bonneville must comply with its environmental responsibilities.

BPA's Response to comments, *supra* note 46, at 6. There is a real risk of market manipulation under the conditions that BPA outlines, so a strong market monitor and regulatory force would be necessary to assure such manipulation did not occur. The

The wind generators argue that the OMP is the redispatch policy under another name, because the same "non-comparable" results occur: involuntary displacement; direct, negative impact on nonfederal transmission service; and an inability to satisfy renewable portfolio standards.[151] In other words, the BPA continues to provide non-comparable and unduly discriminatory service to nonfederal generators, regardless of the fact that it would now reimburse displacement costs.[152] Notably, the wind generators submit that displacement payments under the OMP, while characterized by the BPA as reimbursing renewable generators for losses due to necessary displacement, would actually establish new, reduced rates.[153] Thus, the wind generators argue, the BPA does engage in negative pricing—even though the BPA claims that the OMP is a necessary alternative to an unsustainable strategy of paying negative hydropower prices.[154] "[T]he only difference between comparable transmission service that is not unduly discriminatory or preferential and the [OMP] is the risk that Bonneville might incur higher costs in market purchses [sic] at negative prices than under the [OMP.]"[155]

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entire Pacific Northwest is still reeling from the price shocks that propagated across the region during the California energy crisis in 2000–2001, so BPA is understandably wary. *See* Duane, *supra* note 19.

151. *2012 Petition*, *supra* note 146, at 14–15.

152. *Id*. at 15.

153. *Id*. at 18–20. The wind generators point to a Ninth Circuit case, which held that the BPA effectuated the sale of its power at a new, reduced rate when it purchased Trojan nuclear plant's scheduling rights—enabling the BPA to shut the plan down and replace nuclear power with BPA power. Cal. Energy Res. Conservation & Dev. Comm. v. Bonneville Power Admin., 754 F.2d 1470 (9th Cir. 1985). "[P]roviding displacement energy at the FPS-12 Rate of 0 mills per kilowatt hours, plus payment of non-Federal, renewable generators' displacement costs, is exactly like charging for Trojan replacement energy costs at an established rate, plus payment of a fee for scheduling rights. The combination is an effective rate." *2012 Petition*, *supra* note 146, at 20–21.

154. *2012 Petition*, *supra* note 146, at 18.

155. *Id*. The 2012 petition contains many other arguments from which we may develop key concerns for other transmission system providers, whether classified as an RTO, ISO, or a utility. For example, the wind generators argue that the OMP's requirement that renewable generators submit displacement costs in advance is unrealistic. *Id*. at 22. Because generators must market power and RECs in real time, in a market that is constantly in flux, they argue that FERC should require the BPA to update its cost curve within 24 hours of revised data submitted by an individual generator. *Id*. at 22–23. Similarly, wind generators argue that generators must be entitled to establish minimum generation levels and maximum ramp rates as necessary to efficiently operate their plants. *Id*. at 25. While these arguments likely do reflect the reality of a volatile real-time renewable energy market, it is not clear how far such arguments would go, given the new FERC Order No. 764 on variable energy resources integration to take effect in June 2013. *See* News Release, Fed. Energy Regulatory Comm'n, *supra* note 14; *see also*

E. Policy Ramifications of the BPA-Wind Dispute

It is unclear how persuasive the wind generators' new legal arguments brought against the OMP may be. After analyzing the key legal issues with respect to the BPA's redispatch policy and new arguments brought against the OMP, however, we believe we have an implicit answer to the question that FERC apparently declined to address—namely, whether a transmission provider can unilaterally curtail a class of generation and still comply with the comparable service requirements of section 211A. Over-generation will inevitably occur, be it due to federal hydropower because of high-volume runoff or solar power because of record drought. An OATT must account for this eventual occurrence. And curtailment of one class of generators is just one potential resolution to the over-generation problem. However, any protocol that seeks to reduce generation on the grid inherently impacts those generators' transmission rights and, therefore, that protocol must be comparable and not unduly discriminatory. Transmission providers can no longer treat over-generation as an unforeseeable, emergency situation that justifies non-comparable, unilateral curtailment of a class of generators—especially one whose variability renders it more unreliable and, seemingly, expendable. Exactly how curtailment can be comparably implemented, however, is another question. How does reimbursing displacement ensure comparable transmission service when, in the case of the BPA, federal hydropower is never displaced by variable-energy generation?

Moreover, how will we reduce the total system costs of integration in the absence of curtailment—and how will we allocate the costs of renewable integration within the hybrid regulatory structure? The real driver of integration conflict—including the BPA-wind curtailment conflict—is money. How much will each stakeholder group have to pay? BPA and its customers do not want to fund California's RPS by spilling BPA hydro, thereby possibly increasing total system costs and therefore rates for BPA's customers. But BPA's DSO 216 curtailment policy fails to account for REC and PTC income lost by wind operators; BPA would not spill the wind if BPA owned it. We therefore need an institutional structure, including both the state and federal regulatory systems, and incentives, including RPS criteria and PPAs, to allocate the costs of renewable integration as a regular and foreseeable cost of operating modern transmission systems.

Radford, *supra* note 75, at 27 (discussing whether negative prices are really subsidies, which BPA has now chosen to pay to wind industry); *see* Ben Tansey, *BPA Oversupply Management Protocol Still Looking for Love*, NORTHWEST FISHLETTER (Apr. 19, 2012), http://www.newsdata.com/fishletter/302/8story.html (discussing subsidy argument in part, including whether BPA has authority to make such payments).

Fortunately, there are a number of policy strategies that can be adopted to reduce the total system costs of integrating high levels of renewable generation. Part IV outlines the most promising strategies and discusses how they could lower integration costs. Part V then discusses the difficult policy choice of allocating those integration costs.

IV. STRATEGIES TO REDUCE THE COST OF INTEGRATING RENEWABLES

The challenge of integrating high levels of renewable generation is now firmly on the agenda of a wide range of stakeholders and governing institutions in the electricity sector. The issue has moved beyond academic and scholarly debate, generating extensive technical studies by the National Renewable Energy Laboratory (NREL), North American Electric Reliability Corporation (NERC), and Western Electricity Coordinating Council (WECC). Both technical studies and policy initiatives have been conducted and initiated by FERC, the Western Governors' Association (WGA), BPA, CAISO, the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), and other state regulatory agencies. International analyses of integrating high levels of renewables, especially in Europe, also offer important insights into how to integrate renewables most cost-effectively.

The consistent theme in these analyses is that the technical challenge of integration can be overcome but that integration may incur significant economic costs unless institutional reforms are adopted. We believe the WGA report,[156] which was released in June 2012, is the most comprehensive assessment to date and offers the clearest set of policy initiatives to reduce the cost of integrating renewables and maintain a reliable western electricity grid. In this Part, we summarize the recommendations of the WGA report and discuss how many of the strategies are complementary and would dramatically reduce the cost of integration.

The WGA Report agrees with our assertion that "[i]ntegration is not an issue that is unique to renewable resources; conventional forms of generation also impose generation costs."[157] The challenge of integration is especially complex in the West, however, where there are 37 interconnecting

156. W. GOVERNORS' ASS'N, REGULATORY ASSISTANCE PROJECT, MEETING RENEWABLE ENERGY TARGETS IN THE WEST AT LEAST COST: THE INTEGRATION CHALLENGE (2012) [hereinafter WGA REPORT].

157. *Id*. at ES-2.

BAs.[158] Some of those BAs are ISOs or RTOs; others (including BPA) want to avoid FERC regulation as an RTO for a variety of institutional reasons. Coordinating consistent policies across the vast geographic scale and institutional complexity of the WECC grid is therefore more challenging than in tighter, more closely-coordinated regions where RTOs or ISOs exist such as the PJM Interconnection,[159] ISO-New England (ISO-NE),[160] or the Electric Reliability Council of Texas (ERCOT).[161] Each of the latter regions has more similarity among their members than the WECC and has experience with complex and sophisticated markets, so it has been easier to get agreement on policy. The RTO/ISO structures also give FERC more direct authority over those BAs and their generation and integration policies, although FERC's definition of the BPA dispute as a *transmission* conflict allowed FERC to exercise jurisdiction over BPA's curtailment policies.

The WGA report identifies nine strategies to reduce renewable integration costs:

1. *Expand Subhourly Dispatch and Scheduling*
2. *Facilitate Dynamic Transfers Between Balancing Authorities*
3. *Implement an Energy Imbalance Market*
4. *Improve Weather, Wind, and Solar Forecasting*
5. *Take Advantage of Geographic Diversity of Resources*
6. *Improve Reserves Management*
7. *Retool Demand Response to Complement Variable Generation*
8. *Access Greater Flexibility in the Dispatch of Existing Generating Plants*
9. *Focus on Flexibility for New Generating Plants*

We summarize and discuss each of these strategies in this Part. Our overview is only a summary of the key considerations for each strategy, so we strongly recommend that policy-makers read the entire 128-page

158. 20 of these 37 BAs are now involved in the Northwest Power Pool, which covers all or part of seven U.S. states and two Canadian provinces. *Id*. at 2.

159. Originally comprised of utilities in Pennsylvania, New Jersey and Maryland (PJM); PJM now includes utilities in 13 states in the mid-Atlantic region and Midwest: all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The PJM region has an area of 214,000 square miles, a population of about 60 million and a peak demand of 163,848 megawatts. *See PJM–Territory Served*, PJM.COM, http://www.pjm.com/about-pjm/who-we-are/territory-served.aspx (last visited Dec. 21, 2012).

160. The New England regional electric power system serves 14 million people living in a 68,000 square-mile area with a peak demand of just over 28,000 MW. It includes all of the states of Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and Maine. ISO NEW ENGLAND, 2012 REGIONAL SYSTEM PLAN 23–24 (2012)

161. ERCOT manages the flow of electric power to 23 million Texas customers (85 percent of the state's electric load). Electric Reliability Council of Tex., *About ERCOT*, ELECTRIC RELIABILITY COUNCIL OF TEX., http://www.ercot.com/about/ (last visited Dec. 21, 2012). Like CAISO (and unlike PJM or ISO-NE), ERCOT operates only within a single state—giving state regulators a greater regulatory role.

WGA Report in order to understand the subtleties and nuances of each policy recommendation. The full WGA Report includes important figures and tables as well as working examples of particular strategies or pilot projects to test the strategies. Our purpose is to illustrate the suite of strategies and policy initiatives that are necessary to minimize renewable integration costs while simultaneously promoting incentives for the development of a robust, resilient, and reliable electricity grid. Such a grid must be able to accommodate the technologically and geographically diverse set of renewable generation technologies necessary to meet environmental policy goals. No single strategy is sufficient, and most strategies are likely to be much more effective if other strategies are also implemented. The nine strategies, and their sub-options, are therefore complementary rather than competitive.

Each of the "integration actions" described in the WGA Report has different expected costs, expected benefits, and projected timeframes to implement the option. The expected costs and benefits are characterized as "low" (less than $10 million region-wide), "medium" (between $10 million and $100 million), or "high" (more than $100 million). The projected timeframe is either "short" (less than two years), "medium" (two to five years), or "long" (more than five years).[162] We summarize that assessment of costs, benefits, and projected timeframes at the end of each strategy and sub-option below.

A. Expand Subhourly Dispatch and Scheduling

The WGA makes an important distinction between economic dispatch ("the process of maximizing the output of the least-cost generating units in response to changing loads") and scheduling ("the advance scheduling of energy on the transmission grid").[163] The temporal variability of many renewables (e.g., wind, photovoltaic solar with partially cloudy conditions) results in a greater need to dispatch resources on a sub-hourly basis and to schedule transmission capacity on a sub-hourly basis. Otherwise, dispatchers would need to ramp other generating resources up or down while facing either underutilization or oversubscription for transmission services. The result is economically inefficient and imposes higher

162. The methods and assumptions used in the WGA Report's assessment of integration actions are described in Appendix A and summarized on page ES-3 of the WGA Report. WGA REPORT, *supra* note 156, at ES-3, app. A.
163. *Id*. at ES-4.

integration costs than would occur with sub-hourly generation dispatch and sub-hourly scheduling.

Only two of the 37 BAs in the West, CAISO and Alberta, regularly use sub-hourly dispatch and scheduling today. The intra-hour dispatch and scheduling frequency may be every 5 minutes, every 15 minutes, every 30 minutes, or every 30 minutes scheduled only once each hour at the top of the hour. The norm—and the *pro forma* OATT under FERC Order No. 890—remains hourly scheduling with sub-hourly dispatch. Shifting to sub-hourly scheduling would reduce conflict over transmission system access as well as the economic costs of integration. BPA has been experimenting with sub-hourly dispatch and scheduling, including a pilot project with CAISO from October 2011 through September 2012 for up to 400 MW between the BAs.[164]

WGA notes that "[a] system-wide regime including dispatch, scheduling, balancing and settlement—all implemented at the same shorter time interval—yields the maximum benefits."[165] Moreover, "integration studies estimating the benefits of intra-hour transmission scheduling assume implementation would be mandatory and bundled with sub-hourly dispatch, balancing and settlement. Expected benefits of intra-hour transmission scheduling could be significantly lower in the absence of these requirements." Therefore, "[o]ptional 15-minute transmission scheduling as a stand-alone product may not result in significant reductions in overall system reserve requirements."[166]

Sub-hourly dispatch and Intra-hour scheduling is broken down into three options:

1. Non-standard, voluntary, not West-wide, with 30-minute intervals (low cost, low benefit, short timeframe).
2. Standard, voluntary, not West-wide, with 5 to 15 minute intervals (low to medium cost, low to medium benefit, short timeframe).
3. Standard, required, West-wide, with unspecified intervals (low to high cost, medium to high benefit, medium timeframe).

As discussed in Part V, FERC Order No. 764 requires sub-hourly scheduling on a 15-minute basis beginning in June 2013. FERC therefore took action on the first WGA recommendation the same month it was released in June 2012. We discuss the adequacy of Order No. 764 in Part V.

164. *Id*. at 6–8.
165. *Id*. at 11.
166. *Id*. at 18, n. 57.

B. Facilitate Dynamic Transfers Between Balancing Authorities

Dynamic transfer involves "electronically transferring generation from the balancing authority area in which it physically resides to another balancing authority area in real-time. Such transfers allow generation to be located and controlled in a geographic location that is outside of the receiving balancing authority area."[167] In essence, it gives one BA that is consuming the power (e.g., CAISO) control over the operation of the generating plant even though the plant is in a different BA (e.g., BPA). This shifts the responsibility for managing the variability of generating output to the consuming BA, but it also requires the source BA to keep transmission open "for maximum dynamic flow that could occur within the scheduling period."[168] Moreover, dynamic transfers also increase power and voltage fluctuations, which "are more difficult to manage as more dynamic transfers have large and frequent ramps [i.e., dramatic changes in output, either up or down] within the scheduling period."[169] These concerns over control, the opportunity costs of potentially unused transmission capacity, and power or voltage fluctuations have limited the use of dynamic transfers.[170]

The benefits of dynamic transfers—especially if transmission investments can be made to reduce the risks of power and voltage fluctuation while expanding the capacity for such transfers—relate primarily to the increased diversity of generating resources from other BAs and increased operational flexibility associated with the aggregated demand and generating resource mix of multiple BAs. Some of the renewable resources located in other BAs are also likely to be lower-cost than generating resources within the consuming BA, so expanding dynamic transfers could lower overall generating costs (whether they would lower total system costs depends on the cost of transmission investments, though.)

167. *Id*. at ES-5.
168. *Id*.
169. *Id*.
170. An out-of-state generator with dynamic transfer qualifies the resource to meet the California RPS under the most desirable category, so there are many generators who would like BPA to give CAISO more dynamic transfer authority for exports from the BPA BA to CAISO. *See* CA PUB UTIL. CODE § 399.16(b)(1). One wind generator in the BPA BA (Public Utility District No. 1 of Cowlitz County) has challenged this provision of the California RPS requiring dynamic transfer (and the unlikelihood of getting it) as a violation of the dormant Commerce Clause. Daniel K. Lee and Timothy P. Duane, *Putting the Dormant Commerce Clause Back to Sleep: Adapting the Doctrine to Support State Renewable Portfolio Standards*, ENVTL. L. (forthcoming 2013).

Dynamic transfers have been used by utilities for decades, but the transfers have generally involved less variable generating resources and have followed hourly, rather than sub-hourly, scheduling and dispatch.

CAISO has accommodated dynamic transfers at a sub-hourly time scale,[171] but its three interties with BPA each have different limits on dynamic transfers that constrain overall use of the option.[172] A recent Joint Initiative Dynamic Scheduling System has been experimenting with dynamic transfers throughout the west since 2009, with 18 entities involved by October 2011.[173] The Joint Initiative has specifically been studying how to facilitate expanded dynamic transfers of wind generation from the Pacific Northwest to CAISO since October 2010 and has developed preliminary options for enhancing transfer variability limits.[174] Those options are primarily technical, rather than institutional, fixes and require significant investments to increase the technical capabilities of the transmission system. Determining who shall pay for those investments remains a sticking point, however, and it is the primary impediment to implementing the technical changes.

Dynamic Transfers are broken into two alternatives in the option assessment:

1. Improved tools and operating procedures (low cost, low to medium benefit, short to medium timeframe).
2. Equipment upgrades, including new transmission lines (medium to high cost, medium to high benefit, short to medium timeframe).

C. Implement an Energy Imbalance Market

Perhaps the most important—and controversial—option considered in the WGA Report is the implementation of a region-wide Energy Imbalance Market (EIM). An EIM "is a centralized market mechanism that would enable dispatch of generation and transmission resources *across* balancing authority areas (BAs) to resolve energy imbalances—differences between generation and demand."[175] The WGA Report's rationale for an EIM is worth quoting at length:

> As proposed for the Western U.S., an EIM is a centralized market mechanism to:
>
> 1. re-dispatch generation every five minutes to maintain load and resource balance, addressing generator schedule deviations and load forecast errors and

171. WGA REPORT, *supra* note 156, at 23, 26–27.
172. *Id*. at 23, 28–29.
173. *Id*. at 24.
174. *Id*. at 30.
175. *Id*. at 32 (emphasis in original).

2. provide congestion management service by re-dispatching generation to relieve grid constraints.

> An EIM would increase the efficiency and flexibility of system operations to integrate higher levels of wind and solar resources by enabling dispatch of generation and transmission resources across balancing authorities. That would harness the full diversity of load and generation in a broad geographic area to resolve energy imbalances. An EIM would optimize the dispatch of imbalance energy within transmission constraints, reducing operating costs and reserve needs and making more efficient use of the transmission system. In addition, an EIM would provide reliability benefits by coordinating balancing across the region, making more generation available to system operators.[176]

In essence, an EIM takes advantage of the portfolio effect on both supply and demand: by having access to a more diverse aggregate set of generating resources and load, costs can be lowered while maintaining reliability. Studies by the NREL show significant potential benefits from a regional EIM with 30% wind penetration. Reduced reserve requirements would save $221 million per year if implemented across the entire West (excluding CAISO and Alberta). The benefits drop to $144 million per year if implemented without BPA and the Western Area Power Administration (WAPA), which is the federal marketing agent for other hydropower generated from federal facilities on the Colorado River and elsewhere outside the Pacific Northwest.[177] Another study commissioned by WECC estimated projected annual benefits of $141 million in 2020.[178]

Achieving such savings entails some risks, however, with an uneven distribution of benefits and costs among the BAs in the West. "Concerns have been raised that market manipulation could lead to costs outweighing potential benefits of an EIM," notes the WGA Report, so "[a] market monitor would be needed to ensure that no abusive scheduling or market manipulation practices occur."[179] Governance structure then becomes central to such an EIM. Many of the BAs in the West are resistant to participation in an RTO or ISO structure, because those BAs believe that doing so would give away too much control over both their operations and their authority to control rates. In essence, establishing an EIM would shift electrical utility operations further from a cost-of-service or

176. *Id*. at ES-6.
177. *Id*. at 37 (citing J. KING, ET. AL., FLEXIBILITY RESERVE REDUCTIONS FROM AN ENERGY IMBALANCE MARKET WITH HIGH LEVELS OF WIND ENERGY IN THE WESTERN INTERCONNECTION, NREL REP. NO. TP-5500-52330 (2011), *available at* http://www.nrel.gov/docs/fy12osti/52330.pdf.).
178. WGA REPORT, *supra* note 156, at 36–37.
179. *Id*. at 34.

rate-of-return regulatory structure toward more of a market-based rate and economic recovery model. Understandably, many utilities (and their customers) with relatively low rates and strong expected rate stability are nervous about such a shift. They fear an EIM throughout the West would expose them to the types of wholesale market manipulation and rate shocks that propagated throughout the West during the California Energy Crisis of 2000-2001.[180]

Despite these concerns—or, perhaps, because of these concerns—the Northwest Power Pool Market Assessment and Coordination Committee has brought together twenty BAs in the West along with several other utilities to evaluate the costs and benefits of an EIM.[181] State public utilities commissions also organized a PUC EIM Group in November 2011 to study the benefits and costs of an EIM throughout the region.[182] Politically, those BAs and PUCs probably have the power to prevent FERC (or Congress) from compelling an EIM throughout the WECC. And those BAs and PUCs are unlikely to support a region-wide EIM unless the issue of integration cost allocation is resolved with clarity in a way that they believe is fair to them.

The WGA explicitly addresses whether an EIM would lead to an RTO or ISO structure and wholesale energy markets by conditioning what an EIM would entail:[183]

> An EIM would not be a full wholesale energy market. It would not include a day ahead market, coordinated unit commitment, financial transmission rights or an ancillary services market. Also, an EIM would not eliminate existing transmission arrangements. Under an EIM, entities may continue current practices for obtaining transmission service, such as reserving and entering into long-term contracts for firm point-to-point and network transmission service.
>
> The EIM proposal would not establish an RTO or a consolidated regional network transmission tariff. The EIM governance documents could include provisions that would allow expansion of functions only with unanimous or supermajority agreement. While FERC would have jurisdiction to determine that EIM rates, terms and conditions are just and reasonable, that would not cause EIM participants to become jurisdictional themselves.
>
> To avoid RTO characteristics or status, the EIM should not provide transmission service or control transmission facilities owned by others and should not have an OATT. Participating transmission providers would retain their own OATTs with modifications to integrate their activities with the EIM. Each transmission owner could add an EIM transmission service and rate to its OATT that conforms to a common, agreed upon approach requiring FERC approval.

180. Duane, *supra* note 19.
181. WGA REPORT, *supra* note 156, at 41.
182. *Id*.
183. *Id*. at 33–34.

Energy Imbalance Markets are broken into two alternatives in the option assessment:

1. Subregion only (medium to high cost, medium benefit, medium timeframe).
2. West-wide (medium to high cost, high benefit, medium to long timeframe).

D. Improve Weather, Wind, and Solar Forecasting

"Weather is a primary influence on all electric systems as it drives load demand, in addition to variable generation sources such as wind and solar," notes the WGA. "Thus, forecasting of variable generation should be viewed in the broader context of weather forecasting."[184] Despite these common sources of variability, however, our uncertainty in predicting load is now considerably smaller than our uncertainty about wind generation: day-ahead forecasting error for load is only 1-3% compared to 15-18% for wind energy and 6-8% for wind capacity on a regional basis. Day-ahead forecasting error for a single wind plant is even greater, as it would also be for a single customer's load: day-ahead forecasts are off by 25-30% for energy and 10-12% for capacity. Hour-ahead wind forecast error is smaller, but still significant: 6-11% for regional energy and 3-6% for regional capacity—10-15% for a single plant's energy and 4-6% for its capacity. Therefore, improving weather, wind, and solar forecasts—including adopting state-of-the-art forecasting methods already available—has significant value.[185]

That value is manifest primarily in reducing the economic costs of maintaining reserves. "Continuing use of and improvements in variable generation forecasting will give balancing authorities more confidence in the forecasts over time," states the WGA, "and allow balancing authorities to hold lower levels of reserves."[186] Lower reserves mean much lower integration costs: NREL has estimated, with 35% wind and solar penetration,[187] that use of state-of-the art day-ahead variable generation forecasting "would reduce annual operating costs in the WECC region by up to $5 billion annually" and that "perfect forecasts would reduce

184. *Id*. at ES-7.
185. *Id*. at 46.
186. *Id*.
187. The benefits of forecasting would be lower with lower levels of renewables penetration.

operating costs in WECC by another $500 million" annually.[188] Note that 90% of the benefits achievable with perfect forecasts would be realized simply by adopting existing state-of-the-art forecasting methods. Thus, existing methods simply need to be adopted to realize these benefits.

Improved weather, wind and solar forecasting would have medium cost, medium-to-high benefit, and could be implemented in a short to medium timeframe. FERC Order No. 764 requires monitoring and reporting that should improve forecasting. We discuss the adequacy of Order No. 764 in Part V.

E. Take Advantage of Geographic Diversity of Resources

As noted in Part II and as demonstrated by the region-versus plant-specific forecast uncertainty estimates in the previous section, increasing geographic diversity is usually associated with reduced variability in renewable generation output. The reason is that "wind and solar projects are less correlated and have less variable output in aggregate."[189] This reduced correlation "reduces ramping of conventional generation for balancing, as well as forecasting errors and the need for balancing (not contingency) reserves."[190] However, the benefits of increased geographic diversity may be counterbalanced by increased transmission investment costs and decreased generator productivity on less resource-rich sites. Less productive sites would generally mean both greater environmental impacts associated with renewable generation (e.g., more land impacted) and higher production costs (excluding any diversity benefits).

"The question," states the WGA Report succinctly, "is whether reducing aggregate variability of variable generation through geographic diversity, with the resulting reductions in reserves requirements and wind and solar forecast errors, justifies initiatives such as transmission expansion."[191] The answer to that question depends on the initial geographic diversity of the BA and the degree to which each BA is integrated with other BAs (e.g., through Dynamic Transfers, an EIM, or both) to acquire functional diversity across the integrated BAs. "Some regions in the U.S. have large balancing authority areas that naturally provide geographic diversity," notes the WGA Report, but "[d]iversity also can be accessed through greater balancing authority cooperation, building transmission and optimized siting of wind and solar plants. Siting these resources without regard to geographic diversity may have higher [total system] costs

188. WGA REPORT, *supra* note 156, at 48.
189. *Id*. at ES-8.
190. *Id*.
191. *Id*.

[including integration costs] compared to projects sited to minimize transmission costs."[192] On the other hand, "if the resource sites are not of equal quality, more wind and solar capacity may be required to achieve the same generation output—at higher cost—compared to developing higher quality resources that are geographically concentrated."[193]

There is no institutional decision process in today's hybrid regulatory structure where all of these cost considerations—the portfolio benefits of reduced variability, the increased transmission costs required to achieve increased geographic diversity, and the increased environmental and economic costs of siting generation in less resource-rich regions—are aggregated to determine which generation and transmission resource mix is truly least-cost.[194] Instead, each party in the system assesses the costs and benefits of individual investments only in terms of those costs and benefits borne directly by that party. With very few exceptions, there are no incentives to make transmission or generation investments based on minimizing total system cost. The result, not surprisingly, is a system that fails to capture the benefits of diversity and fails to compensate those who can provide the benefits of diversity.

The sources of the BPA-wind conflict are at least in part due to this lack of incentives, which translate into a lack of transmission capacity to facilitate geographic diversity. "BPA's service area is an example of wind development concentrating around available transmission," notes WGA. The result is high vulnerability to a wind "ramping event." One such event occurred on February 1-2, 2012 when wind production ramped up 1,410 MW in just 40 minutes, an increase by 37% of BPA's installed wind capacity. "Such rapid rises in wind production over a short period of time are relatively unusual, but they must be managed with sufficient balancing capacity."[195] This then strains the hydropower system and other generation available to BPA, which must be backed down to

192. *Id*.
193. *Id*.
194. Both FERC and state regulatory commissions conduct these analysis when considering the public costs and benefits of specific projects that come before them for approval (e.g., hydroelectric licenses and transmission lines for FERC, approval of utility investments or PPAs for state regulators, permitting decisions by the California Energy Commission or other state or federal permitting authorities such as federal land agencies). None of those state or federal regulators has authority over the other regulators or private parties engaging in market transactions, however, where the *distribution* of costs and benefits will often determine which investments are ultimately built by each party acting independently.
195. WGA REPORT, *supra* note 156, at 66.

accommodate the wind ramp. A more typical wind ramp on the BPA system occurs over several hours—but wind generation is still highly correlated in the BPA system due to the strong Columbia Gorge wind resource and transmission constraints.

High levels of geographic aggregation reduce variability even with high levels of renewables penetration. According to NREL's analysis "WECC-wide, net load variability is actually lower than variability with load alone" with 30% wind and solar penetration. Net load variability is much higher for individual states or BAs, however, due to their lower levels of geographic diversity affecting both load variability and renewable generation variability.[196] But benefits of greater geographical diversity are unlikely to be realized under the current institutional structure.

The WGA Report is filled with citations to similar findings from smaller-scale studies: a portfolio effect in Arizona that dampens rapid wind ramps,[197] dramatic reductions in solar photovoltaic output variability in California, Nevada, Arizona, Colorado, and Germany,[198] and even *negative* integration costs in Montana for dispersed wind generation.[199] Diverse renewables generation, together with diverse loads, can often result in net load profiles that are not significantly any more variable than the existing load profiles. In other words, high renewables penetration—*if* both technologically and geographically diverse—may *not* increase the technical challenge of managing variability in the electrical system.[200] Technological diversity (e.g., wind combined with hydropower in the Pacific Northwest; wind combined with wave energy in Scotland, Ireland,

196. *Id.* at 55 (citing NATIONAL RENEWABLE ENERGY LABORATORY, GE ENERGY, WESTERN WIND AND SOLAR INTEGRATION STUDY (2010), *available at* http://www.nrel.gov/wind/systemsintegration/wwsis.html). A subsequent study by the WECC Variable Generation Subcommittee found that improved coordination reduced load following and regulation reserve requirements by roughly 50%. WGA REPORT, *supra* note 156, at 55 (citing WESTERN ELECTRICITY COORDINATING COUNCIL VARIABLE GENERATION SUBCOMMITTEE, ELECTRICITY MARKETS AND VARIABLE GENERATION INTEGRATION, 2012 ADDENDUM (2012), *available at* http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/2012%20Addendum%20%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf).

197. WGA REPORT, *supra* note 156, at 56 (citing NORTHERN ARIZONA UNIVERSITY, FINAL REPORT: ARIZONA PUBLIC SERVICE WIND INTEGRATION COST IMPACT STUDY (2007), *available at* http://www.uwig.org/APS_Wind_Integration_Study_Final9-07.pdf).

198. WGA REPORT, *supra* note 156, at 58–60. In Germany, 50% variation in single plant output was reduced to only 10% variation for 100 dispersed sites. Ramp rates for solar output were also reduced by 90% for the 100 sites when aggregated compared to ramp rates for individual plants.

199. *Id*. at 64.

200. *Id*. at 62. The WGA Report cites a study by CAISO demonstrating this relationship for July 2003, but significant increases in renewables penetration, together with other changes to the CAISO portfolio, are likely to alter this conclusion by 2020. *See infra* Part V.

and California; wind, wave and solar in Denmark) is a key element in these systems. Geographic diversity alone is unlikely to yield the same level of benefits.[201]

"By itself," concludes the WGA, "geographic diversity is probably insufficient to justify new or upgraded transmission lines but it may be an additional benefit. Regardless, the benefits of geographic diversity clearly support balancing authority area aggregation and greater cooperation across areas."[202] This conclusion highlights the complementary character of many of the WGA options: many of them are more valuable if others are simultaneously implemented.

Geographic Diversity is broken into two alternatives in the option assessment:

1. If using existing transmission (low to medium cost, low to medium benefit, medium timeframe).
2. If new transmission needed (high cost, medium benefit, long timeframe).

F. Improve Reserves Management

Power system reserves are those "quantities of generation or demand that are available as needed to maintain electric service reliability." The WGA Report distinguishes *contingency* reserves ("for unforeseen events, such as an unscheduled power outage") from *balancing* reserves ("for day-to-day balancing of generation and demand").[203] Balancing reserves are either for *regulation* (to "balance the momentary fluctuations in generation and load and deviations from forecasts" through Automatic Generation Control [AGC] systems) or *load-following* ("used to respond to changes on a slower time scale—tens of minutes to hours" due to "expected imbalances as a result of predicted changes in near term load and generation").[204]

The cost of maintaining and operating such reserves—which generally must be increased with higher levels of renewables penetration to manage more variable generation—can be reduced through four management strategies: (1) reserve sharing; (2) dynamic calculation of reserve requirements; (3) contingency reserves for extreme wind drops; and (4) wind ramp rate limits or controls on variable generation with curtailment

201. WGA REPORT, *supra* note 156, at 62.
202. *Id*. at ES-8.
203. *Id*. at ES-9.
204. *Id*. at 68.

compensation.[205] *Reserve sharing* "can reduce the individual reserve requirements of the system by averaging out short-term load and resource fluctuations across balancing authority areas."[206] *Dynamic calculation of reserve requirements* would shift from a system of static reserve requirements (i.e., reserve requirements that are independent of the specific conditions affecting the BA in a given hour) to one "based on factors such as the load forecast, the variable generation forecast, net load variability forecast, the confidence in forecasts, and possibly information on the expected behavior of conventional generation."[207] Improved forecasting confidence is critical to deploying this strategy successfully. This is another example of how most of the WGA options' effectiveness can be enhanced by the implementation of one or more of the other WGA strategies.

"There are situations in which the loss of wind generation is similar to the loss of conventional units," states WGA, "such as when wind plants are tripped at their point of interconnection."[208] In these situations, "it may be desirable to assess whether large wind ramp events should be treated as contingencies [rather than as necessitating balancing reserves] because use of contingency reserves could reduce costs and increase reliability."[209] Treating these rare wind events as contingencies would shift the reserve requirement from *balancing* reserves to *contingency* reserves—which are generally less flexible and responsive and therefore less costly to maintain in reserve. WGA cautions that this approach requires further analysis, however, before the reclassification could be implemented.[210]

The most controversial policy option from the perspective of renewable generators is the strategy used by BPA that triggered its dispute with wind generators before FERC: *controlling variable generation*. It is also a strategy that is very attractive to many BAs, because "[r]elatively modest limits on wind turbine operations could significantly reduce the need to hold balancing reserves."[211] One way to encourage such regulation would be to offer higher payments for variable generators who accept such limits—a version of the negative pricing approach advocated by

205. *Id*. at ES-9.
206. *Id*. at 69.
207. *Id*. at 70–71.
208. *Id*. at 72.
209. *Id*. at 71.
210. *Id*. at 71–72. The ramifications of reclassifying reserve requirements as contingency rather than balancing depend on the generation mix and the degree of BA integration, so this BA-specific analysis may be required to determine if such a reclassification is appropriate. Moreover, whether or not other WGA strategies are adopted will influence the reliability consequences of reclassifying reserve requirements.
211. *Id*. at 72.

wind generators in the BPA dispute. But current “bilateral markets and transmission tariffs do not make distinctions based on these factors.”[212] Moreover, “supplying regulation from wind and solar generators would require the units to operate below full capacity to be able to ramp up, foregoing low-cost and clean generation.”[213] The strategy therefore has some costs. Wind already provides regulation service in Denmark, however, and ramp rate controls are in operation in Hawaii, Texas, Ireland, and Germany.[214] Xcel is also adding AGC to wind plants to increase operator confidence and reduce wind curtailments.[215]

The overall potential for some of these reserve management strategies ultimately depends on the degree of cooperation and coordination among the 37 BAs in the WECC. NREL estimated that consolidation to just five BAs would yield annual operating cost savings of $1.7 billion with a 10% renewables penetration scenario. Penetration to 30% wind and renewables would double reserve requirements, but “the presence of renewable resources on the system can free up conventional generators to provide up-reserves” so that “reserves required to accommodate wind and solar can be supplied by existing natural gas plants that are backed down.”[216] The paradoxical result is that “net load variability increases” with 30% renewables, but “there was no need to commit additional reserves to cover variability resulting from increased wind and solar” generation.[217] The NREL analysis assumes “full balancing authority coordination,” though, rather than 37 independent and uncoordinated BAs.[218]

Reserves Management is broken into four alternatives in the option assessment:

1. Reserves Sharing (low cost, low to medium benefit, short timeframe).
2. Dynamic Calculation (low cost, low to medium benefit, short timeframe).
3. Using Contingency Reserves for Wind Events (low to medium cost, low to medium benefit, short to medium timeframe).
4. Controlling Variable Generation (assuming requirements are prospective) (low to medium cost, low to medium benefit, medium to long timeframe).

212. *Id*.
213. *Id*.
214. *Id*. at 73.
215. *Id*. at 104.
216. *Id*. at 73.
217. *Id*.
218. *Id*.

G. Retool Demand Response to Complement Variable Generation

Improved energy efficiency and demand response (DR) or demand side management (DSM) are essential ingredients of an integrated electrical system with a high level of renewables penetration. Improving DR as a complement to supply-side investments is also a cost-effective strategy for matching demand with supply. FERC adopted Order No. 745 (Demand Response Compensation in Organized Wholesale Energy Markets) in 2011 to encourage more effective DR,[219] and it already plays a significant role in the PJM, ISO-NE, and ERCOT markets.[220] The WGA Report highlights how DR can be tailored to improve integration of renewables while reducing integration costs compared to some supply-side or transmission investments. "To realize significant integration benefits," states WGA, "this must be done through either direct control of the load or pre-programmed responses to real-time prices."[221]

WGA differentiates the role played by DR when load is uncertain (where DR can be implemented to reduce peak load) from when supply is uncertain (and also more variable daily and throughout the year);[222] in particular, some DR programs and technologies may be most useful because they can quickly increase demand to absorb "excess" generation from renewables and then store it for later use. Examples include pilot programs by Mason County PUD No. 3 in Washington[223] and BPA, where customers' electric hot water heaters are controlled to consume electricity that is then converted to thermal energy by heating the water—which can then be used as thermal energy without impacts on the grid. BPA is also testing space heating and cold storage systems "as distributed energy storage devices to provide load following (10- to 90-minute load ramps both up and down)" to manage variable renewable generation on the system.[224] Cold storage systems have also been proposed to accommodate morning solar ramps in California both to consume the excess solar generation, thereby reducing the need to ramp down other generators, and to reduce afternoon and early evening peak demand by releasing the cold storage during hot periods of normal air conditioning

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219. Demand Response Compensation in Wholesale Organized Markets, 134 FERC ¶ 61,187 (Mar. 15, 2011); *see also* Joel B. Eisen, *Who Regulates the Smart Grid?: FERC's Authority Over Demand Response Compensation in Wholesale Electricity Markets*, 4 SAN DIEGO J. CLIMATE & ENERGY L. 69, 81 (2013).

220. WGA REPORT, *supra* note 156, at 75 (discussing ERCOT), 112 (discussing New England ISO and PJM).

221. *Id*. at ES-10.

222. *Id*. at 75.

223. *Id*. at 86.

224. *Id*. at 85.

demand.[225] Other "proofs of concept" in the WGA Report include programs to balance French nuclear plants, Denmark's EcoGrid Project, and ERCOT—which "already gets 50 percent of its spinning reserves from demand response."[226] ERCOT had 21 load resource deployments from 2006-2012 with 8.5% wind generation—15 of which were outside of the summer, and eight of those were between 8 p.m. and 8 a.m.[227] Similar reliance on DR in the WECC could reduce reserve requirements.

Implementation of FERC Order No. 745 occurs in the context of new information, communication, and control technologies,[228] all of which have the potential to transform both the technical and economic feasibility of widespread reliance on DR to address integration.[229] WGA estimates that DR costs only 10-30% of pumped storage or compressed air storage,[230] but there is still debate over how much DR can be achieved through real-time price signals versus direct control.[231] Third-party aggregators may also play a prominent role under Order No. 745.[232] One estimate of DR potential in the West shows over 13,000 MW of capacity in 2022 in a "High DSM Case" through a combination of: (1) interruptible load; (2) direct load control; (3) critical peak pricing; and (4) load as a capacity resource.[233]

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225. Kelly Foley, Vote Solar, Presentation to the Environmental Law Conference at Yosemite, (Oct. 27, 2012).

226. WGA REPORT, *supra* note 156, at 85–86.

227. *Id*. at 75 n.283.

228. *Id*. at 75.

229. Joel Eisen, Edward Randolph, and Tom Brill have all used iPhone metaphors to describe the challenge of "smart grid" design today: like the iPhone, designers of the smart grid and associated markets do not know how future applications (apps) may evolve to take advantage of the underlying smart grid structure. Joel B. Eisen, Professor, University of Richmond School of Law, Presentation to the Fourth Annual Climate & Energy Law Symposium (Nov. 9, 2012); Edward Randolph, Director, Energy Division, California Public Utilities Commission, Presentation to the Fourth Annual Climate & Energy Law Symposium (Nov. 9, 2012); Tom Brill, Director of Strategic Analysis, San Diego Gas & Electric, Presentation to the Fourth Annual Climate & Energy Law Symposium (Nov. 9, 2012).

230. WGA REPORT, *supra* note 156, at 76.

231. *Id*. at 81–82. Both equity issues (for real-time pricing) and privacy issues (for direct control through so-called Smart Meters) are prominent as regulators explore DR options.

232. *See* Audrey Zibelman, Founder, President and CEO, Viridity Energy, Presentation to the Fourth Annual Climate & Energy Law Symposium (Nov. 9, 2012), *available at* http://www.sandiego.edu/law/news/webcasts/2012.php#cel-symposium-2012.

233. WGA REPORT, *supra* note 156, at 84.

Demand Response is broken into three alternatives in the option assessment (all have low to medium cost, low to medium benefit, short to medium timeframe):

1. Discretionary Demand
2. Interruptible Demand
3. Distributed Energy Storage Appliances

H. Access Greater Flexibility in the Dispatch of Existing Generating Plants

Flexibility in the non-renewables resource mix lowers integration costs. Individual generating plant flexibility is determined primarily by "[o]utput control range, ramp rate and accuracy—along with minimum run times, off times and startup times,"[234] but those characteristics are already established for most of the existing generating fleet. Therefore, the WGA report lists retrofitting existing generators as only the last priority among four strategies to increase flexibility: "First, establish generator scheduling rules that do not block access to the flexibility capability that already exists" (WGA strategy 1); "Second, perform balancing over as large a geographic area as possible" (WGA strategies 2, 3, 5 and 6); "Third, design flexibility into each new generator by selecting technologies that are more flexible" (WGA strategy 9). Finally, retrofit existing generators "when this is practical and cost-effective."[235] "Among the barriers to retrofitting plants," however, "are the fundamental limitations of the technology, uniqueness of each plant, cost and uncertain payback. The benefits of increasing existing plant flexibility may be comparatively small compared to other ways to reduce integration costs, such as larger balancing authorities and intra-hour scheduling."[236]

The WGA Report discusses a wide range of technology-specific opportunities for innovation (for new plants) and retrofitting (for existing plants) to improve flexibility. Cycling wear and tear costs are often plant-specific, but generally highest for coal and nuclear power plants.[237] Natural gas supply scheduling is also a constraint for some natural gas-fired plants.[238] WGA states that in 2005 "thermal ramping capability exceed[ed] load-ramping requirements" for CAISO, PJM, and WAPA, but existing administrative rules limited operator access to that full flexibility.[239] Dramatic increases in renewable generation since 2005,

234. *Id*. at 89.
235. *Id*. at ES-11.
236. *Id*.
237. *Id*. at 98.
238. *Id*. at 106.
239. *Id*. at 93.

together with other constraints on the operation of existing generators, may make this study less illustrative of actual conditions today. CAISO is now dealing with strict existing air quality constraints on some fossil-fuel facilities, the unexpected shut down of the San Onofre Nuclear Generating Station (SONGS) in 2012, and new state water quality regulations that will require either the retirement or repowering of 12,000 MW of existing thermal generation by 2020.[240] Approximately 80% of CAISO's current load-following requirements are due to loads while only 20% is due to variable energy generation[241]—but the impact of variable generation on load-following demands will increase by 2020.[242] Therefore, it is critical that flexibility be valued and rewarded as the existing generator fleet transitions.

The costs of cycling existing plants vary widely and are often plant-specific; NREL is now modeling those costs in an effort to refine integration cost estimates for high-penetration renewables scenarios.[243] Inclusion of any new lower cost base load generator, including non-renewable generators, in the resource mix can increase coal plant cycling as the most expensive units—which often have greater flexibility—are pushed out of the dispatch order.[244] There is also a relationship between technological investments and operational practice. The flexibility needs of the grid ultimately "depend on the institutional framework that is in place. If the operational and market tools described earlier in [the WGA] report are further developed in the Western U.S., less physical flexibility will be needed" for integration.[245]

Reliability of Existing Plants is broken into two alternatives in the option assessment:

1. Minor Retrofits (low to medium cost, low to medium benefit, short to medium timeframe).
2. Major Retrofits (medium to high cost, medium to high benefit, medium to high timeframe).

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240. Rothleder, *supra* note 10.
241. WGA REPORT, *supra* note 156, at 94.
242. Rothleder, *supra* note 10.
243. WGA REPORT, *supra* note 156, at 101.
244. *Id*. at 100.
245. *Id*. at 102–03.

I. Focus on Flexibility for New Generating Plants

High levels of renewable penetration will require new non-renewable generating plants to have high levels of flexibility. As the WGA Report notes, however, "[r]esource planning and procurement processes typically are not focused on flexible capability" for either renewables or non-renewable generation."[246] Therefore, new institutional incentives must be established to ensure that new generating plants can provide the specific flexibility needed with high renewables penetration. "New criteria and methods are needed to evaluate flexible capabilities of resource options" in procurement processes,[247] because a utility may risk a disallowance from rate recovery if it pays more for more flexible resources than lower-cost, but less flexible resources.[248] As a consequence, more flexible resources may not be built or operated if not valued by either the market or regulators.

There are three distinct operating conditions where integration requires flexibility: (1) high load with low renewables output; (2) low load with high renewables output; and (3) moment-to-moment variation. New non-renewable generating plants must have the ability to follow *net load* rather than *load* to integrate renewable generation—and the types of flexibility needed to meet net load differ under each of those conditions. An MIT analysis of European strategies to achieve an 80% reduction in greenhouse gas emissions by 2030 determined that Europe will need more "flexible base-load" gas combined-cycle plants to operate with more cycling, but with annual capacity factors comparable to current gas combined-cycle plants. "Together with more responsive demand, expanded transmission systems and larger balancing areas, more flexible generating resources are needed to optimize production and consumption" in the European analysis. "Essentially what is needed is a portfolio of 'flexible base-load' supply resources capable of matching net load—with its shrinking share of round-the-clock demand—without compromising efficiency."[249]

WGA identifies four approaches to procuring flexible capacity: (1) utility resource planning and procurement; (2) forward capacity markets and auctions; (3) reserve adequacy requirement with regulatory backstop for planning and procurement; and (4) voluntary capacity markets and regional pooling.[250] This mix of approaches reflects the hybrid regulatory structure: in some cases, traditional cost-of-service ratemaking or rate-of-return regulation will create incentives for utilities to invest in flexible

246. *Id*. at ES-12.
247. *Id*. at 118.
248. *Id*. at 119.
249. *Id*. at 117.
250. *Id*. at 111–13.

generation with an assurance of recovering those investments; in other cases, market incentives must be created to provide the needed flexibility. Once again, the wide variety of institutional structures under which different BAs, generators, and load-serving entities operate creates a very complex setting for establishing consistent rules and incentives in the WECC. Moreover, the variety of institutional structures increases the risk of gaming and market manipulation in the absence of strong monitoring and enforcement mechanisms.[251]

Reliability for New Generating Plants is assessed as having low to high costs, medium to high benefits, and medium to long timeframe.

J. An Integrated Approach to Integration

The WGA Report lays out an ambitious agenda that "will require an unprecedented level of cooperative action within the electric industry and between the industry and state, subregional and federal entities."[252] Each of the individual strategies and sub-options has its own merits, but successfully meeting the challenge of integrating high penetration levels of renewable generation in the WECC requires deployment of the full portfolio of complementary strategies and options:

> While any of these actions may be put in place independently of one another, all are important elements of a regional approach to low-cost integration. In addition, the extent to which any of these actions is undertaken, and therefore its costs and benefits, depends in part on the level of adoption of other actions. Further, many of these tools have important synergies (for example, forecasting, scheduling and reserves management).[253]

The most effective way to minimize integration costs is with "greater cooperation among utilities, states, subregions and federal entities to share resources, loads and transmission in order to take advantage of least-cost strategies to integrate renewable resources."[254] Cooperation is already evident among many of the BAs in the WECC, but conflicts over integration cost allocation continue to impede progress at the level required. FERC, state regulators, state legislatures, and possibly even Congress therefore now must act to "break down institutional barriers

251. Duane, *supra* note 19.
252. WGA REPORT, *supra* note 156, at ES-1.
253. *Id*. at 2.
254. *Id*.

that stand in the way of a less costly, more reliable and cleaner power system for residents and businesses."[255]

V. IMPLEMENTING THE WGA STRATEGIES

In this Part, we show that FERC has only partially implemented just three of the WGA's nine recommendations through Orders No. 745 and 764. We then recommend specific policy initiatives by FERC, state regulators, state legislatures, and Congress to reduce the costs of integrating high levels of renewables into the electrical grid.

A. FERC Orders No. 745 and 764 Only Partially Implement the WGA Strategies

FERC Order No. 764 on the Integration of Variable Energy Resources (VER),[256] which takes effect in June 2013, addresses only portions of two of the nine strategies recommended in the WGA report: (1) intra-hourly (15-minute) transmission scheduling; and (2) requiring VER generators to provide meteorological and forced outage data for production forecasting through changes to the pro forma Large Generator Interconnection Agreement [LGIA]. The benefits of intra-hourly scheduling and better forecasting were discussed in Part IV. But the Order would only partially implement the WGA's recommendations in this regard—Strategy 1: Expand Sub-hourly Dispatch and Scheduling; Strategy 4: Improve Weather, Wind, and Solar Forecasting—because the Final Rule does not require sub-hourly dispatching and the LGIA modifications are prospective only (i.e., do not apply to existing VER generators). Moreover, Order No. 764 does not require BAs to use the improved monitoring and reporting data through state-of-the-art forecasts to reduce VER generation forecast uncertainty for purposes of system operation. Many of the benefits that WGA identified for these two strategies will therefore not be realized even after Order No. 764 is implemented.

FERC's action in adopting Order No. 745 in 2011 also supports WGA Strategy 7 (Retool Demand Response to Complement Variable Generation), so FERC has taken initial steps on three of the nine WGA recommendations. FERC took no action in Order No. 764 however, on ancillary services markets (which would support WGA Strategies 8 and 9), dynamic transfers (WGA Strategy 2), energy imbalance markets (WGA Strategy

255. *Id*.
256. Integration of Variable Energy Resources, 139 F.E.R.C. ¶ 61,246 (June 22, 2012).

4), consolidated balancing areas (WGA Strategies 2, 5, and 6), or cost recovery mechanisms for integration costs (i.e., determining how the costs of integrating VER generation will be allocated). The latter issue—which affects how quickly and cost-effectively many of the other strategies could be implemented—remains the critical policy choice before FERC.

Many of the other WGA Strategies have been partially implemented in specific BAs (e.g., CAISO) or are under active exploration by key stakeholders in the WECC. Indeed, many of these stakeholders urged FERC to delay action on some of the most important policy options in order to allow those stakeholder studies and processes to continue without a "one size fits all" policy prescription from FERC. Even the actions FERC did adopt in Order No. 764 were resisted by some parties: Southern California Edison (SCE), for example, urged FERC to allow three to five years to implement those changes.

Such a timeframe may be necessary to implement some of the larger-scale policy changes that WGA recommends; until FERC adopts an Order mandating such changes, however, the implementation clock will not begin ticking. FERC therefore must act soon if some of the policy changes will be implemented by the time California's RPS requires California utilities to meet 33% of their annual load from renewables in 2017-2020. Yet the two strategies that are likely to yield the greatest benefits are also the most politically controversial: a region-wide Energy Imbalance Market (EIM) and consolidated BAs. But they both have to be considered seriously—and, in our view, mandated by FERC, Congress, or both—if the total system costs of integrating high levels of renewable penetration are to be minimized. Only by reducing those costs can allocation proceed equitably.

There are intermediate steps that FERC can take before adopting such far-reaching policies. In particular, FERC should authorize ancillary services markets and adopt broad policies that will assure subsequent FERC approval for RPS procurement mechanisms that value operational flexibility, technological diversity, and geographic diversity. This will allow state RPSs and PPAs to compensate generators for providing the flexibility necessary to operate a reliable system with high levels of renewable penetration while also encouraging procurement policies that favor renewables that impose fewer integration costs on the system. Ancillary services markets are necessary to encourage short-term operational flexibility and responsiveness and to compensate generators who operate in real-time markets through RTOs and ISOs. Cost recovery assurance for long-term PPAs for renewables that are not "least-cost" on a per kWh basis—but whose pattern of output complements the system's needs due to its timing, geographic location, or technological diversity—are necessary to encourage both technological innovation and compensation for long-term provision of these attributes by both renewable and non-renewable generators. This will allow a BA like CAISO to ensure that it has the ramping and load-following flexibility it will need by 2017-2020 even if a region-wide EIM or BA consolidation has not been implemented by then. And should FERC or Congress ultimately mandate a region-wide EIM or BA consolidation, the existence of ancillary services markets and flexible PPA standards will improve operations and lower costs.

But ultimately, none of these measures will resolve the core issue at the heart of the BPA-wind dispute: who will pay the additional costs for ensuring reliable integration of renewables? In particular, who should pay for the costs of integrating renewables in one BA (e.g., BPA) that are primarily serving customers in another BA (e.g., CAISO)? A region-wide EIM would start to address that issue by creating economic incentives associated with reducing energy imbalances among different BAs. Consolidating BAs would be an even stronger way to internalize those costs, leading to more efficient dispatch decisions that consider all of the costs associated with the entire BA. But the hybrid regulatory structure we work with today will continue to create very different incentives for market-based stakeholders compared to cost-of-service or rate-of-return stakeholders. Each is compensated for the services it provides and recovers its costs and earns its profit in different ways, so each would benefit differently from different policies. We therefore need to develop a hybrid set of policies to reflect the hybrid regulatory structure in the WECC. Those policies will not uniformly benefit every stakeholder but they are necessary to reduce the total system costs of a robust, resilient, reliable renewables-based grid.

B. Integration Cost Allocation is the Critical Policy Decision

We stated in the Introduction that it is important to distinguish among four distinct, but interrelated, integration problems: (1) the *technical* challenges of integrating variability; (2) the *economic* costs of integrating variability; (3) the *policy* choice regarding distribution of integration costs; and (4) the *legal* framework for implementing that policy. From a *technical* standpoint, variable energy resources clearly can be integrated if there are sufficient incentives (e.g., ancillary services markets, energy imbalance markets) and investments in the technology (e.g., to facilitate dynamic transfers, balancing reserves). The *economic* costs of integrating variability are also manageable if the suite of strategies recommended by the WGA is implemented. Most importantly, those economic costs can be minimized if the geographic diversity associated with larger balancing authority areas (e.g., only five rather than the 37 BAs now in the WECC) is utilized to reduce net load variability so as to reduce the costs of contingency and balancing reserves. If there is one clear lesson from the WGA Report, it is this: the "benefits of geographic diversity clearly support balancing authority area aggregation and greater cooperation across areas."[257]

Resolution of the cost allocation *policy* decision is therefore the critical impediment to development of a new institutional structure that will promote high levels of renewable generation. As we have demonstrated, cost-of-service ratemaking and rate-of-return regulation internalize the costs of integrating both load and generating resources by minimizing total system costs; integration costs are neither calculated for nor assigned to individual generators when considering whether or not to add them to the resource mix. Thus, internalization of those costs under the traditional rate recovery system addressed the cost allocation policy choice by default: integration costs were treated as system costs, so they were borne by all ratepayers across the system. We believe the same policy principle should guide allocation of renewables integration costs going forward.

We recognize, however, that our hybrid regulatory structure makes that difficult. We therefore call for the development of more specific and explicit criteria to guide policies—and legal disputes under those policies, like the BPA-wind dispute—that will create the proper incentives for continuing investment in renewable generation and the transmission necessary to most cost-effectively develop renewable resources. In some cases, the proper incentive is action by a state regulator to support utility investment in transmission or to assure rate recovery for a PPA that may be higher-cost but better-fit due to its flexibility or other operating characteristics (e.g., geographic diversity) for the contracted resources. In other cases, the proper incentive is action by FERC or an RTO or ISO to set locational marginal prices for transmission services to encourage investments in transmission to reduce congestion. Both FERC and RTOs or ISOs can also structure ancillary services markets that will

257. WGA REPORT, *supra* note 156, at ES-8.

reward those resources that provide necessary operational flexibility; this is preferable to trying to impose integration costs on renewable generators that are unable to provide such flexibility. The carrot will be more effective than the stick in reducing integration costs.[258]

The *legal* framework for developing and implementing the policy choice to allocate integration costs across the system must be developed through four distinctive legal processes: (1) FERC rulemaking under its existing authority; (2) state regulators under their existing authority; (3) state legislatures to ensure that state regulators have the authority necessary to implement the WGA recommendations; and, in very limited cases, (4) Congressional action to amend FERC's authority to implement those recommendations. We believe that FERC has existing authority to establish ancillary services markets, facilitate dynamic transfers, establish energy imbalance markets, and to establish principles to guide future litigation over cost recovery mechanisms for integration costs (e.g., the BPA-wind dispute). However, consolidating balancing authority areas—the single WGA recommendation likely to yield the highest benefit in reduced integration costs—is probably beyond FERC's authority and would require Congressional action. It is also the most controversial action and could result in inequitable burdens for some existing BAs or states, so we believe it warrants careful legislative consideration by Congress. We are hopeful that the Obama Administration could put forward proposed legislation on this issue and get Congressional support for such a change during its second term.

But neither FERC nor the states should hold its breath awaiting Congressional action. Instead, FERC should move forward by building on Orders No. 745 and 764 with Orders related to ancillary services markets, cost recovery for investments that facilitate dynamic transfers, and policy principles that will encourage provision of integration flexibility and allocation of integration costs as system costs. FERC should then go even further and establish a region-wide EIM throughout the WECC. Establishing an EIM that is carefully monitored and enforced to prevent possible market manipulation would strengthen operational ties between existing BAs and would help reduce political opposition to BA aggregation. A regional EIM, together with the other WGA strategies, would help to create de facto integration even if Congress is unable to adopt legislation to consolidate BAs more formally into a more efficient set for renewables integration.

258. This principle applies to the BPA-wind dispute: incentives for wind curtailment—perhaps funded by California ratepayers, who are ultimately the consumers of the RECs associated with the wind power—are likely to be more effective than DSO 216 or the OMP.

The existing grid and regulatory system were built and designed to accommodate one set of problems, but the Climate Change Era requires us to green the grid through high levels of renewable generation.[259] Neither the existing grid nor today's hybrid regulatory structure is adequate to assure that we can do so at the least cost. We must therefore innovate institutionally in order to build the generation and transmission system of the future that is necessary for a robust, resilient, and reliable electricity system that comprises much more renewable generation. Otherwise, we will continue to have legal conflicts like the BPA-wind dispute—but they will detract from, rather than facilitate, further expansion of renewable generation. FERC must make the critical policy choice of allocating integration costs as system costs and then adopt the policies to implement that policy choice.

259. Duane, *supra* note 30.