Federal Regulatory Barriers to Grid-Deployed Energy Storage

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INTRODUCTION

Until recently, the most advanced form of grid-deployed energy storage[1] involved pumping water up a hill.[2] But "newer storage technologies like flywheels and chemical batteries have recently achieved technological maturity and are well into successful pilot stages and, in some cases, commercial operation."[3] If widely adopted, these new energy storage technologies will fundamentally alter the operation of our electricity system.

Energy storage carries electricity through time, just as transmission lines carry it through space—without it, electrical

1. For the purposes of this Article, "grid-deployed energy storage," "energy storage," or just "storage" refers to the storage of different forms of energy that may be *useful* to the bulk power system. For example, pumped hydroelectric storage refers to the potential energy stored in a reservoir of water, but it is the conversion of that energy to electricity by a water turbine generator that makes it useful. Similarly, a flywheel stores kinetic energy to spin a generator, and batteries convert chemical energy directly into electricity. Some forms of stored energy (for example, thermal energy) do not convert energy into electricity, but they can substitute for electricity by directly providing an end use. These types of energy storage are not the subject of this paper because the Federal Energy Regulatory Commission ("FERC") has only limited jurisdiction over them.

2. Pumped storage is the oldest form of energy storage. The earliest known use of pumped storage technology was in Switzerland in 1882. For nearly a decade, a pump and turbine operated with a small reservoir as a hydro-mechanical storage system. Beginning in the early 1900s, several small pumped storage plants were constructed in Europe, mostly in Germany. The first unit in North America was the Rocky River Pumped Storage plant, constructed in 1929 on the Housatonic River in Connecticut. *See* NAT'L HYDROPOWER ASS'N PUMPED STORAGE DEV. COUNCIL, CHALLENGES AND OPPORTUNITIES FOR NEW PUMPED STORAGE DEVELOPMENT 24 (2012) [hereinafter NHA PUMPED STORAGE], *available at* http://www.hydro.org/wp-content/uploads/2012/07/NHA_PumpedStorage_071212b1.pdf.

3. FED. ENERGY REGULATORY COMM'N, Docket No. AD10-13-000, 75 Fed. Reg. 36,381, REQUEST FOR COMMENTS REGARDING RATES, ACCOUNTING AND FINANCIAL REPORTING FOR NEW ELECTRIC STORAGE TECHNOLOGIES (2010), *available at* http://www.ferc.gov/media/headlines/2010/2010-2/06-14-10-notice.pdf.

energy must be used at the instant it is generated.[4] Storage resources transform electrical energy into another form of energy that can be stored and then used to regenerate electricity when needed.[5] Because, like other countries,[6] the U.S. grid has limited energy storage capacity, grid operators must match the supply of thousands of generators with the load[7] of millions of end users in an unceasing, moment-to-moment dance of staggering complexity. And the dance is only becoming more complicated as renewable resources like solar and wind—which have variable and unpredictable outputs—account for an increasing portion of our generation mix.[8]

The prospect of energy storage is nothing new,[9] but a confluence of factors has occasioned an energy storage renaissance. Most importantly, technological breakthroughs have driven down the cost of certain advanced storage technologies.[10] Furthermore, energy storage can address some of the major energy challenges of

4. *See, e.g.*, ELEC. ADVISORY COMM., 2012 STORAGE REPORT: PROGRESS AND PROSPECTS 1 (2012) [hereinafter EAC 2012], *available at* http://energy.gov/sites/prod/files/EAC%20 Paper%20-%202012%20Storage%20Report%20-%2015%20Nov%202012.pdf.

5. *See, e.g.*, Norton Energy Storage, L.L.C., 95 FERC ¶ 61,476 (2001) (describing Norton's plan to convert non-storable electricity into compressed air, a storable form of energy, which Norton will then keep in an underground facility until energy prices rise, when Norton will re-convert the compressed air to electricity by feeding gas-fired turbines).

6. For an up-to-date database of global energy storage projects, see *Global Energy Storage Database*, DEP'T OF ENERGY ("DOE"), http://www.energystorageexchange.org/ (last visited Aug. 12, 2014).

7. "Load" refers to an end-use device or customer that receives power from the electric system. It may also refer to the aggregate of loads, and in that usage is interchangeable with "demand."

8. *See, e.g.*, AM. PHYSICAL SOC'Y, INTEGRATING RENEWABLE ELECTRICITY ON THE GRID 8 (2010), *available at* http://www.aps.org/policy/reports/popa-reports/upload/integrating elec.pdf ("[Higher levels of renewable generation on the grid introduce] . . . uncertainties . . . [that] are much greater than the relatively predictable uncertainties of a few per cent in demand that system operators now deal with regularly. Variability becomes increasingly difficult to manage as penetration levels increase.").

9. *See generally* NHA PUMPED STORAGE, *supra* note 2 (discussing the origins of pumped storage).

10. *See* ELEC. POWER RESEARCH INST., ELECTRICITY ENERGY STORAGE TECHNOLOGY OPTIONS: A WHITE PAPER PRIMER ON APPLICATIONS, COSTS, AND BENEFITS 5-1 (2010) [hereinafter EPRI, TECHNOLOGY OPTIONS], *available at* https://www.parliament.nsw.gov.au/prod/parlment/committee.nsf/0/7482f370da08bf4eca 257a38000982f6/$FILE/CSIRO%20attachment%201c%20-%20US%20storage%20 economics.PDF. Indeed, projected growth in the advanced storage sector is remarkable. A recent study predicts that global, grid-deployed energy storage will grow significantly, becoming a $113.5 billion market by 2017 and accounting for nearly 52 GW of capacity. *See* Brian Warshay, *Forecasting Global Demand for Grid Storage: 2012 through 2017*, LUX RESEARCH (June 22, 2012), http://blog.luxresearchinc.com/blog/2012/06/forecasting-global-demand-for-grid-storage-2012-through-2017/.

our time by enhancing the reliability, resiliency, and efficiency of the electricity system, while reducing greenhouse gas ("GHG") emissions.[11] Among other benefits, energy storage resources can reduce our dependence on inefficient peaking plants, increase the capacity factor[12] of existing generation and transmission infrastructure, and facilitate the integration of renewable resources—typically with zero direct emissions.[13]

A dramatic surge in federal and state support is helping to fuel the storage boom. In a provision of the Energy Independence and Security Act of 2007 ("EISA"), called the United States Energy Storage Competitiveness Act, Congress allocated $295 million to the Department of Energy ("DOE") each fiscal year through 2018 (about $2.7 billion total) to support the research, development, and demonstration of advanced storage technologies.[14] Most recently, in early 2013, the Secretary of Energy announced a new Joint Center for Energy Storage Research, with $120 million to research advanced battery systems incorporating nanotechnology.[15] The DOE has also used $185 million from the American Recovery and Reinvestment Act of 2009 ("ARRA") to provide matching funds for sixteen energy storage pilot projects, with a total value of $772

11. In recent years, a variety of high-profile studies have emphasized the benefits and applications of various advanced energy storage resources. *See generally* EAC 2012, *supra* note 4; JIM EYER & GARTH COREY, SANDIA NAT'L LAB., ENERGY STORAGE FOR THE ELECTRICITY GRID: BENEFITS AND MARKET POTENTIAL ASSESSMENT GUIDE (2010), *available at* http://www.sandia.gov/ess/publications/SAND2010-0815.pdf.

12. "Capacity factor" is the ratio of actual generation (i.e. usage) to the maximum potential output (i.e. nameplate capacity), expressed as a percent. *See Guide to Market Oversight: Glossary*, FED. ENERGY REGULATORY COMM'N, http://www.ferc.gov/market-oversight/guide/glossary.asp (last updated Nov. 26, 2013).

13. The only storage resource with direct emissions is traditional compressed air energy storage. *See infra* Part I.C.

14. *See* 42 U.S.C. § 17231(p) (2007). The program is intended to promote "energy storage systems for electric drive vehicles, stationary applications, and electricity transmission and distribution." *Id.* at § 17231(c). Congress also instructed the Secretary of Energy to establish an Energy Storage Advisory Council ("EAC") within DOE, consisting of representatives of the energy storage industry. According to a recent Government Accountability Office ("GAO") study, between fiscal years 2009 and 2012, the federal government allocated a total of $1.3 billion to research and development in advanced energy storage technologies. *See* GOV'T ACCOUNTABILITY OFFICE, BATTERIES AND ENERGY STORAGE (2012), *available at* http://www.gao.gov/assets/650/647742.pdf.

15. *See* JOINT CTR. FOR ENERGY STORAGE RESEARCH, DOE ENERGY INNOVATION HUB—BATTERIES AND ENERGY STORAGE (2013), *available at* http://science.energy.gov/~/media/bes/pdf/hubs/JCESR_Fact_Sheet.pdf.

million and total capacity of 537MW.[16] ARRA also established a 30% investment tax credit, known as the Advanced Energy Manufacturing Tax Credit, to support domestic manufacturing of energy storage devices and other advanced energy technologies.[17]

Aggressive Renewable Portfolio Standards ("RPSs") and attendant grid reliability concerns have motivated state interest in storage. California, Texas, New York, Hawaii, and Washington have all proposed significant policies on storage.[18] Most significantly, the California legislature enacted AB 2514 in 2010, which instructed the California Public Utilities Commission ("CPUC") to adopt an energy storage procurement target for state-regulated public utilities by October 2013.[19] Even before finalizing its AB 2514 rules, the CPUC made history by becoming the first state regulator to set an energy storage procurement target, mandating that Southern California Edison procure at least 50MW of energy storage as part of its long-term local capacity requirements for the Los Angeles Basin.[20] And on October 17, 2013, the CPUC again made history when it issued a rule implementing AB2514, requiring the state's three public utilities to procure a combined 1,325 MW of energy storage by the end of 2020.[21]

But federal regulations threaten to undermine the successful deployment of storage on the grid. The Federal Energy Regulatory Commission ("FERC" or "the Commission") regulates the rates, terms, and conditions of interstate transmission and interstate

16. *See* ELEC. ADVISORY COMM., ENERGY STORAGE ACTIVITIES IN THE UNITED STATES ELECTRICITY GRID 3 (2011), *available at* http://www.doe.gov/sites/prod/files/oeprod/DocumentsandMedia/FINAL_DOE_Report-Storage_Activities_5-1-11.pdf.

17. 26 U.S.C. § 48C (2012). Notably, ARRA tax credits are not included in the GAO's $1.3 billion figure. *See* GOV'T ACCOUNTABILITY OFFICE, *supra* note 14, at 1. In February 2013, the DOE made another $150 million in tax credits available for storage and other advanced energy manufacturers under the ARRA program. *Energy Department, Treasury Announce Availability of $150 Million in Tax Credits for Clean Energy Manufacturers*, DOE (Feb. 7, 2013), http://energy.gov/articles/energy-department-treasury-announce-availability-150-million-tax-credits-clean-energy.

18. *See* DOE, GRID ENERGY STORAGE 13 (2013), *available at* http://energy.gov/sites/prod/files/2013/12/f5/Grid%20Energy%20Storage%20December%202013.pdf.

19. *See* CAL. PUB. UTIL. CODE § 2836(a) (West 2013).

20. *See* Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, No. 13-02-015, 2013 WL 652439 (Cal. Pub. Util. Comm'n Feb. 23, 2013).

21. *See* Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems, Decision 13-10-040, (Cal. Pub. Util. Comm'n Oct. 17, 2013), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF.

wholesale energy transactions.[22] Although states regulate local distribution facilities and retail sales, substantially all electricity ultimately delivered to consumers in the United States passes through FERC's jurisdiction.[23] Depending on the circumstance, a storage device might behave like any of the traditional grid classifications: generation, transmission, distribution, and load. These multifaceted operational characteristics, which make storage so useful, also confound regulatory rules and categories tailored to the more rigid operational characteristics of legacy technologies. "However, for energy storage technologies used on the grid, regulatory policies and rules provide the framework for the business case and economics of storage systems."[24] Consequently, storage cannot compete on a level playing field with traditional resources in FERC-jurisdictional markets. This federal regulatory lag impedes the commercialization of technologies that the federal government itself supports with billions of dollars in funding, while obstructing the success of state experimentation with policies promoting storage and renewable energy resources.[25]

Laudably, FERC has proactively addressed some particular barriers to storage, but many significant barriers remain.[26] This Article aims to identify these barriers and offer pathways around them. Part I introduces energy storage, particularly its history,

22. *See infra*, Part II.A.1.

23. *See infra*, Part I.

24. *See* GRID ENERGY STORAGE, *supra* note 18, at 12.

25. A123 Systems, Inc., a developer and manufacturer of advanced lithium ion batteries, was awarded a federal grant of as much as $249.1 million to establish battery manufacturing operations in Michigan before it filed for bankruptcy in late 2012. Bill Vlasic & Matthew L. Wald, *Maker of Batteries Files for Bankruptcy*, N.Y. TIMES, Oct. 16, 2012, at B1, *available at* http://www.nytimes.com/2012/10/17/business/battery-maker-a123-systems-files-for-bankruptcy.html. In a conversation with the author, a representative of one major storage company opined that A123's bankruptcy was not a result of technological immaturity or cost-ineffectiveness. Rather, A123's debt commitments accrued faster than the company could commercialize its technologies because existing regulations simply do not adequately accommodate grid-deployed storage. After its reorganization, A123 remains a major player in the advanced energy storage sector, under the name A123 Systems, LLC.

26. In recent years, FERC has become increasingly proactive in developing and formulating policies and regulations to address new technologies and other emerging issues that affect energy and transmission markets under FERC's jurisdiction. The Office of Energy Policy and Innovation ("OEPI"), established in June 2010, has played a large part in this development. *See* FED. ENERGY REGULATORY COMM'N, Delegations to Office of Energy Policy and Innovation, 75 Fed. Reg. 32,657 (June 9, 2010). The OEPI focuses on a number of issues including demand response, distributed generation, energy efficiency, smart grid standards, and storage. *See Office of Energy Policy and Innovation*, FED. ENERGY REGULATORY COMM'N, http://www.ferc.gov/about/offices/oepi.asp (last updated May 30, 2014).

operational uses, and benefits. Part II introduces federal electricity regulation and analyzes various FERC-jurisdictional opportunities and barriers to energy storage. It also highlights recent FERC actions that proactively address or incidentally affect energy storage resources. Finally, Part III proposes actions FERC should take to remedy identified barriers. In particular, it argues that the Federal Power Act ("FPA") requires FERC to eliminate unjust, unreasonable, and unduly discriminatory barriers to energy storage in organized wholesale markets and resource adequacy planning processes. It then argues that the Commission should clarify its policies for classifying storage devices so as to allow storage resources to perform multiple functions, thereby providing the grid with multiple benefits. Finally, it argues that energy storage resources should be considered comparably alongside traditional resources in transmission planning processes.

I. ENERGY STORAGE: TECHNOLOGIES, USES, AND BENEFITS

All storage resources do one thing in common: they store energy. But the catch-all term "energy storage" belies a diversity of technologies and applications. This section briefly introduces the electricity system. Then it establishes a framework for conceptualizing energy storage systems and introduces the most mature energy storage technologies. Finally, it discusses the applications and benefits of grid-deployed energy storage. Rather than preferring one technology to another, this Article is technology-agnostic, focusing primarily on the various benefits to the grid of different storage applications.

A. The Electricity System: A Quick Primer

To understand how energy storage works, and how it benefits the grid, it is useful to first describe how our electricity system works. Electricity infrastructure is divided into three basic categories: generation, transmission, and distribution.[27] The "bulk power system" includes long-distance transmission infrastructure and

27. For a more complete primer on the electricity system and its regulation, see generally REGULATORY ASSISTANCE PROJECT, ELECTRICITY REGULATION IN THE UNITED STATES: A GUIDE (2011) [hereinafter "RAP GUIDE"], *available at* http://www.raponline.org/document/download/id/645.

energy from large, centralized generators.[28] Generation resources are usually location-constrained: wind is strongest in particular areas, for example, and pollution-intensive coal plants should not be sited in densely populated urban centers. Thus, a transmission grid plays a vital role by moving power over long distances from sites of generation to areas of demand. The United States is divided into three such grids, or "synchronous interconnections," known as the Western Interconnection, the Eastern Interconnection, and the Texas Interconnection.[29] The transmission grid ends where a high-voltage transmission line meets a step-down transformer connecting to the distribution grid, consisting of local, lower voltage lines that deliver electricity to end users.[30]

To satisfy demand, the United States bulk electricity system relies on a diverse portfolio of generation sources. In 2012, the United States's net generation share by primary energy source was as follows: coal, 37%; natural gas, 30%; nuclear, 19%; hydroelectric, 7%; other renewables (wind, solar, biomass, etc.), 5%; and other sources, 2%.[31] "Baseload" generators satisfy the significant, constant demand for electricity. Common baseload generators include coal, nuclear, and, increasingly, combined-cycle gas turbine ("CCGT") plants.[32] Most baseload plants have high capital costs but low variable costs, meaning it is most efficient to run them continuously at a high capacity factor.[33] Additionally, technical constraints (especially for nuclear plants) restrict rapid changes in

28. *See* 16 U.S.C. § 824o (2012) (The Energy Policy Act of 2005 defines the "bulk power system" as "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and . . . electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.").

29. RAP GUIDE, *supra* note 27, at 15.

30. *Id.* at 65.

31. ENERGY INFO. ADMIN. ELECTRIC POWER MONTHLY DATA FOR DECEMBER 2012 (2013), *available at* http://www.eia.gov/electricity/monthly/current_year/february2013.pdf.

32. CCGT plants are the most efficient natural gas-fueled power plants, with efficiencies of up to 60%. Traditional gas turbines have efficiencies only as high as 42%. *See* INT'L ENERGY AGENCY, ENERGY TECHNOLOGY SYSTEMS ANALYSIS PROGRAMME: GAS-FIRED POWER 1 (2010), *available at* www.iea-etsap.org/web/E-TechDS/PDF/E02-gas_fired_power-GS-AD-gct.pdf. With natural gas prices driven to historic lows by the shale boom and increasing regulatory costs for coal generation, CCGT plants have become cost competitive with coal plants as baseload resources, leading to so-called "coal-to-gas switching." *See, e.g.*, Ken Silverstein, *Coal to Gas Moves are Generating Economic Waves*, FORBES (Mar. 13, 2013, 8:46 AM), http://www.forbes.com/sites/kensilverstein/2013/03/13/coal-to-gas-moves-are-generating-economic-waves/.

33. *See* RAP GUIDE, *supra* note 27, at 106.

output.[34] To meet predictable daily demand fluctuations, grid operators usually call on hydroelectric and natural gas plants to serve as "intermediate" or "load following" units, which increase and decrease output to match daily load fluctuations.[35] Finally, grid operators call on peaking plants, inefficient gas- or oil-fired turbines, to meet the very highest periods of demand.[36] The essential feature of peaking plants is that they are capable of rapid ramping.[37] In other words, they can respond quickly and accurately, within minutes or even seconds, to a request for increased or decreased energy output, something baseload generators could not hope to do. Because load-following units are less efficient than baseload units, and peaking plants are yet worse,[38] the marginal cost of power—to generators, utilities, and ultimately, consumers[39]—increases during peak hours, sometimes spectacularly during the highest peak days.[40]

In addition to meeting the predictable daily and seasonal variations in demand, grid operators must keep additional reserves available to meet unforeseen, unpredictable, and/or rapid fluctuations in the demand or supply of power. That is because

34. *See, e.g.*, *Nuclear Power Reactors*, WORLD NUCLEAR ASS'N, http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Power-Reactors/Nuclear-Power-Reactors/ (last updated Nov. 2013).

35. For a typical daily load profile, see, for example, *Today's Outlook*, CAL. INDEP. SYS. OPERATOR, http://www.caiso.com/outlook/SystemStatus.html (last visited Apr. 14, 2014) (showing real-time system demand, day-ahead demand forecast, hour-ahead demand forecast, and available resources in CAISO).

36. *Glossary*, ENERGY INFO ADMIN., http://www.eia.gov/tools/glossary/index.cfm?id=P#peak_load_plant (last visited Apr. 14, 2014).

37. Ramp is the rate, expressed in megawatts per minute, at which a generator can change its output. N. AM. ELEC. RELIABILITY CORP., GLOSSARY OF TERMS 59 (2014), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

38. *See, e.g.*, *Electric generator dispatch depends on system demand and the relative cost of operation*, ENERGY INFO. ADMIN. (Aug. 17, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7590 (showing typical supply curve, or "generation stack," and the increasing marginal cost, or variable operating cost, of generation).

39. The cost of electricity to consumers—the retail rate—has traditionally been set at a fixed price, regardless of the time of day or year. Some states are experimenting with incentive retail rates, or time-of-use rates, that vary depending on system demand to send price signals to end users that accurately communicate the real-time marginal cost of wholesale power. Regardless, even consumers in fixed-rate regions ultimately pay for the high marginal cost of peak power because the fixed rate accounts for the full cost of power, albeit not in real-time. *See* RAP GUIDE, *supra* note 27, at 55.

40. *See, e.g.*, *Texas Heat Wave, Aug. 2011: Nature and Effects of an Electricity Supply Shortage*, ENERGY INFO. ADMIN. (Sept. 9, 2011), http://www.eia.gov/todayinenergy/detail.cfm?id=3010 (discussing "super peak" prices in ERCOT during a heat wave in Aug. 2011, when real-time energy prices reached the market-cap $3,000/MWh).

grid operators must ensure that the instantaneous generation of electricity meets constantly changing load. These reserve resources provide "ancillary services," which FERC defines as "[t]hose services that are necessary to support the transmission of capacity and energy from resources to loads."[41] To provide ancillary services, meet predictable peak loads, and ensure adequate resources in case of a system contingency (such as an unplanned generator or transmission line outage) or a demand forecast error, bulk power systems generally maintain installed reserve capacity exceeding the annual projected peak load by a margin of around fifteen percent or more.[42] Energy storage also functions as an alternative method of providing reserve capacity.

Energy storage provides a variety of uses and benefits for the grid, depending on its deployment within the electricity system. Before addressing these in detail, this Article first considers the history of energy storage.

B. The Origin of Energy Storage, or, Pumping Water up a Hill

The current surge of interest in energy storage centers on advanced storage systems, including batteries, flywheels, and other technologies, which are discussed below. But energy storage has been used for nearly a century in the form of pumped-storage hydroelectric power stations ("PSH"), i.e. pumping water up a hill and later letting it fall back down. It seems laughably simple, but PSH is by far the most common form of energy storage currently in use.[43] In the United States, there are forty PSH projects accounting for 22 GW, or about 2.2 percent of net summer capacity in the United States.[44] PSH facilities consist of a lower and upper reservoir. During off-peak hours, pumps draw excess electricity from the bulk power system and move water to the upper reservoir, storing it as gravitational potential energy. When the grid requires

41. *Guide to Market Oversight: Glossary*, supra note 12.

42. *See, e.g.*, *Planning Reserve Margin*, N. AM. ELEC. RELIABILITY CORP., http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx (last visited Apr. 14, 2014).

43. About 99% of energy storage resources deployed globally are PSH. EAC 2012, *supra* note 4, at 20.

44. *See* ENERGY INFO. ADMIN., ANNUAL ENERGY REVIEW 2011 258 (2012), *available at* http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf. Net summer capacity is "[t]he maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through Sept. 30). This output reflects a reduction in capacity due to electricity use for station service or auxiliaries." *Glossary*, *supra* note 36 (enter "net summer capacity" in search field).

additional energy, the operators release the water to the lower reservoir, creating kinetic energy that turns turbines, generating electricity.[45] PSH facilities may be closed-loop[46] or open to a natural waterway like normal hydroelectric dams. Round-trip efficiencies are around eighty-five percent, and in the United States, the capacities of PSH systems range from a few MW to 3000MW.[47]

The history of PSH illustrates the value of energy storage as an enabling and enhancing technology for other grid resources, such as nuclear power. Enormous upfront capital costs and low variable and marginal costs of operation incentivize nuclear plants to run constantly and at high capacity factors.[48] But in some cases, maximizing the output of large nuclear plants generates electricity in excess of off-peak system demand,[49] and output from nuclear plants cannot easily be varied.[50] Unlike peak loads, where demand exceeds baseload supply, nuclear plants pose the opposite problem: when optimally utilized, a nuclear generator's invariable baseload output might exceed the lowest trough in daily demand, thereby destabilizing the grid.[51]

Therefore, PSH plants provided the perfect complement to new nuclear generators.[52] While conventional load-following or peaking plants can only add energy to the grid, storage resources like PSH can both add energy to the grid and absorb energy from the grid for later use. Because of PSH's ability to absorb the excess electricity generated by nuclear plants, it is no surprise that the

45. *See* NAT'L HYDROPOWER ASS'N PUMPED STORAGE DEV. COUNCIL, CHALLENGES AND OPPORTUNITIES FOR NEW PUMPED STORAGE DEVELOPMENT 30 (2012), *available at* http://www.hydro.org/wp-content/uploads/2012/07/NHA_PumpedStorage_071212b1.pdf.

46. All operational PSH in the United States are open-loop systems. *See id.* But in a trend worth noting, more and more proposed PSH projects are closed-loop. Closed-loop systems are considered less environmentally destructive than open-loop systems because they do not affect rivers and related resources and can utilize abandoned mines that are already heavily impacted by human activity. These differences may make closed-loop systems easier to site and permit. *See Pumped Storage Projects*, FERC, http://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage.asp (last updated Feb. 3, 2014).

47. *See* ENERGY INFO. ADMIN., *Form 860 Data* (2011), *available at* http://www.eia.gov/electricity/data/eia860/.

48. *See* STAN KAPLAN, CONG. RESEARCH SERV., POWER PLANTS: CHARACTERISTICS AND COSTS 11 (2008), *available at* http://www.fas.org/sgp/crs/misc/RL34746.pdf.

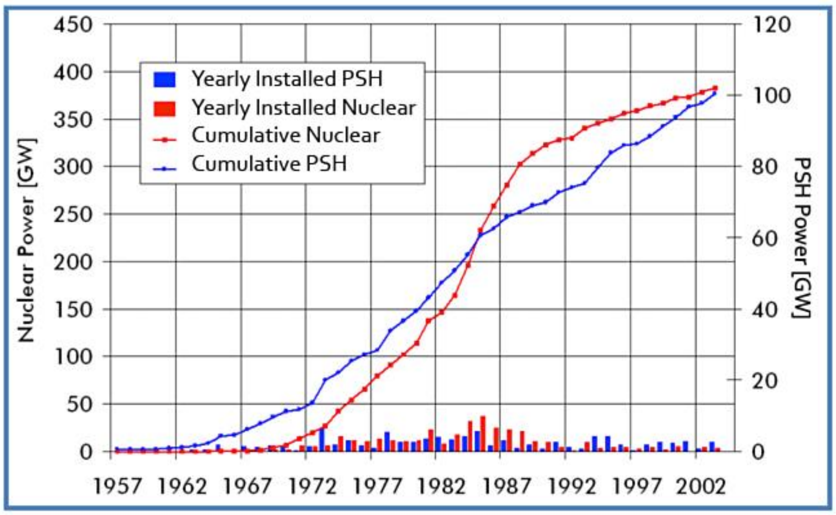
49. The reliable operation of the bulk electricity system requires supply to meet demand. An excess of energy, no less than an undersupply of energy, affects system stability.

50. *See, e.g.*, World Nuclear Association, *supra* note 34.

51. Other baseload plants, like CCGT and to some extent coal, do not confront this issue because their output is more easily varied.

52. *See* NAT'L HYDROPOWER ASS'N, *supra* note 45, at 30.

primary development of pumped storage power in the United States and worldwide occurred in the late 1960s, 1970s, and early 1980s, when many nuclear power stations went online.[53] Between 1970 and 1985, seventy percent of currently installed PSH capacity in the United States was constructed, with only thirteen percent constructed since.[54] The following graph illustrates the historical relationship between nuclear and PSH.[55]



Worldwide Installed Nuclear and PSH, Development History

Traditional PSH served as a time-shifting storage resource, to save excess generation during off-peak hours for use during daytime peak loads. Accordingly, all of the installed PSH in the United States have simple, single-speed pumps and turbines, only designed to save or generate electricity at a fixed rate.[56] This limitation distinguishes PSH from other more nimble storage technologies, discussed below, which are capable of varying input and output to respond more rapidly and precisely to system needs, thereby providing a variety of different services.[57]

53. *Id.*

54. *See* EIA, Form 860 Data (2011), *available at* http://www.eia.gov/electricity/data/eia860/.

55. NAT'L HYDROPOWER ASS'N, *supra* note 45 at 25 (providing data for the following table).

56. *See id.* at 30.

57. Although adjustable-speed PSH systems have been developed elsewhere, notably Japan, none are currently deployed in the United States. *See id.* This may change soon,

FERC statistics may indicate a revived interest in PSH. Under section 10 of the FPA, FERC has licensing authority over hydroelectric power projects, including PSH.[58] Under section 10, an applicant may apply for a "preliminary permit," which has "the sole purpose of maintaining priority of application for a license" for up to three years.[59] As of February 2014, FERC has issued over fifty active preliminary permits for PSH, with a total proposed capacity of 48,457MW.[60] In 2005, FERC received fewer than five applications for a preliminary permit, while in 2008, 2010, and 2011, FERC received over thirty per year.[61]

The rapid deployment of wind turbines may be driving the renewed interest in PSH. Nationally, wind capacity has grown by an order of magnitude in the last decade, from 3,900MW of net summer capacity in 2001 to 45,200MW in 2011.[62] Wind has the inconvenient tendency to blow stronger at night, when demand is lowest[63]—an operational difficulty strikingly similar to the invariable off-peak output of nuclear plants.[64] Although wind turbine output can be reduced by adjusting blade pitch, foregoing generation is wasteful, particularly for a resource with almost zero variable operating costs.[65] Perhaps unsurprisingly, nearly 20% of preliminary permits for new PSH are for projects in California,[66]

however. In September, 2011, the Department of Energy, jointly with the Department of the Interior, awarded $6.8 million to an advanced PSH facility designed to "dynamically respond to the electrical grid." Press Release, DOE, Departments of Energy and Interior Award Nearly $17 Million for Advanced Hydropower Technologies (Sept. 26, 2011), *available at* http://energy.gov/articles/departments-energy-and-interior-award-nearly-17-million-advanced-hydropower-technologies.

58. 16 U.S.C. § 797 (2012).

59. *Id.* § 798.

60. *See* FED. ENERGY REGULATORY COMM'N, *Hydropower: General Information: Licensing*, http://www.ferc.gov/industries/hydropower/gen-info/licensing.asp (last updated Apr. 9, 2014) (click "issued preliminary permits").

61. *See* FED. ENERGY REGULATORY COMM'N, PUMPED STORAGE PROJECTS, MAP OF PRELIMINARY PERMIT APPLICATION TRENDS (2014), *available at* http://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage/trends-pump-storage.pdf.

62. U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY REVIEW 2011 258 (2012), *available at* http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf.

63. *See, e.g.*, EPRI., TECHNOLOGY OPTIONS, *supra* note 10, at A-18 to 19.

64. *See supra* notes 48–51 and accompanying text.

65. *See, e.g.*, U.S. ENERGY INFO. ADMIN, *Electric Generator Dispatch Depends on System Demand and the Relative Cost of Operation* (Aug. 17, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7590 (showing wind and other renewables at the low-cost end of the supply curve).

66. *See* FED. ENERGY REGULATORY COMM'N, *supra* note 60 (noting that 10,374MW of the 48,457MW of issued preliminary permit capacity for new PSH are located in California).

where CAISO estimates that wind capacity will soon exceed off-peak demand by 3,000 to 5,000MW.[67]

PSH is an efficient energy storage technology for shifting bulk energy generation and consumption, and adjustable-speed PSH may be capable of providing other services. But PSH has a variety of limitations. Most significantly, PSH requires highly specific land formations to accommodate a lower and upper reservoir. Moreover, like any hydroelectric facility, PSH facilities have significant land use footprints and attendant environmental impacts.[68] In considering a license application for a new PSH system under the FPA, FERC must comply with the National Environmental Policy Act ("NEPA")[69] and complete a lengthy analysis of the proposed project's impacts on the human environment.[70] Other federal, state, and local laws applicable to land- and water-intensive projects may also slow PSH development, while offering a number of hooks for legal challenges.[71] A final obstacle to PSH, and one which may make other technologies more attractive up front, is that PSH is the most capital intensive form of

67. MATTHEW DEAL ET AL., CAL. PUB. UTIL. COMM'N, ELECTRIC ENERGY STORAGE: AN ASSESSMENT OF POTENTIAL BARRIERS AND OPPORTUNITIES 7 (2010), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/71859AF5-2D26-4262-BF52-62DE85C0E942/0/CPUCStorageWhitePaper7910.pdf. California installed wind capacity has grown three-fold in the last decade. *See Installed Wind Capacity*, U.S. DEP'T OF ENERGY, http://www.windpoweringamerica.gov/wind_installed_capacity.asp (last updated May 1, 2014).

68. For example, FERC has issued a final environmental impact statement pursuant to NEPA for one of two newly proposed and licensed PSH plants. The project, a closed-loop 1300MW PSH plant located on the site of an inactive mine in Riverside County, CA, would require 2688.26 acres of land. *See* FED. ENERGY REGULATORY COMM'N , FINAL ENVIRONMENTAL IMPACT STATEMENT FOR THE PROPOSED EAGLE MOUNTAIN PUMPED STORAGE HYDROELECTRIC PROJECT (P-13123-002) § 1, at 1 (2012), *available at* http://www.ferc.gov/industries/hydropower/enviro/eis/2012/01-30-12.asp.

69. 42 U.S.C. §§ 4321, 4331–4370(h) (2012).

70. *See, e.g.*, 42 U.S.C. § 4332(C) (2014) (establishing the reporting requirement).

71. For example, new hydropower projects would require a Water Quality Certification from the California State Water Resources Control Board under Section 401 of the Clean Water Act. *See* 33 U.S.C. § 1341 (2012). Other hooks include the Endangered Species Act, which may pose a significant barrier to open-loop PSH systems to the extent they could jeopardize listed aquatic and other wildlife. *See* 16 U.S.C. §§ 1531–1544 (2012). Meanwhile, many state-level environmental review statutes, such as the California Environmental Quality Act, impose even more stringent environmental review requirements than NEPA, leading to more development cost and delay for large PSH projects. *See* Cal. Pub. Res. Code §§ 21000–21189.3 (West 2014).

long-duration energy storage, with an estimated capital cost of $1275/kW of capacity.[72]

Perhaps indicative of the difficulty of finding an appropriate location and obtaining the necessary approvals, only two new PSH projects have come online in the last decade,[73] and notwithstanding the large number of preliminary permits, only two PSH projects, with a total capacity of 42MW, are planned for 2012-2016 according to the Energy Information Administration ("EIA").[74]

This Article discusses the potential for expanding the role of conventional PSH, but it focuses primarily on more nimble advanced energy storage systems. New storage resources often perform better than PSH, while facing fewer location constraints and requiring fewer (if any) licenses or approvals (other than energy regulatory approvals). Moreover, advanced systems have become more cost-effective in recent years, and in some cases, have significantly lower capital costs.

C. Conceptualizing Energy Storage: Power, Duration, and Energy

This section provides a brief technical overview of energy storage and the criteria by which storage technologies are assessed and compared. Because this Article is technology-agnostic, the following discussion focuses more on operational characteristics than particular technologies.

Output from a conventional generator is only limited by the facility's power capacity (also called "nameplate capacity") and the availability of primary energy.[75] In the case of thermal plants, like coal, natural gas, and nuclear, primary energy is practically unlimited. Thermal plants can generate electricity unceasingly for indefinite periods of time (assuming a stable source of primary fuel, and excepting occasional maintenance). Energy storage devices, on the other hand, are limited energy resources because they cannot indefinitely discharge energy and require recharging after a certain amount of use.

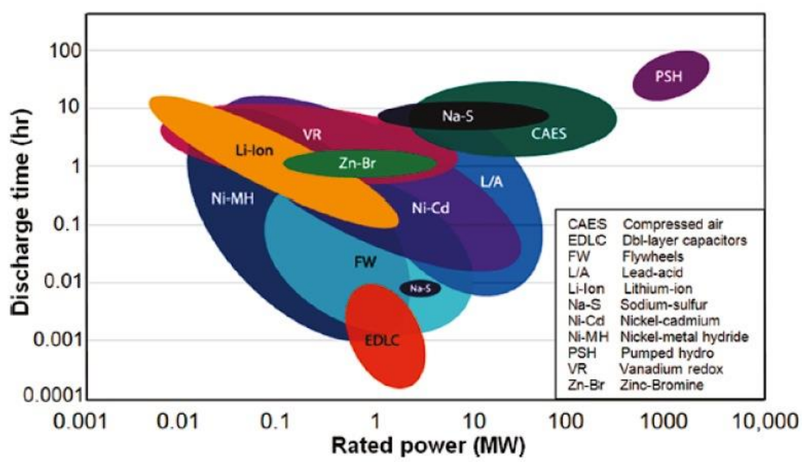
72. *See* SUSAN SCHOENUNG, SANDIA NAT'L LABS., ENERGY STORAGE SYSTEMS COST UPDATE: A STUDY FOR THE DOE ENERGY STORAGE SYSTEMS PROGRAM (2011), *available at* http://prod.sandia.gov/techlib/access-control.cgi/2011/112730.pdf.

73. *See* ENERGY INFO. ADMIN., ELECTRIC POWER ANNUAL 2011 67 tbl. 4.1 (2013), *available at* http://www.eia.gov/electricity/annual/archive/2011/.

74. *See id.* at 73, tbl. 4.5.

75. *See Glossary*, *supra* note 36 (enter "nameplate capacity" in search field).

Energy storage devices can be analyzed along two axes, which together constitute a third: (1) power capacity, (2) duration of discharge, and (3) energy storage capacity.[76] "Power capacity" is the maximum rate at which a resource can generate energy, expressed in kW or MW, and is comparable to the nameplate capacity of conventional generators.[77] But unlike conventional generators, storage resources are time- and energy- limited. "Duration of discharge" is the duration over which a storage device can discharge at its rated power capacity. Finally, "energy storage capacity" is simply the total electrical energy a storage device can generate in one full discharge cycle, expressed in kWh or MWh (and is roughly found by multiplying power capacity by duration of discharge). Take for example a battery with a power capacity rating of 1MW and a discharge time of 10 hours. In one full discharge cycle, the battery would produce 10MWh of energy and would then require recharging. The below graph illustrates one way of conceptualizing the power-duration-energy framework.



Rated Power (MW) vs. Discharge Time[78]

76. *See* ELECTRIC POWER ANNUAL 2011, *supra* note 73, at *id.* at 2-4.

77. Notably, the nameplate capacity of a storage device is actually bi-directional. For example, the nameplate capacity of a battery might be 10MW, *and* -10MW, because it can also absorb energy. Thus, a more accurate measure of its net power capacity might be 20MW.

78 CAL. ENERGY COMM'N, 2020 STRATEGIC ANALYSIS OF ENERGY STORAGE IN CALIFORNIA 15 (2011) [hereinafter CEC 2020], available at http://www.energy.ca.gov/2011publications/

In addition to the power-duration-energy criteria, energy storage devices have other critical operational characteristics. Most importantly, storage resources differ in how quickly they can adjust output and how accurately they can track system requests. Finally, different storage resources have different round-trip efficiencies.[79] Below are descriptions of the four most mature storage technologies,[80] defined by reference to power, duration, energy, response, ramp, and accuracy.[81]

PSH and compressed air energy storage ("CAES"): High-power, long-duration, high-energy, quick-response, medium-ramp, medium-accuracy. CAES, like PHS, harnesses mechanical energy to generate electricity. During off-peak hours, CAES systems pump air into a contained space, such as a subterranean cavern or closed tank. During peak hours, air is released, reheated, and passed through a turbine to generate electricity.[82] By installed capacity, CAES is third to PHS and batteries, with about 400MW worldwide as of August 2012.[83] However, while PHS and CAES are generally faster and more accurate than traditional generators, other storage resources are significantly more so. Moreover, traditional CAES and PHS face significant location constraints, requiring highly specific land features, such as a salt cavern or tiered reservoirs, respectively.[84]

CEC-500-2011-047/CEC-500-2011-047.pdf. This graph is only approximate. Certain technologies extend beyond the operational limits expressed herein.

79. Round-trip efficiency is expressed as a percentage, calculated by dividing the output of a device in kWh or MWh by the amount of energy put into the device. For example, a PSH with an 85% round-trip efficiency would discharge 85MWh if it were originally charged with 100MWh.

80. For a comprehensive and more detailed discussion of the various storage technologies, see generally ELEC. POWER RESEARCH INST., *supra* note 10.

81. The graph above and the discussion below are only approximate. Particular instances of a given technology may defy the more general characteristics of the technology. For example, advanced CAES technologies with lower power, duration, and energy and faster response and ramp are being developed. Lightsail Energy has developed a CAES technology that fits in shipping container. LIGHTSAIL ENERGY, http://www.lightsail.com/ (last visited June 4, 2014).

82. Conventional CAES involves reheating compressed air by combusting natural gas, making it the only storage resource with direct emissions. Conventional CAES is less efficient than PHS, with round-trip efficiency of about 50%.

83. *See* EAC 2012, *supra* note 4, at 21.

84. New CAES technologies are in development that may increase the efficiency and flexibility of CAES technology. *See, e.g.*, LIGHTSAIL ENERGY, *supra* note 81. Likewise, new PSH

Flywheels: Low-to-medium-power, short-duration, low-energy, instantaneous response, fast-ramp, high-accuracy. Flywheels store kinetic energy during normal grid operation in heavy spinning cylinders. When a grid operator sends a signal that requests the system to absorb power, the flywheel uses power from the grid to drive the flywheel motor/generator, which in turn spins up the flywheel. When the operator signals for electrical power to be provided, the momentum of the spinning flywheel drives the generator/motor and the kinetic energy is converted into electrical energy for release to the grid.[85] Flywheels can discharge at their rated power capacity for about fifteen minutes.[86] Importantly, flywheels can respond instantaneously and accurately to system signals, rapidly adjusting and alternating between output and input.[87]

Batteries: Low-to-medium-power, medium-to-long-duration, medium-to-high-energy, instantaneous-response, fast-ramp, high-accuracy. Batteries have emerged as the most flexible energy storage option, offering a range of power, duration, and energy capabilities. Moreover, unlike traditional PSH and CAES, batteries can be deployed as distributed resources closer to or at the "edge" of the grid, at the community level (also called Community Energy Storage ("CES")), behind the meter, or even as transportable resources deployed where- and as-needed.[88] Driven in part by the technology developed in the emerging hybrid, plug-in hybrid electric, and electric vehicle sectors (collectively, "EVs"), battery technology has advanced significantly in recent years. Batteries use electricity to create and store chemical energy, and now account for about half of installed non-PSH energy storage globally, or

technologies may make PSH less land-intensive and more nimble. *See, e.g.*, CEC 2020, *supra* note 78, at 38–40 (describing underground pumped storage technology).

85. Beacon Power is among the most prevalent companies in the flywheel sector. Their Smart Energy 25 flywheel stores energy by spinning at rates up to 16,000 rpm (or 267 rotations per second), levitated on hybrid magnetic bearings operating in a near-frictionless vacuum-sealed environment. *Carbon Fiber Flywheels*, BEACON POWER, http://beaconpower.com/carbon-fiber-flywheels/ (last visited June 4, 2014). Beacon owns and operates the largest flywheel in the United States, in Stephentown, NY. The 20MW flywheel facility consists of 200 high-speed 100 kW (25 kWh) flywheels. *Stephentown, New York*, BEACON POWER, http://www.beaconpower.com/products/smart-energy-25.asp (last visited June 4, 2014).

86. *See Applications*, BEACON POWER, http://beaconpower.com/applications/ (last visited June 4, 2014).

87. *See id.*

88. *See* CEC 2020, *supra* note 78, at 167–78; EYER & COREY, *supra* note 11, at 128.

556MW, as of August 2012.[89] Like flywheels, most batteries can ramp almost instantaneously and respond to system demand with precision unparalleled in conventional resources.

D. Uses and Benefits

Although energy storage resources face time constraints that conventional generators do not, they nevertheless may provide a variety of time-limited services to address operational challenges arising from the need to constantly and instantaneously match the supply and demand of electricity. Storage resources can perform these functions more reliably and more efficiently than traditional resources, while reducing emissions and other environmental harms of the bulk power system. The following sections discuss various uses for storage on the grid, grouped under three basic benefit categories: 1) reliability and resiliency, 2) efficiency, and 3) environment and climate.

1. Reliability and Resiliency

Enhanced transmission-side system quality: Storage resources can perform a variety of ancillary services critical to grid reliability and stability, in many cases better than traditional resources.[90] Perhaps most promising, storage can replace conventional reserves used for frequency control and other grid support services that require fast response and rapid ramping.[91] Natural gas or hydroelectric generators, which currently perform ancillary services, can only add power to the grid and require minutes to respond. A flywheel or battery can respond instantly and ramp at rates significantly higher than traditional generators, within an

89. EAC 2012, *supra* note 4, at 21.

90. Some ancillary services are discussed *infra*, at section II.B. Other transmission-side ancillary functions include providing system inertia, ramping, and voltage support. *See* S. CAL. EDISON, MOVING ENERGY STORAGE FROM CONCEPT TO REALITY: SOUTHERN CALIFORNIA EDISON'S APPROACH TO EVALUATING ENERGY STORAGE 6 (2011), *available at* http://www.edison.com/content/dam/eix/documents/innovation/smart-grids/Energy-Storage-Concept-to-Reality-Edison.pdf. Currently, fast-ramping generation resources like natural gas and hydroelectric plants provide most ancillary services.

91. When the instantaneous supply and demand of electricity is equal, the grid's high-voltage alternating current pulses at a frequency of 60Hz. The best analogy is a balancing scale: When the weights on each side (generation and load) are in balance, the scale is centered and reads 60Hz. Minor frequency deviations affect energy consuming devices; major deviations cause generation and transmission equipment to separate from the grid, in the worst case leading to a cascading blackout. *See* FERC, Order No. 755, 137 FERC ¶ 61,064, at P5 (Oct. 20, 2011).

effective operating range twice its rated capacity.[92] Through faster and more accurate performance, storage resources provide up to four times more frequency control per-MW of capacity than traditional generators.[93] Frequency control is widely considered the most cost-effective current application of energy storage.[94] And fast and accurate grid support resources capable of ramping up and down will become critical to grid reliability with the growing penetration of renewables and electric vehicles.[95]

Enhanced distribution-side system quality: Similarly, on the distribution side, batteries and flywheels would be effective for providing ancillary services, including power quality and voltage control.[96] Distribution-side concerns have magnified in recent years with increased penetration of distributed generation—especially rooftop solar photovoltaic ("PV")—and EVs.[97] With local and state governments promoting distributed generation and EVs throughout the country, storage will likely play a key role—whether as CES or distributed at load sites—in ensuring continuing distribution-side reliability.

Enhanced grid resiliency: Recent extreme weather events have prompted greater concern for grid resiliency. Superstorm Sandy, for example, left over eight million homes in the dark, some for over two weeks,[98] and resulted in billions of dollars of power outage-related economic losses and related costs.[99] Storage resources located downstream from system failures, including load-site storage resources used for uninterruptible power supply, could

92. A 50MW storage device, for example, has an approximate -50 to +50MW operating range that is equivalent to a zero to 100MW range for a combustion turbine for regulation purposes. This is because the storage device can switch between charging from and discharging to the grid.

93. *See* RALPH MASIELLO ET AL., KEMA, INC., RESEARCH EVALUATION OF WIND AND SOLAR GENERATION, STORAGE IMPACT, AND DEMAND RESPONSE ON THE CALIFORNIA GRID 6 (2010), *available at* http://www.energy.ca.gov/2010publications/CEC-500-2010-010/CEC-500-2010-010.PDF.

94. *See* EAC 2012, *supra* note 4, at 38–39.

95. *See* MASIELLO ET AL., *supra* note 93, at 3 (noting that with increasing penetration of renewables, frequency regulation needs grow exponentially).

96. *See* EAC 2012, *supra* note 4, at 15–16.

97. *See id.*

98. *See Electricity restored to many in the Northeast but outages persist*, ENERGY INFO. ADMIN. (November 9, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=8730; CNN Wire Staff, *Costs from Sandy into the billions as thousands struggle, still, without power*, CNN (Nov. 13, 2012, 9:52 AM), http://www.cnn.com/2012/11/12/us/northeast-weather.

99. *See* ERIC S. BLAKE ET AL., NAT'L HURRICANE CTR., TROPICAL CYCLONE REPORT: HURRICANE SANDY (2013), *available at* http://www.nhc.noaa.gov/data/tcr/AL182012_Sandy.pdf.

carry critical load until system failures are resolved.[100] Likewise, transportable storage devices like large batteries could serve areas temporarily disconnected from the grid. Storage could also serve as a blackstart[101] resource to restore operation to generation facilities in the event of plant shut down and grid-wide outage, in lieu of diesel generators and costly blackstart interconnections. And unlike the alternatives, storage, including batteries and flywheels, respond instantaneously—indeed, so quickly that end users would be unaware of any difference in supply even during a temporary grid failure. Energy storage also can improve the resiliency of the grid in the event of more routine contingencies, including transmission congestion or generation outages. For these applications, storage resources could replace traditional generators that are kept online (spinning reserves) or offline but ready (non-spinning reserves) to compensate for lost capacity in the event of a contingency.[102]

2. Efficiency

Increased capacity factor of existing generation resources: Most importantly, energy storage can increase the efficiency of the bulk power system by increasing the capacity factor of existing generation resources. As demonstrated in the case of nuclear and PSH, high-energy storage resources like batteries, compressed air, and PSH could permit greater reliance on efficient baseload facilities, and simultaneously, less reliance on costly traditional reserves and peaking facilities.[103] Storage could likewise ensure that

100. *See* S. CAL. EDISON, *supra* note 90, at 21–22. For example, the erstwhile largest battery in the world, located outside Fairbanks, AK, is a nickel-cadmium battery with a discharge duration of seven minutes at a peak power of 40MW, or fifteen minutes at 26MW. The local electricity cooperative installed the battery to seamlessly power the region's residents in the event of an outage because (1) outages are relatively common, since the entire region is dependent on a single intertie with Anchorage, and (2) the residents live in remote areas and extreme weather conditions, making unreliable electricity particularly dangerous. *Battery Energy Storage System (BESS)*, GOLDEN VALLEY ELEC. ASS'N, http://www.gvea.com/energy/bess (last visited June 4, 2014).

101. A blackstart is the process of restoring a power station to operation without relying on the external electric power transmission network. Normally, a power station runs on its own energy. In the event of a total plant shut down, it might draw energy from the grid. However, power plants must be prepared to restart with self-supplied power, a so-called blackstart resource. *See Glossary of Terms*, N. AM. ELEC. RELIABILITY CORP , GLOSSARY OF TERMS IN NERC RELIABILITY STANDARDS 12 (last updated June 14, 2014) [hereinafter NERC GLOSSARY], *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

102. *See infra*, section II.B.

103. *See supra*, section I.B.

no energy from variable renewables goes unutilized by shifting off-peak energy to meet peak demand.[104] Together, these deployments of energy storage would reduce the cost of meeting demand by reducing reliance on expensive generating reserves, resources that are constructed but mostly kept idle.[105] For example, the average capacity factor of the two most common peaking plants, petroleum and (non-CCGT) natural gas turbines, was 7.8% and 10.1% respectively in 2009.[106] In short, storage enhances the efficiency of cost-effective baseload and renewable generators, while reducing reliance on inefficient reserves and peaking facilities.

Increased utility of existing transmission resources: On the transmission side, storage would likewise improve the capacity of existing transmission infrastructure. For example, storage could alleviate transmission congestion and thereby defer the need for new transmission lines.[107] Storage can also be used to defer other kinds of infrastructure upgrades to the transmission or distribution system. For example, storage is particularly valuable where transmission line upgrades would be extremely capital intensive relative to the load to be served, as in remote areas.[108]

104. For example, wholesale electricity prices occasionally become *negative* on low-demand nights with a high penetration of inflexible generators, like wind, nuclear, and sometimes hydroelectric. *See Negative prices in wholesale electricity markets indicate supply inflexibilities*, ENERGY INFO. ADMIN. (Feb. 23, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=5110. Nuclear and hydroelectric generators simply cannot curtail their output in some cases. Wind generators, on the other hand, can curtail their output. But because they are currently eligible for a production tax credit of approximately $22/MWh, it is rational for wind generators to sell power for up to negative $22/MWh, in other words, to *pay* buyers up to $22/MWh. *See id.*

105. At the moment, these facilities, mainly oil and gas turbines, pose the most significant competitive threat to energy storage resources. Because of historically low natural gas prices, currently hovering just above $3/Mbtu, the marginal cost of power from natural gas-fired operating reserves is relatively low. This marginal cost sets the benchmark with which storage must compete.

106. *See* ENERGY INFO. ADMIN., ELECTRIC POWER ANNUAL 2009 48 tbl. 5.2 (2011), *available at* http://www.eia.gov/electricity/annual/archive/03482009.pdf. Combined-cycle gas turbines had a capacity factor of 42.2% in 2009, though that number has risen steadily with low natural gas prices. *See Average utilization of the nation's natural gas combined-cycle power plant fleet is rising,* ENERGY INFO. ADMIN. (June 9, 2011), http://www.eia.gov/todayinenergy/detail.cfm?id=1730.

107. Congestion occurs when flows of electricity over a line reach the physical or electrical capacity of the line or a related facility. In such cases, generators contributing to the congestion must be curtailed, and because those were the least-cost generators, other more expensive generators must ramp up to ensure reliable grid operation. The result is higher electricity prices.

108. Presidio, Texas, on the Rio Grande border with Mexico, is connected to ERCOT by a single 60-mile transmission line built in 1948. The line's service frequently goes out. Instead of installing a new transmission line, which would cost about $50 million, the transmission

Cost savings to consumers: Without storage, electricity markets are highly volatile, especially during peak events and system contingencies that limit available supply.[109] Even when markets are not supply constrained, the variable operating cost of generation—and thus the cost to consumers—increases dramatically during peak periods.[110] By shifting cheap and efficient off-peak energy to peak periods, storage will promote price stability and enhance system efficiency by providing the same amount of power at a lower unit cost.[111]

3. Climate and Environment

Zero direct emissions alternative to traditional reserves: With the exception of traditional CAES, energy storage resources have zero direct emissions, in stark contrast to the GHG-intensive reserves and peaking resources they would replace.[112] Storage could be used to replace peaking resources on the supply side or shave peak demand through distributed deployment. Storage could also replace traditional reserves for providing ancillary services, many of which are held running in idle around the clock, wasting energy and emitting GHGs.[113] Additionally, the physical environmental footprint of storage resources, particularly small distributed

utility sought and received permission from ERCOT to build a battery into its transmission asset rate base. Nicknamed the "Big-Old Battery," or "BOB," the battery has a power rating of 4MW, (Presidio's peak summer demand), and a discharge duration of 8 hours, at a cost of $25 million. The battery also acts as a source of reactive power to ensure power quality. *See In Texas, One Really Big Battery*, NPR (Apr. 4, 2010, 3:00 PM), http://www.npr.org/templates/story/story.php?storyId=125561502.

109. *See Texas Heat Wave*, *supra* note 40, discussing super-peak prices in ERCOT.

110. The clearing price for wholesale power is equal to the highest dispatch price for any given period of time. Thus, the clearing price—the price all sellers are paid per MWh—is set by the most expensive and least efficient generator/seller. The cost and inefficiency of peaking resources is higher than baseload plants by multiple orders of magnitude. *See, e.g.*, *Electric generator dispatch depends on system demand and the relative cost of operation*, ENERGY INFO. ADMIN. (Aug. 17, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7590 (showing hypothetical supply curve with rapidly increasing marginal cost at and above peak load).

111. Cost-effective energy storage resources would at once increase demand during off-peak hours and decrease demand during on-peak hours. Consequently, storage increases the capacity factor of the cheaper, more efficient generation fleet, and reduces the capacity factor of the less efficient, more expensive fleet. The latter may very well be pushed out of the generation stack altogether.

112. *See, e.g.*, RICHARD FIORAVANTI & JOHAN ENSLIN, KEMA, EMISSIONS COMPARISON FOR A 20MW FLYWHEEL-BASED FREQUENCY REGULATION POWER PLANT (2007), *available at* http://www.storagealliance.org/sites/default/files/whystorage/CO2%20Emissions%20Reduction%20Report%20-%20KEMA.pdf.

113. S. CAL. EDISON, *supra* note 90, at 78.

resources, is significantly less intense than traditional centralized generating reserves.

Maximizing the capacity factor of renewable resources: Energy storage devices are efficiency-enhancing technologies for renewable resources. Many renewable energy resources, wind and solar in particular, are variable, non-dispatchable resources, whose output can neither be entirely controlled nor predicted. By shifting excess off-peak wind energy to meet on-peak demand, high-energy storage resources could firm variable capacity and maximize the utility of renewable resources. Without storage, output from variable clean resources may at times exceed system demand, and thus go wasted.[114] Storing unneeded off-peak energy for use during peak hours would enhance system efficiency and increase revenues for these inflexible but cost-effective generators.

Enabling renewables integration: Equally important, storage can address severe reliability concerns that may otherwise limit the adoption of renewables.[115] Because the output of renewable sources like solar and wind vary significantly depending on the weather, fossil-fuel fired power plants must frequently ramp up and ramp down to maintain grid reliability, but this process leads to considerable inefficiencies and additional GHG emissions.[116] Consequently, clean energy storage has gained significant attention in recent years. In particular, batteries and flywheels would be effective for smoothing variable output and providing rapid frequency and voltage control.[117] Fast-ramping storage resources would also effectively handle predictable but more significant

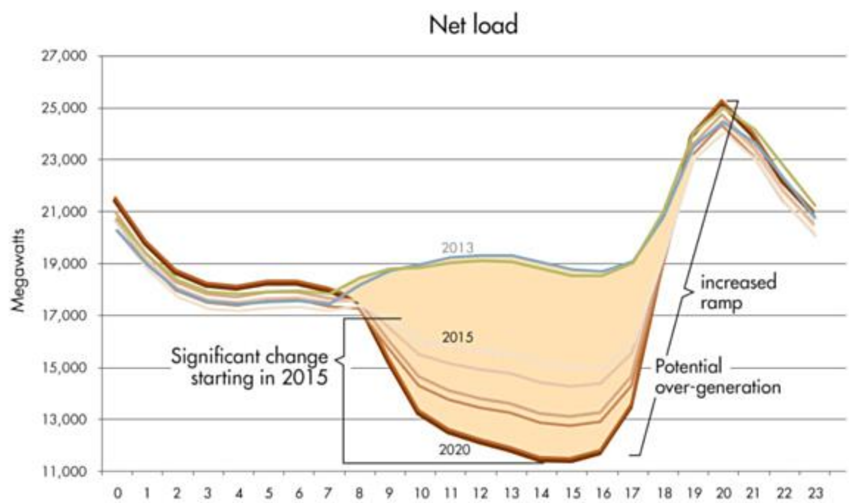
114. *See* DEAL ET AL., *supra*, note 67, (noting CAISO's estimate that wind capacity will soon exceed off-peak demand by 3,000 to 5,000MW in its region).

115. *See, e.g.*, AM. PHYSICAL SOC'Y, INTEGRATING RENEWABLE ELECTRICITY ON THE GRID 3 (2010) ("As renewable generation grows it will ultimately overwhelm the ability of conventional resources to compensate renewable variability, and require the capture of electricity generated by wind, solar and other renewables for later use."), *available at* http://www.aps.org/policy/reports/popa-reports/upload/integratingelec.pdf.

116. A Carnegie Mellon University study estimated that 20 percent of the CO_2 emission reduction and up 100 percent of the NO_X emission reduction expected from introducing wind and solar power will be lost because of the additional ramping requirements they impose on traditional generation. Warren Katzenstein & Jay Apt, *Air Emissions Due to Wind and Solar Power*, 43 ENVT'L SCI. & TECH. 253–58 (2009), *available at* http://pubs.acs.org/doi/pdf/10.1021/es801437t.

117. The largest grid-deployed battery attached to a wind farm was recently brought online in Texas. *See Smoothing Renewable Wind Energy in Texas,* DEP'T OF ENERGY (Apr. 9, 2013), http://energy.gov/articles/smoothing-renewable-wind-energy-texas.

fluctuations in net load.[118] For example, the graph below shows CAISO's projected net load through 2020. The projected net daytime load decreases from 2013 to 2020, due to increasing penetration of RPS-driven daytime solar output.[119] Subsequently, the net load difference between daytime and evening peak increases sharply, resulting in a very rapid, significant change in net load during dusk and early evening.[120] Fast ramping energy storage resources will be critical in maintaining system stability during these periods of rapid and volatile net load change.



Projected net load in CAISO through 2020.[121]

Enabling distributed renewable generation: Increased penetration of distributed renewable generation—especially PV

118. Net load is gross load minus non-dispatchable renewable generation. Thus, it is the load that a grid operator must satisfy through dispatchable resources.

119. Mark Rothleder, Vice-President of Market Quality and Renewable Integration, Cal. Indep. Sys. Operator, Powerpoint Presentation at Long Term Resource Adequacy Summit 3 (Feb. 26, 2013), *available at* http://www.caiso.com/Documents/Presentation-Mark_Rothleder_CaliforniaISO.pdf.

120. *Id.* The rapid change in net load is like the net velocity of two cars driving in opposite directions on a highway. Each may be moving 60 mph, but combined, their net velocity is 120 mph. In the graph, solar generation drops off just as consumers commence energy-intensive evening activities involving air conditioners, televisions, and other load-heavy end uses. The net load result is dramatic.

121. *Id.*

panels on rooftops[122]—raises distribution-side reliability problems because PV has variable output and causes voltage instabilities.[123] In decentralized deployment, whether as CES or at individual load sites, storage would facilitate more widespread installation of distributed solar PV generation by providing critical distribution-side reliability services, like voltage control and power quality.[124]

Enabling electric vehicle integration: EVs will constitute an increasing portion of the United States vehicle fleet in coming years.[125] When charging, EVs are significant loads. Accommodating high EV penetration will pose novel grid reliability challenges. Fast-ramping and accurate storage resources can address these reliability concerns, easing the integration of EV load into the grid.[126] Simultaneously, EVs can serve as storage resources themselves, in particular for providing grid support functions.[127] The establishment of vehicle-to-grid market rules and operational protocols could incentivize the widespread adoption of EVs by providing a new revenue opportunity that would substantially cover the cost of owning or leasing an EV.[128]

II. ELECTRICITY REGULATION AND ENERGY STORAGE: BARRIERS AND OPPORTUNITIES

Advanced storage resources clearly hold great promise. Recent developments in federal electricity regulation have opened opportunities for storage, at times directly targeting discriminatory rules and practices that kept energy storage from competing on a level playing field with other resources. But unjustified barriers

122. California, for example, has already installed over 1.5 GW of rooftop distributed PV generation. *See* Chris Clarke, *A Different Solar Milestone: 1.5 Gigawatts of Rooftop in California*, KCET (Mar. 14, 2013, 2:13 PM), http://www.kcet.org/news/rewire/solar/photovoltaic-pv/a-different-solar-milestone-15-gigawatts-of-rooftop-in-california.html.

123. *See* EAC 2012, *supra* note 4, at 15–16.

124. *See id.*

125. *See, e.g.*, Press Release, Navigant Research, Worldwide Electric Vehicle Sales to Reach 3.8 Million Annually by 2020 (Jan. 3, 2013), *available at* http://www.navigantresearch.com/newsroom/worldwide-electric-vehicle-sales-to-reach-3-8-million-annually-by-2020.

126. *See* CEC 2020, *supra* note 78, at 180–81. ("The delivery of so much electrical power in a short period of time could stress the local distribution network, so the addition of energy storage between the grid and Level 3 [EV] chargers could provide needed buffering.").

127. *See, e.g.*, Matthew L. Wald, *In Two-Way Charging, Electric Cars Begin to Earn Money from the Grid*, N.Y. TIMES (Apr. 25, 2013), *available at* http://www.nytimes.com/2013/04/26/business/energy-environment/electric-vehicles-begin-to-earn-money-from-the-grid.html.

128. *See id.* ("When the cars work with the grid, they earn about $5 a day, which comes to about $1,800 a year . . . .").

remain, in both organized wholesale markets and regions with incumbent transmission utilities. After briefly introducing the structure and functions of federal electricity regulation, this section discusses particular opportunities and barriers to grid-deployed storage, focusing particularly on FERC orders and policies.

A. Background

1. FERC Jurisdiction and Statutory Mandate

The states and the federal government share jurisdiction over the electricity system. The boundaries of federal jurisdiction remain grounded in the Federal Power Act of 1935 ("FPA"), which vested in the Federal Power Commission (now FERC) plenary jurisdiction to regulate the "transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce".[129] The FPA defines "sale of electric energy at wholesale" as "a sale of electric energy to any person for resale".[130] Although the statute extends FERC's jurisdiction only to wholesale transactions, the courts have construed its authority broadly, reaching a variety of intrastate wholesale transactions by virtue of the grid's interconnectedness and essentially interstate character.[131] The courts construe FERC's jurisdiction over interstate transmission even more broadly, extending not only to interstate transmissions of wholesale power, but also to interstate transmission of unbundled retail electricity.[132] In practice, FERC

129. 16 U.S.C. §§ 824–824w. Prior to the FPA, states regulated all aspects of electric utility service, until state authority over interstate electricity transactions was invalidated under the dormant Commerce Clause. *See* Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927). Congress enacted the FPA to fill the so-called "*Attleboro* gap," so called because no regulator had jurisdiction over interstate power transactions and transmission.

130. 16 U.S.C. § 824(d) (2012).

131. *See* Fed. Power Comm'n v. Fla. Power & Light Co., 404 U.S. 453, 458 (1972) (sufficient to show that power from intrastate transaction "commingled" with power from interstate transaction); Jersey Cent. Power & Light Co. v. Fed. Power Comm'n, 319 U.S. 61 (1943) (sufficient to show that party in intrastate transaction was "no more than a funnel" to out-of-state party). *Cf.* 16 U.S.C. § 824(c) (2012) ("[E]lectric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof . . . .").

132. In a more recent case, the Supreme Court held that the plain language of the FPA supported the Commission's assertion of jurisdiction over unbundled retail transmission in interstate commerce. "The unbundled retail transmissions targeted by FERC are indeed transmissions of 'electric energy in interstate commerce,' because of the nature of the national grid . . . [No statutory language . . . limit[s] FERC's *transmission* jurisdiction to the wholesale market, although the statute does limit FERC's *sale* jurisdiction to that at

regulates both the rates, terms, and, conditions of wholesale sales of electric power for resale in interstate commerce and the rates, terms, and conditions of interstate transmission.

Nonetheless, the FPA does limit FERC's authority to "those matters which are not subject to regulation by the States."[133] The FPA expressly reserves state jurisdiction over "facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce".[134] In practice, state public utility commissions ("PUCs") regulate the retail rates charged to end-use consumers, the lower-voltage distribution infrastructure that delivers electricity to end users, and the construction and siting of transmission and generation facilities.[135]

"[W]ith respect to any transmission or sale subject to the jurisdiction of the Commission," FERC must ensure that rates are "just and reasonable" and not unduly discriminatory or preferential.[136] Traditionally, FERC has utilized a "cost-of-service" approach to rate regulation, setting rates to meet revenue requirements that provide a rate of return on equity adequate to attract investors.[137] Courts initially interpreted the "just and reasonable" standard as requiring agencies to employ a particular cost-of-service methodology; then in 1944, the Supreme Court held that the "result reached" in the ratemaking process, rather than the methodology used, would determine whether the rate was "just and reasonable" under the FPA.[138]

wholesale." *New York v. Fed. Energy Regulatory Comm'n*, 535 U.S. 1, 17 (2002) (emphasis in original) (quoting 16 U.S.C. 824 (2012)).

133. 16 U.S.C. § 824(a) (2012).

134. *Id.* at § 824(b)(1).

135. *See* FRED BOSSELMAN ET AL., ENERGY, ECONOMICS AND THE ENVIRONMENT: CASES AND MATERIALS 683 (3rd ed. 2010).

136. 16 U.S.C. § 824d(a)–(b) (2012).

137. "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 693 (1923).

138. Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944). In the *Permian Basin Rate Cases*, the Supreme Court further held that a court must uphold an agency's decision to authorize particular rates if those rates fall within a "zone of reasonableness." *In re* Permian Basin Rate Cases, 390 U.S. 747, 767 (1968) (citing Fed. Power Comm'n v. Natural Gas Pipeline Co., 315 U.S. 575, 585 (1942)). Judge David Bazelon once described the "zone of reasonableness" as "bounded at one end by the investor interest against confiscation and at the other by the consumer interest against exorbitant rates." Washington Gas Light Co. v. Baker, 188 F.2d 11, 15 (D.C. Cir. 1950).

Within its zone of ratemaking discretion,[139] FERC began in the early 1980s to entertain what were, at the time, "highly unusual" rate filings, requesting approval of "market-based" (rather than cost-of-service) rates for wholesale power.[140] FERC determined that negotiated market-based rates are "just and reasonable" under the FPA, but the entity proposing such rates must not have, or must have adequately mitigated, market power in generation and transmission and must not control other barriers to entry.[141] Rather than specifically approve market-based rates, the Commission grants market actors market-based rate authority, pursuant to rules codified through a number of orders.[142]

2. Grid Operators: ISO/RTOs and Transmission Utilities

In encouraging market-based rates and competition among wholesale generators and sellers, the Commission has promoted the creation of organized wholesale markets and independent grid operators, called Independent System Operators ("ISOs") or Regional Transmission Operators ("RTOs").[143] There are currently

139. In considering FERC's tariff-approving authority, the Supreme Court has emphasized "that the just and reasonable standard does not compel the Commission to use any single pricing formula." Mobil Oil Exploration & Producing Se. Inc. v. United Distribution Cos., 498 U.S. 211, 224 (1991) (discussing the "just and reasonable" requirement in the natural gas context).

140. *Pub. Serv. Co. of N.M. et al.*, 25 FERC ¶ 61469 (1983).

141. *See, e.g.*, *Citizens Power & Light Corp.*, 48 FERC ¶ 61210 (1989). Courts have approved FERC's use of market-based rates as consistent with the FPA's "just and reasonable" standard. *See* California *ex rel.* Lockyer v. FERC, 383 F.3d 1006, 1012–13 (9th Cir. 2004); La, Energy & Power Auth. v. FERC, 141 F.3d 364 (D.C. Cir. 1998). The economic policy argument for authorizing market-based power rates is simple: Transmission and distribution are natural monopolies, but the generation and sale of electricity itself is not. *See* David B. Spence, *The Politics of Electricity Restructuring: Theory vs. Practice*, 40 WAKE FOREST L. REV. 417, 418 (2005). In theory, competition increases efficiency and drives down prices for consumers, leading to inherently more just and reasonable rates.

142. *See* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity & Ancillary Services by Public Utilities, 119 F.E.R.C. ¶ 61295 (2007), *order on reh'g*, 121 F.E.R.C ¶ 61260 (2007); *order on reh'g*, 131 F.E.R.C. ¶ 61021 (2010). For example, FERC has approved storage facilities for market-based rate authority. *See, e.g.*, F.E.R.C, Letter order conditionally accepting Stephentown Regulation Services, LLC's filing for market-based rate authority, Docket No. ER10-1403-000, *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12386870.

143. Organized wholesale markets for energy, capacity, and ancillary services emerged from FERC Orders No. 888, 889, and 2000. Order No. 888 established the foundation for competitive electricity markets by requiring open, nondiscriminatory access to transmission facilities. Specifically, Order No. 888 required transmission utilities to file a nondiscriminatory open access transmission tariff ("OATT"), separately stating (i.e. "unbundling") rates for energy, transmission, and ancillary services. In addition, Order No. 888 required transmission utilities to take transmission service under the OATT on equal

six independent operators in the United States that are subject to FERC,[144] which together with ERCOT in Texas, service two-thirds of electricity consumers in the United States.[145] ISO/RTOs administer the grid under OATTs[146] filed on behalf of transmission owners, under which transmission customers pay regulated rates for transmission service. Under rules promulgated by FERC,[147] RTOs/ISOs perform the following tasks:

- Dispatch—the commands to turn on, turn off, hold in readiness, or repair significant generating units;
- Transmission scheduling—the decisions to open, close, or reserve transmission lines and to schedule, implement or defer desired maintenance;
- Planning—the projection of expected demand and potential and preferred ways of meeting that demand, whether through capacity auctions or resource adequacy requirements;
- Market management—conducting auctions for energy and ancillary services which give participants the price signals to match scheduled load with expected demand;

terms with non-utility users, such as IPPs. Order No. 888 also encouraged utilities to cede functional control of transmission assets to an ISO, to avoid conflicts of interest and ensure nondiscriminatory open access for non-utility generators. Order No. 2000 further encouraged formation of RTOs to transfer functional control of the bulk power system to an independent operator, and promote regional coordination of transmission facilities. The Commission provided comprehensive guidelines as to the minimum functions and characteristics of properly organized RTOs. Notably, neither Order No. 888 nor Order No. 2000 *required* formation of such independent operators; thus, grid operators in some regions are ISO/RTOs, and in others the incumbent transmission utilities retain control. *See* Clinton A. Vince et al., *What Is Happening and Where in the World of RTOs and ISOs?*, 27 ENERGY L.J. 65, 66–74 (2006).

144. The following RTOs and ISOs are subject to FERC: PJM Interconnection, LLC ("PJM"); New York Independent System Operator, Inc. ("NYISO"); Midwest Independent Transmission System Operator, Inc. ("MISO"); ISO New England Inc. ("ISO-NE"); California Independent System Operator Corp. ("CAISO"); and Southwest Power Pool, Inc. ("SPP").

145. *See About the IRC*, ISO/RTO COUNCIL, http://www.isorto.org/about/default (last visited March 6, 2014). The Electric Reliability Council of Texas (ERCOT) is not subject to FERC under the FPA because the ERCOT grid does not synchronously interconnect with any facilities outside the state of Texas, and thus does not engage in interstate transmission or interstate wholesale power transactions. *See* ERCOT, ERCOT QUICK FACTS 2 (2012), *available at* http://www.ercot.com/content/news/presentations/2012/ERCOT%20Quick%20Facts%20-%20Jan%202012.pdf.

146. *See supra*, note 144, discussing OATTs under Order No. 888; *Pub. Serv. Co. of N.M. et al.*, *supra* note 140.

147. An independent operator is a "public utility" subject to FERC's jurisdiction under the FPA. *See* 16 U.S.C. § 824(e) (2005).

- Market monitoring—maintaining market discipline based upon monitoring for and enforcement of sanctions for that abuse; and
- Rate collection—the collection of billions of dollars through charges on the use of monopoly transmission facilities to be distributed to transmission owners in ways that will compensate past and incentivize future investment.[148]

By contrast, traditional, vertically-integrated utilities retain control over regional grids serving the remaining one-third of U.S. electric consumers living in the Southeast, Southwest, Inter-Mountain West, and Northwest.[149] In those regions, the utilities retain operational control and reliability responsibilities for transmission service. Non-utility entities can utilize transmission facilities pursuant to an OATT, which in theory provides open nondiscriminatory transmission service for IPPs and other third-party service providers, such as storage; however, in practice, the utilities can freely satisfy power and other service requirements with their own facilities, rather than buying services from IPPs or others. In these markets, independent energy providers generally engage in bilateral contracts with incumbent utilities, LSEs ("Load-Serving Entities", i.e. wholesale customers who in turn provide electricity service to end users), or directly with bulk loads (e.g. industrial or large commercial facilities).

B. Ancillary Services

Ancillary services are services necessary to ensure that capacity and energy are capable of constantly matching bulk load. Historically, traditional generators have performed ancillary services. In Order No. 890, FERC amended its pro forma OATT to require that ISO/RTOs and transmission utilities permit "other non-generation resources" to provide ancillary services, thus opening the opportunity for resources like storage and demand response to provide ancillary grid functions.[150] Typically,

148. Michael H. Dworkin & Rachel Aslin Goldwasser, *Ensuring Consideration of the Public Interest in the Governance and Accountability of Regional Transmission Organizations*, 28 ENERGY L.J. 543, 553 (2007)

149. *See* BOSSELMAN ET AL., *supra* note 137, at 656.

150. Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service, 72 Fed. Reg. 12,266, 12,527–28 (Feb. 16, 2007) (codified at 18 C.F.R. pts. 35, 37).

ISO/RTOs require LSEs to procure ancillary services in proportion to their loads, either through self-supplying, bilateral agreements, or organized wholesale markets.[151] Outside of ISO/RTOs, transmission utilities charge regulated ancillary service rates, listed separately on an OATT, or permit transmission customers to self-supply. Although transmission operators use a variety of names, ancillary services are commonly grouped into three categories—primary, secondary, and tertiary frequency control—approximately organized from quickest response and shortest duration, to slowest response and longest duration.[152]

In many circumstances, storage resources can perform ancillary services more reliably and efficiently, and with less environmental impact, than traditional generators. But the Order No. 890 promise to ensure comparable participation of non-generation resources in ancillary service markets is incomplete. Recently, FERC has acted to remedy undue discrimination in secondary frequency control markets, but barriers to storage resources remain in markets for other ancillary services.

1. Primary Frequency Control: Frequency Response

Primary frequency control, or "frequency response," is performed by an automatic, autonomous resource that instantaneously adjusts output or load to offset significant, abrupt changes in frequency.[153] Primary frequency control acts in real-time to arrest a sharp drop or spike in frequency.[154] It is designed to keep the frequency within specified limits in response to the unexpected forced outage of a generator or transmission facility or, in the event of the loss of a large load, to prevent frequency disruptions that compromise system security and that threaten to cause a blackout.[155] Once the primary ancillary resource arrests the

151. *See id.*

152. This framework is suggested in JAMES F. ELLISON ET AL., SANDIA NAT'L LABS., PROJECT REPORT: A SURVEY OF OPERATING RESERVE MARKETS IN U.S. ISO/RTO-MANAGED ELECTRIC ENERGY REGIONS (2012), *available at* http://www.sandia.gov/ess/publications/SAND2012_1000.pdf,.

153. NERC GLOSSARY, *supra* note 101, at 38.

154. For a discussion of the importance of frequency control to efficient grid performance, *see supra* notes 90–95 and accompanying text.

155. *See* Mandatory Reliability Standards for the Bulk Power Sys., 130 F.E.R.C. ¶ 61218 para. 6 (Mar. 18, 2010). *See also* U.S.-CANADA POWER SYSTEM OUTAGE TASK FORCE, *FINAL REPORT ON THE AUGUST 14, 2003 BLACKOUT IN THE UNITED STATES AND CANADA: CAUSES AND RECOMMENDATIONS* 99 (2004), *available at* http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf.

frequency deviation, the grid operator dispatches secondary and tertiary frequency control resources (discussed below) to ensure longer-duration stability.

A recent FERC-commissioned study observed that "[t]he declining quality of frequency control in the U.S. interconnections is currently a significant reliability concern," and particularly emphasized that "[t]he amount of primary frequency control reserves that are on line and always available may be reduced as the conventional generation-based sources for these reserves are displaced by variable renewable generation, which currently does not provide primary frequency control."[156] As a solution, the study recommended "[e]xpanded use of advanced technologies, such as energy storage" for primary frequency control, among other measures.[157] For example, storage resources, especially batteries and flywheels, can respond more quickly and accurately to sudden frequency disturbances than conventional generators and demand response resources.[158] Moreover, storage resources combine the characteristics of generation and demand response in a single resource, with the capability of controlling both up (by discharging) and down (by charging).

Notwithstanding the study's recommendation, energy storage resources currently have extremely limited prospects as primary frequency control resources. Primary frequency control is not provided through wholesale markets in any of the ISO/RTOs.[159] Although FERC has recognized that traditional frequency response resources will soon become inadequate,[160] ISO/RTOs continue to rely on a combination of conventional generation and, to a limited extent, demand response resources. Without a wholesale market and/or performance-based incentives for frequency response that account for storage resources' inherently greater frequency response capabilities, storage resources have no opportunity as

156. *See* JOSEPH H. ETO ET AL., LAWRENCE BERKELEY NAT'L LAB., USE OF FREQUENCY RESPONSE METRICS TO ASSESS THE PLANNING AND OPERATING REQUIREMENTS FOR RELIABLE INTEGRATION OF VARIABLE RENEWABLE GENERATION xvi (2010), *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf.

157. *Id.*

158. *See generally* Oudalov et al., *Optimizing a Battery Energy Storage System for Primary Frequency Control*, 22 IEEE TRANSACTIONS ON POWER SYSTEMS 1259 (2007), *available by subscription at* http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=04282047 (discussing value of battery storage systems for frequency control in Europe).

159. *See* Ellison et al., *supra* note 153, at 14.

160. *See* ETO ET AL., *supra* note 157.

frequency response resources inside or outside of organized markets.

2. Secondary Frequency Control: Frequency Regulation

"Secondary frequency control," or "frequency regulation," refers to the rapid injection or withdrawal of real power by facilities capable of responding automatically to a grid operator's signal, generally within minutes.[161] Like frequency response, frequency regulation ensures that, on the margin, generation continuously matches load to maintain system frequency within a one percent deviation from 60Hz.[162]

Currently, frequency regulation is the most commercially viable storage application.[163] That is because certain storage resources can respond more quickly and accurately than traditional generators to the frequency regulation needs of the grid, and, crucially, many regions already have organized frequency regulation markets. However, the compensation practices of most ISO/RTOs and transmission utilities—designed for the functional characteristics of conventional generators—do not always account for the inherently greater frequency regulation provided by certain storage devices.[164] Recently, FERC has acted to remedy such unjust and unreasonable market rules, constituting the Commission's first

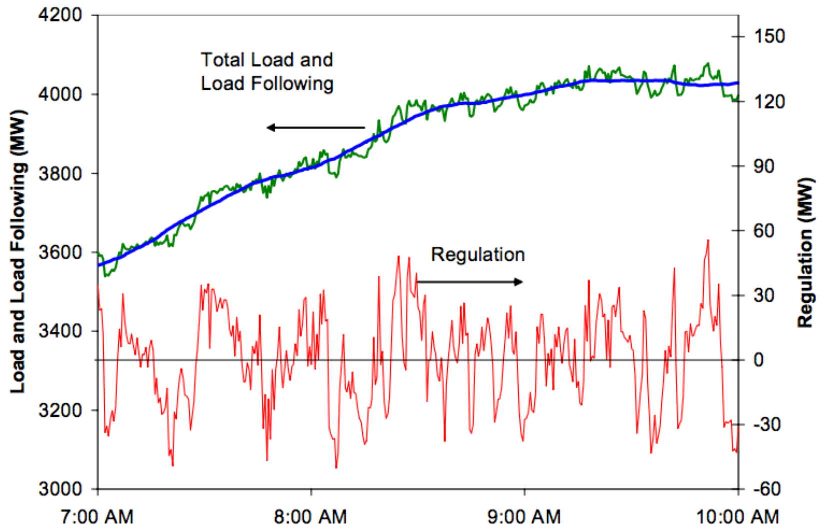
161. The frequency regulation signal is called an automatic generator control ("AGC") signal. Frequency regulation resources are designed to automatically respond to the AGC, rather than requiring manual control. The signal is updated every 4 or 6 seconds, depending on the system. Frequency regulation is not to be confused with primary frequency control, or frequency response. Regulation behaves in response to the AGC, which is usually dispatched when frequency deviates a certain percentage from its baseline, whereas frequency control/response acts automatically in response to changes in system frequency itself. *See* Order No. 755, Frequency Regulation in the Organized Wholesale Power Markets, 137 F.E.R.C. ¶ 61,064 (October 20, 2011).

162. *See* NERC GLOSSARY, *supra* note 101, at 38.

163. *See, e.g.*, Dan Rastler, Program Manager, Cal. Energy Comm'n, *Energy Storage Applications and Economics: Costs, Benefits, and Revenue*, Powerpoint Presentation at the IEPR Committee Workshop 10 (April 28, 2011), *available at* http://www.energy.ca.gov/2011_energypolicy/documents/2011-04-28_workshop/presentations/11_EPRI_Rastler_Panel2_IEPR_Applications_and_Economics.pdf.

164. In May 2009, FERC approved tariff revisions making the NYISO the first grid operator in the nation to establish provisions for limited energy storage resources ("LESRs") to provide regulation services in the NYISO market. *See* ISO/RTO COUNCIL, 2011 ISO/RTO METRICS REPORT 218 (2011), *available at* https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2011-08-31%20Docket%20No.%20AD10-5-000.pdf. But even NYISO's rules do not adequately compensate energy storage resources for actual regulation performance.

major—albeit piecemeal—action toward ensuring comparable treatment of storage resources.



Frequency regulation: the regulation signal (red) is dispatched to compensate for minute-to-minute discrepancies between total system load (green) and load-following generation (blue).[165]

a. Order No. 755 and Frequency Regulation in ISO/RTOs

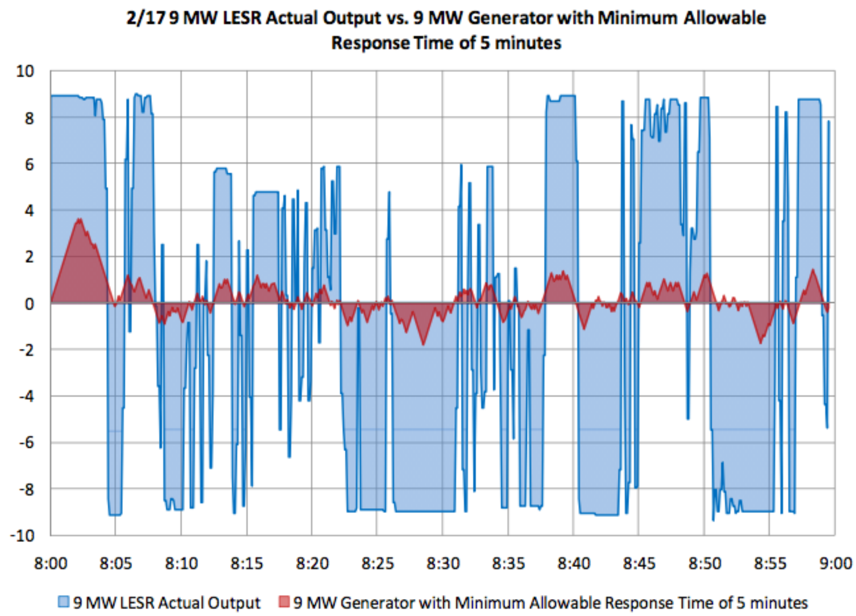
Through Order No. 755,[166] FERC successfully identified and remedied undue discrimination in frequency regulation markets by requiring ISO/RTOs to adopt market rules that account for the performance characteristics of certain storage resources. Wholesale markets already exist to provide for transactions in frequency regulation as needed to maintain grid stability. Today, traditional generators, such as fast-ramping natural gas turbines, provide most frequency regulation. The faster a resource can ramp up or down, the more accurately it can respond to the AGC signal and avoid over- or under- performing. Alternatively, when a resource ramps too slowly, it may work against the needs of the

165. BRENDAN J. KIRBY, U.S. DEP'T OF ENERGY, FREQUENCY REGULATION BASICS AND TRENDS 5 (2004), *available at* http://www.ornl.info/sci/ees/etsd/pes/pubs/TM2004-291_Frequency_Regulation_Basics_and_Trends.pdf.

166. Order No. 755.

system and force the system operator to commit additional regulation resources to compensate.[167]

Under compensation practices prior to Order No. 755, resources were not compensated for actual frequency regulation provided to the grid. In many instances resources affording inherently different levels of regulation were compensated identically. For example, the Commission found that some ISO/RTOs compensated regulation resources for a flat rate based simply on the amount of capacity devoted to regulation, plus a payment or charge for net energy used.[168] For example, 10MW of flywheel



Relative frequency regulation of conventional generator (red) and a flywheel (blue), in following regulation signal. These resources would be compensated identically under pre-Order No. 755 rules in most ISO/RTOs.[169]

capacity might receive less compensation than 10MW of natural gas plant capacity, even though the battery could track the dispatch signal with far greater precision and could provide 20MW of

167. *See* KIRBY, *supra* note 166 at 4–5.

168. *See* ELLISON ET AL., *supra* note 153 at 14.

169. Judith Judson, *Beacon Power Corporation Comments to California Public Utilities Commission*, Powerpoint Presentation to CPUC 6 (2011), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/706E0452-3533-48FE-ABAC-B49D8D8105ED/0/BeaconPowerpresentationforCPUC62811.pdf.

capacity (10MW down, plus 10MW up), thus affording the system substantially more regulation service.

In response to this and other discriminatory rules in frequency regulation markets, Order No. 755 ensures that ISO/RTOs compensate for actual frequency regulation performed by mandating a two-part payment: (1) payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal, and (2) a capacity payment reflecting the marginal unit's opportunity costs.[170]

The first so-called "mileage payment"[171] ensures that resources are compensated for their actual performance, based on the absolute amount of frequency regulation up and down a resource provides in response to the system operator's dispatch signal. As in the above graphic example, fast-ramping resources can perform substantially more frequency regulation work than a slower-ramping traditional resource in a given period of time.[172] Moreover, storage devices can regulate *down*, by charging and actually taking generation in excess of load off the grid. Regulating down is as important to grid reliability as regulating up,[173] but many organized markets still lack a mechanism for compensating such performance because, quite simply, the rules were designed for traditional generators, which can only regulate up. FERC also specifically required that the performance payment be market-based, to ensure the least-cost and most efficient dispatch of frequency regulation resources.[174] Layered onto the mileage payment, FERC required compensation to account for the accuracy with which a regulation resource tracks the operator's dispatch signal. Batteries and flywheels generally track dispatch signals with far higher precision and accuracy than traditional generators, providing high value regulation while avoiding costly inaccuracies that might require additional corrective regulation. Although

170. *See* Order No. 755 para. 78.

171. The mileage payment is so called because it compensates for the distance traveled, regardless of whether the movement was up or down. FERC seems unwilling to define the performance payment without absolute actual mileage as a component. For example, the Commission rejected PJM's Order No. 755 compliance filing to the extent it did not make the performance payment specifically contingent on total mileage, "find[ing] that the regulatory text adopted by Order No. 755 is clear." *See* P.J.M. Interconnection, LLC, 141 F.E.R.C. ¶ 61,134, at 16 (Nov. 16, 2012).

172. *See also* MASIELLO ET AL., *supra* note 93, at 6.

173. *See, e.g.*, Order No. 755 paras. 100, 159.

174. *See id.* paras. 128–30.

FERC did not require any particular accuracy metric, the Commission required that all resources be gauged by the same one.[175]

Similarly, the Commission required that all resources be compensated at a uniform market-based capacity payment equal to the marginal unit's stated opportunity cost. FERC required a uniform clearing price, to ensure an efficient preference for resources with lower opportunity costs of participating in frequency regulation markets as opposed to other markets, e.g., those providing energy or capacity.[176]

In Order No. 755, FERC identified and remedied market rules that did not adequately account for the novel operational characteristics of certain storage resources. In doing so, FERC leveled the playing field for a variety of new technologies, particularly batteries and flywheels, while making the market for frequency regulation more competitive and efficient.[177] By eliminating these barriers to the provision of frequency regulation, FERC took an important step to promote the integration of variable renewable resources.[178] As of this writing, the ISO/RTOs are at various stages of implementing Order No. 755.[179] MISO, the Midwest ISO, implemented Order 755 in December 2012 by adding a regulation mileage product.[180] The California ISO (better known as CAISO) was granted an extension for implementation of Order 755 until June 2013 , but implementation is still pending as of February 2014.[181] The PJM energy market implemented Order No. 755, but it is the only market that has seen prices rise considerably since implementation. It is important to note that FERC allows each ISO/RTOs considerable flexibility in interpreting and implementing Orders.

175. *See id.* para. 153.

176. *See id.* para. 99.

177. *See* MASIELLO ET AL., *supra* note 93, at 6.

178. *See* ETO ET AL., *supra* note 157, at xvi.

179. *See, e.g.*, PJM Interconnection, L.L.C., 145 F.E.R.C. ¶ 61,011 (Oct. 2, 2013); N.Y. Indep. Sys. Operator, Inc., 143 F.E.R.C. ¶ 61,194 (May 31, 2013); Cal. Indep. Sys. Operator Corp., 142 F.E.R.C. ¶ 61,233 (Mar. 27, 2013); Midwest Indep. Transmission Sys. Operator, Inc., 140 F.E.R.C. ¶ 61,224 (Sept. 20, 2012).

180. *See generally* MISO, REGULATION MILEAGE PRODUCTION OBSERVATION—FERC ORDER 755 5 (2013), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2013/20130806/20130806%20MSC%20Item%2005f%20Regulation%20Mileage%20Compensation.pdf.

181. *Pay for Performance Regulation*, CAISO (March 6, 2014), https://www.caiso.com/informed/Pages/StakeholderProcesses/PayforPerformanceRegulation.aspx

b. Frequency Regulation Outside the ISO/RTOs

Order No. 755 does not apply outside of ISO/RTOs, where the transmission utilities retain operational control of the grid and where there are no organized wholesale markets for ancillary services.[182] Outside of ISO/RTOs, transmission utilities must ensure grid reliability, including an adequate supply of ancillary services. The procurement duty and cost of ancillary services falls on transmission customers (such as LSEs). One option for customers is to pay the transmission utility a regulated rate (stated in the OATT) for ancillary services. In that case, the transmission utility would either own and operate ancillary service resources or procure such services through bilateral market-based agreements with third parties.[183] Alternatively, customers can self-supply, either with their own ancillary service facilities or through bilateral agreements with third-parties.[184]

To remedy barriers similar to those targeted in Order No. 755, FERC recently issued Order No. 784, addressing ancillary service procurement and compensation outside of organized markets.[185] Partly to eliminate barriers to storage where customers choose to self-supply regulation and frequency response outside of ISO/RTOs, Order No. 784 required each public utility transmission provider to include provisions in its OATT explaining how it will determine frequency regulation and response service reserve requirements in a manner that takes into account the speed and accuracy of resources used.[186]

Transmission utilities generally state customers' reserve requirements in simple quantities of capacity, e.g.. MWs, without accounting for the performance characteristics of the resource providing frequency regulation or response. Consequently, if a customer chooses to self-supply (whether through ownership or third-party agreement), under prevailing requirements prior to Order No. 784 it would be irrational to utilize a quick and accurate resource that is more cost-effective per amount of frequency

182. Order No. 784, Third-Party Provision of Ancillary Servs.; Accounting and Fin. Reporting for New Elec. Storage Techs., 144 F.E.R.C. 61,056 (July 18, 2013) .

183. The latter option is in theory possible but in practice non-existent, at least until Order No. 784 is implemented. *See infra* notes 189–191 and accompanying text, discussing the *Avista* policy.

184. *See, e.g.*, Order No. 888, Promoting Wholesale Competition Through Open-Access, Non-Discriminatory Transmission Services, 75 F.E.R.C. 61,080.(Apr. 24, 1996).

185. *See* Order No. 784, *supra* note 183, para. 1.

186. *Id.*

regulation or response provided, if it is more expensive per MW of capacity. Thus, the Commission found that accounting for speed and accuracy in a public utility transmission provider's determination of regulation and frequency response reserve requirements is necessary to address the potential for undue discrimination against customers choosing to self-supply their regulation and frequency response needs.[187]

Order No. 784 also seeks to eliminate barriers to storage where a transmission utility decides to procure frequency regulation and response services through market-based agreements with third-parties, in satisfying the utility's own duty to offer customers ancillary services at regulated rates through its OATT.[188] In such circumstances, the Commission's *Avista* policy required a potential ancillary service provider to perform a study demonstrating a lack of market power for the particular ancillary service in the particular geographic market.[189] However, partly because information required to perform the market power study is unavailable, the Commission found that "the effect of the *Avista* policy is to

187. *See id.* para. 3.

188. *See id.* That is, the customer does not want to self-supply, thus it must pay the transmission utility for the ancillary services incident to its transmission service. The transmission utility must offer such services, and can do so either through owning and operating its own ancillary service resource, or through bilateral market-based agreements with third-parties. Order No. 784 addresses the later situation.

189. *See* Avista Corp., 87 FERC ¶ 61,223, *order on reh'g*, 89 FERC ¶ 61,136 (1999). The Commission must ensure that market-based rates are just and reasonable, primarily by ensuring that parties lack market power. In *Avista*, the Commission determined that requiring applicants for market-based rates in ancillary services to perform market power studies poses insurmountable barriers because the information needed to perform such studies is unavailable. Thus, the Commission permits a third-party supplier to sell ancillary services at market-based rates without showing a lack of market power in certain circumstances. For example, where selling ancillary services to transmission customers, the Commission reasoned that a third-party ancillary service provider would not be able to charge unjust or unreasonable rates because the customer could always fall back to the regulated OATT rates. However, the Commission did not exempt third parties offering ancillary services to a transmission utility. The Commission reasoned that:

> [T]he public utility's ability to recover such purchase costs in OATT rates might lead it to increases in those OATT ancillary service rates that may reflect the exercise of market power thus reducing the rates' ability to serve as an effective alternative to purchases from a third-party seller unable to show lack of market power. This would undermine the effectiveness of the mitigation measure that the Commission relied upon in *Avista* to relax the requirement for a market power analysis.

Order No. 784 para. 8. One purpose of Order 784 is to revisit this policy.

categorically prohibit sales of ancillary services to public utility transmission providers outside of the RTO and ISO markets."[190]

The finer points of the Order No. 784's market power policy are beyond the scope of this Article. Unlike other aspects of the Order, the novel operational characteristics of emerging energy technologies do not motivate the Commission with respect to this particular issue. Rather, the Commission's goal is to loosen *Avista*'s general stranglehold on market-based ancillary service provision to transmission utilities, without regard to the resource providing such services.[191] However, lowered barriers to supplying transmission utilities with ancillary services through market-based rates will open opportunities for storage to the extent storage resources are cost-effective and the utilities' procurement decisions account for the inherently faster and more accurate performance of certain storage technologies.[192] Indeed, the limited opportunity to engage in long-term service contracts with transmission utilities (because of the *Avista* policy) is among the most significant barriers to storage deployment. Without long-term contracts (or the ability to participate in capacity markets, as explained as follows in section II.C.), storage projects cannot secure long-term revenue streams, increasing investment risk and making it difficult to secure financing for development and capital costs. Loosening the *Avista* policy will eliminate barriers to such long-term contracts, thereby facilitating storage resource deployment.

3. Tertiary Frequency Control: Spinning and Non-Spinning Reserves

Tertiary frequency control consists of tailored changes in scheduled unit commitment and dispatch levels in order to bring frequency back to ideal values when secondary frequency control is unable to perform this task.[193] The ISO/RTOs use a variety of

190. Notice of Proposed Rulemaking, Third-Party Provision of Ancillary Services; Accounting & Fin. Reporting for New Elec. Storage Technologies, 139 F.E.R.C. 61,245 para. 11 (June 22, 2012).

191. *See* Order No. 784 paras. 1–5.

192. Order 784 requires transmission utilities are required under Order 784 to account for the speed and accuracy of frequency regulation and response resources in setting procurement requirements. Order No. 784 para. 1. In addition, under their OATTs, utilities must take transmission service on the same rates, terms, and conditions as customers. So once Order 784 is fully implemented, utilities should be incentivized to prefer performance over mere capacity to the extent such resources are cost-effective.

193. ELLISON ET AL., *supra* note 153, at 13.

terms for tertiary ancillary services, but generally speaking, there are two basic categories: spinning and non-spinning reserves.[194] Spinning and non-spinning reserves provide frequency regulation in the event of a system contingency, like an unexpected loss of generation or transmission resources, and also provide load-following reserves. Load-following reserves are similar to frequency regulation in that they compensate for changes in the balance of generation and load, but load-following resources track the general trending load pattern within a day, rather than the moment-to-moment patterns addressed by frequency regulation.[195]

Most of the ISO/RTOs require that a resource be able to provide continuous output for some specified duration of time in order to qualify as a reserve provider. For example, CAISO requires that spinning and/or non-spinning reserve resources be able to maintain a constant level of power output for a minimum of 30 minutes, whereas ISO-NE and MISO require such resources to be able to maintain a constant power output for a minimum of 60 minutes.[196] Minimum duration requirements serve the operational need to manage medium- to longer-duration reserve requirements, and shorter-duration products function better as primary or secondary frequency control mechanisms.

Certain storage resources can meet these criteria and should be able to participate in spinning and non-spinning reserve markets. However, most flywheels would not, because they usually can only discharge for about fifteen minutes at their rated capacity.[197] Although flywheels are not ideal tertiary frequency control providers, other storage resources, including batteries and PSH, could perform as spinning or non-spinning reserves and as load following.

Nonetheless, as with secondary frequency control markets, the ISO/RTOs do not adequately account for the valuable operational characteristics of storage resources. For example, spinning and non-spinning reserves are often defined as resources that can respond within ten minutes, a vestige of the operational characteristics of traditional load-following resources like natural gas turbines. But storage resources can provide near-instantaneous

194. *See* Order No. 890-B, Preventing Undue Discrimination and Preference in Transmission Service, 123 FERC ¶ 61,299 (June 23, 2008) (pro forma OATT, Schedule 5-6).

195. *See supra* note 166 and accompanying graph (showing the difference between load following and frequency regulation).

196. *See* ELLISON ET AL., *supra* note 153, at 18.

197. *See supra*, section I.C.

response and sustained discharge. Current market rules in tertiary frequency control markets—no less than in secondary—do not adequately account for or incentivize the performance characteristics of certain storage resources. Consequently, tertiary frequency control compensation mechanisms undervalue quick-response, rapid ramping, and accurate storage resources, resulting in unjust and unreasonable rates.

C. Capacity Markets and Resource Adequacy Requirements

For much of the history of the electric power industry, vertically integrated utilities planned for and built generation resources, which they then incorporated into their rate base.[198] Since the introduction of market-based rates and wholesale competition (not to mention retail competition), LSEs increasingly purchase energy from IPPs through wholesale markets or bilateral agreements.[199] Consequently, utilities—especially those participating in organized wholesale markets—are less concerned with the long-term planning needed to ensure that the development and maintenance of generation resources matches future load-side requirements. At the same time, revenue from energy and ancillary service sales is usually insufficient to cover the production costs, fixed O&M, and capital investments of new generation because the cost of wholesale power generally covers only the marginal, or variable, cost of generation.[200]

In response to this resource-planning deficit, certain organized wholesale markets have developed mechanisms to ensure the development and maintenance of generation resources by compensating for their fixed costs.[201] These mechanisms operate both through markets and regulations. Capacity markets are a market-based solution, whereas resource adequacy mechanisms function through administratively determined procurement

198. See *supra*, section II.A.

199. About one third of all power consumed in the United States is generated by IPPs. *See* ENERGY INFO. ADMIN., *supra* note 73, tbl. 1.3..

200. *See* MARK GRIFFITH, VENTYX, CAPACITY MARKETS DEMYSTIFIED 4 (2008), *available at* http://www.energycentral.com/download/products/wp08-capacity-markets-demystified.pdf.

201. The ISO/RTOs with capacity markets include NYISO, ISO-NE, PJM, and MISO. CAISO is considering a capacity market but has not instituted one. *See Capacity Markets*, CAISO, http://www.caiso.com/informed/Pages/StakeholderProcesses/Completed StakeholderProcesses/CapacityMarkets.aspx (last visited June 18, 2014).

requirements.[202] ISO/RTOs generally set installed capacity targets for a given period (for example, a one-year commitment period three years in advance) with variations depending on the load and transmission constraints of different locations.[203] Once they have set the overall capacity target for their jurisdiction, ISO/RTOs assign each utility or LSE with responsibility for procuring a particular quota of capacity.[204] In response to the procurement bids of utilities and LSEs, generation resources sell capacity, thereby committing to provide power in the future period, if in fact that power is necessary to satisfy demand.

Capacity payments are particularly useful for providing a significant stream of revenue to contribute to the recovery of total costs for new and existing peaking units. Peaking units dispatch only during certain periods of high demand, with capacity factors on average around 8-10%.[205] They typically incur high marginal costs when dispatched, so they command high energy prices and, indeed, usually set the clearing price during peak periods. But revenue from energy alone is generally insufficient to cover the total costs of peaking resources. Thus, peaking plants rely heavily on capacity revenues to cover fixed costs. The capacity market also provides significant revenues to cover the fixed costs of investing in new intermediate and base load units, but capacity revenues are a larger part of net revenue for peaking units.

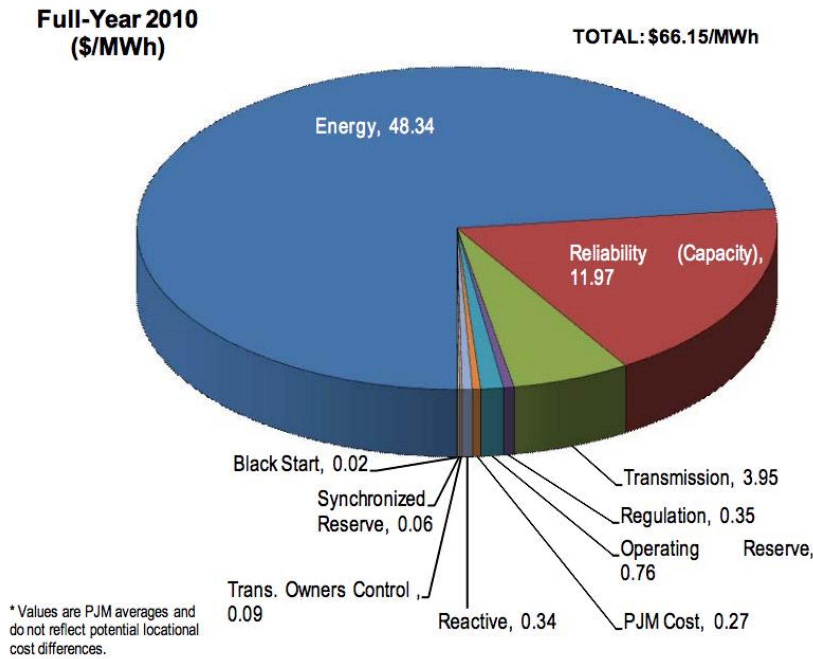
202. Capacity markets are critical for incentivizing efficient market entrants. A prospective investor estimates the cost of investment over the life of a project minus the expected variable profits from providing energy and ancillary services (after netting the associated variable costs). This difference between investment costs and variable profits, which is known as Net Cost of New Entry ("Net CONE"), is the estimated capacity revenue that would be necessary for the investment to be profitable. In an efficient market, the investments with the lowest Net CONE will be the first to occur. *See* DAVID B. PATTON ET AL., POTOMAC ECON., 2011 ASSESSMENT OF THE ISO NEW ENGLAND ELECTRICITY MARKETS 106–7 (2012), *available at* http://www.iso-ne.com/markets/mktmonmit/rpts/ind_mkt_advsr/emm_mrkt_rprt.pdf

203. NERC reliability standards require ISO/RTOs to maintain a capacity reserve margin sufficient to satisfy a "one day in ten year" probability of median forecast peak load exceeding installed capacity, often referred to as a "loss-of-load" event. *See* N. AM. ELEC. RELIABILITY CORP, PLANNING RESOURCE ADEQUACY ANALYSIS, ASSESSMENT AND DOCUMENTATION 1, *available at* http://www.nerc.com/files/BAL-502-RFC-02.pdf.

204. *See, e.g.*, N.Y. INDEP. SYS. OPERATOR, INSTALLED CAPACITY MANUAL §§ 2-1–3-1 (2014), *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

205. *See* MONITORING ANALYTICS, LLC, 2012 STATE OF THE MARKET REPORT FOR PJM 190 (2013), *available at* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012/2012-som-pjm-volume2-sec6.pdf; ENERGY INFO. ADMIN., *supra* note 106, at tbl. 5.2.

For example, for the year 2012, PJM estimated that a hypothetical gas turbine running as a peaking resource might have net energy revenues of $23,240 per MW-year and net capacity revenues of $30,116.[206] Thus, capacity constituted 55% of net revenues for a gas turbine peaking facility.[207] On the other hand, PJM estimated that a hypothetical CCGT (likely running as an intermediate or baseload resource) would have net energy revenues of $97,260 per MW-year, and net capacity revenues of $31,422 (only a 24% share of net revenues).[208] Indeed, overall, capacity payments constitute the second greatest component of PJM's overall wholesale costs—about 18% in 2010.[209]



Components of PJM Total Wholesale Power Cost, 2010[210]

206. *See* MONITORING ANALYTICS, LLC, *supra* note 206, at 193.
207. *Id.*
208. *Id.*
209. *Id.*
210. PJM INTERCONNECTION, 2010 PJM MARKET HIGHLIGHTS 2 (2011), *available at* http://www.pjm.com/~/media/documents/reports/20110513-2010-pjm-market-highlights.ashx.

Advanced storage technologies are well suited to ensure resource adequacy by functioning as peaking capacity (by shifting low-cost, off-peak energy to meet high-cost, peak load). However, as a matter of policy rather than operational rationale, most of the RTOs/ISOs prohibit storage from participating in capacity markets and resource adequacy planning.[211] Thus, storage resources are generally limited to revenue from ancillary service and—for longer-duration, energy-intensive devices—energy markets. In other ISO/RTOs without organized capacity markets, LSEs must satisfy capacity reserve margins through bilateral agreements or self-owned generation, but similarly, those ISO/RTOs do not permit LSEs to satisfy their capacity requirements with storage capacity. Therefore, storage resources lack one of the most useful mechanisms for recouping their total costs, a significant barrier for any resource, but especially for emerging technologies with slim margins.[212]

D. Some Classification Problems

"[E]lectricity storage devices . . . do not readily fit into only one of the traditional asset functions of generation, transmission or distribution. Under certain circumstances, storage devices can resemble any of these functions or even load."[213] However, the nature of the Commission's jurisdiction often hinges on the classification of a resource. Moreover, the lack of an established policy for classifying storage engenders regulatory uncertainty that inhibits investment by market actors and regulated utilities alike. To date, the Commission has been hesitant, only "address[ing] the classification of energy storage devices on a case-by-case basis".[214]

211. NYISO is one of the few ISO/RTOs that permit storage to participate in a capacity market. However, NYISO permits an "Energy Limited Resource" to participate only if it can offer capacity for a minimum of four hours. *See* N.Y. INDEP. SYS. OPERATOR, *supra* note 205, at § 4.8.2. PJM has also has begun the process of creating rules to accommodate more storage resources. *See PJM to Consider Storage as Capacity*, RTO INSIDER (Oct. 1, 2013), http://www.rtoinsider.com/pjm-consider-storage-capacity/.

212. M. KINTER-MEYER ET AL., DEP'T OF ENERGY, NATIONAL ASSESSMENT OF ENERGY STORAGE FOR GRID BALANCING AND ARBITRAGE: PHASE 1, WECC xii (2012), *available at* http://energyenvironment.pnnl.gov/pdf/PNNL-21388_National_Assessment_Storage_Phase_1_final.pdf (noting that storage will require additional revenue streams such as capacity payments to be viable).

213. W. Grid Dev., LLC, 130 F.E.R.C. ¶ 61056 para. 44 (2010) [hereinafter *Western Grid*].

214. *Id.*

One question is whether a storage device deployed on the bulk grid constitutes a transmission or generation asset. In a matter of first impression, the Commission had little difficulty granting "exempt wholesale generator" status to a 20MW battery system intended to provide frequency regulation at market-based rates in NYISO's competitive wholesale market.[215] In classifying the project, the Commission looked primarily to the applicant's intended use—exclusively providing ancillary services.[216] Indeed, from an operational perspective, the "generation" bucket is perhaps the most comfortable fit for storage resources intended to perform energy and ancillary service functions,[217] especially in an organized market.[218]

Two recent rulemakings also indicate that the Commission treats storage resources as generation. On November 22, 2013, FERC issued Order No. 792, which reformed the Small Generator Interconnection Agreements and Procedures ("SGIA" and "SGIP") to, among other things, "specifically include energy storage devices" as a type of resource eligible to utilize the SGIA/SGIP.[219] Order No. 792 also permits storage resources of up to 20MW in capacity to utilize the "Fast Track Process," which reduces the cost, time, and regulatory burden of interconnecting with utility grids.[220] Order 792 thus eliminates substantial uncertainty as to the procedures and standard terms by which a storage resource may connect with the grid, while also eliminating administrative costs associated with gaining approval for storage resources less than 20MW.

Separately, the Commission also discussed the possible application to storage of Order No. 764, which promotes the integration of variable energy resources ("VERs") by requiring each public utility transmission provider to offer intra-hourly (fifteen-

215. AES ES Westover, LLC, 131 F.E.R.C 61008, 61043 (2010) ("We note that this is the first instance in which the owner of a battery storage facility has sought EWG status.").

216. *Id.* at 61043–44 ("Applicant has represented that it will operate the Facility in such a manner that it will be engaged directly and exclusively in selling electric energy at wholesale.").

217. *See, e.g.*, Norton Energy Storage, L.L.C., 95 F.E.R.C. 61476 (2001) (ruling that energy exchange transactions for charging/discharging the first merchant CAES generator in the United States were wholesale transactions under the FPA subject to the exclusive jurisdiction of the Commission).

218. *See* AES ES Westover, LLC, 131 F.E.R.C. 61008 (2010).

219. Order No. 792, 145 F.E.R.C. 61159 para. 1 (2013).

220. *Id.* at para. 6. *See also* Small Generator Interconnection Agreements and Procedures, 142 F.E.R.C. 61049 (2013) (order finalized by 145 F.E.R.C. 61,159 (Nov. 22, 2013)).

minute) transmission scheduling.[221] While primarily intended to eliminate barriers to wind and solar resources,[222] the Commission emphasized that "many types of entities, not only VERs, may benefit from the availability of intra-hour scheduling. . . . This includes, for example, . . . transmission customers taking delivery from energy constrained resources (such as flow-limited hydro-electric generators . . . and energy storage resources)."[223] This rulemaking once again suggests that FERC considers storage to be a generation resource.

On the other hand, FERC seems less inclined to consider a storage device as a transmission asset, particularly for the purposes of granting cost-of-service rate treatment. Nonetheless, in certain circumstances, the Commission has found that storage devices may constitute transmission facilities. FERC faced this question in *Western Grid Development, LLC*, where a CAISO Participating Transmission Owner ("PTO") proposed a series of sodium sulfur batteries ranging in size from 10MW to 50MW. [224] The PTO stated the batteries would "provide transmission services to solve existing reliability problems [on the CAISO grid] at a lower cost than traditional transmission upgrades."[225] Contingent on CAISO's approval of the projects through its own transmission planning process,[226] and "based on the specific circumstances and characteristics" of the proposal, the Commission found the projects were "wholesale transmission facilities" subject to its jurisdiction.[227] The Commission emphasized the storage resources would function analogously to other transmission assets, such as "capacitors that address voltage issues or alternate transmission circuits that address

221. Integration of Variable Energy Res, 139 F.E.R.C. 61246 (2012).

222. *Id.* at para. 22 ("Implementation of intra-hour scheduling under this Final Rule will provide VERs and other transmission customers the flexibility to adjust their transmission schedules, thus limiting their exposure to imbalance charges.").

223. *Id.* at para. 94.

224. *Western Grid*, supra note 214, at para. 4. A Participating Transmission Owner is a transmission owner who agrees to place its facilities under the operational control of an ISO/RTO. The owner has no operational discretion (though may retain actual control), but receives the regulated rates paid for transmission service by customers.

225. *Id.* at para. 3. "Western Grid claims that the Projects will facilitate reliability on the CAISO system by (1) mitigating normal transmission overload; (2) addressing transmission line trips; (3) responding to transmission lines taken off for maintenance; and/or (4) reacting to voltage dips on transmission line segments on the CAISO system." *Id.* at para. 4.

226. Notably, CAISO strongly opposed the projects. *See id.* at paras. 32–37.

227. *Western Grid*, *supra* note 214, at para. 2. The Commission further emphasized the exceptionality of Western Grid's proposal by expressly limiting its "finding . . . to the facts presented . . . in this proceeding."). *Id.*

line overloads or trips."[228] The Commission rejected the objection that unlike capacitors, which are passive grid components, batteries are dispatchable and thus, in effect, behave at times like generators.[229] The Commission also emphasized that Western Grid would not retain any incidental net revenue from the purchase and sale of energy, thus distinguishing the projects from generation assets used for providing energy or ancillary services.[230] Finally, the Commission emphasized that CAISO would exercise total operational control over the storage devices, similar to normal transmission facilities. Ultimately, the Commission cabined its decision as "unique," but the decision nonetheless indicates that the Commission will classify storage resources based on a careful and open-minded consideration of the project's intended uses and capabilities.[231]

Earlier, the Commission refused to grant an advanced PSH project cost-of-service recovery as a transmission facility, in what it called at the time an "issue[] of first impression."[232] The applicant requested cost-of-service rate treatment for a high-voltage transmission line and PSH project (the Lake Elsinore Advance Pump Storage project ("LEAPS")), which were intended to "help the [CAISO] manage grid operations, shift off-peak energy closer to the demand center during peak periods, and enhance the reliability of the Southern California transmission grid while helping the State of California achieve its renewable resource use goals."[233] Importantly, the Commission agreed with Nevada Hydro that the project, a PSH project, qualified as an "advanced transmission technology" under the Energy Policy Act of 2005.[234]

228. *Id.* at para. 45.

229. *Id.*

230. *Id.* at para. 46.

231. *Accord* Third-Party Provision of Ancillary Services; Accounting & Financial Reporting for New Electric Storage Technologies, 135 F.E.R.C. 61,240 para. 7 (June 16, 2011) ("When faced with various proposals to use energy storage technologies for jurisdictional purposes, the Commission has analyzed the intended use and capability of storage proposals on a case-by-case basis.").

232. *See* The Nevada Hydro Co., 117 FERC 61,204 para. 26 (Nov. 17, 2006) [hereinafter *Nevada Hydro I*].

233. *Id.* at paras. 2–3.

234. *Id.* at para. 27. *See also* Energy Policy Act of 2005 § 1223, 42 U.S.C. § 16422 (2012). Section 1223 states, "[i]n carrying out the Federal Power Act (16 U.S.C. 791a et seq.) and the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601 et seq.), the Commission shall encourage, as appropriate, the deployment of advanced transmission technologies." § 16422(b). In addition, Section 1223 defines an advanced transmission technology as "a

Going one step further, the Commission seemed to interpret the legislation as evidencing Congressional support for classifying "advanced transmission technology" as FERC-jurisdictional transmission assets.[235] Nonetheless, the Commission refused to grant the project regulated cost recovery through the CAISO's transmission rates.[236]

In *Nevada Hydro II*, the Commission suggested a distinction between older PSH technologies on the one hand, and smaller, more nimble advanced storage technologies on the other hand.[237] Among other concerns, the Commission noted that all of the PSH within CAISO's territory provide generation services, despite not benefitting from rolled-in transmission pricing.[238] The Commission concluded "that allowing LEAPS to receive a guaranteed revenue stream through CAISO's [transmission tariff] would create an undue preference for LEAPS compared to these other similarly situated pumped hydro generators."[239] In a more recent determination, the Commission noted that "[w]hile the Commission has no basis to believe it is impossible . . . no [large-scale] pumped storage developer has successfully demonstrated such a non-'production' use . . . [unlike] smaller-scale energy storage technologies, where one battery developer has successfully supported a non-production, transmission use."[240] Thus, newer storage technologies, which are bound by no comparable precedent, and smaller facilities, which have less capability to behave like a generator and more capability to perform flexible "non-production" functions, may be more likely to receive approval as FERC-jurisdictional transmission facilities subject to a cost-of-service rate.

technology that increases the capacity, efficiency, or reliability of an existing or new transmission facility," including pumped hydro. § 16422(a).

235. The Commission also found the proposed batteries in *Western Grid* to qualify as "advanced transmission technologies," but did not cite that finding in concluding the projects were FERC-jurisdictional transmission facilities. *See Western Grid*, *supra* note 214, at para. 97.

236. The Commission determined that the applicant had not provided "sufficient evidence to support its requested ROE." *Nevada Hydro I*, *supra* note 233, at para. 32.

237. The Nevada Hydro Co., 122 F.E.R.C. 61,272 (Mar. 24, 2008) [hereinafter *Nevada Hydro II*].

238. *Id.* at para. 83.

239. *Id.*

240. Third-Party Provision of Ancillary Services; Accounting & Fin. Reporting for New Elec. Storage Technologies, 139 F.E.R.C. 61,245 para. 77 (June 22, 2012) (citing *Western Grid*, *supra* note 214).

Perhaps equally important in the *Nevada Hydro* proceedings, however, was the Commission's apparent discomfort with an ISO/RTO taking operational control over a facility capable of behaving at times like a large (500MW) generator. As in *Western Grid*, the applicant proposed to turn over operational control of the project to CAISO.[241] But the Commission, CAISO, and a number of interveners objected that CAISO's operational control over LEAPS, and in particular its decision-making authority over when to charge and discharge the facility, would compromise its independence from market participants (required under Order No. 2000), render the ISO a "de facto market participant," and distort market prices.[242] Nevada Hydro argued that every CAISO operational decision affects market prices, including decisions to dispatch real power from Reliability Must-Run ("RMR") units.[243] Indeed, because RMRs do not clear in the market, and are dispatched and compensated directly by the ISO/RTO, an RMR is functionally a generator under an ISO/RTO's operational control. However, in *Western Grid*, the Commission distinguished *Nevada Hydro* on the simple basis that the applicant would retain responsibility for maintaining the state of charge, including the cost of charging, and it would return any net revenues to its customers.[244] Thus, in *Western Grid* (and as with RMRs), CAISO had no incentive to become a profit-seeking market participant. But in *Nevada Hydro*, the Commission also seemed intent on deferring to the outcome of a Commission-ordered CAISO stakeholder process, which on an "extensive record," concluded that it would be inappropriate for CAISO to take operational control of LEAPS.[245] After *Western Grid* and *Nevada Hydro*, it is ultimately unclear in what circumstances an ISO/RTO may exercise operational control of a storage resource. ISO/RTOs presented with the opportunity are unlikely to embrace it, and participating transmission owners are unlikely to themselves propose a storage device in lieu of

241. *Nevada Hydro II*, *supra* note 238, at para. 5.

242. *See id.* at paras. 10, 61.

243. An RMR unit is a facility the ISO may call upon to run when required for grid reliability.

244. *Western Grid*, *supra* note 214, at para. 49.

245. The Commission agreed with CAISO that it "would not be appropriate to require CAISO to assume any level of control over the LEAPS facility." *Nevada Hydro II*, *supra* note 238, at para. 82.

traditional transmission infrastructure without further clarification. The Commission has provided little guidance.[246]

In *Western Grid*, there was no question that the proposed storage projects related to wholesale power and thus that their rates were within FERC's jurisdiction; rather, the question was whether the storage devices at issue were transmission or generation assets, a pivotal question in determining the Commission's jurisdiction and the available means of cost recovery. Another unresolved issue is how to distinguish between transmission and distribution facilities. As an example, consider CES functioning exclusively to provide distribution-side power quality, voltage control, and emergency energy services. In a jurisdiction with bundled retail rates, the state would have exclusive jurisdiction over such resources and related rates, terms, and conditions of service.[247] In a jurisdiction with unbundled retail rates, however, the Commission exercises jurisdiction over retail transmission facilities (and related rates, terms, and conditions), but not purely local distribution facilities.[248] The question is thus whether CES resources performing distribution-side services constitute local distribution facilities outside FERC's jurisdiction. The Commission distinguishes between retail distribution and transmission facilities with a seven-part test established in Order No. 888. The seven indicia of local distribution facilities are as follows:

> 1. Local distribution facilities are normally in close proximity to retail customers.
> 2. Local distribution facilities are primarily radial in character.
> 3. Power flows into local distribution systems; it rarely, if ever, flows out.
> 4. When power enters a local distribution system, it is not reconsigned or transported on to some other market.

246. *See, e.g.*, Tres Amigas LLC, 130 F.E.R.C. 61,207 para. 46 (Mar. 18, 2010) (In approving a merchant transmission line, the Commission emphasized that it was *not* approving related storage projects, and noted uncertainty as to "whether any battery storage facilities are transmission assets subject to the negotiated rate authority granted in this order.").

247. *See* New York v. FERC., 535 U.S. 1, 26 (2002) (affirming FERC's decision in Order No. 888 to not assert jurisdiction over the transmission of bundled retail services).

248. *See* Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 695 (D.C. Cir. 2000) (distinguishing between state and FERC authority based on whether the transaction is a local unbundled sale or an interstate transmission).

5. Power entering a local distribution system is consumed in a comparatively restricted geographical area.

6. Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.

7. Local distribution systems will be of reduced voltage.[249]

The Commission "will defer to recommendations by state regulatory authorities concerning where to draw the jurisdictional line under [the seven-part test] for local distribution facilities, and how to allocate costs for such facilities to be included in rates."[250]

Considering the Order No. 888 factors, the hypothesized CES facility fits more comfortably on the local distributional side, beyond the Commission's jurisdiction. Certainly, the Commission would defer to a well-reasoned state regulator's determination that such CES were state-jurisdictional. But what if the very same facilities, providing unbundled, local distribution services, also sold ancillary services in an organized wholesale market?[251] In that case, FERC would exercise jurisdiction over the ancillary service sales, and the CES would, in effect, become both a distribution and generation resource. But dividing the storage device into different functional assets—one rate-regulated, the other rate-unregulated; one state-regulated, the other FERC-regulated—raises a new set of currently unresolved classification problems.

Considering the CES hypothetical in light of the *Western Grid* and *Nevada Hydro* decisions, it is apparent not only that the Commission might classify a given storage device as a distribution, transmission, or generation asset, but that it *should* as well. Legacy technologies do not pose the energy storage classification conundrum, both because they are operationally less flexible and because the

249. Order No. 888, Promoting Wholesale Competition Through Open-Access, Non-Discriminatory Transmission Services, 61 Fed. Reg. 21540-01, 21620 (May 10, 1996) (codified at 18 C.F.R. pts. 35, 385).

250. *Id.* at 21627.

251. *See* A123, Comments in Docket No. AD10-13-000, at 11 (Aug. 29, 2010) ("If placed at a distribution site, the [CES] itself would meet some of the seven-factor criteria, including factors (1) close proximity to retail customers, (2) primarily radial, and (7) relatively reduced voltage. The voltage support service would satisfy the remaining four factors. However, the regulation service would be inconsistent with factors (3) unidirectional flow, (4) energy not transported to another market, (5) energy consumption in a restricted geographic area, and (6) meters used to measure flows into the distribution system. In fact, the regulation capability would utilize bidirectional flows, the energy would be readily transportable to another market for consumption, and the meters would measure upstream flows to the transmission system.")

classifications themselves arise from and are tailored to traditional resources. But maximizing the value of a given storage asset within the traditional generation-transmission-distribution framework may require classifying it in more than one asset category. For example, a transmission utility might deploy a 50MW battery as a transmission asset performing routine ancillary grid functions and recover its costs under a FERC-approved cost-of-service rate stated in its OATT. But the utility might also deploy the battery to sell wholesale energy at market-based rates during peak demand, perhaps shifting excess renewable generation from off-peak hours. The problem posed is that the utility would receive a guaranteed rate of return on the battery through its cost-of-service transmission rate, and simultaneously receive market-based revenues from selling wholesale energy. A different version of the same problem is implicated in the CES example, above, where a distribution utility receives regulated retail rates and simultaneously bids ancillary services into wholesale markets. In both instances, because the storage device is subsidized by its guaranteed cost-of-service rates, the utility could offer its services at below-market wholesale prices, affording it an unfair advantage and distorting market signals. Likewise, if the utility is also selling energy in an unbundled, competitive retail market, its wholesale revenues could subsidize its retail rates and affect competition on the retail level. In both instances, the device would over-recover its costs. The utility would ultimately over-recover its costs by combining regulated and market-based revenues.

FERC is justifiably wary of such "cross-subsidization" or "double recovery,"[252] but it has provided little guidance as to how a storage asset might maximize its value through flexible, multifaceted deployment. The Commission has permitted a single project or physical asset to receive revenues from both regulated and market-based sources when the device's different functions were owned separately. For example, in *Linden VFT*, a developer installed new cooling equipment to increase the thermal capacity of an existing regulated line by 300MW.[253] The Commission permitted Linden to operate the incremental capacity as a merchant transmission project while the original capacity, under separate ownership,

252. *See* Third-Party Provision of Ancillary Servs.; Accounting & Fin. Reporting for New Elec. Storage Techs., 135 F.E.R.C. 61,240 para. 7 (June 16, 2011) (notice of inquiry).

253. Linden VFT, LLC, 119 F.E.R.C. 61,066 paras. 3–4 (Apr. 19, 2007), *order on reh'g* 120 F.E.R.C. 61,242 (Sept. 20, 2007).

remained under regulated rates.[254] However, in *Linden VFT*, the distinction between the old and new assets—i.e., that each rate type was hooked onto a distinct set of assets—seemed critical. What about a single battery system, the entire capacity of which is sometimes performing transmission functions under a cost-of-service rate and sometimes performing generation functions at market-based rates? In this regard, FERC precedent provides only limited guidance, leaving significant regulatory uncertainty and inhibiting storage adoption by regulated transmission-owning entities.

Taking its first step toward resolving the classification problem in a rulemaking context, the Commission's Order No. 784 revised the accounting and reporting requirements for FERC-jurisdictional entities to better account for and report transactions associated with the use of energy storage devices in public utility operations.[255] The Notice of Proposed Rulemaking that preceded the Order recognized that "entities using energy storage assets may seek multiple methods of cost recovery for their investments in and use of a single energy storage asset to provide various utility services," and thus, in theory, "a public utility could simultaneously recover costs under both cost-based and market-based rates."[256] To accommodate the multiple functions and value streams of storage resources and to ensure "transparent information on the activities and costs of new energy storage operations," the Commission proposed relatively simple revisions to its Uniform System of Accounts. In short, Order No. 784 adds a new storage-specific expense account to existing functional classifications.[257]

The much-needed Order No. 784 accounting reforms strike a balance between transparency and flexibility, requiring public utilities to account for storage-specific financial and operational information, while also affording flexibility in allocating such costs between existing functional classifications (e.g. generation,

254. *Id.* at para. 15.

255. *See* Order No. 784, Third-Party Provision of Ancillary Servs.; Accounting and Fin. Reporting for New Elec. Storage Techs., 144 F.E.R.C. 61,056 (July 18, 2013).

256. Third-Party Provision of Ancillary Servs.; Accounting and Fin. Reporting for New Elec. Storage Techs., 139 F.E.R.C. 61,245 paras. 55, 67 (June 22, 2012) (notice of proposed rulemaking).

257. *Id.* at paras. 68–69. The Commission rejected the suggestion of some commenters to create an entirely new and independent functional class for energy storage, reasoning that it "is unnecessary because the existing functional classifications can adequately support energy storage operations." *Id.* at para. 70.

transmission). However, and importantly, the Commission acknowledges the limited effect of the Order, when it states that the "Commission's accounting and reporting requirements . . . do not dictate the ratemaking decisions of this Commission or State Commissions."[258] They merely aim to "support the rate oversight needs of both this Commission and State Commissions."[259]

Order No. 784 requires useful revisions to accounting practices relating to storage resources, but it punts on the question of how the Commission itself will classify storage if and when it faces future cost-of-service, or yet more difficult, hybrid cost-of-service/market-based rate proposals for storage resources. The lack of clarity as to how a storage device might be categorized inhibits regulated utilities from considering storage in making investment and planning decisions.[260] To reiterate, with a guaranteed rate of return for doing business as usual, transmission utilities have no incentive to consider new storage technologies laced with regulatory uncertainties. Order 784's modest accounting reforms stand in sharp relief to the comprehensive inquiries launched in the Request for Comments that initiated the rulemaking process.[261] Perhaps the Commission continues to formulate next steps, but in the meantime, the Commission's reluctance to resolve these questions, even in the context of a generalized Request for Comments, is unfortunate, and leaves significant barriers to energy storage in public utility transmission development.

E. Transmission Planning

Although significant uncertainty remains as to how the Commission will classify any given storage deployment, the Commission has in certain circumstances classified storage as a jurisdictional transmission facility. Indeed, Congress has instructed that "[i]n carrying out the Federal Power Act (16 U.S.C. 791a et

258. Order No. 784, *supra* note 183, at para. 11

259. *Id.*. Among other things, the Commission noted that the transparency-enhancing revisions would "enhance the Commission's and other form users' ability to make a meaningful assessment of a utility's cost-of-service rates, and will provide for better monitoring of cross-subsidization." *Id.* at para. 136.

260. For example, the Commission noted in the Notice of Proposed Rulemaking that it "has not to date received any proposals from public utilities that simultaneously seek to recover costs under cost-based and market-based rate mechanisms using a single energy storage asset, but the Commission remains open to innovative solutions and will evaluate proposals on a case-by-case basis." 139 F.E.R.C. 61,245, at n.90.

261. *See* Request for Comments Regarding Rates, Accounting and Fin. Reporting for New Elec. Storage Techs., 75 Fed. Reg. 36,381 (June 25, 2010).

seq.) and the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601 et seq.), the Commission shall encourage, as appropriate, the deployment of advanced transmission technologies."[262] "The term 'advanced transmission technology' means a technology that increases the capacity, efficiency, or reliability of an existing or new transmission facility, including— . . . (11) energy storage devices (including pumped hydro, compressed air, superconducting magnetic energy storage, flywheels, and batteries)".[263] In *Western Grid* and *Nevada Hydro*, the Commission did not interpret EPAct of 2005 as requiring it to either (A) categorize storage as "transmission" assets, or (B) "encourage" every storage proposal by approving storage transmission projects in all circumstances.[264] The Commission rightly emphasized that Congress gave it discretion to "'encourage, *as appropriate*,'" the deployment of storage resources (and other advanced transmission technologies), and did not foreclose classification of storage as non-transmission in appropriate circumstances.[265] Nonetheless, Congressional intent and FERC precedent suggest that storage will increasingly be utilized as transmission facilities, thus raising questions as to how it will fit into FERC's transmission planning policies.

Partly implementing Congress's mandate to encourage advanced transmission technologies like storage, FERC has adopted incentive rates to promote investment in certain transmission projects. EPAct of 2005, which added a new section 219 to the FPA, instructs FERC to "provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies); [and] (3) encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities."[266] The Commission has implemented this mandate through Order No. 679.[267] Order No. 679 established a "nexus test," which requires incentive applicants to demonstrate a

262. 42 U.S.C. § 16422(b) (2012).

263. 42 U.S.C. § 16422(a) (2012).

264. *See Western Grid*, *supra* note 214; *Nevada Hydro I*, *supra* note 233; *Nevada Hydro II*, *supra* note 238.

265. *See Nevada Hydro II*, *supra* note 238, at para. 84, citing Energy Policy Act of 2005 § 1223, U.S.C. § 16422 (2012) (emphasis in opinion).

266. 16 U.S.C. 824s(b)(2)–(3).

267. Order No. 679, Promoting Transmission Inv. Through Pricing Reform, 116 F.E.R.C. 61,057 (July 20, 2006) (codified at 18 C.F.R. pt. 35).

connection between the incentive(s) requested under Order No. 679 and the proposed investment.[268] The requested incentive(s) must address the risks and challenges that a project faces.[269] In considering the use of advanced transmission technologies, the Commission will, "as part of the overall nexus analysis, account[] for the risks and challenges associated with utilizing such advanced technology."[270]

Order No. 679 appears to have influenced regulated transmission investment.[271] Before Order No. 679 was promulgated in 2006, total regulated transmission investment in 2010 inflation-adjusted dollars totaled only $6.5 billion annually; following the order, however, annual investment increased to an average of $9.3 billion annually, or an increase of over 42 percent.[272] Although uncommon, the Commission appears willing to consider and approve generous incentive rates for storage resources applying for regulated rates.[273] These rates have been so developer-friendly that some have argued that Order No. 679 has provided for incentives to too many transmission projects.[274] Former FERC Chairman Jon Wellinghoff, for example, has emphasized that incentives "should be more narrowly targeted to transmission investments that provide incremental benefits, such as those that result from the deployment of 'best available technologies' that increase operational and

268. Policy Statement, Promoting Transmission Inv. Through Pricing Reform, 141 F.E.R.C. 61,129 (Nov. 15, 2012). In this policy statement, the Commission reformed the "nexus test," eliminating a test based on whether the proposed project was "routine" or "non-routine." *See id.* at para. 10. The Commission also eliminated its practice of awarding a stand-alone return-on-equity (ROE) incentives based simply on the utilization of an advanced technology. *See id.* at para. 23.

269. *Id.* at para. 1.

270. *Id.* at para. 23.

271. Incentives under Order No. 679 only apply to regulated transmission projects (i.e. those receiving cost-of-service compensation), not market-based projects.

272. *See* Edison Electric Inst., Comments on Docket No. RM 11-26-000, at 7, *available at* http://www.eei.org/issuesandpolicy/testimony-filings-briefs/Documents/110912OwensFerc TransmissionInvestmentNoi.pdf..

273. *See Western Grid*, *supra* note 214, at para. 3 (generously offering advanced battery storage (1) inclusion of 100 percent of construction work in progress in the rate base; (2) combined rates of return on equity adders of as high as 195 basis points; (3) deferred cost recovery by creating a "regulatory asset" for pre-commercial costs; and (4) a hypothetical capital structure of 50 percent equity and 50 percent debt).

274. For example, Former Commissioner Suedeen Kelly once stated that "granting incentives requests for routine projects . . . solidifies incentive rate making as the new . . . normal." Pepco Holdings, Inc., 124 F.E.R.C. 61,176, 62,613 (Aug. 22, 2008) (dissenting opinion), *available at* http://www.ferc.gov/eventcalendar/Files/20080827145047-ER08-686-000Statement.pdf.

energy efficiency, enhance grid operations, and result in greater grid flexibility."[275] As the Commission tries to tailor Order No. 679-incentives more narrowly,[276] it may be more likely to focus incentives on advanced transmission technologies, including energy storage projects.

FERC has also exercised significant influence over the way transmission utilities plan transmission system development. In July 2011, FERC issued Order No. 1000, the latest in a series of orders intended to improve federal transmission access, planning, and coordination.[277] FERC explained in Order No. 1000 that over the last few decades, and especially in recent years, federal and state policies have significantly affected the generation mix and, subsequently, future transmission needs—in particular, policies promoting development of renewable generation. As FERC acknowledged, its existing orders regarding transmission did not provide regional planners adequate direction as to how to consider these reforms.[278] Addressing these issues, Order No. 1000 affirmatively requires all public utility transmission providers to participate in a regional planning process that satisfies the requirements set out in Order No. 890 and to produce a regional transmission plan.[279] Among other requirements, the planning process must (1) consider transmission needs driven by "public policy requirements" and (2) give non-transmission and transmission alternatives comparable consideration.[280]

FERC demurred when asked to cite specific "public policy requirements" that must be considered and on rehearing, explained that planning must incorporate currently enacted "state

275. *Nevada Hydro II*, *supra* note 238, at 62,613–14 (Wellinghoff, Commissioner, concurring in part).

276. *See generally* Bruce W. Radford, *Killing the Goose*, PUB. UTIL. FORT., Mar. 2012, *available at* http://www.fortnightly.com/fortnightly/2012/03/killing-goose.

277. Order No.1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 76 Fed. Reg. 49,842 (August 11, 2011) (codified at 18 C.F.R. pt. 35). Order 1000 builds on Order No. 888, Order No. 2000, and Order No. 890. Order No. 890, in addition to requiring "non-generation" resources be permitted to provide ancillary services in organized markets, improved transmission access rules, and established "an open, transparent, and coordinated transmission planning process." Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service, 72 Fed. Reg. 12,266 para. 3 (Mar. 15, 2007) (codified at 18 C.F.R. pts. 35, 37.

278. Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 76 Fed. Reg. 49,842 para. 31 (Aug. 11, 2011) (codified at 18 C.F.R. 35).

279. *Id.* at para. 6.

280. *Id.* at paras. 6, 203–16.

or federal laws or regulations that drive transmission needs."[281] This statement obliquely refers to the state RPSs and federal incentives that have fueled the development of renewable generation resources, especially wind and solar.[282] As we know, wind and solar are variable. But renewables have drawbacks not only in terms of generation, but in terms of transmission as well: strong winds and bright sun are usually located far from load centers and existing transmission infrastructure.[283] Thus, integrating the expanding fleet of renewable generation that state and federal public policy requirements have encouraged will require substantial new transmission infrastructure.[284] As discussed above, storage can perform a variety of transmission functions, including functions that facilitate renewables integration. Moreover, energy storage is itself a public policy priority in some regions, most notably California.[285] However, Order No. 1000 does not mention storage, and the Commission's compliance orders to date do not indicate any intention to require regional planning, to consider how storage resources might address transmission-related public policy requirements, and/or to require consideration of storage as a public policy priority.[286]

A second important contribution of Order No. 1000 is to require "comparable consideration" during the planning process of transmission and non-transmission alternatives for meeting

281. Order No. 1000-A, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 77 Fed. Reg. 32,184 (May 31, 2012) (order on rehearing and clarification).

282. *See, e.g.*, Order No. 1000, *supra* note 278, at para. 29 ("Much of this investment in renewable generation is being driven by renewable portfolio standards adopted by states. Some 28 states and the District of Columbia have now adopted renewable portfolio standard measures.").

283. *See* Alexandra B. Klass & Elizabeth J. Wilson, *Interstate Transmission Challenges for Renewable Energy: A Federalism Mismatch*, 65 VAND. L. REV. 1801, 1811 (2012).

284. Order No. 1000 notes that in its 2010 Long-Term Reliability Assessment, NERC identifies 39,000 circuit-miles of projected new high-voltage transmission over the next 10 years. NERC estimates that roughly a third of these transmission facilities will be needed to integrate variable and renewable generation. *See* Order No. 1000, *supra* note 2788, at para. 29.

285. *See supra* notes 18–21 and accompanying text.

286. *See* PJM Interconnection, L.L.C. et al., 142 F.E.R.C. 61,214 (Mar. 22, 2013) (order on compliance filings); Midwest Indep. Transmission Sys. Operator, Inc. et al., 142 F.E.R.C. 61,215 (Mar. 22, 2013) (order on compliance filings and tariff revisions); Pub. Serv. Co. of Colo. et al., 142 F.E.R.C. 61,206 (Mar. 22, 2013) (order on compliance filings); Me. Pub. Serv. Co., 142 F.E.R.C. 61,129 (Feb. 21, 2013) (order on compliance filing); Duke Energy Carolinas LLC et al., 142 F.E.R.C. 61,130 (Feb. 21, 2013) (order on compliance filings).

identified regional transmission needs.[287] By requiring this comparable treatment, Order No. 1000 recognizes the important fact that even once a potential transmission need is identified, a new line is not always the best way to meet that need. Such "non-wires" solutions may be at once more cost-effective and more socially desirable. For example, demand response and energy efficiency can obviate the need for new transmission lines in some circumstances.[288] Likewise, storage performing ancillary services or alleviating congestion could provide a cost-effective and prudent alternative to new transmission lines. But the Commission did not indicate in Order No. 1000, nor in any of the compliance filings to date, any indication whether storage should be considered as a non-transmission alternative, and none of the public utility filings have indicated whether regional planning processes have considered storage as non-transmission alternatives. Notwithstanding the bold promise of Order No. 1000, storage does not appear to be a priority in regional transmission planning that the Commission will require transmission planners to consider.

III. Recommendations for FERC: Comparability and Clarity

This Article casts the problem of energy storage as one of regulatory adaptation to technological change. Advanced storage is a disruptive technology that confounds regulatory categories and market rules developed for legacy systems. As regulator, FERC must proactively ensure that markets adapt to new technologies. The Commission should focus not on technologies per se, but rather on their operational characteristics. Where an emerging technology performs a function differently than existing technologies, or where it performs an entirely novel type of function, regulatory categories and market rules may under-incentivize, inhibit, or entirely preclude its adoption. Such barriers unduly discriminate against new technologies. FERC should take the following actions to ensure comparable consideration of storage alongside traditional resources and clarify the Commission's approach to classifying storage assets.

287. Order No. 1000, *supra* note 2788, at para. 155.

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

A. Remedying Discrimination in the Provision of Ancillary Services

FERC has successfully remedied undue discrimination in organized markets for frequency regulation,[289] and it has reformed the *Avista* policy to eliminate a categorical barrier to third-party provision of ancillary services outside of ISO/RTOs.[290] Now it must implement those orders effectively. However, the Commission's decision to remedy undue discrimination in ancillary service markets piecemeal has left intact the preferential treatment for incumbent resources in the provision of other ancillary services. Perhaps justifiably, the Commission has decided to progress with caution. But the very same principles that animate its orders relating to frequency regulation apply equally to primary and tertiary frequency control and other reserve products. Eventually, the Commission must address remaining barriers to energy storage in the provision of other ancillary services.

None of the ISO/RTOs procure frequency response through organized markets. FERC has not historically required the creation of organized wholesale markets for wholesale products; rather, it has ensured that once established, such markets are governed by just, reasonable, nondiscriminatory rules. "As the amount of power provided by variable renewable generation increases, the fraction of on-line generation capacity offering primary frequency control will decrease. In the future, market mechanisms may be needed to ensure sufficient provision of primary frequency control reserve."[291] Regardless of whether FERC should mandate the creation of frequency response markets, or whether the ISO/RTOs independently conclude that such markets are necessary, FERC must ensure that rules for the provision of frequency response are not unduly discriminatory or preferential if and when such markets are created.[292] Likewise, if and when primary frequency response becomes an unbundled service outside of ISO/RTOs, the Commission must ensure that procurement targets and compensation practices account for actual performance.

Perhaps more immediately, FERC must remedy undue discrimination in the provision of spinning and non-spinning reserves. Once discharging, storage resources perform just as well

289. *See supra* Section II.B.2.

290. *See id.*

291. *See* ELLISON ET AL., *supra* note 153, at 15

292. *See supra* Part II.B for further discussion of the benefits of storage as an ancillary service provider.

as conventional generators as far as providing tertiary frequency control. However, the spinning and non-spinning reserve products in ISO/RTOs do not reward, or even consider the possibility of, a resource capable of ramping to a substantial output within instants of system need. This example clearly demonstrates how market rules are tailored to the operational characteristics of traditional resources. The rules assume that quick reserve resources will take ten minutes to ramp up, without recognizing or rewarding resources capable of substantially quicker response and ramp times.

Ultimately, new reserve rules—for all ancillary services—should eliminate "arbitrary definitions of reserve categories common in current market designs . . . which reference the operational characteristics of the technologies thought best able to provide that category of reserves."[293] Instead, market categories and rules should signal system needs—such as response time and location, ramp rate, and duration of service delivery—and reward resources capable of best satisfying those needs, regardless of technology. The increased competition in the provision of ancillary services will enhance market efficiency and ensure just and reasonable wholesale rates. Ancillary service provision will become more cost-effective, while freeing many traditional generators to do what they do best: generate energy.

B. Incorporating Storage into Resource Adequacy Mechanisms

FERC must amend its regulations under the FPA to ensure that qualified storage resources will be considered equally alongside conventional generation and demand-side resources in capacity markets and resource adequacy planning.[294] Certain storage technologies can perform functions comparable to resources that participate in capacity markets, while increasing system reliability and efficiency, and mitigating the system's environmental impact. Requiring ISO/RTOs to consider storage as a capacity resource will enhance the competitiveness of organized wholesale markets and remove barriers to the participation of energy storage resources, thus ensuring just and reasonable and not unduly discriminatory or preferential wholesale rates.

293. ELLISON ET AL., *supra* note 153, at 33.

294. *See supra* Part III.B for further discussion of the benefits of storage as capacity provider.

Resource adequacy is the ability of the electric system to supply and deliver the total quantity of electricity demanded at any given time taking into account scheduled and unscheduled outages of system elements. In practice, resource adequacy requirements focus on procuring capacity to satisfy peak load events.[295] The ISO/RTOs set capacity procurement targets to satisfy NERC's "one day in ten year" standard, under which system planners should ensure adequate capacity such that, under a probabilistic analysis, demand will exceed available capacity no more than once every ten years.[296] Thus, taking into consideration locational differences and related energy security needs, the primary resource adequacy consideration is simple: whether anticipated peak summer and winter capacity exceed, by a safe margin, the forecast peak summer and winter load.[297] If not, then the ISO/RTO will adjust the administrative capacity market demand curve, and/or increase the capacity procurement targets for the responsible utility or LSE, expressed simply in MWs of capacity.[298]

Both because resource adequacy focuses on the bulk power system's ability to satisfy peak demand and because storage devices are capable of functioning as peaking resources, storage should qualify as a capacity resource for purposes of capacity markets and resource adequacy requirements. Indeed, perhaps because of its long history, PSH is permitted to participate in some capacity markets,[299] but other storage resources with comparable operational characteristics are not. Unequal treatment for resources capable of comparable performance is a hallmark of a

295. *See, e.g.*, James F. Wilson, *Reconsidering Resource Adequacy–Part 1*, PUB. UTIL. FORT., Apr. 2010, at 33, *available at* http://www.fortnightly.com/fortnightly/2010/04/reconsidering-resource-adequacy-part-1 ("Electric utilities and regional transmission organizations (RTOs) in the United States aim to have enough electric generating capacity to meet anticipated peak loads with a reserve margin for reliability.").

296. *See* N. AM. ELEC. RELIABILITY CORP., *supra* note 204.

297. *See, e.g.*, N.Y. INDEP. SYS. OPERATOR, 2012 RELIABILITY NEEDS ASSESSMENT C-1 (2012), *available at* http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Reliability_Planning_Studies/Reliability_Assessment_Documents/2012_RNA_Final_Report_9-18-12_PDF.pdf ("In order to perform the 2012 [Resource Needs Assessment], a forecast of summer and winter peak demands and annual energy requirements was produced for the years 2013 - 2022.").

298. The demand curve in capacity markets is administratively determined based on the resource adequacy planning analysis.

299. *See generally* E. ELA ET AL., NAT'L RENEWABLE ENERGY LAB., THE ROLE OF PUMPED STORAGE HYDRO RESOURCES IN ELECTRICITY MARKETS AND SYSTEM OPERATION 3 (2013), *available at* http://www.nrel.gov/docs/fy13osti/58655.pdf ("PSH can be remunerated through ancillary services, capacity markets, and energy.").

discriminatory rule in wholesale electricity markets. For example, FERC recently mandated that ISO/RTOs permit demand response[300] resources to participate, under certain conditions, in organized wholesale energy, capacity, and ancillary service markets on comparable terms with conventional generation-side resources.[301] FERC's reasoning was simple: if a demand-side resource is operationally comparable to a supply-side resource (in providing energy, capacity, or ancillary services), the resources should participate and be compensated comparably.[302] The Commission's reasoning is apt here: storage resources are comparable to conventional generation and demand-side resources, in that each can function as a capacity resource capable

300. Demand response is "a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy." Non-discriminatory open access transmission tariff, 18 C.F.R. § 35.28 (2012); *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 (2012-13).

301. In Order No. 719, the Commission required ISO/RTOs to accept bids from demand response resources in markets for certain ancillary services on a basis comparable to other resources. To qualify, demand response resources must: (1) be "technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules at or below the market-clearing price, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate." Order No. 719, Wholesale Competition in Regions with Organized Electric Markets, 73 Fed. Reg. 64,100, 64,107 (Oct. 28, 2008) (codified at 18 C.F.R. pt. 35), *order on reh'g*, Order No. 719-A, 128 F.E.R.C. 61,059 para. 47 (July 16, 2009). The order applies "to competitively-bid markets, if any, for energy imbalance, spinning reserves, supplemental reserves, reactive supply and voltage control, and regulation and frequency response." *Id.* More recently, in Order 745, the Commission required each RTO and ISO in which demand response participates in its energy market to pay a demand response resource "the market price for energy, [also] referred to as the locational marginal price (LMP)," when two conditions are met. First, the demand response resource must have "the capability to balance supply and demand as an alternative to a generation resource." Second, "dispatch of th[e] demand response resource [must be] cost-effective as determined by the net benefits test." The "net benefits" condition is intended to address what is known as the "billing unit effect" of dispatching demand response. By decreasing load, demand response decreases the LMP. However, by decreasing load, demand response also decreases the number of billing units over which utilities recover their costs. Accordingly, "dispatching demand response resources may result in an increased cost per [billing] unit ($/MWh) to the remaining wholesale load." Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets, 134 F.E.R.C. 61,187 paras. 1–3 (Mar. 15, 2011).

302. Order No. 745, 134 F.E.R.C. 61,187 at para. 119 ("This Final Rule addresses the need for organized wholesale energy markets to provide compensation to demand response resources on a comparable basis to supply-side resources when demand response resources are comparable to supply-side resources, so that both supply and demand can meaningfully participate.").

of meeting peak capacity needs, and thus storage should be permitted to participate in capacity markets on comparable terms.

Demand response provides an illuminating analogy for storage. The ISO/RTOs have developed rules for permitting demand response resources, many of which are duration-limited, to participate in capacity markets. For example, PJM permits "Limited Demand Resources" to participate in its Reliability Pricing Model.[303] Such resources must commit to at least ten interruptions of demand during a given commitment period, with a minimum capable duration of six hours each.[304] Remarkably, PJM does not permit storage resources with comparable capabilities to participate in its capacity market, e.g. a storage device capable of six hours of discharge at some specified capacity. This contradiction is magnified considering that storage resources *can* participate in PJM's capacity market so long as they bid as demand response resources. For example, if storage were deployed behind the meter, and utilized by a load during peak hours to reduce the load's effective demand on the grid, the storage device could be used as the basis for a Limited Demand Response capacity resource in PJM's Reliability Pricing Model. That a storage device would qualify as a capacity resource if presented as a demand resource, but not if presented as supply-side capacity, further indicates that the operational characteristics of certain storage resources are consistent with capacity resources and should be considered alongside generation and demand-side resources in resource adequacy planning.

FERC has explicitly required the ISO/RTOs to permit behind-the-meter generation to qualify as a demand response resource capable of participating in capacity markets. Order No. 719 states that "the Commission has not excluded from eligibility any type of resource that is technically capable of providing [an] ancillary service, including a load serving entity's . . . or eligible retail

303. Under an earlier PJM tariff, the RTO established only one demand response category, defined identically to Limited Demand Response. In December of 2010, it sought permission to amend its tariff to include two additional demand response products, both of which would be available an unlimited number of times each year, during the entire year, for minimum durations of ten hours each interruption. *See* PJM Interconnection, L.L.C., 134 F.E.R.C. 61,066 paras. 12–14 (Jan. 31, 2011) (order on proposed tariff provisions).

304. *See* PJM INTERCONNECTION, L.L.C., RELIABILITY ASSURANCE AGREEMENT AMONG LOAD SERVING ENTITIES IN THE PJM REGION §1.43A (2014), *available at* http://www.pjm.com/~/media/documents/agreements/raa.ashx.

customer's behind-the-meter generation . . . resource."[305] Likewise, in an Order No. 745 compliance filing, FERC required MISO to amend its proposed demand response resource categories to clarify that each category would include "Behind the Meter Generation".[306] FERC's interpretation of its demand response orders is appropriate: behind-the-meter generation and other distributed resources can be dispatched to reduce effective load or provide ancillary services in a manner indistinguishable—from a grid-operational perspective—from an actual reduction or adjustment in consumption. Taking one-step further, FERC should require comparable treatment of energy storage performing as capacity, in addition to storage performing—with identical operational characteristics—as duration-limited demand response.

Although bidding as a demand response resource is a backdoor into capacity markets, it is insufficient. Market rules for demand response resources are tailored to load-side curtailment and would impose arbitrary and unnecessary limits on storage opportunities. For example, if distributed storage resources are categorized as demand response to bid into capacity markets but also seek to participate in energy markets, they will be limited by the net benefits test.[307] But unlike demand response resources, distributed storage could behave as dispatchable distributed *generation*.[308] When selling wholesale power to the grid, storage would not trigger the "billing unit effect" because the number of billing units over which utilities recover their costs would not decrease; indeed, it would increase. Similarly, to perform as a demand response resource, storage must be deployed on the community level or at a load site. But storage resources are capable of a variety of other modes of deployment. Quite simply, the demand response market rules do not fit all of the operational characteristics and opportunities of storage resources, so the demand-response backdoor offers an incomplete means for storage to access capacity payments.

One must, however, acknowledge that energy storage differs fundamentally from other capacity resources, particularly traditional generators, energy efficiency, and duration-unlimited

305. *See* Order No. 719, 73 Fed. R 64,107.

306. Midwest Indep. Transmission Sys. Operator, Inc., 137 F.E.R.C. 61,214 at para. 41 (Dec. 15, 2011).

307. *See supra* note 302, discussing Order No. 745 and the "net benefits test".

308. The dispatchability of a charged energy storage resource distinguishes it from other forms of distributed generation, namely solar PV, which is non-dispatchable.

demand response. Those resources contribute to the long-term, indefinite balance of supply and demand, while storage, which is duration- and energy-limited, can only contribute to short-term, marginal balancing. In an age before variable renewable resources, traditional generators were capable of providing both firm capacity—i.e. resources to meet (and exceed) peak demand—and flexibility necessary to ensure system quality—i.e. through ancillary services.[309] Ensuring system quality requires not only raw MWs of capacity, but particular operational characteristics, such as quick and accurate response and fast-ramping. With the increasing penetration of variable generation, traditional resources will no longer be adequate for ensuring the moment-to-moment, marginal balance of supply and demand.[310] Fast, accurate, and flexible resources, including many storage technologies, will play a critical role in ensuring system quality in the near future.[311] Thus, system quality and resource flexibility pose not only an operational concern for which grid operators must dispatch resources in real-time, but also an investment consideration for which operators should plan in advance through resource adequacy processes. But storage resources do not fit neatly into a planning framework based on simple MW of capacity. Understandably, to include storage as "capacity" without qualification is uncomfortable within a long-term planning framework. But capacity markets and resource adequacy requirements that only consider duration- and energy-unlimited resources (with the contradictory exception of limited demand response) will under-incentivize and thus forego the possible efficiency, reliability, and environmental gains of deploying grid storage.

This discussion illustrates there is no basis for excluding storage from resource adequacy planning—storage resources can help meet peak capacity and system quality requirements—but because it is duration- and energy-limited, an independent planning mechanism for storage may be justifed. Consider a hypothetical option called "Energy Storage Capacity" ("ESC").[312] An ESC planning process could set an independent target for storage

309. *See* MIKE HOGAN ET AL., REGULATORY ASSISTANCE PROJECT, WHAT LIES "BEYOND CAPACITY MARKETS"? DELIVERING LEAST-COST RELIABILITY UNDER THE NEW RESOURCE PARADIGM 3 (2012), *available at* http://www.raponline.org/document/download/id/6041.

310. *See generally* MASIELLO ET AL., *supra* note 93.

311. *See id.*

312. *See* Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, Cal. P.U.C. (Feb. 23, 2013), *available at* 2013 WL 652439.

resources, considering their unique operational characteristics—e.g., flexible, fast-ramping, up and down regulation, energy- and duration-limited—in light of system needs. For example, in requiring the ISO/RTOs to permit demand response in capacity markets, FERC approved the creation of independent demand response capacity categories.[313] Moreover, FERC approved PJM's proposal to distinguish between and set independent procurement targets for "annual resources" (generation, unlimited demand response, and energy efficiency) and "limited resources" (limited demand response).[314] Thus, the Commission is comfortable with distinctions among capacity products based on operational characteristics. Similarly, by setting independent ESC targets, ISO/RTOs would incentivize ESC resources to meet peak load capacity and ensure system quality with the superior flexibility of storage resources. At the same time, the ISO/RTOs would be able to set independent capacity targets to incentivize firm capacity resources necessary to ensure long-term resource adequacy, such as unlimited demand response, energy efficiency, and generation.[315] By planning for an optimal resource mix that includes flexible storage resources, ISO/RTOs could ensure reliability while integrating renewables, avoid unnecessary capital investment, and ultimately deliver power at lower cost.

As an alternative to an ESC capacity product, ISO/RTOs could consider a mechanism that distinguishes between firm capacity on the one hand, and—more broadly than ESC—"Flexible Capacity" ("FC") on the other. An FC product would be defined not by technology type per se, but rather by operational system needs. FC would include energy- and duration-limited resources like storage, in addition to flexible traditional generators. The need for FC will

313. *See, e.g.*, PJM Interconnection, L.L.C., 134 F.E.R.C. 61,066 (Jan. 31, 2011).

314. *See id.* at 29.

315. Including energy storage within the general capacity resource category could also incentivize installation of storage beyond optimal levels. The marginal utility of energy storage may decrease as it forms a greater part of the capacity mix because, ultimately, storage does not generate energy. But the general capacity mechanism would not provide corresponding price signals because storage would be incentivized equally alongside traditional generation resources. At some point, hypothetically, storage capacity would cause increasing operational costs and ultimately exceed the capacity of generation resources available to charge storage during off-peak hours. This Article merely aims to illustrate how storage may have diminishing marginal utility: The day, if ever, that storage forms such a substantial portion of capacity is far off indeed. *See* PJM Interconnection, L.L.C., 139 F.E.R.C. 61,130 para. 12 (May 17, 2012) (proposing a benefits factor in implementing Order No. 755, "because there are decreasing marginal benefits from each additional MW" of frequency regulation from storage).

continue to grow as the penetration of variable resources increases and net load becomes more volatile.[316] Meanwhile, natural events capable of temporarily compromising the bulk power system have and will continue to become more frequent with climate change, but the traditional one-dimensional resource adequacy paradigm fails to account for resources like storage capable of providing resiliency in the event of a significant emergency or contingency.

Just as frequency regulation markets prior to Orders Nos. 755 and 784, existing capacity markets do not properly account for the varying operational characteristics of different resources. Without a mechanism for recouping fixed costs, energy storage will lack sufficient incentives, regardless of whether barriers are eliminated in energy and ancillary service markets. Thus, FERC might consider requiring the ISO/RTOs to study whether it would be beneficial to create an FC resource adequacy product to ensure the adequacy of flexible resources necessary to satisfy future system needs.[317]

Ultimately, it is beyond the scope of this Article to argue *how* the ISO/RTOs should accommodate energy storage in resource adequacy planning.[318] But it is clear that FERC must remedy unduly discriminatory barriers to storage in organized wholesale markets, where traditional resources enjoy preferential capacity mechanisms. In Order No. 1000, FERC recognized the need to give "comparable consideration" to transmission and non-transmission alternatives.[319] It is time to require the analogue in

316. The CPUC is currently considering a flexible capacity procurement requirement to serve precisely this function. *See* CAL. PUB. UTIL. COMM'N, BRIEFING PAPER: A REVIEW OF CURRENT ISSUES WITH LONGTERM RESOURCE ADEQUACY 25 (2013), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/E2A36B6A-977E-4130-A83F-61E66C5FD059/0/CPUCBriefing PaperonLongTermResourceAdequacyBriefingPaperFebrua.pdf. (noting that "some demand response and energy storage resources are, fast responding, [sic] and may be able to provide a significant amount of flexibility for the grid.").

317. FERC recently initiated a proceeding to consider the design of capacity markets. Specifically, the Commission held a technical conference "to consider how current centralized capacity market rules and structures are supporting the procurement and retention of resources necessary to meet future reliability and operational needs." The Staff Report specifically discussed the emerging need to consider operational characteristics in addition to simple MWs of capacity. FED. ENERGY REGULATORY COMM'N, COMM'N STAFF REPORT AD13-7-00, CENTRALIZED CAPACITY MARKET DESIGN ELEMENTS, (2013), *available at* http://www.ferc.gov/CalendarFiles/20130826142258-Staff%20Paper.pdf.

318. For one proposal of how to ensure adequate flexible capacity, *see* HOGAN ET AL., *supra* note 310.

319. *See* Order No. 1000, *supra* note 278, at para. 155. *Cf.* Order No. 890, *supra* note 151 ("non-generation resources" must be considered comparably alongside generation resources in ancillary service markets).

resource adequacy planning and capacity markets. Capacity markets and resource adequacy planning should fairly consider storage with operational characteristics comparable (and often superior) to traditional generators and demand response.

C. Some Classification Considerations

Advanced storage technologies are amorphous. They provide multiple grid benefits and exhibit operational characteristics that cut across existing regulatory and jurisdictional boundaries. As discussed above, FERC has cautiously approached the classification of storage devices on a case-by-case basis.[320] It is time for the Commission to clarify—through a policy statement or rulemaking—the factors it will consider in (1) classifying storage resources, (2) determining whether and how a storage device may avail itself of multiple types of revenue streams, and (3) establishing mechanisms necessary to prevent cross-subsidization and over-recovery. In doing so, FERC should craft regulations flexible enough to accommodate the diverse characteristics of storage resources. To bind new and more nimble resources to rules tailored to the rigid operational characteristics of legacy technologies is arbitrary and will inhibit more efficient wholesale markets, resulting in unjust and unreasonable rates.

First, the threshold classification question: should energy storage be fit into existing regulatory categories (generation, transmission, and/or distribution), or should FERC create a stand-alone functional classification for storage? While attractive on its face, the latter option of creating a stand-alone storage category does not resolve deeper substantive questions. An independent storage category would superficially consolidate accounting for storage costs and assets and perhaps make accounting and cost-of-service rate setting more convenient.[321] But a stand-alone storage product would not necessarily enhance the operation of organized wholesale markets.

320. *See infra* Part II.C for a discussion of FERC's piecemeal approach to re-classification.

321. It is important that storage receive independent consideration in the Commission's accounting protocols. Precisely how the Commission provides this consideration matters less. For instance, the recent NOPR proposes to add various expense accounts for storage to each of the existing functional classifications. This has the virtue of being flexible, affording operators significant leeway in deploying and accounting for storage costs and assets. On the other hand, a consolidated energy storage functional classification might superficially make it easier to manage storage-related financial and operational data. This is issue is less important as the substantive issues discussed herein.

The only stand-alone storage service that does not fit neatly into an existing regulatory product is a time-shifting service. For example, a storage unit might bid into an organized market for storing energy at a per-MWh cost, plus a duration cost. The most likely time-shifting customer would be a generator storing off-peak energy for retrieval during peak hours. A transmission utility could likewise offer a time-shifting service under regulated rates as an open-access transmission service, to transfer energy through time just as traditional transmission services transfer energy through space. In that case, however, storage might simply be categorized as a transmission service, as it is in the natural gas context.[322] And as with natural gas storage, independent storage operators might offer time-shifting storage services at negotiated rates to transmission utilities and generators.[323] Aside from this particular stand-alone product, the question of a "stand-alone" storage classification seems superficial. Moreover, in considering how utilities should account for storage-related transactions and operational data, FERC has already declined to create an independent storage asset category in Order No. 784.[324]

The classification question does matter, however, for determining whether and how storage fits into certain planning and procedural rules. For instance, if a storage facility is considered generation, then it might seek interconnection under the SGIP/SGIA or LGIP/LGIA under Order No. 792, but if a storage is considered transmission, then it would have to comply with transmission-related interconnection requirements. Likewise, planning requirements differ. If a storage device is considered generation, then it should be able to participate in resource adequacy planning and capacity markets, and if the storage device is considered transmission, then it should be considered through transmission planning under Orders Nos. 890 and 1000. If FERC

322. *See* Order No. 636, Pipeline Serv. Obligations, 59 F.E.R.C. 61,030 (Apr. 8, 1992). For an explanation of natural gas storage, *see* ENERGY INFO. ADMIN., U.S. UNDERGROUND NATURAL GAS STORAGE DEVELOPMENTS: 1998-2005 (2006), *available at* http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2006/ngstorage/ngstorage.pdf.

323. Modifying the *Avista* policy will ease the provision of market-based services to transmission utilities. If a time-shifting product were created, the question does remain how to functionally classify it. The question is not just academic. If it were a merchant transmission facility, for example, then it would be FERC-jurisdictional and might be eligible for incentives, but it would have to go through a cumbersome transmission planning process. On the other hand, if it were generation then it would be easier to interconnect, but the facility itself would not be subject to FERC jurisdiction.

324. *See* Order No. 784, *supra* note 183, at para. 43.

were to create an entirely new asset category, then all of these practical questions would also need resolution. But because each of the particular operational characteristics can be comfortably accommodated in existing categories, with their attendant procedures and requirements, the costs and uncertainty of creating a new category may exceed the benefits, if any. The complication, of course, is that while each operational characteristic in isolation fits into existing categories, the total operational characteristics of a given storage device exceed any given category.

Accordingly, the second and more difficult issue is whether, and if so how, the Commission should permit a given storage device to perform multiple grid functions, provide multiple grid benefits, and access multiple value streams, while preventing cross-subsidization or over-recovery. Studies have recognized that storage resources are already cost-competitive resources, so long as they are permitted to access multiple value streams and benefit the grid in a variety of ways.[325] This problem does not arise where a merchant energy-storage provider owns and operates a storage device, selling services in a wholesale market and/or through a bilateral contract with a transmission utility. But take, for example, a large battery deployed by a regulated transmission utility, for frequency regulation and voltage control. The utility expects the battery will primarily perform such ancillary grid functions, and seeks regulated-rate recovery for the device. However, during the peak days of summer, the utility intends to sell energy from the batteries to LSEs downstream at negotiated rates. The precise classification of the battery matters less than the policy for integrating cost-based and market-based recovery mechanisms for a single physical asset. In answering this question, the Commission must be nimble, and without enough experience, it would premature to establish any policies that impose prior restrictions on innovation in the deployment of storage resources. An ideal policy would prevent over-compensation while simultaneously ensuring that energy storage resources can perform multiple functions with arbitrary restrictions, thus providing maximal benefits to the grid and allowing the storage resource to access multiple revenue streams.

One such policy is asset partitioning. The utility could receive cost-of-service transmission for some pro rata share of battery-

325. *See* M. KINTER-MEYER ET AL. *supra* note 213 at xii (noting that storage will require additional revenue streams such as capacity payments to be viable).

related costs and pursue market-based rates with the portion of battery resources not devoted to transmission. However, the logistics of designing and policing the rates for a partitioned storage device are problematic. FERC has approved multiple rates for a single device based on partitioned assets, but in those cases, no single asset performed a function under more than one rate.[326] The battery in our hypothetical, however, would at times be devoted to transmission services, and at other times energy service, making FERC precedent an awkward fit. And attempting to apportion the device before the fact might not correspond with actual revenues, potentially resulting in either over- or under-recovery.

A better option, based on actual rather than projected revenues, might be to include the entire battery in the utility's transmission rate-base. If the storage resource was permitted to conduct market-based transactions for energy as well, but the revenue from such transactions then offset the regulated rates charged to transmission customers, the storage resource would not over-recover. But FERC would have to ensure that the utility does not distort market prices by bidding lower than other, non-subsidized market participants. For example, the utility could be a price taker, only able to accept the LMP but not able to bid into the market.[327] FERC might also establish a rule permitting the storage device to engage in market-based transactions only where the storage device's transmission services are not required to satisfy reliability requirements, thereby prioritizing reliability over profit-seeking. This model of permitting incremental market transactions from an otherwise rate-regulated asset also fits better into FERC precedent. The Commission has authorized utilities to sell excess capacity and energy from rate-based generation; authorizing the market-based sale of energy from rate-based storage seems indistinguishable.

A related wrinkle is how the Commission should permit a given storage device to perform both distribution-side (i.e. non-jurisdictional) *and* transmission-side or wholesale generation-side (i.e. jurisdictional) functions simultaneously, while avoiding cross-subsidization or over-recovery. The problem posed is in many regards identical to the problem of multiple value streams discussed in the preceding paragraphs, but here the device and/or

326. *See, e.g.*, *Linden VFT*, *supra* note 254.

327. For example, demand response participates in energy markets as a price taker under Order No. 745. *See* Order No. 745, *supra* note 302.

its activities are partially outside the Commission's jurisdiction.[328] The divided jurisdiction makes the solution proposed above (offsetting regulated rates with market-based revenues) impracticable because the cost-of-service rates are set by state regulators. This puzzle implicates federalist concerns and practical barriers more complicated than simple divided rate recovery. But the question is critical: distributed storage is considered among the most promising modes of grid deployment.[329] While largely within the states' jurisdiction, the Commission's policies will also affect distributed deployment, by permitting or inhibiting additional revenue streams and grid benefits. It is crucial that FERC initiate a collaborative stakeholder process—including local and state regulators—to clarify how distributed energy storage might participate in FERC-jurisdictional activities.

One final classification problem concerns what circumstances an ISO/RTO should be permitted to operate a storage device, while maintaining independence and not unduly affecting market competition. Under Orders Nos. 888 and 2000, ISO/RTOs must maintain independence from market participants to ensure healthy competition and undistorted market signals.[330] If an ISO/RTO were to have a stake in market outcomes, and were thus a profit-seeking entity, its role as impartial grid operator and market manager would be compromised. The Commission indicated in *Nevada Hydro* that permitting an ISO/RTO to operate a PSH facility might compromise its independence because the ISO would have to buy energy from the market to charge and discharge the facility and would be incentivized to consider energy prices.[331] In *Western Grid*—where an applicant proposed batteries as transmission assets to be operated by CAISO—the Commission distinguished *Nevada Hydro* on the grounds that CAISO would not manage the storage

328. *See supra* Part II.D., discussing the CES example.

329. Five of DOE's sixteen ARRA-funded storage pilots are distributed storage projects. *See* EAC 2012, *supra* note 4, at 31. *See also* CEC 2020, *supra* note 78, at 167–78.

330. Order No. 2000, Regional Transmission Organizations, 65 Fed. Reg. 810 (2000) (codified at 18 C.F.R. pt. 35), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg 12,088 (2000), *aff'd sub nom.*, *Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001). Order No. 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21,540 (1996) (codified at 18 C.F.R. pts. 35, 385), *order on reh'g*, Order No. 888-A, (1997), *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (1997), *order on reh'g*, Order No. 888-C, (1998) *aff'd in relevant part sub nom.*, *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.*, *New York v. FERC*, 535 U.S. 1 (2002).

331. *See supra*, Part II.D.

devices' charge and would not retain any net revenues from buying or selling energy.[332] Thus, at a minimum, it seems that for an ISO/RTO to manage a storage device as a transmission asset, the ISO/RTO must be indifferent to energy prices in deciding when to charge or discharge the device. One option is the *Western Grid* mechanism, where a third-party manages charge and revenues, and any net revenues are credited to regulated-rate.[333] Another might be to functionally separate storage-related operations within an ISO/RTO, such that storage operators are screened from real-time energy price information, with any net revenues credited or charged to customers. One might object that, with either mechanism, the ISO/RTO would still have an undue ability to affect market prices. However, while an ISO/RTO's control of storage resources could affect market prices, its operational control over any transmission facility impacts related markets. The ISO's/RTO's ability to affect prices using a storage device is conceptually and practically indistinguishable from any decision relating to the construction or operation of a new transmission wire, tower, substation, transformer, switch, or other facility, so long as the decision is indifferent to (and perhaps entirely ignorant of) market prices.

Ultimately, this Article has merely charted some of the thornier classification questions faced by FERC and stakeholders. How the Commission resolves these questions must be determined through a notice and comment process involving all relevant stakeholders. That these questions are ripe for resolution, however, is beyond question.

D. Incorporating Energy Storage into Transmission Planning

Under Order No. 1000, FERC should ensure comparable consideration of storage alongside traditional transmission infrastructure as a solution to meeting public policy-driven transmission needs, and as a transmission or non-transmission alternative to traditional infrastructure in satisfying identified transmission needs.[334]

Order No. 1000's mandate to consider "public policy requirements" most obviously informs regional transmission-line

332. *See id.*
333. *See id.*
334. For an introductory discussion of Order 1,000, *see supra* Part II.D.

planning necessary to link new renewable generation to load. While a storage resource cannot connect a distant wind farm to a load center, it can help integrate variable renewable resources driven by public policy requirements. Deployed to smooth output or provide frequency control on lines with high-levels of variable resources, storage could be an effective transmission solution to a public policy-driven transmission need, as an alternative to new transmission line interconnections.[335] Moreover, transmission planning must consider public policy-driven transmission needs other than those related to renewables. Energy storage is itself a public policy requirement in some places, most notably California.[336] Thus, to the extent that storage is a cost-effective or otherwise prudent solution to resolving a transmission issue, in a state like CA with an energy storage policy requirement, it should be preferred to traditional transmission line infrastructure.[337]

Storage resources could also be considered "non-transmission" alternatives and should thus be considered comparably alongside traditional lines in transmission planning. Properly deployed, storage can resolve identified transmission needs comparably to high-voltage lines, for example, by alleviating congestion and servicing remote load centers. A refrain throughout this Article is that storage resources must be considered comparably alongside legacy technologies performing comparable functions; Order No. 1000 makes this mandate clear in the context of transmission planning.

Although Order No. 1000 seems to mandate comparable consideration of storage resources in transmission planning, other practical considerations may make it yet more appealing than additional lines. As is widely recognized, local and state incentives are not aligned with regional transmission needs, yet state and local governments retain exclusive jurisdiction over the siting and permitting of new transmission lines.[338] Meanwhile, FERC has only

335. One technique for integrating renewables and mitigating the impact of variability is to further integrate the grid on a regional scale. The larger the grid, the less effect variability has on system quality. Storage could be an alternative to new transmission lines intended to provide such regional interconnection for system quality purposes.

336. *See supra* notes 18–21 and accompanying text.

337. Relatedly, some commenters have persuasively argued that local, state, and federal demand response and energy efficiency initiatives are likewise public policies that must be considered in regional transmission planning to ensure that transmission is not *over*-built. *See* Welton & Gerrard, *supra* note 289, at 11027.

338. *See* Klass & Wilson, *supra* note 284, at 1827.

extremely limited "backstop" authority to override state or local resistance to a proposed interstate transmission project.[339] This "federalism mismatch," which permits parochial interests to veto projects of regional and national concern, has stymied interstate transmission-line development critical for regional reliability and renewables integration.[340] Because storage devices are self-contained, intra-state facilities only subject to the jurisdiction of one state, siting storage resources may avoid the gridlock associated with interstate transmission infrastructure.[341]

At the very least, where storage is not a replacement for transmission lines (as in the case of distant renewable resources), it is a complementary option for planning and upgrading the transmission system. Whether the Commission treats storage as a transmission or non-transmission resource is ultimately irrelevant: transmission and non-transmission solutions deserve comparable treatment. So regardless of which bucket storage falls into, FERC should ensure that storage is considered comparably alongside traditional lines in planning the transmission infrastructure of tomorrow.

IV. CONCLUSION

Over the next twenty years, generation, transmission, and distribution systems in the United States will require between $1.5 and $2 trillion dollars of investment.[342] FERC's policies relating to interstate transmission and wholesale power sales will significantly affect the decision making processes of market actors, regulated utilities, state regulators, consumers, and other stakeholders who, collectively, will bear the costs and reap the benefits of these investments. FERC's antiquated rules and categories threaten to

339. *See Piedmont Envtl. Council v. F.E.R.C.*, 558 F.3d 304, 310 (4th Cir. 2009) (holding that FERC does not have backstop jurisdiction when a state commission withholds approval of a permit application for over one year).

340. *See id. See also* Sandeep Vaheesan, *Preempting Parochialism and Protectionism in Power*, 49 HARV. J. ON LEGIS. 87 (2012).

341. Indeed, the problem is severe. Order No. 890 stated that, "transmission capacity is being constructed at a much slower rate than the rate of increase in customer demand, with transmission capacity per MW of peak demand declining at an average rate of 2.1 percent per year during the period 1992 to 2002." Order No. 890, *supra* note 151, at In the decade since, things have not improved significantly, although incentive rates have resolved some problems.

342. Peter S. Fox-Penner et al., *Transforming America's Power Industry: The Investment Challenge*, THE BATTLE GROUP (Apr. 21, 2008) http://brattlegroup.com/_documents/UploadLibrary/Upload678.pdf.

stymie investment in storage technologies that will play a vital role on the smart, resilient, reliable, clean, and efficient grid of tomorrow. Unless and until FERC acts, investment will continue to flow to legacy technologies that may fit more comfortably into existing regulations but provide less value at higher costs.

The time for FERC to act is now. The federal government is pouring billions of dollars into storage research, development, and demonstration, while state policies promoting storage and/or renewables have intensified the demand for flexible, grid-deployed storage resources. In the Commission's own words, some storage technologies are already cost-effective, particularly where permitted to access multiple revenue streams by providing multiple grid services. And while other technologies are still developing, deferring action by arguing that storage resources are not yet mature is a red herring—the only way to know whether storage is effective is in a market with just and reasonable rules. In the near-term, storage will compete with resources fueled by cheap natural gas.[343] But storage technology will improve and system needs for flexibility will intensify, while natural gas prices will likely gradually increase from current historic lows. Regardless, FERC's duty is not to divine who should win or lose; the Commission must simply ensure that the game is fair.

343. *See, e.g.*, Felicity Carus, *Energy Storage Startups Battle Natural Gas, Looking to Asia and Europe*, BREAKING ENERGY (May 15, 2012, 9:00 AM), http://energy.aol.com/2012/05/15/energy-storage-startups-battle-natural-gas-looking-to-asia-and/.