

Washington Utilities and Transportation Commission Staff

Modeling Energy Storage

Challenges and Opportunities
for Washington Utilities



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Issue

After reviewing the 2013 integrated resource plans (IRPs) of Washington's investor-owned utilities, the Washington Utilities and Transportation Commission (commission) directed all three utilities to improve their analysis of energy storage resource options in their 2015 IRPs. With input from staff and other stakeholders, the utilities have made good-faith efforts to follow the commission's direction. However, as the 2015 planning cycle nears its end and the utilities are preparing to file their plans, it has become apparent to staff that there is a need for more structured, formalized guidance from the commission.

Many of the challenges that energy storage faces in Washington, and in the Pacific Northwest in general, can be traced to the lack of an organized energy market. Absent the clear price signals that a market can set for various energy services, determining the value of the services that energy storage provides can be a challenge. Even if that challenge is overcome, there is no transparent way for a utility to monetize the identified benefits.

This white paper will examine current trends in energy storage development and how Washington utilities have approached the issue in their planning and procurement activities. It will then discuss barriers to the development of energy storage and policies in other jurisdictions that have proven successful in overcoming them. It concludes with staff's recommendation that the commission develop a policy requiring utilities to account for the benefits of energy storage in their planning and procurement activities, and offers some preliminary suggestions of what such a policy might look like. The list is not meant to be exhaustive; staff hopes for a collaborative process involving a wide range of stakeholders that results in a policy that addresses the challenges and opportunities unique to Washington.

Background

Recent developments in energy storage

Seismic developments are taking place in the energy industry that increase the value proposition of storage at the same time that costs are falling. Robust research in federal and private laboratories, combined with government grants and tax credits, have created a favorable environment for demonstration projects that have served to improve understanding of energy storage and drive down its costs. Automotive industry investments in battery development and manufacturing are creating advances and cost reductions in battery storage that will create spillover benefits for grid-scale electric storage.

The standard technology for battery-based electricity storage, lithium-ion, has seen costs fall by two-thirds since 2009, to the range of \$300/kilowatt-hour (kWh).¹ Driven by the automotive industry's investments into reducing costs through large-scale manufacturing infrastructure, analysts expect that lithium-ion batteries could cost as little as \$200/kWh by 2020.² Newer technologies that promise longer life expectancies, such as vanadium redox, could fall to the \$300/kWh range in the near future as well.³ At a price of \$230/kWh, batteries will be cost-competitive with traditional pumped hydro storage, but without the environmental and site restrictions that have been a limiting factor for that technology.⁴

Staff sees significant parallels between the current state of the energy storage industry and the renewable industry in the early 2000s. At that time, years of tax credits and research moved renewable generation technology to an inflection point that allowed states to adopt policies, such as renewable portfolio standards, that facilitated continued development and advancement. The continued growth of renewable energy and an ever-increasing focus on the environmental impacts of energy generation are creating a "virtuous cycle" of increased penetration and reduced costs for energy storage technologies, similar to the recent trends in the solar photovoltaics industry.⁵

In Washington, these macro-level trends have translated into a flurry of activity. With significant assistance from federal and state funds, Washington utilities in the last two years have announced or begun development on seven battery storage projects totaling 9.5 megawatts (MW) in capacity.⁶ These developments promise to increase those utilities' working knowledge of energy storage and the benefits that it can provide to their respective systems.

Almost all of these pilot projects, however, are premised upon one-time funds from outside sources.⁷ Absent a policy to guide the utilities in their evaluation of energy storage projects after the grant money is spent, there is a risk that the utilities will default to current planning procedures, which fail to grant energy storage an opportunity to fairly compete against other alternatives.

¹ Jaffe, Sam, 2015. "2015: A Turning Point for Batteries," Navigant Research Blog. Accessed March 9, 2015. <https://www.navigantresearch.com/tag/energy-storage>

² McKinsey & Company, 2012. "Battery Technology Charges Ahead." Accessed March 9, 2015. http://www.mckinsey.com/insights/energy_resources_materials/battery_technology_charges_ahead

³ Eller, Alex. 2015. "Vanadium Batteries Await Breakthrough," Navigant Research Blog. Accessed March 9, 2015. <https://www.navigantresearch.com/tag/energy-storage>

⁴ CitiGroup, 2015. "Investment Themes in 2015: Dealing with Divergence," page 53.

⁵ *Id.*, page 52.

⁶ energystorageexchange.org.

⁷ This is particularly true of the energy storage projects being sponsored by investor-owned utilities, all of which received substantial funding from the federal or state government.

Current planning practices in Washington

In 2013, Washington's three investor-owned electric utilities (IOUs) each submitted an IRP to the commission for review. Generally, each utility reached the same conclusion regarding energy storage: it costs too much and its benefits can't be quantified. Two of the utilities, Puget Sound Energy (PSE) and Avista Corporation (Avista), concluded that there was no reason to model energy storage and omitted the resource from their IRPs, though Avista did commit to developing a tool for modeling energy storage in its 2015 IRP.⁸ Pacific Power & Light Company (Pacific or PacifiCorp) included energy storage in its IRP, but with no quantified benefits to offset its relatively high capital costs, the resource was not selected.⁹

In its letters acknowledging each company's IRP, the commission challenged the companies' use of outdated information in building their assumptions around energy storage and informed each company that more would be expected of its energy storage analysis in the 2015 IRP. The commission's letter to PSE is indicative of the general message that the commission sent to each company:

In its next IRP, PSE should update its energy storage analysis with recent market data, clarify its assumptions regarding expected operational conditions for storage systems, and include ancillary services in the energy storage analysis. The Commission encourages PSE to rely on a wide variety of national and state data.¹⁰

In preparing their 2015 IRPs, the utilities have responded to the commission's direction to varying degrees. PSE partnered with the Pacific Northwest National Laboratory to prepare a study of the potential for energy storage projects within the company's system, and PSE is analyzing specific sites on its system where storage may provide enough benefits to be cost-effective. PacifiCorp used the same basic approach that it used in its 2013 IRP, though with updated cost assumptions and an additional model run that presumed the existence of storage on the company's system, which allowed Pacific to quantify some generic benefits of storage at the system level. Avista is working on the modeling approach that it committed to develop in its 2013 IRP.

Staff believes that further guidance from the commission is the next natural step in this process, one that would formalize the efforts that the companies have begun and provide consistency in their approaches. That consistency would translate into stability for energy storage developers and create a more conducive environment for the energy storage industry in Washington.

⁸ See Puget Sound Energy 2013 Integrated Resource Plan at page 5-26; Avista 2013 Integrated Resource Plan at page 6-10.

⁹ PacifiCorp 2013 Integrated Resource Plan at pages 139-140.

¹⁰ Docket UE-120767, Acknowledgment Letter, Attachment A, page 6. (Feb. 6, 2014).

Discussion

The valuation challenge

Traditionally, energy storage projects have been developed on the arbitrage model – the money made by storing energy during low-cost, off-peak hours and then reselling it during high-cost, on-peak hours. In addition to being the most readily available service provided by traditional, large-scale pumped hydro and compressed air storage projects, it is also the easiest to quantify. However, this model faces challenges in the Pacific Northwest, where the use of low-cost hydro for load following generally limits daily price differentials, and the lack of an organized energy market means there is little transparency into the magnitude of those differentials.

Modern technologies such as batteries and flywheels, with their ability to move between charging and discharging modes instantaneously, have opened up a new suite of services that energy storage can provide, such as frequency response, voltage regulation, and energy imbalance. Though crucial to maintaining the electric grid, the values of these services are more difficult to quantify and are unlikely to be large enough to offset the cost of an energy storage project at current prices. Energy storage projects, therefore, still need that “killer app” – a high-value service that provides a large enough value stream to justify the technology’s cost.

Though opportunities for daily arbitrage may be few in Washington, energy storage’s ability to smooth the output of variable renewable resources and better integrate them into the grid may prove to be that killer app. Washington’s renewable portfolio standard (RPS) has resulted in major investments in wind power by the state’s regulated utilities. While these investments have created significant benefits for ratepayers in the forms of increased economic activity and emissions-free energy, the variable nature of wind power has also created costly integration challenges for the utilities.¹¹

To date, utilities have been able to absorb the integration costs through the federal Production Tax Credit (PTC), which gives each utility a credit of about \$23 per megawatt-hour of wind energy produced. But the PTC expired at the end of 2014 and its renewal is unlikely, meaning that future projects will likely be unable to rely on that revenue stream to offset their integration costs, which will increase their overall cost. Additionally, the PTC only lasts for the first 10 years of a project’s life, and many of Washington’s wind projects are nearing that 10-year mark. The absence of the PTC could be a major challenge for Washington’s investor-owned utilities, as at least one utility will have to acquire additional RPS-eligible resources within the next

¹¹ PacifiCorp’s 2014 Wind Integration Study identifies an integration cost of \$3.06 per MWh of wind generation. PSE’s wind integration costs are available in the company’s 2013 PCORC (UE-130617) on page 10 of the confidential direct testimony of Matthew D. Rarity.

decade.¹² Given the current state of renewable technologies and the physical characteristics of Washington, it seems likely that wind will be a major component of future eligible resource additions.

Energy storage is projected to be a rapidly growing component of cost-effective renewable energy integration over the next decade. Navigant research projects that the market for energy storage projects designed for renewable integration is expected to grow from \$32 million in 2015 to \$2.9 billion by 2024.¹³ But this is not a consensus view in the industry; the National Renewable Energy Laboratory, for example, has concluded that energy storage is not necessary for renewables integration until a balancing area has a renewable penetration rate of 20 percent.¹⁴

Staff does not believe that the commission needs to venture into this debate. Washington's investor-owned utilities already have quantified renewable integration costs; to the degree that energy storage is able to provide integration, those become avoided costs. Where those resources that were previously held back for integration can be released to meet the utility's load or be sold in the market, there is an avoided cost associated with further delaying future generation needs and the potential for increased revenue through additional market sales. Where that same storage project can also be optimized to provide other grid services, there are additional benefits from increased system efficiency and avoided costs associated with additional generation that can be freed up for serving load and making sales.

This type of holistic analysis goes far beyond the current modeling practices of the utilities, which to date have not identified or quantified the benefits associated with energy storage. This precludes the IRP models from selecting energy storage, because without those offsetting benefits, energy storage remains cost prohibitive. Identifying and quantifying those benefits will admittedly be a significant challenge. Staff believes that a collaborative approach involving all of the utilities and various stakeholders offers a greater chance of success than leaving each utility to work through the problem in isolation. Furthermore, federal and state agencies from around the U.S. have already done valuable work on which the commission can build.

¹² Staff analyzed each utility's future compliance need based the incremental RPS targets in statute, the utility's projected load growth, and the utility's existing eligible resources, accounting for resource banking provisions. This analysis showed that PSE will need to add an additional eligible resource no later than 2023. PacifiCorp has determined that it will meet RPS requirements by purchasing renewable energy credits (RECs) from third parties in the short and mid-term, but changing market conditions could result in the company needing to acquire additional resources. Avista, which will be able to claim its Kettle Falls biomass facility beginning in 2016, will not require an additional resource for RPS compliance until the 2030s.

¹³ Energy Storage Association, 2015. "Energy Storage for Renewables Integration: A Burgeoning Market." Accessed March 19. <http://energystorage.org/news/esa-news/energy-storage-renewables-integration-burgeoning-market>.

¹⁴ National Renewable Energy Laboratory, 2015. "Transmission Grid Integration: Energy Storage." Accessed March 19. http://www.nrel.gov/electricity/transmission/energy_storage.html.

FERC proceedings

In 1996, the Federal Energy Regulatory Commission (FERC) issued Order 888, which defined six ancillary services that “are needed to accomplish transmission service while maintaining reliability within and among control areas affected by the transmission service.”¹⁵ They are: scheduling, system control and dispatch service; reactive supply and voltage control; regulation and frequency response; energy imbalance; spinning reserves; and supplemental reserves.¹⁶ The order stated that transmission providers were required to offer these services to their customers; customers were required to purchase some services from the transmission provider and given the option to self-provide others or purchase them from third parties.

While energy storage has been demonstrated to have applications in providing each of those six ancillary services, much of the focus in subsequent years has been on its ability to provide regulation and frequency response service.

In 2011, FERC issued Order 755 to require that regional system operators (RTOs) and independent system operators (ISOs) establish performance-based rates for frequency regulation providers. The rule was the result of an extensive investigation, in which FERC determined that the ability of resources like batteries and flywheels to quickly ramp up (by discharging stored energy into the grid) or down (by absorbing excess energy from the grid) made them more efficient at providing frequency regulation, but existing capacity-based compensation structures failed to account for those capabilities and unfairly advantaged larger, less efficient generation facilities.¹⁷ In its order, FERC concluded that:

Both existing market participants and potential entrants are affected by inefficient pricing. It is possible that existing market participants would offer faster ramping capabilities to the system operator in response to a pricing scheme that recognized such service.¹⁸

Several commenters in FERC’s proceeding quantified the economic benefits of using smaller, faster resources for frequency regulation. One commenter showed that under this approach, one ISO could reduce the amount of capacity it needed to reserve for frequency regulation by 40 percent, reduce its total frequency regulation expenses by 27 percent, and release 40 megawatts of generation capacity into the market.¹⁹ Order 755 concluded that:

The use of faster-ramping resources for frequency regulation has the potential to improve operational and economic efficiency and, in turn, lower costs to

¹⁵ 75 FERC ¶ 61,080; Order 888 at page 206.

¹⁶ *Id.*, at pages 200-201.

¹⁷ 137 FERC ¶ 61,064; Order 755 at pages 10-11.

¹⁸ *Id.*, page 2, footnote 4.

¹⁹ *Id.*, pages 15-16.

consumers in the organized markets. Faster-ramping resources may be able to replace resources that currently provide frequency regulation, so that RTOs and ISOs may be able to procure less regulation capacity, thereby lowering costs to load.²⁰

The impacts of this order were substantial and prompt. Within a year of instituting market rules as directed by Order 755, an influx of storage resources had enabled PJM Interconnection to reduce its expenditures on regulation services by 10 percent and free up more than 240 MW of capacity that had previously been needed for regulation.²¹

In 2014, the vast majority of the 61.9 MW of energy storage that were installed in the U.S. were installed in organized markets that have ancillary markets capable of fairly compensating energy storage. PJM, the RTO that has the most robust ancillary markets, was home to two-thirds of all energy storage capacity installed in 2014.²²

The 2014 data are indicative of a broader trend, which has seen the majority of storage projects in the U.S. move toward the ISOs and RTOs that were required by Order 755 to develop compensatory mechanisms for energy storage. According to the U.S. Department of Energy's database of energy storage projects around the world,²³ of the 4,064 MW of energy storage projects in the U.S. that have been announced or begun construction, 84 percent are located in an organized market covered by Order 755.²⁴

In 2013, FERC built on its previous orders with Order 784, which required transmission providers to consider the "speed and accuracy of regulation resources" when determining a customer's reserve requirements for the regulation and frequency response service,²⁵ which FERC had identified as one of the ancillary services necessary for balancing the grid in Order 888.

While FERC's orders apply only to the wholesale markets and interstate transmission activities that it regulates, they were based on fundamental principles of grid operations and economics. A utility operating its own balancing area, like Washington's three investor-owned utilities, may not be subject to FERC's orders, but it is still responsible for providing the ancillary services that, as identified in Order 888, are necessary for keeping the grid in balance. And among those necessary services are the frequency and regulation service that Orders 755 and 784 sought to

²⁰ *Id.*, page 12.

²¹ Wolff, Eric. 2015. "Better Grids through Batteries, or how Performance-based Regulation Saves PJM Money," *SNL*, May 2.

²² Energy Storage Association, 2015. "U.S. Energy Storage Market to Grow 250% in 2015." Accessed March 11, 2015. <http://energystorage.org/news/esa-news/us-energy-storage-market-grow-250-2015-0>

²³ www.energystorageexchange.org

²⁴ Based on staff's analysis of all projects labeled "announced" or "under construction" on energystorageexchange.org.

²⁵ 144 FERC ¶ 61,056; Order 784 at page 5.

make more efficient. Even if the utility does not have a market to monetize all of the benefits that energy storage provides, those benefits have a quantifiable and tangible benefit to the utility's system that should be reflected in the utility's planning.

By requiring organized electricity markets to quantify and monetize the value of energy storage, FERC has shown energy storage is feasible and cost-effective now. The commission may not have a market to implement storage valuation as FERC did, but it does have authority over how utilities treat these resources in their planning and procurement processes. By requiring utilities to account for the value of energy storage in their planning, the commission can ensure that utilities will identify and pursue the energy storage projects that will improve system operations and reduce costs for ratepayers.

Other states

While efforts are underway in many states to better understand the costs and benefits of energy storage,²⁶ California and New York have moved to the leading edge. But the two states widely differ in their approach – New York's is based on planning and economic resource selection, while California implemented a mandate for its utilities to acquire defined amounts of energy storage resources.

The New York Department of Public Service recently issued the first order in its "Reforming the Energy Vision" (REV) docket, which is fundamentally re-evaluating the state's regulatory framework for electric utilities. That order implemented a staff recommendation to redefine electric distribution utilities as "distribution system platform providers," charged with planning and operating systems that consider all energy resources, including distributed generation.²⁷

Storage will play an "essential role" in the plans of the distribution system platform providers, according to the staff report that launched the REV docket. The report concluded that a plan-based approach, in contrast to a mandate, would ensure that economically feasible projects are pursued.²⁸

In California, the Public Utilities Commission (CPUC) was directed by the legislature to "consider a variety of possible policies to encourage the cost-effective deployment of energy storage systems, including refinement of existing procurement methods to properly value energy

²⁶ See Stanton, Tom, 2014. "Envisioning State Regulatory Roles in the Provision of Energy Storage," National Regulatory Research Institute.

²⁷ New York Department of Public Service Staff, "Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal," April 24, 2014, pg. 12.

²⁸ *Id.*, page 14.

storage systems.”²⁹ The enabling legislation directed the CPUC to consider mandatory targets, but did not require their adoption.

The CPUC ultimately chose to impose a mandate on the state’s three large, investor-owned utilities to procure 1,325 MW of energy storage systems by 2020. In its order, commissioners indicated that they selected the mandate as a means of driving market transformation in the energy storage industry.³⁰

Staff anticipates that the CPUC’s proceeding on energy storage will create two significant spillover benefits that Washington can harness. First, the state’s goal of driving market transformation is already being realized, as evidenced by Southern California Edison’s recent acquisition of 260 MW of economic energy storage resources through an all-source request for proposals in which storage competed against traditional capacity resources.³¹ Competition among energy storage providers in California is already driving cost reductions and technology improvements that will spread throughout the industry.

Second, although the CPUC opted to institute a mandate, CPUC staff invested significant resources in preparing alternative approaches that can serve as a foundation as other states explore the issue. Specifically, CPUC staff prepared a framework proposal that broke the wide variety of energy storage technologies and services into a handful of use cases – simplifying assumptions about how a particular device might be employed and the benefits it would generate under each scenario. Staff believes that this work would be of significant value if the commission takes up this issue in Washington, as it provides an example framework for a thorough analysis of energy storage benefits.

Staff’s proposal

Staff proposes to engage Washington’s investor-owned utilities and stakeholders in developing a way for utilities to reflect the value of energy storage in their planning and procurement processes. As evidenced above, energy storage is cost-competitive now, provided that its benefits are recognized. Crafting a mechanism for utilities to identify and quantify the benefits of energy storage in their planning will ensure that the benefits of cost-effective energy storage are captured by Washington utilities and their ratepayers.

As a starting point, staff envisions several potential forms that this mechanism could take:

²⁹ California Public Utilities Code, Section 2836(a)(1).

³⁰ California Public Utilities Commission, Decision 13-10-040 (Oct. 17, 2013), page 7.

³¹ Corder, Christine. 2014. “Battery Energy Storage Makes Big Showing in SoCalEd Competitive Solicitation.” *SNL*, Nov. 5.

- Developing a proxy value of energy storage’s ancillary benefits based on the rates for those services in established ancillary markets.
- Identifying the ancillary services that utilities must recognize in their planning and directing the utilities to determine the value of each service on their individual systems based on how the utility currently provides that service. Those values could then be inputs for a use case approach like the one developed by CPUC staff.
- Requiring the utilities to file an “Avoided Ancillary Services Cost” tariff that identifies how much it costs the utility to provide each service. Those costs would be used as planning inputs and to set the compensation for independent energy storage projects that interconnect with the utility.

Timing

As the energy storage industry rapidly expands, it is important for Washington’s utilities to be prepared to recognize when projects become cost effective. By 2019, the U.S. energy storage industry is expected to be about 20 times larger than it was in 2014, going from 61.9 MW installed in 2014 to a projected total of more than 800 MW in 2019.³² As the industry experiences this rapid expansion, development opportunities for Washington utilities are certain to increase, and it is important that the investor-owned utilities be prepared to recognize and identify cost-effective opportunities as they arise.

In fact, a number of large energy storage opportunities have already been identified in the Pacific Northwest. The Pacific Northwest National Laboratory has identified a viable site for compressed air energy storage near Yakima,³³ EDF Renewables is planning a large pumped hydro storage project in Pacific Power’s service territory in southern Oregon,³⁴ and Klickitat PUD is looking for partners on an ideally sited pumped hydro storage project.³⁵ Washington’s Clean Energy Fund, which last year allocated almost \$15 million for energy storage projects in the state, has created a cottage energy storage industry in Washington.³⁶ That developing infrastructure, combined with the opportunity for major projects in the near future, is a significant opportunity for the utilities to embrace, and its growth would generate significant economic benefits for the state.

³² GTM Research and Energy Storage Association, 2015. “U.S. Energy Storage Monitor – 2014 Year in Review: Executive Summary,” page 13.

³³ Pacific Northwest National Laboratory, 2014. “Compressed Air Energy Storage: Grid-Scale Technology for Renewables Integration in the Pacific Northwest.”

³⁴ EDF Renewable Energy, 2015. “Swan Lake North Pumped Storage Hydro.” Accessed March 19. <http://www.edf-re.com/employment.php>.

³⁵ Prengman, Kate, 2015. “Klickitat PUD wants to build \$2.5 billion power storage system near Goldendale,” *Yakima Herald*, Feb. 17.

³⁶ St. John, Jeff. 2014. “Why Washington State’s \$14.3M Storage Program is so Different from Others,” *Greentech Media*, July 10.

Conclusion

The rapid development of energy storage projects in markets that have adopted a means of compensating those projects for the grid services they provide clearly demonstrates that the largest impediment to energy storage is market failure. Simply put, where energy storage's benefits are recognized, it thrives. Where they are not, development is slow or nonexistent. By developing a proxy method for ensuring that the full value of energy storage is reflected in utility planning, the commission can ensure that cost-effective energy storage projects will be developed in Washington, thereby allowing utilities and ratepayers here to harness the benefits that energy storage is already providing in organized markets.

Washington's investor-owned utilities operate within a smaller footprint than those organized markets, but are otherwise indistinguishable from those larger entities. They all must constantly maintain a delicate balance between load and resources; they all must ensure reliability at all times. If the creation of ancillary services markets enabled the organized markets to capture the benefits of energy storage and improve the efficiency of their systems, then it is reasonable to argue that the creation of a reasonable proxy to those ancillary services markets will allow utilities operating outside of an organized market to capture those benefits as well.

While there is still much inquiry to be done before recommending a specific approach, staff has outlined a starting point and believes the issue is ripe for broader discussion with the utilities and other stakeholders. Staff is confident that the issue can be clearly framed for a workshop setting, allowing for the robust discussion that will be necessary to identify existing barriers, consider possible solutions, and inform the proposed policy statement.