

ENTERED MAR 21 2017

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1751

In the Matter of

PUBLIC UTILITY COMMISSION OF
OREGON,Implementing Energy Storage Program
Guidelines pursuant to House Bill 2193.

ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED

This order memorializes our decision, made and effective at our March 21, 2017 Regular Public Meeting, to adopt Staff's recommendation in this matter. The Staff Report with the recommendation is attached as Appendix A.


Dated this 21 day of March, 2017, at Salem, Oregon.


Lisa D. Hardie
Chair



COMMISSIONER SAVAGE WAS
UNAVAILABLE FOR SIGNATURE

John Savage
Commissioner


Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Circuit Court for Marion County in compliance with ORS 183.484.

ITEM NO. 4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT


PUBLIC MEETING DATE: March 21, 2017

REGULAR X CONSENT _____ EFFECTIVE DATE March 22, 2017

DATE: March 16, 2017

TO: Public Utility Commission

FROM: Jason R. Salmi Klotz 

THROUGH:  Jason Eisdorfer and  John Crider

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket UM 1751) HB 2193 Implementing an Energy Storage Program –
Staff Report Pursuant to Order No. 16-504.

STAFF RECOMMENDATION:

- 1) Adopt Staff recommended framework for Storage Potential Evaluations that addresses items (a) through (g) listed in section A(3)(1) of Commission Order No. 16-504.
- 2) Extend the due date for utilities' draft evaluations from June 1, 2017 to no later than July 15, 2017, and clarify that the Commission will hold a special public meeting for stakeholder input within 30 calendar days of the date of the last submitted draft Storage Potential Evaluation.
- 3) With regard to the requirement stated in HB 2193 (Section 2 (1)) "... an electric company *shall procure* on or before January 1, 2020, as part of project described in section of 3 of this 2015 Act...", validate Pacific Power's interpretation that "shall procure" to mean that contracts are in place to engineer, procure and construct or implement the selected energy storage projects.
- 4) Adopt Staff's nine recommendations regarding requirements for system evaluations.

DISCUSSION:

Issues

- (1) Whether the Commission should adopt the Staff proposed framework for Storage Potential Evaluations and Staff's recommendations regarding the detail required in

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electric companies' draft and final Storage Potential Evaluations due June 1, 2017, and January 1, 2018.

(2) Whether the Commission should postpone the due date for draft Storage Potential Evaluations from June 1, 2017, to no later than July 15, 2018.

Applicable Law

House Bill 2193 (2015 Oregon Legislative Session)¹ requires the Commission to evaluate electric companies' proposals for procuring qualifying energy storage systems and to implement guidelines to facilitate the submission and Commission review of proposals. HB 2193 specifies that each energy storage proposal must be accompanied by the electric company's evaluation of the storage potential on its system (hereinafter referred to as "Storage Potential Evaluation"). In Order No. 16-504, the Commission directed Staff to conduct workshops with Stakeholders to develop a consensus framework for the Storage Potential Evaluations and to present the framework at a special public meeting no later than April 1, 2017. The Commission also specified in Order No. 16-504 that electric companies must submit draft Storage Potential Evaluations by June 1, 2017, and final Storage Potential Evaluations with the energy storage project proposals due January 1, 2018.

Analysis

Background

HB 2193 directs large Oregon electric companies (PacifiCorp, dba Pacific Power, and Portland General Electric Company (PGE)) to submit proposals for qualifying energy storage systems with the capacity to store at least 5 MWh of energy no later than January 1, 2018. HB 2193 outlines several requirements for the proposals, including that each proposal must be accompanied by an evaluation of the potential to store energy in the electric company's system. The Storage Potential Evaluation includes an analysis of operations and system data, examination of how storage would complement the electric company's existing action plans, and identification of areas with opportunity to incentivize energy storage.

On December 28, 2016, the Commission issued Order No. 16-504 providing final energy storage project and proposal guidelines and also directing Staff to "convene workshops to develop a framework for the electric companies' [Storage Potential] evaluations."² In particular, the Commission directed Staff to:

¹ <https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193>

² Commission Order No. 16-504, p. 8, available at: <http://apps.puc.state.or.us/orders/2016ords/16-504.pdf>

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- a. Establish a consistent list of use cases or applications to be considered in the evaluation;
- b. Establish a consistent list of definitions of key terms;
- c. Determine the timeframe for analyses;
- d. Assess the potential valuation methodology or methodologies the electric companies may use for estimating storage potential in each use case or application;
- e. Establish criteria for identifying the main opportunities for investment in storage;
- f. Determine the approach for identifying system locations with the greatest storage potential; and
- g. Establish the level of detail required in the evaluation results and required supporting data.

In addition, the Commission clarified,

the objective for the workshops is to assess potential valuation methodologies the electric companies may use for estimating storage potential in each use case or application. With this groundwork, the electric companies would then determine what methodology they will utilize and use this in preparing their draft evaluation. During review of the draft evaluation, Staff, the Commission, and stakeholders will have the opportunity to comment and suggest refinements.³

Staff's recommended framework is summarized below and described at greater length in the Staff Recommendation document included with this memorandum as Appendix A. Although Staff sought to create a consensus framework, not all Stakeholders agreed to every element of the framework.

Below, Staff also discusses the proposed valuation methodologies put forth by PacifiCorp and PGE during the workshops. Finally, Staff recommends that the Commission extend the due date for filing the draft Storage Potential Evaluations and clarify its understanding of what must be done by the January 1, 2020, energy storage procurement deadline.

Process

With assistance from experts at the Pacific Northwest National Laboratory, Staff developed a straw proposal or draft discussion document addressing the seven issues highlighted by Commission Order No. 16-504 section A(3)(1) items (a) through (g) and disseminated a copy of the draft for discussion prior to workshops held on January 27

³ Order No. 16-504 at 9.

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and February 17, 2017. Staff opened two comment periods on the Staff draft discussion document. The first comment period was opened February 8 and, the second comment period was opened on February 28, 2017. The February 28 comment period was staggered whereby each utility was provided opportunity to comment on Staff's revised discussion document and to submit system evaluation proposals. Stakeholders' deadline for reply comments was March 7, 2017. A synopsis of comments received by Stakeholders can be found in Appendix B; a synopsis of utility February 28, 2017, comments are found herein.

After reviewing comments and input from all stakeholders, Staff developed the following framework:

Staff Recommended Framework:

a: *Consistent list of use cases or applications to be considered in the evaluation;*

Staff proposed, vetted and found consensus with stakeholders on a list of use cases including definitions and services. This set of use cases is set forth in detail in the attached Staff Recommendation document (Appendix A).

b: *Consistent list of definitions of key terms;*

Building upon efforts that have taken place nationally where the industry has already adopted and established a comprehensive lexicon, Staff and stakeholders reached consensus on using the U.S. Department of Energy Glossary of Energy Terms.⁴ In addition, Staff and stakeholders agreed to use the *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA*, Sandia National Laboratories, Akhil, Hill et al (September 2016).⁵

c: *Timeframe for analyses;*

Staff and stakeholders reached a consensus that the time frame for the initial system analysis that is needed to define the landscape of opportunities, including potential sites for energy storage, should be 10 years. For the proposal due on January 1, 2018, the analysis timeframe should be equal to the lifetime and life-cycle cost of the proposed energy storage system.

⁴ Available at: <https://energy.gov/eere/energybasics/articles/glossary-energy-related-terms>

⁵ Akhil, A., G. Huff, A. Currier, B. Kaun, D. Rastler, S. Chen, A. Cotter, D. Bradshaw, and W. Gauntlett. 2015. DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA (pp. 29, 149-166). Albuquerque, NM.

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d: *Potential valuation methodology or methodologies the electric companies may use for estimating storage potential in each use case or application;*

Staff proposed and reached consensus with stakeholders on the valuation methodology factors that should be included in any valuation analysis. The agreed-upon list of factors and examples are provided in the attached Staff Recommendation document. (Appendix A.)

e: *Criteria for identifying the main opportunities for investment in storage;*

Staff and stakeholders struggled to see the connection between establishing criteria for investments and the main charge by the Commission to address the system evaluations. For stakeholders the criteria for investments seem more related to how the Commission would review utility storage project proposals. Nonetheless, Staff and stakeholders reached tentative consensus on a list of criteria which are similar to other criteria used by the Commission when reviewing utility program or procurement proposals. These criteria are:

- 1) *Cost-effectiveness* - with tolerance for proposals that are reasonable and meet statutory requirements, even if the individual proposal is not cost-effective.
- 2) *Diversity* - of ownership, of technology, and of applications.
- 3) *Location* - the portfolio of proposals should examine the range of eligible storage systems, including those located on the customer side of the meter (i.e., behind-the-meter, or BTM), interconnected at the distribution system level, and interconnected at the transmission level.
- 4) *Utility learning* - activities that will support applications or technologies that will provide operational experience and reasonably lead to future high-value deployments.

During the workshop and comment process, stakeholders, utilities and Staff identified additional criteria that could potentially be considered in selecting the highest value storage opportunities, including technology readiness level, financial stability of technology provider and commercial terms.

f: *Approach for identifying system locations with the greatest storage potential;*

Staff suggested and vetted with stakeholders the following set of initial criteria to be used in identifying system locations with the greatest storage potential. These criteria are also found in the Staff Recommendation document (Appendix A):

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- Total capacity of the storage unit should be large enough to meet the challenges identified while also addressing other potential use cases.
- Locational planning information should be used such as expected load growth and historical growth patterns, and expected electric customer demand. These last criteria would incorporate demand-side interests for resiliency and reliability and may capture interest from high use customers in customer-sited energy storage investments.
- The investment needed for both the storage infrastructure and the grid infrastructure whether or not storage is used.
- Reliability and safety statistics or metrics such as SAIDI or SAIFI should be a factor in matching the value of energy storage.
- Peak load (limited energy requirements) should be a factor in identifying system location. However, Staff has separated peak load from locational planning information because peak load may be a locational factor for feeders or substations but may also be a grid level concern that storage can address regardless of its location.
- Utilities should consider the administrative permitting and approval challenges and physical space limitations when assessing whether a location has greatest value to the utility system.
- Utilities should review internal distribution planning for potential distribution substations/feeder capacity/ congestion issues that could be alleviated with storage solutions.

Staff has also outlined evaluation criteria in the attached Staff Recommendation document (Appendix A). Additional evaluation criteria outlined in the Staff Recommendation include diversity measures, such as the maturity and potential of energy storage technologies, varying ownership models, differentiating uses and applications and grid placement.

Staff views it as essential that the approach used to identify system locations with the greatest storage potential include consideration of:

- technologies with varying degrees of maturity based on the US Department of Energy's Technology Readiness Assessment Guide, which establishes Technology Readiness Levels (TRLs), a common framework for commercialization of innovative technologies;
- different ownership models;
- grid placement at the transmission and distribution levels; and

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- locations where energy storage can serve multiple use cases.

Addressing each of these criteria will enhance the learning that occurs through the Storage Potential Evaluation and will better inform the final evaluations submitted on January 1, 2018. Based on this assessment, Staff believes that PGE's proposal to exclude transmission-level deployments while focusing on a single mature technology is not sufficient.

g: *The level of detail required in the evaluation results and required supporting data.*

Staff proposes nine key elements that address the level of detail required in the evaluations and expands on the proposal guidelines contained in Commission Order No. 16-504.

1. **Electric Companies should analyze each use case listed in Appendix A for each evaluated storage site.** As noted previously, Staff and stakeholders have agreed upon a set of use cases to be considered. Staff agrees with stakeholders that not all use cases will generate value at each site evaluated. However, Staff views the PacifiCorp proposal of focusing on a small subset of use cases to be too restrictive. Use cases (e.g., regulation and load following) that can be evaluated using well-understood industry modeling approaches should be included. Each use case should be considered at each site with brief justifications provided when not valued. The economic benefits by use case can be generalized in the draft evaluations but should reflect location-specific benefits in the final evaluations due January 1, 2018.
2. **Final Storage Potential Evaluations should include detailed cost estimates for each proposed energy storage system (ESS).** ESS costs should include, but not be limited to: battery and battery management systems, power control and conversion systems, balance of plant, construction and commissioning, and fixed and variable operations and maintenance. These costs should be used to estimate the revenue requirements of each energy storage system (ESS). Costs should reflect cost trends evident in the marketplace as forecast to the year when a purchase would be made. Staff recognizes that the best method for estimating these costs would be through the issuance of a request for proposals (RFP) but agree that given the limited time available to secure such proposals, engineering estimates can be used.
3. **When storage services can be defined based on market data, a market valuation should be used for such identified services.** When an entity is participating in the Energy Imbalance Market (EIM), EIM market-based values

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should be used for EIM services. Staff recognizes that many benefits in the region will be defined in terms of avoided costs. When calculating avoided costs, the methodology used should generally rely on the comparison of the next-best alternative used to provide the service being analyzed for valuation. Evaluated benefits can include those accruing to the utility, the customer or society through, for example, enhanced reliability/resiliency or reduced emissions.

4. **Final evaluations submitted January 1, 2018, should provide detailed descriptions of proposed sites.** Staff can support PGE's proposal that the draft evaluation include generalized locational benefits – e.g., distribution system at a substation or behind-the-meter (BTM). However, this level of detail is not sufficient for the final evaluations.
5. **“Resiliency” should be defined in the form of a use case or as a unique quantifiable benefit if it is included in the Final Storage Potential Evaluation.** Staff is interested in the results of PacifiCorp's proposal to evaluate resiliency as a feature of proposed energy storage systems, specifically “localized” resiliency. Resiliency benefits were identified by several stakeholders as an important value to consider in developing energy storage system proposals, but no specific definition in the form of a use case, or unique quantifiable benefit was developed during the initial discussions.
6. **Models used in evaluations should have the following attributes:**
 - a. **Capacity to evaluate sub-hourly benefits;**
 - b. **Ability to evaluate location-specific benefits based on utility-specific values;**
 - c. **Enables co-optimization between services;**
 - d. **Capacity to evaluate bulk energy, ancillary service, distribution-level and transmission-level benefits;**
 - e. **Ability to build ESS conditions (e.g., power/energy capacity, charge/discharge rates, charging/discharging efficiencies, efficiency losses) into the optimization.**

Energy storage systems have several unique attributes that generate value to the electric grid, including the capacity to act as both generation and load, the ability to provide benefits at multiple points in the grid, the capacity to be more effective than conventional generation in meeting ramping requirements and responding to signals at the sub-second level. In consideration of these attributes, Staff views it as essential that any models used in the evaluations have the attributes listed above. All of these modeling features should be reflected in the final

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evaluation results presented with final energy storage proposal submitted no later than January 1, 2018. Staff believes that the June 1, 2017, draft evaluations need not include items (a) through (c).

7. **The components of each model, including the attributes in Staff Recommendation No. 6, should be identified and documented in both the draft and final evaluations.** Staff agrees with PGE that the model used to evaluate the economic benefit of each ESS may be proprietary. However, to the extent possible, it is necessary that the evaluations be transparent.
8. **A single base year may be used for modeling purposes.** The use of complex models (e.g., production cost models) to define the benefits associated with specific use cases (e.g., regulation, load following, and spin/non-spin reserves) can justifiably result in limiting the number of analysis years for certain services. The year chosen for modeled purposes should have a correlative relationship to the utility's latest IRP model run. A detailed transparent explanation including underlying quantitative data should be submitted to support the choice of a particular year. However, the analysis of certain benefits (e.g., distribution deferral) may require an assessment that covers multiple years. While the base year analysis may be appropriate for modeling purposes, benefits should be evaluated for the economic life of each proposed ESS.
9. **Staff must be able to validate the assumptions and methods used to evaluate the cost effectiveness of each proposed ESS in the final proposals.** Utilities should submit reports documenting the approaches used to estimate the value associated with the service(s) provided by each ESS. Staff will need a detailed discussion of the methods used, including the basis of assigning value to each service. Further, data used as input into the valuation models will need to be provided to Staff. This data should include the hourly or sub-hourly economic value of each use case, as appropriate, and the power/energy demands each use case places on the ESS. All battery characteristics and financial data will also need to be provided to Staff, as necessary for validation using publically available models, including the Pacific Northwest National Laboratory's Battery Storage Evaluation Tool or the Electric Power Research Institute's Energy Storage Evaluation Tool.

Utility-proposed Evaluation Methodologies:

Portland General Electric's Proposed System Evaluation Approach

PGE believes that utilities should be required to evaluate three generic types of storage projects:

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1. Transmission-interconnected storage;
2. Distribution interconnected storage; and
3. Behind-the-meter storage.

However, PGE does not intend to propose transmission-interconnected projects in the context of UM 1751 given the time required for such interconnection. PGE does intend to propose projects interconnected to the distribution system and those involving behind-the-meter storage.

PGE proposes that in the draft Storage Potential Evaluations currently due by June 1, utilities should, at a minimum, grossly quantify the benefits from "typical" installations of the three project types identified above. A typical installation is one that does not necessarily focus on significant locational values. Rather it is in a generic location on the utility's system. The "gross" quantification for each project would be determined by summing – not co-optimizing – the values for all of the appropriate services such a project would provide. The equations below represent PGE's understanding of the values that will be determined by June 1.

1. Value of "typical" transmission interconnected storage =
energy arbitrage and ancillary services benefits (from production cost model) +
bulk generation capacity + transmission services
2. Value of "typical" distribution interconnected storage =
energy arbitrage and ancillary services benefits (from production cost model) +
bulk generation capacity + transmission services + distribution services
3. Value of "typical" behind the meter storage =
distribution services + (customer energy management services OR
energy arbitrage and ancillary services benefits (from production cost model))

When PGE submits their energy storage project proposals accompanied by a final Storage Potential Evaluation, PGE will have identified specific locations on their system that offer explicit values due to where they are located. At that time, utilities should be required to provide a robust explanation of the approach chosen to determine these locations.

PacifiCorp's Proposed System Evaluation Approach

PacifiCorp has issued a Request for Proposal (RFP) to obtain the services of a qualified consultant to prepare storage potential evaluation plans and conduct an assessment of Pacific Power's Oregon service territory. Additionally, PacifiCorp will issue a Request

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for information to potential suppliers of turnkey energy storage solutions and their respective technologies.

PacifiCorp is proposing to leverage their prior energy storage work and PacifiCorp study "Battery Energy Storage Study for the 2017 IRP" conducted by DNV-GL.⁶ The conclusions of the DNV-GL study form the foundation of PacifiCorp's proposed analysis. Pacific Power proposes to focus on three primary storage applications: 1. Distribution Upgrade Deferral, 2. Transmission Upgrade Deferral, 3. Power Reliability and Resiliency.

The Pacific Power approach to evaluate energy storage potential on the distribution system will leverage its 10-year distribution system capital budget. Pacific Power will review the budget focusing on the years beyond the January 1, 2020, procurement date. Pacific Power believes that a review of these projects will identify a variety of project types and sizes. This will help identify energy storage potential by technical application.

The selection of potential projects will be performed by evaluating each project's ability to meet Pacific Power's system needs and provide benefits that can be realized with benefits stacking (i.e., ancillary services, capacity adequacy and arbitrage). The effort to identify any specific projects to be submitted on January 1, 2018, will be performed after June 1, 2017.

When evaluating power reliability and resiliency Pacific Power will evaluate localized reliability or resiliency of key concern. Pacific Power will evaluate applications of energy storage where traditional benefit stacking can be augmented by providing localized reliability. As customer resiliency is difficult to analyze under traditional cost effectiveness modeling, the resiliency metrics will by necessity be based on individual project criteria, specific application and potentially qualitative aspects.

Other Issues:

Evaluation Model & Framework Development

Staff and stakeholders devoted a majority of workshop time and comments to two opposing concerns: the timelines imposed for utility work products and the level of detail needed to conduct a quality, transparent system evaluation. In order to create and develop models that can identify and attribute value to multiple use cases and the many services provided by energy storage, a great of data acquisition and model modification

⁶ DNV-GL's *Battery Energy Storage Study for the 2017 IRP* report is available at PacifiCorp's website at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf

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needs to take place over many months if not longer. Additionally, development of such tools to produce a detail system evaluation is an evolutionary or iterative process, which would start a revolution of system modeling tools and techniques. Current models that identify asset value against avoided costs, such as the production cost models, do not recognize smaller assets on the distribution system. While production cost models can give some valuation to larger, bulk power storage systems such as pumped hydropower or compressed air, the existing models do not typically examine locational value, evaluate sub-hourly benefits, or consider benefits-stacking valuation for storage deployments.

The Commission anticipated the complexity of this process in Order No. 16-504 and noted that Staff and stakeholders' work on the evaluation process could continue after Staff's presentation of a framework in March 2017. Although full consensus was not reached among stakeholders regarding the detail required for system evaluations, the robust dialog did uncover a generally held desire to identify a path forward based on the understanding that what is developed presently would represent a first step towards creation of an evaluative modeling, data acquisition and tool. This tool would be capable of properly identifying the capabilities of all storage technologies and services, whether sited behind the meter, or at a distribution or transmission substation; an approach that one day may be capable of being incorporated into IRP modeling runs. Such an approach will require extraordinary granular knowledge of the distribution system and distribution system assets which at present simply does not exist.

Therefore, Staff's recommended framework presents a compromise in order to accelerate learning while meeting legislative and Commission expectations. While Staff agrees in principle with Oregon Solar Energy Industries Association (OSEIA) and Renewable Northwest's comments that a highly detailed system evaluation is optimal, the timeline for delivery of such a product is unworkable. Therefore, Staff moves the present recommendation with an understanding that the Commission will support the ongoing evolution of storage system evaluations as more data becomes available.

Due date for draft Storage Potential Evaluations

Staff, utilities, and other stakeholders are concerned about the timeline for system evaluations. The June 1 draft Storage Potential Evaluation date is only 8 weeks away from a Commission acceptance of this memorandum leaving the utilities little time to modify their current approach. Additionally, utilities and stakeholders worry that the January 1, 2018, deadline is very soon after utilities receive comments on their draft evaluations and that the final evaluations will need more preparation time in order to be more robust than the initial draft evaluations. To alleviate some anxiety and be responsive to utility and stakeholder concerns, Staff recommends that the Commission allow the utilities to file their draft evaluation between June 1 and July 15, 2017.

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Staff also recommends the Commission clarify that a special public meeting be held 30 calendar days from the date of the last utility submittal. While this approach may require two separate special public meeting it will address several stakeholder comments; 1) that the June 1 draft evaluation submittal date be extended, and 2) if the draft submittal date is extended that the July 31 special public meeting for receiving stakeholder comment be extended to allow stakeholders time to thoroughly review and prepare robust comments.

Resource Agnosticism and Technology Inclusivity

Several stakeholders submitted comments stating concern that the Commission and Staff process may favor battery technology for energy storage projects.

At least one stakeholder raised in comments and at workshop meetings that the Commission should not rule out thermal energy storage as a viable energy storage opportunity or at least not view this technology and strategy solely as a demand response resource.

Water heaters and some commercial agricultural spaces, as well as commercial HVAC applications, are capable of storing energy to ride through peak usage periods. Additionally, some technology applications can allow water heaters to store energy as heat or curtail warming periods to provide fast acting energy services. Stakeholders wanted to highlight these capabilities and have them defined as energy storage. Staff has no recommendation on this issue as the process should be able to identify, assess and choose the correct ESS.

Several parties have intervened in docket UM 1751 in an effort to assure that the development of tools do not preclude or impair the ability of pumped hydro technologies to be considered as viable energy storage resources. There was some concern from these parties that Staff, the Commission and stakeholders are overly focused on battery technology. Thus, these stakeholders wanted to remind all involved in UM 1751 that the legislation is technology agnostic, therefore our work needs to remain technology agnostic.

Staff believes the Staff Recommendation document attached in Appendix A is resource and technology agnostic. Staff has gone a step further in this memorandum in suggesting that PGE's proposal to only review one type of technology is inappropriate. Additionally, Staff points out that the acquisition requirement of 5MWh and the resource acquisition cap outlined in the legislation does make consideration of traditional large supply side pumped hydro units difficult, unless the Commission exercises its discretion to lift the procurement cap.

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Procedural

PacifiCorp asks the Commission to clarify whether the date on page 9 of Order No. 16-504, in the first full paragraph, in the sentence "We will hold a special public meeting by July 1, 2017, for Informal input from the Commission and stakeholders," should be July 31, 2017, to be consistent with item 3 on the same page that states: "The Commission and stakeholders will have the opportunity to review and comment on the draft evaluations We will hold a special public meeting by July 31, 2017, for informal input from the Commission and stakeholders on the draft evaluations."

Procurement

With regard to the requirement stated in HB 2193 (Section 2 (1)) "... an electric company *shall procure* on or before January 1, 2020, as part of project described in section of 3 of this 2015 Act" Pacific Power interprets "shall procure" to mean that contracts are in place to engineer, procure and construct or implement the selected energy storage projects.

Staff sees no reason to conclude this interpretation is not valid. However, to assure Pacific Power that their interpretation is correct Staff recommends the Commission validate Pacific Power's interpretation.

PROPOSED COMMISSION MOTION:

- 1) Adopt Staff recommended framework for Storage Potential Evaluations that addresses items (a) through (g) listed in section A(3)(1) of Commission Order No. 16-504.
- 2) Extend the due date for utilities' draft evaluations from June 1, 2017, to no later than July 15, 2017, and clarify that the Commission will hold a special public meeting for stakeholder input within 30 calendar days of the date of the last submitted draft Storage Potential Evaluation.
- 3) With regard to the requirement stated in HB 2193 (Section 2 (1)) "... an electric company *shall procure* on or before January 1, 2020, as part of project described in section of 3 of this 2015 Act....", validate Pacific Power's interpretation that "shall procure" to mean that contracts are in place to engineer, procure and construct or implement the selected energy storage projects.
- 4) Adopt Staff's nine recommendations regarding requirements for system evaluations.

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APPENDIX A

UM 1751, Order 16-504 Staff Recommendation Addressing Items (a-g) from section A(3)(1)

Establish a consistent list of definitions of key terms

Staff endorses using the US Department of Energy Glossary of Energy Terms available at <https://energy.gov/eere/energybasics/articles/glossary-energy-related-terms>.

Additionally, Staff offers the following terms and definitions:

Energy Storage System - means a technology that is capable of retaining energy, storing the energy for a period of time and delivering the energy after storage.⁷

Use Case - A specific deployment of a storage system for one or more applications and/or one or more benefits.

Benefits-stacking - The ability for a technology or system to generate revenue, avoid costs, or otherwise generate value for utilities and customers by providing multiple compatible applications is referred to as "benefit stacking. Compatibility is measured in terms of a technology's ability to technically provide and operationally manage the applications included in the benefits stack. When benefits are stacked, they must be co-optimized in order to guard against double-counting of benefits.

Energy storage technology descriptions

Staff endorses the use of, **DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA**, Sandia National Laboratories, Akhil, Huff et al (September 2016) for a list electricity storage technologies, see Chapter Two.

Establish a consistent list of use cases or applications to be considered in the evaluation

Energy Storage Use Cases

Current Use Cases Identified by Staff:

Category	Service	Value
Bulk Energy	Capacity or Resource Adequacy	The ESS is dispatched during peak demand events to supply energy and shave peak energy demand. The ESS reduces the need for new peaking power plants.
	Energy arbitrage	Trading in the wholesale energy markets by buying energy

⁷ House Bill 2193 Section 1(2)

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Category	Service	Value
		during low-price periods and selling it during high-price periods.
Ancillary Services	Regulation	An ESS operator responds to an area control error in order to provide a corrective response to all or a segment portion of a control area.
	Load Following	Regulation of the power output of an ESS within a prescribed area in response to changes in system frequency, tie line loading, or the relation of these to each other, so as to maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits.
	Spin/Non-spin Reserve	Spinning reserve represents capacity that is online and capable of synchronizing to the grid within 10 minutes. Non-spin reserve is offline generation capable of being brought onto the grid and synchronized to it within 30 minutes.
	Voltage Support	Voltage support consists of providing reactive power onto the grid in order to maintain a desired voltage level.
	Black Start Service	Black start service is the ability of a generating unit to start without an outside electrical supply. Black start service is necessary to help ensure the reliable restoration of the grid following a blackout.
Transmission Services	Transmission Congestion Relief	Use of an ESS to store energy when the transmission system is uncongested and provide relief during hours of high congestion.
	Transmission Upgrade Deferral	Use of an ESS to reduce loading on a specific portion of the transmission system, thus delaying the need to upgrade the transmission system to accommodate load growth or regulate voltage or avoiding the purchase of additional transmission rights from third-party transmission providers.
Distribution Services	Distribution Upgrade Deferral	Use of an ESS to reduce loading on a specific portion of the distribution system, thus delaying the need to upgrade the distribution system to accommodate load growth or regulate voltage.
	Volt-VAR Control	In electric power transmission and distribution, volt-ampere reactive (VAR) is a unit used to measure reactive power in an AC electric power system. VAR control manages the reactive power, usually attempting to get a power factor near unity (1).
	Outage Mitigation	Outage mitigation refers to the use of an ESS to reduce or eliminate the costs associated with power outages to utilities.
	Distribution	Use of an ESS to store energy when the distribution system is

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Category	Service	Value
	Congestion Relief	uncongested and provide relief during hours of high congestion.
Customer Energy Management Services	Power Reliability	Power reliability refers to the use of an ESS to reduce or eliminate power outages to utility customers.
	Time-of-Use Charge Reduction	Reducing customer charges for electric energy when the price is specific to the time (season, day of week, time-of-day) when the energy is purchased.
	Demand Charge Reduction	Use of an ESS to reduce the maximum power draw by electric load in order to avoid peak demand charges.

Source: Modified from Akhil et al. 2015.

Proposal - time frame for analyses

Staff recommends that the time frame for the initial system analysis as required to define the landscape of opportunities, including potential sites for energy storage, be 10 years.

For the proposals due on January 1, 2018, the analysis time frame should be equal to the lifetime and life-cycle cost of the proposed energy storage systems. Life-cycle costs should consider the depth and duration of cycling, per anticipated use. Technology type will affect total life-cycle costs. Any contractual warranty should be considered as part of storage life-cycle costs. Additionally, analysis should consider tax, insurance, overhead, interconnections, returns to investors, installation costs, site development costs, power conversion systems and other costs as appropriate. A contingency cost may be added, but should be noted on a separate line item for transparency.

Determining the valuation methodology or methodologies for estimating storage potential in each use case or application

Staff recommends using a relatively straightforward valuation approach. When services can be correlated to market-based benefits, a market valuation should be used for such identified services. When an entity is participating in the Energy Imbalance Market (EIM), then EIM market-based values should be used for EIM services. When calculating avoided costs, the methodology used should generally rely on comparison of the next-best alternative used to provide the service being analyzed for valuation. Staff has identified the following factors which must be considered in any valuation analysis: energy costs, efficiency losses, ability to operate in an optimal manner to realize benefits, breadth of services offered by the storage unit and of those which services can be co-optimized. Any single use would rarely yield positive returns on investment; services usually must be bundled and co-optimized.

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Illustrative Valuation Approaches

Service	Value
Energy arbitrage	Profit of trading in Mid-C or EIM, as appropriate, (peak vs. off-peak) while accounting for round-trip efficiency losses and accounting for variable operations and maintenance (O&M) costs.
Regulation	Cost of next-best alternative for providing service based on either historic EIM prices, if applicable, or production costs while accounting for energy losses and variable O&M costs.
Spin/Non-spin Reserve	Cost of next-best alternative for providing service based on either historic EIM prices, if applicable, or production costs. The spin and non-spin reserve bid or amount provided * the reserve price or avoided cost.
Load Following	Cost of next-best alternative for providing service based on either historic EIM prices, if applicable, or production costs, while accounting for any efficiency losses and variable O&M costs.
Voltage Support	Cost of next-best alternative for providing service based on production costs.
Black Start Service	Cost of next-best alternative for providing service based on production costs.
Capacity	Incremental slice of next best alternative adjusted for incremental capacity equivalent of energy storage in relation to next-best alternative (e.g., combustion turbine).
Distribution Upgrade Deferral	Present value difference in cost to ratepayers of distribution asset investment

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	deferred due to presence of energy storage.
Transmission Congestion Relief	Benefit as assigned through BPA-sponsored program.
Transmission Upgrade Deferral	Present value difference in cost to ratepayers of distribution asset investment deferred due to presence of energy storage.
Volt-VAR Support	Reduction in cost due to enhanced distribution efficiency, reductions in cap switching events or reduction in required distribution-level assets (e.g., capacitors/regulators).
Demand Response	Measured in terms of either existing utility-sponsored program or through enlisting in BPA-sponsored program
Power Reliability	Estimated in terms of avoided interruption costs to customers and lost sales or avoided reliability-based investment costs to the utility.

Use case methodology input

Commission Staff must be able to validate the assumptions and methods used to evaluate each use case assessment. Thus, utilities should submit reports documenting the approach used to estimate the value associated with the service(s) provided by the energy storage system. Here we offer additional guidance and illustrative methodology sections presented at an appropriate depth for two use cases: capacity/resource adequacy and distribution deferral. The illustrative methodology descriptions were modified from Balducci et al. (2013).

Capacity or Resource Adequacy

The basis for estimating the capacity benefit of energy storage is typically either the reduced or avoided cost of an incremental slice of a new peaking plant or a capacity price set through a local market or contract. Capacity is often referred to as resource adequacy.

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- Basic Assessment of Capacity Benefit = Capacity Payment (\$/kW-year) * Incremental Capacity Equivalent (ICE) of Energy Storage.
1. The capacity addition cost is calculated based on an increment of an installed cost of the next best alternative – e.g., a simple-cycle or combined-cycle combustion turbine technology. An annual fixed charge rate is used to determine the installation cost in terms of a \$/kW-year metric. Annual fixed O&M cost would also be included in the benefit estimation.
 2. ICE represents the availability of the resource in relation to the next best alternative against which it is being compared. Thus, if an energy storage device has only 60 percent of the reliability of a combustion turbine, it would only be assigned 60 percent of the benefit. ICE is typically calculated by performing a loss of load probability analysis or through some form of a performance test. Thus, if the incremental cost of a peaking plant equals \$150/kW-year, the capacity value attributable to energy storage would be \$100/kW-year. Alternatively, energy storage could be subject to a performance standard or test. For example, if the system were required to provide four hours of continuous energy during system peaks, a 1MW / 1MWh could only provide 250 kW of capacity benefit. If a utility does not currently need additional capacity, the benefit might not accrue immediately but could be of value later in its economic life.

Illustrative capacity or resource adequacy methodology description. The basic assumption governing the capacity value analysis is that an ESS could offset an increment of an investment in an F-Class simple-cycle turbine with a peak winter capacity of 221 MW. For example, adding the 5 MW system at Site A was assumed to offset a 5 MW equivalent of a peaking turbine. A detailed pro forma was built to estimate the revenue requirements for the combustion turbine. The capital cost of the turbine was estimated at \$202.2 million (\$915 per kW), and that value was inflated to \$228.8 million for the 2018 analysis base year. Total operations and maintenance costs on the combustion turbine were estimated at \$20 per kW-year and the book life of the asset was 35 years. The net present value (NPV) revenue requirements for the turbine totaled \$1,616 per kW. Further assumptions were required to determine the line loss gross-up, avoided reserves and incremental capacity equivalent as follows:

- The ESS is assumed to avoid 5 percent in line losses when compared to centralized generation.

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- Though the ESS is modular and resilient, Utility A does not credit the system with an avoided reserve requirement.
- Given that storage does not have extended discharge capabilities, unlike a combustion turbine, it may not be as useful to Utility A for both peaking events and contingency events when extended duration may be needed. With that noted, Utility A performed an incremental capacity equivalent (ICE) analysis for an energy storage device with the characteristics of the proposed battery system and found the ICE to be 100 percent provided the ESS can supply four hours of energy.

Based on these assumptions, the capacity value was set at \$1,697 per kW or \$142.21 per kW per year.

To determine the hours when energy storage would be needed to provide capacity services, hourly system-wide load forecast data were obtained for 2018. The capacity trigger was set at the peak capacity minus the power capacity of the ESS placed at Site A. When the peak hourly load was forecast to exceed this value, the ESS will be called upon to meet the load requirement.

An alternative to the peak-driven basis is the use of Mid-C transmission contracts as the foundation of the valuation assessment. Mid-C is a reference to the Mid-Columbia transmission system, which delivers generation from dams along the Columbia River located between Oregon and Washington. In the short-run, the value of adding storage could be that Utility A is enabled to shed or re-sell portions of Mid-C contracts. Utility A currently relies on approximately 1,500 MW of transmission to acquire energy and capacity from the market, and holds a multitude of Mid-C transmission contracts with various termination dates. These contracts only need to be renewed for five-year terms to preserve Utility A's unilateral roll-over rights in the future. In any given year, Utility A has the option to renew a portion of Mid-C capacity and reevaluate the Mid-C transmission need. This scenario does not fully account for generation costs and given the 5-year planning horizon around the decision to invest in storage, the Mid-C scenario was not selected as the base case.

- **Distribution Deferral.** There are opportunities for energy storage to defer investment in several distribution assets. The value of cost deferral can be significant due to the nature of utility cost accounting. For example, if an energy storage system could be used to shave local load peaks, resulting in deferral of a \$10 million substation for five years, the benefit would be \$3.2 million. Present value costs are estimated by dividing the cost of the asset by one plus the discount rate

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raised to the number of deferral years. If the discount rate was 8 percent, moving the deferral out four years reduced the present value cost of the asset to \$6.8 million (\$10 million/ 1.08^4).

- Benefit Calculation = Cost of the Proposed Investment – (Cost of the Proposed Investment / $(1 + \text{Utility Cost of Capital})^{\text{Number of Years the Investment is Deferred Due to the Presence of Energy Storage}}$).
- The cost of the proposed investment includes all revenue requirements for the system, including installation, information technology, site and civil engineering, power conversion system and all taxes, insurance and borrowing costs.
- The weighted average cost of capital is typically used as the discount rate, and it represents the weighted average of all the various debt instruments used by the facility.
- The number of years the investment is deferred results from an assessment of the capacity of energy storage to reduce peak load or wear and tear on existing distribution assets.
- If the use of energy storage eliminates the need for the distribution investment, the entire cost of the asset would be avoided.

Distribution Deferral Estimation. Utility A has considered many options for adding additional capacity at Site A but currently favors adding a new substation near existing Substation A. The estimated capital cost of the new 25 megavolt-ampere (MVA) substation would be \$10.5 million in 2018. The deferral value (\$5.2 million) is calculated as the difference in the NPV revenue requirements between building the new substation as planned versus deferring it for nine years. The revenue requirement calculation is based on a pro forma reflecting the full cost that would be incurred by Utility A customers from building and operating any new capital upgrades. Utility and general economic parameters governing the analysis are presented below.

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Utility Description Data and General Economic Parameters

Utility Description Data

Effective Income Tax Rate x%
Weighted Cost of Capital x%
Annual Other Taxes and
Insurance Premiums as
Fraction of Capital Investment x%
Base Year for Dollars X

General Economic Parameters

Rate of General Inflation x%
Escalation Rate for
Capital Costs x%
Escalation Rate for
Operating and
Maintenance Costs x%

To determine the number of deferral years, forecasts of peak events were used to construct the 2/1/2011 curve shown below. The orange dotted line in the figure shows the 58 MW planning trigger, while the green dotted line demonstrates the capacity with the 4 MW ESS added to the existing substations. Note that it would take roughly two to three years to plan, permit and construct a substation once the trigger has been reached. The figure shows that adding energy storage is forecast to defer the need for the new substation from 2015 to 2024. Thus, the deferral period was estimated at nine years.

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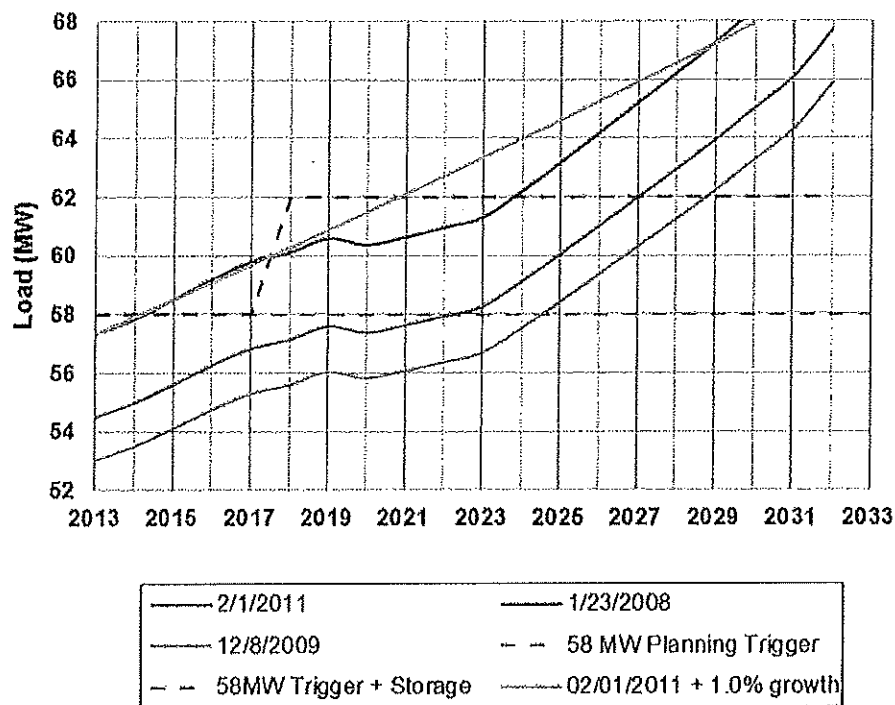


Figure 3.13. Forecast Load Growth (Substations A and B)

The load forecast was applied to 2016, 15-minute data registered at Substations A and B. When the load exceeds the 58 MW load trigger, the ESS would be engaged to provide additional power to the system. These hours were identified and along with the value of the deferral service, input into the optimization tool.⁸

Proposal for establishing criteria for identifying the main opportunities for investment in storage

Staff views it as essential that the approach used to identify system locations with the greatest storage potential include:

- Technologies with varying degrees of maturity based on the US Department of Energy's Technology Readiness Assessment Guide, which establishes Technology Readiness Levels (TRLs), a common framework for commercialization of innovative technologies,

⁸ Balducci, P. C., Jin, D. Wu, M. Kintner-Meyer, P. Leslie, C. Daitch, and A. Marshall. 2013. Assessment of Energy Storage Alternatives in the Puget Sound Energy System – Volume 1: Financial Feasibility Analysis (pp. 3.21, 4.1-4.2). Richland, WA.

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- Different ownership models,
- Grid placements at the transmission and distribution levels, and
- Locations where energy storage can serve multiple use cases.

Additionally, Staff recommends looking to features in Order No. 16-504 such as cost effectiveness, diversity of ownership types, diversity of technology, utility learning and strategic location.

"Criteria" suggests a more rigorous review than "factors" for consideration. Order No. 16-504 does not prescribe criteria but indicates several topics that are encouraged for utility investigation and could be considered potential criteria for both providing a complete suite of proposals and for evaluating proposals once submitted.

Looking to HB 2193 we find the following objectives:

- Deferred generation and T&D investments
- Reduced need for generation during peak demand
- Improved renewable resource integration
- Reduced greenhouse gas emissions
- Improved reliability of transmission and distribution systems
- Reduced portfolio variable power costs
- Any other value reasonably related to application of energy storage

HB 2193 directs the Commission to consider whether each energy storage proposal meets the established guidelines and strikes a "reasonable balance" for ratepayers and utility operations, but also to consider whether the proposal is in the public interest. Section 3, (3)(a)(C).

Staff additionally recommends criteria should include items from Order No. 16-504, which each utility will need to address in their project proposals such as:

1. Cost-effectiveness

Staff recommends leveraging the benefit-cost ratios established for energy efficiency measures. This includes the resource replacement comparison costs. Stakeholders should first develop a list of questions that should be addressed before establishing a cost effectiveness methodology. Where resources exist that can be leveraged or used to address these questions such should be identified and used if only during this initial phase of storage resource evaluation.

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Additionally, the UM 1751 process should lead to a list of other quantifiable and non-quantifiable benefits that could be used to help buttress the case for investment approval such as:

- the overall cost is not great;
- the application provides a unique system or public benefit; or
- the success of the project could enable future cost-effective proposals.

2. Diversity

HB 2193 "directs us... to encourage electric companies to invest in different types of systems." [Order, p.2] Therefore, the Project Guidelines state that electric companies should propose energy storage projects that "balance technology maturity, technology potential, short- and long-term project performance and risks, and short- and long-term potential value." [Guideline 3.]

A. Maturity and Potential

Only two storage technologies can reasonably be considered mature: pumped storage hydropower and lithium-ion batteries. The remainder represents a tiny fraction of deployed systems worldwide today. According to the DOE Energy Storage Exchange, lithium-ion technologies represent 65 percent of all 1.1 GW of battery storage deployed domestically, and pumped storage hydropower represents 110 GW worldwide. The DOE Hydropower Vision states that available pumped storage is 21.6 GW nationally or 97 percent of the total utility-scale energy storage in the United States.⁹

Example criterion:

Staff suggests utilities propose a minimum of one "mature technologies" project and one "potential technologies" project.

B. Ownership models

Energy storage systems around the U.S. are funded under a variety of ownership models, including utility-owned, customer-owned or through third-party agreement. Each structure has their relative merits and drawbacks, including those related to risk, cost efficiencies, tax implications and access to markets.

Example criterion:

All proposals must evaluate the relative merits between utility, customer and third-party

⁹ Energy Storage Exchange <http://www.energystorageexchange.org/>
Hydropower Vision (2016) <https://energy.gov/eere/water/articles/hydropower-vision-new-chapter-america-s-1st-renewable-electricity-source>

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ownership models as it relates to cost-effectiveness.

C. Differentiating Uses and Applications

Electric companies are also encouraged to submit proposals for systems that will be used for different purposes. [Guideline 2.] The goal of this guideline may be to increase utility learning, test actual values against estimated values, and develop experience with key features of storage systems that may improve future performance and cost-effectiveness, such as communications and supporting electrical equipment.

Example criterion:

Utilities should provide storage proposals that serve at least two primary purposes, such as:

- Primarily designed to provide energy or primarily provide capacity.
- Provide customer-focused behind-the-meter services, solve distribution system-level challenges, or address transmission system issues.
- Serve additional public benefits, such as resiliency benefits through placement at a critical infrastructure site or emergency services center.

3. Strategically Located

Under Guideline 5, "Electric companies are encouraged to submit projects that are strategically located to help defer or eliminate the need for system upgrades, provide voltage control or other ancillary services, or supply some other location-specific service that will improve system operation and reliability."

This criterion could be relatively straightforward to apply. Proposals are required to indicate estimated benefits from distribution or transmission deferral, or voltage support, or another critical locational need such as the resiliency benefits discussed above.

Example criterion:

Proposals must appear to offer location-specific benefits (non-zero values). Proposals will receive greater weight where these locational benefits are especially high (produce at least 30 percent of the estimated benefit of the system).

A. Grid placement

Under the AB 2514 procurement mandate in California, utilities are required to procure energy storage at varying points of interconnection, including transmission, distribution and customer (behind-the-meter) deployments. The Commission could encourage utilities to evaluate energy storage at various interconnection points.

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Example criterion:

Proposals must consider the tradeoffs associated with deploying energy storage at the transmission, distribution and customer (behind-the-meter) levels, and evaluate projects located in at least two of these interconnection levels. Companies are required to submit costs and benefits and "to evaluate the cost-effectiveness of the project in a manner we [the Commission] establish by rule or order."

Determine the approach for identifying system locations with the greatest storage potential

Staff recommends the following approach to calculating an estimate of high-value applications. Staff recommends establishing the following set of initial criteria to be used in identifying system locations with the greatest storage potential:

- Total capacity of the storage unit should be large enough to meet the challenges identified while also addressing other potential use cases.
- Locational planning information should be used such as expected load growth and historical growth patterns, expected electric customer usage requirements, or demand. These last criteria would incorporate demand side interests for resiliency and reliability and may capture interest from high use customers in customer-sited energy storage investments.
- The investment needed for both the storage infrastructure and the grid infrastructure whether or not storage is used.
- Reliability and safety statistics or metrics such as SAIDI or SAIFI should be a factor in matching value energy storage.
- Staff believes the peak load (limited energy requirements) should be a factor in identifying system location. However, Staff has separated peak load from locational planning information because peak load may be locational factor for feeders or substations, but may also be a grid level concern that storage can address regardless of its location.
- Utilities should consider the administrative permitting and approval challenges, and physical space limitations when assessing whether a location has greatest value to the utility system.
- Utility side of the meter, reviewing distribution planning for matches, potential distribution substations/feeder capacity/ congestion issues.

Establish the level of detail required in the evaluation results and required supporting data

Staff recommends a list of minimum criteria for evaluation and suggests use of one comparable associated energy storage model. Utilities are free to use one proprietary

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model as long as they give the Commission, Staff and stakeholders the required data to validate their results. Any model or approach used by the utility assessing energy storage must meet the following minimum criteria:

- Capacity to evaluate sub-hourly benefits,
- Ability to evaluate location-specific benefits based on utility-specific values,
- Enables co-optimization between services,
- Capacity to evaluate bulk energy, ancillary service, distribution-level and transmission-level benefits,
- Ability to build ESS conditions (e.g., power/energy capacity, charge/discharge rates, charging/discharging efficiencies) into the optimization,
- Methods must be clearly detailed and results specified.

Evaluation results should be detailed enough to support modeling for individual energy storage system projects. Staff must be able to validate the assumptions and methods used to evaluate the cost effectiveness of each proposed ESS in the final proposals. Utilities should therefore submit reports documenting the approaches used to estimate the value associated with the service(s) provided by each ESS. Staff will need a detailed discussion of the methods used, including the basis of assigning value to each service. Further, data used as input into the valuation models will need to be provided to Staff. This data should include the hourly or sub-hourly economic value of each use case, as appropriate, and the power/energy demands each use case places on the ESS. All battery characteristics and financial data will also need to be provided to Staff, as necessary for validation using publically available models, including the PNNL's Pacific Northwest National Laboratory's Battery Storage Evaluation Tool.

Appendix B

First Round Comment Summary (February 8 Comment Period)

Comment Number	Section	Comment	PUC Staff Response
<i>(write in name of reviewing organization; further breakdown by individual reviewer if desired)</i>			
Commenter #1: PacifiCorp			
1.	Use cases	PacifiCorp agrees to the addition of the word "utility" in the definition of Value for Customer Services, Power Reliability	Staff recognizes that power reliability also generates benefits to utilities and as such, should be added as a use case in the distribution system.
2.	Use cases	PacifiCorp intends to choose specific use cases from Staff's proposed list that are most useful and applicable to PacifiCorp's needs.	Staff agrees that the use case list provided is not absolute and that utilities should pull from this list as appropriate and add use cases if not adequately captures in the current use case matrix.
3.	Definitions	PacifiCorp agrees with the change to the definition for benefit-stacking developed in the workshop, "The ability for a technology or system to create or receive value or avoided costs for utilities and customers by providing multiple compatible application is referred to as 'benefit stacking.'"	The definition has been changed to, "The ability for a technology or system to generate revenue, avoid costs or otherwise generate value for utilities and customers by providing multiple compatible applications is referred to as "benefit stacking."
Commenter #2: Renewable Northwest			
4.	Use cases	We suggest deleting the term "off-peak" as it has a specific definition (hours and days of the week) which no longer accurately reflects all of the energy arbitrage opportunities and benefits given the current changing market conditions.	Staff agrees and has changed the use case list.
	Use cases	Transmission Services (Upgrade Deferral): We propose adding the following clause at the end of the definition of the use case: "or avoiding the purchase of additional transmission rights from third-party transmission providers."	Staff agrees and has adopted this language.

Comment Number	Section	Comment	PUC Staff Response
6.	Use cases	We support EQL's suggestion to add or change Demand Charge Reduction to "Customer Energy Management."	The Staff recognizes the input from several stakeholders who have suggested aggregating several customer-oriented use cases into a single "customer energy management" or "bill reduction" use case. The Staff has not adopted this recommendation, however, because customer energy management comprises several discrete use cases as previously defined. For example, time-of-use charges and demand charges send two different price signals and as such should be treated differently. With that noted, the use case list should not be viewed as absolute. Utilities may add use cases as appropriate based on project-specific opportunities.
7.	Criteria for Identifying Opportunities	We support the utilization of the Technology Readiness Level approach developed by the National Aeronautics and Space Administration.	US DOE commonly uses TRL 1-9 as an indicator of commercialization progress. In some instances, TPL (Total Performance Levels) are used for less mature technologies such as wave and tidal energy. PNINL used the TRLs and manufacturing readiness levels in a report prepared for DOE in 2012
Commenter #3: Small Business Utility Advocates			
8.	Use Cases	It is important for the OPUC to consider aggregation of behind the meter energy storage resources deployed by small businesses and others as a resource.	Staff does not have an objection to aggregation of behind the meter storage. However, Staff does not feel that an express acknowledgment of aggregation is needed. Utilities are free to propose an aggregated storage project. However, Staff notes the intent of the statutory charge was to gain learnings from storage technologies. Thus

Comment Number	Section	Comment	PUC Staff Response
			aggregation should contemplate robust utilization and exploration of various services optimally utilized to support identified system needs.
Commenter #4: Portland General Electric			
9.	Methodology	<p>PGE proposes to examine known distribution constrained locations on the system and the following generic locations in the storage potential evaluation:</p> <ol style="list-style-type: none"> 1. At a substation connected at the distribution level 2. Distributed storage along a distribution feeder 3. At a customer location, in front of the meter 4. At a customer location, behind the meter <p>We plan to model as many of different, applicable services for each project type/location as possible, including bulk energy, ancillary services, distribution services, and customer services. When we submit our final project proposals, we expect to specify precise locations for energy storage projects, and expect that the evaluations performed at that time to specify the benefits from storage at such precise locations. Those proposals will also include a discussion of how specific locations were determined.</p>	<p>Staff does not accept all elements of the proposed approach. More specifically, the near-term system-level analysis should include transmission-level investments as part of the analysis, and it should also identify a number of high-value locations for energy storage. Staff assumes there will be a down-selection process between June or July 2017 and January 2018. Thus, the sites identified as part of the system-level analysis should not constrain the final selection process.</p>
10.	Analysis Time Frame	<p>PGE proposed the use of 2021 as a base year for modeling purposes.</p>	<p>The use of complex models (e.g., production cost models) to define the benefits associated with specific use cases (e.g., ancillary services) can justifiably result in limiting the number of analysis years for certain services. Thus, the use of complex models for a base year analysis for some use cases is appropriate. However, the analysis of certain benefits (e.g., distribution deferral) may require an assessment that covers multiple years. While the base</p>

Comment Number	Section	Comment	PUC Staff Response
			year is appropriate, the utility will need to use the values estimated for that year and expand them over the economic life of the energy storage system.
Commenter #5: Unrecorded			
11.		One organization noted that we should consider distribution congestion management.	Staff believes inclusion of distribution congestion management is workable.

Second Round

Comment Summary (March 7 Comment Period)

Comment Number	Section	Comment	PUC Staff Response
<i>(write in name of reviewing organization; further breakdown by individual reviewer if desired)</i>			
Commenter #1: IREC or Interstate Renewable Energy Council, Inc.			
1.	Evaluation Study Requirements	Utilities should be required to study their systems as comprehensively as possible.	Staff agrees with IREC that there are many current and future benefits of requiring the utilities to provide as detailed evaluations as possible in the time allowed.
2.	Deadline for storage potential evaluation	The Commission should push back the deadline for the storage potential evaluations to give the utilities more time to conduct comprehensive assessments of their system needs.	Staff agrees that the utilities should have the option of filing later than June 1, 2017 if a better more detailed product can be developed.
3.	Approach of utility system evaluation	If the Commission requires storage potential evaluations by June 1 to inform the January 1, 2018 project proposals, the Commission should require an evaluation approach incorporating elements from both utilities' proposals.	Staff agrees that there is merit in finding a path forward that includes aspects of each utility's proposed system evaluation approach.
Commenter #2: CREA or Community Renewable Energy Association			
	Deadline for storage	CREA shares PacifiCorp's concern regarding the proposed timeline. As such they support PacifiCorp's request to delay the submittal date from June 1 to	Staff agrees that the utilities should have the option of filing later than June 1, 2017 if a better more detailed

Comment Number	Section	July 15, 2017	Comment	PUC Staff Response
	potential evaluation			product can be developed.
5.	The need to uniform but flexible criteria		CREA is generally supportive of the utilities' request to be granted reasonable flexibility in their responses. However, CREA supports the OPUC's effort to identify uniform criteria.	Staff agrees and has proposed several uniform yet flexible criteria.
6.	Including volt-var, transmission, quantifiable values of capacity, energy arbitrage, Volt-VAR control, outage mitigation and investment deferral		CREA supports the inclusion of the economic benefits from volt-VAR support, transmission level storage, quantifiable values of capacity, energy arbitrage, Volt-VAR control, outage mitigation and investment deferral. However, CREA does not support treating regulation, load following, reserves, black start, curtailment or renewable energy as optional to the analysis.	Staff supports CREA's position and would like to see as much analysis as possible to identify the value of these services that storage can offer.
7.	Technology readiness level and full lifecycle costs.		CREA supports consideration of criteria that include technology readiness level and full lifecycle costs as well as diversity of ownership types, technology and location.	Staff, as stated in the workshop, was able to find consensus on the use of technology readiness and full life cycle costs. The Commission has through Order No. 16-504 encouraged diversity or ownership and location.

Comment Number	Section	Comment	PUC Staff Response
8.	Concern that UM 1751 is not truly technology neutral.	CREA states by example that the process may not be technology neutral citing PGE statement that "focus should be on the attributes of technologies that are more prevalent in new storage installations today, like lithium ion batteries."	Staff agrees with CREA that the process should remain technology neutral. As explained to CREA and stakeholders Staff welcomes specific identification of where the process creates a barrier to participation for any eligible storage technology...
Commenter #3: OSEIA or Oregon Solar Energy Industries Association			
9.	Range of Storage Types	OSEIA urges the Commission to require a range in the types of storage technologies and projects considered by utilities.	Staff agrees that the utilities should analyze a range of storage types. The Commission in Order No. 16-504 encouraged the utilities to include a range of storage types, but did not establish a requirement. Staff is also concerned that PGE seems to limit their analysis to the lithium ion battery technology.
10.	Information Sharing	OSEIA believes it is essential to use open source models in order to allow for non-utility parties to be able to offer well-researched and equally-sufficient proposals.	Staff is supportive of using open source models as well but also want the utilities to be able to use other proprietary models offered by contractors. Therefore Staff is recommending that utilities not only thoroughly explain their processes to stakeholders but also supply the data used and the assumptions made to acquire the data point and supply the needed data for stakeholders to use in publically available models such as BSET or EPRI's ESVT model. Staff notes that these identified models are suitable for individual storage projects, not for system evaluations.
	Cost Effectiveness	OSEIA argues that discussions on "cost-effectiveness" need to include avoided costs in order to expand stakeholder understanding and	Staff supports a discussion of cost effectiveness but believes the legislature did not require these initial

Comment Number	Section	Comment	PUC Staff Response
12.	Timeline Extension	July 15 deadline for Energy Storage Potential studies seems reasonable to us.	storage proposals to be cost effective. Staff does believe that cost effectiveness should generally rely on comparison of the next-best alternative use to provide the service being analyzed for valuation. Lastly, Staff currently has no position on evaluating reliability and resiliency of storage combined with renewables.
13.	Procure	OSEIA also interprets "shall procure" in HB 2193 Section 2(1) as meaning that contracts are in place to engineer, procure, and construct or implement the selected energy storage projects by January 1, 2020.	Staff agrees.
14.	Customer-side storage	The proposals should include customer-side of the meter approaches as well as larger storage solutions.	Staff agrees.
Commenter #4: Renewable Northwest			
15.	Storage Potential Evaluations should be as comprehensive as possible	Despite timeline constraints Renewable Northwest believes the storage potential evaluations should be as comprehensive and faithful to the language in HB 2193 and Order No. 16-504 as possible. Renewable Northwest encourages the utilities and Commission Staff to ultimately recommend an approach that is still mindful of the system potential evaluation requirements in HB 2193 and Order No. 16-504. Renewable Northwest understands that time constraints may not ultimately allow utilities to conduct system potential evaluations at an ideal level of detail. However, we respectfully suggests that the framework for system potential evaluation that OPUC Staff ultimately proposes attempts to reconcile the language in	Staff is recommending an approach we believe balances the need for detail and the time constraints faced by the utilities, stakeholders and the Commission.

Comment Number	Section	Comment	PUC Staff Response
16.	PacifiCorp's request for an extension of the deadline	HB 2193 and Order No. 16-504 with the timeline for this storage program. Renewable Northwest is concerned that granting Pacific Power's deferral request, without simultaneously extending the stakeholder comment period, would limit the time stakeholders and storage companies have to review and comment on the draft studies to only two weeks. Two weeks is simply insufficient to thoroughly review the documentation and underlying data supporting these studies and does not afford stakeholders the opportunity to provide meaningful comment.	Staff is also concerned about submittal deadlines and allowing both utilities the time needed to fulfill expectations and allowing stakeholders enough time to review submitted materials.
17.	PacifiCorp's proposed approach to develop system potential evaluations	Renewable Northwest supports PacifiCorp's decision to conduct a RFP to obtain a consultant to prepare a storage potential evaluation plan and conduct an assessment of PacifiCorp's Oregon service territory. Renewable Northwest also supports PacifiCorp's plan to leverage its 2016 "Battery Energy Storage Study for the 2017 IRP" into its draft system potential study process. However, this does not appear to sufficiently form the underlying basis for a comprehensive system potential study. Additionally, Renewable Northwest considers "regulation, load following, reserves, black start, and curtailed renewable energy" to be fundamental components of any storage analysis. Renewable Northwest notes that if "avoided capacity" and "curtailed renewable energy" are quantified, it should be possible to estimate the reductions in CO2 emissions associated with the ESS.	Staff generally agree with Renewable Northwest comments and has attempted to address them with our recommendation to the Commission.
18. APPENDIX A	PGE's proposed approach to develop system potential evaluations	Renewable Northwest is concerned about PGE's limited focus on lithium ion battery technology. Renewable Northwest believes our view is that the utilities should provide at least a high-level review and analysis of all potential ESS applications and technologies. If certain applications and technologies do not warrant taking the next step and conducting more rigorous analysis, then the utilities should justify and defend that decision, provide the supporting	Staff shares Renewable Northwest's concern regarding PGE's focus on lithium ion battery technology and that utilities document the approach used to estimate the value of ESS's and provide stakeholders with the inputs and data used in their modeling efforts.

Comment Number	Section	Comment	PUC Staff Response
		documentation and data, and focus scarce time on the applications that appear most promising. Renewable Northwest agrees with PGE's comments on item 1(g) of the Storage Potential Requirements in Order No. 16-504 in that what is most important in this process, in terms of models used by the utilities, is that utilities document the approach used to estimate the value of ESS's and provide stakeholders with the inputs and data used in their modeling efforts.	
Commenter #5: ITM Power, Inc.			
19.	Definition of Storage	ITM suggests that it is important that the state not preclude evolving systems that are particularly suited to Oregon's seasonal and variable energy-supply mix and that will enable the state's policy move from fossil-sourced power generation to variable renewables, including enhanced efficiencies for the Northwest's uniquely valuable hydroelectric power resources. The examples of storage technologies used in the definition of Energy Storage are examples only.	Staff agrees with ITM that Oregon as a member of the Northwest leverage storage technology that is best suited for the Northwest's unique power system. Staff agrees that the examples given in the definition of Energy Storage are only intended as examples.
Commenter #6: Northwest Power and Conservation Council Staff			
20.	Locational Benefits should be included in the draft evaluations	Initial proposals for June 1 should not be submitted without locational benefits. This is a value stream which is not typically evaluated during planning processes and therefore it is very important to be able to review and provide public comment on their methodology prior to the submission of final proposals.	See Staff's recommendation in the March 21, 2017 Public Meeting Memorandum and in the Staff Recommendation document Appendix A of March 21, 2017 Public Meeting Memorandum.
21.	PGE should include an RFI	PGE has not included a component of an RFI in this process. This should be done to enable developers to provide up-to-date information.	See Staff's recommendation in the March 21, 2017 Public Meeting Memorandum and in the Staff Recommendation document Appendix A of March 21, 2017 Public Meeting Memorandum.
22.	Dispatch of Storage	Utilities should include language in the January 1, 2018 final proposals	See Staff's recommendation in the March 21, 2017 Public Meeting Memorandum and in the Staff Recommendation

Comment Number	Section	Comment	PUC Staff Response
		which ensures that they are planning to do more than manual dispatch, something like "An assessment of the technology and effort needed to automate the storage dispatch to achieve the full co-optimized benefits as predicted by planning tools".	document Appendix A of March 21, 2017 Public Meeting Memorandum.
23.	Response to Pacific Power Proposal	<p>I do not agree that a reliability/resiliency focused application is needed. A circuit suffering from reliability issues is likely to have high deferral value and resilience alone on an otherwise reliable circuit is extremely unlikely to outweigh high value deferral opportunities. Customer-sited storage should be added instead.</p> <p>I do not agree that the language "may be addressed" is appropriate for Quantifiable Values of regulation, load following, and reserves in particular. Not including these values would essentially repeat the narrow evaluation of storage in PacifiCorp's previous IRPs and would offer very little insight into the value of storage when considering stacked benefits.</p>	See Staff's recommendation in the March 21, 2017 Public Meeting Memorandum and in the Staff Recommendation document Appendix A of March 21, 2017 Public Meeting Memorandum.