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A DIVISION OF PACIFICORP

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April 2, 2018

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

RE: UM 1857 – PacifiCorp's Final Energy Storage Potential Evaluation and Final Storage Project Proposals

PacifiCorp d/b/a Pacific Power submits the enclosed Final Energy Storage Potential Evaluation and Final Storage Project Proposals, consistent with Oregon House Bill (HB) 2193 and Public Utility Commission of Oregon (Commission) Order No. 16-504, Order No. 17-118, and Order No. 17-375.

The enclosed Final Energy Storage Potential Evaluation and Final Storage Project Proposals can be summarized as follows:

Final Energy Storage Potential Evaluation
Following the filing of the Revised Draft Energy Storage Potential Evaluation on December 29, 2017, PacifiCorp has incorporated valuable feedback from critical stakeholders and Commission staff (Staff) to develop the Final Energy Storage Potential Evaluation enclosed. PacifiCorp has updated assumptions regarding in-service dates for net present value calculations and energy imbalance market escalation factors and ceilings, and performed an overall refresh using the Generation and Regulation Initiative Decision Tools model. This final evaluation represents PacifiCorp's best efforts to provide greater transparency into the evaluation methodology, further expand on each requirement as prescribed by legislation, and specifically address comments from Staff and stakeholders. Furthermore, this final evaluation provides a more thorough analysis regarding the benefits and avoided costs associated with energy storage at both a system level and project level, including an expansion of initial use cases investigated and the calculation of co-optimized benefits.

Final Storage Project Proposals
PacifiCorp has identified two pilot projects to achieve an aggregate capacity of 4 MW, or 11 MWh. The construct of each of these projects provides a controlled environment to explore multiple use case, address system needs as identified in the Final Energy Storage Potential Evaluation, and optimize system controls to maximize benefit from the technology. As requested by Staff and stakeholders, this final proposal includes specific plans and criteria for progression of the various phases of each pilot project, greater transparency into the costs

calculated for each of the projects, and a more thorough analysis of potential costs and benefits. PacifiCorp believes that these pilot projects meet the requirements of HB 2193 and Order No. 16-504, provide benefit to residents of Oregon, and allow PacifiCorp to experiment with energy storage in preparation for potential future wide scale deployment, while remaining fair and reasonable to customers.

Confidential information is designated as Protected Information under Order No. 17-274 and may only be disclosed to qualified persons as defined in that order.

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

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Informal inquiries may be directed to me at (503) 813-6583.

Sincerely,

Natasha Siores
Manager, Regulatory Affairs

Final Energy Storage Potential Evaluation

PacifiCorp

HB 2193, Order No. 16-504, Order No. 17-118, & Order No. 17-375

April 2, 2018

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Definitions of Common Terms/Acronyms

ACE	Area Control Error
BAA	Balancing Area Authority
BAL-001-2	NERC Real Power Balancing Control Performance Requirement
CCCT	Combined Cycle Combustion Turbine
CF Method	Capacity Factor Method
COB	California-Oregon Border
EIM	Energy Imbalance Market
EPC	Engineer, Procure, Construct (and Commission)
ESS	Energy Storage Solution
GRID	Generation and Regulation Initiative Decision Tool
HB 2193	House Bill 2193
IRP	Integrated Resource Plan
LAP	Load Aggregation Point
LOLP	Loss of Load Probability
NERC	National Electric Reliability Corporation
OFPC	Official Forward Price Curve
OPUC	Public Utility Commission of Oregon
PACE	PacifiCorp East
PACW	PacifiCorp West
PDDRR	Partial Displacement Differential Revenue Requirement
QF	Qualifying Facilities
RFP	Request for Proposal
RFI	Request for Information
RVOS	Resource Value of Solar
SCCT	Simple Cycle Combustion Turbine
T&D	Transmission and Distribution

Executive Summary

Following the filing of the Revised Draft Energy Storage Potential Evaluation on December 29, 2017, PacifiCorp, d/b/a Pacific Power, has incorporated valuable feedback from stakeholders and Commission Staff to develop this Final Energy Storage Potential Evaluation. This final evaluation represents PacifiCorp's best efforts to provide transparency into the evaluation methodology, further expand on each requirement as prescribed by legislation and Commission guidance, and specifically address Commission Staffs comments, which can be found in Section 2.0.

To complete the Final Energy Storage Potential Evaluation, PacifiCorp leveraged existing company tools and processes to ensure a robust, repeatable, and compliant storage potential evaluation. As described in more detail in Section 3.0, the following tools were used or adapted to model the potential benefits of energy storage on the PacifiCorp network for each use case.

Table 1 Final Storage Potential Evaluation Tools

Tool	Description
Integrated Resource Plan (IRP) - System Optimizer (SO) and Planning and Risk (PaR) Models[1]	- Prepared on a biennial schedule, the IRP uses the SO and PaR models to determine the long-run economic and operational performance of a range of resource portfolios to select a "preferred portfolio."
Generation and Regulation Initiative Decision Tools (GRID) Model[2]	- The GRID model simulates the operation of the PacifiCorp's power system on an hourly basis and provides more flexible and transparent results than the models used in the IRP. Access to the GRID model and the corresponding confidential data is available subject to a non-disclosure agreement. Under the Partial Displacement Differential Revenue Requirement (PDDRR) methodology, resources under consideration are added at zero cost. Partially displace resources in the IRP preferred portfolio based on their capacity contribution. - This tool is critical for deriving value for the capacity and ancillary services use cases.
EIM Dispatch Model	- The EIM Dispatch model combines resource dispatch characteristics with EIM operating processes and historical pricing results to estimate EIM benefits. - Critical for determining values for ancillary services use cases. - This tool is critical for deriving value for ancillary services.
Resource Value of Solar (RVOS) Model	- While originally developed to evaluate solar resources, the RVOS model can be used to evaluate any resource with fixed generation profiles and is used to complete capacity contribution calculations, energy arbitrage market value, and avoided line losses. - This tool is critical for deriving value from the energy arbitrage use case.

[1] A description of the SO and PaR models is available in Chapter 7 of the 2017 IRP, available online at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf

[2] Access to the GRID model is available subject to a non-disclosure agreement to protect confidential information.

Transmission and Distribution (T&D) Planning Studies	- This tool evaluates PacifiCorp's existing capacity and potential load growth over five and ten year planning horizons to identify a critical list of projects to mitigate potential system deficiencies. - This list of projects functions as a short list of potential locations to begin evaluating for both traditional and alternative resources, such as energy storage.
Alternative Evaluation Tool	- This tool screens the list of projects identified through the T&D Planning Studies for potential locations where energy storage is both technically feasible and cost competitive as compared to traditional solutions. - Projects that pass screening are flagged for detailed analysis, allowing energy storage to compete at the project level.
Request for Information (RFI) Analysis	- In alignment with HB 2193 and Order No. 16-504, PacifiCorp issued an RFI including approximate company load data and received information regarding market trends, benchmarks, available technologies, and potential qualified EPC contractors. See Appendix A for more details.

PacifiCorp leveraged these tools and the methodology described in Section 4.0 to determine both the maximum potential for energy storage per use case as well as the potential co-optimized value of energy storage on the PacifiCorp network. The results included in Figure 1 below were calculated for seven different scenarios, described in Section 6.0, which covered a range of co-optimization strategies and technology variance.

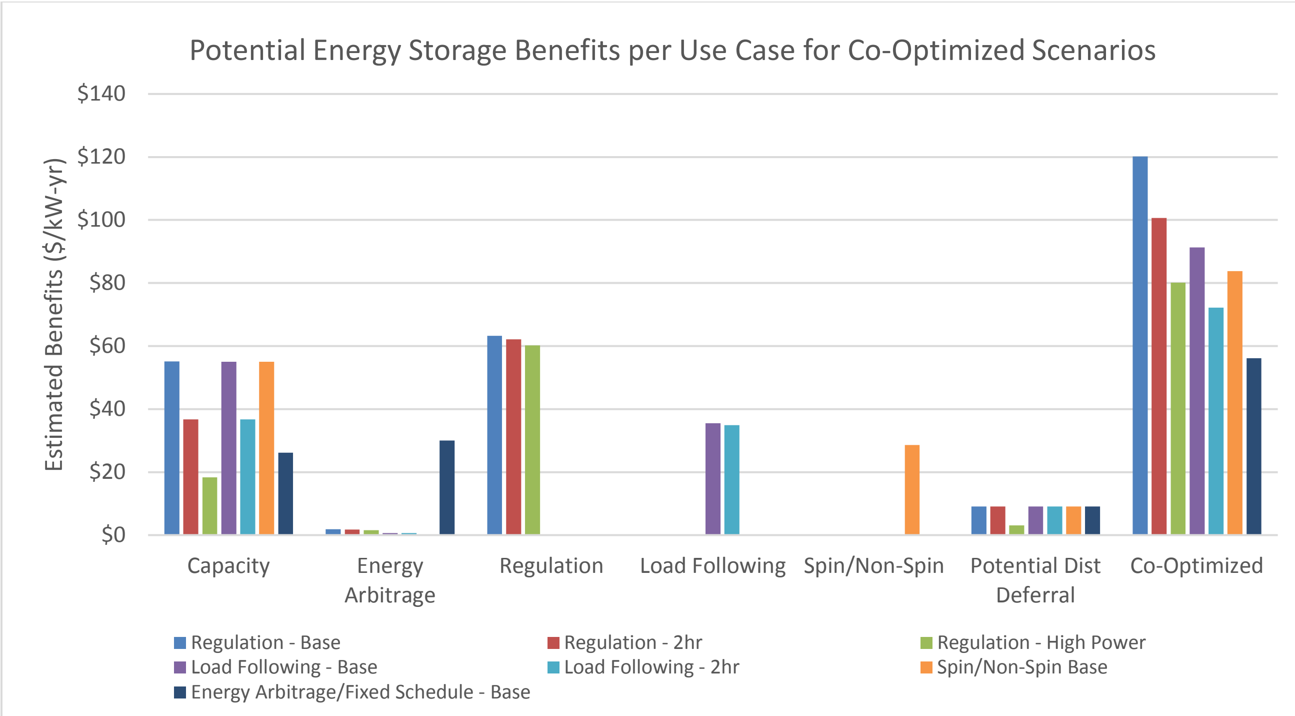

Figure 1 Potential Energy Storage Co-Optimized Benefits per Use Case

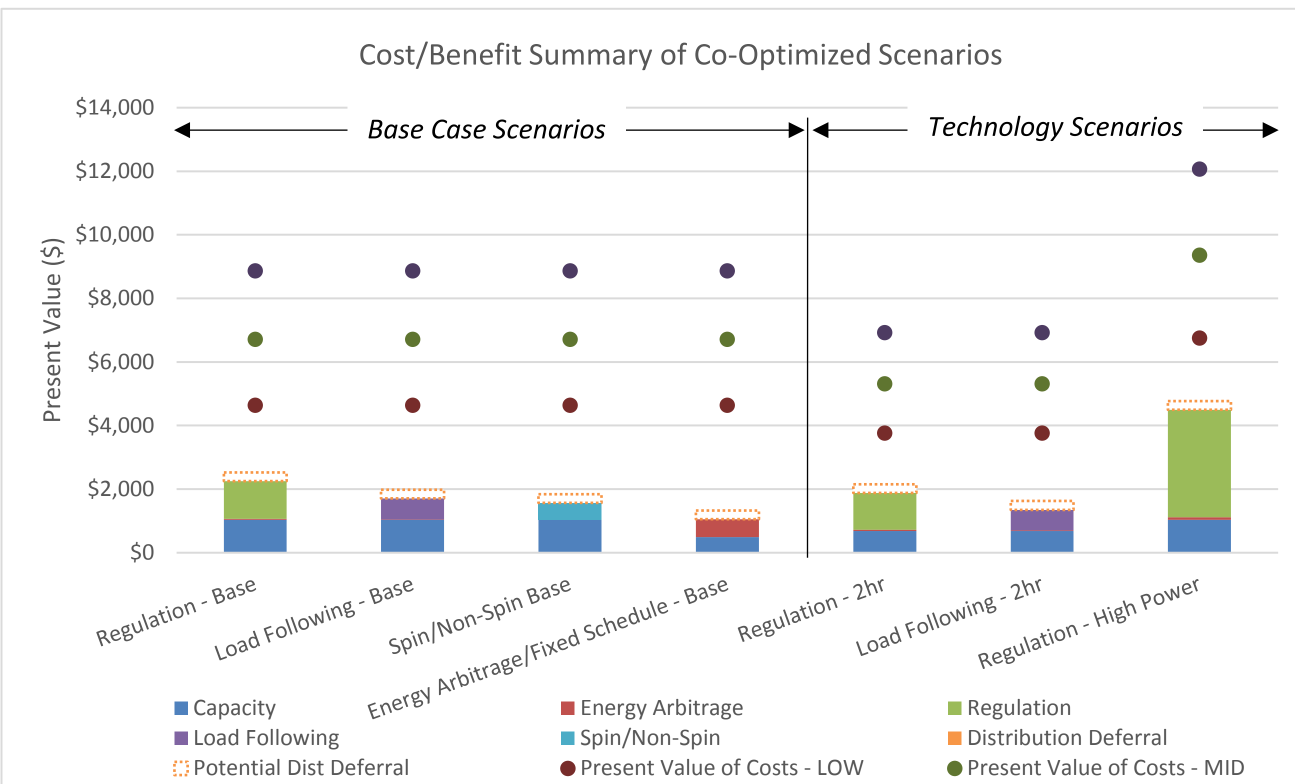

Figure 2 Cost/Benefit Summary of Co-Optimized Scenarios

Table 2 Summary of Co-Optimized System Level Cost/Benefit Analysis

	Base Case [2 MW x 3 hours] Co-Optimization Scenarios				System Level Technology Scenarios		
	Regulation - Base	Load Following - Base	Spin/Non-Spin Base	Energy Arbitrage/Fixed Schedule - Base	Regulation - 2hr [2MW x 2 hr]	Load Following - 2hr [2MW x 2 hr]	Regulation - High Power [6MW x 1 hr]
Potential Benefits ($/kW-yr)	$120.19	$91.28	$83.80	$56.17	$100.63	$72.18	$80.08
BCR Range	0.25 - 0.48	0.19 - 0.37	0.18 - 0.34	0.12 - 0.23	0.27 - 0.50	0.20 - 0.36	0.37 - 0.66
Avg NPV ($)	($4,463,049)	($5,004,189)	($5,144,261)	($5,661,500)	($3,429,759)	($3,962,354)	($4,857,768)

Energy Storage was not found to be cost effective in any modeled scenarios. However, this analysis demonstrates that a range of energy storage benefits and costs exists, highly dependent on use case parameters, such as reserving capacity for regulation as opposed to spin/non-spin reserve, and technology parameters, such as capacity or energy rating. This analysis also demonstrates that the greatest potential benefit from energy storage on the PacifiCorp network for all utility customers is likely achieved through co-optimizing around regulation, as highlighted in the table above.

PacifiCorp used this general principle and the list of critical projects identified through the T&D Planning Studies to evaluate potential locations for Pilot Project #1. Of 19 potential locations identified with transmission or distribution upgrade needs, 14 were located in Oregon, 12 of which could be deferred or resolved through energy storage technology, and three of which appeared cost-competitive. See table below.

Table 3 Short List of Locations Considered for Pilot Project #1

Potential Project Location	**Distribution Site #1**	**Distribution Site #2**	**Distribution Site #3**
Estimated BCR (range)	0.27 – 0.51	0.28 – 0.54	0.26 – 0.50
Load / Capacity	21.5 / 25 MVA	25.2 / 30 MVA	5.2 / 5.75 MVA
Less than 5MW Capacity Need	Yes	No	Yes
Growth Rate > 1.00%	Yes	Yes	No
Existing Load Data to Support Assumptions	Yes	Yes	No
Easily Accessible	Yes	Yes	No
Generation Resources on Circuit	Yes	No	No
Customer Partnership	Yes	No	No
Ability to Test Most Use Cases	Yes	No	No
Risks	Load growth	Load growth	Load growth and modeling uncertainty
Perceived Risk Level of Project Delivery and Benefits	Low	Medium	High
Recommendation	**Pursue Energy Storage Pilot Project #1**	Consider energy storage longer term	Consider energy storage longer term

The table below summarizes the cost-effectiveness analysis performed for the three feasible and cost-competitive locations and alternative technology scenarios for Pilot Project #1.

Table 4 Cost-Effectiveness Analysis for Pilot Project #1 Locations and Sizing

	Potential Locations Evaluated for Pilot Project #1			Pilot Project #1- Technology Scenarios	
	Distribution Site #1 Base Case	Distribution Site #2 Base Case	Distribution Site #3 Base Case	2 Hours of Storage	High Power
Sizing	2 MW x 3 hours	2 MW x 3 hours	2 MW x 3 hours	2MW x 2 hours	6 MW x 1 hours
Present Value of Benefits ($)	$2,382,980	$2,528,519	$2,360,519	$2,928,720	$4,479,336s
Present Value of Costs ($)	$4,678,060 - $8,965,966	$4,678,060 - $8,965,966	$4,678,060 - $8,965,966	$3,808,381 - $7,018,646	$6,786,542 - $12,159,976
BCR Range	0.27 - 0.51	0.28 - 0.54	0.26 - 0.50	0.42 - 0.77	0.37 - 0.66
NPV ($) *Revenue Requirement*	($2,302,048) – ($6,589,955)	$2,156,517 - $6,444,423	$2,324,517 - $6,612,423	($884,111) – ($4,099,376)	($2,307,211) – ($7,680,644)

Based on the above analysis, the Pilot Project #1 Base Case scenario was selected as it presented the least risk, lowest cost opportunity to pilot small scale energy storage in a location that provides great flexibility for the full range of use cases and maximizes learning opportunities for PacifiCorp.

While the two-hour storage scenario produced the highest potential benefit-to-cost ratio, it was not considered for preliminary sizing as this sizing would not meet the minimum threshold of five MWh set forth in HB 2193,[3] nor could it accommodate the historic outage characterization on the feeder. While the high power scenario did produce the second highest benefit-to-cost ratio, it also demonstrated the highest risk by potentially requiring the greatest costs. Therefore, PacifiCorp selected the 2MW x 3 hours base case energy storage solution as the preliminary sizing for the Pilot Project #1 proposal, as described in Section 4.0 of the Final Oregon Energy Storage Project Proposal document. This sizing meets the minimum threshold of five MWh as set forth by HB 2193, accommodates the historic outage characterization on the feeder, and presents the lowest risk option given the information available to PacifiCorp at this time.

While the pilot projects described in this document may not currently be cost-effective, PacifiCorp anticipates that in the future, changes to PacifiCorp's system and in the energy storage market have the potential to make energy storage more competitive and potentially cost effective. Using the methodology and assumptions in this document, PacifiCorp created a forward looking projection for energy storage on the PacifiCorp network, as included in Figure 3. Based on this analysis, PacifiCorp anticipates that energy storage has the potential to become cost effective in 2029.

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[3] According to HB 2193, if authorized by the Commission, electric companies shall procure on or before January 1, 2020 one or more qualifying energy storage systems that have the capacity to store at least 5 MWh and no more than one percent of the company's 2014 Oregon system peak load.

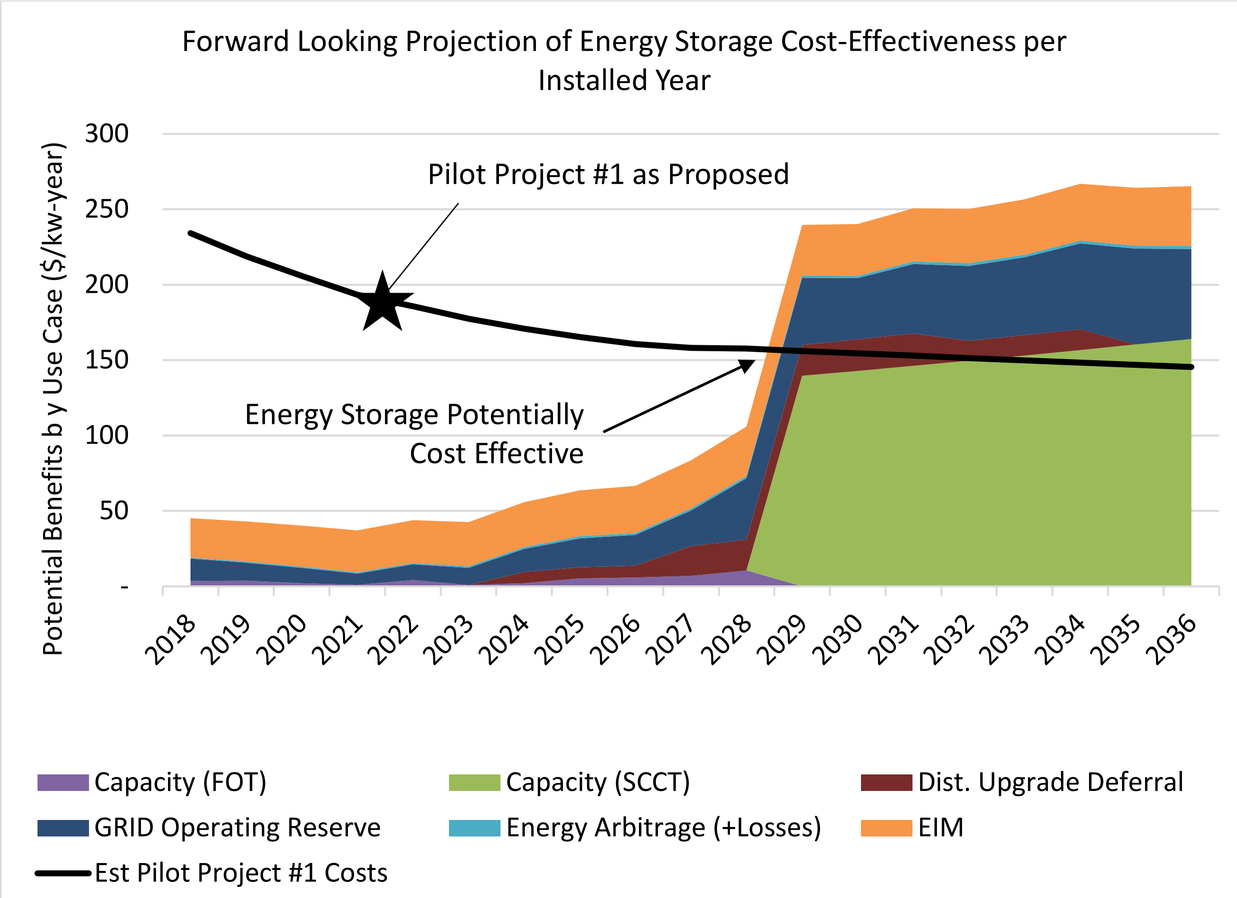

Figure 3 Forward Looking Projection of Energy Storage Cost-Effectiveness

In preparation for this, PacifiCorp has chosen targeted pilot projects that not only meet the legislative requirements but also provide critical information to support continuous improvement and refinement of the valuation of energy storage. PacifiCorp is excited to leverage the proposed pilot projects to learn how to properly control and integrate energy storage solutions into the existing network, and explore both the costs and benefits to all utility customers as well as specific customer locations. As energy storage has the potential to play a significant role in PacifiCorp's resource mix in the future, its costs and benefits must be accurately accounted for if it is to be part of a least-cost, least-risk portfolio. PacifiCorp also intends to leverage these learning opportunities for future implementation of cost-effective energy storage projects/programs.

As stated previously, PacifiCorp believes the methodology and approach to the evaluation of energy storage to be robust, repeatable, and compliant with legislation. However, PacifiCorp recognizes that lessons learned from the proposed pilots and the evolution of both energy storage technology and its range of applications will require refinement and adjustment of the proposed evaluation methodologies to reflect best practices, current market trends and co-optimization scenarios. With a commitment to the continued exploration of alternative resources and clean energy solutions, PacifiCorp intends to keep a critical eye on various aspects of energy storage, as included in Section 9.0, and revisit this methodology with stakeholders and staff as part of the company's 2019 Integrated Resource Planning process, which is scheduled to begin in the fall of 2018.

1.0 Introduction and Background

House Bill (HB) 2193,[4] passed in June of 2015, directs electric companies in Oregon to identify and evaluate one or more energy storage project(s) between five megawatt-hours (MWh) and 1 percent of 2014 Oregon system peak load (25 megawatts for PacifiCorp). The bill requires that electric companies submit project proposals to the Public Utility Commission of Oregon (Commission) by January 1, 2018, and, pending project approval, procure energy storage solutions by January 1, 2020. HB 2193 also tasked the Commission with drafting guidelines to be used by electric companies to create project evaluations and proposals.

As a result, four workshops were held between January 2016 and March 2017 to address concerns and solicit feedback from both electric company representatives and key stakeholders[5], culminating in Order No. 16-504 in docket UM 1751,[6] which formally established guidelines and instructed electric companies to submit draft potential storage evaluations by July 14, 2017, as an intermittent step to project proposals. In Order No. 17-118 the Commission adopted Staff's recommended framework for Storage Potential Evaluations that addresses items (a) through (g) listed in section A(3)(1) of Order No. 16-504.

PacifiCorp d/b/a Pacific Power, elected to leverage existing company specific tools, including its current IRP and 10 year distribution system capital budget, to identify potential needs within its Oregon service territory where energy storage was expected to be a viable solution. This resulted in a focus on distribution deferral, transmission deferral, and power reliability/resiliency applications. In support of this work, PacifiCorp issued a request for proposals (RFP), and, after a competitive bidding process, commissioned the consulting services of DNV GL on March 27, 2017. DNV GL was tasked with assisting PacifiCorp with developing draft energy storage evaluation methodologies and conducting a draft a preliminary report for submission to the Commission, included in Appendix C.

PacifiCorp's draft evaluation was filed on July 14, 2017, and presented to Staff and stakeholders on August 3, 2017. After a thorough review of the filing and careful consideration of both formal and informal comments from stakeholders, Staff drafted and presented a memo to the Commission during a regularly scheduled public meeting on September 26, 2017, which provided an update and requested changes be made to the requirements and timeline of UM 1751.

Staff's requested changes included that PacifiCorp re-focus efforts on the evaluation methodology, expanding upon its list of analyzed use cases, and provide transparency into the identification of system needs. Staff also requested that the Commission amend the timeline to include a Revised Draft Energy Storage Potential Evaluation to be submitted no later than January 1, 2018, which was authorized in Order No. 17-375 in docket UM 1857. PacifiCorp incorporated valuable feedback from stakeholders and Staff, amended the initial submission, and created the Revised Draft Energy Storage Potential Evaluation, which was filed on December 29, 2017.

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[4] https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193

[5] See Attachment A.

[6] *In the Matter of the Public Utility Commission of Oregon, Implementing Energy Storage Program Guidelines pursuant to HB 2193*, Docket No. UM 1857, Order No. 16-504 (Dec. 28, 2016).

Following the submission of the Revised Draft Energy Storage Potential Evaluation, PacifiCorp hosted a workshop in Portland, Oregon on February 23, 2018 to present a summary of the Revised Draft Energy Storage Potential Evaluation and Draft Project Proposals to stakeholders and Staff. Informally during the workshop and, formally, through written comments submitted on March 14, 2018, PacifiCorp received valuable and constructive feedback from both stakeholders and Staff. Staff specifically requested that PacifiCorp focus on amending the evaluation to include the following:

- An explanation of why Project #1 represents the best opportunity for ESS development in all of the PacifiCorp's utility network
- An explanation of how outage mitigation and/or interruption costs influenced the choice of Project #1
- The benefit-cost ratios of all sites proposed
- An evaluation of transmission deferral benefits
- Clarification on the benefits Project #2 will provide.

PacifiCorp used this feedback and these specific requirements to refine and inform this final storage potential evaluation. PacifiCorp updated company assumptions regarding in-service dates for net present value calculations and EIM escalation factors and ceilings, and performed an overall refresh on the GRID model. PacifiCorp's Final Energy Storage Potential Evaluation reflecting these changes and updates is included in the following section.

2.0 Evaluation Requirements

Order No. 16-504 outlined the requirements and guidelines regarding the Energy Storage Potential Evaluation to be completed by electric companies as directed by HB 2193. The following table summarizes these minimum requirements as required in Order No. 17-118 and addressed PacifiCorp's approach to meeting these minimum requirements.[7]

Table 5 Evaluation Requirements per Order No. 17-118

Requirement	PacifiCorp's Approach
a. Identify storage potential by use case or application for specified time frames	PacifiCorp leveraged the existing IRP methodology and preferred portfolio in addition to T&D deferral screening tools as described in Section 4.0 to identify storage potential by use case included in Section 5.0.
b. Identify higher and lower value applications	Specific valuations and applications for PacifiCorp's project proposals are discussed in more detail in Section 6.0. Additional expertise was leveraged from DNV GL's "Energy Storage Potential Evaluation" Section 2.1 beginning on page 10. See Appendix C.
c. Describe criteria for designating higher and lower value applications and explain how criteria were applied	PacifiCorp calculated values specific to each use case. Based on those results, the PacifiCorp combined use cases with the highest values and the least conflicting overlap to develop an achievable stack of uses cases that best makes use of a given energy storage resource's capabilities. Specific valuations and applications for PacifiCorp's project proposals are discussed in more detail in Section 6. Additional expertise was leveraged from DNV GL's "Energy Storage Potential Evaluation" Section 2.1 beginning on page 10. See Appendix C.
d. Identify system locations with the greatest storage potential	PacifiCorp considered locations that minimize new construction and integration costs associated with energy storage and locations with customer-sited generation that maximize benefits to have the greatest storage potential. See Section 6.0 for more information.

[7] *In the Matter of Public Utility Commission of Oregon Implementing Energy Storage Program Guidelines pursuant to House Bill 2193,* Docket No. UM 1751, Order No. 17-118 at 8 (Mar. 21, 2017).

	Additional expertise was leveraged from DNV GL's "Energy Storage Potential Evaluation" Section 2.3 beginning on page 13. See Appendix C.
e. Describe the methodology for determining storage potential, explain how the methodology was applied, and identify all limiting factors that affect estimates of storage potential by application	Details regarding PacifiCorp's approach for each specified use case/application is included in Section 4.0. Estimates of storage potential, calculated as avoided costs, by application can be found in Section 5.0.
f. Provide all input, assumptions, and other calculations used to designate higher and lower value applications and identify locations with the greatest potential	See Section 4.0 regarding evaluation assumptions and methodology for each use case and Section 5.0 for information regarding storage calculations.
g. Provide high level summary results of electric company's Request for Information (RFI), including description of RFI and the number and types of responses	See Appendix A.
h. Include any other provisions identified in the Staff-led workshops	See subsequent Table 6 thorough Table 9

In addition to the above minimum requirements, the following items were examined through various workshops held between January 2016 and March 2017, establishing the framework for the evaluation as required by Order No. 17-118, Appendix A.[8] PacifiCorp incorporated these requirements into its overall strategy.

Table 6 Staff Approved Framework for Evaluations per Order No. 17-118

Framework Requirement[9]	Description/Resolution
a. Consistent list of use cases or applications to be considered in the evaluation	See Table 11 for use case list and definitions.
b. Consistent list of definitions of key terms	Staff and stakeholders agreed to use the U. S. Department of Energy's (DOE) Glossary of Energy Terms and the DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA, Sandia National Laboratories, Akhil, Hill et al (September 2016).
c. Timeframe for analysis	Initial system analysis = 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.
d. Potential valuation methodology or methodologies the electric companies may use for estimating storage potential in each use case or application	The agreed-upon list of factors and examples are provided in Appendix B of the Staff recommendation document UM 1751.

[8] Order No. 17-118, Appendix A at 4-9.
[9] Order No. 16-504 at 8; Order No. 17-118, Appendix A at 4-9.

e. Criteria for identifying the main opportunities for investment in storage	Cost-effectiveness, diversity, location and utility learning
f. Approach for identifying system locations with the greatest storage potential	The following criteria were identified: - Meet identified challenges - Location planning information should be utilized (expected load growth, historic growth patterns, and expected customer demand) - Investment needed for storage and grid infrastructure - SAIDI or SAIFI metrics - Peak load data - Permitting and approval challenges - Incorporate internal distribution planning
g. The level of supporting detail required in the evaluation results and required supporting data	Staff proposed nine key elements discussed below.

The following table describes Staff's nine key elements, as referenced in item (g) above, and PacifiCorp's high-level approach for each.

Table 7 Staff Recommended Nine Key Elements for Evaluations per Order No. 17-118

Key Element[10]	PacifiCorp's Approach
1. Electric companies should analyze each use case listed for each evaluated energy storage system	PacifiCorp leveraged both existing tools and a third-party consultant, DNV GL, to analyze all use cases. See Section 3.0 for detailed descriptions of tools leveraged. Methodology for each use case is included in Section 4.0 and results of potential benefit, calculated as avoided costs, can be found in Section 5.0.
2. Final Storage Potential Evaluations should include a detailed cost estimate for each proposed energy storage system (ESS).	The evaluation methodology focuses on technology agnostic benefits and avoided costs associated with prescribed use cases. Scoping costs were included in DNV GL's report for specific energy storage solutions to begin to frame cost effectiveness to be used in project selection. Project specific costs are included in PacifiCorp's Energy Storage Final Project Proposals document Section 4.5.

[10] Order No. 16-504; Order No. 17-118, Appendix A at 7-9.

3. When storage services can be defined based on market data, a market valuation should be used.	PacifiCorp issued an RFI to provide market trends and data. A summary is included in Appendix A.
4. Final evaluations submitted January 1, 2018 should provide detailed descriptions of proposed sites.	Detailed descriptions of sites are included in PacifiCorp's Energy Storage Final Project Proposals document.[11]
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.	Resiliency has been included in the Power Reliability use case under Customer Energy Management Services. This has been a key use case for both pilot projects proposed.
6. Modeling attributes	See Table 8 below for modeling attribute requirements.
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.	PacifiCorp leveraged existing modeling tools describes in Section 3.0.
8. A single base year may be used for modeling purposes	PacifiCorp leveraged data available from the 2017 IRP to perform this analysis. Fifteen-year modeling assumptions were used in the GRID model and IRP process. A single year of actual data was used to derive EIM benefits or dispatch values.
9. Staff must be able to validate the assumptions and methods used to evaluate the cost effectiveness or each proposed ESS in the final proposals.	See Section 3.0 for detail regarding modeling. See Section 4.0 for additional detail regarding each use cases methodology and assumptions. See Section 7.0 for project-specific costs.

[11] Oregon Energy Storage Final Project Proposals document includes all detailed information regarding project specific justifications and benefits.

Table 8 below summarizes the model attribute requirements per key element 6 above.

Table 8 Model Attributes per Key Element #6

Model Attribute[12]	PacifiCorp Approach
Capacity to evaluate sub-hourly benefits	All models and tools use sub-hourly benefits, including EIM dispatch as described in Section 4.0.
Ability to evaluate location-specific benefits based on utility-specific values	Section 7.0 describes how the tools can be used to evaluate location specific (or project specific) benefits calculated. Planning studies as described in Section 3.0 evaluate location specific needs.
Enable co-optimization between services	Inherent to the models used, services can be run to see maximum benefits possible. Remaining capacity can then be dispatched for other use cases, resulting in stacked benefits. Section 5.0 describes the calculation of maximum potential benefits associated with each use case. Section 6.0 describes how these use cases can be co-optimized and stacked for additional value.
Capacity to evaluate bulk energy, ancillary services, distribution-level and transmission-level benefits	See Section 4.0.
Ability to build ESS conditions into optimization	Given assumptions, the existing model can cater to specific needs and optimize the use of energy storage devices. See Section 6.0 for more information.

Table 9 below outlines how PacifiCorp addressed Staff's additional recommendations found in Order No. 17-375 pages 15-16.

Table 9 Staff Recommendations per Order No. 17-375

Staff Recommendation[13]	PacifiCorp's Response
Co-optimize the identified use cases found in Order No. 17-118.	See Section 6.0 for co-optimization methodology.
Provide the input values for each of the services modeled	See Section 3.0 for modeling inputs and outputs.
Review the requirements of Order No. 17-118 and address each.	See Table 5, Table 6, Table 7, and Table 8 above.
Include all bulk power and ancillary services use cases.	See Sections 4.1 and 4.2 for methodology description and Section 5.0 for values.
Input a capacity value into storage modeling.	See Section 4.1 for methodology and Section 5.0 for values.
Perform analysis on ancillary services such as spin/non-spin reserves, load following, regulation, and others.	See Section 4.2 for methodology and Section 5.0 for values.

[12] Order No. 17-118, Appendix A at 8.
[13] Order No. 17-375, Appendix A at 15-16.

Following PacifiCorp's filing of the Revised Draft Energy Storage Potential Evaluation and subsequent stakeholder workshop, Staff provided additional requirements for PacifiCorp's final filing, as included in Table 10 below.

Table 10 Additional Staff Requirements per Written Comments

Staff Requirement[14]	PacifiCorp's Response
Explanation of why Project #1 represents the best opportunity for ESS development on all PacifiCorp's utility network	See Section 6.0 for general methodology and Section 7.0 for project specific site selection process and calculations regarding Pilot Project #1 and other potential locations.
Explanation of how outage mitigation and/or interruption costs influenced the choice of Project #1	Pilot Project #1 was selected through the use of the transmission and distribution planning studies, the Alternative Evaluation Tool, and a subsequent risk-based analysis of three potential locations. From this list of potential locations, Project #1 was ultimately selected as it presented the least risk, lowest cost opportunity to pilot small scale energy storage in a location that provides opportunities for learning and the flexibility to evaluate the largest range of use cases, including customer specific outage mitigation. See Section 7.0 for more information regarding Pilot Project #1 location selection.
Benefit-to-cost ratios of all sites proposed	See Section 6.0 for system level benefit-to-cost calculations and Section 7.0 for project specific calculations.
Evaluation of transmission deferral benefits	The evaluation of transmission deferral benefits was included in Section 4.3 and monetized in Section 5.0.

[14] Staff's Comments (March 14, 2018).

Table 11 Use Cases per Order No. 17-118[15]

Use Case	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 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, 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 Services	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 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 electric power system. VAR control manages the reactive power, usually attempting to get a power factor near unity (l).
	Outage Mitigation	Outage mitigation refers to the use of an ESS to reduce or eliminate the costs associated with power outages to utilities.
	Distribution Congestion Relief	Use of an ESS to store energy when the distribution system is 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.
Other[16]	Frequency Response	Use of ESS to supply or absorb power in response to deviations from the nominal frequency and imbalances between supply and demand.

[15] See Order No. 17-118, Appendix A at 15-17.
[16] Added to the use case list after careful consideration of both stakeholder feedback and system needs.

3.0 PacifiCorp's Approach to Energy Storage Evaluation

PacifiCorp used existing evaluation tools and processes to identify system needs within its Oregon service territory where, given the construct of the legislative requirements and timeline, energy storage was not only expected to be a technological solution but also a learning opportunity for PacifiCorp. See the high-level description of the tools below:

Integrated Resource Plan:[17] The IRP is a comprehensive decision support tool and road map for meeting PacifiCorp's objective of providing reliable least-cost electric service to all of PacifiCorp's customers while addressing the substantial risk and uncertainties inherent to the electric utility business. Prepared on a biennial schedule, the IRP uses system grid modeling tools as part of its analytical framework to determine the long-run economic and operational performance of alternative resource portfolios. These models simulate the integration of new resource alternatives within existing assets, thereby informing the selection of a preferred portfolio judged to be the most cost-effective resource mix after considering risk, supply reliability, uncertainty, and government energy resource policies. Specifically pertaining to energy storage resources in this filing, PacifiCorp is proposing using the PDDRR methodology to identify resources which could be deferred as a result of incremental capacity provided by energy storage resources. The PDDRR methodology includes capacity costs from the IRP and energy costs calculated in the GRID model, as discussed below. As more experience is gained with energy storage resource valuation, future IRP modeling is expected to be adjusted to account for use case benefits that are not fully represented at present, for instance ancillary services and transmission and distribution deferral. Further detail on the calculation of these elements can be found in the following subsections.

GRID Model:[18] The GRID model is a PacifiCorp tool used to calculate the net power costs associated with traditional and renewable resources, such as energy storage solutions. It is also used for retail ratemaking and the calculation of avoided costs for qualifying facilities. The GRID model provides a long term, hourly forecast of PacifiCorp's system dispatch, including the impact of resource additions identified in the IRP preferred portfolio. The GRID model is used to estimate the marginal system dispatch impacts of energy storage resources and deferred IRP preferred portfolio resources. Specifically, the GRID model includes operating reserve (ancillary services) requirements intended to reflect reliable system operation consistent with National Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards. When dispatchable energy storage resources provide operating reserves they can free up low-cost system resources which would otherwise have held those operating reserves, potentially allowing the low-cost resources to generate more and reduce the dispatch of higher cost market purchases or fuel cost savings. These benefits are part of regulation, load following, and spin/non-spin reserve use cases. The GRID model also calculates the benefits provided by the portion of the IRP preferred portfolio resource that is assumed to be deferred by an energy storage resource. The lost benefits that would have been provided by a deferred IRP preferred portfolio resource are part of the generation capacity use case.

EIM Dispatch Model: The IRP and GRID models do not have sub-hourly dispatch and do not account for all of the costs and benefits of resources that can be dispatched on a sub-hourly basis. Since sub-hourly dispatch is particularly relevant to energy storage resources, PacifiCorp has collected EIM pricing results

[17] PacifiCorp's 2017 IRP can be found at http://www.pacificorp.com/es/irp.html
[18] See PacifiCorp 2017 IRP Volume I Chapter 7 – Modeling and Portfolio Evaluation Approach, beginning on page 143.

for the twelve months ending September 2017 and developed spreadsheets that estimate the dispatch, costs, and benefits of energy storage resources during that timeframe. The regulation and load following use cases include benefits calculated based on EIM dispatch. PacifiCorp has also developed a similar spreadsheet for the simple cycle combustion turbine simple cycle combustion turbine (SCCT) assumed to be deferred from the IRP preferred portfolio by energy storage resource additions. The lost EIM dispatch benefits associated with SCCT deferral are a component of the generation capacity use case.

T&D Planning Studies: PacifiCorp performs planning studies on the distribution and sub-transmission systems to evaluate how the planned load growth over the five and ten year planning horizons compare with PacifiCorp's current ability to deliver this load to customers and identify specific transmission and distribution needs. Additionally, PacifiCorp performs an annual Bulk Electric System assessment for compliance with the NERC TPL-001-4 Reliability Standard. From these various planning studies, PacifiCorp develops a list of projects needed to mitigate identified system deficiencies and incorporates the list into a 10 year capital investment strategy.

Alternative Evaluation Tool: Following the combined results of the T&D Planning Studies, all low cost technical solutions are screened using an alternative evaluation tool that selects the lowest cost technical solution to meet these identified needs and incorporates the project into the 10 year capital investment strategy**.** This internally developed tool identifies projects where the cost of an energy storage solution is estimated to be within 20 percent of a conventional solution. These projects are flagged for a more thorough analysis to fully evaluate the costs and benefits and allow energy storage to compete with traditional T&D applications.

Resource Value of Solar (RVOS) Model: While the RVOS spreadsheet model was developed for valuing solar resources, most of the elements may be applicable to any resource with a fixed generation profile (i.e. that is not dispatchable by PacifiCorp). Fixed generation profiles may be likely when energy storage resources are used for transmission or distribution deferral or for customer benefits such as time-of-use or demand charge reduction. The RVOS model also provides a relatively straightforward template for combining various elements or use cases and reporting the results. As a result, PacifiCorp intends to use it to the extent possible for each energy storage pilot project proposal.

RFI Analysis: In alignment with HB 2193 and Order No. 16-504, PacifiCorp issued an RFI including approximate company load data to better inform both the evaluation of energy storage and the potential options for projects meeting the legislative directive. PacifiCorp received responses from 19 potential contractors ranging in both experience and technology provided. While PacifiCorp received a lot of high level information regarding market trends and availability, not a single project specific solution was proposed. Without these specifics, the use of the RFI results in both the storage evaluation and project selection became limited to providing benchmarks and market trends. More information is included in Appendix A.

DNV GL Analysis: Location specific load data regarding projects passing the financial screening of the energy storage evaluation layer were provided to DNV GL to perform a more thorough analysis and provide recommendations regarding technology, sizing, and potential project specific benefit-to-cost ratios. This deep dive provided insight into which project specific use cases might provide the greatest benefit to PacifiCorp project(s).

The following chart describes the inputs and outputs associated with each relevant model or tool described above.

Table 12 Input/output for Tools/Models Used

Model/Tool	Input	Output
Integrated Resource Plan (IRP)	Load data, market prices and system constraints, characteristics of existing and potential resources including costs	Preferred Portfolio of low cost least risk solutions, cost and characteristics of resources selected. (Resource-specific capacity contribution values)
Generation and Regulation Initiative Decision Tools (GRID) Model	Same as IRP but leverages the preferred portfolio as a starting point for evaluation	Marginal system impacts of operating reserves and deferred IRP resources
EIM Dispatch Model	Twelve months of EIM pricing results, characteristics of resources under consideration	Expected EIM benefits for specific resources
Resource Value of Solar (RVOS) Model	Charge/Discharge profiles, efficiency, interconnection voltage, & export condition	Value of generation capacity deferral, net energy and losses, levelized values for T&D deferral and ancillary services
Transmission and Distribution (T&D) Planning Studies	Current load data, predicted load growth, capacity of existing infrastructure	Needs for T&D Projects, low cost solutions to meet needs
Alternative Evaluation Tool	T&D projects identified by planning study, typical cost of traditional solutions, typical cost of alternate solutions	High level cost estimates for alternative solutions - closer look is performed if costs are within 20% of traditional solutions
Request for Information (RFI)	Load data, use cases, legislative requirements	Market trends and benchmarks, available technology capable of addressing use cases
DNV GL Analysis[19]	*See DNV GL Energy Storage Evaluation in Appendix C for specific model assumptions, inputs, and outputs*	

[19] See DNV GL Energy Storage Evaluation in Appendix C for specific model assumptions, inputs, and outputs.

Figure 4 depicts how these tools were applied as part of PacifiCorp's process to identify system needs and associated least cost, low risk resources and projects.

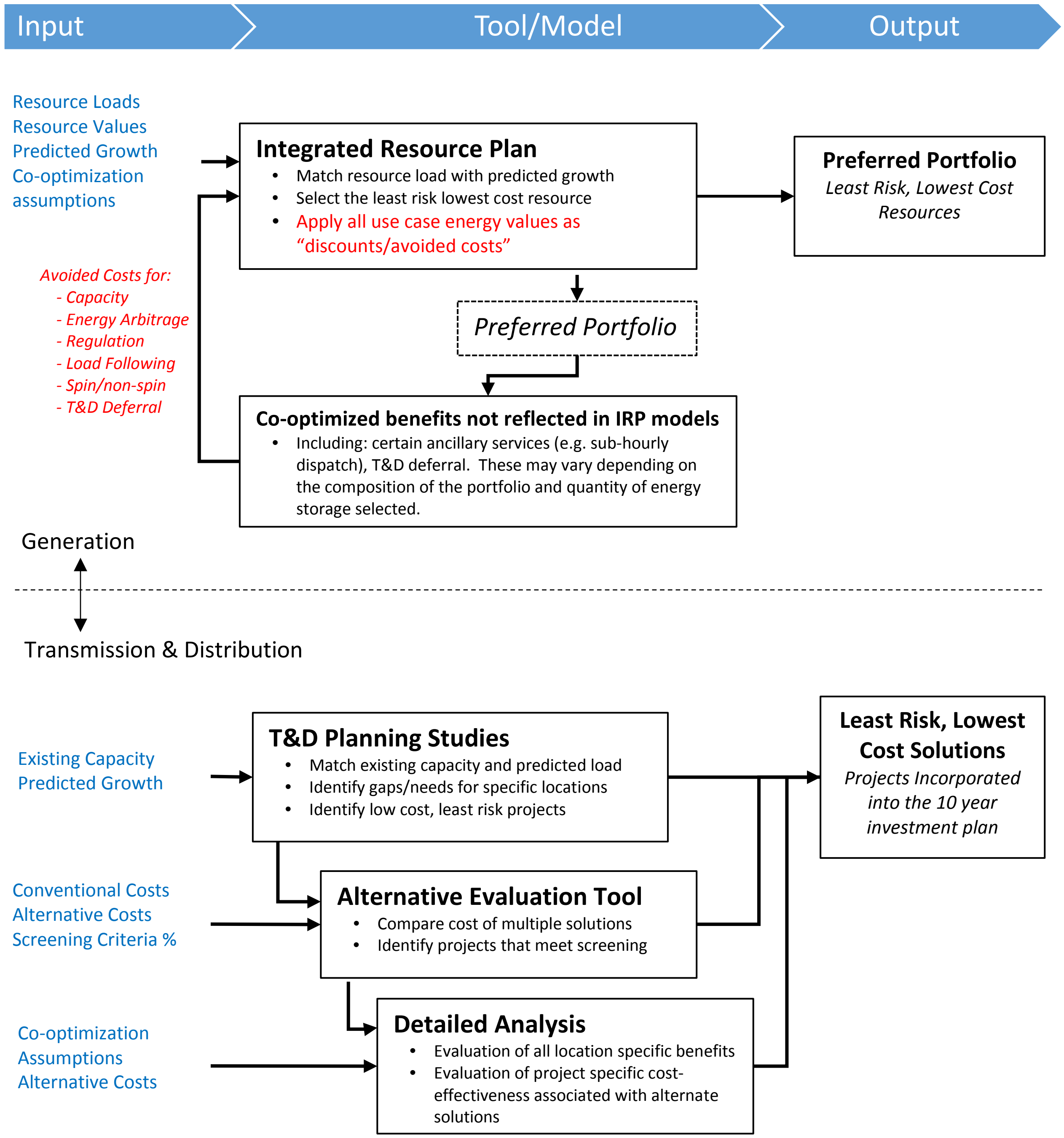

Figure 4 Energy Storage Evaluation Process

4.0 Use Case Evaluation Methodology

The table below summarizes how each tool previously described was used to evaluate each use case.

Table 13 Evaluation Approach for Each Identified Use Case

Use Case	Service	Evaluation Approach/Tools Leveraged
Bulk Energy	Capacity or Resource Adequacy	IRP: preferred portfolio and capacity contribution; GRID: displaced resource dispatch impacts and PDDRR methodology; RVOS: calculations and avoided line losses [Section 4.1]
	Energy Arbitrage	RVOS: energy arbitrage and avoided line losses [Section 4.1]
Ancillary Services	Regulation	GRID: operating reserve opportunity costs; EIM: participating resource benefits [Section 4.2]
	Load Following	GRID: operating reserve opportunity costs; EIM: non-participating resource benefits [Section 4.2]
	Spin/Non-spin Reserve	GRID: operating reserve opportunity costs [Section 4.2]
	Voltage Support	Included in T&D Deferral, [Sections 4.4 and 4.4]
	Black Start Services	No need currently identified. [Section 4.2]
Other	Frequency Response[20]	No need currently identified. [Section 4.2]
Transmission Services	Transmission Congestion Relief	Included in Energy Arbitrage [Section 4.1]
	Transmission Upgrade Deferral	IRP preferred portfolio, Alternative Evaluation Tool [Section 4.3]
Distribution Services	Distribution Upgrade Deferral	IRP preferred portfolio, Alternative Evaluation Tool [Section 4.4]
	Volt-VAR Control	Included in T&D Deferral [Sections 4.4 and 4.3]
	Outage Mitigation	Customer specific (not aggregate) case-by-case benefit [Section 4.5]
	Distribution Congestion Relief	Included in Distribution Deferral [Section 4.4]
Customer Energy Management Services	Power Reliability	Included in Outage Management [Section 4.4]
	Time-of-Use Charge Reduction	Customer specific (not aggregate) case-by-case benefit [Section 4.5]
	Demand Charge Reduction	Customer specific (not aggregate) case-by-case benefit [Section 4.5]

[20] While not a requirement of Order No. 17-118, PacifiCorp elected to highlight the potential for Frequency Response as a use case under ancillary services for evaluation after careful consideration of system needs and stakeholder feedback.

4.1 Bulk Energy

Bulk Energy as relating to energy storage use cases includes both capacity or resource adequacy and ancillary services.

Capacity or Resource Adequacy

Capacity or resource adequacy, also referred to as generation capacity, as a use case for energy storage reflects the dispatch of stored energy during peak demand periods, in turn providing benefit through the reduction in need for new peaking power plants or other peak supply sources.

PacifiCorp's current generation capacity needs and expected costs are determined by the "preferred portfolio" in its 2017 IRP, published April 4, 2017. [21] This portfolio represents the least-cost, least-risk plan for maintaining sufficient generation capacity to reliably meet customer loads. The calculations and models inherent to this process assume that all resources provide both capacity and energy benefits.

Since IRP modeling is data intensive and time-consuming, PacifiCorp calculates the value (cost or benefit) associated with potential generation capacity additions through the PDDRR Methodology and PacifiCorp's production cost model, GRID.[22]

The PDDRR method is currently used by PacifiCorp in Oregon, Utah, Wyoming, and Idaho to calculate non-standard qualifying facility avoided cost prices.[23] The PDDRR method directly measures the impact a resource has on PacifiCorp's power costs by utilizing the GRID model to calculate the value of energy and capacity based on the unique characteristics of the proposed energy storage resource and PacifiCorp's system.

The PDDRR methodology has two main assumptions: (1) the next deferrable capacity resource is defined by PacifiCorp's most recent IRP preferred portfolio, and (2) removing the capacity from the next deferrable resource (one equivalent to an alternative solution) should result in a portfolio with comparable cost and risk as the preferred portfolio. For example, a proposed energy storage resource would be eligible to defer a portion of the next capacity resource, generally a major thermal resource addition such as a SCCT (Simple Cycle Combustion Turbine) or a combined cycle combustion turbine.

The GRID model leverages this methodology and PacifiCorp's most recent IRP resource portfolio to run simulations and determine avoided energy costs. To perform this calculation, PacifiCorp runs two simulations. The first simulation, the Base Simulation, calculates the net power costs associated with PacifiCorp's existing resource portfolio and planned resource additions as identified by the IRP's "preferred portfolio." The second simulation, the Avoided Cost Simulation, calculates the net power costs associated with the same resource portfolio with two distinct modifications:

(1) The operating characteristics of the proposed energy storage resources are added at zero cost.

[21] http://www.pacificorp.com/es/irp.html

[22] See PacifiCorp 2017 IRP Chapter 7 – Modeling and Portfolio Evaluation Approach, beginning on page 143.

[23] A variation of the PDDRR is used in Idaho called the Highest Displaceable Incremental Cost method, or the IRP Method.

(2) The capacity of the next deferrable resource is reduced by an amount equal to the energy storage resource's capacity contribution.

The difference in net power costs between the Avoided Cost Simulation and the Base Simulation equals the avoided energy cost associated with capacity or bulk energy specific to the PacifiCorp grid and portfolio.

PacifiCorp recognizes that the capacity-equivalence of energy storage technologies as applied above in the PDDRR methodology is an area that has the potential for additional refinement – specifically relating to the number of hours of storage assumed for an energy storage facility to provide the same contribution as a thermal resource to meet customer loads during peak periods.

Previously, PacifiCorp's IRP has assumed four hours of storage as the minimum necessary to achieve a 100 percent capacity contribution. By this metric, an energy storage solution with two-hours of storage would provide a 50 percent capacity contribution, as this is the amount of capacity that could be sustained for four hours. While the output of the ESS is important, it is not clear that four hours is necessary, as many peak events have a shorter duration. Furthermore, PacifiCorp is subject to reliability standards which require it to maintain a supply of operating reserve capacity over and above its load. Since this capacity must be maintained at all times but is rarely called upon, energy storage resources can support reliable operation by providing operating reserves across the entire peak without any energy being deployed.

PacifiCorp has used a capacity factor approximation method (CF Method)[24] to determine the capacity contribution for wind and solar resources, which can often be paired with energy storage technology for resource optimization. The CF Method compares the expected generation profile of a resource to the load profile requirements during historic high risk load loss time periods.[25] A resource that is expected to be available during all loss-of-load events would receive a 100 percent capacity contribution. As indicated above, an energy storage solution's availability during potential loss-of-load events is limited by its storage capacity. Unfortunately, the results of PacifiCorp's simulation only identified the number of events per hour, and did not identify the duration of events. As a result, in the existing analysis it is not possible to determine whether the loss-of-load probability in two successive hours was a single event or was separate events in two different iterations. Assuming an energy storage system could be deployed once per day in the hours with the highest loss-of-load probability (LOLP) results in a capacity contribution of 68 percent during the four-hour storage solution, which is significantly lower than the current assumption.

In response to the above identified challenges, PacifiCorp proposes that, moving forward, energy storage resources with three hours of storage available for dispatch during peak load conditions be credited with a 100 percent capacity contribution, as long as duration-limited resources do not exceed PacifiCorp's contingency reserve requirements during peak periods (roughly six percent of peak load). By this metric, a battery with two hours of storage would be credited with a 67 percent capacity contribution, while a battery with one hour of storage would be credited with a 33 percent capacity contribution. Duration-limited resources in excess of PacifiCorp's contingency reserve requirements would continue to require four hours of storage to receive a 100 percent capacity contribution.

[24] See PacifiCorp 2017 IRP Appendix N Page 313 for more information.

[25] High risk load loss time period and load profile identified through a 500-iteration Monte Carlo simulation of PacifiCorp's system during a one year study period.

The next major thermal resource in PacifiCorp's 2017 IRP preferred portfolio is an SCCT starting 2029, with fixed costs of $139/kW-year starting in 2029, and increasing at inflation thereafter. This resource provides many similar benefits to energy storage resources, some of which are being more thoroughly vetted for the first time in this analysis. For instance, to the extent EIM dispatch benefits are quantified for energy storage resources, the lost EIM dispatch benefits from the SCCT proxy being deferred should also be accounted for. The same is true for any other use cases under consideration.

Energy Arbitrage

This use case represents trading in the wholesale energy markets by buying energy during low-price periods and selling it during high-price periods. PacifiCorp distinguishes this use case from ancillary services by assuming that the energy storage release occurs on a fixed hourly schedule, rather than in response to PacifiCorp dispatch instructions. To be dispatched and provide benefits, the revenue from sales during high-price periods must exceed the cost of storage during low price periods, including the cost of losses and storage degradation.

To calculate energy arbitrage benefits for energy storage, PacifiCorp proposes using the energy value assumptions developed for the Resource Value of Solar docket (UM 1910), with allowances made for the dispatch capabilities and incremental benefits associated with energy storage. Under this proposal, the average energy price in each month is based on a blend of the forward prices for the Mid-Columbia, California-Oregon Border (COB), and Palo Verde markets in PacifiCorp's Official Forward Price Curve (OFPC). The ratio of the blended prices varies by month and by on-peak hours and off-peak hours.[26]

PacifiCorp's OFPC includes on- and off-peak granularity, but does not include hourly granularity. To create an hourly shape, the proposed RVOS methodology uses the results of EIM operations. Specifically, PacifiCorp uses fifteen-minute EIM market prices for the most recent twelve month period. Under this approach, hourly shaping would be based on EIM load aggregation point (LAP) prices, with Mid-Columbia hourly shaping based on the PacifiCorp west (PACW) LAP, Palo Verde hourly shaping based on the PacifiCorp east (PACE) LAP, and COB hourly shaping based on the Malin LAP. The market price shape is a "scalar" based on the average market prices in a month during a given hour, relative to the average market price in that month during all hours. For example, if the average market price during hour ending 10 in May is $18/MWh, and the average market price during all hours in May is $20/MWh, then the scalar for hour ending 10 in May would be 90 percent. Before the monthly shape from the OFPC is incorporated, the average of the 24 hourly scalars for a given month is always 100 percent. Similarly, when the monthly and hourly shapes are combined, the hourly market price shapes average to one over the course of each year.

Since no correlation between solar resource output and market price has been established, the RVOS model uses a 12x24 profile, and reflects average solar generation and average market prices for each hour and each month. The energy arbitrage use case reflects fixed dispatch and storage profiles for each month optimized against the 12x24 hourly market price shape. This fixed dispatch distinguishes the Energy Arbitrage use case from the Regulation and Load Following use cases, which instead reflect dynamic energy storage resource dispatch in response to the current market conditions. These dispatchable energy storage use cases are discussed in the next section. As the calculation of energy arbitrage benefits is

[26] Based on the relative weighting of the incremental transactions by market in a PacifiCorp GRID study as a result of the addition of a new zero-cost resource in Oregon.

dependent on the efficiency of the energy storage resource, the storage degradation cost, and the number of hours of storage, the benefits will vary for each potential energy storage resource.

4.2 Ancillary Services

According to Order No. 16-504, ancillary services include regulation, load following, spin/non-spin reserve, voltage support, and black start services. For the purposes of evaluating benefits associated with energy storage PacifiCorp has grouped regulation, load following, and spin/non-spin reserve together as its IRP and GRID models have limited ability to distinguish between these different requirements. A high level description of these use cases is provided below:

Regulation/Load Following: Deployed to compensate for changes in load or generation, either as a result of expected changes (ramping) or deviations from forecasts (uncertainty).

- Regulation typically refers to rapid responses over the course of a few minutes to maintain the balance between load and resources. PacifiCorp has interpreted regulation service as EIM participation including both the 15-minute real-time pre-dispatch (RTPD) market and the 5-minute real-time dispatch (RTD) market. A resource providing regulation service would participate in each 15-minute RTPD market interval, and would also be dispatched in 5-minute RTD market increments, in both cases it's based on the buy and sell bid prices and is subject to its available storage capacity. Any changes from the RTPD schedule are settled at the RTD market price.

- Load following typically refers to longer duration responses over the course of an hour. PacifiCorp has interpreted load following service as non-participating resources that respond to the 15-minute RTPD market prices on an hourly basis. Since load and non-participating resources are settled on an hourly basis, the average of the four 15-minute market prices in an hour was assumed to be used for dispatch and settlement. A resource providing the service is assumed to be dispatched up or down in 60-minute increments, based on its buy and sell bid prices and is subject to its available storage capacity.

Spin/Non-Spin: Resources are deployed in response to specific contingency events such as mechanical failure at a generation resource or a major transmission element.[27] PacifiCorp's contingency reserve obligation is defined by NERC Standard BAL-002-WECC-2, and requires that at least half of the requirement be met with "spinning" resources that are immediately and automatically responsive to changes in frequency. At present, PacifiCorp's West Balancing Authority Area has a negligible quantity of non-spinning resources, so incremental spinning and non-spinning resources contribute equally to fulfilling its obligation and thus have equal value. Resources held as contingency reserve are deployed infrequently and provide limited opportunities to recharge when market prices are low, as they would need to be refilled soon after a contingency event occurred.

Frequency Response: Deployed in response to system frequency deviations.[28] Batteries are particularly suited to frequency response because only a few minutes of storage capacity is required, rather than hours as is typical in other applications, which significantly reduces the project cost. However, PacifiCorp has sufficient frequency responsive resources in its PACW balancing authority area through the 2017 IRP study period.

[27] NERC Standard BAL-002-WECC-2: http://www.nerc.com/files/BAL-002-WECC-2a.pdf
[28] NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Setting: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.pdf

Collectively, these services are components of the operating reserve, which NERC defines as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[29] Generally, capability above firm system demand is referred to as "up flexibility" while the ability to ramp down resources in response to reductions in load or increases in intermittent resource output is referred to as down flexibility. All of the ancillary services use cases provide value by meeting "up flexibility" requirements. Reliable system operation requires load and resources to remain balanced at all times, and the regulation and load following provide additional value by meeting down flexibility requirements.

The follow subsections describe the basic differences between each of the ancillary services use cases included in operating reserve. Voltage Support and Black Start Services have been included as separate subsections at the end of Section 4.2.

Regulation/Load Following

Purpose: Regulation/Load-following Reserve, or collectively just regulation reserve, is held for compliance with NERC standard BAL-001-2. This allows a utility to maintain compliance with specified control performance standards, primarily related to area control error (ACE), which is the difference between a BAA's scheduled and actual interchange, and reflects the difference between electrical generation and load within that BAA.[30]

Requirement 2 of BAL-001-2 defines the compliance standard as follows:

> *"Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…"*

In addition, Requirement 1 of BAL-001-2 specifies that PacifiCorp's Control Performance Standard 1 (CPS1) score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated on a monthly basis, it does not require a response to each and every ACE event, but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month.

Volume: NERC standard BAL-001-2 does not specify a regulation reserve requirement based on a simple formula, but instead requires utilities to hold sufficient reserve to meet performance standards as discussed above. The 2017 Flexible Reserve Study estimates the regulation reserve necessary to cover the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system, with requirements varying as a function of the wind and solar capacity on PacifiCorp's system, as well as forecasted wind and solar output.

Ramp rate: While regulation is considered faster-responding and load-following is slower responding, PacifiCorp does not currently model distinct reserve requirements for these categories. Because

[29] NERC Glossary of Terms: http://www.nerc.com/files/glossary_of_terms.pdf, updated July 13, 2016.
[30] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: http://www.nerc.com/files/BAL-001-2.pdf

Requirement 2 includes a 30 minute time limit for compliance, ramping capability that can be deployed within 30 minutes contributes to meeting PacifiCorp's regulation reserve requirements. PacifiCorp has not specifically evaluated reserve needs for CPS1 compliance. The reserve for CPS1 is not expected to be incremental to the need for compliance with Requirement 2, but may require that a subset of resources held for Requirement 2 be able to respond more rapidly to manage ACE relative to interconnection frequency.

Duration: PacifiCorp is required to submit balanced load and resource schedules as part of its participation in EIM. PacifiCorp is also required to submit resources with up flexibility and down flexibility to cover uncertainty and expected ramps across the next hour. Because forecasts are submitted prior to the start of an hour, deviations can begin before an hour starts.[31] As a result, a flexible resource might be called upon for the entire hour. In order to continue providing flexible capacity in the following hour, energy must be available in storage for that hour as well. The likelihood of actually deploying for two hours or more for reliability compliance is likely small, particularly when storage resources are only a small portion of the flexible resources in PacifiCorp's portfolio. Because much of the benefits of flexible capacity are in hour-ahead scheduling rather than intra-hour dispatch, resources with less than two hours of storage capacity will have a pro-rated scheduling value. Since EIM dispatches can cover as little as five minutes, a resource with limited storage capacity can still capture much of the potential intra-hour dispatch benefits.

Spin/Non-spin Reserve

Purpose: Spin/Non-spin Reserve is held for compliance with contingency reserve standard BAL-002-WECC-2 and may only be deployed in response to specified contingency events, such as the mechanical failure of a generation resource or transmission element.[32]

Volume: At least three percent of the load and three percent of the generation in a BAA.

Ramp rate: Only up capacity available within ten minutes can be counted as contingency reserve. At least half of a BAA's requirement must be met with "spinning" resources that are online and immediately responsive to system frequency deviations, while the remainder can come from "non-spinning" resources that do not respond immediately, though they must still be fully deployed in ten minutes.

[31] The CAISO, as the market operator for the EIM, requests base schedules at 75 minutes ("T-75") prior to the hour of delivery. PacifiCorp's transmission customers are required to submit base schedules by 77 minutes ("T-77") prior to the hour of delivery – two minutes in advance of the EIM Entity deadline. This allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-75 for the entirety of PacifiCorp's two BAAs. The base schedules are due again to CAISO at 55 minutes ("T-55") prior to the delivery hour and can be adjusted up until that time by the EIM Entity (i.e., PacifiCorp Grid Operations). PacifiCorp's Transmission customers are required to submit updated, final base schedules no later than 57 minutes ("T-57") prior to the delivery hour. Again, this allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-55 for the entirety of PacifiCorp's two BAAs. Base schedules may be finally adjusted again, by the EIM Entity only, at 40 minutes ("T-40") prior to the delivery hour in response to CAISO sufficiency tests. T-55 is the base schedule time point used throughout this study because it is the deadline which most closely corresponds to the final T-57 deadline for all transmission customers to submit final base schedules.

[32] NERC Standard BAL-002-WECC-2, http://www.nerc.com/files/BAL-002-WECC-2.pdf, which became effective October 1, 2014.

Duration: Except within 60 minutes of a qualifying contingency event, a BAA must maintain the required level of contingency reserve at all times. Generally, this means that up to 60 minutes of generation are required to provide contingency reserve, though successive outage events may result in contingency reserves being deployed for longer periods. To restore contingency reserves, other resources must be deployed to replace any generating resources that experienced outages, typically either market purchases or generation from resources with slower ramp rates.

Frequency Response

Purpose: Frequency Response Reserve is held for compliance with contingency reserve standard BAL-003-1 and is deployed in response to system frequency deviations.[33]

Volume: A BAA's Frequency Response Obligation is specified annually and specifies the number of megawatts of frequency responsive resources it must deploy as a function of the deviation of interconnection frequency from normal, and is typically referenced in megawatts per 0.1 Hertz (MW/0.1Hz). The lower the interconnection frequency, the greater the required frequency response. PacifiCorp's 2017 Frequency Response Obligation was 19.51 MW/0.1Hz for PACW, and 48.93 MW/0.1Hz for PACE.

Ramp rate: Capacity must be deployed immediately in response to interconnection frequency, rather than a signal from the system operator. This typically involves either a governor control for synchronous resource or an electronic equivalent for other resources.

Duration: Performance is measured over a period of seconds, amounting to under a minute. In addition, compliance is based on median performance under selected WECC-wide events, rather than under all conditions as is the case for the other reserve obligations. Because the performance measurement for the contingency reserve obligation (BAL-002-1) is similar to that for BAL-003-1, frequency response capacity is effectively incremental to the contingency reserve obligation. On the other hand, standard BAL-003-1 is based on median performance under selected WECC-wide events, while regulation reserve obligations under BAL-001-2 is based on minimum performance during PACW events. Since median performance is adequate for BAL-003-1 compliance, BAL-001-2 compliance can take precedence, so long as the overlap is sufficiently low. Therefore, to the extent adequate regulation reserve is available to make potential BAL-001-2 events relatively rare, the potential overlap between BAL-003-1 events and BAL-001-2 events is likely to be low, unless there is a significant positive correlation between the two. As a result, frequency response can be considered a subset of regulation reserve capacity.

Batteries are particularly suited to frequency response because only a few minutes of storage capacity is required, rather than hours as is typical in other applications, which significantly reduces the project cost. However, PacifiCorp has sufficient frequency responsive resources in its PACW balancing authority area through the study period of the 2017 IRP. As a result, PacifiCorp has not identified an incremental need for frequency responsive resources beyond that already accounted for in meeting regulation reserve requirements as previously discussed.

[33] NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Setting: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.pdf

Ancillary Services Operational Distinctions

In actual operations, PacifiCorp identifies two types of flexible capacity as part of its participation in the EIM. The contingency reserve held on each resource is specifically identified and is not available for economic dispatch within the EIM. Any remaining flexible capacity on participating resources that is not designated as contingency reserve can be economically dispatched in EIM based on its operating cost (i.e. bid) and system requirements and can contribute to meeting regulation reserve obligations. Because of this distinction, resources must either be designated as contingency reserve or as regulation reserve. Contingency events are relatively rare while opportunities to deploy additional regulation reserve in EIM occur frequently. As a result, PacifiCorp schedules its lowest-cost flexible resources to serve its load, and blocks off capacity on its highest-cost flexible resources to meet its contingency obligations, subject to any ramping limitations at each resource. This leaves resources with moderate costs available for dispatch up by EIM, while low-cost flexible resources remain available to be dispatched down by EIM.

Energy Storage Dispatch Costs

As described above, energy storage dispatch costs involve both efficiency and storage degradation. Systems with relatively low efficiency and/or high degradation costs are likely to be designated as contingency reserve, as the cost of deploying these resources is relatively high. Likewise, systems with relatively high efficiency and low degradation costs are more likely to be dispatched within EIM. As related to ancillary services dispatch costs, the opportunity cost of energy storage dispatch increases as the amount in storage decreases. For example, once the storage drops below an hour it may not be sufficient to provide contingency reserves for the full duration of an event. As a result, storage bidding is likely to vary as a function of the remaining storage, and energy storage resources that are somewhat depleted may be designated as contingency reserve until they are adequately refilled. Unlike other generating resources, energy storage systems can also act as loads to provide down flexibility, subject to their storage capacity limits. The price point at which it is optimal to dispatch or refill is dependent on storage system parameters and expectations of future conditions, so a realistic representation will reflect a bidding strategy rather than perfect execution against historical market results.

Ancillary Services Modeling

The opportunity cost of maintaining sufficient operating reserve capability in each hour to cover contingency and regulation reserve obligation is represented within the GRID model, as previously discussed in Section 4.1. The operating reserves provided by an energy storage resource allow capacity held on other resources to be deployed for other purposes, and the GRID model calculates the value of using freed up operating reserve capacity to avoid higher cost generation or purchases. If an energy storage resource has sufficiently low variable costs such that it is expected to be dispatched in EIM (rather than designated as contingency reserve), incremental intra-hour dispatch benefits are calculated. Intra-hour dispatch benefits are calculated using the same EIM data set used to calculate the hourly energy arbitrage values described above.

Voltage Support

Voltage support consists of providing reactive power to the grid in order to maintain a desired voltage level. Per the DNV GL report, "Grid operators are required to maintain the grid voltage within specified limits. Voltage support is especially valuable during peak load hours when distribution lines and transformers are the most stressed. An application of an energy storage system could be to serve as a source or sink of the reactive power. These energy storage systems could be placed strategically at central or distributed locations.” [34]

System voltage support requirements are typically identified through the distribution, sub-transmission and NERC TPL-001-4 planning assessments and result in distribution and/or transmission projects. These projects are assessed in the same manner as other transmission and distribution projects, using the Alternatives Evaluation Tool to determine if an energy storage solution may be a cost effective alternative. Therefore, benefits associated with this use case are included in Transmission Deferral and Distribution Deferral use cases.

Black Start Services

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. At this time, PACW relies on black start services from BPA. Therefore, PacifiCorp has not identified any needs for Black State Services within its Oregon territory (as required by the legislation) and has assigned a value of $0 to this use case.

[34] See DNV GL Energy Storage Potential Evaluation Report Section 2.1 PG 9

4.3 Transmission Services

Transmission Services includes transmission congestion relief and transmission upgrade deferral.

Transmission Congestion Relief

Transmission assets can become congested, or fully utilized, when the marginal cost of resources in the importing area exceeds the marginal cost of resources in the exporting area. This can occur either because of a shortfall of resources in an importing area or a surplus of resources in the exporting area. The value of transmission congestion relief is a function of the congestion frequency and the magnitude of the difference in price. While a transmission resource would provide value based on the simultaneous difference in price between two areas, energy storage resources provide indirect transmission congestion benefits reflecting the difference in price in a single area between the period when storage is filled, including losses and degradation, and the period when storage is discharged. While PacifiCorp recognizes the difference in classification, this benefit or avoided costs is essentially captured in the existing energy arbitrage calculation as described in Section 4.1.

Transmission Upgrade Deferral

Strategically placed energy storage within a specific portion of a transmission, sub-transmission or distribution system may be used to offset peak loading conditions or system overloads during off-normal system conditions, thereby deferring transmission system upgrades. Two key considerations for energy storage in this application are as follows:

(1) The energy storage system must provide sufficient incremental capacity, in both peak MW and duration, to defer a large lump sum investment in new transmission lines and/or equipment.
(2) The energy storage system must be reliable and controllable such that load shedding will not be required as a result of energy storage system unavailability.

Importantly, the Bulk Electric System is subject to NERC Reliability Standards. Consideration of an energy storage system to defer a transmission project necessary to maintain compliance with NERC Reliability Standards must be approached carefully to ensure the energy storage system will meet all compliance needs. As such, PacifiCorp considers energy storage systems on a case-by-case basis alongside other alternative solutions during the project development and justification phase of an initial project proposal. The energy storage system must be designed to serve sufficient load, as long as required, to resolve the identified system deficiencies.

Generally speaking, the maximum potential benefits or avoided costs associated with energy storage as used for transmission upgrade deferral would be a megawatt for megawatt replacement of traditional transmission costs, grossed up for losses if applicable, over the life of the energy storage resource. For example, 3 MW of energy storage strategically leveraged could defer 3 MW of traditional transmission projects, starting in the year it is installed. In other cases, transmission may not be needed until a later date, if at all, or the energy storage resource may not be able to sustain output for a long enough period to defer the transmission upgrade. As previously described, energy storage is evaluated initially on a case-by-case basis as transmission upgrade needs are identified.

4.4 Distribution Services

Distribution Services includes distribution upgrade deferral, Volt-VAR control, outage mitigation, and distributed congestion relief.

Distribution Upgrade Deferral

Strategically placed energy storage used within a distribution system may offset peak loading constraints, thereby deferring distribution grid upgrades. A key consideration of energy storage in this application is that the system can provide enough incremental capacity, in both peak MW and duration, to defer a large lump sum investment in new distribution equipment. As such the energy storage system is designed to serve sufficient load, as long as required, to keep the loading of the distribution equipment below a specified maximum to extend equipment service life.

Another potential benefit of energy storage systems in this application is the mitigation of the risk that a planned load growth does not occur after upgrades of transmission/distribution lines and transformers. Benefits and avoided costs associated with this use case are captured on a macro-level during the IRP process, and at the project level during distribution project identification.

High Level IRP

On a macro-level, as included in the IRP planning process, distribution upgrade deferral benefits are calculated based on a megawatt for megawatt replacement and benchmarked against traditional distribution costs, resulting in an avoided cost being applied to energy storage resources. While this calculation is sufficient for high level resource planning, it may not fully represent distribution deferral benefits on the project level.

Distribution Planning Project Level

When a distribution capacity constraint is identified, PacifiCorp performs an evaluation of traditional (i.e. equipment upgrades) and non-traditional (i.e. energy storage, distributed energy resources, energy efficiency) solutions to propose recommendations for implementation. The Alternative Evaluation Tool takes into account the load shape and system requirements to determine the size of energy storage solution that would be required to resolve the capacity constraint. The alternative evaluation tool, as described in Section 3.0, is updated on an annual basis to include the latest available information and costs for the non-traditional alternatives, including energy storage solutions.

Volt-VAR Control

"Grid operators are required to maintain grid voltage within specific limits. This requires management of reactive power, also referred to as Volt/VAR support."[35] In the event that PacifiCorp identified a need for Volt/VAR support, the specific location and requirement would be identified as a potential T&D project. As part of the methodology described in the Transmission Services and Distribution Services section this project would then be analyzed on a case by case basis to benchmark both traditional and non-traditional costs of solutions. Therefore, PacifiCorp views this use case and its associated benefits and avoided costs to already be captured in transmission and distribution upgrade deferral calculations above.

[35] See DNV GL Draft Energy Storage Potential Evaluation Section 2.0 at 9.

Outage Mitigation

"Outage mitigation refers to the use of an energy storage system to reduce or eliminate the costs associated with power outages to utilities."[36] PacifiCorp views outage mitigation as a strong component of customer reliability which is both incredibly valuable and undeniably challenging to measure. As described in DNV GL's report, in 2008, Lawrence Berkeley National Labs (LBNL) published a Department of Energy (DOE) funded study estimating the interruption cost per outage event, average kilowatt load, and unserved kilowatt hour by duration and customer class for both small and large commercial and industrial customers across the United States. The DNV GL reported identified a cost of $4.13 per customer-minute for PacifiCorp customers (or $74.3 per kWh).[37]

While very effective in understanding outage mitigation benefits as applied to specific customers or projects, this methodology cannot directly be applied to the high level evaluation of system benefits. PacifiCorp intends to continue applying this methodology on a case-by-case basis to specific projects or outage events to understand specific customer benefits and will leverage data collected through pilot projects to develop a greater understanding of benefits to both the utility and the customer.

PacifiCorp also recognizes that while outage mitigation is primarily a specific customer benefit, distributed energy storage resources installed by customers to mitigate their own outage risk have the potential to provide value if they can be dispatched for local or system needs under specified conditions. Pilot Project #1 will provide PacifiCorp with valuable experience, resulting in the ability to better characterize and understand outage mitigation. These lessons learned will potentially inform efforts to develop operating procedures and contractual terms in order to provide value from distributed energy storage resources to both specific customers and all utility customers.

Pilot Project #1

PacifiCorp has not incorporated utility benefits associated with outage mitigation in its storage potential analysis, as the benefits accrue to an individual customer, rather than customers as whole. As part of Project 1, PacifiCorp intends to reserve the capacity of the energy storage solution for outage mitigation services during pre-scheduled customer-hosted events that have historically experienced a high frequency of service interruptions. This reserved time where the energy storage solution will not be available for grid services accounts for a very small percentage of the overall availability of the energy storage solution throughout the year (approximately 5%). PacifiCorp will not receive monetary compensation during these times beyond its standard customer rates, the incremental impact of which is expected to be negligible. However, PacifiCorp will benefit through learning opportunities and the ability to evaluate customer benefits and co-optimization.

PacifiCorp's analysis of Pilot Project #1 accounts for the reduction in system benefits during these selected intervals when outage mitigation is the highest priority for the affected customer. During other intervals, the energy storage resource is optimized for system benefits through grid services and might not have adequate supply to mitigate additional outages.

[36] Order No. 17-118, Appendix A at 16.
[37] DNV GL Energy Storage Potential Evaluation Section 6.1.2.6 at 50.

Distribution Congestion Relief

PacifiCorp does not currently have distribution congestion. Benefits associated with this use case have already been accounted for in the distribution deferral use case.

4.5 Customer Energy Management Services

Customer energy management services includes power reliability, time-of-use charge reduction, and demand charge reduction.

Power Reliability

"Power reliability refers to the use of an ESS to reduce or eliminate power outages to utility customers."[38] PacifiCorp views power reliability to be strongly related to outage mitigation and that power reliability has been included in this calculation. As previously described, PacifiCorp has leveraged existing market research and known load conditions to calculate the value of reliability to specific customers.

Time-of-Use Charge Reduction

The time-of-use charge reduction use case involves reducing customer charges associated with electric energy purchased during specific time periods (e.g. season, day of week, time-of-day) when the price of energy increases. The Commission encourages electric companies to "focus on the benefits that accrue to the electric system and all utility customers from the project."[39] PacifiCorp views time-of-use charge reduction as a benefit applied to a singular customer with no clear aggregate system or company benefits and that any values are already captured in other use cases such as distribution deferral. Therefore, PacifiCorp has assigned a $0.00 value associated with this use case for this particular evaluation of energy storage given the construct of the legislative directive.

However, PacifiCorp recognizes that the benefits associated with energy storage used for time-of-use charge reduction are not zero to specific customers. As a part of Pilot Project #2, PacifiCorp intends to measure customer benefits associated with the operation and dispatch of energy storage for specific customers. This information will be used to better inform customers and the potential future wide-scale deployment of energy storage. For more information, see the Oregon Energy Storage Final Project Proposals document, Section 5.0.

Demand Charge Reduction

Demand charge reduction involves the use of an energy storage systems to reduce the maximum power draw by electric load in order to avoid peak demand charges. Benefits associated with demand charge reduction are seen by a singular customer. Aggregated benefits would already be included in other distribution service use cases such as distribution deferral. Following the same methodology applied to the time-of-use charge reduction, PacifiCorp has assigned a $0.00 value for this use case given the legislative directive. However, PacifiCorp recognizes this use case can be of significant value to specific customers, and intends to measure and quantify these benefits as part of Pilot Project #2, as described in the Oregon Energy Storage Final Project Proposals document, Section 5.0.

[38] Order No. 17-118, Appendix A at 17.
[39] Order No. 16-504 at 7.

5.0 Energy Storage Potential Calculations

Energy storage resources placed within the existing PacifiCorp network in Oregon were assumed to be deployed for each of the use cases described. This allowed the maximum potential benefit that could be derived from each use case to be quantified. As this calculation was meant to represent a high level view of the maximum potential value for energy storage within PacifiCorp's existing Oregon service territory, energy storage solutions were added as zero-cost resources and co-optimization was not factored into these calculations. The storage potential evaluation methodology is technology agnostic; however, for purposes of estimating potential benefits typical values based on lithium ion technology were used for parameters such as efficiency, storage degradation, and anticipated lifetime cycles.

Table 14 and Table 15 summarize both the broad technical assumptions used in this evaluation and specific assumptions used for the model to evaluate the potential benefit of energy storage.

Table 14 Energy Storage Device Assumptions

Parameter		Value	Unit	Source of Input/Value
Financial	Study Life	15	year	Maximum expected life of any of the technologies per Table 8 on page 15 of the "Battery Energy Storage Study for the 2017 IRP."
	Study Start Year	2021	year	Phase I commercial operation date per the Final Project Proposal Section 4.1.
	Inflation Rate	2.3	%	Standard company inflation rate
Sizing & Use	Discharge Capacity	2	MW	Peak load to address historic outages per Section 6.1.2.3 of the "DNV GL Draft Energy Storage Potential Evaluation."
	Storage Capacity	6	MWh	Total energy to address historic outages per Section 6.1.2.3 of the "DNV GL Draft Energy Storage Potential Evaluation."
	Hours Discharging	3	hours	Storage capacity divided by discharge capacity
	Availability Outage Rate	3	%	Up-time of 97% per Table 8 of the "Battery Energy Storage Study for the 2017 IRP."
	Planned Outages	3	days/yr	Per Table 8 of the "Battery Energy Storage Study for the 2017 IRP."
Technology Dependent	Efficiency	81	%	Average efficiency for lithium ion battery technology per Table 8 on page 15 of the "Battery Energy Storage Study for the 2017 IRP."
	Hours Charging	3.70	hours	Storage capacity divided by charge capacity and efficiency
	Expected Lifetime Cycles	3500	cycles	Typically, the number of cycles until 80% of storage capacity due to degradation is reached. Per Section 3.6, page 12 and Table 8, page 15 of the "Battery Energy Storage Study for the 2017 IRP."
	Energy Storage Equipment Cost	37.13	$/kWh	End of cycle life storage replacement costs based on the low end of forward projections for lithium ion technology per Figure 3 in Section 4.9 of the "Battery Energy Storage Study for the 2017 IRP."
	Storage Capacity Degradation Cost	10.61	$/MWh	Energy storage equipment replacement cost divided by assumed lifetime cycles
	Storage Capacity Degradation Rate	3.5	%/1000 cycles	Decline in maximum storage capability (MWh)

Table 15 Use Case Calculation Assumptions

Use Case	Service	Notes
Bulk Energy	Capacity or Resource Adequacy	Deferral of market transactions followed by deferral of the 2029 SCCT in the 2017 IRP preferred portfolio. Fixed costs are netted against foregone GRID and EIM dispatch benefits.
	Energy Arbitrage	Dispatch during top three hours of each day by month and storage in bottom 3.7 hours (longer due to efficiency losses). A subset of energy arbitrage is the incremental benefits associated with avoided transmission losses for energy storage resources that serve loads at the primary, secondary, or transmission level. Values for avoided secondary losses are assumed in the analysis.
Ancillary Services	Regulation	The value from freeing up existing resources from holding operating reserves as calculated using the GRID model, plus the value of energy storage dispatch with EIM participation, against both fifteen-minute and five-minute prices.
	Load Following	The value from freeing up existing resources from holding operating reserves as calculated using the GRID model, plus the value of energy storage dispatch without EIM participation, against hourly average prices.
	Spin/Non-spin Reserve	The value from freeing up existing resources from holding operating reserves as calculated using the GRID model.
	Voltage Support	Included in T&D Deferral
	Black Start Services[40]	No need currently identified as described in Section 4.2
Other	Frequency Response	No incremental need identified as described in Section 4.2.
Transmission Services	Transmission Congestion Relief	Included in Energy Arbitrage
	Transmission Upgrade Deferral	MW for MW deferral of typical transmission costs, grossed up for losses, beginning in 2021.
Distribution Services	Distribution Upgrade Deferral	MW for MW deferral of typical distribution costs, grossed up for losses, beginning in 2021.
	Volt-VAR Control	Included in T&D Deferral
	Outage Mitigation	Zero value applied as described in Section 4.5 [specific customer benefit]
	Distribution Congestion Relief	Included in distribution deferral.
Customer Energy Management Services	Power Reliability	Included in Outage Mitigation [specific customer benefit]
	Time-of-Use Charge Reduction	Zero value applied as described in Section 4.5 [specific customer benefit]
	Demand Charge Reduction	Zero value applied as described in Section 4.5 [specific customer benefit]

[40] While energy storage can provide benefits through black start services, no need exists within PacifiCorp's Oregon service territory. Therefore, this benefit was calculated at zero for the evaluation.

Table 16 below summarizes the estimated maximum potential benefit associated with energy storage on the PacifiCorp network for each use case specified. These calculations are meant to describe the potential that exists and are not representative of the net benefit associated with individual energy storage projects.

Table 16 Calculated Maximum Potential Benefits by Use Case

Use Case	Service	Benefit ($/kW-yr)[41]
Bulk Energy	Capacity or Resource Adequacy	**$56.73**
	Deferred resource lost benefits	**($1.66)**
	Energy Arbitrage	**$16.52**
Ancillary Services	Regulation	**$63.27**
	Load Following	**$35.55**
	Spin/Non-spin Reserve	**$28.60**
	Voltage Support	*Included in T&D Deferral*
	Black Start Services	**$0.00**
Transmission Services	Transmission Congestion Relief	*Included in Energy Arbitrage*
	Transmission Upgrade Deferral	**$8.09**
Distribution Services	Distribution Upgrade Deferral	**$17.89**
	Volt-VAR Control	*Included in T&D Deferral*
	Outage Mitigation[42]	**$0.00**
	Distribution Congestion Relief	*Included in Distribution Deferral*
Customer Energy Management Services	Power Reliability	**$0.00**
	Time-of-Use Charge Reduction	**$0.00**
	Demand Charge Reduction	**$0.00**

The above table demonstrates the maximum potential benefits assuming that energy storage on the PacifiCorp network is used exclusively for a single use case. However, a given energy storage resource cannot provide the maximum values for all of the use cases identified simultaneously. Instead, use cases can be stacked together but, in doing so, the achievable benefits associated with each case may be reduced. For example, in order to leverage the full value associated with regulation, all of the capacity of a given energy storage resource would be reserved for regulation and, therefore, unable to provide additional benefit from energy arbitrage, load following or spin/non spin reserve at the same time. The relationship between generation capacity, transmission and distribution deferral and the other use cases is more involved, but can also result in restrictions when combining use cases.

In general, stacked benefits can be realized in two different ways:

(1) Simultaneous use of the capacity of an energy storage resource for use cases such as capacity and regulation or capacity and distribution deferral resulting in additive benefits. For example, when a resource is being dispatched to support distribution deferral it simultaneously reduces the need for system resources.

[41] Values represent the maximum potential benefits assuming energy storage solutions added at zero cost.
[42] PacifiCorp recognizes that outage mitigation has great benefit to customers as summarized in Section 4.4, but currently assumed $0.00 in benefit to the utility.

(2) Reserving all or a portion of the capacity of an energy storage resource for different use cases during strategic time periods throughout a given day, resulting in additive benefits from use cases such as distribution deferral and regulation.

The co-optimization of the various use cases is discussed in more detail in Section 6.0.

6.0 Co-optimization of Benefits Methodology

This section includes PacifiCorp's methodology of identifying storage potential, higher and lower value applications, and the co-optimization of multiple use cases.

Identification of Storage Potential by Use Case

a. Identify storage potential by use case or application for specified time frames

Figure 5 summarizes PacifiCorp's long-term forecast of demand for the primary utility use cases identified previously and described in this section. The metric and source of the demand values are described below.

- **Generation Capacity (Front Office Transactions)** – PacifiCorp system obligation by year from the 2017 IRP Preferred Portfolio.
- **Generation Capacity (Thermal)** – PacifiCorp system cumulative incremental obligation from the 2017 IRP Preferred Portfolio.
- **Energy Arbitrage** – Average daily load variation in PacifiCorp's West BAA (daily maximum minus daily minimum) from current hourly load forecast.
- **Regulation and Load Following** – Maximum PacifiCorp West BAA annual obligation contained in GRID model, calculated using the methodology developed in the 2017 IRP Flexible Reserve Study (Appendix F)
- **Spin Reserve** – Maximum PacifiCorp West BAA obligation by year calculated by the GRID model
- **Non-Spin Reserve** – Maximum PacifiCorp West BAA obligation by year calculated by the GRID model
- **Distribution Upgrade Deferral** – Energy storage capacity with distribution deferral potential in Oregon from the DER Screening Tool
- **Transmission Upgrade Deferral** [not shown] – PacifiCorp has not yet identified any transmission upgrades that were likely to be suitable for deferral by energy storage resources.

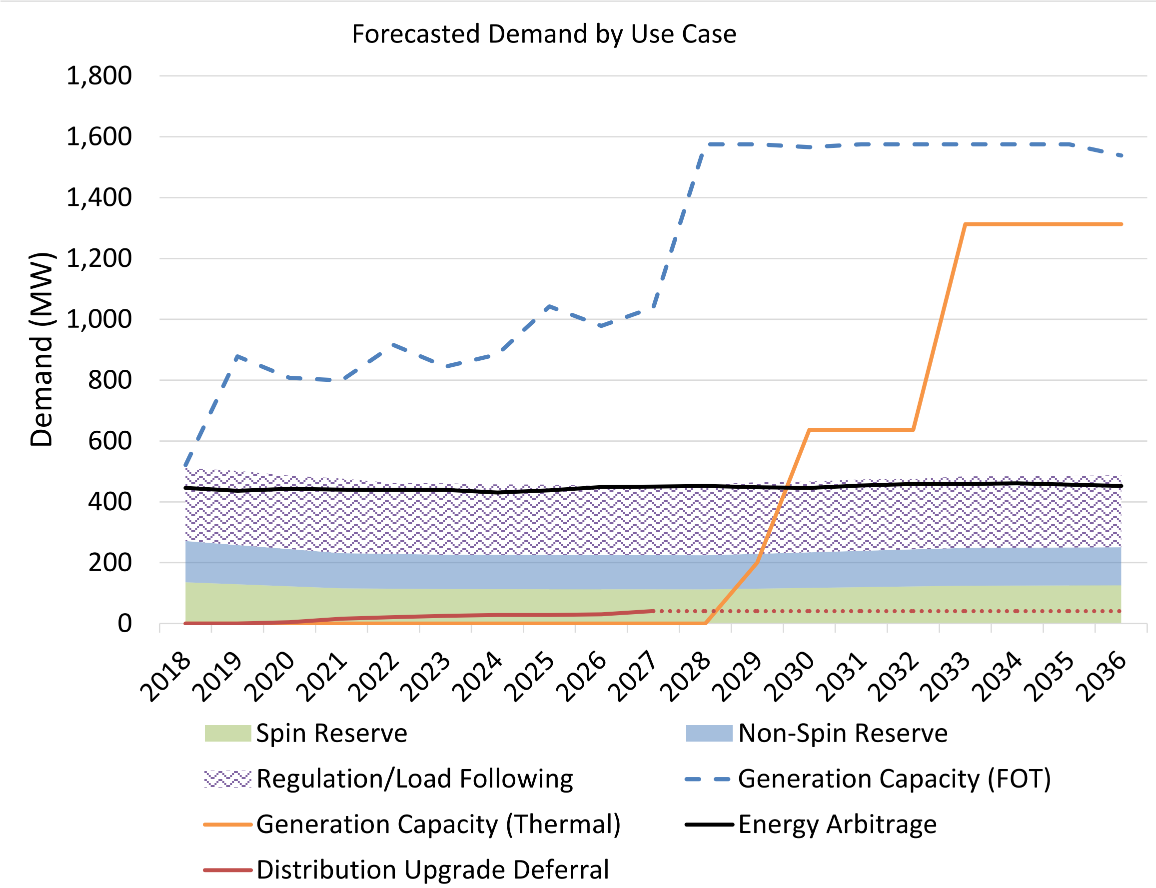

Figure 5 Forecasted Demand on the Pacific Power Network per Use Case

The storage potential for transmission and distribution deferral is highly location specific and is discussed in more detail in sections 4.3 and 4.4. While most transmission and distribution upgrades could potentially be deferred with sufficient additional resources and/or energy storage additions, cost-effectiveness is a limiting factor. PacifiCorp already uses screening tools to evaluate energy storage, resource additions, and targeted DSM as alternatives to transmission and distribution upgrades, and intends to use the results of the energy storage methodology to enhance that analysis.

Identification of Higher and Lower Value Applications

b. ***Describe how higher and lower value applications were identified***

As previously discussed, to the extent energy storage power capacity or storage capacity is reserved for one use case in a given interval, it generally cannot also be used for other uses cases in that interval. Generation capacity deferral is something of an exception, as reliably serving peak system load requires scheduled resource dispatch (i.e. energy arbitrage), ancillary services, and the ability to deliver to load in all locations (i.e. adequate transmission and distribution capacity). As a result, generation capacity benefits are generally additive to the benefits from other use cases. PacifiCorp has identified two relatively narrow exceptions to this.

First, to account for the fact that ancillary services must be held in all hours but are only deployed under limited circumstances, PacifiCorp proposed using three-hour storage capacity to determine the capacity contribution for ESS providing ancillary services, versus four hours for ESS providing scheduled resource dispatch (either energy arbitrage for the system, or for a specific location that allows transmission and distribution capacity upgrade deferral). To the extent the ancillary service supply exceeds PacifiCorp's ancillary service obligations, any incremental ESS would receive capacity consistent with four-hour storage capacity. This circumstance is not anticipated for ESS in Oregon under consideration in this proceeding.

Second, generation capacity benefits may be reduced to the extent a transmission or distribution upgrade deferral application does not allow for dispatch during system peak conditions, for instance if the distribution peak is not coincident with the system peak, or if a portion of the resource's storage capacity is exclusively reserved for outage mitigation. Fixed dispatch, rather than flexible dispatch, also results in a reduced capacity contribution.

The remaining use cases are mutually exclusive in any given interval. The designation of an ESS for energy arbitrage or one of the ancillary services can be modified on an hourly basis, subject to adequate energy being present in storage. On the other hand, transmission and distribution upgrade deferral requires resource availability and dispatch in all of the intervals in which a circuit would otherwise exceed its rated limits. In addition, the ESS must be adequately filled before potential exceedance events, which can restrict its availability for other uses for a period prior to dispatch.

While the annual benefits associated with distribution upgrade deferral are lower than that for the energy arbitrage or ancillary services use cases, the portion of the year devoted to that use case can be very low, as illustrated in the table below. The illustrative value of two percent usage represents four hours per day during weekdays in two months per year, which is likely higher than the requirement in many distribution upgrade deferral applications.

Table 17 Stacked Use Case Comparison

	Use Case Benefit $/kw-year	Annual Usage %	Avg. Use Case Benefit $/MWh	Capacity Benefit $/MWh
Distribution Upgrade Deferral	$17.89	2%	$102.09	varies
Transmission Upgrade Deferral	$8.09	2%	$46.19	varies
Ancillary Services - Regulation	$63.27	100%	$7.22	$6.29
Ancillary Services - Load Following	$35.55	100%	$4.06	$6.29
Ancillary Services - Spin/Non-spin	$28.60	100%	$3.26	$6.29
Energy Arbitrage - Fixed Schedules, Blended optimization	$30.01	100%	$3.66	$2.99

As shown in Table 17, distribution and transmission upgrade deferral provides the highest marginal benefits during intervals when they are required. The next highest benefit comes from ancillary services, with the most flexible use case, regulation, providing the greatest benefits. When capacity value is also taken into account, energy arbitrage provides the lowest benefits. This is unsurprising as it represents the least flexible use case, with fixed schedules of dispatch determined in advance.

In light of these considerations and after accounting for generation capacity deferral, distribution upgrade deferral provides the greatest value (where available), with regulation service providing the greatest benefit in any remaining hours.

To the extent a portion of the capacity in an energy storage resource is used to provide specific customer benefits and is not dispatchable for grid services or system requirements, it may still provide generation capacity as well as energy arbitrage benefits between low and high price periods across the day, depending on the particular customer use case. However, resources that are dispatched according to fixed daily schedules or a customer-specific requirement will provide less value than a resource that can be dispatched in coordination with actual market conditions and system requirements.

System Locations with the Greatest Storage Potential

a. Identify system locations with the greatest storage potential

System locations with the greatest potential for cost-effective energy storage include the following:

- Locations that make use of existing facilities to keep upgrade costs low.
- Locations with planned upgrades that can be readily configured to include energy storage additions.
- Locations with planned upgrades that can be avoided by energy storage additions.
- Customer-sited or generation-sited energy storage that can provide the benefits above and may provide other benefits or efficiencies.

While distribution and transmission upgrade deferral has the potential to provide significant value, the potential is limited by four factors. First, these deferrals are highly location specific, as an ESS must provide relief to a specified system element. Second, as described above, the number of hours per year in which system elements are at risk of being overloaded is small. Third, overload conditions often are not projected for several years in the future, and may be dependent on significant load growth or block load additions which may or may not come to pass. Fourth, if load growth continues, an energy storage resource will be deployed more often and may rapidly become inadequate to cover the maximum shortfall in capacity or energy, at which point a significant expansion of the ESS would be needed to continue deferring upgrades. In addition, as an ESS is devoted to distribution and transmission upgrade deferral in more hours the total cost of the deferral remains fixed and the average benefit declines, while benefits from alternative use cases in those hours are lost. Similarly, an ESS with fixed dispatch schedules to reduce loading on system elements require four hours of storage (as opposed to three hours for dispatchable resources), to receive the full generation capacity deferral.

As a result, as the hours a resource is dispatched for transmission and/or distribution deferral increase, capacity benefits may be reduced. These effects are incorporated in PacifiCorp's evaluation, and as a result of the trade-off with generation capacity deferral, PacifiCorp identified scenarios in which transmission and distribution deferral would cease in 2028, as generation capacity deferral becomes a more valuable use in 2029. A distribution system upgrade is cheaper than the fixed costs of an SCCT in 2029 at $139/kW-year, so this result makes sense.

PacifiCorp has evaluated 22 transmission upgrade projects and 14 distribution substation upgrade projects currently in the planning stages in Oregon with in-service dates after 2018. Of these, three distribution substation upgrade projects were identified in which energy storage resources compared most favorably to the traditional alternative, and benefits were prepared specific to each of the three locations. Please see Section 7.0 for more details.

Co-optimization Methodology and Assumptions

Enable co-optimization between services

PacifiCorp first independently evaluated the maximum potential benefit associated with each of the energy storage system use cases with the assumption that an ESS was optimally dispatched for a single use case. This represents the maximum benefit a use case can provide as included in Table 16 of Section 0 on page 38.

Next, PacifiCorp evaluated the overlap between the various use cases to identify which use cases could be stacked for maximum benefits. Based on the prioritization from the higher and lower value applications described above, and the identified system needs, generation capacity and distribution deferral are the primary use cases, with value in remaining intervals based on regulation service. The net benefits of distribution deferral are calculated on an annual basis so that periods when other use cases provide greater value can be identified. Should DER screening identify transmission upgrade deferral opportunities, the same co-optimization process would apply. The co-optimization of distribution deferral includes:

- **Upgrade probability by year**: This incorporates both the probability that load growth will result in a need for an upgrade as well as the number of years before continued growth is expected to exceed the capability of the ESS.
- **Avoided upgrade cost**: Location specific costs, where available.
- **Energy and avoided line losses**: This specifically accounts for the expected ESS dispatch when loading would otherwise exceed rated limits and accounts for the energy arbitrage benefits associated with that dispatch.
- **Lost EIM dispatch benefits**: An ESS dispatched due to local loading is no longer available for dispatch in response to system requirements. In addition, the ESS must be filled prior to intervals in which it may be called upon for local requirements, further limiting its availability for EIM dispatch. To reasonably ensure reliable operation, the ESS is likely to be reserved under a range of conditions (i.e. not just the peak load day for that area which is not known in advance), but any day that could reasonably end up being a peak load day. This accounts for the lost benefits relative to a case in which the ESS was available for EIM dispatch at all times.
- **Lost operating reserve benefits**: An ESS dispatched due to local loading is no longer available for dispatch in response to system requirements. This accounts for the lost benefits relative to a case in which the ESS was available for system dispatch at all times, as calculated within the GRID model. The analysis assumes that, for distribution deferral applications, when an ESS is reserved for distribution or outage mitigation but not currently being dispatched, it continues to be credited against operating reserve requirements and can be called upon in system emergencies.
- **Lost capacity contribution**: The fixed schedule dispatch associated with transmission or distribution related dispatch (as opposed to reserved capacity) has a lower capacity contribution than dispatchable resources. This adjustment accounts for the impact on avoided capacity costs.

Cost Analysis Assumptions for Benefit-to-Cost Ratio Calculations

Table 18 below includes the various capital cost items used to evaluate the cost effectiveness of system level energy storage including both a range of values and the source of the values used.

Table 18 Capital Cost Assumptions and Values for Lithium Ion Energy Storage

Cost Parameter & Description	Source of Estimate	Low	Mid	High
Energy storage equipment cost ($/kWh) - Cost of Li-ion battery cells - Assembly cost for DC battery system	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$92	$154	$215
Balance of system for DC battery system ($/kW) - Power conversion equipment (inverter, packaging, container, and controls) - Control system - Other supporting equipment, such as thermal management, wiring and interconnection equipment, and protection of various components	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$257	$310	$362
EPC Cost ($/kWh) - All direct costs for development and project management, and costs associated with a fixed price, turn-key, EPC contract	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$150	$225	$300
Interconnection Application and Assumed Upgrades ($/project) - Interconnection studies costs owed to the transmission provider - Laydown area improvements and addition of distribution equipment	http://www.pacificorp.com/tran/ts/gip/qf/oregon.html	$449,300	$556,300	$663,300
Communications Upgrade ($/project) - Modifications to both the central service center and local communications devices	PacifiCorp estimate based on similar projects within the company	$17,000	$17,000	$17,000
Owner's Engineering PM ($/Project) - Owner's direct engineering & project management	PacifiCorp estimate based on similar scale projects within the company	$54,000	$57,000	$60,000
Fixed O&M Cost ($/kW-yr) - Maintenance and adjustment activities - Tightening of mechanical and electrical connections, cleaning, power stack and pump replacements, tightening of plumbing fixtures [not chemistry refresh]	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$6	$8.50	$11
Annual Monthly Inspection ($/yr) - Monthly inspection of location, equipment, fencing, etc	Typical range of substation inspection cost for PacifiCorp OR territory	$2,280	$2,778	$3,276

Other costs such as real estate fees and location specific additional inspections were considered for location specific cost analysis.

Co-optimization Calculations and Results

PacifiCorp stacked benefits using the co-optimization described above to identify ESS configurations and uses with the greatest potential stacked benefits. PacifiCorp used the consistent technical parameters (as identified in Table 14 and Table 15 in Section 0, unless otherwise noted) to ensure proper comparison could be made across a range of scenarios. Key scenarios are described in Table 19, with results of the potential benefits by use case in $/kW-yr for each scenario shown in Table 20. Note that while the benefits per kW drop for resources with higher capacity or fewer hours of storage, the total benefits for an ESS with 6MW/6MWh are higher than those of a 2MW/6MWh ESS.

Table 19 Description of Scenarios for Potential Benefit Sensitivity Analysis

Scenario	Primary Use Case for Co-Optimization	Power (MW)	Energy Capacity (MWh)	Description
Regulation – 3hr	Regulation	2	6	Base case 2 MW x 3 hours energy storage base case co-optimized around regulation
Load Following – 3hr	Load Following	2	6	2 MW x 3 hours energy storage base case co-optimized around load following
Spin/Non-Spin – 3hr	Spin/Non-Spin	2	6	2 MW x 3 hours energy storage base case co-optimized around spin/non-spin reserve
Fixed Schedule – 3hr	Energy Arbitrage	2	6	2 MW x 3 hours energy storage base case co-optimized around energy arbitrage with a fixed schedule
Addition Scenarios with Various Technologies				
Regulation – 2hr	Regulation	2	4	2 MW x 2 hours scenario optimized around regulation
Load Following – 2hr	Load Following	2	4	2 MW x 2 hours scenario co-optimized around load following
Regulation – 1hr	Regulation	6	6	6 MW x 1 hours high power scenario optimized around regulation

Table 20 Location Agnostic System Level Potential Co-optimized Benefits[43] for Energy Storage

Service	Base Case 2MW x 3 hours				Technology Scenarios		
	Regulation – Base Case ($/KW-yr)	**Load Following Base Case ($/kW-yr)**	**Spin/Non-Spin Base Case ($/kW-yr)**	**Fixed Schedule Base Case ($/kW-yr)**	**Regulation – 2hr ($/kW-yr)**	**Load Following – 2hr ($/kW-yr)**	**Regulation – High Power ($/kW-yr)**
Capacity or Resource Adequacy	$56.73	$56.73	$56.73	$26.95	$37.82	$37.82	$18.91
Deferred resource lost benefits	($1.66)	($1.66)	($1.66)	($0.79)	($1.11)	($1.11)	($0.55)
Energy Arbitrage (+Losses)	$1.85	$0.62	$0.13	$30.01	$1.77	$0.62	$1.54
Regulation	$63.27 *[EIM: $34.66 GRID: $28.60]*	-	-	-	$62.14 *[EIM: $33.54 GRID: $28.60]*	-	$60.19 *[EIM: $31.59 GRID: $28.60]*
Load Following	-	$35.55 *[EIM: $6.95 GRID: $28.60]*	-	-	-	$34.85 *[EIM: $6.25 GRID: $28.60]*	-
Spin/Non-spin Reserve	-	-	$28.60 *[GRID only]*	-	-	-	-
Transmission Upgrade Deferral	*location specific*	*location specific*	*location specific*	*location specific*	*location specific*	*location specific*	*location specific*
Distribution Upgrade Deferral Potential[44]	*location specific*	*location specific*	*location specific*	*location specific*	*location specific*	*location specific*	*location specific*
TOTAL $/kW-yr	**$120.19**	**$72.18**	**$83.80**	**$56.17**	**$100.63**	**$72.18**	**$80.08**

These results were compiled into Figure 7 to demonstrate both the value assigned to each use case, as well as the range of potential total co-optimized benefits for the full range of scenarios modeled.

[43] Benefits calculated as avoided costs assuming energy storage installed as a zero cost resource per Section 4.1.
[44] Distribution Deferral potential benefits were included in this chart but not added to the total. This value represents the maximum potential that could exists if energy storage was placed in a location to meet a distribution upgrade deferral need.

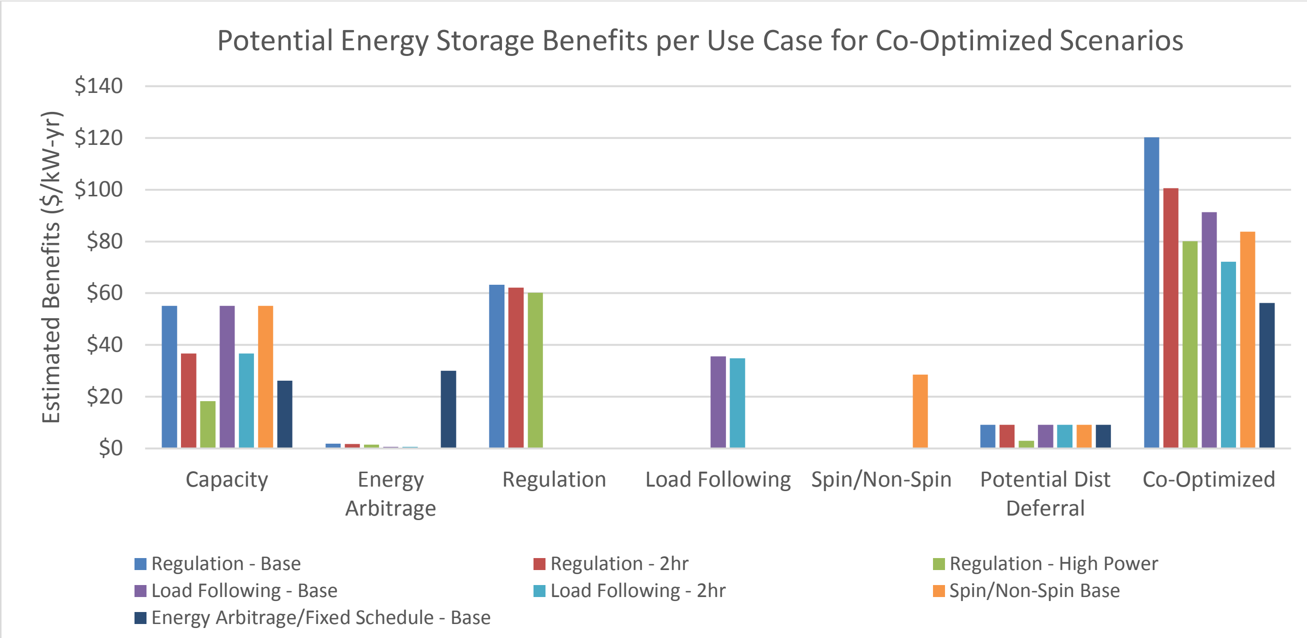

Figure 6 Potential Energy Storage Benefits per Use Case for Multiple Co-Optimized Scenarios

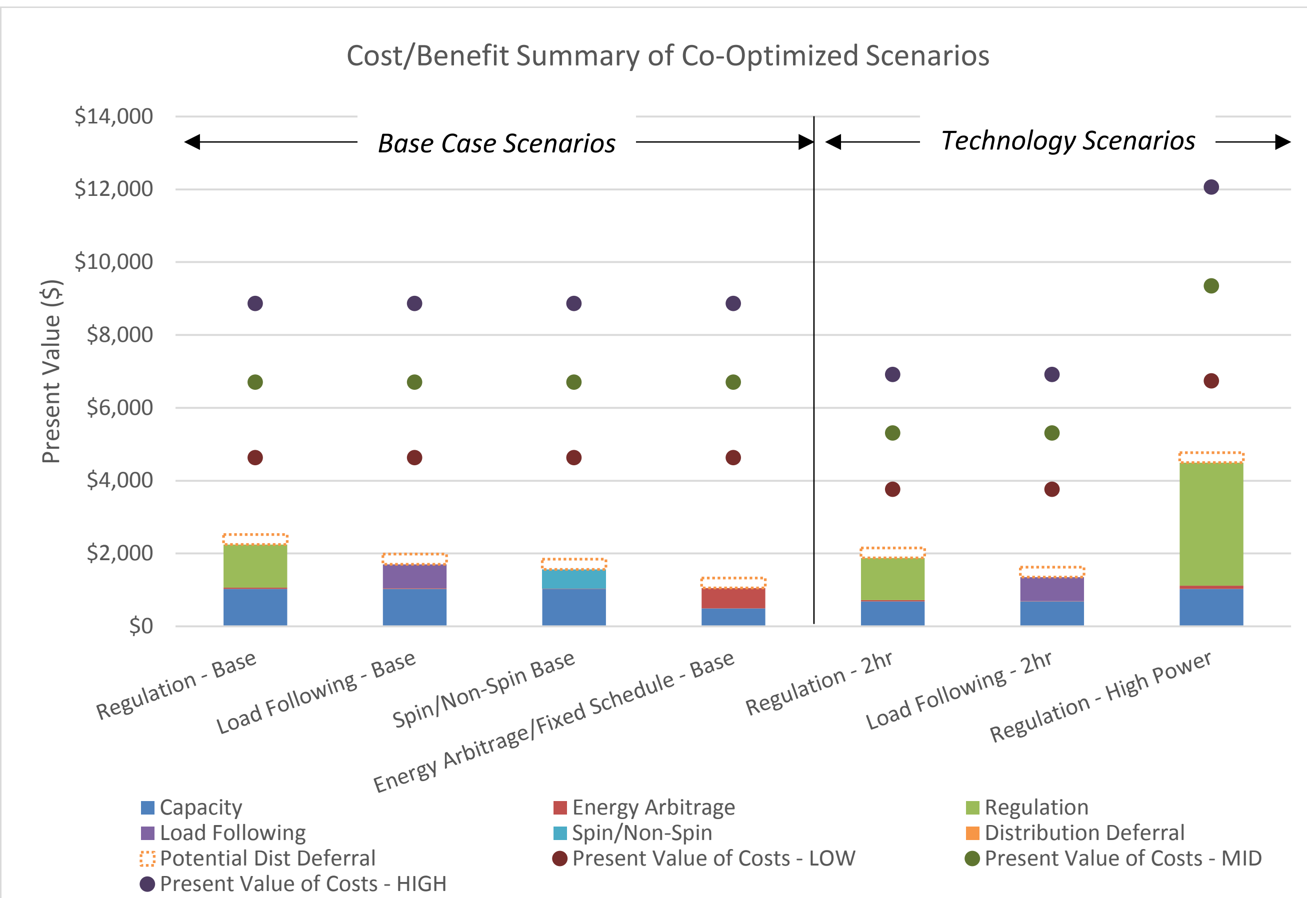

Figure 7 Cost/Benefit Analysis of Co-Optimized Scenarios

The following table summarizes the benefit-to-cost ratios and the average net present value (revenue requirement) to all utility customers for each of the above scenarios.

Table 21 Summary of Co-Optimized System Level Cost/Benefit Analysis

	Base Case [2MW x 3 hours] Co-Optimization Scenarios				System Level Technology Scenarios		
	Regulation - Base	Load Following - Base	Spin/Non-Spin Base	Energy Arbitrage/Fixed Schedule - Base	Regulation - 2hr	Load Following - 2hr	Regulation - High Power
BCR Range	0.25 - 0.48	0.19 - 0.37	0.18 - 0.34	0.12 - 0.23	0.27 - 0.50	0.20 - 0.36	0.37 - 0.66
Avg NPV RR ($)	($4,463,049)	($5,004,189)	($5,144,261)	($5,661,500)	($3,429,759)	($3,962,354)	($4,857,768)

In all scenarios modeled above, energy storage was not found to be cost effective in the near term. However, this analysis demonstrated that a range of both benefits and costs exists for energy storage that is highly dependent on both use case parameters, such as being reserved for regulation as opposed to spin/non-spin reserve, and technology parameters, such as capacity or energy rating. This analysis also demonstrated that the greatest potential benefit from energy storage on the PacifiCorp network for all utility customers is likely achieved through co-optimizing around distribution deferral and regulation. PacifiCorp used this general principle to begin identifying project specific locations where energy storage could meet potential transmission and distribution deferral needs and future modeling of costs and benefits assumed that co-optimization around regulation would provide the greatest benefit to all utility customers.

Both the methodology described in this document and the calculations performed in the DNV GL report in Appendix C demonstrate the complexity and challenges associated with determining the value of energy storage within the existing PacifiCorp Oregon service territory. The costs, benefits, and cost effectiveness values presented in this document are meant to describe the methodology and assumptions regarding energy storage evaluation at PacifiCorp and provide a starting point for pilot project identification and selection.

Common trends identified throughout the evaluation include the following:

- ESS costs are declining and forecasted to continue declining for the next decade, requiring regular updates to market prices and models.
- Projects with the greatest economic viability tended to have stacked use cases including capacity, T&D deferral, and regulation service (i.e. EIM participation).
- The benefit from avoided capacity costs is expected to increase significantly as PacifiCorp's generation capacity deficiency year (currently 2029) gets closer to the commercial operation date of the ESS.
- Market conditions and costs of both traditional and alternative solutions will change over time, resulting in variations to both benefit and cost calculations in different years, and potential near term opportunities for distribution or transmission deferral.

7.0 Project Specific Site Selection & Calculations

As described in Section 6.0, the greatest potential benefit for energy storage on the PacifiCorp network exists where energy storage technology can meet either a transmission or distribution upgrade need and allow for additional stacked benefits co-optimized around generation capacity and regulation.

Consistent with the methodology described in 3.0, potential locations with transmission and distribution upgrade needs within the next 10 years were identified through T&D Planning studies and screened using the alternative energy evaluation tool as described in Section 3.0. Of 19 potential locations identified with transmission or distribution upgrade needs, 14 were located in Oregon, 12 could be deferred or resolved through energy storage technology, and 3 were relatively competitive as compared to traditional solutions. The costs and benefits for each of these three locations were calculated consistent with the methodology described in Section 6.0. Table 22 below includes the results of this analysis as well as the list of qualitative benefits used in PacifiCorp's site-selection process.

Table 22 Risk Based Decision Criteria for Pilot Project #1 Location Selection

BCR	PacifiCorp evaluated the potential benefits and costs associated with each location to calculate a benefit-to-cost ratio with a larger value indicating a more cost-effective project. PacifiCorp also evaluated the corresponding range of NPV Revenue Requirement to understand which location resulted in the least cost to all utility customers.
Less than 5MW Capacity Need	The calculated distribution deferral benefits inherent to the BCR are contingent on the energy storage solution meeting the capacity need as opposed to another project. Locations with large potential capacity needs have a greater likelihood that the energy storage solution will not be sufficient to meet the entire need, and the distribution upgrade project will still be required. Therefore, locations with > 5MW capacity were classified as higher risk locations for Pilot Project #1.
Growth Rate > 1.00%	The ability to realize the estimated benefits from distribution deferral benefits relies on load growth. Locations without projected load growth, have a greater likelihood that the BCR is overstated. PacifiCorp considered locations with projected load growth of less than 1.00% to be higher risk for pilot project location selection.
Existing Load Data to Support Assumptions	Distribution deferral benefits inherent to the BCR calculation rely on load growth projections. If specific load data is not available, the load growth projections have a higher range of uncertainty, resulting in a location with higher project risk.
Location Accessibility	Highly accessible locations near service centers or other PacifiCorp facilities are preferred over rural or inaccessible locations for pilot project selection.
Generation Resources on Circuit	Locations adjacent to generation are considered favorable for pilot project selection as these locations provide PacifiCorp with additional opportunities to understand how energy storage integrates with other forms of distributed generation.
Customer Partnership	An existing customer partnership is favorable as it reduces the risk to project execution and the overall collection and evaluation of data.
Potential to Evaluate a Majority of Use Cases	Locations with the ability to evaluate more of the use cases prescribed in the legislation was considered favorable to pilot project location selection.

Table 23 below summarizes the results on this evaluation for the top three potential locations previously identified. The costs and benefits for each of these three locations were calculated consistent with the methodology described in Section 6.0.

Table 23 Short List of Project Locations Cost, Benefit, and Risk Summary

	Distribution Site #1	Distribution Site #2	Distribution Site #3
Estimated BCR (range)	0.27 – 0.51	0.28 – 0.54	0.26 – 0.50
Load / Capacity	21.5 / 25 MVA	25.2 / 30 MVA	5.2 / 5.75 MVA
Less than 5MW Capacity Need	Yes	No	Yes
Growth Rate > 1.00%	Yes	Yes	No
Existing Load Data to Support Assumptions	Yes	Yes	No
Easily Accessible	Yes	Yes	No
Generation Resources on Circuit	Yes	No	No
Customer Partnership	Yes	No	No
Ability to Test Most Use Cases	Yes	No	No
Risks	Load growth	Load growth	Load growth and modeling uncertainty
Perceived Risk Level of Project Delivery and Benefits	Low	Medium	High
Recommendation	**Pursue Energy Storage Pilot Project #1**	Consider energy storage longer term	Consider energy storage longer term

Based on the above analysis, Distribution Site #1 presented the least risk, lowest cost opportunity to pilot small scale energy storage in a location that provides great flexibility for the full range of use cases, and maximizes learning opportunities for PacifiCorp. Therefore, Distribution Site #1 was chosen as the location for Pilot Project #1.

Pilot Project #1 Costs and Benefits Summary

PacifiCorp analyzed the benefits and costs associated with the co-optimization of multiple technologies around regulation, specific to Phase I of Pilot Project #1 as described in Table 24 below.

Table 24 Pilot Project #1 Technology Scenarios Co-Optimized Around Regulation

	Capacity (MW)	Energy (MWh)	Description
Distribution Site #1 – Base Case	2	6	2 MW x 3 hours base case sized to accommodate historic outage characterization at location #1
Distribution Site #2 – Base Case	2	6	2 MW x 3 hours base case at location #2
Distribution Site #3 – Base Case	2	6	2 MW x 3 hours base case at location #3
Addition Technology Scenarios for Location #1			
Pilot Project #1 - 2hr	2	4	2 MW x 2 hours scenario co-optimized around regulation at location #1
Pilot project #1 – 6 MW	6	6	6 MW x 1 hours high power scenario co-optimized around regulation at location #1

Figure 8 below demonstrated the potential range of benefits and costs for the three scenarios described as compared to the system level analysis performed in Section 6.0.

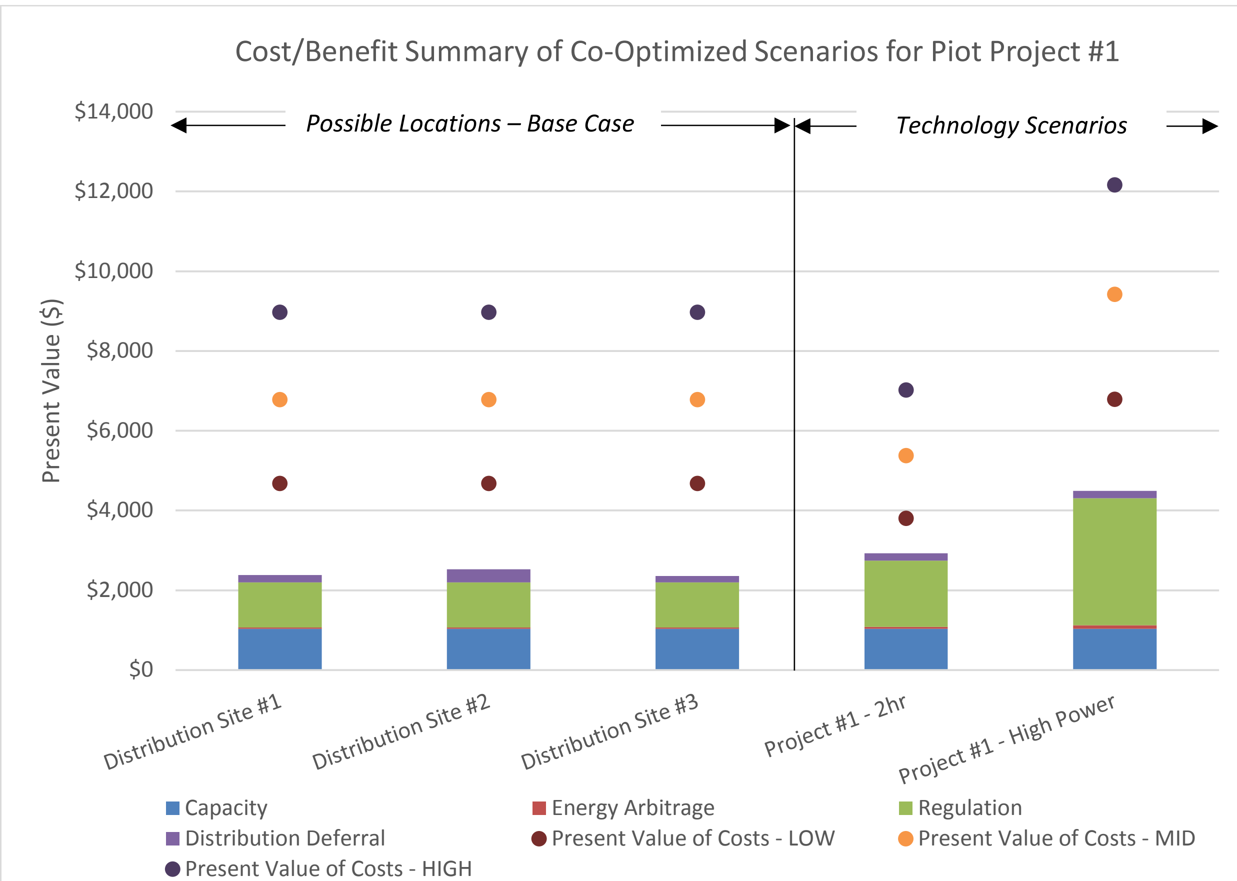

Figure 8 Cost/Benefit Summary of Pilot Project #1 Scenarios

The table below includes the potential range of costs, benefits, benefit-to-cost ratios and revenue requirements associated with Phase I of Pilot Project #1 for each of the scenarios modeled.

Table 25 Benefit-to-Cost Ratio Results for Pilot Project #1 Scenarios

	Potential Locations Evaluated for Pilot Project #1			Pilot Project #1- Technology Scenarios	
	Distribution Site #1 Base Case	Distribution Site #2 Base Case	Distribution Site #3 Base Case	2 Hours of Storage	High Power
Sizing	2 MW x 3 hours	2 MW x 3 hours	2 MW x 3 hours	2MW x 2 hours	6 MW x 1 hours
Present Value of Benefits ($)	$2,382,980	$2,328,519	$2,360,519	$2,928,720	$4,493,336
Present Value of Costs ($)	$4,678,060 - $8,965,966	$4,678,060 - $8,965,966	$4,678,060 - $8,965,966	$3,808,381 - $7,018,646	$6,786,542 - $12,159,976
BCR Range	0.27 - 0.51	0.28 - 0.54	0.26 - 0.50	0.42 - 0.77	0.37 - 0.66
NPV ($) *Revenue Requirement*	($2,295,080) – ($6,582,986)	($2,149,541) – ($6,437,447)	($2,317,541) – ($6,605,447)	($874,661) – ($4,089,926)	($2,293,207) – ($7,666,640)

This analysis demonstrates that a range of costs, benefits, and subsequent benefit-to-costs ratios and revenue requirements exist for Phase I of Pilot Project #1. This analysis also demonstrates that the potential benefit-to-cost ratios for Pilot Project #1 are similar to those calculated for other potential locations as well as the system level co-optimized scenarios in Section 6.0. This analysis further supports the selection of Pilot Project #1 as it could potentially provide the least cost to all utility customers with the least risk of project delivery.

In consideration of the three technologies modeled for Pilot Project #1 (base case, two hours, high power), the two MW x two hours scenario does produce the highest potential benefit-to-cost ratio. However, this does not meet the minimum threshold of five MWh set forth in HB 2193[45] and PacifiCorp elected not to use these specifications for the preliminary sizing of the project. While the high power scenario does produce the second highest potential benefit-to-cost ratio, due to the large uncertainty and high range of costs, it also has the potential to have the lowest net present value, or greatest revenue requirement.

Therefore, PacifiCorp selected the two MW x three hours base case energy storage solution as the preliminary sizing for the Pilot Project #1 proposal as included in Section 4.0 of the Final Oregon Energy Storage Project Proposal document. This sizing meets the minimum threshold of five MWh as set forth by HB 2193, accommodates the historic outage characterization on the feeder, and presents the lowest risk option given the information available to PacifiCorp at this time.

While this analysis represents PacifiCorp's best estimate of the potential costs and benefits of Pilot Project #1 Phase I, PacifiCorp recognizes this analysis was not fully exhaustive of all potential scenarios and sizing

[45] According to HB 2193, if authorized by the Commission, electric companies shall procure on or before January 1, 2020 one or more qualifying energy storage systems that have the capacity to store at least 5 MWh and no more than one percent of the company's 2014 Oregon system peak load.

options that exist for Pilot Project #1. Therefore, a detailed engineering analysis should be performed to choose the optimum technical specifications that result in the greatest benefit-to-cost ratio. Upon project approval from the Commission, PacifiCorp intends to issue an RFP for an Owners' Engineer to perform this detailed analysis, including the final sizing and benefit-to-cost ratio calculation. This is expected to occur in May of 2019, at which time PacifiCorp intends to review any modifications with the Commission and seek any additional approvals to continue progressing the project. This is consistent with the strategy described in Section 4.0 of the Oregon Energy Storage Final Project Proposal.

Pilot Project #2 Costs and Benefits Summary

Using the same methodology and assumptions as described in Section 6.0, PacifiCorp modeled the potential benefits and costs to all utility customers associated with Pilot Project #2. For a description of this pilot project, see Section 5.0 of the Oregon Energy Storage Project Proposal. The following cost-sharing scenarios were analyzed:

Scenario #1: 75%/25% cost share between PacifiCorp and specific customer(s) participating in the program, respectively. Customer(s) receive outage mitigation benefits with their share of the ESS, PacifiCorp receives all benefits associated with its share of the ESS.

Scenario #2: 50%/50% cost share between PacifiCorp and specific customer(s) participating in the program respectively. Customer(s) receive outage mitigation benefits with their share of the ESS, PacifiCorp receives all benefits associated with its share of the ESS.

The table below includes the specific assumptions used for each of these two scenarios.

Table 26 Pilot Project #2 Scenario Assumptions

Parameter	Scenario #1 - 75% share	Scenario #2 – 50% share
Capacity (MW)	1	1
Hours (hrs)	4	4
Storage (MWh)	4	4
Hours Reserved for Specific Customer	1 [25%]	2 [50%]
Hours Reserved for all Utility Customers [grid services]	3 [75%]	2 [50%]

The following table describes the potential benefits to all utility customers associated with scenarios #1 and #2 above. Because of the small size of individual projects, it is unclear whether participation in EIM is feasible due to metering and other operational requirements. Participation in EIM is subject to the provisions within PacifiCorp's Open Access Transmission Tariff, in particular those contained within Attachment T (EIM), as well as in the tariff of CAISO as the EIM market operator. If EIM participation by small resources proves infeasible for particular project proposals, PacifiCorp would work to optimize benefits among the remaining use cases. The table below shows benefits associated with load following service rather than regulation.

Table 27 Summary of Potential Benefits to all Utility Customers for Pilot Project #2

Use Case	Service	Scenario #1 - 75% Potential Benefit to All Utility Customers ($/kW-yr)	Scenario #2 -50% Potential Benefit to All Utility Customers ($/kW-yr)
Bulk Energy	Capacity or Resource Adequacy	$56.73	$37.82
	Deferred resource lost benefits	($1.66)	($1.11)
	Energy Arbitrage	$0.66	$0.62
Ancillary Services	Regulation	$35.55 *[EIM: $6.95 GRID: $28.60]*	$34.85 *[EIM: $6.25 GRID: $28.60]*
	Load Following	$0.00	$0.00
	Spin/Non-spin Reserve	$0.00	$0.00
	Voltage Support	*Included in T&D Deferral*	
	Black Start Services	$0.00	$0.00
Transmission Services	Transmission Congestion Relief	*Included in Energy Arbitrage*	
	Transmission Upgrade Deferral	$0.00	$0.00
Distribution Services	Distribution Upgrade Deferral	$4.56	$4.56
	Volt-VAR Control	*Included in T&D Deferral*	
	Distribution Congestion Relief	*Included in Distribution Deferral*	
Total Potential Benefit to All Utility Customers		**$91.28**	**$72.18**

Table 28 Additional Potential Benefits to be explored through Pilot Project #2

Use Case	Service	Potential Benefit
Distribution Services	Outage Mitigation	*Customer benefit specific to participant to be assessed through Technical Assistance Concept*
Customer Energy Management Services	Power Reliability	*Included in Outage Mitigation*
	Time-of-Use Charge Reduction	*Customer benefit specific to participant to be assessed through Technical Assistance Concept*
	Demand Charge Reduction	*Customer benefit specific to participant to be assessed through Technical Assistance Concept*

8.0 Forward Looking Cost Effectiveness

While the projects described in this document are not currently cost-effective, PacifiCorp anticipates that in the future, both the needs at PacifiCorp and the market prices regarding energy storage have the potential to change, making energy storage more competitive and potentially cost-effective. The following diagram demonstrates the potential benefits and costs modeled for Pilot Project #1 over time.

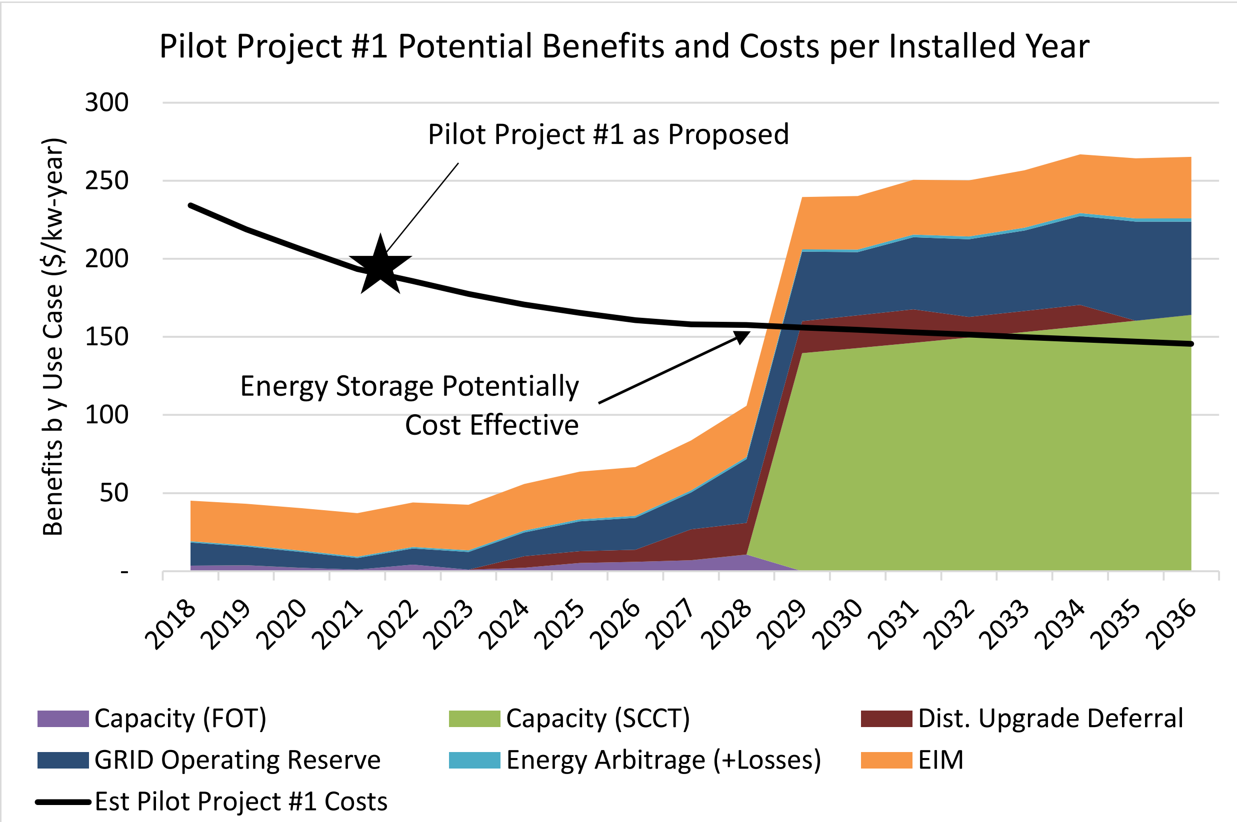

Figure 9 Pilot Project #1 Base Case Costs and Benefits Over Time

From 2018 to 2029, the value of energy storage remains low and in the range of approximately $50-$100/kW-year, strongly influencing the cost-effectiveness analysis. However, PacifiCorp anticipates that the value of energy storage will increase dramatically at the time of its next thermal resource addition in 2029 as shown in the figure above. In addition, the cost of energy storage is anticipated to fall significantly over the next ten years. As seen in the figure above, PacifiCorp anticipates that energy storage has the potential to become cost effective in 2029.

While Pilot project #1 is not presently cost-effective, this project allows PacifiCorp to validate modeling through field test data, learn how to properly control and integrate energy storage solutions into the existing network, and evaluate the range of potential benefits to utility customers on a small scale pilot project. Energy storage has the potential to play a significant role in PacifiCorp's resource mix in the future, and its costs and benefits must be accurately accounted for if it is to be part of a least-cost, least-risk portfolio. PacifiCorp intends to be prepared to efficiently implement energy storage if it becomes cost-effective.

9.0 Go-Forward Strategy

PacifiCorp is committed to the continued exploration of alternative resources and clean energy solutions. While PacifiCorp believes the described approach to evaluation of energy storage to be robust, thorough, and compliant with legislation, PacifiCorp has identified that as both energy storage technology and its range of applications evolve, evaluation methodologies will require refinement and adjustment to reflect current market trends. PacifiCorp is therefore keeping a critical eye on the following areas for potential improvement and refinement regarding energy storage evaluation:

Capacity-Equivalence of Energy Storage Resources: Identified in the capacity description in Section 4.1.

Co-optimization: The existing methodology and modeling allow the highest value application for energy storage to be selected with the remaining capacity applied to subsequent use cases. PacifiCorp recognizes that while this does allow for stacked applications to be considered, the co-optimization of such stacked applications may not be perfect. The proposed pilot projects are structured to allow experimentation with co-optimization algorithms and measurement of benefits to validate existing models and further refine future evaluations.

Integration of Evaluation Methodologies: Ensure company alignment regarding various initiatives and tools leveraged currently or in the future to value energy storage either independently or paired with other energy technologies.

In support of the continuous improvement and refinement of storage evaluation methodologies described above, the pilot projects proposed in the Oregon Energy Storage Final Project Proposals document provide diverse learning opportunities and valuable information which will directly impact future evaluation.

PacifiCorp also proposes revisiting this methodology with stakeholders as part of its 2019 Integrated Resource Plan process, which will begin in fall of 2018.

Critical Components from Project #1

The following list depicts critical components of Project #1 that will be used to inform future energy storage evaluations and modeling:

Outage mitigation benefits: Identification of company benefits leveraged through outage mitigation and validation of existing customer values.

Efficiency assumptions: Validate efficiency assumptions regarding energy storage technology and further refine models to reflect field data.

Use Case Benefits: Validate benefits calculated through field test data to refine models and future projections.

Prioritization of use cases: Experiment with energy storage controls and various algorithms to validate higher and lower value application assumptions.

Co-optimization: Experiment with energy storage controls and various algorithms to identify co-optimization of stacked benefits and validate model assumptions through field data.

Critical Components from Project #2

Project #2 is designed to provide the utility an opportunity to explore the unquantified customer benefits discussed above (resiliency/reliability, time-of-use charge reduction, and demand reduction), and test how those values can be stacked with utility focused benefits at customer-sited storage facilities. Through Project #2, PacifiCorp will gain an understanding of the design characteristics for customer-sited storage installations installed primarily to increase a facility's resiliency. PacifiCorp will then estimate the potential customer benefits of time-of-use charge reduction and demand reduction. Through supporting the installation of a small number of customer-sited facilities and monitoring them over the first five years of operation, PacifiCorp will be able to compare these estimates with actual results.

PacifiCorp will also install equipment that will allow shared use of the ESS, providing the ability to stack customer and utility benefits. Through testing of shared use of energy storage systems, PacifiCorp will gain experience deriving value from customer-owned equipment, which can inform the development of future energy storage offerings.

Appendix A – PacifiCorp RFI Results Summary

On March 24, 2017, PacifiCorp issued a RFI regarding potential energy storage solutions in alignment with HB 2193 and Order No. 16-504 to better understand potential options and market trends. PacifiCorp included approximate load data and made both the legislative use cases and requirements available to potential vendors and requested that bidders propose potential solutions to address the use cases provided for the load data provided. On April 28, 2017, PacifiCorp received 19 responses from potential vendors ranging from technology manufacturers with limited experience to EPC providers with extensive experience in the industry. The results were sorted and analyzed based on the following categories:

- **Performance and Project History**: Description of previous or planned energy storage projects including size, technology, application, and success in delivering planned use cases
- **Sector Experience**: Categorization of projects as residential, commercial, industrial, or agricultural
- **Technology Resource**: Identification of technology proposed including benefits, maturity, and potential challenges associated with deployment
- **Type of Contract or Service to be provided:** Description of services to be provided ranging from technology manufacturing to EPC delivery.
- **Identification and Application of use cases**: Identification of which use cases can be addressed with the proposed technology and costs
- **Cost and Justification:** High level scoping costs associated with type of technology, timeframe or project, and services to be provided
- **Project Location Identification:** Description of the electrical location of the proposed solution (distribution, transmission, customer sited)

As required by the RFI, vendors were asked to submit potential energy storage technology solutions. Upon review of the 19 submissions, only four unique technologies were identified, with an overwhelming majority of responses proposing the use of lithium-ion batteries. These results were congruent with PacifiCorp's additional research and study of market trends and mature technological solutions. See Table 29 below for a detailed summary of technologies included in all 19 submissions.

Table 29 RFI Technology Response Summary

Technology	# of Solutions Submitted
Lithium-Ion Battery	13
Iron Flow Battery	2
Technology Agnostic	2
Flywheel	1
Power to Gas Storage	1

In addition to the proposed technology, PacifiCorp requested that RFI responses also include a list of use cases and services that the proposed solution could address. Many responses included solutions capable of addressing a range of use cases, while others identified only one or two that could be addressed. The ability of proposed technology to provide benefit through transmission and distribution deferral as well as capacity was a common theme. In contrast, not a single submission identified the ability to provide distribution congestion relief. These results are summarized in Table 30 below.

Table 30 Use Case and Service Options Summary

Use Case	Service	Number of Viable Solutions Identified Through the RFI
Bulk Energy	Capacity or Resource Adequacy	10
	Energy Arbitrage	6
Ancillary Services	Regulation	7
	Load Following	5
	Spin/Non-spin Reserve	5
	Voltage Support	4
	Black Start Services	4
Other	Frequency Response[46]	8
Transmission Services	Transmission Congestion Relief	2
	Transmission Upgrade Deferral	14
Distribution Services	Distribution Upgrade Deferral	14
	Volt-VAR Control	4
	Outage Mitigation	2
	Distribution Congestion Relief	0
Customer Energy Management Services	Power Reliability	2
	Time-of-Use Charge Reduction	1
	Demand Charge Reduction	3

Overall, PacifiCorp was very encouraged with both the number of responses as well as the level of interest from potential vendors. PacifiCorp received a lot of high level information from a range of potential vendors regarding scoping costs and availability of technology. However, due to the timing of the RFI's release and the request to submit RFI results to the Commission as part of PacifiCorp's draft evaluation report, PacifiCorp did not receive a single customized proposal specifically relating to the scope provided. Therefore, the use of the RFI results in both the storage evaluation and project selection was limited. For example, scoping costs provided for specific technologies were leveraged as a benchmark to company estimates, but did not provide additional level of certainty to project specific cost estimates.

[46] While not directed by Order No. 16-504, PacifiCorp elected to add Frequency Response as a use case under ancillary services for evaluation after careful consideration of system needs and stakeholder feedback.

Appendix B – IRP

PacifiCorp's complete 2017 IRP with all supporting documentation can be found online at http://www.pacificorp.com/es/irp.html.

As a part of the 2017 IRP, DNV GL was consulted to study energy storage trends. The following report was included in PacifiCorp's 2017 IRP filing in Appendix P of Volume II beginning on Page 415.

Battery Energy Storage Study for the 2017 IRP

PacifiCorp

Customer Reference: Battery Energy Storage Study for IRP 2016 SOW
Document No.: 128197#-P-01-A
Date of this Issue: 9/8/2016
Date of last Issue: 8/22/2016
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DNV GL doc. No.:	128197

About this document

Report Title:	Energy Storage Technology Review
Date of this issue:	2016-09-08
Date of last revision:	2016-08-22
Validity of Report:	30 days from date of issue
Document Classification (see key below):	Customer's Discretion

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1.0 INTRODUCTION

1.1 Objective and Scope of Work

At the behest of PacifiCorp, DNV GL has provided a status report and assessment of future potential applications for battery energy storage. DNV GL understands that PacifiCorp's objective is to compile and maintain a catalog of engineering estimates of costs and performance metrics for utility scale battery energy storage technology, both demonstrated for currently commercially available technology as well as forecasted for emerging technology. The 2017 PacifiCorp Integrated Resource Plan (IRP) will include a portfolio of generating resources and energy storage options for evaluation. The provided estimates and information is intended for PacifiCorp's use when preparing their upcoming and future IRPs and assessing energy storage applications for traditional utility transmission and distribution planning issues.

The scope of work is divided between cataloging technology updates and cost trends. The technology updates are broken down by current stage of commercialization, utility applications with associated value streams, and a detailed list of technology performance metrics. The cost analysis includes current system costs for the battery, PCS, controls, installation and O&M, as well as 10-year cost trends for each listed technology. PacifiCorp has specifically requested the scope to include NCM, $LiFePO_4$, and LTO Lithium-Ion (Li-Ion) batteries, Sodium Sulfur (NaS) batteries, Vanadium Redox (VRB) and Zinc Redox (ZnBr) flow batteries, as well as Zinc Hybrid Cathode (also known as Zinc-air) batteries. The report scope does not include application modeling or costs related to a specific vendor, but instead aims to cover the broader energy storage industry as it applies to applications being pursued by PacifiCorp.

The final report provides PacifiCorp with a catalog of commercially available and emerging battery energy storage technologies with forecasts and estimates for both performance and costs. DNV GL has compiled this catalog through the proposed scope of work. To further support PacifiCorp's bi-annual IRP, DNV GL has produced probabilistic cost graphs for each of the proposed technologies, broken out by technology, energy conversion system, controls, and the remaining balance of system.

1.2 Background and Materials

In 2013, PacifiCorp hired HDR Engineering to prepare an energy storage screening study, examining utility-scale storage potential, which was updated by HDR for PacifiCorp's 2015 IRP. This study covered operating and cost data for various energy storage technologies, with a section dedicated to batteries, including details on system size and lifecycle, comparing them to other storage options. The HDR study considers specific manufacturer's products and reference cases under standard operating conditions. PacifiCorp utilized the information from the HDR research to contribute to the modeling of future energy consumption, and how various technologies impact load profiles, costs, and CO2 emissions. This and other previous energy storage studies performed for PacifiCorp are available at www.pacificorp.com/es/irp.html. Energy storage continues to be of interest to stakeholders – and options for advanced large batteries (one megawatt or larger) are detailed in the IRP as quoted from the HDR study, including the battery types DNV GL has been requested to explore. To the extent possible, DNV GL has built upon and utilized existing studies and reports, to expand and update a battery catalog to include a deeper dive into battery technologies, costs, and applications for PacifiCorp's use in their 2017 IRP.

As a global advisory, classification, certification, and technical assurance company, DNV GL has served the energy sector as well as maritime and oil & gas industries for over 150 years. DNV GL is a leading authority on consulting, implementation, research, testing, and certification of solutions for the energy sector. Recognized as a global leader in the area of energy storage, DNV GL provides strategic advisory services, innovative modeling tools, and independent testing and certification of energy storage products to clients across various sectors. DNV GL operates as an independent entity without ties to any vendor, with no investments, affiliations, or financial interest with any equipment or service providers.

Most notably related to this effort, DNV GL has been actively involved in supporting multiple energy storage procurement efforts in the US. Our models for energy storage cost-effectiveness have been employed by state energy commissions, system operators, electric utilities, and project developers to assess the application value of energy operating the grid for a variety of current and future applications. DNV GL has performed independent bid evaluation for utility wholesale and distribution connected energy storage RFOs. This work involved processing energy storage offers from project developers and providing a ranking and bid evaluation on the capital and O&M costs as well as an assessment of the proposed warranty and performance guarantees. Finally, DNV GL is the industry leader in providing independent engineering analysis and technical due diligence to support third-party financing of energy storage deployments. As part of this work, DNV GL has gained significant insight into the costs, technical characteristics, and life-time performance guarantees of energy storage projects being developed in the US. For this report, DNV GL leveraged their experience with battery technology and the broader energy industry to develop reasonable average values for technology parameters, as well as how these parameters affect the cost and feasibility of a particular technology for an application.

Additionally, this study draws on a recommended practice (RP) document called GRIDSTOR (DNV GL-RP-0043), which was developed by DNV GL in partnership with members of the energy storage industry, including technology vendors, grid service providers, energy consultants, and universities. The GRIDSTOR RP provides a breadth of actionable information for deploying safe and reliable grid-connected energy storage systems, offering a blueprint for an independent quality guarantee of the safe implementation and operation of energy storage systems. This guideline draws on DNV GL experience, credible industry insight, and globally accepted regulations and best practices (such as IEC, ISO, and IEE standards), and was utilized as a reference for this report. GRIDSTOR is publicly available for free download at www.DNV GL.com/energy/brochures/download/gridstor.html.

Finally, under the scope of this effort, DNV GL also conducted current market research. This research included a review of published reports from consulting and energy-related clearinghouses, such as Navigant and IRENA, publicly available specification sheets and pricing for reviewed systems, and university and government sponsored research.

2.0 Stage of Commercial Development

In this chapter, DNV GL provides an overview of the commercial development of each battery technology requested by PacifiCorp. DNV GL understands the importance of assessing the commercial viability of technologies which are intended to be procured as 10 to 20 year critical assets. With this consideration, DNV GL has provided definitions and basic information surrounding each considered technology and the associated system, followed by a sample of technology providers and sample products available on the market. This is followed by a summary of data available on current industry installation rates, including additional insight into some of the drivers behind the recent trends on installations.

2.1 Lithium-Ion Batteries

Lithium-Ion (Li-Ion) batteries utilize the exchange of Lithium ions between electrodes to charge and discharge the battery. Li-ion is a highly attractive material for batteries because it has high reduction potential, i.e., a tendency to acquire electrons (-3.04 Volt versus a standard hydrogen electrode), and it is lightweight. Li-Ion batteries are typically characterized as power devices capable of short durations (approximately 15 minutes to 1 hour) or stacked to form longer durations (but increasing costs). Rechargeable Li-ion batteries are commonly found in consumer electronic products, such as cell phones and laptops, and are the standard battery found in electric vehicles. In recent years this technology has developed and expanded its portfolio of applications considerably into utility-scale applications. Today, Li-Ion batteries have been implemented for applications relating to ancillary services in grid connected storage. Because of its characteristics, Li-Ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term (30-minutes or less) spinning reserve applications.

Li-Ion batteries do carry some safety and environmental risk. Toxic or reactive gases may be released both during creation of the battery cells, as well as in case of thermal runaway within an operating system. However, this risk is being managed across the industry. During cell manufacture, effluent gases can be scrubbed and captured, to be disposed of safely.

Once fully constructed, Li-Ion battery systems come with various methods of cooling, not only to help prevent thermal runaway but also to provide the most beneficial operating temperatures for the battery cells. This risk is being managed from a broader perspective, too; local authorities are preparing to appropriately address any fire concerns. The New York Fire Department (FDNY) and their stakeholders in the National Fire Protection Association (NFPA) have worked with DNV GL to develop ventilation, extinguishing, and cooling requirements for battery fires. Similar types of precautions have been taken industry-wide, in coordination with local communities.

Figure 1 provides a schematic showing what is entailed in a general Li-Ion battery system. This includes monitoring, control, and management systems, power converter/inverter, and the batteries themselves.

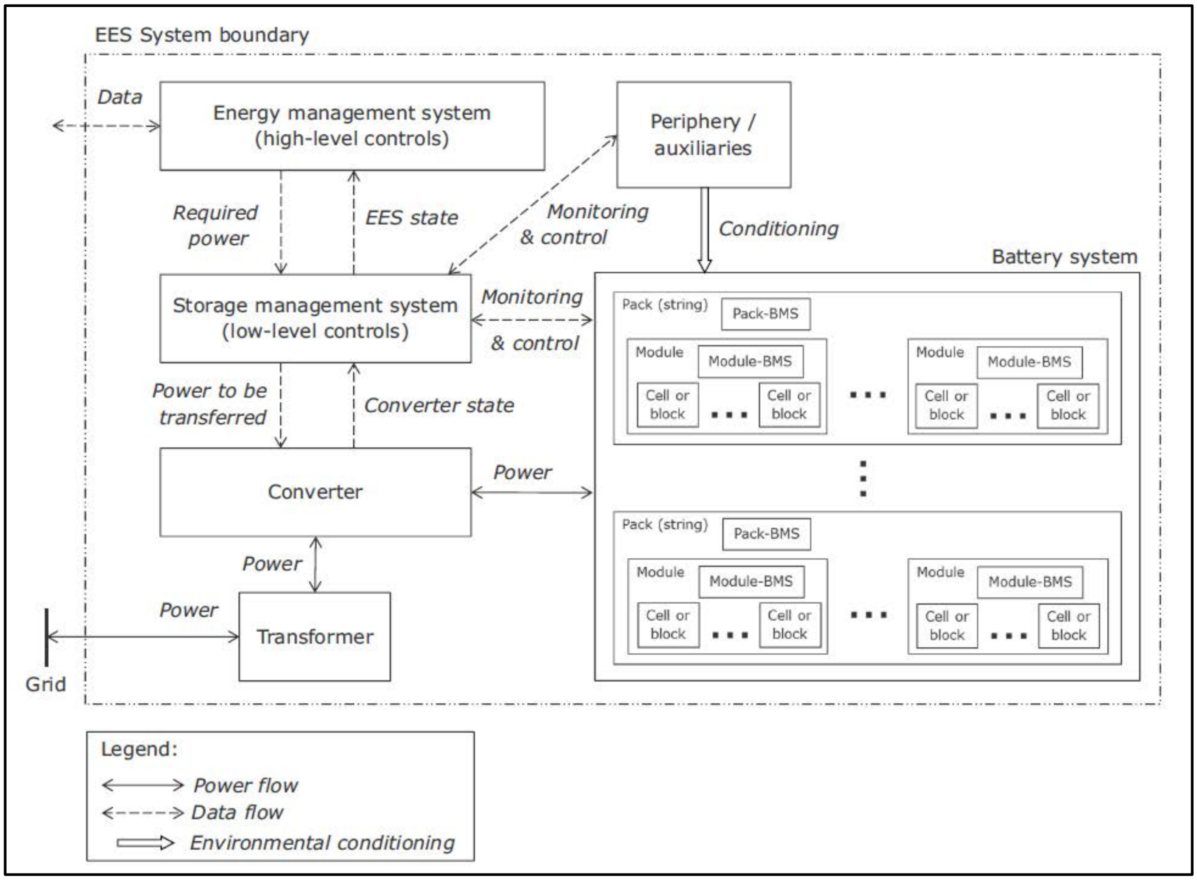

Figure 1 General Schematic and Components of a Cell-Based Battery Energy Storage System

Li-ion technology varies between chemistries. This report will focus on three of the most prominent and promising chemistries, Lithium Nickel Manganese Cobalt Oxide ($LiNiMnCoO_2$ or NCM), Lithium Iron Phosphate ($LiFePO_4$), and Lithium Titanate (Li_4Ti5O_{12} or LTO), and compare and contrast their attributes.

NCM is one of the most commonly used chemistries in grid-scale energy systems. This technology demonstrates balanced performance characteristics in terms of energy, power, cycle life, and cost. NCM chemistry is very common due to these features – it provides an engineering compromise.

$LiFePO_4$, on the other hand, can be purchased at a low cost for a high power density, and its chemistry is considered one of the safest available within Li-Ion batteries. Further, due to its very constant discharge voltage, the cell can deliver essentially full power to 100% DOD. However, LiFePO4 batteries are typically applicable to a more limited set of applications due to its low energy capacity and elevated self-discharge levels.

Finally, LTO offers a stable Li-Ion chemistry, one of the highest cycle lifetimes reported, and a high power density. Further, it is the fastest charging Li-Ion chemistry of those reviewed here. However, in balance, it has a much lower energy density and much higher average cost.

These systems are manufactured widely, but there is relatively high turn-over in manufacturers. Some of the more prominent or market-tested systems are included below, in Table 1.

Table 1 Li-Ion Battery Manufacturers

Technology	Manufacturer	Cell or System Product
NCM	Enerdel Hitachi LeClanche LG Chem Panasonic PBES Samsung XALT Electronova	CE175-360, 160-365 Moxie+ Graphite/NMC JH2 NCR18650A 25R 31,40, 53, 75Ah HE; 31, 40, 63, 75Ah HP; 31, 37Ah UHP
$LiFePO_4$	A123 BYD K2 Energy Microvast Saft Sony Thundersky XO Genesis	AMP20, AHP14, ANR26650, APR18650 LFP123A VL10Fe, VL25Fe IJ1001M WB-LYP, TS-LYP
LTO	Altainano LaClanche Microvast Toshiba XALT	nLTO LTO LpTO (Gen 1) SCiB 2.9, 20, 23Ah 60Ah LTO

2.2 Sodium Sulfur Batteries

Sodium-sulfur (NaS) batteries are a type of molten-salt battery. The systems have high energy density, fast response times, and long cycle lives. They also have some of the longest durations available on the market.

The inclusion of the term “molten” alludes to the battery operating temperature. NaS batteries store electricity through a chemical reaction which operates at 300 °C or above. At lower temperatures the chemicals become solid and reactions cannot occur. The high operating temperature makes the NaS batteries suitable for larger applications supporting the electric grid, but not personal electronic devices or vehicles. Further, due to the high temperature and natural reactivity of pure Sodium when exposed to water, the system can present a safety hazard if damaged.

Figure 1 above provides a schematic showing what is entailed in a general NaS battery system, which is parallel in its architecture to Li-Ion systems. This includes monitoring, control, and management systems, power converter/inverter, and the batteries themselves.

NaS batteries are a mature technology, and the system cost has generally leveled off. Although manufactured by more than one company, the market-share, and thus proven performance, of the company listed in Table 1 represents the majority of installations.

Table 2 NaS Battery Manufacturers

Technology	Manufacturer	Cell or System Product Description
NaS	NGK	NAS

2.3 Vanadium Redox Batteries

Vanadium Redox batteries (VRB), or Vanadium flow batteries, are based on the redox reaction between the two electrolytes in the system. "Redox" is the abbreviation for "reduction-oxidation" reaction. These reactions include all chemical processes in which atoms have their oxidation number changed. In a redox flow cell, the two electrolytes are separated by a semi-permeable membrane. This membrane permits ion flow but prevents mixing of the liquids. Electrical contact is made through inert conductors in the liquids. As the ions flow across the membrane, an electrical current is induced in the conductors to charge the battery. This process is reversed during the discharge cycle. Figure 2 below provides a schematic showing what is entailed in a general VRB system. This includes monitoring, control, and management systems, power converter/inverter, and the electrolyte tanks and stack of the batteries themselves.

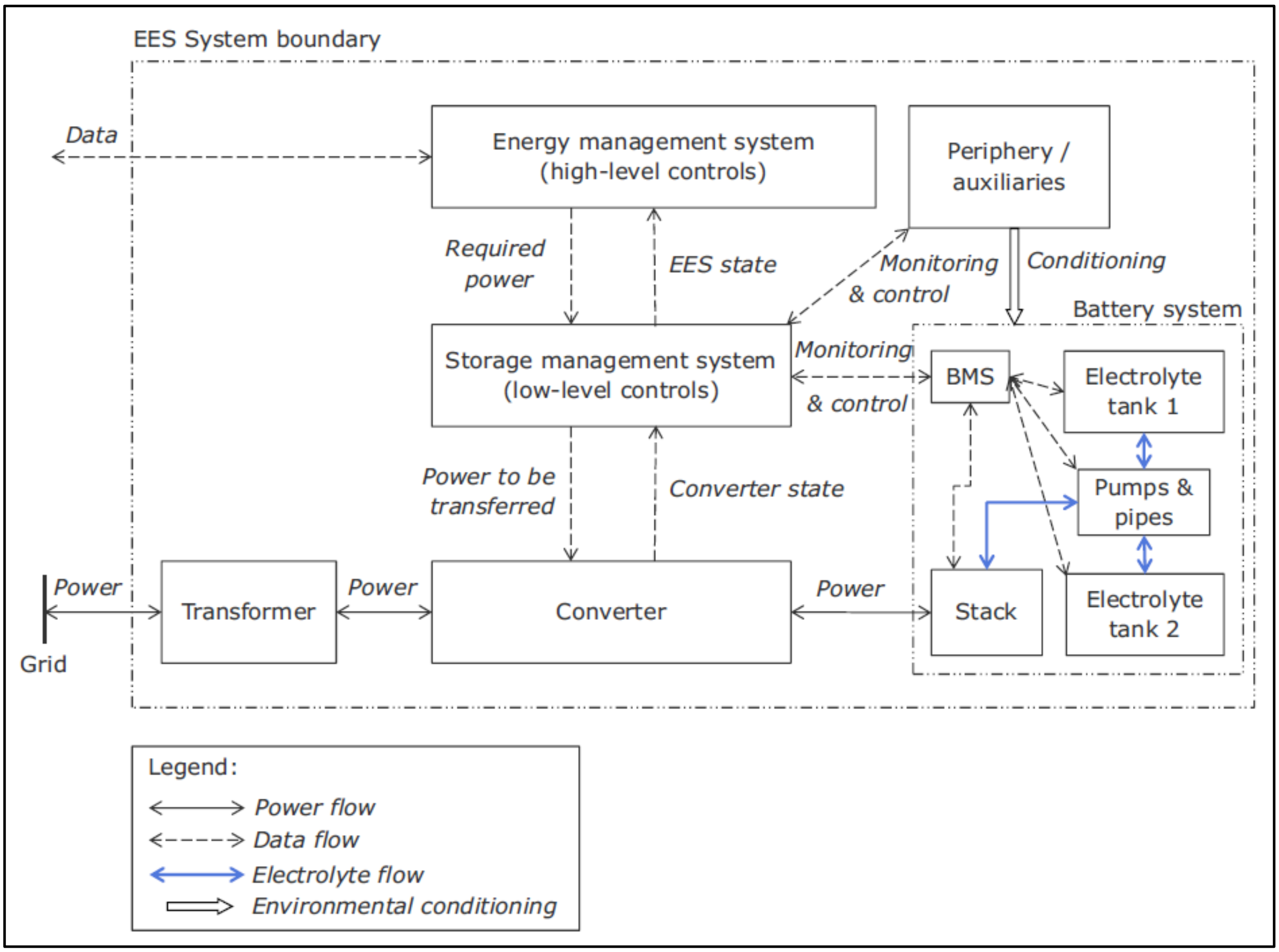

Figure 2 General Schematic and Components of a Redox Flow Battery Energy Storage System

In VRBs, the liquid electrolyte used for charge-discharge reactions is stored externally and pumped through the cell. This allows the energy capacity of the battery to be increased at a low cost. Energy and power are decoupled since energy content depends on the amount of electrolyte stored. VRB systems are unique in that they use one common electrolyte, which provides opportunities for increased cycle life. These large, liquid solution containers do however limit the VRB to stationary storage applications.

An important advantage of VRB technology is that it can be “stopped” without any concern about maintaining a minimum operating temperature or state of charge. This is a key point to most flow batteries in that the batteries can actually be “turned off.” This technology can be left uncharged essentially indefinitely without significant capacity degradation.

These systems are relatively new to the battery industry but are solidifying their place in the market. Some of the more prominent or market-tested systems are included below, in Table 3.

Table 3 VRB Manufacturers

Technology	Manufacturer	Cell or System Product Description
VRB	American Vanadium Imergy UET/UniEnergy Vionx	CellCube ESP5, 50, 250 UniSystem, ReFlex

2.4 Zinc Redox Batteries

The Zinc Bromine (ZnBr) battery utilizes similar flow battery technology as the previously discussed VRB. Due to this, it shares many of the same advantages: little to no claimed degradation over time (both in use and in the fully-discharged state), high energy density, 100% DOD, and easily scalable. The ZnBr consists of a zinc-negative electrode and a bromine-positive electrode, separated by a micro-porous separation. Solutions of zinc and a bromine complex compound are circulated through the two compartments. In a ZnBr the electrodes (Zn- and Br+) serve as substrates for the reaction. During charging, the Zinc is electroplated at the anode and bromine is evolved at the cathode. When not cycled, there is a potential for the Zinc to form dendrites that can degrade capacity or damage the battery components. To prevent this, the battery must be regularly and fully discharged.

Figure 2 above provides a schematic showing what is entailed in a general ZnBr system, which is of similar physical structure to VRB, though differing completely in chemistry at the core of energy storage. This includes monitoring, control, and management systems, power converter/inverter, and the electrolyte tanks and stack of the batteries themselves.

The response time for this technology is thought to be inadequate for fast-response applications; this should be verified on a case by case basis as new system designs may be able to improve on this limitation. ZnBr is a promising technology for balancing low-frequency power generation and consumption. However, cycle life tends to be less than that of VRBs.

These systems are in the early stages of commercialization but are being produced by multiple manufacturers. Some of the more prominent or market-tested systems are included below, in Table 4.

Table 4 ZnBr Battery Manufacturers

Technology	Manufacturer	Cell or System Product Description
ZnBr	Enphase (Previously ZBB) Primus Power Flow RedFlow	Enerstor, Agile EnergyCell ZBM2, ZBM3

2.5 Zinc Hybrid Cathode Batteries

Zinc hybrid cathode (Zinc-air) batteries are a type of metal-air battery which uses an electropositive metal in an electrochemical couple with oxygen from the air to generate electricity. Zinc-air batteries take oxygen from the surrounding air to generate current. The oxygen serves as an electrode while the battery construction includes an electrolyte and a zinc electrode that channels air inside the battery.

Zinc-air batteries have power densities similar to Li-ion batteries, but lower energy density. On the other hand, Zinc-air batteries in comparison to flow batteries can have both higher power and energy densities. Unlike Li-Ion, however, Zinc-air batteries are generally claimed to be benign, though their electrolytes – like those of other battery technologies – contain acidic or alkaline compounds and could produce SO2 if burned. The main Zinc-air battery material, zinc-oxide, is theoretically fully recyclable, though this has yet to be demonstrated at scale. In addition, the metals used or proposed in most metal-air designs are low cost.

Zinc-air systems appear attractive for utility applications if their ability to charge and recharge can be improved. The challenge for researchers has been to devise a method where the air electrolyte is not deactivated in the recharging cycle to the point where the oxidation reaction is slowed or stopped. The cessation of the oxidation reaction reduces the number of times that a Zinc-air battery can be recharged. Some of the newest emerging technology, as created by Eos, claims to have addressed these issues by implementing a near-neutral, non-dendritic, and self-healing electrolyte solutions. This, Eos claims, prevents air electrode clogging, rupture of the membrane due to dendrites, and the drying out of the electrolyte, along with other innovations that have prepared the system for commercial launch.

Potential applications include integrating renewable assets, peak shifting and load balancing, and frequency regulation. Consolidated Edison (ConEd) is currently pursuing one of the first utility-scale systems for demonstration with Eos technology.

These systems are in the early stages of commercialization and, as such, manufacturing is limited. Although being researched by more than one company, the earliest product being actively used in demonstration projects is produced by the manufacturer listed in Table 5.

Table 5 Zinc-Hybrid Cathode Battery Manufacturer

Technology	Manufacturer	Product name (if available)
Zinc-air	Eos	Znyth cell in Aurora 1000, 4000

2.6 Commercialization Data

Commercialization and installation data are based on DNV GL's research and publicly available information. This data excludes projects that have been decommissioned for any reason, or construction has not yet started.

Table 6 Installation and Commercialization Data

System Attributes	Li-Ion NCM	Li-Ion $LiFePO_4$	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air[47]
Typical project size (kW)[48]	6,500	5,000	2,000	6,000	4,000	1,000	3,500
Typical project size (kWh)	15,000	3,100	1,300	40,000	14,000	2,000	13,000
Largest project size installed (kW)[49]	30,000	31,500	40,000	50,000	15,000	1,000	250
Largest project size installed (kWh)	60,000	12,000	40,000	300,000	60,000	2,000	1,000
Current total power capacity installed (MW)[50]	77	142	31	186	66	5	0.25
Current total energy capacity installed (MWh)	30	220	19	1,254	226	25	1

[47] Zinc-air is an emerging technology. Due to this, the majority of the projects DNV GL cited are publicly announced but not yet installed and operational. This clarification is provided to give context to the typical system size being larger than the largest installed system size.

[48] Typical project size, both kW and kWh, are based on averages of publicly known projects that are operational, under construction, contracted, and announced. Decommissioned projects have been excluded from these counts.

[49] Largest project size, both kW and kWh, is based on projects that are currently operational, under construction, or contracted. Announced and decommissioned projects have been excluded from these counts.

[50] Current total power and energy capacity installed are based on publicly known projects that are operational, under construction, or contracted. Announced and decommissioned projects have been excluded from these counts.

3.0 PERFORMANCE CHARACTERISTICS

This chapter of the report provides a summary of technical parameters for each of the proposed storage technologies in a number of requested fields identified by PacifiCorp as useful for consideration within their 2017 IRP. The specific technology parameters of interest, as identified by PacifiCorp, are as follows:

1. Power Capacity
2. Energy Capacity
3. Recharge Rates
4. Roundtrip Efficiency
5. Availability
6. Degradation
7. Expected Life
8. Environmental Impact upon disposal

Each of the specified parameters are first defined and discussed below followed by a summary of values for each technology. Further, these characteristics are utilized later in this report, in Chapter 5, in determining the appropriateness of a technology for a particular application.

3.1 Power Capability

In composing this analysis, a variety of values were available given DNV GL's experience in the field, depending on operating conditions as well as marketing versus as-built specs. In all cases, all technologies in the study were available down to at least the 1 MW power capacity level, with many having wide use at smaller sizes, for commercial and industrial, residential or non-stationary storage applications. The maximum values were based on the largest installed or proposed and contracted systems to date.

The minimum size of 1 MW was based on feedback from PacifiCorp based on their IRP planning needs. DNV GL notes that all of these technologies are available in sizes smaller than 1 MW and can be installed as customer-sited, behind-the-meter resources. Storage is emerging as a technology being considered to provide utility services from aggregated behind-the-meter resources. Most notably, in 2014 Southern California Edison awarded two (2) capacity contracts to aggregated behind-the-meter energy storage.

3.2 Energy Capacity

The energy capacity DNV GL has compiled is what has been quoted by manufacturing specs as the optimal charge pattern of the entire capacity of the battery as designed. However, in many cases, these units are sold and marketed at a capacity reduced from the system's true total capacity. As such, useable or nameplate system capacity values are provided specified so that the system operates at a usable 0-100% SOC range.

3.3 Recharge Rates

All batteries have certain tolerances with regard to the rate at which they are charged or discharged. The current rating determines the C-rate for the battery, i.e., the rate at which a battery is discharged relative to its maximum energy capacity. Some batteries are more tolerant than others to high discharge rates. On the manufacturer specification sheets that accompany batteries, C-rates that are less than 1 are typically conservative, and may be recommended by the manufacturer to attain longer cycle lifetimes. Typically, discharge rates are higher than charge rates.

3.4 Round Trip Efficiency

Efficiency data provided in this report is the full energy storage system round trip efficiency (RTE). Full system RTE includes the losses from the power conversion system, HVAC equipment loads, control system losses, and self-consumption. Often a manufacturer will provide battery efficiency rather than RTE when promoting their technology. However, there can be a 5-10% difference between these efficiency ratings, when conversion equipment, air conditioning, and other "parasitic" balance of plant devices from the full system are taken into consideration. Auxiliary losses like air conditioning or heating vary considerably according to the technology and the specific application it must perform. For example, the heating requirement for a NaS battery is about 3 percent of its rating but heating is not needed if the battery is discharged daily because heat released during discharge will keep it warm. In this case, typically RTE values are reported based on the system performed a minimum amount of cycling per day.

3.5 Availability

The availability that DNV GL notes is based on guarantees being offered by manufacturers and distributors. Aside from these availability guarantees, annual planned maintenance carve-outs are typically included which do not contribute to these availability figures. Data here is provided based on currently observed guarantees being offered along with utility-scale energy storage systems, however, it should be noted that longer term operation experience will be required before these values are fully verified in practice.

3.6 Degradation

Storage is a unique technology in that its performance characteristics are significantly influenced by degradation. Degradation is highly dependent on system operation. System operation is in turn affected by location, power and energy capacity, applications, and how frequently those applications are utilized. Typically, manufacturer packaging, control and management systems, and environmental considerations are in place to ensure these parameters stay within safe and non-destructive ranges. However, outside influences and one-time events resulting from environmental control failure, BMS failures, or dispatch control error can lead to significant degradation of the device.

The degradation ranges that DNV GL has provided are given at year 10 after installation, based upon the average system operation, segmented by application type. The most common energy applications include electric time shift, electric supply capacity, spinning and non-spinning reserves, and T&D congestion relief. The Power applications include regulations, voltage support, load following and ramping support, and frequency response.

As noted previously, battery performance deteriorates as a result of various degradation mechanisms. The complexity and interactions of these mechanisms are given in detail below.

- **Temperature**: All batteries have an ideal temperature operating range; most batteries control their operation to 30ºC or less. High temperatures (generally above 30-40ºC) tend to degrade capacity severely. Many battery chemistries will indicate operational temperature ranges between 0-60ºC, however operation at or near these limits can severely impact efficiency of the cell as well as lifetime.
- **Charge and Discharge Rates:** For many batteries, high charge/discharge rates lead to higher temperature, compounding the degradation effect.
- **High or Low Average State of Charge:** If a battery spends a significant amount of time at a high state of charge, it will degrade faster than if it is left and maintained at a mid-level state of charge. Some batteries are more sensitive to this than others, but generally it is known that the higher the average state of charge (SOC) over the battery life, the faster it will degrade. Similarly, if a battery is kept at very low average SOC, it will also degrade quickly. This phenomenon has been studied extensively and it has been shown that battery capacity and average SOC are inversely proportional.
- **Depth of Discharge:** Generally, the greater the average depth of discharge (DOD), the faster the battery capacity will fade. In most cases, battery spec sheets will list the lifetime of the battery as number of cycles until 80% of capacity is reached at 100% DOD at 25 C. These conditions are considered nominal and if cycle life of the battery is mentioned without these additional specifications, it is important to verify the DOD, final capacity, and temperature of the tests. Unfortunately, these conditions are often unlike what the battery may experience in an actual application. It is often not noted whether long rest times between charge and discharge were implemented (allowing the battery to cool). Longer rest times can inflate the total cycle life.
- **Calendar Life:** The calendar life of the battery can affect its capacity as much or more than the cycling effects, but it is largely dependent on temperature. Assessing the time the battery is left at rest as a function of temperature is relevant to assessing its state of health. For this reason, most state of health predictions includes both calendar and cycling components.
- **Maintenance:** It is assumed that batteries will not operate completely autonomously. This Maintenance ensures unit operate optimally, given product specific operating constraints. Some manufacturers will further offer capacity maintenance agreements wherein systems are provided with maintenance, supplemental units integrated into the system, or refreshed electrolyte solutions in order to ensure capacity does not degrade past agreed to trigger points.
- **Compounding and Consequential Effects:** It is not possible to list the degradation factors from greatest to least without caveat considerations for specific chemistries, environment and duty cycle, but within the conservative limits established on a battery specification sheet, it may generally be assumed that abuse factors from least to greatest are: Temperature > Depth of Discharge > C-Rates . All of these factors are linked, however, and therefore have compounding effects depending on the battery duty cycle.

3.7 Expected Life

Most systems have not been available at a commercially mature stage for long enough to provide meaningful field data on lifetime performance, so the expected life is currently based on vendor projections, accelerated life-testing (ALT) on cells or modules and limited field results. Cell life tests are typically a good representation of the maximum possible lifetime under ideal conditions, and validation of these results is recommended on a case-by-case basis. With these caveats in mind, the expected life based on standardized cycling and disregarding extenuating circumstances is at least 10 years in all cases. Many manufacturers claim longer calendar lives; these claims assume periodic maintenance, including integrating new modules or adding new electrolyte. The number of cycles that these claims cover varies from technology to technology, based on the applications expected for use. As with calendar life claims, vendors typically claim cycle life in excess of 3,000 cycles. These claims are tied to the same periodic maintenance as previously mentioned. Further, all of the mechanisms discussed above that cause degradation are related to expected life and the system’s ability to continue to meet the needs of the customer.

3.8 Environmental Effect Upon Disposal

While batteries claim advantages over traditional energy sources, including the ability to provide energy and power essentially instantaneously and without emission, the components will eventually require disposal. Disposal or recycling, however, comes with consequences. The United States Environmental Protection Agency states that no rechargeable electrochemical cells may lawfully be disposed of to be taken to a landfill. Li-ion and nickel-based electrochemical cells are classified as toxic due to the presence of lead, as well as cobalt, copper, nickel, chromium, thorium, and silver.

The majority of energy storage technologies covered in this report have yet to see adoption rates, much less decommissioning rates, high enough that significant research has been conducted on opportunities and limitations to recycling. While the US Department of Energy has pursued research on the subject, even producing functional Li-Ion cells from recycled materials, the process is so far limited to small pilot operations. For this reason, when decommissioning, disposing of, or pursuing potential recycling of batteries, the manufacturer of the energy storage system should be consulted for guidance. As energy storage systems are deployed in greater numbers, decommissioning and recycling are rising as important facets to financing agreements, contributing to the total cost of ownership.

Lead-acid battery repurposing and recycling activities are a well-established and extremely successful system. The policy has not addressed lithium and nickel-based battery recycling the same way it has lead-acid, and this is due to a number of challenges. The construction materials used in these systems are similar to the advanced technologies covered in this report (alloy and mild steel, aluminum alloys, copper, titanium, HPDE, etc.) and thus the majority of the challenge faced has to do with disassembly, destruction, sorting and any potential contamination. These batteries are mechanically varied between manufacturers and technologies, and packs are very sophisticated relative to lead-acid. In addition, there is a much larger range of materials in each battery, as well as a wide range of chemistries between batteries. Mined Lithium itself is low cost so although recycling is feasible, at present it is not economical. Instead, the primary components of interest are nickel and cobalt (and copper), and not all Li-ion batteries contain them in sufficient quantities. In many cases, the metals involved may just be sent to slag, to be burned for process heat (with the appropriate emission scrubbing). Materials can be recovered from this slag, but they must be in high enough quantity, quality, and demand to merit the additional effort. NCM batteries, for instance, contain a high enough percentage of valuable constituents (nickel and cobalt) to be recyclable.

Beyond the potential for emissions from burning slag, the chemicals have additional properties that affect disposal options. A universal issue for Li-Ion battery recycling is Lithium's high reactivity, creating a risk of fire if handled incorrectly. Otherwise, DNV GL's own research indicates that the materials within Li-Ion batteries are individually not exotic – for instance, Iron Phosphate is used as a non-toxic pesticide – but their destruction or combustion can create flammable gases such as ethylene, methane, and carbon monoxide. Toxic gases are also created, such as hydrogen fluoride, hydrogen chloride, and hydrogen cyanide. It should be noted that all of these gases are also created during the burning of plastics. To provide perspective as to Li-Ion battery toxicity, on a mass and volume equivalence, plastics are equally or more toxic than the by-products of Li-ion battery combustion.

As to redox flow batteries, electrolytes such as Zinc bromide and Vanadium solutions can typically be reused, sometimes for the life of the battery. However, contaminants or impurities may occur, requiring monitoring and removal. Additionally, upon decommissioning, the Vanadium and Zinc from these batteries may be recycled. It should be noted, however, that several materials commonly found in redox flow batteries are environmentally hazardous and regulated and thus should be disposed of according to regional government requirements. VRB electrolytes can dry or evaporate to form V_2O_5 dust as well as sulfate salts, while ZnBr electrolytes can evolve bromine at temperatures above 50ºC.

Finally, Zinc-air batteries, upon decommissioning, have similar overall construction materials that can be recycled via standard processes. Further, the aqueous electrolyte is non-flammable and non-hazardous (both non-toxic to humans and the environment). This electrolyte solution contains salts that are mildly corrosive but are not uniquely different or more hazardous than competing chemistries. The main component of Zinc-air batteries is Zinc-oxide, which is theoretically fully recyclable, although this has not yet been demonstrated on a large scale.

Properties of potential byproducts of battery decomposition are shown in Table 7.

Table 7 Combustion Byproducts of Commercially Available Batteries

		Concentration (ppm unless otherwise noted)								
	Chemical Formula	**LEL (Lower Explosion Limit)**	**IDLH (Immediately Dangerous to Life and Health)**	**Solubility in Water (mg/L)**	**Autoignition Temp (degC)**	**Thermal Instability Threshold (deg C)**	**NFPA Flammability**	**NFPA Health**	**NFPA Reactivity**	**Ref.**
Methane	CH4	50,000	5,000	22.7	537	-	4	1	0	NJ DOH
Carbon Monoxide	CO	12,500	1,500	27.6	609	-	4	2	0	CDC.gov
Ethylene	C2H4	27,000	-	2.9	490	-	4	2	2	Matheson MSDS
H2S	H2S	4,000	300	4,000.0	260	-	4	4	0	CDC.gov
Hydrogen Fluoride	HF	-	30	miscible	-		0	4	0	CDC.gov
Hydrogen Chloride	HCl	-	100	720.0	-	1500	0	3	1	CDC.gov
Hydrogen Cyanide	HCN	-	50	miscible	-		4	4	2	CDC.gov
V2O5 Dust	V2O5	-	35 mg/m^3	0.8	-		0	3	0	CDC.gov
Pb Vapor, salts, dust	Pb	-	700 mg/m^3	10^-5 to 4400	-		0	2	0	CDC.gov
SO2	SO2	-	100	94,000.0	-		0	3	0	CDC.gov

3.9 Technical Parameters Data

System parameters and characteristics are based on DNV GL's industry experience, internal research, and publicly available data. They are subject to the assumptions detailed in the previous sections.

Table 8 Technical Parameters and Performance Characteristics Data, from Both Cell and Project-Scale Perspectives

Parameter/ Technology		Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Power capability	Available down to 1 MW1	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Maximum2 (MW)	35	35	40	50	20	20	15
Energy capacity[3]	SOC upper limit	90%	85%	98%	90%	95%	98%	98%
	SOC lower limit	10%	15%	10%	10%	5%	5%	10%
Recharge rates		1C	2C-1C	3C-1C	1C-0.5C	1C-0.25C	1C-0.25C	2C-1C
Round trip efficiency		77 - 85%	78 - 83%	77 - 85%	77 - 83%	65 - 78%	65 - 80%	72 - 75%
Availability	Up-time	97%	97%	96%	95%	95%	95%	96%
	Carve Outs	72 hr/yr	72 hr/yr	72 hr/yr	72 hr/yr	1 wk/yr	1 wk/yr	72 hr/yr
Energy Capacity Degradation[4]	Energy Applications	30-40%	20-40%	15-25%	15-30%	5-10%	5-10%	15-25%
	Power Applications	10-20%	15-25%	5-15%	5-15%	5-10%	5-10%	5-15%
Expected life5	Years	10	10	10	15	10	10	10
	Cycles	3,500	2,000	15,000	4,500	5,000	3,000	5,000
Environmental effect upon disposal?[6]		Yes	Yes	Yes	Yes	Yes	Yes	Yes

[1] The minimum size of 1 MW was based on feedback from PacifiCorp based on their IRP planning needs. DNV GL notes that all of these technologies are available in sizes smaller than 1 MW and can be installed as customer-sited, behind-the-meter resources.

[2] Maximum power capability based on largest publicly proposed project.

[3] For usable energy capacity, manufacturers will commonly advertise their battery as allowing 100% DOD based on nameplate capacity. SOC limits given here reflect limits with respect to actual installed energy capacity.

[4] Degradation value based on percent of installed nameplate capacity lost after 10 years of operation. These values assume maintenance is performed as a part of normal operation. Flow battery degradation (VRB and ZnBr) can be mitigated to an extant through normal maintenance and chemistry refresh.

[5] Expected life in calendar years is given for the energy storage component of an ESS and is based on operation at 100% DOD, 25°C, 1C for the number of cycles shown. These values assume maintenance is performed as a part of normal operation. Full system life, including PCS and balance of plant equipment have been observed in range of 15-25 years, implying full replacement of energy storage system components.

[6] Discussion of the severity and risk of these effects are discussed in detail in section 3.8.

4.0 COST ESTIMATES AND TRENDS

In addition to the commercial and technical review, PacifiCorp requested DNV GL utilize industry experience, in-house data, and market research to the prepare capital and O&M cost estimates for each technology, expressed in mid-2016 dollars. Costs estimates are broken down as follow:

1. Energy Storage Equipment
2. Power Conversion Equipment
3. Power Control System
4. Balance of System
5. Installation
6. Fixed Operation and Maintenance

Each of these costs components are provided as a range covering currently observed industry estimates. In addition to current cost estimates, cost trends over 10 years will be provided as graphs demonstrating a breakdown of system costs in the requested components.

The capital cost for an installed energy storage system is calculated for a system by adding the costs of the energy storage equipment, power conversion equipment, power control system, balance of system, and the installation costs. Each of these categories is accounted for separately because they provide different functions or cost components and are priced based on different system ratings. System component costs based on the power capacity ratings are priced in $/kW, while component costs based on the energy capacity ratings, such as the DC energy storage system, are priced in $/kWh. A description of the system and project development elements included in each cost component is provided below, followed by a summary table of all system costs and graphs depicting 10-year cost trends of relevant components.

4.1 Energy Storage Equipment Costs

Energy storage equipment costs are inclusive of the DC battery system which includes the costs of the energy storage medium, such as Li-Ion battery cells or flow battery electrolyte, along with associated costs of assembling these components into a DC battery system. For Li-Ion systems, battery cells are arranged and connected into strings, modules, and packs which are then packaged into a DC system meeting the required power and energy specifications of the project. The DC system will include internal wiring, temperature and voltage monitoring equipment, and an associated battery management system responsible for managing low-level safety and performance of the DC battery system. For flow batteries, the DC system costs include electrolyte storage tanks, membrane power stacks and container costs for the system along with associated cycling pumps and battery management controls. Energy storage equipment costs are provided on a $/kWh basis which is most appropriate for quantifying the cost of an energy capacity constrained resource. The DC system cost trends are shown in Figure 3.

4.2 Power Conversion System Equipment Costs

Power conversion system (PCS) costs are inclusive of the cost of the inverter, packaging, container, and controls. Inverters employed in energy storage systems are more expensive than the grid-tied inverters widely deployed for solar PV generation, and differentiated by their bi-directional, 4-quadrant operational capabilities. The cost of the power conversion equipment is proportional to the power rating of the system and provided in $/kW. The PCS cost trends are shown in Figure 4.

4.3 Power Control System Costs

Unique to energy storage systems are the required high-level controllers being deployed to dispatch and operate the systems. With dispatch becoming an ever more important part of storage system design, controllers have to combine multiple functions – from forecasting the load, to understanding the tariff structure and factoring in the type of charge management required for a specific application and technology. The energy industry is currently seeing a number of software companies emerging which are focused solely on control and management of energy storage systems. This includes companies such as Geli, Greensmith, 1Energy Systems, and Intelligent Generation. System integrators and battery storage vendors themselves are also producing controls to operate their systems. These companies include storage and renewable energy companies such as Stem, Advanced Microgrid Systems, RES Americas and SolarCity, as well as established utility energy industry players such as General Electric, Schneider Electric, and ABB. For systems owned or operated by a utility, these controllers must additionally be integrated with utility monitoring and control systems such as Supervisory Control and Data Acquisition Systems (SCADA), Energy Management Systems (EMS), and Distribution Management Systems (DMS), among others. As more advanced applications are considered, such as the energy storage Virtual Power Plants (VPP) currently being considered at Duke Energy and Consolidated Edison, these control layers will become increasingly critical to the success of a given project. At present, the costs for the power control systems have been observed to vary widely and are provided here based on the power capacity of a plant as $/kW. The trend graphs show conservative reduction in costs over ten years; as controls grow more prevalent and efficiencies are found, the control requirements and designs will likely increase in intricacy. The controls cost trends are shown in Figure 5.

4.4 Balance of System

The equipment cost of the storage system will further depend on ancillary equipment necessary for the full storage system interconnection. The balance of system cost here includes wiring, interconnecting transformer, and additional ancillary equipment. For some technologies, this may include the cost of centralized HVAC systems which is required for maintaining acceptable environmental equipment. The balance of system cost is proportional to the power rating of the system and provided in $/kW. The balance of system cost trends are shown in Figure 6.

4.5 Installation

Installation cost accounts for associated Engineer-Procure-Construct (EPC) costs inclusive of installation parts and labor, permitting, site design, and procurement and transportation of all equipment.

4.6 Fixed O&M

Yearly operation and maintenance costs is currently a debated issue for storage projects employing the technologies discussed in this report, as the industry does not yet have longer term operating experience with the technologies. O&M requirements for Li-Ion systems are generally assumed to be light and include maintenance of HVAC system, tightening of mechanical and electrical connections, cabinet touch up painting and cleaning, and landscaping maintenance. Further, the majority of projects being developed for utilities applications include some type of capacity maintenance agreement. This capacity maintenance agreement guarantees some fixed level of available energy capacity in the system over the term of the project. The cost of the capacity maintenance agreement can be accounted for in the Fixed O&M or as part of the upfront capital costs of the system. For flow battery systems, maintenance services include power stack and pump replacements, tightening of plumbing fixtures, tightening of mechanical and electrical connections, as well as semi-annual chemistry refresh and full discharge cycles to refresh capacity. Further, while many technologies are developing third party training and qualification programs for O&M services, at present many of vendors technology companies themselves are providing O&M services.

Variable O&M costs, while typical to conventional generation sources, are generally assumed negligible for most energy storage systems. It is noted that systems operators can use a variable O&M cost as one means of including the capacity degradation within an energy storage dispatch model. However, there is not currently a uniform or industry acceptable methodology for quantifying variable O&M in this manner. For the purposes of this report, energy storage variable O&M is considered to be negligible.

4.7 Total System Cost Estimates

System costs are based on DNV GL's industry experience, internal research, and publicly available data. These costs are provided in 2016 dollars. This information is given in further context in Section 4.9, which provides calculations for an example installation.

Table 9 Energy storage system cost estimates[1]

Cost Parameter/ Technology	Li-Ion NCM	Li-Ion $LiFePO_4$	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Energy storage equipment cost ($/kWh)[2]	$325-$450	$350-$525	$500-$850	$425-$550	$500-$700	$525-$725	$200-$400
Power conversion system equipment cost ($/kW)[3]	$350-$500	$350-$500	$350-$500	$500-$750	$500-$750	$500-$750	$350-$500
Power control system cost ($/kW)[4]	$80-$120	$80-$120	$80-$120	$80-$120	$100-$140	$100-$140	$100-$140
Balance of system ($/kW)[5]	$80-$100	$80-$100	$80-$100	$100-$125	$100-$125	$100-$125	$80-$100
Installation ($/kWh)[6]	$120-$180	$120-$180	$120-$180	$120-$180	$140-$200	$140-$200	$120-$180
Fixed O&M cost ($/kW yr)[7]	$6-$11	$6-$11	$6-$11	$12-$18	$7-$12	$7-$12	$6 - $12

[1] All cost estimates provided in mid-2016 dollars

[2] Energy storage equipment includes the full DC battery system which includes the costs of the energy storage medium, such as Li-Ion battery cells or flow battery electrolyte, internal wiring and connections, packaging and containers, and battery management system (BMS).

[3] PCS equipment includes the inverter, packaging, container and inverter controls.

[4] Control system includes supervisory control software, along with the controller and communications hardware required to dispatch and operate energy storage systems.

[5] Balance of system includes site wiring, interconnecting transformer, and additional ancillary equipment.

[6] Installation includes Engineer-Procure-Construct (EPC) costs inclusive of installation parts and labor, permitting, site design, procurement and transportation of equipment.

[7] Fixed O&M costs are provided as real levelized dollars with assumed 20 year project life.

4.8 Example Installed Cost Calculation

Table 10 below shows an example calculation to estimate the installed cost of 10 MW, 20 MWh NCM Li-Ion energy storage system using the cost estimates provided in Table 9. The provided cost estimates result in a low side estimate of $14,000,000 and a high side estimate of $19,800,000 for the system, with component sub-total costs based on the power or energy rating of the system.

Table 10 Example Installed Capital Cost Calculation for 10 MW, 20 MWh NCM Li-Ion Energy Storage System

Cost Parameter	ESS Size	Component Unit Cost Low	Component Unit Cost High	Component Sub-Total Low	Component Sub-Total High
Energy storage equipment cost ($/kWh)	20,000 kWh	$325/kWh	$450/kWh	$6,500,000	$9,000,000
Power conversion equipment cost ($/kW)	10,000 kW	$350/kW	$500/kW	$3,500,000	$5,000,000
Power control system cost ($/kW)	10,000 kW	$80/kW	$120/kW	$800,000	$1,200,000
Balance of system ($/kW)	10,000 kW	$80/kW	$100/kW	$800,000	$1,000,000
Installation ($/kWh)	20,000 kWh	$120/kWh	$180/kWh	$2,400,000	$3,600,000
				Low Total	**High Total**
				$14,000,000	$19,800,000
				Average	
				$16,900,000	

4.9 System 10-Year Cost Trends

As referenced in sections 4.1 to 4.4, graphs depicting 10-year future cost trends are shown below. Cost trends are based on currently available industry projections, as well as DNV GL's interaction with industry partners, and basic cost reduction assumptions, as well as the information discussed in the relevant section, 4.1 through 4.4. These trends are provided for the period from 2016 to 2026.

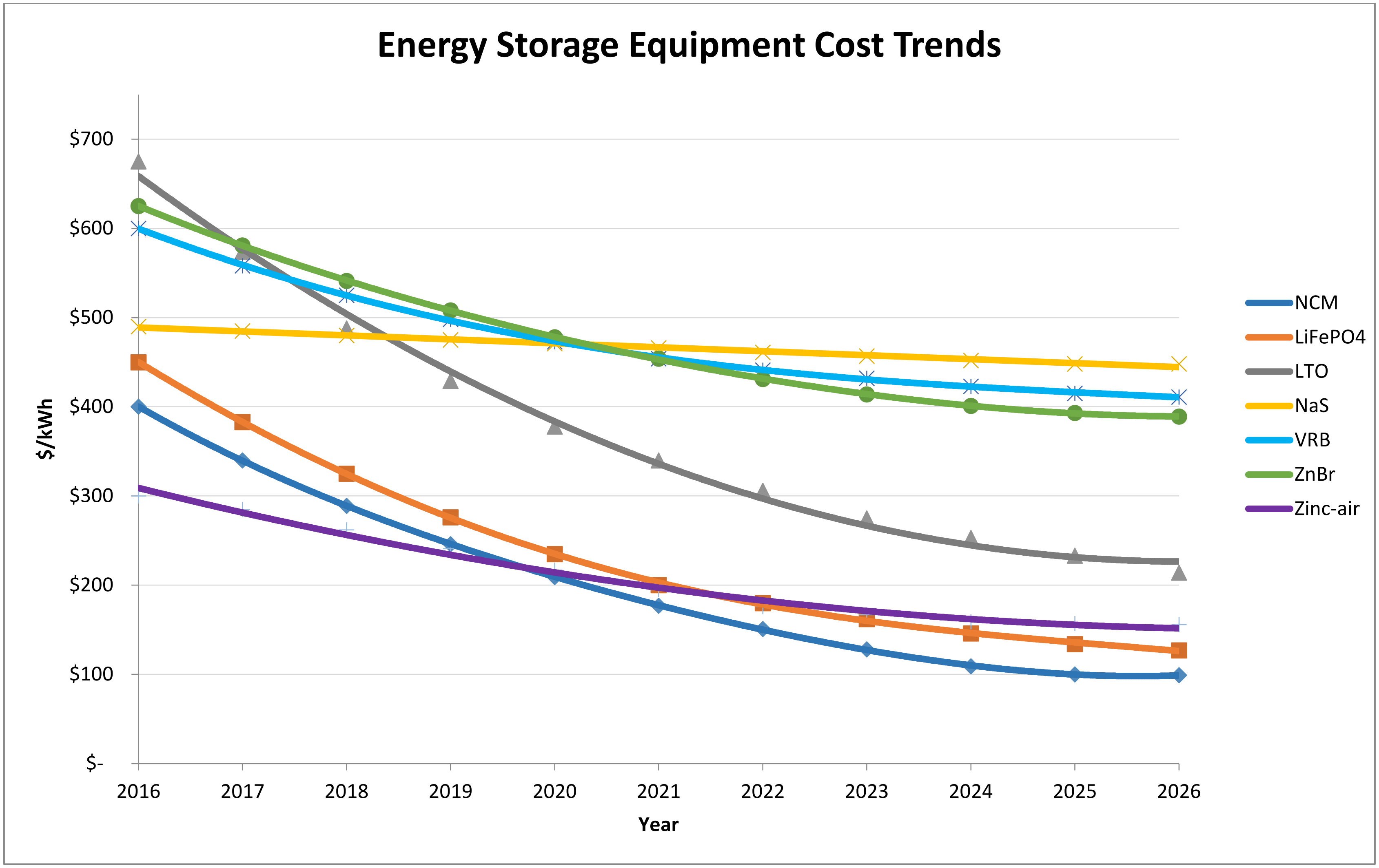

Figure 3 Projected Energy Storage Equipment Cost Trends for Various Technologies, From 2016 to 2026

PCS cost trends are shown in Figure 4. The PCS cost trends mirror each other across two technology groupings. The PCS costs for all Li-ion and Zinc-air technologies are expected to follow similar trends as they are pulling from the same manufacturers utilizing more mature PCS architectures. PCS costs for flow batteries, while currently offered at a higher price point, are expected to converge to similar costs as the Li-ion over time as these technologies mature and gain additional commercial adoption. While NAS is a more mature technology, current PCS costs are above those of Li-ion technologies with future cost reductions expected to benefit from increased adoption of flow battery PCS architectures.

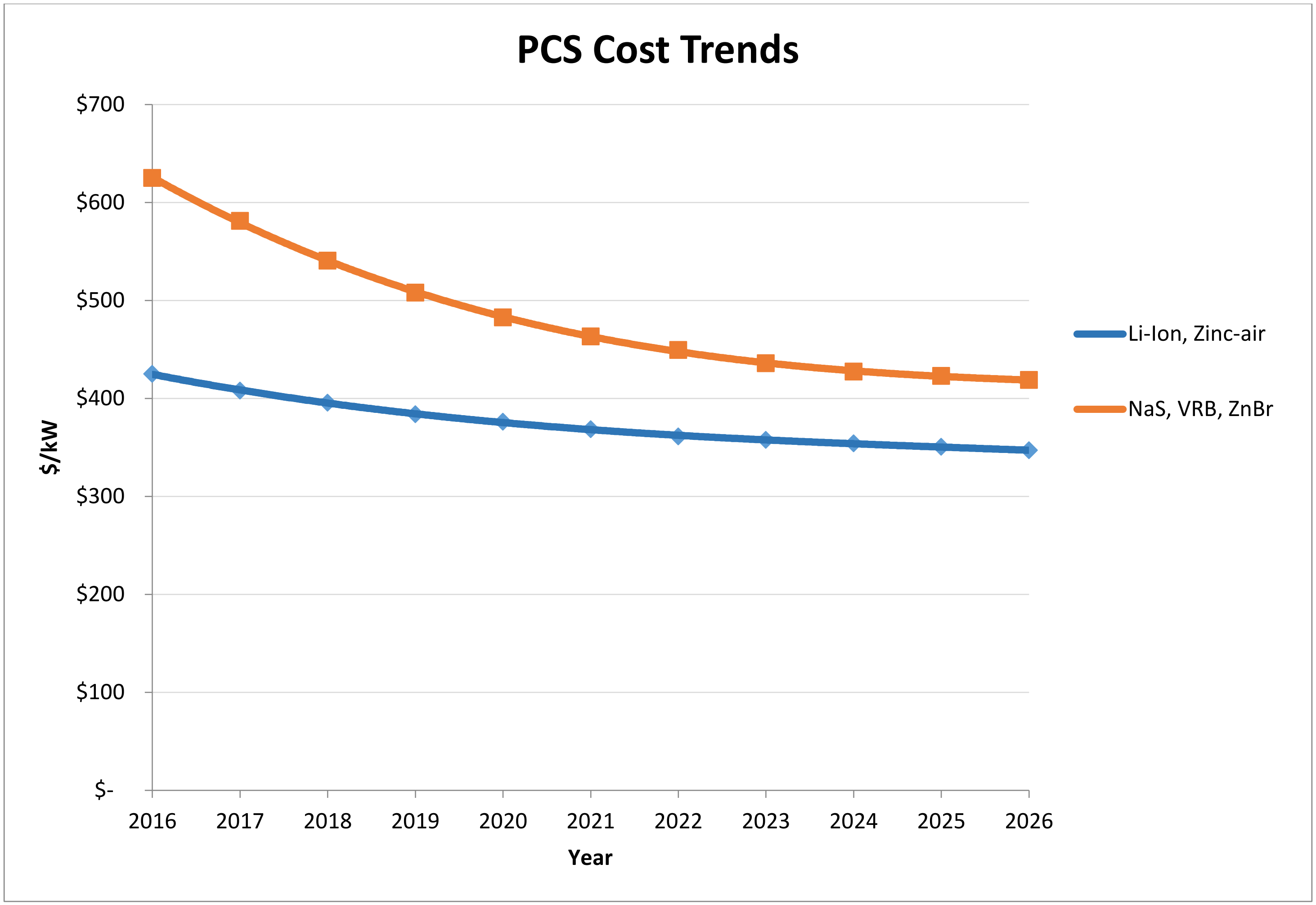

Figure 4 Projected PCS Cost Trends for Various Technologies, From 2016 to 2026

Controls cost reductions, shown in Figure 5, are expected to be relatively uniform across all technologies. While competition in the space is expected to continue, the need for increasingly sophisticated controllers which interact with both utility and distributed behind-the-meter storage assets are expected to result in modest cost reductions over time, converging to a relatively uniform price across technologies.

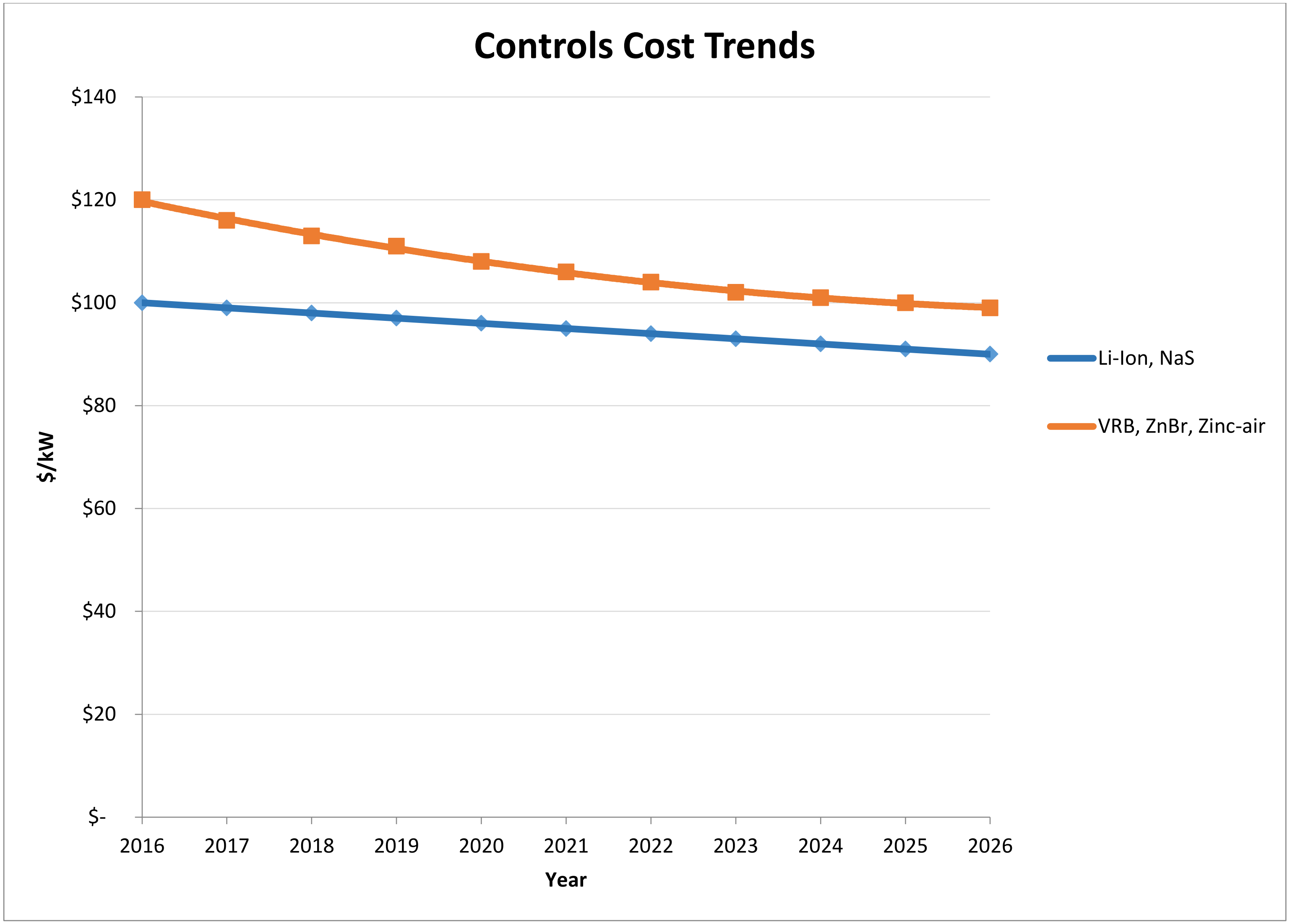

Figure 5 Projected Controls Cost Trends for Various Technologies, From 2016 to 2026

Balance of system costs, shown in Figure 6, is expected to fall dramatically over the next 5 years with continued modest gains through 2026. Cost reductions are expected as project developers gain experience deploying these technologies and system interconnection requirements become more uniform for storage technologies. Li-ion technologies and Zinc-air follow similar trends due to similarities in construction and balance of plant requirements, while reductions for flow batteries and NaS systems are expected to follow similar patterns.

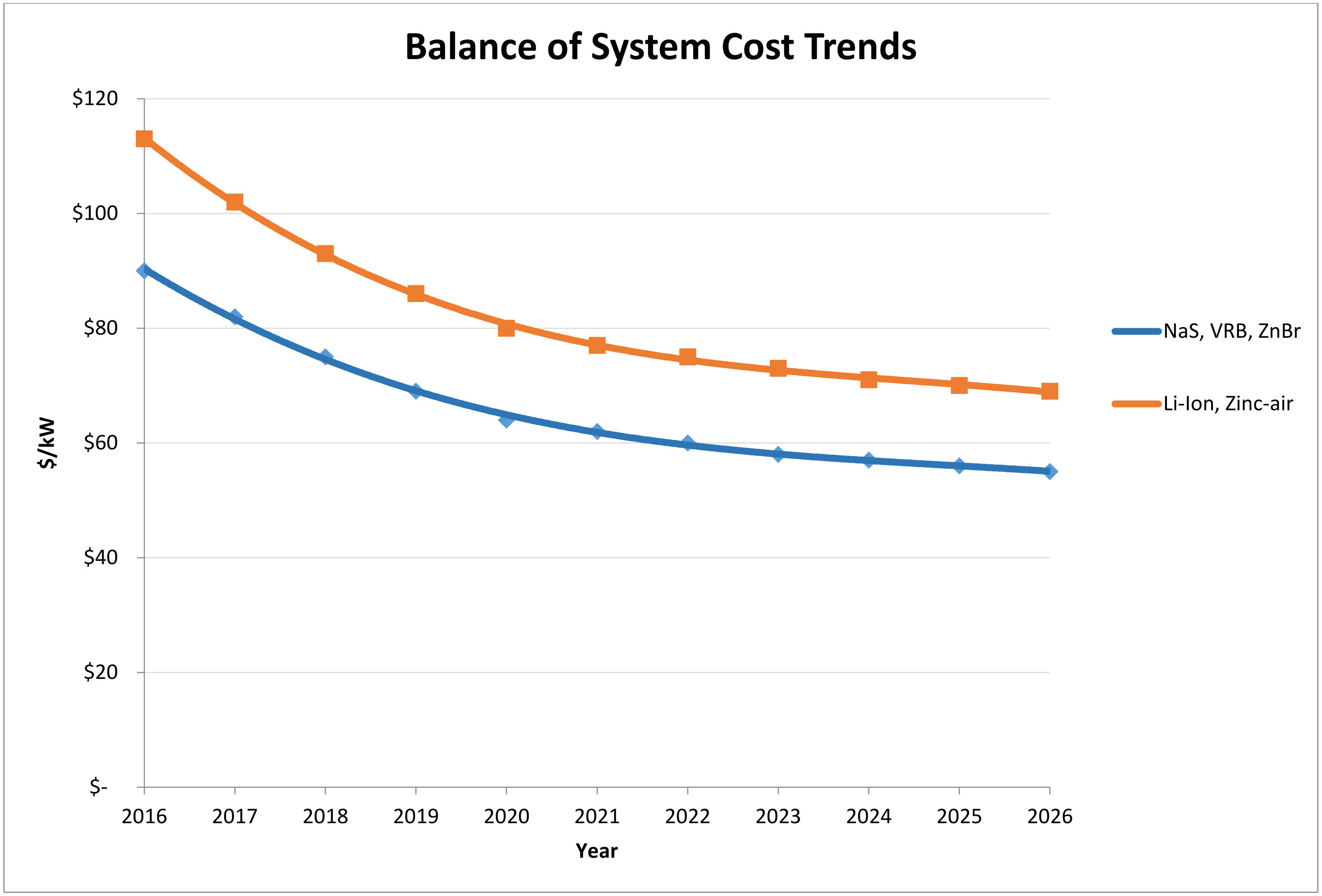

Figure 6 Projected Balance of System Cost Trends for Various Technologies, From 2016 to 2026

5.0 UTILITY APPLICATIONS AND VALUE STREAMS

In this chapter, an application-technology ranking is provided which is intended to indicate the applicability of each technology and their relative potential for generating economic value for at least one of eight (8) benefit cases within PacifiCorp's service territory over the next 20 years. This assessment considers both the likelihood that a particular storage application is relevant to the current PacifiCorp market, as well as the appropriateness of a specific technology to serve the needs of that application. The eight applications identified by PacifiCorp for considerations are as follows:

1. Electric Energy Time Shift
2. Electric Supply Capacity
3. Regulation
4. Spinning, Non-Spinning, and Supplemental Reserves
5. Voltage Support
6. Load Following/Ramping Support for Renewables
7. Frequency Response
8. T&D Congestion Relief

In this chapter, definitions of each application will be provided, followed by an overview of regulatory concerns specific to PacifiCorp territory providing an assessment of both planned regulatory initiatives and local network and market conditions in the PacifiCorp region. These will be reviewed specifically as they relate to energy storage potential. Finally, results of the assessment are provided indicating the applicability of each technology and the relative potential for generating economic value for at least one of the benefit cases within PacifiCorp's service territory over the next 20 years. These rankings are provided on a 1 to 10 scale.

At PacifiCorp's request, this report additionally includes an assessment on applicability of each technology and the relative potential for generating economic value under an alternative market scenario with PacifiCorp operating under market rules similar to those implemented in California ISO (CAISO).

5.1 Considered Applications

DNV GL reviewed applications for energy storage systems based on the regulations and standards in place in PacifiCorp territories, including the availability of financial resources to support energy storage development, as well as the general expansion of demand. Descriptions of these applications are provided below, based on the Department of Energy's Energy Storage Handbook and DNV GL's recommended practice guide, GRIDSTOR.

- **Electric energy time shift –** Energy storage systems operating within an electrical energy time-shift application are charged with inexpensive electrical energy and discharged when prices for electricity are high. On a shorter timescale, energy storage systems can provide a similar time-shift duty by storing excess energy production from, for example, renewable energy sources with a variable energy production, as this might otherwise be curtailed. If the difference in energy prices is the main driver and energy is stored to compensate for (for example) diurnal energy consumption patterns, this application is often referred to as arbitrage.

Storing energy (i.e. in charge mode) at moments of peak power to prevent curtailment or overload is a form of peak shaving. Peak shaving can be applied for peak generation and also – in discharge mode – for peak demand (e.g. in cases of imminent overload). Peak shaving implicates that the energy charged or discharged is discharged or recharged, respectively, at a later stage. Therefore, peak shaving is a form of the energy time-shift application.

An energy storage system used for energy time-shift could be located at or near the energy generation site or in other parts of the grid, including at or near loads. When the energy storage system used for time-shift is located at or near loads, the low-value charging power is transmitted during off-peak times.

Important for an energy storage system operating in this application are the variable operating costs (non-energy related), the storage round-trip efficiency and the storage performance decline as it is being used (i.e. ageing effects).

- **Electric Supply Capacity -** An energy storage system could be used to defer or reduce the need to buy new central station generation capacity and/or purchase capacity in the wholesale electricity market. In this application, the energy storage system supplies part of the peak capacity when the demand is high, thus relieving the generator by limiting the required capacity peak. Following a (partial) discharge, the energy storage system is recharged when the demand is lower. The power supply capacity application is a form of generation peak shaving, therefore a form of electrical energy time-shift. An energy storage system participating in the electrical capacity market may be subject to restrictions/requirements of this market, for example required availability during some periods.

- **Regulation** - Regulation is used to reconcile momentary differences between demand and generation inside a control area or momentary deviations in interchange flows between control areas, caused by fluctuations in generation and loads. In other words, this is a power balancing application. Conventional power plants are often less suited for this application, where rapid changes in power output could incur significant wear and tear. Energy storage systems with a rapid-response characteristic are suitable for operation in a regulation application.

  Energy storage used in regulation applications should have access to and be able to respond to the area control error (ACE) signal (where applicable), which may require a response time of fewer than five seconds. Furthermore, energy storage used in regulation applications should be reliable with a high quality, stable (power) output characteristics.

- **Spinning, Non-spinning, and supplemental reserves** - A certain reserve capacity is usually available when operating an electrical power system. This reserve capacity can be called upon in case some generation capacity becomes unavailable unexpectedly, thus ensuring system operation and availability. A subdivision can be made based on how quickly a reserve capacity is available:

  - Spinning reserve is reserve capacity connected and synchronized with the grid and can respond to compensate for generation or transmission outages. In remote grids spinning reserve is mainly present to cover for volatile consumption. In case a reserve is used to maintain system frequency, the reserve should be able to respond quickly. Spinning reserves are the first type of backup that is used when a power shortage occurs.

- Non-spinning reserve is connected but not synchronized with the grid and usually available within 10 minutes. Examples are offline generation capacity or a block of interruptible loads.
- Supplemental reserve is available within one hour and is usually a backup for spinning and non-spinning reserves. Supplemental reserves are used after all spinning reserves are online.

Stored energy reserves are usually charged energy backups that have to be available for discharge when required to ensure grid stability. An example of a spinning reserve is an uninterruptible power supply (UPS) system, which can provide nearly instantaneous power in the event of a power interruption or a protection from a sudden power surge. Large UPS systems can sometimes maintain a whole local grid in case of a power outage; this application is called island operation.

- **Voltage support** - Grid operators are required to maintain the grid voltage within specified limits. This usually requires management of reactive power (but also active power, e.g. in the LV grid), therefore also referred to as Volt/VAr support. Voltage support is especially valuable during peak load hours when distribution lines and transformers are the most stressed. An application of an energy storage system could be to serve as a source or sink of the reactive power. These energy storage systems could be placed strategically at central or distributed locations.

  Voltage support typically is a local issue at low voltage (LV), medium voltage (MV) or high voltage (HV) level. The distributed placement of energy storage systems allows for voltage support near large loads within the grid. Voltage support can also be provided by operation of generators, loads, and other devices. A possible advantage of energy storage systems over these other systems is that energy storage systems are available to the grid even when not generating or demanding power.

  Note that no (or low) real power is required from an energy storage system operating within a voltage/VAr support application, so cycles per year are not applicable for this application and storage system size is indicated in MVAr rather than MW. The converter needs to be capable of operating at a non-unity power factor in order to source or sink reactive power. The nominal duration needed for voltage support is estimated to be 30 minutes, which allows the grid time to stabilize and/or begin orderly load shedding.

- **Load following / ramping support for renewables** - Load following is one of the ancillary services required to operate a stable electricity grid. Energy storage systems used in load following applications are used to supply (discharge) or absorb (charge) power to compensate for load variations. Therefore, this is a power balancing application. In general, the load variations should stay within certain limits for the rate of change, or ramp rate. Therefore, this application is a form of ramp rate control. The same holds for generation variations, which is very applicable to renewable energy sources. Due to the intermittency of renewables production, having a storage device with several hour durations can provide a large advantage to renewable efficiencies, easing of grid impacts, and renewable production. Conventional power generation can also operate with a load following (or RES compensating) application. Within these applications, the benefits of energy storage systems over conventional power generation are that:
  - most systems can operate at partial load with relatively modest performance penalties
  - most systems can respond quickly with respect to a varying load

- systems are suitable for both load following down (as the load decreases) and load following up (as the load increases) by either charging or discharging.

Note that an energy storage system operating with a load-following or ramp rate control application within a market area needs to purchase (when charging) or sell (when discharging) energy at the going wholesale price. As such the energy storage efficiency is important when determining the value of the load following application.

- **Frequency response -** Synthetic inertia behavior is the increase or decrease in power output proportional to the change of grid frequency; physical inertia is provided by conventional power generators, i.e. synchronous generators. If the total amount of physical inertia decreases in a power system, the amount of synthetic inertia should be increased to maintain a certain minimum amount of total inertia. Many grid-connected renewable energy sources do not provide additional synthetic inertia. Therefore, larger grid frequency deviations may occur as the total inertia in the power system decreases. Keeping track of the total system inertia could be a future task of ISOs.

  Some energy storage systems add synthetic inertia to the system and can thereby be used to compensate for fluctuations in the grid frequency. Causes of fluctuations could be the loss of a generation unit or a transmission line (causing a sudden power imbalance). Various generator response actions are needed to counteract a sudden frequency deviation, often within seconds.

  Energy storage within a frequency response application could support the grid operator and thereby assure a smoother transition from an upset period to normal operation. For a frequency response type of application, the energy storage is required to provide support within milliseconds. Storage helps to maintain the grid frequency and to comply with Control Performance Standards (CPSs) 1 and 2 of the North American Reliability Council (NERC). Aside from this quick response, the frequency response application is similar to load following and regulation, as described previously.

- **Transmission and distribution congestion relief** – During moments of peak demand, it may occur that the available transmission lines do not provide enough capacity to deliver the least-cost energy to some or all of the connected loads. This transmission congestion may increase the energy cost.

  Energy storage systems at strategic positions within the electricity grid help to avoid congestion-related costs and charges. The energy storage system can be charged when there is no congestion and discharged when congestion occurs. Energy storage can, in this way, additionally delay and sometimes avoid the need to upgrade a transmission or distribution system.

5.2 PacifiCorp Territory Regulatory Concerns and Application Drivers

Currently, the largest drivers of energy storage deployment nationally have been a direct result of state and federal level regulatory actions encouraging or mandating procurement and installation of energy storage technologies. Much of the regulatory action has come as follow-up initiatives to more aggressive renewable portfolio standards (RPS) with storage seen as an enabling technology which can mitigate issues associated with higher level of renewable penetration. To a lesser extent, regulatory action around energy security has additionally spurred some development opportunities for energy storage as a reliability resource.

Additionally, a small set of cost-effective applications in select markets, such as frequency regulation, supply capacity, and transmission and distribution deferral have been driving installations. Where market operators have permitted energy storage systems to obtain capacity credits, larger-scale energy storage systems have been justified financially based on the capacity payments over 10-20 year contracts. These structures have additionally supported storage applications for transmission and distribution (T&D) congestion relief. Finally, markets which have developed mechanisms to compensate fast regulation or pay-for-performance market products, have allowed for an opportunity for battery energy storage systems which can obtain high-performance scores in these markets.

Of note, the growth of commercial and industrial behind-the-meter storage installations has been driven in select markets where customers are exposed to high retail rates, and more importantly, high monthly peak demand charges. At the residential level, in select markets where net-metering rules are unfavorable to customers installing solar generation, and high retail energy rates exist, residential self-supply is also seen as a cost-effective energy storage application.

Based on these current trends, storage applications related to capacity such as supply capacity and T&D congestion relief, as well as applications supporting renewable integration, such as renewable time shifting, regulation, and load following, and to a lesser extent, frequency response and voltage support, are likely to be the more likely application for storage over the next 20 years. The relative ranking of these applications is more nuanced and requires a look at the policies in-place or planned for PacifiCorp's service territory.

The PacifiCorp territory is comprised of regions throughout California, Oregon, and Washington (under PacificPower), and Idaho, Utah, and Wyoming (under Rocky Mountain Power). Each state observes a variety of regulations relating to energy security, distribution, and storage. Further, the federal government provides additional regulation that must be observed. At both the state and federal level, incentives are additionally provided in some cases.

The PacificPower region, in particular, has a well-developed set of regulations and incentives already in place. Oregon, Washington, and California all have Renewable Portfolio Standards (RPS) as well as other legislation that encourages utility pursuit of clean energy and potentially energy storage systems.

Oregon's most influential energy storage-specific legislation that passed in 2015, HB 2193, directs the state's electric utility companies to procure one or more energy storage systems capable of storing a specified energy capacity by 2020, allowing them to recover all costs through electrical rates. Additionally, SB 1547 passed in 2016, requiring, among other things, an RPS which would amount to 50% renewables for PacifiCorp by 2040, and the elimination of coal-generated energy utilization by 2030. This legislation will put additional pressure for energy storage to support the growing renewables portfolio.

In the state of Washington, several bills have been passed that create a supportive infrastructure for energy storage. For example, HB 1897 established a program in support of R&D to develop next generation clean energy technology sustainably; HB 1296 legislated that an IRP is required to include energy storage; SB 5025 amended laws to support the meeting of renewable energy targets by utilities and minimum standards for energy efficient buildings; and HB 1895, a bill currently pending a hearing, if passed would promote the deployment of clean distributed energy, and prioritizes deployment of smart grids and microgrids. Further, the Energy Independence Act, or I-937, specifically requires a 15% RPS by 2020. The pursuit of these standards has recently been supported by HB 1115. This legislation sets aside $44 million in grants that are to be directed towards renewables advancement and technology, specifically including energy storage.

California has for many years been a leading state in the pursuit of clean energy. Many pieces of legislation support renewable technology infrastructure, especially focused on the causes of reducing emissions and improving energy resiliency. For instance, SB 1358 specifies emission performance standards and SB 350 requires an increase in the amount of electricity generated and sold from renewable energy resources in order to strengthen the diversity and resilience of the electrical system. California further passed SB 83, requiring public utilities to enact net metering tariffs to enhance diversification and reliability of the state's energy resources. Recently, AB 1530 states that clean distributed energy must be deployed by utilities, and prioritizes deployment of smart grids and microgrids. Specifically, California utilities must meet an RPS of 50% by 2030, with intermediate goals, as initiated by AB 327 and SB 350, noted previously.

In contrast, the Rocky Mountain Power region does not have as many or as specific regulation or support. While Utah provides a renewable energy target of 20% by 2025, but not an RPS, neither Idaho nor Wyoming has any RPS or voluntary renewable goals. There are, however, several pieces of legislation that support, directly or indirectly, energy storage, chiefly as a method to support reliability and resiliency.

Utah leads the way with SB 0115, called the Sustainable Transportation and Energy Plan (STEP) Act. This bill allows for the Public Service Commission to authorize the implementation of tariffs by utilities in order to establish electric efficiency technology programs, allows the utility to provide incentives for air quality improvement technology and electric vehicle infrastructure development, and provides support for clean energy programs implemented by utilities. PacifiCorp has already reacted to this legislation with their STEP initiative. This includes the STEP Pilot programs, 5-year programs providing funding to, among other projects, battery storage development. Additionally, PacifiCorp has applied to the Public Service Commission to offer large customers the option to participate in a Renewable Energy Tariff, paying directly to get part or all of their electricity from a specific renewable project. Further, Utah has passed SB 280, which promotes the development of diverse energy resources, including nonrenewable and renewable resources, nuclear, and alternative transportation fuels. This distributed generation policy's focus is to promote resiliency and reliability of the grid, and will likely naturally lead to an investigation of energy storage procurement and integration.

Idaho passed HB 189, which removed all property taxes on renewable generation sites, in favor of a 3-3.5% tax on generation. Otherwise, although Idaho has neither net metering law nor RPS, it does offer tax credits for renewable energy.

Wyoming, meanwhile, has no net metering law and provides no credits or exemptions for clean distributed energy resources. Further, Wyoming taxes wind generation and is currently considering further raising those taxes. As noted previously, Wyoming has no RPS.

Finally, the Federal Government has put in place regulations to encourage renewables and energy storage. Widely known and utilized is the Investment Tax Credit provided by the Federal government. This 30% direct tax credit was extended until 2019, reduced stepwise annually after that, to 26% in 2020, 22% in 2021, and 10% in 2022, before ending. As to standards, the Clean Power Plan, as regulated by the EPA, assigns each state an emissions reduction target by 2030, contributing to a 32% reduction nationwide. Specific to PacifiCorp, Wyoming, Utah, and Washington have aggressive reduction targets, above 31%, while California, Oregon, and Idaho have reduction targets below 20%, in comparison with 2012 levels. These targets are based on, among other things, generation activity, as well as actions already taken to reduce emissions. States are required to submit a plan for compliance by September 2016, or be subject to a federally developed plan, both likely to directly affect utilities. Although there is some Congressional action to block these requirements, none has currently passed.

5.3 Application Ranking Methodology and Results

DNV GL developed a ranking system for the various applications that battery energy storage systems may be utilized for within PacifiCorp territory. Within this ranking system, information about each technology is used to ascertain its appropriateness for a particular application. The battery type's typical size, technology maturity level, market penetration, as well as technical parameters and various costs influenced these rankings.

First, each application was defined by its requirements for power, energy, cycling, and response time. These Application Requirements were scored on a comparative scale. For instance, in the case of the application of Electric Energy Time Shift, the energy capacity of the system is paramount and thus ranked highly. Alternatively, in the case of the application for Frequency Response, the energy capacity of the system is of lesser importance while response time and power capability are the prioritized requirements. Each technology was then defined by its capabilities to meet these requirements for power, energy, cycling, and response time. These technology capabilities were similarly scored on a comparative scale. For instance, Li-ion technology provides nearly instantaneous response time and was thus ranked highest in that parameter. Flow batteries, on the other hand, scored highest for cycling as they are capable of fully discharging daily with less impact on lifetime and degradation. A Technology Maturity score was then also assigned to technology each based on its current stage of commercialization and scale of field deployments.

The Application Requirements and Technology Capability scores were then compared, defining how well-matched a specific technology was for a given application. For instance, if an application required fast response time, the technologies that provide a fast response time would score highest. Scores across each property were then averaged to provide a Technology Application score for each technology providing each application.

A PacifiCorp Application Need score was then assigned to each application based on the high-level cost-effectiveness and regulatory analysis of the PacifiCorp territory. Based on current PacifiCorp market scenario, storage applications with high value that are not dependent on market-related rule changes, such as T&D congestion relief, are expected to be the most likely candidates for PacifiCorp to deploy energy storage. Additionally, as noted in the review, renewable portfolio standards across the PacifiCorp region will drive some renewable integration applications such as renewable time shifting, regulation, and load following. Faster regulation applications such frequency response and voltage support are likely to be lower value applications. A second set of Scores for PacifiCorp Application Need scores were provided for the alternative market scenario with PacifiCorp operating under market rules similar to those implemented in California ISO (CAISO). For this scenario, CAISO market rules which directly allow storage to qualify for supply capacity credit increased this application score. Also, further developed fast regulation and emerging ramping market products increased the PacifiCorp Application Need score for frequency regulation and applications tied to renewable integration.

Finally, PacifiCorp application rankings were computed for each application and technology under each market rules scenarios. The final rankings were computed by taking the average score over the Technology Application score, the Technology Maturity Score, and the PacifiCorp Need score. This methodology resulted in Table 11 and Table 12.

Table 11 Application Rankings in Current Market Rules Scenario

Application	Current Market Scenario						
	Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Electric Energy Time Shift	9	8	8	9	8	8	7
Electric Supply Capacity	9	9	9	9	8	8	7
Regulation	9	9	9	9	8	8	7
Spinning, Non-spin, Supplemental reserves	8	8	9	8	8	8	7
Voltage support	7	8	8	7	6	6	6
Load following / ramping support for renewables	8	8	9	8	8	8	7
Frequency response	7	7	8	7	6	6	5
Transmission and distribution congestion relief	9	9	9	9	9	9	8

Table 12 Application Rankings for CAISO Market Rules Scenario

Application	CAISO Market Scenario						
	Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Electric Energy Time Shift	9	9	9	9	9	9	7
Electric Supply Capacity	9	9	9	9	9	9	8
Regulation	9	9	9	9	8	8	7
Spinning, Non-spin, Supplemental reserves	9	9	9	9	8	8	7
Voltage support	7	8	8	7	6	6	6
Load following / ramping support for renewables	9	9	9	9	8	8	7
Frequency response	7	7	8	7	6	6	5
Transmission and distribution congestion relief	9	9	9	9	9	9	8

6.0 CONCLUSION

The data from this study is intended to support PacifiCorp in making decisions regarding energy storage procurement and grid integration to support their 2017 IRP, giving confidence in the current state of the industry while providing insight into what trends and regulations which will prevail in the future. Further, this study is intended to provide general guidance on the appropriateness of each presented technology for specific applications, as needs and requirements vary across each PacifiCorp region. The inclusion of battery energy storage, particularly when paired with other distributed energy resources, will allow PacifiCorp to comply with emerging energy regulations while also providing greater flexibility, resiliency, and efficiency in the allocation of resources.

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Appendix C – DNV GL Draft Storage Potential Evaluation

On March 27, 2017 PacifiCorp commissioned the consulting services of DNV GL to develop energy storage evaluation methodologies and draft a preliminary energy storage evaluation report. This preliminary report was completed and included in PacifiCorp's Draft Energy Storage Evaluation submission on July 14, 2017. The report has been included in the following pages for reference.

DNV·GL

Energy Storage Potential Evaluation

PacifiCorp

Report No.: 10046409-R-01-E
Issue: E **Status:** Final Draft
Date: 11 July 2017

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Report title:	Energy Storage Evaluation	
Customer:	PacifiCorp	
	825 NE Multnomah St, 20th Floor	DNV GL - Energy
	Portland, OR 97232	Energy Advisory
Contact person:	Greg Stratton	4377 County Line Rd
Date of issue:	07/11/2017	Chalfont, PA 18914
Report No.:	10046409-R-01-E	Tel: +1 215 997 4500
Issue:	E	
Status:	Final	

Prepared by:	Verified by:	Approved by:
S.Lahiri, J.Flinn, N.Mirhosseini, W.Zhang, V. Carey	M. Kleinberg	J. David Erickson

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Keywords:
Energy Storage, Use Case Assessment, Modeling

Issue	Date	Reason for Issue
A	6/20/2017	In-progress draft issue
B	6/30/2017	In-progress draft issue
C	7/6/2017	In-progress draft issue
D	7/8/2017	Final draft for client approval
E	7/11/2017	Final issue

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List of abbreviations

ACE	Area Control Error
AGC	Automatic Generation Control
BCR	Benefit/Cost Ratio
BESS	Battery Energy Storage System
BPA	Bonneville Power Administration
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CPCs	Control Performance Standards
EIM	Energy Imbalance Market
ESS	Energy Storage System
FRO	Frequency Response Obligation
HV	High Voltage
IRP	Integrated Resource Plan
IRR	Internal Rate of Return
ISO	Independent System Operator
Li-Ion	Lithium-Ion
LMP	Locational Marginal Price
LV	Low Voltage
MCC	Marginal Congestion Component
MEC	Market Energy Component
MLC	Marginal Loss Component
MV	Medium Voltage
NERC	North American Reliability Council
O&M	Operations and Maintenance
OPUC	Public Utility Commission of Oregon
POI	Point of Interconnection
PV	Photovoltaic
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
UPS	Uninterruptible Power Supply
WECC	Western Electricity Coordinating Council

1.0 EXECUTIVE SUMMARY AND DOCUMENT SCOPE

PacifiCorp D/B/A PacifiCorp (referred to in this document as “PacifiCorp” or “the Company”) has developed this document and the process and results described herein to comply with Oregon’s 2015 HB 2193, the subsequent Order 16-504 UM 1751, and the final guidelines from the Public Utility Commission of Oregon (OPUC) relating to these items. PacifiCorp’s understanding of these requirements is described below:

1. Identify energy storage potential by use case or application with the ability to be implemented by year end 2026. The use of the 2026 time horizon is understood to limit uncertainty associated with the volatility of energy storage coasts and technology. A key objective is to provide recommendations for storage projects and their proposed use that can be procured by 2020.
2. Identify higher- and lower-value applications for energy storage.
3. Develop criteria for designating higher- and lower-value applications and explain how the criteria are applied.
4. Identify locations within the Company’s service territory in the state of Oregon with the greatest energy storage potential. Including:
    - Applications such as customer-side (e.g. residential, commercial, industrial) and/or utility-side (e.g. distribution and transmission).
5. Develop a recommended methodology for determining energy storage potential, including:
    - How the methodology should be applied, and
    - Identify critical limiting factors that affect estimates of storage potential by application.
6. Provide all material inputs, assumptions and other calculations needed to designate higher- and lower-value applications.
7. Estimate potential costs and associated cost effectiveness of the addition of energy storage to the Company’s system.
8. Provide an assessment of potential qualitative and quantitative benefit of energy storage to the electric system and customer.

In this draft energy storage potential evaluation, PacifiCorp contracted and collaborated with DNV GL to develop methodologies to assess a variety of use cases for energy storage, execute these methodologies on selected to sites to demonstrate their performance, and develop initial results upon which further analysis could be conducted to select the most appropriate case for future implementation. This draft evaluation was conducted qualitatively on the transmission system, and quantitatively on six feeders and one large customer site. The use cases evaluated were transmission congestion relief and deferral, frequency response, volt/VAR optimization, reliability, distribution asset deferral, and customer sited storage, including stacked applications at a customer site for reliability (including renewables integration and microgrid formation), frequency response, and distribution upgrade deferral. Additionally, the distribution asset deferral case was examined at a high-level for implications on the whole system.

Where possible, a benefit-cost ratio (BCR), which is defined as the value of benefits divided by the value of the costs, was used as the standard to compare the cases. The larger the value of the BCR, the more favorable the economics of the project. A BCR of 1 indicates a project in which the costs are equivalent to the benefits. Additional details about the economic considerations specific to each use case are described within the noted document references. Based on PacifiCorp’s cost of traditional grid upgrades versus the cost of implementation of energy storage as well as the needs of the grid and customers, the most viable options from the results of these studies are summarized in Table 1-1. Other options are described in further detail within the noted sections. The transmission congestion relief and substation level reliability applications were not found to be necessary or effective under current grid conditions, and are thus not noted within this chart.

Table 1-1 Summary of most viable modeling results

Use Case	Energy Storage System Size	Economic considerations	Document reference
Frequency response (FR)	10 MW / 2 MWh (20 year FR contract @ $81/kW-yr)	BCR = 1.78	Section 4.1
Volt/VAR	17 kVA / 4 hr (Addresses 1 voltage violation, high cost capacitor upgrade)	BCR = 1.56	Section 5.1
Distribution upgrade deferral	(1) 1 MW / 2 MWh 2 years deferral Stand alone, and stacked with frequency response @ $81/kW-yr (2) 4 MW / 8 MWh 7 years deferral Stand alone, and stacked with frequency response @ $81/kW-yr	(1) Stand alone BCR = 0.36 Stacked BCR = 0.81 (2) Stand alone BCR = 0.27 Stacked BCR = 0.41	Section 5.3
Customer Sited with Stacked Applications	(1) 2 MW / 4 MWh ESS + PV, 4 years deferral, and frequency response @ $81/kW-yr (2) 4 MW / 6 MWh ESS + PV, 6 years deferral, and frequency response @ $81/kW-yr	(1) BCR = 1.36 (2) BCR = 1.35	Section 6.1

For these results, the systems were assumed to be generic Lithium Ion battery energy storage systems (BESS) of the noted size. Although other types of chemistries and technologies can and should be considered, this assumption reduced variables in the modeling and allowed for more direct comparison between cases. Other technologies are discussed in further detail in later sections of the report.

The challenge in comparing these varied use cases is in determining their economic value to both the utility and the customer, values which are not always comparable and may sometimes be in conflict. Additionally, economic value is not the only type of value PacifiCorp is assessing. The BCR scores therefore are not as nuanced as the full consideration of each potential project, but provide a single metric to compare cases as a starting point of that full consideration.

Of the applications noted in Table 1-1, the most economically viable were those in which the benefits from use cases were stacked, including distribution upgrade deferral, frequency response, and solar + storage integration for reliability. The benefits from the volt/VAR use case were also proposed as stackable, although a detailed analysis of this option was not conducted. Further, the urgency of these use cases should be considered, with the voltage violations and transformer overloads being the primary concerns to PacifiCorp providing safe and reliable service. In these cases, though the costs PacifiCorp ascribes to traditional solutions are lower than those of the energy storage systems (ESS) proposed, the viability of stacked benefits can provide more favorable economics, especially when considered as a distributed aggregated resource, where customer sites may also receive non-economic benefit. As such, if it is determined that the traditional solutions are more expensive than originally cited, the economics of each case would improve in favorability.

As such, to ensure safe, reliable, and low-cost power to its customers, as well as to meet the requirements laid out by the state of Oregon and the OPUC, PacifiCorp is considering the noted options.

2.0 USE CASE AND APPLICATION SELECTION

2.1 High level use case and application descriptions

As cited in the Battery Energy Storage Study for PacifiCorp's 2017 IRP [1], energy storage systems can be supportive of multiple applications, with some more economically feasible or appropriate for PacifiCorp's grid. Descriptions of the applications considered within that document are transcribed below.

> DNV GL reviewed applications for energy storage systems based on the regulations and standards in place in PacifiCorp territories, including the availability of financial resources to support energy storage development. Descriptions of these applications are provided below, based on the Department of Energy's Electricity Storage Handbook [2] in collaboration with NRECA and DNV GL's recommended practice guide, GRIDSTOR [3].
>
> - **Electric energy time shift –** Energy storage systems operating within an electrical energy time-shift application are charged with inexpensive electrical energy and discharged when prices for electricity are high. On a shorter timescale, energy storage systems can provide a similar time-shift duty by storing excess energy production from, for example, renewable energy sources with a variable energy production, as this might otherwise be curtailed. If the difference in energy prices is the main driver and energy is stored to compensate for (for example) diurnal energy consumption patterns, this application is often referred to as arbitrage.
>
>   Storing energy (i.e. in charge mode) at moments of peak power to prevent curtailment or overload is a form of peak shaving. Peak shaving can be applied for peak generation and also – in discharge mode – for peak demand (e.g. in cases of imminent overload). Peak shaving implicates that the energy charged or discharged is discharged or recharged, respectively, at a later stage. Therefore, peak shaving is a form of the energy time-shift application.
>
>   An energy storage system used for energy time-shift could be located at or near the energy generation site or in other parts of the grid, including at or near loads. When the energy storage system used for time-shift is located at or near loads, the low-value charging power is transmitted during off-peak times.
>
>   Important for an energy storage system operating in this application are the variable operating costs (non-energy related), the storage round-trip efficiency and the storage performance decline as it is being used (i.e. ageing effects).
>
> - **Electric Supply Capacity -** An energy storage system could be used to defer or reduce the need to buy new central station generation capacity and/or purchase capacity in the wholesale electricity market. In this application, the energy storage system supplies part of the peak capacity when the demand is high, thus relieving the generator by limiting the required capacity peak. Following a (partial) discharge, the energy storage system is recharged when the demand is lower. The power supply capacity application is a form of generation peak shaving, therefore a form of electrical energy time-shift. An energy storage system participating in the electrical capacity market may be subject to

restrictions/requirements of this market, for example required availability during some periods.

- **Regulation** - Regulation is used to reconcile momentary differences between demand and generation inside a control area or momentary deviations in interchange flows between control areas, caused by fluctuations in generation and loads. In other words, this is a power balancing application. Conventional power plants are often less suited for this application, where rapid changes in power output could incur significant wear and tear. Energy storage systems with a rapid-response characteristic are suitable for operation in a regulation application.

  Energy storage used in regulation applications should have access to and be able to respond to the area control error (ACE) signal (where applicable), which may require a response time of fewer than five seconds. Furthermore, energy storage used in regulation applications should be reliable with a high quality, stable (power) output characteristics.

- **Spinning, Non-spinning, and supplemental reserves** - A certain reserve capacity is usually available when operating an electrical power system. This reserve capacity can be called upon in case some generation capacity becomes unavailable unexpectedly, thus ensuring system operation and availability. A subdivision can be made based on how quickly a reserve capacity is available:

  - Spinning reserve is reserve capacity connected and synchronized with the grid and can respond to compensate for generation or transmission outages. In remote grids spinning reserve is mainly present to cover for volatile consumption. In case a reserve is used to maintain system frequency, the reserve should be able to respond quickly. Spinning reserves are the first type of backup that is used when a power shortage occurs.

  - Non-spinning reserve is connected but not synchronized with the grid and usually available within 10 minutes. Examples are offline generation capacity or a block of interruptible loads.

  - Supplemental reserve is available within one hour and is usually a backup for spinning and non-spinning reserves. Supplemental reserves are used after all spinning reserves are online.

    Stored energy reserves are usually charged energy backups that have to be available for discharge when required to ensure grid stability. An example of a spinning reserve is an uninterruptible power supply (UPS) system, which can provide nearly instantaneous power in the event of a power interruption or a protection from a sudden power surge. Large UPS systems can sometimes maintain a whole local grid in case of a power outage; this application is called island operation.

- **Voltage support** - Grid operators are required to maintain the grid voltage within specified limits. This usually requires management of reactive power (but also active power, e.g. in the LV grid), therefore also referred to as Volt/VAR support. Voltage support is especially valuable during peak load hours when distribution lines and transformers are the most stressed. An application of an energy storage system could be to serve as a source or sink of the reactive power. These energy storage systems could be placed strategically at central or distributed locations.

Voltage support typically is a local issue at low voltage (LV), medium voltage (MV) or high voltage (HV) level. The distributed placement of energy storage systems allows for voltage support near large loads within the grid. Voltage support can also be provided by operation of generators, loads, and other devices. A possible advantage of energy storage systems over these other systems is that energy storage systems are available to the grid even when not generating or demanding power.

Note that no (or low) real power is required from an energy storage system operating within a voltage/VAR support application, so cycles per year are not applicable for this application and storage system size is indicated in MVAR rather than MW. The converter needs to be capable of operating at a non-unity power factor in order to source or sink reactive power. The nominal duration needed for voltage support is estimated to be 30 minutes, which allows the grid time to stabilize and/or begin orderly load shedding.

- **Load following / ramping support for renewables** - Load following is one of the ancillary services required to operate a stable electricity grid. Energy storage systems used in load following applications are used to supply (discharge) or absorb (charge) power to compensate for load variations. Therefore, this is a power balancing application. In general, the load variations should stay within certain limits for the rate of change, or ramp rate. Therefore, this application is a form of ramp rate control. The same holds for generation variations, which is very applicable to renewable energy sources. Due to the intermittency of renewables production, having a storage device with several hour durations can provide a large advantage to renewable efficiencies, easing of grid impacts, and renewable production. Conventional power generation can also operate with a load following (or RES compensating) application. Within these applications, the benefits of energy storage systems over conventional power generation are that:

    - most systems can operate at partial load with relatively modest performance penalties
    - most systems can respond quickly with respect to a varying load
    - systems are suitable for both load following down (as the load decreases) and load following up (as the load increases) by either charging or discharging.

  Note that an energy storage system operating with a load-following or ramp rate control application within a market area needs to purchase (when charging) or sell (when discharging) energy at the going wholesale price. As such the energy storage efficiency is important when determining the value of the load following application.

- **Frequency response -** Synthetic inertia behavior is the increase or decrease in power output proportional to the change of grid frequency; physical inertia is provided by conventional power generators, i.e. synchronous generators. If the total amount of physical inertia decreases in a power system, the amount of synthetic inertia should be increased to maintain a certain minimum amount of total inertia. Many grid-connected renewable energy sources do not provide additional synthetic inertia. Therefore, larger grid frequency deviations may occur as the total inertia in the power system decreases. Keeping track of the total system inertia could be a future task of ISOs.

Some energy storage systems add synthetic inertia to the system and can thereby be used to compensate for fluctuations in the grid frequency. Causes of fluctuations could be the loss of a generation unit or a transmission line (causing a sudden power imbalance). Various generator response actions are needed to counteract a sudden frequency deviation, often within seconds.

Energy storage within a frequency response application could support the grid operator and thereby assure a smoother transition from an upset period to normal operation. For a frequency response type of application, the energy storage is required to provide support within milliseconds. Storage helps to maintain the grid frequency and to comply with Control Performance Standards (CPSs) 1 and 2 of the North American Reliability Council (NERC). Aside from this quick response, the frequency response application is similar to load following and regulation, as described previously.

- **Transmission and distribution congestion relief** – During moments of peak demand, it may occur that the available transmission lines do not provide enough capacity to deliver the least-cost energy to some or all of the connected loads. This transmission congestion may increase the energy cost.

  Energy storage systems at strategic positions within the electricity grid help to avoid congestion-related costs and charges. The energy storage system can be charged when there is no congestion and discharged when congestion occurs. Energy storage can, in this way, additionally delay and sometimes avoid the need to upgrade a transmission or distribution system.

DNV GL also, beyond what is noted from the IRP, considered the following application:

- **Distribution upgrade deferral** – Strategically placed electrical energy storage used within a distribution system may act as an energy buffer and alternative to major component replacements, thereby deferring distribution grid upgrades. The key consideration of energy storage in this application is that the system can provide enough incremental capacity to defer a large lump sum investment in new distribution equipment. As such the energy storage system is designed to serve sufficient load, as long as required, to keep the loading of the distribution equipment below a specified maximum to extend equipment service life. Another potential benefit of energy storage systems in this application is the minimization of the risk that a planned load growth does not occur after upgrades of transmission/distribution lines and transformers.

2.2 Criteria to determine application value

In the Battery Energy Storage Study for PacifiCorp's 2017 IRP [1], an application assessment methodology is laid out to assess the appropriateness of various energy storage technologies for PacifiCorp's territories. Although not specific exclusively to PacifiCorp's territory in Oregon, this assessment methodology provided the baseline for the use case value determination. Because this proposal is intended to be technology agnostic, the assessment here was only based on the PacifiCorp Application Need score. The section describing this is excerpted below:

> A PacifiCorp Application Need score was then assigned to each application based on the high-level cost-effectiveness and regulatory analysis of the PacifiCorp territory. Based on current

PacifiCorp market scenario, storage applications with high value that are not dependent on market-related rule changes, such as T&D congestion relief, are expected to be the most likely candidates for PacifiCorp to deploy energy storage. Additionally, as noted in the review, renewable portfolio standards across the PacifiCorp service territory will drive some renewable integration applications such as renewable time shifting, regulation, and load following. Faster regulation applications such frequency response and voltage support are likely to be lower value applications. (Figure 2-1) A second set of Scores for PacifiCorp Application Need scores were provided for the alternative market scenario with PacifiCorp operating under market rules similar to those implemented in California ISO (CAISO). For this scenario, CAISO market rules which directly allow storage to qualify for supply capacity credit increased this application score. Also, further developed fast regulation and emerging ramping market products increased the PacifiCorp Application Need score for frequency regulation and applications tied to renewable integration. (Figure 2-2)

Application	Current Market Scenario						
	Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Electric Energy Time Shift	9	8	8	9	8	8	7
Electric Supply Capacity	9	9	9	9	8	8	7
Regulation	9	9	9	9	8	8	7
Spinning, Non-spin, Supplemental reserves	8	8	9	8	8	8	7
Voltage support	7	8	8	7	6	6	6
Load following / ramping support for renewables	8	8	9	8	8	8	7
Frequency response	7	7	8	7	6	6	5
Transmission and distribution congestion relief	9	9	9	9	9	9	8

Figure 2-1 Application ranking for current market scenario from Battery Energy Storage Study

Application	CAISO Market Scenario						
	Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Electric Energy Time Shift	9	9	9	9	9	9	7
Electric Supply Capacity	9	9	9	9	9	9	8
Regulation	9	9	9	9	8	8	7
Spinning, Non-spin, Supplemental reserves	9	9	9	9	8	8	7
Voltage support	7	8	8	7	6	6	6
Load following / ramping support for renewables	9	9	9	9	8	8	7
Frequency response	7	7	8	7	6	6	5
Transmission and distribution congestion relief	9	9	9	9	9	9	8

Figure 2-2 Application rankings for CAISO Market Scenario from Battery Energy Storage Study

The above rankings were tailored to particular BESS chemistries, rather than other non-chemical types of ESS, and were generalized for the full PacifiCorp territory, including locations outside of Oregon. However, the factors consider to not vary significantly between states, and as such, are representative of the predicted applicability of storage within Oregon only.

Additionally, the requirements and funding restrictions of 2015 HB 2193 and the subsequent Order 16-504 UM 1751 were considered, as these economics were not directly considered in the original ranking. As such, use cases appropriate to centralized or aggregated systems between 5 MWh and 25 MW, over a 10-year time frame, and with a focus on systems that “defer or eliminate the need for system upgrades, provide voltage control or other ancillary service, or supply some other location-specific service that will improve system operation and reliability” were given priority. Finally, PacifiCorp selected a variety of feeders and sites, and the known loading, voltage, or reliability concerns at such sites were taken into account in selecting the applications to be modeled.

2.3 Applications selected

Based on the criteria described in Section 2.2, the following use cases were selected for review:

- Transmission-connected
    - Frequency response
    - High level review of curtailment and congestion
- Distribution-connected

    - Volt/VAR optimization
    - Reliability
    - Distribution asset deferral
- Customer sited
    - Customer reliability
        - Renewables integration
        - Microgrid formation
    - Frequency response
    - Distribution asset deferral
    - Stacked applications

3.0 ENERGY STORAGE COST ASSUMPTIONS

The Battery Energy Storage Study for PacifiCorp's 2017 IRP [1] conducted by DNV GL was used to support cost assumptions for this report. Results presented in the Battery Energy Storage study were assumed mid-2016 storage costs. Storage costs are evolving rapidly and DNV GL has observed costs for NCM Li-Ion (the technology assumed throughout this report) trending to the low-end of the cost ranges presented in the Study. The values from the Battery Energy Storage Study were updated based on current observed costs, with 2018 and 2021 values obtained by applying year-on-year cost reduction projection rates for each component noted. These assumptions are detailed in Table 3-1 and referenced throughout the report.

Table 3-1: Energy Storage Cost Assumptions

Cost Category	2018 Value	2021 Value
Energy storage equipment cost ($/kWh)	$234.81	$143.81
Power conversion equipment cost ($/kW)	$325.92	$303.62
Power control system cost ($/kW)	$78.40	$76.00
Balance of system ($/kW)	$66.67	$55.11
Installation ($/kWh)	$120.00	$120.00
Total Cost of power components ($/kW)	$470.99	$434.73
Total Cost of energy components ($/kWh)	$354.81	$263.81
Fixed O&M cost ($/kW yr)	$6.00	$6.00
Capacity maintenance cost ($/kWh-year)	$7.5	$7.5

The aggregated cost of energy components and power components will be used to calculate ESS project capital cost. For example, the total cost of a 2 MW 4 MWh system deployed in 2018 will be calculated as:

- Cost of power components is 2000 x $470, i.e. $940,000
- Cost of energy components is 4000 x 355, i.e. $1,420,000
- Total cost of ESS project at $2,360,000 is the sum of cost of power components and cost of energy components.

Details of the cost components are as follows:

- Energy storage equipment includes full DC battery system which includes the cost of energy storage medium, such as Li-Ion battery cells or flow battery electrolyte, internal wiring and connections, packaging and containers, and battery management system (BMS).
- PCS equipment includes the inverter, packaging, container and inverter controls.
- Control system includes supervisory control software, along with the controller and communications hardware required to dispatch and operate energy storage systems.

- Balance of system includes site wiring, interconnecting transformer, and additional ancillary equipment.
- Installation includes Engineer-Procure-Construct (EPC) costs inclusive of installation parts and labor, permitting, site design, procurement and transportation of equipment.
- Fixed O&M costs are provided as real levelized dollars with assumed 20 year project life.
- Capacity maintenance cost is required to maintain the energy capacity of the system under degradation over project life. Capacity cost over a 20 year project is calculated by levelizing the cost of replacing the full DC battery system once at a replacement cost of $150/kWh.

4.0 TRANSMISSION-CONNECTED ENERGY STORAGE SYSTEM ASSESSMENT

These use-cases describe the methodology for evaluating the cost-effectiveness of ESS connected to the transmission system. Such systems are generally large, on the scale of several tens of Megawatts, and perform a single application. In de-regulated energy markets, such as PJM, participation in the frequency regulation market is the highest volume application for transmission connected ESS. In a vertically integrated environment, frequency balancing resources may be procured through a bi-lateral contract with an asset providing Primary Frequency Response or Automatic Generation Control (AGC). The congestion on the transmission system was also considered qualitatively.

4.1 Frequency response system assessment

4.1.1 Inputs required

The inputs required for this use case evaluation are:

- Line frequency measurements at 1s time intervals for average summer, extreme summer, average winter, extreme winter, large event and average event days
- Capital and operating costs of energy storage system
- Line frequency data for 20 frequency events in 2016 and 5 frequency events in 2017

4.1.2 Methodology description

In this application, the BESS monitors the line frequency and responds in accordance with a preset dispatch directive when the deviation in system frequency exceeds a certain threshold. This response time of frequency response in seconds is faster than the response time of a frequency regulation signal generated by an Independent System Operator (ISO). An ISO's frequency regulation signal is an integral function of the Area Control Error (ACE) of the balancing area, that is characterized by deviations of the line frequency from a nominal frequency.

In compliance with NERC Standard BAL-003-1 – Frequency Response and Frequency Bias Setting, PacifiCorp East has to maintain a Frequency Response Obligation (FRO) of -48.9 MW/0.1 Hz, while the FRO for PacifiCorp West is -19.5 MW/0.1 Hz [4]. This obligation implies that PacifiCorp is required to respond to a Western Electricity Coordinating Council (WECC)-wide frequency event with generation capacity in proportion to the magnitude of frequency deviation. For example, a frequency reduction by 0.2 Hz to 59.8 Hz would require an increase in generation of 39.0 MW by PacifiCorp West.

This evaluation methodology takes a bottom up approach by simulating storage system operations under typical frequency response events. Operational simulations are used to assess system energy capacity and performance requirements. Performance requirements include annual energy throughput, annual energy charging and annual number of cycles. Energy capacity requirement is used to size the energy storage system. The other performance requirements are used to estimate operating cost in terms of cost of charging energy and cost of capacity maintenance contracts.

The basic operating principle is as follows: the storage system will constantly monitor the grid frequency on the storage system side of the Point of Interconnection (POI) and continuously compute the rate of frequency change. If the frequency drops below a specified trigger point or if the frequency falls at a faster than specified rate, the ESS will respond with full assigned power capacity for a specified duration. If the state of charge of the ESS is below full capacity, the system will charge if the line frequency and the rate of change of line frequency are above a specified threshold. Ramping rates during charging are maintained within specified limits.

DNV GL analyzed frequency data for 20 frequency events in 2016 and 5 frequency events in 2017. Based on frequency data and industry standard examples, the operating parameters for a characteristic ESS providing 10 MW of frequency response capacity are provided in Table 4-1.

Table 4-1: Energy storage system operational parameters for frequency response use case

Parameter	Value
Real Power Output on frequency response trigger	10 MW discharging (under-frequency)
Duration of real power output on frequency response trigger	360s
Frequency threshold for frequency response trigger	59.927 Hz
Rate of change of frequency threshold for frequency response trigger	0.006% (based on 15s moving average)
Time between frequency event trigger and full power response from ESS	10s
After the conclusion of response duration, duration of response power ramp to zero power	360s
Ramp down time to zero power while discharging	120s
Frequency threshold to allow storage charging	Greater than 59.98 Hz
Rate of change of frequency threshold to allow charging	0.002% (based on 15s moving average)
Maximum down-ramp during charging cycle	1 MW/min
Maximum up ramp during charging cycle	1 MW/min

Figure 4-1 shows a simulation example of BESS responding to a frequency event. The response is triggered by line frequency dropping to 59.89 Hz. The BESS reaches full power output within 10s and sustains it for 6 minutes after which it ramps down to zero power within 120s. The BESS waits 12 minutes for system frequency to stabilize before initiating charging. Ramp rates during charging are within limits of 10% per minute, i.e. 1 MW per minute.

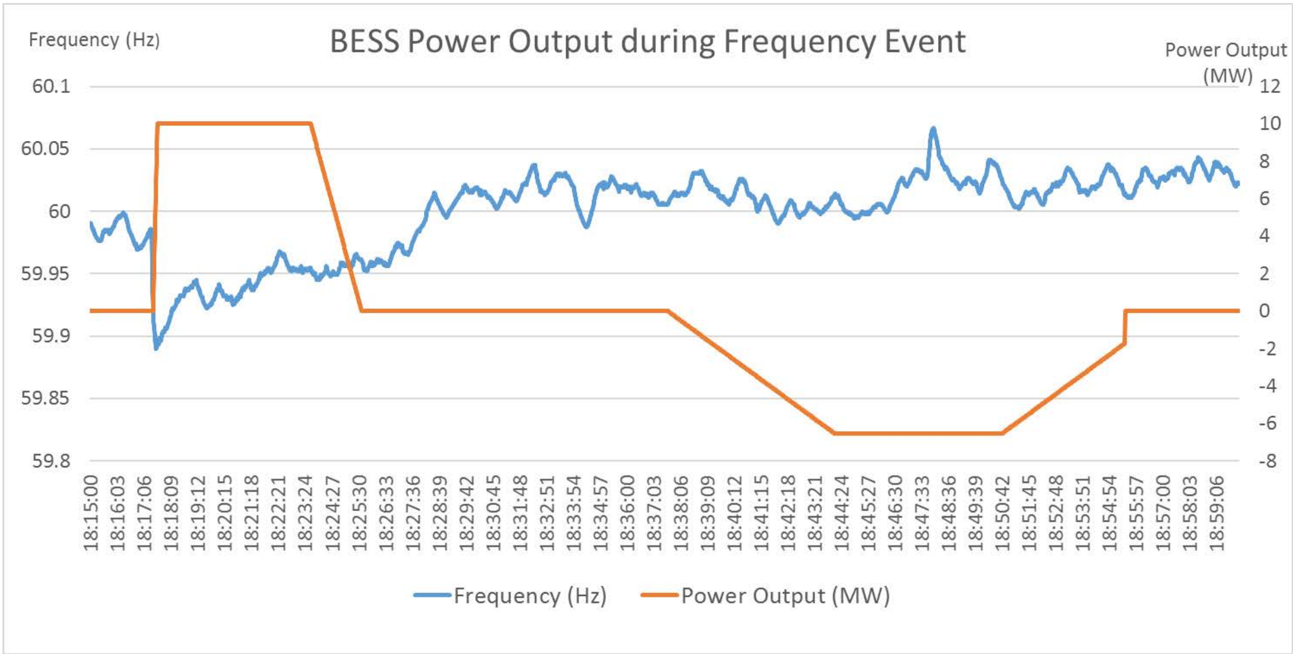

Figure 4-1: Simulation example of energy storage system to frequency response event

As shown in Figure 4-2, the state of charge of the battery system drops to 0.9 MWh from 2.2 MWh. The charging cycle lasts approximately 18 minutes until full state of charge is regained.

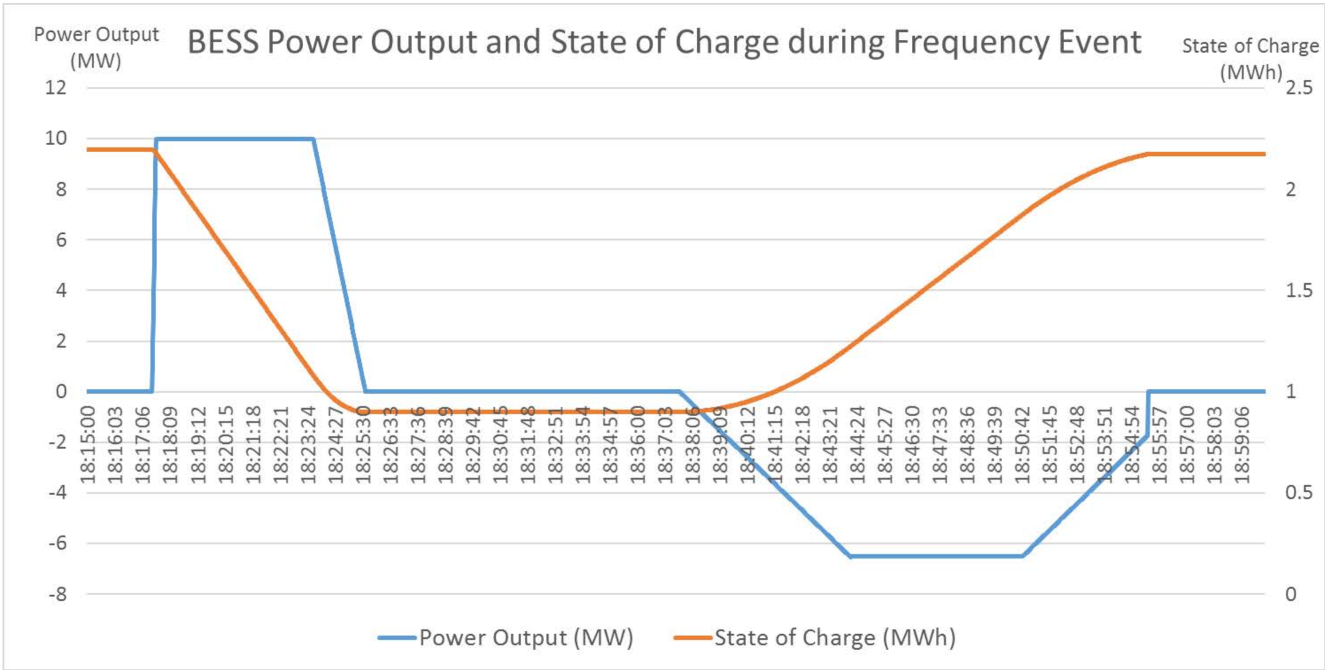

Figure 4-2: BESS power output and state of charge during frequency response event

4.1.3 Assumptions and methodology limitations

The cost-effectiveness analysis for ESS providing frequency response has been performed under the following assumptions:

- The value of frequency management services in a deregulated environment is determined by market requirement. In contrast, the contract value of frequency response service under a vertically integrated utility environment is determined through bilateral contracts and is not publicly available. This evaluation has referenced frequency response payment that a market operator CAISO, has contracted with two utilities in the Pacific North-West. These contract values are assumed to be a proxy for the value of frequency response service to PacifiCorp.

- Primary frequency response balances instantaneous deviations between generation and load. Deviations may be caused by large scale renewable intermittency or contingencies such as generation trip and loss of transmission line. As the penetration of intermittent renewable resources increase, the power system is expected to require more frequency response. Fast response energy storage resources are ideally suited to perform frequency response. However, as with any resource or service, at sufficiently high volume of ESS deployment, the marginal value of additional deployment may reduce, i.e. the service may be saturated. We believe that the mandated volume of ESS deployment in Washington will not result in a saturation of the frequency response service.

  Conditions in the mid-Atlantic ISO PJM may illustrate this point. Among Independent System Operators (ISOs) PJM has the highest volume of fast response ESS deployed to perform fast regulation (Reg D). Although Reg D response requirement is slower than primary frequency response, batteries and fly-wheels have the highest performance scores in the Reg D market [5]. Recent changes in the PJM market that went into effect on Jan 9, 2017 may reduce the revenue potential of batteries performing Reg D in PJM. This has led to speculation that the Reg D market in PJM is close to saturation due to high ESS deployment.

  However, under closer examination it is not clear whether the PJM Reg D market is close to saturation. The changes reflect a recalibration in commitment and dispatch methodology for Reg D resources. Selection of better performing resources such as batteries and fly-wheels is prioritized to reduce issues caused by market mechanics and operation of lower performance resources [6]. As of 2015, PJM Reg D market had approximately 700 MW of registered resources. However, 420 MW was hydro and only 140 MW was batteries and fly-wheels.

4.1.4 Modeling results

For this application, a battery system with a duration between 8 minutes and 15 minutes is sufficient. To evaluate the cost-effectiveness of a characteristic system, a battery system with 12-minute duration is considered. It is assumed that the storage system is procured through a 10-year contract. An estimated contract value provides the potential benefit for the cash-flow evaluation. The California Independent System Operator (CAISO) contract values are used as the representative value of frequency response contracts:

- CAISO contract with Bonneville Power Administration (BPA) for 50 MW/0.1 Hz of frequency response for $2.22 M per year or $44.40 per kW-year [7].

- CAISO contract with Seattle City Light for 15 MW/0.1 Hz of frequency response at $1.22 M per year or $81 per kW-year [8].

The contract value of $44.4 per kW-year provides a low-benefit estimate, whereas the contract value of $81 per kW-year may be considered as the high-benefit estimate.

The financial parameters and cost inputs to the cash flow model are based on typical industry values for Li-Ion Nickel Cadmium Manganese (NCM) battery systems as listed in Section 3, which were simplified to be applied to both high energy and high power batteries. For ESS installation on 2018, the cost of power components is assumed to be $471/kW and for energy components is assumed to be $355/kWh. The total cost of a 10 MW 12 minute ESS is calculated at $5,420,000, a value, as noted previously, based on projections from the Battery Energy Storage Study, which is in line with other similarly sized systems utilized for the same application observed in the PJM market. DNV GL believes that these costs are conservative and reasonable. A 20-year cash-flow analysis was performed using financial parameters supplied by PacifiCorp. These parameters were: debt to equity ratio, debt financing rate and financing period. Net Present Value (NPV) was calculated based on a discount rate of 6.59%. Financial results for a utility owned storage project in terms of the Net Present Value (NPV), Internal Rate of Return (IRR) and Benefit to Cost Ratio (BCR) is shown in Table 4-3.

Table 4-3: Financial results under low and high benefit estimates for frequency response application

System description	NPV	IRR	BCR
10 MW, 2 MWh ESS with 20-year frequency response contract at $44.4 / kW-year	-$165,112	6.1%	0.97
10 MW, 2 MWh ESS with 20-year frequency response contract at $45.6 / kW-year	$4,626	6.6%	1.00
10 MW, 2 MWh ESS with 20-year frequency response contract at $81 / kW-year	5,011,896	22.2%	1.78

At a contract value of $44.4 / kW-year the Internal Rate of Return (IRR) is 6.1% and the storage project is marginally under cost-effectiveness. At the contract value of $81 / kW-year, the financial performance is very high with an IRR of 22.2%. The contract value of $45.6 / kW-year can be seen as the break-even point for cost-effectiveness.

Table 4-4 shows the 20-year cash-flow analysis for a 10 MW 2 MWh ESS performing primary frequency response at a contract value of $81/kW-year. The revenue from primary frequency response is assumed to escalate at 2.5% per year. Debt payment term is 10 years.

Table 4-4: 20-year cash flow for 10 MW / 2 MWh energy storage system performing primary frequency response at contract value of $81/kW-year ('000s)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Project revenue	$810.0	$830.3	$851.0	$872.3	$894.1	$916.4	$939.4	$962.8	$986.9	$1,011.6
Fixed O&M cost	($60.0)	($61.5)	($63.0)	($64.6)	($66.2)	($67.9)	($69.6)	($71.3)	($73.1)	($74.9)
Capacity maintenance cost	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)
Equity draw	($2,788.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Interest payment	($138.4)	($127.6)	($116.1)	($104.1)	($91.4)	($78.0)	($64.0)	($49.2)	($33.6)	($17.2)
Principal payment	($206.7)	($217.6)	($229.0)	($241.1)	($253.8)	($267.1)	($281.2)	($296.0)	($311.5)	($327.9)
Debt payment	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)
Total revenue	$810.0	$830.3	$851.0	$872.3	$894.1	$916.4	$939.4	$962.8	$986.9	$1,011.6
Total cost	($3,208.2)	($421.7)	($423.2)	($424.8)	($426.4)	($428.1)	($429.7)	($431.5)	($433.3)	($435.1)
Annual cash flow	($2,398.2)	$408.6	$427.8	$447.5	$467.7	$488.4	$509.6	$531.3	$553.6	$576.5

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Project revenue	$1,036.9	$1,062.8	$1,089.4	$1,116.6	$1,144.5	$1,173.1	$1,202.4	$1,232.5	$1,263.3	$1,294.9
Fixed O&M cost	($76.8)	($78.7)	($80.7)	($82.7)	($84.8)	($86.9)	($89.1)	($91.3)	($93.6)	($95.9)
Capacity maintenance cost	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)
Equity draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Interest payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Principal payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Debt payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total revenue	$1,036.9	$1,062.8	$1,089.4	$1,116.6	$1,144.5	$1,173.1	$1,202.4	$1,232.5	$1,263.3	$1,294.9
Total cost	($91.8)	($93.7)	($95.7)	($97.7)	($99.8)	($101.9)	($104.1)	($106.3)	($108.6)	($110.9)
Annual cash flow	$945.1	$969.1	$993.7	$1,018.9	$1,044.7	$1,071.2	$1,098.4	$1,126.2	$1,154.7	$1,184.0

4.2 Qualitative Curtailment and Congestion Transmission Assessment

4.2.1 Methodology description

DNV GL has significant experience in performing detailed curtailment/congestion studies and utilizes industry best practices in establishing study design and assumptions. This section provides a brief overview of key elements and methods employed to assess curtailment at the Project, including DNV GL's approach to congestion and curtailment analysis.

DNV GL assesses congestion and curtailment risk through measuring the impact of individual transmission constraints that pose a congestion risk to the Project. Typically, a congestion analysis is conducted within a five-year window of the current date in order to utilize transmission planning and generation queue data maintained and provided by system operators. Such planning data generally does not extend beyond a five-year period. Congestion results may be sensitive to near-term market changes such as new generation entering service near the Project, transmission system upgrades, adjustments in market rules or structures, etc. Significant near-term expansion of wind and solar projects in the study area may constitute an important risk factor that can be investigated through analysis of future operations within the five-year planning window.

DNV GL understands that there are no third-party curtailment studies or transmission assessment studies available for this Project. Therefore, DNV GL performed a high-level, qualitative assessment of the curtailment risk and transmission assessment for the Project based on available information regarding the Project's location, existing transmission planning documents from PacifiCorp, feasibility studies and system impact studies for nearby generation queues. For this review, DNV GL has also relied upon the CAISO and Energy Imbalance Market (EIM) published locational marginal price data (LMP) [9], and internal knowledge of the Pacific Northwest market.

4.2.2 Transmission System

PacifiCorp is considering several potential locations for the Project. The DNV GL high-level assessment focused on the following areas within the PacifiCorp service territory:

- Klamath Basin
- Willamette Valley
- Central Oregon

4.2.3 Location Marginal Prices (LMP)

The LMP reflects the marginal cost of energy at each transmission node based on transmission congestion and losses on the system. The LMP is the sum of three components: the Market Energy Component (MEC), the Marginal Congestion Component (MCC), and the Marginal Loss Component (MLC). The MEC is the market clearing price for the marginal MW of load; MCC is the marginal cost of congestion at a given pricing point; the MLC is the marginal cost of losses at a given pricing point.

Historical prices at the selected representative points are an indicator of curtailment risk and transmission congestion, with negative prices indicating congestion and/or curtailment. Figure 4-3 lists historical LMP at Proxy nodes in three areas of interest and the CAISO EIM Mid-C Scheduling Point (Mid-C SP). The average marginal congestion component is $-1.04/MWh in Klamath Falls area, $-1.05/MWh in Willamette Valley and Central Oregon areas, and $-0.76/MWh in Mid-C Scheduling point in 2015. In 2016, the average marginal congestion component of three areas are all decreased to $-0.40/MWh. The average marginal congestion component of three areas for the past 6 months decreased to around $0.80/MWh, but is likely due to above average hydro conditions this year. The LMP basis of these three areas with the Mid-C SP is relatively small, which means the transmission system in the area as currently configured, including BPA and PacifiCorp assets, is robust. Therefore, the potential congestion risk is low.

Figure 4-3: Historical CAISO day ahead EIM Market LMP

2015	EIM DAY AHEAD MARKET LMP ($/MWh)							
	Klamath Falls Proxy Point		Willamette Valley Proxy Point		Central Oregon Proxy Point		Mid-C Scheduling Point	
	LMP	Congestion	LMP	Congestion	LMP	Congestion	LMP	Congestion
1	29.97	-4.17	29.67	-4.33	29.67	-4.33	32.98	-1.02
2	29.63	-0.27	29.59	-0.25	29.60	-0.25	29.60	-0.26
3	29.43	0.27	29.41	0.29	29.42	0.30	29.40	0.27
4	30.06	1.55	30.08	1.60	30.10	1.63	30.06	1.56
5	31.51	2.47	31.54	2.51	31.56	2.54	31.47	2.45
6	33.24	-1.37	33.25	-1.36	33.22	-1.36	33.22	-1.34
7	32.95	-2.97	32.88	-2.98	32.87	-2.99	32.91	-2.95
8	30.92	-3.40	30.95	-3.38	30.95	-3.39	31.03	-3.34
9	31.73	-1.55	31.76	-1.54	31.76	-1.56	31.84	-1.52
10	28.83	-2.46	28.78	-2.53	28.74	-2.58	28.89	-2.48
11	28.13	-0.02	28.14	-0.02	28.15	-0.02	28.17	-0.02
12	27.25	-0.39	27.25	-0.39	27.26	-0.39	27.24	-0.42
Summary	**30.30**	**-1.04**	**30.28**	**-1.05**	**30.28**	**-1.05**	**30.57**	**-0.76**

2016	EIM DAY AHEAD MARKET LMP ($/MWh)							
	Klamath Falls Proxy Point		Willamette Valley Proxy Point		Central Oregon Proxy Point		Mid-C Scheduling Point	
	LMP	Congestion	LMP	Congestion	LMP	Congestion	LMP	Congestion
1	27.26	-0.38	27.25	-0.38	27.27	-0.38	27.26	-0.40
2	22.89	-0.38	22.86	-0.38	22.88	-0.38	22.88	-0.39
3	18.15	-0.03	18.14	-0.03	18.15	-0.03	18.17	-0.02
4	20.17	1.21	20.16	1.18	20.19	1.19	20.18	1.15
5	19.90	-0.50	19.93	-0.49	19.95	-0.50	19.98	-0.49
6	26.55	-2.30	26.57	-2.32	26.59	-2.32	26.66	-2.29
7	30.56	-1.86	30.63	-1.83	30.66	-1.83	30.75	-1.80
8	33.13	-0.82	33.18	-0.83	33.24	-0.76	33.23	-0.82
9	33.21	0.21	33.28	0.23	32.89	-0.03	33.25	0.20
10	32.11	-0.56	32.17	-0.55	32.30	-0.48	32.18	-0.56
11	28.68	0.17	28.69	0.15	28.71	0.16	27.70	-0.08
12	35.57	0.34	35.60	0.33	35.60	0.33	33.14	0.33
Summary	**27.38**	**-0.41**	**27.40**	**-0.41**	**27.40**	**-0.42**	**27.14**	**-0.43**

2017	EIM AHEAD MARKET LMP ($/MWh)							
	Klamath Falls Proxy Point		Willamette Valley Proxy Point		Central Oregon Proxy Point		Mid-C Scheduling Point	
	LMP	Congestion	LMP	Congestion	LMP	Congestion	LMP	Congestion
1	33.99	0.14	34.03	0.13	34.03	0.13	34.00	0.11
2	27.99	0.60	28.06	0.61	28.05	0.61	27.13	0.51
3	21.37	-0.07	21.42	-0.07	21.42	-0.07	20.52	-0.07
4	20.80	-2.00	20.65	-2.23	20.66	-2.24	19.21	-0.42
5	26.96	-1.06	27.11	-1.04	27.11	-1.04	25.26	-2.88
6	29.87	-2.39	29.95	-2.40	29.93	-2.42	30.03	-2.39
Summary	**26.83**	**-0.80**	**26.87**	**-0.84**	**26.86**	**-0.84**	**26.02**	**-0.87**

4.2.4 Analysis results

The Project is under consideration for possible location in the Klamath Basin, Willamette Valley, or Central Oregon. In the past two years, day-ahead EIM prices at the proxy nodes were robust and there is limited LMP risk or congestion risk in this area. There is the continued possibility of additional wind and solar build-out over the next few years in the Pacific Northwest region. With additional development, congestion may increase in the future years, depending on points of interconnection. However, regional transmission providers, including PacifiCorp and BPA, are actively monitoring congestion to ensure efficient renewable integration and reliable grid operation. Therefore, DNV GL expects congestion risk to be low and at this time does not recommend energy storage on the transmission system for this use case alone.

5.0 DISTRIBUTION-CONNECTED ENERGY STORAGE SYSTEM ASSESSMENT

The PacifiCorp distribution system was assessed using various software, models, and methodologies, depending on the use case or application being investigated. As such, the assessment is segmented by use case.

5.1 Volt/VAR Potential Evaluation Model Development

5.1.1 Inputs required

For this use case, the following inputs were provided by PacifiCorp:

- Load flow model of Redmond feeder 5D22;
- Load data for Redmond feeder 5D22.

5.1.2 Methodology description

PacifiCorp identified a specific feeder – Redmond 5D22 – as having potential voltage issues which could be solved by the addition of energy storage, using a Volt/VAR control scheme. DNV GL imported the load flow model provided by PacifiCorp to Synergi Electric format for analysis. A load allocation was performed for the forecast peak load for the year 2026. This model provided by PacifiCorp had several large customer loads already identified, along with a number of distribution transformers. The large customer loads were kept constant, and the remaining load required to make up the peak load value was allocated to the distribution transformers in proportion to their kVA rating.

Once the load had been allocated to the model, a load flow analysis was run. The results were used to identify locations on the feeder with high or low voltage. Where there were violations in this peak load case their location was also identified. Where low voltages were identified, an ESS with Volt/VAR control was sited and sized sufficiently to remove the low-voltage violation. The worst voltage violation was addressed first. The system was then re-studied, and any further violations were addressed in turn. The default Volt/VAR curve planned for use in California was assumed, shown in Figure 5-1 below.

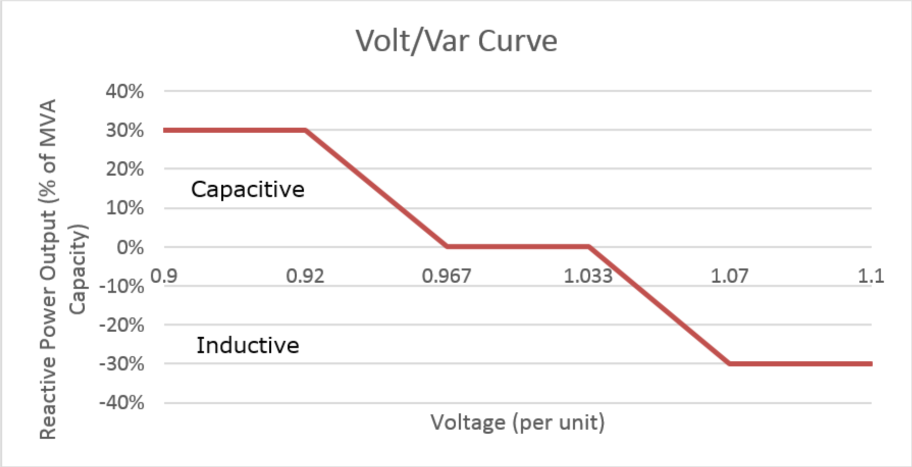

Figure 5-1: Default inverter Volt/VAR curve

5.1.3 Assumptions and methodology limitations

The technical criterion used in this study is that static voltage on the feeder should remain within the range of nominal voltage ±5%. Anything outside this range constitutes a technical violation, and an energy storage unit will be used to attempt to remove the problem.

5.1.4 Modeling results

The base case analysis was conducted using the model provided by PacifiCorp, with load allocation as described in Section 5.1.2 above. The forecast peak load value for 2026 provided by PacifiCorp is 13.95 MW, with a power factor of 0.98. The base case analysis showed all voltages within the range of nominal voltage ±5%, so no voltage violations are present. The feeder voltage profile is shown in 5-2. Voltages in this figure are given on a 120V base, so voltage violations would be above 126V and below 114V. The lowest voltage found here is 115.83V, and the highest is 124.0V.

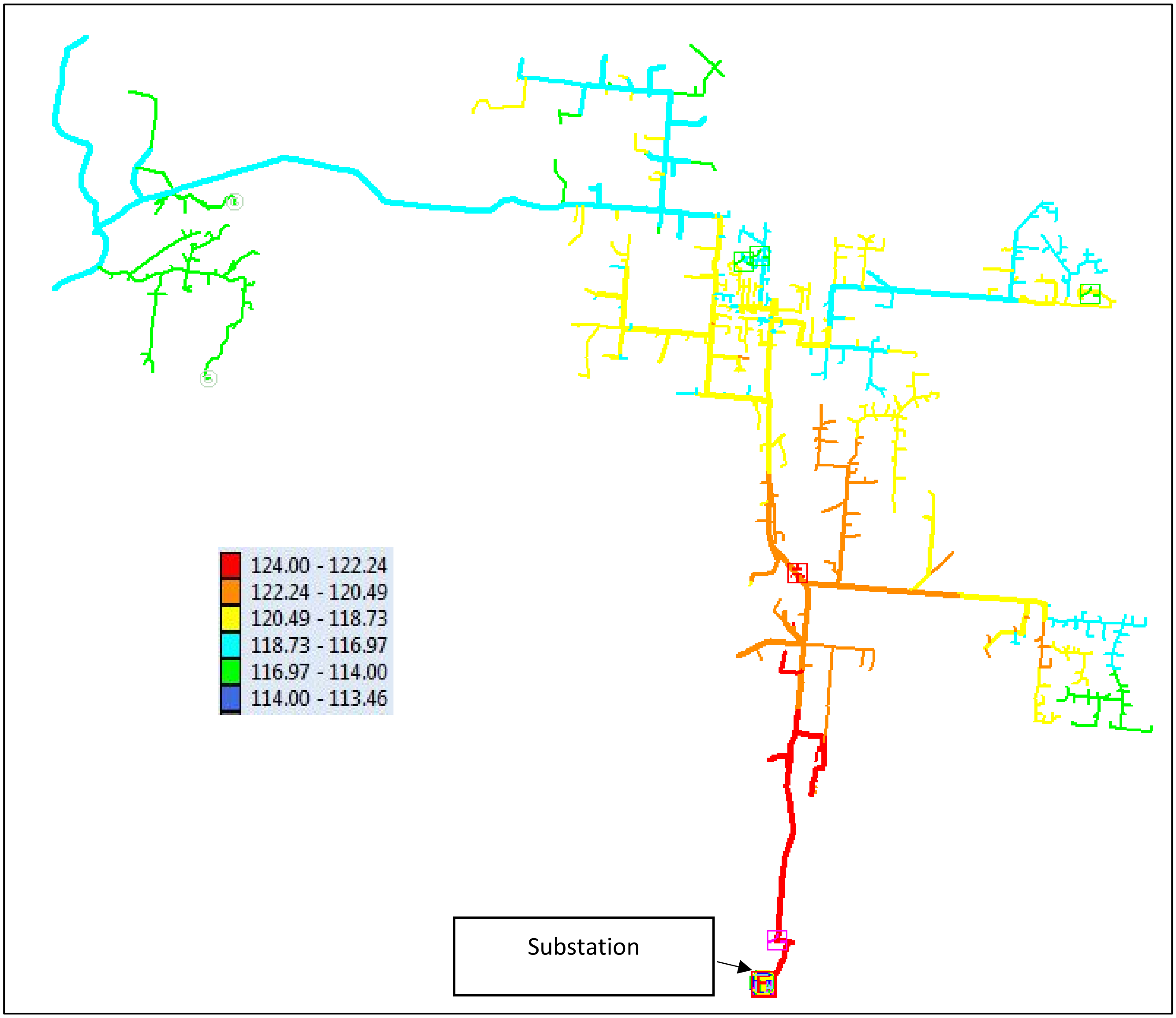

Figure 5-2: Base case Redmond 5D22 voltage profile (voltages reported on a 120V base)

To provide some indications of the potential of ESS to solve voltage problems, a further study was undertaken with reduced feeder voltage. In this case, the voltage setpoint on the feeder voltage regulator was reduced from 124V to 121V. It should be noted that this case is set up for illustrative purposes only, to allow an example of this use-case to be presented. The change in feeder voltage settings are not the real settings for this feeder. The resulting voltage profile is shown in Figure 5-3 on the following page. In this figure, four voltage violations are present.

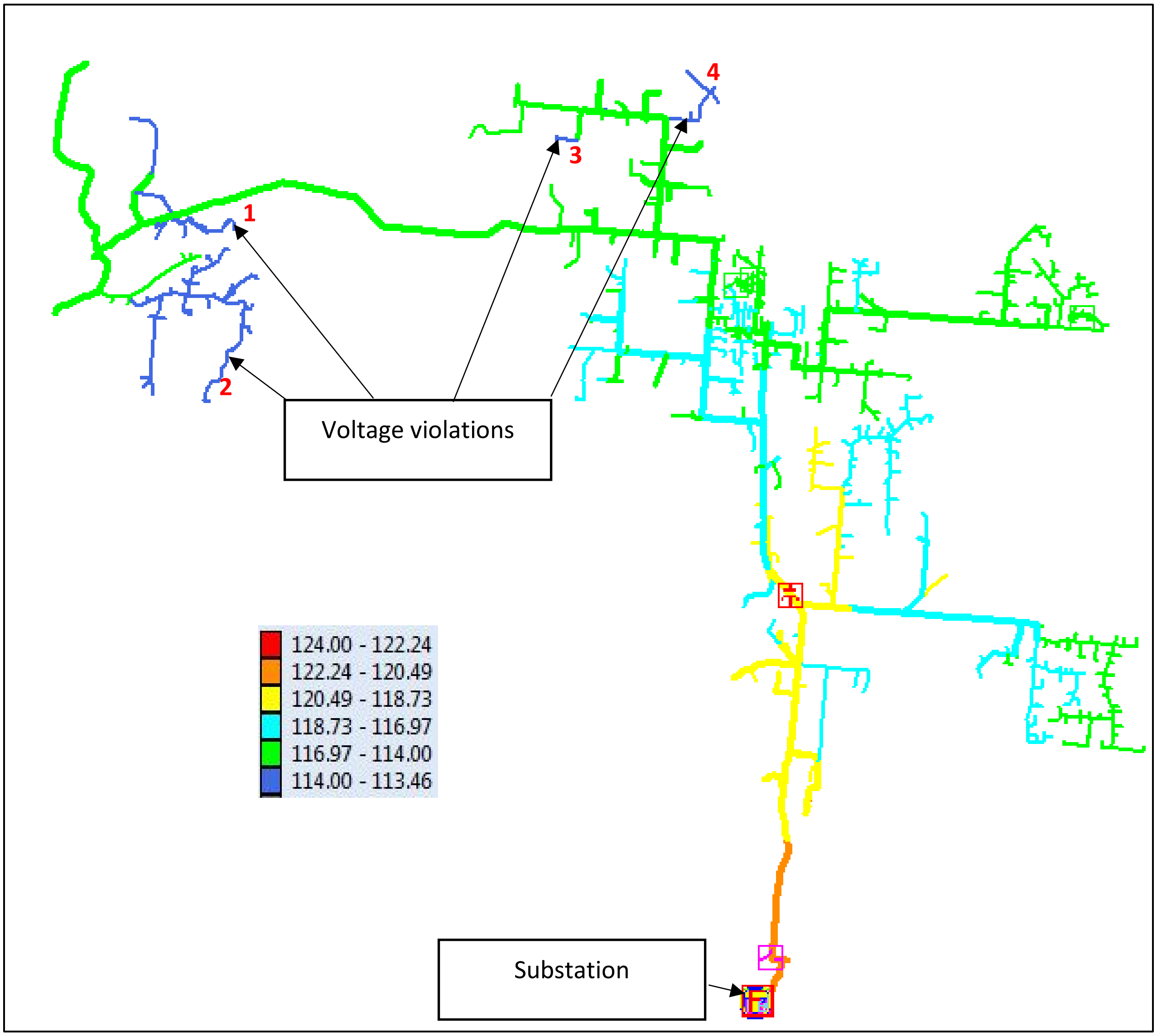

Figure 5-3: Reduced voltage feeder profile (voltages reported on a 120V base)

In Figure 5-3 the four voltage violations are numbered in order of severity. The lowest voltage occurs at point 1, which was found to be at 113.46V on a 120V base. The violations will be addressed in numerical order.

Violation 1:

An energy storage device was placed on the section farthest from the main branch where the voltage violation was present. Its size was increased in 5kVA increments until the voltage violation was removed. It was found that 35kVA was required to increase the voltage on this section from 113.46V to 114.0V, using the volt/VAR profile described previously. Figure 5-4 presents the feeder voltage profile with this energy storage device implemented. Note that this storage device was also sufficient to remove the voltage violations at points 3 and 4 in Figure 5-4.

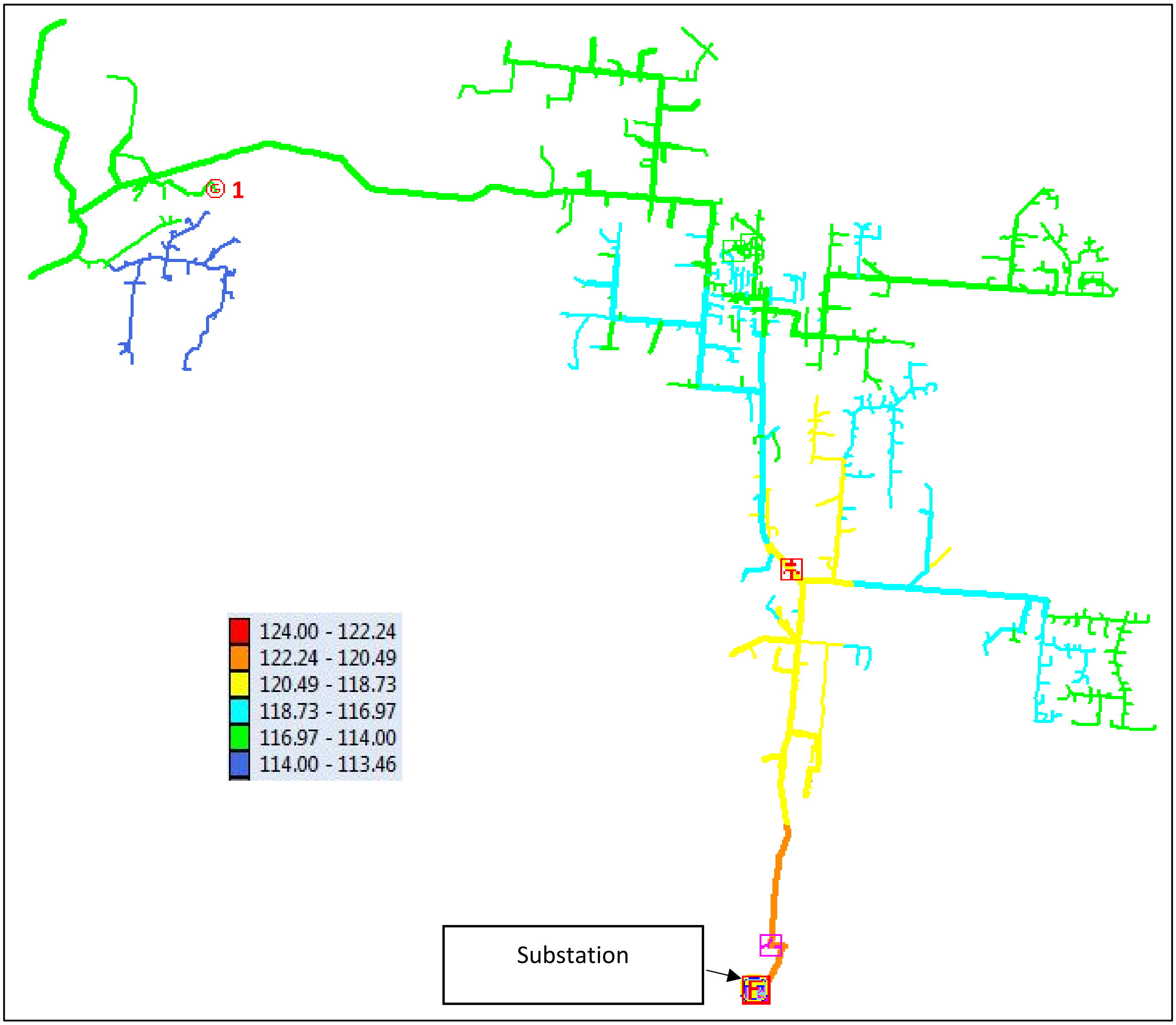

Figure 5-4: Feeder voltage profile with energy storage at violation 1 (voltages reported on a 120V base)

Violation 2:

An energy storage device was placed on the section farthest from the main branch where the voltage violation was present. Its size was increased in 5kVA increments until the voltage violation was removed. It was found that a 17kVA battery was required to increase the voltage on this section from 113.7V to 114.0V, using the volt/VAR profile described previously. Figure 5-5 presents the feeder voltage profile with this energy storage device implemented.

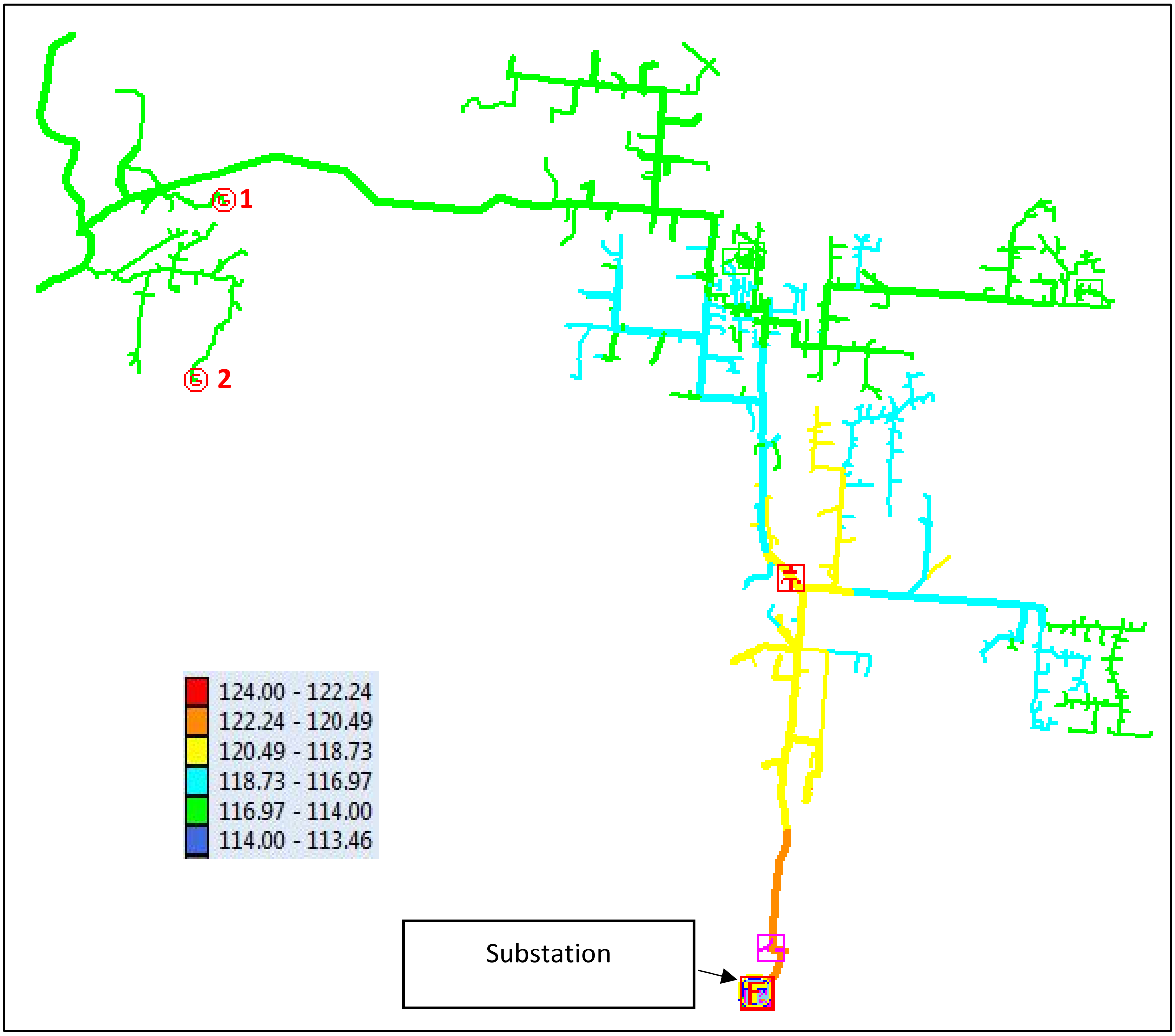

Figure 5-5: Feeder voltage profile with energy storage devices at violation 1 and violation 2 (voltages reported on a 120V base)

With the two energy storage devices installed, there are no more voltage violations on the modeled feeder. Note that the voltage violations did not occur with the voltage regulator set using the given settings (with 124V setpoint and no Line Drop Compensation). If the feeder voltage was to be reduced – for conservation voltage reduction, for example – then the voltage violations described above would be possible.

The results here provide an indication of the energy storage facility size necessary to resolve certain voltage violations on this feeder. For a voltage violation of 0.54V (on a 120V base), 35kVA of storage was required, while 17kVA of storage was required to correct a violation of 0.3V (on a 120V base). These values are dependent upon the feeder loading, and particularly the loading on branches where the violations occur, so other feeders may produce different results. Additionally, the energy storage required could be more distributed than indicated here. Customer-sited storage for this use case is addressed in Section 0.

An alternative solution to a low voltage problem like that described here is placement of capacitor banks. Cost of a capacitor bank on the distribution system can range from a low cost of $15,000 to a high cost of $50,000, with average upgrade costing $20,000. The ESS required in the solution described here would cost approximately $32,000 for the 17kVA battery and around $66,000 for the 35kVA battery, assuming 4 hours of storage (this based on a 2018 cost estimate of $471/kW plus $355/kWh). As such, the capital cost of storage is potentially lower than the cost of traditional voltage mitigation in the first case, and potentially higher in the second case. However, there is the potential for other benefits from customer-sited energy storage such as peak load reduction, which may improve the economics of this option. It should also be noted that energy storage prices are expected to continue to decrease, by up to 12% per year [10].

The relative costs and benefits of the two battery solutions are presented in Table 5-1 below. In this table, the storage benefit is assumed to be the cost (low, average, and high) of the capacitor bank that would otherwise be used to solve the low voltage problem.

Table 5-1: Volt/Var case storage solution results

Storage Size	Storage Cost	Storage Benefit	BCR
17kVA	$32,000	Low: $15,000	Low: 0.47
		Avg: $20,000	Avg: 0.625
		High: $50,000	High: 1.56
35kVA	$66,000	Low: $15,000	Low: 0.23
		Avg: $20,000	Avg: 0.30
		High: $50,000	High: 0.76

5.2 Reliability Potential Evaluation Model Development

5.2.1 Inputs required

For this use case, the following inputs were provided by PacifiCorp:

- Load flow model of Hillview feeder 4M182;
- Load data for Hillview feeder 4M182;
- Reliability data for Hillview feeder 4M182.

5.2.2 Methodology description

PacifiCorp identified a specific feeder – Hillview 4M182 – as having potential reliability issues which could be reduced or relieved by the addition of energy storage. In this case, the energy storage system was intended to act as an alternate source in the event of an outage on the feeder, with the intention of improving the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) for the circuit. The ESS was located and sized such that it could serve the peak load of all the customers on the circuit. The energy storage system was sited at the end of the feeder furthest from the Hillview substation, as shown in Figure 5-6.

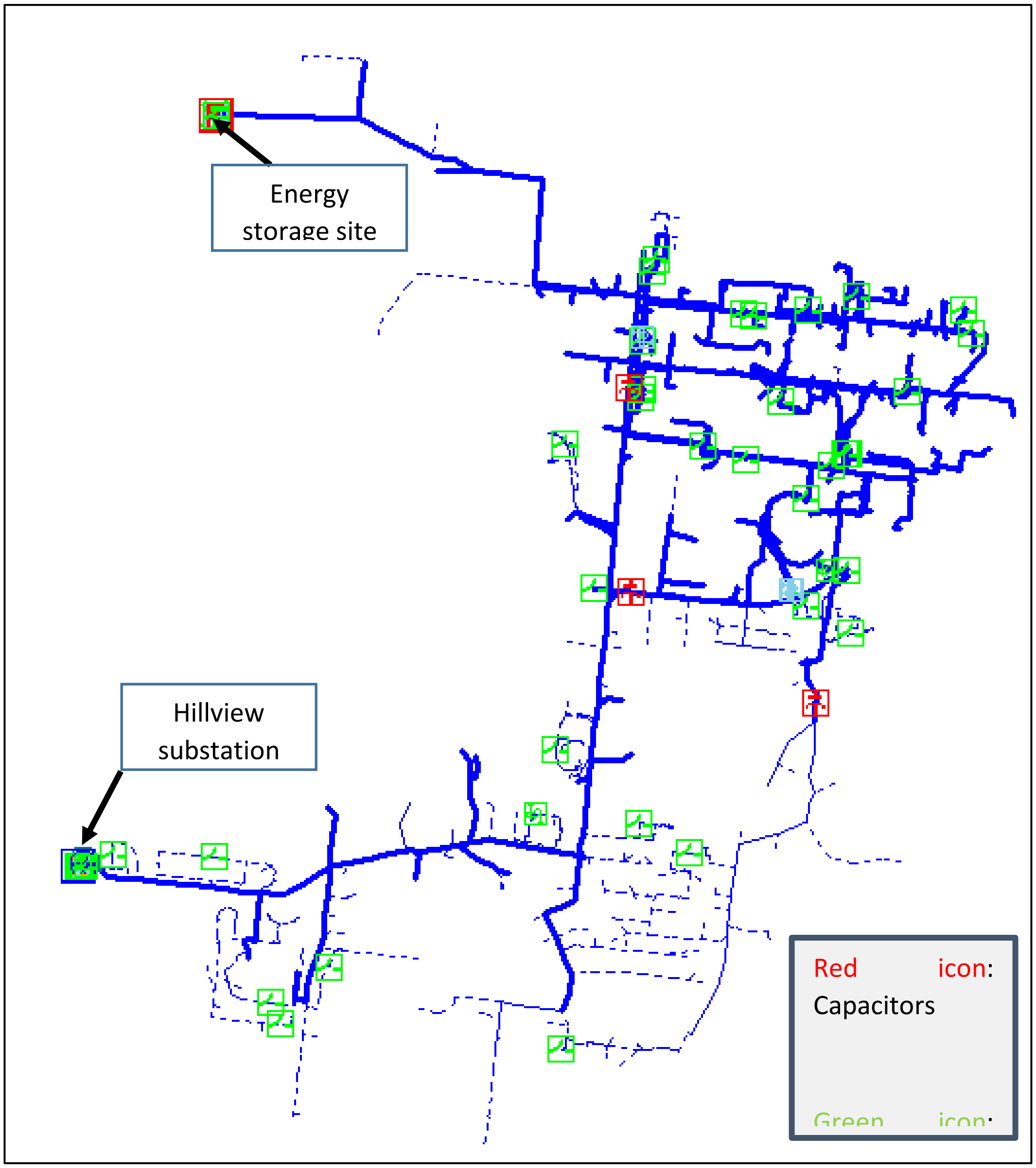

Figure 5-6 Hillview feeder

The load flow model of the circuit was imported to Synergi Electric format. The peak load provided by PacifiCorp was allocated based on distribution transformer sizing in the model. Failure and outage data was provided by PacifiCorp for the circuit, including location of outages, number of customers affected, and customer minutes interrupted. This data was used to derive failure rates and repair times for the components of the system due to different outage causes. An initial reliability analysis was run with the system as it exists at present, followed by an analysis with the energy storage system setup as an alternative source in the model. The SAIDI and SAIFI numbers could then be compared between the cases.

5.2.3 Assumptions and methodology limitations

The methodology involves the creation of an ‘Exposure Zone’ in Synergi Electric. An Exposure Zone defines a set of failure rates and repair times for different outage causes on the system. Failure rates are defined as the number of failures per year per mile of line. The values used for these failure rates are derived from the outage data provided by PacifiCorp, with the assumption that the failure rate is constant across the feeder (i.e. every section has the same probability of failure).

5.2.4 Modeling results

The outage data provided by PacifiCorp for the Hillview feeder was analyzed by DNV GL, and produced the failure rate data shown in Table 5-2 for various categories of outage.

Table 5-2: Failure rate data derived from outage data for Hillview circuit

Trees	10	1	0.0797	3.1033
Equipment failure	29	2.9	0.2311	4.9791
Planned	17	1.7	0.1355	3.7579
Animals	12	1.2	0.0956	1.3565
Other	15	1.5	0.1195	1.1884
Interference	2	0.2	0.0159	1.2825
Weather	5	0.5	0.0398	22.3860

In addition to these circuit-wide values, outage due to loss of source was included at 0.6 failures per year.

With the ESS disconnected to the Hillview feeder, a base case analysis was run. The results for this base case were:

- SAIFI: 4.39 interruptions
- SAIDI: 473.78 minutes

The ESS was then added to the model at the end of the circuit furthest from the Hillview substation, and connected to the feeder through a normally-open automatic switch. The reliability analysis was repeated with this setup, and the following results were obtained:

- SAIFI: 4.39 interruptions
- SAIDI: 473.76 minutes

There is no reduction in SAIFI, as the number of interruptions remains the same. The reduction in SAIDI is also negligible at 0.004%. The reasons for the minimal impact on the circuit reliability values may be due to the circuit having a large amount of connectivity already, indicating that outages other than source outages can be mitigated quickly by circuit re-configuration through other automated switching processes. As the circuit configuration and customer distribution has a significant impact on SAIDI and SAIFI results, similar analyses on other circuits may produce different results in terms of the effectiveness of energy storage systems on improved reliability. Reliability benefits of an ESS at a customer site on this circuit is discussed in Section 6.1.

5.3 Upgrade Deferral Potential Evaluation Model Development

5.3.1 Inputs required

Technical Inputs

For this use case, PacifiCorp provided data for four substations which are likely to be overloaded soon or in the future. These substations are: Hillview, Independence, Lyons, and Redmond. Table 5-3 shows the feeders associated with each substation.

Table 5-3 Substations used in upgrade deferral use case with associated feeders

Substation	Feeder No.
Hillview	4M182
Independence	4M22
	4M25
Lyons	4M70
	4M120
Redmond	5D22

PacifiCorp provided the following inputs for each substation:

- Substation-level 15-min load profile for 2016-2026
- Summer and winter load-growth rates
- Existing substation transformer ratings
- Feeder-level summer and winter power factors for feeders 4M70 and 4M120
- Substation transformer upgrade cost

Table 5-4 presents the summer and winter load growth rates for each substation, as well as existing substation transformer ratings.

Table 5-4: Summer and winter load growth rates and transformer ratings

Substation	Feeder	Annual Load Growth Rate		Transformer Rating (MW)
		Summer	Winter	
Hillview	4M182	2.5%	1.8%	19.00
Independence	4M22 and 4M25	1.8%	1.3%	23.75
Lyons	4M70	1.8%	2.0%	23.37
	4M120	1.6%	0.75%	
Redmond	5D22	5.0%	1.0%	23.75

DNV GL processed the load data provided by PacifiCorp to extend load forecast to 2037 and convert 15-min load profiles to hourly profiles. Table 5-5 shows the annual peak load for each substation over a 20-year period from 2018 to 2037. The data in Table 5-5 shows that Hillview will be overloaded and require upgrades in 2023 while Independence and Lyons will be overloaded and require upgrades starting in 2018. It was assumed that the overloading will be mitigated by other alternative methods until the end of 2017. Redmond does not need an upgrade for at least 20 years. These estimates assume that an upgrade will not be required until load reaches 100% of substation transformer capacity. If PacifiCorp decides to reserve some capacity to account for load growth uncertainties, these upgrades should take place sooner than stated above.

Table 5-5: Substation-level annual peak load (MW)

Substation	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hillview	17.74	18.18	18.64	19.10	19.58	20.07	20.57	21.09	21.61	22.16
Independence	27.70	28.71	29.30	29.83	30.11	30.40	30.69	30.99	31.29	31.70
Lyons	27.30	27.66	28.02	28.38	28.76	29.13	29.52	29.91	30.30	30.70
Redmond	9.41	9.50	9.60	9.69	9.79	9.89	9.99	10.09	10.19	10.29
	2028	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Hillview	22.71	23.28	23.86	24.46	25.07	25.69	26.34	26.99	27.67	28.36
Independence	32.11	32.53	32.95	33.53	34.14	34.75	35.38	36.01	36.66	37.32
Lyons	31.11	31.53	31.95	32.38	32.82	33.26	33.71	34.17	34.63	35.11
Redmond	10.39	10.50	10.60	10.71	10.81	11.13	11.69	12.28	12.89	13.53

Other Input Assumptions

Inputs required for the economic assessment of the storage system are as shown in Table 5-6:

Table 5-6: Other Input Assumptions

Parameter	Value
Storage round-trip efficiency (%)	80%
Storage calendar life (years)	10
Transformer life (years)	50

5.3.2 Methodology description

A linear programming algorithm is used to determine the optimal hourly dispatch of energy storage based on a deterministic load profile, with the objective of minimizing overall peak load of the year. The constraints used in the optimization ensure that storage charge and discharge levels are within its power limits. Also, state of charge is monitored and updated each hour based on the charge and discharge levels and storage efficiency.

The optimization is run for every year within project analysis period. Outputs include hourly storage dispatch profile, number of years of upgrade deferral, and days on which storage is dispatched for peak shaving. It is important to note that once storage cannot reduce the load below transformer rating, it will not be dispatched for deferral application anymore. However, storage remains on the feeder until the end of its calendar life. We will evaluate the benefit from using storage for frequency response when deferral is not possible anymore.

Load reduction optimization is performed for all energy storage sizing scenarios.

The optimization results are then fed into a financial model to estimate costs and benefits associated with storage sizing scenario. Two financial metrics are used for comparing the cost effectiveness of scenarios: net present value of total costs and BCR, which is NPV of total benefits over NPV of total costs.

Both storage capital costs and transformer upgrade costs are calculated using an equity draw and debt payment structure. Transformer upgrade deferral benefit is evaluated by calculating the impact of moving transformer upgrade payment by the number of years of deferral.

5.3.3 Modeling results

Modeling results are presented for the Hillview, Independence, and Lyons substations below.

Hillview Substation Scenarios and Results

To maximize deferral benefits, we assumed that storage will be installed in 2023, the year in which Hillview transformer will be overloaded. Table 5-7 presents the storage sizing scenarios evaluated for Hillview substation. The possible number of years of deferral given optimal dispatch of energy storage and perfect forecast of feeder load profile are shown in Table 5-7 as well.

Table 5-7 Hillview storage sizing scenarios and year of deferral

Scenario #	ES Power Rating (MW)	ES Energy Capacity (MWh)	Years of Deferral
Scenario 1	1	2	2
Scenario 2	1	4	2
Scenario 3	2	4	4
Scenario 4	2	8	4
Scenario 5	4	8	7
Scenario 6	4	16	8
Scenario 7	6	12	9
Scenario 8	6	24	10
Scenario 9	8	8	7

Table 5-8 presents annual peak load for the base (no storage) scenario and all storage sizing scenarios.

Table 5-8: Hillview substation base and reduced peak load (MW)

Scenario	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Base	19.1	19.6	20.1	20.6	21.1	21.6	22.2	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
1	18.1	18.6	20.1	20.6	21.1	21.6	22.2	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
2	18.1	18.6	20.1	20.6	21.1	21.6	22.2	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
3	17.1	17.6	18.1	18.6	21.1	21.6	22.2	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
4	17.1	17.6	18.1	18.6	21.1	21.6	22.2	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
5	15.9	16.4	16.9	17.3	17.8	18.3	18.8	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
6	15.1	15.6	16.1	16.6	17.1	17.6	18.2	18.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
7	15.0	15.5	15.9	16.4	16.9	17.3	17.8	18.3	18.9	23.9	24.5	25.1	25.7	26.3	27.0
8	14.0	14.4	14.8	15.1	15.5	16.0	16.4	16.8	17.3	17.9	24.5	25.1	25.7	26.3	27.0
9	15.9	16.4	16.9	17.3	17.8	18.3	18.8	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0

Independence Substation Scenarios and Results

Table 5-9 presents the storage sizing scenarios evaluated for Independence substation. The possible number of years of deferral given optimal dispatch of energy storage and perfect forecast of feeder load profile are shown in Table 5-9 as well.

Table 5-9: Independence Storage Sizing Scenarios and Year of Deferral

Scenario #	ES Power Rating (MW)	ES Energy Capacity (MWh)	Years of Deferral
Scenario 1	6	24	1
Scenario 2	10	20	1
Scenario 3	10	60	2

Table 5-10 presents annual peak load for the base (no storage) scenario and all storage sizing scenarios.

Table 5-10: Independence Substation Base and Reduced Peak Load (MW)

Scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base	27.7	28.7	29.3	29.8	30.1	30.4	30.7	31.0	31.3	31.7	32.1	32.5	32.9	3.53	34.1
1	23.5	28.7	29.3	29.8	30.1	30.4	30.7	31.0	31.3	31.7	32.1	32.5	32.9	3.53	34.1
2	23.7	28.7	29.3	29.8	30.1	30.4	30.7	31.0	31.3	31.7	32.1	32.5	32.9	3.53	34.1
3	22.8	23.7	29.3	29.8	30.1	30.4	30.7	31.0	31.3	31.7	32.1	32.5	32.9	3.53	34.1

Lyons Substation Scenarios and Results

Table 5-11 presents the storage sizing scenarios evaluated for Lyons substation. Possible number of years of deferral given optimal dispatch of energy storage and perfect forecast of feeder load profile are shown in Table 5-11 as well.

Table 5-11: Lyons Storage Sizing Scenarios and Year of Deferral

Scenario #	ES Power Rating (MW)	ES Energy Capacity (MWh)	Years of Deferral
Scenario 1	6	36	1
Scenario 2	8	32	1
Scenario 3	8	48	2
Scenario 4	10	60	3

Table 5-12 presents annual peak load for the base (no storage) scenario and all storage sizing scenarios.

Table 5-12: Lyons Substation Base and Reduced Peak Load (MW)

Scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base	27.3	27.7	28.0	28.4	28.8	29.1	29.5	29.9	30.3	30.7	31.1	31.5	31.9	32.4	32.8
1	23.2	27.7	28.0	28.4	28.8	29.1	29.5	29.9	30.3	30.7	31.1	31.5	31.9	32.4	32.8
2	23.2	27.7	28.0	28.4	28.8	29.1	29.5	29.9	30.3	30.7	31.1	31.5	31.9	32.4	32.8
3	23.0	23.3	28.0	28.4	28.8	29.1	29.5	29.9	30.3	30.7	31.1	31.5	31.9	32.4	32.8
4	22.8	23.1	23.4	28.4	28.8	29.1	29.5	29.9	30.3	30.7	31.1	31.5	31.9	32.4	32.8

5.3.4 Financial Results

General input assumptions used in distribution upgrade deferral financial analysis are shown in Table 5-13. Transformer upgrade costs were provided by PacifiCorp for three substations. Storage capital cost values for 2018 and 2021 are derived from Table 5-13.

Table 5-13: Distribution Upgrade Deferral Financial Assumptions

Parameter	Value
Storage Fixed O&M Cost Annual Escalation Rate (%)	2%
Hillview Transformer Upgrade Cost ($)	$3,000,000
Independence Transformer Upgrade Cost ($)	$2,760,000
Lyons Transformer Upgrade Cost ($)	$3,980,000
Transformer Annual O&M Cost ($)	$8,500

Storage capital cost and transformer upgrade costs are calculated using an equity draw and debt payment structure. Storage fixed O&M cost is an annual payment which increases every year with a rate of 2%.

Deferral benefit is simply the value of money realized by PacifiCorp because of moving upgrade cost stream by the number of deferral years. And finally, we assumed that transformer operations and maintenance (O&M) cost is avoided for the years that upgrade is deferred. To illustrate the cashflow analysis, an example case is shown in Table 5-14.

Table 5-14: Cashflow example - Hillview scenario 1

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ES Capital Cost - Equity	($618.4)	-	-	-	-	-	-	-	-	-
ES Capital Cost – Debt	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)
ES Fixed O&M Cost	($6.4)	($6.5)	($6.6)	($6.8)	($6.9	($7.0)	($7.2)	($7.3)	($7.5)	($7.6)
Deferral Benefit – Equity	$1,543.2	-	-	($1,543.2)	-	-	-	-	-	-
Deferral Benefit - Debt	$83.0	$83.0	-	-	-	-	-	-	-	-
Avoided TX O&M Cost	$8.5	$8.5	-	-	-	-	-	-	-	-

Two financial metrics are used to evaluate sizing scenarios and compare them against each other. These metrics are NPV of total costs and benefits, and BCR. BCR is calculated by dividing the present value of total benefits by the present value of total costs.

Hillview Substation Financial Results

For Hillview substation, DNV GL also evaluated the benefit from bundling upgrade deferral application with frequency response in the years in which storage is not dispatched for deferral. Two prices were assumed for capacity in frequency response application. Financial metrics for these cases are presented in Table 5-15.

Table 5-15: Hillview Transformer Upgrade Deferral Financial Summary

Scenario	Deferral Only		Deferral + Frequency Response ($44.4/kW-year)		Deferral + Frequency Response ($81/kW-year)	
	NPV	BCR	NPV	BCR	NPV	BCR
1	$(653,017)	0.36	$(397,246)	0.61	$(188,910)	0.81
2	$(1,180,819)	0.23	$(925,047)	0.40	$(716,711)	0.53
3	$(1,349,450)	0.34	$(989,393)	0.51	$(697,595)	0.66
4	$(2,405,053)	0.22	$(2,044,995)	0.34	$(1,753,198)	0.43
5	$(2,971,961)	0.27	$(2,639,614)	0.35	$(2,375,665)	0.41
6	$(4,963,582)	0.20	$(4,744,847)	0.23	$(4,574,552)	0.26
7	$(4,770,846)	0.22	$(4,602,627)	0.24	$(4,478,980)	0.26
8	$(7,832,398)	0.15	$(7,814,178)	0.15	$(7,814,178)	0.15
9	$(4,922,077)	0.18	$(4,919,139)	0.29	$(4,919,139)	0.38

Independence Substation Financial Results

Financial metrics for Independence substation are presented in Table 5-16. Low benefit-to-cost ratios are due to low transformer upgrade costs compared to the cost of storage as well as the power rating and energy capacity needed to reduce peak load below transformer power capacity.

Table 5-16: Independence Transformer Upgrade Deferral Financial Summary

Scenario	NPV	BCR
1	$(11,813,645)	0.02
2	$(12,491,664)	0.01
3	$(26,961,598)	0.01

Lyons Substation Financial Results

Financial metrics for Lyons substation are presented in Table 5-17.

Table 5-17: Lyons Transformer Upgrade Deferral Financial Summary

Scenario	NPV	BCR
1	$(16,150,812)	0.01
2	$(15,757,488)	0.02
3	$(21,386,095)	0.02
4	$(26,635,601)	0.03

While independently the deferral use case does not reach a BCR = 1, when stacked with other applications (such as frequency response as noted in the Hillview scenarios), the economics improve. Additionally, if transformer upgrade costs are found to be greater than cited, the economic calculations can be updated to reflect this and provide more favorable BCR.

5.4 System Level Distribution Upgrade Deferral Opportunities

Beyond the specific deferral case studies evaluated here for the Hillview, Independence, and Lyons substations, DNV GL performed a high-level assessment of the system-wide deferral opportunities across PacifiCorp's Oregon service territory. The objective of this system-wide evaluation is to assess the number of potential deferral opportunities which can be facilitated by energy storage and to provide an estimate of the total energy storage capacity required to enable these deferral opportunities.

5.4.1 Inputs required

This analysis requires a list of all substations in PacifiCorp's Oregon territory with the following data for each substation:

- Base 2016 loading level
- Substation capacity rating

- Load growth projections for 2017-2026

PacifiCorp provided a database of the 271 substations across its Oregon territory along with the above data for each substation. A sample anonymized excerpt of this data set is shown in Table 5-18.

Table 5-18: Sample excerpt of the PacifiCorp Oregon substation database

Bus #	Substation Name	Base 2016 Loading (MW)	Low Side Power Factor	Substation Capacity (MVA)	2017 (MW)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)
1001	Sub X	8.97	0.97	13.13	9.06	9.15	11.14	11.26	11.37	11.48	11.60	11.71	11.83	11.95
1001	Sub Y	8.03	0.96	13.13	8.10	12.36	12.46	12.56	12.66	12.76	12.87	12.97	13.07	13.18
1001	Sub Z	7.00	0.98	17.54	7.04	7.07	7.11	7.14	7.18	7.21	7.25	7.28	7.32	7.36

5.4.2 Methodology description

This high-level analysis is designed to identify the following:

- The number of substations in the PacifiCorp Oregon service territory which are projected to require upgrade within the next 10 years
- The total transformer capacity corresponding to these identified substations
- The total amount of projected storage capacity to address deferral opportunities across all identified substations

To identify the number of substations which are projected to require an upgrade within the next 10 years, the projected yearly load growth from 2017-2026 for each substation was compared against its respective capacity rating, accounting for power factor. For each substation identified as requiring an upgrade from 2017-2026, the transformer capacity was recorded.

Optimal sizing of energy storage for upgrade deferral requires detailed analysis as presented in Section 4.3. While there are no general rules-of-thumb to specify the energy storage capacity for upgrade deferral, the detailed analyses in Section 4.3 can provide a reasonable range of storage-to-transformer power capacity ratios which provide optimal BCR. Looking across the results from the Hillview deferral analyses, which were assumed to have similar load growth assumption, the storage-to-transformer power capacity ratios with the best BCRs ranged from 0.05 to 0.20. Barring a detailed analysis on every candidate substation, these values provide a reasonable range of capacity ratios for determining the total energy storage capacity required to address deferral opportunities across all candidate substations. This range of storage-to-transformer power capacity ratios is also in line with DNV GL's observations obtained while performing upgrade deferral analysis for two California IOUs and the California Energy Commission [11].

5.4.3 System Level Energy Storage Potential for Upgrade Deferral

Evaluation of the 271 substations across PacifiCorp's Oregon service territory resulted in 46 substations with projected overloads occurring over the time-period of 2017 to 2026. These 46 substations represent 936 MVA of total substation transformer capacity. Using an assumed range of 0.05 to 0.20 as the storage-to-substation power capacity ratio, this represents 47 MW to 187 MW of potential energy storage power capacity for distribution upgrade deferral. Assuming 2-hour duration for each system, a duration selected based on the most cost-effective of the deferral cases studied in Section 5.3, this corresponds to 94 MWh to 374 MWh of storage energy capacity.

6.0 CUSTOMER-SITED ENERGY STORAGE SYSTEM ASSESSMENT

Energy storage located at customer sites provide unique opportunities to locate energy sources closer to demand than possible with traditional substations. These devices, especially if paired with on-site generation, can provide additional local reliability and other ancillary grid services. Further, if owned by the customer, additional cost saving benefits may be garnished by the customer with time of use load shift and demand reduction. This section details one customer-sited, utility owned case, under various conditions, and also discusses the potential to distribute and aggregate previously modeled cases for behind the meter installations.

6.1 Customer-sited, Utility Owned Storage Potential Evaluation Model Development

This use case examines the cost-effectiveness of an ESS deployed on the distribution system and performing customer benefit applications. The system is deployed on the utility side of the meter at a [redacted] that is located at the end of the [redacted] distribution circuit. This use-case evaluates the following single and stacked applications:

- ESS providing reliability to customer loads under distribution or transmission system outage.
- ESS providing reliability to customer loads, substation upgrade deferral and primary frequency response

6.1.1 Inputs required

- Circuit topology showing feeders, switchgear, metering, distributed assets, and load centers on the campus
- Customer energy consumption and peak demand by facility
- Distribution and transmission circuit outage data
- Distribution circuit loading conditions to evaluate requirement for deferral
- Frequency event data

6.1.2 Methodology description

In this use case, customer facilities are aggregated into two clusters as follows:

- [redacted]
- [redacted]

We assume that the ESS is interconnected to the [redacted] distribution circuit such that under outage conditions, the ESS can be islanded with either one of the customer facility groups. Hence, two separate reliability scenarios can be evaluated:

- Distribution outage – In this scenario there is an outage upstream on the [redacted] circuit and the [redacted] facilities are switched to the [redacted] circuit. The [redacted] are islanded and supplied by the energy storage system.
- Transmission outage – In this scenario, supply is lost on the [redacted] and [redacted] circuits. If the [redacted] has critical load requirements, such as a scheduled event, the energy storage system is islanded with the [redacted] facilities. The loads on the [redacted] circuit are not supplied.

6.1.2.1 Load modeling

Monthly energy consumption data and annual peak demand was provided for each facility. Table 6-1 gives an overview of the load requirements at the [redacted] loads. It was assumed that the coincident peak demand of the [redacted] is equal to the sum of the peak demand of the individual buildings. The coincident peak demand of the [redacted] loads was assumed to be [redacted]% of annual peak demand.

Table 6-1: Overview of energy consumption and demand at customer facilities

	[redacted]	[redacted]	[redacted]
Annual Energy Consumption (kWh)	[redacted]	[redacted]	[redacted]
Sum of annual peak demand (kW)	[redacted]	[redacted]	[redacted]
Assumed coincident peak demand (kW)	[redacted]	[redacted]	[redacted]

For evaluating customer reliability, hourly consumption data for each customer group is required over a calendar year. To generate representative hourly consumption profiles, energy consumption was simulated using the software *EnergyPlus* in statistically benchmarked buildings equivalent to ASHRAE 90.1 2013 – code efficiencies and requirements. The location of statistically benchmarked buildings was assumed to be Portland, Oregon. [redacted] was used to characterize the consumption profile at the [redacted] facilities and [redacted]. The consumption profile of a [redacted] building was used as a representative of the [redacted]. The simulated consumption profiles were then calibrated to actual meter data by the following steps:

- Consumption profiles were aligned such that the peak demand hour on the [redacted] circuit corresponds to the peak demand hour on the simulated [redacted] load profiles. The peak demand hour on the [redacted] loads was selected as September 24th, 5 pm, corresponding to [redacted].
- Simulated consumption profiles were calibrated such that annual peak demand matched the assumed coincident demand of the load clusters given in Table 6-1.

- For each month, the simulated consumption profiles were calibrated such that the total energy requirement of the month matched the metered energy for the load clusters. Hourly consumption was discretized into ten samples – from 0% to 100% of monthly peak demand. The consumption within each sample was adjusted per seasonal variations and calendar events. Figure 6-1 shows an example of the adjustment process to match metered consumption data at the [redacted] facilities for Jan 2016. The total monthly consumption of the load profile generated from *EnergyPlus* aligned to [redacted] peak demand hour and calibrated to an annual peak demand of [redacted] is shown in blue. The monthly consumption in Jan 2016 under this profile is [redacted] kWh, whereas the meter data recorded is [redacted] kWh. The orange line shows the adjustment to the simulated profile to increase total monthly consumption to meter data while maintaining the load characteristics.

[redacted]

Figure 6-1: Adjustment of simulated load profiles for [redacted] facilities to match metered consumption in January 2016

6.1.2.2 Solar PV modeling

Solar photovoltaic (PV) installation is planned at several customer facilities within the microgrid. [redacted] To evaluate the reliability impact of combining the ESS with customer sited solar PV production, DNV GL developed hourly production profiles of the customer sited PV.

Since details of specific array and mounting technology were not available, DNV GL simulated a [redacted] ground mounted solar PV installation at the approximate location of the customer facilities. The simulation was performed using the commercially available software *Helioscope* based on generic, industry standard technology assumption and parameters shown in Table 6-2.

Table 6-2: Solar PV simulation parameters

Parameter	Value
Module DC Nameplate	[redacted]
Inverter AC Nameplate	[redacted]
DC to AC ratio	1.28
Annual AC production	[redacted]
Racking and Orientation	Fixed tilt / vertical

Figure 6-2 shows an overview of simulated solar PV production and the source of system losses. The peak coincident PV production was derived to be [redacted].

[redacted]

Figure 6-2: Overview of simulated Solar PV production by month and sources of system loss

6.1.2.3 Outage characterization

DNV GL analyzed data on 96 outage events from 2006 to 2017. The data comprised 90 distribution system events on the [redacted] circuit and 6 transmission events that also caused load loss on the distribution circuit. Table 6-3 shows the characteristics of all outages on the [redacted] circuit. The customer average annual interruption duration is calculated as 146.4 minutes. Since the [redacted] are located at the end of the [redacted] circuit and susceptible to any upstream outage on the distribution system, it is assumed that the average annual interruption duration at those facilities is 146.4 minutes. Moreover, the average duration of a single outage event is 17.5 minutes

Table 6-3: [redacted] circuit outage characteristics

Year	Number of events	Total number of customer interruptions	Sum of all customer interruption durations (mins)	Customer average interruption duration (mins)
2017	2	3505	40,014	11.4
2016	13	444	67,301	151.6
2015	7	146	10,770	73.8
2014	12	1775	217,020	122.3
2013	8	85	10,193	119.9
2012	16	3444	536,432	155.8
2011	10	333	32,539	97.7
2010	2	2	107	53.5
2009	6	440	109,579	249.0
2009	7	1972	100,033	50.7
2007	3	8	1,026	128.3
2006	10	2035	952,832	468.2
Average Annual	**8.3**	**1234**	**180,682**	**146.4**

Table 6-4 shows the inception time and duration of the six transmission system outages that occurred in the past 11.5 years. The maximum recorded duration of a transmission system outage is 117 minutes, or approximately 2 hours.

Table 6-4: Inception time and duration of transmission outages

Outage Inception Timestamp	Outage Duration (mins)
Mar 03, 16:42	10
Feb 06, 17:13	13
Jul 13, 12:48	2
Apr 28, 16:33	117
Dec 16, 19:27	63
Aug 16, 14:40	111

6.1.2.4 Energy Storage System sizing

In this use case the following ESS sizes have been evaluated:

- 2 MW 2-hour system (approximately 4 MWh)
- 4 MW 1.5-hour system (approximately 6 MWh)

The reasons for the selecting the 2 MW 2-hour system are as follows:

- Assumed coincident peak demand of [redacted] load cluster is [redacted] kW. A 2 MW ESS can supply peak load if these facilities are islanded.
- Assumed coincident peak demand of [redacted] loads is [redacted] kW. The 2 MW ESS can supply peak demand during a critical period, for example if there is a transmission system outage during an event at the [redacted].
- The maximum duration of any transmission system outage over the past 11.5 years is 117 minutes. A 2 MW 2 hour ESS will be able to provide islanded backup for the [redacted] loads in the event of transmission system outage under peak load conditions.

The reasons for evaluating a larger size 4 MW 1.5-hour system are as follows:

- 4 MW power capacity potentially doubles the frequency response capacity that can be contracted with the system.
- 6 MWh energy capacity can supply peak [redacted] loads under islanded condition [redacted] hours.

6.1.2.5 Evaluation of islanded reliability

We evaluate customer reliability under distribution and transmission outage scenarios by simulating minute by minute operation of ESS under islanded conditions for each of the 96 recorded outages. At the inception of the outage, the state of charge of the storage device is assumed to be 100%. Islanded load during the outage is derived from the hourly load profiles of the customer facilities. The islanded load served is modeled through a continuous function under the assumption that there exists sufficient measurement fidelity and fast switching to enable appropriate load shedding that balances load and generation at each time interval. This assumption ignores the impact of distribution system topology, load shedding and restoration schedules and switchgear controls. Instead, the assumption allows the use case to focus on the capability of installed devices to meet customer load during outage conditions.

The ESS may be integrated with customer installed PV under islanded conditions. An ESS can monitor solar PV production and customer load to balance generation, load, and state of charge. This configuration allows additional customer loads to be suppled under outages longer than 2 hours, particularly during periods of solar production.

Islanded operation under five outage scenarios is shown in Table 6-5 and Table 6-6. Table 6-5 shows customer load served under an integrated Solar + Storage system, while Table 6-6 depicts customer load served under stand-alone ESS. The outage scenarios are as follows:

- Outage scenario 1: The outage occurs at 12:18 PM and lasts for 164 minutes. Total customer load requirement over the duration is [redacted] kWh with an average load of [redacted] kWh per hour. PV production is low due to cloudy conditions and the storage system supplies most of the load.

- Outage scenario 2: This outage starts at 4:24 PM and lasts over 15 hours. Total customer load over this period is [redacted] kW at an average of [redacted] kW. PV production is negligible since the outage period is mostly during the night. The ESS supplies load until it runs out of charge. Overall, 38% of customer load is served.
- Outage scenario 3: The outage starts at 9:00 AM and lasts over 6 hours. PV production is high during this period. Combined PV and storage supplies 90% of the load.
- Outage scenarios 4 and 5: Both outages are of duration less than an hour. 100% of customer load under outage is served.

Table 6-5: Customer load served during PV + Storage islanding under 5 example outages

Outage #	Outage Inception	Duration (min)	Customer Load (kWh)	PV Production (kWh)	PV to Load (kWh)	PV to Storage Charging (kWh)	Storage to Load (kWh)	Load Served (kWh)	% Load Served
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

As shown in Table 6-5, there is a substantial difference in customer load served under outage scenario 3 between solar + storage and stand-alone storage systems. Without solar PV, the battery supplies load until it runs out of energy. In this scenario, 61% of customer load under outage is served.

Table 6-6: Customer load served during stand-alone Storage islanding under 5 example outages

Outage #	Outage Inception	Duration (min)	Customer Load (kWh)	Storage to Load (kWh)	Load Served (kWh)	% Load Served
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 6-7 shows the results of evaluating 87 distribution system outages and 6 transmission system outages. It is assumed that under transmission system outage, the microgrid will prioritize serving [redacted] loads. Customer load in [redacted] will not be served. A 2 MW 2 hour stand-alone ESS can supply on an average [redacted]% of customer load under outage. A 4 MW 1.5-hour ESS can supply [redacted]% customer load under outage at an average. Integrating the ESS with customer sited Solar PV under islanded conditions results in the possibility of supplying an additional [redacted]% of customer load. 100% of [redacted] loads can be supplied under both storage sizing scenarios for all outage cases examined.

Table 6-7: Reliability evaluation results

	Distribution outages, Solar + Storage	Distribution outages, only storage	Transmission outages, Solar + Storage	Transmission outages, only storage
Average customer load served under outage by 2 MW 2 hour system	[redacted]	[redacted]	[redacted]	[redacted]
Average customer load served under outage by 4 MW 1.5 hour system	[redacted]	[redacted]	[redacted]	[redacted]

6.1.2.6 Benefit of mitigating customer interruptions

Reliability benefits to specific customers may not accrue as a tangible benefit to a storage project. However, the 'soft value' of this benefit may be assessed for storage cost-effectiveness evaluation. The U.S. Department of Energy funded a report by Lawrence Berkeley National Labs (LBNL) to derive average and specific values of power disruptions for different customer classes in various regions in the U.S. Table 6-8 shows the estimated interruption cost per outage event, average kW, and unserved kWh by duration and customer class.

From Table 6-8, the interruption cost of medium and large commercial and industrial (C&I) customers varies from $96.5 to $10.6 per kWh from momentary interruptions to 8 hour outages. The average duration of an outage event on [redacted] is 18 minutes. Through linear interpolation, the cost of customer interruption for an 18-minute outage is $58.1 in US 2008$. Escalating the value of US $ by 2.5% annually, the equivalent cost is $74.3 in US 2018$.

Table 6-8: Estimated average electric customer interruption costs US 2008$, anytime by duration and customer type [12]

Interruption Cost	Interruption Duration				
	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$6,558	$9,217	$12,487	$42,506	$69,284
Cost Per Average kW	$8.0	$11.3	$15.3	$52.1	$85.0
Cost Per Un-served kWh	$96.5	$22.6	$15.3	$13.0	$10.6
Cost Per Annual kWh	9.18E-04	1.29E-03	1.75E-03	5.95E-03	9.70E-03
Small C&I					
Cost Per Event	$293	$435	$619	$2,623	$5,195
Cost Per Average kW	$133.7	$198.1	$282.0	$1,195.8	$2,368.6
Cost Per Un-served kWh	$1,604.1	$396.3	$282.0	$298.9	$296.1
Cost Per Annual kWh	1.53E-02	2.26E-02	3.22E-02	$0.137	$0.270
Residential					
Cost Per Event	$2.1	$2.7	$3.3	$7.4	$10.6
Cost Per Average kW	$1.4	$1.8	$2.2	$4.9	$6.9
Cost Per Un-served kWh	$16.8	$3.5	$2.2	$1.2	$0.9
Cost Per Annual kWh	1.60E-04	2.01E-04	2.46E-04	5.58E-04	7.92E-04

The value of customer average interruption duration on the [redacted] circuit is 146.4 minutes per year. For the 93 outages simulated, the average customer load under outage over [redacted] kW per hour. Hence the average customer load interrupted annually is [redacted] kWh. Table 6-9 derives the annual value of microgrid reliability for mitigating distribution system outages on [redacted]. The range of annual benefits is from $[redacted]. Integrating the ESS with customer sited Solar PV increases benefits by $[redacted] over stand-alone ESS.

Table 6-9: Customer reliability benefit results

	Solar + Storage	Stand-alone ESS
Customer average interruption duration	[redacted]	[redacted]
Average customer load under outage per hour	[redacted]	[redacted]
Average customer load interrupted annually	[redacted]	[redacted]
Customer load under interruption served by microgrid with 2 MW 2 hr ESS (%)	[redacted]	[redacted]
Customer load under interruption served by microgrid with 4 MW 1.5 hr ESS (%)	[redacted]	[redacted]
Customer load under interruption served by microgrid with 2 MW 2 hr ESS (kWh annual)	[redacted]	[redacted]
Customer load under interruption served by microgrid with 4 MW 1.5 hr ESS (kWh annual)	[redacted]	[redacted]
Value of customer reliability ($) @ $74.3 per kWh of interrupted load served with 2 MW 2 hour ESS	[redacted]	[redacted]
Value of customer reliability ($) @ $74.3 per kWh of interrupted load served with 4 MW 1.5 hour ESS	[redacted]	[redacted]

It is to be noted that the benefits in Table 6-9 are estimated only for mitigating distribution system outages on the [redacted] circuit. Transmission outages are extremely rare and using this methodology, the benefit estimate of supporting stadium loads during a transmission outage would be negligible. However, even though the statistical probability is low, the actual cost of a transmission outage causing loss of load at the [redacted] particularly during [redacted] would be extremely high. Neglecting this benefit provides a conservative estimate of cost-effectiveness of energy storage systems for microgrid reliability.

6.1.2.7 Stacked application evaluation

In providing microgrid reliability, the ESS discharges at an average of 8 times a year for a total discharge time of 146 minutes. Due to very low usage requirements, this application can be stacked or combined with the following additional applications

- Primary frequency response – The power capacity of the ESS can be contracted to provide primary frequency response. Per the frequency response application methodology detailed in Section 4.1.2, on receiving a frequency response trigger, the ESS will respond as follows:
    - Zero to full power within 10 seconds.
    - Discharge at full power for 360 seconds.
    - Ramp down to zero power from full power within 120 seconds.

  Assuming an ESS with 82% round-trip frequency, for a frequency response contract of 2 MW, the total energy discharged during this performance cycle is 260 kWh. If the contracted capacity is 4 MW, the total energy discharged is 520 kWh.

  When stacking frequency response with distribution transformer upgrade deferral, there is non-zero probability that a frequency event will occur after the ESS has discharged full capacity to reduce circuit load and has not had the opportunity to recharge sufficiently. Hence, for this stacked application, system energy capacity needs to be reserved for frequency response.

- [redacted] substation upgrade deferral – The ESS can discharge during circuit peak load day to defer substation transformer upgrade required to mitigate circuit overload conditions. A power flow analysis of the [redacted] circuit demonstrates that there is negligible difference in power requirement for deferral if the ESS is interconnected at the end of circuit instead of the substation. Reserving energy capacity for frequency response, the available capacity for upgrade deferral is as follows:
    - For a 2 MW 2 hr ESS, 300 kWh is reserved for frequency response and 3.7 MWh is available for upgrade deferral.
    - For a 4 MW 1.5 hr ESS, 550 kWh is reserved for frequency response and 5.45 MWh is available for upgrade deferral.

  Evaluating upgrade deferral by the methodology detailed in section 5.3.3 a 2 MW 3.7 MWh ESS can defer $3,000,000 transformer upgrade over a four-year period from 2021 to 2024. A 4 MW 5.45 MWh ESS can defer the transformer upgrade over a 6 year period from 2021 to 2026.

  We evaluate benefits of deferral per the methodology described previoulsy. The benefits of four year substation transformer deferral with 2 MW 3.7 MWh ESS is shown in Table 6-10, and six year substation transformer deferral with 4 MW 4.45 MWh ESS is shown in Table 6-11.

Table 6-10: Benefits of four year substation transformer deferral with 2 MW 3.7 MWh ESS

	2021	2022	2023	2024	2025
Deferral benefit - equity	$1,543,200	$0	$0	$0	$(1,543,200)
Deferral benefit - debt	$83,026	$83,026	$83,026	$83,026	$0
Avoided transformer O&M cost	$8,500	$8,500	$8,500	$8,500	$0

Table 6-11: Benefits of six year substation transformer deferral with 4 MW 5.45 MWh ESS

	2021	2022	2023	2024	2025	2026	2027
Deferral benefit - equity	$1,543,200	$0	$0	$0	$0	$0	$(1,543,200)
Deferral benefit - debt	$83,026	$83,026	$83,026	$83,026	$83,026	$83,026	$0
Avoided transformer O&M cost	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$0

Note that the upgrade deferral and primary frequency response applications can be combined with microgrid reliability in a non-intrusive manner. In the event of outages, the ESS would be disconnected from the electric grid and will provide islanded reliability. Under parallel operation, the ESS may perform circuit load reduction or primary frequency response.

6.1.3 Assumptions and methodology limitations

The following assumptions are embedded within our methodology for evaluating microgrid reliability and stacked application benefits of ESS:

- Customer load profiles were derived by simulating the energy consumption of statistically benchmarked buildings equivalent to ASHRAE 90.1 2013 – code efficiencies and requirements and calibrating the hourly profiles to monthly meter data. The simulated building types are assumed to approximate the behavior of evaluated buildings. Accuracy of benefit evaluation can be improved by using actual interval metered load measurements.
- Outage analysis was performed at a circuit level. We assume that since the customers under evaluation are at the end of the [redacted] circuit, all circuit outages will affect this customer. The analysis can be improved by using logged outage data recorded at evaluated customer sites.
- Benefits of serving interrupted customer load are based on a national average of C&I customers. This benefit is heavily dependent on building population, activity and services interrupted by outage. Outage mitigation benefits for specific customers can be determined by conducting a survey of the facility, energy consumption, scheduled activities and their estimated monetary value as determined by the customer. We believe the outage benefit values used in this analysis is conservative
- The islanded load served is modeled through a continuous function under the assumption that there exists sufficient measurement fidelity and fast switching to enable appropriate load shedding that balances load and generation at each time interval. This assumption ignores the impact of load categorization, load shedding and restoration schedules and switchgear controls that will be implemented in an actual deployed system.

- Microgrid reliability benefits are evaluated only considering distribution outage on the [redacted] circuit. The value of reliability provided to stadium loads under transmission outage has been neglected due to the low frequency of transmission outages. This assumption is extremely conservative. The cost of an outage on the [redacted] during a highly visible event can be very high and may be estimated by reviewing the contract value of scheduled events.

6.1.4 Modeling results

Cash flow analysis is performed over twenty-year project life using cost and financial assumptions detailed in Table 6-12. Cost-effectiveness results in terms of Net Present Value (NPV), Internal Rate of Return (IRR) and Benefit to Cost Ratio (BCR) is shown in Table 6-12. Results for all combinations of the following scenarios are presented:

- ESS size 2 MW 2 hr and 4 MW 1.5 hr
- Microgrid reliability with stand-alone ESS and integration with customer sited Solar PV
- Upgrade deferral of 4 years achieved with 2 MW 2 hr ESS and 6 years with 4 MW 1.5 hr ESS
- Frequency response at contract value of $44.4/kW-year and $81/kW-year

High level conclusions that can be drawn from the results are:

- A high number of scenarios are cost-effective. Of the 24 scenarios evaluated, 9 are cost effective with a BCR greater than 1.
- A further 3 scenarios are marginally cost effective with BCR greater than 0.9 and less than 1.
- Microgrid reliability and upgrade deferral applications are not cost-effective individually. Combined with frequency response at contracted value of $81/kW-year, these applications are cost-effective.
- 2 MW 2 hour ESS performing microgrid reliability with customer PV integration, 4 year upgrade deferral and frequency response at a contract value of $44.4/kW-year may be considered the break-even scenario.
- In general, the 2 MW 2 hour system is marginally more cost-effective than the 4 MW 1.5 hour system. However, the larger sized system can provide higher reliability to customer loads, particularly [redacted] loads. Additionally, the 4 MW system can contract higher capacity for frequency response.

Table 6-12: Cost effectiveness results for microgrid reliability and stacked applications

ESS Size	Project Cost	Reliability integration scenario	Upgrade deferral scenario	FR scenario	NPV	IRR	BCR
2 MW 4 MWh	$2,362,000	Stand-alone ESS	N/A	N/A	($1,915,052)	-11.6%	0.34
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	N/A	N/A	($1,819,787)	-10.1%	0.37

ESS Size	Project Cost	Reliability integration scenario	Upgrade deferral scenario	FR scenario	NPV	IRR	BCR
2 MW 4 MWh	$2,362,000	Stand-alone ESS	4 year	N/A	($1,352,540)	-13.6%	0.53
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	4 year	N/A	($1,257,274)	-11.6%	0.56
2 MW 4 MWh	$2,362,000	Stand-alone ESS	N/A	$44.4/kW-yr	($658,991)	1.7%	0.77
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	N/A	$44.4/kW-yr	($563,726)	2.5%	0.80
2 MW 4 MWh	$2,362,000	Stand-alone ESS	4 year	$44.4/kW-yr	($96,479)	5.4%	0.97
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	4 year	$44.4/kW-yr	($1,213)	6.6%	1.00
2 MW 4 MWh	$2,362,000	Stand-alone ESS	N/A	$81/kW-yr	$376,410	9.2%	1.13
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	N/A	$81/kW-yr	$471,676	9.9%	1.16
2 MW 4 MWh	$2,362,000	Stand-alone ESS	4 year	$81/kW-yr	$938,923	17.8%	1.33
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	4 year	$81/kW-yr	$1,034,188	18.9%	1.36
4 MW 6 MWh	$4,014,000	Stand-alone ESS	N/A	N/A	($3,760,527)	N/A	0.23
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	N/A	N/A	($3,689,181)	-17.5%	0.24
4 MW 6 MWh	$4,014,000	Stand-alone ESS	6 year	N/A	($2,966,238)	N/A	0.39
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	6 yr	N/A	($2,894,892)	N/A	0.41
4 MW 6 MWh	$4,014,000	Stand-alone ESS	N/A	$44.4/kW-yr	($1,248,406)	1.1%	0.74
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	N/A	$44.4/kW-yr	($1,177,059)	1.5%	0.76
4 MW 6 MWh	$4,014,000	Stand-alone ESS	6 year	$44.4/kW-yr	($454,116)	3.7%	0.91

ESS Size	Project Cost	Reliability integration scenario	Upgrade deferral scenario	FR scenario	NPV	IRR	BCR
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	6 year	$44.4/kW-yr	($382,770)	4.2%	0.92
4 MW 6 MWh	$4,014,000	Stand-alone ESS	N/A	$81/kW-yr	$822,398	10.0%	1.17
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	N/A	$81/kW-yr	$893,744	10.2%	1.18
4 MW 6 MWh	$4,014,000	Stand-alone ESS	6 year	$81/kW-yr	$1,616,687	16.1%	1.33
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	6 year	$81/kW-yr	$1,688,033	16.5%	1.35

Table 6-11 and Table 6-12 (following page) shows the 20-year cash flow for 2 MW 2 hr ESS performing microgrid reliability with solar and storage integration, primary frequency response at contract value of $81/kW-year in the first year and substation transformer upgrade deferral for four years.

Table 6-11: 20-year cash-flow for 2 MW 2 hour ESS performing microgrid reliability with solar + storage integration, primary frequency response at contract value of $81/kW-year and substation transformer deferral ($ '000s)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Reliability benefit	$75.1	$77.0	$78.9	$80.9	$82.9	$85.0	$87.1	$89.3	$91.5	$93.8
Frequency response benefit	$162.0	$166.1	$170.2	$174.5	$178.8	$183.3	$187.9	$192.6	$197.4	$202.3
Upgrade deferral benefit	$0.0	$0.0	$0.0	$1,634.7	$91.5	$91.5	$91.5	($1,543.2)	$0.0	$0.0
Total savings / revenue	$237.1	$243.0	$249.1	$1,890.1	$353.3	$359.8	$366.5	($1,261.3)	$288.9	$296.1
Fixed O&M cost	($12.0)	($12.3)	($12.6)	($12.9)	($13.2)	($13.6)	($13.9)	($14.3)	($14.6)	($15.0)
Capacity maintenance cost	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)
Equity draw	($1,215.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Interest payment	($60.3)	($55.6)	($50.6)	($45.4)	($39.8)	($34.0)	($27.9)	($21.4)	($14.7)	($7.5)
Principal payment	($90.1)	($94.8)	($99.8)	($105.1)	($110.6)	($116.4)	($122.5)	($129.0)	($135.8)	($142.9)
Total debt payment	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)
Total savings / revenue	$237.1	$243.0	$249.1	$1,890.1	$353.3	$359.8	$366.5	($1,261.3)	$288.9	$296.1
Total costs	($1,407.4)	($192.7)	($193.0)	($193.3)	($193.7)	($194.0)	($194.3)	($194.7)	($195.0)	($195.4)
Annual cash flow	**($1,170.3)**	**$50.3**	**$56.1**	**$1,696.7**	**$159.6**	**$165.8**	**$172.2**	**($1,456.0)**	**$93.9**	**$100.7**

Table 6-12: (continued) 20-year cash-flow for ESS performing microgrid reliability with solar + storage integration, primary frequency response at contract value of $81/kW-year and substation transformer deferral ($ '000s)

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Reliability benefit	$96.2	$98.6	$101.0	$103.6	$106.1	$108.8	$111.5	$114.3	$117.2	$120.1
Frequency response benefit	$207.4	$212.6	$217.9	$223.3	$228.9	$234.6	$240.5	$246.5	$252.7	$259.0
Upgrade deferral benefit	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total savings / revenue	$303.5	$311.1	$318.9	$326.9	$335.0	$343.4	$352.0	$360.8	$369.8	$379.1
Fixed O&M cost	($15.4)	($15.7)	($16.1)	($16.5)	($17.0)	($17.4)	($17.8)	($18.3)	($18.7)	($19.2)
Capacity maintenance cost	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)
Equity draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Interest payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Principal payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total debt payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total savings / revenue	$303.5	$311.1	$318.9	$326.9	$335.0	$343.4	$352.0	$360.8	$369.8	$379.1
Total costs	($45.4)	($45.7)	($46.1)	($46.5)	($47.0)	($47.4)	($47.8)	($48.3)	($48.7)	($49.2)
Annual cash flow	**$258.2**	**$265.4**	**$272.8**	**$280.3**	**$288.1**	**$296.0**	**$304.2**	**$312.5**	**$321.1**	**$329.9**

6.2 Distribution Upgrade Deferral with Distributed Storage

6.2.1 Inputs required

The inputs required for this methodology are as described in Section 5.3.

6.2.2 Methodology description and assumptions

The methodology required is as described in Section 5.3. The methodology and results presented for distribution upgrade deferral in Section 5.3 consider centralized energy storage system at the substation. Determining the optimal sizing and location of distributed storage along the feeder is beyond the scope of this project. However, assuming that the same amount of peak reduction can be provided by distributed storage, a financial evaluation can be performed to estimate the cost effectiveness of distributed storage and compare it against centralized storage.

For this application, we consider a use case where PacifiCorp procures capacity for upgrade deferral from an aggregator. The aggregator is responsible for the integration and operation on energy storage systems, and must ensure that the procured capacity is provided to PacifiCorp when needed.

6.2.3 Results

The results from 5.3.3 were used to estimate the capacity needed for deferral. Further, the number of years of deferral and total deferral benefit were used to estimate the capacity price which makes this application cost-effective for PacifiCorp. Capacity rate (in $/kW-month) is the monthly payment per kW capacity which PacifiCorp pays an aggregator to provide the capacity needed for peak reduction. The monthly capacity rate can be extended out to an annual rate by multiplying the rate by 12.

Table 6-15 shows the capacity requirements and capacity rates at the break-even point for [redacted] substation. Any values above the rates shown in Table 6-13, makes the use case financially nonviable, based on the transformer upgrade costs cited by PacifiCorp.

Table 6-15: Capacity Requirement and Rates for Distributed Energy Storage Use Case on Hillview

Substation	Scenario #	ES Power Rating (MW)	ES Energy Capacity (MWh)	Years of Deferral	Capacity Requirement (MW)	Capacity Rate ($/kW-month)	Capacity Rate ($/kW-year)
Hillview	Scenario 1	1	2	2	1.00	$15.10	$181.16
	Scenario 3	2	4	4	2.00	$7.10	$85.15
	Scenario 5	4	8	7	3.41	$3.80	$45.64
	Scenario 6	4	16	8	4.00	$3.15	$37.78
	Scenario 7	6	12	9	4.48	$2.73	$32.77
	Scenario 8	6	24	10	6.00	$1.13	$13.62

Typically, DNV GL has observed capacity rates in the current market to be approximately twice the rates calculated here for Scenario 1. As such, this case is likely not viable on its own, as was previously noted in the use case for a centralized system. However, located at a customer-site behind the meter, these systems could additionally provide reliability, peak shaving, load shifting, and renewables integration support to the customer. These stacked benefits could provide a viable case for this application. Additionally, if transformer upgrade costs are found to be greater than cited, the economic calculations can be updated to reflect this and provide more favorable BCR.

6.3 Voltage Support with Distributed Storage

6.3.1 Inputs required

The inputs required for this methodology are as described in Section 5.1.

6.3.2 Methodology description and assumptions

The methodology required is as described in Section 5.1.

6.3.3 Results

As previously described in Section 5.1, Figure 5-2 showed the branches of the feeder that experience voltage violations. Provided that the ESS is of the required size, it can be sited anywhere on these branches, or distributed around several customers on these branches. As noted for the other customer sited cases, more distribution of energy storage systems could provide additional benefits, such as improving customer reliability, supporting customer savings through peak shaving or load shifting, and facilitating integration of on-site renewables, such as residential scale solar PV. Since the economics for the 17 kVA ESS case are positive, stacking these applications would provide an even more desirable BCR. The 35 kVA case, while calculated at a lower BCR for the centralized solution, stacked with other applications and distributed over multiple customers, who could broaden the scope not only of economic benefit, but customer satisfaction.

7.0 MODELING RESULTS ASSESSMENT

PacifiCorp has developed this document and the process and results described herein to comply with 2015 HB 2193, the subsequent Order 16-504 UM 1751, and the final guidelines from the OPUC relating to these items. As described in the previous sections, PacifiCorp considered multiple use cases, and applications to benefit the transmission system, distribution system, and customer were analyzed based on 6 representative feeders, other publicly available data, and assumed market conditions. A high level consolidation of the results of these studies are summarized in Table 7-1.

Table 7-1: Summary of modeling results

Use Case	**Energy Storage System Size**	**Economic considerations**		
Frequency response	10 MW / 2 MWh	FR rate @ $44.40, BCR = 0.97 FR rate @ $81, BCR = 1.78		
Congestion	None recommended	N/A		
Volt/VAR	(1) 35 kVA / 4 hr (2) 17 kVA / 4 hr	(1) Low: BCR = 0.23 Average: BCR = 0.30 High: BCR = 0.76 (2) Low: BCR = 0.47 Average: BCR = 0.625 High: BCR = 1.56		
Reliability	None recommended	N/A		
Distribution upgrade deferral	Hillview	**Deferral yrs**	**BCR w/ Deferral**	**BCR w/ Stacked**
	(1) 1 MW / 2 MWh	2	0.36	0.81
	(2) 1 MW / 4 MWh	2	0.23	0.53
	(3) 2 MW / 4 MWh	4	0.34	0.66
	(4) 2 MW / 8 MWh	4	0.22	0.43
	(5) 4 MW / 8 MWh	7	0.27	0.41
	(6) 4 MW / 16 MWh	8	0.20	0.26
	(7) 6 MW / 12 MWh	9	0.22	0.26
	(8) 6 MW / 24 MWh	10	0.15	0.15
	(9) 8 MW / 8 MWh	7	0.18	0.38
	Independence	-	-	-

Use Case	Energy Storage System Size	Economic considerations			
	(1) 6 MW / 24 MWh	1	0.02	N/A	
	(2) 10 MW / 20 MWh	1	0.01		
	(3) 10 MW / 60 MWh	2	0.01		
	Lyons	-	-	-	
	(1) 6 MW / 36 MWh	1	0.01	N/A	
	(2) 8 MW / 32 MWh	1	0.02		
	(3) 8 MW / 48 MWh	2	0.02		
	(4) 10 MW / 60 MWh	3	0.03		
Customer Sited, Utility Owned with Stacked Applications	(1) 2 MW / 4 MWh	**(1) System**	**(1) Deferral**	**(1) FR**	**(1) BCR**
		ESS	N/A	N/A	0.34
		Solar + ESS	N/A	N/A	0.37
		ESS	4 year	N/A	0.53
		Solar + ESS	4 year	N/A	0.56
		ESS	N/A	$44.40	0.77
		Solar + ESS	N/A	$44.40	0.80
		ESS	4 year	$44.40	0.97
		Solar + ESS	4 year	$44.40	1.00
		ESS	N/A	$81	1.13
		Solar + ESS	N/A	$81	1.16
		ESS	4 year	$81	1.33
		Solar + ESS	4 year	$81	1.36
	(2) 4 MW / 6 MWh	**(2) System**	**(2) Deferral**	**(2) FR**	**(2) BCR**
		ESS	N/A	N/A	0.23
		Solar + ESS	N/A	N/A	0.24
		ESS	6 year	N/A	0.39
		Solar + ESS	6 year	N/A	0.41
		ESS	N/A	$44.40	0.74
		Solar + ESS	N/A	$44.40	0.76
		ESS	6 year	$44.40	0.91

Use Case	Energy Storage System Size	Economic considerations			
		Solar + ESS	6 year	$44.40	0.92
		ESS	N/A	$81	1.17
		Solar + ESS	N/A	$81	1.18
		ESS	6 year	$81	1.33
		Solar + ESS	6 year	$81	1.35

As previously noted, for these results, the systems were assumed to be generic Lithium Ion systems of the noted size. This assumption reduced variables in the modeling. Additionally, Lithium Ion's current dominance in the energy storage industry provides it with some of the better economics of potential systems, while the technology's flexibility to perform both short and longer duration applications make it practical to assume in the case of stacked applications. It additionally has some of the highest energy density of mature technologies currently on the market. Other technologies should, however, be considered. As such, following are brief overviews of other relatively mature technologies and their appropriateness for these applications, utilizing industry knowledge, the Battery Energy Storage Study [1], DNV GL's Gridstor [3], and Lazard's Levelized Cost of Storage [10].

Flow batteries store electrolyte in tanks. As such, they do not experience the degradation that affects Lithium Ion batteries, their capacity can be increased at relatively low cost with the addition of electrolyte, and they can remain stored for long periods of time without concern for damage. Additionally, they are especially suited to serve long duration storage needs. This technology, however, is higher in cost and less mature, so less field data is available to validate manufacturer claims. Additionally, they have larger footprints than Lithium Ion systems, and thus are only suitable for large commercial, industrial, or utility installations, not distributed smaller systems.

Thermal energy storage is a broad term for a variety of energy storage devices. It covers a wide range of different technologies, wherein a medium is heated or cooled, and that energy is used at a later time. The energy to heat of cool the medium can come from the grid during off-peak times, renewable production that exceeds demand, waste heat, or other sources. This technology is very low cost and, depending on the type of technology, can have a reasonably minimal footprint. Thermal energy storage's largest limiting factor is the speed of response, which can take from seconds to minutes.

Hydroelectric energy has been connected to the grid for decades, and pumped hydro energy storage systems leverage this technological experience. Pumped hydro does not have the chemical degradation concerns which batteries face, but the addition of key moving components provides a different risk. The systems are capable of very high capacity storage, but have large footprints and physical constraints relating to the water source.

While these technologies are either leading in the industry or of particular interest to PacifiCorp, further research will continue to assess other options. Technologies open to consideration span from mechanical (such as flywheels, which are especially suited for fast response, high power applications) to other emerging battery technologies (such as Zinc-air) and further. PacifiCorp is utilizing the contents of this report to support the development of one or many ESS projects which will both meet the guidelines and requirements of the State and the OPUC, and also best serve its customers and stakeholders, ensuring the delivery of safe, reliable, low-cost energy.

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Oregon Energy Storage Final Project Proposal

PacifiCorp

HB 2193, Order No. 16-504, Order No. 17-118, & Order No. 17-375

April 2, 2018

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Definition of Common Acronyms

BHE	Berkshire Hathaway Energy
BESS	Battery Energy Storage System
DEM	Distributed Energy Management
DER	Distributed Energy Resource
DOE	Department of Energy
EIM	Energy Imbalance Market
EMS	Energy Management System
EPC	Engineer, Procure, Construct (and Commission)
ESS	Energy Storage System
HB 2193	House Bill 2193
HMI	Human Machine Interface
ICCP	Inter-Control Center Communication Protocol
IRP	Integrated Resource Plan
KW	Kilo-watt, capacity
KWH	Kilo-watt-hour, energy
MESA	Modular Energy Storage Architecture
MW	Mega-watt, capacity
MWH	Mega-watt-hour, energy
NERC	North American Electric Reliability Corporation
OPUC	Public Utility Commission of Oregon
R2P2	Renewable Resilient Power for Portland
RMP	Rocky Mountain Power
RFP	Request for Proposal
RFI	Request for Information
RTU	Remote Terminal Unit
UM	Utility Matter

Executive Summary

With a firm commitment to both customers and the environment, PacifiCorp d/b/a Pacific Power is actively seeking low cost, low risk opportunities to deliver a cleaner power grid and meet the growing needs and requirements of both customers and policymakers. PacifiCorp's current efforts are focused on reducing system costs through cost-effective energy efficiency programs, growing renewable resources through strategic investment and innovation, reducing emissions with carbon capture, and protecting natural habitats.

With more than 30 percent of PacifiCorp's current generating capacity already coming from renewable resources, the company is continually expanding its resource portfolio through programs that are helping the company meet its goals of increasing renewable energy development, while also meeting the Oregon legislature's requirement of 50 percent renewables by 2040 per Senate Bill 1574.[1] As PacifiCorp continues to expand its renewables resource portfolio, PacifiCorp recognizes that energy storage could provide additional benefits and become a key component to full utilization of such resources.

House Bill (HB) 2193,[2] passed in June of 2015, directed electric companies[3] in Oregon to identify and evaluate potential energy storage technologies, propose one or more specific projects to Commission with the capacity to store at least five mega-watt-hours (MWh) by January 1, 2018, and, pending project approval, procure energy storage solutions by January 1, 2020.

In alignment with the company's strategy and vision regarding the expansion and integration of renewable technologies into the preferred portfolio, PacifiCorp is proposing the following targeted pilot projects:

1. **Project #1 – Utility Owned Distributed Storage Pilot**: Phased approach to leverage a unique opportunity with a single customer to study distributed storage applications alongside a blend of renewable and conventional generation. This project will inform future investment and test how energy storage can be used as a distributed resource within the PacifiCorp network.

   Phase I – *Single utility owned energy storage device to address historic outage characterization on a specific feeder, validate modeling through field test data, create a research platform, and optimize energy storage controls and integration on the PacifiCorp network.*

   Phase II *– Additional energy storage device to pilot distributed storage, optimize use cases per Phase I results, explore tariff structure and ownership models, and continue research.*

2. **Project #2 – Community Resiliency Pilot** - State wide grant pilot for PacifiCorp customers in Oregon consisting of two phases for communities to explore small scale energy storage projects for increased localized resiliency in the event of an emergency or natural disaster causing long term power outages.

   Phase 1 (Technical Assistance) *– Provide on-site technical assistance and analysis to communities regarding the selection and implementation of energy storage solutions.*

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[1] https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled
[2] https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193
[3] Electric company is defined as an electric company that makes sales of electricity to 25,000 of more retail customers in the state of Oregon. This definition applies to PacifiCorp and Portland General Electric Company (PGE).

Phase 2 (Project Development) - *Execute 2-4 projects identified through the technical assistance that provide benefit for all utility customers and/or learning opportunities to both to PacifiCorp and customers.*

The pilot projects above not only address system needs but also allow PacifiCorp to validate modeling through field test data, learn how to control and integrate energy storage solutions into the existing network, and explore the full range of benefits prescribed in the legislation. The construct of each of these projects provides a controlled environment to explore these objectives, optimize the application of technology and system controls, and prepare for potential future wide scale deployment of energy storage, with limited risk to customers. In doing so, each of these projects allows PacifiCorp to meet the requirements set forth in HB 2193 and Order No. 16-504 while providing benefit to Oregon customers and maximum learning opportunities for PacifiCorp.

Table 1 PacifiCorp's Project Proposal Summary

Project Name	Preliminary Sizing, MW[4]	Estimated Final Sizing Date	Estimated In-Service Costs ($mil)	Estimated BCR	Estimated NPV Revenue Requirement ($mil)	Estimated In-Service Date
Pilot Project #1 - Phase I	2MW [6MWh]	May 2019	$4.0	0.27 - 0.51	($2.3) – ($6.6)	May 2021
Pilot Project #1 - Phase II	1 MW [1 MWh]	October 2021	$2.0	1.0[5]	n/a	April 2023
Pilot Project #2 - Community Resiliency Pilot *[2-4 projects]*	1 MW [4MWh]	December 2019	$1.8	TBD[6]	TBD	November 2021

For Pilot Project #1, PacifiCorp intends to hire an Owner's Engineer to complete the detailed engineering analysis and final sizing, followed by an RFP for EPC to procure and construct the energy storage solutions. For Pilot Project #2, PacifiCorp will contracts with an engineering consultant to provide on-site technical analysis at customer sites. The following diagram depicts PacifiCorp's high level project plan to design and implement the proposed pilot projects.

[4] Sizing represents preliminary sizing. Final sizing will be completed following the detailed engineering analysis. PacifiCorp intends to review any significant changes to the sizing or subsequent BCR with the Commission and seek additional approvals.
[5] PacifiCorp proposes a BCR of 1.0 or greater to progress Phase II of Pilot Project #1.
[6] As specific projects and locations have not yet been determined, meaningful cost-effectiveness analysis for this pilot is not available at this time. See Section 5.11.

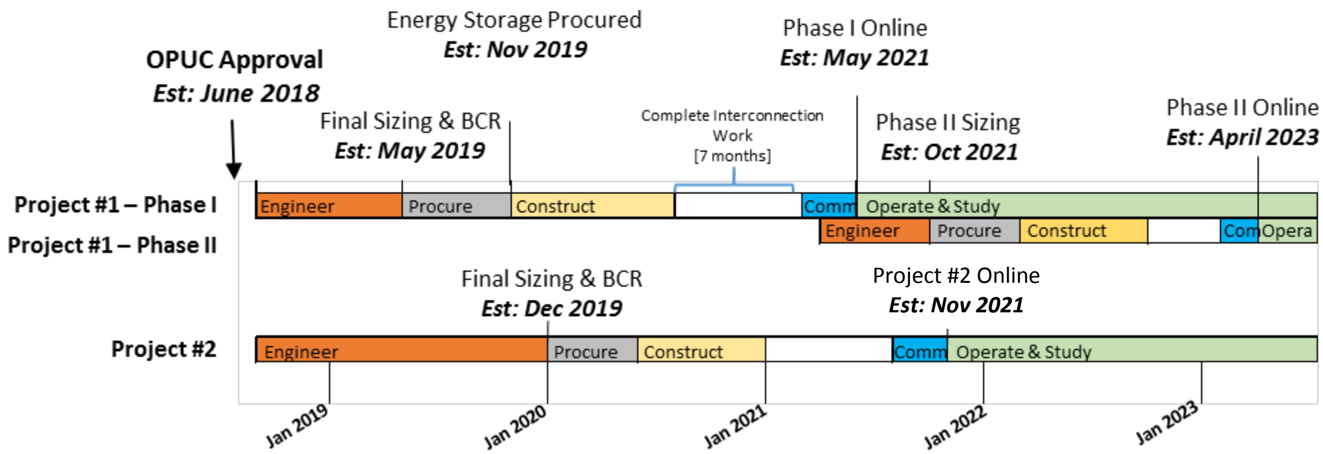

Figure 1 High Level Project Schedule for Proposed Pilot Projects

The following table summarizes how use cases will be leveraged or studied within the construct of each pilot project proposed.

Table 2 Pilot Project Use Case Summary

	Primary Use Cases		Secondary Use Cases				Test
	Generation Capacity	Ancillary Services	T&D Deferral	Outage Mitigation	Resiliency	Customer Energy Management	Frequency Response
Distributed Storage Phase I	✓	✓	✓	✓	✓	✓	✓
Distributed Storage Phase II[7]	*TBD*	*TBD*	*TBD*	*TBD*	✓	✓	
Community Resiliency	✓	✓			✓	✓	

The targeted pilot projects proposed above meet the requirements of HB 2193 and Order No. 16-504, provide benefit to Oregon customers and allow PacifiCorp to gain experience with energy storage, in preparation for future wide scale deployment. Greater detail regarding these pilot projects in fulfillment of the requirements outlined in Order No. 16-504 can be found in the following sections.

[7] At this time, the planned use cases for Phase II are identical to Phase I with the exception of frequency response, as PacifiCorp intends to further optimize the most valued use cases as identified in Phase I.

1.0 Introduction and Background

HB 2193,[8] passed in June of 2015, directs electric companies in Oregon to identify, select, and design one or more energy storage project(s) between 5 mega-watt-hours (MWh) and 1 percent of PacifiCorp's 2014 Oregon system peak load (25 mega-watts for PacifiCorp). The bill requires that electric companies submit project proposals to the Commission by January 1, 2018, and, pending project approval, procure energy storage solutions by January 1, 2020.

HB 2193 also tasked the Commission with drafting guidelines to be used by electric companies to create project evaluations and proposals. On December 28, 2016, the Commission issued Order No. 16-504 providing these guidelines and requirements for meeting HB 2193 in docket UM 1751. Through a series of collaborative workshops with Staff, stakeholders, and electric company representatives, the parties reached general consensus on requirements for the project proposals and energy storage evaluation.

These requirements directed electric companies to submit both an energy storage potential evaluation and a thorough project proposal, including details such as but not limited to the technology specification, location selection, estimated cost-effectiveness, and assessment of benefits. PacifiCorp's detailed methodology regarding the evaluation of energy storage can be found in the Final Energy Storage Potential Evaluation. The completed list of proposal requirements can be found in Section 3.0 of this document.

In addition to the specific requirements summarized in Section 3.0, Order No. 16-504 also provided general guidance and recommendations regarding project selection. According to Order No. 16-504, electric companies are encouraged to submit multiple projects with short and long term potential that could serve multiple applications and improve system operation and reliability while providing a platform for research and optimization. PacifiCorp incorporated both specific requirements and general guidance into the identification and selection of potential pilot projects as described in Section 2.0.

Draft project proposals were submitted to the Commission on December 29, 2017 and presented to both stakeholders and Commission Staff at a subsequent stakeholder workshop on March 14, 2018. PacifiCorp received valuable feedback from both stakeholders and Commission Staff that informed critical changes and improvements to the draft proposal. Additionally, as documented in written comments, Staff specifically requested that PacifiCorp focus on amending the final project proposals to include or evaluate the following:

"Pilot Project #1
- *Includes a credible quantification of all benefits associated with each use case listed in previous orders*
- *Include a more detailed explanation and/or timeline for final sizing analysis*
- *Include a more detailed set of requirements for progressing to Phase II*

Pilot Project #2
- *A completed explanation of the projects' benefits, including how resiliency is measured as a benefit*
- *A more detailed explanation and/or timeline for final sizing analysis*

[8] https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193

- *A more detailed explanation of individual project evaluation and selection criteria"*[9]

PacifiCorp amended the draft filing, as included in the following sections, and has specifically addressed these new requirements in Table 4 and Table 5 of Section 3.0.

PacifiCorp continues to view this legislative directive as an exciting opportunity to gain experience with energy storage on the company's existing network, understand the benefits and applications of energy storage, leverage existing or planned projects elsewhere within PacifiCorp's service territory, and prepare a long term strategy for potential future deployment of energy storage.

[9] Per Staff's written comments UM 1857 submitted March 14, 2018.

2.0 PacifiCorp's General Approach to Projects

After incorporating stakeholder feedback and Commission directives, PacifiCorp elected to use the following criteria and objectives when selected potential projects:

- **Maximized Learning Opportunities:** Focus on pilot projects with the greatest number of transferrable learning opportunities to further understand both quantitative and qualitative benefits of energy storage within PacifiCorp's Oregon service territory.
- **Incorporation of Multiple Use Cases:** Identify projects with multiple energy storage use cases that will allow for the evaluation of stacked benefits, validation of modeling assumptions, and may inform future investment decisions.
- **Controlled and Targeted Location Selection:** Select projects with a limited number of customer interfaces to reduce project risks and ensure both consistency and flexibility of the energy storage device operation and data collection.
- **Integration with Existing Portfolio:** Select projects that integrate with the needs identified in PacifiCorp's most recent Integrated Resource Plan (IRP) and the 10-year transmission and distribution capital investment strategy.
- **Feasibility:** Given both the possible resource limitations and experimental nature of the projects, select projects or locations with limited risk that can be completed within the time constraints of the legislation.
- **Cost/Benefit Analysis:** Select projects that provide the greatest and most balanced expected benefit to all utility customers.
- **Customer Sited Solutions:** Incorporate market research and explore opportunities for behind-the-meter customer-sited solutions in preparation for potential wide-scale deployment.

Leveraging both this list of priorities, and the results of the Final Energy Storage Potential Evaluation,[10] PacifiCorp has selected two pilot projects to be included in this proposal.

1. **Utility Owned Distributed Storage Pilot**: Phased approach to leverage a unique opportunity with a single customer to study distributed storage applications alongside a blend of renewable and conventional generation to inform future investment and test how energy storage can be used as a resource within the PacifiCorp network.
2. **Community Resiliency Pilot**: State wide grant pilot for Oregon communities to understand and explore small scale energy storage projects for increased localized resiliency.

The following sections provide more information regarding the detailed project proposals.

[10] See Final Energy Storage Potential Evaluation for more information.

3.0 Project Proposal Overview & Requirements

In alignment with Order No. 16-504, each project proposal contains the following information:

Table 3 Proposal Structure and Components

Section[11]	Description
Comprehensive Project Description [5]	Project description, objectives, general process, timeline, and key attributes
Justification [4]	Reason for selecting chosen technology, grid location, application, and ownership structure with supporting evidence or findings
Project Plan [6]	Plan for constructing, maintaining, and operating the energy storage system
Technical Specifications [1a-1f]	Section includes - Capacity of the project to store energy - Location selection - Description of system needs - Description of the technology - Description of services provided - Risk analysis to project delivery
Project Cost [2a-2c]	Section includes - Estimated capital cost - Estimated output cost - Grant money available - Proposed cost recovery method
Benefits [3a-3c]	Section includes - Projected in-state benefits - Projected regional benefits - Potential benefits to the electric company's entire system
Lifecycle Costs [7]	Comprehensive analysis of all identified costs of the life cycle of the project
Project Risks [8]	Comprehensive analysis of all project risks over the life of the project
Benefits Summary [9]	Comprehensive assessment of all quantitative and qualitative benefits to the electric system and all customers over the life of the project. Assessment of larger societal benefits, where applicable
Benefits Methodology [10]	Description of methodology for assessing project benefits including aggregation of benefits
Cost-Effectiveness Analysis [11]	Cost-effectiveness of the energy storage system including benefit-cost ratios and net present value revenue requirements over the energy storage system lifetime, and all underlying inputs and assumptions used in the calculation, where applicable
Project Data and Research [12, 13, 14, 15]	Section includes - Projected trends in energy storage system cost and performance - Strategy for large-scale deployment of technology over time, where applicable - Comparative analysis of energy storage versus tradition solution - Data collection and evaluation plan with identified research objectives

[11] Each section number in the table references guideline per Order No. 16-504 at 5-6 and Appendix A at 2-5.

Additional Project Proposal Requirements per Staff Comments:

The following tables outline Staff's written comments dated March 14, 2018 in docket UM 1857 and PacifiCorp's general responses.

Table 4 Pilot Project #1 Specific Additional Requirements per Staff Comments

Project #1 Staff Requirement[12]	PacifiCorp Response
Includes a credible quantification of all benefits associated with each use case listed in previous orders	See Section 7.0 of the Final Energy Storage Potential Evaluation for quantified benefits associated with each use case pertaining to Pilot Project #1. These values are also referenced in Section 4.6 included in this document. Section 5.0 of the Final Energy Storage Evaluation Potential Evaluation provides addition potential benefits from each use case, and Section 6.0 of the Final Energy Storage Potential Evaluation describes the process for co-optimization.
Include a more detailed explanation and/or timeline for final sizing analysis	Following project approval, PacifiCorp intends to hire an Owners' Engineer to perform a more detailed technical analysis and assist in identifying the optimum sizing for Pilot Project #1. PacifiCorp anticipates that this will be completed in May of 2019. At that time, PacifiCorp intends to review any significant changes to either the sizing or benefit-to-cost analysis with the Commission, and seek additional approval to progress the project. Additional information is included in Section 4.4.
Include a more detailed set of requirements for progressing to Phase II	Progressing to Phase II of Pilot Project #1 will be dependent on the following criteria: • Successful deployment, integration and operation of Phase I • Successful validation of anticipated in-service capital spend • Continued support of the identified partner • Project BCR of 1.0 or greater, or subsequent cost sharing model that increases the BCR to 1.0 or greater See Section 4.1 for more information.

[12] Per Staff's written comments in UM 1857 submitted March 14, 2018.

Table 5 Pilot Project #2 Specific Additional Requirements per Staff Comments

Project #2 Staff Requirement[13]	PacifiCorp Response
A completed explanation of the projects' benefits, including how resiliency is measured as a benefit	See Section 7.0 of the Final Energy Storage Potential Evaluation and Section 5.6 below. Specifically relating to resiliency, PacifiCorp has classified resiliency as a benefit for specific customers and included it in Power Reliability [as clarified under Staff Key Element #5 in of the Final Energy Storage Potential Evaluation]. Concurrent with the methodology described in the Final Energy Storage Potential Evaluation, PacifiCorp intends to measure project benefits and costs based on customer interest and the level of participation from specific communities in Pilot Project #2, as identified through the Technical Assistance Concept and the Project Development Funding Concept.
A more detailed explanation and/or timeline for final sizing analysis	PacifiCorp will hire a technical consultant to work with customers to develop the appropriate size system based on the unique needs of each site. The final sizing of Pilot Project #2 will be a component of the Technical Assistance Concept and the Project Development Funding Concept as described in Section 5.0. PacifiCorp anticipates completing Phase 1 of the project in December of 2019 and Phase 2 by December 2026.
A more detailed explanation of individual project evaluation and selection criteria	See Section 5.0 below, Table 23 and Table 24. These tables list the minimum application and evaluation criteria for Pilot Project #2. PacifiCorp will engage an independent, third-party consultant, selected through a competitive request for proposals process, to review and score projects based on the minimum established criteria outlined in Tables 22 and 23. PacifiCorp will work closely with the technical consultant to ensure that applicant evaluation tools and practices align with pilot project objectives.

[13] Per Staff's written comments in UM 1857 submitted March 14, 2018.

4.0 Project #1 – Utility Owned Distribution Storage Pilot

The Utility Owned Distribution Storage Pilot involves leveraging a unique opportunity with a single customer to study distributed storage applications alongside a blend of renewable and conventional generation that will inform future investment and test how energy storage can be used as a resource within the PacifiCorp network. PacifiCorp, in partnership with [redacted], has identified a phased approach to address existing reliability concerns, stack multiple use cases, and optimize the operation of energy storage through research in preparation for potential wide scale deployment. Each of the distinct phases of the proposed pilot project allows PacifiCorp to meet the requirements set forth in HB 2193 and Order No. 16-504 while providing benefits to both customers and residents of Oregon. A high level description of each phase has been included below:

Phase I: *Single utility owned energy storage device co-located at the customer-site*

> *In Phase I of Pilot Project #1, PacifiCorp proposes installing an energy storage solution on the utility side of the primary meter, with an underlying focus on evaluating benefits to all utility customers through grid services while gaining experience with controls and co-optimization on a historically underperforming circuit. The preliminary sizing for Phase I reflects both historic distribution and transmission level outages as well as a fair and balanced benefit-to-cost ratio for all utility customers.*[14] *While the primary objective of Phase I will be to improve customer reliability, PacifiCorp intends* [redacted] *to expand the use cases, gain experience with energy storage controls, validate current modeling and assumptions regarding the benefits of energy storage, and integrate energy storage with micro-grid technology for improved sustainability.*

Phase II*: Pilot distributed storage with an additional company owned device at customer-site*

> *Phase II will expand upon Phase I with the addition of one or more additional energy storage solution solution(s) with a minimum proposed capacity of 1 MW. Through continued research and experimentation, PacifiCorp intends to further optimize the most valued use cases as identified in Phase I, exploring tariff structures, ownership models, and interconnection requirements, in preparation for future wide scale deployment.*

The following sub-sections provide more detail regarding the pilot project per requirements of Order No. 16-504.

[14] See Section 7.0 of the Final Energy Storage Potential Evaluation.

4.1 Comprehensive Proposed Project Description

As introduced in the previous section, PacifiCorp is proposing a multi-phased pilot project in partnership with [redacted] to explore the application of energy storage, system integration, and operational optimization. Each of the two phases intends to tackle specific objectives, build upon the previous phase, and prepare PacifiCorp for potential wide scale deployment of energy storage while meeting the requirements of both HB 2193 and Order No. 16-504.

This location presents a unique opportunity as the network can be configured in such a way that the energy storage solution can be on either on the utility side or customer side of the primary meter. Therefore, the flexibility of this strategic location will allow PacifiCorp to study the benefits of a wide range of use cases included in the filing.

See the high level pilot project process and timeline below for the multi-phased approach.

High-Level Pilot Project Process

PacifiCorp's general approach to the pilot project process can be seen below:

Engineer	RFP for Owners' Engineer to perform detailed engineering analysis including optimizing capacity and technology.
Procure	RFP for EPC contractor to execute the detailed engineering analysis.
Construct	Perform any required environmental studies, acquire necessary permits, construct facilities, and install energy storage at the identified location.
Commission	Commission new energy storage solution and begin testing energy storage device in line with primary use case.
Study	Optimize controls, expand to addition use cases, quantify stacked benefits, validate models, and integrate with micro-grid technology. This could include minor changes to how the energy storage device is applied to the system to maximize learning and benefit.

This process will be followed for all phases [I-II] of the project.

High Level Pilot Project Schedule

Figure 2 demonstrates the high level planned project timeline, including the strategic timing and dependency of the two phases. Each phase relies on the completion and review of the preceding phase prior to beginning of any detailed engineering analysis.

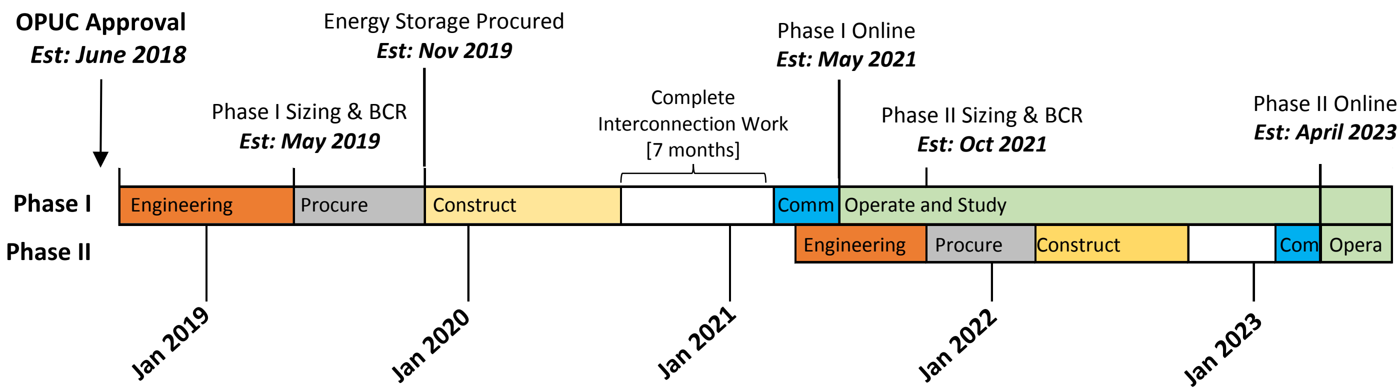

Figure 2 Pilot Project #1 High-Level Project Schedule

The resulting high level milestones can be seen in Table 6 below.

Table 6 Pilot Project #1 High Level Project Milestones

Milestone	Estimated Completion Date
Proposal Approval from OPUC[15]	June 2018
Phase I Final Sizing, BCR Analysis, and Approval to Progress	May 2019
Phase I Procurement Complete[16]	Nov 2019
Phase I Commissioning Complete	May 2021
Phase II Final Sizing, BCR Analysis, and Approval to Progress	Oct 2021
Phase II Commissioning Complete	April 2023
Proposed Check In and Review of Installed Projects	May 2026

[15] PacifiCorp built the potential project schedule to illustrate potential delivery dates. This proposed timeline is an initial look and subject to change as we work though the proceeding with staff.

[16] According to HB 2193, if authorized by the Commission, electric companies shall procure on or before January 1, 2020 one or more qualifying energy storage systems that have the capacity to store at least 5 MWh and no more than one percent of the company's 2014 Oregon system peak load.

Phase I: Single, utility owned energy storage device

Description

PacifiCorp is proposing to engineer, procure, and install a single energy storage solution adjacent to the [redacted]. As previously discussed, this location provides a unique opportunity as the network can be configured in such a way that the energy storage solution can be on either on the utility side or customer side of the primary meter. Therefore, the flexibility of this strategic location will allow PacifiCorp to study the benefits of a wide range of use cases included in the filing over the life of the project.

For Phase I of the project, PacifiCorp, intends to install the energy storage solution on the utility side of the primary meter with an underlying focus on evaluating utility specific benefits and use cases while gaining experience with controls and co-optimization on a historically underperforming circuit. Therefore, the preliminary size has been determined according to historic outage data and peak load requirements of [redacted] representatives and balanced by the potential range of costs and benefits as described in Section 7.0 of the Final Energy Storage Potential Evaluation.

In partnership with [redacted], PacifiCorp will research benefits from stacked applications such as but not limited to generation capacity, ancillary services, T&D deferral, and outage mitigation. Upon completion of a planned micro-grid [redacted], the energy storage device will be strategically integrated with existing solar and conventional generation to provide further benefits of increased sustainability and added resiliency in the event of an emergency or natural disaster.

PacifiCorp intends to own, operate, and fully integrate this energy storage solution into the company's outage management system for both local and remote monitoring and controlling capability.

Objectives

PacifiCorp intends to achieve the following objectives as part of Phase I:

- Improve customer reliability.
- Provide benefits to all utility customers through grid services.
- Gain experience with energy storage controls to optimize flexibility and future applications for energy storage.
- Create a platform for research opportunities to study energy storage and [redacted].
- Expand upon the primary use case of generation capacity deferral and ancillary services to study and quantify potential stacked benefits.
- Leverage data from primary use case as well as stacked benefits analysis to validate modeling and calculations for future optimization and energy storage evaluation.
- Integrate with micro-grid technology for improve sustainability and resiliency in the event of an emergency or natural disaster.

Key Attributes

The key attributes of Phase I of the proposed pilot project are included in Table 7 below.

Table 7 Pilot Project #1 Phase I Key Attributes

Attribute	**Description**
Minimum Sizing[17]	PacifiCorp is currently considering a 6 MWh [2MW x 3hr] system but has set a minimum threshold of 5 MWh [redacted]
Primary Location	[redacted]
On-Site Generation	[redacted]
Primary Use Case[18]	Generation Capacity, Ancillary Services
Secondary Use Case(s)	T&D Deferral, Outage Mitigation, Resiliency, Customer Energy Management Services
Test Use Case(s)	Frequency Response

Phase I Specific Timeline

The estimated time to design, construct and commission Phase I of the proposed project is approximately 3 years, or the second quarter of 2021. The following table outlines the high level milestones associated with Phase I of Pilot Project #1.

Table 8 Pilot Project #1, Phase I Project Milestones

Milestone	Estimated Completion Date
Approval of Project from OPUC[19]	June 2018
Award RFP Owner's Engineer	Q4 2018
Complete Detailed Engineering Analysis *[includes final sizing and benefit-to-cost ratio]*	Q2 2019
Review modifications and seek additional approval from the Commission	May 2019
Award EPC Contract/Procure Energy Storage Solution[20]	Q4 2019
Construct	Q4 2020
Interconnection Work Complete	Q1 2021
Commission	Q2 2021
Study	Q2 2021 – project closure
Estimated Micro-Grid Integration	Mid - 2022

[17] This represents the minimum size that PacifiCorp will consider for this phase of the pilot project. The final sizing requirements will be dictated by the detailed engineering analysis to follow approval of the project. See Section 7.0 of the Final Energy Storage Potential Evaluation for more information regarding preliminary sizing.

[18] Primary and secondary use cases as determine by the Final Energy Storage Potential Evaluation.

[19] PacifiCorp built the potential project schedule to illustrate potential delivery dates. This proposed timeline is an initial look and subject to change as we work though the proceeding with staff.

[20] According to HB 2193, if authorized by the Commission, electric companies shall procure on or before January 1, 2020 one or more qualifying energy storage systems that have the capacity to store at least 5 MWh and no more than one percent of the company's 2014 Oregon system peak load.

Phase II: Pilot distributed storage [redacted]

Description

For Phase II of the proposed pilot project, PacifiCorp intends to engineer, procure, and install an additional company owned high power energy storage device, also located [redacted]. Initially, this energy storage device will be incorporated behind the meter to expand upon the use cases and lessons learned through Phase I. Through continued research, PacifiCorp intends to further optimize the most valuable use cases as identified in Phase I, exploring tariff structures, ownership models, and interconnection requirements, in preparation for potential future wide scale deployment.

Criteria for Progression to Phase II

As Phase II remains fairly conceptual and is heavily dependent on the lessons learned during Phase I of Pilot Project #1, PacifiCorp will require has developed the following criteria to determine whether or not Phase II should progress.

- Successful deployment, integration and operation of Phase I.
- Successful validation of anticipated in-service capital spend.
- Continued support from the identified partner.
- Project BCR of 1.0 or greater, or
- Subsequent cost sharing model that increases the BCR to 1.0 or greater for all utility customers.

Objectives

PacifiCorp intends to achieve the following objectives as part of Phase II:

- Integrate additional distributed storage solution with Phase I.
- Evaluate the differences in application and benefits of high energy, low power versus high power low energy storage solution.
- Further optimize use cases to maximize stacked benefits and refine modeling and energy storage evaluation within PacifiCorp's service territory.
- Explore tariff structures, ownership models, and interconnection requirement.
- Identify optimized technology and framework for wider scale deployment outside of primary location.

Key Attributes

The key attributes of Phase II of the proposed pilot project are included in Table 9 below.

Table 9 Pilot Project #1, Phase II Key Attributes

Attribute	Description
Minimum Sizing[21]	1 MWh *PacifiCorp is currently considering a minimum of 1 MW of capacity*
Primary Location	TBD [redacted]
On-Site Generation	[redacted]
Primary Use Case[22]	Expansion of Phase I with optimization for the highest value use cases
Secondary Use Case(s)	Additional Resiliency and Customer Energy Management benefits

Phase II Specific Timeline

As the detailed engineering analysis and design relies on results and lessons learned from Phase I, the engineering design work for Phase II will not begin until Phase I is commissioned. The estimated completion date to engineer, procure, construct, and commission Phase II of the proposed pilot project is the first quarter of 2022. See milestones for Phase II below:

Table 10 Project #1 Phase II Project Milestones

Milestone	Estimated Completion Date
Approval of Project from OPUC[23]	June 2018
Award RFP Owner's Engineer	April 2021
Complete Detailed Engineering Analysis *[includes final sizing and benefit-to-cost ratio]*	October 2021
Review modifications and seek additional approval from the Commission	October 2021
Award EPC Contract/Procure Energy Storage Solution[24]	March 2022
Construct Energy Storage Solution	October 2022
Complete Remaining Interconnection Work	February 2023
Commission Pilot Project #1 Phase I	April 2023
Operate and Study	Q2 2023 – project closure

[21] This represents the minimum size that PacifiCorp will consider for this phase of the pilot project to ensure meeting the objective of exploring participation in the EIM. The final sizing requirements will be dictated by the detailed analysis as part of the Owners' Engineer's work as described in the project process.
[22] Primary and secondary use cases as determine by the energy storage evaluation.
[23] PacifiCorp built the potential project schedule to illustrate potential delivery dates. This proposed timeline is an initial look and subject to change as we work though the proceeding with staff.
[24] According to HB 2193, if authorized by the Commission, electric companies shall procure on or before January 1, 2020 one or more qualifying energy storage systems that have the capacity to store at least 5 MWh and no more than one percent of the company's 2014 Oregon system peak load.

4.2 Justification

Pilot Project #1 is expected to provide generation capacity and ancillary services benefits that are comparable to other potential locations within PacifiCorp's Oregon service territory. PacifiCorp also expects that Pilot Project #1 will provide distribution deferral benefits that have similar economics and significantly greater learning opportunities relative to other locations with alternative distribution deferral applications. Finally, the energy storage system is expected to reduce outages and increase reliability, providing outage mitigation for [redacted]. Instead of strictly reserving the energy storage solution for outage mitigation, which would significantly limit the range of applications and potential benefits to all utility customers, PacifiCorp is proposing that the energy storage solution be fully charged prior to limited, pre-scheduled time periods, as identified by [redacted]. During these time periods, the energy storage solution could be called upon for either system or local emergencies.

[redacted] was specifically selected due to the frequency of outage events, which are expected to provide real-world operational experience, and the unique opportunity to locate energy storage mid-feeder for a [redacted]. Additionally, this location allows PacifiCorp to leverage its [redacted] to maximize learning opportunities and benefit residents of the state of Oregon. The current grid configuration at [redacted] provides an opportunity to combine distributed energy storage with both conventional and renewable generation.

The phased approach of this pilot project allows PacifiCorp to meet the minimum requirement of 5 MWh as established by legislation through Phase I and then apply the lessons learned in the deployment of Phase II, to the extent that the additional benefits justify doing so.

4.3 Plan for constructing, maintaining, and operating

This sections describes PacifiCorp's proposed plan to design, permit, procure, commission, operate and maintain, and decommission the energy storage solution per proposed project #1.

Design

As described in the high level project process, following project approval from the Commission, PacifiCorp intends to issue an RFP for an Owners' Engineer to perform a detailed engineering analysis and identify both the optimized size and technology to meet the objectives and timeline of the project. At a minimum, the Owners' Engineer will be responsible for the following:

- Validate proposed sizing calculations for optimum benefits
- Perform detailed engineering calculations
- Develop a usage profile
- Support the permitting process to acquire necessary permits
- Assist with the interconnection application
- Create detailed project specifications
- Assist with development of subsequent RFP for an engineer-procure-construct (EPC) contract
- Identify hardware and software requirements for necessary control, operation, and optimization

To ensure accuracy of the eventual engineering analysis, PacifiCorp is proactively purchasing temporary metering equipment which will produce the necessary load profiles for targeted buildings as identified through outage history and prioritized by [redacted].

Permitting and Interconnection

Permits required will be dictated by the final siting and technology chosen to execute this pilot project. Where appropriate, permits will be acquired prior to the EPC RFP. However, permits may fall under the responsibility of the winning EPC contractor. The interconnection application requires proof of site control, single- line system design, and selection of typical or representative equipment to be used in the project. This agreement will be in place prior to issuing the RFP for the EPC contractor.

Procurement and Commissioning

As previously outlined, PacifiCorp intends to issue an RFP for an EPC contractor. The EPC will be selected through a competitive bidding process based on total life cycle financial and technical considerations as well as ability to meet the required project objectives and proposed project timeline. The winning EPC contractor, at minimum, will be responsible for the following:

- Procurement of energy storage solution and associated materials
- Construction of the device per detailed engineering design
- Commissioning of the energy storage solution into the existing electrical network
- Provide operations capabilities and requirements to be performed by the owner (PacifiCorp) through the life of the project
- Propose maintenance costs and schedules
- Provide energy storage equipment replacement requirements and estimated costs
- Provide decommissioning requirements and estimated costs

Operating and Maintaining

Throughout Phase I of this project, PacifiCorp intends to maintain ownership and control of the energy storage device. An expected usage profile will be developed as part of the detailed engineering design. This expected usage profile will then be used to evaluate operations and maintenance costs associated with system efficiency losses and expected performance degradation due to factors such as cycling, idle time, and weather. As part of the EPC proposals, bidders will be expected to provide both a baseline maintenance contract according to proposed technology and expected usage profile and an additional sensitivity analysis regarding cost variability due to exceeding the anticipated usage profile. Bidders will also be asked to provide a detailed list of maintenance activities to be performed by the owner (company) over the life of the project with associated pricing schedules.

As previously stated, PacifiCorp intends to partner [redacted] to [redacted] to properly study and evaluate the benefits of energy storage with regard to distributed generation. During this partnership, PacifiCorp will make data readily available to [redacted] and work together to maximize learning opportunities, but maintain responsibility for everyday operation and maintenance of the energy storage device.

Controlling

Daily operations and the ability to experiment and optimize use cases, relies heavily on the energy storage solution controls and IT integration into the PacifiCorp network. The following diagram in Figure 3 depicts how PacifiCorp intends to accomplish this integration.

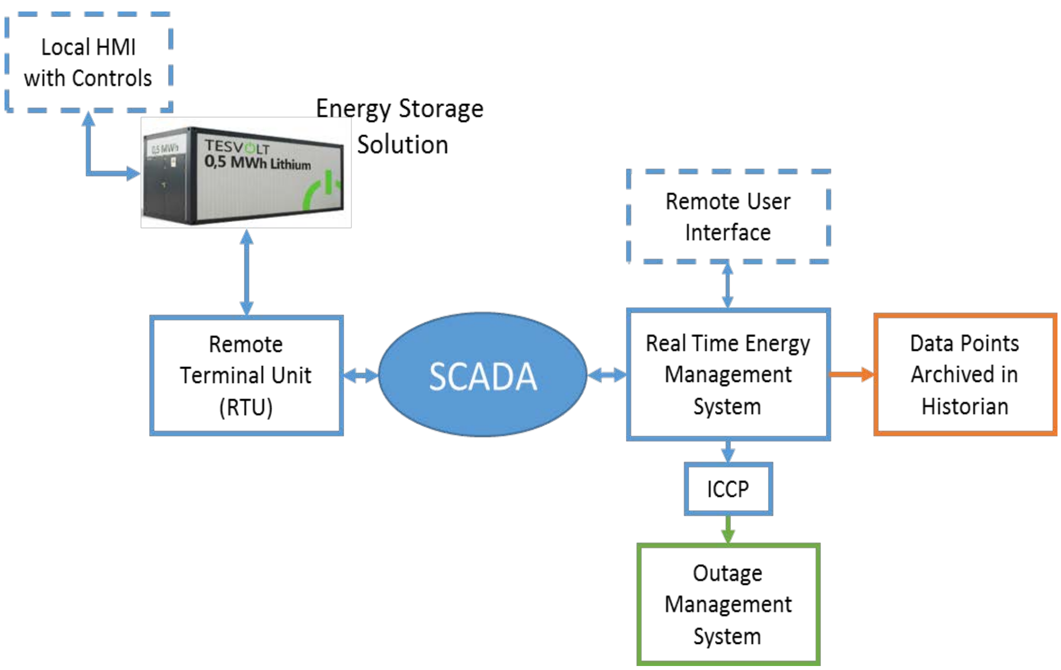

Figure 3 Open SCADA Design Description

While PacifiCorp intends to more thoroughly document the needs of the energy storage solution and refine the design of the controls as part of the detailed engineering work, the following critical components for success have been identified:

Strategy: While this energy storage solution will be small in comparison to the entire PacifiCorp network and other conventional forms of generation, it is a trial for future integration and deployment. Therefore, regardless of minimum thresholds and requirements, PacifiCorp intends to fully integrate the device into existing energy management system [EMS] and troubleshooting software for maximum visibility and control. This will provide PacifiCorp dispatch with remote monitoring and controlling capabilities and test the integration of distributed generation. PacifiCorp also recognizes that a scalable, modular open architecture should be used for this pilot project to allow for expansion, addition of future energy storage solutions, and overall alignment with distributed generation projects elsewhere within the greater PacifiCorp service territory. This will provide a platform to optimize and study energy storage, understand differences in regional benefits, and inform the company's future strategy.

Location: Having both local and remote operation capability with autonomous features will be critical to the above strategy. Local operations will allow for troubleshooting and experimentation on location during the pilot project. Remote operations will allow for integration into the existing PacifiCorp controls system used for other components of its electrical network.

Human Interface: PacifiCorp intends to install a Human Machine Interface (HMI) both locally, at the energy storage location, and remotely, at the controls center. This will allow for localized troubleshooting and experimentation as well as remote monitoring and controlling capabilities.

IT Integration: As a part of this overall integration philosophy, data will flow from the source to EMS by way of a local Remote Terminal Unit (RTU), the local HMI, and a microwave communication system. As part of the detailed engineering analysis, the required data and subsequent number of ports for the RTU will be defined. This will include the number of features needed for direct control and the level of information to be viewed remotely (push and pull of data). PacifiCorp intends to follow DNP3 protocol[25] communication standards and Modular Energy Storage Architecture (MESA)[26] standards for IT design and implementation.

Programmability: Inherent logic to the energy storage solution controls will allow for use cases and prioritization to be programmed for autonomous operation and optimization. Assumptions around storage performance, charge/discharge rates, and load requirements will feed the underlying logic which will control the storage device. PacifiCorp intends to experiment with these assumptions and with the prioritization of use cases to co-optimize and maximize benefit.

Alarms: In addition to specific engineering measurements, PacifiCorp intends to include both local and remote alarms. These alarms with have specific codes to aid in dispatch and troubleshooting efforts should the energy storage device operate outside of normal conditions. PacifiCorp will use this pilot to refine what types of alarms are required and how each can be used to maintain energy storage solutions throughout its service territory.

This above list represents a high level description critical components for energy storage controls. This is not meant to be an exhaustive list but a representation of PacifiCorp's strategy and basic assumptions. The controls will be defined further during the engineering analysis, and PacifiCorp will ultimately chose

[25] https://www.dnp.org/pages/aboutdefault.aspx
[26] http://mesastandards.org/

a system that allows for greatest experimentation with use cases, with scalability and expansion opportunities to future projects.

Decommissioning

The EPC RFP will require that qualified bidders describe the requirements and estimated costs for decommissioning and/or recycling of the system and its components, which will be included in the total life cycle cost used for bid evaluations.

4.4 Technical Specifications

This section includes the technical specifications as required by Order No. 16-504 for the proposed utility owned distribution storage pilot project (Project #1).

Capacity and Sizing

4.4.1 *The capacity of the project to store energy including both the amount of energy the project can store and the rate at which it can respond, charge, and discharge as well as any other operational characteristics needed to assess the benefits of the energy storage system*

PacifiCorp is currently considering a 2MW x 3 hours as the preliminary sizing requirements for Phase I of Pilot Project #1 to accommodate both historic distribution and transmission level outages as well as a fair and balanced benefit-to-cost ratio for all utility customers.[27]

Historic outage data at [redacted] indicates that the average durations of transmission and distribution outages are [redacted] respectively.[28] During these previous outages, critical buildings with a combined peak load of [redacted] did not have backup generator capabilities and, therefore, were without electricity for the duration of the outage. After initial review of this data, PacifiCorp considered a [redacted] energy storage solution for Phase I of the pilot project to meet both the peak load and outage characterization of historic data. This sizing would be sufficient to improve reliability, which is the primary use case identified for this pilot project.

However, PacifiCorp recognized that this simplified analysis does not fully optimize the capacity and discharge rates for stacked benefits of all use cases or the balance of costs and benefits for all utility customers. As a result, PacifiCorp modeled the costs and benefits for additional technologies and sizing specifications for comparison with this base case as described in Section 7.0 of the Final Energy Storage Potential Evaluation.

As previously described, upon project approval, PacifiCorp intends to issue an RFP for an Owners' Engineer to holistically study the system, incorporate newly captured load data, and optimize the design parameters. As part of this RFP, PacifiCorp will set forth the minimum design criteria of 5MWh to ensure legislation requirements are met and reliability is improved.

PacifiCorp anticipates that this detailed analysis will be completed in May of 2019. At that time, PacifiCorp intends to review any significant changes to either the preliminary sizing or benefit-to-cost analysis with the Commission, and seek additional approval to progress the project.

[27] See Section 7.0 of the Final Energy Storage Potential Evaluation for more information on preliminary sizing.
[28] See Section 6.1.2 of the DNV GL potential evaluation for outage characterization.

Location

4.4.2 *Project Location*

As previously described, the proposed location for Phase I of this pilot project is adjacent to [redacted]. This specific location was selected as part of a collaborative effort between [redacted]. In an effort to minimize risk, multiple physical locations [redacted] were considered and screened based on the following criteria:

- **Electrical Integration/Distance:** Technical challenges and physical distance associated with electric connections with closer proximity and simple integration being more favorable
- **Capital Integration Cost:** Overall magnitude of spend or reduction in current value associated with construction and operation or re-purposing of existing land at the given location
- **Code and Zoning Requirements:** Address the complexity and requirements/restrictions of codes or zoning laws, such as exclusion from flood zones, and [redacted]
- **Installation, Operation, and Maintenance Access:** Availability and ease of access during both construction and long term operation of the energy storage device
- **Available Footprint:** Availability of total real estate for use at each site with a larger footprint being more favorable

The following table describes the final locations and ranking as potential sites for the energy storage solution [redacted].

Table 11 Pilot Project #1 Potential Location and Ranking

Rank	Name	Address
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

The map below in Figure 4 depicts the potential locations with ranking for Pilot Project #1.

[redacted]

Figure 4 Energy Storage Solution Potential Location Map

The primary location for the energy storage device selected [redacted] which provides approximately 6,000 ft^2 of footprint. This location provided the largest available and accessible footprint with the lowest cost electrical integration and limited impact from [redacted]. The following pictures depict this physical location and two conceptual footprint options for the energy storage system. The box labeled “C&C” is for communications and controls.

[redacted]

Figure 5 Primary Location for Energy Storage Solution (1 MWh per 40' Shipping Container)

[redacted]

Figure 6 Primary Location for Energy Storage Solution (2 MWh per 40' Shipping Container)

Energy density of currently advertised energy storage systems (ESS) ranges from 1.0 MWh per 40' shipping container to a maximum of 9.1 MWh per 40' shipping container. Figure 5 shows a conceptual laydown for an ESS that has a technology capable of 2 MWh per 40' container and Figure 7 shows a conceptual laydown for an ESS that has a technology capable of 1 MWh per 40’ container. While these conceptual diagrams provide confidence that the project could be executed at the preferred location, PacifiCorp recognizes that a more detailed design is required to determine if there is sufficient area for access around each container and/or group of containers.

The following picture in Figure 7 depicts the proposed electrical location associated with the physical location described above. The energy storage device will be connected at [redacted].

[redacted]

Figure 7 Proposed Grid Location of Energy Storage Device

The location of Phase II will depend on the results of Phase I and the final sizing requirements per the detailed engineering design. Backup locations as previously presented in this proposal will be reviewed for potential fulfillment of Phase II if needed.

System Needs and Applications

4.4.3 *A description of the electric company's electric system needs and the application that the energy storage system will fulfill as the basis for the project*

In alignment with its existing strategy and clean energy portfolio, PacifiCorp leveraged current evaluation tools and processes to identify system needs within the Oregon service territory where, given the construct of the legislative requirements and timeline, energy storage was not only expected to be a viable solution but also a learning opportunity for the company.[29] Based on the analysis, the following primary system needs were identified:

Generation Capacity Deferral: *The dispatch of stored energy during peak demand, providing benefit through the reduction in need for new peaking power plants or other sources of peak supply.*

Ancillary Services: *The ability for an energy storage solution to provide balance and regulation due to forecasting errors or failures for applications such as but not limited to load following, spin/non-spin reserve, and voltage support.*[30]

After thorough consideration of feedback from both stakeholders and industry experts, PacifiCorp has also determined that the following use cases could provide additional benefits to the PacifiCorp network, particularly when stacked with a primary use case above:

Distribution Deferral: *The ability for an energy storage solution to defer traditional distribution asset investment.*

Outage Mitigation: *The ability for an energy storage solution to reduce or eliminate the costs associated with power outages to utilities.*

Resiliency: *The ability for a customer-sited energy solution to provide resilient backup power during a long-term outage.*

Customer Energy Management Services: *Customer energy management services include power reliability, time-of-use charge reduction, and demand charge reduction. Project 1, phase 1, provides limited reliability enhancement and does not provide time-of-use or demand charge benefits to the customer. The experience gained and data collected in phase 1 may result in increased customer participation in Phase 2.*

As previously described, the primary objective of this pilot project is to provide system generation capacity deferral and ancillary services. The selected location also provides opportunities for distribution deferral, outage mitigation, resiliency, and customer energy management services. When reviewing historic outage frequency, the energy storage device may only be needed [redacted] for an average discharge time of [redacted]. Due to this low frequency of usage, PacifiCorp believes that through pilot projects and optimization, this energy storage solution could meet many of the system needs above, providing benefits to all utility customers.[31]

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[29] For more detailed information regarding this need identification, please see "Draft Energy Storage Evaluation".
[30] See Appendix A and the "Final Energy Storage Potential Evaluation" for more detailed information.
[31] For more detailed information regarding these stacked benefits, refer to section 7.0 of the Final Energy Storage Potential Evaluation.

Technology

4.4.4 *A description of the technology necessary to construct, operate, and maintain the project, including a description of any data or communication system necessary to operate the project*

As previously described, upon receiving project approval from the Commission, PacifiCorp intends to issue an RFP for an Owners' Engineer to perform the detailed engineering analysis required for this project. The technology required for this proposed project must be capable of receiving, storing, and returning electrical energy to the grid and/or the customer. Based on PacifiCorp's benefits valuation, RFI results, and the proposed system size, a chemical battery is expected to the most appropriate storage technology that meets the project and company's needs, but PacifiCorp would not apply unnecessary restrictions in the EPC RFP.

When considering both PacifiCorp's Request for Information[32] (RFI) regarding energy storage results, completed July of 2017, and recent awards of contracts for similar projects listed in the DOE Global Energy Storage Database,[33] PacifiCorp anticipates that a lithium ion battery may prove to be the optimum chemistry for this project. Therefore, detailed project specifications used for scoping will be based on the use of lithium ion batteries.

However, PacifiCorp recognizes that both the technology and market conditions with regard to energy storage solutions are changing rapidly and, at the time of the RFP, will strongly encourage proposals for technologies other than lithium ion batteries with associated benefits. When the RFP is awarded, the most cost-effective packaged solution that clearly meets the objectives of the project will be selected.

As safety is a top priority at PacifiCorp, proposed solutions will be required to demonstrate high safety standards and comprehensive safety testing. Bidders will be expected to use prudent engineering judgement and follow guidance as described in the following documents to ensure all applicable safety codes and standards are followed.

- **Energy Storage Safety:** 2016 Guidelines developed by the Energy Storage Integration Council for Distribution-Connected Systems developed by the Electric Power Research Institute and Sandia National Laboratory
- **DOE OE Energy Storage Systems Safety Roadmap**: Focus on Codes and Standards developed by Pacific Northwest National Laboratory and Sandia National Laboratory

As previously discussed in Section 4.3, a requirement of bids associated with the RFP for EPC contractor will include submission of required maintenance activities and schedule with associated pricing over the life of the project. These requirements and costs remain conceptual to date and highly dependent on the technology selected, but will be a strong consideration during the bid evaluations.

PacifiCorp does not expect that this pilot project will require NERC (North American Electric Reliability Corporation)/CIPS security requirements. Planned communications via supervisory controls and data acquisition (SCADA) will meet MESA standards. As described in Section 4.3, PacifiCorp anticipates that this project will be capable of autonomous operations, storing operating data on site while exporting data and receiving commands through the company's existing energy management system (EMS). Commands to

[32] Included in Appendix A of the Final Energy Storage Potential Evaluation.
[33] www.energystorageexchange.org

the system may include but not be limited to switching and/or prioritizing among operating modes needed to support the multiple use cases identified for this project. During the detailed design of the project, specific hardware and software requirements will be identified.

Services

4.4.5 *A description of the types of services that the electric company expects the project to provide upon completion*

At a minimum, PacifiCorp expects that this pilot project will provide the following services upon completion:

- Monetary benefits calculated described in Section 7.0 of the Final Energy Storage Potential Evaluation document.
- Provide the opportunity to study ancillary services, validate current models through field data, and inform future energy storage evaluation.
- Provide the ability to test system integration including outage identification and dispatch management associated with energy storage solutions as distributed resources.
- Leverage programming and advance controls to co-optimize use cases.

Project Delivery Risks

4.4.6 *An analysis of the risk that the electric company will not be able to complete the project*

PacifiCorp has identified the following risks associated with this proposed pilot project delivery:

Location: The primary location identified was selected to maximize opportunities for stacked use cases, facilitate research opportunities, and ensure low cost electrical integration into the existing grid. While the preliminary screening is promising, a formal review must be conducted following the detailed engineering design per the proposed RFP. The results of the assessments below could preclude the energy storage device from being constructed at the primary location.

1. Foundation study to assess ability to support structures: Ensure the soil can support the physical structure to be installed.
2. Environmental/wetland review: Formal review of physical location including any restrictions due to wetland classification or environmental.
3. Zoning: Identify additional fencing, camouflage or other steps required to ensure zoning or historical code compliance.
4. Formal land lease agreement: Create mutually beneficial terms and conditions for land [redacted].

In recognition of how critical the physical location selection is in meeting the project objectives, collaborative reviews and site walk-throughs, including participation from both PacifiCorp [redacted], have already been conducted for multiple locations. Each location was evaluated based on established criteria and ranked. This analysis provides backup locations which can be leveraged to mitigate this project risk.

Research Partnership: The ability of PacifiCorp to leverage [redacted] to collaborate through research is a critical component to the evaluation and optimization of multiple use cases. While PacifiCorp could meet the minimum objectives of this project internally, the potential collaboration is key to maximizing the benefits of the project.

Labor and Resources*:* Internal resources required to complete this project may pull from existing resources dedicated to many other capital projects currently included in PacifiCorp's 10 year investment plan. While this is true with any new project, the uncertainty and experimental nature of a pilot project may require substantially more resources than initial planning could have identified. Therefore, PacifiCorp has taken a phased approach to the pilot project and included contingency in both the conceptual project schedule and budget. These plans will be reviewed quarterly and adjusted to mitigate this project delivery risk.

Technology Integration: As energy storage technology in constantly evolving and not yet widely used within the existing electrical network, PacifiCorp had identified the proper integration and control of energy storage solutions to be a potential risk to project delivery. Therefore, PacifiCorp is proposing a phased approach to mitigate this risk and take advantage of most up to date technology resources, and best practices throughout the pilot project.

4.5 Project Costs

The following subsections outline the anticipated costs for the Utility Owned Distribution Storage Pilot Project (Project #1). These calculations reflect PacifiCorp's best estimate given available data. However, PacifiCorp intends to revise these estimates through both the detailed engineering analysis and the RFP for EPC process as described in Section 4.3. Specific review points and additional approvals have been factored into the project schedule to ensure cost control and transparency.

Capital Cost

4.5.1 The estimated capital cost of the project

Consistent with the assumptions discussed in Section 6.0 of the Final Energy Storage Potential Evaluation, the following assumptions, sources, and ranges of values were used to calculate the capital cost for Pilot Project #1.

Table 12 Capital Cost Assumptions for Pilot Project #1

Capital Cost Parameter & Description	Source of Estimate	Low	Mid	High
Energy storage equipment cost ($/kWh) - Cost of Li-ion battery cells - Assembly cost for DC battery system	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$92	$154	$215
Balance of system for DC battery system ($/kW) - Power conversion equipment (inverter, packaging, container, and controls) - Control system - Other supporting equipment, such as thermal management, wiring and interconnection equipment, and protection of various components	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$257	$310	$362
EPC Cost ($/kWh) - All direct costs for development and project management, and costs associated with a fixed price, turn-key, EPC contract	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$150	$225	$300
Interconnection Application and Assumed Upgrades ($/project) - Interconnection studies costs owed to the transmission provider - Laydown area improvements and addition of distribution equipment	http://www.pacificorp.com/tran/ts/gip/qf/oregon.html	$449,300	$556,300	$663,300
Communications Upgrade ($/project) - Modifications to both the central service center and local communications devices	PacifiCorp estimate based on similar scale projects within the company	$17,000	$17,000	$17,000
Owner's Engineering PM ($/Project) - Owner's direct engineering & project management	PacifiCorp estimate based on similar scale projects within the company	$54,000	$57,000	$60,000

Given the above assumptions and the proposed preliminary sizing of Pilot Project #1, the table below includes the range for equivalent $/Watt and total cost of in-service capital.

Table 13 Pilot Project #1 Range of Capital Cost Estimates

	Equivalent $/Watt	Estimated In-Service Capital Cost ($)
Phase I (2MW x 3 hours)	$ 1.07 – $2.05	$2,140,000 - $4,100,000
Phase II (1MW x 1 hours)	$ 1.06 - $ 1.94	$ 1,060,000 - $2,000,000
Total	n/a	**$3,200,000 - $6,100,000**

Output Cost

4.5.2 *The estimated output cost of the project*

PacifiCorp assumes "output cost" means the total costs associated with operating the energy storage solution. The following assumptions were used to estimate the annual O&M associated with Pilot Project #1.

Table 14 Pilot Project #1 Cost Assumptions for O&M Calculations

Capital Cost Parameter & Description	**Source of Estimate**	**Low**	**Mid**	**High**
Fixed O&M Cost ($/kW-yr) - Maintenance and adjustment activities - Tightening of mechanical and electrical connections, cleaning, power stack and pump replacements, tightening of plumbing fixtures [not chemistry refresh]	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$6	$8.50	$11
Annual Monthly Inspection ($/yr) - Monthly inspection of location, equipment, fencing, etc	Typical range of annual inspection cost for PacifiCorp in Oregon service territory	$2,280	$2,778	$3,276

The following table summarizes the estimated O&M costs associated with Pilot Project #1.

Table 15 Pilot Project #1 Estimated O&M Summary

	Equivalent O&M ($/kW-yr)	Estimated Annual O&M ($)
Phase I	$0.08 - $0.14	$16,000 - $28,000
Phase II	$0.08 - $0.14	$8,000 - $14,000
TOTAL	n/a	$24,000 – $42,000

The results in this section represent PacifiCorp's best estimate given current available information regarding the potential capital and operating and maintaining costs for Pilot Project #1 as described in this proposal.

Grants Available

4.5.3 *The amount of grant moneys available to offset the cost of the project*

While no specific grants have been identified for this project at this time, PacifiCorp will continue to look for opportunities through organizations such as the Oregon Office of Emergency Management and to support both this project and [redacted] to leverage additional funding.

Proposed Cost Recovery

PacifiCorp proposes to implement a surcharge to contemporaneously recover the operating costs of the pilot program. The company further proposes to use a balancing account to track the actual costs and surcharge collections. A tariff advice filing will be made to implement this proposed surcharge at the completion of this proceeding, expected to be in the summer of 2018. PacifiCorp will review the balancing account periodically to determine if changes to the surcharge are necessary. The company proposes to provide annual reporting of the activity in the balancing account to provide an opportunity for prudency reviews of incurred costs.

4.6 Benefits

The following sub-sections outline the benefits associated with the Utility Owned Distribution Storage Pilot Project (Project #1).

4.6.1 Projected in-state benefits to the electric system

4.6.2 Projected regional benefits to the electric system

4.6.3 The potential benefits to the electric company's entire electric system if the electric company installs the energy storage system technology that is the basis for the project system-wide technology has widespread, or limited, applicability on the electric company's system. [STAFF CLARIFICATION: Our objective in this case is a high-level analysis of whether the proposed technology has widespread, or limited, applicability on the electric company's system. We recognize this cannot be calculated precisely but we ask for an order of magnitude estimate.]

The potential quantifiable benefits for Pilot Project #1 were calculated and included in Section 7.0 of the Final Energy Storage Potential Evaluation.[34] The table below summarizes these findings.

Table 16 Pilot Project #1 Range of Quantifiable Benefits

Use Case	Service	Base Case ($/kW-yr)	Technology Opt #1 2 hr ($/kW-yr)	Technology Opt #2 High Power ($/kW-yr)
Bulk Energy	Capacity or Resource Adequacy	$56.73	$37.82	$18.91
	Deferred resource lost benefits	($1.66)	($1.11)	($0.55)
	Energy Arbitrage (+Losses)	$1.74	$1.74	$1.64
Ancillary Services	Regulation	$60.61 *[EIM: $32.01 GRID: $28.60]*	$59.25 *[EIM: $30.65 GRID: $28.60]*	$56.71 *[EIM: $28.11 GRID: $28.60]*
	Load Following	-	-	-
	Spin/Non-spin Reserve	-	-	-
	Black Start Services	-	-	-
Trans Services	Transmission Upgrade Deferral	-	-	-
Dist Services	Distribution Upgrade Deferral	$9.87	$6.59	$3.30
Total ($/kW-yr)		**$127.29**	**$104.29**	**$80.00**

In addition to these quantifiable benefits, Pilot Project #1 provides the following benefits for both the company and customer:

- Opportunity for PacifiCorp to study ancillary services, validate current models and inform future energy storage evaluation.
- Ability to test system integration in preparation for future deployment, including outage identification and dispatch management associated with energy storage solutions as distributed resources.
- Leverage programming and advanced energy storage controls to co-optimize use cases.

[34] See the "Final Energy Storage Potential Evaluation"

- Provide additional customer benefits through research opportunities.
- Opportunity to update existing safe-work practices, hazard recognition, and company manuals regarding the operation and maintenance of energy storage solutions.

As previously described, this project involves improving reliability for a single customer while gaining experience with multiple use cases and energy storage control and operation. The lessons learned and optimization techniques identified as a result of this pilot project, will be used to inform potential future wide scale deployment within PacifiCorp's service territory. Additionally, these lessons learned will be shared across multiple business platforms within Berkshire Hathaway Energy (BHE) – Rocky Mountain Power, NV Energy, Northern PowerGrid and MidAmerican Energy Company. While each business platform operates under different market conditions and legislative requirements, PacifiCorp views the opportunity for collective learning as a system wide benefit.

Table 17 below summaries the benefits and whether or not each benefit has state, region, or system wide implications.

Table 17 Benefits Summary for Pilot Project #1

Benefit	In-State	Regional	System-Wide[35]
Potential benefits for all utility customers as calculated and described in the Final Energy Storage Potential Evaluation[36]	✓		✓
Specific Customer Benefits	✓		
Opportunity for PacifiCorp to study ancillary services	✓	✓	✓
Validation of current models to inform future energy storage evaluation	✓	✓	✓
Ability to test system integration in preparation for potential future deployment	✓	✓	✓
Leverage programming and advanced energy storage controls to co-optimize use cases	✓	✓	✓
Provide additional utility customer benefits through research opportunities	✓		
Enhanced safety policies and work practices regarding energy storage solutions	✓	✓	✓

In summary, Pilot Project #1 presents the least risk, lowest cost opportunity to pilot small scale energy storage in a location that provides great flexibility for the full range of use cases and maximizes learning opportunities for PacifiCorp in preparation for the future deployment of energy storage.

[35] All tangible costs and benefits associated with Pilot Project #1 are assumed to be allocated solely to Oregon customers.
[36] See Section 7.0 of the Final Energy Storage Potential Evaluation document.

4.7 Lifecycle Costs

Consistent with the assumptions discussed in Section 6.0 of the Final Energy Storage Potential Evaluation, the following assumptions, sources, and ranges of values were used to calculate the full range of potential costs associated with Pilot Project #1.

Table 18 Cost Components and Estimates for Pilot Project #1

	Cost Parameter & Description	Source of Estimate	Low	Mid	High
Capital In-Service Cost Components	Energy storage equipment cost ($/kWh) - Cost of Li-ion battery cells - Assembly cost for DC battery system	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$92	$154	$215
	Balance of system for DC battery system ($/kW) - Power conversion equipment (inverter, packaging, container, and controls) - Control system - Other supporting equipment, such as thermal management, wiring and interconnection equipment, and protection of various components	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$257	$310	$362
	EPC Cost ($/kWh) - All direct costs for development and project management, and costs associated with a fixed price, turn-key, EPC contract	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$150	$225	$300
	Interconnection Application and Assumed Upgrades ($/project) - Interconnection studies costs owed to the transmission provider - Laydown area improvements and addition of distribution equipment	http://www.pacificorp.com/tran/ts/gip/qf/oregon.html	$449,300	$556,300	$663,300
	Communications Upgrade ($/project) - Modifications to both the central service center and local communications devices	PacifiCorp estimate based on similar projects within the company	$17,000	$17,000	$17,000
	Owner's Engineering PM ($/Project) - Owner's direct engineering & project management	PacifiCorp estimate based on similar scale projects within the company	$54,000	$57,000	$60,000
O&M Cost Components	Fixed O&M Cost ($/kW-yr) - Maintenance and adjustment activities - Tightening of mechanical and electrical connections, cleaning, power stack and pump replacements, tightening of plumbing fixtures [not chemistry refresh]	Cost update to the Battery Energy Storage Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$6	$8.50	$11
	Annual Monthly Inspection ($/yr) - Monthly inspection of location, equipment, fencing, etc	Typical range of inspection cost for PacifiCorp OR territory	$2,280	$2,778	$3,276
	Land Lease Estimated Spend ($/yr) - Annual spend to lease land for energy storage solutions	Estimated from comparables for given size and geographic region.	$3,525	$6,010	$9,018

An overall summary of both capital and O&M costs associated with Pilot Project Phase I have been included in Table 19.

Table 19 Pilot Project #1 Total Cost Analysis Summary

Cost Component	Estimated Value/Range
Estimated In-Service Capital Cost ($/Watt)	$ 1.07 – $2.05 *[$0.33 - $0.62 /Watt for system integration]*
Estimated In-Service Capital Cost ($)	$2,140,000 - $4,100,000 *[$660,000 – $1,240,000 for system integration]*
Estimated Total O&M ($/kW-yr)	$0.08 - $0.14
Present Value of All Costs ($)	($4,678,060) - ($8,872,025)

The results in this section represent PacifiCorp's best estimate at the time of this submission regarding the potential capital and operating and maintaining costs over the lift of Pilot Project #1 as described in this proposal.

Following project approval, PacifiCorp intends to hire an Owner' Engineer to perform a more detailed technical analysis and identify the optimum sizing for Pilot Project #1. PacifiCorp anticipates that this will be completed in May of 2019. At that time, PacifiCorp intends to review any significant changes to either the sizing, costs, or benefit-to-cost analysis with the Commission, and seek additional approval to progress the project.

4.8 Lifetime Project Risks

PacifiCorp has identified the following lifetime project risks associated with this proposed pilot project:

Physical Damage to Equipment: PacifiCorp recognizes that damage to the energy storage device may occur over the life of the project due to both environmental exposure and operator error. These unexpected costs potentially reduce both the benefits realized and the cost effectiveness of the project. PacifiCorp intends to strictly follow the maintenance procedures per manufacturer recommendations and limit operation of the technology to qualified personnel to reduce this risk and maximize benefits.

Supplier Diversity: With certain technologies (such as zinc air) all equipment, repair parts, and labor can only be provided by a singular contractor. While this may be acceptable in present day, this poses a lifetime project risk as equipment or services required for mid-project repairs may be too costly or impossible. Due to the regulated nature of the electric utility business, PacifiCorp intends to consider this impact during the selection of technology for proposed Pilot Project #1.

Decommissioning: As critical in evaluating any project, decommissioning requirements must be understood up front in order to select the least cost lowest risk solution. As many energy storage solutions include the use of chemical batteries, PacifiCorp intends to include this in the future RFP and require all potential bidders to provide decommissioning and disposal requirements in subsequent proposal submissions. While these requirements will be current upon submission, environmental rules and regulations are always subject to change. PacifiCorp intends to stay current with any pertaining rule changes, and plans to identify impacts to existing and future energy storage projects.

Technology Degradation: The performance characteristics of storage technology can be significantly influenced by degradation, which is a function of system operation, environmental exposure, type of application, and frequency of use. As discussed in DNV GL's report[37], unexpected temperature fluctuations, improper maintenance, and higher or lower average states of charge can result in sub-standard performance of the storage device. While some of these factors for degradation can be mitigated, PacifiCorp recognizes that degradation may still occur, and should be considered in the technical scoping and ultimate selection of the energy storage technology.

Technology Life Cycle: Most energy storage systems have not been available at a commercially mature stage for long enough to provide meaningful field data on lifetime performance. The expected life of each technology is currently provided by vendor projections based on standard cycling, limited exposure to extenuating circumstance, and accelerated life-testing. While a great representation for the average project, these projections may not be specific to the pilot project proposed and will be applied cautiously.

Long Term Ownership Model: Currently, PacifiCorp owns and maintains the electrical network [redacted]. This provides for a very simple ownership and operation model for both the integration and execution of this pilot project. However, should this agreement change, the project would begin to involve shared assets between both PacifiCorp and the specific customer. PacifiCorp has identified this as a future risk, and will incorporate this into any future contract negotiations or agreements.

[37] See DNV GL Document # 128197#-P-01-A, "Battery Energy Storage Study for the 2017 IRP" PG 11-12

4.9 Benefits Summary

Comprehensive assessment of all quantitative and qualitative benefits to the electric system and all customers over the life of the project. Assessment of larger societal benefits, where applicable, is encouraged but those assessments will not be incorporated into the cost-effectiveness calculation of the proposals [STAFF CLARIFICATION: We encourage utilities to identify and attempt to quantify all potential benefits—system or societal—from a project and include this analysis in project proposals. However, we resolve that in this context the focus is properly on the benefits that accrue to the electric system and all utility customers from the project. This is consistent with the language of HB 2193, which asks electric companies to analyze in their proposals the benefits of each project to the electric company's electric system including in-state and regional benefits and the potential benefits of installing the technology system-wide.]

In addition to the in-state, regional, and system wide benefits outlined in Section 4.6, the company has also identified the following large scale societal benefits associated with this pilot project:

Carbon Reduction: To the extent that wide scale deployment of energy storage solutions enable greater reliance on renewable and zero-emitting resources that displace fossil resources, such initiatives could support existing initiatives and programs to reduce carbon emissions as reflected in the preferred portfolio of the 2017 IRP.

"The 2017 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO2) emissions. PacifiCorp's emissions have been declining and continue to decline as a result of a number of factors, including PacifiCorp's participation in the Energy Imbalance Market (EIM), which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going expansion of renewable resources and transmission; and Regional Haze compliance that capitalizes on flexibility. The Figure below compares projected annual CO2 emissions between the 2017 IRP and 2015 IRP preferred portfolios. Over the first 10 years of the planning horizon, average annual CO2 emissions are down by over 10.5 million tons (21 percent) relative to the 2015 IRP. By the end of the planning horizon, system CO2 emissions are projected to fall from 43.8 million tons in 2017 to 33.1 million tons in 2036—a 24.5 percent reduction." [38]

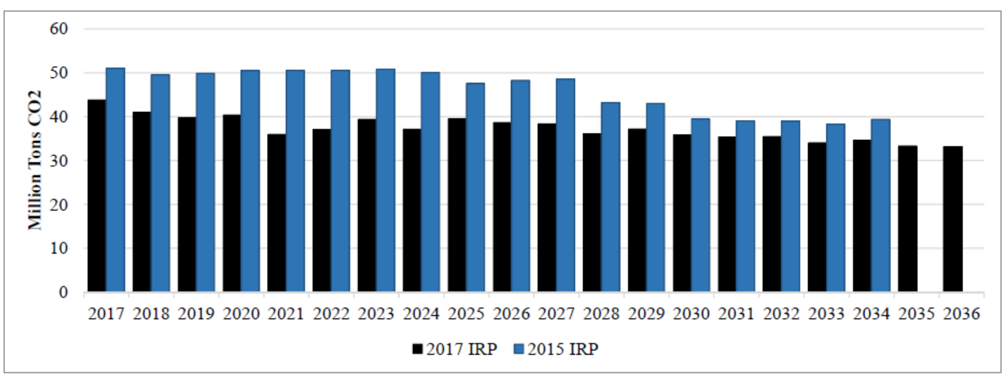

Figure 8 Comparison of CO2 Emission Forecasts between the 2017 and 2015 IRP Preferred Portfolio

[38] PacifiCorp 2017 IRP Volume I Chapter 8 PG 242-243

4.10 Benefit Methodology

Description of methodology for assessing projects benefits, including aggregation of benefits [STAFF CLARIFICATION: We encourage utilities to identify and attempt to quantify all potential benefits—system or societal—from a project and include this analysis in project proposals. However, we resolve that in this context the focus is properly on the benefits that accrue to the electric system and all utility customers from the project. This is consistent with the language of HB 2193, which asks electric companies to analyze in their proposals the benefits of each project to the electric company's electric system including in-state and regional benefits and the potential benefits of installing the technology system-wide.

Benefits for Pilot Project #1 are discussed in sections 4.6 and 4.9 above. The methodology for calculating benefits associated with Pilot Project #1 is included in the Final Energy Storage Potential Evaluation.

4.11 Cost Effectiveness

Cost-effectiveness of the energy storage system including benefit-cost ratios and net present value revenue requirements over the energy storage system lifetime, and all underlying inputs and assumptions used in the calculation

PacifiCorp leveraged the methodology and inputs included in Section 6.0 of the Final Energy Storage Potential Evaluation.

The following table summarizes the costs, as described in Section 4.5 above, the benefits, as calculated in Section 7.0 of the Final Storage Potential Evaluation, the net present value revenue requirement, and the range of benefit-to cost ratios for Pilot Project #1.

Table 20 Cost Effectiveness Summary for Pilot Project #1

	Pilot Project #1 Base Case	2 Hours of Storage	High Power
Present Value of Benefits ($)	$2,382,980	$2,928,720	$4,493,336
Present Value of Costs ($)	$4,678,060 - $8,965,966	$3,808,381 - $7,018,646	$6,786,542 - $12,159,976
BCR Range	0.27 - 0.51	0.42 - 0.77	0.37 - 0.66
NPV ($) *Revenue Requirement*	($2,295,080) – ($6,582,986)	($874,661) – ($4,089,926)	($2,293,207) – ($7,666,640)

PacifiCorp elected to select the base case for preliminary sizing as it meets the minimum threshold of 5 MWh as set forth by HB 2193, accommodates the historic outage characterization on the feeder, and presents the lowest risk option given the information available to PacifiCorp at this time.[39]

These calculations reflect PacifiCorp's best estimate given available data. However, PacifiCorp intends to revise these estimates through both the detailed engineering analysis and the RFP for EPC process as described in Section 4.3. Specific review points and additional approval points have been factored into the project schedule to ensure cost control and transparency.

As described in Section 4.1, PacifiCorp is proposing a BCR requirement of 1.0 or greater to progress Phase II of Pilot Project #1. PacifiCorp intends to revisit the final sizing and cost-effectiveness of Phase II project with the Commission, following the successful deployment of Phase I. PacifiCorp anticipated this will occur in May of 2021.

[39] See Section 7.0 of the Final Storage Potential Evaluation for more information.

5.0 Project #2 – Community Resiliency Pilot Project

Since 2016, PacifiCorp has been an active participant in the City of Portland's Renewable Resilient Power for Portland (R2P2)[40] working group. With an ultimate goal of improving resiliency in local communities, R2P2 intends to design a replicable, neighborhood-scale planning process for the identification and prioritization of sites for solar plus energy storage systems that can assist communities during potential long-term power outages caused by natural disasters, such as a Cascadia Subduction Zone earthquake. Since the Company's active participation and involvement in R2P2, PacifiCorp has begun actively working with other communities who have an interest in how energy storage can support community resiliency in the event of a catastrophic event. The proposed Community Resiliency Pilot will support continuing these efforts in two primary ways:

(1) **Technical Assistance Concept:** PacifiCorp will hire an expert consultant to provide limited on-site technical assistance and engineering analysis to select facilities critical for emergency response or disaster recovery that are interested in resiliency-focused energy storage projects. The selected consultant will assist in designing the minimum requirements for an applicant to be considered for technical assistance support, and determining the criteria that will be used to select participants if demand exceeds available funding.

(2) **Project Development Funding Concept:** PacifiCorp will provide financial assistance for up to 4 energy storage installation projects that will further support community resiliency while also providing benefits to the utility system. The selected consultant will assist in designing the minimum requirements for an applicant to be considered for project development funding, and to determining the criteria that will be used to select participants if demand exceeds available funding.

Objectives

Through the proposed Community Resiliency Pilot, PacifiCorp intends to achieve the following objectives:

- Identify how to implement a customer-sited energy storage program and how to access energy storage utility benefits while ensuring the storage system is available during emergencies for the host customer and the community.
- Gain experience interfacing with and controlling customer-sited energy storage systems.
- Develop communication systems and operational framework for utility control of customer-sited equipment.
- Identify market barriers, solutions, and additional value streams of energy storage in non-emergency situations.
- Develop methodologies for balancing the benefits of customer-sited equipment between the host and other utility customers.
- Strengthen existing community connections through active participation in local disaster preparedness planning.
- Understand the effectiveness of sponsored technical assistance grants to inform and motivate customers on energy storage.
- Evaluate and identify cost effective, viable energy storage applications that will inform PacifiCorp's potential future energy storage initiatives.

[40] https://rmi.org/our-work/electricity/elab-electricity-innovation-lab/elab-accelerator/elab-accelerator-2017-teams-r2p2/

Key Attributes

The key attributes of the proposed pilot project concepts are included in Table 21 below.

Table 21 Pilot Project #2 Key Attributes

Attribute	Description
Pilot Concepts	1) Technical Assistance: between 10-20 facilities critical to emergency response or disaster recovery 2) Project Development Funding: Up to 4 projects
Sizing	1 MW/4 MWh combined (estimated)
Primary Location	PacifiCorp Oregon service territory – locations to be determined through a competitive selection process
Primary Use Case[41]	Resiliency during a long term power outage
Secondary Use Case(s)	Grid Services: Capacity, Energy Arbitrage, Voltage Support, Volt-Var Control, and Load Following Specific Customer: Reliability, Demand Charge Reduction, Time-of-use Charge Reduction
Estimated Utility Pilot Costs	$1.8 million over 8 years

Estimated Timeline

The following chart describes the proposed timeline for the Pilot Project #2 and is subject to change.

Table 22 Project #2 Estimated Timeline

Milestone	Date
Commission Approval of Pilot Project[42]	June 2018
Issue RFP for Technical Assistance Concept consultant – Award contingent on Commission approval of the pilot	August 2018
Open the Technical Assistance Concept to potential participants	Dec 2018
Select Initial Technical Assistance Concept Recipients	Feb 2019
Complete Technical Assistance Assessments and Final Report	Dec 2019
Open Project Development Funding process to potential participants	Q1 2020
Award Project Development Funding Concept grant (Complete Final Sizing)	**Q2 2020**
Begin Construction of Funded Projects	Q1 2021
Estimated In-Service Date	Q4 2022
Five years of analysis and review of installed projects	Q4 2026

The following subsections include detailed information regarding PacifiCorp's Community Resiliency Pilot Project per HB 2193 and Order No. 16-504.

[41] Primary and secondary use cases as determined by the energy storage evaluation.
[42] PacifiCorp built the potential project schedule to illustrate potential delivery dates. This proposed timeline is an initial look and subject to change as we work though the proceeding with staff.

5.1 Comprehensive Proposed Project Description

This section summarizes PacifiCorp's proposed Community Resiliency Pilot Project to expand upon its existing understanding of energy storage within Oregon communities and facilitate the exploration of the available technologies to address resiliency needs of specific facilities critical to emergency response or disaster recovery, while allowing PacifiCorp to learn about customer-sited energy storage technologies, costs, benefits, use cases, and feasibility. As previously stated, this pilot consists of two concepts: (1) Technical Assistance and (2) Project Development Funding, with an approximate total budget of $1.8 million in investment over an 8 year period.

Technical Assistance Concept

Description

The proposed technical assistance concept services will provide on-site technical support and limited customized engineering analysis to help explore energy storage solutions for facilities critical to emergency response or disaster recovery. Selected facilities will receive a customized report and a set of site-specific recommendations regarding the installation of an energy storage systems (focused on local support during times of an extended outage), while allowing PacifiCorp to learn about customer-sited energy storage technologies, costs, benefits, use cases, and feasibility, for a small number of sites.

PacifiCorp and a technical consultant will work directly with selected facilities and be responsible for the following:

- Assisting in designing the minimum requirements for an applicant to be considered for technical assistance support, and to determine the criteria that will be used to select participants if demand exceeds available funding.
- Conducting engineering analysis used to determine the costs and suitability of installing energy storage technologies at a specific location.[43]
- Documenting, through a transparent methodology, the recommended technologies, locations, and applications for a project.
- Providing on-site technical assistance for community emergency response or disaster recovery organizations that will identify critical needs during resiliency events, develop operations plans for resiliency events that coordinate the use of storage with onsite renewable generation and/or back up diesel generation.
- Scoping operations and maintenance impacts caused by the installation of storage, and provide the size and operating characteristics of the storage equipment.
- Creating a project report for each site, addressing factors such as project cost, development timeline, use cases, benefits, provide an assessment of the costs and benefits of non-resiliency operation.
- Compiling results and findings from the individual assessment analysis reports and provide PacifiCorp with a summary report that will inform future programs and projects. The report will seek to:
    - Understand the diversity in customer-sited energy storage system costs, performance and likely use cases across different types of facilities.
    - Inform PacifiCorp's strategies for increasing community resiliency.
    - Based on the results of the technical analysis provide support in the development of an evaluation plan and scoring criteria for the Project Development Funding Concept.

Duration: PacifiCorp is proposing a two year pilot program for the Technical Assistance Concept. PacifiCorp intends to encourage geographic diversity, while initially seeking to award funding to facilities in communities in multiple regions throughout the state. However, site selection will ultimately depend on factors such as community interest.

[43] This will directly correlate to the legislative requirements per HB 2193 and Order No. 17-504.

Approximate Budget: $500,000

Eligibility: Facilities critical to emergency response or disaster recovery in PacifiCorp's Oregon service territory. [44]

Funding level: Up to 100 percent of consultant expenses

Eligible expenses: Design such as site suitability, preliminary engineering design, coordination with on-site renewable generation and/or back-up generation, development of standard operational procedures, identification of critical needs during resiliency events, development of resiliency event operation plans, identification of installation funding sources and development of project budgets.

Outcome: Fund approximately 10 to 20 studies for PacifiCorp communities in Oregon. Compile analysis and findings to inform future programs and projects.

Use Cases

Resiliency and Shared Use Case Opportunity Identification: The technical assistance will not necessarily result in the actual installation of energy storage; however, it is PacifiCorp's intent that the technical analysis will facilitate the future development of energy storage throughout the state of Oregon.

Learning Objectives

- Identify market barriers, solutions, and additional value streams of energy storage in non-emergency situations.
- Identify how to implement a customer-sited energy storage program and how to access energy storage benefits for the utility system while ensuring the storage system is available during emergencies.
- Understand the effectiveness of technical assistance grants to inform customers and encourage the implementation of energy storage systems.
- Evaluate and measure the benefits, costs, use cases and applications of potential customer site specific projects.
- Evaluate and identify potential cost effective, viable energy storage applications that will inform PacifiCorp's future energy storage initiatives.

Application Evaluation and Selection

PacifiCorp will hire a third party technical consultant for Phase 1 of Project #2 who will assist in designing the minimum requirements for an applicant to be considered for technical assistance support, and to determine the criteria that will be used to select participants if demand exceeds available funding. PacifiCorp anticipates that the participation threshold and selection process will at a minimum consider the following criteria:

[44] For examples see: Federal Emergency Management Administration Fact Sheet, "Critical Facilities and Higher Standards." Available at: https://www.fema.gov/media-library-data/1436818953164-4f8f6fc191d26a924f67911c5eaa6848/FPM_1_Page_CriticalFacilities.pdf:

Table 23 Potential Technical Assistance Applicant Evaluation Criteria

Criteria	Measures
Project Feasibility/ Utilization	• Readiness of the project team. • Willingness to participate in shared-benefit storage tests.
Use of Funds	• Willingness of project team to develop a potential budget proposal that includes customer and/or third party funding for the installation of energy storage, if feasible.
Innovation	• Willingness to incorporate emerging technologies, such as renewable generation. • Creative project design, partnerships and utilization of resources, particularly in serving underserved populations. • Ability to incorporate potential future distributed energy resources in the project design (e.g., demand response).
Data availability	• Willingness to allow PacifiCorp's technical consultant to collect and analyze data.
Community benefits	• Expectation that the project will have a positive impact on community resiliency. • The extent to which the project is incorporated in the formal community resiliency planning.

Project Development Funding Concept

Description

In addition to providing technical assistance, PacifiCorp will identify and fund approximately 2-4 projects that provide the company the greatest opportunity to learn how to leverage community resiliency with utility benefits. Grant funding will aim to supplement available funding from other sources, if available.

The Project Development Funding Concept will provide an opportunity for PacifiCorp to develop and test tools to work with customer owned equipment. Initially, PacifiCorp will seek to fund projects that can be integrated into a company controlled energy management system (EMS).[45] Through the EMS, PacifiCorp will attempt to maximize the benefit of the energy storage for the utility system, while always leaving an operating reserve for the host customer during a resiliency event. During normal operations, PacifiCorp anticipates testing different utility benefit use cases either through the individual storage unit or potentially in aggregate with other systems. The specifics of how the energy storage capabilities will be shared have not been determined and will be informed by the Technical Assistance Concept.

Duration: Seven year pilot project with up to five years of evaluation.[46]

Budget: up to $1 million

Project Total: 2-4 projects with combined estimated total capacity of up to 1 MW, or 4 MWh

Eligibility: Facilities critical to emergency response or disaster recovery in PacifiCorp's Oregon service territory.[47]

Funding level: Up to 100 percent of eligible expenses, but applicants are encouraged to leverage additional funding sources.

Eligible expenses: Expenses directly associated with the installation of energy storage infrastructure.

Use Cases

The following use cases have been identified for this pilot project:

- **Primary:** Generation Capacity, Ancillary Services
- **Secondary:** Resiliency, Customer Energy Management Services such as Demand Charge Reduction, Time-of-use Charge Reduction

[45] See Figure 3 in Section 4.3 for more information regarding this planned integration.
[46] Duration to include procurement, installation, commissioning and up to 5 years of operation and study.
[47] For examples see: Federal Emergency Management Administration Fact Sheet, *Critical Facilities and Higher Standards*. Available at: https://www.fema.gov/media-library-data/1436818953164-4f8f6fc191d26a924f67911c5eaa6848/FPM_1_Page_CriticalFacilities.pdf.

Learning Objectives

- Identify how to implement a customer-sited energy storage program and how to access energy storage benefits for the utility system while ensuring the storage system is available during emergencies.
- Gain experience interfacing with and/or controlling customer-sited energy storage systems.
- Develop communication systems and operational frameworks for utility control of customer-sited equipment.
- Develop methodologies for balancing the benefits of customer-sited equipment between the host customer and other utility customers.

Application Evaluation and Selection

PacifiCorp will hire a third party consultant for Phase 2 of Project #2, who will assist in developing the minimum requirements needed for application evaluation and selection criteria. In addition, the Technical Assistance Concept phase will inform the evaluation and selection process and the final screening criteria and weighting. To ensure PacifiCorp targets feasible energy storage projects, the PacifiCorp anticipates that the evaluation and selection process will at a minimum consider the following criteria:

Table 24 Potential Applicant Evaluation Criteria

Criteria	Measures
Project Feasibility/ Utilization	• Readiness of the project team and reasonableness of the project plan and timeline. • Technical study results, including compliance with national, state and local permitting requirements. • Expectation that the project will have a positive impact on community resiliency. • Project life (as reported by the applicant) and robustness of the ongoing operations and maintenance plan. • Plan to address interoperability of PacifiCorp's systems such as Energy Management System (e.g. capabilities to interact with AMI when installed). • Willingness to participate in shared-benefit storage tests. • Ability for proposed storage system to operate in a coordination with onsite generating resources to enhance customer resiliency
Use of Funds	• Applicant financial commitment and willingness to leverage funds from other sources. • Alignment of project costs with industry standards. • Reasonableness of the proposed budget (i.e., risk of exceeding budget). • How the project is designed to avoid risk of stranded investments. • Applicant and project need for funding support.
Innovation	• Incorporation of emerging technologies, such as renewable generation. • Creative project design, partnerships and utilization of resources, particularly in serving underserved populations. • Understanding if energy storage technology can assist PacifiCorp with its Targeted Communities Pilot that seeks to assess non-wires alternatives.
Data availability	• Type(s) of data available through the project. • Plan to collect and analyze data. • Mechanism(s) to share data with PacifiCorp. • Ability to incorporate potential future electric grid benefits (e.g., demand response).
Community benefits	• Impact of the applicant on the community. • The extent to which the Project is incorporated in the formal community resiliency planning.

5.2 Justification

This pilot will inform PacifiCorp and its customers on how to implement new behind-the-meter energy storage infrastructure. The intent of the pilot is to support communities during a long-term outage, providing power to critical facilities, vital communications equipment, or other critical infrastructure which will assist in restoration efforts.

While promoting community resiliency is the primary objective of this pilot, the pilot also provides PacifiCorp an opportunity to gain experience with controlling, aggregating, and utilizing customer-sited energy storage to benefit the electrical system. Understanding how customer-sited energy storage can be operationally maximized and controlled will enhance PacifiCorp's ability to include energy storage in future distributed energy resource planning.

5.3 Plan for constructing, maintaining, and operating

PacifiCorp will provide technical support through the Technical Assistance Concept process that will assist the company and its customers in understanding site-specific construction, maintenance and operation of customer-sited energy storage systems. In addition, PacifiCorp's Oregon customers that receive technical assistance will be encouraged to apply for the Project Development Funding Grant.

Facilities requesting grant funding through the Project Development Funding Grant will be required to provide a construction, maintenance, and operations plan. The robustness and thoughtfulness of this plan will be a key criteria for project selection.

5.4 Technical Specifications

As previously discussed, the Technical Assistance Concept will provide technical analysis and on-site support to facilities regarding the selection and implementation of energy storage systems for local resiliency. This analysis and final report will include the technical specifications for an energy storage system and follow the requirements of the legislation per HB 2193 and Order No. 16-504 as specified below. Please refer to Appendix E and H for specific details.

Capacity and Sizing

5.4.1 *The capacity of the project to store energy including both the amount of energy the project can store and the rate at which it can respond, charge, and discharge as well as any other operational characteristics needed to assess the benefits of the energy storage system*

Research indicates that there is significant diversity in the capacity characteristics of energy storage systems installed where resiliency is identified as a significant driver of the installation. In the United States there are currently 26 operational resiliency storage projects ranging in size from 5 kW to 30 MW of capacity. Eliminating the 30 MW project as an outlier, the average storage system size of projects currently installed in the United States for resiliency is 536 kW. This suggests that 1 MW of program capacity would allow the installation of two average resiliency projects. While this information provides perspective, the actual projects and their corresponding capacity will be determined by the site-specific analysis provided for selected projects.

PacifiCorp intends to encourage grant applicants to size systems based on the primary objective of improving resiliency during a long-term outage caused by an emergency situation or natural disaster. PacifiCorp expects that customer preference will dictate the specific characteristics of the energy storage system (e.g. capacity, size, and configuration) driven by costs, load profiles, identification of critical loads, and future planned use of the system. For example, a customer may choose a high power, low energy storage solution, as dictated by short duration, high peak load needs. Conversely, a different customer who requires lower peak loading for longer durations may chose a high energy, low power storage solution.

PacifiCorp proposes to leverage the detailed analysis completed through the Technical Assistance Concept to determine what sizing and which customer sites have benefit for all utility customers. PacifiCorp anticipates completing this analysis in December of 2019.

Additional considerations will include integration with existing or future on-site generation, dictating whether or not the energy storage system will be in a direct current (DC) or alternating current (AC) coupled configuration and require associated grid-tier inverters. See Figure 9 below.[48]

[48] National Renewable Energy Laboratory's Installed Cost Benchmarks and Deployed Barriers for Residential Solar Photovoltaics with Energy Storage: Q1 2016, which can be found at https://www.nrel.gov/docs/fy17osti/67474.pdf.

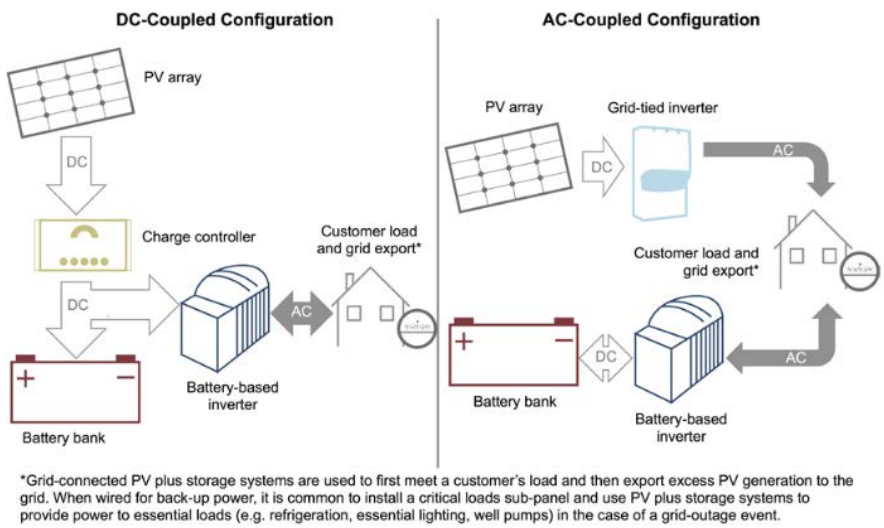

Figure 9 DC vs AC Coupled Configuration

Location

5.4.2 *Project Location*

PacifiCorp hopes to fund projects across a diverse set of communities (e.g., small/large, rural/urban) and facilities (e.g., hospital, schools, recreation centers) to enhance the value and applicability of data gathered for potential future programs, however, site selection will ultimately depend on numerous factors such as the support of public partners.

System Needs and Applications

5.4.3 *A description of the electric company's electric system needs and the application that the energy storage system will fulfill as the basis for the project*

As previously described, the primary objective of this pilot project is to provide resiliency for local communities in Oregon**.** However, PacifiCorp is also interested in understanding how additional use cases can bring value to the electrical system without compromising the system's ability to perform during critical times.

Technology

5.4.4 *A description of the technology necessary to construct, operate, and maintain the project, including a description of any data or communication system necessary to operate the project*

Lithium ion battery technology is currently the fastest growing market segment for stationary storage applications.[49] It has been deployed in a wide range of utility energy-storage applications, ranging from a few kilowatt-hours in residential systems with rooftop photovoltaic arrays to multi-megawatt containerized batteries for the provision of grid ancillary services.[50] While any feasible energy storage technology will be eligible for funding, based on current market conditions, PacifiCorp anticipates that the majority of energy storage projects installed through the Project Development Funding Concept will be lithium ion battery storage.

Services

5.4.5 *A description of the types of services that the electric company expects the project to provide upon completion*

At a minimum, PacifiCorp expects funded projects that provide resiliency benefits. However, PacifiCorp understands that energy storage is capable of providing numerous services. Based on data from the DOE Global Energy Storage Database (DOE Database), the top 10 specific use cases are as follows:

1. Electric Bill Management
2. Electric Energy Time Shift
3. Renewables Capacity Firming
4. Electric Bill Management with Renewables
5. Renewables Energy Time Shift
6. Onsite Renewable Generation Shifting
7. Grid-Connected Residential (Reliability)
8. Resiliency
9. Grid-Connected Commercial (Reliability & Quality)
10. Electric Supply Capacity

The top 10 use cases identified above were mapped to five use cases and services from Order No. 17-118 and are listed below:

- Time-of-Use Charge Reduction
- Energy Arbitrage
- Capacity or Resource Adequacy
- Power Reliability
- Outage Mitigation

[49] Energy Storage Study 2014 for the Interlock Irrigation District, Willie G. Manuel, available at: http://www.energy.ca.gov/assessments/ab2514_reports/Turlock_Irrigation_District/2014-10-28_Turlock_Irrigation_District_Energy_Storage_Study.pdf

[50] *Id.*

Project Delivery Risks

5.4.6 *An analysis of the risk that the electric company will not be able to complete the project*

PacifiCorp has identified the following risks associated with this proposed pilot project delivery:

Permitting: As energy storage technology matures, so do regulations. PacifiCorp is committed to compliance with local and federal safety and environmental codes. Dependent on the specified technology, the final projects could require other changes within the facility to ensure public safety, such as fire safety or environmental compliance. PacifiCorp recognizes this may result in the exclusion of certain technologies or locations in the project development to reduce this risk.

Funding: As with any project, execution relies on adequate funding. Pacific Power intends the project sponsor to leverage additional funding sources for the development of the storage facilities. During the selection process Pacific Power will evaluate the amount and the reliability of the sources of the funding the applicant proposes to provide for the project.

Ownership Model: In accordance with the structure of this pilot project, PacifiCorp anticipates customers will own and maintain the energy storage device, and PacifiCorp will operate the energy storage system to maximize host and system benefits. As this relies on the willingness of customers to assume responsibility and risk, the technical assessment will include a prescriptive maintenance procedure, hazard assessment, and operations guidelines for the full life of the equipment.

Technology Integration: As behind the meter energy storage solutions remain a fairly new concept, understanding the challenges of properly integrating storage into the existing grid and network is a work in progress, complicated by the fact that the storage market is rapidly evolving. PacifiCorp has, therefore, taken a phased approach to this project appropriately leveraging current technology and best practices, while being flexible and understanding that use cases and operating characteristics may change over the duration of the program.

Market Changes: As energy storage evolves in both the electric utility industry and other markets, PacifiCorp anticipates that prices and availability may fluctuate, resulting in potential changes to budgets and cost-effectiveness of projects selected to participate. Should actual installation costs rise unexpectedly, PacifiCorp will work with the host customer to evaluate the continued viability of the project and may need to reevaluate project selection or design to reflect the higher costs.

PacifiCorp plans on mitigating the risk of equipment obsolescence and potential stranded investments, by encouraging the host customer to use commercially proven technologies with sufficient performance warranties and control software that conforms to the emerging MESA standards, minimizing the risk that these installations are unable to perform the primary resiliency function will be limited.

5.5 Project Costs

The estimated cost during the pilot period is $1.8 million, as shown in Table 11. PacifiCorp anticipates that roughly 80 percent of pilot funds will go directly to customers through technical assistance and project development grants, with other pilot funds dedicated to program administration, evaluation and outreach. Actual funding levels will be driven by customer demand, project viability and requested financial commitment by the applicant. If funds remain un-awarded at the end of the pilot period, PacifiCorp will either propose to the Commission to use them for a different storage program or return them to customers. The 2018 budget reflects a lower relative funding level due to expected program approval and implementation timelines. See Table 25 below.

Table 25 Estimated In-Service Capital Cost for Community Resiliency Pilot Project

Task	2018	2019	2020	2021	2022-2026	Total
Technical Assistance Concept Pilot	$100,000	$300,000	$100,000	-	-	$500,000
Project Development Concept Pilot	-	-	$200,000	$700,000	$100,000 in 2022	$1,000,000
Program Administration	$50,000	$50,000	$50,000	$50,000	$20,000 per Year	$300,000
Total Estimated Costs	$150,000	$350,000	$350,000	$750,000	$200,000	**$1,800,000**

Capital Cost

5.5.1 The estimated capital cost of the project

This project does not include any PacifiCorp capital investment.

Output Cost

5.5.2 *The estimated output cost of the project*

The Technical Assistance Concept analysis will conduct a cost evaluation, which will include estimated output costs. The Project Development Funding Concept will require an in-depth budget that will outline output costs. Output costs will be calculated in a similar manner as described for Project #1.

Grants Available

5.5.3 *The amount of grant moneys available to offset the cost of the project*

Applicants may request up to 100 percent of eligible expenses, but are encouraged to explore additional funding opportunities to maximize the value of PacifiCorp's investment. Evaluation metrics will favor applicants providing a funding match and leveraging multiple partners and funding sources. Participants will be responsible for all project costs not explicitly included in the project funding agreement. While no additional specific grants have been identified at this time, applicants are encouraged to seek funding through organizations such as the Federal Emergency Management Administration, the Oregon Office of Emergency Management, the U.S. Department of Energy, and Energy Trust of Oregon to support the installation of the projects.

Proposed Cost Recovery

PacifiCorp proposes to implement a surcharge to contemporaneously recover the operating costs of the pilot program. The company further proposes to use a balancing account to track the actual costs and surcharge collections. A tariff advice filing will be made to implement this proposed surcharge at the completion of this proceeding, expected to be in the summer of 2018. PacifiCorp will review the balancing account periodically to determine if changes to the surcharge are necessary. The company proposes to provide annual reporting of the activity in the balancing account to provide an opportunity for prudency reviews of incurred costs.

5.6 Benefits

This section describes the in-state benefits, regional benefits, and high-level benefits to PacifiCorp's entire electric system associated with Pilot Project #2

5.6.1 Projected in-state benefits to the electric system

5.6.2 Projected regional benefits to the electric system

5.6.3 The potential benefits to the electric company's entire electric system if the electric company installs the energy storage system technology that is the basis for the project system-wide technology has widespread, or limited, applicability on the electric company's system. [STAFF CLARIFICATION: Our objective in this case is a high-level analysis of whether the proposed technology has widespread, or limited, applicability on the electric company's system. We recognize this cannot be calculated precisely but we ask for an order of magnitude estimate.]

PacifiCorp calculated the potential benefits to all utility customers associated with Pilot Project #2 for two different cost sharing models, as included in Section 7.0 of the Final Energy Storage Potential Evaluation.

Initially, the pilot benefits will likely be limited. Understanding the potential benefits to the company's entire electric system will provide valuable information. As previously discussed in Section 5.1, PacifiCorp intends to primarily use this pilot to improve resiliency in local communities but also intends to explore additional utility and customer use cases.

PacifiCorp recognizes that resiliency in a specific community is unlikely to provide benefits to all utility customers, however, the funded projects will allow the company to test use cases that may provide such benefits.

Concurrent with the methodology described in this document and included under Staff Key Element #5 in Section 2.0 of the Final Energy Storage Potential Evaluation, resiliency has been included in the evaluation of power reliability. PacifiCorp intends to measure the value of resiliency based on customer interest and the level of participation from specific communities in Pilot Project #2, as identified through the Technical Assistance Concept.

As described in Section 5.1 above, PacifiCorp also intends to revisit this analysis following the detailed engineering work during the Technical Assistance Concept portion of this project.

5.7 Lifecycle Costs

The Technical Assistance Concept portion of this pilot project will assess customized and estimated costs associated with the installation, operation, and decommissioning of site-specific energy storage systems. After these are fully understood, PacifiCorp will review the applicant's plan to meet these obligations. While these remain unknown until the Technical Assistance Concept portion of the project is completed, PacifiCorp anticipates the following costs will be critical to understanding the full life-cycle costs of energy storage solutions:

- **Procurement:** Acquiring the necessary materials to construct the energy storage solution
- **Permitting:** Costs required to perform necessary environmental surveys and acquire permits prior to construction of the project
- **Land Acquisition**: Costs required to purchase or lease specific land for the energy storage system or the reduction in value due to repurposing existing space
- **Construction and Commissioning:** Time and materials costs associated with constructing the energy storage system and initial operations
- **Daily Operations:** Time and material cost related to daily operations, regular maintenance or recommended inspections
- **IT Integration/Controls Software**: IT costs related to the integration of systems and controls for the energy storage system
- **Repair Costs**: Cost of spare parts and/or labor due to either normal wear and tear or unforeseen damage
- **Decommissioning:** Costs required to de-construct and dispose of equipment and technology at either the end of project life or end of technology life

5.8 Lifetime Project Risks

PacifiCorp has identified the following lifetime project risks associated with this proposed pilot project:

Physical Damage to Equipment: PacifiCorp recognizes that damage to the energy storage device may occur over the life of the project due to both environmental exposure and operator error. These unexpected costs potentially reduce both the benefits realized and the cost effectiveness of the project. As these storage devices will be maintained and operated by customers, PacifiCorp intends to educate and provide a maintenance and operations plan as part of the technical assessment analysis.

Supplier Diversity: Certain technologies (such as zinc air), equipment, repair parts, and labor can only be provided by a small set of contractors. While this may be acceptable currently, this poses a lifetime project risk as equipment or services required for mid-project repairs may be too costly or impossible to perform. To limit this risk, PacifiCorp intends to evaluate this when selecting the energy storage technology and specific project site.

Technology Degradation: The performance characteristics of storage technology can be significantly influenced by degradation, which is a function of system operation, environmental exposure, type of application, and frequency of use. As discussed in DNV GL's report,[51] unexpected temperature fluctuations, improper maintenance, and higher or lower average states of charge can result in sub-standard performance of the storage device. While some of these factors for degradation can be mitigated, PacifiCorp recognizes that degradation may still occur, and should be considered in the technical scoping and ultimate selection of the energy storage technology.

Technology Life Cycle: Most energy storage systems have not been available at a commercially mature stage for long enough to provide meaningful field data on lifetime performance. The expected life of each technology is currently provided by vendor projections based on standard cycling, limited exposure to extenuating circumstance, and accelerated life-testing. While a great representation for the average project, these projections may not be specific to the pilot project proposed. This life-cycle should be re-evaluated as part of the technical evaluation, once a specific application and location is identified.

Funding: The ability to execute this pilot as proposed relies on participating organizations understanding the lifecycle costs of the interconnection of a storage facility. This pilot project is designed to provide an understanding of those costs through technical assessments for a larger set of customer sites, and then through installation funding for a smaller set of projects. However, PacifiCorp recognizes that changing priorities in a community could cause a project to be discontinued before completion or before the expected project life is complete. To mitigate this risk, PacifiCorp intends to select candidates for project development with a clear plan for funding and low risk of budgetary reallocation, grant funding will be held until the interconnection is complete, and the projects will enter into five year contracts laying out the specifics of the shared usage of the facility.

Continuing Operation: As proposed, facilities would assume responsibility for ownership, operation and maintenance of the energy storage system with engineering support provided by PacifiCorp. Personnel changes within a facility could result in a lack of trained personnel available to properly operate and maintain the equipment, resulting in potential lapse in operation and data collection. PacifiCorp intends

[51] See DNV GL Document # 128197#-P-01-A, "Battery Energy Storage Study for the 2017 IRP" PG 11-12

to select candidates with the lowest risk of a lapse in operation and will encourage interested facilities to propose both primary and backup operations plans.

Decommissioning: As critical in evaluating any project, decommissioning requirements must be understood up front in order to select systems with low cost and risk. For this pilot project, decommissioning will be the responsibility of the facility (customer) as opposed to a utility-owned assets which are the responsibility of PacifiCorp. These requirements and estimated costs will be included in the technical assessment to ensure transparency prior to project development.

5.9 Benefits Summary

Comprehensive assessment of all quantitative and qualitative benefits to the electric system and all customers over the life of the project. Assessment of larger societal benefits, where applicable, is encouraged but those assessments will not be incorporated into the cost-effectiveness calculation of the proposals [STAFF CLARIFICATION: We encourage utilities to identify and attempt to quantify all potential benefits—system or societal—from a project and include this analysis in project proposals. However, we resolve that in this context the focus is properly on the benefits that accrue to the electric system and all utility customers from the project. This is consistent with the language of HB 2193, which asks electric companies to analyze in their proposals the benefits of each project to the electric company's electric system including in-state and regional benefits and the potential benefits of installing the technology system-wide.]

In addition to the benefits previously described in Section 5.6, PacifiCorp recognizes that behind the meter, customer-sited energy storage provides value beyond just resiliency and has an opportunity to provide benefits to the entire electrical system. This pilot project will allow PacifiCorp to control of customer-sited energy storage to explore opportunities to provide benefits to all customers.

Table 26 below summarizes the potential stacked applications that PacifiCorp may investigate through this project and maps them to the use cases as described in legislation.

Table 26 Valuable Use Cases as Leveraged for Existing Resiliency Projects

Use cases / services accompanying Resiliency (DOE Definitions)	Use cases / services accompanying Resiliency (approximate mapping to Order No. 16-504 list)
Black Start Electric Energy Time Shift Renewables Capacity Firming Electric Bill Management Grid-Connected Commercial (Reliability & Quality) Grid-Connected Residential (Reliability) Frequency Regulation Onsite Renewable Generation Shifting Electric Bill Management with Renewables Renewables Energy Time Shift Microgrid Capability **Resiliency** Demand Response	Bulk Energy - Capacity of Resource Adequacy - Energy Arbitrage Ancillary Services - Regulation - Black Start Distribution Services - Outage Mitigation Customer Energy Management Services - Power Reliability - Time-of-Use Charge Reduction - Demand Charge Reduction

5.10 Benefit Methodology

Description of methodology for assessing projects benefits, including aggregation of benefits

Potential benefits for Pilot Project #2 are discussed in sections 5.6 and 5.9 and the methodology for calculating these benefits is included in the Final Energy Storage Potential Evaluation.

Additionally, as part of the Project Development Funding Concept, PacifiCorp will hire a third party consultant to assist in quantifying the benefits achieved from the installation of the energy storage system for both the host customer and the company. The selected consultant will assist in developing a cost-benefit computation methodology. This methodology will attempt to compare achieved benefits realized through the shared operation of the storage facility, with projected benefits for the customer as established during the Technical Analysis Concept and for PacifiCorp as described in the Energy Storage Potential Evaluation. PacifiCorp will also seek to compare the realized benefits over time, as use cases are tested and operational characteristics are modified. Though the exact methodology is not known at this time for either phase of the pilot project, PacifiCorp anticipates the following steps to be completed for this work:

- Hire a qualified third-party consultant with expertise in energy storage analysis and evaluation.
- Quantify the value of use cases to the utility through company-specific models, tools and methodologies as outlined in the Energy Storage Potential Evaluation.[52] Quantify the value of use cases to PacifiCorp and its customers through the collection and analysis of actual on-site data.
    - Technical assistance reports will include estimated participant benefits and costs for specific projects based on expected use.
    - For funded projects, PacifiCorp will hire a consultant to evaluate actual project operations data to assess the benefits to the company and its customers
- Identify which benefits and costs cannot be assessed and why:
    - Are they not easy to access because there is limited data?
    - Can they not be quantified at all (i.e. qualitative benefits)?
    - There is no established market needed to capture the benefits.

[52] See the "Revised Draft Energy Storage Potential Evaluation" submission for more information regarding available tools and processes.

5.11 Cost Effectiveness

Cost-effectiveness of the energy storage system including benefit-cost ratios and net present value revenue requirements over the energy storage system lifetime, and all underlying inputs and assumptions used in the calculation..

As specific projects and locations have not yet been determined, meaningful cost-effectiveness analysis for this pilot is not available at this time. Based on the projects funded and the operation of those specific projects, PacifiCorp will calculate the benefits to the electrical system and compare these benefits to the company's cost contribution to each project to assess the cost-effectiveness of specific projects.

6.0 Project Data and Research

6.1 Projected trends in energy storage system cost and performance

As part of PacifiCorp's 2017 IRP, PacifiCorp contracted with DNV GL to perform a study regarding the current status and future potential applications for battery energy storage, specifically focused on cataloging available technology and associated cost trends. This study, titled "Battery Energy Storage Study for the 2017 IRP,"[53] is included in Appendix B of the Final Energy Storage Potential Evaluation. A cost update to this report, also prepared by DNV GL, can be found in Appendix D.

Additionally, PacifiCorp issued an RFI on March 24, 2017 regarding potential energy storage solutions in alignment with HB 2193 and Order No. 16-504 to better understand potential options and market trends. On April 28, 2017, PacifiCorp received 19 responses from potential contractors ranging from technology manufacturers with limited experience to Engineer, Procure, and Construct providers with twenty years in the industry. A brief summary of these responses was included in the Revised Draft Energy Storage Potential Evaluation in Appendix A.

6.2 Strategy for large-scale deployment of technology over time, if applicable

As previously described, both proposed pilot projects aim to address a range of applications including behind-the-meter storage. Specifically, the phased approach of Pilot Project #1 allows for lessons learned during one portion to be transferred and leveraged into subsequent phases to optimize the use and control of energy storage in preparation for wide scale deployment. While the company does not currently have an established framework for large scale deployment at this time, PacifiCorp is committed to continuous evaluation and exploration of this application of energy storage and intends to use these proposed pilot projects as a the first step toward large-scale deployment.

6.3 Comparative Analysis of (1) the proposed storage solution and (2) other storage and non-storage solutions for the proposed application

Both pilot projects proposed involve the use of energy storage devices alongside traditional solutions to enhance potential benefits to both PacifiCorp and the customer. During the initial screening of projects, traditional solutions proved to be more cost-effective than energy storage solutions. However, after reviewing the range of projects modeled by DNV GL, stacked benefits not typically available from traditional solutions significantly closed this cost gap. Additionally, after focusing on projects with enhanced learning opportunities as opposed to a simple one-to-one replacement, PacifiCorp was able to select potentially cost-effective projects.

Specific to Pilot Project #1, the strategic grid location will allow for the testing and co-optimization of a range of use cases not available through traditional distribution projects.

As pertaining to Pilot project #2, local communities could invest in other forms of conventional generation such as diesel generators to improve community resiliency. However, in the event of a natural disaster, fuel shortages and transportation challenges during prolonged month-long outages could render such generators useless. As opposed to strictly replacing conventional solutions, Pilot Project #2 intends to

[53] The study can also be found at http://www.pacificorp.com/es/irp.html.

leverage existing conventional and renewable generation such as diesel generators or solar, integrate energy storage solutions, and create the required extended resiliency for communities to weather natural disasters and support recovery efforts. Once again, this project allows the energy storage solution to provide benefits not available through traditional projects.

6.4 Data collection evaluation plan, and reporting with identified research objectives

At a high level, PacifiCorp intends to measure cost to operate, technology performance metrics, and bottom-line impact to net power costs associated with these pilot projects. While specific data collection requirements will be included in the engineering analysis, PacifiCorp has identified the following items as potentially critical for measurement:

- Effective charge and discharge rates
- Percent utilization
- Idle time
- Daily operating cost
- Number of applications
- Regular maintenance costs
- Unplanned maintenance cost

In order to achieve this, the energy storage solutions will be incorporated into the PacifiCorp system through SCADA where possible and data will be archived. More information regarding this concept, including a data flow diagram can be found in Section 4.3. Data will be reviewed for completeness on a monthly basis, and compiled annually for a more thorough review.

PacifiCorp will develop an evaluation plan with the following objectives:

- Conduct process and impact evaluation, cost effectiveness analyses, and if necessary market characterization/potential studies;
- Provide technical support for the design and redesign of energy storage programs;
- Determine available potential and associated utility and customer costs and benefits;
- Estimate costs of future implementation from a variety of sources, including marketing, contractors and published cost data;
- Design, test and administer systems;
- Conduct on-site assessments;
- Provide impact assessments of programs;
- Establish baseline operating practices and/or efficiency levels;
- Document and communicate external project drivers including non-energy benefits as requested;
- Provide, install and remove short term temporary monitory equipment in accordance with company requirements;
- Conduct billing analysis, simulation modeling and engineering calculations using monitoring data as required;
- Analyze and document program attribution;
- Estimate actual energy and demand impacts;
- Evaluate the impact of peak management programs on energy use, i.e. avoided energy verses shifted usage;

- Assess program delivery including internal coordination and communication regarding the program, customer decision making, effectiveness of program features in influencing customer decisions, effectiveness of company data collection mechanisms;
- Perform primary analysis/data collection by system or technology sales and market practice date by region to help determine available (net and gross) potential;
- Compare program designs with other program offerings and make recommendations regarding program delivery;
- Provide records of correspondence related to the projects;
- Respond to external stakeholder review and comments and represent company and the program in an accurate, positive professional manner; and
- Maintain working knowledge of current company energy storage programs, including utility owned programs and customer-sited programs.

PacifiCorp proposes the following reporting strategies to the Commission and/or Commission Staff:

- Provide an annual update on the company's progress of the proposed pilots no later than March 31 of the following year.
- Provide a final report upon completion of the pilot, no later than one year from the completion of the pilot performance period. The final report will include the following:
    - A summary of results on the Company's data collection and evaluation plan

Appendix A: List of Commons Use Cases[54]

Use Case	Service	Value
Bulk Energy	Capacity of 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 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 Services	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 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 electric power system. VAR control manages the reactive power, usually attempting to get a power factor near unity (l).
	Outage Mitigation	Outage mitigation refers to the use of an ESS to reduce or eliminate the costs associated with power outages to utilities.
	Distribution Congestion Relief	Use of an ESS to store energy when the distribution system is 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.

[54] Per Order No. 16-504. Does not include frequency response.

Appendix B: Project #1 Potential Location(s) Map

[redacted]

Appendix C: Pilot Project #1 Letter of Endorsement

[redacted].

[redacted]

Appendix D: Cost Update to Battery Energy Storage Study for the 2017 IRP

As a part of the 2017 IRP, DNV GL was consulted to study energy storage trends. This report, issued in September of 2016, was included in the 2017 IRP filing in Appendix P of Volume II beginning at Page 415 and can be found in the Final Energy Storage Potential Evaluation document in Appendix B. The following report was prepared in November of 2017 as a cost update to this initial report and was leveraged to complete up to date cost calculations.

Cost Update to Battery Energy Storage Study for the 2017 IRP

PacifiCorp

Report No.: 10072126-R-01-A

Issue: A **Status:** Final

Date: 11/17/2017

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Report title:	Cost Update to Energy Storage Technology Review (Change Order #1)
Customer:	PacifiCorp
Contact person:	Ian Hoag
Date of issue:	11/17/2017
Report No.:	10072126-R-01-A
Issue:	A
Status:	Final

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☐ DNV GL only

☒ Customer's Discretion

☐ Published

Keywords:

Energy Storage

Issue	Date	Reason for Issue
A	11/17/2017	Final

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1.0 COST ESTIMATES AND TRENDS UPDATE

1.1 Introduction

DNV GL was engaged by PacifiCorp to update the costs and cost trends outlined in the Battery Energy Storage Study for the 2017 IRP. This update is based on installations and contracts that have been executed for the installation of energy storage systems in 2016 and 2017. In addition, trends were updated based on this new baseline rate as well as new developments in the industry since the completion of the original report. All values are for 2018, based on in-house data, industry experience, or publicly available data, as well as data provided by PacifiCorp, and are expressed in mid-2017 dollars.

Costs estimates are broken down as follow:

1. Batteries ($/kWh)
2. Balance of System (BOS) ($/kW)
3. Engineering, Procurement, and Construction (EPC) ($/kWh)
4. Fixed Operation and Maintenance (O&M) ($/kw-yr)

Each of these costs components are provided as a range covering currently observed industry estimates. In addition to current cost estimates, cost trends over 10 years will be provided as graphs for the energy storage system equipment, the batteries and balance of system.

The capital cost for an installed energy storage system is calculated for a system by adding the costs of the energy storage equipment, power conversion equipment, power control system, balance of system, and the installation costs. Each of these categories is accounted for separately because they provide different functions or cost components and are priced based on different system ratings. System component costs based on the power capacity ratings are priced in $/kW, while component costs based on the energy capacity ratings, such as the DC battery system, are priced in $/kWh.

1.2 Updated features

Unless noted otherwise, the original definitions of terminology as well as assumptions remain unchanged from the original Battery Energy Storage Study for the 2017 IRP, and can be referenced there. However, places where this update differs from the original report are detailed below.

For this update, the ancillary system components, i.e., not the batteries, were considered as a single cost as “Balance of System” or BOS. The main components of the BOS are the power conversion equipment, the control system, and other supporting equipment, such as thermal management, wiring and interconnection equipment, and protection of various components.

For all the trends, the graphs display the average value for each year as the trend line. Table 1 should be referenced for the high and low ranges of all costs.

The installation cost has been updated to an EPC cost. Whereas the installation cost is exclusively associated with the materials and labor of the installation, EPC includes all direct costs for development and project management, and costs associated with a fixed price, turn-key, EPC contract. As a rule of thumb, and EPC costs range from approximately 0.5 times the $/kWh cost of the energy storage system for large systems (larger than 1 MW) to 2.5 times the $/kWh cost of the energy storage system for smaller systems (smaller than 1 MW). As this report originally only considered systems larger than 1 MW, DNV GL's costs are nearer to the 0.5 times value.

The Fixed O&M costs are expected to increase over time due to inflation, of approximately 2% per year. In addition, O&M costs are often fixed for the term of the energy storage system warranty, but may rise after the warranty. O&M costs do not include the cost of any capacity maintenance. The original report provides additional details regarding capacity maintenance and Variable O&M

Key cost updates were to the Li-Ion and VRB technologies, as they have seen the most dramatic reductions in cost since the original report. Li-Ion batteries specifically have fallen to as low as $150/kWh. NaS and ZnBr were tuned slightly to address cost reductions to the BOS. DNV GL has not observed Zinc-air technology making any significant commercial progress, and as such, has not altered the initial cost from the original report, and has reduced the impact of the trend lines.

1.3 Cost Estimates

Table 1 Updated Cost Estimates for 2018

Cost Parameter/ Technology	Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Energy storage equipment cost ($/kWh)	$150-$350	$225-$375	$300-$500	$425-$550	$300-$500	$525-$725	$200-$400
Balance of system ($/kW)	$320-$450	$320-$450	$320-$450	$750 - 800	$750-$900	$750-$900	$325-$500
EPC Cost ($/kWh)	$150-$300	$150-$300	$150-$300	$140-$200	$140-$200	$140-$200	$140-$200
Fixed O&M cost ($/kW-yr)	$6-$11	$6-$11	$6-$11	$12 - $18	$7-$12	$7-$12	$6 - $12

Table 2 Example installed cost

10 MW, 20 MWh Li-Ion NCM Storage System	ESS Size (kW or kWh)	Low $	High $	Sub-Total Low	Sub-Total High
Energy storage equipment cost ($/kWh)	20,000	$150	$350	$3,000,000	$7,000,000
Balance of system ($/kW)	10,000	$320	$450	$3,200,000	$4,500,000
EPC Cost ($/kWh)	20,000	$150	$300	$3,000,000	$6,000,000
				Total Low $	Total High $
				$9,200,000	$17,500,000
				Average	$13,350,000

1.4 Trends 2018 – 2028

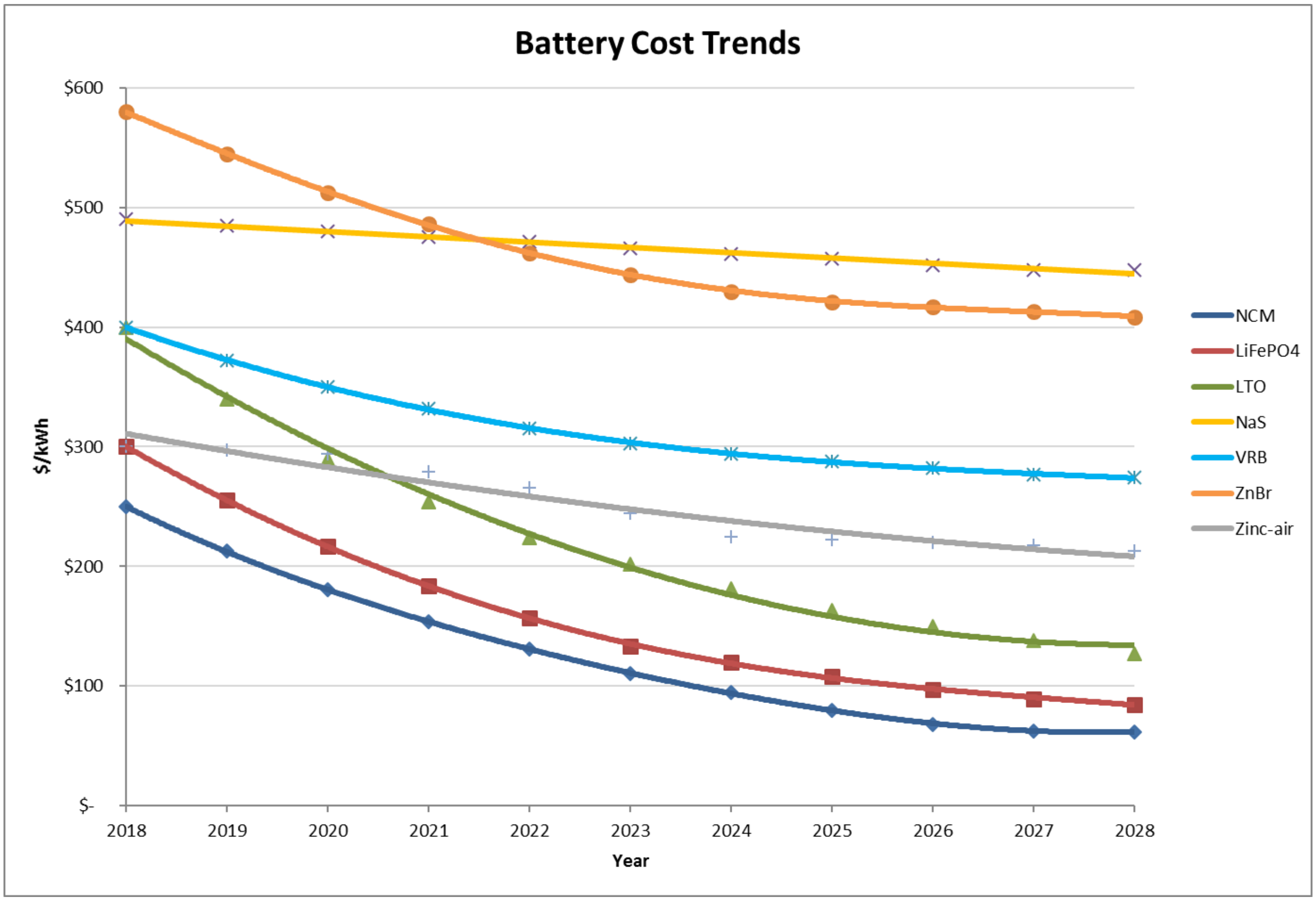

Figure 1 Battery cost trends

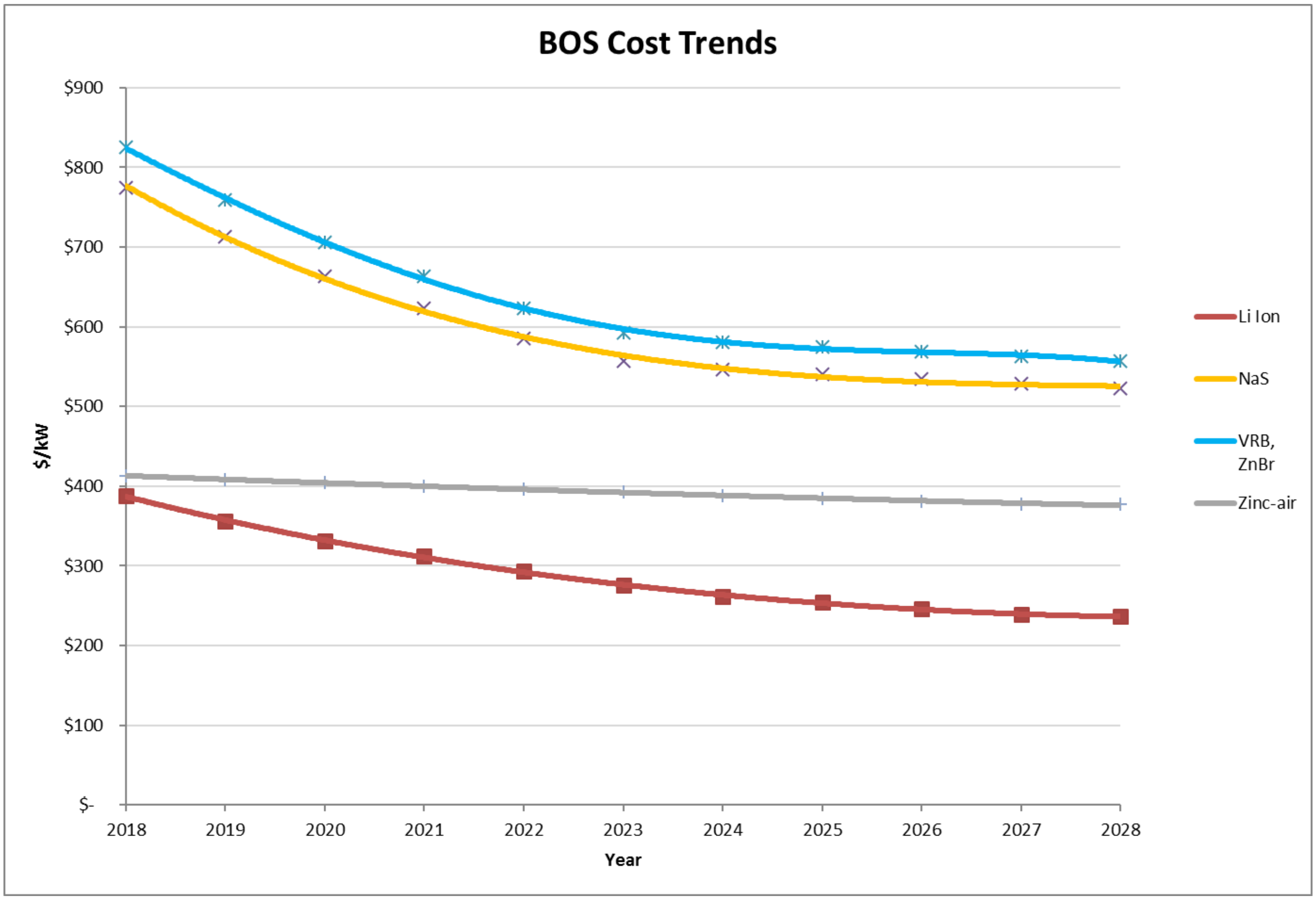

Figure 2 Balance of system cost trends

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Appendix E: Energy Storage Grant Application

Customer-sited Energy Storage Grant Application

Overview

PacifiCorp is one of the West's leading utilities, serving approximately 1.8 million customers in six states. Today, PacifiCorp consists of two business units: Pacific Power and Rocky Mountain Power. Pacific Power delivers electricity to customers in Oregon, Washington and California, and is headquartered in Portland, Oregon. Rocky Mountain Power delivers electricity to customers in Utah, Wyoming and Idaho, and is headquartered in Salt Lake City, Utah. Pacific Power is headquartered in Portland, Oregon. PacifiCorp is a subsidiary of Berkshire Hathaway Energy Company.

Background

On June 15, 2015, the Oregon legislature passed House Bill (HB) 2193. The primary purpose of HB 2193 is to encourage the development of energy storage programs in Oregon. HB 2193 requires the electric companies to submit energy storage project proposals by January 1, 2018 and if authorized by the Commission procure one or more qualifying energy storage systems with the capacity to store at least five (5) megawatt hours (MWh) of energy by January 1, 2020. The legislation directs the Commission to adopt guidelines for the electric company in submitting project proposals to examine the potential value of applying energy storage system technologies, consider ways to encourage electric companies to invest in energy storage systems and otherwise determine factors necessary for examination prior to the procurement of energy storage systems. HB 2193 provides authority for utilities, should the Commission authorize the project proposal, to create new energy storage projects. For additional information on this requirement, please refer to Oregon HB 2193[55], and Public Utility Commission of Oregon's (OPUC) docket: UM 1751[56].

Eligible Projects

Through this grant program, PacifiCorp provides opportunities to qualifying parties to receive financial support to design eligible energy storage projects. For additional information on the program and/or project funding please visit our website at pacificpowerpower.net.

Eligible projects include 1) emergency response critical facilities in PacifiCorp's Oregon service territory, (2) single customer-sited projects that serve single buildings or loads, (3) single customers with existing or planned on-site generation, or (4) a subset of customers that can be fed through one point of delivery such as a small community campus

[55] Oregon House Bill 2193 can be found here: https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193.

[56] Oregon Public Utility Commission docket 1751 can be found here: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19733.

The following costs are NOT eligible for reimbursement:

- Structural improvements or other site preparation that would be considered general facilities maintenance (e.g.re-roofing, upgrading an overloaded electrical panel, tree removal or trimming, landscaping, construction of a carport or other facility that will host the renewable energy equipment). Site preparation activities that are only required for the renewable energy project and are otherwise not required for general facility maintenance (e.g., ballast rock removal, roof reinforcement, trenching a new wire run exclusively for the solar array), may be considered an eligible expense on an individual basis.
- Administrative or project management costs
- Construction bond costs, interest and warranty charges
- Ongoing system or facility maintenance or repair costs
- Donated, in-kind or volunteer labor or materials
- Engineering/design costs incurred to date (e.g., site evaluations, estimates/bids)
- Interconnection studies
- Marketing or advertising, other than approved on-site signage

How to Apply for Funds

Step 1: Review eligibility requirements, award recipient responsibilities, evaluation and selection criteria, and application tips at pacificpowerpower.net.

Step 2: Complete and sign the application form, including the supplemental document checklist. **Applicants must complete all fields in the application form for their project to be considered for funding**. This application and supplemental material will serve as the primary means by which projects will be evaluated. Pacific Power and/or its designee may contact you for further information, so please provide current and complete contact information.

Step 3: Submit completed application form in **Microsoft Word** format along with supplemental documents (a single PDF is preferred).

2017 Application/Award Timeline

January 17, 2019	Pacific Power begins accepting applications
March 14, 2019	5 p.m. – PST – Submittal deadline
May 2019 *(Tentative)*	Applicants will be notified in writing of award decision; projects selected for funding will be asked to sign an agreement detailing the conditions and requirements of accepting the grant funds. Funds will be disbursed upon completion of the project and once reporting requirements are met.
One year from award receipt notice	Project installation must be complete. Extensions to this timeline may be considered on a case-by-case basis for projects associated with the construction of a new building or structure.

Proposal Format

Proposals should organize the proposal into the following sections in Microsoft Word files and/or Adobe Acrobat pdf files. The table of contents and organization of the proposal must be ordered as described below. Please include as many subdivisions as deemed necessary. Note: proposals should be no more than 50 pages in total, including appendices.

1) **Cover Letter** – Bidders should include an overview of its organization, rationale why the organization is a good fit, and the expected team composition; including information in Project Information Form.
2) **Executive Summary** – At a minimum, the Bidder's executive summary should address the following:
    - Comprehensive description of the project;
    - Reasoning for selecting chosen technology, grid location, application, and ownership structure, with supporting analysis including findings from any system-wide potential evaluation, identification of any criteria used to select projects and an explanation of how the criteria were applied, and any other relevant input on evaluations; and
    - Plan for constructing, maintaining, and operating the energy storage system.
3) **Approach to Program** – The Bidder should describe the following:
    - Technical specifications for each project, including:
        - The capacity of the project to store energy including both the amount of energy the project can store and the rate at which it can respond, charge, and discharge as well as any other operational characteristics needed to assess the benefits of the energy storage system.
        - The location of the project
        - A description of the electric company's electric system needs and the application that the energy storage system will fulfill as the basis for the project
        - A description of the technology necessary to construct, operate, and maintain the project, including a description of any data or communication system necessary to operate the project.
        - A description of the types of services that the electric company expects the project to provide upon completion.
        - An analysis of the risk that the electric company will not be able to complete the project.
    - The benefits of each project to the electric company's electric system, including:
        - Projected in-state benefits to the electric system.
        - Projected regional benefits to the electric system.
        - The potential benefits to the electric company's entire electric system if the electric company installs the energy storage system technology that is the basis for the project system-wide technology has widespread, or limited, applicability on the electric company's system.
    - Comprehensive assessment of project risks over the life of the project.
    - Comprehensive assessment of all quantitative and qualitative benefits to the electric system and all customers over the life of the project. Assessment of larger societal benefits, where applicable, is encouraged but those assessments will not be incorporated into the cost-effectiveness calculation of the proposals.
    - Description of methodology for assessing projects benefits, including aggregation of benefits.

- Cost-effectiveness of the energy storage system including benefit-cost ratios and net present value revenue requirements over the energy storage system lifetime, and all underlying inputs and assumptions used in the calculation.
- Comparative analysis of: (1) the proposed storage solution, and (2) other storage and non-storage solutions for the proposed application.
- Data collection and evaluation plan with identified research objectives.

4) **Cost** – The proposal should include a budget for the proposed project in a separate file. Bidders should use the Exhibit B Pricing Template.
    - The estimated cost of each project, including:
        - The estimated capital cost of the project
        - The estimated output cost of the project
        - The amount of grant moneys available to offset the cost of the project
    - Comprehensive analysis of all identified costs over the life of the project to the electric system and all customers
5) **Timeline** – The Bidder should include a timeline demonstrating the Bidder's ability to begin offering the program to the Company's customers by the estimated program implementation deadline specified in the Schedule.

Appendix F: Grant Application Information Form

company Name *Organization occupying the property where the energy storage project will be installed.*	
Type of Organization	
company Address	
Primary company Phone	
company Website	
Name of individual completing application *Include affiliation and contact information if different from primary contact.*	
Please verify that the project satisfies the *Requirements & Eligibility* *A full listing is available at pacificpowerpower.net*	☐ I certify that this energy storage project meets PacifiCorp's funding award eligibility requirements

Primary Contact Information

Name	
Title	
Organization Name	
Role in the project	
Phone *Please indicate type of phone: cell or desk*	
Email	

Engineer/Contractor/Installer Contact Information

Name	
Title	
Organization Name	
Role in the project	
Phone *Please indicate type of phone: cell or desk*	
Email	

Energy Storage Project Information

Project Name	
Energy Storage project owner *Indicate if different from host organization. If more than one party, describe ownership structure.*	
Physical address where project will be installed *Include facility name, street address, city, state, zip code, and/or GPS coordinates where appropriate.*	
Location of installation on property *Where will it be located?*	
Technology type *Battery type, etc*	
Project size *kW nameplate capacity rating*	
Estimated annual kWh generation	
Current annual electricity demand of the facility where the power will be consumed *If this is a new site, please provide the estimated annual electricity demand. Please include PacifiCorp meter number(s) at installation site and provide the temporary meter number for new construction.*	
Is this project a new installation, addition to an existing installation, or research and development?	
Anticipated commissioning/on-line date	
Has the project team been in contact with the PacifiCorp's customer generation group? *For more information on interconnection requirements please visit* ***pacificpower.net/netmetering***	
Interconnection plan *Indicate whether this project be connected behind the meter (net metered) or in front of the meter (PPA/interconnection agreement)?* [57]	
Please certify that your project will be grid-tied, i.e. interconnected to the PacifiCorp system	☐ I certify that this project will be interconnected to the PacifiCorp system
Are there other renewable energy installation components in your project? (please itemize)	

[57] **Onsite projects** generate electricity that is consumed onsite and excess electricity is passed through a meter and onto the grid. **Utility-side projects** are intended to provide power directly to the grid.

Use Cases

Category	Service	*Check All that Apply*
Bulk Energy	Capacity or Resource Adequacy	
	Energy arbitrage	
Ancillary Services	Regulation	
	Load Following	
	Spin/Non-spin Reserve	
	Voltage Support	
	Black Start Service	
Transmission Services	Transmission Congestion Relief	
	Transmission Upgrade Deferral	
Distribution Services	Distribution Upgrade Deferral	
	Volt-VAR Control	
Customer Services	Power Reliability	
	Time-of-Use Charge Reduction	
	Demand Charge Reduction	
Not included in PUC Use Cases	Frequency Response	

Permitting and Approvals

Please identify the status of all necessary permits or other approvals required for the project:[58]

Permit/Agreement Description	Not required	Required, Application not yet Submitted	Application Submitted	Permit/ approval received	Unsure if required
Air/land use					
Electrical					
Structural					
Mechanical					
Plumbing					
Zoning					
Environmental impact					
Cultural/historic impact					
Interconnection/ net metering					
Power purchase agreement					
City council/ board approvals					
Other:					
Please include an explanation of permitting status if necessary					

[58]This should prove as an initial review of existing or required permits. A thorough evaluation will be include in the engineering design work.

CERTIFICATE OF SERVICE

I certify that I electronically filed a true and correct copy of PacifiCorp's **Final Storage Potential Evaluation and Final Storage Project Proposals** on the parties listed below via electronic mail and/or overnight delivery in compliance with OAR 860-001-0180.

Service List
UM 1857

CREA	
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ALLIANCE OF WESTERN ENERGY CONSUMERS	
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OREGON CITIZENS UTILITY BOARD	
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Dated April 2, 2018.

Jennifer Angell

Jennifer Angell
Supervisor, Regulatory Operations