PACIFIC POWER
A DIVISION OF PACIFICORP

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October 18, 2019

VIA ELECTRONIC FILING

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

Attn: Filing Center

Re: UM 1857—PacifiCorp's Second Compliance Filing – Energy Storage Pilot and Evaluation Plan Update

PacifiCorp d/b/a Pacific Power submits for filing in compliance with Public Utility Commission of Oregon (Commission) Order No. 18-327, and modified by Order Nos. 19-242 and 19-333, updated estimated benefits and costs associated with the company's energy storage system pilots.

Pilot Project 1

On April 2, 2018, PacifiCorp selected and proposed Pilot Project #1 to the Commission for approval in this docket. PacifiCorp selected the 2MW/6MWh 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 met the minimum threshold of five MWh as set forth by HB 2193, accommodates the historic outage characterization on the feeder, and presented the lowest risk option given the information available to PacifiCorp at the time. PacifiCorp now provides an additional update on the current status of this project.

The company is currently in the process of procuring a parcel of land near the Hillview Substation in Corvallis, Oregon for the project. The property cost is forecasted to be $125,000 more than originally planned due to the current market value of property in the area, property rights negotiations, and permitting requirements. However, the company determined that purchasing the property is a lower cost option over the available opportunities for lease payments for the life of the project. Procuring the property has taken longer than originally estimated to due to negotiation of property rights with owners along the circuit.

The Owner's engineering is being provided by an external engineering firm and was procured through competitive bid and awarded at the end of 2018. The Owner's Engineer was selected based on lowest bid. The winning bid was for $[redacted]. This cost is in addition to the internal engineering reviews and project management. These costs were originally estimated to be approximately $60,000; however, based on current estimates and awarded contracts, this portion of the project is now estimated to be $255,000. The Owner's Engineers have completed the conceptual design, interconnection application, and permitting review.

The engineering, procurement, and construction (EPC) request for proposals (RFP) is currently posted for competitive bid. The EPC contract is anticipated to be awarded in December of 2019. Engineering and procurement is planned to be completed in Q2 2020 and, depending on material availability and permits, construction is planned to start in Q4 2020. The EPC contract comprises the majority of the project costs. Based on market trends for energy storage, the energy storage equipment costs will be approximately $765,000. This is in the lower end of the range of $553,500 to $1,291,500 in PacifiCorp's April 2018 estimate.

Finally, the cost of interconnecting the battery system to the distribution system was originally estimated at $550,000, but is now estimated at $815,000 based on the current design.

[redacted]

<u>Pilot Project 2—Community Resiliency Pilot</u>

In the stipulation filed in UM 1857 by PacifiCorp on July 18, 2018, and adopted by the Commission in Order No. 18-327 (September 4, 2018), PacifiCorp committed to developing a Community Resiliency Pilot to provide technical and financial assistance to study and deploy energy storage resources to facilities critical to emergency response or disaster recovery. The stipulation laid out a phased approach for the Pilot, beginning with a consultant-led technical assistance concept resulting in a limited number of initial studies (Phase 1), followed by financial assistance for the installation of energy storage resources for up to four critical facilities (Phase 2).

In Order No. 18-327, the Commission authorized PacifiCorp to recover up to $200,000 in Phase 1 of the Pilot. After the completion of Phase 1, but prior to beginning Phase 2, PacifiCorp will file a revised plan estimating the costs, benefits and anticipated learnings associated with the Pilot for Commission approval and seek Commission authorization to recover costs associated with Phase 2.

PacifiCorp intends to maximize the learnings from Phase 1 of this Pilot and expects that it will be able to commission between four and eight studies based on the funding authorized by the Commission.[1] Of the $200,000 authorized, PacifiCorp has reserved $50,000 for internal administration and support costs, with the remainder allocated to third-party technical assistance support. PacifiCorp filed to defer its costs for Phase 1 of the Pilot on June 17, 2019 and is currently awaiting Commission approval.

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[1] The costs associated with the performance of technical assistance for a given site will vary depending on an array of factors, including the type of facility, complexity of associated systems, and travel required to conduct a site visit.

Beginning in November 2018, PacifiCorp conducted a competitive procurement process to select a consultant to perform the Phase 1 technical assistance support. Through that process, PacifiCorp awarded a contract to TRC, finalized on August 5, 2019.

PacifiCorp is working with TRC to develop and implement Phase 1 of the Pilot with the following objectives:

1. Identifying the value of an energy storage system to meet resiliency needs of the host customer, community and utility customers in emergency situations;
2. Identifying the value of energy storage to the host customer and utility customers during periods of normal grid operation;
3. Identifying any market barriers, solutions, and additional value streams of energy storage;
4. Developing methodologies for balancing the benefits of customer-sited equipment between the host customer and other utility customers;
5. Strengthening existing community connections through active participation in local disaster preparedness planning;
6. Understanding the effectiveness of sponsored technical assistance to inform and motivate customers to install energy storage, and
7. Summarizing results in a manner designed to inform PacifiCorp's potential future energy storage initiatives.[2]

In furtherance of these objectives, PacifiCorp is developing the processes necessary to perform Phase 1 of the Pilot. This includes researching potential sites and identifying criteria to inform eventual site selection, identifying PacifiCorp-internal processes to facilitate TRC's work, developing an outreach plan and materials, and establishing timelines and deliverables.

PacifiCorp expects to be able to schedule the first site visit in early November 2019, with future site visits occurring on a rolling basis through the first quarter of 2020. Each participating facility will receive a site-specific report informed by the first three Phase 1 objectives defined above. The goal is to provide a facility manager with enough information to decide whether to pursue energy storage resources for resiliency purposes.

Using information learned in the process of reviewing historical facility usage data, conducting site visits, preparing individual reports, and analyzing utility benefits, PacifiCorp will prepare and provide to the Commission a final report detailing key learnings from Phase 1 of the Pilot. PacifiCorp expects to file this report by the end of the second quarter of 2020. Key learnings from the final Phase 1 report will shape PacifiCorp's expectations related to Phase 2 of the Pilot, which PacifiCorp will begin developing after submission of the final Phase 1 report in the second quarter of 2020.

[2] PacifiCorp Community Resiliency Pilot – Phase 1 Technical Assistance Request for Proposals, released November 12, 2018.

Please direct any informal correspondence and questions regarding this filing to Cathie Allen Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

Attachment 1

CAPITAL UP FRONT

Cost Parameter/ Technology	Description/ What does this value include?	Source (where did I get this number?)	Project #1 Specific - LOW	Project #1 Specific - MID	Project #1 Specific - HIGH	Project #1 October 2019
Energy storage equipment cost ($/kWh)	DC battery system including: - The costs of the energy storage medium (Li-Ion battery cells or flow battery electrolyte) - Associated costs of assembling these components into a DC battery system	Cost update to the Battery Energy Storgae Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$553,500	$922,500	$1,291,500	$765,000
Balance of system ($/kW)	Balance of Systen Costs include: - Power conversion equipment (inverter, packaging, container, and controls) - The control system - Other supporting equipment, such as thermal management, wiring and interconnection equipment, and protection of various components	Cost update to the Battery Energy Storgae Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$514,720	$619,280	$723,840	$410,000
EPC Cost ($/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 Storgae Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$900,000	$1,350,000	$1,800,000	$1,190,938

UP FRONT SUBTOTAL	$1,968,220	$2,891,780	$3,815,340	$2,365,938
$/kW equivalent	$984	$1,446	$1,908	$1,183
$/W equivalent	$0.98	$1.45	$1.91	$1.18

OWNER's COSTS

Sales tax ($)	State & local sales tax	https://www.taxrates.com/state-rates/oregon/	$0	$0	$0	$0
Interconnection application ($)	Interconnection studies costs owed to the transmission provider	http://www.pacificorp.com/tran/ts/gip/qf/oregon.html	$3,300	$7,300	$11,300	$7,000
Interconnection (upgrades) ($)	Laydown area improvements and addition of distribution equipment	Grandview Energy Storage Detailed Integration Estimate	$446,000	$549,000	$652,000	$939,874
Communications upgrade ($)	Portland Service Center and a Local Service Center comms modifications	Grandview Energy Storage Detailed Integration Estimate	$17,000	$17,000	$17,000	$17,000
Owner's project management ($)	Owner's direct engineering & project management	Grandview Energy Storage Detailed Integration Estimate	$54,000	$57,000	$60,000	$254,418
AFUDC ($)	7%	RMP Capital Reporting	$174,196	$246,546	$318,895	$250,896
Cap surcharge ($)	7 - 12%	RMP Capital Reporting	$186,390	$358,019	$584,944	$364,337

OWNER's COST SUBTOTAL	$880,887	$1,234,865	$1,644,139	$1,833,525
$/kW equivalent	$440	$617	$822	$917
$/W equivalent	$0.44	$0.62	$0.82	$0.92
CAPITAL TOTAL	$2,849,107	$4,126,645	$5,459,479	$4,199,462
$/kW equivalent	$1,425	$2,063	$2,730	$2,100
$/W equivalent	**$1.42**	**$2.06**	**$2.73**	**$2.10**

O&M SUMMARY

Cost Parameter/ Technology	Description/ What does this value include?	Source (where did I get this number?)	Project #1 Specific - LOW	Project #1 Specific - MID	Project #1 Specific - HIGH	Project #1 Specific - High Confidence
Fixed O&M cost ($/kW-yr)	Maintenance of HVAC system, tightening of mechanical and electrical connections, cabinet touch up painting and cleaning, and landscaping maintenance, 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. **Does not include capacity maintenance or augmentation.**	Cost update to the Battery Energy Storgae Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$12,000	$17,000	$22,000	$17,000
Addition Inspection O&M ($/yr)	Monthly inspection	Range of values for Current Transmission and Distribution Substation Inspection Costs in the Albany District	$2,280	$2,778	$3,276	$2,778.00
Land Lease Costs ($/yr)			$3,525	$6,010.00	$9,018	$0.00

O&M $/yr Equivalent	$17,805	$25,788	$34,294	$19,778
O&M $/kW-year	**$9**	**$13**	**$17**	**$9.89**
Equivalent O&M $/kW	$89.03	$128.94	$171.47	$98.89
Equivalent O&M $/Watt	$0.09	$0.13	$0.17	$0.10
TOTAL $/Watt Equivalent	**$1.51**	**$2.19**	**$2.90**	**$2.20**

Attachment 2

Oregon Energy Storage System Project #1: 3-hour Lithium Ion Battery Benefits

$/kw-yr	Capacity Deferred Stand-alone Li-Ion 4hr Fixed Cost	Capacity Deferred 4hr Benefit	Capacity Primary Losses Gen Capacity Adj	Energy Hourly Market Energy	Energy Deferred 4hr Benefit	Energy Primary Losses Energy	Energy Intra-hour Flex Credit	Energy Deferred 4hr Benefit	Op. Rsv. Operating Reserve	T&D T&D Deferral	T&D T&D Dispatch Lost Energy Margin	Total Total
2021	-	-	-	-	-	4	27	-	54	-	-	**84**
2022	-	-	-	-	-	4	28	-	55	-	-	**86**
2023	-	-	-	-	-	4	28	-	56	-	-	**89**
2024	-	-	-	35	-	5	29	-	-	8	(0)	**76**
2025	-	-	-	41	-	5	30	-	-	8	(0)	**83**
2026	-	-	-	44	-	6	30	-	-	8	(1)	**87**
2027	-	-	-	44	-	6	31	-	-	20	(1)	**100**
2028	173	(11)	18	45	(49)	6	32	(30)	-	21	(1)	**202**
2029	177	(11)	18	49	(54)	6	32	(31)	-	21	(1)	**207**
2030	181	(11)	18	56	(61)	7	33	(31)	-	22	(2)	**211**
2031	185	(11)	19	59	(65)	7	34	(32)	-	22	(2)	**215**
2032	189	(12)	19	64	(70)	7	35	(33)	-	14	(1)	**212**
2033	193	(12)	20	68	(75)	8	35	(34)	-	14	(1)	**216**
2034	198	(12)	20	72	(79)	8	36	(34)	-	14	(1)	**221**
2035	202	(12)	21	72	(80)	8	37	(35)	-	-	-	**213**
	Valuation inputs											
15 year Present Value at 6.92% Discount Rate												
Benefits	76	(5)	8	37	(27)	6	31	(13)	16	10	(1)	**137**
Sub-total			79					33	16		9	
											Costs	**267**
											Benefit:Cost Ratio	**0.51**

Summer Capacity Contribution Equivalent per MW Nameplate

	Li 4hr	Li 3hr	Li 3hr w/Losses
Contribution	94%	88%	98%
Adjustment		-6%	11%

Attachment 3

APPENDIX Q – ENERGY STORAGE POTENTIAL EVALUATION

Introduction

Energy storage resources can provide a wide range of grid services and can be flexibly sized and sited. Many of these grid services have been increasing in value with increasing penetration of variable energy resources such as wind and solar, while energy storage costs have been falling. As a result, storage resources are an increasing component of PacifiCorp's least-cost, least-risk preferred portfolio. While the 2019 IRP portfolio analysis captures the system benefits of energy storage, it does not fully account for localized benefits and siting opportunities. This appendix provides details on how energy storage resources can be configured to maximize the benefits they provide.

Because energy storage resources are highly flexible, with the ability to respond to dispatch signals and act as both a load and a resource, they can potentially provide any of the grid services discussed herein. Other types of resources, including distributed generation, energy efficiency, and interruptible loads can also provide one or more of these grid services, and can complement or provide lower-cost alternatives to energy storage. Given that broad applicability, Part 1 of this appendix first discusses a variety of grid services as generically and broadly as possible. Part 2 discusses the key operating parameters of energy storage and how those operating parameters relate to the grid services in Part 1. Finally, Part 3 discusses how to optimize the configuration and dispatch of energy storage and other distributed resources to maximize the benefits to the local grid and the system. Part 3 also provides examples of specific applications and examples of applications that may be cost-effective in the future.

Part 1: Grid Services

PacifiCorp must ensure that sufficient energy is generated to meet retail customer demand at all times. It also must maintain resources that can respond to changing system conditions at short notice, these operating reserves are held in accordance with reliability standards established by the National Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC). Both energy and operating reserves are dispatch-based, and dependent on the specific conditions at a specific place and time. These values are generally independent from hour to hour, as removing a resource in a subset of hours may not impact the value in the remaining hours.

Because load can be higher than expected and some resources may be unavailable at any given time, sufficient generation resources are needed to ensure that energy and operating reserve requirements can be met with a high degree of confidence. This is referred to as generation capacity. The transfer of energy from the locations where it is generated to the locations where it is delivered to customers requires poles, wires, and transformers, and the capability of these assets is referred to as transmission and distribution (T&D) capacity. Generation and T&D capacity are both generally asset-based, and provide value by allowing changes in the resources and T&D elements. In general, assets cannot be avoided based on changes to a subset of the hours in which they are needed and only limited changes are possible once constructed or contracted. It should also be noted that the impact of asset or capacity changes on dispatch must also be included in any valuation.

These obligations are broken down into the following grid services, which are discussed in this section:

- Energy, including losses;
- Operating reserves, including:
    - Spinning reserve;
    - Non-spinning reserve;
    - Regulation and load following reserves; and
    - Frequency response;
- Transmission and distribution capacity; and
- Generation capacity.

Energy Value

Background

Because PacifiCorp's load and resources must be balanced at all times, when an increment of generation is added to PacifiCorp's system, an increment of generation must also be removed. This could take the form of a generator that is backed down, an avoided market purchase, or an additional market sale. The cost of the increment that is removed (or the revenue from the sale), represents the energy value, and this value varies by location and by time. Location can also impact losses relative to the generation which would otherwise have been dispatched, with losses manifesting as a larger effective volume. With regard to time, there are two relevant time scales: hourly values, and sub-hourly values.

The energy value in a location is dependent on PacifiCorp's load and resource balance, the dispatch cost of its resources, and the transmission capability connecting those resources to load. Differences in energy value occur when the economic resources in area exceed the transmission export capability to an area that must then use higher cost resources to serve load. Once transmission is fully utilized, the higher cost resources must be deployed to serve the importing area and lower cost resources will be available in the exporting area. As a result, the value in each location will reflect the marginal resources used to serve load in each area. If transfers are not fully utilized in either direction, the marginal resource in both areas would be the same, and the energy value would be the same.

Both load and resource availability change significantly across the day and across the year. Differences in value over time are driven by the cost of the marginal resource needed to serve load, which changes when load or resource availability change. When load goes up, or the supply of lower-cost resources goes down, the marginal resource needed to serve load will be more expensive.

The value by location is also dependent on the losses relative to the generation which would otherwise have been dispatched. Losses occur during the transfer of energy across the T&D system to a customer's location. As distance and voltage transformation increase, more generation must be injected to meet a customer's demand. As a result, a distributed resource that is close to customer load or located on the same voltage level can avoid both energy at its location as well as the losses which otherwise would have occurred in delivering energy to that location. As a result, the marginal generation resource's output may be reduced by an amount greater than the metered output of a distributed resource. This increase in volume due to losses is also relevant to generation and T&D capacity value. In addition to varying by location and voltage, losses vary across time, primarily due to line loading, as loss rates increase as loading increases. To the extent distributed resources impact line loading, it is reasonable to incorporate the marginal losses that they avoid.

Modeling

There are two basic sources of energy values: market price forecasts and production cost models. There are also two relevant time scales: hourly values, and sub-hourly values.

PacifiCorp produces a non-confidential official forward price curve (OFPC) for the major market points in which it typically transacts on a quarterly basis. The OFPC represents the price at which power would be transacted today, for delivery in a future period. The OFPC contains prices for each month for heavy load hour (HLH) and light load hour (LLH) periods and goes forward approximately 20 years.[1] However, not all hours in the HLH or LLH periods have equal value. To differentiate between hours, PacifiCorp uses scalars calculated based on historical hourly results. For PacifiCorp's operations and production cost modeling, scalars are based on the California Independent System Operator's day-ahead hourly market prices. Because these values are used in operations, the details on the methodology and the resulting prices are treated confidentially. To allow for transparency, PacifiCorp has also developed non-confidential scalars using historical Energy Imbalance Market prices. With either scalars, the result is a forecast of hourly market prices that averages to the values in the OFPC over the course of a month. Using hourly market price to calculate energy value implies that market transactions are either the avoided resource, or a reasonable representation of the avoided resource's cost.

Production cost models contain a representation of an electric power system, including its load, resources, and transmission rights, as well as markets where power can be bought or sold. They also account for operating reserve obligations and the resources held to cover those obligations. All models are simplified representations, and there are several key simplifying assumptions. The granularity of a model is its smallest calculated timestep. While calculating twice as many timesteps should take roughly twice as long from a mechanical standpoint, maintaining inputs to represent those timesteps is more complicated, and a model is only as good as its inputs. To simplify the representation of location, transmission areas can be defined by the key transmission constraints which separate them, with transmission within each area assumed to be unconstrained. Another simplifying assumption is to model all load and resources at a level equivalent to generator input. For instance, load is "grossed up" from the metered volume to a level that includes the estimated losses necessary to serve it. This allows for a one for one relationship between all volumes, which vastly simplifies the model.

PacifiCorp's production cost models with these representations include the Planning and Risk (PaR) model, used to evaluate portfolios in the IRP, and the Generation and Regulation Initiative Decision Tools model (GRID), used to calculate net power costs in general rate cases and for some qualifying facility avoided cost rates. Both of these models reflect the system down to an hourly granularity. While these production cost models use the hourly market prices from the OFPC, a distributed resource's energy value in these models will depend on its location and other

[1] HLH is 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays. LLH is all other hours.

characteristics and can be either higher or lower than the market price in a given hour. Generally, a resource's value is based on the difference between two production cost model studies: one with the resource included, and one with the resource excluded. This explicitly identifies the marginal resources dispatched in the absence of the resource being evaluated.

More detailed models of the electrical power system also exist, for instance PacifiCorp uses physical models for grid operations and planning that account for power flows and the loading of individual system elements. Similarly, the California Independent System Operator (CAISO) uses a "Full Network Model" with detailed representations of all resources and loads, as well as the transmission system. CAISO's model includes a representation of PacifiCorp's system for the purpose of dispatching resources in the Western Energy Imbalance Market (EIM), and models a five minute granularity for that purpose. The added detail these physical models produce comes from a significant increase in the complexity of inputs and computational requirements.

Hourly market prices can be used to provide a readily available estimate of energy value, as shown in Table Q.1 for various energy storage technologies. The variables which impact energy margin include: hours of storage, efficiency, forced outage rates, and variable degradation costs. Table Q.1 contains twenty-year nominal levelized values for 2019-2038, and reflects an average of the margins at the Mid-Columbia and Four Corners markets.

Table Q.1 - Energy Margin by Energy Storage Technology

Technology	Hours of Storage	Efficiency (%)	Forced Outage (%)	Variable Cost ($/MWh)	Energy Margin ($/kw-yr)
Lithium Ion	2	88%	1%	12.48	32.13
Lithium Ion	4	88%	1%	12.48	49.77
Flow	6	65%	2%	0	53.03
Pumped Hydro	9	79%	3%	0	81.67

These market values do not account for the effects of location, volume, or operating reserve requirements. For instance, PacifiCorp is obligated to hold contingency reserves equal to three percent of all generation in its balancing authority areas, but is not required to hold those reserves for market purchases. This is analogous to the additional regulation reserves held to account for the variability and uncertainty in the output of wind and solar (a.k.a. integration costs). Adjustments can be applied to account for these differences, but the results are likely to diverge as market prices and resource portfolios change. Hourly market prices are also more likely to understate the value of dispatchable resources.

The PaR model and the GRID model both identify resources to carry operating reserves for each hour, but do not include the intra-hour changes that would cause those resources to be deployed. Because resources that are dispatchable within the hour can be dispatched up when marginal energy costs are high, and down when marginal energy costs are low, this can result in incremental value relative to an hourly market price or hourly production cost model result. In practice, sub-hourly dispatch benefits are largely derived from PacifiCorp's participation in EIM, and the specific rules associated with that market. For instance, resources must be participating in EIM in order to receive settlement payments based on their five-minute dispatches. Resources that are not participating receive settlement payments based on their hourly imbalance. Because non-participating resources are not visible to the market, their sub-hourly dispatch would not impact the market solution. Because distributed resources can be aggregated for purposes of EIM participation, size should not be an impediment; however, the structure of the EIM may dictate some aspects of their use and would need to be aligned with the other services a distributed resource provides.

To help identify sub-hourly energy value not captured in its hourly production cost models, during the development of the 2019 IRP, PacifiCorp calculated intra-hour flexible resource credits (IHFRC) for a variety of resource types, based on expected economic dispatch relative to historical EIM sub-hourly pricing. Unsurprisingly given their flexibility, energy storage resources provide the highest value of the resources evaluated, as shown in Table Q.2 below. Values shown are in 2018$.

Table Q.2 – Intra-hour Flexible Resource Credits by Resource Type

Resource	Credit ($/kw-year)	Dispatch (% of Nameplate)	Cycles/day	Source
Pumped Hydro 6-14hr	30.44	9.2% - 9.8%	0.2 - 0.4	Proxy
CAES 48hr	30.28	11%	0.05	Proxy
Flow 6hr	27.24	10%	0.38	Proxy
Li-Ion 4hr	25.60	9%	0.56	Proxy
Li-Ion 2hr	25.02	8%	0.90	Proxy
Load Control - 528 hrs/yr	19.20	6%	n/a	Proxy
Load Control - 30 hrs/yr	6.00	0.3%	n/a	Proxy
Resource			**Minimum operating level (%)**	
SCCT Intercooled	18.51	8%	15%	Proxy
SCCT Aero	16.58	10%	40%	Proxy
Baseload Steam	5.54	*	24%	Actual
Peak Steam	4.89	*	24%	Actual
CCCT	3.77	*	70%	Actual
SCCT Frame F	3.47	1%	43%	Proxy
Resource/Bid Price			**% of annual output**	
Solar/$0	1.22	-1.7%	5.6%	Proxy
Wind/$0	0.87	-1.1%	2.9%	Proxy
Wind/PTC	0.14	-0.04%	0.1%	Proxy

*Resources are dispatched up and down from base schedule in EIM.

PacifiCorp initially proposed that IHFRC values be netted out of the resource costs identified in its supply-side resource table, such that the net costs would be used for portfolio selection and valuation. In response to stakeholder feedback about the concept and methodology, the adjustment for IHFRC values was not incorporated as part of the 2019 IRP. PacifiCorp anticipates that the resources above would generate incremental value relative to the hourly granularity of the 2019 IRP modeling, but additional work is required to engage stakeholders and ensure that the results are truly additional.

Operating Reserve Value

Background

Operating reserve is defined by NERC as “the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[2] Operating reserves are capability that is not currently providing energy, but which can be called upon at short notice in response to changes in load or resources. Operating reserves and energy are additive – a resource can provide both at the same time, but not with the same increment of its generating capability. Operating reserves can also be provided by interruptible loads, which have an effect comparable to incremental resources. Additional details on operating reserve requirements are provided in Volume II, Appendix F (Flexible Reserve Study).

As with energy value, operating reserve value is based on the marginal resource that would otherwise supply operating reserves, and varies by both location, time, and the speed of the response. Because operating reserve requirements are primarily applied at the Balancing Authority Area (BAA) level, the associated value is typically uniform within each of PacifiCorp's BAAs. An exception to this is that operating reserves must be deliverable to balance load or resources, so unused capability in a constrained bubble without additional export capability does not count toward the meeting the requirements. Operating reserve value is somewhat indirect in comparison to energy value, as it relates to the use of the freed up capacity on units that would otherwise be holding reserves. If that resource's incremental energy is less expensive that what is currently dispatched, it can be dispatched up, and more expensive energy can be dispatched down. The value of the operating reserves in that instance is the margin between the freed up energy and the resource that is dispatched down. Note that the dispatch price of the resource being evaluated does not impact the value, since holding operating reserves does not require dispatch. When the freed up resource is more expensive than what is currently dispatched, it will not generate more when the operating reserve requirement is removed, and the value of operating reserves would be zero. With this in mind, operating reserves are generally held on the resources with the highest dispatch price. Finally, operating reserve value is limited by the speed of the response: how fast a unit can ramp up in a specified time period, and how soon it begins to respond after receiving a dispatch signal. Reliability standards require a range of operating reserve types, with response times ranging from seconds to thirty minutes.

Modeling

As discussed above, the value of incremental operating reserves is equal to the positive margin between the dispatch cost of the lowest cost resource that was being held for reserve, and the dispatch cost of the highest cost resource that was dispatched for energy. Similar to the value of energy, the price of different operating reserve types could be forecasted by hour, based on forecasts of reserve capability, demand, and resource dispatch costs. Given the range and variability in these components, this would be an involved calculation. In addition, because operating reserves are a small fraction of load, they are more sensitive to volume than energy. For instance, spinning reserve obligations are approximately three percent of load in each hour. As a result, resource additions may rapidly cover that portion of PacifiCorp's requirement met by resources that could otherwise provide economic generation and which produce a margin when released from reserve holding. This is particularly true for batteries and interruptible load resources that can respond rapidly and thus count all or most of their output toward reserve obligations.

While a market price for operating reserve products does not align well with PacifiCorp's system, the specifics of the calculation described above are embedded within PacifiCorp's production cost models. Those models allocate reserves first to energy limited resources in those periods where

[2] NERC Glossary of Terms: http://www.nerc.com/files/glossary_of_terms.pdf, updated May 13, 2019.

they could generate, but are not scheduled to do so. Examples of energy limited resources include interruptible loads, hydro, and energy storage. If called on for reserves, these resources would lose the ability to generate in a different period, so the net effect on energy value for that resource is relatively small. As a result, the unused capacity on these resources can't be used for generation, but that also means it can count as reserves without forgoing any generation and incurring a cost to do so. After operating reserves have been fully allocated to the available energy-limited resources, reserves are allocated to the highest cost generators with reserve capability in the supply stack, up to each unit's reserve capability, until the entire requirement is met. This is generally done prior to generation dispatch and balancing, because the requirements are input to the model or based on a formula and aren't typically restricted based on transmission availability. After the reserve allocations are complete, the remaining dispatch capability of each unit is used to develop an optimized balance of load and resources.

As part of the calculation of wind and solar integration costs for the 2019 IRP, as reported in Volume II, Appendix F (Flexible Reserve Study), PacifiCorp prepared a study assessing the cost of holding incremental operating reserves. That study identified a cost of $50/kw-yr (2018$), based on a 2018-2036 study period. This value would be applicable to any resource that provided operating reserves uniformly throughout the year.

Transmission and Distribution Capacity

For the first time, the 2019 IRP has endogenously included transmission upgrades as part of portfolio selection. This allows the cost of transmission upgrades to be considered as part of the modeled cost of resources in each area. However, energy efficiency, load control, and stand-alone energy storage resources were not subject to these constraints, placing them at an advantage relative to both thermal and renewable resource options. In addition, while the cost of specific T&D projects varies, a generic system wide estimate of transmission upgrade costs is included as a credit to energy efficiency in the 2019 IRP, and amounts to $4.16/kw-year (2018$). In practice, these costs would vary by project and some transmission upgrades would not be suitable for deferral by distributed resources. Because of the large scale of many transmission upgrades, and the binary nature of the expenditures, it may be difficult to procure adequate distributed resources to cover the need in a timely fashion and in accordance with reliability requirements, though it is always appropriate to consider the available options when considering expenditures on an upgrade. Distribution capacity upgrades are more likely to be suitable for deferral by a distributed resource, as the scale of the need is closer to that of these types of resources.

To that end, PacifiCorp maintains an "Alternative Evaluation Tool" which is used to screen the list of projects identified during T&D planning to assess where distributed resources, including energy storage, could be both technically feasible and cost competitive as compared to traditional T&D solutions. If a study shows that distributed resource alternatives are feasible and potentially cost-competitive that project is flagged for detailed analysis.

To help illustrate the potential for distribution capacity deferral, PacifiCorp assessed the peak loading and forecasted growth at each of the distribution substations across its system. Once peak loading reaches 90 percent of a distribution substations capability, PacifiCorp takes steps to either reconfigure the loads or add capacity to ensure that it remains sufficient to serve customers. For this analysis, substations were classified as having a high potential for distribution capacity deferral if their current loading is at or above the 90 percent threshold, medium if they are anticipated to exceed the 90 percent threshold within the next twenty years, and low if they are not expected to exceed the 90 percent threshold in the next twenty years. The results shown in Table Q.3 identify the portion of PacifiCorp's distribution load that is part of each of these three categories in each state. The "low" category represents a majority of PacifiCorp's system, which indicates that programs targeting distributed resources in specific locations have the potential to provide significantly greater value.

Table Q.3 – Share of Distribution Load by State with Potential Upgrade Deferral

State	High	Medium	Low
CA	13%	3%	84%
ID	38%	38%	23%
OR	13%	36%	51%
UT	8%	30%	62%
WA	24%	32%	43%
WY	7%	21%	72%
Total	**13%**	**31%**	**56%**

Because distribution upgrades are primarily driven by load growth, distributed resources need to be sufficient to maintain load within existing peaks to defer distribution upgrades. Energy storage resources can be cost-effective to cover brief peaks, but are less cost-effective as the duration of the shortfall increases. To the extent load in an area continues to grow, the deferred distribution upgrade is likely to be necessary eventually. Table Q.4 illustrates the distribution load growth by state that is likely to trigger distribution upgrades during the IRP planning period. The forecasted distribution capacity deferral value is $21.89/kw-yr (2018$) for substations with a planned upgrade that can be deferred indefinitely. If distributed resource programs result in resources on a mix of substations that include medium or low value areas, the effective distribution capacity deferral value would be reduced.

Table Q.4 - Forecasted Distribution Load Growth Above the 90 Percent Planning Threshold

Year	CA	ID	OR	UT	WA	WY	Total
2019	1	19	30	79	12	9	151
2020	1	22	30	108	18	11	190
2021	1	22	30	116	18	11	199
2022	1	23	42	123	21	11	221
2023	1	23	42	164	25	11	266
2024	1	31	51	164	25	11	283
2025	1	34	63	165	26	11	300
2026	2	35	72	170	26	11	315
2027	2	35	74	172	30	14	327
2028	2	35	77	194	33	14	354
2029	2	35	86	196	33	55	406
2030	2	39	90	206	33	55	424
2031	2	40	94	248	33	59	476
2032	2	40	99	279	33	59	511
2033	2	43	99	313	36	61	554
2034	2	46	101	353	36	63	601
2035	2	46	106	357	36	68	615
2036	2	51	108	367	36	68	633
2037	2	51	115	384	36	68	655
2038	2	52	118	395	43	70	679

Generation Capacity

Background

To provide reliable service to customers, a utility must have sufficient resources in every hour to:

- Serve customer load, including losses and any unanticipated load increase.
- Hold operating reserves to meet NERC and WECC reliability standards, including contingency, regulation, and frequency response.
- Replace resources that are unavailable due to:
  - Forced and planned outages
  - Dry hydro conditions
  - Wind and solar conditions
  - Market conditions

PacifiCorp refers to "Generation Capacity" as the total quantity of resources necessary to reliably serve customers, after accounting for the items above. The level of resources needed for reliable operation is discussed in Volume II, Appendix I (Planning Reserve Margin Study). For the 2019 IRP, PacifiCorp selected a planning reserve margin of 13 percent over its coincidental peak loads and this is applied to both summer and winter peaks. The planning reserve margin does not translate directly into either resources or need. Instead, PacifiCorp assesses the capacity contribution of each of its resources in Volume II, Appendix N (Capacity Contribution Study). Capacity contribution represents the portion of a resource that can be counted on to reliably meet peak demand. This is inherently dependent on the composition of a portfolio, so for the first time in the 2019 IRP, PacifiCorp performed a detailed assessment of the hourly reliability of each portfolio and increased requirements for portfolios that failed to achieve a minimum reliability level.

All resources contribute to a reliable portfolio, but they do so in ways that are not straightforward to measure. Removing a resource from a portfolio will make that portfolio less reliable unless it is replaced with something else, ideally in a quantity that provides an equal capacity contribution and results in equivalent reliability. As indicated above, reliability is difficult to predetermine, hence PacifiCorp's reliance on a reliability assessment for the 2019 IRP.

As a result, the most direct measurement of the generation capacity value of a resource is to build a portfolio that includes it, and compare that portfolio to one without it. But even that analysis would identify more than just generation capacity value, as it would also include energy and operating reserve impacts related to both the resource being added and resources that were delayed or removed. This is an essential description of the steps used to develop portfolios in the IRP, and while powerful, the IRP models and tools do not lend themselves to ease of use, rapid turnaround, or the evaluation of small differences in portfolios.

As an alternative, a simplified approach to generation capacity value can be used when the resources being evaluated are similar to the proxy resource additions identified in the IRP preferred portfolio. The premise of the approach is that the IRP preferred portfolio resources represent the least-cost, least-risk path to reliably meet system load. The appropriate level of generation capacity value is inherently embedded in the IRP preferred portfolio resource costs, because those resources achieve the stated goal of reliable operation. Again, while it is difficult to identify exactly what portion of the resource cost should be considered generation capacity as opposed to energy or operating reserve value, the total resource cost is straightforward and known.

The 2019 IRP preferred portfolio includes stand-alone four-hour lithium-ion battery storage resources starting in 2028. These resources have annual fixed costs (capital recovery and fixed operations and maintenance) of approximately $173/kw-yr in 2028. After netting out energy values based on market as described above, the remainder is $111/kw-yr (2028$) based on Four Corners market prices and $130/kw-yr (2028$) based on Mid-Columbia market prices. In 2018 dollars, this is equivalent to $89-$104/kw-yr (2018$). These values do not include any value from operating reserves or from charging during periods of renewable resource over-supply when the marginal dispatch cost on PacifiCorp’s system is less than market due to transmission congestion or limits on market volumes.

While uncertainty remains in these generation capacity values, the uncertainty in the conclusions can be small to the extent a resource being evaluated provides largely the same services as the resource in the 2019 IRP. As a result, it is reasonable to compare the costs and benefits of energy storage resources that provide energy value, operating reserves, and charging during renewable resource over-supply to the costs and implicit benefits of energy storage resources in the 2019 IRP, which also provide those same services. To the extent the resources being evaluated vary significantly in characteristics or timing relative to the resources in the 2019 IRP preferred portfolio, a more thorough analysis using a production cost model would be necessary to ensure the relative benefits of preferred portfolio resources and a resource being evaluated are characterized accurately.

Part 2: Energy Storage Operating Parameters

This section discusses some of the key operating parameters associated with energy storage resources. Beyond just defining the basic concepts, it is important to recognize the specific ways in which these parameters are measured, and ensure that any comparison of different technologies or proposals reports equivalent values. For example, many battery systems operate using direct current (DC) rather than the alternating current (AC) of the vast majority of the electrical grid. When charging or discharging from the grid, inverters must convert DC power to AC power, which creates losses that reduce the effective output when measured at the grid, rather than at the battery. To handle this distinction, PacifiCorp uses the AC measurement at the connection to the electrical grid for all parameters, as this aligns with the effective “generation input” of an energy storage resource. As previously discussed, an additional adjustment for line losses on the electrical grid may also be necessary, but that is dependent on the location and conditions on the electrical grid, rather than the energy storage resource.

- **Discharge capacity**: The maximum output of the energy storage system to the grid, on an AC-basis, measured in megawatts (MW). This is generally equivalent to nameplate capacity.
- **Storage capacity:** The maximum output of the energy storage system to the grid, on an AC-basis, when starting from fully charged, measured in megawatt-hours (MWh).
- **Hours of storage:** The length of time that an energy storage system can operate at its maximum discharge capacity, when starting from fully charged, measured in hours. Generally, the hours of storage will be equal to storage capacity divided by discharge capacity.
- **Charge capacity:** The maximum input from the grid to the energy storage system, on an AC-basis, measured in megawatts (MW).

- **Round-trip efficiency:** The output of the energy storage system to the grid, divided by the input from the grid necessary to achieve that level of output, stated as a percentage. A storage resource with eighty percent efficiency will output eight MWh when charged with ten MWh. If charge and discharge capacity are the same, losses result in a longer charging time. For instance, an energy storage system with four hours of storage, eighty percent efficiency, and identical charge and discharge capacity would require five hours to fully charge (4 hours of discharge divided by 80 percent discharge MWh per charge MWh).
- **State of charge:** This is a measure of how full a storage system is, calculated based on the maximum MWh of output at the current charge level, divided by the storage capacity when fully charged, and is stated as a percentage. One hundred percent state of charge indicates the storage system is full and can't store any additional energy, while zero percent state of charge indicates the storage system is empty and can't discharge any energy. As previously indicated, PacifiCorp's state of charge metric is based on output to the grid. As a result, the entire round-trip efficiency loss is applied during charging before reporting the state of charge. For example, a storage system with a ten MWh storage capacity and eighty percent efficiency would only have an eighty percent state of charge after ten MWh of charging had been completed, starting from empty.
- **Station service:** Round-trip efficiency is a measure of the losses from charging and discharging. Some energy storage systems also draw power for temperature control and other needs. This is typically drawn from the grid, rather than the energy storage resource.

Some energy storage technologies experience degradation of their operating parameters over time and based on use. The following parameters are used to quantify the effects of degradation.

- **Storage capacity degradation:** The primary impact of degradation is on storage capacity. Much of the degradation occurs as part of charge-discharge cycles, and can be measured as the degradation per thousand cycles. After one thousand cycles, a four-hour storage system might only be capable of storing 3.5 hours of output. Some storage resources also experience degradation that isn't tied to cycles, for instance based on differing state of charge levels or time.
- **Cycle life:** This is the total number of full charge and discharge cycles that energy storage equipment is rated for. Three thousand cycles is common for lithium-ion resources, but operating under harsh conditions can also cause the effective cycle count to decline faster. Once storage capacity has degraded by thirty percent degradation per cycle may accelerate.
- **Depth of discharge:** Operating at a very high or very low state of charge, particularly for an extended period of time, can cause more rapid degradation. This metric can be used to identify how particular operations impact the effective remaining cycle life.
- **Variable degradation cost:** Lithium-ion energy storage equipment is composed of a large number of battery modules, each of which experience degradation. These modules can be gradually replaced over time to maintain a more consistent storage capacity, or they can be replaced all at once when cycle limits are reached, at the expense of a reduced storage capacity in the interim. In either case, the replacement cost of storage equipment can be expressed per MWh of discharge, and accounted for as part of resource dispatch.

Part 3: Distributed Resource Configuration and Applications

This section described the potential benefits of different distributed resource siting and configuration options. Due to economies of scale, distributed resource solutions generally higher cost relative to utility-scale assets. For example, the 2019 IRP supply-side table shows fixed costs for a fifteen megawatt, four-hour lithium-ion battery costs that are approximately half that of the costs for a one megawatt, four-hour battery. While these savings are appreciable, it should be noted that a fifteen megawatt battery is small and can be considered modular relative to traditional resources such as a simple cycle combustion turbine. Many of PacifiCorp's distribution substations have capacity in excess of fifteen megawatts, such that a battery of that size could be feasible at the distribution level, with the potential for incremental benefits relative to the transmission-connected battery resources modeled as part of the 2019 IRP preferred portfolio. The most cost-effective locations for distributed resource deployment are likely to reflect a balance of local requirements and economies of scale.

Secondary Voltage

A distributed resource which is located downstream from the high voltage transmission grid will have a larger energy impact than its metered output would indicate, due to line losses. This is true for both charging and discharging; however, the marginal loss rate increases with load, so the effects are not equal. To the extent discharging is aligned with periods with higher load, and charging is aligned with periods with lower load, the benefits will increase. For example, the marginal primary voltage losses for Oregon are estimated at 9.5 percent on average across the year. Savings based on primary losses would be appropriate to apply to a resource connected at the secondary voltage level so long as it is not generating exports to the higher voltage system, as losses would still occur within that level, but would be reduced due to lower deliveries across the higher voltage system. When the hourly loss profile is applied to the hourly market prices used to calculate the energy values described in Part 1, the result is 16 percent higher for a four-hour lithium-ion battery. Much of the incremental benefit is due to high loss rates in summer and winter peak load months, when prices are relatively high. For lithium-ion batteries, there is also an incremental benefit related to variable degradation costs. While the effect of losses makes the battery appear larger from a system benefits perspective, it discharges the same amount, so the variable cost component doesn't scale with losses, creating an additional benefit that is captured in this energy margin.

In addition to incremental energy value, resources connected at primary or secondary voltage will also have a proportionately higher generation capacity value. In the example for Oregon above, this amounts to a roughly 11 percent increase in effective capacity contribution based on avoided primary losses.

T&D Capacity Deferral

As indicated in the grid services section, distributed resources can allow for the deferral of upgrades by reducing the peak loading of the transmission and distribution system elements serving their area. In order for deferral to be achieved, a distributed resource must reliably reduce load under peak conditions. However, the timing of peak conditions for a given area is likely to vary from the peak conditions for the system as a whole. As a result, the energy or generation capacity value of energy-limited resources used for a T&D capacity deferral application are likely to be reduced. For instance, when energy-limited resources are reserved for local area requirements they would not be available for system reliability events or a period of high energy prices.

Combined Solar and Storage

Solar resources can qualify for a thirty percent federal investment tax credit (ITC) if they come online prior to the end of 2023. Thereafter, solar resources will continue to qualify for a ten percent ITC. Storage that is constructed in combination with a solar resource and which is charged using that solar resource for the first five years of operation qualifies for the same ITC as the solar resource. This can result in 10-30 percent reduction in the costs of combined solar and storage, relative to stand-alone storage. There are also construction and operational efficiencies that can further improve the economics of combined storage and solar assets, including shared construction crews, inverters, property, and maintenance.

As a result of the items benefits above, the 2019 IRP found that the inclusion of storage with solar resources produced an across the board benefit relative to portfolios that included new solar resources without storage. The 2019 IRP analysis assumed that storage resources combined with solar would be sized equivalent to 25 percent of the solar nameplate and have four hours of storage. These sizing parameters will evolve as PacifiCorp goes out to procure specific resources to capture the benefits of the expiring ITC at the end of 2023, based on both the costs and effective capabilities of different configurations. In general, energy storage should be sized to allow it to be fully filled each day using co-located solar output.

Cost-Effectiveness Results

Table Q.5 provides details on the year-by-year benefits of various lithium-ion battery applications, and identifies years and configurations that are estimated to be cost-effective, either on a stand-alone basis or with the applicable solar ITC at that time.

Since a stand-alone battery is included in the preferred portfolio starting in 2028, it is assumed to be cost effective and providing benefits equal to its costs starting in 2028. Prior to 2028, benefits are based on the intra-hour flexible reserve credit values and operating reserve benefits through 2023, as the battery penetration in this time frame is unlikely to fully cover the operating reserve requirements. Starting in 2024, benefits are assumed to be based on hourly market energy value and the intra-hour flexible reserve credit values, as the higher value operating reserve values are assumed to be fully satisfied with the 2024 battery resources in the preferred portfolio.

Table Q.5 - Energy Storage Applications - Annual Benefits Stream and Cost-Effectiveness

$/kw-yr	Stand-alone Li-Ion 4hr Fixed Cost	Hourly Market Energy	Intra-hour Flex Credit	Operating Reserve	Utility-scale Resource	Primary Losses Energy	Primary Losses Gen Capacity	Primary Losses	T&D Deferral	Primary + T&D Deferral
2019		22.90	26.19	51.17	**77.36**	4.00		**81.35**	22.39	**103.74**
2020		22.64	26.78	52.34	**79.12**	3.98		**83.10**	22.90	**106.00**
2021		25.52	27.39	53.53	**80.93**	4.36		**85.28**	23.42	**108.70**
2022		29.53	28.02	54.75	**82.77**	4.78		**87.56**	23.95	**111.51**
2023		34.02	28.66	56.00	**84.66**	5.28		**89.94**	24.50	**114.44**
2024		40.54	29.31	57.28	**69.85**	5.99		**75.84**	25.06	**100.90**
2025		46.87	29.98	58.58	**76.85**	6.36		**83.21**	25.63	**108.84**
2026		51.12	30.66	59.92	**81.79**	6.79		**88.58**	26.22	**114.79**
2027		51.43	31.36	61.29	**82.79**	6.72		**89.50**	26.81	**116.32**
2028	172.72	52.15	32.08	62.68	**172.72**	6.73	18.69	**198.13**	27.42	**225.56**
2029	176.66	57.36	32.81	64.11	**176.66**	7.21	19.11	**202.98**	28.05	**231.03**
2030	180.69	64.79	33.56	65.57	**180.69**	7.92	19.55	**208.15**	28.69	**236.84**
2031	184.81	69.40	34.32	67.07	**184.81**	8.30	19.99	**213.11**	29.34	**242.45**
2032	189.02	74.71	35.10	68.60	**189.02**	8.78	20.45	**218.26**	30.01	**248.27**
2033	193.33	79.63	35.90	70.16	**193.33**	9.20	20.92	**223.45**	30.70	**254.14**
2034	197.74	84.30	36.72	71.76	**197.74**	9.57	21.39	**228.70**	31.40	**260.10**
2035	202.25	84.73	37.56	73.40	**202.25**	9.49	21.88	**233.61**	32.11	**265.73**
2036	206.86	88.33	38.42	75.07	**206.86**	9.68	22.38	**238.92**	32.84	**271.76**
2037	211.57	94.67	39.29	76.78	**211.57**	10.36	22.89	**244.82**	33.59	**278.41**
2038	216.40	103.07	40.19	78.53	**216.40**	11.15	23.41	**250.96**	34.36	**285.32**
2039	221.33	105.42	41.10	80.32	221.33	11.41	23.95	256.68	35.14	291.83
2040	226.38	107.83	42.04	82.16	226.38	11.67	24.49	262.54	35.94	298.48
2041	231.54	110.29	43.00	84.03	231.54	11.93	25.05	268.52	36.76	305.28
2042	236.82	112.80	43.98	85.95	236.82	12.20	25.62	274.64	37.60	312.25

Valuation inputs
Cost-effective w/ 30% ITC
Cost-effective w/ 10% ITC
Cost-effective 0% ITC

CERTIFICATE OF SERVICE

I certify that I electronically filed a true and correct copy of PacifiCorp's **Second Compliance Filing – Energy Storage Pilot and Evaluation Plan Update** on the parties listed below via electronic mail and/or overnight delivery in compliance with OAR 860-001-0180.

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