Portland General Electric
121 SW Salmon Street • Portland, Ore. 97204
PortlandGeneral.com

January 5, 2018

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem OR 97308-1088

**RE: UM 1856 Direct Testimony for PGE's Energy Storage Proposal**

Filing Center:

Enclosed for filing, in the above referenced matter, please find the following:

- Direct Testimony of Jim Riehl, Rebecca Brown (PGE Exhibit 100)
  - Exhibit 101 – Energy Storage Proposal
  - Exhibit 102 – Compliance with Guidelines Outlined by Staff in Order No. 16-504
- Direct Testimony of Elaine Hart, Tess Jordan, Jay Landstrom (PGE Exhibit 200)

PGE submits this filing pursuant with Commission Order Nos. 16-504, 17-118, and 17-375 and in response to House Bill 2193, which mandates PGE to procure at least five megawatt hours of energy storage systems by 2020. In addition, PGE submits confidential work papers that provide the benefit/cost model. This is subject to Protective Order No. 17-441 and will be sent separately.

If you have any questions or require further information, please call Rebecca Brown at (503) 464-8545. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Robert Macfarlane
Interim Manager, Pricing and Tariffs

Cc: Seth Wiggins, OPUC

Enclosure

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

# UM 1856

Energy Storage Proposal

**PORTLAND GENERAL ELECTRIC COMPANY**

**DIRECT TESTIMONY AND EXHIBITS**

**January 5, 2018**

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

# UM 1856

# Energy Storage Proposal

**PORTLAND GENERAL ELECTRIC COMPANY**

**Direct Testimony of**

***Jim Riehl***
***Rebecca Brown***

**January 5, 2018**

# Table of Contents

# I. Introduction

**Q. Please state your names and positions with Portland General Electric Company.**

A. My name is Jim Riehl. I am a Project Manager in the Generation, Transmission, and Distribution Project Management Office. My qualifications appear in Section IX of this testimony.

My name is Rebecca Brown. I am a Senior Regulatory Analyst in the Rates and Regulatory Affairs department. My qualifications appear in Section IX of this testimony.

**Q. What is the purpose of your testimony?**

A. The purpose of this testimony is to provide support for Portland General Electric Company's (PGE's) Energy Storage System Proposal (Proposal), which we filed with the Public Utility Commission of Oregon (OPUC or Commission) November 1, 2017. The Proposal, provided as PGE Exhibit 101, was filed in compliance with House Bill (HB) 2193, 2015 Regular Legislative Session, (HB 2193)[1], and incorporates the guidance provided by the Commission in OPUC Docket No. UM 1751 (UM 1751). HB 2193 directs us, subject to Commission authorization, to procure one or more qualifying energy storage systems that have the capacity to store at least five megawatt hours (MWh). The total capacity may not exceed one percent of PGE's 2014 peak load,[2] which equates to 38.7 megawatts (MW).

Q. **What are the primary elements of PGE's filing?**

A. PGE's filing consists of two testimonies. In this testimony, PGE Exhibit 100, we discuss the detail of each project, the anticipated learnings, and the project-specific results of the cost-

[1] 2015 Oregon Laws Chapter 312.
[2] See HB 2193, Section 2(a).

effectiveness analysis. In PGE Exhibit 200, we discuss the costs, benefits, and portfolio results of the cost-effectiveness analysis.

**Q. What is PGE seeking from the Commission in this docket?**

A. PGE is requesting Commission authorization to proceed with the development of projects proposed in its filed Proposal.[3] Once authorized, we intend to issue Request for Proposals (RFPs) for each of the authorized energy storage system projects to meet HB 2193 requirement of procurement "on or before January 1, 2020."[4] Once the proposed energy storage systems (which consist of three projects and two pilots) have been thoroughly vetted by stakeholders and the Commission, we will seek rate recovery through an automatic adjustment mechanism.[5]

**Q. How does PGE propose to optimize learnings from storage investment?**

A. To optimize learning, our Proposal includes a diversity of projects across project ownership models and use cases. We are purposefully casting a wide net across a full spectrum of applications (e.g., generation-related, distribution-related, near the meter/behind-the-meter, utility-owned/customer-owned). The Commission specifically directed the utilities to "submit multiple, differentiated projects that test varying technologies or applications" in its guidance[6] for proposal submissions.

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[3] HB 2193 provides that the Commission may authorize an electric company to develop one or more projects that include one or more qualifying energy storage system, after considering certain statutory factors. See Enrolled HB 2193 (2015 Legislative Session), Section 3(3)(b).

[4] See HB 2193 Section 2(1).

[5] Enrolled Oregon Senate Bill 1547 (2016 Legislative Session), Section 11 provides that there be an automatic adjustment clause to allow timely recovery of prudently incurred costs for costs related to associated energy storage.

[6] PGE Exhibit 102 provides the guidelines outlined in OPUC Order No. 16-504 and how PGE met the guidelines.

**Q. As one of the requirements in HB 2193, the Commission shall consider each proposal submitted is in the public interest. How is PGE's proposed portfolio in the public interest?**

A. Energy storage is one part of an integrated approach to supporting customer's clean energy goals. In addition to complying with HB 2193, PGE aims to develop projects to learn about storage and its varied uses, system impacts, customer benefits, operational impacts, and distribution system benefits. PGE is committed to building a cleaner energy future for Oregon, and energy storage system can provide a range of grid services to support the transition to that clean energy future while meeting customers' growing demands for resilient power. The proposed projects allow PGE and stakeholders to best understand the approaches to storage that might make the most sense in the future. These learnings will inform future integration of energy storage system, ensure that PGE can effectively operationalize energy storage system on our grid, and maximize the benefits we realize from future storage systems. Our Proposal helps enable the pathway to achieve Oregon's clean energy goals and thus, is in the public interest.

**Q. What is PGE proposing?**

A. We are proposing five separate energy storage system projects:

- Power System Integration (Baldock Mid-feeder) – Outlined in Section II, a mid-feeder-sited storage project that provides capacity, energy, ancillary services, and outage mitigation benefits. This project is co-located with an existing 1.75 MW solar array;
- Power System Integration (Coffee Creek Substation) – A substation-sited, distribution interconnected, large-scale energy storage system project with the

purpose of gaining operational experience with utility-scale energy storage system while providing capacity, energy, ancillary services, and outage mitigation benefits to the grid. Additional detail is provided in Section III;

- Generation Kick Start – A four to six megawatt transmission-connected storage project to create a "hybrid plant." As described in Section IV, this project provides an innovative use case of a relatively small storage installation to realize the full value of spinning reserves of an off-line generator (approximately 18.9 MW), reducing fuel use and emissions at the plant or otherwise allowing another plant (e.g., hydro) to operate at full capacity;
- Customer and Community Microgrid Resiliency Pilot (Microgrid Pilot) – Described in Section V, consists of two to five microgrids to pilot energy resilience by leveraging existing distributed energy resources (DERs) and new energy storage system; creating at least one customer and one community microgrid (two to five total microgrids); and
- Residential Storage Pilot – Approximately 500 residential, behind-the-meter, PGE-controlled storage units to pilot the development of a residential storage program and operation of a distributed, aggregated fleet of storage assets. The Residential Storage Pilot is described in Section VI.

**Q. Should the Commission approve PGE's proposal?**

A. Yes. In addition to complying with HB 2193, incorporating the guidance given by the Commission in UM 1751, and meeting the guidelines in Commission Order No. 16-504 (Order 16-504), provided as PGE Exhibit 102, PGE's proposal will benefit customers in multiple ways. The learnings from these proposed projects will allow us and stakeholders to better understand the costs and benefits of energy storage system today and improve understanding of how technology innovations could evolve and inform approaches to integrating additional energy storage system in the future. The specific project learnings are discussed in the following sections.

The learnings gained from the proposed projects are critical as energy storage system is an important technology for the efficient operation of the distribution grid in the future. The focus on energy storage system as a promising grid technology is increasing in Oregon, as evidenced by the passage of HB 2193, and other parts of the country prompted by a number of trends, including the acceleration of variable renewable development, the increased adoption of distributed resources, and growing concerns around resiliency.

**Q. How do Energy storage systems benefit PGE?**

A. PGE's proposal includes a diverse set of projects that will allow us to deploy energy storage system resources that provide immediate value to the system and teach us more about procuring, enabling, controlling, integrating, and evaluating individual energy storage system resources and aggregated distributed energy storage system fleets. This will give us more information to support the efficient development and utilization of energy storage system in the future, as the need for system flexibility and distribution services continues to increase. Energy storage system resources can be rapidly dispatched, deployed at large or very small scales due to their modularity, can be relatively easily sited and quickly developed, and have zero direct emissions. For these reasons, they have the potential to provide the types of balancing and distribution services that are increasingly needed on our system, while supporting the environmental and resiliency goals of the local communities we serve. Prior to planning energy storage system deployments, we analyzed our system and evaluated what system and customer needs storage might address. Table 1 provides five system and customer needs we identified and whether the proposed projects meet it.

**Table 1**
**Summary of Proposed Energy Storage System Projects**

| Project Name | No. of energy storage systems | Cum. Capacity (MW) | Cum. Energy (MWh) | System Needs | | | Customer Needs | |
|---|---|---|---|---|---|---|---|---|
| | | | | Capacity | Energy and Ancillary Services | Outage Mitigation | Power Reliability | Resiliency |
| Baldock Mid-feeder | 1 | 2 | 4 – 8 | ✓ | ✓ | ✓ | | |
| Coffee Creek Substation | 1 | 17 – 20 | 68 – 80 | ✓ | ✓ | ✓ | | |
| Generation Kick Start | 1 | 4 – 6 | 16 – 24 | ✓ | ✓ | | | |
| Microgrid Pilot | 2 – 5 | 3 – 12.5 | 6 – 100 | ✓ | ✓ | ✓ | ✓ | ✓ |
| Residential Storage Pilot | 300 – 500 | 2 – 3.5 | 6 – 8 | ✓ | ✓ | ✓ | ✓ | ✓ |
| **Portfolio Aggregate** | **305 – 508** | **28 – 38.7*** | **100 – 250** | ✓ | ✓ | ✓ | ✓ | ✓ |

***** Total portfolio aggregate will not exceed 38.7 MW (one percent of PGE's 2014 peak load), per HB 2193, Section (2)(a).

**Q. What benefits do the projects provide to PGE customers?**

A. Generally, all of the projects provide system benefits[7], which extend to all customers, as do the projects' learning opportunities. Both pilots, Microgrid and Residential Storage, provide specific benefits to program participants. Specific information about the value and learning opportunities presented by each component of the proposal are described in the following sections. In addition, benefits are discussed in PGE Exhibit 200, Section III, of this docket.

**Q. How do these projects differ from the energy storage system that PGE already owns and operates?**

A. The SSPC has a discharge capacity of five megawatts and energy storage capacity of 1.25 MWh, making it a 15-minute duration energy storage system. This short duration significantly limits the applications that can be served relative to the projects in the Proposal.

[7] Capacity, Energy Arbitrage, Ancillary Services, and Outage Mitigation.

In particular, this short duration limits outage mitigation, power reliability, and capacity benefits. For example, the capacity contribution of SSPC is 6.25% of installed capacity, relative to 100% for a four-hour energy storage system.

**Q. What project costs did PGE identify?**

A. Table 2 provides a cost summary of each proposal. In total, the portfolio's estimated overnight capital cost range is $55.8-97.8 million (low versus high price indicative vendor bids). Combined with non-capital ongoing maintenance and power augmentation, and programmatic components for the pilot projects, total costs are associated with a year 1 revenue requirement of $11.7-16.4 million. These costs were calculated based on the request for information (RFI)[8] that was issued and may not reflect current market prices or prices that we will see when we issue a RFP.

**Table 2**
**Cost Summary of Energy Storage System Proposals ($M)**

| | **Low-Cost Estimate** | | **High-Cost Estimate** | |
|---|---|---|---|---|
| **Project** | **Overnight Capital** | **Year 1 Rev. Req.** | **Overnight Capital** | **Year 1 Rev. Req.** |
| Baldock Mid-feeder* | $2.8 | $0.6 | $4.1 | $1.0 |
| Coffee Creek Substation* | $30.4 | $6.7 | $35.7 | $8.2 |
| Generation Kick Start* | $5.9 | $1.4 | $7.7 | $1.9 |
| Microgrid Pilot* | $11.6 | $1.5 | $41.2 | $2.8 |
| Residential Storage Pilot | $2.1 | $0.8 | $6.0 | $1.6 |
| Controls and System Integration | $3.1 | $0.4 | $3.1 | $0.4 |
| Administration and Evaluation | - | $0.4 | - | $0.4 |
| **Total** | **$55.8** | **$11.7** | **$97.8** | **$16.4** |

* Assumed 20-year maintenance and capacity contracts. Costs include portfolio controls and administration.

[8] See PGE Exhibit 101, Section 2.1, and PGE Exhibit 200, Section II, for more information on the RFI process.

**Q. Has PGE sought feedback from external stakeholders in advance of filing the application?**

A. Yes. PGE held two public workshops in 2017 on August 1 and September 7 to discuss proposal ideas. In addition, as part of UM 1751, we participated in two Staff Workshops held in 2016 on January 21 and February 29. We received valuable feedback that we considered in the final drafting of the Proposal.

**Q. How is the remainder of your testimony organized?**

A. The remainder of PGE's testimony is organized into the following sections:

- Section II: Power System Integration (Baldock Mid-feeder);
- Section III: Power System Integration (Coffee Creek Substation);
- Section IV: Generation Kick Start;
- Section V: Customer and Community Microgrid Resiliency Pilot;
- Section VI: Residential Storage Pilot;
- Section VII: Controls and System Integration;
- Section VIII: Conclusion; and
- Section IX: Qualifications.

## II. Power System Integration (Baldock Mid-feeder)

**Q. Please describe PGE's Power System Integration (Baldock Mid-feeder) project.**

A. PGE proposes to install a two megawatt (four megawatt hours) energy storage system at the existing 1.75 MW Baldock Solar array in Aurora, OR. The Baldock energy storage system will be interconnected to PGE's Canby–Butteville feeder.

This project will provide capacity, energy, ancillary services, and outage mitigation benefits. Additionally, this energy storage system will allow us to test and gain experience in optimizing the use of solar generated power, and has the potential to allow us to island a portion of the feeder to test medium-voltage microgrid applications. Table 3 below shows the key project attributes for this pilot.

**Table 3**
**Key Project Attributes (Baldock Mid-feeder)**

| Attribute | Value |
|---|---|
| Charge/Discharge Rate (MW) | 2 MW |
| Energy Storage System (MWh) | 4-8 MWh |
| Technology/Material | TBD |
| Response Rate | < 1 second |
| Location | Aurora, OR |
| Substation | Canby |
| Feeder | Canby – Butteville |
| Target In-Service Date | 2020 |

**Q. What are PGE's goals and anticipated learnings for this project?**

A. A mid-feeder project was selected to allow PGE to explore automation schemes to island various sections of the feeder. It will test medium-voltage microgrid applications and the integration of storage into large-scale renewable facilities, in addition to grid services benefits. The operation of this project will provide real-world data that will inform future identification, use cases, and evaluation metrics for implementation of energy storage system as an asset for PGE's system, including identifying the potential for locational value.[9]

In addition, since the project is connected to a solar generation site, the solar array will be able to sustain the energy storage system in the event of a grid outage. The Canby-Butteville feeder serves over 1,100 customers who could potentially immediately benefit from this project.

**Q. How did PGE determine Baldock Mid-feeder as the site for this project?**

A. The process used to select the Canby-Butteville feeder was similar to that used to select Coffee Creek Substation. The Integrated Planning Tool (IPT)[10] and additional considerations analysis yielded 18 feeders with a high potential system value and a viable engineering and operational profile. Canby-Butteville was identified as the preferred feeder due to its locational value and its engineering and operational qualifications; the feeder ranked high in the IPT analysis due to the risk of the assets at Canby Substation, and the feeder's high exposure to non-asset sources of failure (e.g., tree falls).

In addition, the Baldock Solar array site was selected for PGE's ability to meet the HB 2193 construction timeline due to infrastructure readiness and land availability and public visibility of the site.

**Q. How did PGE determine the size of two megawatts (four megawatt hours) for Baldock?**

A. The proposed project sizing was selected for multiple reasons. The two megawatts capacity was informed by:

- The analysis completed by BIS Consulting;

[9] See PGE Exhibit 101, Section 6.12, for more information on PGE's evaluation of this pilot.
[10] See PGE Exhibit 101, Section 2.2(a), and PGE Exhibit 200, Section III, for more information regarding IPT.

- An analysis of the generation output of the Baldock Mid-feeder solar array;
- A review of the capacity available on the feeder or any restrictions due to the wire size;
- Land availability; and
- A review of the capacity of the transformer located at the Canby Substation.

The two-hour duration was driven by physical space constraints on site. Though benefit streams are larger for four-hour energy storage system compared to a two-hour, we do not anticipate that a four-hour energy storage system will fit on the site.

**Q. What were the results of the cost effectiveness analysis for the Baldock Mid-feeder project?**

A. For all of the projects, including the Baldock Mid-Feeder project, the 20-year, low-cost energy storage system asset performs the best. The Baldock Mid-Feeder project provides benefits valued at 84% of costs under the Total Resource Cost Test (TRC). For this energy storage system, total carrying cost (Net Present Value or NPV of initial capital investment and ongoing operation and maintenance or O&M costs for an energy storage system maintenance and power augmentation) is estimated at $4.6 million. Offsetting the costs are benefits that produce a NPV of $3.9 million. This results in a net cost of $800,000. PGE expects the cost gap will be offset, at least in part, by the value of the project's learning objectives described above.

Because this is a two-hour (versus four-hour) energy storage system, capacity provides a smaller share of the benefits (around 45%). Energy and ancillary services provide 42% of the benefits, while outage mitigation provides the remaining 12%.

Across all mid-feeder energy storage system profiles, the cost-effectiveness range is 0.34 (10-year, high-cost, energy storage system) to 0.84 (20-year, low-cost energy storage system) as shown in Table 4 below. As with all profiles, cost-effectiveness increases with longer energy storage system life.

The mid-feeder energy storage system would be cost effective with a total cost reduction (across either or both capital and ongoing O&M) of 16%, or a 20% increase in benefits.

**Table 4**
**TRC and RIM Tests, Baldock Mid-feeder (NPV, $ in 000,000's)**

| | **10 Year** | | **20 Year** | |
|---|---|---|---|---|
| **TRC and RIM Tests** | **Low** | **High** | **Low** | **High** |
| Benefit Cost Ratio | 0.57 | 0.34 | 0.84 | 0.50 |

## III. Power System Integration (Coffee Creek Substation)

**Q. Please describe PGE's Power System Integration (Coffee Creek Substation) project.**

A. PGE proposes to develop and build a 17–20 MW (68–80 MWh) energy storage system on PGE-owned property adjacent to the existing Coffee Creek Substation. This system will be able to provide capacity and energy and ancillary services to our system during normal operations, as well as mitigate outages caused by asset failure or other system issues during outage conditions. We will control and operate the project for system needs and have the ability to dispatch the system as needed. Table 5 below shows the key project attributes for this pilot.

**Table 5**
**Key Project Attributes (Coffee Creek Substation)**

| Attribute | Value |
|---|---|
| Charge/Discharge Rate (MW) | 17 – 20 MW |
| Energy Storage System (MWh) | 68 – 80 MWh |
| Technology/Material | TBD |
| Response Rate | < 1 Second |
| Location | Sherwood, OR |
| Substation | Coffee Creek |
| Target In-Service Date | 2020 |

**Q. What are PGE's goals and anticipated learnings for this project?**

A. This project will allow PGE to gain additional experience, expertise, and learnings with all aspects of utility-scale Energy storage systems, including project development and design, and contracting. It is large enough for PGE's Balancing Authority and Power Operations to deploy in our resource stack, and to support the entire substation during a transmission outage. The real world data it will provide will support learnings around the best practices for implementation and integration of energy storage system into our power system, as well as the locational value of energy storage system.[11]

[11] See PGE Exhibit 101, Section 5.12, for more information on our evaluation plans for this pilot.

**Q. Why did PGE select Coffee Creek Substation for this project?**

A. There were several reasons why PGE selected Coffee Creek Substation. We conducted detailed modelling and analysis within the IPT. The results ranked this site high in site-specific outage mitigation benefits due to the reduction of system risks, based on a $1.2 million risk profile for the substation assets. The additional internal review of site-specific criteria (i.e., land availability, environmental characteristics, existing telemetry, existing substation equipment, and planned near-term projects) scored this site as the top option for capturing the most value from the applicable use cases for a project located at a distribution substation. This available space will allow for flexibility in the design of the energy storage system, and the permitting process will help identify the available space for the project within the property boundary.

**Q. What additional locational benefits does Coffee Creek Substation provide?**

A. This project has a unique profile from the other projects because it is electrically tied to the substation bus. Therefore, PGE will be able to test the ability of the energy storage system to support the entire substation load during different transmission outage scenarios. Coffee Creek Substation utilizes circuit switchers in a selective transfer scheme, which means if the primary transmission source sustains an outage, then an energy storage system could be used to ride through the outage while the scheme transfers to the secondary transmission source. The learnings from this are likely to be valuable and attainable.

**Q. What are the cost-effectiveness results for this project?**

A. The Coffee Creek Substation project is cost-effective using the 20-year, low-cost, energy storage system profile resulting in a benefits/cost ratio of 1.06 (TRC). For this profile, total energy storage system carrying costs are $52.7 million (NPV of revenue requirement for capital and annual O&M costs). Benefit streams produce a NPV of $55.8 million. This results in a net benefit of $3.2 million. Capacity provides roughly 64% of the project's benefits, energy and ancillary services comprise roughly 29%, and outage mitigation provides the remainder.

Across all substation energy storage system profiles, the cost-effectiveness range is 0.61 (10-year, high-cost, energy storage system) to 1.06 (20-year, low-cost, energy storage system), shown below in Table 5. A detailed discussion of project costs and benefits appears in PGE Exhibit 200.

**Table 5**
**TRC and RIM Tests, Coffee Creek Substation (NPV, $M)**

| | 10 Year | | 20 Year | |
|---|---|---|---|---|
| **TRC and RIM Tests** | **Low** | **High** | **Low** | **High** |
| Benefit Cost Ratio | 0.75 | 0.61 | 1.06 | 0.86 |

# IV. Generation Kick Start

**Q. Please describe PGE's Generation Kick Start project.**

A. PGE proposes to develop a four to six megawatt, four-hour energy storage system at its Port Westward 2 Generating Station (PW2) located in Clatskanie, Oregon. In addition to providing capacity and energy and ancillary service benefits, this system will also be coupled with PGE's existing plant control system on one of the plants reciprocating engines to supply up to 18.9 MW of spinning reserves. To meet the spinning reserve requirements, the energy storage system will immediately and automatically respond to frequency deviations while the plant's reciprocating engine is not running. If called on, the engine will be able to ramp up to full output and respond within the ten minute requirement. Table 6 below shows the key project attributes for this pilot.

**Table 6**
**Key Project Attributes (Generation Kick Start)**

| Attribute | Value |
|---|---|
| Charge/Discharge Rate (MW) | 4 – 6 MW |
| Energy Storage System (MWh) | 16 – 24 MWh |
| Technology/Material | TBD |
| Response Rate | < 1 second |
| Location | Clatskanie, OR |
| Generation Facility | PW2 |
| Target In-Service Date | 2020 |

**Q. What are PGE's goals and anticipated learnings for this project?**

A. PGE's goal is to test and understand how to utilize an entire generating unit as spinning reserve even when not synchronized to the grid, and hence not burning fuel. The current requirements for spinning reserve were not written with energy storage system in mind, and more typically include generating units that are fully synchronized (spinning) to the grid. However, implementation of energy storage system technology is starting to challenge the conventional definition. Unlike other locations on the grid, an energy storage system at this facility yields more than its own capacity in spinning reserves.

PGE will learn how to use this project to gain experience developing, contracting for and constructing utility-scale energy storage system projects, as well as integrating the system into the existing PW2 plant control system and controlling energy storage system assets for System Control and Power Operations benefits. Additional PGE grid operations and plant staff will benefit from the experience gained from this project.

In addition, the operation of this project will provide real-world data that will enable future identification, use cases and evaluation metrics for implementation of energy storage system as an asset for our system, including identifying the potential for locational value and the value of spinning reserves to our system.[12]

**Q. Why did PGE choose PW2 for this project?**

A. PGE evaluated all the fast starting units in the generation fleet, including Beaver units 1-6 and unit 8 for this hybrid power plant.[13] Only PW2 units qualified by meeting the ten minute startup time required for spinning reserve. The PW2 operating facility is ideally suited to this project due to its staffing level (including maintenance staff), interconnection in our system, modern communication/telemetry systems, and flexible construction space.

**Q. How did PGE determine the size of four to six megawatts (16-24 MWh)?**

A. A four to six megawatts (four-hour duration) is being proposed to support both the short duration needed to provide frequency support when the system is operating to provide spinning reserves, and the longer duration needed to provide the most value for capacity and

[12] See PGE Exhibit 101, Section 8.12, for more information on PGE's evaluation of this pilot.
[13] PGE considers fast starting units as those that can ramp to full capacity in less than 10 minutes. This is typically limited to simple cycle plants.

energy and ancillary services when the system is not providing spinning reserves. However, a detailed analysis will be required to determine the final energy storage system size to ensure that the system will meet the spinning reserve requirements. PGE anticipates that the energy storage system will need to be sized to provide the same level of frequency support to the system as the engine operating at minimum load.

**Q. What are the results of the cost-effectiveness analysis for the Generation Kick Start project?**

A. The Generation Kick Start project is cost-effective for the 20-year, low-cost, energy storage system profile with a benefit/cost ratio of 1.23 (TRC). For this profile, total energy storage system carrying cost is $10.1 million (NPV of revenue requirement for capital and annual O&M costs). Offsetting the costs are benefits that produce a NPV of $12.5 million. This results in a net benefit of $2.3 million. Capacity provides 67% of the project's benefits while energy and ancillary services comprise the remainder. There is no outage mitigation benefit associated with a generation-located energy storage system.

Across all substation energy storage system profiles, the cost-effectiveness range is 0.58 (10-year, high-cost, energy storage system) to 1.23 (20-year, low-cost, energy storage system), shown in Table 7 below. A detailed discussion of project costs and benefits appears in PGE Exhibit 200 of this docket.

**Table 7**
**TRC and RIM Tests, Generation Kick Start (NPV, $M)**

| | **10 Year** | | **20 Year** | |
|---|---|---|---|---|
| **TRC and RIM Tests** | **Low** | **High** | **Low** | **High** |
| Benefit Cost Ratio | 0.79 | 0.58 | 1.23 | 0.82 |

**Q. Does this project provide other benefits?**

A. Yes. The project also provides a unique use case to utilize a relatively small energy storage system to realize the full value of spinning reserves of an off-line turbine. PGE has not quantified this potential value, but will use this project to investigate what additional value can be yielded from a hybrid generation-storage project. By providing the required frequency support, the energy storage system will allow the generator to be utilized for spinning reserves without actually starting the unit. If called upon the plant will start; otherwise, the plant will be on standby and provide spinning reserves. We expect that coupling this storage system with the plant will allow us to reduce plant startups and low load operations, saving fuel, variable O&M, and startup costs, and reducing emissions.

## V. Customer and Community Microgrid Resiliency Pilot

**Q. Please describe PGE's Customer and Community Microgrid Resiliency Pilot project.**

A. PGE proposes to create a pilot program that models a replicable community storage/microgrid program, and meets customer demand for clean and resilient energy solutions. Through the pilot, we will install energy storage system to create at least one customer microgrid and one community microgrid (two to five total microgrids) in combination with customers' new or existing DERs. We expect to install up to 12.5 MW of energy storage for these projects. The microgrid projects will be pilots with scope limits, cost limits, and time limits. As pilots, PGE will balance technical feasibility, complexity, costs, and potential learnings in selecting projects. Table 8 shown below provides the key project attributes for this pilot.

**Table 8**
**Key Project Attributes (Microgrid Pilot)**

| Attribute | Estimated Value (per site) | Estimated Value (cumulative) |
|---|---|---|
| Charge/Discharge Rate (MW) | Up to 5 MW | Up to 12.5 MW |
| Energy Storage System (MWh) | 2 – 8 | 6 – 100 |
| On-site Customer Generation | DSG and/or Solar | |
| Technology/Material | TBD | |
| Response Rate (sec) | TBD | |
| Locations | Community: At a feeder location<br>Customer-sited: At critical business customer sites | |
| Target In-Service Date | 2019 – 2021 | |

**Q. What is a microgrid?**

A. A microgrid is a small-scale electric grid that operates in conjunction with the electrical grid through a network of on-site generation, energy storage, and integrated controls. Under normal conditions it is connected to the main grid. During a grid disturbance, the microgrid resources would provide stability support to the main grid. In the event the main grid experiences an outage, the microgrid would isolate itself and operate independently (islanding). Through this proposal, PGE is considering installation of energy storage systems as part of two types of microgrids:

1. Single Customer Microgrid: serves a single customer metered site (single building, facility, or campus). The single customer has on-site generation to sustain power during an outage.
2. Community Microgrid (partial feeder microgrid): serves a subset of customers on a feeder; a segment of the feeder is isolated during an outage event. This could be a neighborhood or otherwise closely located facilities on the same feeder section.

**Q. What are PGE's goals and anticipated learnings related to this pilot?**

A. PGE's customers are interested in clean and resilient power. Anticipated learnings from this pilot include experience with microgrid planning, installation, and operations, informing larger-scale microgrid program deployment. As an operationalized program, this offering could be scaled to any community/feeder section or non-residential customer.[14] The pilot aims to inform the creation of a community microgrid and customer resiliency program that leverages PGE's existing Dispatchable Standby Generation (DSG) program, along with future program design elements, including but not limited to:

- Recruitment and enrollment strategies and best practices;
- The value of and right questions to ask during a feasibility assessment;
- Participation requirements and design specifications;
- Sizing considerations;
- Construction and commissioning processes and best practices;
- Operational strategies and best practices;

[14] See PGE/101, Section 4.11, for more information on our evaluation of this pilot.

- Billing and Credits;
- Maintenance; and
- Automated dispatch.

The pilot will also evaluate:

- Program costs;
- Realized system benefits;
- Realized customer value and willingness to pay; and
- Program structure/design considerations (e.g., who owns which equipment, who pays for what/how much).

**Q. You stated that customers want resilient power. What does that mean to PGE?**

A. PGE refers to resiliency in the same manner as the Department of Homeland Security which is "the ability to adapt to changing conditions and withstand and rapidly recover from disruption due to emergencies." PGE aims to support resilient communities that are able to withstand and recover from major catastrophic event (e.g., Cascadia subduction zone seismic event).

**Q. Why is PGE proposing two to five small microgrids as opposed to one large microgrid?**

A. Microgrids are very different in nature, and thus learning from different types of sites and different types of microgrids is important. Different considerations include access to existing on-site generation (e.g., solar and/or dispatchable standby generation), distribution system considerations, site use cases (normal operation and emergency operation), etc. PGE is proposing at least one customer microgrid and at least one community microgrid. Both have unique design and operation considerations that add diversity to our proposed portfolio, which was encouraged as a guideline in Order 16-504. Further, in OPUC Docket No. UM

1657, PGE's 2017 Smart Grid Report, the Commission acknowledged PGE's road map which included plans to include microgrids in its system. Thus, by implementing both types and engaging various customer types/use cases allows us diverse learning opportunities to better serve customers in the future. In addition, providing two to five microgrids allows us to test different areas of the system, customer types, use cases, or interconnected DERs (e.g., Solar + Storage; Solar + Storage + DSG; Storage only).

**Q. After Commission approval, how will PGE determine installation sites?**

A. PGE will select specific sites by a qualitative assessment that evaluates the suitability of potential sites based on the following criteria:

- Site criticality – A critical facility is one that is reasonably expected to be safe and functional during and after a major catastrophic event;[15]
- Multi-modal – Site serves multiple purposes during an emergency event (e.g., a food distribution facility that may also be used as an emergency gathering point);
- Proximity to underserved communities (as defined by local municipalities);[16]
- Existence of on-site generation (e.g., solar, DSG);
- Potential for new on-site generation (e.g., solar potential);
- Population density (accessibility in major disaster);
- Potential for matching funds (participants willingness to pay);

[15] This includes seismic risk and structural integrity, emergency plan and function, facility should not be located in a flood zone if at all possible; soil stability, and recognition as an emergency site by city, state, or other governing body will be considered (e.g., the City of Portland's Basic Earthquake Emergency Communication Node sites).

[16] PGE's definition of "underserved communities" aligns with local municipalities. In general, we define them as being low-income (people experiencing poverty and/or homelessness and are below 80% of Oregon median income) and can be one or more the following: older adults (people over the age of 65); medically-needed adults (people who are mentally and/or physically disabled); Native American Tribal communities (registered tribal members); African Americans and Hispanic communities; and Immigrant populations.

- Potential for distribution system deferral/minimal distribution system upgrades required;
- Access to PGE communications infrastructure (fiber or wireless);
- Served by a substation or substations with modern protection, control, and communications systems;
- Configuration of existing electrical panels, critical load panel, etc.;
- Size and number of facility(ies) within microgrid; and
- Community support – PGE may solicit input from local resiliency organizations and municipalities to aid in selecting sites.

PGE will rank potential sites based on the criteria outlined above. PGE will likely consider at least one project at a PGE facility (e.g., Readiness Center, Integrated Operations Center, or a Distribution Line Center).

**Q. Will selected sites need to meet all criteria?**

A. No. Not all criteria will be met for every project. PGE will evaluate projects to balance the criteria above and rank potential sites based on the criteria.

**Q. Has PGE already selected sites?**

A. No. PGE has elected not to select communities, customers, or facilities in advance of this filing as we do not want to burden customers by navigating them through the regulatory process without certainty that the project will be approved. Once sites are identified as high-potential sites, PGE's customer management team will directly engage with appropriate stakeholders at prospective organizations to gauge interest and verify willingness to participate.

**Q. What other assessments will PGE use to determine project site location?**

A. To develop a microgrid that can effectively operate under normal and contingency conditions, PGE will conduct the initial feasibility study to select sites as potential microgrid candidates. There will be additional feasibility assessments that will determine site viability, site-specific system sizing, system valuation (cost-benefit estimates), and if necessary, a site project scope of work to inform procurement. These feasibility studies will include an on-site evaluation and will verify each of the following are suitable for the microgrid in question:

- Seismic and structural integrity;
- Communications infrastructure;
- Customer electrical loads and critical loads;
- Substation suitability;
- Physical site suitability;
- Outage simulations and system performance modelling; and
- Cost study including a preliminary bill of materials needed to construct the microgrid.

**Q. Please describe normal and stressed conditions.**

A. In normal conditions, a microgrid is interconnected to the distribution system and operates as a part of that system. Critical facilities on a microgrid will be served by a mix of energy from the grid and energy from the Energy storage systems or small-scale generation installed as part of the microgrid. The microgrid may also back feed energy to the grid, serving other loads. The energy storage device – in conjunction with other energy storage devices included in this proposal – will be controlled to provide capacity, energy and ancillary services.

In the event of an outage, the microgrid will island from the grid and the energy storage device will be used to serve the customers' critical loads. Stressed conditions occur when an event impacts the distribution system. For example, when there is a grid outage and the microgrid is not capable of supporting grid operation, the microgrid's integrated controls will island it from the distribution system. When islanded, each microgrid will use the energy storage system and onsite generator to maintain electrical service to the critical facilities within. When service is restored to the grid, the microgrid will revert back to the standard interconnection (normal condition) with PGE's distribution system.

**Q. What are the cost-effectiveness results for this pilot?**

A. The Microgrid Pilot (20-year, low-cost estimate) provides benefits valued at 64% of costs under the TRC test. For this energy storage system profile, total carrying cost (NPV of initial capital plus ongoing O&M costs) is estimated at $24.3 million. The microgrid pilot differs from those of the larger energy storage system projects in that it contains ongoing program elements such as marketing and oversight, and initial site assessments (year one), which increase total costs. Offsetting the costs are benefits that produce an NPV of $15.5 million. This results in a net cost of $8.8 million. PGE expects the gap will be offset, at least in part, by the as yet unquantified value of the pilot's learning objectives, as described above.

At 55%, capacity is the largest benefit. Energy and ancillary services, and reliability, provide 24% and 21% of the benefits stream, respectively. No participant contribution was modeled for the Microgrid Pilot; participant's willingness to pay is one key anticipated learning.

The 10-year, high-cost, energy storage system performed the worst, with a benefit/cost ratio of 0.36. For the Microgrid Pilot, energy storage system size increases by 150% under the high-cost profile, which amplifies the variation in per megawatt pricing.

The Microgrid Pilot would be cost effective with a total cost reduction (across either or both capital and ongoing O&M) of 36%, or a 57% increase in benefits. Additional factors that may increase cost-effectiveness include grant funding (as discussed in the Proposal),[17] municipal funding contribution, and participant contribution of funds, land, or human resources. Detail on both costs and benefits are reported in PGE Exhibit 200.

**Q. The proposed pilots are not cost-effective. What steps will PGE take to maximize project benefits and minimize project costs?**

A. PGE does not anticipate that the pilot to be cost effective. PGE has a number of site-selection criteria established to either reduce project cost or increase project benefits:

- Potential for matching funds: reduce project costs to ratepayers by leveraging funds from customers or 3rd party funds (e.g., grants);
- Potential for distribution system deferral / minimal distribution system upgrades required: maximize locational value/reduce location-specific costs;
- Existence of on-site generation: reduce project cost by leveraging existing resources already installed by customer(s);
- Access to PGE communications infrastructure: reduce cost of infrastructure upgrades required for the project;

[17] See PGE Exhibit 101, page 60, for Grant Funding Availability of PGE's Energy Storage Proposal.

- Served by a substation or substations with modern protection, control, and communications systems: reduce cost of infrastructure upgrades required for the project;
- Configuration of existing electrical panels, critical load panel, etc.: reduce cost of infrastructure upgrades required for the project; and
- Community support: PGE will solicit input from local resiliency organizations and municipalities to aid in selecting sites: this could reduce administrative costs.

Further, though PGE is not aware of any funds today to buy-down the cost of these projects, PGE will continue to monitor the industry for funds to supplement these projects.

# VI. Residential Storage Pilot

**Q. Please describe PGE's Residential Storage Pilot project.**

A. PGE proposes to pilot residential energy storage system with 500 customers by installing battery inverter systems (BIS) at residential customers' homes in response to increasing customer demand. The pilot will evaluate customer adoption of a bring-your-own-device/rebate model and a lease-model in which the customer leases the device from us. Individually, the BIS would provide enhanced power reliability capabilities for the program participants by offering back-up power during grid outage events. As a fleet, the BIS would act in aggregate to provide capacity, and energy and ancillary services to PGE and our customers. In aggregate the pilot aims to realize roughly two megawatts (five to six megawatt hours) of controllable energy storage system. Table 9 below, shows the key project attributes for this pilot.

**Table 9**
**Key Project Attributes (Residential Storage Pilot)**

| Attribute | Site-level | Fleet-level |
|---|---|---|
| Charge/Discharge Rate (MW) | 3 – 6 kW | 2 – 4 MW |
| Energy Storage System (MWh) | 12 – 16 kWh | 6 – 8 MWh |
| Technology/Material | TBD during procurement process | |
| Response Rate | < 10 seconds* | |
| Location | Residential Customers' Homes | |
| Target In-Service Date | Deployments to begin in 2020 | |

* Response rate is defined as the time between PGE issuing the command and the unit responding to the command

**Q. What are PGE's goals and learning objectives for this project?**

A. By implementing this pilot, PGE will explore the ability of highly distributed assets to provide grid services, learn how to deploy assets with benefit streams shared between participants and our customers, develop best practices for integrating distributed resources into existing asset control systems, and test market interest in two ownership models. These objectives require a threshold number of distributed devices.

**Q. What benefits are provided by the Residential Storage Pilot?**

A. This pilot will provide benefits to PGE and our customers by adding residential energy storage system to the portfolio of assets supporting a more flexible grid. Enhanced grid flexibility is crucial for a future with higher levels of renewables. Customers who currently elect to install residential Energy storage systems cannot discharge to the grid, leaving valuable services from these devices unutilized. This pilot will provide a pathway for all customers to benefit from assets already being deployed.

The pilot will also have direct benefits to program participants in the form of enhanced power reliability and lower financial barriers for adoption. Recent surveys show that PGE's residential customers highly value power reliability (63% of customers found it to be highly important to never experience a power outage, and 34% of customers without backup electric power have already considered a power reliability solution). However, customers interested in energy storage system must pay upwards of $7,000 to $15,000 in equipment and installation costs, resulting in many choosing lower cost, fossil-fuel powered options. These systems typically do not provide grid services and potentially expose customers to harmful emissions (e.g., improperly ventilated back-up generators caused 800 deaths from 1999 to 2012 from carbon monoxide poisoning). [18] This pilot would lower the financial barriers for energy storage system adoption by providing zero dollars down energy storage system lease from PGE. Those that choose to purchase their own energy storage system will also benefit through compensation for providing grid services to PGE. We will gain

[18] Winter Warning: Portable Generators Hold Top Spot in CPSC Report on Carbon Monoxide Deaths & Incidents. (2016, August 22). Retrieved January 02, 2018, from https://www.cpsc.gov/content/winter-warning-portable-generators-hold-top-spot-in-cpsc-report-on-carbon-monoxide-deaths

valuable insight into customer desire for increased power reliability, and test market interest in two program models: Customer Ownership and PGE Ownership.

**Q. What are the eligibility requirements for residential customers to participate in the pilot?**

A. This pilot would be available to any residential customer in PGE's service area that meets requirements[19] including:

- Owning the residence in which the equipment will be installed;
- Electrical service that meets all current electrical codes;
- Sufficient service panel capacity, space for the installation of a critical loads panel, and space for a BIS; and
- Reliable communications for BIS control.

**Q. Where will storage be installed on residential homes and on the system?**

A. PGE proposes to locate the BIS behind-the-meter to maximize the number of services provided. Energy storage systems located further upstream (e.g., mid-feeder, substation, transmission) are capable of providing many of the same capacity, energy, and ancillary services but cannot provide the same individualized power reliability enhancements. Behind-the-meter systems are capable of providing both. We may target installations to areas of our distribution system that underperform our reliability targets.

**Q. How many units does PGE propose installing?**

A. We propose a fleet size of approximately 500 units to access a diversity of installation locations, residential loads, grid service deployment scenarios, and ownership models. Further, a 500-unit fleet allows program costs to be spread over a sufficiently large number

[19] See PGE Exhibit 101, page 103, for a complete discussion of the requirements.

of units, improving program cost-effectiveness and lowering potential costs to program participants.

**Q. Who will own this energy storage system asset for these behind-the-meter installations?**

A. House Bill 2913 creates an opportunity for us to test and gain experience in two behind-the-meter program structures for our customers: a PGE ownership option and a customer ownership option. We propose to pilot both ownership models to maximize program learnings and to allow customers to choose the option that works best for them. Customers may either opt for PGE Ownership and pay a monthly lease fee on their electricity bill, or elect to own their own equipment and receive a monthly bill credit for allowing the device to be used for grid services. Customers who own their own equipment must select PGE-approved BIS and allow us control of the system to participate. Under both options, we will use the equipment for grid services during normal operations. During an outage, the energy storage system will power some loads at the customers' premise. Details for each ownership model are provided in PGE Exhibit 101, Section 7.4, of the docket.

The PGE Ownership model was included to address potentially significant barriers to program participation. Program participants who opt to install their own BIS will be responsible for purchasing upfront or financing the full cost of the BIS, ranging from $7,000 to $15,000. These participants will also be responsible for arranging installation, maintenance, and potential removal at end-of-life of the BIS. Some customers cannot afford the up-front costs (or don't qualify for financing) and/or don't wish to spend the time selecting installation and maintenance contractors.

**Q. Describe the Customer Ownership model.**

A. In the Customer Ownership model, the participant assumes the upfront energy storage system cost (modeled as financed by a third party and paid off over the life of the energy storage system). The cost to the participant is modeled as amortized via mortgage-style amortization over the 10-year energy storage system life, resulting in a cost of $94.0 per month. PGE then pays the customer a monthly $55.0 check in exchange for controlling the energy storage system to support grid services (other than in the event of an outage). PGE's monthly contribution lowers the participant's net cost of ownership to $36.0. This net cost is considered the participant's value of power reliability.

**Q. Describe the PGE Ownership model.**

A. In this model, PGE owns the energy storage system and capitalizes the asset. We are responsible for the acquisition, installation, and maintenance of the energy storage system. Cash flows in the opposite direction: the participant pays PGE $55.0 monthly for the value of power reliability. This program revenue is modeled as a benefit to us rather than a cost reduction.

We assume approximately $55.0 per month participant cost (payment to PGE) for the PGE Ownership model, and a $36.0 per month net participant cost (energy storage system financing minus PGE incentive) for customer ownership model. Though we may adjust the pricing and incentives to increase pilot participation, we propose to cap the total cost of the program (meaning increased incentive levels would result in a reduced number of pilot participants).

**Q. What were the results of the cost-effectiveness analysis for the Customer Ownership model of the Residential Storage Pilot?**

A. The Customer Ownership model (low-cost estimate) provides benefits valued at 69% of costs under the TRC test. Pricing varies most broadly in the residential market; the high vendor quote is 100% higher than the low scenario pricing.

Projected benefits include capacity, energy and ancillary services, and power reliability. Capacity is a smaller component of the residential energy storage system benefit stream given its 2.7-hour duration. Power reliability accrues to the participant only, and is the largest benefit component. The value of power reliability was modeled as equivalent to participant willingness to pay. Under the Customer Ownership model, the NPV of participant benefits are 115% of participant costs, because benefits (PGE monthly check) extend through energy storage system failure (in years 11-15), whereas the participant's energy storage system costs end in year 10 with financing payments.

The Proposal assumes 250 BISs under the Customer Ownership model. The NPV of total program cost is $3.4 million under the TRC, which includes the customer's purchase of the BIS. Cost to PGE is $2.8 million, which includes the monthly cash payment to program participants. This pilot involves the largest programmatic component, encompassing PGE administration, energy storage system inspection and maintenance, Information Technology investment, ongoing software expense, and sales and marketing costs. With a benefit/cost ratio less than 1.0, net pilot cost is $1.1 million. We understand this gap to be associated with the value of learnings detailed above.

Cost-effectiveness will improve with program size, as programmatic components are spread over a greater number of participants, and with continued energy storage system price declines. Bulk purchase pricing may be available to achieve pricing lower than the retail pricing assumed here. Total program carrying costs would need to decrease by 31% to achieve cost-effectiveness under current cost/benefit estimates; benefits would need to increase by 46%.

**Table 10**
**Cost-effectiveness of Residential Storage Pilot (NPV, $M) – Customer Ownership Model**

| | Low-Cost Estimate | | | High-Cost Estimate | | |
|---|---|---|---|---|---|---|
| | **TRC** | **RIM** | **PCT** | **TRC** | **RIM** | **PCT** |
| Benefit Cost Ratio | 0.69 | 0.50 | 1.15 | 0.42 | 0.28 | 1.16 |

**Q. What were the results of the cost-effectiveness analysis for the PGE Ownership model of the Residential Storage Pilot?**

A. The PGE Ownership model targets a similar TRC result (0.71 versus 0.69 under the Customer Ownership model, shown in Table 11 below). Given the preliminary nature of cost estimates, we consider the cost-effectiveness results of the two program models to be essentially equivalent. In this model, PGE assumes the entire cost of BIS acquisition, in exchange for the benefit of monthly customer payments. PCT results are equal 1.0 in this model, as we receive a monthly check from participants for the same period over which we realize benefits from the energy storage system (through the year of energy storage system failure). Under this model, customer payment is roughly $55.0 per month, higher than the net customer cost under the Customer Ownership model. Participant's willingness to pay was varied to achieve consistent TRC results, and under the assumption that customers may pay more to forsake the responsibility and effort involved in acquiring, installing and maintaining the BIS.

**Table 11**
**Cost-effectiveness of Residential Storage Pilot (NPV, $M) – PGE Ownership Model**

| | Low-Cost Estimate | | | High-Cost Estimate | | |
|---|---|---|---|---|---|---|
| | **TRC** | **RIM** | **PCT** | **TRC** | **RIM** | **PCT** |
| Benefit Cost Ratio | 0.72 | 0.72 | 1.00 | 0.31 | 0.31 | 1.00 |

Capacity and energy and ancillary services benefit streams are identical under the two ownership models. Power reliability – participant's willingness to pay – varies between the two, resulting in differing total benefits. Energy storage system costs are higher under the PGE Ownership model, driven by income and property tax, and the gross up of PGE's rate of return to reflect tax impacts. Because benefits are also higher, the pilot's net cost is similar at $1.1 million.

Cost-effectiveness will improve with program size, as programmatic components are spread over a greater number of participants, with continued energy storage system price declines, or with decreased customer incentives paid by PGE to customers for our use of the energy storage system. Bulk purchase pricing may be available, resulting in lower capital costs than the retail pricing employed here. Total program carrying costs would need to decrease by 28% to achieve cost-effectiveness under current cost/benefit estimates; benefits would need to increase by 39%.

Cost-effectiveness is described in greater detail in PGE Exhibit 200, Section IV, of this docket.

## VII. Controls and System Integration

**Q. Please describe PGE's Controls and System Integration.**

A. PGE intends to implement a control system that provides the necessary features to capture benefits associated with the use cases identified in PGE's Energy Storage Potential Evaluation report.[20] To accomplish this in the short term, we intend to use the existing GenOnSys software utilized by the distributed generation group. This software platform already provides many of the functions needed to interface with systems in the field. Functionality will be added to help us define the requirements for a vendor supported controls platform in the future.

**Q. What is GenOnSys?**

A. GenOnSys is an electronic platform used to integrate multiple resources and which operates on a 24-hour per day, seven days per week basis. It is controlled by operators in PGE's fully-instrumented command center during daytime hours and supported by on-call operators during off hours. The platform is also integrated with other enterprise systems including Energy Management System and Generation Operations that are used for grid monitoring and control. GenOnSys currently manages a portfolio of DERs including 86 customer-owned generators, 16 solar Photovoltaic plants, SSPC, and one residential energy storage system pilot.

**Q. Why is PGE using the existing GenOnSys software and not vendor software?**

A. PGE considered vendor software, but did not find one with proven capabilities to sufficiently differentiate its value for the proposed energy storage system projects when

[20] See PGE Exhibit 101, Appendix 4, for the Potential Evaluation report.

compared with GenOnSys.[21] The GenOnSys system provides a foundation for integrating distributed Energy storage systems. This approach enables us to readily make meaningful and regular changes in our integration methods throughout the project period based on the experience gained in the implementation and testing of the various use cases. In addition, developing experience across the enterprise is a primary objective of this project – this will provide subject matter expertise in Power Operations, the Balancing Authority, and Distribution Operations. For Energy storage systems at customer sites, this experience will help us define requirements to be our customer's trusted energy partner.

**Q. What functionality does PGE intend to add?**

A. As part of the project, PGE will develop new functionality within GenOnSys. This includes improving existing interfaces and building new interfaces with other enterprise systems used for grid monitoring, control, and generation dispatch. The primary functionality being added will:

1. Allow for real-time and scheduled operation of the various assets by the appropriate "owner" of each use case. For example, Power Operations will use assets to serve peak demand and the Balancing Authority will use the assets for primary frequency response;
2. Provide the necessary two-way communications to receive, display and store all system data in a meaningful and useful format;
3. Capture data to help inform interested stakeholders regarding system performance, thus supporting the goal of maximizing learnings and allowing both internal and external agencies to study use case viability; and

[21] See PGE Exhibit 101, Section 9.2, for more information on the commercially available software.

4. Since we expect to use the storage assets on par with other PGE generation resources, the costs include a fully redundant system as required for critical systems.

**Q. Describe the approach that PGE used to determine the control system.**

A. To leverage the value of distributed devices, PGE is planning a control system and integration approach that is capable of supporting automated decisions within a set of defined business rules and appropriately dispatching distributed resources assigned to those rules. To address the high level of diversity involved with this plan, a hierarchical approach will be necessary.[22]

**Q. What are the control system costs?**

A. The control systems cost estimate is based upon PGE's experience with GenOnSys and its recent work to join the Western Energy Imbalance Market. This results in an estimated capital investment of $3.1 million. For detailed annual cost estimates, see PGE Exhibit 101, Section 9.4, of the docket.

[22] See PGE Exhibit 101, Section 9.3, for the control system's hierarchy.

## VIII. Conclusion

**Q. Summarize PGE's request.**

A. PGE requests that the Commission find that our Proposal for the portfolio of energy storage system projects and pilots: a) is consistent with the guidelines adopted; b) reasonably balances the value for ratepayers and utility operations that is potentially derived from the application of energy storage system technology and the costs of construction, operation, and maintenance of the storage systems; and c) is in the public interest.[23] After such a finding, we request that the Commission authorize us to develop the projects proposed. The projects will integrate storage at various sites on our system: transmission, substation, mid-feeder, commercial/industrial customer sites, and residential premises. We estimate the portfolio will cost $106-190 million (NPV of the total carrying cost) and will generate $93-117 million of value for customers (NPV). We expect our portfolio to further our understanding of the value of storage across our grid, as well as to expand our ability to effectively integrate storage into the grid in the future.

[23] The required findings are found in HB 2193, Section 3(3).

# IX. Qualifications

**Q. Mr. Riehl, please describe your educational background and qualifications.**

A. I received a Bachelor of Science degree in Electrical Engineering from Oregon State University in 2005. I was previously employed as an Electrical Engineer at the Bonneville Power Administration. I joined PGE in 2011 as an Electrical Project Engineer in the Generation Projects group and am currently a Project Manager in the Generation, Transmission and Distribution Project Management Office.

**Q. Mrs. Brown, please describe your educational background and qualifications.**

A. I received a Bachelor of Science degree in Accounting from the University of Nevada-Reno and a Master of Business Administration with an emphasis in Finance from the University of Wyoming. I am a Certified Public Accountant. I have worked at three state commissions (Wyoming, Texas and Oregon) totaling 12 years of direct regulatory experience. I also worked at PacifiCorp for nearly three years in Corporate Accounting and have been with PGE since 2007 (in the Rates and Regulatory Affairs department for over seven years), totaling over 25 years of experience.

**Q. Does this conclude your testimony?**

A. Yes.

# List of Exhibits

| **PGE Exhibit** | **Description** |
|---|---|
| 101 | PGE's Energy Storage System Proposal |
| 102 | Compliance with Guidelines Outlined in OPUC Order No. 16-504 |

# Energy Storage Solutions

UM 1856 | November, 2017

PGE

# Table of Contents

# Acronyms

AMI ........ Advanced Metering Infrastructure
BEECN ........ Basic Earthquake Emergency Communication Node
BIS ........ Battery Inverter System
BIS Consulting ........ Consultant that developed IPT
BPA ........ Bonneville Power Administration
CAISO ........ California Independent System Operator
C&I ........ Commercial and Industrial
CVR ........ Conservation Voltage Reduction
DSG ........ Dispatchable Standby Generation
DER ........ Distributed Energy Resource
DERMS ........ Distributed Energy Resource Management System
DR ........ Demand Response
EIM ........ Energy Imbalance Market
EMS ........ Energy Management System
EPC ........ Engineering, Procurement, and Construction
EPRI ........ Electric Power Research Institute
ES ........ Energy Storage
ESA ........ Energy Storage Association
ESS ........ Energy Storage System
ETO ........ Energy Trust of Oregon
E&AS ........ Energy & Ancillary Services
FEMA ........ U.S. Federal Emergency Management Agency
FTE ........ Full-time equivalent
GW ........ Gigawatt, a measure of capacity
HB ........ Oregon House Bill
HVAC ........ Heating, Ventilation, and Air Conditioning
IPT ........ Integrated Planning Tool
IRP ........ Integrated Resource Plan
ISO ........ Independent System Operator
kW ........ kilowatt, a measure of capacity
kWh ........ kilowatt-hour, a measure of energy
MAP ........ Mitigation Action Plan
MDMS ........ Meter Data Management System
MW ........ Megawatt, a measure of capacity
MWh ........ Megawatt-hour, a measure of energy
MUSH ........ Municipalities, Universities, Schools, and Hospitals
NIST ........ National Institute of Standards and Technology
NPV ........ Net Present Value
NVEST ........ Navigant Value of Energy Storage Tool
NYSERDA ........ New York State Energy Research and Development Authority

ODOT ........................................................ Oregon Department of Transportation
OEM .......................................................... Oregon Office of Emergency Management
OPUC ........................................................ Oregon Public Utility Commission
OSSAC ...................................................... Oregon's Seismic Safety Policy Advisory Commission
OSSC ......................................................... Oregon Structural Specialty Code
O&M ......................................................... Operations and Maintenance
PCT............................................................ Participant Cost Test
PGE ........................................................... Portland General Electric
PNNL ........................................................ Pacific Northwest National Lab
PSU ........................................................... Portland State University
PUC ........................................................... Public Utility Commission
PUD ........................................................... Public Utility District
PV.............................................................. Photovoltaic
PW2 .......................................................... Port Westward 2
RDF ........................................................... Renewable Development Fund
ROM.......................................................... Resource Optimization Model
RFI ............................................................ Request for Information
RFO .......................................................... Request for Offering
RFP............................................................ Request for Proposal
RMI ........................................................... Ratepayer Impact Test
RMI .......................................................... Rocky Mountain Institute
RPS............................................................ Renewable Portfolio Standard
RTO .......................................................... Regional Transmission Organization
SAIDI ......................................................... System Average Interruption Duration Index
SAIFI.......................................................... System Average Interruption Frequency Index
SAM ......................................................... Strategic Asset Management
SCADA...................................................... Supervisory Control And Data Acquisition
SSPC ......................................................... Salem Smart Power Center
TOU........................................................... Time-of-Use
TRC............................................................ Total Resource Cost Test
T&D .......................................................... Transmission and Distribution
UM ........................................................... Utility Matter
USDOE ..................................................... US Department of Energy
WECC ....................................................... Western Electricity Coordinating Council

# Executive Summary

## *Introduction*

Portland General Electric (PGE) is committed to building a cleaner energy future for Oregon. Last year more than 40 percent of the energy we delivered was from carbon-free sources. For the past eight years, PGE customers have made our voluntary renewable power program the biggest green power program in the country. PGE customers and the Energy Trust of Oregon have also helped make PGE one of the top 10 utilities in the nation for energy efficiency. And last year we worked with stakeholders and the Oregon Legislature to pass aggressive new clean energy goals, requiring us to provide 50 percent of our customers' energy from qualified renewable resources by 2040. This will mean approximately 70 percent of the energy we deliver will be carbon-free by that date.

If we are going to meet these clean energy goals, we will need to incorporate energy storage as a key part of our energy strategy. Renewable resources are inherently variable, and it will be increasingly important for PGE to integrate technologies supporting grid flexibility to make sure that power is always available to meet our customers' needs. Likewise, growing customer demand for resilient power systems indicates that PGE must also integrate technologies that support customers' ability to sustain power during major outage events. Energy storage technologies can provide a range of grid services to provide resiliency as well as support PGE's transition to a clean energy future.

In 2015, PGE worked together with stakeholders to craft an energy storage mandate that was passed into law by the Oregon State Legislature. By developing this legislation, PGE sought to obtain the regulatory, technical, and operational experience with energy storage to best prepare the state for the broad-scale deployment of storage. To that end, Chapter 312, Oregon Laws 2015, mandated that PGE procure at least 5 MWh – and up to one percent of 2014 peak load (38.7 MW for PGE) – of energy storage by 2020. The Oregon Public Utility Commission (OPUC) has encouraged PGE to "submit multiple, differentiated projects that test varying technologies or applications" in its guidelines for proposal submissions.

In order to meet the guidelines and prepare for the future, PGE proposes investing in a variety of storage projects that allow the Company and stakeholders to best understand the approaches to storage that might make the most sense in the future. The goal is to optimize learning about energy storage by conducting a wide variety of energy storage "experiments". These learnings will inform future strategic investments in energy storage.

PGE's proposed projects are diverse in size, system location, and application. In its proposal, PGE suggests:

- A microgrid pilot to improve the region's energy resilience. Through the pilot, PGE will leverage existing distributed energy resources (DERs) and new energy storage to create at least one customer microgrid and one community microgrid (up to five total microgrids);
- A substation-sited, distribution interconnected, large-scale storage project to gain experience developing, controlling, contracting for, constructing, operating, and maintaining utility-scale energy storage;
- A mid-feeder-sited, storage asset co-located and integrated with an existing 1.75 MW solar array to gain experience integrating large-scale solar with storage and to test the integration of energy storage with distribution automation to increase reliability;
- Up to 500 residential, behind-the-meter, PGE-controlled storage projects to pilot the development of a residential storage program and develop the ability to operate a distributed, aggregated fleet of storage assets;
- A 4-6 MW transmission-connected storage device to create a "hybrid plant". The project provides a unique use case to utilize a relatively small storage device to realize the full value of spinning reserves of an off-line turbine (18.9MW), reducing fuel use and emissions at the plant or otherwise allowing another plant (e.g. hydro) to operate at full capacity.

## *System Needs*

Prior to planning for energy storage deployments, we first analyzed our system and evaluated what system needs storage might address. PGE's analysis of our system identified five primary system needs:

- **Capacity:** the retirement of coal-fired capacity and an increase in variable renewable resources will require more installed capacity per unit of generation due to relatively low capacity factors of these resources.
- **Ancillary services:** includes spin/non-spin reserves, load following, and frequency regulation.
- **Outage Mitigation:** benefits stemming from the reduced risk of an outage to a group of customers (e.g. customers on a feeder served by storage); "risk" includes the direct economic impact on the customer due to the outage. A reduction in system risk also serves to extend asset life due to reduced consequence of asset failure (resulting in a deferred capital investment).
- **Power Reliability:** benefits stemming from the reduced risk of an outage to individual customers (e.g. customers with an on-site storage device). This risk includes the direct economic impact on the customer due to the outage.
- **Resiliency:** there is an increasing recognition of the need for more resilient power systems in the Pacific Northwest region. According to the 2013 Oregon Resilience Plan,

  > *"The Pacific Northwest has a high likelihood of a magnitude 9.0 earthquake on the Cascadia subduction zone," and "substantial improvements to the critical energy infrastructure are necessary" in order "to minimize [the] extensive direct earthquake damage, indirect losses, and possible ripple effects,."*

  The City of Portland's Mitigation Action Plan (MAP) also prioritizes actions that the City can take to protect citizens and infrastructure from the impacts of natural disasters, including earthquakes. Three of the nine priority actions identified in the 2016 MAP call for energy storage systems (paired with solar energy) at facilities throughout the City.

Stakeholders have also indicated a regional systems need, expressing much interest in PGE's ability to utilize energy storage for asset deferral and transmission congestion relief:

- **Distribution asset deferral:** as indicated above, is included in PGE's outage mitigation analysis. It is important to note, however, that most of PGE's distribution system is built with N-1 redundancy, meaning power can be manually restored to affected customers for a single asset failure. Consequentially, there are few areas of PGE's distribution system that would see substantial distribution deferral benefits.
- **Transmission Congestion Relief:** there likely is a regional benefit to PGE installing energy storage for transmission congestion relief, just as there would be for transmission deferral. However, quantifying that benefit is challenging today as PGE has no insight into the price BPA is willing to pay for schemes that would alleviate their I-5 issue. PGE would consider bidding any storage projects constructed under HB 2193 to meet BPA's need with the following caveat:

power flows into PGE's system from multiple transmission paths, meaning a locally-sited storage system corresponds to only a 30% load reduction along the I-5 corridor (the other 70% of reduction is seen amongst the other transmission paths into our system).

In summary, PGE's system has various needs that energy storage can help meet. Some of these needs (capacity/resource adequacy) provide equal value at any location within PGE's system. Other needs (i.e. outage mitigation) vary meaningfully based on location within PGE's system and the proximity of the storage system to customers most impacted by an outage. PGE's system needs will change over time, and PGE will update and refine our analysis as the needs of PGE's system change.

## *Approach*

PGE employed the following approaches to identify costs of, optimal locations for, and benefit streams of energy storage projects. Our goal is to deliver projects that advance PGE's ability to efficiently deploy storage in the future, and create value for our customers; PGE employed a number of initiatives to identify costs of, optimal locations for, and benefit streams of energy storage projects:

- **Request for Information (RFI):** to better understand current market conditions such as vendors or pricing, PGE conducted an RFI for companies who could likely engineer, procure, and construct one or many energy storage systems to meet the HB 2913 mandate.
- **Location Study:** PGE worked with BIS Consulting to determine which sites on PGE's system which would gain the most value from an energy storage project. We modeled risk reduction achievable by deploying energy storage at various locations in our system. The goal of the analysis was, in essence, to ascertain where in PGE's system customers and PGE would most benefit from storage's outage mitigation.
- **Energy Storage Potential Study:** PGE retained Navigant to value system benefits associated with deployment of energy storage. Navigant relied on its Navigant Value of Energy Storage Tool (NVEST) model to quantify the stacked value for each use case. PGE provided key input data and modeling results from our Resource Optimization Model (ROM) and Integrated Planning tool (IPT) tools to characterize system-specific benefits (energy and ancillary service benefits, and outage mitigation and power reliability benefits).
- **Valuation (cost-effectiveness):** considers all quantitative costs and benefits to the electric system and its customers over the life of the project. Assessment of larger societal benefits (e.g. resiliency) was discussed but not quantified. Two cost effectiveness tests were applied to all project proposals: the Total Resource Cost test (TRC) and the Ratepayer Impact test (RIM); additionally, a Participant Cost Test (PCT) was conducted for customer pilots.

The aforementioned models and tools informed PGE's planning for the proposed projects and pilots.

## *Project Proposals*

The following proposals include a diversity of project sizes, locations on PGE's system, uses cases, and ownership structures that will create vast learnings for PGE:

1. **Customer & Community Microgrid Resiliency Pilot:** PGE proposes to create a pilot program that serves as a model for a replicable community storage/microgrid program and meet customer demand for clean, resilient energy solutions. Through the pilot, PGE will install energy storage to create at least one customer microgrid and one community microgrid (up to 5 total microgrids) in combination with customers' new or existing DERs. The projects will create microgrids that aim to meet customers' resiliency and clean energy goals. The pilot will evaluate communities and customers at critical facilities with and without solar and dispatchable standby generation in order to test a variety of energy storage/microgrid use cases for resiliency. The pilot aims to inform the creation of a community microgrid and customer resiliency program that advances leverages PGE's existing Dispatchable Standby Generation (DSG) program. Through the pilot, PGE expects to install up to 12.5 MW of energy storage across 2-5 customer and community sites.
2. **Power System Integration (Coffee Creek Substation):** PGE proposes to develop and build a 17 – 20 MW, 68 – 80 MWh energy storage system on PGE owned property adjacent to the existing Coffee Creek Substation. This project will allow PGE to gain additional experience, expertise, and learnings with all aspects of utility-scale energy storage systems, including project development and design, contracting. It will also help PGE gain learnings around the best practices for implementation and integration of energy storage into our power system, as well as allowing for the evaluation of the locational value of energy storage to our system.
3. **Power System Integration (Baldock Mid-feeder):** PGE proposes to install a 2 MW (4 MWh) energy storage device at the existing 1.75 MW Baldock Solar array in Aurora, OR. The Baldock energy storage system will be interconnected to PGE's Canby Substation via the Canby – Butteville feeder. A mid-feeder project was selected to allow PGE to explore utilizing automation schemes to island various sections of the feeder to test medium-voltage micro grid applications.
4. **Residential Energy Storage Pilot:** PGE proposes to pilot residential energy storage with 500 customers by installing battery inverter systems (BIS) at residential customers' homes. By implementing this pilot, PGE will explore the ability of distributed assets to provide grid services, learn how to deploy assets with benefit streams shared between participants and all PGE customers, and develop best practices for integrating distributed resources into existing asset control systems. The pilot will test customer adoption of a bring-your-own-device/rebate model against a lease-model where the customer leases the device from PGE. In aggregate the pilot aims to realize 2-4 MW/6-8 MWh of controllable energy storage. Customers would utilize the batteries during an outage for added power reliability.
5. **Generation Kick-Start:** PGE proposes to develop a 4-6 MW, 4 hour energy storage system at our Port Westward 2 (PW2) Generating Station located in Clatskanie, Oregon. This storage system will be coupled with our existing plant control system and will be capable of supplying 18.9 MW of spinning reserves when partnered with one of the plants reciprocating engines. To meet the

spinning reserve requirements, the energy storage system will immediately and automatically respond to frequency deviations while the engine is not running, but if called on, the engine will be able to ramp up to full output and respond within the 10 minute requirement.

During normal operating conditions, the energy storage devices will provide grid services (capacity, energy, and ancillary services). During an outage event, the storage devices will provide outage mitigation or power reliability (depending on location). Table 1 outlines key features of the projects:

**Table 1: Summary of Proposed Energy Storage Projects**

| Project Name | Location | No. of Storage Devices | Cumulative Capacity (MW) | Cumulative Energy (MWh) | Primary Applications | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Capacity | Energy + Ancillary Services | Outage Mitigation | Power Reliability | Resiliency |
| Microgrid Resiliency Pilot | Mid-Feeder/ Business Customer Premise | 2 – 5 | 3 – 12.5 | 6 – 100 | ✓ | ✓ | ✓ | ✓ | ✓ |
| Power System Integration (Coffee Creek) | Substation | 1 | 17 – 20 | 68 – 80 | ✓ | ✓ | ✓ | | |
| Power System Integration (Baldock) | Mid-feeder | 1 | 2 | 4 – 8 | ✓ | ✓ | ✓ | | |
| Residential Storage Pilot | Residential Customer Premise | 300 – 500 | 2 – 3.5 | 6 – 8 | ✓ | ✓ | | ✓ | |
| Generation Kick-Start | Trans-mission | 1 | 4 – 6 | 16 – 24 | ✓ | ✓ | | | |
| **Portfolio Aggregate** | | **305 – 508** | **28 – 38.7*** | **100 – 220** | ✓ | ✓ | ✓ | ✓ | ✓ |

**Note: total portfolio aggregate will not exceed 38.7-MW (1% of PGE's 2014 peak load), per HB2193.*

In order to inform decisions about whether and how to best use storage at a larger scale, the proposed pilots will emphasize collection and analysis of data and information. PGE proposes to hire an experienced external storage consultant to evaluate the projects whose insights from similar projects will benefit PGE's assessment of project data and information regarding this rapidly-evolving technology.

PGE intends to implement a control system that provides the necessary features to capture benefits associated with the use cases identified in the Storage Potential report. Developing experience across the enterprise is a primary objective of this project – this will provide subject matter expertise in Power

Operations, the Balancing Authority, and distribution operations. For storage systems at customer sites, this experience will help PGE define requirements to provide an outstanding customer experience. Our experience leads us to believe that a commercial solution capable of meeting our needs is still some time out. To bridge the gap until this technology is available, the proposed path forward is an expansion of PGE's Dispatchable Standby Generation system, GenOnSys. PGE is fortunate to have an established system to control appropriately sized generation projects and employees with experience interfacing with Power Operations and the Balancing Authority to dispatch assets.

The projects and pilots discussed in this proposal have asset lives of ten to twenty years. PGE proposes that the "project period" for the projects and pilots be considered as five years. That is to say, PGE will report on progress, learnings, costs, benefits, and evaluation of these initiatives for 5 years from 2018 to 2022.

The costs associated with these projects and pilots (including procurement and evaluation costs) are subject to deferral and later recovery. PGE plans to modify its Schedule 122 Renewable Resources Automatic Adjustment Clause tariff to add energy storage as eligible resources for cost recovery. Cost recovery for specific storage projects will consist of the annual revenue requirement associated with the project. A summary of estimated proposed costs is included below:

**Table 2: Cost Summary of Energy Storage Proposals**

| | Low Cost Estimate | | | High Cost Estimate | | |
|---|---|---|---|---|---|---|
| **Project** | **Overnight Capital** | **NPV of RevReq** | **Year 1 RevReq** | **Overnight Capital** | **NPV of RevReq** | **Year 1 RevReq** |
| Microgrid Resiliency Pilot | $11.6 | $24.3 | $1.5 | $41.2 | $66.9 | $2.8 |
| Power System Integration (Coffee Creek Substation) | $30.4 | $52.7 | $6.7 | $35.7 | $64.8 | $8.2 |
| Power System Integration (Baldock Mid-feeder) | $2.8 | $4.6 | $0.6 | $4.1 | $7.8 | $1.0 |
| Residential Storage Pilot | $2.1 | $6.7 | $0.8 | $6.0 | $16.1 | $1.6 |
| Generation Kick Start | $5.9 | $10.1 | $1.4 | $7.7 | $15.1 | $1.9 |
| Controls | $3.1 | $5.9 | $0.4 | $3.1 | $5.9 | $0.4 |
| Administration & Evaluation | - | $3.2 | $0.4 | - | $3.2 | $0.4 |
| **Total** | **$55.8** | **$105.5** | **$11.7** | **$97.8** | **$189.8** | **$16.4** |

*Note: assumed 20-year maintenance and capacity contracts for Baldock, Coffee Creek, Microgrid pilot, and Port Westward 2 projects. Costs include portfolio controls and administration.*

PGE anticipates utilizing storage devices for capacity, energy & ancillary services, and locational value (outage mitigation and/or power reliability) benefits, because these functions have the highest value and ability to be co-optimized:

- Capacity: the energy storage devices will be dispatched during peak demand periods to supply energy and shave peak demand, reducing the need for new peaking power plants.
- Energy and Ancillary Services: storage will be used for a variety of system ancillary services, including system regulation, load following, spinning reserves, voltage support, and black start.
- Locational Value Benefits:
    - Outage Mitigation: the energy storage device can be used to reduce customers' economic impacts associated with outages and defer capital by extending the life of existing distribution assets; and/or
    - Power Reliability: the energy storage device will also be used to reduce or eliminate outage impact costs to specific participating customers.
      *Note: whether power reliability benefits, outage mitigation benefits, or both are accrued for a specific project depends largely on the project's location in the grid and project-specific design criteria.*

For each project, PGE has estimated cost effectiveness on a total resource cost (TRC), ratepayer impact measure (RIM), and participant cost test (PCT). In aggregate, PGE estimates that the TRC for all projects in aggregate to be 0.61 – 0.86 (high and low cost scenarios). The battery profiles included in the following aggregate table align with those in Table 2.

**Table 3: Cost Effectiveness Summary: Proposed Energy Storage Portfolio (2017$, $M)**

| | Low Cost Estimate | | | High Cost Estimate | | |
|---|---|---|---|---|---|---|
| | **TRC** | **RIM** | **Participant[a]** | **TRC** | **RIM** | **Participant** |
| Benefits | 92.8 | 88.6 | 7.1 | 116.6 | 107.4 | 14.6 |
| Costs | 108.1 | 107.5 | 3.5 | 190.0 | 189.8 | 5.7 |
| Net Benefit | (15.3) | (18.9) | 3.6 | (73.5) | (82.4) | 8.9 |
| **Benefit/Cost Ratio** | **0.86** | **0.82** | **2.03** | **0.61** | **0.57** | **2.56** |

*Note: assumed 20-year maintenance and capacity contracts for Baldock, Coffee Creek, Microgrid pilot, and Port Westward 2 projects. Costs include portfolio controls and administration.*

PGE believes that the proposals discussed in this report meet the intent of HB2193 by supporting the development of regulatory, technical and operational experience with energy storage by electric companies and stakeholders in Oregon to best prepare the state for the broad-scale deployment of storage over time.

[a] Note: the participant cost test only applies to programs/projects with participants (residential and microgrid pilots).

# Section 1. Background & Introduction

The enactment of HB 2193 mandated that PGE procure at least 5 MWh – and up to 1% of 2014 peak load (38.7 MW for PGE) – of energy storage by 2020.[1] Given changes in PGE's energy mix, opportunities to best serve customers, and a changing energy storage landscape, the law was well-timed.

This proposal begins with an overview of changes in PGE's energy portfolio and customer expectations along with a description of the energy storage landscape. Then we discuss PGE's approach to developing proposals in response to HB 2193. We follow with an overview of each proposal as it relates to OPUC guidelines outlined in Order 16-504. We then discuss each of the five proposals in detail, followed by a discussion of controls integration for all projects. Then outline considerations for administration and program evaluation.

The OPUC has encouraged PGE to develop a portfolio of projects that examine a variety of applications and use-cases. This aligns with PGE's understanding of the primary purpose of HB 2193: the development of regulatory, technical and operational experience with energy storage by electric companies and stakeholders in Oregon to best prepare the state for the broad-scale deployment of storage over time. To truly match the intent of HB 2193 and maximize learning and operational experience with the energy storage, electric companies, stakeholders, and the OPUC need to develop, consider, and deploy a variety of storage projects.

## 1.1. History and Intent of HB 2193

In the 2015 Oregon Legislative session, PGE assisted in the drafting of HB 2193, proactively advocating for its enactment. PGE's enthusiasm for the law continues, as the Company views its mandate as an opportunity to "invest in different types of energy storage" that may demonstrate long-term benefit for PGE's system.[2] Though many deployments of energy storage may not currently be cost-effective for PGE's customers given the relatively low price of electricity, the technology is cost-justified in a number of parts of the U.S. and globally today. As storage prices continue to drop, HB 2193 (and its provision for recovering "above-market costs"[3]) offers PGE and stakeholders the opportunity to become acquainted with the technology and prepare for broad least-cost/least-risk deployment within PGE's system as the market develops. Given the timeline associated with HB 2193 and the speed and scale of advancements in the storage arena, it could be that storage on PGE's system is cost-justified contemporaneously with HB 2193 projects becoming operational. In such a situation, the work of PGE and stakeholders to understand storage technology, storage project development, regulatory paradigms for storage, and the integration of both utility-scale and distributed/aggregated storage into PGE's system and operations will give the region an advantage in the swift deployment of storage resources.

In the regulatory docket for implementation of HB 2193 (UM 1751), the OPUC and stakeholders focused initially on the development of guidelines for storage project proposals. On May 9, 2016, PGE presented responses to the OPUC on a number of questions the Commission had asked of the utilities. Two of these questions were especially pertinent to the OPUC's consideration of storage proposals:

- How should the Commission rank and evaluate the proposed projects, and which criteria should be used?
- How strongly should the Commission encourage investment for different applications or in different types of storage systems? Is diversity preferable? Or should the focus be on testing and developing specific uses and technologies over others?[4]

PGE responded by encouraging the Commission's adoption of four "**principles for evaluating utility proposals**" for energy storage [5]:

- **Validated learning:** require hypotheses prior to implementation, as well as regular evaluations after implementation to ensure on-going and systematic learning
- **Scalability:** position utilities to effectively scale approaches to energy storage if they prove beneficial
- **Cost-effectiveness:** benefits, costs, and risks should be considered but not a determining factor in approving factor in these proposals
- **Diversity:** encourage the consideration and pursuit of a number of different approaches for energy storage

On December 28, 2016, the OPUC adopted guidelines and requirements to implement HB 2193 in Order 16-504. The Commission encouraged PGE to "submit multiple, differentiated projects that test varying technologies or applications."[6] Furthermore, the OPUC encouraged PGE "to submit a portfolio of projects that balance technology maturity, technology potential, short- and long-term project performance and risks, and short- and long-term potential value."[7]

The OPUC's encouragement of PGE to develop a portfolio of projects that examine a variety of applications and use-cases aligns with PGE's understanding of the primary purpose of HB 2193: the development of regulatory, technical and operational experience with energy storage by electric companies and stakeholders in Oregon to best prepare the state for the broad-scale deployment of storage over time. To truly deliver upon HB 2193's intent to maximize learning and operational experience with energy storage, electric companies, stakeholders, and the OPUC need to not only develop and consider, but actually deploy a variety of storage projects.

## 1.2. PGE's System Needs

PGE's energy portfolio is changing from traditional coal, gas, and hydroelectric generation to integrate increasing amounts of variable energy resources (e.g. wind and solar). The enactment of Senate Bill 1547 mandated the end of coal-fired generation in PGE's portfolio by 2030 and ensured that at least 50% of energy would come from qualified renewable resources by 2040. Given stakeholder feedback in PGE's 2016 Integrated Resource Plan (IRP)[8] – along with recent resolutions from the City of Portland[9] and Multnomah County[10] for 100 percent renewable electricity by 2035 – it is important to incorporate technology with the ability to enable decarbonization of the system. This shift towards carbon-free resources requires more installed capacity per unit of generation (due to relatively low capacity factors of wind and solar[11]) and an increasingly flexible grid (due to the variable nature of wind and solar output).

There is also an increasing recognition of the need for more resilient power systems in the region. According to the 2013 Oregon Resilience Plan:

> *"The Pacific Northwest has a high likelihood of a magnitude 9.0 earthquake on the Cascadia subduction zone…. To minimize extensive direct earthquake damage, indirect losses, and possible ripple effects, substantial improvements to the critical energy infrastructure are necessary."* [12]

The City of Portland's Mitigation Action Plan (MAP) prioritizes actions that the City can take to protect citizens and infrastructure from the impacts of natural disasters, including earthquakes. Three of the nine priority actions identified in the 2016 MAP call for energy storage systems (paired with solar energy) at facilities throughout the City.[13]

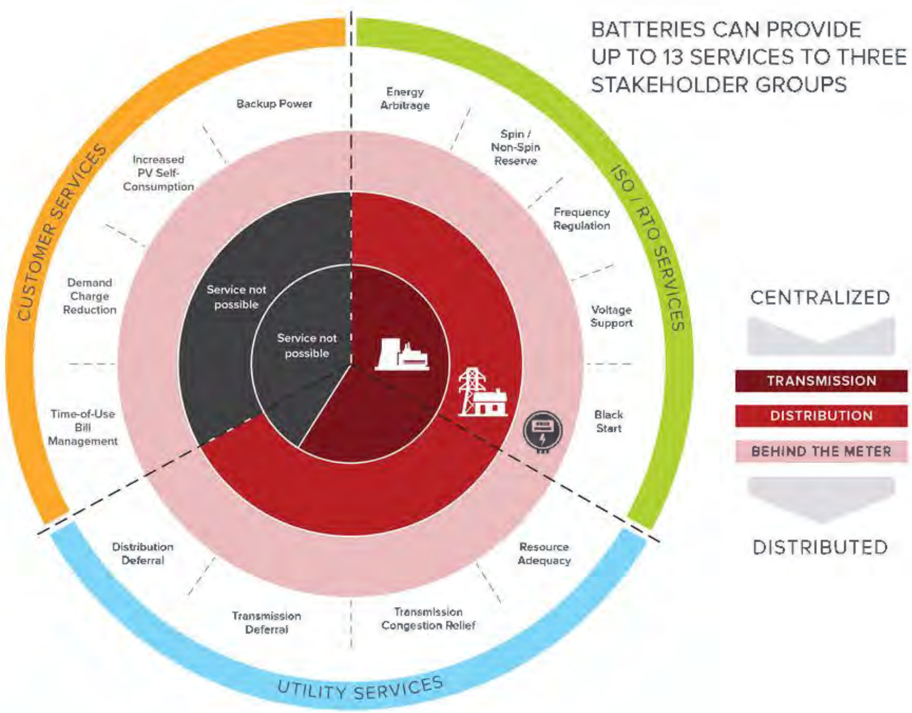
Energy storage technologies can provide a range of "grid services" that help to meet the needs of PGE's system and customers. Figure 1 describes the services that energy storage can provide to the grid based on the location of the storage system. The innermost rings of the diagram indicate where the storage system is located – on the transmission system; on the distribution system; or behind the customer meter. The outermost rings describe the range of services battery systems can provide: ISO/RTO Services (which also could be described as "generation services" or energy and ancillary services); Utility Services (which could also be described as transmission services and distribution services); and Customer Services.

A transmission-sited storage system can provide generation and transmission services, but not distribution and customer services. A distribution-sited system can provide all services, except customer services. A behind-the-meter system can provide all of the services described.[b] Customer services provide value only to the specific customer who hosts the storage system, whereas the other values in the figure accrue to many (or all) of the customers within a utility's footprint. Importantly, while a storage system located at a customer site can unlock all of these value streams, in reality the storage

[b] RMI explains in *The Economics of Battery Energy Storage that* "our results come with one major caveat: for any of the scenarios illustrated herein to manifest in the real world, several regulatory barriers to behind-the-meter energy storage market participation must be overcome."

system (or the entity that controls it) will choose which services the system provides. Storage systems typically only perform a subset of the services identified. The Salem Smart Power Center (SSPC), for example, has been tested to perform all or nearly all of these services, but that was to demonstrate capability. As a system resource, the SSPC typically only provides frequency regulation and capacity/resource adequacy.

**Figure 1: Storage Providing Grid Services**[14]



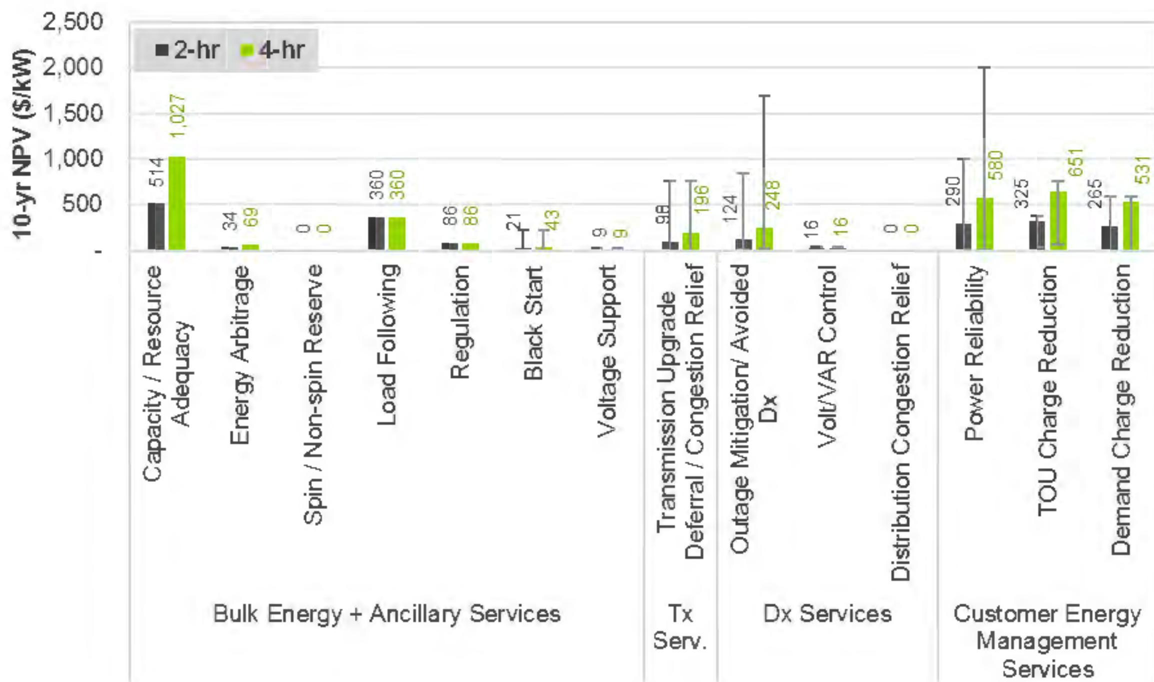

While Rocky Mountain Institute (RMI) identifies thirteen different grid services or “applications” that storage can provide in Figure 1 (e.g., Energy Arbitrage, Spin/Non-Spin Reserve, Demand Charge Reduction, etc.), OPUC Order 17-118 established sixteen applications for PGE to evaluate in this proceeding.[c15] PGE’s Energy Storage Potential Evaluation (Appendix 4) quantifies the benefit of each of these services on PGE’s system, as demonstrated by Figure 2.

Figure 2 illustrates the estimated benefits of the sixteen energy storage applications for both two-hour and four-hour storage systems on PGE’s systems. A greater benefit for a given application indicates a greater need for that application on PGE’s system. Accordingly, the greatest need for PGE’s system is generation capacity – a conclusion also reached by PGE’s 2016 IRP, and that flows intuitively from the retirement of coal-fired capacity and an increase in variable renewable resources.[16] Likewise, increased

[c] Compared to Figure 1, Order 17-118 added Load Following, Volt/VAR control, Outage Mitigation, and Distribution Congestion Relief; and excluded Increased PV Self-Consumption

renewable resources suggest a need for load following, which shows a meaningful benefit to PGE's system.

**Figure 2: 10-Year Benefit of Each Storage Application**[17]




As the error bars on Figure 2 indicate, there is a significant range of benefits for many applications, especially transmission upgrade deferral, outage mitigation, and the three customer applications – power reliability, time-of-use (TOU) charge reduction, and demand charge reduction. One reason for the large range of transmission deferral benefits is because those benefits for distribution-interconnected storage are 30% of the benefits for transmission-interconnected storage. Because the transmission system operates as a network, power flow is distributed across the grid in multiple directions. An injection of 1 MW at any given distribution substation will flow proportionately across each transmission circuit at that interface. An example of a transmission path is Bonneville Power Administration's (BPA) I-5 corridor, which is the primary location in the region where the opportunity for transmission deferral exists.[18] A load reduction in our service territory from the dispatch of a locally-sited storage system corresponds to only a 30% load reduction along the I-5 corridor; the other 70% of reduction is seen amongst the other transmission paths into our system.[d] For example, dispatching a 10 MW battery located at PGE's Coffee Creek Substation will result in approximately a 3 MW reduction of power flow on the I-5 transmission path.

[d] PGE estimated this 30% factor by modeling the South of Allston path flow in our transmission planning power flow software, PowerWorld. The path flow was modeled at 3,100 MW in peak summer conditions, with the aggregate DER in the Portland metro area producing 0 MW (base case) and a total of 76 MW (full output). The South of Allston path flow is reduced to 3,077 MW as a result of the DERs in this example scenario. The injection of 76 MW of DERs in the Portland metro area for this scenario reduces the South of Allston path flow by 23 MW (~30%).

The large range in the outage mitigation benefits results from large differences in the locational value of energy storage within PGE's system. Both the risk of an outage and the cost of an outage vary at different locations within our system; accordingly the outage mitigation benefits also vary by location.[e]

Customer service benefits have significant ranges because customers differ significantly. Not only are customer rates different depending on class of customer (e.g., residential vs. small business), but customer usage also varies widely. These differences lead to broad ranges of benefits for time-of-use charge reduction and demand charge reduction.

Power reliability benefits also vary significantly because some customers value electric service much more than others. For example, an outage will impact a hotel or pizza parlor differently than a residential customer. Moreover, even within customer classes, the value of power reliability ranges significantly. For example, a residential customer that works from home and keeps important medicine refrigerated may value service much more than a college student who only returns to their residence to sleep.

In our modeling efforts, PGE did not isolate the specific value of spin and non-spin reserves, though their value is included in the total operational (i.e., bulk energy system) value incorporated throughout the potential evaluation. Non-spin reserves likely comprise a very small portion of the total value because PGE has adequate non-spin resources through its Dispatchable Standby Generation (DSG) program. Spinning reserves are also expected to comprise a relatively small share of the total operational value because these are often provided by hydro resources at zero or low opportunity cost and because the load following requirement may result in additional availability of spinning reserves at no incremental cost in some time periods. In the decomposition of the operational applications, the value of Spin and Non-Spin reserves are included in the Load Following category. Operation within the EIM and piloting spinning reserve applications on storage systems will provide PGE with additional visibility into the opportunity costs specifically associated with meeting its spinning reserve obligations.

Stakeholders have questioned the lack of benefit from distribution asset deferral and transmission congestion relief.[19,20] Importantly, however, benefits from distribution asset deferral are included in PGE's analysis – as part of the outage mitigation benefits. PGE generated values for outage mitigation benefits using its Integrated Planning Tool (IPT), a project valuation tool that calculates the value of investments in PGE's transmission and distribution system by looking at their costs and benefits. The benefits of such investments stem from the reduced risk of an outage to a customer; "risk" includes the direct economic impact on the customer due to the outage and the extended asset life due to reduced consequence of asset failure (resulting in a deferred capital investment). This direct economic impact on the customer due to an outage is the primary economic driver of the benefit. Storage's ability to avoid such an outage is referred to as "outage mitigation" when it benefits many customers and "power reliability" when it benefits only one customer. In other words, depending on where the storage system is located, IPT demonstrates a value that includes both distribution asset deferral and the economic

[e] More information on how PGE determined these different values using its Integrated Planning Tool is available in the Storage Potential Evaluation (Appendix 4).

impact of reducing outage impacts. Because the vast majority of the benefit modeled by IPT comes from outage mitigation or power reliability (and not distribution asset deferral), we refer to it as such. It is important to note, however, that most of PGE's distribution system is built with N-1 redundancy, meaning power is able to be manually restored to affected customers for a single asset failure. Consequentially, there are few areas of PGE's distribution system that would see substantial distribution deferral benefits. Further, regarding distribution congestion, PGE has sufficient distribution infrastructure to handle peak loading conditions. Thus, PGE does not have significant congestion issues on its distribution system. If PGE did face congestion issues, the most straightforward basis for monetizing the benefits would be via deferred/avoided investments.

For transmission congestion relief, many stakeholders recognize that PGE currently has no system need, but point to BPA's need to relieve transmission congestion along the I-5 corridor.[21] [22] Accordingly, there likely is a regional benefit to PGE installing energy storage for transmission congestion relief just as there is for transmission deferral. However, quantifying that benefit is challenging today as PGE has no insight into the price BPA is willing to pay for schemes that would alleviate their I-5 issue. If BPA were to release another Request for Offerings (RFO) for non-wires alternatives to alleviate their transmission concerns, similar to that issued in 2016,[23] PGE would strongly consider bidding any storage projects constructed under HB 2193 to meet their need, assuming the systems met the RFO criteria and the economics were beneficial for PGE customers.

In summary, PGE's system has a number of needs that energy storage can help meet. Some of these needs, like capacity/resource adequacy, provide equal value at any location within PGE's system. Other needs, like outage mitigation, vary meaningfully based on location within PGE's system (and the proximity of the storage system to customers who are most impacted by an outage). It is also important to note that the value of the services an energy storage system can provide to PGE's system will change over time as the needs of PGE's system change. Most of the benefits identified in the Potential Evaluation are based on 2021 projections. Given the increasing amount of renewable energy that will be on PGE's system, it is likely that the value of many of the services storage can provide could increase past 2021.

## 1.3. PGE's History with Storage

Given PGE's changing energy portfolio and our customers' evolving expectations, PGE is enthusiastic about energy storage. PGE recognizes the coming dominance of variable renewables on the grid – and the potential for low-cost power at times of high renewable output. As such, PGE began seriously examining the potential to add a significant amount of energy storage to its grid in 2008.

As Congress began developing the bill that would eventually become the American Recovery and Reinvestment Act, PGE learned of the opportunity to partner with other entities in the region as part of what would become the Pacific Northwest Smart Grid Demonstration Project. In collaboration with the Pacific Northwest National Lab (PNNL) and others, PGE was awarded a grant to build the Salem Smart

Power Center (SSPC). This 5 MW, 1.25 MWh lithium-ion battery has successfully performed 19 different applications.[f]

The primary purpose of the SSPC was to demonstrate that a large battery could perform a number of grid services – both for PGE and the industry at large. The storage industry has evolved quickly since the 5 MW battery was installed, but the lessons and data therefrom remain important building blocks in recognizing the role storage can play now and in the future. As SSPC (and similar early battery storage deployments) proved how battery storage could benefit the grid, PGE continued to investigate how best to build and integrate storage into the company's system.

One focus of this work has been investigating the potential for aggregated, customer-sited energy storage. In 2016, PGE partnered with Portland State University (PSU) to deploy a 20 kWh Aquion battery storage system in a residence (an employee's home). The prototype was developed to study whether:

- long-duration, potentially low-cost storage technology could be successfully deployed in a residential setting, and
- a communications approach to aggregate small energy storage devices could be engineered to enable control of many small storage assets as if they were one larger asset.

As PGE and PSU successfully piloted the Aquion technology, PGE decided to also test the capability of a lithium-ion based battery in a residential setting to perform grid services. Several firms have emerged to provide this functionality to both residential customers and utilities, and PGE discussed the pilot in depth with three of them: Tesla (previously Solar City), Sonnen, and Sunverge.

In 2017, PGE procured a Sunverge battery energy storage system and connected it to a customer's (employee's) residence that already had installed rooftop solar. The pilot gives PGE active experience using externally-developed battery control software that could be adopted for a large number of distributed and aggregated storage devices.

Finally, PGE is actively partnering with the City of Portland on the integration of solar and storage at Fire Station One in downtown Portland. The City won a grant from PGE's Renewable Development Fund (RDF) to develop the project to increase the energy resilience of the facility. Since the grant was awarded, PGE and the City have continued the partnership by discussing potential for deploying the battery for the use of grid services; the system is expected to be installed by the end of 2017.

Another key focus of PGE's investigation of energy storage has been the layering of value streams. Conventionally in the storage industry, this layering corresponds to the stacking (or staggering) of applications onto one another. For example, deploying a storage system to provide frequency regulation and then capacity and then outage mitigation and so on (depending on the conditions of the grid). While PGE is, of course, keen on maximizing value in this way, the Company is also aware that other value

[f] For more information about the Salem Smart Power Center, review PGE's 2016 Smart Grid Report: http://edocs.puc.state.or.us/efdocs/HAQ/um1657haq135730.pdf

streams can be brought to bear. Consider that one could potentially increase value of an energy system by deploying it at a customer site to provide backup in addition to grid services.

PGE is also pursuing other complementary approaches to energy storage including the utilization of hot water heaters as thermal storage devices and electric vehicles as mobile lithium ion batteries. Since 2016, PGE has had an active employee pilot exploring the use of water heaters for grid services. In 2017, this approach is being tested more broadly in the Pacific Northwest in collaboration with BPA and other local utilities.[24] PGE also plans to deploy a pilot retrofitting electric resistance water heaters at the end of 2017, with a goal of 8,000 water heaters enabled for grid-services by the end of the pilot. [25]

In 2016, PGE launched a pilot to test the ability of a Nissan Leaf electric vehicle to provide energy to one of PGE's own facilities, as a first step towards understanding the ability to dispatch the energy storage devices embedded in electric vehicles to provide grid services.

In summary, PGE has years of experience actively investigating a number of energy storage technologies, use cases, and business models. This experience has been foundational to the Company's understanding of storage and its development of the proposals found herein to meet the HB 2193 mandate.

## 1.4. The Energy Storage Landscape

Energy storage technology is advancing rapidly. When PGE installed the SSPC in 2013, it was the first "big" battery in the western U.S. at 5 MW/1.25 MWh. As Figure 3 describes, 221 MW of battery energy storage was installed in 2016 alone. GTM Research expects the storage market to grow almost 12 times (to 2.6 GW) by 2022. To date, most deployments have been on the utility-side of the meter; with customer-sited installations representing only 20% of the 2016 market. GTM Research expects customer-sited installations to grow to 53% of the U.S. storage market by 2022.[26]

Figure 3: U.S. Annual Energy Storage Deployment Forecast, 2012-2022 (MW)[27]

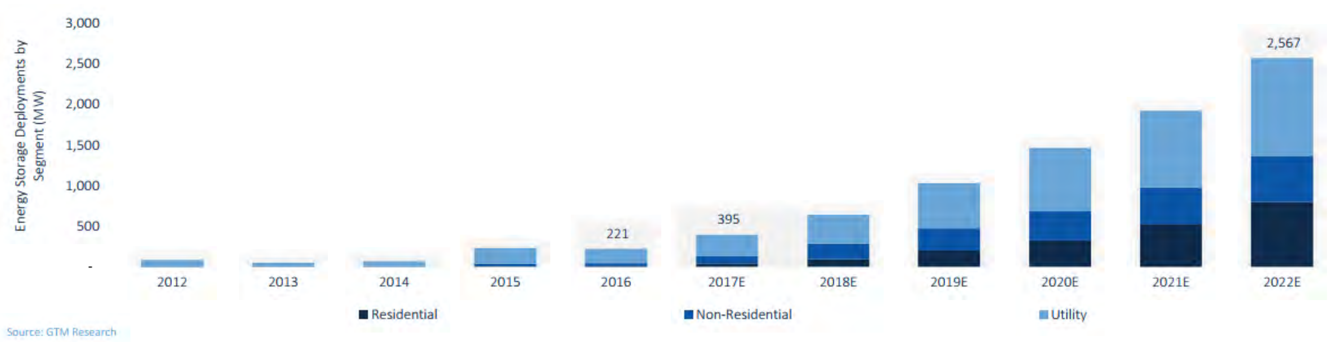
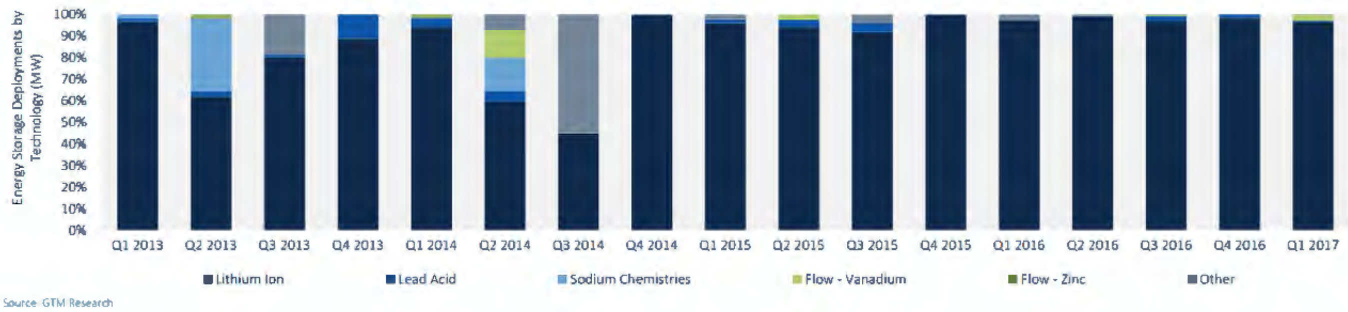



Figure 4 shows the overwhelming preponderance of lithium-ion batteries in the installation of energy storage in the U.S. since 2013. Lithium-ion batteries held 96.5% of the U.S. market in Q1 2017; vanadium flow batteries came in second with 3%; and lead-acid came in third with 0.7% of the market.[28]

Figure 4: Quarterly Energy Storage Deployment Share by Technology (MW %)[29]




Lithium-ion batteries are poised to continue their dominance in the market for three reasons:

1. Costs of lithium-ion batteries are projected to continue falling for the foreseeable future. Figure 5 shows current battery prices (which represent the largest portion, but not the full cost of an installed storage system) through 2030.[30]
2. As lithium-ion firms dominate deployments, they also gain valuable operational experience, that better enables those procuring storage to validate the battery performance.
3. That experience with those deployments and a firm's fiancial stability make them more viable and trustworthy. In short, the lithium-ion battery storage industry is in the midst of a virtuous cycle.

Figure 5: Lithium-ion battery prices 2010-2030 ($/kWh)[31]


In contrast, the non-lithium ion battery industry faces a vicious cycle – firms lack real world performance experience to win new projects; lack of new projects challenges the financial health of these firms and their projects; lack of new projects disrupts efforts to lower prices further through economies of scale. According to Bloomberg New Energy Finance,

> *"Investors appear to be conscious of these challenges [for non-lithium ion firms] and venture capital and private equity investment has slowed since 2015. This is both due to, and a cause for several high profile companies collapsing over the last couple of years."*[32]

A June 2017 article in the *MIT Technology Review* discusses the dilemma and unfortunate fate of Aquion Energy – whose saltwater-based battery PGE piloted in a residential setting in 2016:

> *"What is clear is that despite the compelling need for better grid storage technology, any startup today faces several daunting realities. First, the slowly developing market for advanced grid storage still isn't large, in part because the technologies are immature and expensive. Second, and more important in the immediate term, the price of existing technology in the form of lithium-ion batteries has dropped far faster than expected, narrowing the promised benefits of new approaches like Aquion's. 'Don't hold your breath for the things that come after lithium-ion,' says Ilan Gur, founding director of the Cyclotron Road program for energy entrepreneurs, who previously cofounded a battery company that was acquired by Bosch. 'We're much more likely to ride the lithium-ion cost curve for another few decades.'"*[33]

Nevertheless, alternatives to lithium ion storage do exist:

- One is hot water heaters, a technology PGE is currently exploring via two pilots outside the HB 2193 framework.[34]
- Others options include pumped hydro and compressed air storage – both of which historically have been geographically dependent, typically much larger than the HB 2193 cap, and – in the case of pumped hydro – require years of environmental review and permitting that would exceed the deadlines established in HB 2193.
- Other technologies include flywheels and redox flow batteries. One redox flow battery company of prominence is UniEnergy Technologies (UET), which has commissioned storage projects with Avista and Snohomish PUD.[35,36] UET, like many other redox flow battery vendors, focuses on longer-duration storage.

A general consensus of industry observers acknowledge that lithium ion batteries are the clear winners for short-duration storage applications like frequency regulation. UET and their variety may beat lithium ion vendors on applications like power reliability and outage mitigation that benefit from long duration storage.

As Table 4 demonstrates, these companies also quote prices that are competitive with the cheapest lithium ion providers. Notably, turnkey price is not the only relevant metric, and technologies with calendar lives that are 20+ years may prove to be cheaper than lithium ion on a full lifecycle basis. Bloomberg New Energy Finance caveats the values in their table:

> *"Based on discussions with developers and potential customers, we are skeptical whether these costs represent actual costs for a system delivered in 2017. Instead they are dependent on volume and potentially future delivery dates."*[37]

**Table 4: Emerging Storage System Costs Overview**[38]

| Company | Technology | Power:energy | Cell cost ($/kWh)* | Turnkey system cost ($/kWh) | LCOS ($/kWh) | Calendar life (years) | Cycle life | Target application** |
|---|---|---|---|---|---|---|---|---|
| | Li-ion | 1:4 | 175 | 400-600 | 0.06-0.09 | 10-15 | 6,000 | >1 h |
| | Li-ion | 2:1 | 175 | 600-1,200 | 0.10-0.20 | 10-15 | 6,000 | <1 h |
| EOS Energy | Zinc-halide | 1:4 | 163 | 400 | 0.08 | 15 | 5,000 | >1 h |
| ESS inc. | Iron RF | 1:8 | - | 400 | 0.04 | 25 | >10,000 | >1 h |
| redT Energy | Vanadium RF | 1:4-1:15 | - | 490-790 | 0.09-0.05 | >25 | - | >1 h |
| Primus Power | Zinc-bromide RF | 1:5 | - | 500 | 0.07 | 20 | | >1 h |
| ViZn Energy | Zinc-iron RF | 1:4 | 400 | 500 | 0.05 | 20 | 10,000 | >1 h |
| Rongke Power | Vanadium RF | 1:4 | - | 650 | 0.09 | 10 | 10,000 | >1 h |
| Highview Power | LAES | 1:4 | - | 665 (capex) | 0.03 | 30-40 | 20,000 | >1 h |
| Ecoult (Ultrabattery) | Lead carbon | 2:1 | 415 | 1,200 | 0.12 | 10 | 10,000 | <1 h |
| Amber Kinetics | Flywheel | 1:4 | - | - | - | 30 | 15,000 | >1 h |
| Ambri | Liquid-metal | - | - | - | - | 20 | 10,000 | >1 h |
| Fluidic Energy | Zinc-air | 1:4-1:10 | 200-250 | - | - | >10 | 3,000 | >1 h |
| Gridtential | Lead silicon | - | - | - | - | 10 | 1,500 | <1 h |
| RedFlow | Zinc-bromide RF | 1:2 | 800 | - | - | 10 | - | >1 h |
| UET | Vanadium RF | 1:4 | - | - | - | 20 | 10,000 | >1 h |

*Source: Company websites, specification sheets and interviews.*The cell cost refers to the cost of the cell and in places the BMS. **This is a judgment made by BNEF based on the merits of the system, and does not mean the technology cannot also participate in other applications. Li-ion turnkey system cost are based on the range reported in* Storage System Costs: More than Just a Battery *(web | terminal). Flow batteries have long calendar lives of 15-25 years, which generally refers to the electrolyte. While the pumps need replacing every 7-10 years, although this cost is relatively low as a percentage of the capex.*

In summary, deployments as directed by HB2913 are timely given that deployments are on the rise, and lithium ion battery costs continue to fall. Despite the fact that other storage technologies struggle to compete with lithium ion, there are potentially cost competitive alternatives, especially those focused on longer-duration applications.

PGE plans to remain technology agnostic in its development of storage projects, only picking a specific technology and vendor after the OPUC has approved project proposals and after careful vetting through a Request for Proposal (RFP) process. RFP vetting will include not only the applicability of a technology to the applications sought for the project and cost, but also operational experience and financial stability of vendors.

# Section 2. PGE's Approach to HB 2193

In evaluating how to most effectively develop one or more storage proposals that exemplify the spirit of HB 2193, advance PGE's ability to efficiently deploy storage in the future, and create value for our customers; PGE employed a number initiatives to identify costs of, optimal locations for, and benefit streams of energy storage projects. These efforts along with two external stakeholder workshops have helped inform our project proposals.[g]

This section outlines our vendor request for information, locational benefits of storage analysis, storage potential evaluation analysis, and our cost-effectiveness methodologies.

## 2.1. Request for Information

PGE issued a Request for Information (RFI) on May 23rd, 2016 to assist in understanding and evaluating the capabilities of companies that can function as the engineering, procurement, and construction (EPC) primary contractor for energy storage projects. The RFI requested company professional background, financials, energy storage program development experience, technology performance, performance guarantees, and references. Responses were collected until June 10th, 2016. PGE received responses from 27 firms.

Responses were evaluated on the strength of the organization and personnel, financial viability, experience and technical competence, preferred storage technology, the ability to provide performance guarantees, and references.

The majority of respondents focused on larger, grid-scale storage solutions. Less than 1/3 of respondents provided information focused on customer-sited storage installations. Of the 27 responses, 19 proposed lithium-ion battery technology, three proposed flow-battery technology, three were technology agnostic, one proposed a zinc battery, and one proposed lithium air battery technology. Seven responses were from storage manufacturers. Most respondents were willing to negotiate with PGE to create capacity guarantees. However, costs were difficult to compare because of the inconsistent inclusion of additional equipment (e.g. power conversion systems).

The RFI provided PGE a relatively short list of companies that could likely engineer, procure, and construct one or many energy storage systems to meet the HB 2913 mandate. From a high-level, PGE was pleased by both the quality and quantity of responses, and has benefited from the responses and follow-up discussions with many of the vendors.

[g] PGE held stakeholder workshops on August 1, 2017 and September 7, 2017 to discuss the draft potential evaluation and the preliminary project proposals.

## 2.2. Energy Storage Potential Study

In addition to mandating energy storage procurement, HB 2193 required the utilities to conduct energy storage potential evaluations on their systems. The purpose of the study is to analyze and estimate the expected benefits of deploying energy storage systems at different locations (e.g. transmission, substation, distribution, and customer) on PGE's grid for different grid applications (e.g. capacity, reliability, etc.).

In December 2016, the OPUC adopted Guidelines for the energy storage projects procured for compliance with HB 2193, the proposals for these projects, and the Storage Potential Evaluations.[h] Among other things, the Guidelines required OPUC Staff to develop frameworks for the potential evaluations through a series of public workshops. OPUC Staff held and PGE attended workshops on January 27, 2017 and February 17, 2017. PGE and other stakeholders submitted informal comments following each workshop (February 8, 2017 and February 28, 2017). Staff filed their resulting report with proposed requirements for the energy storage potential evaluations and a proposal to extend the deadline for filing draft potential evaluations to July 15, 2017 on March 16, 2016 and the Commission adopted Staff's recommendations on March 21, 2017.[i]

PGE engaged Navigant Consulting, Inc. to conduct the Company's Energy Storage Potential Evaluation. In the process of developing the evaluation, PGE and Navigant worked together to leverage PGE's existing tools for quantifying the locational and bulk energy benefits associated with energy storage and to integrate these analyses with additional insights from Navigant utilizing their NVEST model. In the following sections, we describe the modeling efforts undertaken by PGE for identifying locational and bulk energy system value, summarize the methodology and findings of the potential evaluation, and identify some next steps that the Company intends to undertake to further improve upon our ability to quantify the value of energy storage resources in the future.

### 2.2(a) Locational Benefits Analysis

PGE's Strategic Asset Management (SAM) team has developed lifecycle cost models for its most vital transmission and distribution (T&D) assets. These models calculate the lifecycle cost of ownership of an asset, inclusive of outage costs to customers and future PGE replacement costs, among other inputs. SAM's models generate a stream of future costs based on an asset's current state; this is the base case for determining the lifecycle cost of a given asset, or a collection of assets in the T&D system.

A key component of an asset's lifecycle cost is its "risk cost." "Risk cost" is the product of an asset's likelihood of failure, and the economic and financial consequences of that service failure should it occur.[j]

[h] UM 1751, Order 16-504.

[i] UM 1751, Order 17-118.

[j] An asset's likelihood of failure is determined by the type, age, and condition of an asset, as well as location-based risk factors, like exposure to vegetation. Consequence costs are primarily driven by customer outage impact costs, which are calculated using asset-specific outage scenarios (type and extent), load affected, outage duration, and Value of Service survey inputs. Some direct costs to PGE are also represented in SAM's consequence costs, related to the cost of reactive outage response, but they are negligible in relation to customer outage costs.

Outside of the storage initiative, SAM's models support long-range planning by identifying where in the T&D system there are large concentrations of risk, and the factors that are most driving risk and thus should be considered for remediation (e.g., aging assets, heavy loads, long outage durations, etc.).

PGE's Integrated Planning Tool (IPT) is a project valuation tool, also developed by SAM, that calculates the value of proposed investments in PGE's T&D system, once projects are scoped and estimated, via a benefit/cost calculation (with "benefit" defined as "reduction in lifecycle cost"). The IPT helps T&D identify which proposed investments have the most value from a customer's perspective, so that T&D can consider this important metric in the development of its annual capital investment portfolio.

The IPT has proven to be of use for the energy storage evaluation as well. Installing a battery at a station, on a feeder, or at a customer meter reduces the impact of service failure for customers by creating redundancy from a power supply perspective. Expressed in modeling terms, a battery can eliminate or reduce a customer's outage duration, should a service failure occur, which in turn reduces the outage impact costs of the assets associated with that battery. This has a downward effect on risk. A secondary effect on asset lifecycle cost then also occurs: if risk goes down, an asset's economic life is extended, and PGE can (theoretically) defer replacement and reduce capital spending. Put simply, installing a battery creates a benefit for customers in the form of reduced outage impacts and, hence, risk costs. Customers and PGE then also experience a secondary benefit, which is the theoretical delay of T&D asset replacement due to extended asset economic lifecycles.

Both risk reduction and lifecycle cost reduction benefits are captured in SAM's life-cycle cost models for all of T&D's vital assets (transformers, breakers, etc.). Which assets are affected by a battery depends on whether storage is installed at the station, on the feeder, or at a customer site, and the application's ability to affect risk drivers/lifecycle cost.

In order to determine which sites on PGE's system which would gain the most value from an energy storage project, PGE worked with BIS Consulting, which developed the IPT for SAM, to modify the analysis tool. The modified IPT looked solely at the reduction in baseline risk to customers and PGE that would be achievable should a battery be placed in the locations identified for analysis (substation sites, mid-feeder sites, and customer sites). The goal of the analysis was to ascertain where in the system a reduction in outage duration would have the maximum risk and lifecycle cost reduction benefit—in other words, where in PGE's system customers and PGE would most benefit from storage's outage mitigation benefits.

Note that a true business case evaluation of a battery investment would actually be comparative in nature: it would look at the risk and lifecycle cost reduction benefits of a battery *in relation to its installation costs*, and *in relation to the cost of other possible risk reduction investments* (e.g., asset replacement, system reconfiguration, distribution automation, etc.). However, for the purposes of this analysis, PGE simply strived to evaluate the basic industry presumption that a battery installation could result in a T&D investment deferral, and to assess whether any additional benefits could be derived in the transmission and distribution system due to a battery install. Indeed, we identified that customer risk reduction benefits exist, and that these are, in fact, essential for creating T&D deferral benefits.

Also worth noting is that analyses of the benefits of energy storage in the distribution grid at other utilities have typically focused on identifying the specific transformers or other distribution assets for which impending replacement *due to load growth* can be deferred. Such an approach was deemed inapplicable for PGE's analysis given the company's load growth profile. Within our territory, load growth tends to be large, clustered, and sudden (e.g., a new server farm or expansion to industrial facility) as opposed to slow and incremental. The type of load growth PGE experiences ("lump load additions") typically requires the installation of significant new infrastructure that cannot feasibly be deferred through the installation of energy storage alone. As a case in point, there are no incremental upgrades currently pending in PGE's system for which energy storage was deemed an adequately reliable and appropriate alternative to fundamental asset replacement.

Lastly, note that in order to determine cost-effectiveness, the benefits from avoided outage risk and T&D deferral must be considered alongside other benefits from energy storage, such as peak-shaving. In some cases, these benefits will "compete" for the capacity of the battery – i.e., if energy is used for peak-shaving, it is not available for backup.

The complete study is included in Appendix 2.

## 2.2(b) Bulk Energy System Benefits Analysis

In both the IRP and the Energy Storage Potential Evaluation, PGE has considered a range of modeling methodologies for quantifying the benefits of energy storage (ES) on the bulk system. There are two primary classes of models that serve this purpose: production cost models and price-taker models. PGE believes that both of these types of models provide useful insight and will likely have a place in the evaluation of ES resources in the future. However, the Company believes that it is important to clearly differentiate between these modeling approaches because they are often suitable to answering different types of questions.

### *Price-taker Models*

Price-taker models simulate the behavior of an ESS within an organized electricity market. Given prices for energy and any ancillary services that are priced in the market, a price-taker model will simulate the dispatch of an ESS to maximize the total market revenue that can be collected by the ESS. These models allow for the co-optimization of energy and ancillary services through constraints on the ESS. For example, the ESS cannot use the same capacity or energy to provide both regulation and load following at the same time. However, a portion of the battery may provide regulation at the same time that another portion of the battery provides load following. This so-called stacking of benefits occurs in every time step of the simulation.

Price-taker models inherently assume that the presence of the ESS does not impact the market price, which is a reasonable assumption when the ESS being modeled is very small relative to the size of the market. The benefits of price-taker models are that they are computationally fairly straightforward, can be run quickly, and can easily differentiate between the value of applications because revenues are tracked independently by market products.

There are two primary drawbacks of price-taker models.

1. The first is that they do not account for the size of the ES fleet. In a price-taker model, the first MW of ES has the same value as the 1,000th MW of ES, which we know not to be the case. As storage development occurs, the need for the services provided by storage decreases, and thus the value of providing more of those services also decreases.
2. The second drawback is that it is challenging to produce meaningful results in price-taker models when considering ESSs where there is not an organized market for energy or ancillary services, as is the case in the Pacific Northwest. To model an ESS in a price-taker model in the absence of an organized market for energy or ancillary services, one must estimate price streams for products that do not exist. Such exercises often rely on data from other markets or estimates based on known prices from historical bilateral transactions for specific services. Because price-taker models are so sensitive to the input prices, such assumptions can dramatically impact results and lead to inaccuracies and false precision.

### *Production Cost Models*

Production cost models instead simulate an entire electricity system or balancing area. In these simulations, the model solves for the least cost dispatch of an entire fleet of resources in order to meet load and ancillary service requirements. Like price-taker models, production cost models directly co-optimize energy and ancillary services through constraints on the battery system, resulting in co-optimized and stacked benefits in each time step. ESSs are evaluated in these models by simulating the system with and without the ESS. The difference in cost between the two simulations represents the value provided by the ESS.

Production cost models can also be run in multiple stages (e.g., day-ahead, hour-ahead, and real-time) in order to account for the operational and cost impacts of making unit commitment and scheduling decisions with imperfect information. This framework directly captures the value of resources that can mitigate the impacts of load and renewable forecast errors.

Production cost models also allow the user to understand how the size of the ES fleet impacts its value. As more ESSs are modeled in a production cost model, the value tends to decrease as the costs associated with meeting ancillary service requirements decrease. This makes production cost modeling especially useful in exercises that require portfolio evaluation, like an Integrated Resource Plan.

Production cost models are also useful in regions that lack an organized energy or ancillary service market. The value of an ESS quantified by a production cost model directly captures the avoided fuel and variable cost across the fleet associated with relying on the battery to meet a portion of the system's ancillary service requirements in each time step, rather than estimating this value with artificial ancillary service prices.

One drawback of production cost modeling is that because the value is determined as a difference in cost, rather than a collection of revenues, it is more challenging to interpret which portion of the value is associated with which service. Multiple simulations are required in order to layer in the various services if one seeks to differentiate the value of load following, for example, versus regulation. Another drawback of production cost models is that they involve significant computational complexity and require long run times. This can make it challenging to run multiple scenarios or to test a wide range of systems on a frequent or rapid basis.

A comparison of both modeling functions is included in Table 5:

**Table 5: Comparison of Price-taker and Production Cost Models**

| Feature | Price-taker | Production Cost |
|---|---|---|
| Quick | ✓ | |
| Repeatable | ✓ | ✓ |
| Portfolio Evaluation | | ✓ |
| Program Evaluation | ✓ | ✓ |
| Ancillary Services | Requires prices or proxy prices | Value calculated endogenously |
| Decomposition of value streams | Simple | Complicated |
| Examples | EPRI & PNNL storage models | ROM & PLEXOS |

As illustrated in Table 5, above, both models have value and short-comings.

In PGE's 2016 IRP, PGE chose to use a production cost model (the Resource Optimization Model, or ROM) in order to evaluate the energy and ancillary service benefits of ESSs in order to co-optimize benefit streams, capture the value of ancillary services directly rather than synthesizing proxy prices, and to capture portfolio interactions, like declining marginal value. PGE received positive feedback from its stakeholders and members of the energy storage community around the country about its approach to quantifying energy and ancillary service value in the IRP. PGE's ROM methodology was highlighted in the Energy Storage Association's 2016 primer on energy storage modeling in IRPs, and PGE was invited to present the analysis at industry and policy forums, including the Western Energy Institute's Integrated Resource Planning Forum, the North Carolina Sustainable Energy Association's Energy Storage Working Group, the 2017 Northwest Demand Response and Energy Storage Summit, and the Western Interstate Energy Board's Fall 2017 Joint CREPC-WIRAB Meeting. Moreover, at a May 24th Pacific Coast Distributed Energy Summit, Staff from the California PUC indicated that they were urging the utilities in California to essentially adopt a ROM-like approach to determine the benefits of energy storage to a utility's existing resource portfolio.

For the purposes of this evaluation and in the interest of providing significant insights while making the best use of our resources on behalf of our customers, PGE chose to leverage the production cost modeling work developed in the IRP. Toward this end, PGE conducted additional ES simulations in ROM based on updated energy market pricing from the 2016 IRP and configured the modeling to isolate the value of the three largest operational value streams: energy arbitrage, regulation, and load following.

### 2.2(c) Evaluation Report

PGE filed the resulting Draft Energy Storage Potential Evaluation with the Commission on July 14, 2017. PGE conducted a public workshop on the potential evaluation on August 1, 2017. Parties filed comments on the draft potential evaluations on August 25, 2017, and Staff filed its report with recommendations for revision of the potential evaluations on September 26, 2017. PGE incorporated modifications to the draft potential evaluation based on comments from parties and recommendations from Staff. The resulting Final Storage Potential Evaluation can be found in Appendix 4 of this proposal.

In accordance with the Commission's requirements for the potential evaluations, PGE's energy storage potential evaluation considers several energy storage use cases and a range of applications on the PGE system. The applications and end uses considered by Navigant are summarized in Table 6 below:

**Table 6: Summary of use cases and applications considered in PGE's Draft Energy Storage Potential Evaluation**

| Location | Configuration | Operational Strategy | Applications |
|---|---|---|---|
| Transmission-Connected | 20 MW, 2-hr<br>20 MW, 4-hr | PGE-controlled to prioritize operational benefits | Capacity, energy, ancillary services, transmission deferral |
| Distribution Substation | 10 MW, 2hr<br>10 MW, 4hr | PGE-controlled to prioritize operational benefits | Capacity, energy, ancillary services, transmission deferral, outage mitigation/avoided distribution investments |
| Distribution Feeder | 2 MW, 2hr<br>2 MW, 4hr | PGE-controlled to prioritize operational benefits;<br>PGE-controlled to prioritize distribution benefits | Capacity, energy, ancillary services, transmission deferral, outage mitigation/avoided distribution investments |
| Medium & Large Commercial & Industrial Customer-Sited | Aggregated fleet:<br>1 MW, 2hr<br>1 MW, 4hr | PGE-controlled to prioritize operational benefits;<br>Customer-controlled to manage demand charges | Capacity, energy, ancillary services, transmission deferral<br>*Customer applications:* power reliability, demand charge reduction |
| Small Commercial & Industrial and Residential Customer-Sited | Aggregated fleet:<br>1 MW, 4hr | PGE-controlled to prioritize operational benefits;<br>Customer-controlled to manage TOU billing | Capacity, energy, ancillary services, transmission deferral<br>*Customer applications:* power reliability, TOU charge reduction |

In addition to the system applications identified in Table 6, Navigant also considered voltage support, black start, transmission congestion (internal to PGE system), distribution deferral (due to load growth on a feeder), distribution congestion, and Volt/VAR Control, but did not incorporate these applications into the analysis due to low or non-monetizable value and/or poor compatibility with other higher value applications. A summary of all storage benefit streams considered is included in Table 7.

.

**Table 7: Storage Potential Valuation Methodology by Application [Source: Navigant]**

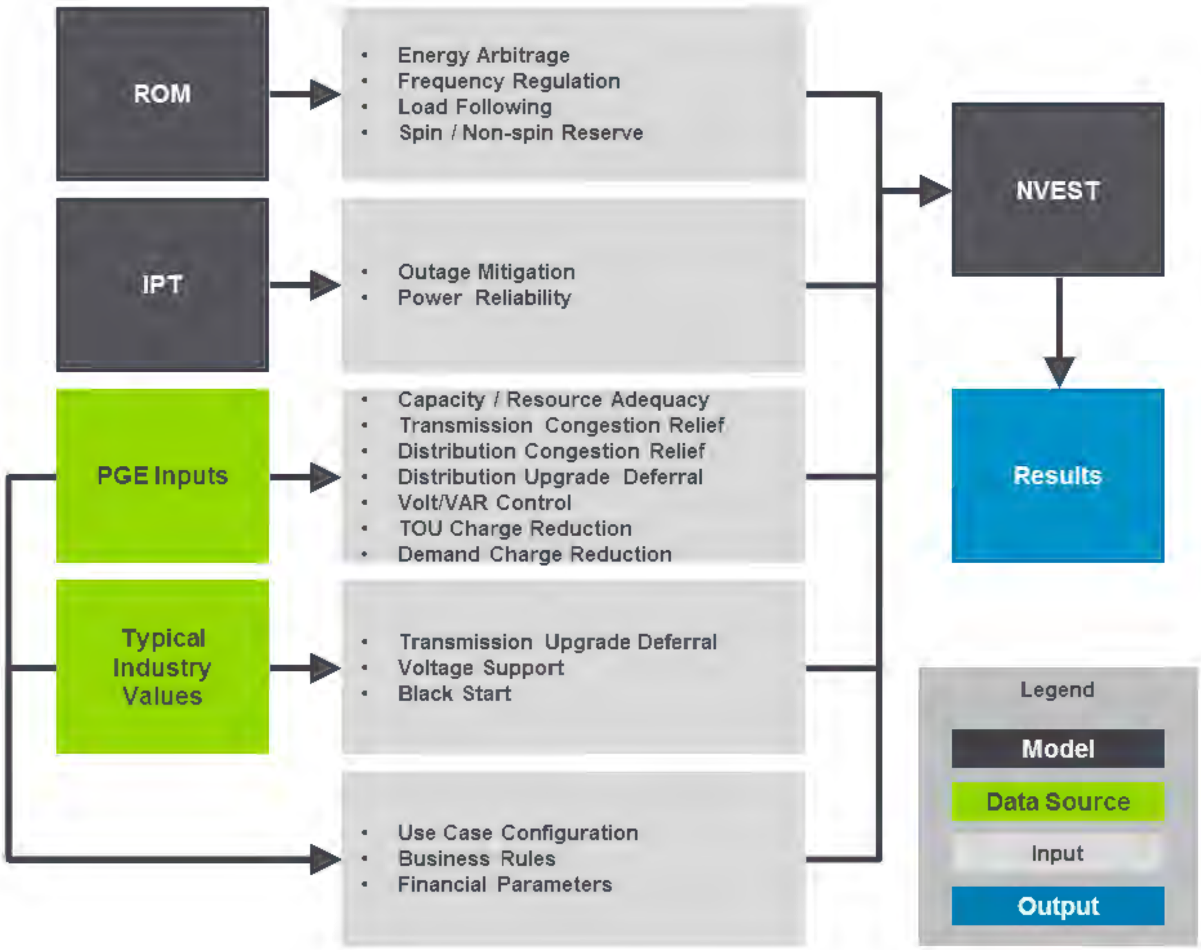
| Category | Application | Methodology & Data Sources |
|---|---|---|
| Bulk Energy | Capacity/ Resource Adequacy | Calculated as the net cost of a new Generic Capacity resource, consistent with the 2016 IRP. This capacity value is applied to the maximum discharge power that can be sustained for 4 hours. |
| | Energy Arbitrage | Determined from an energy-only energy storage dispatch simulation with 15-min prices from the 2016 IRP Reference Case. This represents the value of Energy Arbitrage in the absence of ancillary service opportunities. |
| Ancillary Services | Spin/ Non-spin Reserve | Spin and non-spin reserves are included in the ROM analysis. PGE did not isolate the specific value of spin and non-spin reserves, though their value is included in the total operational (i.e., bulk energy system) value incorporated throughout the potential evaluation. Non-spin reserves likely comprise a very small portion of the total value because PGE has adequate non-spin resources through its Dispatchable Standby Generation (DSG) program. Spinning reserves are also expected to comprise a relatively small share of the total operational value because these are often provided by hydro resources at zero or low opportunity cost and because the load following requirement may result in additional availability of spinning reserves at no incremental cost in some time periods. In the decomposition of the operational applications, the value of Spin and Non-Spin reserves are included in the Load Following category. Operation within the EIM and piloting spinning reserve applications on storage systems will provide PGE with additional visibility into the opportunity costs specifically associated with meeting its spinning reserve obligations. |
| | Load Following | Load following is included in the ROM analysis and was isolated by comparing ROM results for an energy storage device that provides Energy Arbitrage, Spin / Non-spin Reserve, and Load Following to the isolated Energy Arbitrage value. This value represents the marginal benefit of providing Load Following (and, to a lesser extent, Spin/Non-Spin) on top of the benefit of providing only Energy Arbitrage. Note that the value does not represent the value of performing Load Following alone (i.e., without also providing Energy Arbitrage), and the isolated value is dependent upon the order in which applications are added to the stack. Load Following is inclusive of forecast error mitigation and sub-hourly flexibility down to five minutes. |

| Category | Application | Methodology & Data Sources |
|---|---|---|
| | Regulation | Regulation is included in the ROM analysis and was isolated by comparing ROM results for an energy storage device that provides all operational or bulk energy system applications to an energy storage device that provides all but Regulation. In other words, it represents the increase in the co-optimized value for Energy Arbitrage, Spin/ Non-spin Reserve, and Load Following with Regulation versus the co-optimized value without Regulation. Note that the value does not represent the value of performing Regulation alone, and the value is dependent upon the order in which applications are added to the stack. |
| | Voltage Support | Navigant based the value upon typical market values in wholesale for this service where voltage support markets exist. |
| | Black Start | Navigant based the value upon typical market values for this service where Black Start markets exist. |
| Transmission Services | Transmission Congestion Relief | At present, the most straightforward basis that PGE has for monetizing the value of Transmission Congestion Relief is through deferred/avoided investments in the transmission infrastructure required to provide the relief. Thus, the value of Transmission Upgrade Deferral may be used as a basis for the value of Transmission Congestion Relief. |
| | Transmission Upgrade Deferral | This value is based upon representative capital costs of transmission ($125/kW) assuming a 1-year deferral period with 2% inflation, a fixed charge rate of 8%, and an ESS with 5% of the capacity (kW) of the transmission equipment being deferred. |
| Distribution Services | Distribution Upgrade Deferral | PGE prioritizes investments in distribution system upgrades based on a probabilistic analysis of potential component failure. The value of Distribution Upgrade Deferral is encompassed within the values calculated using the Integrated Planning Tool (IPT). This value is incorporated into the combined Outage Mitigation / Avoided Distribution Investments application.<br>Opportunities for distribution investment deferrals on the PGE system are primarily driven by aging infrastructure for two reasons. Historically, PGE has constructed a distribution system to reliably serve all customers during peak loading conditions, even when a single asset is out of service (i.e., N-1 redundancy). Secondly, at present new load growth tends to be caused by significant commercial or industrial demand that is inherently clustered (e.g., a server farm), requiring significant new infrastructure. |
| | Volt/VAR Control | The value used is representative of a recent investment in Volt/VAR equipment by PGE and reflects an avoided cost in similar equipment used for conservation voltage reduction (CVR). |
| | Outage Mitigation | The value of Outage Mitigation is encompassed within the values calculated using the Integrated Planning Tool (IPT), as describe, which includes the cost associated with maintaining distribution assets for reliability.<br>The values were calculated using the Integrated Planning Tool (IPT) and are included within the Outage Mitigation / Avoided Distribution Investments application. |
| | Distribution Congestion Relief | As discussed above for Distribution Upgrade Deferral, PGE has sufficient distribution infrastructure to handle peak loading conditions. Thus, PGE does not have significant congestion issues on its distribution system. If PGE did face congestion issues, the most straightforward basis for monetizing the benefits would be via deferred/avoided investments. |

| Category | Application | Methodology & Data Sources |
|---|---|---|
| Customer Energy Management Services | Power Reliability | Power Reliability benefits were calculated in a similar fashion to the Outage Mitigation benefits (see above), but these benefits are specifically for customer-sited systems and apply only to a single customer. The benefits are based upon customer value of service ranges, which were generated from surveys and used as inputs in the IPT model. |
| | TOU Charge Reduction | The range was calculated based upon the margin between peak and off-peak retail price of electricity for rate schedules 7, 32, 83, and 85. The analysis assumes one cycle per weekday with 90% round-trip efficiency. |
| | Demand Charge Reduction | The range was calculated based upon monthly demand charges per kW for rate schedules 7, 32, 83, and 85. |

Navigant relied on its NVEST model to quantify the stacked value associated with each use case. PGE provided key input data and modeling results to characterize system-specific benefits. For example, as discussed above, PGE's Resource Optimization Model (ROM) was used to estimate energy and ancillary service benefits and PGE's Integrated Planning Tool (IPT) was used to estimate outage mitigation and power reliability benefits.

Figure 6: Modeling approach utilized in PGE's Draft Energy Storage Potential Evaluation [Source: Navigant]



The analysis yielded a wide range of potential value for energy storage systems on the PGE system that will depend on configuration, location, operational strategy, and the opportunity to monetize specific applications. On a 10-yr NPV basis, benefits ranged from \$960 to \$2,214/kW for transmission-connected systems, \$992-\$1,865/kW for distribution substation systems, and \$992-\$2,926 for distribution feeder systems. Systems at customer sites yielded benefits both for the utility (which accrue to all customers) and benefits for the individual customer at which the system was sited. The allocation of benefits between the utility and the individual customer for these systems depends strongly on the operational strategy. Table 8 summarizes the ranges of levelized benefits for the customer-sided systems modeled.

**Table 8: Benefits associated with customer-sited energy storage systems [Source: Navigant]**

| System | Utility benefits NPV ($/kW) | Customer benefits NPV ($/kW) |
|---|---|---|
| Medium to large C&I | | |
| PGE-controlled | 985-1,733 | 1-1,406 |
| Customer-controlled | 208-991 | 303-2,405 |
| Small C&I and Residential | | |
| PGE-controlled | 1,505-1,733 | 0-1,406 |
| Customer-controlled | 1,038-1,267 | 226-1,945 |

Navigant's analysis was technology agnostic, however they also investigated the sensitivity of their findings to project-specific parameters, including round-trip efficiency, capacity degradation, and project life. The analysis found that the round-trip efficiency had a relatively small impact on the value of the energy storage system, while degradation had a larger impact. Increasing the project life from 10 to 20 years was found to significantly impact project value.

### 2.2(d) Future Opportunities

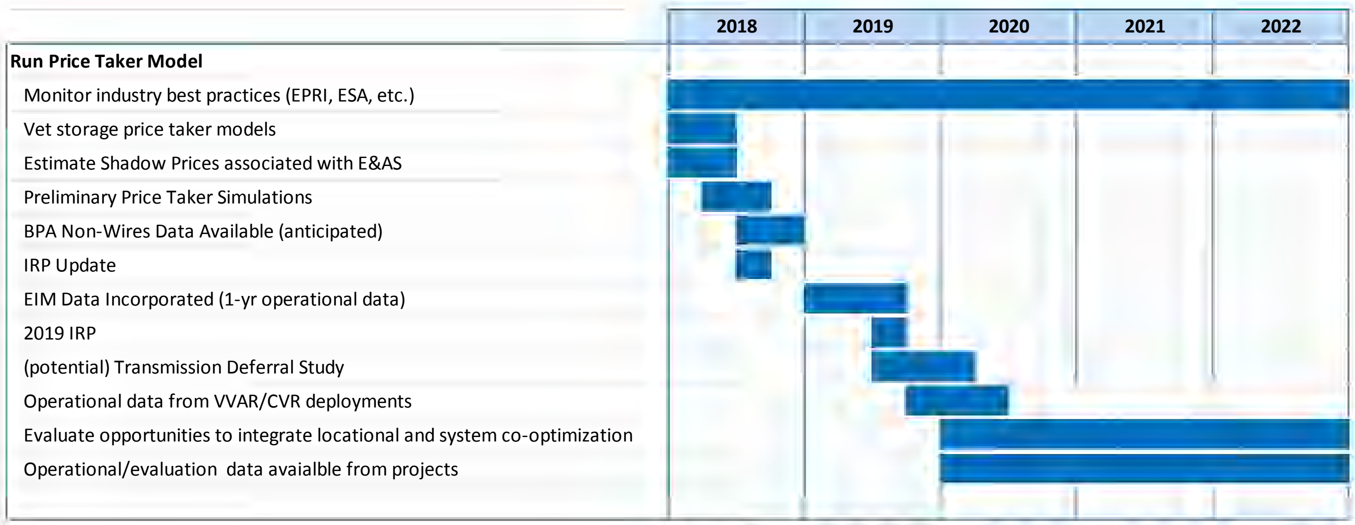
PGE believes that its Energy Storage Potential Evaluation represents a substantial contribution to the understanding of the value of ES in the region (both in terms of bulk system benefits and locational benefits) and satisfies the intent of HB2193. Our modeling efforts are innovative and evolutionary[k] and are being developed with the intent that our storage efforts integrate into PGE's existing system and T&D planning efforts. PGE does believe, however, that there remain opportunities for continued improvement in the modeling tools we use and the data/assumptions we use to input in our model.

PGE proposes the following steps for refining our modeling efforts going forward:

[k] In the 2013 IRP PGE did not model energy storage; in the 2016 IRP PGE modeled storage utilizing ROM; in the 2017 energy storage evaluation study, PGE evaluated storage using ROM while layering in locational value.

1. Monitor industry trends/best practices: the exercise for valuing energy storage is largely a new concept and modeling tools and best practices are evolving rapidly. PGE will continuously monitor and track trends and emerging best practices through channels such as EPRI or ESA.
2. Vet energy storage price taker models: PGE will evaluate, vet, and select a price taker model for conducting quick, small project/program-level storage valuation studies.
3. Estimate Shadow Price associated with Energy and Ancillary Services: PGE is interested in leveraging the production cost modeling in order to produce the input data required to run a price-taker model on its system. This would allow PGE to model ES systems both in the context of a broader portfolio using ROM in exercises, like the IRP, that require portfolio analysis, while also having the ability to more nimbly analyze the value of small incremental ES resources or programs on a more frequent basis. Toward this end, PGE proposes as its next step in ES modeling, to configure ROM to output the shadow prices associated with the load balance and ancillary service requirement constraints. This data, which would be available with 15-min granularity, could then be used in a price-taker model to estimate co-optimized energy and ancillary service value for small systems in future exercises. This exercise would not be a replacement for the production cost modeling performed in the Energy Storage Potential Evaluation or in the 2016 IRP, but it would leverage the work to date in order to provide more analysis in the future.
4. EIM Operationalize: PGE will use real data from participating in the EIM for at least one year (depending on the time required for the effects of PGE's participation to stabilize in the market) to refine modeling estimates, assumptions, or zero values.
5. BPA Non-Wires Solicitation: PGE anticipates BPA publishing values for non-wires congestion relief in 2018. If/when those values become available, PGE will incorporate those into our evaluation.
6. Transmission Deferral Valuation Study: to the extent stakeholders believe a more detailed analysis on estimating the value of transmission deferral, PGE proposes to fund a system-wide study to estimate this cost. PGE estimates this study would cost $200,000 - $300,000 and could be completed in late 2019.
7. Operationalize storage projects/pilot evaluation: PGE anticipates refining our models and modeling inputs as we have real operational data from the projects and pilots included in this proposal. As those pilots produce meaningful data regarding the output, integrity, and value of storage, we will incorporate these learnings into our models.
8. Operationalize VVAR/CVR: when PGE deploys VVAR/CVR beyond a pilot, PGE will update models to include estimates for the value of these services.

**Table 9: Storage Valuation Modeling Efforts Roadmap**




PGE looks forward to working with Staff, stakeholders, and other utilities to improve modeling practices in the future.

## 2.3. Valuation: Cost-Effectiveness Methodology

Cost effectiveness considers all quantitative costs and benefits to the electric system and its customers over the life of the project. Assessment of larger societal benefits, where applicable, is encouraged but outside the scope of this assessment. Three cost effectiveness tests were applied to the project proposals: the Total Resource Cost test (TRC), the Ratepayer Impact test (RIM), and the Participant Cost Test (PCT).

The TRC test measures net benefits of a program for all stakeholders involved (both the utility and program participants). Costs borne by both the utility and participants are included, but cash transfers between the entities are not. The RIM test takes the utility perspective only, and excludes any benefits or costs borne by the participants. Typically RIM benefit/cost ratios are lower than TRC test results. A RIM test with a benefit: cost ratio less than 1.00 indicates net cost to all customers. For the purposes of these projects, these costs can attributable to technology learnings and readiness.

The Participants Test considers benefits and costs accrued by program participants only. For energy storage proposals that target the system rather than unique participants (the Coffee Creek Substation, Baldock mid-feeder project, and the Generation Kick-start project), the inputs and results of the TRC and RIM tests will be the same, and the Participant Test is not applicable.

Costs and benefits were calculated on a net present value basis over a 10 and 20-year time frame for non-residential projects, and over a 10-year timeframe for the residential proposal. Cost effectiveness increases with the duration of energy storage maintenance and capacity contracts. For a relatively small incremental cost, PGE can extend the useful life (and benefits) of the asset from 10- to 20-years. Vendors provided indicative pricing for energy storage assets of both 10- and 20-year lives.

# Section 3. Project Proposals

This section outlines an overview of our proposals and discusses the alignment of our proposed portfolio of storage projects and pilots with the OPUC's guidelines outlined in Order No. 16-504. The section is succeeded by six sections: five sections describing in detail each projector pilot and a fifth section to discuss controls and system integration.

## *Overview of Proposals*

PGE is proposing four separate energy storage project types. The purpose of this section is to describe how we arrived at the portfolio of projects and how it collectively meets the seven "Project Guidelines" outlined by the OPUC in Order No. 16-504. The specifics of each project are detailed in subsequent sections.

PGE believes that the fundamental purpose and value of HB 2193 is to prepare for broader deployment of energy storage in the future by investing in a variety of storage projects today that allow PGE and stakeholders to best understand the approaches to storage that might make the most sense in the future. In short, the purpose is to optimize learning about energy storage; to conduct a variety of energy storage "experiments" to learn more about what works best on PGE's system to effectively guide future investments. Accordingly, PGE values the ability to propose and ultimately build, operate, and evaluate a suite of projects.

PGE's draft storage potential evaluation evaluated five project types; these are – from a high level – the principal types of storage projects available to support the energy network today:

- Transmission-connected
- Distribution-connected (at a substation)
- Distribution-connected (on a feeder)
- Customer-sited (medium/large business customers)
- Customer-sited (small business and residential customers)

PGE's five proposed project types below align with all of the five projects described in the draft storage potential evaluation. The five proposed projects are:

- A microgrid pilot to improve the region's energy resilience. Through the pilot, PGE will leverage existing distributed energy resources (DERs) and new energy storage to create at least one customer microgrid and one community microgrid (up to five total microgrids);
- A substation-sited, distribution interconnected, large-scale storage project to gain experience developing, controlling, contracting for, constructing, operating, and maintaining utility-scale energy storage;
- A mid-feeder-sited, storage asset co-located and integrated with an existing 1.75 MW solar array to gain experience integrating large-scale solar with storage and to test the integration of energy storage with distribution automation to increase reliability;

- Up to 500 residential, behind-the-meter, PGE-controlled storage projects to pilot the development of a residential storage program and develop the ability to operate a distributed, aggregated fleet of storage assets;
- A 4-6 MW transmission-connected storage device to create a “hybrid plant”. The project provides a unique use case to utilize a relatively small storage device to realize the full value of spinning reserves of an off-line turbine (18.9MW), reducing fuel use and emissions at the plant or otherwise allowing another plant (e.g. hydro) to operate at full capacity.

## *Alignment* of PGE’s Portfolio with OPUC’s Project Guidelines

Each of the seven guidelines outlined by the OPUC in Order 16-504 are phrased as “encouragements” to electric companies. Of the seven guidelines, five are relatively simple to demonstrate alignment. Table 10 summarizes the key attributes associated with the five storage projects proposed and provides a reference for seeing how the projects compare to one another.

**Table 10: Energy Storage Proposal Key Attributes Summary**

| Project Name | Location | No. of Storage Devices | Cumulative Capacity (MW) | Cumulative Energy (MWh) | Primary Applications | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Capacity | Energy + Ancillary Services | Outage Mitigation | Power Reliability | Resiliency |
| Microgrid Resiliency Pilot | Mid-Feeder/ Business Customer Premise | 2 – 5 | 3 – 12.5 | 6 – 100 | ✓ | ✓ | ✓ | ✓ | ✓ |
| Power System Integration (Coffee Creek) | Substation | 1 | 17 – 20 | 68 – 80 | ✓ | ✓ | ✓ | | |
| Power System Integration (Baldock) | Mid-feeder | 1 | 2 | 4 – 8 | ✓ | ✓ | ✓ | | |
| Residential Storage Pilot | Residential Customer Premise | 300 – 500 | 2 – 3.5 | 6 – 8 | ✓ | ✓ | | ✓ | |
| Generation Kick-Start | Trans-mission | 1 | 4 – 6 | 16 – 24 | ✓ | ✓ | | | |
| **Portfolio Aggregate** | | **305 – 508** | **28 – 38.7*** | **100 – 220** | ✓ | ✓ | ✓ | ✓ | ✓ |

**Note: total portfolio aggregate will not exceed 38.7-MW (1% of PGE’s 2014 peak load), per HB2193.*

The first guideline encourages PGE "to submit multiple projects with an aggregate capacity close to [the cap] allowed by HB 2193."[39] PGE's cap is 38.7 MW; collectively the projects proposed will contain 27-31 MW of capacity.

The second guideline encourages PGE "to submit a range of projects that are differentiated by use case, application, or other differentiating factor."[40] The five projects are all sufficiently differentiated; among other differences, they are located at different places on the grid, require different types of operational support and integration into PGE's systems, benefit different groups of and classes of customers, and they seek to answer different research questions.

The fourth guideline encourages the submission of "projects that can serve multiple applications."[41] As Table 10 illustrates, each of the projects proposed will serve at least three applications. Importantly, "energy + ancillary services" is not a single application, but the combination of four applications performed by PGE's power operations group: energy arbitrage, frequency regulation, load following, and spinning/non-spinning reserve.[l] Similarly, outage mitigation benefits include reduced costs to customers from a power outage (i.e., outage mitigation) and benefits from deferral of replacing assets in PGE's system (i.e., distribution deferral).

The fifth guideline encourages PGE "to submit projects that are strategically located to help defer or eliminate the need for system upgrades, provide voltage control or other ancillary services, or supply some other location-specific service that will improve system operation and reliability," and the seventh guideline encourages the use of "established models…to estimate the value of energy storage applications. Models must be transparent and auditable."[42] As discussed in Section 2, PGE utilized the IPT to model and rank locational benefits for all substation, feeders, and business customer sites using PGE's risk accounting methodology. Further, as the Storage Potential Evaluation discusses in more detail, PGE and Navigant worked together to leverage PGE's existing tools for quantifying the locational and bulk energy benefits associated with energy storage and to integrate these analyses with additional insights from Navigant utilizing their NVEST model. NVEST was originally developed by Navigant for the US Department of Energy (USDOE) to evaluate the potential of energy storage in various grid applications across the United States. This framework was peer-reviewed, evaluated by many industry stakeholders, and adopted by the USDOE for use by recipients of the Smart Grid Demonstration program.[m]

The sixth guideline encourages PGE to learn more about storage vendors and technologies through a Request for Information (RFI) process.[43] PGE completed a RFI in 2015; a summary of that RFI is provided in Section 2.1.

[l] These applications are grouped together due to the design of PGE's Resource Optimization Model (ROM), which is used to estimate the value of certain storage benefits. More information on ROM can be found in the Storage Potential Evaluation (Appendix B).
[m] A detailed description of NVEST's methodology is available online:
https://www.smartgrid.gov/recovery_act/analytical_approach/energy_storage_computational_tool.html

The seventh guideline encourages PGE to "use established models — such as, but not limited to, the Pacific Northwest National Laboratory's Battery Storage Evaluation Tool or the Electric Power Research Institute's Energy Storage Valuation Tool — to estimate the value of energy storage applications. Models must be transparent and auditable." As discussed in Section 2, PGE commissioned Navigant to utilize the Navigant Valuation of Energy Storage Tool (NVEST) to estimate the stacked value associated with each use case presented in this proposal. PGE held a workshop with stakeholders on August 1, 2017 to discuss the model and proposed approach and filed a draft evaluation report for stakeholders to review on July 14, 2017. The final report is included in Appendix 4, and the model inputs in confidential Appendix 3.

While the alignment of PGE's portfolio of projects with the guidelines discussed above is relatively straightforward, one of the seven guidelines requires a broader discussion. The third guideline encourages PGE "to submit a portfolio of projects that balance technology maturity, technology potential, short- and long-term project performance and risks, and short- and long-term potential value."[44] PGE's portfolio of proposed storage projects addresses technology maturity and potential through a technology agnostic focus on needs for the storage system. PGE does not intend to issue a RFP that requires specific technologies, for example, a lithium ion battery storage system. Rather, PGE intends to issue one or more RFPs that describe the needs of the storage system. For example, for the substation-sited project, PGE would issue an RFP for storage systems that is 17 – 20 MW and can provide 17 – 20 MWs of capacity reduction for at least four hours up to [25] times per year and can complete a full charge/discharge cycle daily for the specified use cases, for the life of the project. The RFP would outline any site-specific considerations (e.g. land availability, interconnection location, etc.). This approach hopefully compels a variety of technology providers to submit bids.

Ultimately, the decision on which technology (and technology provider) PGE would chose depends upon the criteria used to score these proposals. The specific criteria developed for these RFPs will be open to stakeholder comment through the Competitive Bidding Requirements established in Order 16-504.[45] Those RFPs have not yet been designed, but technology providers would be compared based on their technology's abilities, its field and laboratory results, total cost, the company's financial health, and other factors. As described in more detail in Section 1.4, in many ways, lithium ion batteries are the default technology for use in storage projects today. Non-lithium ion technology may have a better chance to compete in projects that focus on longer duration storage, and PGE's microgrid resiliency pilot may offer an opportunity for use cases capable of providing requiring six or eight-hour duration energy storage devices.

In addition to technology considerations, the third guideline also encourages PGE to balance short- and long-term performance and risks and short- and long-term potential value. While PGE's proposal consists of five projects, in certain instances, it is helpful to consider the proposal in two parts. One part consists of a large, substation-sited storage system focused primarily on integrating the storage device into the Balancing Authority and evaluating assumptions associated with the economic modelling of storage. The second part consists of a collection of smaller energy storage devices, one tied directly to the transmission system, one at a larger solar installation, a handful at critical facilities, and hundreds at residential customer homes. The focus of this second part of the proposal portfolio is on determining potential future approaches to energy storage to see if they offer the promise of providing sufficient benefits to PGE's system given higher integration costs. The first portion provides short-term performance and provides PGE with direct experience with utility-scale storage, which is potentially cost-effective during the timeframe of the project and almost certainly cost-effective in the near-term. This operational experience provides PGE with the background in storage contracting, permitting, construction, and operation to ensure future success.

PGE faces an uncertain future regarding the needs of our system and the costs of storage technology. But we know certain things will hold true: large, "utility-scale" applications are the approach responsible for most applications today and it holds significant short-term promise. Economies of scale make the installed per-kWh costs lower than any other project-type. Furthermore, these projects can be installed relatively quickly – usually within 12 months from Notice to Proceed. Gaining expertise with the full proposal, approval, design, procurement, construction, and operation of these types of storage projects by PGE, the OPUC and stakeholders will increase the inherent energy resiliency of the region. If the grid needs more capacity quickly, the development of one of these projects now would increase PGE readiness to deploy storage even more rapidly in the future.

As noted above, storage systems may provide additional value streams the closer such systems come to the end-use customer. As such, there is value in building the foundation for programs that will allow PGE and our customers to partner on storage installations that support both increased reliability and resilience for individual customers and broad, system-based benefits for all of our customers. The second portion of the proposal focuses on these types of projects. While projects closer to the customer do have greater benefits than projects that are connected directly to the transmission or distribution system, they also have greater costs. These costs are a result of higher costs due to increased installation, design, preventative and corrective maintenance, and storage system costs, (e.g., the lack of economies of scale enabled by larger systems). Increased costs also result from increased development costs in the short-term, as new systems need to be designed and constructed to fully take advantage of distributed energy storage systems. These systems largely consist of new software and communications infrastructure used to control and integrate distributed storage into PGE's system.

In short, PGE is balancing technology, performance, risk and value over the short- and long-term by proposing a portfolio of significantly differentiated project types that enable broad experience and learning, as encouraged by the Commission.

# Section 4. Customer & Community Microgrid Resiliency Project

## 4.1. Pilot Description

PGE proposes to create a pilot program that serves as a model for a replicable community storage/microgrid program and meet customer demand for clean, resilient energy solutions. A microgrid is a small-scale electric grid that operates in conjunction with the electrical grid through a network of on-site generation, energy storage, and integrated controls. Under normal conditions it is connected to the main grid. During a grid disturbance, the microgrid resources would provide stability support to the main grid. In the event the main grid experiences an outage, the microgrid would isolate itself and operate independently ("islanding"). Through this proposal, PGE is considering installation of energy storage as part of two types of microgrids:

1. Single Customer Microgrid: serves a single customer metered site (single building, facility, or campus). The single customer has on-site generation to sustain power during an outage.
2. Community Microgrid (partial feeder microgrid): serves a subset of customers on a feeder; a segment of the feeder is isolated during an outage event. This could be a neighborhood or otherwise closely located facilities on the same feeder section.

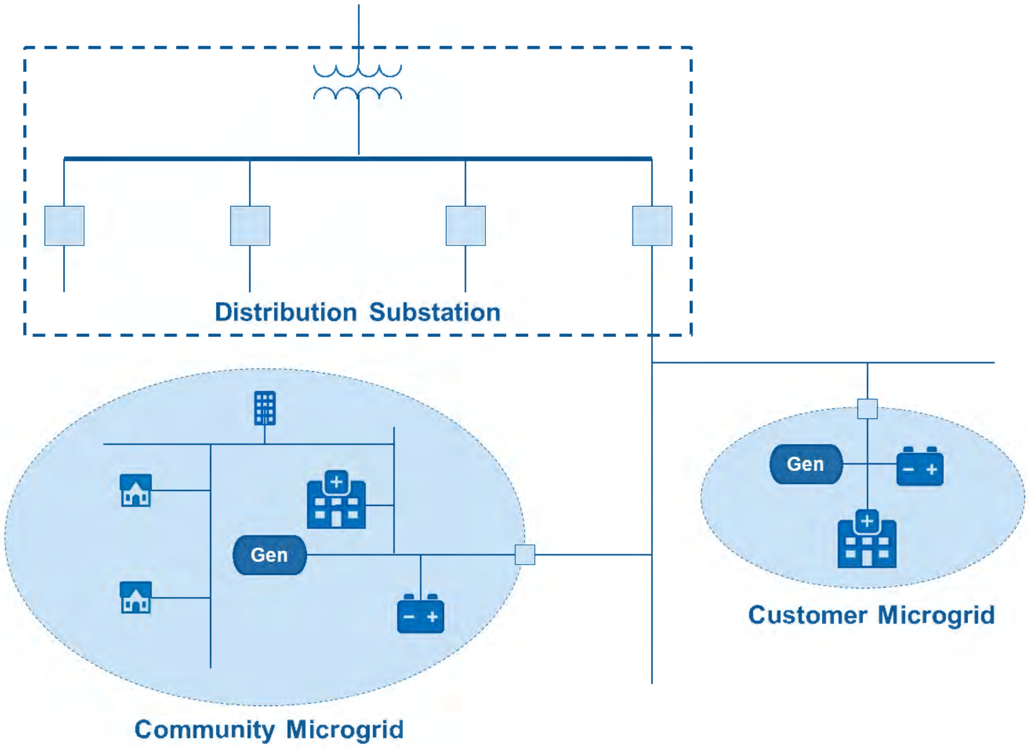



Figure 7: Microgrid Conceptualization

The Department of Homeland Security defines resilience as "the ability to adapt to changing conditions and withstand and rapidly recover from disruption due to emergencies." Resilience includes: (1) reducing the likelihood that outages will occur, and (2) managing and recovering from outage events when they do occur. Oregon's seismic resilience goal is defined in Further Oregon's Seismic Safety Policy Advisory Commission (OSSPAC):

> *"Oregon citizens will not only be protected from life-threatening physical harm, but because of risk reduction measures and pre-disaster planning, communities will recover more quickly and with less continuing vulnerability following a Cascadia subduction zone earthquake and tsunami."*[46]

Through the pilot, PGE will install energy storage to create at least one customer microgrid and one community microgrid (up to 5 total microgrids) in combination with customers' new or existing DERs. The projects will create microgrids that aim to meet customers' resiliency and clean energy goals. The pilot will evaluate communities and customers at critical facilities with and without solar and dispatchable standby generation in order to test a variety of energy storage/microgrid use cases for resiliency. The microgrid projects will be pilots with scope limits, cost limits, and time limits. As pilots, PGE will balance technical feasibility, complexity, costs, and potential learnings in selecting projects.

PGE will control and operate the energy storage devices for grid services under normal operations. During an outage event, however, the energy storage device (and, where applicable, the customer's on-site DERs) will island from the grid such that the customer or community continues to receive power.

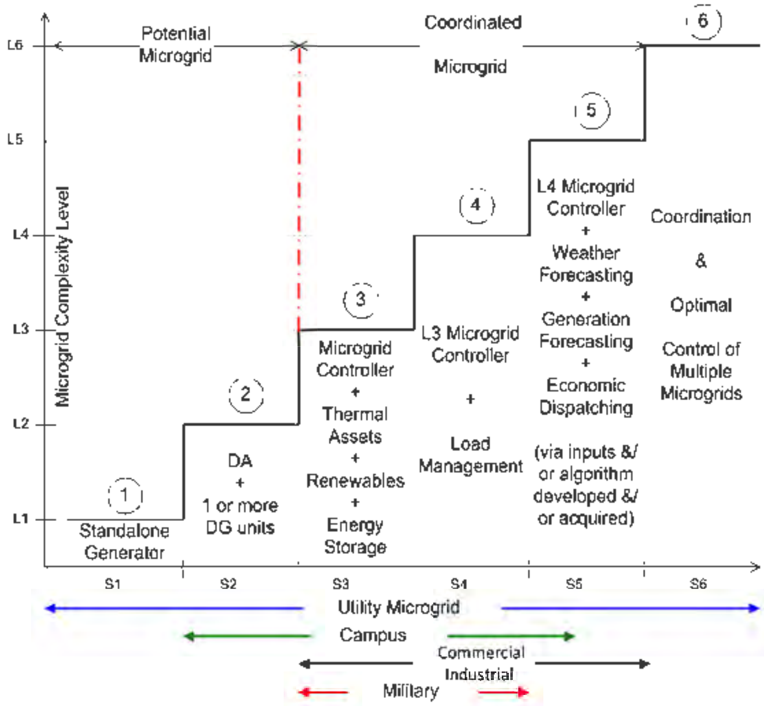
The pilot aims to test technical viability of microgrids. Projects will be designed with:

- Ability to dispatch grid services
- Integrated load management and load prioritization plan (within the microgrid)
- Ability to island from the grid
- Ability to reconnect to the grid

The pilot aims to inform the creation of a community microgrid and customer resiliency program that leverages PGE's existing Dispatchable Standby Generation (DSG) program.

As the microgrid industry matures, it is important to consider the current state of PGE's DSG program, which currently manages 122 MW of customer-owned backup generation, relative to an optimized network of microgrids. "S&C Electric has identified six different levels of microgrid sophistication, stepping up from the simplest which has only a back-up generator to the most advanced microgrid with multiple forms of generation, energy storage, sophisticated controller capabilities and even the ability to coordinate multiple microgrids."[47]

Figure 8: Microgrid Level by Complexity (S&C Electric) [a]




By these definitions, PGE's existing DSG program is a level 1 microgrid. The proposed pilot microgrids would be the installation of 2-5 level 4 microgrids, with the long-term intent of developing programs which creates a network of level 5-6 microgrids. In order to appropriately leverage the microgrid investment, PGE will need an energy storage control system capable of controlling the microgrids as they increase in sophistication. See Section 8 for more detail on PGE's control system plan.

## Key Attributes

**Table 11: Key Project Attributes (Microgrid Resiliency)**

| Attribute | Est. Value (per site) | Est. Value (cumulative) |
|---|---|---|
| Charge/Discharge Rate (MW) | up to 5 MW | up to 12.5 MW |
| Energy Storage (MWh) | 2-8 | 6-100 |
| On-site customer generation | DSG and/or Solar | |
| Technology/Material | TBD | |
| Response Rate (sec) | TBD | |
| Locations | Community: at a feeder location<br>Customer-sited: at critical business customer sites | |

Each microgrid will include automated switching schemes and controls that will allow PGE to utilize the energy storage device for capacity, energy and ancillary services, as well as asset deferral (for community microgrids). For the customer-sited projects, in exchange for providing staff time, real estate, site access, and control of their generator and solar array, the customer will have access to the storage and generation as a backup resource in the event of an outage or major natural. This is in addition to typical benefits they receive as participants in DSG: generator testing, maintenance, and diesel fuel.

## Pilot Process

The pilot will take a three-phase approach to ensure that we select customer sites that maximize value from pilot learnings:

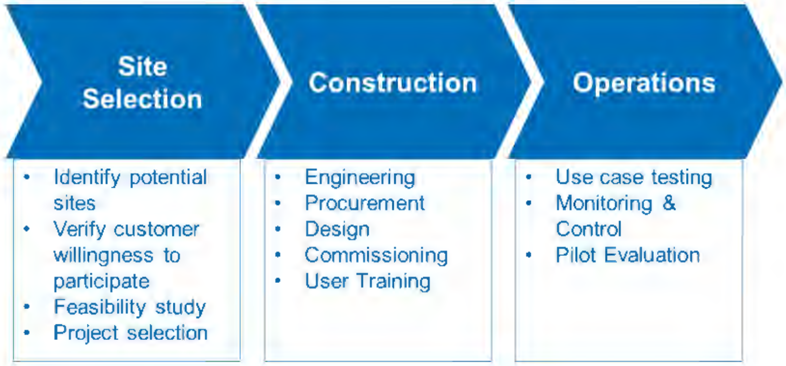



**Figure 9: Microgrid Pilot Process Overview**

PGE's goal is to have 2-5 microgrids installed on PGE's system between 2019-2021 under the pilot.

## 4.2. Site Selection

The Company will select specific sites by a qualitative assessment that evaluates the suitability of potential sites based on these criteria:

- Site criticality: A critical facility is one that is reasonably expected to be safe and functional during and after a magnitude 9.0 Cascadia subduction zone seismic event.
  - Seismic risk & structural integrity
  - Emergency plan & function: for customer-sited microgrids, the facility must have a documented emergency response plan. The facility must support the health, safety, basic function, or resilience of the community (such as emergency operations centers, hospitals, police and fire stations, emergency responders, utilities, schools, housing, certain retail stores, and banks).
  - Facility should not be located in a flood zone if at all possible. [48]
  - Soil stability
  - Recognition as an emergency site by city, state, or other governing body will be considered (e.g. the City of Portland's Basic Earthquake Emergency Communication Node [BEECN] sites)[49]
- Multi-modal: site serves multiple purposes during an emergency event (e.g. a food distribution facility that may also be used as an emergency gathering point).
- Proximity to underserved communities
- Existence of on-site generation (e.g. solar, DSG, etc.)
- Potential for new on-site generation (e.g. solar potential)
- Population density (accessibility in major disaster)
- Potential for matching funds (customer willingness to pay)
- Potential for distribution system deferral / minimal distribution system upgrades required
- Access to PGE communications infrastructure (fiber or wireless)
- Served by a substation or substations with modern protection, control, and communications systems
- Configuration of existing electrical panels, critical load panel, etc.
- Size and number of facility(ies) to be islanded
- Community support: PGE will solicit input from local resiliency organizations and municipalities to aid in selecting sites.

Not all criteria will be met for every project. PGE will evaluate projects to balance the criteria above.

PGE will rank potential sites based on the criteria outlined above. PGE will likely consider at least one project at a PGE facility (e.g. Readiness Center, Integrated Operations Center, or a Distribution Line Center).

*Note: PGE has elected not to select communities, customers, or facilities in advance of this filing as we do not want to burden customers by navigating them through the regulatory process without certainty that the project will be approved. Once sites are identified as high-potential sites, PGE's customer* *management team will directly engage with appropriate stakeholders at prospective organizations to gauge interest and verify willingness to participate.*

### *Feasibility Assessments*

In order to develop a microgrid that can effectively operate under these conditions, PGE will conduct a feasibility study at sites identified as potential microgrid candidates. Said feasibility studies will include an on-site evaluation and will verify each of the following are suitable for the microgrid in question:

- Seismic & structural integrity
- Communications infrastructure
- Customer electrical loads and critical loads
- Substation suitability
- Physical site suitability
- Outage simulations and system performance modelling
- Cost study including a preliminary bill of materials needed to construct the microgrid

Feasibility assessments will determine site viability, site-specific system sizing, system valuation (cost-benefit estimates), and (when viable) a site project scope of work to inform procurement.

## 4.3. Technology Considerations

In normal conditions, a microgrid is interconnected to the electric distribution system and operates as a part of that system. During normal conditions, critical facilities on a microgrid will be served by a mix of energy from the grid and energy from the energy storage devices or small-scale generation installed as part of the microgrid. The microgrid may also backfeed energy to the grid, serving other loads. However, when there is an outage on the distribution system, the microgrid's integrated controls will island it from the distribution system. When islanded, the microgrids will use the energy storage device and on-site generator to maintain electrical service to the critical facilities therein. When service is restored to the grid, the microgrid will revert back to the standard interconnection with PGE's distribution system.

### *Distribution System Requirements*

PGE anticipates that the microgrid projects could require upgrades to the existing distribution system such as:

- Substation upgrades: protection equipment, communication equipment, power circuit breakers, SCADA system, etc.
- Customer Site upgrades: protection equipment, communication equipment, power circuit breakers, and SCADA system, etc.
- Distribution feeder upgrades: reclosers, switches, faulted circuit indicators, etc. with smart controls.

## *Load Management*

A major Cascadia subduction zone earthquake or natural disaster could increase restoration times for some customers for extended periods of time. As such, it is important for microgrid customers to have outlined plans for load management to account for and extend limited and intermittent energy supply. The following load management strategies will be encouraged for participation in the customer microgrid pilot:

- Load Management Plan: customers must document a resiliency plan for load management in the event of a major outage. This plan must identify critical loads, their load profiles, and how they will be managed during a major outage event. Further, the plan may identify a priority loading order for all loads in the facility (i.e. must run, discretionary, emergency load shed, etc.). PGE will support the development of this plan, however, many of the considerations will be largely driven by the customer's resiliency goals.
- Critical Loads Panel: if determined necessary in the project feasibility assessment, the customer must install one or more critical load panels to isolate 'must-run' loads and ensure microgrid stability. PGE would support the customer with this effort, however, it would be at the customers' expense.
- Demand Response-Enabled: customers may be able to extend power availability by implementing load control strategies to reduce peak demand. Participants will be encouraged to enroll in PGE's commercial and industrial automated demand response program. This is important given that load supply resources may be limited at times during a major disaster, and consequently customers must be capable of and experienced in shifting loads from periods of limited or no supply.

## *Energy Storage Technology*

Storage sizing will be evaluated on a site-by-site basis for capacity needs, energy needs, and land-availability. PGE does not anticipate identifying any particular storage technology for each site during procurement; however we do anticipate that the desire for long-duration outage support could make one or more of these projects good candidates for flow batteries.

## 4.4. Ownership Structure

As indicated in Figure 3 (p. 22), business customer-sited storage is expected to grow significantly over the coming years. There is significant opportunity to utilize these proliferating resources for grid services. In order to maximize learning and customer value, PGE proposes to own the energy storage system and control the asset for testing grid services and to own the energy storage system.

For the customer microgrid(s), the pilot will employ a combination of customer- and PGE-owned assets:

Table 12: Anticipated Asset Ownership Model, Customer Microgrid

| Asset | Ownership |
|---|---|
| Energy Storage Device | PGE |
| Battery Inverter | PGE |
| Solar Array | Customer |
| Solar Inverter | Customer or PGE |
| Communications Infrastructure | PGE |
| Generator | Customer |
| Controls, Switch gear, Relays, etc. | Customer and/or PGE |
| Behind the meter transformer(s) | PGE |
| Meter(s) | PGE |
| Critical loads panel | Customer |
| Energy Management System | Customer |

For viable candidates who also intend to add DERs, PGE will support the customer(s) in identifying funding streams for those DERs (e.g. tax credits, grant funding, Energy Trust of Oregon (ETO) incentives, etc.).

For the community microgrid, PGE will own the energy storage and all necessary equipment to control and operate the microgrid. PGE may evaluate opportunities to incorporate customers' existing on-site generation to extend the microgrid's ability to sustain power during an outage.

## 4.5. Construction and Implementation Plan

### *Procurement*

PGE anticipates selecting 1-2 engineering firms to conduct all feasibility assessments and develop a scope of work for the selected sites.

PGE intends to install 2-5 microgrids over a 3-4 year period. The projects will be selected based on viable projects determined from the feasibility assessment and the customer's ability to accommodate construction in the following year.

After selecting sites through the feasibility assessment process, PGE will evaluate whether the projects should be developed under an Engineering, Procurement, and Construction (EPC) agreement or through a combination of PGE and vendor services. We expect to issue RFPs or work associated with 1-2 microgrid projects at a time in order to account for likely site-specific differences and to accommodate a tiered installation schedule.

### *Engineering-Design*

PGE will conduct or contract for all necessary engineering work associated with that microgrid project, including but not limited to:

- Site development
- Electrical design
- Protection, automation, and controls schemes
- Technology/materials selection
- Network design
- Load management strategy (if applicable)
- Structural design (if applicable)
- Solar or back-up generation design (if applicable)
- Interconnection

PGE will support and participate in the specification development and site design.

### *Permitting*

The project team will secure all necessary permits and approvals to meet the requirements of the appropriate jurisdiction for all aspects of the project, including but not limited to all applicable conditional use, electrical, mechanical, building permits, environmental impacts, etc.

### *Mobilization*

For each project, PGE or the construction contractor will oversee mobilization after securing necessary permits with the local jurisdictions.

## Construction Management

PGE will oversee the construction of each microgrid, including work on PGE's system (work inside the substation, protections, breakers, relays, fiber, etc.) and work on the customer site (energy storage device installation, controls, switch gear, relays, critical load panel, etc.).

For each project, the project manager will coordinate key project stakeholders for all project work:

- Contractors, Vendors, etc. as needed for the project
- System protection engineering lead
- Communications engineering lead
- Distribution engineering lead
- T&D planner lead
- Substation engineering lead (if applicable)
- Control system engineer lead
- Substation construction lead
- Networking/IT lead

## Commissioning, Testing, and Training

Testing & commissioning of sub-systems will follow manufacturer specifications. Integration testing will be performed by PGE technicians and/or special testers to PGE specifications.

Testing will begin upon substantial completion and will encompass two key areas of work:

- Testing and commissioning of the energy storage device per manufacturer specifications (likely requiring internal and external testing and commissioning resources).
- Testing and commissioning protection schemes, automation, relays, etc. including fully islanding the microgrid from PGE's grid and reconnection.

During testing and commissioning, the customer (if applicable) and PGE operations and maintenance personnel will receive training on how to operate and maintain the microgrid.

## *Pilot Schedule*

PGE has already begun working with municipal customers to identify potential candidate sites for the microgrid pilot. We anticipate actively recruiting customers upon approval of this proposal and intend to complete feasibility assessments in 2018. This would allow construction for 2-5 microgrid sites to be staggered over the 2019-2021 period.

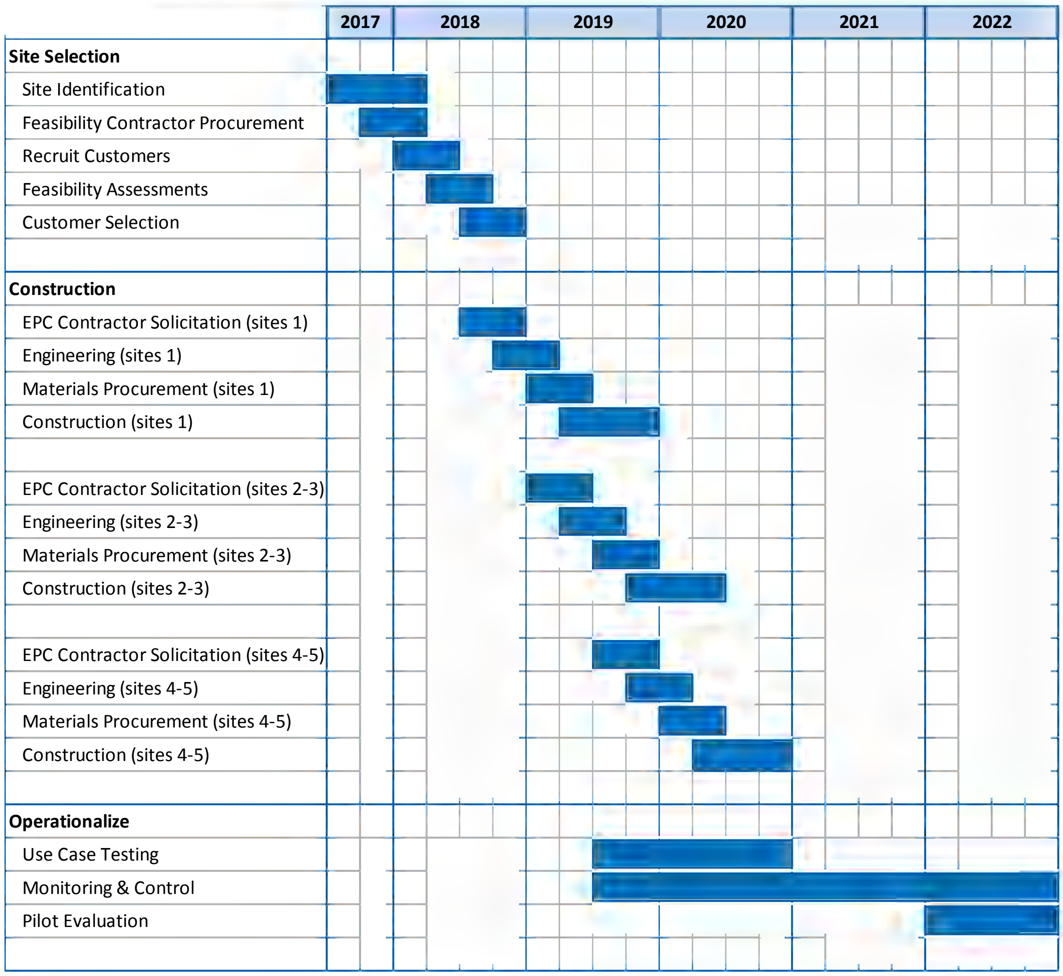



**Figure 10: Microgrid Projects Timeline**

## *Deployment Risks*

**Customer/site selection (for customer microgrid)**: PGE is confident that there are a substantive number of sites that meet the pilot requirements. However, failure to secure sites would limit the ability to run the customer portion of this pilot. Potential barriers include:

1. Meeting many of the criteria for ideal site selection. As outlined in Section 4.2, we have a number of criteria that would identify an ideal candidate.
2. Lack of willingness to participate. Customers may be unwilling to participate in the pilot despite our identification of their site as a candidate. Because this is a pilot, customers will likely be very engaged in project planning/site design. This will require a commitment of staff resources from the customer. The limited duration of storage (batteries will not power facilities indefinitely) and their physical size may influence a customer's willingness to participate.

PGE expects public and business interest in resiliency to mitigate the above risks, and anticipates that more than 2-5 customers will be willing to participate in this preliminary pilot.

**Partner risk:** few manufacturers, contractors, or engineers have material experience with energy storage and microgrids because these assets are relatively new to the broader utility landscape. Finding the right mix of experienced and capable contractors will be critical to the success of this pilot. During the procurement phase, PGE will carefully vet potential contractors prior to awarding any contracts. We anticipate our experience with the DSG program will help our team ensure that contractors possess the requisite skill for a successful deployment.

**Permitting:** Storage is a relatively new technology, and as such, we may face challenges or delays from some jurisdictions when permitting new storage projects.

**Labor/resources:** many planned and future projects (e.g. T&D resilience, distribution automation, communications, upgrades, etc.) may draw upon the same internal resources (e.g. SCADA technicians, protections engineers, etc.) required to successfully deploy microgrids. This risk can be mitigated during the project-specific scoping/estimating to ensure adequate resources are allocated to successfully deploy the projects.

**Shared assets (contracting & legal for customer microgrids):** the pilot will explore a variety of microgrid ownership models (see Section 4.4 for details). PGE anticipates the need for an open and evolving conversation with customers regarding the allocation of value and costs for the underlying assets. This complexity will require that roles and responsibilities for all parties are clearly defined during the contracting phase.

## 4.6. Operations and Maintenance

### *Expected Functionalities*

During normal operations, PGE will operate the energy storage device and microgrid for daily grid services. The energy storage device – in conjunction with other energy storage devices included in this proposal – will be controlled to provide capacity, energy and ancillary services.

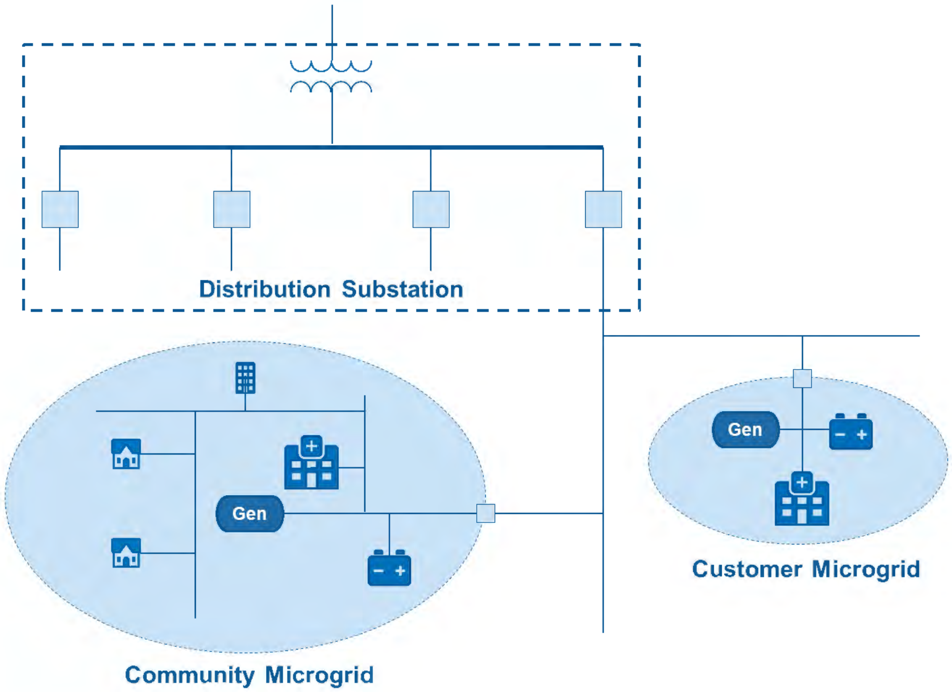



Figure 11: Microgrid Conceptual Schematic (Normal operation—grid-connected)

In the event of an outage, the microgrid will island from the grid and the energy storage device will be used to serve the customers' critical loads as illustrated below:

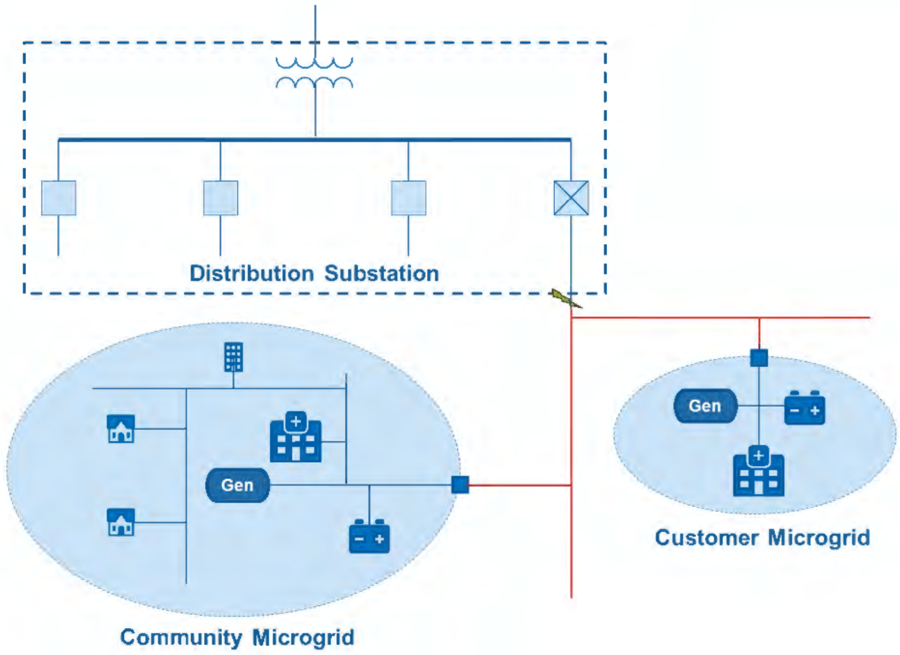



Figure 12: Microgrid Conceptual Schematic (Islanded during "outage mode")

## *Operations and Maintenance Plan*

Maintenance work will be overseen by PGE and informed by manufacturer specifications. PGE anticipates at least the following:

1. Periodic inspections
2. Periodic predictive and preventive maintenance
3. Remote annunciation of trouble alarms
4. Response to alarms by PGE technicians
5. Repair and replacement both by PGE technicians and equipment suppliers
6. Periodic microgrid testing at intervals agreed upon by PGE and the customer(s).

In the event of a power outage, the energy storage device and on-site generation assets will be available to the customer for emergency backup power generation.

## *Life Cycle Risks*

**Safety/Damage to the Equipment:** As the storage devices will be located on or near customer sites, they may be in the public view. Like any asset in the field, it is important that PGE maintain necessary protective borders and signage to prevent unauthorized parties from tampering with, vandalizing, or otherwise accessing the system.

**System Integrity (Technology Failure/Degradation):** energy storage devices can fail or degrade over time. PGE believes that we can leverage best practices and lessons learned to reduce long-term system risks. PGE will mitigate system integrity by developing maintenance plans and negotiating favorable maintenance contracts with storage vendors during project procurement.

## 4.7. Project Costs

The microgrid proposal differs from those of the larger energy storage devices in that it contains ongoing program elements such as marketing and oversight, and initial site assessments (year one) which increase total costs. PGE anticipates that costs will vary significantly based on the specific requirements of each project. Actual pricing will be evaluated during the feasibility assessments, implementation plan development, and procurement.

The microgrid pilot will identify 2-5 projects that are up to 5 MW each, up to 12.5 MW cumulative. To illustrate a range of potential project sizes we have modelled small potential projects and large potential projects. The cost range presented below varies by indicative vendor pricing and also by battery size. In the high cost estimate, the five batteries are 2.5 MW each (assumed 4 hour duration; total of 50 MWh). In the low cost estimate, batteries are 1.0 MW each (assumed 4 hour duration; total of 20 MWh). Costs include interconnection, switchgear/switching schemes, and PGE's owner costs; this result in a total capital investment range of $11million for (five) smaller batteries (range is driven by battery life), and $41 million for (five) larger batteries. In the high cost estimate, capital costs did not increase with battery life. This translates into a total carrying cost (defined as net present value of revenue requirement over the life of the energy storage device, including ongoing annual O&M costs) ranging from $20-$24 million for the smaller batteries and $64-77 million for the larger batteries (range is driven by battery life; O&M and program costs increase with battery life even if capital costs do not).

**Table 13: Overall Project Cost Estimates**

| | Low Cost Estimate ($M) (assumes five 1 MW/4 hr. microgrids) | | | High Cost Estimate ($M) (assumes five 2.5 MW/4 hr. microgrids) | | |
|---|---|---|---|---|---|---|
| Asset Life | Overnight Capital | NPV of RevReq | Year 1 RevReq | Overnight Capital | NPV of RevReq | Year 1 RevReq |
| 10-Year | $11.4 | $19.7 | $1.3 | $41.2 | $63.6 | $2.7 |
| 20-Year | $11.6 | $24.3 | $1.5 | $41.2 | $76.9 | $2.8 |

Ongoing project costs for energy storage device maintenance and program oversight are estimated at $0.8-$1.1 million annually over the energy storage device life. Costs are driven by battery size and vendor variability more so than by energy storage device duration. For the microgrid energy storage devices, initial capital investment increase by up to 20% as you move from 10-year to 20-yearbatteries, and ongoing maintenance and program oversight costs increase by 15-30% annually (in addition to payments over a longer timeframe).

## *Grant Funding Availability*

Though PGE is not aware of any funds today to buy-down the cost of these projects, PGE will continue to monitor the industry for funds to supplement these projects. The following organizations may be able to provide support:

- **Energy Trust of Oregon:** has recently begun funding feasibility assessments for microgrid projects. PGE may be able to leverage some of these funds during the site selection process.
- **Clean Energy Group:** a national nonprofit advocacy organization working on innovative policy, technology and finance programs in the areas of clean energy and climate change. The organization's resilient power project and energy storage advancement programs have funded smaller feasibility studies and modelling efforts in the past. PGE will explore opportunities to collaborate through this project.
- **Oregon Office of Emergency Management (OEM):** provides several grant opportunities to local governments to assist in preparedness activities. Though none of the current offerings may be available directly PGE, we will evaluate opportunities to collaborate with municipal customers on the application for grant funding to reduce overall pilot costs.[50]
- **Participating Customers:** though PGE does not anticipate requiring a customer contribution to participate in this pilot, PGE will be mindful of matching funds to support relevant resiliency upgrades, investments in on-site generation, or other related cost-share efforts.

## 4.8. Estimated Project Benefits

### *In-state benefits*

As discussed in detail in the Storage Evaluation Study (Appendix 4), PGE anticipates utilizing storage devices for capacity, energy & ancillary services, and locational value (outage mitigation and/or power reliability) benefits, because these functions have the highest value and ability to be co-optimized:

- **Capacity**: the energy storage devices will be dispatched during peak demand periods to supply energy and shave peak demand, reducing the need for new peaking power plants.
- **Energy and Ancillary Services**: storage will be used for a variety of system ancillary services, including system regulation, load following, spinning reserves, voltage support, and black start.
- **Power Reliability**: the energy storage device will also be used to reduce the duration of power outages to participating customers.
- **Outage Mitigation/Avoided Distribution Investment**: the energy storage device will also be used to reduce or eliminate customer risk costs associated with power outages and consequentially will extend the economic life of distribution assets.

Whether power reliability benefits, outage mitigation benefits, or both are accrued for a specific project depends largely on project-specific design criteria. For the purposes of this analysis of estimating benefits of a theoretical system, PGE is assuming power reliability benefits only, however, project-specific benefits (which may include outage mitigation and/or power reliability) will be evaluated during the project assessment phase.

For the purposes of this proposal, PGE assumes the following system-average benefit values for these projects (see Appendix 4 for detail):

Table 14: Estimated In-State Benefits (10-yr NPV)

| Application | Amount ($/kW) |
|---|---|
| Capacity | 1,038 |
| Energy & Ancillary Services | 466 |
| *Sub-Total System Benefit* | *1,505* |
| Power Reliability | 407 |
| *Sub-Total Customer Benefit* | *407* |
| **Total Benefit** | **1,912** |

PGE will evaluate site-specific benefit streams during the feasibility assessment phase of the pilot.

## *Regional benefits*

Because specific sites have not yet been identified for this pilot, we do not know of any planned transmission projects that these storage projects would defer. Accordingly, we currently assume no transmission deferral benefits for this pilot. PGE will evaluate whether there is an opportunity to capture such benefits during our evaluation of specific sites.

PGE recognizes there may be instances in which transmission congestion value associated with energy storage can apply. PGE is currently working with BPA and regional stakeholders to determine if congestion relief on the South of Allston transmission path may be one such instance. Pending the outcome of this regional study effort, the South of Allston transmission congestion relief values, if applicable, will be included in the benefit reporting.

## *Societal Benefits*

**Resiliency:** As indicated in Section 4.2, PGE will target critical facilities that support community resilience in a major natural disaster or outage event. Though there is a clear value to the community, there are no clear methods for quantifying such benefit. EPRI has begun efforts to quantify the value of resiliency through a combination of macro- and micro-economic models, but further work needs to be done.[51] For the purposes of this proposal, we have not made an effort to quantify the value of resilience; however, we may explore this during pilot evaluation.

**Carbon Reduction and other Environmental Benefits:** though not quantified in our analysis, this pilot does have the potential to support carbon reduction. As indicated in Section 4.3, PGE will work to identify customers who have, or are willing to install, on-site solar. If a customer installs solar in order to participate, some or all of the environmental benefits associated with that array could be considered a societal benefit attributable to the project. Further, operating the storage device for resiliency will reduce the reliance on diesel fuel during an outage event; though the resultant benefits would be minimal, they would still reduce diesel emissions and therefore have positive carbon and air quality impacts.

## 4.9. Opportunity for System-wide deployment

PGE believes there is opportunity to learn from this pilot to inform the creation customer and community microgrid program. As a pilot, our focus will be communities and customer sites with resiliency needs. As an operationalized program, this offering could be scaled to any community/feeder section or non-residential customers that have enhanced reliability needs.

PGE recognizes that as proposed, this pilot is not cost-effective. PGE anticipates using these pilot sites to demonstrate value to the system, customer participation impacts, and customer willingness to pay such that we can appropriately price this as a cost-effective program in the future.

## 4.10. Cost-Effectiveness Analysis

Cost effectiveness considers all quantitative costs and benefits to the electric system and its customers over the life of the project. Assessment of larger societal benefits, where applicable, is encouraged but outside the scope of this proposal. Three cost effectiveness tests were applied to the microgrid project: the Total Resource Cost test (TRC), the Ratepayer Impact test (RIM), and the Participant test.

The TRC measures net benefits of a program for all stakeholders involved (both the utility and participating businesses). The cost streams included are overnight capital costs (vendor + PGE investment) and ongoing O&M over the economic life of the investment (energy storage system and operation maintenance, initial site assessments and outreach, and PGE coordination and oversight FTE). Benefits streams are capacity, energy and ancillary services, and power reliability. Power reliability is a benefit that accrues to the participating businesses, rather than to the utility.

The RIM test assumes the utility perspective only. In the RIM test, costs remain the same, but the power reliability benefit accruing to impacted businesses is excluded, resulting in lower overall benefits and lower benefit/cost ratios.

Table 15 reports net present value for cost and benefit streams for 10 year energy storage devices. The TRC under a low cost scenario results in the highest benefit: cost ratio at 0.47 for the TRC and 0.37 for the RIM. As participants are not being asked to contribute financially to the program, participants accrue benefits but no costs. Therefore no ratio is reported for the Participant test.

Table 15: Cost Effectiveness of Microgrid Pilot (NPV, $M) -- 10 Year Project Life

| | Low Cost Estimate | | | High Cost Estimate | | |
|---|---|---|---|---|---|---|
| **10 Year Battery** | **TRC** | **RIM** | **Participant** | **TRC** | **RIM** | **Participant** |
| Benefits | | | | | | |
| Capacity | 5.05 | 5.05 | - | 12.47 | 12.47 | - |
| Energy | 2.27 | 2.27 | - | 5.60 | 5.60 | - |
| Outage Mitigation | - | - | - | - | - | - |
| Reliability | 1.98 | - | 1.98 | 4.89 | - | 4.89 |
| **Total** | **9.30** | **7.32** | **1.98** | **22.89** | **18.07** | **4.98** |
| Costs | | | | | | |
| Capital | 14.42 | 14.42 | - | 51.65 | 51.65 | - |
| Battery O&M | 3.41 | 3.41 | - | 9.75 | 9.75 | - |
| Program | 1.88 | 1.88 | - | 2.17 | 2.17 | - |
| **Total** | **19.71** | **19.71** | **-** | **63.57** | **63.57** | **-** |
| **Net Benefit** | **(10.42)** | **(12.40)** | **1.98** | **(40.61)** | **(45.49)** | **4.98** |
| **Benefit Cost Ratio** | **0.47** | **0.37** | **n/a** | **0.36** | **0.28** | **n/a** |

For 20 year timeframe, benefits increase by a larger multiplier than do costs, resulting in more favorable benefit cost ratios. Of the scenarios considered, the low-cost 20 year energy storage device performs the best, with benefits valued at 64% of costs.

Table 16: Cost Effectiveness of Microgrid Pilot (NPV, $M) -- 20 Year Project Life

| | Low Cost Estimate | | | High Cost Estimate | | |
|---|---|---|---|---|---|---|
| **20 Year Battery** | **TRC** | **RIM** | **Participant** | **TRC** | **RIM** | **Participant** |
| Benefits | | | | | | |
| Capacity | 8.42 | 8.42 | - | 21.05 | 21.05 | - |
| Energy | 3.78 | 3.78 | - | 9.45 | 9.45 | - |
| Outage Mitigation | - | - | - | - | - | - |
| Reliability | 3.30 | | 3.30 | 8.25 | - | 8.25 |
| **Total** | **15.50** | **12.20** | **3.30** | **38.75** | **30.50** | **8.25** |
| Costs | | | | | | |
| Capital | 15.14 | 15.14 | - | 53.69 | 53.69 | - |
| Battery O&M | 6.32 | 6.32 | - | 20.09 | 20.09 | - |
| Program | 2.82 | 2.82 | - | 3.11 | 3.11 | - |
| **Total** | **24.28** | **24.28** | **-** | **76.89** | **76.89** | |
| **Net Benefit** | **(8.78)** | **(12.08)** | **3.30** | **(38.14)** | **(46.39)** | **8.25** |
| **Benefit Cost Ratio** | **0.64** | **0.50** | **n/a** | **0.50** | **0.40** | **n/a** |

As discussed in Section 4.9, PGE recognizes that this pilot as proposed is not cost-effective. As designed, in the pilot phase, we will not charge customers to participate. Their contribution of physical space and staff resources are valuable contributions for our learning, and thus we will not make a request to customers to participate in the pilot. As discussed in Section 4.7, PGE will look for grant funds to reduce the overall cost of this pilot. Ultimately, however, we anticipate using these pilot sites to demonstrate value to the system, customer participation impacts, and customer willingness to pay such that we can appropriately price this as a cost-effective program in the future.

## 4.11. Learning Objectives & Evaluation Plan

PGE envisions this proposed microgrid pilot at 2-5 sites to demonstrate benefits of microgrids to PGE, our customers, and the local community. The pilots will help PGE gain experience with microgrid planning, installation, and operations and will inform a larger-scale microgrid program deployment. The ultimate goal of the pilot program is to develop a replicable community storage/microgrid program and meet customer demand for clean, resilient energy solutions.

This pilot would require evaluation of the following topics:

**Table 17: Evaluation Topics (Microgrid Pilot)**

| Project | Quantitative Topics | | | | | Qualitative Topics | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Capacity | Transmission Deferral | Energy & Ancillary Services | Outage Mitigation | Power Reliability | Resiliency | Procurement | Infrastructural Readiness | Organizational Readiness | Customer Engagement |
| **Microgrid** | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Substation | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| Mid-Feeder | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| Residential | ✓ | ✓ | ✓ | | ✓ | | ✓ | ✓ | ✓ | ✓ |
| Generation | ✓ | | ✓ | | | | ✓ | ✓ | ✓ | |

This pilot has a unique focus on resilience at critical health and safety facilities, and it will help inform other PGE resiliency plans that are in development (e.g., the T&D Seismic Resiliency Plan). To carry out the pilot, PGE will use FEMA's Benefit-Costs Analysis toolkit[n] for guidance, as well as NYSERDA's "Microgrids for Critical Facility Resiliency in New York State" analysis.[o]

This valuation will require extensive data and analysis of the service providers at the critical facilities. For example, the number of people served by the provider, the distance of the nearest other service provider able to serve the population, and the backup generation previously present at the service provider site are all relevant. Additionally, the specifics of particular disaster scenarios will be needed in order to accurately represent the impact of service provider resilience. For example, the extent and level of damage caused by a large earthquake may mean that other service providers simply cannot provide

[n] FEMA Benefit-Cost Analysis Re-Engineering (BCAR): Development of Standard Economic Values, Version 5.0. 2015
[o] Available at http://nyssmartgrid.com/wp-content/uploads/Microgrids-for-Critical-Facility-NYS.pdf

more services in the event of the loss of electric power at a given service provider. On the other hand, the loss of power during a moderate ice storm might cause far less severe impacts.

The pilot will inform future program design elements, including but not limited to:

- Recruitment & enrollment strategies and best practices
- The value of and right questions to ask during a feasibility assessment
- Participation requirements & design specifications
- Sizing considerations
- Construction & commissioning processes and best practices
- Operational strategies and best practices
    - Billing & Credits
    - Maintenance
    - Automated dispatch

The pilot will also evaluate:

- Program costs
- Realized system benefits
- Realized customer value and willingness to pay
- Program structure/design considerations (e.g. who owns which equipment, who pays for what/how much, etc.)

Specific Research questions the pilot will aim to answer:

- What is the value of integrated storage, solar, and DSG on a microgrid?
- What is the cost-effectiveness of adding solar, storage, and a diesel generator?
- What is the cost effectiveness of adding solar and storage (only) to a customer with no backup?
- How can PGE most effectively manage solar, storage, and a diesel generators during an outage?
- What are the best practices for balancing frequency and providing other ancillary services with storage, solar, and generators.
- What is customers' willingness to pay for resiliency/islanding, and what is an appropriate customer cost?
- What are the appropriate considerations for installing, operating, and maintaining customer-sited, utility energy storage devices?
- What impact do such storage & solar systems have on the size of back-up generators required by critical customers?
- How can our power operations and reliability teams most effectively leverage distributed storage to benefit our entire system while the microgrid is operating in conjunction with the main grid?
- What are the technical limitations of solar and storage for critical backup in our service area?
- What are the operational challenges and benefits associated with a microgrid?
- What are the maintenance requirements of a microgrid with diverse resources?

## 4.12. Alternative Solutions

### *Customer-owned storage*

An alternative approach to this pilot would be to incentivize customer-owned energy storage. Though long-term, we believe there may be opportunity to supporting customer-owned storage, we believe that the nascence of the technology creates a potential customer risk and uncertainty around costs and benefits. By partnering with our customers, we will gain valuable learnings about customer-sited storage and microgrids such that we can adequately support our customers' installation of storage in the future.

### *Storage without on-site generation*

Though technically viable, sites that have energy storage without on-site generation (solar or fossil fuel) will not have adequate energy supply to support outage mitigation or a major natural disaster and would not support community resiliency.

# Section 5. Power System Integration (Coffee Creek Substation)

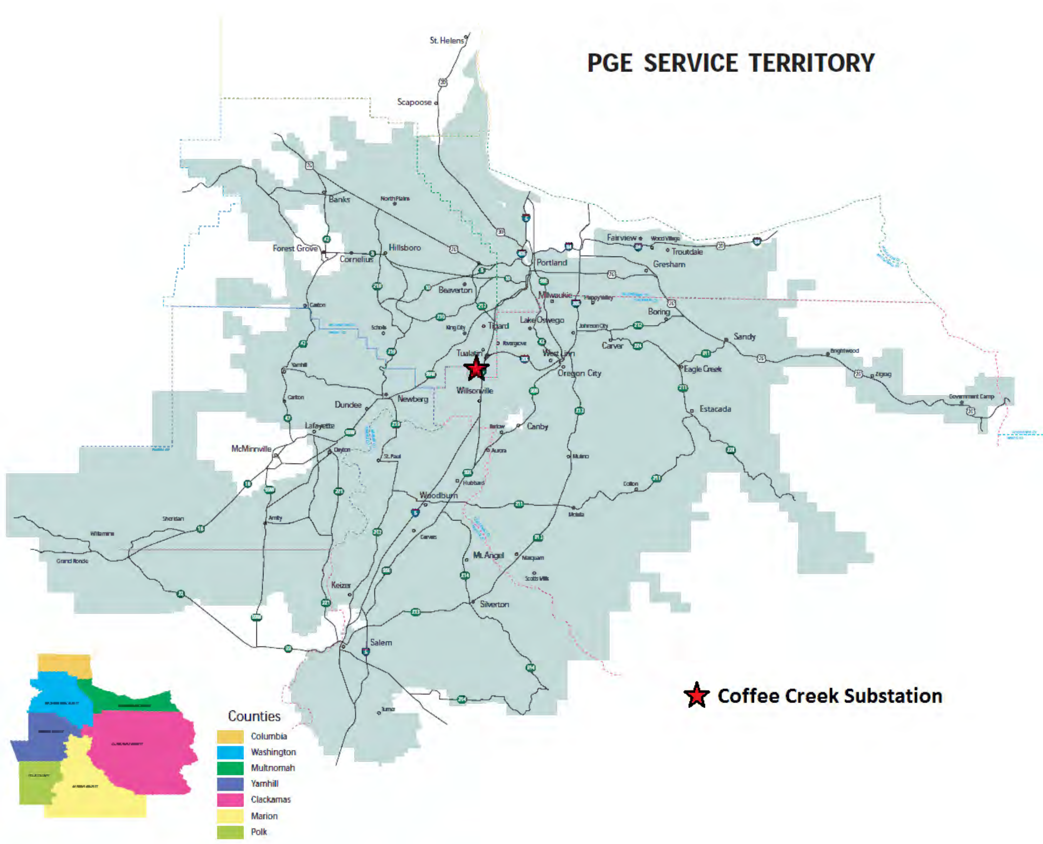
## 5.1. Project Description

PGE proposes to develop and build a 17 – 20 MW, four hour energy storage system on PGE owned property adjacent to the existing Coffee Creek Substation. This system will be able to provide Capacity, Energy and Ancillary services to our system during normal operations, as well as mitigate outages caused by asset failure or other system issues during outage conditions. PGE will control and operate the project for system needs and have the ability to dispatch the system as needed.

This project will allow PGE to gain additional experience, expertise, and learnings with all aspects of utility-scale energy storage systems, including project development, design, and contracting. It will also help PGE gain learnings around the best practices for implementation and integration of energy storage into our power system, as well as allow for the evaluation of the locational value of energy storage to our system.

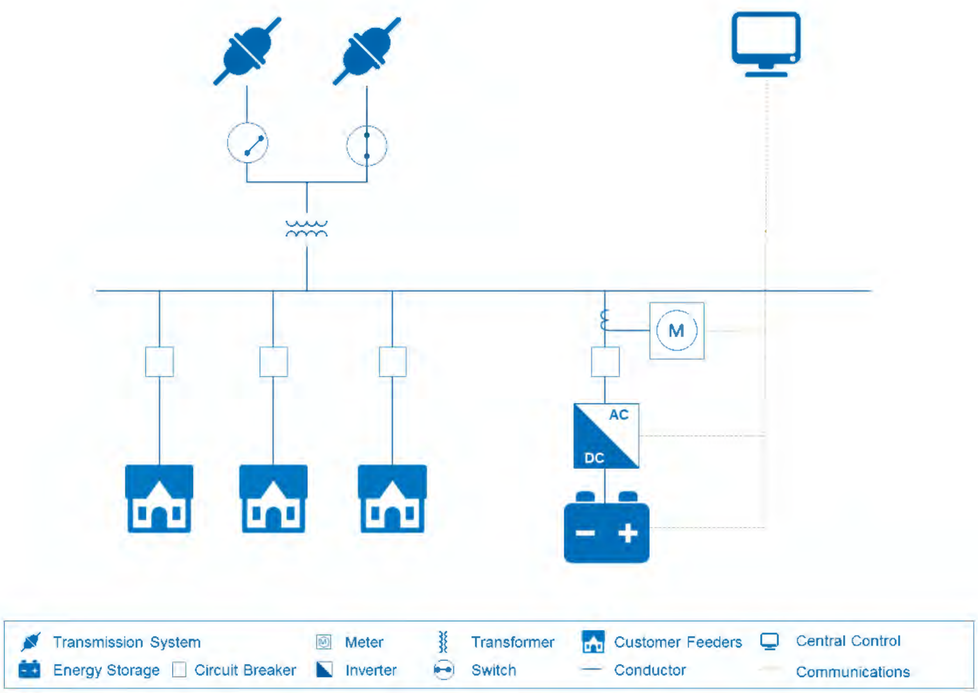
Coffee Creek Substation is centrally located within the PGE service territory in southeast Washington County between Wilsonville and Tualatin, just west of Interstate 5. The PGE owned lot is just over 8 acres in size with the existing substation using ~1.25 acres of the property. This available space will allow for flexibility when selecting the energy storage technology and for construction activities.

Figure 13: Location of Coffee Creek Substation Relative to Service Area



This project will connect to the Coffee Creek Substation bus at the 13kV distribution voltage through a spare breaker position and include all project equipment and systems to operate independently for the specified use cases or via dispatch instructions from PGE's Merchant Operations or our Balancing Area Authority groups. As part of the required interconnection process, an in-depth engineering analysis will be performed to determine the scope and cost of the required work for evaluation by the project team.

Figure 14: Conceptual Schematic of Coffee Creek Storage Interconnection




## Key Attributes

Table 18: Key Project Attributes (Coffee Creek Substation)

| Attribute | Value |
|---|---|
| Charge/Discharge Rate | 17 – 20 MW |
| Energy Storage | 68 – 80 MWh |
| Technology | TBD |
| Response Rate | < 1 Second |

This project includes all energy storage devices, inverters, switchgear, transformers, metering, HVAC, software, control systems, and communications required for operation. The installation may be in a standalone building or in modular enclosures. The equipment will be sized to allow for additional storage capacity to be added, if required, to maintain the full 80MWh of usable energy storage for the entire life of the project.

## 5.2. Site Selection

Coffee Creek Substation serves approximately 550 customers, two-thirds of which are commercial customers, with industrial and residential customers splitting the remaining third. The average amount of commercial load served by the distribution power transformer at Coffee Creek Substation ranks 15th out of the roughly 300 distribution power transformers owned by PGE. The top-decile amount of average commercial load served by the substation results in a higher-than-average monetary consequence when a sustained outage occurs. The 3-year average SAIDI is 37.4 and for SAIFI it is 0.1.

**Table 19: Coffee Creek Substation Loading Characteristics**

| Coffee Creek | Winter | Summer |
|---|---|---|
| Peak Customer Load | 13.6 MW | 15.4 MW |
| Transformer Capacity | 41.2 MW | 32.2 MW |

After detailed modelling and analysis, Coffee Creek Substation has been selected as the proposed project site. This site ranked high in the Integrated Planning Tool (IPT) analysis of site specific outage mitigation benefits due to the reduction of system risks based on a $1.15M risk profile (consequence X likelihood) for the substation assets. The additional internal review of site-specific criteria (i.e., land availability, environmental characteristics, existing telemetry, existing substation equipment, and planned near-term projects) scored this site as the top option for capturing the most value from the applicable use cases for a project located at a distribution substation. One of the main benefits of this site is the space that is available for the energy storage system. The PGE owned parcel is 8.33 acres in size and mostly flat with the existing substation yard using approximately 1.25 acres:

Figure 15: Approximate Land Availability at Coffee Creek Substation

This available space will allow for flexibility in the design of the energy storage system, and the permitting process will help identify the available space for the project within the property boundary. Other sites that ranked highly in our IPT analysis had space constraints that would have limited the project size and/or duration and possibly even the technology type to capture all of the potential site specific benefits.

Additional benefits for Coffee Creek Substation include adequate high-side transformer protective devices to properly protect the substation equipment when the energy storage system is discharging and the typical power flow reverses sending energy back into the transmission system. Coffee Creek also has adequate telemetry for the addition of energy storage and an open breaker position available to be used for the interconnection.

## 5.3. Sizing Considerations

The project sizing was selected at 17 – 20 MW and 68 – 80 MWh for multiple reasons. We started by identifying the minimum and maximum size and duration for the site. The minimum size was determined to be 8MW based on the average load at Coffee Creek Substation and 2 hours duration in order to capture some of the capacity and the site specific outage mitigation benefits identified in the Potential Study. The maximum size was limited by the thermal rating of the existing Coffee Creek Substation transformer at ~32 MW.

A 17 – 20 MW charge/discharge rating was selected because it fit best with the portfolio of projects being submitted with this proposal and is a size that is large enough. Per the project guidelines from the OPUC "*Electric companies are encouraged to submit multiple projects with an aggregate capacity close to the full one percent of 2014 peak load allowed by HB 2193.*" In addition, generation interconnection requests for projects larger than 20 MW are required to go through PGE's Large Generator Interconnection Procedures, which is expected to take a minimum of 12 months before an interconnection agreement can be executed. Generation interconnection requests for 20 MW and less are required to go through the Small Generation Interconnection Procedures, this process is expected to take 4-6 months. Given these factors and the schedule required for project execution it was determined that the Small Generation Interconnection path was best suited for this project. Though a smaller capacity project is viable, one of the primary learnings of this project is how to integrate and utilize a large-scale storage device into our dispatch and balancing authority. Today, typically those stakeholders do not monitor or control resources that are smaller than 15-25 MW. In order to test integration of a large scale system, we cannot consider projects smaller than 15 MW.

The four hour duration was selected for the following reasons:

1. It matches the duration based methodology for assigning capacity value used in our 2016 IRP. A four hour duration effectively doubles the capacity value compared to a two hour battery ($1,038/kW vs. $519/kW).
2. The longer duration also extends the outage mitigation benefits ($25/kW vs. $4/kW).
3. It maintains flexibility for future use cases/value streams.

In our RFI, we did not evaluate costs of a two hour storage device at this scale, so we are not able to compare cost-effectiveness of both options, however, based on our estimates, we do anticipate that these benefits scale at a rate higher than costs would scale from moving from a two hour to a four hour duration.

## 5.4. Technology Considerations

Under normal conditions, the energy storage system will provide capacity, energy, and ancillary services to the PGE system either automatically via the project's control system or via manual dispatch from Merchant Operations or the System Control Center. During an outage condition and after the fault has been isolated, the energy storage system will provide extended reliability to all customers downstream while the cause of the fault is identified, fixed, and the affected portions of the system re-energized.

Based on the responses to our RFI the majority of systems available are lithium ion-based, but flow battery systems and other energy storage technologies also responded. The RFP for this project will be technology agnostic to ensure that all systems that can meet the identified project needs are evaluated.

While some of the functionality of the energy storage system will act autonomously based on measured system conditions from the project's local control system, a dedicated communication link will also be necessary for control and status indication. A dedicated interface with our System Control Center would be necessary to dispatch the energy storage system to charge or discharge in line with the proposed use cases, as well as capture operational data from the system.

## 5.5. Ownership Structure

PGE proposes to own and operate the energy storage assets located at the Coffee Creek Substation. As owners of the underlying property and substation assets, this will make for ease of installation and integration, while giving us full control of the device for use by our dispatch.

## 5.6. Construction and Implementation Plan

### *Procurement*

PGE will develop site specific requirements and specifications for the project to include with an RFP for portions of or all of the Engineering, Procurement and Construction services required to complete the project. Proposal evaluation criteria will be developed with the RFP and used to score each bid. Bids will be ranked on their score and contract negotiations will be completed. A detailed division of responsibilities matrix will be created to clearly define the work to be done by the contractor and the work that PGE will be completing.

### *Engineering-Design*

The EPC contractor is expected to be responsible for doing the necessary engineering and design work associated with the energy storage system located at Coffee Creek, including but not limited to:

- Site development
- Electrical, civil, structural and mechanical design
- Protection, automation, and control system design for the Energy Storage system
- Equipment and materials selection

PGE will determine if any engineering and design work associated with the energy storage system will be completed internally when scoping the project.

The required interconnection facilities at Coffee Creek Substation will be designed by internal PGE resources and defined as result of the interconnection request that will be submitted for the project. The Point of Interconnection will also be defined as part of the interconnection request process and will be the main demarcation point between the EPC and PGE design.

## Permitting

PGE will work closely with the EPC contractor to complete all required studies and secure all necessary permits and approvals to meet the requirements of the appropriate jurisdiction for all aspects of the project, including but not limited to all applicable zoning, conditional use, electrical, mechanical, building permits, environmental impacts, etc. A detailed division of responsibilities matrix will be included as part of the contract to identify which party is responsible for the required permits.

This project will require a Conditional Use Permit through Washington County. The permitting process is expected to take approximately 6 months and will include a public notice. This process was fairly typical for other sites that ranked highly in our IPT analysis, although some required a more rigorous process based on the jurisdiction that would issue the permit.

## Mobilization

The EPC contractor will oversee mobilization after receiving the Notice to Proceed from PGE and once all necessary permits with the local jurisdictions to start construction have been acquired.

## Construction Management

Construction management for the installation of this storage project will require internal construction management resources and external construction management resources. There are two key pieces needed for the successful integration of the energy storage resource into the system. The first is the interconnection facilities at the Coffee Creek Substation, the construction management is expected to be led by internal resources. The second piece of the project would be the site development and installation of the storage asset located adjacent to the Coffee Creek Substation. This effort will be led by the PGE project team and utilize construction management resources as needed throughout the construction phase of the project.

The EPC contractor is expected to be responsible for most aspects of the construction of the energy storage system. It is anticipated that the energy storage system will be housed in a stand-alone building or in modular enclosures on the project site with an adjacent laydown yard to store equipment during construction. It is also anticipated that the racks or skids used for the energy storage system will be assembled off site wherever possible to minimize the installation time. Any construction activities within PGE's scope will be closely coordinated with the EPC contractor. The interconnection facilities will be constructed by internal PGE resources and scoped separately as part of the interconnection process. This process will identify the point of interconnection which will serve as the demarcation point for the EPC work.

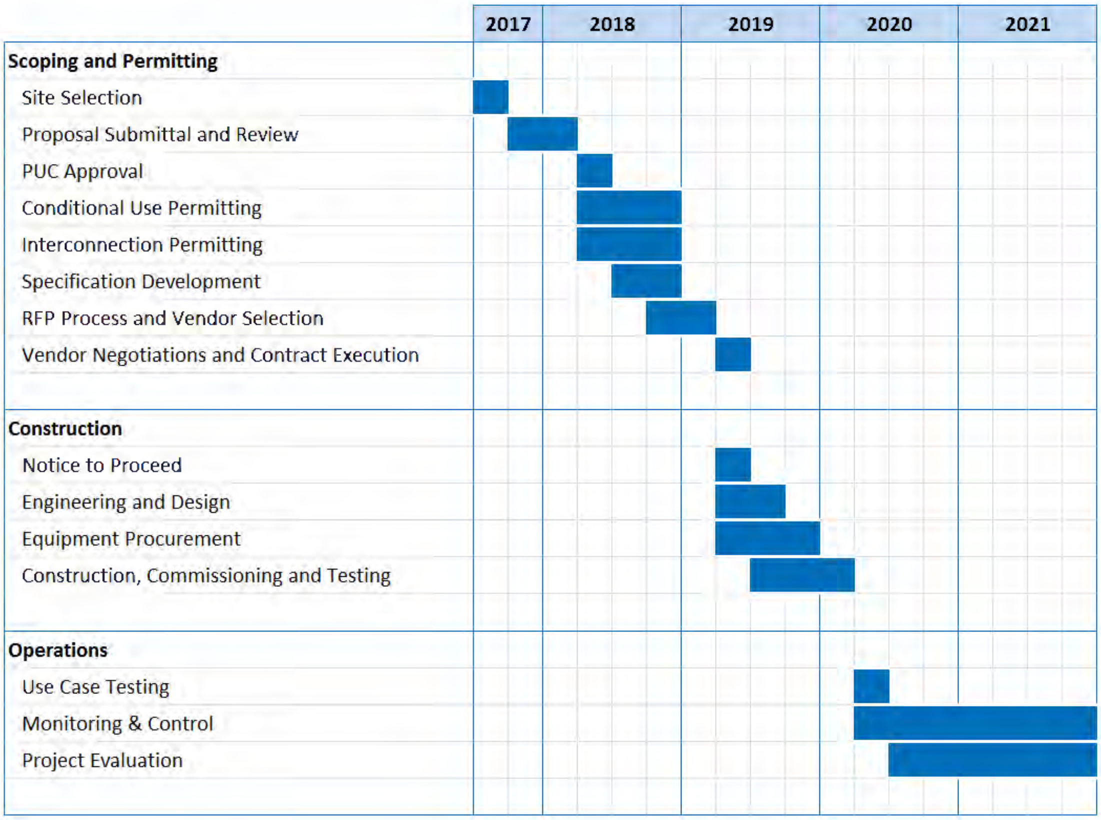
## Commissioning, Testing, and Training

Testing & commissioning of the energy storage system will begin upon substantial completion and will follow the testing plan agreed to by both PGE and the EPC contractor and included in the EPC agreement. Final system integration testing and the interconnection facilities testing will be performed by PGE technicians to PGE specifications. This plan will follow industry best practice and the OEM requirements and is expected to include detailed testing of all systems and equipment provided as well as the entire system as a whole. If special testing is required PGE may contract with third party testers as required for permit compliance. It is expected that this testing and commissioning will require both internal and external resources. Testing and commissioning of the interconnection facilities will primarily rely on internal PGE testing and commissioning resources to complete. PGE staff will work with the EPC to ensure all necessary PGE employees receive adequate training for ongoing operations and maintenance of the storage device.

## *Project Schedule*

The preliminary project schedule is shown below. Changes are expected as actual task durations are refined during the development of the project.

**Figure 16: Coffee Creek Energy Storage Project Schedule**




## *Construction Risks*

**Permitting Risk:** Energy Storage Systems will potentially be new to the jurisdiction(s) issuing permits for the project. In order to mitigate this risk we will have to work closely with the jurisdiction(s) to ensure that all applicable permitting requirements are met.

**Vendor/Technology Risk:** There will be risk associated with the vendor or technology selected. This includes equipment lead times, maturity of the selected technology and construction/installation risks.

In order to mitigate this risk we will have to use our robust procurement process to ensure that these risks are appropriately accounted for in any RFP process.

**System Integration Risk:** Integration of an energy storage system into our control system, including the testing and commissioning aspects of the project are also potential risks. In order to mitigate this risk we will need to have a detailed commissioning and testing plan that includes approvals and handoffs to aid in the transition to operations.

## 5.7. Operations and Maintenance

### *Expected Functionalities*

During day-to-day operations, PGE will operate the energy storage device for daily grid services. The energy storage device will be controlled with other energy storage devices included in this proposal to provide capacity, energy and ancillary services.

In the event of a transmission outage the storage device will extend continuous power to customers on all feeders of the substation.

### *Operations and Maintenance Plan*

Maintenance work will be overseen by PGE and informed by manufacturer specifications. PGE anticipates at least the following:

1. Periodic Inspections
2. Periodic predictive and preventive maintenance
3. Remote annunciation of trouble alarms
4. Response to alarms by PGE technicians
5. Repair and replacement both by PGE and equipment suppliers

### *Life-Cycle Risks*

**Safety Risk:** As most of the energy storage options available are relatively new and each poses its own risks a review of the known and expected risks will need to be done as part of the RFP evaluation process. And during the final design risk mitigation will need to be incorporated and could include items such as fire suppression, physical barriers etc.

**System Availability:** During the initial implementation many of the storage assets will be equivalent to some of the smaller generation assets and the impact to the system will be less impactful. As more projects are brought on line and assets become part of a larger virtual asset the impact will grow. And as such many of the use cases of the storage asset will become similar to a larger generation asset with similar risks associated with failure to operate. With that risk identified many of the same mitigation actions/plans currently being used including maintaining spinning and non-spinning reserve may need to be utilized.

**Technology Risk:** As with all new and emerging technologies there is a risk that the technology or manufacture will not be around for the expected lifecycle of the product. To help mitigate this the sourcing team will need to identify criteria that will be used to help score vendor proposals or include appropriate bonding and insurance requirements to mitigate known risks.

## 5.8. Project Costs

Indicative vendor pricing, coupled with interconnection, system controls, and PGE's owner costs, result in a total capital investment range between $30 and $36 million. This translates into a total carrying cost (net present value of revenue requirement over the life of the energy storage asset, including ongoing annual O&M costs) ranging between $45 and $65 million.

Table 7: Project Cost Range + Carrying Cost (Coffee Creek Substation)

| | Low Cost Estimate ($M) | | | High Cost Estimate ($M) | | |
|---|---|---|---|---|---|---|
| Asset Life | Overnight Capital | NPV of RevReq | Year 1 RevReq | Overnight Capital | NPV of RevReq | Year 1 RevReq |
| 10-Year | $30.4 | $44.7 | $6.5 | $33.9 | $54.9 | $7.9 |
| 20-Year | $30.4 | $52.7 | $6.7 | $35.7 | $64.8 | $8.2 |

Ongoing project costs for service, maintenance, and power augmentation are estimated to range from $550,000 - $800,000 annually over the energy storage asset life. Generally a 20-year energy storage asset is minimally more expensive in terms of initial investment (indicative pricing resulted in a 0% - 5% cost increase); the higher cost of augmenting energy storage asset power over a 20-year timeframe appears as an ongoing O&M investment. In moving from 10 to 20 year energy storage devices, some vendors indicated no annual increase (but investment over a greater number of years); others increased annual O&M charges by up to 35%.

## 5.9. Estimated Project Benefits

### *In-state benefits*

As discussed in detail in the Storage Evaluation Study (Appendix 4), PGE anticipates utilizing storage devices for capacity, energy & ancillary services, and outage mitigation because these functions have the highest value and abilities to be co-optimized:

- **Capacity**: the energy storage devices will be dispatched during peak demand periods to supply energy and shave peak demand, reducing the need for new peaking power plants.
- **Energy and Ancillary Services**: storage will be used for a variety of system ancillary services, including system regulation, load following, spinning reserves, voltage support, and black start.
- **Outage Mitigation/Avoided Distribution Investment**: the energy storage device will also be used to reduce or eliminate customer risk costs associated with power outages and consequentially will extend the economic life of distribution assets.

Navigant calculated site-specific benefits values for the Coffee Creek Substation project using the NVEST model:

Table 20: Estimated In-State Benefits for Coffee Creek Substation (10-yr NPV)

| Application | Amount ($/kW) |
|---|---|
| Capacity | 1,038 |
| Energy & Ancillary Services | 477 |
| Outage Mitigation | 125 |
| **Total Benefit** | **1,641** |

### *Regional benefits*

There are no planned transmission projects that this storage project has the potential to defer, so we are assuming no Transmission deferral benefits for this project.

PGE recognizes there may be instances in which transmission congestion value associated with energy storage can apply. PGE is currently working with BPA and regional stakeholders to determine if congestion relief on the South of Allston transmission path may be one such instance. Pending the outcome of this regional study effort, the South of Allston transmission congestion relief values, if applicable, will be included in the benefit reporting.

### *Societal Benefits*

PGE does not anticipate any societal benefits associated with this project.

## 5.10. Opportunity for System-wide deployment

As indicated in Section 1, the shift towards wind and solar requires more installed capacity per unit of generation and an increasingly flexible grid (due to the variable nature of wind and solar output). As more renewables are deployed to meet our Renewable Portfolio Standard goals and customer needs, it is likely that we will need to be able to quickly deploy and integrate large-scale storage projects like the proposed device (or larger) to meet our needs going forward. This pilot will ensure that we have the expertise to deploy, operate, and maintain these devices such that we can quickly deploy in the future when needed.

## 5.11. Cost-effectiveness analysis

Cost effectiveness considers all quantitative costs and benefits to the electric system and its customers over the life of the project. Assessment of larger societal benefits, where applicable, is encouraged but outside the scope of this proposal.

Three benefit cost tests have been applied to the five projects proposed, the Total Resource Cost (TRC) test, the Ratepayer Impact (RIM) test, and the Participant Test. These tests differ in perspective: The TRC encompasses both the utility and the program participants, whereas the RIM assumes the utility perspective only. The Participant Test incorporates costs and benefits that incur to the participant only. Because the Coffee Creek project has no participants (it serves the system as a whole, rather than individual customers), the inputs and results of the TRC and RIM tests are the same, and the Participant Test does not apply

Costs included are upfront capital and annual O&M (service, maintenance, and operation costs). Benefits included are the system values of capacity, energy and ancillary services, and outage mitigation. The methodology of calculating these benefit values is discussed in Section 2.3.

In the following table, the net present value for benefit and cost streams were calculated for both 10 and 20 year energy storage devices. Moving to the 20 year timeframe, benefits increase by a larger multiplier than do costs, resulting in more favorable ratios. Of the scenarios considered, the low-cost 20 year energy storage asset performs the best, with benefits valued at 106% of costs. Net benefit illustrates the magnitude of dollars (in millions) by which benefits exceed costs. Negative numbers indicate projects for which costs exceed benefits.

Table 21: Total Resource Cost & Ratepayer Impact Tests, Coffee Creek Substation (NPV, $M)

| | 10 Year | | 20 Year | |
|---|---|---|---|---|
| **TRC + RIM Tests** | **Low** | **High** | **Low** | **High** |
| **Benefits** | | | | |
| Capacity | 21.20 | 21.20 | 35.34 | 35.34 |
| Energy | 9.74 | 9.74 | 16.24 | 16.24 |
| Outage Mitigation | 2.55 | 2.55 | 4.25 | 4.25 |
| Reliability | - | - | - | - |
| *Total* | *33.49* | *33.49* | *55.83* | *55.83* |
| **Costs** | | | | |
| Capital | 40.36 | 47.91 | 41.96 | 52.43 |
| Battery O&M | 4.37 | 7.02 | 10.70 | 12.37 |
| Program | - | - | - | - |
| *Total* | *44.73* | *54.93* | *52.65* | *64.80* |
| **Net Benefit** | **(11.25)** | **(21.46)** | **3.18** | **(8.97)** |
| **Benefit Cost Ratio** | **0.75** | **0.61** | **1.06** | **0.86** |

## 5.12. Learning Objectives & Evaluation Plan

PGE aims to use this project to gain experience developing, contracting for and constructing utility-scale energy storage projects, as well as demonstrating the ability to control energy storage assets for T&D and Power Ops benefits. In addition, the operation of this project will give us real-world data that will enable future identification, use cases and evaluation metrics for implementation of energy storage as an asset for PGE's system, including identifying the potential for locational value.

In broad strokes, this pilot would require evaluation of the following topics:

**Table 22: Evaluation Topics (Coffee Creek Substation)**

| Project | Quantitative Topics | | | | | Qualitative Topics | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Capacity | Transmission Deferral | Energy & Ancillary Services | Outage Mitigation | Power Reliability | Resiliency | Procurement | Infrastructural Readiness | Organizational Readiness | Customer Engagement |
| Microgrid | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| **Substation** | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| Mid-Feeder | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| Residential | ✓ | ✓ | ✓ | | ✓ | | ✓ | ✓ | ✓ | ✓ |
| Generation | ✓ | | ✓ | | | | ✓ | ✓ | ✓ | |

PGE would also seek to answer the following research questions:

- How can centralized energy storage simultaneously benefit both PGE's transmission and distribution system?
- What is required for the successful integration of operations and control of centralized energy storage to both Power Operations and Balancing Area Authority?
- What benefits or issues "scale-up" with larger, centralized energy storage, what benefits or issues do not?
- What operations and maintenance issues arise from utility-scale energy storage operation?

## 5.13. Alternative Solutions

### *Additional Procurement*

In order to meet the Capacity, Energy and Ancillary Services benefits provided by the proposed energy storage system, additional products or services that help meet those needs could be procured through a separate process.

### *Asset Upgrades*

Asset upgrades at Coffee Creek Substation could be completed to minimize the risk of outages and support the realization of the outage mitigation benefits provided by the proposed energy storage system.

# Section 6. Power System Integration (Mid-Feeder)

## 6.1. Project Description

PGE proposes to install a 2 MW (4-8 MWh) energy storage device at the existing 1.75 MW Baldock Solar array in Aurora, OR. The Baldock energy storage system will be interconnected to PGE's Canby Substation via the Canby – Butteville feeder.

Like the Coffee Creek Substation-sited energy storage system, this project will provide capacity, energy, ancillary services, , and outage mitigation. Additionally, this energy storage device will allow PGE to test and gain experience in optimizing the use of solar generated power and has the ability to allow PGE to island a portion of the feeder to test medium-voltage micro grid applications.

**Table 23: Key Project Attributes (Proposal 2)**

| Attribute | Value |
|---|---|
| Charge/Discharge Rate (MW) | 2 MW |
| Energy Storage (MWh) | 4-8 MWh |
| Location | Aurora, OR |
| Substation | Canby |
| Feeder | Canby - Butteville |
| Target In-service Date | 2020 |

A mid-feeder project was selected to allow PGE to explore utilizing automation schemes to island various sections of the feeder to test medium-voltage micro grid applications. Further, this specific site will allow PGE to test and gain experience in firming and optimizing the use of solar generated power. The project will inform future mid-feeder automation schemes as well as best practices for integrating storage into large-scale renewable facilities.

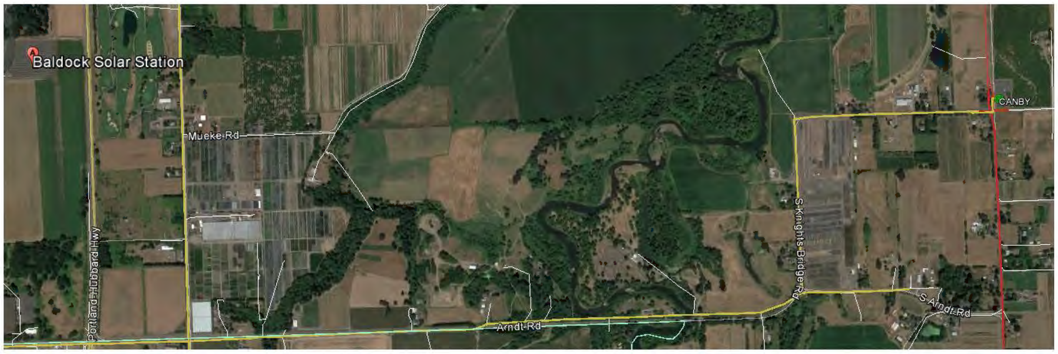
At scale, as the Company aims to meet the RPS requirements for customers, renewable-sited storage has the potential to provide the flexibility PGE will need to effectively integrate new distributed and large-scale renewable resources. As implementation of storage increases there will be a corresponding increase in reliability on the connected feeders.

PGE is targeting an in-service date for this project in 2020.

## 6.2. Site Selection

The Baldock Solar array is on the Canby-Butteville feeder, fed by the Canby Substation:

Figure 17: Map of Baldock Solar Array Relative to the Canby Substation




The Canby-Butteville 13 kV feeder serves approximately 1,188 customers (59% residential, 39% commercial, and 2% industrial). The 3-year average SAIDI is 33.7 and for SAIFI it is 0.1. The feeder is currently under capacity:

Table 24: Canby-Butteville Feeder Loading Characteristics

| Coffee Creek | Winter | Summer |
|---|---|---|
| Peak Customer Load | 8 MW | 5.3 MW |
| Transformer Capacity | 17.5 MW | 13.7 MW |

The process used to select the Canby-Butteville feeder was similar to that used to select Coffee Creek Substation (discussed in Section 5.3). However, additional screening criteria needed to be applied after the initial IPT feeder evaluations and rankings, due to the engineering and operational attributes of some PGE feeders:

- Alternate Service – some customers choose to pay a premium for PGE to reserve capacity on an alternate feed at their point of delivery. In the event their preferred feed sustains an outage, a customer-owned automatic transfer switch will transfer their service to an alternate source, reducing the overall consequence of the outage to their facility. At present, customer alternate service agreements are not automatically accounted for in SAM's risk and economic life models, due to concerns over data management. Therefore, customer outage costs are over-represented in SAM's models for these customers and their associated feeders. As such, customers and feeders with current alternate service agreements were manually excluded from the rankings.
- Dispatchable Standby Generation (DSG) – In the event a DSG customer's preferred feed sustains an outage, a customer-owned, PGE-controlled generator provides service until the sustained outage is resolved, reducing the overall consequence of the outage to their preferred feed. At

present, customers with on-site backup generation are not accounted for in SAM's risk and economic life models, due to concerns over data management. Therefore, customer outage costs are over-represented for these customers and their associated feeders (thus their outage mitigation benefits would be overestimated). As such, customers and feeders affected by PGE's DSG program were manually excluded from the rankings.

- Pending projects – Several of the sites that scored near the top of the IPT list have projects pending. Because these projects are well underway with regard to engineering and/or design, we excluded them from the rankings.
- Nontraditional feeders – There are some feeders in the system for which a typical distribution automation scheme may be difficult or infeasible to apply, due to configuration issues, or lack of adequate feeder ties. These feeders were given added consideration, due to the lack of a traditional outage mitigation alternative.

The IPT and additional considerations analysis yielded 18 feeders with a high potential system value and a viable engineering and operational profile. Canby-Butteville was identified as the preferred feeder due to its locational value and its engineering and operational qualifications; the feeder ranked high in the IPT analysis due to the risk of the assets at Canby Substation, and the feeder's high exposure to non-asset sources of failure (e.g. tree falls).

The Baldock Solar Array site, located on the Canby-Butteville feeder, was furthermore selected because of PGE's ability to test the integration of solar and energy storage at the site; PGE's anticipated ability to construct the facility within the HB 2193 timeline due to infrastructure readiness and land availability; and the visibility of the site from the public. The site will inform PGE learnings and will also serve as a demonstration site to help educate the public on the benefits of energy storage in managing a highly renewable grid.

PGE has preliminarily identified the southwest corner of the site to house the energy storage project, however, actual site selection will be negotiated with the site host (ODOT) upon approval of this proposal.

Figure 18: Preliminary Consideration for Siting Baldock 2 MW/4 MWh Storage Project


## 6.3. Sizing Considerations

The proposed project sizing was selected at 2 MW and 4 MWh for multiple reasons.

The 2MW capacity was informed by:

- The BIS Consulting analysis;
- An analysis of the generation output of the Baldock solar array;
- A review of the capacity available on the feeder or any restrictions due to the wire size; and
- A review of the capacity of the transformer located at the Canby Substation.

The 2 hour duration was selected primarily due to physical space constraints on site. Though benefit streams are great for a 4 hour battery compared to a 2 hour, PGE does not anticipate that a 4 hour storage device will fit on site:

Table 25: Baldock Storage Benefits, based on duration (10 year NPV of $/kW)

| Application | 2 hour benefit | 4 hour benefit |
|---|---|---|
| Capacity | $ 519 | $ 1,039 |
| Energy & Ancillary Services | $ 477 | $ 477 |
| Outage Mitigation | $ 138 | $ 425 |
| **Total** | **$ 1,135** | **$ 1,941** |

Because of the increased value streams for capacity and outage mitigation, PGE will encourage bidders to propose a 4 hour benefit if their technology can fit within the physical site constraints.

## 6.4. Technology Considerations

We do not anticipate the project will require any special technologies for the construction, operations, or maintenance of the storage system, however, this will ultimately be dictated by the procurement and vendor selection process. PGE will utilize Industry standard and vendor recommended methods for the construction, operations, and maintenance of this project.

### 6.4(a) Technology Selection

PGE intends to be technology-agnostic in its procurement and engineering-design phases of the project. PGE will direct bidders to meet our project requirements, not a specific technology type. Based on the preliminary RFI, however, PGE expects that this project will likely be served by a Lithium Ion battery due to physical space constraints and cost. PGE will evaluate proposals on the following criteria:

- Project implementation cost
- Project footprint (compatible with available property footprint)
- Warranty
- O&M cost
- Ability to meet required response rate

### 6.4(b) Distribution Automation

Distribution automation is necessary to maximize the benefits of the storage device located at the Baldock site. The distribution automation scheme will be used to sectionalize the feeder to help island segments of the feeder to create the microgrid during system disruption events.

### 6.4(c) Control

A dedicated communication link for control and status indication is needed. A dedicated interface with our SCADA system would be necessary to dispatch the energy storage system to charge or discharge in line with the proposed use cases, as well as capture operational data from the system. A complete discussion of control system requirements is included in Section 8.

## 6.5. Ownership Structure

PGE proposes to own and operate the energy storage located at the Baldock Solar array. The Oregon Department of Transportation (ODOT) is the site owner and PGE has a site lease agreement with ODOT for the solar array. In order to implement this project, PGE will work with ODOT to obtain any additional easements necessary to extend the footprint of the existing solar facility.

## 6.6. Construction & Implementation Plan

### *Procurement*

PGE will develop site specific requirements and specifications for the project to include with an RFP for portions of or all of the Engineering, Procurement and Construction services required to complete the project. Proposal evaluation criteria will be developed with the RFP and used to score each bid. Bids will be ranked on their score and contract negotiations will be completed. A detailed division of responsibilities matrix will be created to clearly define the work to be done by the contractor and the work that PGE will be completing.

As part of the Baldock storage project we will need to work with the ODOT to discuss the need for an easement or a long term property lease. As part of this discussion we will need to define the physical site size, location and access needs that will be required to site this project adjacent to the existing solar.

### *Engineering-Design*

Engineering for the installation of the mid-feeder storage project will require internal engineering resources as well as external engineering resources. There are two key pieces needed for the successful integration of the storage resource into the system. The first is the interconnection facilities at the Baldock Solar Array, this design will be led by internal resources and defined as result of the interconnection request that will be submitted for the project. The second piece of the project would be the site development and installation of the storage asset located adjacent to the Baldock Solar array, this will most likely require internal and external design resources.

### *Permitting*

The project will meet the requirements of the appropriate jurisdiction for all aspects of the project, including but not limited to all applicable conditional use, electrical, mechanical and building permits. During the prior project at Baldock Solar Array no environmental or property concerns were identified.

### *Mobilization*

Contractor mobilization will begin post award with the civil contractor and contractor site facilities with additional trades mobilizing as the project progresses.

### *Construction Management*

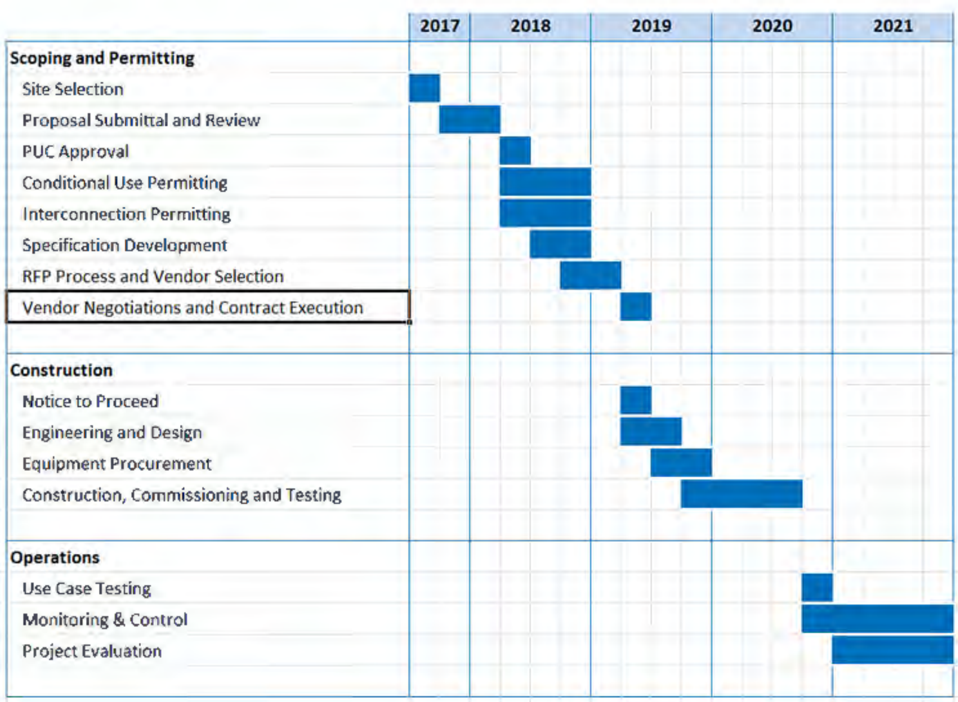
Construction management for the installation of the project will require internal construction management resources and external construction management resources. There are two key pieces needed for the successful integration of the storage resource into the system. The first is the interconnection facilities at the Baldock Solar Array, the construction management is expected to be led by internal resources. The second piece of the project would be the site development and installation of the storage asset located adjacent to the Baldock Solar Array, this is expected to require internal and external construction management resources throughout the construction phase of the project.

## *Commissioning, Testing, and Training*

Testing and commissioning will begin upon substantial completion and will encompass two key areas of work. The first piece will be the testing and commissioning of the interconnection facilities and primarily rely on internal testing and commissioning resources to complete. The second piece will be the testing and commissioning of the energy storage facilities, this will most likely require internal and external testing and commissioning resources to complete. Final system integration testing and the interconnection facilities testing will be performed by PGE technicians to PGE specifications. As part of the implementation of the Energy Storage facility at the Baldock Solar site the EPC vendor/energy storage manufacture will provide training on the use, maintenance and safety procedures for operations personnel.

## *Project Schedule*

Figure 19: Project Schedule (Baldock Storage Project)




## *Construction Risks*

PGE anticipates several, risks that could delay the deployment of this project:

**Land use:** As Energy storage is a relatively new technology few sites have been built, as such any land use reviews may require additional time and resources to navigate.

**Siting:** As the proposed site for the Energy storage project adjacent to the Baldock facility is owned by the Oregon Department of Transportation and easement or property lease will need to be negotiated before the design and RFP can be completed.

**Permitting:** As Energy storage is a relatively new technology few sites have been built, as such any permitting that may be required may require additional time and resources to obtain.

PGE expects the risks to be low and that the risks can be mitigated or limited through proper vendor evaluation and selection and through early and frequent discussion with the municipality where the project will be located.

## 6.7. Operations & Maintenance

### *Expected Functionalities*

During normal operation, the energy storage device will be used for capacity, energy, and ancillary services.

In the event of an outage, the energy storage asset will be used to provide outage mitigation benefits) on the feeder: This will be done by islanding the customer and the energy storage device, creating a microgrid.

Figure 20: Baldock Storage (Normal Mode)

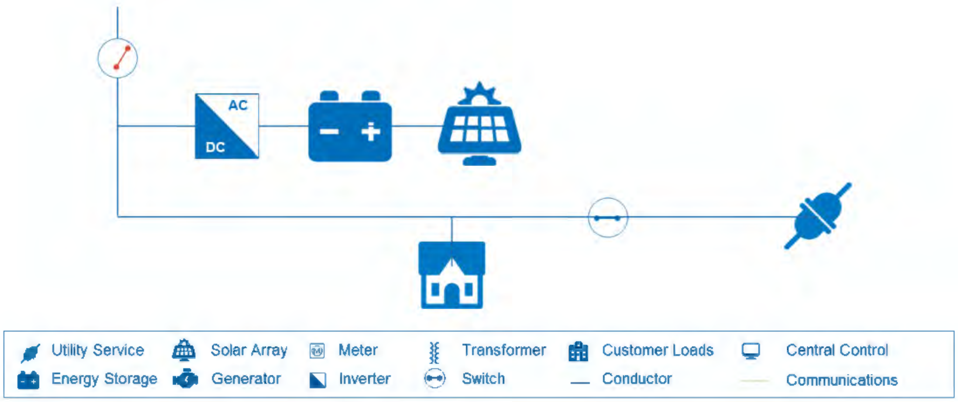
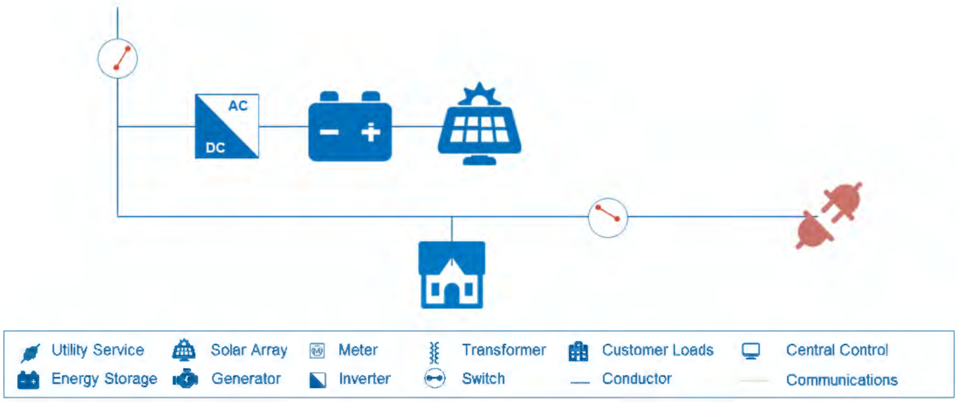



Figure 21: Baldock Storage (Outage Mode—isolated section)



### *Operations and Maintenance Plan*

PGE's approach to maintenance of this project would rely on industry standard maintenance processes and is anticipated to be performed by a combination of vendor staff and internal staff. A plant of this size would not be staffed on a full time basis as the facility will be connected to PGE's control system, the storage device's condition and statuses will be capable of being monitored remotely.

Additional maintenance will be defined by vendor and manufacturer specifications, but PGE anticipates including at least the following:

- Periodic inspections
- Periodic predictive and preventive maintenance
- Remote annunciation of trouble alarms
- Response to alarms by PGE technicians
- Repair and replacement both by PGE technicians and equipment suppliers

### *Life-Cycle Risks*

The risks for this project include:

- Safety Risk – As most of the energy storage options available are relatively new and each poses its own risks a review of the known and expected risks will need to be done as part of the RFP evaluation process. And during the final design risk mitigation will need to be incorporated and could include items such as fire suppression, physical barriers etc.
- System Availability – During the initial implementation many of the storage assets will be equivalent to some of the smaller generation assets and the impact to the system will be less impactful. As more projects are brought on line and assets become part of a larger virtual asset the impact will grow. And as such many of the use cases of the storage asset will become similar to a larger generation asset with similar risks associated with failure to operate. With that risk identified many of the same mitigation actions/plans currently being used including maintaining spinning and non-spinning reserve may need to be utilized.
- Technology Risk – As with all new and emerging technologies there is a risk that the technology or manufacture will not be around for the expected lifecycle of the product. To help mitigate this, the sourcing team will need to identify criteria that will be used to help score vendor proposals or include appropriate bonding and insurance requirements to mitigate known risks.

## 6.8. Project Costs

Indicative vendor pricing, coupled with interconnection, system controls, and PGE's owner costs, result in a total capital investment range between $2.8 and $4.1 million. This translates into a total carrying cost (net present value of revenue requirement over the life of the energy storage asset, including ongoing annual O&M costs) ranging between $4.1 and $7.8 million.

**Table 7: Project Cost Range + Carrying Cost (Mid-Feeder, Baldock)**

| | Low Cost Estimate ($M) | | | High Cost Estimate ($M) | | |
|---|---|---|---|---|---|---|
| Asset Life | Overnight Capital | NPV of RevReq | Year 1 RevReq | Overnight Capital | NPV of RevReq | Year 1 RevReq |
| 10-Year | $2.8 | $4.1 | $0.6 | $4.1 | $6.9 | $1.0 |
| 20-Year | $2.8 | $4.6 | $0.6 | $4.1 | $7.8 | $1.0 |

Ongoing project costs for service, maintenance, and power augmentation are estimated to range from $50,000 - $125,000 annually over the energy storage asset life. Generally a 20-year energy storage asset is minimally more expensive in terms of initial investment; the higher cost of augmenting energy storage asset power over a 20-year timeframe appears as an ongoing O&M investment. In moving from 10 to 20 year energy storage devices, some vendors indicated no annual increase (but investment over a greater number of years); others increased annual O&M charges by up to 15%.

## 6.9. Estimated Project Benefits

### *In-state benefits*

As discussed in detail in the Storage Evaluation Study (Appendix 4), PGE anticipates utilizing storage devices for capacity, energy and ancillary services, and outage mitigation, because these functions have the highest value and the ability to be co-optimized:

- **Capacity**: the energy storage devices will be dispatched during peak demand periods to supply energy and shave peak demand, reducing the need for new peaking power plants.
- **Energy and Ancillary Services**: storage will be used for a variety of system ancillary services, including system regulation, load following, spinning reserves, voltage support, and black start.
- **Outage Mitigation/Avoided Distribution Investment**: the energy storage device will also be used to reduce or eliminate customer risk costs associated with power outages and consequentially will extend the economic life of distribution assets.

Navigant calculated site-specific benefits values for the Baldock storage project using the NVEST model:

**Table 26: Estimated In-State Benefits for Coffee Creek Substation (10-yr NPV, 2 hr. duration)**

| Application | Amount ($/kW) |
|---|---|
| Capacity | 519 |
| Energy & Ancillary Services | 477 |
| Outage Mitigation | 138 |
| **Total Benefit** | **1,135** |

### *Regional benefits*

There are no planned transmission projects that this storage project has the potential to defer, so we are assuming no Transmission deferral benefits for this project.

PGE recognizes there may be instances in which transmission congestion value associated with energy storage can apply. PGE is currently working with BPA and regional stakeholders to determine if congestion relief on the South of Allston transmission path may be one such instance. Pending the outcome of this regional study effort, the South of Allston transmission congestion relief values, if applicable, will be included in the benefit reporting.

### *Societal Benefits*

**Public Education and Awareness:** In addition to its operational benefits, Salem Smart Power Center has been valuable for offering tours to industry stakeholders with over 2,500 visitors to date. There is value in having an additional site that is more visible by and accessible to the public. Co-locating this project with an existing solar array located at a rest stop on I-5 will allow the community to see and learn about the valuable role that energy storage will play in the grid of the future.

## 6.10. Opportunity for System-wide deployment

As indicated in Section 1, the shift towards wind and solar requires more installed capacity per unit of generation and an increasingly flexible grid (due to the variable nature of wind and solar output). As more renewables are deployed to meet our Renewable Portfolio Standard goals and customer needs, it is likely that we will need to be able to quickly deploy and integrate storage projects the proposed device to meet our needs going forward. Further, we hope that the mid-feeder project demonstrates replicable locational value of storage by reducing the economic impact of outages on our customers and extending the life of distribution system assets. This pilot will ensure that we have the expertise to deploy, operate, and maintain these devices such that we can quickly deploy in the future when needed.

## 6.11. Cost-Effectiveness Analysis

Cost effectiveness considers all quantitative costs and benefits to the electric system and its customers over the life of the project. Assessment of larger societal benefits, where applicable, is encouraged but outside the scope of this proposal.

Three tests have been applied to the five projects proposed, the Total Resource Cost (TRC) test, the Ratepayer Impact (RIM) test, and the Participant Test. These tests differ in perspective: The TRC encompasses both the utility and the program participants, whereas the RIM assumes the utility perspective only. The Participant Test incorporates costs and benefits that incur to the participant only. Because the Baldock mid-feeder project has no participants (it serves the system as a whole, rather than individual customers), the inputs and results of these two tests are the same, and the Participant Test does not apply

Costs included are upfront capital and annual O&M (service, maintenance, and operation costs). Benefits included are the system values of capacity, energy and ancillary services, and outage mitigation. The methodology of calculating these benefit values is discussed in Section 2.3.

In the following table, the net present value for benefit and cost streams were calculated for both 10 and 20 year energy storage devices, and are presented here as a benefit/cost ratio. Moving to the 20 year timeframe, benefits increase by a larger multiplier than do costs, resulting in more favorable ratios. Of the scenarios considered, the low-cost 20 year energy storage asset performs the best, with benefits valued at 101% of costs.

**Table 27: Total Resource Cost & Ratepayer Impact Tests, Baldock Mid-Feeder (NPV, $M)**

| | 10 Year | | 20 Year | |
|---|---|---|---|---|
| **TRC + RIM Tests** | **Low** | **High** | **Low** | **High** |
| **Benefits** | | | | |
| Capacity | 1.06 | 1.06 | 1.77 | 1.77 |
| Energy | 0.97 | 0.97 | 1.62 | 1.62 |
| Outage Mitigation | 0.28 | 0.28 | 0.47 | 0.47 |
| Reliability | - | - | - | - |
| *Total* | *2.32* | *2.32* | *3.86* | *3.86* |
| **Costs** | | | | |
| Capital | 3.69 | 5.86 | 3.83 | 6.09 |
| Battery O&M | 0.38 | 1.00 | 0.79 | 1.67 |
| Program | - | - | - | - |
| *Total* | *4.06* | *6.86* | *4.62* | *7.77* |
| **Net Benefit** | **(1.75)** | **(4.55)** | **(0.76)** | **(3.91)** |
| **Benefit Cost Ratio** | **0.57** | **0.34** | **0.84** | **0.50** |

## 6.12. Learning Objective & Evaluation

PGE aims to use this project to gain experience developing and integrating storage and solar, contracting for and constructing utility-scale energy storage projects, and demonstrating the ability to control energy storage assets for Transmission, Distribution, and Power Operations benefits. In addition, the operation of this project will provide real-world data that will enable future identification, use cases, and evaluation metrics for implementation of energy storage as an asset for PGE's system, including identifying the potential for locational value.

In broad strokes, this pilot would require evaluation of the following topics:

**Table 28: Evaluation Topics (Baldock Mid-Feeder Pilot)**

| Project | Quantitative Topics | | | | | Qualitative Topics | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Capacity | Transmission Deferral | Energy & Ancillary Services | Outage Mitigation | Power Reliability | Resiliency | Procurement | Infrastructural Readiness | Organizational Readiness | Customer Engagement |
| Microgrid | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Substation | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| **Mid-Feeder** | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| Residential | ✓ | ✓ | ✓ | | ✓ | | ✓ | ✓ | ✓ | ✓ |
| Generation | ✓ | | ✓ | | | | ✓ | ✓ | ✓ | |

PGE would also seek to answer the following research questions:

- How can utility scale co located energy storage benefit both PGE's distribution system and the adoption of renewable generation?
- What is required for the successful integration of operations and control of local energy storage to both Power Operations and Balancing Area Authority?
- What benefits or issues "scale-up" with the installation of additional local energy storage, what benefits or issues do not?
- What operations and maintenance issues arise from utility-scale energy storage operation?

## 6.13. Alternative Solutions

The primary function of the Mid-feeder project is to provide capacity, energy and ancillary services, and outage mitigation benefits. Alternative solutions that achieve similar benefits are described below. However, no individual solution matches all of storage's proposed applications.

### *Distribution Automation*

A distribution automation scheme involves installing controllable switching devices which are capable of fault location, isolation, and service restoration. The objective of distribution automation is to mitigate the effects of a sustained outage. Distribution automation is relatively low cost but can only provide outage mitigation benefits, as compared to the additional benefits offered by energy storage.

### *Underground Feeder Mainline*

Replacing the existing overhead mainline conductor with underground cable will significantly reduce the probability of a sustained outage due to a non-asset failure event. This is relatively expensive and can only provide outage mitigation benefits, as compared to storage.

# Section 7. Residential Energy Storage Pilot

## 7.1. Pilot Description

PGE proposes to implement a residential energy storage pilot program by installing battery inverter systems (BIS) at residential customers' homes. By implementing this pilot, PGE will explore the ability of distributed assets to provide grid services, learn how to deploy assets with benefit streams shared between participants and all PGE customers, and develop best practices for integrating distributed resources into existing asset control systems.

### *Key Attributes*

Individually, the BIS would provide enhanced power reliability capabilities for the program participants by offering back-up power during grid outage events. As a fleet, the BIS would act in aggregate to provide capacity, energy and ancillary services, and transmission deferral services to PGE. PGE aims to create an aggregated fleet of assets composed of approximately 500 residential BIS and totaling approximately 2 to 4 MW in size and 6 to 8 MWh in duration. Individual systems would likely be sized to provide between 3 to 6 kW of power output and 12 – 16 kWh of energy storage. Key project attributes are further summarized below:

**Table 29: Project Attributes (Proposal 3)**

| Attribute | Site-level | Fleet-level |
|---|---|---|
| Energy Storage | 12 - 16 kWh | 6-8 MWh |
| Charge/Discharge Rate | 3 - 6 kW | 2-4 MW |
| Technology/Material | TBD during procurement process | |
| Response Rate (seconds) | <10 sec* | |
| Location | Residential Customers' Homes | |

**Response rate is defined as the time between PGE issuing the command and the unit responding to the command.*

PGE proposes to locate systems at qualifying residential sites in their service area. The battery and inverter will be installed behind participating customers' meter and will serve a critical loads panel. A conceptual drawing of a potential system configuration is presented below.

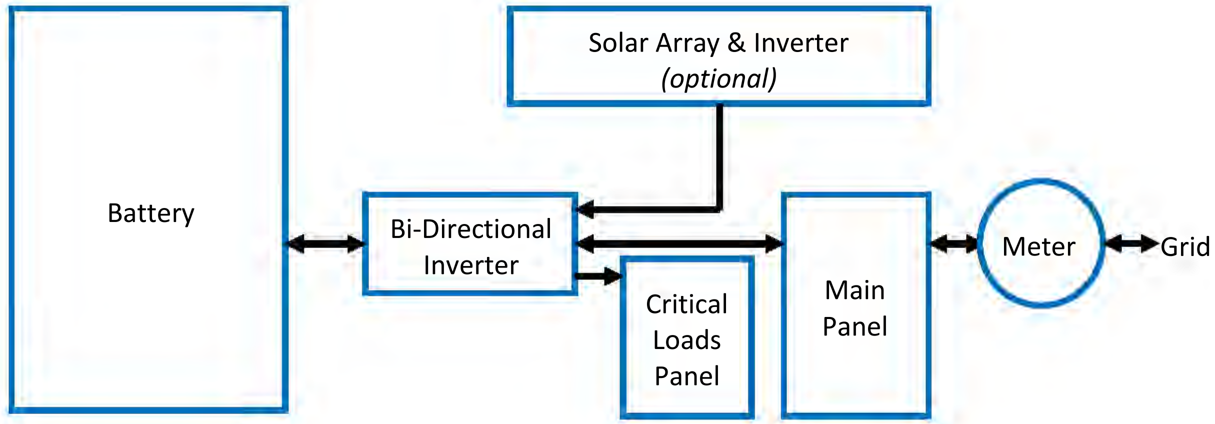



**Figure 22: Residential Battery Inverter System (BIS) Conceptual One-Line Diagram.**

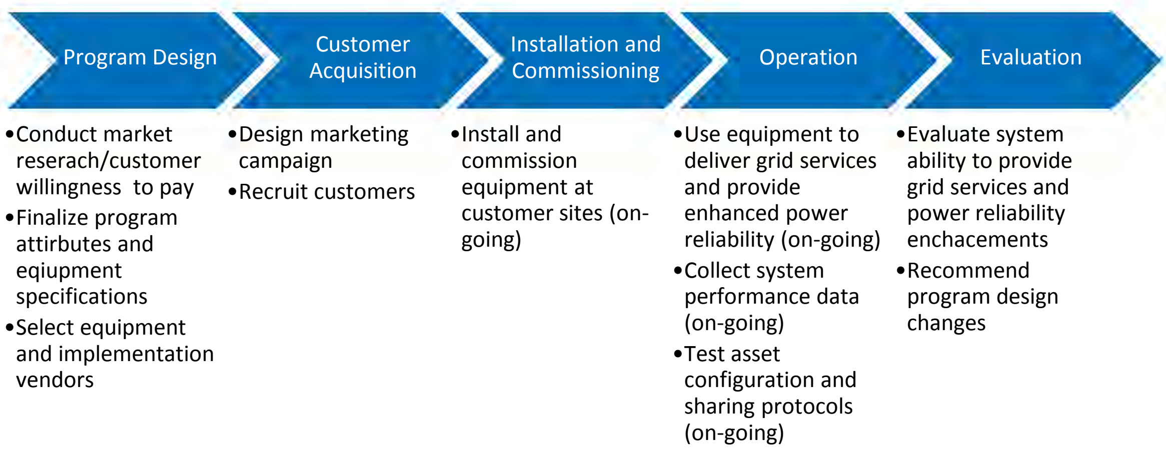
For individual customers, the BIS would improve power reliability at the site of installation by providing a back-up power source for some or all of a customer's loads during portions or all of a grid outage event. For PGE's transmission and distribution system, the aggregated fleet of BIS would provide capacity, energy and auxiliary services, and transmission deferral services.

PGE proposes two BIS ownership models to maximize our experience and program learnings. Customers may either opt for PGE ownership and pay a monthly lease fee on their electricity bills or elect to own their own equipment and receive a monthly bill credit for allowing the device to be used for grid services. Customers who own their own equipment must select a PGE-approved BIS and allow PGE control of the system to participate.

## *Pilot Process*

The proposed residential energy storage pilot program would go through a five stage design, operation, and evaluation process:

**Figure 23: Residential Storage Pilot Process**



PGE anticipates installations starting in 2020, adding approximately 200 units a year until all 500 units are deployed by mid-year of 2022. PGE anticipates testing, analysis, and evaluation would occur from 2020 through 2025 while the BIS would remain active for approximately 10 years.

## 7.2. Site Selection

PGE's proposes to locate the BIS behind-the-meter to maximize the number of services provided. Storage systems located further upstream (mid-feeder, substation, transmission, etc.) are capable of providing many of the same capacity, energy, and ancillary services but cannot provide the same individualized power reliability enhancements. Behind-the-meter systems are capable of providing both.[52]

PGE proposes a fleet size of approximately 500 units to meet minimum viable asset size requirements. Energy storage assets must be large enough to integrate with and dispatch from PGE's existing enterprise control systems. A smaller fleet may be too small to make a measureable difference in system-wide operation, greatly decreasing their value to system operators. A 500-unit fleet also allows program costs to be spread over a sufficiently large number of units, improving program cost effectiveness and lowering potential costs to program participants.

PGE proposes to locate distributed energy resources at residential sites because of customer interest in enhanced power reliability. PGE commissioned a study of residential customer interest in February 2016 and found that 63% of customers found it to be highly important to never experience a power outage. PGE also found that 34% of customers without backup electric power have already considered a power reliability solution.[53]

Customer interest in residential energy storage has also been demonstrated by demand for non-grid integrated products. Tesla reported that their Tesla Powerwall 1 residential energy storage product received 38,000 pre-orders after introduction.[54] PGE's interconnection team has reported twenty-two non grid-integrated storage devices installed in the last nine months with five more expected to complete by the end of 2017. PGE also expects product offerings to advance and prices to fall in the near term. Bloomberg New Energy Finance projects behind-the-meter residential energy storage costs to decline by 38% between 2017 and 2020[55].

Green Mountain Power, a vertically integrated utility serving over 270,000 customers in Vermont, has also seen customer demand for behind-the-meter residential energy storage. Their first program, in which Tesla Powerwall 1 energy storage systems were leased to customers for $37.50 per month, quickly reached the 500 unit maximum program size and began to accumulate a waiting list of interested customers.[56,57] Building on this successful program, Green Mountain Power released a second program where customers can lease a Tesla Powerwall 2 for $15 per month with a program cap of 2,000 units[58]. The Powerwall 2 program launched in August 2017.

The Pilot Program would be available to any residential customer PGE's service area that meets the requirements outlined in Section 7.3.

PGE may target installations to portions of their distribution system with above-average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) scores.

PGE proposes to utilize existing marketing channels that may include bill inserts, websites, radio ads, TV commercials, promotional events, or other activities to encourage customers to participate in the residential energy storage pilot program. We will also coordinate with ETO and its network of trade allies and qualified contractors.

## 7.3. Technology Considerations

### *Household Requirements*

- Program participant owns the residence in which the equipment will be installed;
- Electrical service that meets all current electric codes;
- Sufficient service panel capacity;
- Sufficient space to install a critical loads panel adjacent to the main service panel (as needed);
- Sufficient space to internally or externally house the battery inverter system(s);
- Reliable communications for battery inverter system control ; and
- Other site or distribution system conditions as determined by PGE.

### *Energy Storage Technology*

To minimize pilot project risks and maximize customer safety, PGE will only consider the selection of technologies that are commercially available, UL listed, and already deployed at residential locations. To our knowledge, the only systems that currently meet these requirements are lithium-ion battery energy storage systems, (e.g. Tesla Powerwall 2, Sunverge One, and sonnenBatterie eco residential energy storage systems).[p,q,r]

## 7.4. Ownership Structure

HB 2913 creates an opportunity for PGE to test and gain experience in two behind-the-meter program structures for our customers: an option where all assets are PGE-owned (and rate-based) and an option where assets are customer-owned. PGE proposes a pilot to test both, allowing customers to choose the option that works best for them. Under both options, PGE will use the batteries for grid services during normal operations. During an outage, the storage device will power some loads at the customers' premise. Details for each ownership model are provided below.

- **PGE Ownership:** The customer pays PGE for the service of added reliability—we anticipate the customer cost under this model to be about $50 per month. PGE is responsible for BIS

[p] For more information about the Tesla Powerwall: https://www.tesla.com/powerwall
[q] For more information about the Sunverge One: http://www.sunverge.com/hardware/
[r] For more information about sonnenBatterie eco: https://sonnen-batterie.com/en-us/sonnenbatterie#sonnenbatterie-eco

installation, commissioning, operation, maintenance, and end-of-life.[5] PGE controls the asset during normal operation to provide grid services. During outage events, the BIS provides power reliability services to the customer. If the customer wishes to leave the pilot program before the program end date, the customer may purchase the battery from PGE or pay an early termination fee.

Customers may be presented with three end-of-life options at the end of asset's life:

1. Purchase the battery from PGE for a nominal fee and stay in the program until device failure;
2. Purchase the battery from PGE for a nominal fee and opt out of the program; or
3. Have the battery removed at no cost.

- **Customer Ownership:** The customer independently finances, utilizes on-bill financing, or purchases a PGE-approved BIS directly from a third party. The customer is responsible for arranging BIS installation, commissioning, operation, maintenance, and end-of-life with the vendor as applicable. PGE provides the customer with a monthly on-bill credit of approximately $55 for grid services and the customer agrees to provide PGE direct control of the asset during normal operation. During outage events, the BIS provides power reliability services to the customer. The customer may leave the pilot program at any time. With an estimated monthly financed cost of about $90, the net cost to the customer would be approximately $35 per month under a low battery cost scenario. Monthly net cost increases to over $110 under a high cost scenario, indicating the large variability in market pricing.

Under each model PGE will evaluate customer price and incentives based on market research and market adoption. We may adjust the pricing and incentives to increase pilot participation, however, we propose to cap the total cost of the program (meaning increased incentive levels would result in a reduced number of pilot participants).

[5] PGE anticipates contracting with OEM for maintenance services as a component of the product warranty.

## 7.5. Construction and Implementation Plan

### *Procurement*

PGE would select and procure energy storage systems through an RFP from leading BIS manufacturers and evaluating responses based on criteria that may include:

- Equipment cost;
- System performance characteristics;
- Installation requirements, including installation time and materials;
- Available communications protocols;
- Maintenance requirements;
- Equipment life;
- Length of time equipment has been on the market;
- Number of units installed;
- Length of time manufacturer has been in business;
- Control software capabilities;
- Sufficient communications protocols; and
- Other criteria as determined by PGE.

PGE may also seek to select vendors capable of operating the entire pilot program, from customer acquisition to operation.

### *Engineering-Design*

PGE may seek packaged, turn-key BIS designs that result in equipment capable of being shipped to installation sites ready to install. This may include BIS that are housed in a single packaged unit and supported by control software capable of controlling individual units as well as the entire fleet of BIS.

PGE may also seek systems that are modular in nature and capable of serving whole-home energy requirements through the installation of multiple units at a single site (customer costs would scale accordingly).

### *Permitting*

PGE or a third party implementation partner will secure all necessary permits and approvals to meet the requirements of all appropriate jurisdictions for all aspects of the project, including but not limited to all applicable conditional use, electrical, mechanical, and building permits, and interconnection agreements.

### *Mobilization*

PGE may select equipment that can be installed using conventional construction techniques by a licensed electrician. PGE may select a BIS vendor that is responsible for installations or hire a third party installation contractor. All installations shall be done in accordance with all PGE and BIS vendor terms and conditions.

## Construction Management

The vendor or 3rd party installation contractor will coordinate and manage all installation jobs. The BIS will likely be mounted on the outside of the residence on an exterior wall or concrete pad. In instances where a customer's entire household electrical load exceeds the capacity of the battery inverter system a critical loads panel may be required. Household loads located on the critical loads panel are intended to remain powered during an outage until the battery is drawn down to its minimum state of charge. All other loads would not be powered during an outage. The critical loads panel would typically be located adjacent to the customer's main service panel.

## Commissioning, Testing, and Training

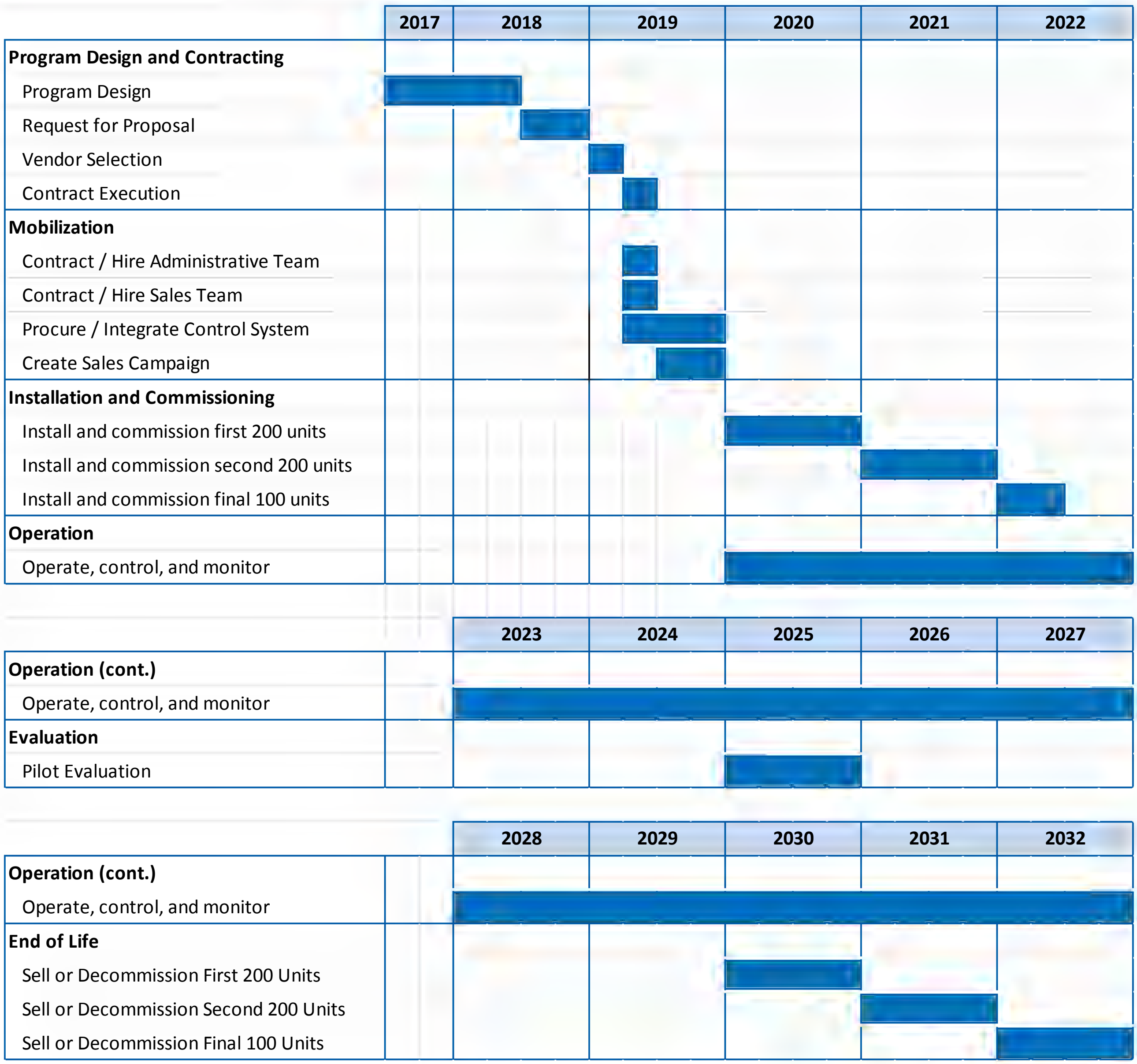
System commissioning may be conducted by PGE or a third party and may include the following:

- On-site verification of system operation and network connectivity;
- Remote verification of system network connectivity and operation by equipment vendor; and
- Equipment inspection and testing to ensure adherence to all applicable codes, rules, and guidelines from all applicable jurisdictions.

At the end of the commissioning process, the BIS would be approved for operation by PGE, the installation contractor, the equipment vendor, and all applicable jurisdictions.

PGE staff will receive training from the vendor on how to operate and maintain the storage devices.

## Pilot Schedule




## Deployment Risks

Risks of insufficient aggregated capacity and limited learnings from the pilot exist if too few customers enroll in the pilot. Based on the experiences of other utilities running similar pilots, customer demand has exceeded enrollment caps with little/no customer outreach. If enrollments are lower than anticipated, PGE will evaluate outreach techniques to and adjust to mitigate this risk.

## 7.6. Operations and Maintenance

### *Expected Functionalities*

During normal operating conditions, the BIS would operate in parallel to the electrical distribution grid, as shown below. This arrangement would allow the BIS to charge and discharge as needed to provide grid services and/or serve site loads.

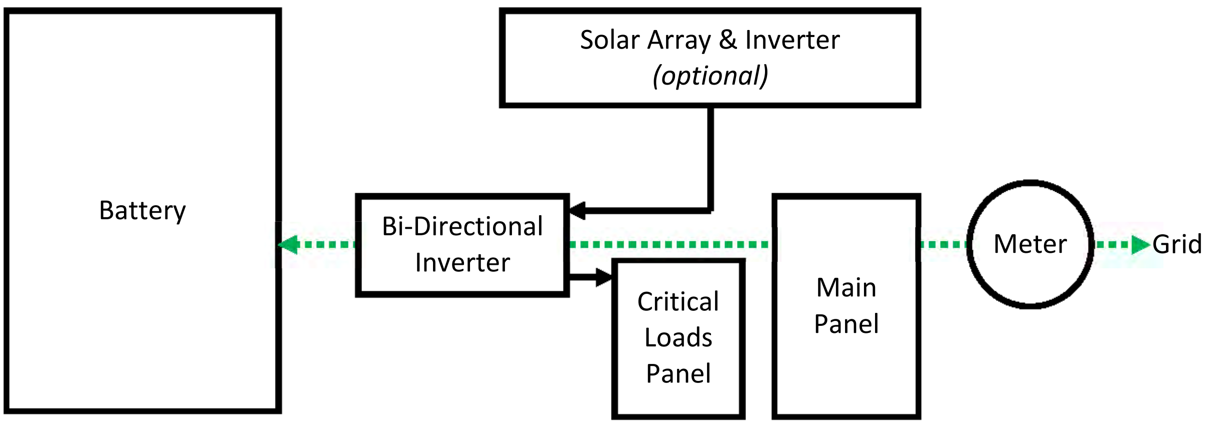



Figure 24: The battery inverter system (BIS) in Normal Operating Mode.

Grid services could include but are not limited to:

**System Capacity Services (Capacity)***:* The BIS discharges in response to a system-wide peak demand period. The unit may be charged from on-site photovoltaics or grid power.

- *Frequency:* Four to eight times per year, including winter and summer seasons.
- *Duration:* Approximately three hours.

**Premises Peak Shaving (Capacity)***:* The BIS discharges during daily household peaks. The unit may be charged from on-site photovoltaic or grid power.

- *Frequency:* Daily, up to 365 days per year.
- *Duration:* Approximately three hours.

**Utility Economic Dispatch (Energy)***:* The BIS charges during times of low price periods and discharges during times of high price. The unit may be charged from on-site photovoltaic or grid power.

- *Frequency:* Daily, up to 365 days per year.
- *Duration:* No event time limit.

**Ancillary Services***:* The BIS unit charges and discharges according to commands for frequency regulation, spinning reserve, or load following services.

- *Frequency:* Sub-minute.
- *Duration:* No event time limit.

During a grid outage event, the BIS would island itself from the grid and provide back-up power to the whole home or a subset of household loads isolated by the critical loads panel, as shown in the figure below. Back-up power duration would depend on system size, battery state of charge, and site loads. No grid services are available to PGE in this mode of operation.

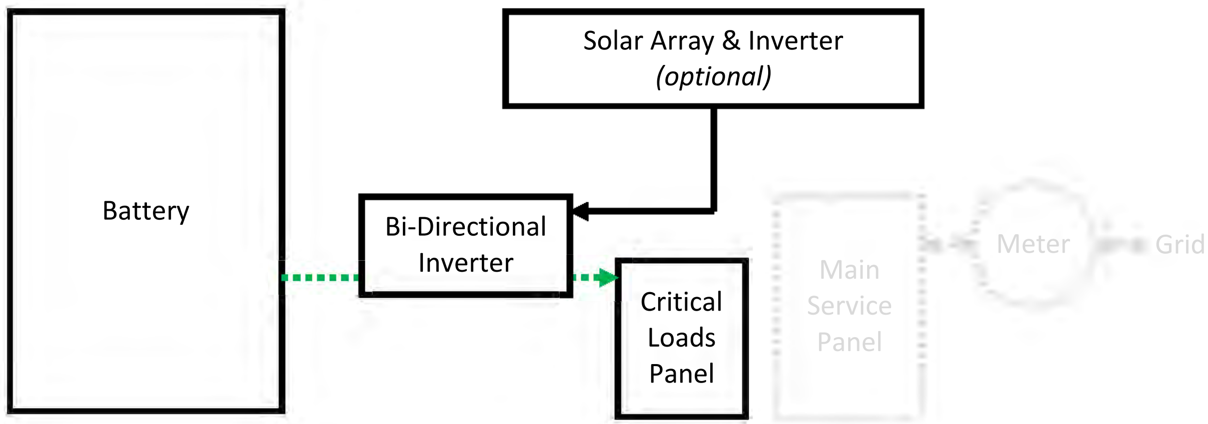



**Figure 25: Battery inverter system (BIS) in Grid Outage Mode: The BIS automatically islands itself from the grid and provides back-up power to the Critical Loads Panel.**

## *Maintenance Plan*

PGE may seek to procure equipment from vendors offering full maintenance services. PGE may also contract with third party maintenance providers. All services would guarantee that the BIS would receive all routine maintenance as recommended by the manufacturer and/or vendor. Maintenance services may include:

- Periodic inspections;
- Periodic predicative and preventative maintenance;
- Remote annunciation of trouble alarms;
- Response to alarms by maintenance technicians; and
- Repair and replacement of equipment.

### Life Cycle Risks

PGE foresees a number of risks associated with installing and operating BIS at residential customer sites. PGE plans to implement mitigation strategies for all risks early in the program design process. Risks and mitigation strategies are summarized below.

**Table 30: Life Cycle Risks (Residential Pilot)**

| Category | Potential Risk | Mitigation Strategies |
|---|---|---|
| Liability | • Personal injury<br>• Property damage | • Use proven technologies with all applicable certifications and listings<br>• Use manufacturer-certified installers<br>• Monitor and inspect equipment regularly |
| Partner Risk | • Vendor cannot meet product delivery expectations<br>• Vendor cannot support product after installation | • Select vendors with robust balance sheets<br>• Use products that adhere to open communications protocols and can be installed, maintained, and controlled by third parties<br>• Design program such that alternative products can be used if needed |
| Program Risk | • Not enough customers enroll in program to create the minimum fleet size | • Choose products with a high level of existing customer interest<br>• Dedicate sufficient funds to sales and marketing<br>• Price the programs aligned with customers' willingness to pay. |
| Technology Obsolescence | • New technology is subject to disruption | • Select technologies that can receive hardware / software upgrades<br>• Contract with vendors to guarantee support of legacy products over entire program life |

## 7.7. Project Costs

The residential proposal differs from the larger energy storage devices in that it contains ongoing program elements such as marketing and oversight, increasing total program carrying costs. Costs are highly variable based on project specifics requirements. Actual pricing will vary and be evaluated during the feasibility assessments, implementation plan development, and procurement. In addition, two distinct residential program models are being proposed: PGE ownership and customer ownership. Each program has a unique cost structure.

Table 31 presents PGE costs by assuming an equal split of participants between the customer-owned and PGE-owned options: 250 batteries to each ownership structure (half of the total pilot project target). Only the PGE ownership model classifies equipment purchase and installation costs as capital (assets that will be depreciated over time and included in PGE's rate base). Indicative vendor pricing, coupled with interconnection, system controls, and PGE's owner costs, result in a broad capital investment range between $2.1 and $6.0 million. Indicative vendor pricing varied broadly. Vendor pricing translates into a total carrying cost (net present value of revenue requirement over the life of the battery, including ongoing O&M and program management) ranging between $5.4 and $14.1 million (program total across both ownership models). Program costs vary by year; the first three years incur additional coordination, marketing, and sales conversion costs.

**Table 31: Overall Pilot Cost Estimates (assuming 500 residential batteries; assuming 250 in each ownership model)**

| | Low Cost Estimate ($M) | | | High Cost Estimate ($M) | | |
|---|---|---|---|---|---|---|
| **Ownership Model** | **Overnight Capital** | **NPV of RevReq** | **Year 1 RevReq** | **Overnight Capital** | **NPV of RevReq** | **Year 1 RevReq** |
| PGE owns | $2.1 | $3.9 | $0.4 | $6.0 | $10.0 | $1.1 |
| Customer owns | - | $2.8 | $0.3 | - | $6.0 | $0.5 |
| **Total Pilot** | **$2.1** | **$6.7** | **$0.8** | **$6.0** | **$16.1** | **$1.6** |

In the customer ownership model, equipment costs are removed, reflecting the customer's upfront contribution to the battery cost (assumed to be financed by a third party and paid off over the life of the battery). The battery cost to the customer is modeled as amortized via mortgage-style amortization over the 10 year battery life. This modeling assumes the customer's financing is equivalent to that of PGE: an interest rate of 7.26% (PGE's Weighted Cost of Capital) and a discount rate of 6.27% (PGE's after-tax Nominal Cost of Capital).

In this model, total PGE cost ranges between $2.0 and $4.8 million. This model assumes a cash payment to the customer to reduce the customer's cost of ownership and to reflect the value to PGE of operating the battery for grid services; this payment is included in the NPV of revenue requirement cost. In the PGE ownership model, cash flows in the opposite direction (the customer pays monthly for the value of power reliability). This program revenue is modeled as a benefit to PGE rather than a cost reduction. As such, it is excluded from the above table, which considers costs only. This is further discussed in the cost-effectiveness analysis below.

In this model, PGE assumes approximately $50 per month customer cost for the PGE-ownership model and a $55 per month incentive for the customer ownership model. As indicated in Section 7.4, we may adjust the pricing and incentives to increase pilot participation, however, we propose to cap the total cost of the program (meaning increased incentive levels would result in a reduced number of pilot participants).

Program management cost assumptions (marketing, administration, and sales conversion fees) are identical between the two ownership models. The high cost estimate assumes additional O&M warranty realized in the year of the battery purchase; this is born by the customer under the ownership model and by PGE under the PGE ownership model.

### Grant Funding Availability

PGE is not aware of any grant funding available for this project at this time.

## 7.8. Estimated Project Benefits

### In-state benefits

As discussed in detail in the Storage Evaluation Study (Appendix 4), PGE anticipates utilizing storage devices for capacity, energy and ancillary services, and power reliability because these functions have the highest value and abilities to be co-optimized:

- **Capacity**: the energy storage devices will be dispatched during peak demand periods to supply energy and shave peak demand, reducing the need for new peaking power plants.
- **Energy and Ancillary Services**: storage will be used for a variety of system ancillary services, including system regulation, load following, spinning reserves, voltage support, and black start.
- **Power Reliability**: the energy storage device will also be used to reduce or eliminate the economic impacts associated with power outages to participating customers.

For the purposes of this proposal, PGE is assuming the system-average benefit values for these projects identified in the potential study for capacity and energy services. The value of power reliability varies by customer. This analysis equates the value of power reliability with the customer's willingness to pay. A different customer net cost was assumed under each model; the total net present value is therefore displayed as a range.

Table 32: Estimated In-State Benefits, Residential Pilot (10-yr NPV)

| Application | Amount ($/kW) |
|---|---|
| Capacity | $701 |
| Energy & Ancillary Services | $466 |
| *Sub-Total System Benefit* | *$1,167* |
| Power Reliability[t] | $70-$125 |
| *Sub-Total Customer Benefit* | *$70-$125* |
| **Total Benefit** | **$1,237-$1,292** |

[t] For the residential cost-effectiveness analysis, we assume the value of power reliability realized by the customer is equal to the amount they are paying for energy storage.

### *Regional benefits*

Because of the small-scale and distributed nature of this pilot, we do not anticipate being able to realize any transmission deferral benefit, so we are assuming no transmission deferral benefits for this pilot.

PGE recognizes there may be instances in which transmission congestion value associated with energy storage can apply. PGE is currently working with BPA and regional stakeholders to determine if congestion relief on the South of Allston transmission path may be one such instance. Pending the outcome of this regional study effort, the South of Allston transmission congestion relief values, if applicable, will be included in the benefit reporting.

### *Societal Benefits*

**Carbon Reduction and other Environmental Benefits:** the alternative back-up power for residential homes is a fossil-fueled generator. As such, it is conceivable that environmental savings could be captured as a benefit of this pilot. We are not, however, including an estimate for that value in this preliminary analysis.

## 7.9. Potential benefits for System-wide deployment

PGE imagines large-scaled deployment of distributed energy storage assets as a potential low-cost tool to support the Company's long-term flexibility needs. Unlike central storage, distributed storage options like this one allow PGE to leverage individual customers' willingness to pay for increased reliability to reduce the first cost of energy storage systems. When aggregated, a dispatchable fleet is capable of providing grid services to the benefit of all customers.

## 7.10. Cost-Effectiveness Analysis

Cost effectiveness considers all quantitative costs and benefits to the electric system and its customers over the life of the project. Assessment of larger societal benefits, where applicable, is encouraged but is outside the scope of this proposal.

Three tests have been applied to the five projects proposed, the Total Resource Cost (TRC) test, the Ratepayer Impact (RIM) test, and the Participant Test. These tests differ in perspective: The TRC encompasses both the utility and the program participants, whereas the RIM assumes the utility perspective only. The Participant Test includes only costs and benefits that accrue to the participant. The tests have different inputs and results under the two proposed ownership options. They also vary significantly under the low and high cost scenarios.

In the customer ownership model, the TRC includes the full cost of the battery (which is born by the customer). The customer's cost of ownership assumes the customer's financing is equivalent to that of PGE: an interest rate of 7.26% (PGE's Weighted Cost of Capital) and a discount rate of 6.27% (PGE's after-tax Nominal Cost of Capital). This interest rate is similar to that available to participants in PGE's third-party financed heat pump program.

PGE will pay the customer monthly for the ability to control the battery for grid benefits. As a transfer between the utility and the customer, this value is excluded in the TRC test. The value of power reliability has been set at the customer's willingness to pay, here modeled at $35 monthly. In the RIM test, this is excluded, as it accrues to customers exclusively. The RIM test introduces the cost of PGE's cash payment to the customer, roughly $55 monthly in the low cost scenario. This monthly payment was set to result in a net customer cost of $35 per month, given an estimated cost to the customer for battery ownership of roughly $91 under the low cost scenario. In the high cost scenario, the PGE monthly payment increases to $151 monthly, in order to keep the net customer cost at $35 monthly. Note that the table below is presented in total program net present value, rather than per battery monthly costs.

The residential batteries profiled are warrantied for 10 years. This analysis models a 3% annual degradation rate annually and a steeply declining failure rate in years 11-14 (the number of batteries declines). Some decreased level of benefits is therefore realized post year 10. In these final years, the customer's cost of ownership is eliminated (assuming a 10 year loan, if financed), whereas PGE's cash payment to the customer – compensation for PGE's control of the battery – remains consistent until battery failure. Because of this cash flow that extends beyond the battery payment period, benefits exceed cost under the Participant Cost Test.

For both the TRC and RIM tests, benefits also include system values of capacity, and energy and ancillary services. Benefits are higher in the high cost scenario because these are larger batteries (6 kW each vs. 5 kW under the low cost scenario). The use case assumption is that the energy storage devices are reserved for 20 event days per year for capacity needs; the remainder of the time the energy storage devices serve system needs of energy and ancillary services, and are available to the customer for power reliability according to the energy storage devices' average state of charge. The methodology of calculating these benefit values is discussed in Section 2.3.

In a low cost scenario, the TRC results in a ratio of 0.69 and a negative net benefit of ($1.07 M). The negative net benefit is higher under the RIM, and the benefit cost ratio is lower. With this test, the negative net benefit is the dollar amount by which the cost to PGE exceeds the system benefits realized by PGE. Results are considerably less favorable under the high cost scenario.

Table 33: Cost-Effectiveness Results, Residential Pilot (NPV, $M) Customer Ownership Model

| | Low Cost Estimate | | | High Cost Estimate | | |
|---|---|---|---|---|---|---|
| | TRC | RIM | PCT | TRC | RIM | PCT |
| Benefits | | | | | | |
| Capacity | 0.85 | 0.85 | - | 1.02 | 1.02 | - |
| Energy | 0.56 | 0.56 | - | 0.68 | 0.68 | - |
| Outage Mitigation | - | - | - | - | - | - |
| Reliability | 0.94 | - | 0.94 | 0.94 | - | 0.94 |
| Cash | - | - | 1.48 | - | - | 4.05 |
| **Total** | **2.35** | **1.41** | **2.43** | **2.64** | **1.69** | **4.99** |
| Costs | | | | | | |
| Equipment | 2.12 | - | 2.12 | 4.31 | - | 4.31 |
| Battery Controls | 0.10 | 0.10 | - | 0.80 | 0.80 | - |
| Program | 1.20 | 1.20 | - | 1.20 | 1.20 | - |
| Cash | - | 1.28 | - | - | 4.05 | - |
| **Total** | **3.43** | **2.79** | **2.12** | **5.65** | **6.04** | **4.31** |
| **Net Benefit** | **(1.07)** | **(1.38)** | **-** | **(3.67)** | **(4.35)** | **-** |
| **Benefit Cost Ratio** | **0.69** | **0.50** | **1.15** | **0.42** | **0.28** | **1.16** |

In the PGE ownership model, the full cost of the battery is born by PGE and thus included in both the TRC and RIM tests. The cost of the battery is higher in this model, the result of income and property tax, and the gross up of PGE's rate of return to reflect tax impacts. PGE ownership also applies different book and tax depreciation schedules than are applied to the customer-owned, mortgage-style amortization schedule.

In the TRC test, benefits include the customer benefit of power reliability (the benefit is assumed to be equal to the cost paid by the customer, modeled at approximately $50 monthly). Power reliability is modeled as a higher value than in the customer ownership model, under the assumption that customers may value PGE assuming liability for battery operations and maintenance. System benefits accruing to PGE remain the same under both ownership models.

In the RIM test, customer benefit is excluded, but cash transfers from the customer to the utility are included (under PGE ownership, the cash transfer is a benefit rather than a cost to the utility). As the customer's value of power reliability is equivalent to the customer's monthly payment, the results of these two tests are the same under the PGE ownership model.

Due to the varying assumption on customer willingness to pay, the TRC benefit/cost ratio is very similar under both ownership models (0.72 vs. 0.69). Under PGE ownership, the RIM test reports a higher ratio of 0.72, equivalent to the TRC test. Negative net benefit is estimated to be lower under the PGE ownership model ($1.09 million, vs. 1.38 million), due to the varying direction of cash flow between PGE and the customer in each model: under the customer ownership model, PGE payment to participants continues through battery failure (despite declining benefits streams due to battery degradation) and after battery payments have concluded, whereas under the PGE ownership model, the customer pays PGE for power reliability through battery failure and after PGE has fully depreciated the battery. Benefits extend cost under both scenarios, but the scenarios vary in their assignment of costs and benefits.

Under the high cost scenario, the battery costs increase significantly, while the customer's willingness to pay has been held constant at approximately $50 a month (equal to their cost). PGE bears the increased cost. The result is significantly lower ratios for the TRC and the RIM, and larger negative net benefits.

The Participant test has been modeled to result in 1.00 for both high and low cost scenarios. The Participant Test includes only the benefit of power reliability and the monthly cost to the customer. This analysis defines the two values as equivalent.

**Table 34: Cost-Effectiveness Results, Residential Pilot (NPV, $M) PGE Ownership Model**

| | Low Cost Estimate | | | High Cost Estimate | | |
|---|---|---|---|---|---|---|
| | TRC | RIM | PCT | TRC | RIM | PCT |
| Benefits | | | | | | |
| Capacity | 0.85 | 0.85 | - | 1.02 | 1.02 | - |
| Energy | 0.56 | 0.56 | - | 0.68 | 0.68 | - |
| Outage Mitigation | - | - | - | - | - | - |
| Reliability | 1.40 | | 1.40 | 1.40 | | 1.40 |
| Cash | - | 1.40 | - | - | 1.40 | |
| **Total** | **2.81** | **2.81** | **1.40** | **3.10** | **3.10** | **1.40** |
| Costs | | | | | | |
| Equipment | 2.59 | 2.59 | - | 7.82 | 7.82 | - |
| Battery Controls | 0.10 | 0.10 | - | 1.03 | 1.03 | - |
| Program | 1.20 | 1.20 | - | 1.20 | 1.20 | - |
| Cash | - | - | 1.40 | - | - | 1.40 |
| **Total** | **3.90** | **3.90** | **1.22** | **10.05** | **10.05** | **1.40** |
| **Net Benefit** | **(1.09)** | **(1.09)** | **-** | **(6.95)** | **(6.95)** | **-** |
| **Benefit Cost Ratio** | **0.72** | **0.72** | **1.00** | **0.31** | **0.31** | **1.00** |

## 7.11. Learning Objectives & Evaluation Plan

PGE aims to use this pilot program to gain experience in residential energy storage program design, procurement, customer acquisition, deployment, operation, maintenance, and end-of-life.

In broad strokes, this pilot would require evaluation of the following topics:

**Table 36: Evaluation Topics (Residential Pilot)**

| Project | Quantitative Topics | | | | | Qualitative Topics | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Capacity | Transmission Deferral | Energy & Ancillary Services | Outage Mitigation | Power Reliability | Resiliency | Procurement | Infrastructural Readiness | Organizational Readiness | Customer Engagement |
| Microgrid | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Substation | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| Mid-Feeder | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| **Residential** | ✓ | ✓ | ✓ | | ✓ | | ✓ | ✓ | ✓ | ✓ |
| Generation | ✓ | | ✓ | | | | ✓ | ✓ | ✓ | |

The pilot will inform future program design elements, including but not limited to:

- BIS design, power output, and energy storage specifications;
- Customer acquisition and enrollment strategies;
- Procurement, installation, and commissioning best practices;
- Operational strategies;
- Fleet command software design; and
- BIS maintenance and end-of-life.

PGE would also seek to answer the following research questions:

- How can PGE most effectively leverage distributed energy storage to benefit the entire electrical distribution system?
- Was PGE successful in dispatching the aggregated BIS fleet to provide capacity, energy and ancillary services, and transmission deferral services? If not, what improvements are required?
- Was PGE successful in dispatching the aggregated BIS fleet for other services that should be considered system benefits? If so, how can these benefits be best included in future program designs?

- What are PGE customers willing to pay for enhanced and power reliability?
- How should battery capability be shared between PGE and customers to maximize total benefits?
- What operations and maintenance issues arise from BIS operation?

PGE would also evaluate program costs, realized system benefits, realized customer benefits and willingness to pay, and equipment ownership structure.

## 7.12. Alternative Solutions

The primary functions of the Residential Energy Storage Pilot Program are to provide enhanced outage mitigation and power reliability to individual customers who choose to install these systems at their residences when grid outage events occur and provide PGE with grid services during normal grid operation. Customer-sited BIS are unique in their ability to offer both sets of services. Alternative solutions can typically provide only outage mitigation and power reliability or grid services.

**Table 37: Alternative Solutions to Proposal 3**

| Technology | Relative Cost | Power Reliability | Capacity | Energy and Ancillary Services |
|---|---|---|---|---|
| Residential Energy Storage Pilot Program | $$ | ✓ | ✓ | ✓ |
| Customer-sited Back-up Generator | $ | ✓ | | |

### *Customer-sited Back-up Generator*

A standard residential back-up generator uses proven and inexpensive technology to provide customers with a back-up power source during grid outage events. Installations vary in complexity and range from manually powering a single circuit islanded from the grid to systems that can sense grid outages, automatically start the back-up generator, and transfer an entire customer's load. Back-up generators are typically powered by fossil fuels (gasoline, diesel, propane, or natural gas) and are not usually configured to provide grid services during normal grid operation for residential installations, meeting only part of the service requirements provided by a BIS. Systems could theoretically be designed to provide both power reliability services *and* grid services but would require additional equipment to isolate the generator from the residential loads and connect the generator to the grid.

# Section 8. Generation Kick Start

## 8.1. Project Description

PGE proposes to develop and build a 4-6 MW, four hour energy storage system at our Port Westward 2 Generating Station located in Clatskanie, Oregon. In addition to providing energy and ancillary service benefits like the other energy storage systems in this proposal, this system will also be coupled with our the existing plant control system on and one of the plants reciprocating engines in order to supply up to 18.9 MW of spinning reserves.

To meet the spinning reserve requirements, the energy storage system will immediately and automatically respond to frequency deviations while the engine is not running, but if called on, the engine will be able to ramp up to full output and respond within the 10 minute requirement. For contrast, without a storage device the engine must be idling at minimum load to respond to frequency deviations and be used for spinning reserves. This approach is modeled after a similar battery-fast start combustion turbine package owned by Southern California Edison and operating in the California Independent System Operator's Balancing Authority.[59] These spinning reserves will be available when the reciprocating engine is not running, saving on fuel costs and emissions as it allows PGE to release those reserves that are held elsewhere within the Balancing Area. When not being utilized as spinning reserves, this system will be able to provide capacity, energy and other ancillary services. PGE will control and operate the project for system needs and have the ability to dispatch the system as needed.

An important learning opportunity of this storage system lies in understanding how to utilize an entire generating unit as spinning reserve even when not synchronized to the grid, and hence not burning fuel. The current requirements for spinning reserve were not written with energy storage in mind, and more typically include generating units that are fully synchronized ("spinning") to the grid. However, implementation of energy storage technology is starting to challenge the conventional definition. Unlike other locations on the grid, a storage device at this facility yields more than its own capacity in spinning reserves. A 4 – 6 MW storage system on the distribution system or at a customer site would typically yield just 4 – 6 MW of spinning reserves; however, because this storage system is coupled with the generator's regulator, the 4 – 6 MW storage system can yield the entire capacity of the turbine as spin reserves (in this case 18.9 MW). This concept is illustrated in Figure 26, below:

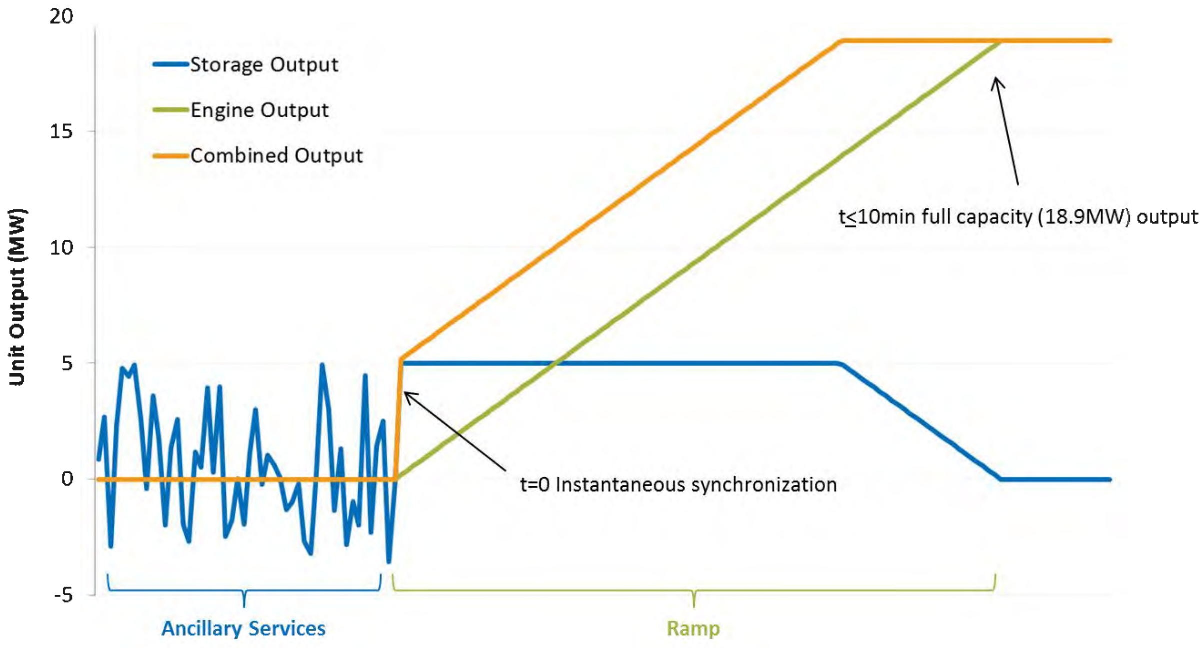



Figure 26: Conceptualization for Storage and Engine Dispatch and Ramp for Spinning Reserves

Port Westward 2 is flexible 220 MW capacity resource located adjacent to the existing Port Westward Unit 1 and the Beaver Generating Station. The plant consists of 12 state of the art, highly efficient natural gas fired reciprocating engine-generator sets, each capable of generating 18.9 MWs.

The energy storage system will be located at the plant. The project will connect to an existing bus and include all control systems and project equipment to operate the system coupled with the plant. Control and dispatch will continue to be through PGE's System Operations.

The plant control system and protection schemes will require additional hardware and modifications to incorporate the energy storage system, and the existing telecommunications system will be used. Power cabling will be trenched and terminated inside the central plant building. Auxiliary power will be required for the transformer cooling fans, the HVAC system(s), and any other required equipment.

## Key Attributes

This project includes all energy storage devices, inverters, switchgear, transformers, HVAC, software, control systems (including modifications to existing control systems), fire protection and communications required for operation. The installation may be in a standalone building or in modular enclosures on site. The equipment will be sized to allow for additional storage capacity to be added, if required, to maintain the full 16 – 24MWh of usable energy storage for the entire life of the project.

**Table 35: Key Project Attributes (Generation Kick Start Project)**

| Attribute | Value |
|---|---|
| Charge/Discharge Rate (MW) | 4 – 6 MW |
| Energy Storage (MWh) | 16 – 24 MWh |
| Location | Clatskanie, OR |
| Generation facility | Port Westward 2 |
| Target In-service Date | 2020 |

## 8.2. Site Selection

PGE evaluated all the fast starting units in the generation fleet, including Beaver units 1-6 and unit 8 for this hybrid power plant.[u] Only Port Westward 2 units qualified by meeting the 10 minute startup time required for spinning reserve. Port Westward 2 is flexible 220 MW capacity resource located adjacent to the existing Port Westward Unit 1 and the Beaver Generating Station. The plant consists of 12 state of the art, highly efficient natural gas fired reciprocating engine-generator sets, each capable of generating 18.9 MWs. These are fast start units that synchronize to the grid in less than two minutes and achieve full load in 7-10 minutes. These units dispatch through PGE's Automated Generation Control system and currently provide non-spinning operating reserves, peaking capacity, and load following services.

The Port Westward 2 operating facility is ideally suited to this project due to its staffing level (including maintenance staff), interconnection in the PGE grid, modern communication/telemetry systems, and flexible construction space. Since the plant has an air permit and adding a storage system does not result in added emissions we do not see any issues with permitting.

## 8.3. Sizing Considerations

The range for the project size and duration was selected at 4 – 6MW and 16 – 24MWh. A detailed analysis will be required to determine the final battery size, but it is anticipated that the battery will need to be sized to provide the same frequency support to the system as the engine operating at minimum load. When being used for spinning reserve the battery will continuously provide frequency support which allows the full capability of the generator to be counted as spin even when the unit is not online.

[u] PGE considers fast starting units as those that can ramp to full capacity in less than 10 minutes. This is typically limited to simple cycle plants.

A 16 – 24MWh, or four hour duration is being proposed to support both the short duration needed to provide frequency support when the system is operating to provide spinning reserves and the longer duration needed to provide the most value for Capacity, Energy and Ancillary services when the system is not providing spinning reserves.

## 8.4. Technology Considerations

The energy storage system will provide capacity, energy and ancillary services to the PGE system either automatically via the project's control system or via the System Control Center. By combining the storage system with an existing fast start generator, additional value will be leveraged by being able to count the off-line generator as on-line spinning contingency reserve. This will results in fuel savings and additional market opportunity for the on-line resources currently being utilized for spin. Based on the responses to PGE's RFI, the majority of systems available are lithium ion based, but flow battery systems and other energy storage technologies also responded. The RFP for this project will be technology agnostic to ensure that all systems that can meet the identified project needs are evaluated.

While some of the functionality of the energy storage system will act autonomously based on measured system conditions from the project's local control system, a dedicated communication link will also be necessary for control and status indication. A dedicated interface with our System Control Center will be necessary to dispatch the energy storage system to charge or discharge in line with the proposed use cases, as well as capture operational data from the system. This system will also require integration with the existing plant and specific engines control system, vendor support will be needed for successful integration.

## 8.5. Ownership Structure

PGE proposes to own and operate the Energy Storage located at the Port Westward 2 Generating Station. As owners of the underlying property and generation assets, this will make for ease of installation and integration, while giving us full control of the device for use by our dispatch as needs fluctuate.

## 8.6. Construction and Implementation Plan

### *Procurement*

PGE will develop site specific requirements and specifications, including control system interface requirements, to include with an RFP for portions or all of the Engineering, Procurement and Construction services required to complete the project. Proposal evaluation criteria will be developed with the RFP and used to score each bid. Bids will be ranked on their score and contract negotiations will be completed. A detailed division of responsibilities matrix will be created to clearly define the work to be done by the contractor and the work that PGE will be completing.

## *Engineering-Design*

The EPC contractor will be responsible for doing all necessary engineering and design work associated with this project, including but not limited to:

- Site development
- Electrical, civil, structural and mechanical design
- Protection, automation, and control system design for the Energy Storage system
- Equipment and materials selection

PGE will determine if any engineering and design work associated with the energy storage system will be completed internally when scoping the project.

The existing interconnection agreement for Port Westward 2 will be reviewed to confirm compliance with all requirements. If necessary the process to modify and restudy the facility and interconnection will be completed prior to energization of the energy storage system.

## *Permitting*

An amendment to the existing Port Westward 2 site certificate will likely be required to include the energy storage system being proposed. This process is expected to take 9-12 months and will be coordinated with EFSC.

In addition, PGE will work closely with the EPC contractor to complete all other required studies and secure all necessary permits and approvals to meet the requirements of the appropriate jurisdiction for all aspects of the project, including but not limited to all applicable zoning, conditional use, electrical, mechanical, building permits, environmental impacts, etc. A detailed division of responsibilities matrix will be included as part of the contract to identify which party is responsible for the required permits.

## *Mobilization*

The EPC contractor will oversee mobilization after receiving the Notice to Proceed from PGE and once all necessary permits with the local jurisdictions to start construction have been acquired.

## *Construction Management*

Construction management for the installation of this storage project will require both internal and external construction management resources. The site development and installation of the storage asset located adjacent to the Port Westward 2 Generating Station will be led by the PGE project team and utilize construction management resources as needed throughout the construction phase of the project.

The EPC contractor is expected to be responsible for most aspects of the construction of the energy storage system. It is anticipated that the energy storage system will be housed in a stand-alone building or in modular enclosures on the project site with an adjacent laydown yard to store equipment during construction. It is also anticipated that the racks or skids used for the energy storage system will be assembled off site wherever possible to minimize the installation time. Any construction activities within PGE's scope will be closely coordinated with the EPC contractor.

### *Commissioning, Testing, and Training*

Testing & commissioning of the energy storage system will begin upon substantial completion and will follow the testing plan agreed to by both PGE and the EPC contractor and included in the EPC agreement. This plan will follow industry best practice and the OEM requirements and is expected to include detailed testing of all individual systems and equipment, the entire system as a whole, and the integration with the existing plant systems. If special testing is required PGE may contract with third party testers as required for permit compliance. It is expected that this testing and commissioning will require both internal and external resources. PGE staff will work with the EPC to ensure all necessary PGE employees receive adequate training for ongoing operations and maintenance of the storage device.

### *Project Schedule*

The preliminary project schedule is shown below. Changes are expected as actual task durations are refined during the development of the project.


**Figure 27: Port Westward 2 Energy Storage Project Schedule**

## *Construction Risks*

**Permitting Risk:** Combining an energy storage system with an existing generation plant has only been done at a small number of sites and there will likely be new to the jurisdiction(s) issuing permits for the project. In order to mitigate this risk PGE will have to work closely with the jurisdiction(s) to ensure that all applicable permitting requirements are met.

**Vendor/Technology Risk:** There will be risk associated with the vendor or technology selected. This includes equipment lead times, maturity of the selected technology and construction/installation risks. In order to mitigate this risk PGE will have to use a robust procurement process to ensure that these risks are appropriately accounted for in any RFP process.

**System Integration Risk:** Integration of an energy storage system into the plant control system, including the testing and commissioning aspects of the project are also potential risks. In order to mitigate this risk PGE will need to have a detailed commissioning and testing plan that includes approvals and handoffs to aid in the transition to operations.

## 8.7. Operations and Maintenance

### *Expected Functionalities*

During day-to-day operations, PGE will operate the energy storage system for daily energy, capacity and ancillary services including utilization for spinning reserves. One of the Port Westward 2 Units can be dedicated for spinning reserves at times when it is not operating for other services.

In the event of a grid outage the storage device could be utilized to provide power to plant systems as required.

### *Operations and Maintenance Plan*

Maintenance work will be overseen by PGE and informed by manufacturer specifications. PGE anticipates at least the following:

1. Periodic Inspections
2. Periodic predictive and preventive maintenance
3. Remote annunciation of trouble alarms
4. Response to alarms by PGE technicians
5. Repair and replacement both by PGE and equipment suppliers

Life-Cycle Risks

**Safety Risk:** As most of the energy storage options available are relatively new and each poses its own risks a review of the known and expected risks will need to be done as part of the RFP evaluation process. And during the final design risk mitigation will need to be incorporated and could include items such as fire suppression, physical barriers etc.

**System Availability:** During the initial implementation many of the storage assets will be equivalent to some of the smaller generation assets and the impact to the system will be less impactful. As more projects are brought on line and assets become part of a larger virtual asset the impact will grow. And as such many of the use cases of the storage asset will become similar to a larger generation asset with similar risks associated with failure to operate. With that risk identified many of the same mitigation actions/plans currently being used including maintaining spinning and non-spinning reserve may need to be utilized.

**Technology Risk:** As with all new and emerging technologies there is a risk that the technology or manufacture will not be around for the expected lifecycle of the product. To help mitigate this, the sourcing team will need to identify criteria that will be used to help score vendor proposals or include appropriate bonding and insurance requirements to mitigate known risks.

## 8.8. Project Costs

Indicative vendor pricing, coupled with interconnection, system controls, and PGE's owner costs, result in a total capital investment range between $6 and $8 million. This translates into a total carrying cost (net present value of revenue requirement over the life of the energy storage asset, including ongoing annual O&M costs) ranging between $10 and $15 million.

Table 36: Project Cost Range + Carrying Cost (Generation Kick-Start Project)

| | Low Cost Estimate ($M) | | | High Cost Estimate ($M) | | |
|---|---|---|---|---|---|---|
| **Battery Life** | **Overnight Capital** | **NPV of RevReq** | **Year 1 RevReq** | **Overnight Capital** | **NPV of RevReq** | **Year 1 RevReq** |
| 10-Year | $5.9 | $9.4 | $1.4 | $7.7 | $12.9 | $1.9 |
| 20-Year | $5.9 | $10.1 | $1.4 | $7.7 | $15.1 | $1.9 |

Ongoing project costs for service, maintenance, and power augmentation are estimated to range from $130,000 - $315,000 annually over the energy storage asset life. Cost estimates for longer lived storage devices increase the timeframe over which O&M expenses occur, but hold the annual O&M expense constant.

## 8.9. Estimated Project Benefits

### *In-state benefits*

As discussed in detail in the Storage Evaluation Study (Appendix 4), PGE anticipates utilizing storage devices for capacity, energy & ancillary services (including spinning reserves), and outage mitigation because these functions have the highest value and abilities to be co-optimized with the scheduled dispatch of the Port Westward 2 plant:

- Capacity: the energy storage devices will be dispatched during peak demand periods to supply energy and shave peak demand, reducing the need for new peaking power plants.
- Energy and Ancillary Services: storage will be used for a variety of system ancillary services, including system regulation, load following, spinning reserves, voltage support, and black start.

Navigant calculated the expected benefit values using the NVEST model, these values have been applied to the Port Westward 2 project in Table 19 below:

Table 37: Estimated In-State Benefits for Port Westward 2 (4-hr duration, 10-yr NPV)

| Application | Amount ($/kW) |
|---|---|
| Capacity | 987 |
| Energy & Ancillary Services | 477 |
| **Total Benefit** | **1,464** |

The project also provides a unique use case to utilize a relatively small storage device to realize the full value of spinning reserves of an off-line turbine. PGE has not quantified this potential value, but will use this project to investigate what additional value can be yielded from a hybrid generation-storage project. We expect that this storage system coupled with the plant will allow PGE to reduce plant startups and low load operations. By providing the required frequency support the battery will allow the generator to be utilized for spinning reserves without actually starting the unit. If called upon the plant will start otherwise be on standby providing spinning reserves.

In the absence of the storage device providing spinning reserves, another generator on the system would need to be rotating and ready to put megawatts on the grid when called. This practice consumes fuel and if a fossil resource is being utilized, it also emits incremental pollution at lower, less efficient loads. Other units on PGE systems also function non-optimally: combined cycles, for example, could be producing at 90% capacity, holding back 10% for spinning reserves. Having this Port Westward 2 unit take up the slack will allow the combined cycles to continue to operate at their optimum design maximum output point if market opportunities exist.

### *Regional benefits*

PGE does not anticipate any regional benefits associated with this project.

### *Societal Benefits*

The economic benefits described above may also provide environmental benefits by lowering the number of starts and reducing the overall run time, thereby reducing fuel consumption and emissions. Flexibility while avoiding incremental emissions lowers PGE’s carbon footprint.

## 8.10. Opportunity for System-wide deployment

If successful, PGE could evaluate deployment of additional storage units at Port Westward 2's other turbines to be used in a similar fashion as proposed in this Section.

## 8.11. Cost-effectiveness analysis

Cost effectiveness considers all quantitative costs and benefits to the electric system and its customers over the life of the project. Assessment of larger societal benefits, where applicable, is encouraged but outside the scope of this proposal.

Three benefit cost tests have been applied to the five projects proposed, the Total Resource Cost (TRC) test, the Ratepayer Impact (RIM) test, and the Participant Test. These tests differ in perspective: The TRC encompasses both the utility and the program participants, whereas the RIM assumes the utility perspective only. The Participant Test incorporates costs and benefits that incur to the participant only. Because the Generation Kick Start project has no participants (it serves the system as a whole, rather than individual customers), the inputs and results of the TRC and RIM tests are the same, and the Participant Test does not apply.

Costs included are upfront capital and annual O&M (service, maintenance, and operation costs). Benefits included are the system values of capacity and energy and ancillary services. The methodology of calculating these benefit values is discussed in Section 2.3.

In the following table, the net present value for benefit and cost streams were calculated for both 10 and 20 year energy storage devices. Moving to the 20 year timeframe, benefits increase by a larger multiplier than do costs, resulting in more favorable ratios. Of the scenarios considered, the low-cost 20 year energy storage asset performs the best, with benefits valued at 123% of costs. Net benefit illustrates the magnitude of dollars (in millions) by which benefits exceed costs. Negative numbers indicate projects for which costs exceed benefits.

Table 38: Total Resource Cost & Ratepayer Impact Tests, Port Westward 2 (NPV, $M)

| | 10 Year | | 20 Year | |
|---|---|---|---|---|
| **TRC + RIM Tests** | **Low** | **High** | **Low** | **High** |
| **Benefit** | | | | |
| Capacity | 5.04 | 5.04 | 8.40 | 8.40 |
| Energy | 2.43 | 2.43 | 4.06 | 4.06 |
| Outage Mitigation | - | - | - | - |
| Reliability | - | - | - | - |
| *Total* | *7.47* | *7.47* | *12.46* | *12.46* |
| **Cost** | | | | |
| Capital | 8.35 | 10.40 | 8.35 | 10.93 |
| Battery O&M | 1.06 | 2.53 | 1.77 | 4.22 |
| Program | - | - | - | - |
| *Total* | 9.41 | 12.93 | 10.12 | 15.14 |
| **Net Benefit** | **(1.94)** | **(5.46)** | **2.33** | **(2.69)** |
| **Benefit Cost Ratio** | **0.79** | **0.58** | **1.23** | **0.82** |

## 8.12. Learning Objectives & Evaluation Plan

PGE aims to use this project to gain experience developing, contracting for and constructing utility-scale energy storage projects, as well as demonstrating the ability to integrate the system into the existing Port Westward 2 plant control system and to control energy storage assets for System Control and Power Ops benefits. Additional PGE grid operations and plant staff will benefit from the experience gained from this project. In addition, the operation of this project will provide real-world data that will enable future identification, use cases and evaluation metrics for implementation of energy storage as an asset for PGE's system, including identifying the potential for locational value and the value of spinning reserves to the PGE system.

In broad strokes, this pilot would require evaluation of the following topics:

**Table 39: Evaluation Topics (Generation Kick-Start Project)**

| Project | Quantitative Topics | | | | | Qualitative Topics | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Capacity | Transmission Deferral | Energy & Ancillary Services | Outage Mitigation | Power Reliability | Resiliency | Procurement | Infrastructural Readiness | Organizational Readiness | Customer Engagement |
| Microgrid | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Substation | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| Mid-Feeder | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| Residential | ✓ | ✓ | ✓ | | ✓ | | ✓ | ✓ | ✓ | ✓ |
| **Generation Facility** | ✓ | | ✓ | | | | ✓ | ✓ | ✓ | |

PGE would also seek to answer the following research questions:

- How can centralized energy storage benefit PGE's generation system – in particular, our need for spinning reserves?
- How can energy storage be integrated into an existing generation plant control system?
- How can we best implement energy storage to better utilize existing assets?
- How can energy storage be used to help meet our regulatory requirements?
- What is required for the successful integration of operations and control of generation plant sited energy storage to both Power Operations and Balancing Area Authority?
- What benefits or issues "scale-up" with larger, generation plant sited energy storage, what benefits or issues do not?
- What operations and maintenance issues arise from generation plant sited energy storage?

## 8.13. Alternative Solutions

### *Additional Procurement*

In order to meet the Capacity, Energy and Ancillary Services benefits provided by the proposed energy storage system, additional products or services that help meet those needs could be procured through a separate process, including products capable of providing a portion of PGE's spinning reserve requirement. To meet spinning reserve obligations, PGE may hold back generating capacity on other generation operating units and procure energy from other sources to meet demand.

# Section 9. Controls and System Integration

PGE intends to implement a control system that provides the necessary features to capture benefits associated with the use cases identified in the Storage Potential report. In order to accomplish this in the short term, PGE intends to use the existing GenOnSys software utilized by the distributed generation group. This software platform already provides many of the functions needed to interface with systems in the field. Functionality will be added to help us define the requirements for a vendor supported controls platform in the near future.

The GenOnSys system provides a foundation for integrating the distributed energy storage system. This approach enables PGE to readily make meaningful and regular changes in our integration methods throughout the project period based on the experience gained in the implementation and testing of the various use cases.

Developing experience across the enterprise is a primary objective of this project – this will provide subject matter expertise in Power Operations, the Balancing Authority, and distribution operations. For storage systems at customer sites, this experience will help PGE define requirements to provide an outstanding customer experience.

As part of the project, PGE will develop new functionality within GenOnSys. This includes improving existing interfaces and building new interfaces with other enterprise systems used for grid monitoring, control, and generation dispatch. The primary functionality being added will:

1. Allow for real-time and scheduled operation of the various assets by the appropriate "owner" of each use case (Power Operations plans assets to serve peak demand and the Balancing Authority own frequency response)
2. Provide the necessary two-way communications to receive, display and store all system data in a meaningful and useful format
3. Capture data to help inform interested stakeholders regarding system performance, thus supporting the goal of maximizing learnings and allowing both internal and external agencies to study use case viability

## 9.1. GenOnSys – PGE's Current DER Platform

GenOnSys operates on a 24/7 basis. It is controlled by operators in PGE's fully-instrumented command center during daytime hours and supported by on-call operators during off hours. The platform is also integrated with other enterprise systems including EMS and GenOps that are used for grid monitoring and control. GenOnSys currently manages a portfolio of DERs including 86 customer-owned diesel generators, 16 solar PV plants, PGE's 5MW energy storage plant in Salem, and one pilot residential energy storage system.

The current system provides flexibility as PGE owns the source code and has experienced developers to implement changes as challenges are identified.

PGE has developed a basic road map and a cost estimate for modifying GenOnSys to support additional energy storage devices. This includes increasing the number of data points that the system can manage, enhancing the architecture to interface with new third party platforms, and staffing appropriately to support the project.

## 9.2. Review of Commercially Available Software

Until recently, most vendors focused on products for either T&D operating systems or systems to control demand response programs. Today we see vendors adding functionality in each other's traditional markets and adding battery control.

As noted in PGE's Smart Grid plan, we are developing a business case to justify the implementation of a Distribution Management System (DMS). DMS vendors have focused on situational awareness and remote control of distribution assets like switches. Many of these vendors have the experience to integrate their systems into Power Operations functions. These vendors are creating add-on applications to control DER assets. However, this capability is emerging; this storage project will provide PGE's engineers and operators the experience to objectively evaluate product offerings from DMS vendors.

Other control vendors have focused on the ability to manage and control DERs. At this time, PGE is implementing a software product from one of these vendors to manage our Demand Response (DR) assets in the commercial and residential markets. These vendors have experience in the control of assets, plus they manage the customer enrollment and customer experience for a wide range of small customer technologies. DR control systems interface with end-use devices like water heaters and thermostats, building management systems, energy monitoring equipment, and control gateways. PGE's vendor is also developing similar capability to control customer battery systems. DR control platforms look promising as component in a future controls hierarchy architecture.

Our experience leads us to believe that a commercial solution capable of meeting our needs is still some time out. To bridge the gap until this technology is available, the proposed path forward is an expansion of PGE's GenOnSys system. PGE is fortunate to have an established system to control appropriately sized generation projects and employees with experience interfacing with Power Operations and the Balancing Authority to dispatch assets.

This platform allows for rapid aggregation and optimization of a fleet of energy storage assets to meet a given use case. This approach is well suited to groups of small assets capable of serving a variety of use cases.

## 9.3. Control Systems Hierarchical Approach

In order to leverage the value of distributed devices, PGE is planning a control system and integration approach that is capable of supporting automated decisions within a set of defined business rules and appropriately dispatching distributed resources assigned to those rules. To address the high level of diversity involved with this plan, a hierarchical approach will be necessary.

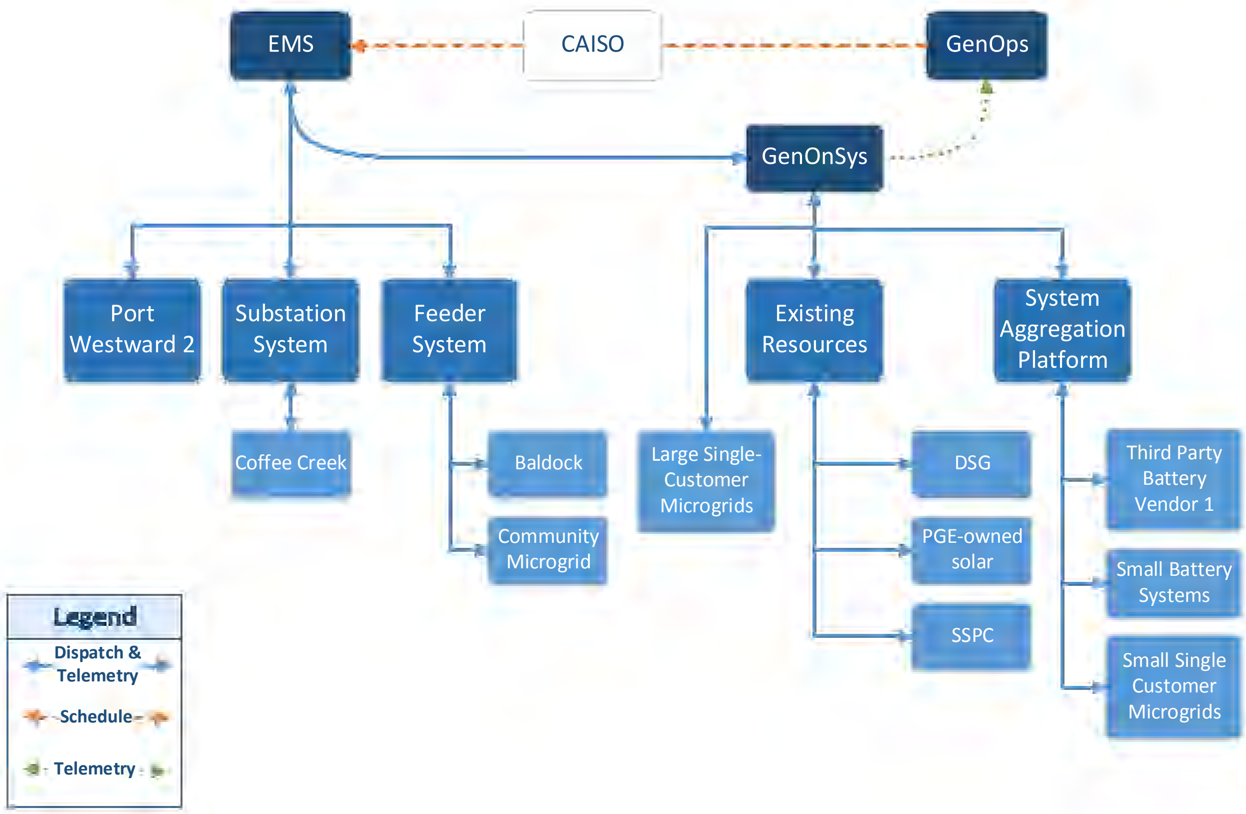



Figure 28: Simplified Control Systems Hierarchy

On the bottom of the hierarchy is direct communication with individual assets such as substation-sited energy storage. On top of this hierarchy are enterprise systems such as PGE's GenOps and EMS that will ultimately determine battery use cases by hour and dispatch such resources. Intermediate layers will be GenOnSys, system aggregation platforms, and commercially available demand response control systems.

PGE anticipates direct communication to and control of the Coffee Creek energy storage project, the Baldock energy storage project, and a potential community microgrid pilot. These sites will utilize traditional utility communication methods such as fiber optics and radio.

The residential energy storage systems will be aggregated to an appropriate capacity to be functional for Power Operations. The most likely solution will include a service provided by the manufacturer that provides a packaged residential systems offer. PGE may consider developing a basic aggregation system for smaller systems where the vendor provides an application interface to the site controller system.

Aggregation platforms will be on a hierarchical level interfacing with GenOnSys to control classes of assets and present them for dispatch by the system operators. This approach will reduce integration costs and maintain PGE's high security standards.

Note that CAISO is shown in the link between GenOps and EMS to reflect the Energy Imbalance Market (EIM) interfaces. No new functionality for CAISO is in the scope of this project.

## 9.4. Control System Costs

The control systems cost estimate is based upon PGE's experience with GenOnSys and its recent work to join the western EIM. This results in an estimated capital investment range of $3 million. This translates into a total carrying cost (net present value of revenue requirement over the life of the energy storage asset, including ongoing annual O&M costs) of $6 million.

**Table 40: Cost Estimates: Controls and System Integration**

| Cost Estimate ($M) | | |
|---|---|---|
| Overnight Capital | NPV of RevReq | Year 1 RevReq |
| $3.1 | $5.9 | $0.4 |

Detailed cost estimates for storage device control systems are as follows:

**Table 41: Cost Estimates: Annual Controls and System Integration ($,000)**

| Cost Element | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| Application Development | $ 326 | $ 350 | $ 290 | $ 265 | - |
| Mission Critical Redundancy | - | $ 200 | $ 400 | $ 600 | $ 400 |
| Hardware | $ 141 | $ 10 | $ 10 | $ 60 | - |
| Controls Operation & Maintenance | $ 205 | $ 555 | $726 | $ 635 | $ 705 |
| **Total** | **$ 672** | **$ 1,115** | **$ 1,426** | **$ 1,560** | **$ 1,105** |

# Section 10. Administration, Testing, and Evaluation

## 10.1. Administration

The projects and pilots discussed in this proposal have asset lives of 10-20 years. PGE proposes that "project period" for the projects and pilots be considered as 5 years. That is to say, PGE will report on progress, learnings, costs, benefits, and evaluation of these initiatives for 5 years (2018–2022). PGE proposes to include project report outs in the Smart Grid Report. At the end of the term, PGE will issue a final report, and then these projects will become a standard component of PGE's resource mix and will no longer be subject to special reporting requirements.

PGE anticipates the portfolio of proposed projects will be overseen by a portfolio director with the support of a program specialist and an energy storage engineer. These individuals will be responsible for portfolio planning, budget tracking, reporting, standards development, documenting best practices/lessons learned, managing evaluation, etc.

Table 42: Portfolio Administration Costs[v]

| Storage Portfolio Admin: O&M | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| Portfolio Program Director | $ 201,305 | $ 201,305 | $ 201,305 | $ 201,305 | $ 201,305 |
| Portfolio Specialist | $ 152,068 | $ 152,068 | $ 152,068 | $ 152,068 | $ 152,068 |
| Energy Storage Engineer | $ 183,028 | $ 183,028 | $ 183,028 | $ 183,028 | $ 183,028 |
| Administrative costs | $ 75,000 | $ 75,000 | $ 75,000 | $ 75,000 | $ 75,000 |
| **Total** | **$ 611,401** | **$ 611,401** | **$ 611,401** | **$ 611,401** | **$ 611,401** |

PGE does, anticipate that the long-term integration of storage and more distributed assets on our system will likely require PGE to create new roles and functions within the company (e.g. maintenance staff, operations engineers, controls specialists, etc.). As we learn from the proposed pilots, we expect to include considerations for new human resources through future rate cases.

[v] Human resource costs are fully-loaded. Administrative costs include travel, training, customer outreach, etc. associated with the project portfolio.

## 10.2. Testing and Evaluation

Although the proposed pilots will provide real value to PGE's customers and system, PGE sees the data and insights resulting from the pilot as important as well. For this reason, PGE plans to place emphasis on collecting data and information from the pilot and analyzing and interpreting them to inform decisions about whether and how to best use storage at a larger scale in the future. PGE proposes to hire an external consultant to evaluate the projects. Because storage technology is advancing rapidly, bringing a consultant's insights from storage projects elsewhere in the country will benefit PGE's assessment of project data and information.

Although PGE has described the unique scope and considerations in evaluating each pilot in the descriptions above, there are many topics that will be assessed in multiple pilots – for example, the potential contribution of the storage assets to system capacity. Table 43 provides a general overview of the topics to be evaluated for these projects and the applicability of each topic to different projects. As indicated in the table, the evaluation will include topics with primarily quantitative assessment, as well as topics with primarily qualitative assessment. Each topic, however, may have some aspects of both quantitative and qualitative analysis.

The quantitative topics focus on the evaluation of net benefits derived from various different applications, including the following:

- **Capacity** – utilization of the Energy Storage System (ESS) during system peak periods to ensure availability of sufficient generation capacity;
- **Transmission Deferral** – utilization of the ESS during peak periods to defer investments in transmission infrastructure;
- **Energy & Ancillary Services** – utilization of the ESS on a regular basis to optimize dispatch in coordination with PGE's portfolio of generation resources;
- **Outage Mitigation** – utilization of available energy within the ESS during periods when a network outage occurs to provide backup power to mitigate the impacts of the network outage;
- **Individual Customer Benefits** – utilization of the ESS to provide benefits to individual customers including Time-of-Use Charge Reduction, Demand Charge Reduction, and Power Reliability.
- **Resiliency** – utilization of the ESS to provide electric power to critical service providers during disasters and disaster recovery.

The qualitative topics focus on the evaluation of PGE's abilities and preparedness to deploy similar energy storage projects at scale:

- **Procurement** – ability to procure systems in an efficient manner that utilizes appropriate tools and processes to ensure procurement of cost-effective ESSs that perform as desired;
- **Infrastructural Readiness** – presence of sufficient enabling infrastructure to manage a large portfolio of ESSs in an optimized fashion, including the necessary infrastructure for communicating with, monitoring, dispatching, measuring, and maintaining ESSs;

- **Operational Readiness** – presence of necessary people and processes to ensure that ESSs will be effectively implemented, operated, and maintained over their operational life on an ongoing basis and that management of ESSs is integrated into regular planning and operations activities;
- **Customer Engagement** – effectiveness of strategies for engaging with end customers who are served by ESSs, including strategies for customer acquisition, ESS implementation, operation, maintenance, and billing.

**Table 43: Evaluation Topics *(Source: Navigant Consulting)***

| Project | Quantitative Topics | | | | | Qualitative Topics | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Capacity | Transmission Deferral | Energy & Ancillary Services | Outage Mitigation | Power Reliability | Resiliency | Procurement | Infrastructural Readiness | Organizational Readiness | Customer Engagement |
| Microgrid | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Substation | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| Mid-Feeder | ✓ | ✓ | ✓ | ✓ | | | ✓ | ✓ | ✓ | |
| Residential | ✓ | ✓ | ✓ | | ✓ | | ✓ | ✓ | ✓ | ✓ |
| Generation Facility | ✓ | | ✓ | | | | ✓ | ✓ | ✓ | |

Table 44 describes the proposed approach for executing the analysis within each of the evaluation topics, including the key questions, the general approach, and the applicable methods. The methods are grouped into six categories including:

- **ESS Data Collection** – Collection of operational data from ESSs to utilize as inputs for quantitative analysis and modeling, including collection of data from both normal operation and from simulated events/activities designed evaluate specific capabilities and/or benefits;
- **PGE Modeling** – Analysis of system-level and ESS-specific data by PGE within its available suite of modeling tools;
- **Independent Modeling** – Data analysis performed by consultant, which will consider both data directly obtained from ESS data collection and outputs from PGE modeling;
- **Secondary Research** – Review of available data and literature from reputable resources to identify appropriate assumptions and inputs, as well as to gather lessons learned and best practices from other ESS deployments
- **Interviews** – Interviews with and/or surveys of project stakeholders (e.g., PGE staff, customers) to identify project successes and areas for improvement, as well as to estimate the value of benefits that may not be directly measured or modeled
- **Workshops** – In-person workshops with a group of stakeholders within PGE to identify lessons

**Table 44: Summary of Evaluation Approaches *(Source: Navigant Consulting)***

| Topic | Key Questions | Summary of Approach | Methods: ESS Data Collection | Methods: PGE Modeling | Methods: Independent Modeling | Methods: Secondary Research | Methods: Interviews | Methods: Workshops |
|---|---|---|---|---|---|---|---|---|
| **Capacity** | • How much value was realized?<br>• How could greater value be realized in subsequent projects?<br>• Did the system operate as designed? | • Dispatch for capacity events and/or simulate events.<br>• Utilize PGE analysis to determine value of capacity alone.<br>• Evaluate net costs and benefits w/ and w/o energy storage.<br>• Evaluate value for immediate dispatch vs. advance notice. | ✓ | ✓ | ✓ | | | |
| **T&D Deferral** | | • Dispatch for deferral events and/or simulate events.<br>• Assess real value of deferral achieved.<br>• Assess theoretical potential of deferral value. | ✓ | ✓ | ✓ | | | |
| **Energy & Ancillary Services** | | • Dispatch regularly for energy + ancillary services.<br>• Utilize PGE analysis (ROM and/or GenOps) to assess net benefit w/ and w/o storage.<br>• Assess T&D capacity limitations on dispatch. | ✓ | ✓ | ✓ | | | |
| **Outage Mitigation** | | • Island during real and/or simulated outages.<br>• Assess ability to achieve theoretical benefits from IPT analysis.<br>• Assess actualize realized benefits from avoided Distribution costs. | ✓ | ✓ | ✓ | | | |
| **Individual Customer Benefits** | • How much value was realized?<br>• How could greater value be realized in subsequent projects?<br>• How much are customers willing to pay for reliability and resiliency?<br>• Did the system operate as designed? | • Dispatch system for individual customer benefits (time-of-use and demand charge reduction).<br>• Evaluate realized customer bill savings.<br>• Island during real and/or simulated outages.<br>• Interview/survey customers to assess willingness to pay for power reliability. | ✓ | ✓ | ✓ | | ✓ | |
| **Resiliency** | • What types of resiliency benefits can be achieved? Are these monetizable?<br>• How much value was realized?<br>• How could greater value be realized in subsequent projects? | • Operate system in islanded mode for real and/or simulated prolonged outage events.<br>• Identify potential monetizable and non-monetizable resiliency benefits.<br>• Utilize system data, secondary research, and customer interviews to determine theoretically achievable and actual resiliency benefits. | ✓ | ✓ | ✓ | ✓ | ✓ | |

| Topic | Key Questions | Summary of Approach | Methods | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | ESS Data Collection | PGE Modeling | Independent Modeling | Secondary Research | Interviews | Workshops |
| **Procurement** | • What procurement tools and processes were effective?<br>• Did the procured resources perform as specified?<br>• How could procurement tools and processes be improved to shorten the procurement timeline, increase the quality of submitted bids, and ease the bid evaluation process? | • Review best practices and lessons learned from other utilities through both primary and secondary research.<br>• Conduct individual interviews and group workshop with PGE stakeholders to identify strengths and areas for improvement. | | | | ✓ | ✓ | ✓ |
| **Infrastructural Readiness** | • Did PGE have the necessary infrastructure, both within individual storage systems and broader enabling infrastructure, for effective operation and optimization?<br>• What enabling infrastructure may be necessary to effectively operation a portfolio of storage resources at scale? | | | | | ✓ | ✓ | ✓ |
| **Organizational Readiness** | • Does PGE have sufficient resources and capabilities to implement, operate, and maintain energy storage on an ongoing basis at scale?<br>• Does PGE have the necessary processes in place to effectively, implement, operate, and maintain energy storage at scale?<br>• What gaps must be addressed in order to effectively integrate energy storage into PGE's broader system operations at scale? | | | | | ✓ | ✓ | ✓ |
| **Customer Engagement** | • Were customers happy with their experience?<br>• What could PGE do to improve customer recruitment and enrollment?<br>• How effectively did PGE balance system benefits vs. individual customer benefits? | • Conduct individual interviews with customers to identify strengths and areas for improvement.<br>• Conduct workshop with PGE stakeholders to identify methods for enhancing customer engagement in subsequent energy storage projects. | | | | | ✓ | ✓ |

PGE anticipates preliminary evaluation work starting in 2020 with most evaluation work occurring in 2021 and final reporting concluding in 2022. PGE estimates the costs of the evaluation to be about $500,000 for the final evaluation report.

**Table 45: Estimated Evaluation Costs**

| 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| - | - | $ 150,000 | $ 300,000 | $ 150,000 |

# Section 11. Cost Recovery

The incremental costs of this pilot are subject to deferral and later recovery. PGE plans to modify its Schedule 122 Renewable Resources Automatic Adjustment Clause tariff to add energy storage as eligible resources for cost recovery. Cost recovery for specific storage projects will consist of the annual revenue requirement associated with the project. In addition, any incremental costs to evaluate and procure energy storage will be deferred and subject to cost recovery.

House Bill 2193 allows for cost recovery:

> *(3) An electric company may recover in the electric company's rates all costs prudently incurred by the electric company in procuring one or more qualifying energy storage systems under this section, including any above-market costs associated with procurement.*

Senate Bill 1547 allows utilities subject to renewable portfolio standards (RPS) to use an automatic adjustment clause to recover energy storage associated with renewable energy sources.

> *(2)(a) The Public Utility Commission shall establish an automatic adjustment clause as defined in ORS 757.210 or another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources [and for], costs related to associated electricity transmission and costs related to associated energy storage.*

# Section 12. Conclusion

To truly deliver upon HB 2193's intent to maximize learning and operational experience with energy storage, electric companies, stakeholders, and the OPUC need to not only develop and consider, but actually deploy a variety of storage projects. PGE has proposed a diverse portfolio of projects and pilots that balance the needs of our customers and the feedback from our stakeholders.

In summary, PGE is proposing a portfolio of energy storage projects and pilots that will integrate storage at various sites on our system: transmission, substation, mid-feeder, commercial/industrial customer sites, and residential premises. We estimate the portfolio will cost $108M - $190M and will generate $89M - $107M of value for customers (net present value). PGE expects our portfolio to demonstrate the value of storage across our grid, as well as to expand our ability to effectively integrate storage into the grid in the future.

We look forward to positive discussions on this proposal with the OPUC and stakeholders in 2017.

# Appendices

# Appendix 1. Compliance with Order No. 16-504

**Table 46: Compliance with Order No. 16-504**

| Section | Detail | Location(s) in Report | | | | |
|---|---|---|---|---|---|---|
| | | Microgrid | Coffee Creek | Baldock | Res | PW2 |
| 1a | 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; | 4.1 | 5.1 | 6.1 | 7.1 | 8.1 |
| 1b | The location of the project; | 4.2 | 5.2 | 6.2 | 7.2 | 8.2 |
| 1c | 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; | 1.2 | | | | |
| 1d | 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; | 4.3 | 5.4 | 6.4 | 7.3 | 8.4 |
| 1e | A description of the types of services that the electric company expects the project to provide upon completion; and | 4.6, 4.8 | 5.7, 5.9 | 6.7, 6.9 | 7.6, 7.8 | 8.7, 8.9 |
| 1f | An analysis of the risk that the electric company will not be able to complete the project; | 4.5 | 5.6 | 6.6 | 7.5 | 8.6 |
| 2a | The estimated capital cost of the project; | 4.7 | 5.8 | 6.8 | 7.7 | 8.6 |
| 2b | The estimated output cost of the project; and | | | | | |
| 2c | The amount of grant moneys available to offset the cost of the project; | | | | | |
| 3a | Projected in-state benefits | 4.8 | 5.9 | 6.9 | 7.8 | 8.9 |
| 3b | Projected regional benefits | 4.8 | 5.9 | 6.9 | 7.8 | 8.9 |
| 3c | Benefits to PGE’s Grid if technology is taken to scale | 4.9 | 5.10 | 6.10 | 7.9 | 8.10 |

| Section | Detail | Location(s) in Report | | | | |
|---|---|---|---|---|---|---|
| 4 | Reasoning for choosing: | | | | | |
| | • Technology | 4.3 | 5.4 | 6.4 | 7.3 | 8.4 |
| | • | 1.2, 2.2 | | | | |
| | • Grid location | 4.2 | 5.2, 5.3 | 6.2 | 7.2 | 8.2 |
| | • Application | 1.2 | | | | |
| | • Ownership structure | 4.4 | 5.5 | 6.5 | 7.4 | 8.5 |
| | • RFI | 2.1 | | | | |
| | • Potential Evaluation | 2.2, Appendix 4 | | | | |
| | • Selection criteria | 4.2 | 5.2, 5.3 | 6.2 | 7.2 | 8.2 |
| 5 | Comprehensive description of project | 4.1 | 5.1 | 6.1 | 7.1 | 8.1 |
| 6 | Plan for constructing, maintaining, and operating | 4.5, 4.6 | 5.6, 5.7 | 6.6, 6.7 | 7.5,7.6 | 8.6,8.7 |
| 7 | Analysis of costs over life of project | 4.7 | 5.8 | 6.8 | 7.7 | 8.6 |
| 8 | Risks over life of project | 4.6 | 5.7 | 6.7 | 7.6 | 8.7 |
| 9 | All quantitative costs & benefits for life of project | 4.10 | 5.11 | 6.11 | 7.10 | 8.11 |
| 10 | Method for assessing project benefits | 2.2, Appendix 4 | | | | |
| 11 | Cost effectiveness of energy storage system | 4.10 | 5.11 | 6.11 | 7.10 | 8.11 |
| | | 2.2, Appendix 4 | | | | |
| 12 | Trends in storage system costs & performance | 1.4 | | | | |
| 13 | Strategy for large deployment | 4.9 | 5.10 | 6.10 | 7.9 | 8.10 |
| 14 | Alternatives analysis | 4.12 | 5.13 | 6.13 | 7.12 | 8.13 |
| 15 | Data collection & evaluation | 10.2 | | | | |
| | | 4.11 | 5.12 | 6.12 | 7.12 | 8.13 |

# Appendix 2. Locational Benefits of Storage Report

**Date** April 18, 2017

**From** Darin Johnson

**To** Brian Spak, PGE

**Copy** Jon Robinson, PGE
Josh Mullins

**Regarding** Report on life-cycle cost analysis of energy storage and locational benefits.

---

BIS Consulting is pleased to submit this report on cost/benefit assessment of energy storage options and the locational benefits. This report is based on life-cycle cost analysis using the Integrated Planning Tool (IPT), developed by the Strategic Asset Management group (SAM) at PGE. It documents estimated benefits of energy storage in terms of avoided outage cost to customers and extended life of assets.

This work was carried out by a project team comprising representatives from T&D, Planning, SAM, and BIS Consulting. Deliverables include this report, and specialized versions of the IPT developed to support the analysis.

## Background

PGE intends to install energy storage systems (i.e., batteries) at one or more locations to satisfy Oregon HB 2193. There are multiple benefits of energy storage, one of which is reduced outage risk to customers. Other benefits are outside the scope of this study.

Reduced outage duration produces benefits in two ways.

- The future cost to customers due to outages is reduced since power can be restored more quickly. This benefit is quantified based on standard outage cost assumptions utilized by SAM for all benefit/cost analyses of this type.
- Reduced consequence of failure, and thereby reduced risk, extends the economic life of aging assets, allowing PGE to delay capital expenditures.

PGE has identified three possible locations for energy storage.

- At substations connected to the bus. This option allows for restoration of power in cases of lost transmission supply.
- At multiple locations along a given feeder trunk, in conjunction with feeder automation. This allows restoration of power for any outage at the substation, and restoration of most customers on the feeder for any feeder-level outage.
- Customer-sited. This option keeps selected customers on-line for any outage on the distribution system.

This analysis is one step in a broader process of benefit/cost/locational assessment for battery options. The intent of this work is to provide input to a more comprehensive discussion of benefits to be performed by others.

## Sources of information

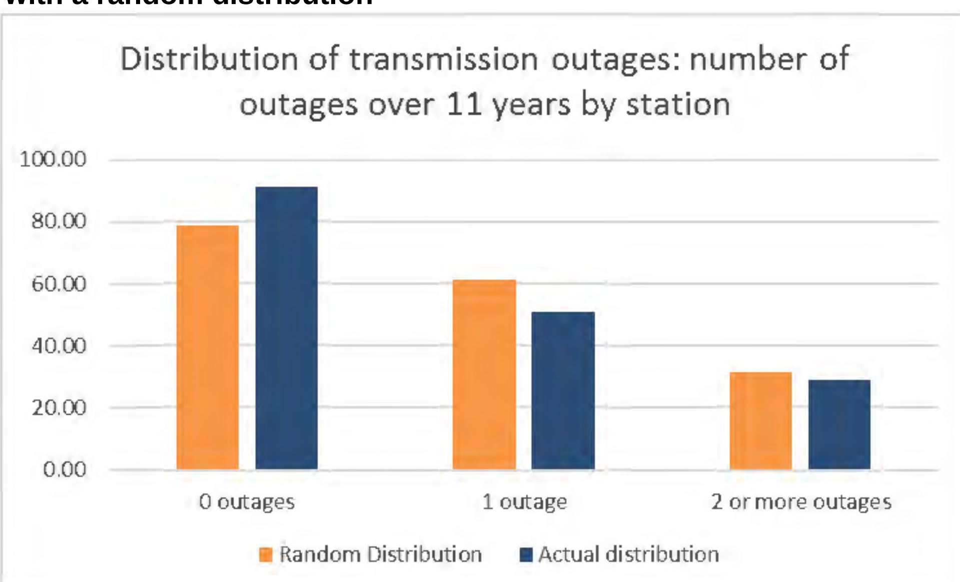
This analysis makes use of two major sources of information.

**SAM tools, including IPT**
The first is the suite of risk-based life-cycle cost tools, which includes the IPT, developed by SAM. These tools quantify risk due to failures, including the cost to customers due to loss of power. The cost of outages is calculated based on customer survey results, which are incorporated into all of SAM's risk analyses. These tools are used to calculate life-cycle cost, including outage risk and future asset replacements, with or without batteries, per the assumptions described below. The results are expressed in net present values, assuming cyclic replacement of aged or failing batteries (i.e., the benefits extend far into the future).

**System Disturbance Database (SDDB) for loss-of-transmission events**
The second source of data is the SDDB and the outage management system. These databases include cause codes, which were used to estimate the frequency of loss-of-transmission events over the past 11 years; the outage validation was completed by the T&D Planning team, a review for inappropriately coded events was done by T&D.

The team expected that some substations would be more susceptible to loss-of-transmission events than others, and that this increased exposure will cause those substations to be more attractive locations for battery installation. However, statistical analysis of the data does not support rejecting the null hypothesis – that loss-of-transmission events are randomly distributed. To see this we compared the actual distribution of how many substations experienced zero, one, or two or more outages over the 11-year period with what we would expect the distribution to look like. The result is shown in the graph below.

**Comparison of actual distribution of loss-of-transmission outage counts by substation with a random distribution**




A Chi-Square test returns a value of 0.14, which is not enough to indicate the distribution is non-random. Therefore, we have assumed that all substations face the average probability of loss of transmission.

The team deemed the duration data for loss-of-transmission outages not reliable enough for use, so the average duration for all such outages was used.

## Substation option

A battery installed at the substation bus will allow PGE to restore power to all customers in the event of an outage at the bus due to failure of the transformer or loss of transmission supply. It will not provide reliability benefits in case of an outage at the bus itself (e.g., wildlife in the buswork, or any feeder-level outages, such as cable failure or non-asset failures from weather, trees, or animals). Assumptions include the following.

- Batteries are installed at each bus at the substation.
- The batteries will restore power in case of loss of transmission supply or substation transformer failure; bus- and feeder-level outages are unaffected.
- Three sizes are evaluated: 2-hour, 4-hour, and “infinite.” These define the number of hours customers can be served by the battery. For example, under the two-hour-battery scenario, any outage less than two hours will be reduced to a momentary. Longer outages will be reduced by the duration of the battery.
- Based on historical data, the annual probability of a loss of supply event is 7.1%. Statistical analysis of the historical data suggests that this probability applies approximately evenly to all substations. Based on discussions among the project team, we have assumed that all loss of transmission events will have a duration of 248 minutes, which is the system average.
- Transformer failure probabilities and failure scenarios (i.e., durations) are based on the assumptions by the T&D team during development of the IPT.

Summary of results:

- The analysis gives the total life-cycle cost of ownership for major assets at each substation under each scenario. The difference from the base case (no battery) is the total benefit due to avoided risk and extended service life from a battery sized to carry the load for that length of time (i.e., 2, 4, or “infinite” hours).
- The benefits are shown in “per kWh” terms, to normalize for the load at each substation. Although the total benefit increases with larger batteries, the benefit per kWh drops because the incidence of longer durations outages that could take advantage of the capacity is less likely.
- If the batteries are used for other purposes, such as peak shaving, and are not fully charged, you will have to interpolate to estimate the actual benefit.

Detailed results are contained in the workbooks accompanying this report. The estimated kWh is the average load at the substation multiplied by the assumed battery duration (12 hours used for “infinite” battery).

The results are heavily stratified, with a few substations showing significant benefits. These are generally substations with a high percentage of commercial load, which has a higher assumed cost per lost kWh than residential or industrial load.

## Feeder option

Feeder batteries will be installed at multiple locations along the length of the feeder. Smart switches will also be installed, so that power can be restored to all customers except those in the same zone where the outage occurs. For example, if a tree falls into the line halfway down the feeder, the customers between the substation and the switch *upstream* from the fault and customers downstream of the switch *downstream* of the fault will be restored after a momentary outage. Customers in the same zone as the fault will face a sustained loss of supply. In case of a loss of supply at the substation, all customers will be restored.

Assumptions include the following.

- Sufficiently sized batteries are installed at two locations on each feeder (i.e., three zones), including the substation. Feeder load is assumed to be distributed evenly among the zone, and all necessary automation is assumed to be installed.
- The batteries will fully restore power in case of loss of transmission supply or substation transformer failure. Two thirds of customers will be restored after a momentary outage for any feeder-level event. Feeder-level events include trunk-asset failures and non-asset risk due to weather, vegetation, animals, etc. Non-asset risk on the taps is assumed to be unaffected.
- Three sizes are evaluated: 2-hour, 4-hour, and “infinite.” These define the number of hours customers can be served by the battery. For example, under the two-hour-battery scenario, any outage less than two hours will be reduced to a momentary. Longer outages will be reduced by the duration of the battery.
- Probabilities and failure scenarios (i.e., durations) for all asset failures and non-asset events are based on the assumptions developed by T&D during development of the IPT.

Summary of results:

- The analysis gives the total life-cycle cost of ownership for major assets at each substation under each scenario. The difference from the base case (no battery) is the total benefit due to avoided risk and extended service life from a battery sized to carry the load for that length of time (i.e., 2, 4, or “infinite” hours).
- The benefits are shown in “per kWh” terms, to normalize for the load at each feeder. This represents to the total average load on the feeder, so the total required battery capacity for the three-battery system.
- If the batteries are used for other purposes, such as peak shaving, and are not fully charged, you will have to interpolate to estimate the actual benefit.
- The per-kWh benefit is substantially higher for feeder-level batteries than for batteries at the substation. The reason is that the feeder batteries will restore power in the event of a non-asset risk event (e.g., weather, vegetation, animals) on the feeder; these events represent the majority of outage risk in the system.

Detailed results are contained in the workbooks accompanying this report. The estimated kWh is the average load on the feeder multiplied by the assumed battery duration (12 hours used for “infinite” battery).

As with substations, the results are stratified, with a few feeders showing significant benefits. These are generally feeders with a high percentage of commercial load, which has higher assumed cost per lost kWh than residential or industrial load.

## Customer option

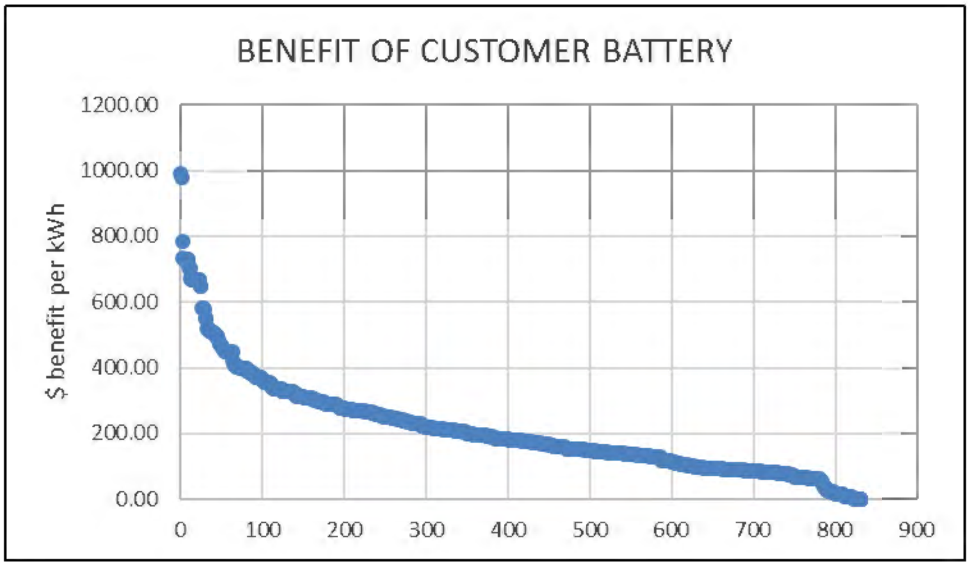
The final option considered is a customer-sited battery that will restore power after any outage in the transmission or distribution system. Assumptions include the following.

- Batteries are installed near the meter for commercial customers identified by PGE.
- Alternate service or backup generation are not available.
- The batteries will fully restore power for any outage to the customer.
- These customers are fed from the trunk, so there are no relevant risks from assets or non-asset events on the tap to consider.
- Only the "infinite" battery size is evaluated. This will generally be a 4-hour battery, although more capacity may be required for customers on rural or remote feeders where outage durations are longer.
- Probabilities and failure scenarios (i.e., durations) for all asset failures and non-asset events are based on the assumptions by T&D during development of the IPT.

Summary of results:

- The analysis gives the total life-cycle cost of ownership for major assets serving key customers. The difference from the base case (no battery) is the total benefit due to avoided risk and extended service life from a battery sized to carry the load for the full duration of any outage.
- The per-kWh benefit for this option is higher than either the substation or feeder option. There are two reasons for this: first, the battery restores power to all the customers it serves (generally one) after any outage. Second, the battery serves only commercial customers, who benefit most in economic terms from reduced outage duration.

Detailed results are contained in the workbooks accompanying this report. The estimated kWh is the average customer load multiplied by the average duration of outages at the feeder: 4 hours for urban, 5 hours for rural, 6 hours for remote. The graph below shows the estimated benefit from avoided risk each customer in per kWh to normalize for load.




## Interpretation of results

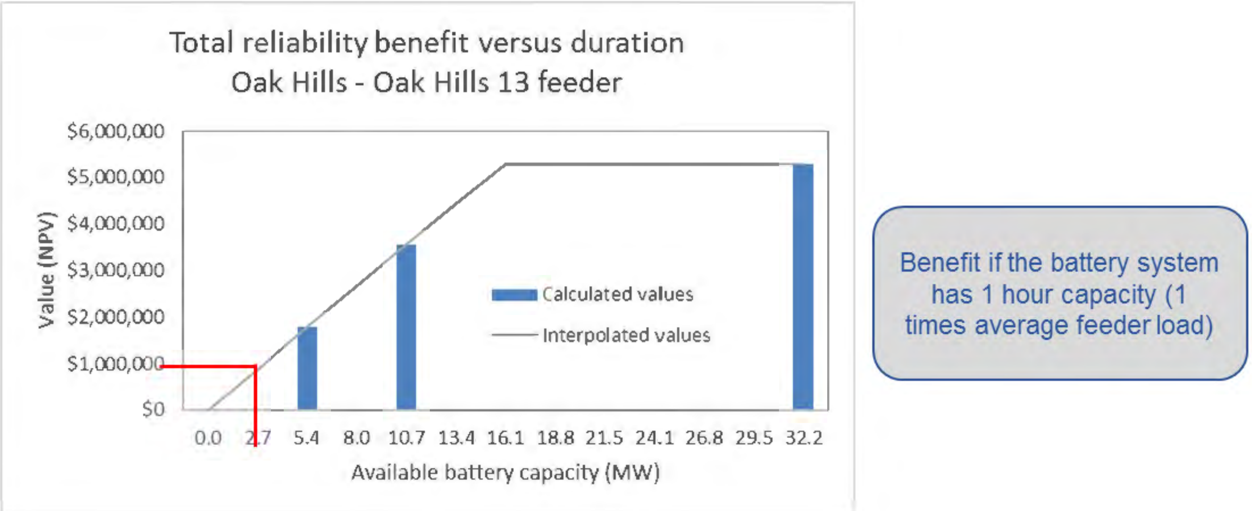
**Incorporation into comprehensive model**

These results are intended to be integrated into a more comprehensive cost/benefit model developed by PGE. Depending on how the batteries will be used, the available capacity may be less than the full capacity of the battery at any given time. In order to estimate the benefit based on actual expected capacity, we recommend you consider the following procedure.

- Assume a linear fit of the value as a function of capacity from zero (the base case) through the four-hour option.
- Extend this line until it reaches the benefit of the "infinite battery, which is the upper limit.
- Graph this curve against duration multiplied by the average load of the feeder or substation.
- Use this graph to pick off benefits for as many scenarios as necessary to populate the benefit/cost model.

An example is show below for the Oak Hills – Oak Hills 13 feeder, which has an average load of 2.7 MW.

**Estimating reliability benefit based on available capacity**




If the battery is expected to have eight hours' capacity 75% of the time ($5.3 million benefit) and one hour's capacity 25% of the time ($1 million benefit), then the expected benefit will be approximately 5.3 x 75% + 1.0 x 25% = $4.0 million.

**Additional recommendations**

Recommended additional steps include the following.

- Continued review and vetting of the results to ensure they conform with expectations.
- Before spending decisions are made, a pre-scoping task to ensure quality results is needed. This should include validation of assumptions, system configuration, and historical outage and other data.
- Additional runs for other scenarios or for sensitivity analysis may be needed. We recommend that you contact us for support. The model used is a specialized version of the IPT, developed specifically for this analysis; training on other SAM tools may not be sufficient for easy use of this one.

We appreciate the opportunity to work with your group on this assessment. Please do not hesitate to contact us with any questions.

# Appendix 3. Input Data for NVEST Model

**Protected information and subject to Protective Order No. 17-441.**

# Appendix 4. Storage Potential Evaluation

# Energy Storage Potential Evaluation

**Prepared for:**

**Portland General Electric**

**Oregon Public Utilities Commission Docket – UM 1751**

***Submitted by:***
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Reference No.: 193652
October 30, 2017

# TABLE OF CONTENTS



 

## DISCLAIMER

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# EXECUTIVE SUMMARY

This Energy Storage Potential Evaluation report has been prepared by Navigant for Portland General Electric (PGE) in compliance with the requirements set forth by Oregon House Bill 2193 (HB 2193) and Docket UM 1751 and addresses stakeholder feedback on the Draft Energy Storage Potential Evaluation.

This report contains the results of analysis of the expected benefits to PGE's system and to individual customers resulting from deploying energy storage systems at different locations on PGE's network (e.g., transmission, distribution, and customer level) for different grid applications (e.g., energy arbitrage, load following, demand charge reduction). Under the specific conditions evaluated across a variety of different use cases, the results indicate that system benefits (socialized benefits that are distributed across all customers) vary from roughly $200/kW to nearly $3,000/kW on a 10-yr net present value (NPV) basis, while individual customer benefits (those that accrue only to one specific customer) range from $0/kW to more than $2,400/kW. These benefits are considered in light of energy storage system (ESS) costs in PGE's Energy Storage Proposal, which considers proposed deployments of energy storage systems at specific locations on PGE's network.

Section 1 introduces the requirements set forth by HB 2193 and UM 1751 and identifies how the approach utilized used to evaluate the potential benefits of energy storage within PGE's territory complies with these requirements. This information provides context for understanding the chosen methodology, which is described in Section 2.

Section 2 provides an overview of the methodology used to evaluate storage potential, including the high-level approach, the models used, the use cases considered, and the approach for considering various technologies. This section provides context to understand and interpret the results provided in Section 3. Appendix A provides further details about the modeling tools.

The approach considers all applications explicitly specified by the Oregon Public Utility Commission (OPUC). Various models and inputs were used to assess the value of individual applications. The PGE Resource Optimization Model (ROM) generated values for energy and ancillary services benefits by co-optimizing the use of energy storage in combination with PGE's generation fleet. The PGE Integrated Planning Tool (IPT) generated values for using energy storage as backup power to extend the economic life of distribution assets – thus deferring investments in distribution infrastructure – and to reduce customer impacts resulting from network outages. A variety of PGE inputs and typical industry parameters were used to determine the value of all other applications. Multiple applications were stacked together for each use case within the Navigant Valuation of Energy Storage Tool (NVEST), which uses a framework that was initially developed for the US Department of Energy and has been peer-reviewed by industry stakeholders. NVEST was used to assess the value of five different use cases of energy storage:

(1) A 20 MW transmission-level ESS

(2) A 10 MW ESS at a distribution substation

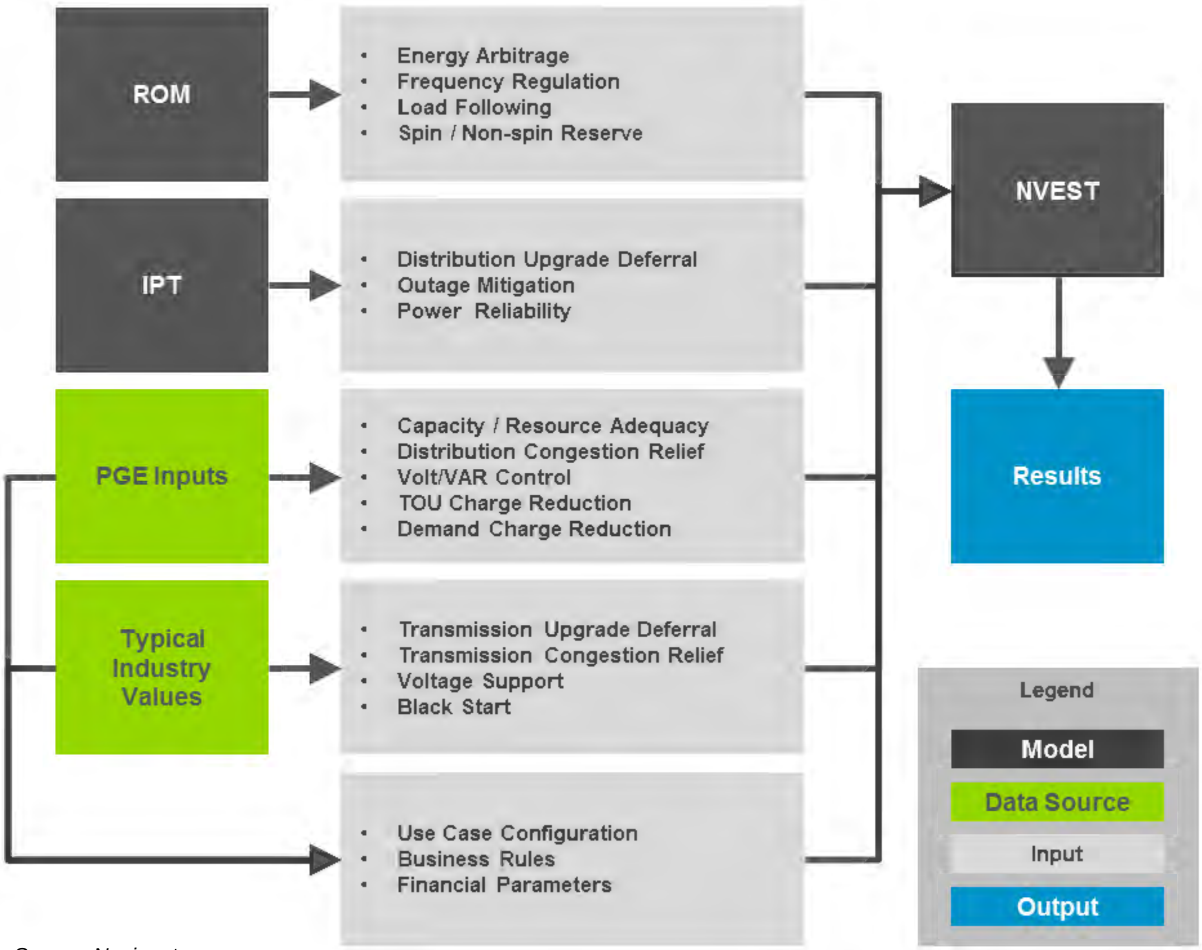
(3) A 2 MW ESS along a distribution feeder

(4) 1 MW of aggregated ESSs located at medium and large commercial and industrial (C&I) customer sites

(5) 1 MW of aggregated ESSs located at residential and small C&I customer sites

Figure 1-1 summarizes the modeling approach.[1]

**Figure 1-1. Modeling Approach**




*Source: Navigant*

Within a given use case, different scenarios were considered with different ESS durations (i.e., 2 hours and 4 hours), as well as different business rules for determining how the ESSs would be dispatched to serve multiple applications.

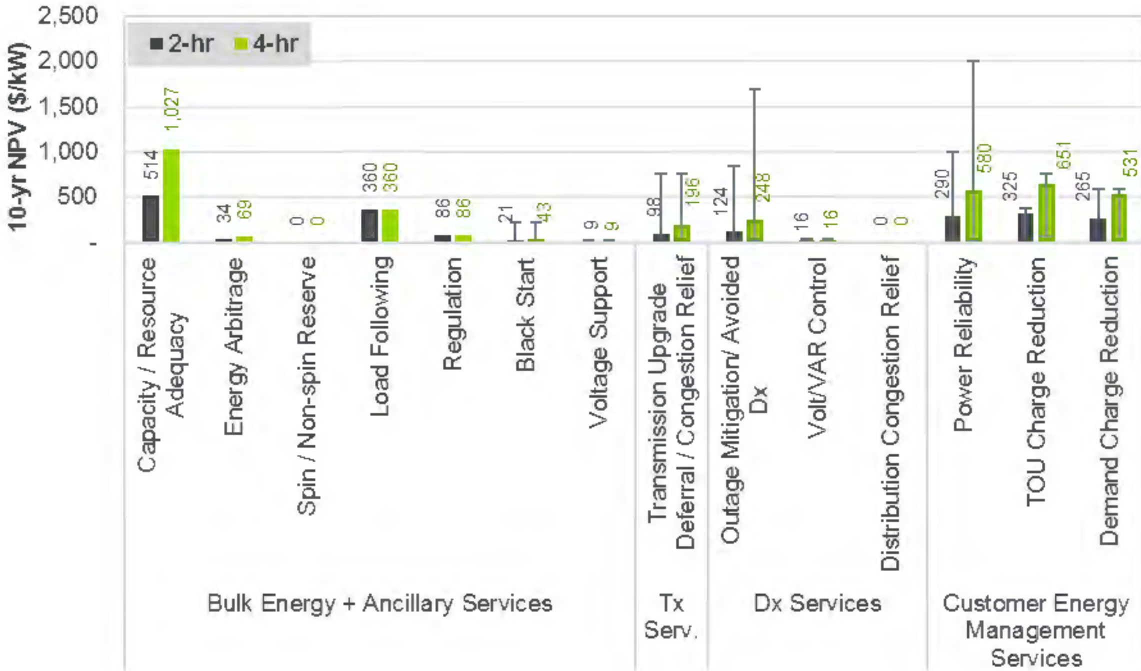
Section 3 provides the results of the analysis. First, benefits were evaluated for individual applications (Figure 1-2). These results helped to guide the use case configuration, as applications were selected for each use case based upon their benefit values and their compatibility with one another.

The analysis for each use case provides a summary of the benefits under each of the associated scenarios, including results under low, base, and high conditions. These conditions help to provide an indicative range of potential benefits due to variability associated with particular benefit streams (e.g., differences in the cost of deferred transmission capacity and the period over which investments may be deferred). The range of potential system benefits is similar between use cases to the range between different scenarios within the same use case (Figure 1-3). Accordingly, the duration of the ESS and the

[1] Appendix A provides additional details regarding the ROM, IPT, and NVEST models.

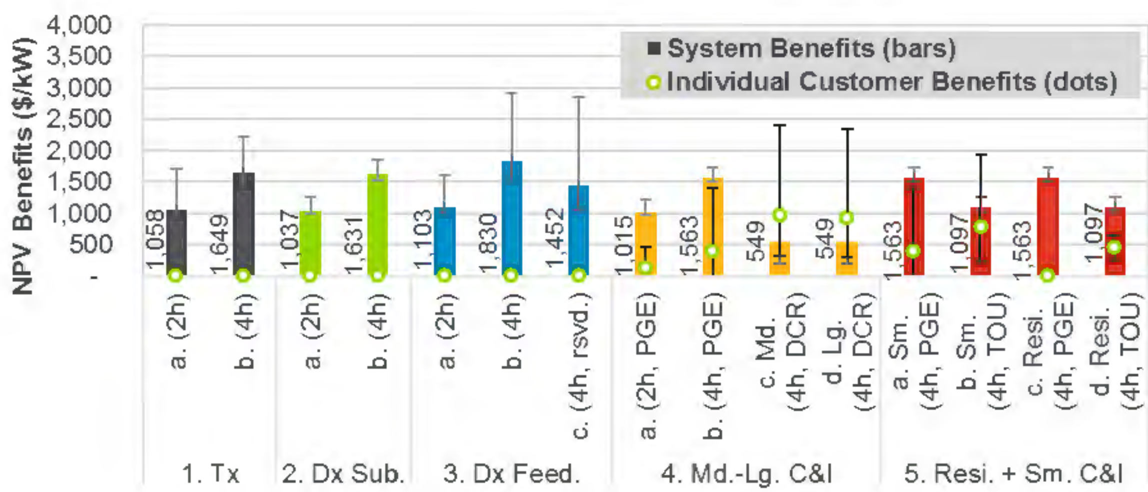
business rules for dispatch are just as important of considerations as the location of the ESS on PGE's network.

**Figure 1-2. 10-year Benefits of Each Application**[2,3]




*Source: Navigant*

**Figure 1-3. Summary of Results for all Use Cases, by Scenario**[4]




*Source: Navigant*

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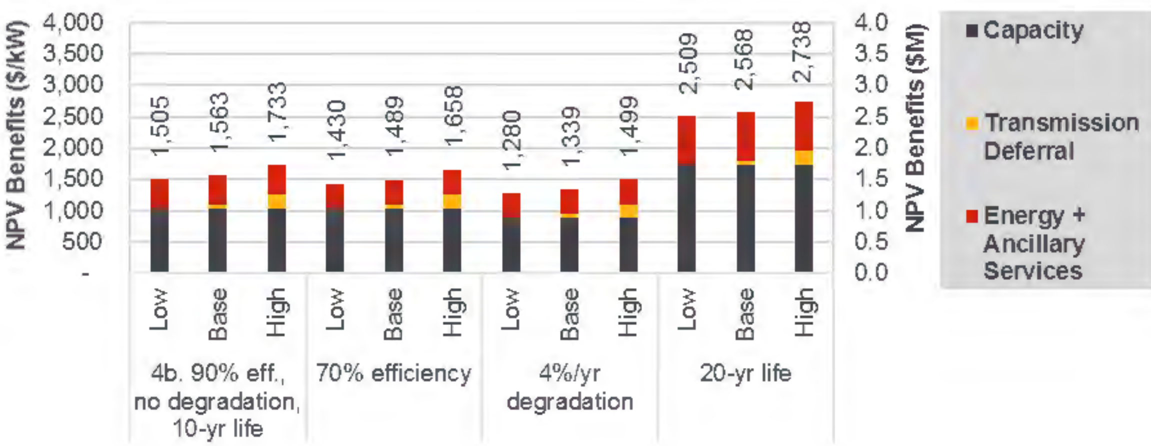
[2] Error bars are provided only for applications with significant uncertainty/variability in benefits.

[3] Tx = Transmission; Dx = Distribution

[4] 2h = 2 hours; rsvd. = reserved; DCR = demand charge reduction, TOU = time-of-use; Tx = transmission; Dx = distribution; Sub. = substation; Feed. = Feeder; Md. = medium; Lg. = large; Sm. = small; Resi. = residential

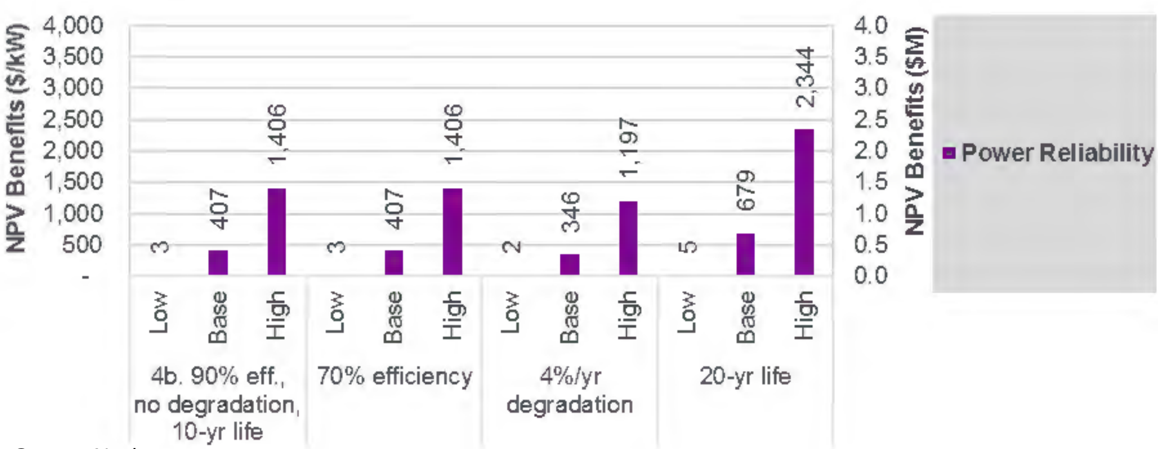
The analysis is intentionally technology-agnostic, as PGE intends to consider bids from a variety of different technologies when procuring ESSs. Key parameters associated with storage technologies (including efficiency, degradation rate, and lifetime) can vary significantly not only between different types of technologies (e.g., Li-ion vs. flow) but also within a family of technologies (e.g., Li-ion batteries from different suppliers). Thus, to evaluate the impact of technology, the analysis focused on the impact of specific parameters rather than assumed parameters associated with different technologies (Figure 1-4 and Figure 1-5). Round-trip efficiency was found to have a modest impact on the results. While round-trip efficiency can have a significant impact for value streams requiring frequent charge and discharge (e.g., energy arbitrage, load following, regulation), many of the benefit streams only require occasional dispatch (e.g., capacity, transmission deferral, outage mitigation). Degradation of the technology over time reduces the available power and energy capacity available to support different applications, which can reduce the net present of benefits by 15% or more. Extending the lifetime of the technology can have a profound impact on the results. A 20-year ESS was found to produce over 60% greater NPV benefits relative to a 10-year ESS. This result is largely tied to PGE's relatively low cost of capital.

**Figure 1-4. Impact of Technology Parameters on System Benefits**




*Source: Navigant*

**Figure 1-5. Impact of Technology Parameters on Individual Customer Benefits**




*Source: Navigant*

This analysis provides a foundation for PGE to consider specific deployments of energy storage at specific locations on its network. Appendix B provides analysis for specific locations, which are further considered and assessed within PGE's Energy Storage Proposal.

# 1. INTRODUCTION

Oregon House Bill 2193 (HB 2193) requires Portland General Electric Company (PGE) to submit a proposal to develop energy storage systems (ESSs) and to procure any authorized projects by January 1, 2020. The Oregon Public Utility Commission (OPUC) UM 1751 sets guidelines and requirements for the implementation of HB 2193, including a requirement to deliver a storage potential evaluation. This report presents Navigant's storage potential evaluation findings.

This section provides an overview of the requirements for the evaluation, which were set forth by HB 2193 (Section 1.1) and the resulting proceedings in Docket UM 1751 (Section 1.2). Section 1.3 provides further details regarding individual requirements for the potential evaluation and the compliance of this analysis with those requirements, including the specific applications of energy storage to be considered in this analysis. This information provides context for understanding the chosen methodology, which is described in Section 2.

Section 2 provides an overview of the methodology used to evaluate storage potential, including the high-level approach, the models used, the use cases considered, and the approach for considering various technologies. This section provides context to understand and interpret the results provided in Section 3. The results include benefits associated with individual applications, the benefits associated with using the ESS for multiple applications within a given use case, and the impact of technology parameters on those benefits.

## 1.1 HB 2193

HB 2193[5] directs large electric companies in Oregon, including PGE, to submit proposals for qualifying ESSs with the capacity to store at least 5 MWh of energy. The bill caps the total capacity of the ESSs procured by each electric company at one percent of the company's peak load in 2014, with an exception for a project of statewide significance. The electric companies adopted proposal guidelines by January 1, 2017 and must submit ESS proposals by January 1, 2018.

HB 2193 outlines several requirements for the energy storage proposals:

1. Each proposal must be accompanied by a comprehensive evaluation of the potential to store energy in the electric company's system.
2. Specific analysis must be provided in the proposal including technical specifications for the project, the estimated cost, and the benefits to the electric grid.
3. Each proposal must be evaluated to determine whether it: (a) is consistent with the guidelines; (b) reasonably balances the value for customers, utility operations, and the costs of construction, operation, and maintenance; and (c) is in the public interest.

The following report presents Navigant's storage potential evaluation to determine the potential economic value of energy storage systems at different locations on PGE's system. If the OPUC authorizes a storage project, the electric company has until January 1, 2020 to procure the qualifying ESS. HB 2193

[5] House Bill 2193, https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193.

specifies that the electric companies may recover in rates all costs prudently incurred in procuring qualifying ESSs under this program, including any above-market costs associated with procurement.

## 1.2 UM 1751

UM 1751[6] sets the guidelines and requirements for the implementation of HB 2193 by adopting the following:

1. Project guidelines to help the electric companies design and select projects to propose for development.
2. Proposal guidelines for the electric companies to submit proposals for authorization.
3. Storage evaluation requirements to help electric companies conduct the mandated system-wide storage potential evaluation.
4. Competitive bidding requirements for HB 2193 programs.

This report achieves compliance with the third item, requiring that electric companies file a system-wide storage evaluation with the OPUC. The Storage Potential Evaluation includes an analysis of operations and system data, an examination of how storage would complement the electric company's existing action plans, and identification of areas with opportunity to partner with customers for the use of energy storage at their locations. Evaluation requirements for this study are provided in Section 1.3.

## 1.3 Potential Evaluation Requirements

The March 21, 2017 public meeting staff report[7] outlines the approach recommended for system-wide storage evaluations. Table 1-1 compares the recommended approach against this report.

**Table 1-1. Comparison of Analysis Requirements and Approach**

| Requirement | Analysis Approach |
|---|---|
| Establish a consistent list of use cases or applications to be considered in the Evaluation | Evaluate use cases identified in Appendix A of UM 1751 Staff Recommendation document and included in Table 1-3. |
| Establish a consistent list of definitions of key terms | As defined in the US Department of Energy Glossary of Energy Storage Terms and *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA*. |
| Timeframe for analyses | 10 years for initial analysis. For the proposal, due on January 1, 2018, the analysis timeframe should be equal to the lifetime of the proposed ESS. |
| Potential valuation methodology or methodologies the electric companies may use for estimating storage potential in each use case or application | Incorporate the agreed-upon list of factors provided in Appendix A of the UM 1751 Staff Recommendation document and included in report Table 2-1. |

[6] UM 1751, Implementing Energy Storage Program Guidelines pursuant to House Bill 2193, http://apps.puc.state.or.us/orders/2016ords/16-504.pdf.

[7] Public Utility Commission of Oregon Staff Report, Implementing an Energy Storage Program – Staff Report Pursuant to Order No. 16-504, http://apps.puc.state.or.us/orders/2017ords/17-118.pdf.

| Requirement | Analysis Approach |
|---|---|
| Criteria for identifying the main opportunities for investment in storage | Cost-effectiveness, diversity, location, and utility learning. |
| Approach for identifying system locations with the greatest storage potential | First considered five generic locations: transmission, distribution substation, distribution feeder, residential/small C&I customers, and medium/large C&I customers. Specific locations are considered in Appendix B and in PGE' Energy Storage Proposal. |
| Level of detail required in the evaluation results and required supporting data. | Detailed in Table 1-2. |

*Source: Adapted by Navigant from Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017*

One of the recommended steps in the evaluation framework is to develop a potential valuation methodology to estimate storage potential in each use case or application. Table 1-2 provides the key elements as outlined in the staff public meeting on March 21, for consideration in the potential evaluation. These key elements provided guidance for the potential evaluation detailed in this report.

**Table 1-2. Key Elements for Potential Evaluation**

| Requirement | Analysis Approach |
|---|---|
| Electric companies should analyze each use case listed in Appendix A for each evaluated storage site. | The analysis considers use cases consisting of a set of applications performed by an ESS at a grid location (transmission, substation, feeder, or customer level). |
| Final Storage Potential Evaluations Should include detailed cost estimates for each proposed storage system. | This evaluation focuses on benefits, rather than costs. Cost estimates are included in PGE's Energy Storage Proposal. |
| When storage services can be defined based upon market data, a market valuation should be used for such identified services. | Where available, market pricing was used as a basis. Otherwise, avoided costs were used. |
| Final evaluations submitted by January 1, 2018 should provide detailed descriptions of the proposed sites. | Appendix B provides analysis for specific sites. Further details about these proposed sites are provided in PGE's Energy Storage Proposal. |
| "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. | The value of reliability, which is one aspect of resiliency, is incorporated within the IPT analysis of Outage Mitigation/ Avoided Distribution Investments and Power Reliability benefits. Resiliency is not evaluated here as a distinct value stream. |
| The components of each model, including the attributes in Staff Recommendation No. 6, should be identified and drafted in both the draft and final evaluations. | These attributes are addressed in Table 1-4. |
| A single base year may be used for modeling purposes. | Simulation of operational value was undertaken for a 2021 test year due to data availability through the 2016 IRP and the timing of PGE's incremental capacity need. |
| Staff must be able to validate the assumptions and methods used to evaluate the cost-effectiveness of each proposed ESS in the final proposals. | The methodology, including models, assumptions, and data sources, is described herein. |

*Source: Adapted by Navigant from Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017*

Table 1-3 provides a description of each of the applications set forth from the public meeting on March 21. Each of these applications has been considered in this analysis.

**Table 1-3. OPUC Storage Applications Evaluated**[8]

| Category | Application | Description |
|---|---|---|
| Bulk Energy | Capacity/ Resource Adequacy | The ESS is dispatched during peak demand periods to supply energy and shave peak 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 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 to maintain a desired voltage level. |
| | Black Start | Black start service is the ability of a generating unit to start without an outside electrical supply. Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. |
| Transmission Services | Transmission Congestion Relief | Use of an ESS to store energy when the transmission system is uncongested and provide relief during hours of high congestion. |
| | Transmission Upgrade Deferral | Use of an ESS to reduce loading on a specific portion of the transmission system, thus delaying the need to upgrade the transmission system to accommodate load growth or regulate voltage or avoiding the purchase of additional transmission rights from third-party transmission providers. |
| Distribution Services | Distribution Upgrade Deferral | Use of an ESS to reduce loading on a specific portion of the distribution system, thus delaying the need to upgrade the system to accommodate load growth or regulate voltage.[9] |
| | Volt/VAR Control | In electric power transmission and distribution, volt-ampere reactive (VAR) is a unit used to measure reactive power in an AC electric power system. VAR control manages the reactive power, usually attempting to get a power factor near unity. |
| | Outage Mitigation | Outage mitigation refers to the use of an ESS to reduce or eliminate the costs associated with power outages to utilities. |

[8] Application descriptions reflect the language in the OPUC Staff Report and do not necessarily reflect PGE's or Navigant's definitions of these grid services for PGE specifically. PGE operates its system consistent with all applicable NERC/WECC standards.

[9] This description was provided by the OPUC. In PGE's case, distribution upgrade deferral is driven more by risk analysis for reliability than by load growth or voltage regulation.

| Category | Application | Description |
|---|---|---|
| Customer Energy Management Services | Distribution Congestion Relief | Use of an ESS to store energy when the distribution system is uncongested and provide relief during hours of high congestion. |
| | Power Reliability | Power reliability refers to the use of an ESS to reduce or eliminate power outages to utility customers. |
| | TOU 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 to avoid peak demand charges. |

*Source: Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017*

Navigant used the modeling attributes outlined in the staff public meeting on March 21, to help guide energy storage potential modeling decisions. Energy storage has several unique characteristics, and staff views it as essential that any models used in the evaluations have the attributes listed in Table 1-4.

**Table 1-4. Modeling Attributes**

| Attribute | Analysis Approach |
|---|---|
| Capacity to evaluate sub-hourly benefits | Sub-hourly analysis is used in the Resource Optimization Model for co-optimization of energy and ancillary services applications (15-min intervals with reserves to manage fluctuations down to one minute). |
| Ability to evaluate location-specific benefits based on utility-specific values | ESSs sited at general transmission, substation, feeder, and customer locations are considered herein. Locational benefits from the IPT model are based on PGE-specific parameters. Specific sites are considered in Appendix B and PGE's Energy Storage Proposal. |
| Enables co-optimization between services | See discussion in Section 2.3. |
| Capacity to evaluate bulk energy, ancillary service, distribution-level, and transmission-level benefits | Benefits are assessed for each application in Section 3.1. |
| Ability to build ES conditions (e.g., power/energy capacity, charge/discharge rates, charging/discharging efficiencies, efficiency losses) into the optimization | The analysis described in Section 2.4 considers the impact of ESS sizing, while the analysis described in Section 2.5 considers the impact of efficiency, degradation, and lifetime. Optimized dispatch in ROM takes into account the listed ES conditions in every time step. |

*Source: Adapted by Navigant from Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017*

# 2. METHODOLOGY

This section summarizes Navigant's methodology for conducting the storage potential evaluation as required by OPUC UM 1751. The following sections provide detail on key aspects of the analysis, including:

- Storage potential evaluation approach
- Models and data sources used for the analysis
- Use cases evaluated
- Energy storage technologies considered

Section 2.1 describes the general approach used to determine the value of each individual application. Section 2.2 describes the models and data sources used in the analysis, along with other inputs and assumptions. Section 2.4 first describes the considerations used in determining how to construct the use cases, then describes the inputs and assumptions associated with each use case. Next, Section 2.5 describes the technology parameters associated with the use case analysis (results in Section 3.2), as well as the approach to analyzing the impact of technology on benefits (results in Section 3.3).

## 2.1 Storage Potential Approach

Navigant determined the typical benefits for each of the applications reflected in the Oregon framework established by the Commission in the March 21, 2017 stakeholder meeting. Our analysis includes values that reflect PGE-specific information to the extent possible. As described in Section 3.1, benefit values may vary within or between use cases, and not all benefits accrue to the same entity. Some applications provide system benefits to PGE (which are socialized across customers), while others provide individual customer benefits to single customers.

**Table 2-1. Storage Potential Valuation Methodology by Application**

| Category | Application | Methodology & Data Sources |
|---|---|---|
| Bulk Energy | Capacity/ Resource Adequacy | Calculated as the net cost of a new Generic Capacity resource, consistent with the 2016 IRP. This capacity value is applied to the maximum discharge power that can be sustained for 4 hours. |
| | Energy Arbitrage | Determined from an energy-only energy storage dispatch simulation with 15-min prices from the 2016 IRP Reference Case. This represents the value of Energy Arbitrage in the absence of ancillary service opportunities. |

| Category | Application | Methodology & Data Sources |
|---|---|---|
| Ancillary Services | Spin/ Non-spin Reserve | Spin and non-spin reserves are included in the ROM analysis. PGE did not isolate the specific value of spin and non-spin reserves, though their value is included in the total operational (i.e., bulk energy system) value incorporated throughout the potential evaluation. Non-spin reserves likely comprise a very small portion of the total value because PGE has adequate non-spin resources through its Dispatchable Standby Generation (DSG) program. Spinning reserves are also expected to comprise a relatively small share of the total operational value because these are often provided by hydro resources at zero or low opportunity cost and because the load following requirement may result in additional availability of spinning reserves at no incremental cost in some time periods. In the decomposition of the operational applications, the value of Spin and Non-Spin reserves are included in the Load Following category. Operation within the EIM and piloting spinning reserve applications on storage systems will provide PGE with additional visibility into the opportunity costs specifically associated with meeting its spinning reserve obligations. See Appendix A for more information. |
| | Load Following | Load following is included in the ROM analysis and was isolated by comparing ROM results for an energy storage device that provides Energy Arbitrage, Spin / Non-spin Reserve, and Load Following to the isolated Energy Arbitrage value. This value represents the marginal benefit of providing Load Following (and, to a lesser extent, Spin/Non-Spin) on top of the benefit of providing only Energy Arbitrage. Note that the value does not represent the value of performing Load Following alone (i.e., without also providing Energy Arbitrage), and the isolated value is dependent upon the order in which applications are added to the stack. Load Following is inclusive of forecast error mitigation and sub-hourly flexibility down to five minutes. See Appendix A for more information. |
| | Regulation | Regulation is included in the ROM analysis and was isolated by comparing ROM results for an energy storage device that provides all operational or bulk energy system applications to an energy storage device that provides all but Regulation. In other words, it represents the increase in the co-optimized value for Energy Arbitrage, Spin/ Non-spin Reserve, and Load Following with Regulation versus the co-optimized value without Regulation. Note that the value does not represent the value of performing Regulation alone, and the value is dependent upon the order in which applications are added to the stack. See Appendix A for more information. |
| | Voltage Support | Navigant based the value upon typical market values in wholesale for this service where voltage support markets exist.[10] |
| | Black Start | Navigant based the value upon typical market values for this service where Black Start markets exist.[11] |
| Transmission Services | Transmission Congestion Relief | At present, the most straightforward basis that PGE has for monetizing the value of Transmission Congestion Relief is through deferred/avoided investments in the transmission infrastructure required to provide the relief. Thus, the value of Transmission Upgrade Deferral may be used as a basis for the value of Transmission Congestion Relief. |

[10] ISO New England. Schedule 2 – VAR Annual Capacity Cost Rate Report (2017).

[11] New York Independent System Operator. Market Administration and Control Area Services Tariff (2017).

| Category | Application | Methodology & Data Sources |
|---|---|---|
| | Transmission Upgrade Deferral | This value is based upon representative capital costs of transmission ($125/kW) assuming a 1-year deferral period with 2% inflation, a fixed charge rate of 8%, and an ESS with 5% of the capacity (kW) of the transmission equipment being deferred.[12] |
| Distribution Services | Distribution Upgrade Deferral | PGE prioritizes investments in distribution system upgrades based on a probabilistic analysis of potential component failure. The value of Distribution Upgrade Deferral is encompassed within the values calculated using the Integrated Planning Tool (IPT), as described in Section 2.2.3. This value is incorporated into the combined Outage Mitigation / Avoided Distribution Investments application described in Section 2.42.4.1.<br>Opportunities for distribution investment deferrals on the PGE system are primarily driven by aging infrastructure for two reasons. Historically, PGE has constructed a distribution system to reliably serve all customers during peak loading conditions, even when a single asset is out of service (i.e., N-1 redundancy). Secondly, at present new load growth tends to be caused by significant commercial or industrial demand that is inherently clustered (e.g., a server farm), requiring significant new infrastructure. |
| | Volt/VAR Control | The value used is representative of a recent investment in Volt/VAR equipment by PGE and reflects an avoided cost in similar equipment used for conservation voltage reduction (CVR).[13, 14] |
| | Outage Mitigation | The value of Outage Mitigation is encompassed within the values calculated using the Integrated Planning Tool (IPT), as described in Section 2.2.3, which includes the cost associated with maintaining distribution assets for reliability.<br>The values were calculated using the Integrated Planning Tool (IPT), as described in Section 2.2.3, and are included within the Outage Mitigation / Avoided Distribution Investments application described in Section 2.4. |
| | Distribution Congestion Relief | As discussed above for Distribution Upgrade Deferral, PGE has sufficient distribution infrastructure to handle peak loading conditions. Thus, PGE does not have significant congestion issues on its distribution system. If PGE did face congestion issues, the most straightforward basis for monetizing the benefits would be via deferred/avoided investments. |
| Customer Energy Management Services | Power Reliability | Power Reliability benefits were calculated in a similar fashion to the Outage Mitigation benefits (see above), but these benefits are specifically for customer-sited systems and apply only to a single customer. The benefits are based upon customer value of service ranges, which were generated from surveys[15] and used as inputs in the IPT model, as described in Section 2.2.3.<br>For ESSs located at the substation or feeder level, benefits associated with customers' value of service are included within Outage Mitigation / Avoided Distribution Investments, as described in Section 2.2.3 and Section 2.4.1. |

[12] T&D Upgrade Deferral. Energy Storage Association. http://energystorage.org/energy-storage/technology-applications/td-upgrade-deferral.

[13] The value is based upon the average cost per installed kVAR for PGE's implementation of CVR in 2013 at two distribution power transformers (five feeders total) using capacitor banks.

[14] This approach is consistent with industry precedent on valuation of Volt/VAR Control. The *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA* (2015) values distribution voltage regulation based upon avoided distribution investments.

[15] Values adapted from *Pacific Gas & Electric Company's 2012 Value of Service Study* from Freeman & Sullivan and modified through the Interruption Cost Estimator from the US Department of Energy (www.icecalculator.com).

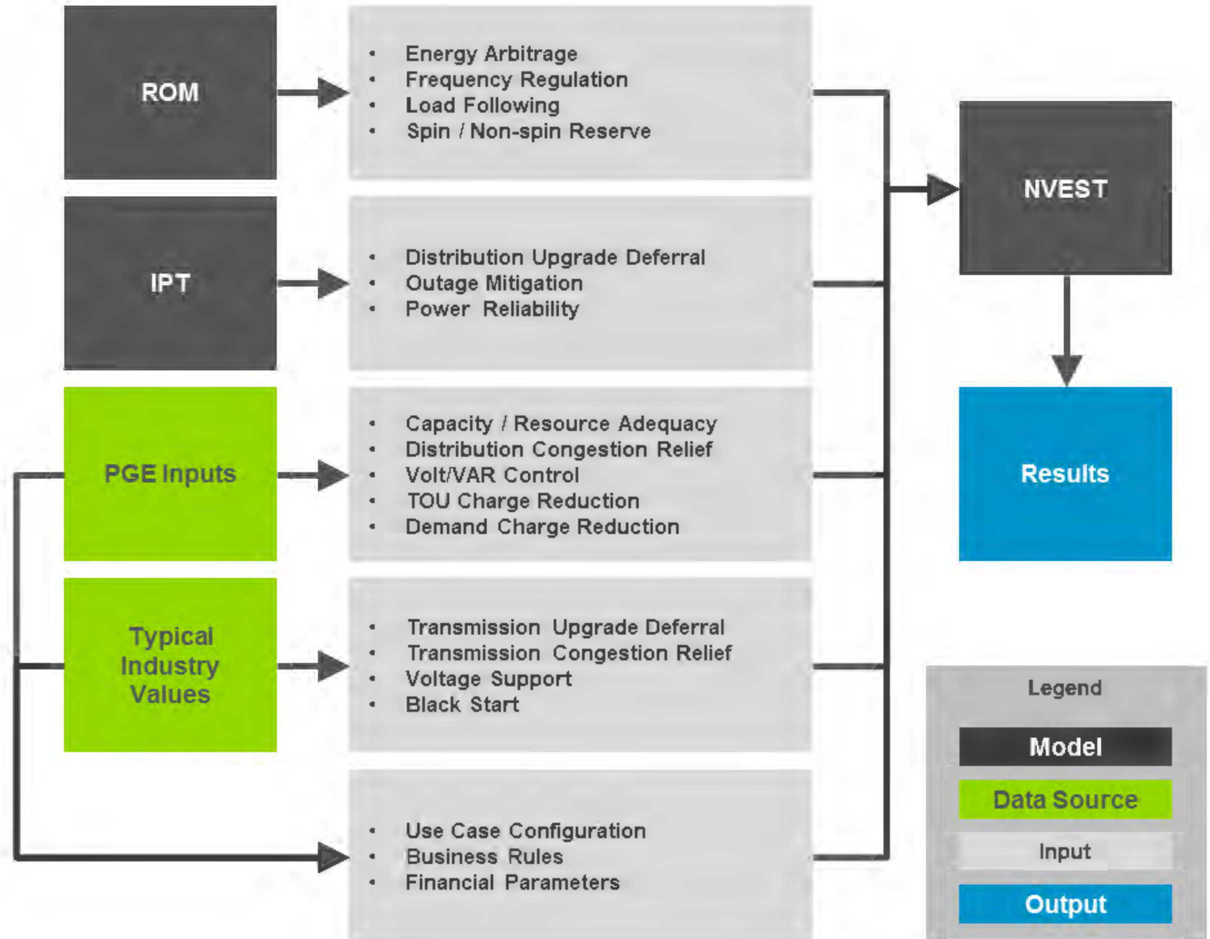
| Category | Application | Methodology & Data Sources |
|---|---|---|
| | TOU Charge Reduction | The range was calculated based upon the margin between peak and off-peak retail price of electricity for rate schedules 7, 32, 83, and 85.[16] The analysis assumes one cycle per weekday with 90% round-trip efficiency. |
| | Demand Charge Reduction | The range was calculated based upon monthly demand charges per kW for rate schedules 7, 32, 83, and 85. |

*Source: Navigant*

## 2.2 Models

Figure 2-1 summarizes the modeling approach utilized in this analysis. The Navigant Valuation of Energy Storage Tool (NVEST) was used to run each of the use cases described in Section 2.4.

**Figure 2-1. Modeling Approach**




*Source: Navigant*

[16] Rate schedules 7, 32, 83, and 85 are representative of residential, small C&I, medium C&I, and large C&I customers, respectively.

The inputs and assumptions for the NVEST model were determined from a variety of sources:

- ROM was used to determine the co-optimized value of energy arbitrage, regulation, Load Following, and Spin/Non-spin Reserve (see Section 2.2.2 below).
- IPT was used to determine the value of Outage Mitigation, Distribution Upgrade Deferral, and Power Reliability benefits as described in Section 2.2.3.
- PGE provided input values for Distribution Congestion Relief, Volt/VAR Control, TOU Charge Reduction, and Demand Charge Reduction (DCR) as indicated in Table 2-1.
- Typical industry values were obtained for Transmission Upgrade Deferral, Transmission Congestion Relief, Voltage Support, and Black Start (Table 2-1).
- The use case configuration (including the size, location, applications, etc.), business rules and assumptions for dispatching the ESS, and the financial parameters (e.g., escalation rates, cost of capital, lifetime) were developed in coordination with PGE and informed by representative industry values and assumptions (see Section 2.4).

### *2.2.1 Navigant Valuation of Energy Storage Tool*

NVEST is based upon a tool originally developed by Navigant in 2008 for the US Department of Energy (DOE) to evaluate the potential of energy storage in various grid applications across the United States. The comprehensive framework provides a methodology that maps applications to benefits with monetized values (Figure 2-2). This framework was later peer-reviewed, evaluated by many industry stakeholders, and adopted by the DOE for use by the recipients of the Smart Grid Demonstration program. A detailed description of the basic methodology is publicly available online.[17]

**Figure 2-2. NVEST High-level Framework**


*Source: Navigant*

Since 2008, Navigant has built upon this framework using the Excel-based NVEST model to execute our framework and valuation methodology, resulting in a net present value (NPV) analysis. This framework

[17] DOE Energy Storage Computational Tool Overview. US Department of Energy. August 2012 https://www.smartgrid.gov/document/doe_energy_storage_computational_tool_overview.html.

has been used to support regulatory filings by other utilities, including five utilities in California for compliance with the requirements of AB2514.[18]

Appendix A provides greater detail regarding the NVEST model and the associated methodology and assumptions for the analysis described in this report.

### *2.2.2 Resource Optimization Model*

ROM is a multi-stage production simulation model of PGE's resource portfolio. PGE described ROM and its application to energy storage resource evaluation in Chapter 8 of PGE's 2016 Integrated Resource Plan (IRP).[19] ROM was originally designed to quantify operational challenges and costs associated with renewables integration. Because of this history, ROM already incorporated the key features required for quantifying the operational value of energy storage resources: optimal unit commitment and dispatch of the PGE resource fleet over multiple time horizons, impacts of forecast errors (e.g., day-ahead to real-time), ancillary service requirements, and sub-hourly dispatch.

ROM simulations allow for the estimation of the operational value of energy storage resources that are operated in a co-optimized, coordinated manner within PGE's resource fleet. Operational value streams include: Energy Arbitrage, Load Following, Regulation, and Spin/ Non-spinning Reserves. ROM does not address Capacity value, values for other services at the transmission, distribution, and customer levels, or the interactions between operational and non-operational value streams.

For the Energy Storage Potential Evaluation, PGE updated energy price assumptions and evaluated three configurations, including: 50-MW 2-hour, 4-hour, and 6-hour ESSs, each with 90% round-trip efficiency. For each of these configurations, a ROM simulation yielded the operational cost of meeting loads and ancillary service requirements across a test year (2021) with and without the ESS. The operational value of the ESS is calculated as the cost difference between these two simulations. This approach optimizes across the energy and ancillary service value streams in order to provide a single number that represents their combined value. Additional information about the ROM modeling approach and the simulations conducted to support the Energy Storage Potential Evaluation can be found in Appendix A.

### *2.2.3 Integrated Planning Tool*

IPT provides a life-cycle analysis of the Outage Mitigation / Distribution Upgrade Deferral (via extended life of PGE assets and reduced impact of outages), and Power Reliability benefits (via avoided outage costs to individual customers) associated with ESSs located at the substation, feeder, and customer level. The tool was developed by the Strategic Asset Management group (SAM) at PGE and BIS Consulting. The analysis was executed by representatives from T&D Planning, SAM, and BIS Consulting.

IPT and other life-cycle cost tools quantify customer and company risks due to service failures, including the cost of future asset replacements, and the economic costs incurred by customers due to a loss of power. The cost of outages to customers is calculated based on study and survey data of the value of

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[18] AB 2514 Energy Storage System Procurement Targets from Publicly Owned Utilities. California Energy Commission. http://www.energy.ca.gov/assessments/ab2514_energy_storage.html (Azusa Light and Water, City of Banning, City of Pasadena, Riverside Public Utilities, and City of Vernon).

[19] Additional information about the development of ROM can be found in Section 7.2.1.1 in PGE's 2016 IRP.

 

reliable electrical service to customers; these same values are used by SAM in all of its risk analyses. The inputs estimate an expected impact cost to customers for each customer class evaluated due to a loss of power. In other words, all residential customers are assumed to have the same outage impact cost, per kilowatt-hour, as are all commercial customers and all industrial customers. System data was used to determine the average annual load, by customer class, for each grid location analyzed. The system disturbance database and the outage management system were then used to evaluate outage frequency at different grid locations. The benefit of battery installation was calculated as the avoided risk cost to customers and PGE—primarily due to outage avoidance or duration reduction—due to the battery installation.

All substations and feeders were evaluated to assess distribution system benefits. For analysis of individual commercial and industrial (C&I) customers, a sample of customers were selected from grid locations expected to have relatively high value. Thus, the base values provided for C&I customer-sited ESSs are greater than system-wide averages.

The results are expressed in NPV, assuming replenishment/replacement of batteries to maintain constant capacity over time in perpetuity. To evaluate ESSs with a finite life, the 10-year NPV was assumed to be 70% of the infinite-life value based upon the discount rate and other assumptions used in the analysis.[20] These values vary significantly depending on the location of the ESS, and different ranges of values were calculated at the substation level and feeder level.

Because PGE uses outage risk to prioritize distribution investments through the IPT, the IPT can be used to estimate system benefits associated with Outage Mitigation, Distribution Upgrade Deferral, and individual customer benefits associated with improved Power Reliability for a customer-sited ESS. These different benefit streams are described below in Section 2.2.3.1 and 2.2.3.2 respectively.

#### *2.2.3.1 System Benefits: Outage Mitigation/ Avoided Distribution Investments*

The IPT analysis considers the value of Distribution Upgrade Deferral due to the extension of the economic life of distribution assets. This extension is a result of the ESS reducing the economic impact of outages on customers. Thus, the IPT analysis provides values that address both the Outage Mitigation and Distribution Upgrade Deferral applications, and this specific benefit stream is hereon referred to as Outage Mitigation/ Avoided Distribution Investments or Outage Mitigation/ Avoided Dx.

#### *2.2.3.2 Individual Customer Benefits: Power Reliability*

The same methodology (probability of outage times cost to affected customers) is used in this evaluation to approximate the Power Reliability benefits for customers with customer-sited ESSs.[21] This evaluation uses average customer outage costs – based on survey data – in order to assign a value to Power Reliability benefits at a general level. The actual cost of an outage for a specific customer will vary

[20] According to BIS Consulting, the 10-year value is approximately 70% of the infinite-life value.

[21] While customer-sited ESSs may be located behind or in front of the meter, this analysis assumes that customer-sited systems are located behind the meter in order to simplify the differentiation between system benefits and individual customer benefits. For these specific scenarios, Power Reliability and Outage Mitigation/ Avoided Distribution Investment benefits are mutually exclusive due to the metering configuration. However, real installations may provide opportunities to operate ESSs in a way to blend Power Reliability and Outage Mitigation/ Avoided Distribution Investment benefits. Such opportunities should be evaluated on an installation-specific basis.

 

significantly from aggregate average outage costs derived from survey data. The only way to know the actual cost of an outage to a specific customer is to ask the customer or to offer increased reliability at a given price and to see if that customer is willing to purchase it. The Power Reliability values used in this report should be taken as one approach to estimating a customer benefit that varies widely from one customer to another; these values should not be assumed to equate to the actual value of Power Reliability to any specific customer.

## 2.3 Approach to Optimization

This methodology employed in this analysis considers optimization in a variety of ways. First, formal co-optimization of applications is performed through modeling sub-hourly dispatch (see Section 2.2.2 and Appendix A.2). In addition, the use case design considers optimal combinations of applications given the value and operating characteristics of each application and the trade-offs between different applications (see Section 2.4.1). Further, multiple scenarios are assessed within each use case (see Section 2.4.2 through Section 2.4.6) to support determination of the optimal system duration and business rules for system dispatch. This approach was tailored to for PGE to provide accurate, insightful results that most effectively leverage PGE's available information and resources in a cost-effective manner within the time constraints required for this analysis.

As detailed in Section 2.2.2 and Appendix A.2, ROM co-optimized the collective value of performing Energy Arbitrage, Regulation, Load Following, and Spin/Non-spin Reserves. Given that PGE operates a portfolio of generation resources outside an organized electricity market, a production cost model must be used to assess these applications rather than a price-taker model.[22] PGE has used this model previously in its 2016 Integrated Resource Plan and has received industry recognition as an effective approach for identifying the benefits of introducing energy storage into a utility's total resource portfolio.

Rather than attempt to perform formal co-optimization of all applications simultaneously, PGE chose to utilize NVEST, which provides a flexible framework customized for PGE to incorporate inputs from a multiple models and other resources to assess the value of a variety of different use cases and scenarios. This approach was ideal and avoided unnecessary costs associated with the analysis for the following reasons:

- While some tools exist to provide formal sub-hourly co-optimization of more applications than those considered within ROM, these models may not be appropriate as is for PGE for the purposes of this evaluation. First, they may not cover all the requires applications in Table 1-3. Additionally, the required inputs and the valuation methodology do not necessarily align with PGE's tools (including ROM and IPT), available data, and the appropriate approaches to valuation specific to PGE. Thus, significant customization would be required to develop a tool that is tailored for PGE and co-optimizes all applications on a sub-hourly basis.
- This approach readily accommodates the appropriate tools and methodologies for PGE. Many applications do not require sub-hourly co-optimization to determine value and, in fact, require separate analytical tools and approaches to determine value. For example, both Capacity and Transmission Upgrade Deferral values are determined separately from sub-hourly analysis. Their benefits are not dependent upon sub-hourly dispatch other than requiring that the ESS be available when called upon. This is addressed here by reducing the value of other applications

[22] See PGE's Energy Storage Proposal for additional discussion regarding the comparison between price-taker models and production cost models.

proportionately with the reduced availability of the system. While the reduction in other benefits may not be perfectly linear, the associated error is within the margin of error for the analysis. For Capacity and Transmission Upgrade Deferral, the uncertainty in the value of applications during these events is less than the uncertainty in the number of days per year that events are called. Thus, running a formal co-optimization for these applications would not provide significant value. As another example, the IPT model is used to determine the value of Outage Mitigation, Distribution Deferral, and Power Reliability. Benefits can be calculated with reasonable precision based upon the average state of charge of the system, which can be determined with a high degree of accuracy based ROM analysis and the business rules for system dispatch. Thus, integrating this tool into another model to provide sub-hourly co-optimization would require a significant amount of investment for limited additional value.

- Selecting a targeted set of high-value applications for a specific use case is a more practical approach from a modeling perspective and a more realistic approach for real-life ESS deployments. Not all applications need to be evaluated simultaneously. As discussed in Section 2.4.1, there are certain applications that clearly offer limited value relative to other applications. Low-value applications with high commitment (e.g., Black Start) would prevent the system from being available for use in other higher value applications. Low-value applications with high utilization (e.g., Volt/VAR for CVR) would conflict with the use of the ESS for other applications with significantly higher value. In the latter case, while some additional value may be theoretically possible, the introduction of such applications would introduce significantly increased complexity in the operation of the energy storage system (likely increasing both capital and operating costs) for a negligible increase in benefits.

In sum, the methodology employed herein provides sub-hourly co-optimization of certain benefit streams in ROM and utilizes the flexible NVEST framework to inform optimal design and selection of proposed projects in a manner that significantly reduces computational complexity without materially impacting the accuracy of the results.

## 2.4 Use Cases

Navigant's analysis evaluated the value of different applications in PGE's service area across five different use cases (specific combinations of grid location, energy storage power rating, and stacked applications). Within a given use case, different scenarios were considered with different durations (i.e., 2 hours and 4 hours), as well as different business rules for ESS dispatch. The subsections below describe the use case design and the assumptions associated with each use case.

### *2.4.1 Use Case Design*

To determine the appropriate set of stacked applications and business rules for each use case, Navigant considered four criteria:

- **Location:** Whether a storage application can be performed at all locations on the grid (transmission, distribution, and customer) or only at certain locations
- **Duration:** The minimum duration required for storage to provide application value (≤2 hours to 4 hours)
- **Utilization:** How frequently the ESS is dispatched to support the application, ranging from low to high

- **Commitment:** How important it is for the ESS to be available at specific times to support the application

For example, Capacity is an application that requires 4 hours of storage, has high commitment (must be available for Capacity when called upon), and low utilization (infrequently called upon for Capacity). By comparison, Regulation requires <1 hr of storage, has low commitment (may choose to provide Regulation or not during any time interval), and high utilization (may use ESS daily for Regulation).

Navigant used these four criteria to assess the stacking compatibility of different applications. Navigant did not evaluate the following applications as part of the stacked use case analysis, as these applications were considered to have low value. Furthermore, each application above has moderate-to-high commitment and/or utilization, which would detract from capturing greater benefits from other more valuable applications.

- **Voltage Support** – As is evident from Figure 3-1, the value of Voltage Support is significantly lower than other ancillary services. Further, while the value used is based upon typical market values,[23] PGE does not have a meaningful basis for monetizing this value, as the Reactive Demand Program with the Bonneville Power Administration was discontinued in 2014, and PGE no longer pays reactive demand charges. Further, PGE does not have voltage stability concerns and has a high reactive power margin in line with WECC/NERC standards.[24,25] Thus PGE does not have a need for additional Voltage Support services. In addition to its low value, it has a relatively high level of commitment. Voltage Support resources should be available when called upon to maintain reliability, which means that performing this application would prevent the ESS from being available to generate greater value from other applications.
- **Black Start** – As shown in Figure 3-1, the value of Black Start is relatively low compared to values for other ancillary services. Further, while the value used is based upon typical market values,[26] PGE does not have a meaningful basis for monetizing this value, as it does not have a need for additional Black Start services. To comply with the EOP-005 NERC Compliance Standard, PGE maintains an official Black Start plan which includes the existence of adequate resource to provide Black Start capability. The introduction of new energy storage resources (distributed or other) would not be considered as a replacement for PGE's existing Black Start resource and would require a reconfiguration of PGE's Black Start plan despite the lack of need to do so. In addition to not providing additional value, this application requires very high commitment, as the ESS must have sufficient energy available during a system outage to be able to re-energize the network per the Black Start plan. Thus, performing this application would prevent the ESS from being available to generate greater value from other applications.
- **Distribution Congestion** – PGE has sufficient distribution infrastructure to handle peak loading conditions. Thus, the value is effectively zero, as PGE does not have significant congestion issues on its distribution system and would not be avoiding/deferring any planned investments in distribution infrastructure.

[23] ISO New England. Schedule 2 – VAR Annual Capacity Cost Rate Report (2017).

[24] Western Electricity Coordinating Council. *Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power*. March 30, 2006

[25] PGE Transmission Planning conducts annual North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) studies, including real power margin assessment (PV analysis) and reactive power margin assessment (QV analysis). This analysis demonstrates that PGE's system is sufficient to handle worst-case scenarios.

[26] New York Independent System Operator. Market Administration and Control Area Services Tariff (2017).

- **Volt/VAR Control** – As shown in Figure 3-1, the value of Volt/VAR Control is quite low relative to values for other applications.[27] While PGE has implemented prior CVR projects with favorable benefit-to-cost ratios, the relatively low cost of alternative technologies makes it more economical to deploy those technologies for CVR and to utilize the ESSs evaluated herein for other applications. While PGE does not face significant voltage issues, use of an ESS for Volt/VAR for reliability purposes would mean that the ESS would need to be available when called upon and thus could not be utilized for higher value applications. Use of the ESS for CVR would require high utilization, which would conflict with the use of the ESS for bulk energy and ancillary services, which offer significantly greater benefits by comparison.

All other applications were incorporated within the use cases. Furthermore, multiple related applications were combined together, including:

- **Energy + Ancillary Services (E+AS) –** This aggregated application considers the co-optimized benefits of Energy Arbitrage, Regulation, Load Following, and Spin/Non-spin Reserves, which may be co-optimized together by PGE to optimize the dispatch of energy storage along with its other generation resources.
- **Transmission Deferral (Tx D) –** This application considers deferral of transmission investments that may be associated with congestion (Transmission Congestion Relief) or load growth (Transmission Upgrade Deferral).
- **Outage Mitigation/ Avoided Distribution Investments (OM/Dx) –** This aggregated application includes benefits associated with Distribution Upgrade Deferral and Outage Mitigation, along with reliability benefits associated with customers' value of service. Deferred investments in distribution infrastructure are achieved by extending the economic life of distribution assets as a result of mitigating the impact of network outages due to the provision of backup power.

Table 2-2 summarizes the compatibility of all applications that were considered for stacking within use cases.

[27] The value is based upon the average cost per installed kVAR for PGE's implementation of CVR in 2013 at two distribution power transformers (five feeders total) using capacitor banks.

**Table 2-2. Application Stacking Compatibility**

| Application | DCR | TOU | PR | OM/Dx | Tx D | E+AS | Cap |
|---|---|---|---|---|---|---|---|
| Capacity (**Cap**) | Partially Compatible | Compatible | Highly Compatible | Highly Compatible | Compatible | Compatible | |
| Energy + Ancillary Services (**E+AS**) | Limited Compatibility | Limited Compatibility | Partially Compatible | Partially Compatible | Compatible | | |
| Transmission Deferral (**Tx D**) | Partially Compatible | Compatible | Highly Compatible | Highly Compatible | | | |
| Outage Mitigation/ Avoided Distribution Investments (**OM/Dx**) | Partially Compatible | Partially Compatible | Incompatible | | | | |
| Power Reliability (**PR**) | Partially Compatible | Partially Compatible | | | | | |
| Time-of-Use Charge Reduction (**TOU**) | Compatible | | | | | | |
| Demand Charge Reduction (**DCR**) | | | | | | | |

- *Highly Compatible* = The benefits of both applications can be captured at or near their full potential value.
- *Compatible* = The applications can technically be performed with one another, but the full benefits may not be realized, because the target duration for the applications may be different.
- *Partially compatible* = Performing one application directly reduces the benefits of the other.
- *Limited compatibility* = Dispatch decisions would be challenging, because the ESS would be used frequently for both applications, one of which is for customers and the other for PGE.
- *Incompatible* = Applications cannot be performed together, as each application works only at specific grid locations that are mutually exclusive.

*Source: Navigant*

The following descriptions provide details to explain the compatibility map in Table 2-2:

- **Capacity (Cap)** is generally compatible with most applications. It is highly compatible with OM/Dx and PR since those applications have very low utilization and have greater benefits when ESS energy is held in reserve. For TOU and E+AS, the ESS may be used for these applications at all other times when not needed for Capacity. For Transmission Deferral (Tx D), both applications are infrequently called upon the dispatch and are unlikely to cause conflict, as both are needed during times of peak system demand. Thus, the ESS may provide Capacity while also supporting Tx D. However, Cap requires 4 hours of energy storage capacity, while TOU, E+AS, and Tx D may require a shorter duration. For DCR, there can be conflict, as a customer's peak load may not be coincident with system peak load. Thus, one application may need to be prioritized at the expense of the other.

- **Energy + Ancillary Services (E+AS)** has limitations in compatibility, because the ESS is dispatched on a regular basis throughout each day. E+AS is compatible with Cap and Tx D, because the ESS capacity can be held in reserve for these applications during a small number of days of the year, while still extracting most of the E+AS benefits. However, Cap and Tx D may require a longer ESS duration than is required for E+AS. OM/Dx and PR benefits scale with the average state of charge and can therefore be partially derived when performing E+AS. TOU and DCR are customer applications that require the ESS to be frequently dispatched or reserved, thus making it challenging to co-optimize the dispatch of TOU and/or DCR for the customer's benefit in coordination with E+AS for PGE's benefit.
- **Transmission Deferral (Tx D)** has duration, utilization, and commitment constraints similar to those for Cap and therefore has similar compatibility with other applications. It is likely that, similar to Cap, transmission deferral will also require ESSs of about 4 hours in duration, but it may be possible in certain cases for a shorter duration ESS to suffice.
- **Outage Mitigation/ Avoided Distribution Investments (OM/Dx)** is highly compatible with both Cap and Tx D since the energy capacity can be held in reserve for all applications. For DCR, TOU, and E+AS, the OM/Dx benefits scale with the average state of charge of the ESS, as the outages are typically random and do not vary significantly with duration on a $/kWh basis. OM/Dx is incompatible with PR, because OM/Dx represents a system benefit associated with avoided distribution investments, which are socialized across customers, while PR represents an individual customer benefit for customer-sited ESSs that may not be visible to the utility.
- **Power Reliability (PR)** is operationally similar to OM/Dx and therefore has similar compatibility with other applications, and benefits scale with the average state of charge of the ESS. As indicated above, PR is incompatible with OM/Dx, because PR is only applicable for customer-sited ESSs, while OM/Dx is only applicable for distribution-sited ESSs.
- **Time-of-use Charge Reduction (TOU)** is similar to E+AS in that it is dispatched frequently, does not require a long-duration ESS, and can have other applications prioritized above it without significantly reducing benefits. Therefore, its compatibility with other applications is similar. The notable difference is with DCR, where it is easier for a customer to co-optimize TOU and DCR (relative to E+AS and DCR), especially if the customer's peak is during the TOU on-peak period.
- **Demand Charge Reduction (DCR)** is less compatible with stacking in comparison to most applications. For Cap and Tx D, there can be conflict if a customer's peak load is not coincident with system peak load. Thus, one application may need to be prioritized at the expense of the other. For OM/Dx and PR, the benefits scale with the average state of charge, which can be quite high for DCR, as the ESS does not need to be dispatched on most days. Compatibility with E+AS is limited, as it can be challenging to co-optimize the dispatch of DCR for the customer's benefit in coordination with E+AS for PGE's benefit.

Based on the ability to stack these applications, Navigant developed use cases covering the highest-value applications from transmission, distribution, and customer-sited perspectives. Table 2-3 below summarizes the five use cases evaluated in 15 different scenarios (labeled 1a through 5d), while the details and assumptions for each use case are provided in Section 2.4.2 through 2.4.6.

**Table 2-3. Use Cases Evaluated**

| Characteristic | Transmission | Distribution Substation | Distribution Feeder | Medium + Large C&I | Small C&I + Residential |
|---|---|---|---|---|---|
| **Power** | 20 MW | 10 MW | 2 MW | 1 MW (aggregated) | 1 MW (aggregated) |
| **Duration** | 2 hr, 4 hr | 2 hr, 4 hr | 2 hr, 4 hr | 2 hr, 4 hr | 4 hr |
| **Scenarios** | 1a. Tx (2h)<br>1b. Tx (4h) | 2a. Dx Sub. (2h)<br>2b. Dx Sub. (4h) | 3a. Dx Feed. (2h)<br>3b. Dx Feed. (4h)<br>3c. Dx Feed. (4h, rsvd.) | 4a. C&I (2h, PGE)<br>4b. C&I (4h, PGE)<br>4c. Med. C&I (4h, DCR)<br>4d. Lg. C&I (4h, DCR) | 5a. Sm. C&I (4h, PGE)<br>5b. Sm. C&I (4h, TOU)<br>5c. Resi. (4h, PGE)<br>5d. Resi. (4h, TOU) |
| **Application** | | | **Scenarios** | | |
| **Cap** | 1a, 1b | 2a, 2b | 3a, 3b, 3c | 4a, 4b, 4c, 4d | 5a, 5b, 5c, 5d |
| **E+AS** | 1a, 1b | 2a, 2b | 3a, 3b | 4a, 4b | 5a, 5c |
| **Tx D** | 1a, 1b | 2a, 2b | 3a, 3b, 3c | 4a, 4b, 4c, 4d | 5a, 5b, 5c, 5d |
| **OM/Dx** | | 2a, 2b | 3a, 3b, 3c | | |
| **PR** | | | | 4a, 4b, 4c, 4d | 5a, 5b, 5c, 5d |
| **TOU** | | | | | 5b, 5d |
| **DCR** | | | | 4c, 4d | |

*Source: Navigant*

The subsections below provide further details for each use case.

### *2.4.2 Transmission*

The transmission use case assumes a 20 MW ESS with a duration of 2 hours (Scenario 1a) and 4 hours (Scenario 1b). In the scenarios evaluated, Transmission Deferral and Capacity each required the ESS to be reserved for 10 days/year. Energy + Ancillary Services took priority for the remainder of the year. Outage Mitigation / Avoided Distribution Investments, Power Reliability, TOU Charge Reduction, and Demand Charge Reduction applications were not considered, as they require the ESS to be located downstream on the network. Table 2-4 summarizes the assumptions and scenarios for this use case.

**Table 2-4. Transmission Use Case Assumptions**

| Applications | Value | Business Rules |
|---|---|---|
| **Power** | 20 MW | (Assumption) |
| **Duration** | 1a: 2 hr<br>1b: 4 hr | (Assumption) |
| **Business Rules** | - | Energy + Ancillary Services |
| **Transmission Deferral** | $125-250/kW<br>*(2-4 hr, 0-2 yr, 5% capacity ratio)*[28] | Reserved 10 days/yr |
| **Capacity** | $120/kW-yr<br>*(4 hr basis)* | Reserved 10 days/yr |
| **Energy + Ancillary Services** | $60/kW-yr | Run when not reserved (345 days/yr) |
| **Outage Mitigation/ Avoided Distribution Investments** | - | - |
| **Power Reliability** | - | - |
| **TOU Charge Reduction** | - | - |
| **Demand Charge Reduction** | - | - |

*Source: Navigant*

### 2.4.3 Distribution Substation

The distribution substation use case assumed a 10 MW ESS with a duration of 2 hours (Scenario 2a) and 4 hours (Scenario 2b). In the scenarios evaluated, Transmission Deferral and Capacity each required the ESS to be reserved for 10 days/year. Energy + Ancillary Services took priority for the remainder of the year. Outage Mitigation/ Avoided Distribution Investments benefits were small, because the ESS is not targeted at specific circuits with low reliability and a high average value of service. The analysis assumed that Outage Mitigation/ Avoided Distribution Investments benefits scale with the average state of charge, as IPT results indicate that the benefits scale approximately linearly with duration. Power Reliability, TOU Charge Reduction, and Demand Charge Reduction applications were not considered, as they require the ESS to be located downstream on the network at a customer site.

For the 4-hour ESS (Scenario 2b), it was assumed that 50% of the energy capacity is used for Energy + Ancillary Services, while 50% of the energy capacity is reserved for Outage Mitigation/ Avoided Distribution Investments, as the ROM analysis indicates that the E+AS benefits do not significantly increase with duration, while the IPT analysis indicates that Outage Mitigation/ Avoided Distribution Investments benefits do scale with duration.

Table 2-5 summarizes the assumptions and scenarios for this use case.

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[28] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral.

**Table 2-5. Distribution Substation Use Case Assumptions**

| Applications | Value | Business Rules |
|---|---|---|
| **Power** | 10 MW | (Assumption) |
| **Duration** | 2a: 2 hr<br>2b: 4 hr | (Assumption) |
| **Business Rules** | - | Energy + Ancillary Services priority |
| **Tx Deferral** | $125-250/kW<br>*(2-4 hr, 0-2 yr, 5% capacity ratio, 30% adjustment)*[29] | Reserved 10 days/yr |
| **Capacity** | $120/kW-yr<br>*(4 hr basis)* | Reserved 10 days/yr |
| **Energy + Ancillary Services** | $60/kW-yr | Run when not reserved (345 days/yr) |
| **Outage Mitigation/ Avoided Distribution Investments** | $7-24-47/kWh | Available capacity used for outages[30] |
| **Power Reliability** | - | - |
| **TOU Charge Reduction** | - | - |
| **Demand Charge Reduction** | - | - |

*Source: Navigant*

### *2.4.4 Distribution Feeder*

The distribution feeder use case assumed a 2 MW ESS with a duration of 2 hours (Scenario 3a) and 4 hours (Scenarios 3b and 3c). The ESS was reserved for the benefit of Transmission Deferral and Capacity for 10 days/year for each application. For the 2-hour ESS in Scenario 3a, Energy + Ancillary Services took priority 345 days of the year, and the Outage Mitigation/ Avoided Distribution Investments benefits were assumed to scale with the average state of charge. For the 4-hour system in Scenario 3b, it was assumed that 50% of the energy capacity is used for Energy + Ancillary Services, while 50% of the energy capacity is reserved for Outage Mitigation/ Avoided Distribution Investments. In Scenario 3c, Outage Mitigation/ Avoided Distribution Investments took priority 345 days throughout the year with the ESS at 100% state of charge except for 20 days of the year when needed for Transmission Deferral and Capacity. Power Reliability, TOU Charge Reduction, and Demand Charge Reduction applications were not considered, as they require the ESS to be located downstream on the network at a customer site. Table 2-6 summarizes the assumptions and scenarios for this use case.

[29] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral. PGE analysis indicates that load reductions at the distribution level yield only ~30% impact along a specific transmission route (see Section 3.2.2).

[30] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. For a 4-hour ESS, half of the energy capacity is set aside, so the average state of charge is approximately 75%.

**Table 2-6. Distribution Feeder Use Case Assumptions**

| Applications | Value | Business Rules |
|---|---|---|
| **Power** | 2 MW | (Assumption) |
| **Duration** | 3a: 2 hr<br>3b/3c: 4 hr | (Assumption) |
| **Business Rules** | - | 3a/3b: Energy + AS priority<br>3c: Outage Mitigation/ Avoided Distribution Investments priority |
| **Tx Deferral** | $125-250/kW<br>*(2-4 hr, 0-2 yr, 5% capacity ratio, 30% adjustment)*[31] | Reserved 10 days/yr |
| **Capacity** | $120/kW-yr<br>*(4 hr basis)* | Reserved 10 days/yr |
| **Energy + Ancillary Services** | $60/kW-yr | 3a/3b: Run when not reserved (345 days/yr)<br>3c: Not used |
| **Outage Mitigation/ Avoided Distribution Investments** | $7-95-425/kWh | Available capacity used for outages[32] |
| **Power Reliability** | - | - |
| **TOU Charge Reduction** | - | - |
| **Demand Charge Reduction** | - | - |

*Source: Navigant*

### *2.4.5 Customer (Medium–Large C&I)*

The medium–large C&I customer use case assumed an ESS size of 1 MW with a duration of 2 hours (Scenario 4a) and 4 hours (Scenarios 4b, 4c, and 4d). In Scenarios 4c and 4d, Demand Charge Reduction is given priority over all other applications. These ESSs are assumed to be 4 hours, as a 4-hour system will offer greater flexibility than a 2-hour system to perform multiple applications, including Demand Charge Reduction, for a greater number of customers. Only a portion of the aggregated capacity is assumed to be committed as a firm resource for Capacity and Transmission Deferral. The Power Reliability benefits were assumed to scale with the average state of charge. For Scenarios 4a and 4b, the ESS is reserved for 10 days per year for each of Transmission Deferral and Capacity, while Energy + Ancillary Services took priority 345 days of the year, and the Power Reliability benefits were assumed to scale with the average state of charge. For 4-hour ESSs, Scenarios 4c and 4d utilized the entire energy capacity for Demand Charge Reduction, while Scenario 4b used half of the energy capacity for Energy + Ancillary Services and reserved the other half for Power Reliability. TOU Charge Reduction was not

[31] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral. PGE analysis indicates that load reductions at the distribution level yield only ~30% impact along a specific transmission route (see Section 3.2.2).

[32] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. In scenario 1, half of the energy capacity is set aside for the 4-hour ESS, so the average state of charge is approximately 75%.

considered, as the low margin between peak and off-peak rates for medium–large C&I customers does not offer as much value as other applications. Outage Mitigation/ Avoided Distribution Investments was not considered, as the application requires the ESS to be located upstream on the distribution network. Table 2-7 summarizes the assumptions and scenarios for this use case.

**Table 2-7. Medium / Large C&I Use Case Assumptions**

| Applications | Value | Business Rules |
|---|---|---|
| **Power** | 1 MW, aggregated | (Assumption) |
| **Duration** | 4a: 2 hr<br>4b/4c/4d: 4 hr | (Assumption) |
| **Business Rules** | - | 4c/4d: Demand Charge Reduction priority<br>4a/4b: Energy + Ancillary Services priority |
| **Tx Deferral** | $125-250/kW<br>*(2-4 hr, 0-2 yr, 5% capacity ratio, 30% adjustment)*[33] | 4c/4d: 20-50-80% firm resource[34]<br>4a/4b: Reserved 10 days/yr |
| **Capacity** | $120/kW-yr<br>*(4 hr basis)* | 4c/4d: 20-50-80% firm resource<br>4a/4b: Reserved 10 days/yr |
| **Energy + Ancillary Services** | $60/kW-yr | 4c/4d: Not used<br>4a/4b: Run when not reserved (345 days/yr) |
| **Outage Mitigation/ Avoided Distribution Investments** | - | - |
| **Power Reliability** | $1-145-500/kWh | Available capacity used for outages[35] |
| **TOU Charge Reduction** | - | - |
| **Demand Charge Reduction** | Schedules 83, 85<br>*(60-80-100% reduction)* | 4c/4d: Used as needed (~5%)<br>4a/4b: Not used |

*Source: Navigant*

### *2.4.6 Customer (Residential & Small C&I)*

The residential (Scenarios 5c and 5d) + small C&I (Scenarios 5a and 5b) use case assumed an aggregated group of ESSs with 1 MW total capacity and a duration of 4 hours. These ESSs are assumed to be 4 hours, as a 4-hour system will offer greater flexibility than a 2-hour system to perform multiple applications, including Demand Charge Reduction, for a greater number of customers. The ESS was

[33] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral. PGE analysis indicates that load reductions at the distribution level yield only ~30% impact along a specific transmission route (see Section 3.2.2).

[34] On an aggregated basis, it assumed that the aggregated ESSs used for DCR can provide Tx Deferral and Capacity, but that the firm resource that can be committed is only a fraction of the total capacity (low = 20%, base = 50%, high = 80%), as some portion of ESSs may be committed to DCR, particularly during system peak periods.

[35] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. In scenario 1, half of the energy capacity is set aside, so the average state of charge is approximately 75%.

reserved for the benefit of Transmission Deferral and Capacity for 10 days/year for each application. In Scenarios 5b and 5d, TOU Charge Reduction took priority 345 days of the year, and the Power Reliability benefits were assumed to scale with the average state of charge. In Scenarios 5a and 5c, the Energy + Ancillary Services took priority 345 days of the year, and the Power Reliability benefits were assumed to scale with the average state of charge. Scenarios 5b and 5d utilized the entire energy capacity for TOU Charge Reduction, while Scenarios 5a and 5c used half of the energy capacity for Energy + Ancillary Services and reserved the other half for Power Reliability. Demand Charge Reduction was not considered, because residential and small C&I customers do not currently have demand charges. Outage Mitigation / Avoided Distribution Investments was not considered, as the application requires the ESS to be located upstream on the distribution network. Table 2-8 summarizes the assumptions and scenarios for this use case.

**Table 2-8. Residential / Small C&I Use Case Assumptions**

| Applications | Value | Business Rules |
|---|---|---|
| **Power** | 1 MW, aggregated | (Assumption) |
| **Duration** | 4 hr | (Assumption) |
| **Scenarios** | - | 5b/5d: TOU priority<br>5a/5c: Energy + Ancillary Services priority |
| **Tx Deferral** | $125-250/kW<br>*(4 hr, 0-2 yr, 5% capacity ratio, 30% adjustment)*[36] | Reserved 10 days/yr |
| **Capacity** | $120/kW-yr<br>*(4 hr basis)* | Reserved 10 days/yr |
| **Energy + Ancillary Services** | $60/kW-yr | 5b/5d: Not Used<br>5a/5c: Run when not reserved (345 days/yr) |
| **Outage Mitigation/ Avoided Distribution Investments** | - | - |
| **Power Reliability** | Resi = $1/kwh<br>Sm C&I = $1-145-500/kWh | Available capacity used for outages[37] |
| **TOU Charge Reduction** | Schedules 7, 32<br>*(40-70-100% of max reduction)* | 5b/5d: Run on weekdays when not reserved<br>5a/5c: Not used |
| **Demand Charge Reduction** | - | - |

*Source: Navigant*

[36] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral. PGE analysis indicates that load reductions at the distribution level yield only ~30% impact along a specific transmission route (see Section 3.2.2).

[37] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. In scenario 1, half of the energy capacity is set aside, so the average state of charge is approximately 75%.

## 2.5 Energy Storage Technologies

The analytical methodology employed in this analysis has been designed to be technology-agnostic. Key technology parameters that would affect the net cost-benefit analysis of an actual deployment include the following:

- **Cost:** Cost not only varies significantly between technologies (e.g., Li-ion vs. flow), but also within a given technology, including multiple sub-chemistries, each with variations in pricing between vendors. The cost also depends on the size and duration of the ESS. Further, different technologies and vendors will achieve different levels of cost reduction between now and 2021. This analysis focuses on benefits. PGE considers representative costs in its Energy Storage Proposal, understanding that actual costs will not be available until PGE receives commercial bids for given ESSs.
- **Lifetime:** For financial evaluation purposes, the ESS life is typically considered equivalent to the warranty period. The actual warranty period not only varies between technologies, but also varies within a specific product, as different warranties can be structured with different associated costs. In this analysis, the lifetime is assumed to be 10 years, which is currently a common warranty period used for different energy storage technologies.
- **Degradation Rate:** The degradation rate impacts the level of achievable benefits over time and depends not only upon the technology, but also upon ESS-specific parameters. For example, degradation depends upon both cycle fade (which depends on the ESS-specific duty cycle) and calendar fade (which is relatively independent of cycling, but may depend on factors such as ambient temperature). Not only is there significant uncertainty in the degradation rate, there are a variety of different approaches to handling degradation, including oversizing the ESS initially to have the required energy capacity at end of life (which results in greater capital costs) or regularly replenishing/replacing capacity regularly to maintain a constant capacity (which results in greater operating costs). In this analysis, degradation is assumed to be negligible as a result of regular capacity replenishment, an increasingly common practice by ESS providers.
- **Efficiency:** The efficiency of the ESS does have an impact on both costs and benefits. In this analysis, the round-trip efficiency is assumed to be 90%, which is representative of various technologies including Li-ion batteries, advanced lead-acid batteries, and flywheels.

Thus, because of the significant variability and uncertainty associated with these parameters, PGE prefers to take a technology-agnostic approach to the analysis and evaluate all viable technologies at the time of procurement. While representative parameters are considered here and in PGE's Energy Storage Proposal, PGE will consider actual parameters associated with specific bids at the time of procurement, including other factors not described above (e.g., response time, footprint, etc.).

As indicated above, the baseline analysis in Section 3.1-3.2 considers benefits associated with a generic ESS with a 10-year life, constant capacity, and a 90% round-trip efficiency. In Section 3.3, the analysis evaluates the impact of lifetime, degradation, and efficiency. Furthermore, Table 2-9 provides typical parameters associated with common energy storage technologies.

**Table 2-9 Parameters of Common Grid Storage Technologies**

| Technology | Duration | Size | Efficiency | Lifetime[38] | Location |
|---|---|---|---|---|---|
| **Mechanical** | | | | | |
| PHES[39] | >6 hr | 100s MW | 75-85% | Decades | Tx |
| CAES[40] | >6 hr | 100s MW | 60-70% | Decades | Tx |
| Flywheel | <1 hr | > 100 kW | 80-90% | > 20,000 cycles | Dx - Tx |
| **Electrochemical** | | | | | |
| Li-ion | 15 min-4 hr | > 5 kW | 80-95% | 2,000 – 20,000 cycles | BTM – Tx |
| Flow | > 2 hr | > 5 kW | 60-75% | 2,000 – 20,000 cycles | BTM – Tx |
| Advanced Lead-Acid | 2-6 hr | > 5 kW | 80-90% | 1,000 – 4,000 cycles | BTM – Tx |
| Molten Salt[41] | 4-8 hr | > 50 kW | 75-85% | 2,000 – 5,000 cycles | Dx – Tx |

*Source: Multiple sources*[42]

Other potential energy storage technologies also exist, including the following:

- **Chemical:** Technologies such as hydrogen and syngas are not yet cost-competitive, have low efficiency, and are not as responsive as electrochemical technologies.
- **Thermal:** Two types of thermal storage that are commercially available today include ice storage and electric water heaters. Ice storage provides space conditioning typically to commercial buildings by making ice overnight when electricity prices are low and then using this ice to lower the building's HVAC load during the day, reducing energy and demand charges. Given the moderate climate and low demand charges in PGE's service area, this technology is not commercially viable here at present. Electric water heaters are the primary other version of thermal energy storage. PGE is actively pursuing the use of water heaters both for demand response and for broader grid integration activities.[43] Accordingly, water heaters are not being actively explored by PGE within UM 1751.
- **Other Electronic/Electrochemical:** A variety of different technologies are available that may not have been captured above. These are either not suitable for the target duration (e.g., ultracapacitors) or are not mature enough to warrant special consideration at this point. However, they may be considered at the point of procurement.

[38] Cycle lifetimes reflect equivalent full cycles in the case of duty cycles with partial depth-of-discharge (e.g., frequency regulation).

[39] Pumped hydroelectric energy storage

[40] Compressed air energy storage

[41] Includes sodium sulfur and sodium nickel halide

[42] Values are primarily obtained from the *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA* (2015). The ranges provided reflect typical values, but some exceptions may exist beyond these ranges.

[43] See PGE's 2017 Smart Grid Report, pp. 47-48, 55, 67. http://edocs.puc.state.or.us/efdocs/HAQ/um1657haq16327.pdf.

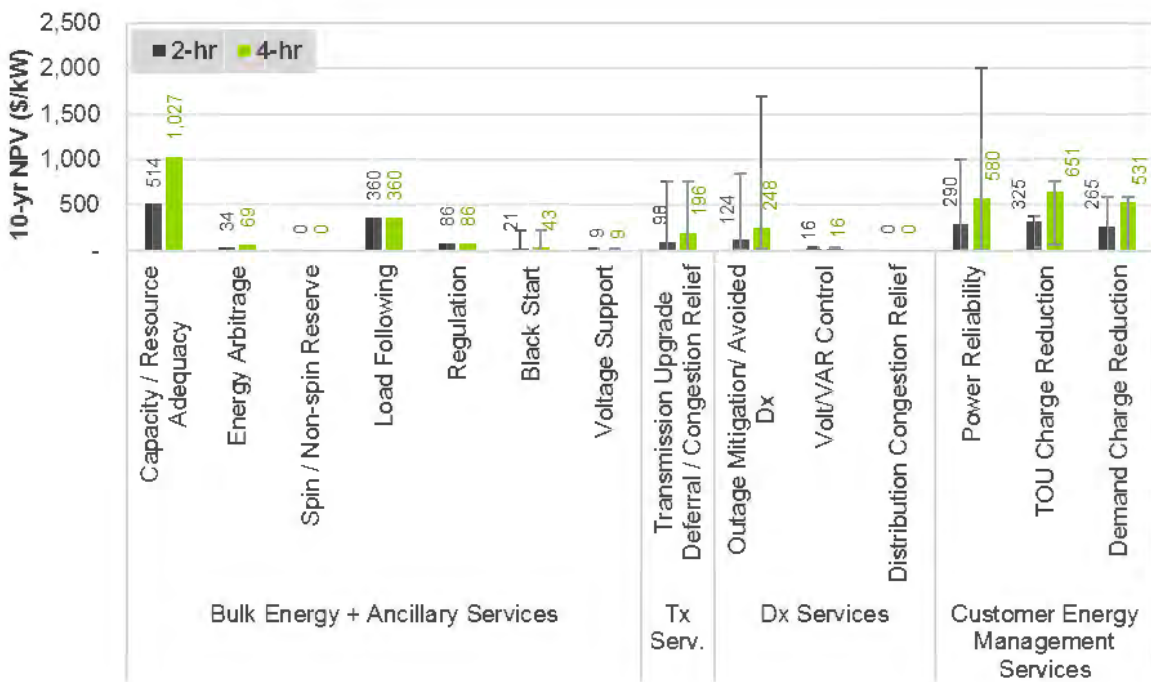
# 3. RESULTS

This section presents the results of the storage potential evaluation analysis. Section 3.1 evaluates the benefits associated with individual applications. Section 3.2 provides the results associated with the five different use cases, including the results of different scenarios with each use case and low, base, and high conditions associated with each scenario. Within a given use case, Navigant considered different scenarios with different durations (i.e., 2 hours and 4 hours), as well as different business rules for ESS dispatch. Section 3.3 evaluates how these results vary depending upon specific technology parameters.

## 3.1 Application Benefits

Figure 3-1 illustrates the 10-year NPV of the benefits associated with specific applications. The range and variability of each application is described below in Table 3-1.

**Figure 3-1. 10-year Benefits of Each Application[44,45]**




*Source: Navigant*

Note that ranges are provided only for benefits with particularly significant variability and/or uncertainty. Further, it is worth noting that the analysis assumes the benefits only vary over time with inflation. Differences in the variability of certain factors (e.g., commodity prices, renewables penetration, changing

[44] Error bars are provided only for applications with significant uncertainty/variability in benefits.

[45] Some applications have been combined here, as the same approach is used to monetize the benefits of each application. Transmission Upgrade Deferral and Transmission Congestion Relief have been combined, as both would be monetized through deferred investments in transmission infrastructure (see Table 2-1). Outage Mitigation and Distribution Upgrade Deferral have been combined, as the value – calculated from IPT analysis – represents the value of mitigating network outages, which is includes the extension of the economic life of distribution assets for reliability purposes (see Section 2.2.3.1).

rate structures, etc.) over time may have a significant impact on the value of these benefits. Further, the analysis assumes only a modest penetration of energy storage. At larger penetrations, certain benefit streams may be diminished. For example, the value of additional Capacity may diminish, or PGE may require longer durations of storage to meet its resource adequacy needs.

**Table 3-1. Benefit Ranges**

| Application | Base Value[46] | Low Value | High Value | Variation with Duration |
|---|---|---|---|---|
| Capacity / Resource Adequacy | $120/kW-yr<br>Assume 4-hour ESS required. | (same as base) | (same as base) | 4 hours of storage is required, so the benefit is half as much for a 2-hour ESS. |
| Energy Arbitrage | $4/kWh-yr | (same as base) | (same as base) | Arbitrage benefits roughly scale with energy, so a 4-hour ESS would provide about twice the benefits of a 2-hour ESS. The actual benefits may be slightly less than double, as the margin between discharge and charge decreases with duration. |
| Spin/ Non-spin Reserve | $0/kW-yr | n/a | n/a | n/a (see Table 2-1) |
| Load Following | $42/kW-yr | (same as base) | (same as base) | ROM results indicate that the value of an ESS performing Load Following does not vary significantly with duration. Instead, benefits scale with power, so the $/kW value is similar for a 4-hour ESS vs. a 2-hour ESS. |
| Regulation | $10/kW-yr | (same as base) | (same as base) | Same as Load Following. |
| Voltage Support | $1/kVAR-yr | $0<br>PGE does not have a need for the service. | $2/kVAR-yr<br>Assume 2x base value. | Benefits scale with power (kW), so the benefits do not increase with duration. |
| Black Start | $5/kW-yr<br>Assume 4 hours required. | $0<br>PGE does not have a need for the service. | $25/kW-yr<br>High end of representative range. Assume 2 hours required. | With 4 hours of storage required, the benefit scales with energy up to 4 hours.<br>For the high case, only 2 hours of storage is required, so the benefit is the same for the 4-hour and 2-hour ESSs. |
| Transmission Congestion Relief | n/a | n/a | n/a | Value is encompassed within Transmission Upgrade Deferral (see Table 2-1). |

[46] Values reflect 2016 dollar values. Units vary depending upon how each value scales. Values may scale with energy (kWh), real power (kW), or reactive power (kVAR). Further, some values represent annual benefits (e.g., $/kW-year), while others represent 10-year lifetime benefits (e.g., $/kW).

| Application | Base Value[46] | Low Value | High Value | Variation with Duration |
|---|---|---|---|---|
| Transmission Upgrade Deferral | $125/kW Tx capacity<br>Assume 1 year of deferral with 4 hours required. | $0<br>Assume grid location limits deferral value. | $250/kW Tx capacity<br>Assume 2 years of deferral with 2 hours required. | With 4 hours of storage required, the benefit scales with energy up to 4 hours.<br>For the high case, only 2 hours of storage is required, so the benefit is the same for the 4-hour and 2-hour ESSs. |
| Distribution Upgrade Deferral | n/a | n/a | n/a | Value is encompassed within Outage Mitigation/ Avoided Distribution Investments (see Table 2-1) |
| Volt/VAR Control | $16/kVAR | $8/kVAR<br>Assume cost is half of representative recent investment. | $32/kVAR<br>Assume cost is twice of representative recent investment. | Benefits scale with power (kW), so the benefits do not increase with duration. |
| Outage Mitigation/ Avoided Distribution Investments[47] | $58/kWh<br>Average of averages at substation and feeder levels | $7/kWh<br>Lowest value at substation level | $415/kWh<br>Highest value at feeder level | The IPT analysis demonstrates that benefits scale approximately linearly with duration, so the value of a 4-hour ESS is about twice the value of a 2-hour ESS. |
| Distribution Congestion Relief | $0 | n/a | n/a | n/a (see Table 2-1 and Section 2.4.1) |
| Power Reliability | $140/kWh<br>Average value at customer level | $1/kWh<br>Lowest value at customer level | $490/kWh<br>Highest value at customer level | The IPT analysis demonstrates that benefits scale approximately linearly with duration, so the value of a 4-hour ESS is about twice the value of a 2-hour ESS. |
| TOU Charge Reduction | $19/kWh-yr<br>Small C&I | $2/kWh-yr<br>Medium and Large C&I | $22/kWh-yr<br>Residential | Benefits scale linearly with duration up to 5 hours (duration of on-peak period), so the value of a 4-hour ESS is about twice the value of a 2-hour ESS. |
| Demand Charge Reduction | $62/kW-yr<br>Large C&I. Assume 4 hours required. | $0/kW-yr<br>Residential and Small C&I | $69/kW-yr<br>Medium C&I. Assume 2 hours required. | With 4 hours of storage required, the benefit scales with energy up to 4 hours.<br>For the high case, only 2 hours of storage is required, so the benefit is the same for the 4-hour and 2-hour ESSs. |

*Source: Navigant*

### 3.1.1 Transmission-Sited Energy Storage Systems

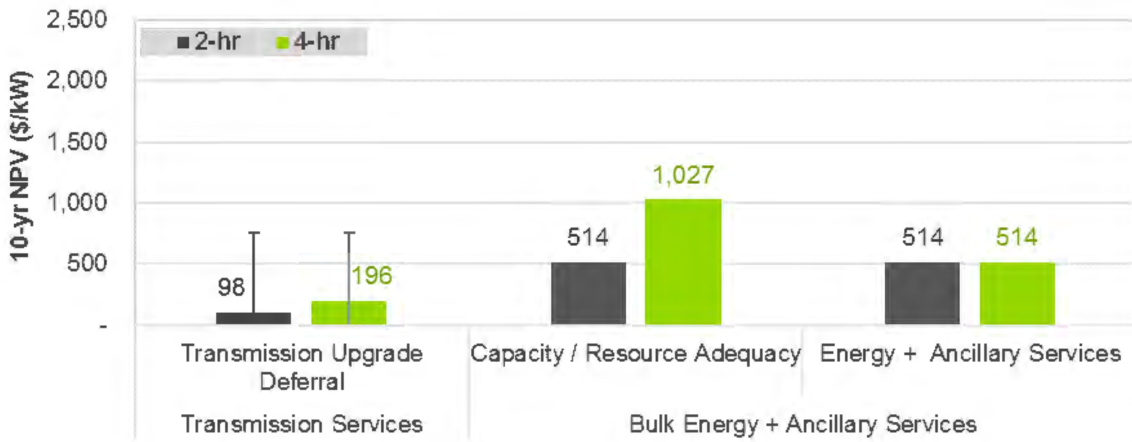
Based on the analysis above, Navigant selected Transmission Upgrade Deferral, Capacity, and Energy + Ancillary Services for inclusion in the use cases with transmission-sited ESSs. Navigant excluded Transmission Congestion Relief, Black Start, and Voltage Support due to their relatively low value and moderate-to-high level of commitment, which impedes the more valuable collection of applications within Energy + Ancillary Services. Figure 3-2 summarizes the benefits of each individual application. Note that

[47] Note that values of Outage Mitigation/ Avoided Distribution Investments have increased from the Draft Energy Storage Potential Evaluation due to a change in the IPT model to better account for the impacts of transmission-level outages.

these values reflect independent applications and do not consider reductions in total value due to stacking.

**Figure 3-2. Benefits of Selected Applications for Transmission-Sited ESSs**



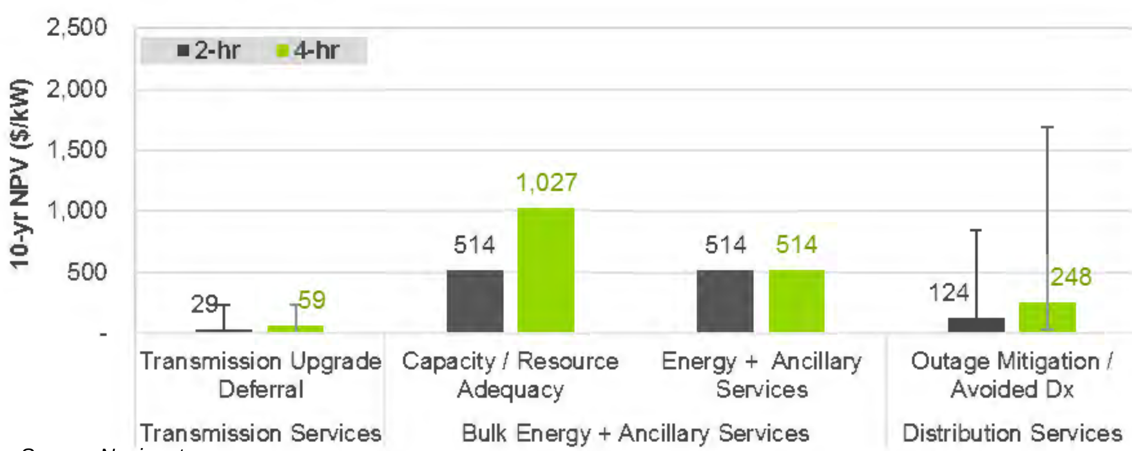

*Source: Navigant*

### *3.1.2 Distribution-Sited Energy Storage Systems*

The use cases for distribution-level ESSs consider all selected transmission applications, as well as Outage Mitigation/ Avoided Distribution Investments. Distribution Congestion Relief, Distribution Upgrade Deferral, and Volt/VAR were excluded due to their low value and moderate-to-high level of commitment, which impede the generation of greater benefit from the more valuable collection of applications within Energy + Ancillary Services. Figure 3-3 summarizes the benefits of each individual application. Note that these values are for independent applications and do not consider reductions in total value as a result of stacking.

These results do, however, consider differences in potential benefits at the distribution level. As described in Section 3.2.2, Transmission Upgrade Deferral benefits are lower than at the transmission level, and Outage Mitigation/ Avoided Distribution Investments benefits are lower than the Power Reliability benefits at the customer level.

**Figure 3-3. Benefits of Selected Applications for Distribution-Sited ESSs**

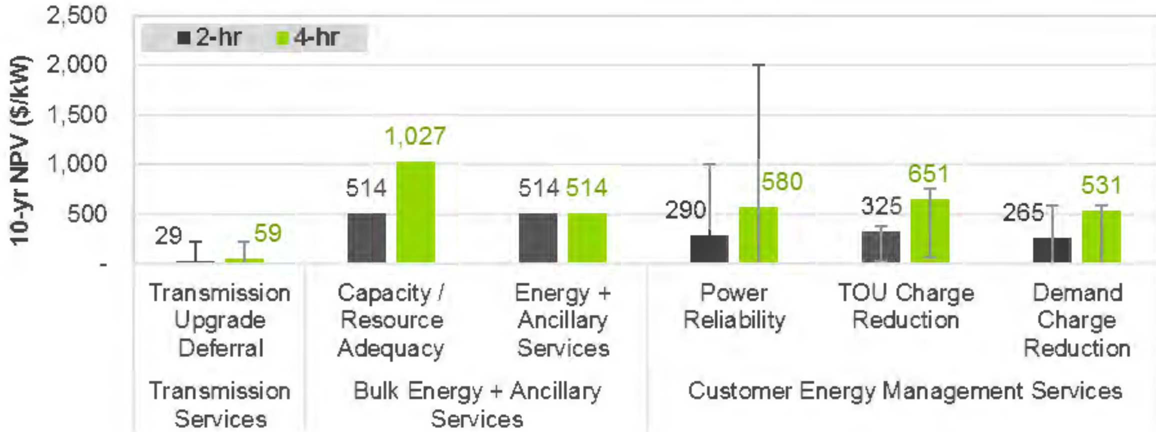



*Source: Navigant*

### *3.1.3 Customer-Sited Energy Storage Systems*

The use cases for customer-level ESSs consider all selected applications for the transmission- level and distribution-level use cases, as well as TOU Charge Reduction and Demand Charge Reduction (DCR). Figure 3-4 summarizes the benefits of each individual application. Note that these values are for independent applications and do not consider reductions in total value as a result of stacking. These do, however, consider differences in potential benefits at the customer level. As described in Section 3.2.2, Transmission Upgrade Deferral benefits are lower than at the transmission level, and Power Reliability benefits are higher than the Outage Mitigation/ Avoided Distribution Investments at the distribution level.

**Figure 3-4. Benefits of Selected Applications for Customer-Sited ESSs**




*Source: Navigant*

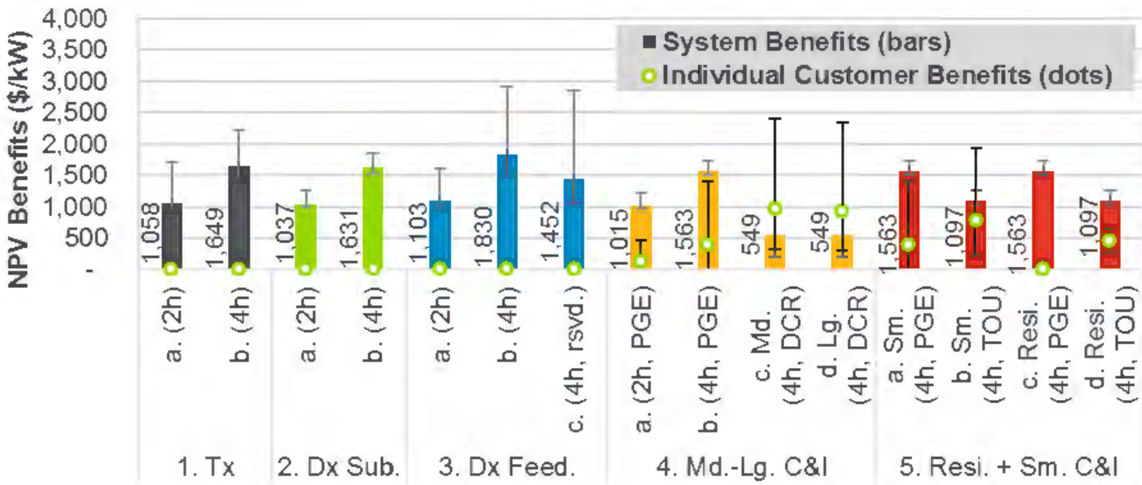
## 3.2 Optimized Use Cases

Figure 3-5 summarizes the range of benefits obtained for each of the use cases.[48] The results delineate between system benefits (all benefits except TOU and DCR) and individual customer benefits (bill savings from TOU and DCR). The details for each use case are discussed in greater detail in Section 3.2.1 through Section 3.2.5. The assumptions and inputs for each use case are described in Section 2.4. The error bars show the range of results between the low and high conditions. The inputs for the base, low, and high conditions are described for each use case in Section 2.4.2 through Section 2.4.6.

Figure 3-6 compares the system benefits of 4-hour vs. 2-hour ESSs at different grid locations. The ratio between system benefits of 4-hour ESSs and the benefits of 2-hour ESSs generally increases going from the transmission level down to the feeder level, which is primarily due to the increase in Outage Mitigation/ Avoided Distribution Investments benefits. There is then a drop-off in in the benefit ratio at the customer level, in part because the Power Reliability benefits are individual customer benefits, whereas Outage Mitigation/ Avoided Distribution Investments benefits are system benefits. For all examples in Figure 3-6, the 4-hour ESS provides greater benefits than a 2-hour ESS at ratio of approximately 1.3 or higher. The ratio is typically about 1.5 and exceeds 1.8 in certain cases. Whether a 2-hour or 4-hour ESS is preferable depends upon the ratio of costs between them, along with other practical considerations and limitations associated with specific projects.

[48] All NPV benefits were calculated in 2020 USD based on the weighted average cost of capital (6.204%), then converted to 2017 USD based upon assumed inflation (2%).

Figure 3-5. Summary of Results for all Use Cases




Source: Navigant

Figure 3-6. System Benefits of 4-hour vs. 2-hour ESSs

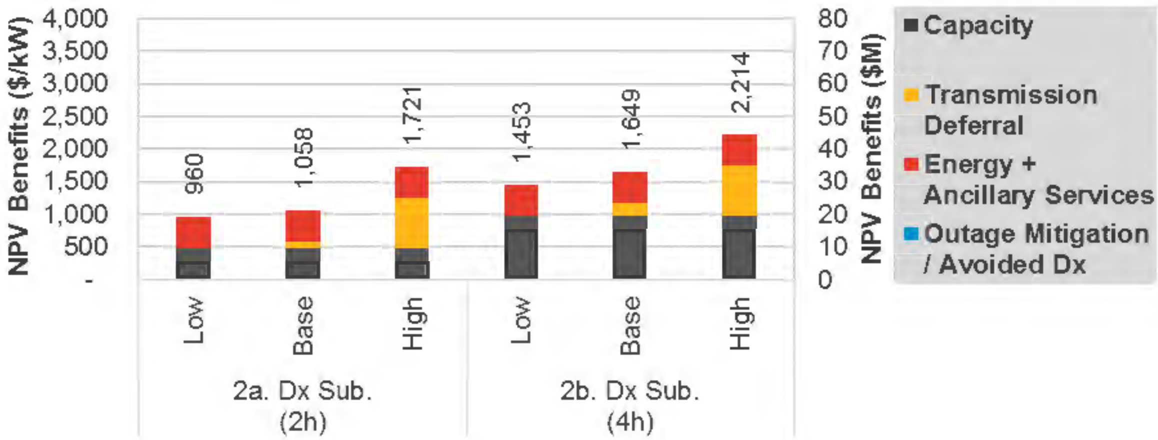

Source: Navigant

### 3.2.1 Case 1: 20 MW ESS on Transmission Line

Figure 3-7 illustrates the system benefits under each of the transmission-level scenarios analyzed. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits. These benefits serve as a benchmark for target ESS costs.

Two scenarios were evaluated, including one for a 2-hour ESS (1a) and one for a 4-hour ESS (1b). In each case, the ESSs support Capacity and Transmission Deferral for 10 days each per year, then provide Energy + Ancillary Services for the other 345 days. The inputs and assumptions for transmission-level ESSs are described in Table 2-3 and Section 2.4.2.

**Figure 3-7. System Benefits of 20 MW Transmission-sited ESSs**




*Source: Navigant*

The benefits increase going from a 2-hour to a 4-hour ESS primarily due to additional Capacity benefits, as 4 hours of storage are required, so only half of the benefit is realized for a 2-hour ESS. The Transmission Deferral benefits are also higher for the 4-hour ESS in the base case, as it assumed that 4 hours of storage are required. However, it is assumed that only a 2-hour ESS is required in the high case.

The key source of variability between the low, base, and high conditions is the Transmission Deferral benefit. The Capacity and E+AS benefits were assumed to be the same for all, as the confidence in the level of these benefits obtained from the ROM analysis is relatively high. However, for Transmission Deferral, the following factors may vary:

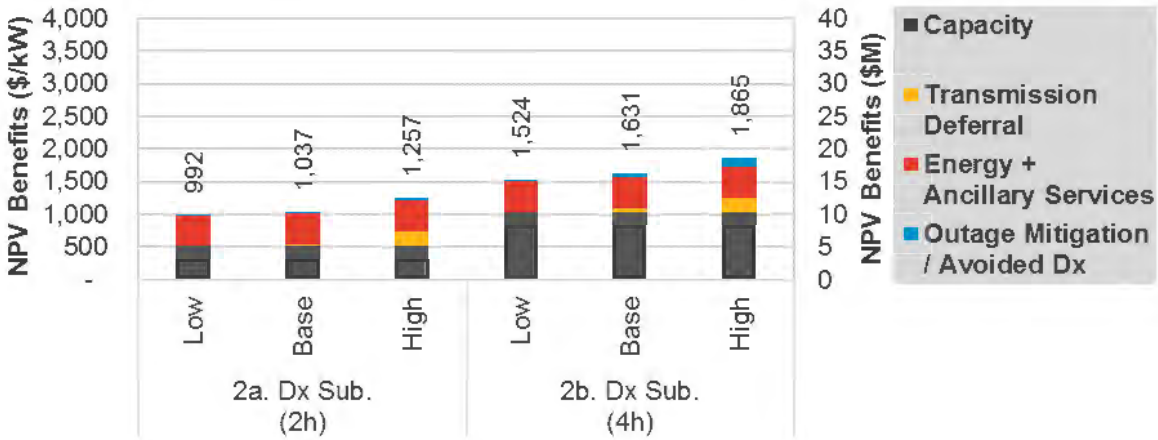
- Required duration (low/base = 4 hours, high = 2 hours)
- Cost of transmission equipment, based on the type of investment (low/base = $125/kW, high = $250/kW)
- Deferral period (low/base = 1 year, high = 2 years)
- Capacity of transmission deferred (low = 0 kW, base/high = 20 kW transmission per kW storage)

### *3.2.2 Case 2: 10 MW ESS at Distribution Substation*

Figure 3-8 illustrates the system benefits under each of the substation-level scenarios analyzed. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits. These benefits serve as a benchmark for target ESS costs.

Two scenarios were evaluated, including one for a 2-hour ESS (2a) and one for a 4-hour ESS (2b). In each case, the ESSs support Capacity and Transmission Deferral for 10 days each per year, then provide Energy + Ancillary Services for the other 345 days. The inputs and assumptions for substation-level ESSs are described in Table 2-3 and Section 2.4.3.

**Figure 3-8. System Benefits of 10 MW Substation-sited ESSs**




*Source: Navigant*

Relative to transmission-level ESSs, the key difference is the amount of Transmission Deferral benefits. PGE analysis indicates that load reductions at the distribution level yield only ~30% impact along a specific transmission route (i.e., 10 MW distribution load reduction = 3 MW load reduction along a specific transmission route), so the distribution-level benefits are assumed to be 30% of the transmission-level benefits.[49]

The differences in other benefits are relatively small. The Capacity and E+AS benefits are similar, except the Capacity benefits at the distribution level are slightly higher (~5%) due to reduced T&D losses during peak periods. The Outage Mitigation/ Avoided Distribution Investments benefits are relatively low, as substation-level storage is only able to mitigate transmission-level outages, while most outages are driven by events at the distribution level.

The sources of variability between the low, base, and high conditions are the same as for the transmission-sited ESS for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. For the Outage Mitigation/ Avoided Distribution Investments benefits, the benefits vary by substation depending upon the frequency of transmission outages at the substation, and the average value of service for impacted customers.

### *3.2.3 Case 3: 2 MW ESS on Distribution Feeder*

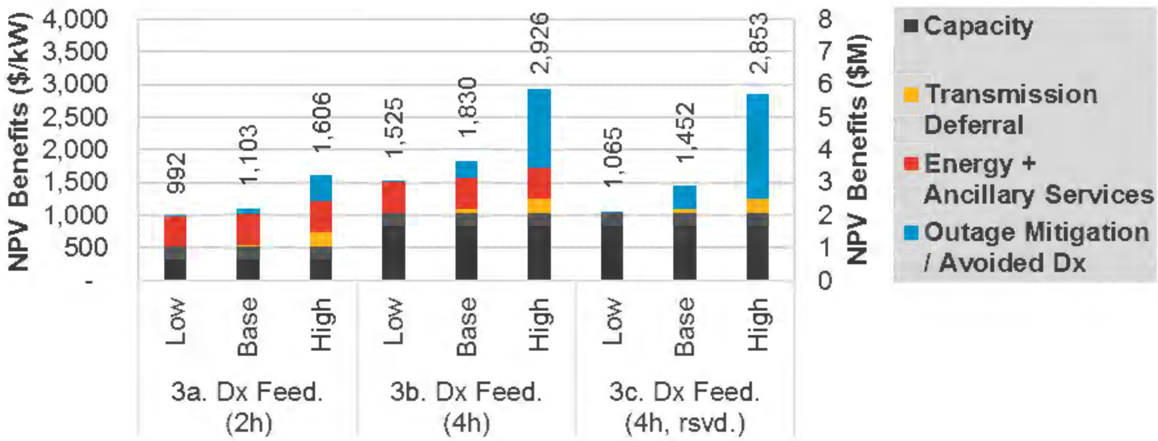
Figure 3-9 illustrates the system benefits under each of the feeder-level scenarios analyzed. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits. These benefits serve as a benchmark for target ESS costs.

Three scenarios were evaluated. In the first two scenarios – one with a 2-hour ESS (3a) and one with a 4-hour ESS (3b) – the ESSs support Capacity and Transmission Deferral for 10 days each per year, then provide Energy + Ancillary Services for the other 345 days, and the Outage Mitigation/ Avoided Distribution Investments application is available with a varying energy capacity depending upon the state

[49] Power flow is distributed across the grid in multiple directions. An injection of 1 MW at any given distribution substation will flow proportionately across each transmission circuit at that interface. PGE's Transmission Planning department assessed the potential impact of distributed solar on the South of Allston path. The studies confirm that path flows are reduced by an average of 1 MW for every 3 MW of distributed generation in the Portland metro area.

of charge when an outage occurs. In the third scenario (3c), the ESS is reserved for Outage Mitigation/ Avoided Distribution Investments during all times when not needed for Capacity or Transmission Deferral (345 days/year). The inputs and assumptions for feeder-level ESSs are described in Table 2-3 and Section 2.4.4.

**Figure 3-9. System Benefits of 2 MW Feeder-sited ESSs**




*Source: Navigant*

Relative to substation-level ESSs, the key difference is the amount of Outage Mitigation/ Avoided Distribution Investments benefits. These benefits are higher than at the substation level, as feeder-level ESSs can help to mitigate distribution-level outages in addition to transmission outages, particularly on long feeders without robust tie lines. There is, however, significant variability in these benefits, as they depend upon the configuration of the feeder, the frequency of outages on the feeder, and the average value of service for impacted customers. Further, the benefits for 4-hour ESSs are greater, because only a 2-hour ESS is needed for E+AS, leaving 50% of the total energy capacity available at all times for Outage Mitigation/ Avoided Distribution Investments except when occasionally needed for Capacity or Transmission Deferral.

For 4-hour ESSs, another scenario (3c) was analyzed that looked at the relative benefits for an ESS that is not used for E+AS and instead holds all of the energy storage capacity in reserve at all times, except when occasionally needed for Capacity or Transmission Deferral. In this case, the average available energy capacity increases from ~75% to nearly 100%. Thus, the Outage Mitigation/ Avoided Distribution Investments benefits increase by about one third. However, the loss in E+AS benefits outweighs this impact, resulting in lower total benefits even in the high condition. Thus, it generally makes sense to utilize the ESS for E+AS rather than holding the full capacity in reserve for Outage Mitigation/ Avoided Distribution Investments. This finding may vary for certain feeders.

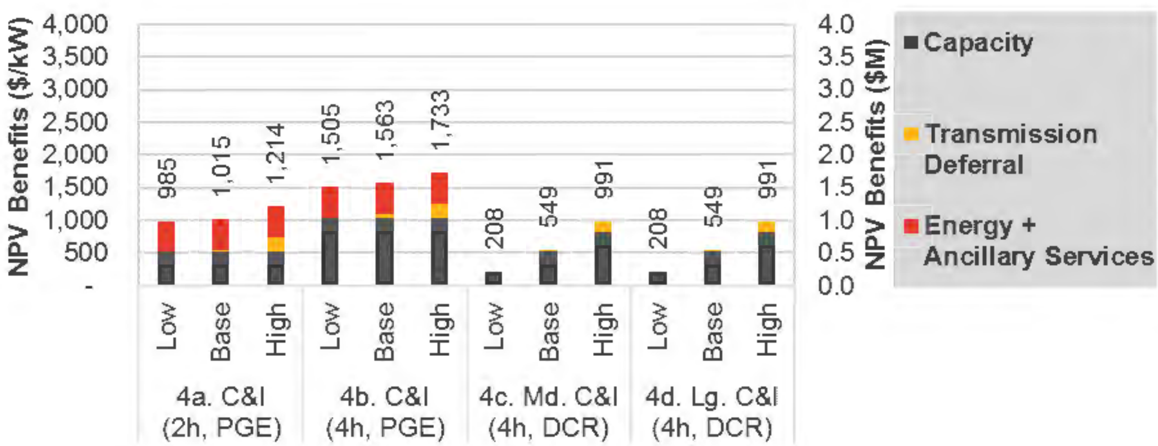
The sources of variability between the low, base, and high conditions are similar to the previous use cases for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. For the Outage Mitigation/ Avoided Distribution Investments benefits, the benefits vary by feeder depending upon the configuration of the feeder, the frequency of outages on the feeder, and the average value of service for impacted customers.

### *3.2.4 Case 4: 1 MW Aggregated Medium–Large C&I Customers*

Figure 3-10 illustrates the system benefits under each of the customer-level scenarios analyzed for medium-to-large C&I customers,[50] while Figure 3-11 illustrates the benefits to the customer where the ESS is sited. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits.

Four scenarios were evaluated. In the first two scenarios – one with a 2-hour ESS (4a) and one with a 4-hour ESS (4b) – the ESSs support Capacity and Transmission Deferral for 10 days each per year, then provide Energy + Ancillary Services for the other 345 days, and Power Reliability is available with a varying energy capacity depending upon the state of charge when an outage occurs. In the last two scenarios – one for a medium C&I customer (4c) and one for a large C&I customer (4d) – the ESS is used primarily for Demand Charge Reduction. A portion of the aggregated capacity is available when needed for Capacity and Transmission Deferral, and Power Reliability is available with a varying energy capacity depending upon the state of charge when an outage occurs. The inputs and assumptions for these ESSs are described in Table 2-3 and Section 2.4.5.

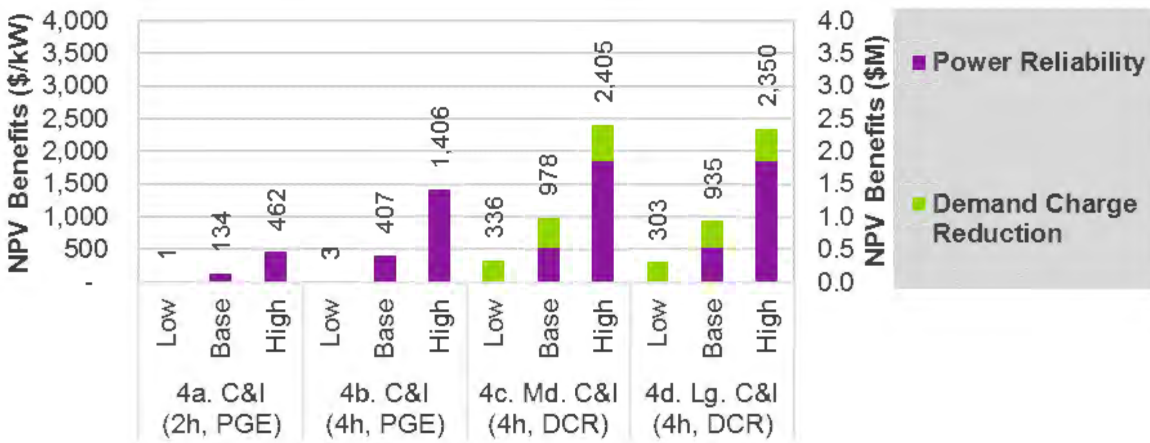
**Figure 3-10. System Benefits of 1 MW Aggregated Customer-sited ESSs (Medium-Large C&I)**




*Source: Navigant*

[50] Customers on rate schedules 83 (31 – 200 kW) or 85 (201 – 4,000 kW).

**Figure 3-11. Individual Customer Benefits of 1 MW Aggregated Customer-sited ESSs (Medium-Large C&I)**




*Source: Navigant*

The first two scenarios (4a, 4b) evaluate 2-hour and 4-hur ESSs are operationally similar to feeder-level ESSs, as they are operated by PGE for E+AS. The key difference relative to feeder-level ESSs is the amount of Power Reliability benefits relative to Outage Mitigation/ Avoid Distribution Investments benefits and the fact that Power Reliability provides individual customer benefits rather than system benefits. Placing the ESS at specific customer sites can target specific locations with high value of service.[51] As discussed in Section 2.2.3.2, Power Reliability benefits for individual customers are likely to vary significantly from customer to customer. Because the benefit accrues uniquely to one customer, the benefit does not stack on the system benefits and instead is an individual customer benefit.

The last two scenarios (4c, 4d) evaluate 4-hour ESSs at medium and large C&I customer sites used for Demand Charge Reduction (DCR) rather than for E+AS. The key differences are:

- Lower Capacity and Transmission Deferral benefits due to lower guaranteed available capacity (low = 20%, base = 50%, high = 80%)
- No E+AS benefits
- Higher PR benefits (i.e., higher average state of charge for DCR vs. E+AS)
- DCR benefits included

The sources of variability between the low, base, and high conditions are the similar to the previous use cases for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. In addition, the Capacity and Transmission Deferral benefits scale depending upon the assumed level of guaranteed capacity. For the Power Reliability benefits, the benefits vary by customer depending upon the configuration of the associated feeder, the frequency of outages for the customer, and the value of service for the customer. For DCR, the average monthly demand reduction may vary depending upon the customer's load profile (assumed reduction relative to ES power rating: low = 60%, base = 80%, high = 100%) and the demand charge (which was the only assumed difference between medium and large C&I customers).

[51] Note that the range of Power Reliability values shown here is from a selected sample of customers that may have a higher average benefit relative to the system-wide average for all PGE customers.

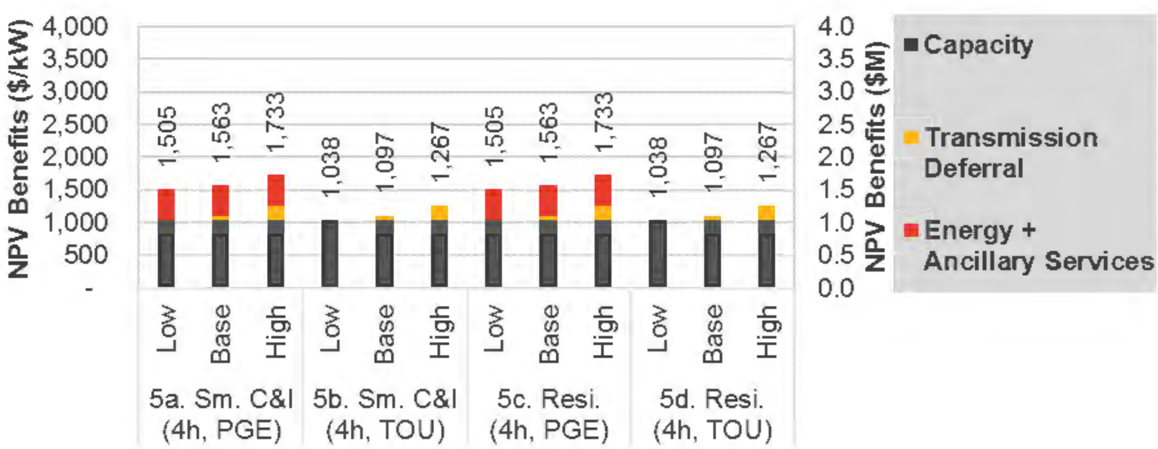
Overall, the system benefits are significantly lower for the DCR ESSs. The magnitude of the individual customer benefits from DCR is similar to the system benefits from E+AS when operated by PGE. However, the DCR benefits also result in lower revenue for PGE, which may increase costs to other customers and is not accounted for in the system benefits. The Power Reliability benefits can be quite high in certain cases, but these benefits accrue to a specific customer.

### *3.2.5 Case 5: 1 MW Aggregated Small C&I + Residential Customers*

Figure 3-12 illustrates the system benefits under each of the customer-level scenarios analyzed for small C&I and residential customers,[52] while Figure 3-13 illustrates the benefits to the customer where the ESS is sited. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits.

Four scenarios were evaluated. In two scenarios – one for a small C&I customer (5a) and one for a residential customer (5c) – the ESSs support Capacity and Transmission Deferral for 10 days each per year, then provide Energy + Ancillary Services for the other 345 days, and Power Reliability is available with a varying energy capacity depending upon the state of charge when an outage occurs. In the last two scenarios – one for a small C&I customer (5b) and one for a residential customer (5d) – the ESS is used for TOU Charge Reduction instead of Energy + Ancillary Services when not needed for Capacity and Transmission Deferral, and Power Reliability is available with a varying energy capacity depending upon the state of charge when an outage occurs. The inputs and assumptions for these ESSs are described in Table 2-3 and Section 2.4.6.

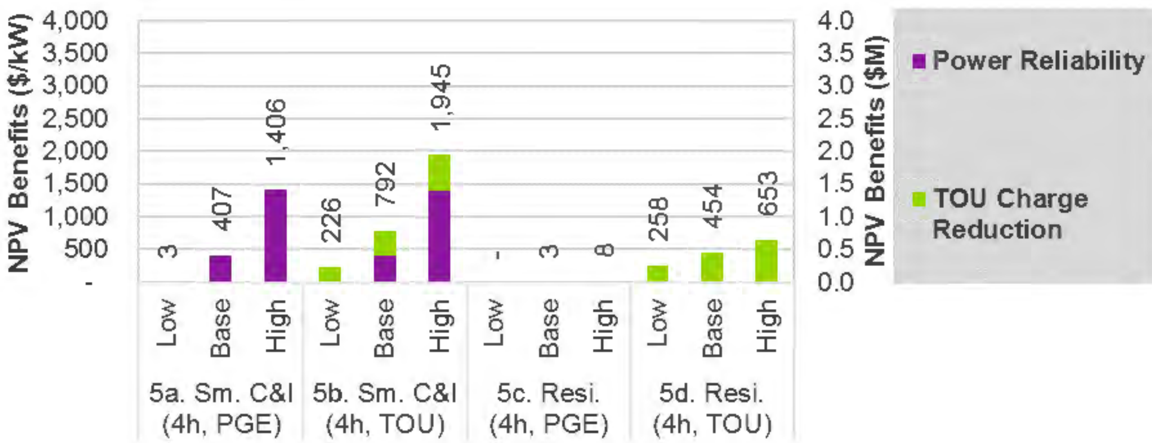
**Figure 3-12. System Benefits of 1 MW Aggregated Customer-sited ESSs (Small C&I + Residential)**




*Source: Navigant*

[52] Customers on rate schedules 7 (residential) or 32 (C&I, <30 kW).

**Figure 3-13. Individual Customer Benefits of 1 MW Aggregated Customer-sited ESSs (Small C&I + Residential)**




*Source: Navigant*

The "PGE" scenarios evaluate 4-hour ESSs that are operationally similar to the ESSs operated by PGE at medium and large C&I customer sites. The results for small C&I customers are identical to those for medium and large C&I customers, as there is no assumed difference in Power Reliability benefits. However, the Power Reliability benefits are assumed to be significantly lower for residential customers due to a lower value of service.

The TOU scenarios in Figure 3-12 evaluate 4-hour ESSs used for TOU Charge Reduction, rather than E+AS. Relative to the ESSs utilized for E+AS, these ESSs have:

- The same Capacity and Transmission Deferral benefits
- No E+AS benefits
- Similar PR benefits (i.e., similar average state of charge for TOU vs. E+AS)[53]
- TOU benefits included

The sources of variability between the low, base, and high conditions are the similar to the prior use case for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. As with medium and large C&I customers, the Power Reliability benefits for small C&I customers vary by customer depending upon the configuration of the associated feeder, the frequency of outages for the customer, and the value of service for the customer. For residential customers, the value of service is assumed to be low under all conditions. The average monthly TOU benefits may vary depending upon the customer's load profile, as the ESS capacity may exceed the customer's load during peak hours (assumed TOU reduction relative to max potential reduction: low = 40%, base = 70%, high = 100%) and the TOU rate schedule.

Thus, the system benefits are lower due to the lack of E+AS benefits. The magnitude of the individual customer benefits from TOU is similar to the system benefits from E+AS when operated by PGE. However, the TOU benefits also result in lower revenue for PGE, which may increase costs to other

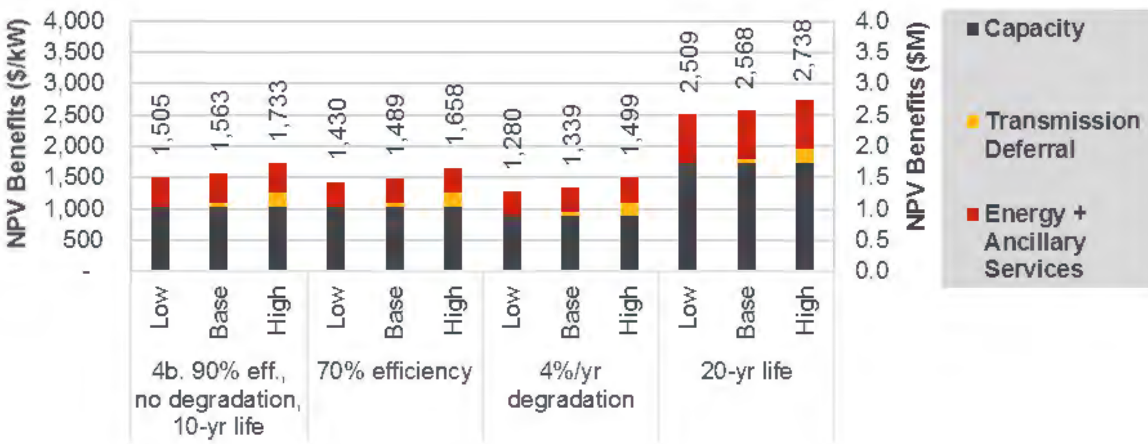
[53] The average state of charge for TOU is higher, but it uses the entire ESS, while the average state of charge for E+AS is lower, but it only uses half of a 4-hour ESS.

customers and is not accounted for in the system benefits. The PR benefits can be quite high in certain cases, but these benefits accrue to a specific customer.

## 3.3 Technology Comparison

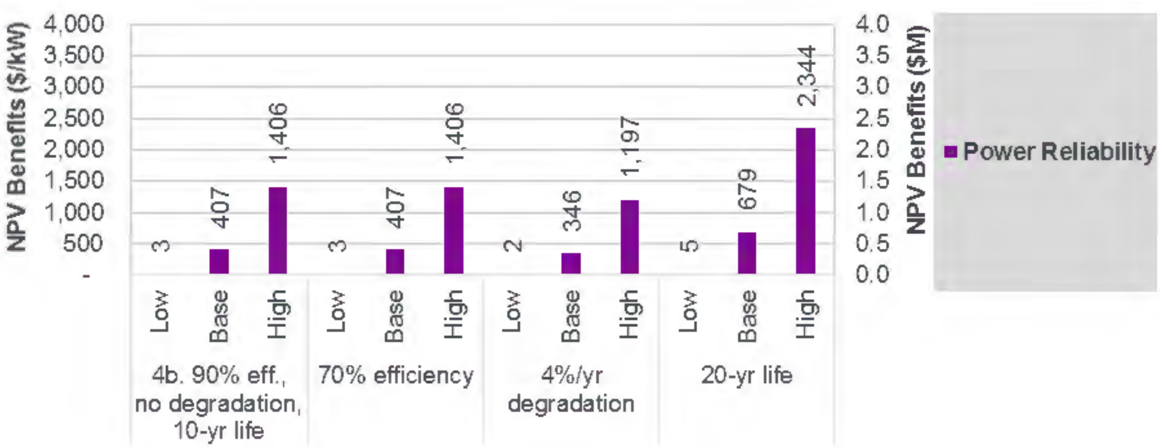
To evaluate the impact of technology on the NPV of lifetime system benefits, key technology parameters (efficiency, degradation, and lifetime) discussed in Section 2.5 were varied for the 4-hour PGE-controlled ESS located at a C&I customer site (4b). This specific scenario was selected to illustrate the impact of these parameters on a variety of benefit streams. The conclusions from this analysis illustrate how benefits would scale under other use cases and scenarios. Figure 3-14 and Figure 3-15 summarize these results for system benefits and individual customer benefits, respectively.

**Figure 3-14. Impact of Technology Parameters on System Benefits**




*Source: Navigant*

**Figure 3-15. Impact of Technology Parameters on Individual Customer Benefits**




*Source: Navigant*

This analysis demonstrates that the impact of efficiency for this use case is relatively small, because most of the benefits (Capacity, Transmission Deferral, and Outage Mitigation/ Avoided Dx) stem from occasional use of the ESS and do not require frequent cycling. The only benefit stream significantly affected by efficiency is E+AS. The E+AS benefits for the 70% efficiency scenario were ~85% of their value for the reference scenario with 90% efficiency. Total system benefits were >95% relative to the reference scenario.

The impact of degradation is more notable, because it has a more significant impact on most benefit streams. The impact on Transmission Deferral benefits is minimal, because those benefits accrue in the first 1-2 years. However, the Capacity, E+AS, and Power Reliability streams are all ~15% lower for the 4%/year degradation scenario relative to the reference scenario with no degradation, as it is assumed the capacity available for each application decreases with the available energy capacity.[54] Because the Transmission Deferral benefits are relatively small, overall systems benefits were also ~15% lower than the reference scenario.

The impact of ESS life is more profound. An ESS with a 20-year life produces nearly 67% more benefit than the reference ESS with a 10-year life. As is the case for degradation, the Capacity, E+AS, and Power Reliability streams are all similarly impacted, while the Transmission Deferral benefits remain about the same. Note that both the 10-year and 20-year cases assume no degradation, which is the result of regular capacity replenishment. If degradation was significant and capacity was not replenished, the impact of extending the life of the ESS to 20 years would be somewhat diminished.[55]

[54] Note that while 4%/year degradation is relatively high, it provides a representative case of significant degradation, and it may be somewhat representative for this use case, in which the ESS is cycled nearly twice per day for Energy + Ancillary Services. Additionally, while the ESS degrades below 70% of initial capacity by the end of the 10-year period (which is below the common 80% threshold), it is not assumed that any replacement or replenishment occurs.

[55] Here, ESS life is assumed to be independent of degradation. Typically, these two parameters are related to one another, often based on the time to degrade to 80% of original energy capacity. However, the ESS life is typically equal to the warranty period for financial purposes, and warranties can have varying periods for the same technology, depending upon how they are structured.

# APPENDIX A. MODELING DETAILS

The following sections provide additional detail regarding the modeling tools and approach used, beyond the discussion in Section 2.2.

## A.1 Navigant Valuation of Energy Storage Tool (NVEST)

Section 2.2.1 describes the NVEST model at a high level. As mentioned above, a detailed description of the basic methodology is publicly available online.[56] Further, many of the assumptions, inputs, and data sources specifically associated with the analysis in this report are described elsewhere within the document:

- Section 2.1 describes the analytical approach and data sources used for each application;
- Section 2.2 describes the sources for the inputs and assumptions that were used;
- Section 2.4 describes the assumptions associated with each use case; and
- Section 2.5 describes the assumptions associated with the energy storage technology and performance.

The list below describes other important assumptions used to determine the value of each use case.

- The net present value (NPV) of each use case reflects the net operating benefit of the ESS. It includes both the benefits accrued from operating the ESS for specific applications, as well as the variable operating costs associated with operating the ESS (e.g., charging costs). It does not include costs associated with ESS ownership (i.e., installed capital costs, as well as fixed operating and maintenance costs).
- Values associated with the energy capacity (kWh) and power capacity (kW) of the ESS (e.g., annual kW available for Energy + Ancillary Services) are reduced by the assumed degradation rate (e.g., 2%/year). Degradation is assumed to be exponential (i.e., Capacity in year 10 = $(1 – 2\%)^9$ = 83% of original capacity).
- Values associated with system benefits (e.g., \$/kW-year for Energy + Ancillary Services) are assumed to escalate at inflation rate of 2% per year. Input values are escalated from their base year (typically 2016) to their value in the initial year (2021), as well escalated during each year of the deployment (typically through 2030).
- The NPV is calculated assuming a discount rate/ weighted average cost of capital of 6.204%. The ESS is assumed to be deployed in 2021, and the NPV is calculated in 2020 USD based upon the assumption that an investment is made in 2020 before the ESS goes live in 2021. This NPV is then converted to 2017 USD by adjusting for inflation (2%).

## A.2 Resource Optimization Model (ROM)

PGE engaged in detailed modeling of ESSs within the 2016 IRP using ROM. ROM is a multi-stage production simulation model of PGE's resource portfolio. ROM was originally designed to quantify operational challenges and costs associated with renewables integration. In addition to energy storage

[56] DOE Energy Storage Computational Tool Overview. US Department of Energy. August 2012. https://www.smartgrid.gov/document/doe_energy_storage_computational_tool_overview.html.

evaluation, ROM is used to calculate PGE's Variable Energy Integration Costs as well as the Day-Ahead Forecast Error costs associated with wind generation in PGE's calculation of Net Variable Power Costs. Recent ROM development work has been discussed in past and ongoing IRP dockets, including LC 56 and LC 66. Key model development decisions and subsequent enhancements were also reviewed by an external Technical Review Committee. Because of this history, ROM already incorporated the key features required for quantifying the operational value of energy storage resources: optimal unit commitment and dispatch of the PGE resource fleet over multiple time horizons, impacts of forecast errors (e.g., day-ahead to real-time), ancillary service requirements, and sub-hourly dispatch. More information about ROM and PGE's preliminary energy storage evaluation can be found in Chapter 8 of the 2016 IRP.[57]

Positive discussions with stakeholders regarding PGE's approach to modeling energy storage in the 2016 IRP encouraged the Company to continue to explore energy storage evaluation through production simulation modeling exercises. PGE also received positive feedback on its methodology from utilities and industry organizations across the country. PGE's methodology was highlighted in the Energy Storage Association's 2016 primer on energy storage modeling in IRPs[58] and PGE was invited to present the analysis at industry and policy forums, including the Western Energy Institute's Integrated Resource Planning Forum and the North Carolina Sustainable Energy Association's Energy Storage Working Group. At these forums, utilities around the country shared similar challenges in quantifying the value of energy storage. Key functionality enabled by PGE's approach includes the ability to: co-optimize value across multiple applications and timescales, capture portfolio effects and declining marginal values; quantify monetizable benefits over short timescales in a region without ancillary service markets, and capture utility-specific opportunities and constraints.

In the Energy Storage Potential Evaluation, PGE sought to leverage and update the analysis presented in the 2016 IRP as part of the broader effort to understand the value of energy storage on the PGE system. This appendix summarizes the new ROM analysis conducted to support the Energy Storage Potential Evaluation. It does not address capacity value, locational value, or the interactions between operational and non-operational value streams. These topics are discussed by Navigant in the main body of the report.

## *ROM Simulation Configuration*

PGE quantified the value associated with operational applications in the Energy Storage Potential Evaluation by conducting multiple ROM simulations, each with a different energy storage configuration, and comparing the results to a base case, in which PGE's resource fleet is modeled without the addition of ESSs. Each ROM simulation yields the operational cost of meeting loads and ancillary service requirements across a test year. PGE assumed that the ESSs were capable of providing all of the modeled ancillary services, including: load following, which encompasses the mitigation of forecast errors and renewables integration challenges down to five minutes; regulation; spinning; and non-spinning reserves. The difference in cost between ROM simulations with and without an ESS yielded the net variable cost impact, or the operational value of the ESS. This cost difference reflects the combined value of the co-optimized operational applications—energy arbitrage and the ancillary services listed above. This value is monetized through energy market transactions and variable cost savings throughout

[57] Additional background about ROM and its use in PGE's Variable Renewable Integration Study can be found in Section 7.2.1.1 in PGE's 2016 IRP.

[58] "Including Advanced Energy Storage in Integrated Resource Planning: Cost Inputs and Modeling Approaches," November 2016, http://energystorage.org/system/files/attachments/irp_primer_002_0.pdf.

the PGE resource fleet, including avoided fuel burn, variable O&M, and unit starts. The operational value identified in this analysis therefore assumes that PGE has the ability to control the ESS in coordination with the dispatch of its resource fleet.

PGE evaluated three ESS configurations, including 50-MW ESSs with 2-hour, 4-hour, and 6-hour durations. While the storage investments made by PGE under HB 2193 are capped at 38.7 MW, PGE chose to model 50-MW ESSs in this analysis due to computational considerations common to production cost models, which are discussed below. The Navigant analysis assumes that the benefits of the ESSs determined by ROM scaled linearly to the specific resource sizes considered in the report. PGE's base resource portfolio in ROM reflected the 2021 fleet modeled in the Variable Energy Integration Study (Run 4) described in Section 7.2.1.1 in the 2016 IRP. Hourly and 15-minute energy prices were based on the Reference Case in the 2016 IRP.

## *Dispatch Behavior*

The dispatch behavior of energy storage resources depends on market conditions as well as system demand and the availability and characteristics of other resources in the portfolio. In particular, the extent to which energy storage resources are dispatched to provide reserves depends strongly on the demand for those reserves and the other resources available to provide them. Depending on the cost of providing various reserves with resources within PGE's portfolio, the optimal energy storage dispatch may also prioritize providing some services over others. For example, in time steps[59] when adequate hydro resources are available to provide reserves, the value of providing these reserves with a storage system is small. However, in time steps in which reserves would otherwise be met with thermal resources, providing these services with an ESS provides the opportunity to avoid fuel burn, O&M costs, and potentially unit starts. These economic considerations vary from time step to time step, so the dispatch and provision of reserves provided by the ESS also varies over time. Such considerations also vary by utility depending on market structures as well as the nature of loads and resources available to meet those loads.

## *Weekly Dispatch Snapshots*

Figure A-1 illustrates the simulated dispatch behavior, state of charge, and reserve provisions for a 50-MW, 2-hour ESS with 90% efficiency over the course of a week in January (left panel) and August (right panel) with 15-minute resolution. On the January week, the charging/discharging pattern does not follow a predictable daily trend and the amount of storage capability being utilized (as indicated by the range in the state of charge) changes dramatically from day to day. The regulation reserve provisions tend to follow a diurnal pattern broadly reflective of the daily net load shape, although some time steps deviate from this pattern. Load following reserve provisions change dramatically both across and within days, with no obvious predictable pattern. Note that while the ESS has a 50 MW capacity, reserve provisions can well exceed 50 MW because the ESS is assumed to be capable of switching between charging and discharging modes over very short timescales.[60] Therefore an ESS that is charging at 50 MW could simultaneously provide up to 100 MW of upward reserves and ESS that is discharging at 50 MW could

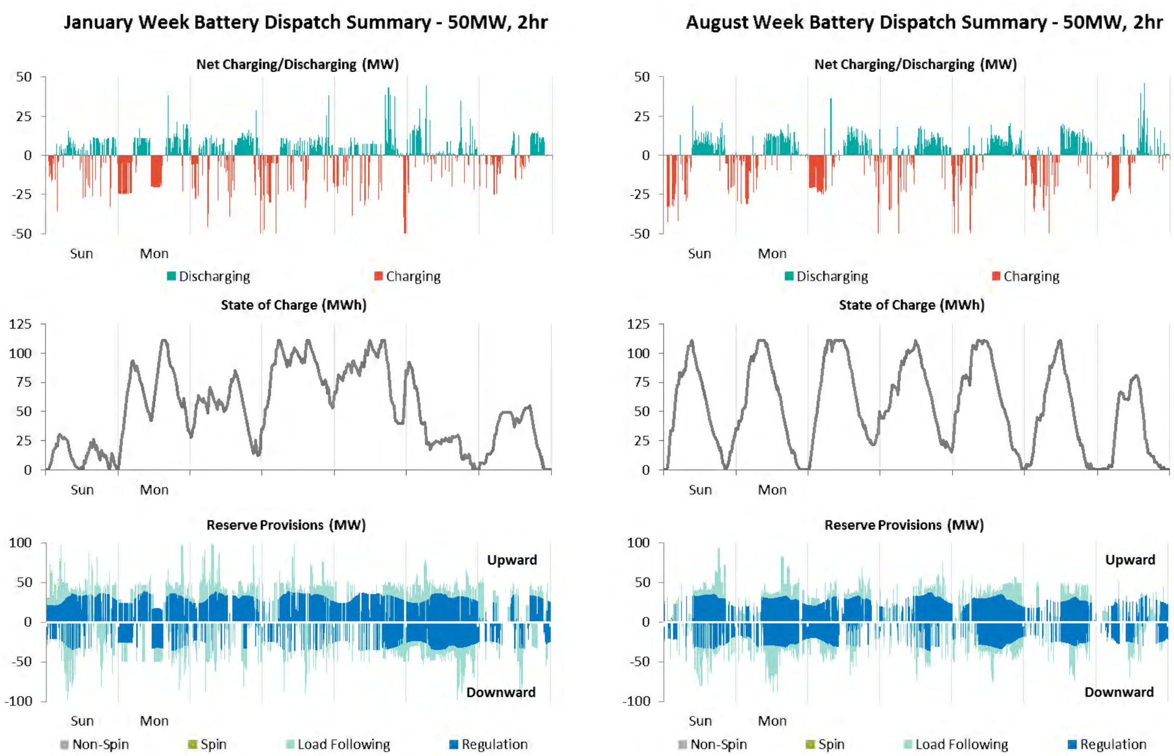
[59] Time steps in the ROM modeling were one hour in the day-ahead stage and 15 minutes for other stages.

[60] Down to four seconds for regulation.

simultaneously provide up to 100 MW of downward reserves.[61] While this assumption is valid for many battery technologies, it may not be valid for energy storage technologies with time delays associated with switching between charging and discharging modes—pumped hydro storage, for example.

In contrast, on the August week, the ESS consistently experiences a full or near-full charge and discharge cycle once per day—charging in the early morning hours and discharging in the evening during peak demand conditions. This periodicity is reflected in the state of charge panel. Similar to the January week, the regulation reserve provisions generally follow a predictable daily shape, while the load following provisions are less predictable.

**Figure A-1. Energy Storage Dispatch – 50-MW, 2-hour ESS**




*Source: PGE*

## *Seasonal Dispatch Patterns*

The dispatch behavior can also be summarized on an average basis across seasons to identify general dispatch trends. Average daily dispatch behavior, state of charge, and reserve provisions are shown by quarter in Figure A-2 through Figure A-5.

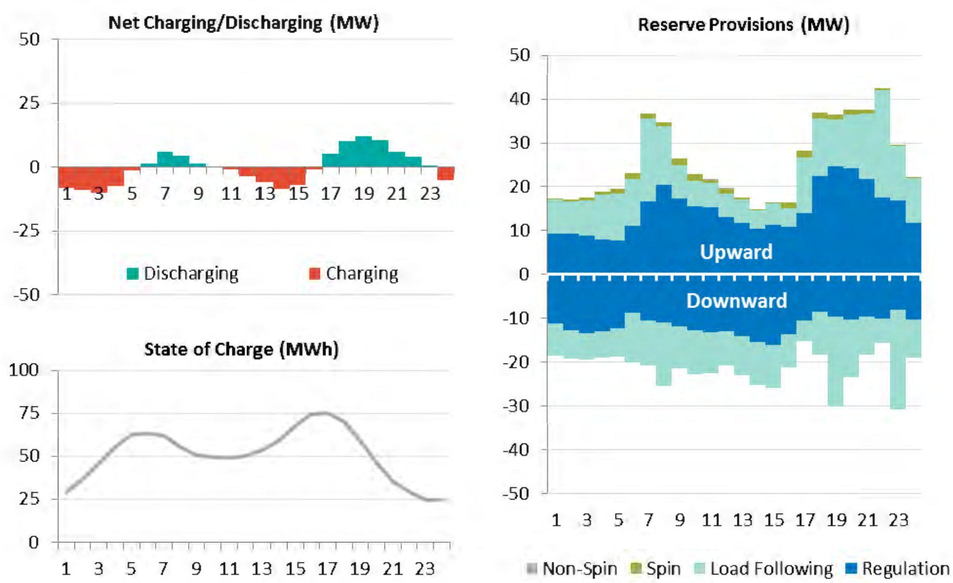
In the first quarter, the ESS tends to charge in the early morning hours and early afternoon and discharge during the morning and evening peaks, reflecting the load shape. Similarly, average reserve

[61] Load following reserve provisions reflect both load following held in the real-time stage and any differences in ESS dispatch between the day-ahead and real-time stages brought about by forecast errors. This accounting may give rise to periods in which the total reserve provisions appear to exceed the physical capabilities of the ESS even though ESS capability constraints are respected in ROM.

provisions are highest during the morning and evening peaks and during these periods the batteries tend to prioritize providing more upward than downward reserves.

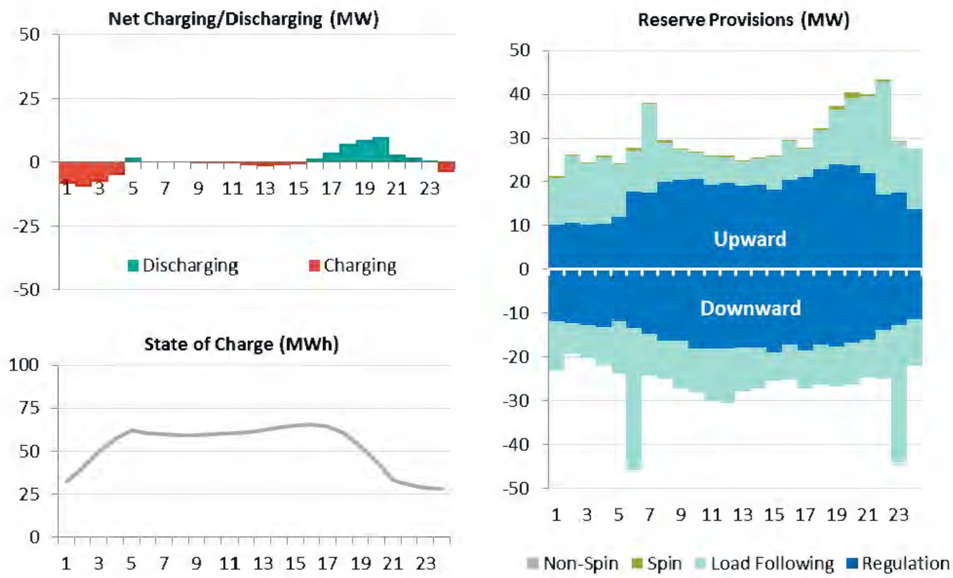
During the second quarter, the average charge/discharge pattern is less reflective of load levels throughout the day and a larger portion of the ESSs' capacity is held to provide both upward and downward reserves. This may be reflective of the constraints on the system imposed by high hydro conditions in the springtime. In addition, the ESS provides significant load following at the on/off-peak boundaries, which helps the system to mitigate the effects of scheduling market purchases in on/off-peak blocks in the day-ahead with imperfect information.

**Figure A-2. Q1 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS**



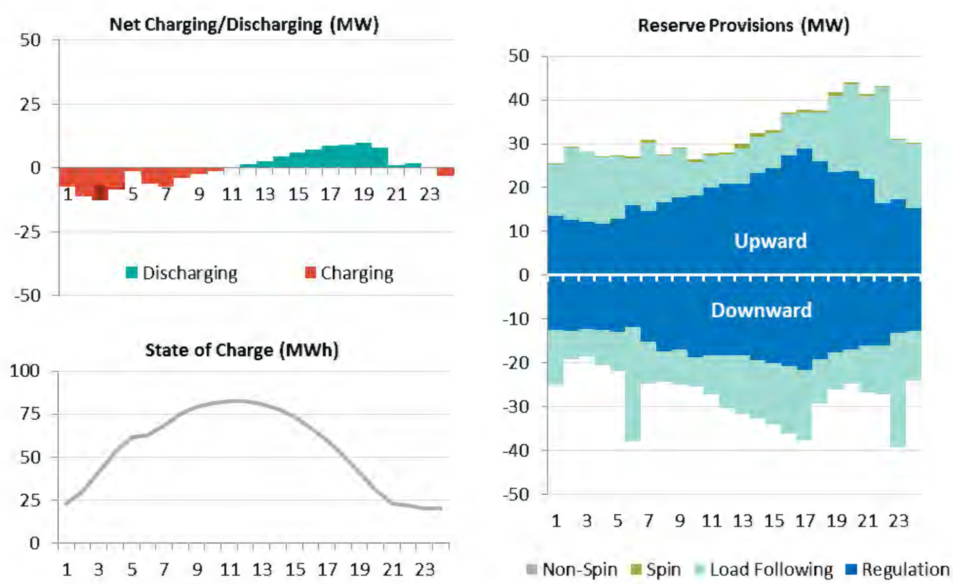

*Source: PGE*

**Figure A-3. Q2 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS**



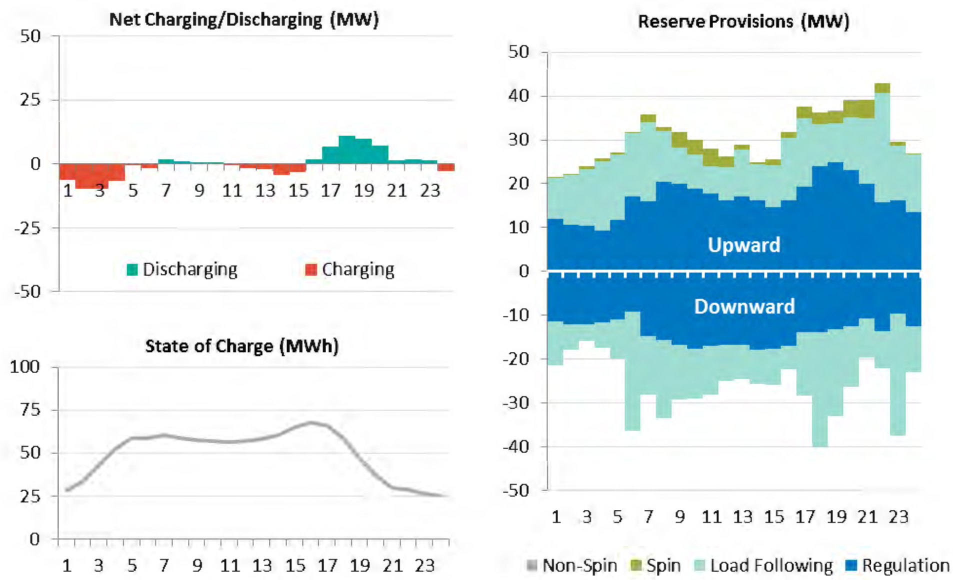

*Source: PGE*

**Figure A-4. Q3 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS**




*Source: PGE*

**Figure A-5. Q4 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS**




*Source: PGE*

In the third quarter, the charge/discharge pattern is largely reflective of the late summer load shape—the ESS tends to charge in the first part of the day and discharge to meet the evening peak. On average, reserve provisions from the ESS are greatest in the third quarter, and the peak provisions for different reserve services are somewhat offset in time, suggesting economics tradeoffs in scheduling these services. For example, while regulation on the ESS peaks in the early evening, load following provisions tend to be higher in the late evening and early morning.

Both charging/discharging patterns and the timing of reserve provisions are similar between the fourth quarter and the first quarter, although the fourth quarter sees a slight increase in the magnitude of reserve provisions on the ESS. While spinning reserve provisions are still relatively small, they tend to be greater in the fourth quarter, which may be reflective of the reduced hydro capability in the fall relative to other seasons.

In all seasons, the daily average charge and discharge patterns are fairly flat relative to the -50 MW to +50 MW potential of the ESS, indicating that if significant ramps are experienced on the ESS, they are not consistently experienced at the same time of day throughout the season. This weak diurnal trend suggests that large ramps are largely driven by dynamic flexibility needs on the system, which vary from day to day and across the day, rather than energy arbitrage opportunities, which typically have a more predictable daily shape. The Reserve Provision panels in Figure A-2 through Figure A-5 corroborate this observation. They show that a significant portion of the ESS capacity is being used to provide regulation and load following reserves. Load following in this context includes both the average upward and downward deviations from day-ahead hourly schedules and fifteen-minute real-time dispatch as well as the additional reserves held in the 15-minute real-time stage to accommodate fluctuations down to the five-minute time scale. The ESS was also found to provide limited spinning reserves and negligible non-spinning reserves due to the ability of other resources in the PGE fleet to provide these services at relatively low cost.

## *Identified Operational Value*

The operational value identified through these simulations is summarized in Table A-1 below. These values are lower than the value identified in the 2016 IRP, in part because the electricity price update reflects increased solar and storage buildout in California and the Southwest.[62] This additional solar generation reduced on-peak prices in the Northwest under Reference Case assumptions. However, the on-peak price reductions were not large enough in the 2021 test year to create the inverted arbitrage opportunities described in California—where ESSs may charge during the day with low or negatively-priced solar and discharge during the high-priced evening peak hours. Instead, the on-peak price reductions experienced in the Northwest and the price-flattened effects of energy storage built elsewhere in the West served to reduce daily price volatility and therefore reduced the value of energy storage in the PGE system relative to prior simulations. PGE anticipates that continued development of renewables will affect the value of energy storage over time and anticipates that higher renewable penetrations are generally likely to increase the value of energy storage in the longer term, despite this near term finding.

**Table A-1. ROM Results for 50 MW ESSs**

| System | Operational Value (nominal $, millions) | Operational Value (2016$/kW-yr) |
|---|---|---|
| 50 MW, 2 hr | 3.27 | 59.2 |
| 50 MW, 4 hr | 3.66 | 66.4 |
| 50 MW, 6 hr | 3.47 | 62.9 |

*Source: PGE*

The ROM simulations also suggest that the operational value of ESSs may increase slightly as the duration is increased from two hours to four hours; however, this value appears to decline in going from a 4-hour to 6-hour duration. This finding highlights the limitations of production simulation models in resolving small differences in operational value. This is discussed further in the following section.

## *Model Convergence*

All production simulation models, including ROM, require the user to specify a convergence tolerance. Typically, the optimization algorithms run until this tolerance is achieved or until a specified time limit is reached. For complex systems with non-linear or non-convex constraints or cost terms, convergence to the specified tolerance can be challenging, resulting in a tradeoff between runtime and precision. To ensure reasonable runtimes, PGE specified a tolerance of 3%. While most weeks[63] achieve converge to a solution well within the 3% target, some weeks in the simulation instead hit the runtime limit, resulting in reduced precision. PGE has also tested ROM using lower tolerance settings (1%) and longer runtime limits (up to 24 hours per simulated week) and found that while these settings affected whether some weeks converged within the runtime limit, it did not significantly affect the findings for most weeks.

These computational and challenges tend to decline for larger ESSs, as they have larger relative impacts on total operational cost. PGE chose to model a 50 MW ESS in this analysis to balance the desire to model small ESSs for compliance with HB 2193 with these computational convergence challenges.

[62] The energy storage evaluation in the 2016 IRP used electricity pricing from the 2013 IRP Update. The differences in electricity pricing described in this study reflect changes in the WECC-wide fleet between the 2013 IRP Update and the 2016 IRP.

[63] ROM simulations optimize dispatch across whole weeks.

### Effects of Forecast Errors

Even with a much tighter tolerance, multi-stage production simulations may result in negative or lower than expected benefits in some weeks due to forecast errors and commitment constraints. While somewhat counterintuitive, these findings reflect real potential outcomes, not spurious modeling artifacts. Consider, for example, a system in which natural gas nominations must be made in the day-ahead stage. Such a system may determine different commitment schedules for natural gas plants in the day-ahead stage if the fleet includes an ESS than if it does not include an ESS. In real-time, the load or renewable output may deviate from the forecasts that were available in the day-ahead and while some of these deviations are accommodated through reserves, there remains a probability that the schedules established for the fleet without the energy storage system are coincidentally more helpful for balancing the realized renewable output than the schedules established for the fleet with the ESS. Because ROM simulates these forecast errors and the associated impact on dispatch, there are some weeks in which the fleet happens to perform better without an ESS or some weeks in which a 4-hour ESS happens to perform better than a six-hour ESS.

To the extent that forecast errors and convergence tolerances affect the identified value of various ESSs, the value of such ESSs is effectively the same to within the precision of the modeling methods. For this reason, PGE recommended that Navigant use the same operational value for all ESSs of duration equal to or greater than 2 hours. This approach does not preclude long duration storage resources from providing additional value through other applications. For example, a 4-hour ESS provides more capacity value and locational value than a 2-hour ESS.

### Differentiating Between Operational Applications

The operational value results suggest that increasing the duration of energy storage resources beyond 2 hours up to 6 hours may not increase the operational value of the ESS within the PGE fleet appreciably. This finding suggests that ancillary services and applications that are associated with short timescales are the primary drivers of operational value in the near term. This observation is largely consistent with the findings in PGE's 2016 IRP energy storage analysis. PGE did not evaluate ESSs with durations longer than 6 hours, but anticipates that longer duration ESSs may provide additional energy arbitrage and other longer timescale benefits not yet quantified.

PGE conducted additional simulations to explicitly identify the portion of the operational value associated with the various operational applications. This exercise is complex and computationally intensive within a production simulation modeling framework. Because ROM optimizes dispatch across all applications and operational value is monetized through avoided fuel and other variable costs across PGE's fleet, there is no straightforward approach to differentiating value associated with one operational application versus another in a single simulation. Instead, multiple simulations are required in which the ESS is modeled with and without the ability to provide specific services in order to isolate the value of providing those services. Such an exercise requires significant time and computational effort.

To broadly characterize the relative value of the operational applications, PGE conducted an additional ROM simulation to isolate the value of providing regulation, conducted an additional simulation in a simplified dispatch model to approximate the value of energy arbitrage, and supplemented this additional data with observations from the dispatch results to infer the value of remaining operational end uses. The results of the ROM run conducted to isolate the value of providing regulation are summarized in Table A-2. These results indicate that regulation comprises approximately 17% of the total operational value.

**Table A-2. ROM Results Isolating the Value of Regulation**

| System | Operational Value (2016$/kW-yr) |
|---|---|
| 50-MW, 2-hr ESS with all capabilities | 59.2 |
| 50-MW, 2-hr ESS that cannot provide regulation | 49.4 |
| **Implied value of providing regulation** | **9.9** |

*Source: PGE*

The simplified energy arbitrage-only dispatch simulation of the 50-MW, 2-hour ESS yielded $426,587 of nominal market revenue in 2021, or $7.7/kW-year in 2016$. This comprises 13% of the total value identified in ROM. Importantly, this value represents the potential for the ESS to reduce costs through energy arbitrage in the market, not the actual market revenue associated with the dispatch simulated in ROM. Because the ESS is dispatched to provide ancillary services in ROM, a portion of this revenue is foregone in the ROM simulations in order to provide these other, higher value services.

PGE assumed that the load following value could be approximately isolated by subtracting the energy arbitrage and regulation value from the total operational value. This assumption was based on the observation that the ESSs rarely provided spinning or non-spinning reserves in the ROM dispatch simulations due to the ability of other low-cost resources within PGE's fleet to provide these reserves. The resulting approximate break out of the value associated with operational end uses is summarized in Table A-3.

As the analysis shows, the majority of the operational benefits of the ESS are associated with providing load following. This finding comports with expectation as load following reserves allow the fleet to mitigate forecast errors of both the load and renewables and to provide sub-hourly balancing down to the five-minute time scale. This finding is also consistent with the observation that increasing the duration to provide longer term services does not appreciably affect the operational value of the ESS.

**Table A-3. Decomposition of the Value of Operational Applications**

| End Use | Operational Value (2016$/kW-yr) | % of Total |
|---|---|---|
| Energy Arbitrage | 7.7 | 13% |
| Load Following | 41.6 | 70% |
| Regulation | 9.9 | 17% |
| Spin & Non-spin Reserves | 0.0 | 0% |
| **All operational applications** | **59.2** | **100%** |

*Source: PGE*

## *Conclusions*

The analysis described in this report represents the continued evolution of PGE's energy storage modeling efforts and provides a snapshot given the information and modeling capabilities available today. The findings are specific to PGE and the resource portfolios modeled and are therefore likely to differ from other utilities and/or markets.

In the future, the operational value of energy storage resources will be affected by PGE's loads and resource fleet, market conditions and new market structures (e.g., the Western Energy Imbalance Market), as wells as new technologies within PGE's service area (both utility-scale and distributed). In particular, resources that provide flexibility to the system, including demand response, may erode some of the future value of energy storage if they can provide the same services over multiple timescales. Conversely, resources that require more flexibility from the system, such as additional wind and solar, may increase the future value of energy storage. As described in the 2016 IRP, the marginal value of energy storage may also tend to decrease on a given ESS as the need for additional flexibility reduces with the size of the energy storage fleet.

PGE will continue to assess these system-level factors within the Integrated Resource Planning process and the Company seeks to incorporate updates to the energy storage analysis as new information becomes available. PGE will also work to refine its modeling capabilities to improve resource characterization, runtimes, and convergence where possible. Through these efforts, PGE aims to be a leader in energy storage evaluation and to continue to provide novel insights into the potential for energy storage resources to provide value to the system.

## A.3 Integrated Planning Tool (IPT)

Additional details for the IPT are provided in the attached report prepared by BIS Consulting for PGE.

# APPENDIX B. EVALUATION OF PROPOSED PROJECTS

This appendix has been prepared as an addendum to the Energy Storage Potential Evaluation Report submitted to the OPUC on July 14, 2017. Further details regarding the proposed projects below are provided in PGE's Energy Storage Proposal.

The analysis below assesses the system benefits for five proposed energy storage projects. These projects and the expected benefits (system benefits and individual customer benefits) are summarized in Table B-1. All projects propose to use systems that are used by PGE to provide Capacity and Energy + Ancillary Services. The ESSs will also provide Outage Mitigation / Avoided Dx benefits for the substation-level (Coffee Creek) and feeder-level (Baldock Solar Facility) projects, as well as Power Reliability benefits for the microgrid and residential ESSs serving specific customers.

In comparison to the prior generalized analysis, Transmission Deferral benefits are not included for these projects, as no specific planned investments in transmission are expected to be deferred. Also, Time-of-Use Charge Reduction and Demand Charge Reduction are not included, as these systems are proposed to be owned by PGE and used daily to provide Energy + Ancillary Services.

**Table B-1. Proposed Energy Storage Projects**

| Project | Power | Capacity | Energy + Ancillary Services | Outage Mitigation / Avoided Dx | Power Reliability |
|---|---|---|---|---|---|
| Coffee Creek Substation | 20 MW | • | • | • | |
| Port Westward 2 Plant | 6 MW | • | • | | |
| Baldock Solar Facility | 2 MW | • | • | • | |
| Microgrids | 5 MW | • | • | | • |
| Residential | 1 MW | • | • | | • |

*Source: Navigant*

The assumptions used in performing these calculations are the same as those for the corresponding use case in the prior analysis, except where specified otherwise within the subsections below. Notably, the analysis assumes a 90% round-trip efficiency, no capacity degradation (due to annual replenishment), and a 10-yr book life. Due to potential improvements in cost-to-benefit ratio with a longer life, PGE may consider ESSs offering a 20-yr life. Assuming the same round-trip efficiency and no capacity degradation, the 20-yr benefits for Capacity, Energy + Ancillary Services, and Outage Mitigation / Avoided Dx would be 67% greater than the 10-yr benefits.[64]

[64] Note that this ratio is based upon the analysis in Section 3.3 of the submitted Energy Storage Potential Evaluation Report. This same ratio is obtained by assuming levelized 10-yr benefits over 20 yr using the inflation-adjusted cost of capital (4.122% instead of 6.204% without adjusting for inflation. This ratio will be different for ESSs with differences in efficiency and capacity degradation.

## *Project 1: 20 MW ESS at Coffee Creek Substation*

Figure B-1 illustrates the expected system benefits for the Coffee Creek substation. The assumptions for this project are the same as those used in scenarios 2a (2-hr substation-level ESS) and 2b (4-hr substation-level ESS), with the following exceptions:

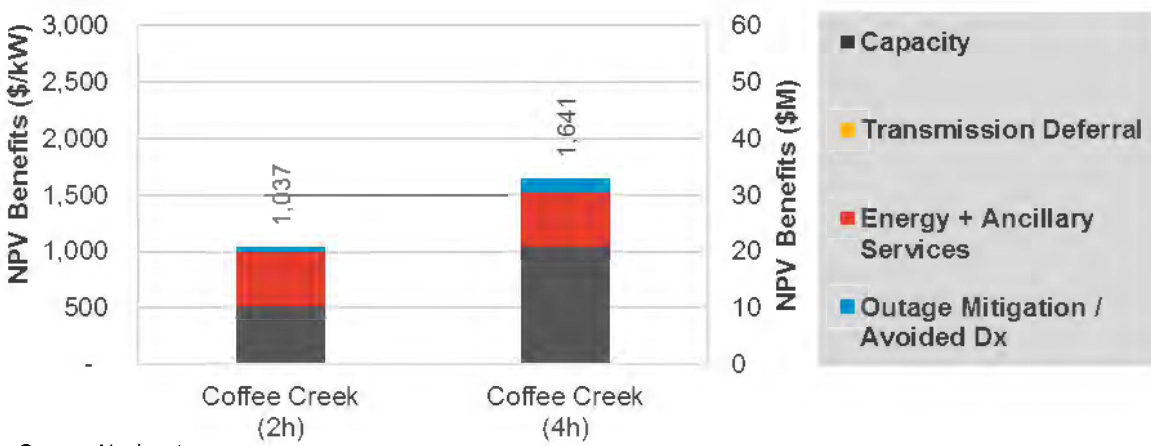
- Low and high cases were not considered.[65]
- Transmission Deferral benefits are not included.
- 12 event days per year are assumed for Capacity (instead of 20 collectively for Capacity and Transmission Deferral).
- Outage Mitigation / Avoided Dx benefits are based upon IPT analysis for this specific site, rather than a range of values between multiple sites.

Note that the reduction in total event days for Capacity and Transmission Deferral serves to increase the Energy + Ancillary Services benefits accordingly by increasing the operational time for that application. On the other hand, the average state of charge is slightly reduced, and the Outage Mitigation / Avoided Dx benefits are assumed to scale accordingly. The Capacity benefits remain the same.

The IPT analysis for this specific site indicates that the base values for Outage Mitigation / Avoided Dx benefits are similar with 4 hr of available capacity vs. 2 hr of available capacity, consistent with prior assumptions that benefits scale linearly with the average SOC.[66]

The hourly loading on the substation was assessed over the course of one year to assess any limitations in charging to prevent overloading. At least 20 MW of capacity were available during 97% of intervals, and an average of 96% of 19.3 MW was available during those intervals, leaving an average of 99.9% capacity available for charging the year, indicating that no significant reduction in Energy + Ancillary Services benefits should occur due to charging constraints.

**Figure B-1. System Benefits of 20 MW ESS at Coffee Creek Substation**




*Source: Navigant*

[65] Because all benefits were based upon outputs from robust analysis in ROM, IPT, and other modeling approaches, there is not expected to be a profound degree of uncertainty/variability in these values. Thus, only a base case was assessed.

[66] The 10-yr base Outage Mitigation benefits (assuming 100% SOC available at all times) for Coffee Creek, as determined via IPT analysis, are $68/kWh for a 2-hr system and $64/kWh for a 4-hr system.

The decision to procure an ESS with 2 hr, 4 hr, or another duration of energy will depend upon a variety of factors, which include but are not limited to the relative cost-to-benefit ratio in each case. Other factors must be considered including the available land at the site and the flexibility for assessing a variety of different operational conditions and circumstances that may provide valuable learning for PGE moving forward.

## *Project 2: 6 MW ESS at Port Westward 2 Plant*

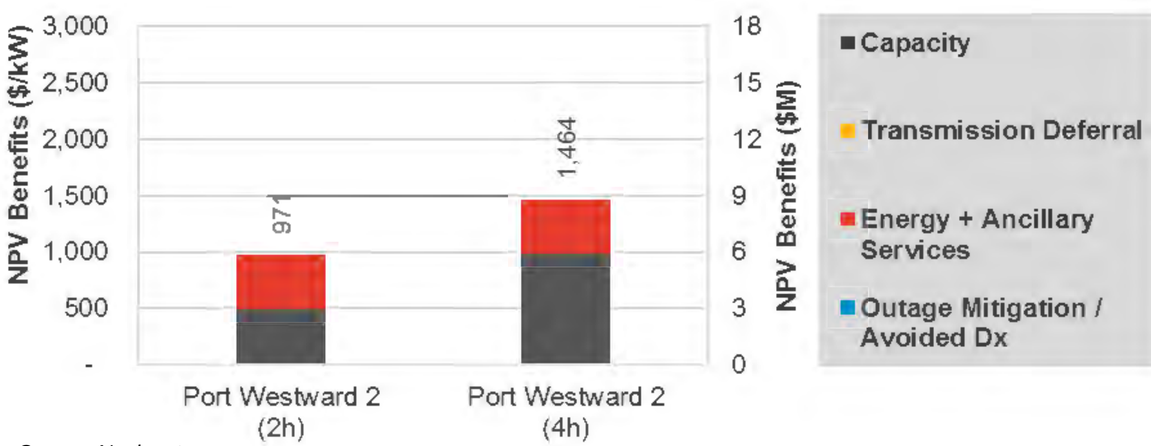
Figure B-2 illustrates the expected system benefits for the Port Westward 2 generation plant. The assumptions for this project are the same as those used in scenarios 1a (2-hr transmission-level ESS) and 1b (4-hr transmission-level ESS), with the following exceptions:

- Low and high cases were not considered.[67]
- Transmission Deferral benefits are not included.
- 12 event days per year are assumed for Capacity (instead of 20 collectively for Capacity and Transmission Deferral).

As with the Coffee Creek analysis, the reduction in total event days for Capacity and Transmission Deferral serves to similarly increase the Energy + Ancillary Services benefits, while Capacity benefits remain the same.

The Port Westward 2 Plant provides a case in which the ESS is co-located with a generation plant, offering a different scenario for co-optimization of Energy + Ancillary Services benefits. The calculated Energy + Ancillary Services benefits assume that the ESS is used to help optimize the dispatch of PGE's entire resource portfolio. However, the system may be used instead to optimize the Energy + Ancillary Services benefits specifically associated with the Port Westward 2 plant, resulting in different Energy + Ancillary Services benefits relative to ESSs that are not co-located with generation.

**Figure B-2. System Benefits of 6 MW ESS at Port Westward 2 Plant**




*Source: Navigant*

[67] Because all benefits were based upon outputs from robust analysis in ROM and other modeling approaches, there is not expected to be a profound degree of uncertainty/variability in these values. Thus, only a base case was assessed.

The decision to procure an ESS with 2 hr, 4 hr, or another duration of energy will depend upon a variety of factors, which include but are not limited to the relative cost-to-benefit ratio in each case. Other factors must be considered including the available land at the site and the flexibility for assessing a variety of different operational conditions and circumstances that may provide valuable learning for PGE moving forward.

### *Project 3: 2 MW ESS at Baldock Solar Facility*

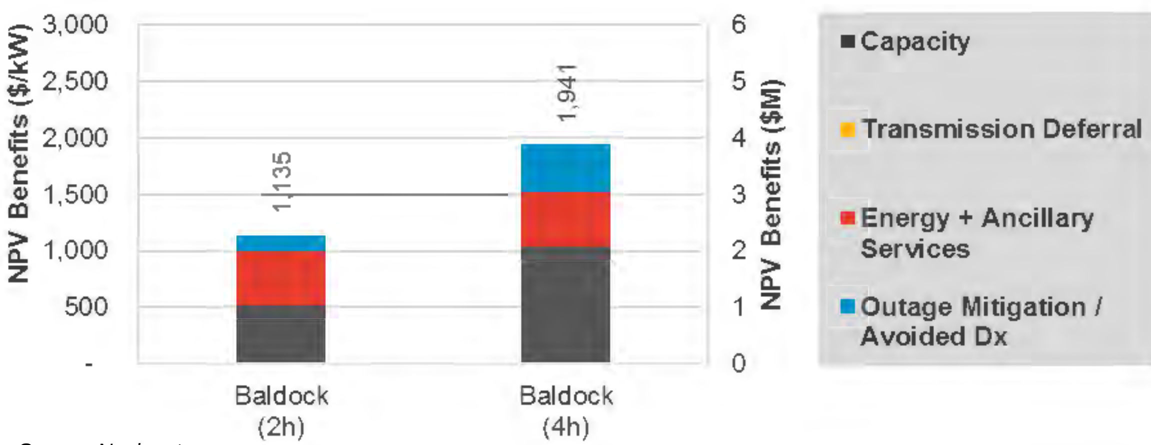
Figure B-3 illustrates the expected system benefits for the Baldock Solar Facility. The assumptions for this project are the same as those used in scenarios 3a (2-hr feeder-level ESS) and 3b (4-hr feeder-level ESS), with the following exceptions:

- Low and high cases were not considered.[68]
- Transmission Deferral benefits are not included
- 12 event days per year are assumed for Capacity (instead of 20 collectively for Capacity and Transmission Deferral)
- Outage Mitigation / Avoided Dx benefits are based upon IPT analysis for this specific site, rather than a range of values between multiple sites.

As with the Coffee Creek analysis, the reduction in total event days for Capacity and Transmission Deferral serves to similarly increase the Energy + Ancillary Services benefits and reduce Outage Mitigation / Avoided Dx benefits, while Capacity benefits remain the same.

The IPT analysis for this specific site indicates that the base values for Outage Mitigation / Avoided Dx benefits are similar with 4 hr of available capacity vs. 2 hr of available capacity, consistent with prior assumptions that benefits scale linearly with the average SOC.[69]

**Figure B-3. System Benefits of 2 MW ESS at Baldock Solar Facility**




*Source: Navigant*

[68] Because all benefits were based upon outputs from robust analysis in ROM, IPT, and other modeling approaches, there is not expected to be a profound degree of uncertainty/variability in these values. Thus, only a base case was assessed.

[69] The 10-yr base Outage Mitigation benefits (assuming 100% SOC available at all times) for the Baldock Solar Facility, as determined via IPT analysis, are $219/kWh for a 2-hr system and $217/kWh for a 4-hr system.

The decision to procure an ESS with 2 hr, 4 hr, or another duration of energy will depend upon a variety of factors, which include but are not limited to the relative cost-to-benefit ratio in each case. Other factors must be considered including the available land at the site, the capacity of the co-located solar generation, and the flexibility for assessing a variety of different operational conditions and circumstances that may provide valuable learning for PGE moving forward.

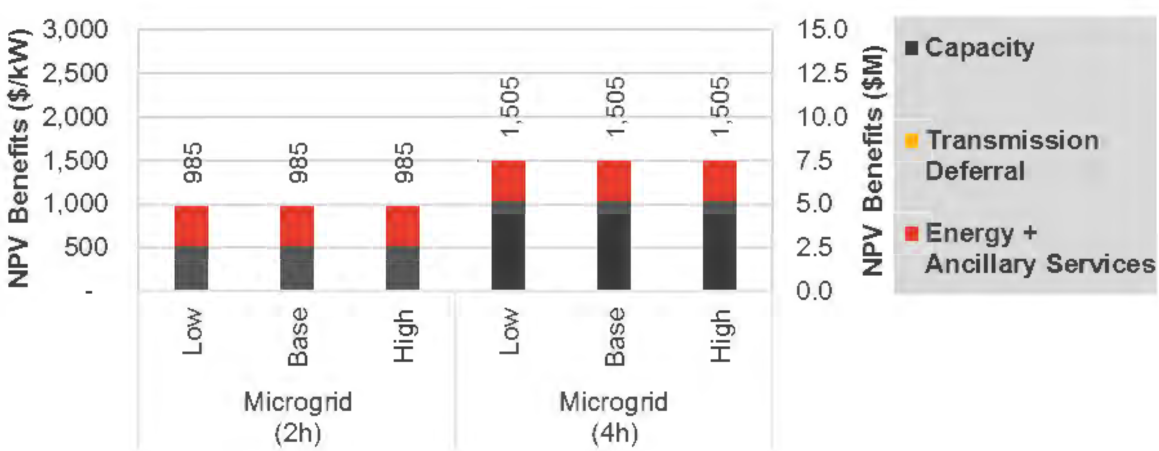
## *Project 4: 5 MW Aggregated ESS for Microgrids*

Figure B-4 and Figure B-5 illustrate the expected system benefits and individual customer benefits, respectively for the microgrid ESSs, which are expected to have 5 MW of total capacity across 3-5 microgrids. The assumptions for these ESSs are the same as those used in scenarios 4a (2-hr feeder-level ESS) and 4b (4-hr feeder-level ESS), except:

- Low and high cases were not considered.[70]
- Transmission Deferral benefits are not included.

The annual number of event days for Capacity is assumed to be the same as the collective number of event days for Capacity and Transmission Deferral (20/yr). The actual number may vary. A lesser quantity of event days per year would increase the Energy + Ancillary Services benefits and reduce Outage Mitigation / Avoided Dx benefits, while Capacity benefits would remain the same.

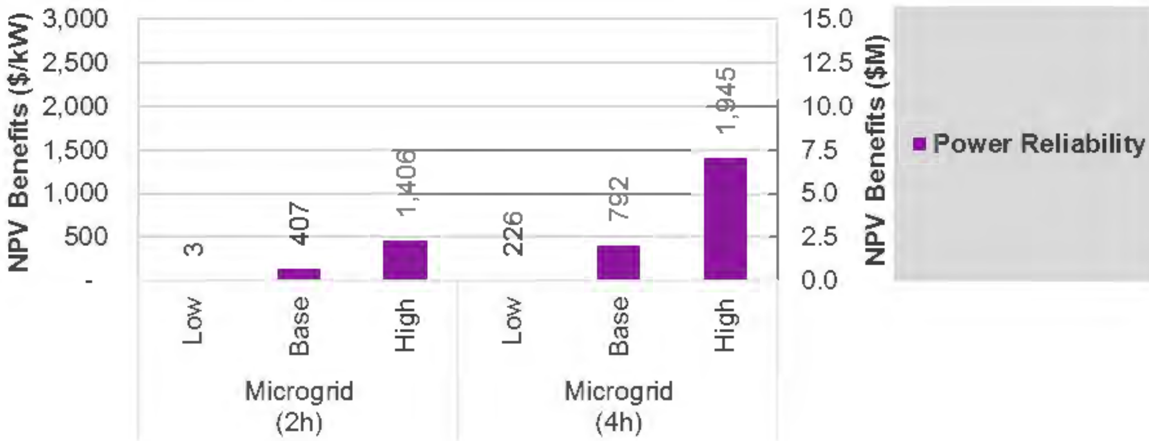
**Figure B-4. System Benefits of 5 MW Aggregated ESS for Microgrids**




*Source: Navigant*

[70] Because all benefits were based upon outputs from robust analysis in ROM, IPT, and other modeling approaches, there is not expected to be a profound degree of uncertainty/variability in these values. Thus, only a base case was assessed.

**Figure B-5. Individual Customer Benefits of 5 MW Aggregated ESS for Microgrids**




*Source: Navigant*

The decision to procure an ESS with 2 hr, 4 hr, or another duration of energy will depend upon a variety of factors, which include but are not limited to the relative cost-to-benefit ratio in each case. Other factors must be considered including the available land at each site and the flexibility for assessing a variety of different operational conditions and circumstances that may provide valuable learning for PGE moving forward.

## *Project 5: 1 MW Aggregated ESS for Residential Customers*

Figure B-6 illustrates the expected system benefits for the microgrid ESSs, which are expected to have 5 MW of total capacity across 3-5 microgrids. The assumptions for these ESSs are the same as those used in scenarios 4a (2-hr feeder-level ESS) and 4b (4-hr feeder-level ESS), except:

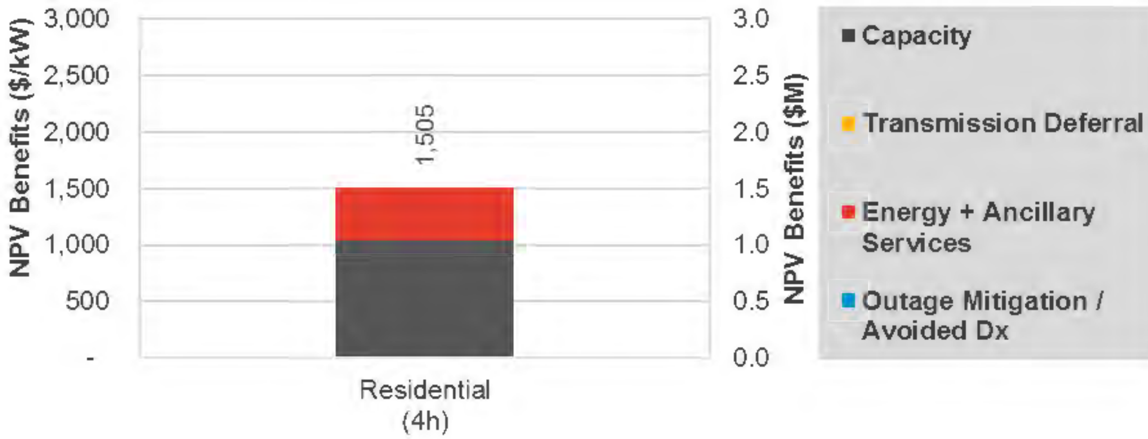
- Low and high cases were not considered.[71]
- Transmission Deferral benefits are not included.
- Power Reliability benefits are not calculated.

Power Reliability benefits are not calculated here, as the benefits to be obtained will be based upon specific customers' willingness to pay a price offered by PGE, rather than average values of service from surveys across a broad base of customers. Notably, while such surveys indicate that the average value of service for residential customers is relatively low, recent adoption of energy storage by residential customers in similar programs with other utilities indicates a higher value of service, at least among the subset of participating customers.

The annual number of event days for Capacity is assumed to be the same as the collective number of event days for Capacity and Transmission Deferral (20/yr). The actual number may vary. A lesser quantity of event days per year would increase the Energy + Ancillary Services benefits and reduce Outage Mitigation / Avoided Dx benefits, while Capacity benefits would remain the same.

[71] Because all benefits were based upon outputs from robust analysis in ROM, IPT, and other modeling approaches, there is not expected to be a profound degree of uncertainty/variability in these values. Thus, only a base case was assessed.

**Figure B-6. System Benefits of 1 MW Aggregated ESS for Residential Customers**




*Source: Navigant*

A 2-hr ESS was not modeled, but the expected system benefits would be proportionally the same versus a 4-hr ESS as for the microgrid case ($/kW).

The decision to procure an ESS with 2 hr, 4 hr, or another duration of energy will depend upon a variety of factors, which include but are not limited to the relative cost-to-benefit ratio in each case. Other factors must be considered including the available land at each site and the flexibility for assessing a variety of different operational conditions and circumstances that may provide valuable learning for PGE moving forward.

For a system of a different duration, benefits may be approximated as follows:[72]

- **Capacity** – For systems with less than 4 hr duration, benefits will scale (relative to the 4-hr ESS benefits) with duration (hr) divided by 4 hr. For systems with greater than 4 hr duration, benefits will remain the same as for the 4-hr ESS.
- **Energy + Ancillary Services** – For all systems with at least 2 hr of capacity, the benefits will remain constant.

[72] These approximations assume that the round-trip efficiency, degradation rate, project life, and other parameters remain unchanged.

# Appendix 5. Works Cited

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[3] HB 2193; Section 2.3.
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# Compliance with Guidelines Outlined in OPUC Order No. 16-504

There are seven guidelines outlined in the Order and are phrased as “encouragements” to electric companies.[1] PGE is encouraged to:

1. Submit multiple projects with an aggregate capacity close to [the cap] allowed by HB 2193.
   - PGE has submitted five project proposals of varying sizes with an aggregate capacity of 28 MW to 38.7 MW, the maximum allowed.
2. Submit a range of projects that are differentiated by use case, application, or other differentiating factor.
   - PGE has proposed projects at multiple locations on our grid, including residential sited, business customer sited, distribution feeder sited, substation sited and transmission sited projects. These projects will require different types of operational support, benefit different groups of and classes of customers, and have different learning opportunities.
3. Submit a portfolio of projects that balance technology maturity, technology potential, short- and long-term project performance and risks, and short- and long-term potential value.
   - PGE intends to remain technology agnostic and issue RFP’s that describe the needs of the energy storage systems including the performance requirements and applications.
4. Submit projects that can serve multiple applications.

[1] See Order No. 16-504, page 4. http://apps.puc.state.or.us./orders/2016ords/16-504.pdf

- The proposed projects will be capable of different applications that will vary based on their location on the grid. These applications include capacity, energy & ancillary services, outage mitigation, power reliability and resiliency.

5. Submit projects that are strategically located to help defer or eliminate the need for system upgrades, provide voltage control or other ancillary services, or supply some other location-specific service that will improve system operation and reliability.
   - PGE utilized the Integrated Planning Tool (IPT) and the Navigant Valuation of Energy Storage Tool (NVEST) model to determine and rank the locational and bulk energy benefits for the substation, distribution, and business customer sited projects.
6. Learn more about storage vendors and technologies through a Request for Information (RFI) process.
   - PGE issued an RFI in May 2016 to energy storage vendors requesting information such as company background, financials, pricing information, energy storage program development experience, technology performance, performance guarantees, and references. Twenty-seven responses were received and evaluated to help inform the proposal document.
7. Use established models (e.g., the Pacific Northwest National Laboratory's Battery Storage Evaluation Tool, the Electric Power Research Institute's Energy Storage Valuation Tool, etc.) to estimate the value of energy storage applications. Models must be transparent and auditable.
   - PGE commissioned Navigant to use the NVEST model to estimate the stacked value for each use case in the proposal. NVEST was originally developed by

Navigant for the US Department of Energy to evaluate the potential of energy storage in various grid applications across the United States. This framework was peer-reviewed, evaluated by many industry stakeholders, and adopted by the USDOE for use by recipients of the Smart Grid Demonstration program. In addition, PGE utilized internal models that have been used in prior regulatory dockets to provide key inputs to the NVEST model. The Resource Optimization Model (ROM) was developed in 2007 to determine wind integration costs. Since then, ROM has been developed further by working with external consultants, independent technical review committees, and through regulatory processes. In addition to quantifying wind integration costs, ROM has been used to calculate day-ahead forecast error costs in the AUT, energy storage value in the 2016 IRP, and structured product value as part of PGE's resource strategy and procurement function. Most recently, ROM was used to quantify flexibility value in PGE's bilateral negotiation process in UM 1892. IPT has been in its early stages since the end of 2016. IPT has been used to value the T&D capital projects that were identified via the Risk Register proposed in UE 319.

UM 1856 / PGE / 200
Jordan-Hart-Landstrom

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

# UM 1856

# Energy Storage Proposal

**PORTLAND GENERAL ELECTRIC COMPANY**

**Direct Testimony and Exhibits of**


***Tess Jordan***
***Elaine Hart***
***Jay Landstrom***


**January 5, 2018**

# Table of Contents

# I. Introduction

**Q. Please state your names and positions with Portland General Electric Company.**

A. My name is Tess Jordan. I am a Senior Analyst in the Financial Forecasting and Economic Analysis department. My qualifications appear in Section VI of this testimony.

My name is Elaine Hart. I am a Senior Analyst in the Integrated Resource Planning department. My qualifications appear in Section VI of this testimony.

My name is Jay Landstrom. I am the Manager of T&D Asset Management. My qualifications appear in Section VI of this testimony.

**Q. What is the purpose of your testimony?**

A. The purpose of this testimony is to provide support for Portland General Electric Company's (PGE's) Energy Storage System Proposal (Proposal), which was filed with the Public Utility Commission of Oregon (OPUC or Commission) November 1, 2017. This testimony also supports PGE Exhibit 100, in this docket and describes PGE's cost-effectiveness analysis, including the methodologies employed to estimate project costs and project benefits.

**Q. What is the purpose of a cost-effectiveness analysis?**

A. Cost-effectiveness analysis considers all quantitative costs and benefits to the electric system and its customers over the life of the project. PGE used the cost-effectiveness analysis to understand how relative costs and benefits might vary across the proposed projects and programs. We did not use the cost-effectiveness tests to screen or prioritize components of the proposal.

**Q. Why didn't PGE use the cost-effectiveness tests to screen or prioritize proposed projects?**

A. Consistent with House Bill (HB) 2193, cost-effectiveness is not the primary purpose for PGE pursuing the proposed projects. Instead, our objective is to bring value to customers while learning across a diverse set of projects. If we were to only pursue the most cost effective projects, then the proposal would inherently lack diversity and may forego valuable learning opportunities. In particular, projects that have relatively high-cost benefit ratios but low total costs may represent relatively low regrets options for additional learning. Our Proposal meets the intent of HB 2193 by supporting the development of regulatory, technical and operational experience with energy storage systems by electric companies and stakeholders in Oregon to best prepare the state for the broad-scale deployment of storage over time.

**Q. How did PGE approach determining cost-effectiveness?**

A. Two cost-effectiveness tests were applied to all project proposals: the Total Resource Cost test[1] (TRC) and the Ratepayer Impact test[2] (RIM). Additionally, a Participant Cost Test[3] (PCT or Participant Test) was conducted for customer pilots (the residential and microgrid program). These tests required PGE to estimate project costs and project benefits, and are discussed in the following sections. A Societal Test is a variant of the TRC; it differs in that it includes externalities such as environmental impacts, national security, job creation, health impacts, and community resiliency, and employs a societal discount rate. This was not included because we do not have an approved methodology for identifying and quantifying

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[1] The TRC measures net benefits of a program for all stakeholders involved (both the utility and program participants). Costs borne by both the utility and participants are included, but cash transfers between the entities are not.

[2] The RIM takes the utility perspective only and excludes any benefits or costs borne by the participants. A RIM with a benefit/cost ratio less than 1.00 indicates net cost to non-participating customers. For the purposes of these projects, these costs can be attributable to technology learnings and readiness.

[3] The PCT considers benefits and costs accrued by program participants only. For energy storage systems proposals that target the system rather than unique participants (i.e., Coffee Creek Substation, Baldock Mid-feeder project, and Generation Kick Start), the inputs and results of the TRC and RIM will be the same, and the PCT is not applicable.

societal costs and benefits. Without an approved methodology, the results of any cost-effectiveness analysis are of limited value.

**Q. What were the results from the TRC, RIM, and PCT tests?**

A. PGE estimates the TRC for all projects in aggregate to be 0.61–0.86 (high and low cost scenarios), shown below in Table 1. Details for each project's cost-effectiveness, and conditions required to bring each project to a benefit/cost ratio of 1.0 or above, are included in Section IV of this testimony.

**Table 1**
**Cost-effectiveness Summary: Proposed Energy Storage Portfolio (2017$, $M)***

| | **Low Cost Estimate** | | | **High Cost Estimate** | | |
|---|---|---|---|---|---|---|
| | **TRC** | **RIM** | **PCT**** | **TRC** | **RIM** | **PCT*** |
| Benefits | $92.8 | $88.6 | $7.1 | $116.6 | $107.4 | $14.6 |
| Costs | $108.1 | $107.5 | $3.5 | $190.0 | $189.8 | $5.7 |
| **Net Benefit** | **$(15.3)** | **$(18.9)** | **$3.6** | **$(73.5)** | **$(82.4)** | **$8.9** |
| **Benefit/Cost Ratio** | **0.86** | **0.82** | **2.03** | **0.61** | **0.57** | **2.56** |

* Assumed 20-year maintenance and capacity contracts for Baldock Mid-feeder, Coffee Creek Substation, Microgrid pilot, and Generation Kick Start. Net benefit illustrates the magnitude of dollars (in millions) by which benefits exceed costs. Negative numbers indicate projects for which costs exceed benefits.
** The PCT only applies to programs/projects with participants (Residential and Microgrid pilots).

The benefits and benefit/cost ratios reported here are conservative in that they include only those benefit streams that PGE considered to be likely achievable and quantifiable with information available today. As described in Section IV of this testimony, potential additional benefits such as contribution to congestion relief on the South of Allston transmission path, benefits associated with participation in the Western Energy Imbalance Market (Western EIM), and additional customer values such as resiliency, were excluded from the analysis but are not precluded from testing or actual operations.

**Q. How is the remainder of your testimony organized?**

A. We first discuss how we determined the costs and benefits for the proposals. Then we discuss the project-specific cost-effectiveness results. The testimony is organized into the following sections:

- Section I: Introduction;
- Section II: Project Cost Analysis;
- Section III: Project Benefits Analysis;
- Section IV: Project-Specific Cost-effectiveness Results;
- Section V: Conclusion; and
- Section VI: Qualifications

## II. Project Cost Analysis

**Q. How did PGE determine Project Costs?**

A. PGE issued a Request for Information (RFI) to companies that could likely engineer, procure, and construct one or more energy storage systems. The RFI results provided by vendors may not represent competitive or market prices that we will see in the Request for Proposal (RFP) process. In our Proposal, we presented a cost range for each project (low and high) based on the range of quotes that companies submitted, combined with PGE construction and programmatic costs. These costs were calculated based on the RFI that was issued and may not reflect current market prices or prices that we will see when we issue a RFP.

**Q. What costs did PGE identify?**

A. Table 2 provides a cost summary of each proposal for the most cost effective energy storage system profile. This was a 20-year energy storage system for all projects other than the Residential Pilot.

**Table 2**
**Cost Summary of Energy Storage Proposals (000,000s)**

| | **Low Cost Estimate** | | **High Cost Estimate** | |
|---|---|---|---|---|
| **Project** | **Overnight Capital** | **Year 1 Rev. Req.** | **Overnight Capital** | **Year 1 Rev. Req.** |
| Baldock Mid-feeder* | $2.8 | $0.6 | $4.1 | $1.0 |
| Coffee Creek Substation* | $30.4 | $6.7 | $35.7 | $8.2 |
| Generation Kick Start* | $5.9 | $1.4 | $7.7 | $1.9 |
| Microgrid Resiliency Pilot* | $11.6 | $1.5 | $41.2 | $2.8 |
| Residential Storage Pilot | $2.1 | $0.8 | $6.0 | $1.6 |
| Controls and System Integration | $3.1 | $0.4 | $3.1 | $0.4 |
| Administration and Evaluation | - | $0.4 | - | $0.4 |
| **Total** | **$55.8** | **$11.7** | **$97.8** | **$16.4** |

* Assumed 20-year maintenance and capacity contracts. Costs include portfolio controls and administration.

**Q. What drives the range in overnight capital costs presented for each energy storage system profile?**

A. Across the total portfolio, the $42 million cost range results from:

1. Range in price quotes across the three non-programmatic projects, a 21% or $8.4 million increase;
2. Microgrid Pilot power variation (five megawatts in the low cost scenario versus 12.5 megawatts in the high cost scenario); coupled with vendor quote variation this results in a $30 million increase, and
3. Residential Pilot program design and hardware cost range, a 186% or $4.0 million total increase.

For projects without programmatic components (i.e., Coffee Creek Substation, Baldock Mid-feeder, and Generation Kick Start) the range is entirely driven by variation in vendor quotes. Vendors priced both overnight capital costs and ongoing operation and maintenance (O&M) associated with service, maintenance, and power augmentation. For the Coffee Creek Substation project, the range between vendor quotes was minimal at 12%. The Baldock Mid-feeder project elicited a much larger range of 66%. Pricing per megawatt hour (MWh) is typically higher for both smaller capacity batteries and shorter duration batteries, although not all quotes reflected this. The two-hour energy storage system was selected due to site space limitations, thus the cost range presented is quite broad. The Generation Kick Start energy storage system pricing per MWh was estimated from data received in our RFI and the Coffee Creek Substation and Baldock Mid-feeder quotes.

The microgrid proposal is unique in that the high range reflects much more power than the low range cost estimate (five 2.5 MW batteries versus five 1 MW batteries, a 150%

increase). This increase in power amplifies a per MWh price gap of 45%. The bids also differ in their structure of power augmentation costs (upfront versus annual). Both the high and low proposals include one ongoing PGE full time equivalent employee (FTE).

The Residential Storage Pilot involves the greatest number of variables, as it reflects a range in product pricing as well as ownership structure. In this market there is the most significant range in hardware costs quotes across vendors. This proposal involves the largest programmatic component, which includes PGE administration, energy storage system inspection and maintenance, Information Technology investment, ongoing software expense, and sales and marketing costs. The high bid includes an upfront warranty investment. Project costs describe a 10-year energy storage system only, the technology currently available on the market.

**Q. Why were 20-year energy storage systems selected for the Proposal cost summary pages?**

A. The 20-year energy storage systems resulted in higher benefit/cost ratios. Upfront capital costs are generally very similar between 10- and 20-year energy storage systems (0-5% increase for 20-year energy storage systems). The higher cost of longer life energy storage systems are captured in a longer stream of maintenance and power augmentation costs, and in some cases, a higher annual cost. In contrast, both system benefits and benefits accruing to the participant are estimated to be constant over the life of the energy storage system (benefits decrease with energy storage system power; in the case of the residential energy storage system only, this was modeled to decrease over time).

**Q. What is PGE's level of confidence around the price range presented?**

A. The energy storage market is evolving rapidly. It includes companies pricing their products aggressively to secure early market share. The pricing presented here is based on an installation date of 2020, with the exception of the Residential Storage Pilot which uses current market pricing. Quotes reflect near-term projected declines in energy storage pricing as determined by the vendors. Given the uncertainty in the projected pricing declines, there is the potential that bids come in lower than the costs presented here. We will issue an RFP for the projects approved by the OPUC and evaluate the resulting site-specific bids. Vendors will be selected that minimize both cost and risk. The high cost range presented in this report reflects the broad range that currently exists on the market, a range that varies significantly by energy storage system profile and installation date. We will not know the exact costs for the proposed energy storage systems until we issue the RFP.

**Q. Please describe controls and system integration costs.**

A. PGE intends to implement a control system that provides the necessary features to capture benefits associated with the use cases identified in our Energy Storage Potential Evaluation, provided as PGE Exhibit 101, Appendix 4 (Potential Evaluation), of this docket. The control system costs shown in Table 2, above, represent the total costs needed to support all proposed projects. These costs are discussed in more detail in Section IV of this testimony. Control system software and functionality is described in PGE Exhibit 100, Section VII, in this docket.

**Q. Please describe Administration and Evaluation costs.**

A. Administration and Evaluation costs are needed to support the portfolio of proposed projects. These include three FTE (i.e., project manager, analyst, and engineer), O&M dollars, and program evaluation in years 2020-2022. Programmatic costs supporting only one energy storage system within the portfolio are included in the project-specific totals. For more information regarding these costs, see PGE Exhibit 101, Section 10.

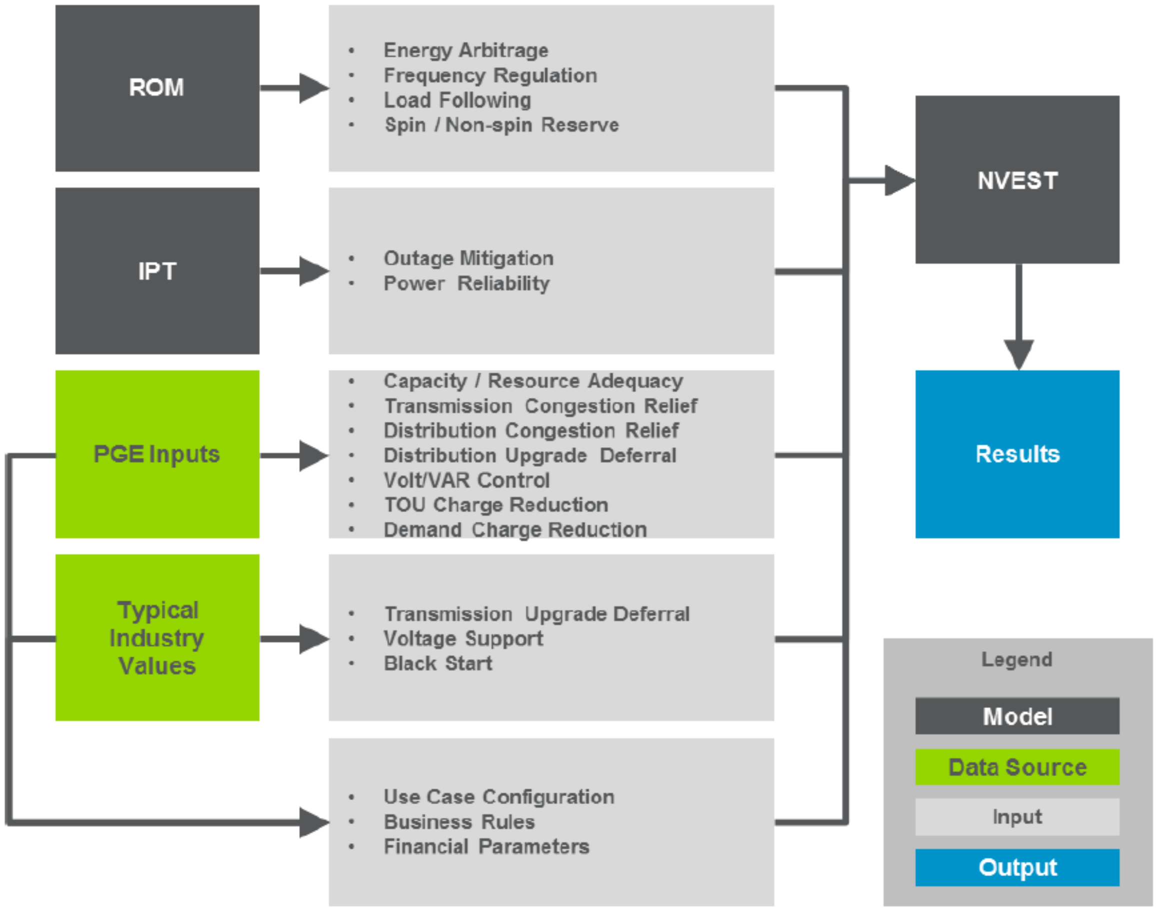
Program evaluation will be led by a consultant, and will encompass both quantitative and qualitative aspects of project benefits and PGE's abilities and preparedness for further energy storage system deployment. Our evaluation strategy is outlined in PGE Exhibit 101, Section 10.2, in this docket.

## III. Project Benefits Analysis

**Q. What approach(es) did PGE use to determine Estimated Project Benefits?**

A. PGE engaged Navigant Consulting, Inc. (Navigant) to conduct our Potential Evaluation and to estimate project benefits. We worked together to leverage our existing tools for quantifying the locational and bulk energy benefits associated with energy storage and to integrate these analyses with additional insights from Navigant utilizing their Navigant Value of Energy Storage Tool (NVEST). Figure 1 shows how Navigant's NVEST model interfaced with our modeling and each of the input assumptions. Results from NVEST that were utilized to determine the Estimated Project Benefits are provided in Appendix B of the Potential Evaluation.

**Figure 1**
**Modeling approach utilized in PGE's Draft Potential Evaluation [Source: Navigant]**




**Q. Does the Potential Evaluation incorporate the nine key elements identified by Staff in Commission Order No. 17-118?**

A. Yes. Navigant describes how the Potential Evaluation incorporates eight of the key elements recommended by Staff in Commission Order No. 17-118 (Order 17-118) in Table 1-2 of the Potential Evaluation. In addition, Navigant describes how the Potential Evaluation incorporates the modeling attributes proposed by Staff in Order No. 17-118 (the ninth key element) in Table 1-4 of the Potential Evaluation.

**Q. Which applications were evaluated in the Potential Evaluation and Estimated Project Benefits analysis?**

A. The Potential Evaluation and Estimated Project Benefits evaluation considered all of the applications listed in Order 17-118, including: capacity/resource adequacy; energy arbitrage; ancillary services (i.e., regulation, load following, spin/non-spin reserves, voltage support, and black start); transmission benefits (i.e., transmission congestion relief and transmission upgrade deferral); distribution benefits (i.e., distribution upgrade deferral, distribution congestion relief, outage mitigation, and volt/VAR control); and customer benefits (i.e., power reliability, time-of-use (TOU) charge reduction, and demand charge reduction).

Navigant includes a description of how each of these applications was evaluated in Table 2-1 of the Potential Evaluation. The resulting individual benefits associated with these applications are listed in Table 3-1 of the Potential Evaluation. The resulting stacked benefits are described for each use case in Section 3.2 of the Potential Evaluation and for the proposed projects in Appendix B of the Potential Evaluation.

**Q. Are there any additional benefits associated with the proposed projects not quantified in the Potential Evaluation?**

A. It is possible that there will be additional benefits associated with the proposed projects that were not quantified in the Potential Evaluation and not reflected in the Estimate Project Benefits. For example, there may be additional benefits associated with participation in the Western EIM, contribution to congestion relief on the South of Allston transmission path, or additional customer values, like resiliency, and enhancing spinning reserves capability at existing thermal resources (i.e., at Port Westward 2 Generating Station (PW2) via the Generation Kick Start project).

**Q. Why weren't these potential additional benefits included in the benefits analysis and cost-effectiveness tests?**

A. PGE focused on quantifying benefits associated with the applications listed in Order 17-118 and prioritized those benefits that we determined were likely achievable and quantifiable with the information known today. In this way, the Estimated Project Benefits could be interpreted as conservative. Exclusion from the Estimated Project Benefits does not preclude any of the projects from realizing additional benefits to the utility nor to customers should opportunities arise in the future. However, we did not believe that it was appropriate to rely on additional, more speculative, future benefits to estimate cost-effectiveness.

**Q. Describe the inputs into the NVEST model.**

A. For this study, PGE provided key input data and modeling results to Navigant from its Resource Optimization Model (ROM) and Integrated Planning tool (IPT) to characterize energy/ancillary service benefits (i.e., energy arbitrage, load following, regulation, spin, and non-spin reserves), and distribution and power reliability benefits, respectively. Additional input data include: system-specific inputs from PGE for capacity value and volt/VAR control; PGE's Tariffed Rate Schedules 7, 32, 83, and 85 to quantify TOU charge reduction and demand charge reduction; and typical industry values supplied by Navigant for voltage support, black start, and transmission benefits.[4]

**Q. Describe how ROM estimates energy and ancillary service benefits.**

A. ROM is a production cost model, which simulates the commitment and dispatch of PGE's resource portfolio with 15-minute resolution over the course of a test year. The portfolio is constrained to meet load and ancillary service requirements, including load following, regulation, spinning, and non-spinning reserves. Ancillary service requirements encompass flexibility requirements on the system down to one minute resolution. We simulated a 2021

[4] More specific information regarding the input data for the NVEST model is provided in PGE Exhibit 101, Table 7 (page 34-36), of the docket.

test year based on assumptions in PGE's 2016 Integrated Resource Plan[5] (IRP) and compared the performance of the portfolio with and without various energy storage systems. The cost differences between simulations with and without energy storage systems represent the combined, co-optimized energy arbitrage and ancillary service benefits associated with the energy storage system. ROM simulation inputs and results were shared with Navigant to provide inputs to the NVEST model and were shared under Protective Order No. 17-441 in PGE Exhibit 101, Appendix 3, of the docket. The full ROM analysis is described in Appendix A.2 of the Potential Evaluation.

**Q. Why did PGE utilize a production cost model rather than a price-taker model to calculate co-optimized energy and ancillary service benefits?**

A. PGE believes that both production cost and price-taker models provide useful insight and will likely have a place in the evaluation of energy storage resources in the future. We selected to utilize a production cost model to support the Potential Evaluation and Estimated Project Benefits analysis for three primary reasons:

1. We used ROM, a production cost model, to evaluate co-optimized energy and ancillary service benefits for energy storage in the 2016 IRP. Utilization of the same approach in the Evaluation ensures alignment with our primary resource evaluation framework, the IRP.
2. Price-taker models, like Electric Power Research Institute's (EPRI) StorageVET and Pacific Northwest National Lab's (PNNL) Battery Storage Evaluation Tool, assume that the energy storage resources operate within organized wholesale energy and ancillary service markets and require pricing information from these markets in order

[5] The simulation incorporated market pricing based on Reference Case assumptions in the 2016 IRP.

to dispatch the energy storage system. We do not participate in an organized ancillary service market and hence ancillary service pricing does not exist for the system.[6] In contrast, production cost models, like ROM, capture the portfolio value of providing ancillary services by identifying potential operating cost reductions on other, higher cost, resources that provide ancillary services in the portfolio. PGE believes that production cost models, like ROM, provide improved accuracy and ability to appropriately co-optimize energy and ancillary service benefits in systems like PGE's.

3. Production cost models, like ROM, capture portfolio effects and decreasing marginal value, while price-taker models do not. In other words, in a price-taker model the first MW of storage is assumed to operate in the same way and to have the same value to the system as the 1,000th MW of storage. For small energy storage system resources in large wholesale markets, this simplification may be appropriate. However, for substantively-sized fleets of energy storage system resources within smaller balancing areas, like PGE, portfolio effects and decreasing marginal value are important considerations.

**Q. Does ROM evaluate benefits associated with operation within the Western EIM?**

A. As a wholesale energy market, the Western EIM can be represented within the ROM modeling framework as an energy arbitrage opportunity; however, PGE did not incorporate Western EIM-related energy storage benefits into the evaluation for three reasons.

First, PGE joined the Western EIM in October of 2017. As a result, we have very limited operating experience within the market, our pricing nodes therefore have limited historical

[6] This is true both before and after PGE joined the Western EIM, as the Western EIM is an energy-only market with no priced ancillary service products.

pricing information, and pricing may be artificially volatile as PGE and other new entrants continue to learn and to improve practices within the market.

Second, multiple utilities are planning to enter the Western EIM prior to 2021 and these new participants are likely to affect Western EIM price volatility and the associated energy arbitrage value. Price volatility may also be driven by changes to market rules or changes to the regional resource portfolio. In general, historical price volatility in a relatively new market may not be indicative of future price volatility and may not be appropriate for quantifying the value of flexible resources like energy storage systems. Evaluations that are based on recent Western EIM pricing data may overstate the long-term benefits achievable in the Western EIM. We therefore sought to understand the value of energy storage system resources to our customers without the assumption of additional Western EIM-driven benefits.

Finally, the sub-hourly modeling and load following requirements in ROM capture value associated with improving sub-hourly operation of our resource portfolio through utilization of energy storage, which is expected to overlap with the benefits provided by the Western EIM. In other words, Western EIM benefits may not be additive to the benefits quantified in the Potential Evaluation. Instead they may increase or decrease benefit streams already quantified. Although these benefits are not estimated in the Potential Evaluation, we recognize that Western EIM participation is an important area of learning for the efficient integration of energy storage systems into its resource portfolio.

**Q. Why did PGE model locational benefits associated with risk reduction on the distribution system rather than load growth?**

A. Analyses of the benefits of energy storage system in the distribution grid at other utilities have typically focused on identifying the specific transformers or other distribution assets for which impending replacement due to load growth can be deferred. Such an approach was deemed inapplicable for PGE's analysis given the company's load growth profile. Within our territory, load growth tends to be large, clustered, and sudden (e.g., a new server farm or expansion to industrial facility) as opposed to slow and incremental. The type of load growth PGE experiences (lump load additions) typically requires the installation of significant new infrastructure that cannot feasibly be deferred through the installation of energy storage systems alone. As a case in point, there are no incremental upgrades currently pending in PGE's system for which an energy storage system was deemed an adequately reliable and appropriate alternative to fundamental asset replacement.

There are benefits to installing storage on PGE's distribution system that are worth analyzing. Installing an energy storage system at a station, on a feeder, or at a customer meter reduces the impact of service failure for customers by creating redundancy from a power supply perspective. Expressed in modeling terms, an energy storage system can eliminate or reduce a customer's outage duration, which in turn reduces customers' outage impact costs (i.e., the economic effect of a loss of power on customers). PGE calls this type of reduction a "risk reduction," and considers it an important locational benefit that should be considered in any benefit/cost analysis of potential infrastructure investment projects, as this aligns with PGE's broader system analysis, reliability planning, risk reduction, and investment evaluation methods.

**Q. Describe how the IPT estimates locational benefits.**

A. PGE uses a suite of risk models to inform many of its Transmission and Distribution (T&D) planning and investment activities. These models quantify risk factors for T&D's most vital T&D assets, including the assets' annual likelihood of failure, and the consequences for customers and PGE should a failure occur. The outputs of these models are used to evaluate the relative value of different risk intervention options, given their respective costs. To do these benefit/cost evaluations, PGE uses a tool called the IPT.

While primarily used as a project options evaluation tool, the IPT can also be used to determine where in the T&D system a specific risk reduction activity is most beneficial. Thus, the IPT was employed to determine the optimal locations for storage in the T&D system, from an outage duration reduction perspective. The IPT estimates expected outage probability and outage consequence throughout the distribution system. This allows PGE to identify the value of location-specific system upgrades that reduce risk. PGE and BIS Consulting used the IPT to test the value of energy storage systems at various locations across the distribution system. For in-front-of-meter energy storage systems, the value identified from the IPT primarily represents expected benefits that will accrue to many PGE customers when outage durations are reduced, due to outage which we've termed "outage mitigation benefits and avoided distribution investments that would be driven by risk reduction." For behind-the-meter energy storage systems, the value identified from the IPT primarily represents a comparable anticipated benefit, but because this benefit only accrues to participants, we've classified it as a "power reliability benefit." The IPT and its application to energy storage locational benefits analysis are further described in the Potential Evaluation in Section 2.2.3[7].

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[7] Also discussed PGE Exhibit 101, Section 2.2(a) and Appendix 2.

**Q. Are benefits co-optimized in the Potential Evaluation and Estimated Project Benefits?**

A. Yes. Co-optimization occurred in two ways in the Potential Evaluation and Estimated Project Benefits.

1. ROM computationally co-optimized energy and ancillary service benefits (including energy arbitrage, load following, regulation, spin, and non-spin reserves), allowing the energy storage systems to dynamically serve different portions of energy and ancillary service applications in each 15-minute increment to maximize value to the portfolio.
2. Navigant used heuristics to co-optimize across other applications. This process involved identifying how the ability to serve each application affected the ability to serve all other applications (using a compatibility matrix) and weighing of the relative value between applications that could not be simultaneously served to identify the optimal combined set of applications for each end use. This approach, which is described in Sections 2.3 and 2.4.1 of the Potential Evaluation, ensures that each use case incorporated the highest value applications and that the benefit stacking did not double-count benefits that could not be provided simultaneously.

**Q. Why did Navigant use heuristics to co-optimize some applications?**

A. In discussions with Navigant and energy storage system vendors, PGE was advised that energy storage system are typically controlled based on operating principles that are designed to target the highest value applications, rather than computational co-optimization across all potential applications. While there are clear economic signals that are considered in co-optimization across energy and ancillary service applications, there is no corresponding real-time cost optimization that occurs in distribution operations that can be easily extended to energy storage operations. The extent to which energy, ancillary service, and locational benefits can be fully co-optimized in operating energy storage systems in real-time remains an area of active focus in the research community. We believe that the proposed projects provide an avenue for exploring various control modes and testing the ability to effectively co-optimize applications in real-time operations. However, given the state of technology and the experience to date across the energy storage system industry, to presume that the proposed projects will computationally co-optimize across all possible applications in real-time may overstate the value of the systems.

We determined that full simultaneous and computational co-optimization across all potential applications would add substantial computational complexity, would require significantly more resources, and would not necessarily improve the accuracy of the results relative to the operating rule heuristics employed by Navigant. Instead, we requested that where full computational co-optimization was impractical and the optimal operating rules were not trivial, Navigant identify multiple bookend operating modes to bound the stacked benefits. For example, for distribution-sited energy storage systems, we will have the option to set aside a portion of the system to be on standby for outage mitigation benefits or to optimize the full energy storage system for other applications and to utilize whatever energy is available in the rare event of a distribution asset failure for outage mitigation. Because the optimal strategy in this situation is not logically apparent, Navigant tested both operating mode bookends in the Potential Evaluation and found that the second mode was anticipated to provide greater total stacked benefits. Navigant applied a similar approach in characterizing interactions of energy and ancillary service benefits with demand charge reduction benefits and time-of-use benefits and found that the operating mode will affect the total benefits and the distribution of benefits between the utility and the customer for behind-the-meter systems.

**Q. Have any changes been made to the Potential Evaluation since PGE filed the draft on July 14, 2017?**

A. Yes. PGE conducted a public workshop on the Potential Evaluation on August 1, 2017. Parties filed comments on the draft Potential Evaluations on August 25, 2017, and Staff filed its report with recommendations for revision of the Potential Evaluations on September 22, 2017. PGE incorporated modifications to the draft Potential Evaluation based on comments from parties and recommendations from Staff. The resulting final Potential Evaluation is provided as PGE Exhibit 101, Appendix 4, of the docket. The primary modifications in response to comments are summarized below:

1. *Expanded discussion of applications with zero value in stacked benefits.* While Navigant considered all applications listed in Order 17-118, not all applications contributed to the total stacked benefits for each use case. In the final Potential Evaluation, Navigant expands on the reasoning behind the assignment of zero value for voltage support, black start, distribution congestion, and volt/VAR control in the stacked benefit analysis. This can be found in the Potential Evaluation, Section 2.4.1. Section 2.4.1 also describes how other applications with non-zero value are aggregated within the stacked benefits analysis.
2. *Expanded discussion of approach to co-optimization.* The final Potential Evaluation includes an additional discussion of and justification for the approaches to co-optimization utilized in the analysis. This can be found in the Potential Evaluation, Section 2.3.

3. C*larification of the identified transmission benefits.* PGE originally interpreted the transmission congestion application to refer to congestion on PGE's internal transmission system and considered the potential for avoided transmission investments for relief of congestion on the South of Allston path as a transmission deferral benefit. The final Potential Evaluation clarifies that the Transmission Deferral benefits are inclusive of transmission investment deferral opportunities associated with load growth as well as congestion relief.
4. *Project-specific benefits*. While the Potential Evaluation focused on generic locations across the PGE system, the final Potential Evaluation includes results for the specific proposed projects in the Potential Evaluation, Appendix B.
5. *Inclusion of cost information in the Proposal.* PGE focused both the draft and final Potential Evaluation on project benefits and conducted a separate RFI process to estimate project costs (described in the prior section). The final Proposal includes both estimated project costs and benefits.
6. *Sharing of modeling and energy storage simulation information.* To address concerns regarding transparency of model data and the extent to which PGE conducted an energy storage simulation, we shared, under Protective Order No. 17-441, all of the data from ROM and the IPT that was shared with Navigant to conduct the evaluation in NVEST as well as key input data utilized by ROM to simulate energy storage operations and operational value in PGE Exhibit 101, Appendix 3, of the docket.

The ROM input data shared included 15-minute resolution load, wind output, solar output, upward and downward load following requirements, upward and downward regulation requirements, spinning reserve requirements, non-spinning reserve requirements, and market prices as well as day-ahead and 15-minute ahead forecasts of each of these parameters for the full test year.  The output data included the energy storage dispatch behavior with 15-minute resolution across the full test year, including charging schedule, discharging schedule, and state of charge as well as the portions of the load following, regulation, spinning, and non-spinning reserves provided by the energy storage system in all time steps.

We also agreed to continue to improve our modeling capabilities and to share shadow prices from ROM under a protective order when they become available.  These shadow prices may be used for future benchmarking exercises with price-taker models to better understand the differences between production cost modeling and price-taker models as they pertain to PGE's Potential Evaluation.

## IV. Project-Specific Cost-effectiveness Results

**Q. Please describe the cost-effectiveness of the Baldock Mid-feeder Project.**

A. Of the mid-feeder energy storage systems profiled, the 20-year, low-cost energy storage system performs the best, with benefits valued at 86% of costs. As with all energy storage system profiles, cost-effectiveness increases with duration. For this energy storage system, benefit streams produce a net present value (NPV) of $3.9 million, resulting in a net cost of $0.8 million. PGE understands this gap to be associated with the value of the project's learning objectives, discussed in PGE Exhibit 100, Section II.

This is a two-hour (versus four-hour) energy storage system, thus the capacity is a smaller share of the benefits stream at 45%. Energy and ancillary services provide 42% of the revenue stack, and outage mitigation provides 12%. Total carrying cost (NPV of initial capital investment and ongoing O&M for energy storage system maintenance and power augmentation) is estimated at $4.6 million.

Future conditions that would render the mid-feeder energy storage system cost effective include a total cost reduction (across either or both capital and ongoing O&M) of 16%, or additional benefit streams/increased benefits streams of 20%.

**Table 3**
**Total Resource Cost & Ratepayer Impact Tests, Baldock Mid-Feeder (NPV, $M)**

| | 10-Year | | 20-Year | |
|---|---|---|---|---|
| **TRC + RIM Tests** | **Low Cost** | **High Cost** | **Low Cost** | **High Cost** |
| **Benefits** | | | | |
| Capacity | $1.1 | $1.1 | $1.8 | $1.8 |
| Energy | $1.0 | $1.0 | $1.6 | $1.6 |
| Outage Mitigation | $0.3 | $0.3 | $0.5 | $0.5 |
| Reliability | - | - | - | - |
| *Total* | *$2.3* | *$2.3* | *$3.9* | *$3.9* |
| **Costs** | | | | |
| Capital | $3.7 | $5.9 | $3.9 | $6.1 |
| Energy Storage System O&M | $0.4 | $1.0 | $0.8 | $1.7 |
| Program | - | - | - | - |
| *Total* | *$4.1* | *$6.9* | *$4.6* | *$7.8* |
| **Net Benefit** | **$(1.8)** | **$(4.6)** | **$(0.8)** | **$(3.9)** |
| **Benefit Cost Ratio** | **0.57** | **0.34** | **0.84** | **0.50** |

**Q. Please describe the cost-effectiveness of the Coffee Creek Substation project.**

A. Of the scenarios considered, the 20-year, low-cost energy storage system performs the best, with benefits valued at 106% of costs under the TRC test. This project is cost effective. While the Coffee Creek Substation energy storage system is the most expensive within the project portfolio ($52.7 million), it generates $3.2 million in net benefit to PGE's system.

Benefits included are the system values of capacity, energy and ancillary services, and outage mitigation. Capacity is the largest benefit, at 63% of the benefit stream. Costs included are upfront capital and annual O&M (maintenance + power augmentation). With no participants and a single device, there are no unique programmatic costs associated with this project. The project benefits the system as a whole and does not involve individual participants. As such, the PCT has been omitted.

In Table 5 below shows the NPV for benefit and cost streams were calculated for both 10- and 20- year energy storage systems. As for all energy storage systems, moving to the

20-year timeframe increases cost-effectiveness, as benefits increase by a larger percentage than do costs. The total cost-effectiveness range is 0.61 – 1.06.

**Table 4**
**Total Resource Cost & Ratepayer Impact Tests, Coffee Creek Substation (NPV, $M)**

| | 10-Year | | 20-Year | |
|---|---|---|---|---|
| **TRC + RIM Tests** | **Low** | **High** | **Low** | **High** |
| **Benefits** | | | | |
| Capacity | $21.2 | $21.2 | $35.3 | $35.3 |
| Energy | $9.7 | $9.7 | $16.2 | $16.2 |
| Outage Mitigation | $2.6 | $2.6 | $4.3 | $4.3 |
| Reliability | - | - | - | - |
| *Total* | *$33.5* | *$33.5* | *$55.8* | *$55.8* |
| **Costs** | | | | |
| Capital | $40.4 | $47.9 | $42.0 | $52.4 |
| Energy Storage System O&M | $4.4 | $7.0 | $10.7 | $12.4 |
| Program | - | - | - | - |
| *Total* | *$44.7* | *$54.9* | *$52.7* | *$64.8* |
| **Net Benefit** | **$(11.3)** | **$(21.5)** | **$3.2** | **$(9.0)** |
| **Benefit Cost Ratio** | **0.75** | 0.61 | 1.06 | 0.86 |

**Q. Please describe the cost-effectiveness of the Generation Kick Start project.**

A. The Generation Kick Start project is cost effective for the 20-year, low-cost energy storage system profile with benefits valued at 123% of costs under the TRC test. For this profile, total energy storage system carrying cost is $10.1 million (NPV of revenue requirement for capital and annual O&M costs). Benefit streams produce a NPV of $12.5 million, resulting in a positive net benefit of $2.3 million. Capacity provides 67% of the project's benefits stream; energy and ancillary services comprise the remainder. There is no outage mitigation benefits associated with a generation-located energy storage system.

Across all substation energy storage system profiles, the cost-effectiveness range is 0.58 (10-year, high-cost energy storage system) to 1.23 (20-year, low-cost energy storage system).

**Table 5**
**Total Resource Cost & Ratepayer Impact Tests, Port Westward 2 (NPV, $M)**

| | **10-Year** | | **20-Year** | |
|---|---|---|---|---|
| **TRC + RIM Tests** | **Low** | **High** | **Low** | **High** |
| **Benefit** | | | | |
| Capacity | $5.0 | $5.0 | $8.4 | $8.4 |
| Energy | $2.4 | $2.4 | $4.1 | $4.1 |
| Outage Mitigation | - | - | - | - |
| Reliability | - | - | - | - |
| *Total* | *$7.5* | *$7.5* | *$12.5* | *$12.5* |
| **Cost** | | | | |
| Capital | $8.4 | $10.4 | $8.4 | $10.9 |
| Energy Storage System O&M | $1.1 | $2.5 | $1.8 | $4.2 |
| Program | - | - | - | - |
| *Total* | $9.4 | $12.9 | $10.1 | $15.1 |
| **Net Benefit** | **$(1.9)** | **$(5.5)** | **$2.3** | **$(2.7)** |
| **Benefit Cost Ratio** | **0.79** | **0.58** | **1.23** | **0.82** |

This energy storage system also provides a unique value in enabling an off-line turbine to provide spinning reserves. Normally, a thermal plant would need to be synched to the grid (operating at minimal output) in order to provide this ancillary services function. At PW2, a five megawatt energy storage system leverages 18.9 MW of spinning reserve on an off-line thermal plant (18.9 MW is the full output of one turbine, which it is capable of achieving in less than 10 minutes). This generates savings in the form of fuel, variable O&M, and startup costs for the hours in which PW2 would otherwise have been operating at minimal output (seven megawatts) to provide spinning reserves.

We have not yet quantified the hours in which the Generation Kick Start Project would be expected to operate in this mode and have not yet estimated how operating in this mode would impact the total expected energy and ancillary service benefits included in the cost-effectiveness analysis. The project's learning objectives include quantifying any additional value that can be yielded from a hybrid generation-storage project.

**Q. Please describe the cost-effectiveness results of the Microgrid Pilot.**

A. Results are reported in Table 6 and Table 7, below, which describe 10- and 20- year energy storage systems, respectively. The energy storage system profile that performs the best is the 20-year, low cost estimate, with benefits valued at 64% of costs.

Benefits streams are capacity, energy and ancillary services, and power reliability. As with most of the projects proposed, capacity is the largest benefit component at 55%. Power reliability is a benefit that accrues to the participating businesses, rather than to the utility.

The cost streams included are overnight capital costs (vendor + PGE investment), and ongoing O&M over the economic life of the investment (energy storage system and operation maintenance, initial site assessments and outreach, and our coordination and oversight of resources). These ongoing programmatic elements increase costs relative to the projects without participants (i.e., Coffee Creek Substation, Baldock Mid-feeder, and Generation Kick Start). The high cost estimate reflects a 150% increase in energy storage system size, which amplifies the increase in vendor price quote.

**Table 6**
**Cost-effectiveness of Microgrid Pilot (NPV, $M) – 10-Year Project Life**

| | **Low Cost Estimate** | | | **High Cost Estimate** | | |
|---|---|---|---|---|---|---|
| **10-Year Energy Storage System** | **TRC** | **RIM** | **Participant** | **TRC** | **RIM** | **Participant** |
| **Benefits** | | | | | | |
| Capacity | $5.1 | $5.1 | - | $12.5 | $12.5 | - |
| Energy | $2.3 | $2.3 | - | $5.6 | $5.6 | - |
| Outage Mitigation | - | - | - | - | - | - |
| Reliability | $2.0 | - | $2. | $4.9 | - | $4.9 |
| **Total** | **$9.3** | **$7.3** | **$2.0** | **$22.9** | **$18.1** | **$5.0** |
| **Costs** | | | | | | |
| Capital | $14.4 | $14.4 | - | $51.7 | $51.7 | - |
| Battery O&M | $3.4 | $3.4 | - | $9.8 | $9.8 | - |
| Program | $1.9 | $1.9 | - | $2.2 | $2.2 | - |
| **Total** | **$19.7** | **$19.7** | **-** | **$63.6** | **$63.6** | **-** |
| **Net Benefit** | **$(10.4)** | **$(12.4)** | **$2.0** | **$(40.6)** | **$(45.5)** | **$5.0** |
| **Benefit Cost Ratio** | **0.47** | **0.37** | **n/a** | **0.36** | **0.28** | **n/a** |

**Table 7**
**Cost-effectiveness of Microgrid Pilot (NPV, $M) -- 20-Year Project Life**

| | **Low Cost Estimate** | | | **High Cost Estimate** | | |
|---|---|---|---|---|---|---|
| **20-Year Energy Storage System** | **TRC** | **RIM** | **Participant** | **TRC** | **RIM** | **Participant** |
| **Benefits** | | | | | | |
| Capacity | $8.4 | $8.4 | - | $21.1 | $21.1 | - |
| Energy | $3.8 | $3.8 | - | $9.5 | $9.5 | - |
| Outage Mitigation | - | - | - | - | - | - |
| Reliability | $3.3 | | $3.3 | $8.3 | - | $8.3 |
| **Total** | **$15.5** | **$12.2** | **$3.3** | **$38.8** | **$30.5** | **$8.3** |
| **Costs** | | | | | | |
| Capital | $15.1 | $15.1 | - | $53.7 | $53.7 | - |
| Energy Storage System O&M | $6.3 | $6.3 | - | $20.1 | $20.1 | - |
| Program | $2.8 | $2.8 | - | $3.1 | $3.1 | - |
| **Total** | **$24.3** | **$24.3** | **-** | **$76.9** | **$76.9** | |
| **Net Benefit** | **$(8.8)** | **$(12.2)** | **$3.3** | **$(38.1)** | **$(46.4)** | **$8.3** |
| **Benefit Cost Ratio** | **0.64** | **0.50** | **n/a** | **0.50** | **0.40** | **n/a** |

Microgrid Pilot cost-effectiveness results range from a low of 0.28 (10-year, high-cost estimate) to a high of 0.64 (20-year, low-cost estimate) on the TRC. This equates to a net cost ranging from $10.4 to $8.8 million. PGE understands this gap to be associated with the pilot's learning objectives, discussed in PGE Exhibit 100, Section V, of the docket.

As with all the projects proposed, benefits increase by a larger percentage when moving between a 10- and 20-year energy storage system than do costs. Results are less favorable on the RIM, which omits the benefit stream of Power Reliability, as this accrues to participants only. The pilot is modeled with no participant payment; according to the PCT, there are benefits but no costs. Participant willingness to pay is one of the key learnings anticipated for this pilot.

For the 20-year, low-cost energy storage system, total costs (energy storage system, O&M, and programmatic) would need to decrease by 36% to equal benefits as estimated. Alternatively, benefits would need to increase by 57% to equal project costs as estimated. Additional factors that may increase cost-effectiveness include grant funding, possible City of Portland funding contribution, and participant contribution of funds, land, or human resources.[8]

**Q. Please describe the cost-effectiveness of the Customer Ownership Model for the Residential Pilot project.**

A. The low-cost estimate results in benefits equal to 69% of costs under the TRC. Cost-effectiveness is the most complex for the two residential pilot programs as the results of these programs vary across the three tests here considered.

Projected benefits include capacity, energy and ancillary services, and power reliability. Capacity is a smaller component of the residential energy storage system benefit stream given its 2.7 hour duration. Power reliability accrues to the customer only, and is the largest benefit component at 40%. The value of power reliability is assumed to equal customer willingness to pay. Under this ownership model, power reliability is the net of a 10-year monthly financing cost $94.0 minus monthly PGE payment for grid services provided (approximately $57.0). Power reliability is thus given the value of $36.0 monthly. This

[8] See PGE/101, pg. 60, for more information on grant funding.

would imply a benefit/cost ratio of 1.0 under the PCT. However, under the customer ownership model, the NPV of participant benefits and costs do not reflect this equivalency, as benefits (PGE monthly check) extend through energy storage system failure (in years 11-15), whereas the customer's energy storage system costs end in year 10 with financing payments. Customer benefit is thus 115% of customer cost.

The low-cost estimate results in a net cost of $1.1 million for 250 energy storage systems. PGE understands this gap to be associated with the value of the project's learning objectives, discussed in PGE Exhibit 100, Section VI, of the docket.

In the RIM, power reliability benefit is excluded, as it accrues to customers exclusively. The RIM introduces the cost of PGE's cash payment to the customer, roughly $57.0 monthly in the low cost scenario (the TRC, in contrast, includes benefits and costs accruing to either the utility or customers, and excludes transfers between the utility and customers). In the high cost scenario, the PGE monthly payment increases to $151.0 monthly, in order to keep the net customer cost at $35.0 monthly. The low-cost RIM results in a lower benefit/cost ratio of 0.50 and a higher net cost of $1.4 million. Results are considerably less favorable under the high cost scenario.

**Table 8**
**Cost-effectiveness Results, Residential Pilot (NPV, $M) Customer Ownership Model**

| | Low Cost Estimate | | | High Cost Estimate | | |
|---|---|---|---|---|---|---|
| | **TRC** | **RIM** | **PCT** | **TRC** | **RIM** | **PCT** |
| **Benefits** | | | | | | |
| Capacity | $0.9 | $0.9 | - | $1.0 | $1.0 | - |
| Energy | $0.6 | $0.6 | - | $0.7 | $0.7 | - |
| Outage Mitigation | - | - | - | - | - | - |
| Reliability | $1.0 | - | $1.0 | $1.0 | - | $1.0 |
| Cash | - | - | $1.5 | - | - | $4.1 |
| **Total** | **$2.4** | **$1.4** | **$2.4** | **$2.6** | **$1.7** | **$5.0** |
| **Costs** | | | | | | |
| Equipment | $2.1 | - | $2.1 | $4.3 | - | $4.3 |
| Energy Storage System Controls | $0.1 | $0.1 | - | $0.8 | $0.8 | - |
| Program | $1.2 | $1.2 | - | $1.2 | $1.2 | - |
| Cash | - | $1.3 | - | - | $4.1 | - |
| **Total** | **$3.4** | **$2.8** | **$2.1** | **$5.7** | **$6.0** | **$4.3** |
| **Net Benefit** | **$(1.1)** | **$(1.4)** | **-** | **$(3.7)** | **$(4.4)** | **-** |
| **Benefit Cost Ratio** | **0.69** | **0.50** | **1.15** | **0.42** | **0.28** | **1.16** |

Cost-effectiveness will improve with program size, as programmatic components are spread over a greater number of participants, and with continued energy storage system price declines. Bulk purchase pricing may be available to achieve pricing lower than the pricing assumed here. Total program carrying costs would need to decrease by 31% to achieve cost-effectiveness under current cost/benefit estimates; benefits would need to increase by 46%.

**Q. Please describe the cost-effectiveness of the Residential Pilot project, PGE Ownership Model.**

A. The PGE ownership model targets a similar TRC result, with benefits equal to 71% of costs, versus 69% under the customer ownership model). Net cost is $1.1 million for 250 BIS. In this model, PGE assumes the entire cost of Battery Inverter Systems (BIS) acquisition, in exchange for the benefit of monthly customer payments. PCT results are equal 1.0 in this model. Customer willingness to pay (monthly check to PGE) is assumed to be equal to customer value of power reliability, as in the customer ownership model. Under PGE ownership, PGE receives a monthly check from customers for the same period over which PGE realizes benefits from the energy storage system (through the year of energy storage system failure). This model assumes a customer payment of roughly $54 per month, higher than the net customer cost under the customer ownership model. Customer willingness to pay was varied in order to achieve consistent TRC results, and under the assumption that customers may pay more to forsake the responsibility and effort involved in acquiring, installing and maintaining the BIS.

Under the high cost range, customer monthly payment remains constant, and the higher priced energy storage system results in a benefit/cost ratio of 0.31 and a net cost of $7.0 million.

Both benefits and costs are higher under the PGE ownership model when compared to the customer ownership model. Benefits are increased due to higher customer value of power reliability (higher net cost to customer) and due to longer energy storage system duration; costs are higher due to our cost structure, which includes income and property tax, and the gross up of our rate of return to reflect tax impacts.

The RIM is equivalent to the TRC under the PGE ownership model. This is because costs remain consistent under both tests, and the benefit of power reliability (TRC) becomes a cash benefit to the utility under the RIM. The net cost is thus lower through the lens of the RIM under the PGE ownership model.

**Table 9**
**Cost-effectiveness Results, Residential Pilot (NPV, $M) PGE Ownership Model**

| | Low Cost Estimate | | | High Cost Estimate | | |
|---|---|---|---|---|---|---|
| | **TRC** | **RIM** | **PCT** | **TRC** | **RIM** | **PCT** |
| **Benefits** | | | | | | |
| Capacity | $0.9 | $0.9 | - | $1.0 | $1.0 | - |
| Energy | $0.6 | $0.6 | - | $0.7 | $0.7 | - |
| Outage Mitigation | - | - | - | - | - | - |
| Reliability | $1.4 | | $1.4 | $1.4 | | $1.4 |
| Cash | - | $1.4 | - | - | $1.4 | |
| **Total** | **$2.8** | **$2.8** | **$1.4** | **$3.1** | **$3.1** | **$1.4** |
| **Costs** | | | | | | |
| Equipment | $2.6 | $2.6 | - | $7.8 | $7.8 | - |
| Energy Storage System Controls | $0.1 | $0.1 | - | $1.0 | $1.0 | - |
| Program | $1.2 | $1.2 | - | $1.2 | $1.2 | - |
| Cash | - | - | $1.4 | - | - | $1.4 |
| *Total* | *$3.9* | *$3.9* | *$1.2* | *$10.1* | *$10.1* | *$1.4* |
| **Net Benefit** | **$(1.1)** | **$(1.1)** | **-** | **$(7.0)** | **$(7.0)** | **-** |
| **Benefit Cost Ratio** | **0.72** | **0.72** | **1.00** | **0.31** | **0.31** | **1.00** |

Cost-effectiveness will improve with program size, as programmatic components are spread over a greater number of participants, and with continued energy storage system price declines. Bulk purchase pricing may be available, resulting in lower capital costs than the pricing employed here. Total program carrying costs would need to decrease by 28% to achieve cost-effectiveness under current cost/benefit estimates; benefits would need to increase by 39%.

**Q. Are there any components of the proposal not considered in the cost-effectiveness analyses?**

A. The project-specific cost-effectiveness analyses exclude portfolio controls and administrative costs. These portfolio components are associated with an estimated $3.1 million in capital spend, and O&M costs that vary between $0.8 and $1.5 million annually over the portfolio's first five years. These costs will vary according to the size of the final approved portfolio.

They are reflected in Table 1 of this testimony, which summarizes total costs and total benefits across the portfolio.

## V. Conclusion

**Q. Summarize PGE's cost-effectiveness analysis.**

A. PGE conducted three cost-effectiveness tests to contextualize project costs with respect to both utility and customer benefits. We estimate that the proposed portfolio of projects and pilots will cost $106-190 million (NPV of the total carrying cost) and will generate $89-107 million of value for customers (NPV), exclusive of participant benefits. Including participant benefits, the proposed projects and pilots are expected to yield approximately $93-117 million in benefits. While we did not find that the full portfolio in its entirety passes the TRC cost-effectiveness test, we note that HB 2193 and the Commission's guidance invites project proposals that are not cost effective under traditional criteria to achieve greater diversity of learnings and to take meaningful steps toward enabling efficient development and integration of energy storage resources in the future.

Our cost and benefits analyses also provided us with the opportunity to enhance our understanding of the value of energy storage systems to the system and to participants. These exercises represent a significant step forward in our capabilities to evaluate energy storage systems, but do not represent an end state for energy storage evaluation in the future. We will continue to improve our modeling capabilities and understanding of energy storage value. More importantly, the proposed projects will help us to understand the opportunities and barriers to realizing the benefits quantified in this analysis and additional value streams that may arise. This will enhance our ability to effectively integrate storage on to the grid in the future.

## VI. Qualifications

**Q. Dr. Hart, please describe your educational background and qualifications.**

A. I joined PGE in 2016 as a Senior Analyst in the Financial Analysis Department working on the Integrated Resource Planning team. In January 2018, I became a Senior Analyst in the Integrated Resource Planning department. Prior to joining PGE, I worked as a Managing Consultant at Energy & Environmental Economics (E3), where I focused on renewable integration and flexible resource (including energy storage) evaluation for clients across the West. I earned a BS in Chemistry from Harvey Mudd College, an MS in Materials Science and Engineering from Stanford University, and a PhD in Civil and Environmental Engineering from Stanford University.

**Q. Ms. Jordan, please state your educational background and qualifications.**

A. I received a Bachelor of Arts from Reed College and a Masters of Urban and Regional Planning from Portland State University. Prior to my current role at PGE I served as a Senior Financial Analyst in the Corporate Planning Department, providing budgeting and financial management for the IT division. My work experience includes financial and economic analysis with the City of Portland's City Budget Office and nine years in economic development consulting with a focus on real estate development and land use planning.

**Q. Mr. Landstrom, please state your educational background and qualifications.**

A. I received a Bachelor of Science degree in Electrical Engineering from North Dakota State University in 1988 and am a registered Professional Engineer in Oregon and Kansas. I currently hold the position of Manager of Transmission & Distribution Asset Management responsible for aspects of technical planning and assessment of PGE's Transmission and Distribution system. I have held previous roles at PGE responsible for the engineering and design of our high voltage transmission lines and electrical substations. I have over 23 years with PGE and 29 years of experience in the electric utility field.

**Q. Does this conclude your testimony?**

A. Yes.