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Rosario Strait Tidal Energy plus Energy Storage — Preliminary Economic Assessment

Energy Systems and Infrastructure Analysis Division

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LIST OF ACRONYMS

aHLH	average heavy load hours
AHWM	Above High Water Mark
BCA	benefit-cost analysis
BCR	benefit-cost ratio
BESS	battery energy storage system
BPA	Bonneville Power Administration
C&I	commercial and industrial
CDQ	contract demand quantity
CSP	customer system peak
DER	distributed energy resources
DNR	Designated Network Resource
ESMO	Energy Storage Microgrid Optimization
HLH	heavy load hours
IRA	Inflation Reduction Act of 2022
LDD	low density discount
LFP	lithium iron phosphate
LLH	light load hours
MW	megawatt
O&M	Operations and maintenance
OPALCO	Orcas Power and Light Co-op
ORLR	operating reserve loss rate
PNNL	Pacific Northwest National Laboratory
PV	photovoltaic or present value
SDD	short duration discount
SOC	state-of-charge
TOCA	tier one cost allocator
TSP	transmission system peak

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EXECUTIVE SUMMARY

The Orcas Power and Light Co-op (OPALCO) is a non-profit utility that provides energy services to approximately 11,700 customers across 20 islands in San Juan County, Washington. OPALCO is developing a diverse set of local renewable energy resources to reduce dependence on mainland Washington State for energy and to reduce the regional need for fossil-fueled power. OPALCO's load doubles in winter but solar production is roughly 20% of levels reached in summer periods. Tidal energy is strong year-round, night and day, and is predictable, requiring much less storage to firm it. To assess the technical and economic feasibility of tidal power, working in combination with multiple other distributed energy resources (DERs), Argonne National Laboratory (Argonne) employed an optimization model to evaluate several economic benefits associated with varying scales of tidal power of between 2.4 and 9.6 megawatts (MW) and other DERs. In addition to existing photovoltaic (PV) and battery energy storage system (BESS) resources located on Decatur Island, Argonne also evaluated the addition of a BESS on southern Orcas Island with power and energy capacities ranging from 1-4 MW and 2-4 hours in storage duration. The placement of the energy assets considered in this evaluation, along with the portions of OPALCO's transmission and distribution system capable of islanding during outages, are illustrated in Figure ES-1.

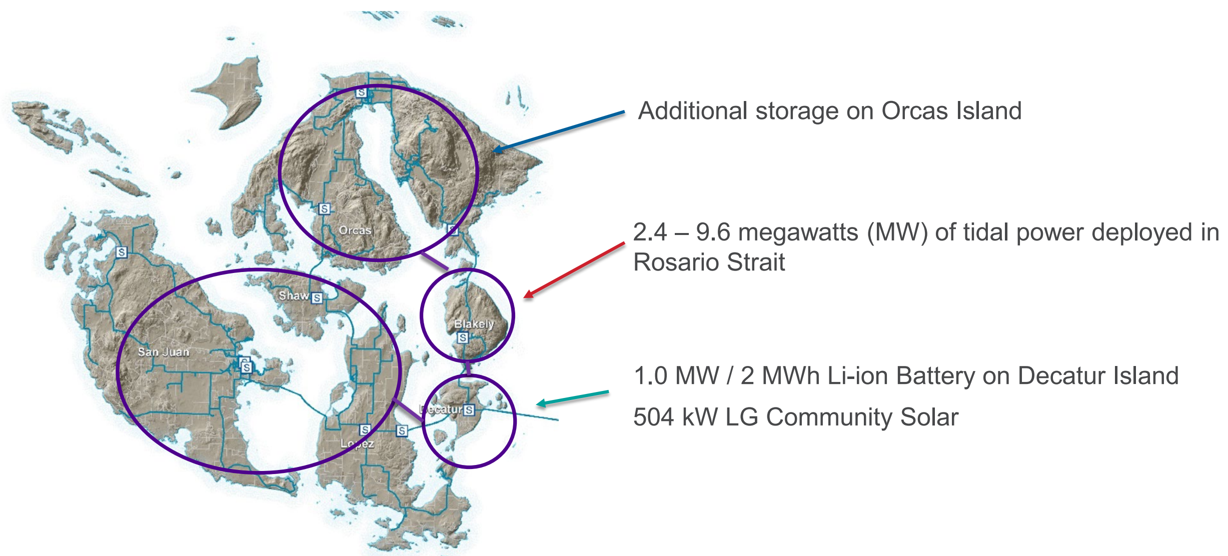

FIGURE ES-1 Four-zone OPALCO System and Placement of Tidal and Energy Assets

In this study, the project team performed a comprehensive resource scheduling simulation spanning an entire year. This simulation aimed to evaluate the impact and value of the Decatur Island Microgrid and new tidal power and BESS options on southern Orcas Island. In order to capture the unique characteristics of the OPALCO power system, such as network topology and the definition of various charges that are not typically well captured in traditional production cost simulation models, the project team developed the Energy Storage Microgrid Optimization (ESMO) model. The ESMO model is a least-cost linear programming model that determines the optimal hourly scheduling of resources in a system while ensuring the total cost is minimized. The least-cost objective function considers the following charges: load shaping charge, demand charges, transmission charges, and miscellaneous charges. In addition to these charges that directly affect the bill paid by OPALCO to PNGC Power, the research team also evaluated the benefits of deferring investment in a submarine cable linking the San Juan Islands to mainland Washington State, and the benefits of outage mitigation to OPALCO customers.

Economic results were prepared for 15 scenarios defined in Table ES-1. Present value (PV) costs are compared to PV economic benefits to determine the net benefits and benefit-cost ratios (BCRs) of each scenario. Under each scenario, the evaluation is performed first from the perspective of the utility in isolation and second from the perspective of the utility plus the customers it serves. Including the customer perspective improves the economic performance of each scenario by removing the costs of payments to members who bought shares in community solar and by including the benefits of improved reliability.

TABLE ES-1 Descriptions of Microgrid Scenarios

Scenario	Scenario Description
1	no DERs
2	Tidal power in isolation
3	Tidal power plus local storage on Orcas Island
4	Scenario 3 plus Decatur PV and BESS
5	Scenario 4 with 2X tidal power
6	Scenario 4 with 3X tidal power
7	Scenario 4 with 4X tidal power
8	Scenario 4 with 2x Orcas storage capacity
9	Scenario 4 with 3x Orcas storage capacity
10	Scenario 4 with 4x Orcas storage capacity
11	Scenario 4 with 1x Orcas storage capacity @ 4 hr.
12	Scenario 4 with 2x Orcas storage capacity @ 4 hr.
13	Scenario 4 with 3x Orcas storage capacity @ 4 hr.
14	Scenario 4 with 4x Orcas storage capacity @ 4 hr.
15	Scenario 4 but no assets are designated network resources

The annual benefits of each of the services provided by the microgrid assets under each scenario are presented in Table ES-2 and Figure ES-2. Note that Scenario 1 was used only to validate the model. Thus, there are no benefits or costs defined under that scenario. Scenario 15 changes how the DERs are recognized by the Bonneville Power Administration, enabling them to be used to reduce transmission charges.

The scenarios yield roughly $458.2 thousand to $1.4 million in annual benefits. Demand and transmission charge reductions of up to $542.4 thousand and $110.9 thousand, respectively, were achieved, and are largely driven by the use of BESSs discharging during peak load hours. Transmission deferral ($142.7-$506.5 thousand), base customer charge ($184.9-$194.0 thousand), and load shaping charge reductions of $166.6-$715.1 thousand were driven mostly by tidal energy production.

TABLE ES-2 Annualized Benefits by Service by Scenario

Scenario ID	Transmission Deferral	Base Customer Charge	HLH Load Shaping Charge	LLH Load Shaping Charge	Demand Charge	Transmission Charge	Misc. Charge	Outage Mitigation
1	$-	$-	$-	$-	$-	$-	$-	$-
2	$142,692	$184,886	$106,580	$71,005	$(53,534)	$4,840	$1,712	$24,716
3	$170,605	$184,886	$96,630	$78,007	$79,846	$4,434	$1,695	$25,806
4	$189,479	$193,980	$98,614	$83,648	$152,843	$4,524	$1,779	$34,696
5	$271,385	$192,209	$205,474	$154,421	$96,709	$9,366	$3,491	$39,405
6	$377,811	$192,209	$312,427	$225,109	$39,159	$14,208	$5,203	$48,068
7	$506,503	$192,209	$419,057	$296,074	$(27,901)	$19,048	$6,914	$38,998
8	$216,983	$192,209	$90,569	$89,101	$257,132	$4,131	$1,763	$45,343
9	$244,284	$190,438	$83,548	$93,659	$345,237	$3,744	$1,747	$67,735
10	$271,385	$188,667	$77,561	$97,386	$415,103	$3,357	$1,730	$73,284
11	$189,479	$190,438	$89,385	$90,226	$182,224	$4,107	$1,763	$42,200
12	$216,983	$186,896	$73,753	$101,125	$317,894	$3,336	$1,730	$57,196
13	$244,284	$183,354	$60,393	$110,219	$438,218	$2,487	$1,697	$74,277
14	$271,385	$179,812	$50,122	$116,516	$542,399	$1,756	$1,665	$86,013
15	$189,479	$192,209	$99,405	$82,969	$152,204	$110,928	$1,779	$34,695

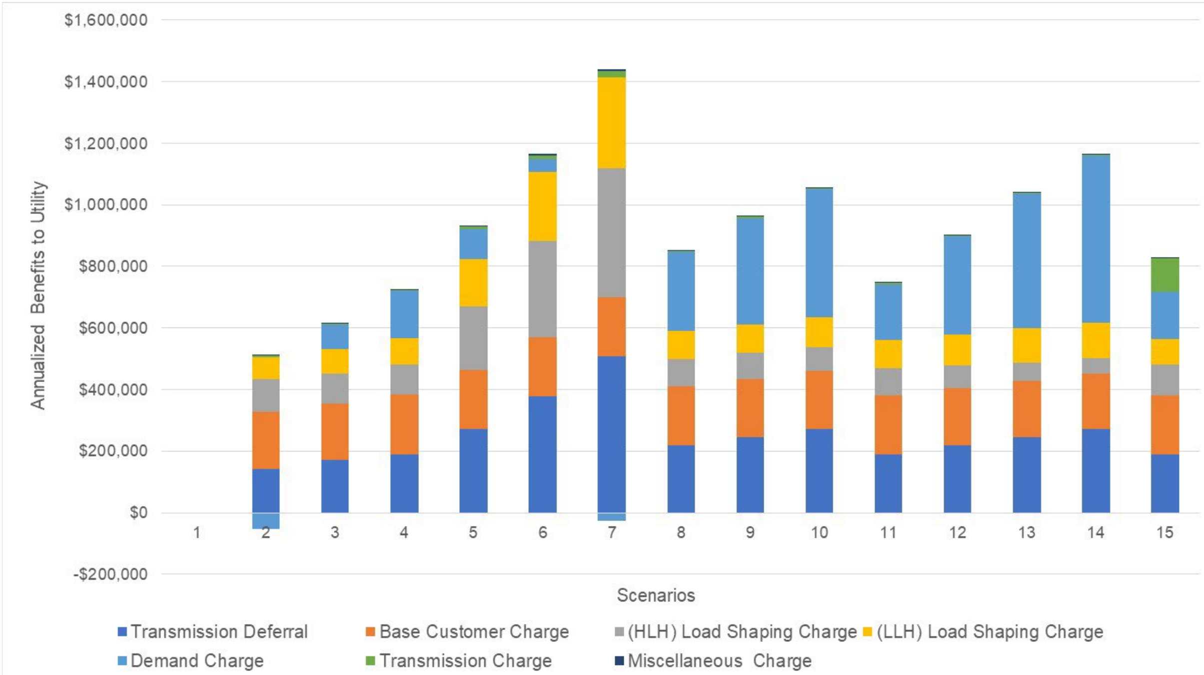

FIGURE ES-2 Annualized Benefits to OPALCO

The results of the benefit-cost analysis (BCA) from a utility perspective are presented in Table ES-3. For this analysis, we use the BCR and net benefits financial metrics. The BCR is calculated by dividing discounted revenue or benefits of the project by discounted costs. A BCR of more than 1.0 demonstrates a positive return on investment. A BCR of 1.2 would indicate that for every dollar invested in the project, a return of $1.20 could be achieved. Net benefits are calculated by subtracting PV costs from PV benefits. BCRs presented in Table ES-3 vary from 0.25 to 0.49, with lifetime net benefits ranging from -$123.6 million to -$33.1 million. While none of the BCRs exceed 1.0, the results of the analysis are very useful in that they define the grant level for tidal power required to break even at $38.9 million. Further, the analysis demonstrates that additional investments in storage on Orcas Island could yield positive net returns of approximately $3 million in PV terms.

TABLE ES-3 Benefit-Cost Analysis Results – Utility Perspective

Scenario	PV Benefits	PV Costs	BCR	Net Benefits
1	$-	$-	-	$-
2	$13,054,594	$51,983,452	0.25	$(38,928,858)
3	$17,554,111	$53,559,847	0.33	$(36,005,736)
4	$20,653,054	$57,374,999	0.36	$(36,721,945)
5	$26,584,765	$91,423,731	0.29	$(64,838,966)
6	$33,225,435	$128,336,577	0.26	$(95,111,142)
7	$40,228,235	$163,817,365	0.25	$(123,589,131)
8	$24,272,180	$58,951,394	0.41	$(34,679,214)
9	$27,428,200	$60,527,790	0.45	$(33,099,590)
10	$30,064,648	$63,739,006	0.47	$(33,674,358)
11	$21,301,394	$58,489,143	0.36	$(37,187,749)
12	$25,691,895	$60,065,539	0.43	$(34,373,644)
13	$29,650,484	$62,756,078	0.47	$(33,105,594)
14	$33,155,064	$68,236,876	0.49	$(35,081,812)
15	$23,619,287	$57,374,999	0.41	$(33,755,712)

The results of the BCA from a utility plus customer perspective produce BCRs that vary from .25 to .53, and net benefits that range from -$121.3 million to $-29.8 million. Note that when capturing all customer benefits, including outage mitigation, the funding gap for tidal power closes to $38.2 million. BESS investments drive positive outcomes through the benefits associated with enhanced outage mitigation, which reaches as high as $86.0 thousand annually in Scenario 14.

The research team evaluated the sensitivity of the results with respect to changes in a number of key assumptions and parameters. Results suggest that the findings are somewhat sensitive to several alternative assumptions. Varying energy price inflation, meaning the price paid by OPALCO to PNGC Power, has a larger effect than that of varying the discount rate, with impacts reaching -$7.7 million (2% price inflation) to $10.4 million (4% price inflation) when compared to a 3% price inflation baseline. These findings suggest that the microgrid assets would form somewhat of a hedge against future price inflation, with economic performance improving significantly under higher rates of inflation. Scenario 4 reaches a breakeven point when annual energy price inflation reaches 7.2%. Increasing the clean energy investment credit authorized under the Inflation Reduction Act of 2022 from 30% to 40% by adding in the bonus for meeting domestic content requirements on the Orcas Island BESS and tidal power would improve the economic performance of the microgrid by $4.3-$11.9 million in total PV terms. Each of these results are from a utility perspective. Setting the BESSs state of charge to 80% in advance of reliability events adds $1-$4.4 million in additional outage mitigation benefits over the life of the units to customers. Note that scenarios where the duration of energy storage is doubled yield significantly higher outage mitigation benefits.

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1 INTRODUCTION

The Orcas Power and Light Co-op (OPALCO) is developing a diverse set of local renewable energy resources to reduce dependence on mainland Washington State for energy and to reduce the regional need for fossil-fueled power. OPALCO's load doubles in winter but solar production is roughly 20% of levels reached in summer periods when island demand is lower. Tidal energy is strong year-round, night and day, and is predictable, requiring much less storage to firm it. To assess the technical and economic feasibility of tidal power, working in combination with multiple other distributed energy resources (DERs), Argonne National Laboratory (Argonne) employed an optimization model to evaluate several economic benefits associated with varying scales of tidal power of between 2.4 and 9.6 megawatts (MW) and other DERs. In addition to existing photovoltaic (PV) and battery energy storage system (BESS) resources located on Decatur Island, Argonne also evaluated the addition of a BESS on southern Orcas Island with power and energy capacities ranging from 1-4 MW and 2-4 hours in storage duration.

OPALCO is a non-profit utility that provides energy services to approximately 11,700 customers across 20 islands in San Juan County, Washington. A map of the San Juan Islands, including the Rosario Strait where the tidal power unit will be located and Decatur Island where the existing 1 MW / 2 megawatt-hour (MWh) BESS and PV system is located, is presented in Figure 1. The island network is located off the northwestern coast of Washington State.

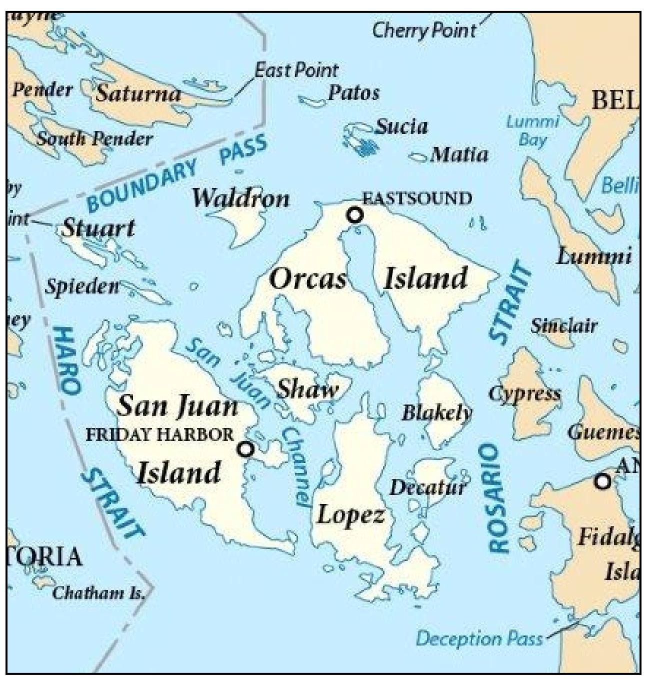

FIGURE 1 Map of the San Juan Islands, Washington

2 MODELED DISTRIBUTED ENERGY RESOURCES

This section presents an overview of the DERs modeled in this study. Modeled DERs include the community solar and BESS together forming the Decatur Island microgrid, plus tidal energy deployed in Rosario Strait at a location between Blakely and Cypress Islands, and a BESS to be deployed in the Olga District of southern Orcas Island.

2.1 COMMUNITY SOLAR ON DECATUR ISLAND

A community solar facility deployed on Decatur Island is a 504 kW DC array that produced 466 MWh of energy in 2022. Figure 2 presents an image of Decatur Island PV. The system includes 1,260 LG400 Watt monocrystalline modules supplied by Puget Sound Solar (Puget Sound Solar 2017). OPALCO customers can purchase shares in the community solar to receive energy credits that are allocated based on the number of shares purchased and used to defray energy costs on their monthly utility bill.

FIGURE 2 Decatur Island Community Solar

OPALCO provided hourly PV production data for the 2019 through 2022 time period. PV production values influence load shaping charges, demand charges, transmission charges, outage mitigation, and transmission submarine cable replacement deferral benefits using the methods outlined in the next section of this report. The research team used the 2022 hourly production values presented in Figure 3 for modeling purposes.

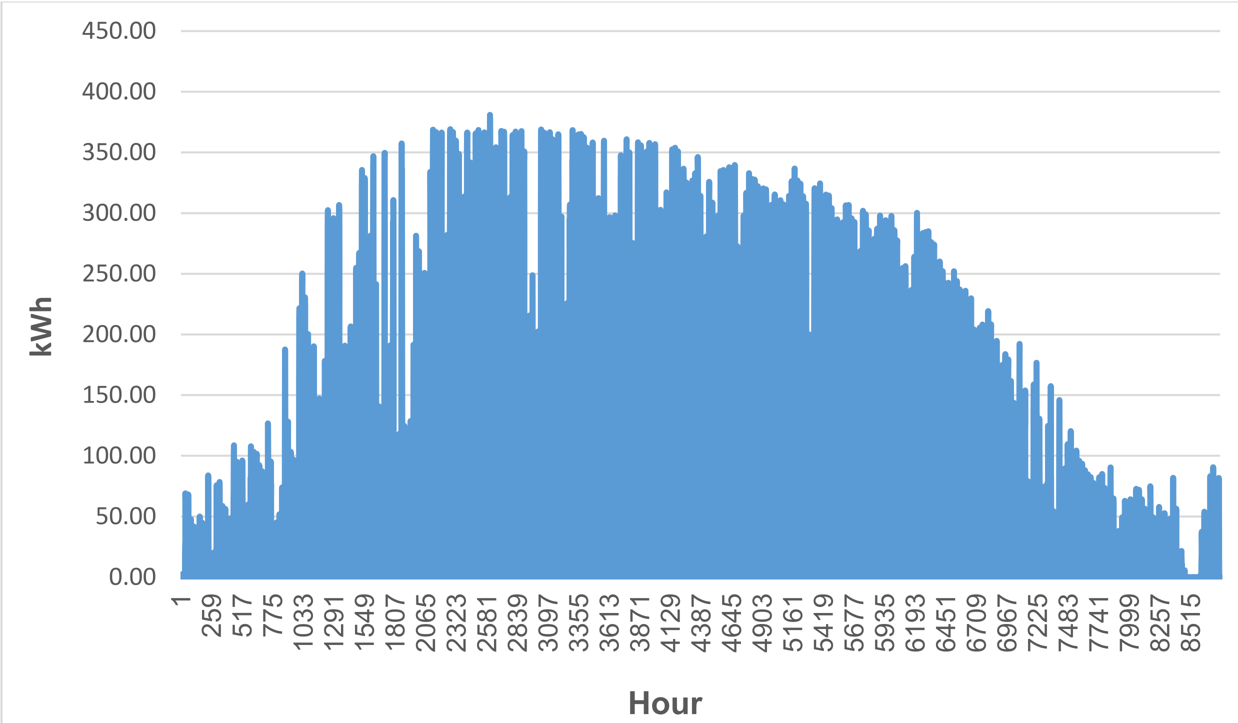

FIGURE 3 Hourly PV Production Data on Decatur Island in 2022

2.2 BATTERY ENERGY STORAGE SYSTEMS

The Decatur Island BESS is a 1 MW / 2 MWh lithium iron phosphate (LFP) battery. The BESS consists of a single container with 12 rack-mounted strings. Each string contains 24 cells in a series or a total of 264 cells. Pacific Northwest National Laboratory (PNNL) conducted extensive testing of the Decatur Island BESS but was unable to accurately account for ancillary systems (e.g., heating and control systems) and the resulting estimates of round-trip efficiency (RTE) (>95%) were, therefore, deemed unsuitable for this study and ultimately not used (Crawford et al. 2022). Instead, when modeling all BESSs considered in this study, we rely on industry average values for LFP presented in Viswanathan (2022) at 83%.

FIGURE 4 Decatur Island Energy Storage System

2.3 TIDAL ENERGY

OPALCO has developed site and cost information on tidal power, working with PNNL, Orbital Marine Power, and the University of Washington. Following an extensive review of potential sites conducted by PNNL (Copping et al. 2021), Rosario Strait was selected as the site for the tidal power unit (Figures 5a and 5b). Note that the maximum power capacity for the Orbital Marine Power tidal unit considered here is 2.4 MW. For this evaluation, we study the costs and benefits of up to four tidal power units with maximum combined power output levels of 9.6 MW.

FIGURE 5a Map of San Juan Islands

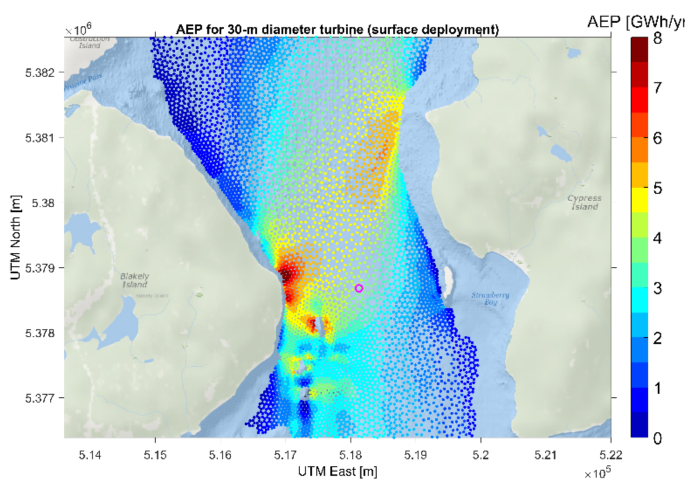

FIGURE 5b Tidal Flow Map of Rosario Strait

Tidal production data was estimated from a simulation of tidal currents throughout the San Juan Islands conducted by PNNL. The hourly values of the two-dimensional currents are converted to a scalar speed, U_o, as

$$U_o = (u^2 + v^2) \tag{1}$$

These hourly values of speed are then linearly interpolated to a 5-minute time basis. From this, electrical power output from the turbine, P, is calculated as

$$\mathrm{P} = \frac{1}{2}\rho\eta A U_o^3 \tag{2}$$

where ρ is the seawater density (1025 kg/m3), η is the "water-to-wire" turbine efficiency (0.39), and A is the turbine area (for a pair of 30 m diameter rotors). This time series is then modified by two constraints:

1. When currents are below the turbine cut-in speed (0.5 m/s), electrical power output is zero.
2. When electrical power output would otherwise exceed the turbine's rated power (2.4 MW), electrical power is capped at this value.

The 5-minute time series is then converted to hourly electrical generation (MWh) by calculating the average power, in MW, for each hour of the year and multiplying this by one hour. Using this approach, hourly tidal power production was prepared for 2022, as presented in Figure 6. Total energy production for the year was estimated at 5.7 gigawatt-hours or 2.4% of total OPALCO energy needs.

Tidal production values influence load shaping charges, demand charges, transmission charges, outage mitigation, and transmission submarine cable replacement deferral benefits.

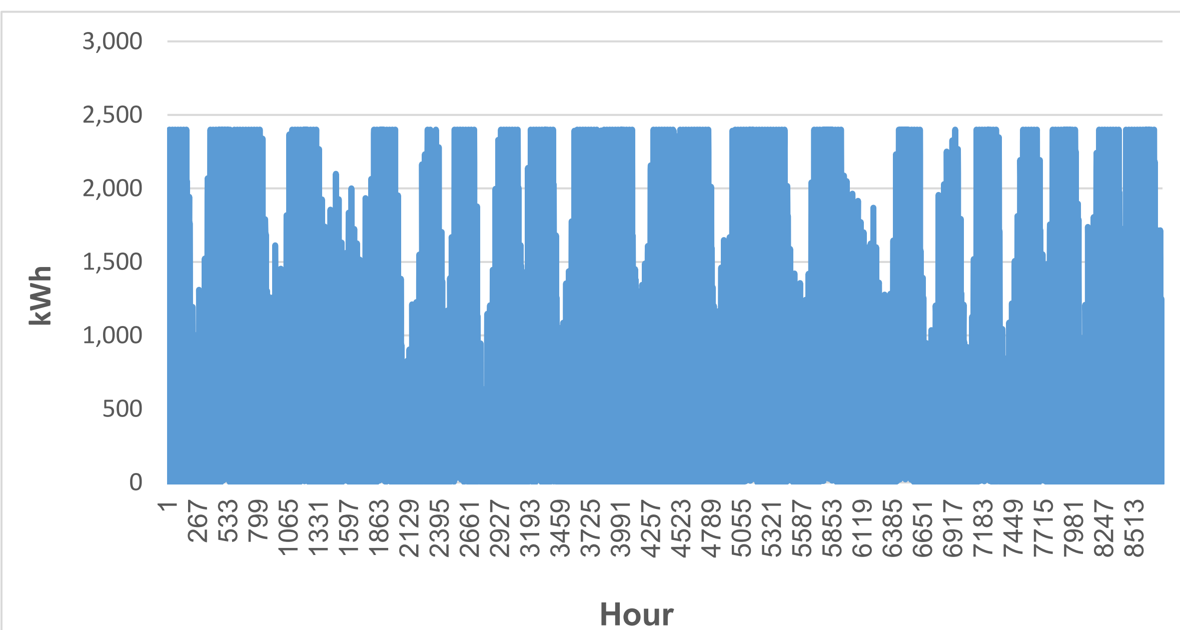

FIGURE 6 Modeled Hourly Tidal Production Data

3 ENERGY STORAGE VALUATION METHODOLOGY

Argonne began its assessment of tidal power, community solar, and BESS benefits by meeting with OPALCO and developing a list of use cases or services that could be offered by the DERs defined for this study. The following use cases were defined for further evaluation:

1. Customer base charge;
2. Load shaping charge reduction;
3. Demand charge reduction;
4. Transmission charge reduction;
5. Miscellaneous charge reduction;
6. Submarine transmission cable replacement deferral; and
7. Outage mitigation.

Each of these use cases are defined in the following sections along with the methodology used to estimate the associated value. The value of each use case by scenario is presented in Section 4.

Note that this section represents an update to a report on a project for which the principal investigator (PI) of this study also served as the PI (Mongird et al. 2018). Some of the text that describes the basis of each charge appears in both reports. With that noted, this study includes certain charges (e.g., spinning and supplemental reserves, regulation and frequency response, and miscellaneous charges) that were not considered in that previous study. Further, text and in some cases equations, have also been modified.

3.1 DIRECT OPALCO CHARGES

OPALCO pays its bill through the electric utility company PNGC Power, but its energy is delivered by the Bonneville Power Administration (BPA) and is, therefore, subject to BPA's rate structure. BPA offers a tiered tariff structure to its customers within which there are multiple levels, differentiated by a MW demand quantity, with each individually priced. The cutoff at which it crosses over from the lower level to the next is established to align with the current generation capabilities of BPA's system.

Tier 1 is the lower price level in BPA's structure and each energy customer is allocated a limited MW quantity that they may purchase at this rate. The reasoning behind the purchase cap is that Tier 1 is constrained by BPA's total current generation capability and the level of MW demand it can readily meet with available resources. Tier 2 rates, on the other hand, are established to cover any remaining customer demand beyond what is covered under Tier 1 and are higher as they are priced according to the cost of BPA obtaining more generation to meet the additional demand.

Tier 1, which accounts for almost all of the power OPALCO purchases, includes five separate charges:

1. the customer base charge;
2. the load shaping charge;
3. the demand charge;
4. transmission charges; and
5. a miscellaneous charge.

3.1.1 Base Charges

The customer base charge is not dependent on either OPALCO's monthly peak demand or the time at which it consumes energy, but rather is a pre-calculated amount based on a forecasted load. Each customer is assigned a tier one cost allocator (TOCA), which defines the portion of BPA generation costs that should be paid by OPALCO. In 2022, OPALCO's TOCA was 0.35 percent. The base charge is calculated at roughly $2 million per percentage point per month. At this rate, the charge to OPALCO would be roughly $700,000 per month. However, the base charge is adjusted downward by non-slice charges and low density discounts. These adjustments reduce the fixed customer base charge at $550,302 monthly or $6.6 million annually. During 2022, OPALCO consumed 241.8 gigawatt-hours of energy. Thus, the base charge can be calculated at 2.7 cents per kWh. Tidal and PV production would affect future year TOCAs and, therefore, the base charges allocated to OPALCO. Thus, the pure energy charge reduction attributed to tidal and PV generation was calculated at 2.7 cents per kWh.

3.1.2 Load Shaping and Demand Charge Reductions

Load shaping and demand charges are components of OPALCO's energy bill that fluctuate on a monthly basis and can appear as either a charge or a credit that is dependent upon whether OPALCO purchases more or less energy than the amount expected by BPA. The demand charge, on the other hand, is a fee OPALCO incurs that is tied to energy purchases during the utility's most load-intensive hour each month. The DERs have the potential to impact both of these charges and, therefore, it is important to understand how they are derived. To be able to accurately calculate the full benefits that the BESS can derive by mitigating these charges, it is necessary to first understand the structure of BPA's rates.

In this section, we will use three key load metrics: total retail load, Tier 1 customer system peak (CSP), and transmission system peak (TSP). Total retail load equals all energy consumed during a month (sometimes split between heavy load hours [HLH] and light load hours [LLH]) including energy consumed by storage (including battery charging) and renewable energy. Tidal power and PV can reduce the load through energy production and the BESSs can shift load from HLH to LLH to reduce cost. Total retail load is the sum of the metered load at the 335 Fidalgo #4 Out meter, 2387/8631 Fidalgo #5 out, and 4831 Decatur out meter. Tier 1 CSP is the customer's maximum load during HLHs each month as measured at the two meters on Fidalgo Island and the one on Decatur Island. This will include load from all customers and utility equipment, including solar and energy storage systems. The TSP adds DER energy production to the load measured at the Fidalgo Island meters and the Decatur Island meter during the peak BPA transmission hour each month, thus negating their effects. Tidal power production will also be added back into the metered load during the TSP. All are considered Designated Network Resources (DNRs) by BPA currently and load served by DNRs are included in the TSP. The threshold for defining a DNR is currently 200 kW but will be raised to 1 MW in 2028. Thus, PV production during the TSP hour could reduce transmission charges starting in 2028 while tidal power will not yield any savings because its nameplate capacity exceeds 1 MW. Batteries are also considered DNRs.

For the amount of power that OPALCO is unable to purchase at Tier 1 rates, it must pay at the higher, Tier 2 rates. This is incorporated into its bill from PNGC under what is called the Above High Water Mark (AHWM) Power Cost. This MWh quantity is set as a fixed amount based on a forecast of how much Tier 2 power BPA expects OPALCO to require. Like the customer base charge described previously, the DERs will not be able to affect the AHWM power cost, as the value is fixed and not dependent on OPALCO's time-of-use or peak energy usage. Nevertheless, the AHWM load that OPALCO makes the obligation to purchase is important, as it allows us to determine the Tier 1 amounts each month that the microgrid assets have the ability to impact.

3.1.2.1 Load Shaping Charge

Load shaping is a Tier 1 charge or credit OPALCO receives that is dependent on whether its actual retail load each month is greater or less than the amount BPA predicted it would purchase. Load shaping is split into two categories: HLH and LLH. A different charge/credit is determined for each that fluctuates depending on energy purchased during set hours.

HLHs include all hours between 6:00am and 10:00pm, Monday through Saturday. LLHs include all other hours on those same days as well as all hours on Sundays and holidays. Those holidays include New Year's Day, Memorial Day, Independence Day, Labor Day, and Christmas Day, which in 2022 fell on January 1, May 30, July 4, September 5, November 24, and December 25 in that order. If OPALCO's power purchases are less than expected, they receive a credit on their bill. Conversely, if they purchase more power than expected, they must pay an additional charge.

For HLHs, the load shaping charge/credit for each month in 2022 is determined by the following formula:

$$\begin{aligned} &HLH\ Load\ Shaping\ Charge \\ &\quad = [(Total\ HLH\ retail\ load\ in\ MWh \\ &\quad - AHWM\ Obligation\ HLH\ in\ MWh) - OPALCO\ HLH\ System\ Shaped\ Load] \\ &\quad \times\ HLH\ Load\ Shaping\ Rate\ per\ MWh \end{aligned} \tag{3a}$$

For LLH it is:

$$\begin{aligned} &LLH\ Load\ Shaping\ Charge \\ &\quad = [(Total\ LLH\ retail\ load\ in\ MWh \\ &\quad - AHWM\ Obligation\ LLH\ in\ MWh) - OPALCO\ LLH\ System\ Shaped\ Load] \\ &\quad \times\ LLH\ Load\ Shaping\ Rate\ per\ MWh \end{aligned} \tag{3b}$$

Where:

Total HLH (LLH) retail load is the MWh quantity that OPALCO purchases each month; *HLH (LLH) system shaped load* is BPA's forecast of OPALCO's MWh total retail load for that month; and *HLH (LLH) load shaping rate* is the mills/kWh rate that BPA charges for these bill components.

Note the two differing values that are subtracted from the total retail load for the respective hours. These values are the AHWM obligations that OPALCO has agreed to pay each month that cannot be charged at the lower Tier 1 rates. By subtracting them from total retail load we are left with the HLH Tier 1 load and LLH Tier 1 load, respectively. OPALCO's monthly AHWM obligations are presented in Table 1.

TABLE 1 OPALCO 2022 AHWM Obligation

Month	HLH (MWh)	LLH (MWh)
January	570.40	490.54
February	547.58	410.69
March	616.03	443.49
April	593.22	433.50
May	570.40	490.54
June	593.22	433.50
July	570.40	490.54
August	616.03	444.91
September	570.40	456.32
October	624.83	492.66
November	600.80	482.14
December	624.83	492.66

The second component of the equations above, the system shaped load, is the total monthly amount of energy BPA expects OPALCO to purchase during the indicated hours across the entire month. These values are predetermined for OPALCO for each month of 2022 for both HLH and LLH, and are provided in Table 2.

TABLE 2 OPALCO 2022 System Shaped Load by Month (MWh)

Month	HLH (MWh)	LLH (MWh)
January	9,287.16	7,038.17
February	8,219.28	5,930.24
March	10,373.84	6,517.83
April	8,081.37	5,032.76
May	12,243.72	5,926.00
June	13,845.15	5,569.58
July	12,277.45	6,155.96
August	11,996.97	5,817.50
September	10,506.40	5,956.03
October	10,230.07	5,720.05
November	12,391.65	7,801.78
December	11,291.61	8,473.72

The difference between the Tier 1 loads and the system shaped loads, as shown in the equation, gives the deviation in energy consumption for which OPALCO will be additionally charged or rewarded. This deviation is charged/credited at the appropriate load shaping rate shown in Table 3. The sum of the HLH and LLH load shaping charges/credits is the total load shaping charge/credit for the month.

TABLE 3 HLH and LLH Load Shaping Rates Set by BPA for 2022 (mills/kWh)

Month	HLH Rate	LLH Rate
January	34.29	25.85
February	34.79	28.29
March	27.57	28.44
April	20.71	25.66
May	16.28	16.30
June	17.15	10.62
July	36.83	21.36
August	35.87	26.85
September	28.15	28.95
October	29.92	28.27
November	31.71	29.14
December	38.76	32.05

OPALCO also qualified for a low density discount (LDD) from BPA of 5.61 percent on its Tier 1 charges in 2022. This discount is given to qualified BPA customers who meet a list of criteria including: low kWh/investment and low consumers/mile of line ratios. During months in which OPALCO purchases more energy from BPA than expected, this discount is applied to the cost it faces. In months in which OPALCO purchases less energy than expected, this discount works against it and any credit it receives is 5.61 percent smaller.

The potential monetary savings that can be gained through the usage of the BESSs is through the shifting of energy consumption away from the pricier HLHs and towards the LLHs. As shown in Table 3, the LLH load shaping rate is generally lower each month. By charging up the BESSs during these hours and discharging during HLH, the price differential generates the potential for benefits. These benefits, however, are typically low for BESS operations due to the cost associated with RTE losses.

3.1.2.2 Demand Charge

The second Tier 1 charge that the DERs have the potential to impact is the demand charge paid by OPALCO. Demand charges are fees incurred by a customer proportional to the highest MWh load it consumes each month. This charge can be reduced by shaving peak loads throughout the month. Demand charges will be reduced as production from the tidal energy and community solar drive down metered load during peak hours. This service can also be provided by the BESSs discharging energy when a specific load threshold is surpassed, thereby reducing peaks. These peak-reducing activities can amount to substantial savings for OPALCO.

The demand charge is determined by three factors: (1) OPALCO's Tier 1 (T1) CSP, (2) OPALCO's Tier 1 average HLH load, and (3) OPALCO's contract demand quantity (CDQ). These three components come together in the following equation each month:

$$\begin{aligned} Demand\ Charge &= \Big[\big((T1\ CSP - AHWM\ Obligation\ at\ T1\ CSP) \\ &- (average\ HLH\ load - AHWM\ Obligation\ at\ T1\ CSP) - CDQ\big)\Big] \times 1{,}000 \\ &\times Demand\ Charge\ Rate \end{aligned} \tag{4}$$

Where,

T1 CSP is OPALCO's peak hourly load for the given month; the AHWM Obligation at T1 CSP is a static obligation; *average HLH load* is the average load across all HLH hours for the month; and *CDQ* is the CDQ set by BPA that is preset for each month.

The AHWM Obligation at T1 CSP, which should not be confused with the AHWM obligation referenced in the load shaping section, was 1.43 MW in January through September of 2022 and 1.502 in October through December 2022.

OPALCO's CDQs in MW are shown for each month in Table 4.

TABLE 4 OPALCO Contract Demand Quantities (MW)

Month	OPALCO CDQ (MW)
January	10.557
February	9.877
March	9.049
April	8.336
May	5.661
June	2.964
July	3.04
August	1.537
September	3.725
October	8.608
November	11.397
December	5.808

As before, note the 1.43 or 1.502 that is subtracted from both the T1 CSP and the average HLH (aHLH) in the equation. By subtracting these Tier 2 amounts from the total load, we are ensuring that only the portion of the total retail load that applies to Tier 1 rates is being used in the equation. CDQs are set independently and only for Tier 1 equations, therefore they do not require any adjustment and are already Tier 1 amounts. The resulting value is charged at the appropriate demand charge rate for the given month, provided below in Table 5.

TABLE 5 BPA Demand Charge Rate for 2022

Month	Rate ($/kW)
January	11.31
February	11.47
March	9.09
April	6.83
May	5.36
June	5.65
July	12.14
August	11.83
September	9.29
October	9.87
November	10.46
December	12.78

The demand charge is also subject to the same LDD discount that applied to the load shaping charge. Therefore, this final calculated value benefits from a 5.61 percent reduction each month.

3.1.3 Transmission Charge Reduction

OPALCO incurs a variety of transmission charges that are calculated using three methods as outlined below:

1. OPALCO pays a transmission service charge each month of \$2.103/kW along with a scheduling, system control and dispatch charge of \$0.389/kW. These rates are applied to the TSP, which is measured during BPA's peak transmission hour in that same month. Unlike the peak loads defined in the previous sections, transmission system peak would add back in any production from the DERs as they are defined as DNRs. Network load as used in determining the transmission charges includes any load served by DNRs. Historically, the OPALCO bill has netted out the effects of solar and BESS operations. During this study, the research team made a strong case that batteries should not be treated as DNRs under the current tariff and while PNGC Power agreed, BPA did not. With that noted, PNGC did agree that energy produced by the DERs should be subjected to a short duration discount (SDD). The SDD is calculated by taking the product of the transmission service charge and the lesser of the energy produced by DERs during the TSP and the aHLH production by DERs multiplied by 0.4. While all DERs are DNRs currently, PV may not be a DNR beginning in 2028. Peak transmission loads were reached in the hours identified in Table 6. Hour 1 occurs between 12am and 1am.

TABLE 6 BPA Transmission Peak Days/Hours in 2022

Month	Day	Hour
January	1/31/2022	HE19
February	2/1/2022	HE19
March	3/7/2022	HE7
April	4/1/2022	HE7
May	5/9/2022	HE21
June	6/27/2022	HE20
July	7/11/2022	HE20
August	8/2/2022	HE17
September	9/6/2022	HE19
October	10/31/2022	HE19
November	11/22/2022	HE18
December	12/22/2022	HE18

2. Spinning and supplemental reserve charges are calculated using the equations below.

$$Spinning\ and\ Supplemental\ Reserves = Trasmission\ Reserve\ Determinant\ in\ MW\ x\ \$18.27 \quad (5)$$

$$Transmission\ Reserve\ Determinant = \left[\left((Total\ Retail\ Load\ in\ kWh)\ x\ (1 + Operating\ Reserve\ Loss\ Rate)\ x\ .03\right) - ((AHWM\ Supply\ x\ AHWM\ \%\ x\ 1{,}000) * (1 + Operating\ Reserve\ Loss\ Rate)\ x\ .015\right] \tag{5a}$$

The operating reserve loss and AHWM supply by month are presented in Table 7.

TABLE 7 Operating Reserve Loss Rate (ORLR) and AHWM supply.

Month	ORLR	AHWM Supply
January	0.0195	7440
February	0.0195	6720
March	0.0195	7430
April	0.0195	7200
May	0.0195	7440
June	0.0231	7200
July	0.0231	7440
August	0.0231	7440
September	0.0195	7200
October	0.0195	7440
November	0.0195	7210
December	0.0195	7440

The AHWM % is 3.063%.

3. The remaining transmission charges, which include regulation and frequency response, peak dues, and WECC dues, are calculated by taking total retail load plus energy discharged from the BESSs and solar production in MWh and multiplying that by 55 cents/MWh.

Once again, there are no current benefits to PV and tidal energy production in terms of reducing these charges. However, benefits will begin to accrue to PV energy production beginning in 2028.

3.1.4 Miscellaneous Charges and Credits

OPALCO incurs miscellaneous charges and credits. One such charge is called the Additional Marginal Contribution (Part A) charge. It is calculated using the following equation:

$$Additional\ Marginal\ Contribution\ (Part\ A) = \left[\left((Total\ HLH\ retail\ load - AHWM\ HLH\ Obligation\ ) + (Total\ LLH\ retail\ load - AHWM\ LLH\ Obligation)\right)\ x\ .25)\right] \tag{6}$$

OPALCO’s AHWM obligations (HLH and LLH) by month are presented in Table 8.

TABLE 8 OPALCO 2022 AHWM Obligation

Month	HLH (MWh)	LLH (MWh)
January	570.40	490.54
February	547.58	410.69
March	616.03	443.49
April	593.22	433.50
May	570.40	490.54
June	593.22	433.50
July	570.40	490.54
August	616.03	444.91
September	570.40	456.32
October	624.83	492.66
November	600.80	482.14
December	624.83	492.66

3.1.5 Transmission Submarine Cable Replacement Deferral

There is a BPA-owned submarine transmission cable that connects Fidalgo Island on mainland Washington near Anacortes with Decatur and Lopez Islands. This location of this cable, referred to as Cable 5, is presented in Figure 7. While the cable currently is under BPA ownership, we value its life extension under the assumption that its replacement could be paid for by OPALCO customers. Value is obtained by using the DERs to reduce peak loads, thereby reducing heat on the cable and acting as a reactor that compensates for the submarine cable's large capacitance. The analysis evaluates the value of extending the 40-year cable life over two rounds of investment.

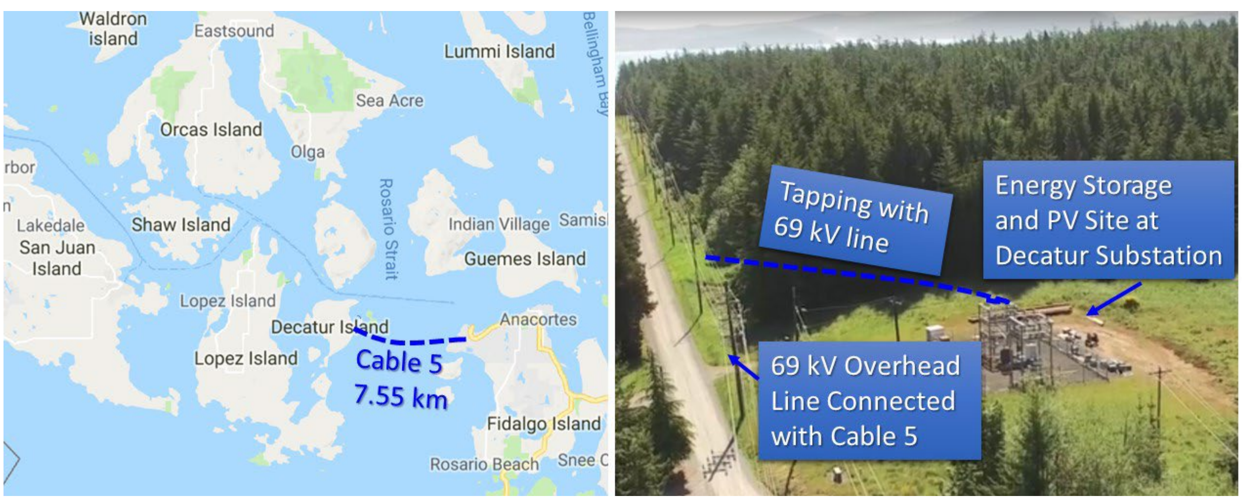

FIGURE 7 Cable 5 Location

The basis of the approach employed for this study is defined in detail in Mongird et al. (2018). In addition to employing the model described in that report, the scenarios defined in Table 9 were evaluated by forecasting load growth at 0.7% annually and additionally exploring how the added load would be accommodated through the DER additions.

TABLE 9 Deferral Periods and Value by Scenario

Scenario	Scenario Description	Deferral Period	Total Present Value	Annualized Value
1	no DERs	0		
2	Tidal power in isolation	5	2,116,805	119,503
3	Tidal power plus local storage on Orcas Island	6	2,530,878	142,879
4	Scenario 3 plus Decatur PV and BESS	7	2,941,907	166,083
5	Scenario 4 with 2X tidal power	10	4,156,959	234,678
6	Scenario 4 with 3X tidal power	14	5,735,761	323,808
7	Scenario 4 with 4X tidal power	19	7,644,868	431,585
8	Scenario 4 with 2x Orcas storage capacity	8	3,349,915	189,117
9	Scenario 4 with 3x Orcas storage capacity	9	3,754,925	211,981
10	Scenario 4 with 4x Orcas storage capacity	10	4,156,959	234,678
11	Scenario 4 with 1x Orcas storage capacity @ 4 hr.	7	2,941,907	166,083
12	Scenario 4 with 2x Orcas storage capacity @ 4 hr.	8	3,349,915	189,117
13	Scenario 4 with 3x Orcas storage capacity @ 4 hr.	9	3,754,925	211,981
14	Scenario 4 with 4x Orcas storage capacity @ 4 hr.	10	4,156,959	234,678
15	Scenario 4 but no assets are DNRs	7	2,941,907	166,083

3.1.6 Outage Mitigation

With the addition of tidal power and the BESS on southern Orcas Island in the Olga District, OPALCO could island a significant portion of its system spanning the Olga District to Decatur and Center Islands.

In the outage mitigation analysis, a four-zone system was employed, consisting of:

1. Olga substation and three lines (Orcas Island),

2. Blakely substation and two feeders (Blakely Island),

3. Decatur substation and two feeders (Decatur Island), and

4. All other islands, including San Juan, Shaw, and Lopez.

The placement of the energy assets considered in this evaluation, along with the portions of OPALCO's transmission and distribution system capable of islanding during outages, is illustrated in Figure 8. It is assumed that the addition of tidal power and an energy storage system would not provide outage mitigation benefits to any customers in the fourth zone identified above and highlighted in Figure 8.

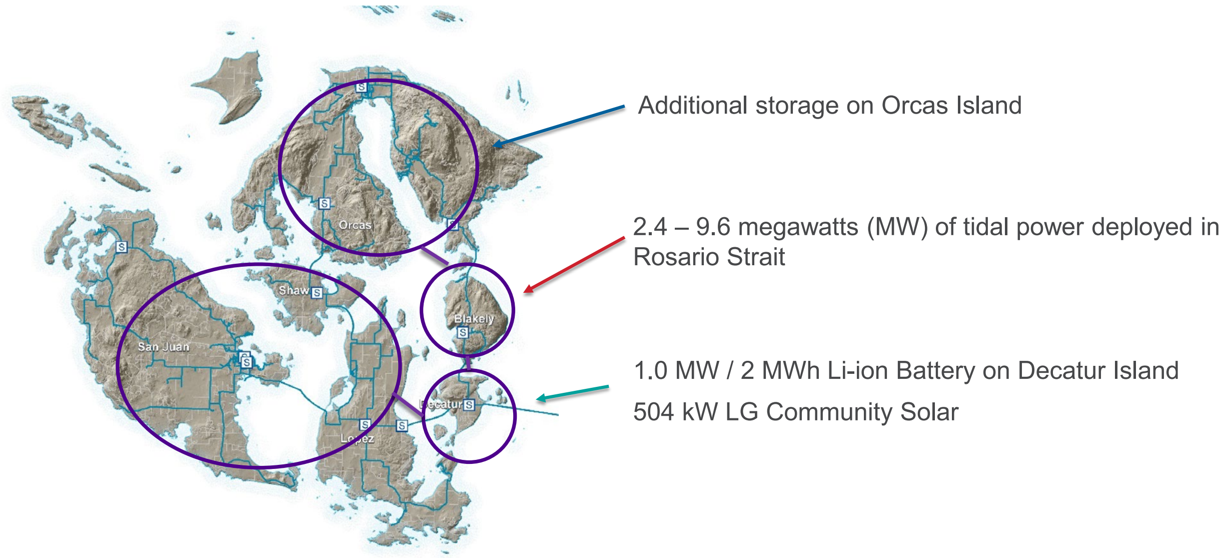

FIGURE 8 Four-zone OPALCO System and Placement of Tidal and Energy Assets

The feeders identified for potential islanding during outage mitigation are detailed in Table 10. These include three on Orcas Island, two on Blakely Island, and two on Decatur Island. Across these seven circuits, there are 2,326 customers, with 92% classified as residential customers, 5.9% as small commercial and industrial (C&I) customers, and 1.6% as large C&I customers. Customer classification accounts for differences in outage costs between residential, small C&I, and large C&I customers.

TABLE 10 Customer Counts by Class for All Feeders with Capacity for Islanding

		Customer Class		
Substation	Circuit	Residential	Small Commercial	Large Commercial
Olga	1	658	59	18
Olga	2	446	26	6
Olga	3	211	4	3
Blakely	1	271	12	0
Blakely	2	46	10	10
Decatur	1	140	11	0
Decatur	2	368	15	0

Outage data was collected for the 2019-2022 time period for any event affecting any of the seven circuits in isolation or in combination. Over this time period, there were 30 outages affecting 32,264 customers. Total hours of load interruption were 188.6, and the average outage duration was just over 6 hours. Total customer minutes of outages reached nearly 11 million over the 4-year timeframe.

For each outage event, we isolate the relevant zone or combination of zones based on the affected areas. For instance, in the case of an outage affecting only Decatur Island, we isolate Decatur and utilize the Li-ion battery and community solar on Decatur to mitigate the outage event. In scenarios covering both Blakely and Orcas Islands, we isolate these regions and employ tidal power and the BESS to address the outage.

The primary objective of the outage mitigation analysis is to systematically minimize both the financial impact and the inconvenience caused by power interruptions. This study takes into account interruption costs for three distinct customer classes: 1) medium and large C&I, 2) small C&I, and 3) residential customers within each region. The outage mitigation analysis is conducted using the Energy Storage Microgrid Optimization (ESMO) model, and is based on a two-stage simulation as shown in Figure 9.

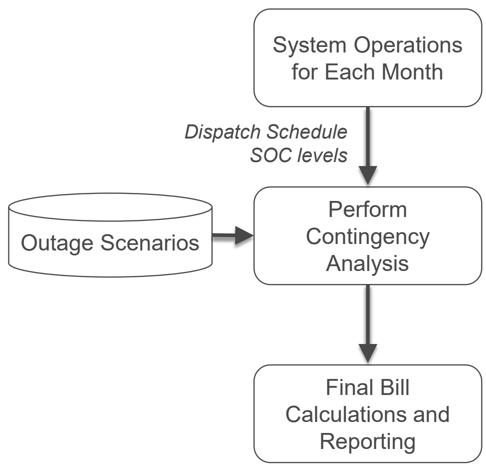

FIGURE 9 Two Stage Structure of Outage Mitigation Analysis

In the first stage, the ESMO model simulates steady-state system operations for each month of the year without considering contingencies. This stage provides hourly dispatch schedules and battery state-of-charge (SOC) levels for all resources in the system. The second stage involves ESMO conducting a contingency analysis for each outage event individually. This contingency analysis model is an optimization model that minimizes total interruption costs by determining the optimal resource utilization strategy. During an outage event, Tidal and PV resources can curtail their outputs only when needed, while energy storage resources can be operated optimally to mitigate the consequences of outage events as much as possible, contingent on the storage energy at the beginning of an outage event derived from the stage 1 outputs. It is important to note that the stage 1 simulations, based on steady-state analysis, are not aware of potential outages. Also, the stage 1 simulations do not incorporate N-1 contingencies explicitly. This means that the energy storage dispatch schedule is not optimized to minimize outage costs; rather, the contingency analysis model simulates how the system would behave when addressing predefined, historically obtained outage events. Also, due to the nature of the simplification made in the outage mitigation analysis, the annual load shedding amounts (in terms of MWh) do not reflect the actual reliability levels of the OPALCO system. Thus, the results should be used solely to compare the relative impact and value of additional tidal and other DERs in mitigating outages and reducing outage costs.

To monetize the value of outages, data from the Interruption Cost Estimate Calculator was utilized.[1] The interruption cost per unserved energy in terms of kWh for each customer class is applied in this study. These values, along with the customer energy consumption rates in percentage terms, are used to derive total outage costs per kWh in each region. The cost functions for each customer class are presented in Equation (7a)-(7c).

$$OC_{MLC\&I} = 52.7 * \alpha_{MLC\&I} * x \tag{7a}$$

$$OC_{SC\&I} = 189.2 * \alpha_{SC\&I} * x \tag{7b}$$

$$OC_{R} = 4.1 * \alpha_{R} * x \tag{7c}$$

Where:

$OC_{MLC\&I}$	Outage costs for medium and large C&I customers
$OC_{SC\&I}$	Outage costs for small C&I customers
OC_{R}	Outage costs for residential customers
$\alpha_{MLC\&I}$	Energy consumption rate for medium and large C&I customers (%)
$\alpha_{SC\&I}$	Energy consumption rate for small C&I customers (%)
α_{R}	Energy consumption rate for residential customers (%)
$x =$	Outage amount (kWh).

3.2 VALUATION MODELING APPROACH

In this study, the project team performed a comprehensive resource scheduling simulation spanning an entire year. This simulation aimed to evaluate the impact and value of the Decatur Island Microgrid and new tidal power and BESS options on southern Orcas Island. In order to capture the unique characteristics of the OPALCO power system, such as network topology and the definition of various charges that are not typically well captured in traditional production cost simulation models, the project team developed ESMO. Figure 10 shows an overview of the ESMO model. In this report, rather than describing all the model features and components in detail, we briefly provide the key characteristics of the ESMO model.

[1] The interruption cost calculator can be accessed at https://icecalculator.com.

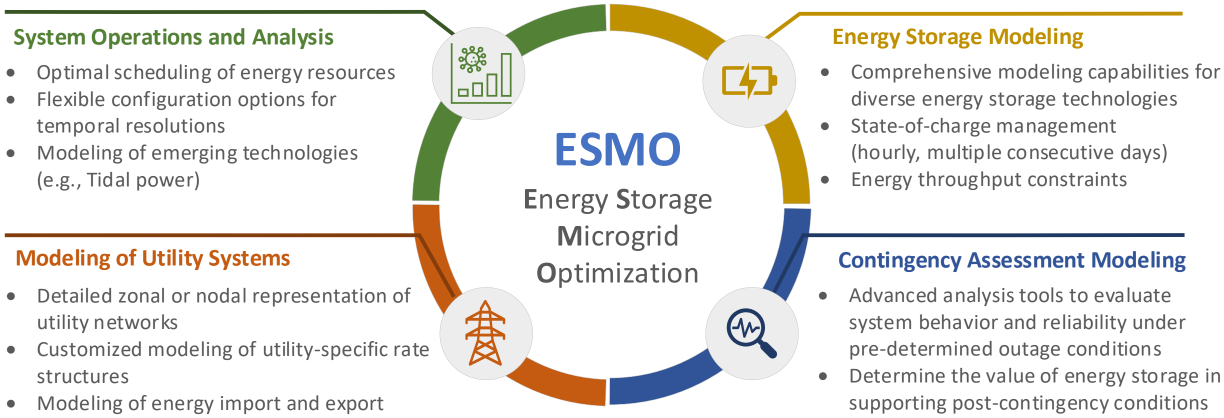

FIGURE 10 Overview of the Energy Storage Microgrid Optimization Model

The ESMO model is a least-cost linear programming model that determines the optimal hourly scheduling of resources in a system while ensuring the total cost (i.e., the summation of various charges described in Section 3.0) is minimized. The least-cost objective function includes the functions of the following charges:

- Load shaping charge,
- Demand charge,
- Transmission charge, and
- Miscellaneous charge.

These charges collectively contribute to the minimization of total system costs. The model accounts for constraints related to technology characteristics, electricity demand profiles, system requirements, and resource availability. The dispatch formulation incorporates constraints to ensure 1) load balance, 2) power flow and transmission limits, and 3) generator operating limits. The load balance constraints ensure that enough power is supplied to meet the demand in each region in each time interval. The power flows between regions are constrained by the transfer capability of transmission lines. A distinctive feature of the ESMO model lies in its detailed representation of the physical and operational constraints of energy storage resources. The model allows energy storage resources to provide all considered grid services. In addition, ESMO tracks and optimizes the SOC levels of energy storage resources through intertemporal constraints. Lastly, the total amount of energy an energy storage resource can be expected to store and deliver over a year is considered in ESMO by an energy throughput constraint. The energy throughput constraint is a proxy for capturing cycle life specifications of energy storage resources, particularly battery storage technologies. The ESMO model, with its nuanced consideration of these constraints and charges, provides a robust framework for evaluating the deployment and utilization of tidal power and energy storage resources within the OPALCO power system.

4 ECONOMIC RESULTS

4.1 INTRODUCTION

Here we evaluate the economic results of the assessment achieved using the ESMO model and approaches defined in the previous section. Value is reported for each service as presented for 15 scenarios defined in Table 11. The ESMO model defines the value of each service individually and when co-optimized. The co-optimized values are reported here. The bundling of services, or use of the microgrid to achieve multiple objectives over a period of time, improves overall economic performance. Present value (PV) costs are compared against the economic benefits to determine net benefits and benefit-cost ratios (BCRs) of each scenario. Under each scenario, the evaluation is performed first from the perspective of the utility in isolation and second from the perspective of the utility plus the customers it serves. Including the customer perspective improves the economic performance of each scenario by removing the costs of payments to members who bought shares in community solar and by including the benefits of improved reliability.

TABLE 11 Descriptions of Microgrid Scenarios

Scenario	Scenario Description
1	no DERs
2	Tidal power in isolation
3	Tidal power plus local storage on Orcas Island
4	Scenario 3 plus Decatur PV and BESS
5	Scenario 4 with 2X tidal power
6	Scenario 4 with 3X tidal power
7	Scenario 4 with 4X tidal power
8	Scenario 4 with 2x Orcas storage capacity
9	Scenario 4 with 3x Orcas storage capacity
10	Scenario 4 with 4x Orcas storage capacity
11	Scenario 4 with 1x Orcas storage capacity @ 4 hr.
12	Scenario 4 with 2x Orcas storage capacity @ 4 hr.
13	Scenario 4 with 3x Orcas storage capacity @ 4 hr.
14	Scenario 4 with 4x Orcas storage capacity @ 4 hr.
15	Scenario 4 but no assets are DNRs

4.2 SYSTEM COST AND FINANCIAL ASSUMPTIONS

This section outlines several cost and financial assumptions used to determine the PV costs of each scenario.

4.2.1 Decatur Solar

The cost of Decatur community solar was $986,239, but was paid for directly by OPALCO members (Baldwin and Wu 2022). Therefore, those costs have been excluded from the analysis. What was included, but only in the utility-focused analysis, is the cost of payments at $0.10 per kWh from OPALCO to those who purchase shares in community solar.

4.2.2 Battery Energy Storage Systems

The cost of the Decatur BESS, including permitting and installation, was $2.5 million (Baldwin and Wu 2022). A Washington Clean Energy Fund grant of $1 million minus a $95,000 contract provided to PNNL for testing the BESS was netted out of the BESS cost. When estimating the cost of the BESS modeled for Orcas Island, we accounted for future cost reductions (40%) predicted for Li-ion technologies between 2018 and 2027 plus a 30% clean energy investment credit authorized under the Inflation Reduction Act (IRA) of 2022 (Cole et al. 2021). The dual impacts of these measures reduce BESS costs to just over $1.0 million. It is further assumed that the Orcas Island BESS will be replaced in year 20 to ensure its economic life aligns with that of the tidal energy system. The analysis includes scenarios with 2x, 3x, and 4x purchases of storage on Orcas Island and also ones where the energy capacity of the units are doubled to 4 hours at a 73% higher expense (Viswanathan 2022).

4.2.3 Tidal Energy

Tidal energy costs by year for the first round of tidal energy investments are presented in Table 12. All costs presented in this section were supplied to the research team by OPALCO staff. Embedded in those cost estimates are $3.1 million in equipment purchases, including submarine cable, and $33.1 million in contracting expenses. Of the contracting expenses, $25.1 million would cover tidal energy deployment costs, including installation, $4 million would be dedicated to submarine cable/anchor installation, and the remaining funds would be used to cover all permitting, environmental, and mitigation expenses. Other costs, at under $4 million, would cover staff time, travel, supplies, and indirect charges. The costs presented in Table 12 were reduced by 30% to account for the clean energy investment credits authorized in the IRA of 2022.

TABLE 12 Budget by Period for Tidal Energy in Rosario Strait

Year	Cost ($Millions)
2024	$3.75
2025	$5.00
2026	$12.50
2027	$18.75
Total	$40.00

Annual operations and maintenance (O&M) costs were estimated by Orbital Marine Power and OPALCO at $304,000. An additional expense of $575,000 would be incurred during a refurbishment operation after 10 years of operation. The 2nd investment in tidal energy was estimated at $15.0 million. The 2nd investment was lower because tidal energy is projected to fall in cost over the next 20 years by 80% and because over $10 million in submarine cable investments and environmental, permitting, and mitigation costs could be avoided. Remaining ancillary costs not tied directly to the development and installation of the tidal power unit was inflated at 4% annually and we assume that the clean energy investment credits of the IRA will have expired before the 2nd investment in tidal power is made.

4.2.4 Key Cost and Financial Assumptions

Table 13 presents several key cost and financial assumptions used in this assessment. These cost and financial parameters were used to address the timing of investments, inflation costs, debt costs, taxes, insurance, and discounting of benefit and cost streams into PV terms. The basis of each assumption is also provided in Table 13. Note that the 4.77% discount rate represents the weighted cost of capital for OPALCO.

TABLE 13 Key Cost and Financial Parameters

Parameter	Assumption	Source
Discount Rate	4.77%	OPALCO
Local Inflation Rate	4.0%	OPALCO
BPA Cost Inflation Rate	3.0%	OPALCO
OPALCO Borrowing Rate	5.5%	OPALCO
Insurance Rate (Annual) as % of Capital Investment	0.271%	OPALCO
Property Tax Rate	0.345%	OPALCO
Clean Energy Investment Credit	30%	IRA
Tidal Development Period		Orbital Marine Power
Timing of Expenditures for Tidal Power		Orbital Marine Power
Year 1 Cost Share	9.4%	
Year 2 Cost Share	12.5%	
Year 3 Cost Share	31.3%	
Year 4 Cost Share	46.9%	

4.3 ECONOMIC RESULTS

The annual benefits of each of the services provided by the microgrid assets under each scenario are presented in Table 14. Note that Scenario 1 was used only to validate the model. Thus, there are no benefits or costs defined under that scenario.

Results from a utility perspective exclude the benefit of outage mitigation, and are presented in Figure 11. The scenarios yield roughly $458.2 thousand to $1.4 million in annual benefits. Demand and transmission charge reductions of up to $542.4 thousand and $110.9 thousand, respectively, were achieved, and are largely driven by the use of BESSs discharging during peak load hours. Transmission deferral ($142.7-$506.5 thousand), base customer charge ($184.9-$194.0 thousand), and load shaping charge reductions of $166.6-$715.1 thousand were driven mostly by tidal energy production.

The results of the benefit-cost analysis (BCA) from a utility perspective are presented in Table 15. For this analysis, we use the BCR and net benefits financial metrics. The BCR is calculated by dividing discounted revenue or benefits of the project by discounted total costs. A BCR of more than 1.0 demonstrates a positive return on investment. A BCR of 1.2 would indicate that for every dollar invested in the project, a return of $1.20 could be achieved. Net benefits are calculated by subtracting PV costs from PV benefits. BCRs presented in Table 15 vary from 0.25 to 0.49, with lifetime net benefits ranging from -$123.6 million to -$33.1 million. While none of the BCRs exceed 1.0, the results of the analysis are very useful in that they define the grant level for tidal power required to break even at $38.9 million. Further, the analysis demonstrates that additional investments in storage on Orcas Island could yield positive net returns of approximately $3 million in PV terms.

The results of the BCA from a utility and customer perspective combined are presented in Figure 12 and Table 16. These results differ from those calculated from OPALCO’s perspective in that they include the value of outage mitigation and they exclude the lost revenue to OPALCO tied to the Decatur Island Community Solar project. BCRs vary from .25 to .53, and net benefits range from -$121.3 million to $-35.0 million. Note that when including all customer benefits, including outage mitigation, the funding gap for tidal power closes to $38.2 million. BESS investments drive positive outcomes through the benefits associated with enhanced outage mitigation, which reaches as high as $86.0 thousand annually in Scenario 14.

Reduction in interruption times were estimated for Blakely and Decatur Islands, and for the Olga District of Orcas Island. Annual interruption reductions, as measured in terms of customer outage times, under Scenario 4 reached 26.6%, 3.8%, and 1.4% for Blakely Island, Decatur Island, and the Olga District, respectively. The annual interruption reduction across the entire microgrid was estimated at 4% under Scenario 4, but reached as high as 9.1% under Scenario 14. An alternative case was considered where the BESS SOCs were maintained at 80% during periods at high risk for outages and under that scenario, the total microgrid-wide interruption reduction reached 9.5% under Scenario 4 and 25.8% under Scenario 14. The economic benefits, as measured in terms of the value of lost load to customers, of this case are presented in the sensitivity analysis section of this report.

TABLE 14 Annualized Benefits by Service by Scenario

Scenario ID	Transmission Deferral	Base Customer Charge	HLH Load Shaping Charge	LLH Load Shaping Charge	Demand Charge	Transmission Charge	Misc. Charge	Outage Mitigation
1	$-	$-	$-	$-	$-	$-	$-	$-
2	$142,692	$184,886	$106,580	$71,005	$(53,534)	$4,840	$1,712	$24,716
3	$170,605	$184,886	$96,630	$78,007	$79,846	$4,434	$1,695	$25,806
4	$189,479	$193,980	$98,614	$83,648	$152,843	$4,524	$1,779	$34,696
5	$271,385	$192,209	$205,474	$154,421	$96,709	$9,366	$3,491	$39,405
6	$377,811	$192,209	$312,427	$225,109	$39,159	$14,208	$5,203	$48,068
7	$506,503	$192,209	$419,057	$296,074	$(27,901)	$19,048	$6,914	$38,998
8	$216,983	$192,209	$90,569	$89,101	$257,132	$4,131	$1,763	$45,343
9	$244,284	$190,438	$83,548	$93,659	$345,237	$3,744	$1,747	$67,735
10	$271,385	$188,667	$77,561	$97,386	$415,103	$3,357	$1,730	$73,284
11	$189,479	$190,438	$89,385	$90,226	$182,224	$4,107	$1,763	$42,200
12	$216,983	$186,896	$73,753	$101,125	$317,894	$3,336	$1,730	$57,196
13	$244,284	$183,354	$60,393	$110,219	$438,218	$2,487	$1,697	$74,277
14	$271,385	$179,812	$50,122	$116,516	$542,399	$1,756	$1,665	$86,013
15	$189,479	$192,209	$99,405	$82,969	$152,204	$110,928	$1,779	$34,695

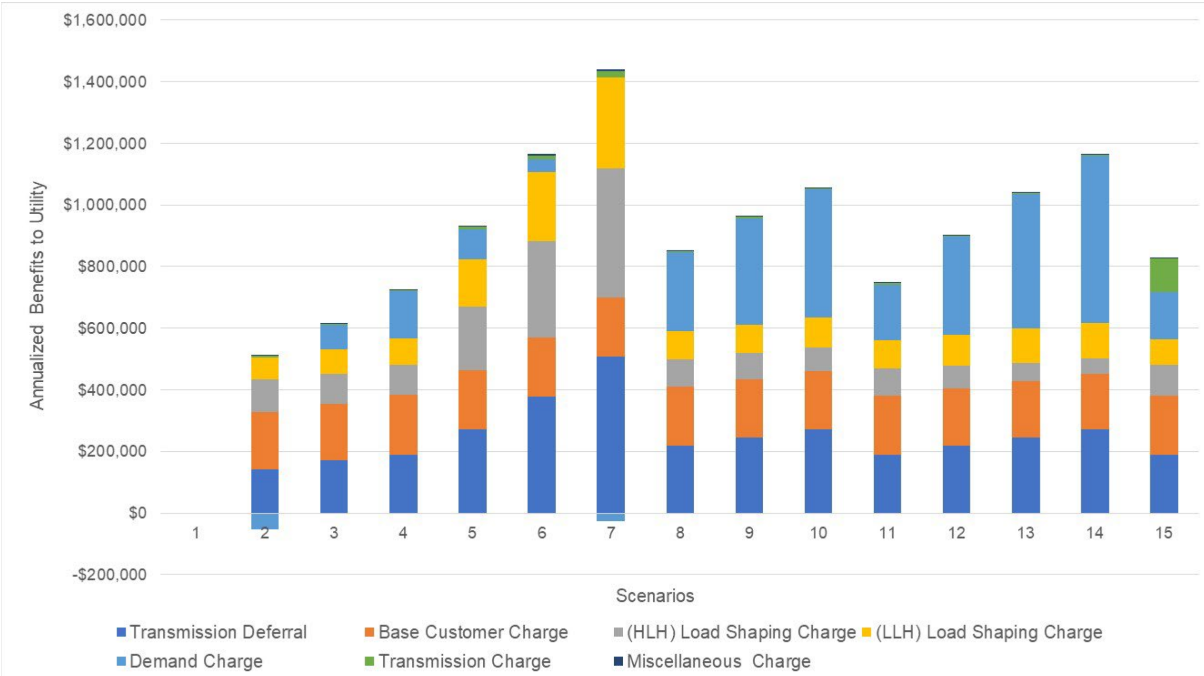

FIGURE 11 Annualized Benefits to OPALCO

TABLE 15 Benefit-Cost Analysis Results – Utility Perspective

Scenario	PV Benefits	PV Costs	BCR	Net Benefits
1	$-	$-	-	$-
2	$13,054,594	$51,983,452	0.25	$(38,928,858)
3	$17,554,111	$53,559,847	0.33	$(36,005,736)
4	$20,653,054	$57,374,999	0.36	$(36,721,945)
5	$26,584,765	$91,423,731	0.29	$(64,838,966)
6	$33,225,435	$128,336,577	0.26	$(95,111,142)
7	$40,228,235	$163,817,365	0.25	$(123,589,131)
8	$24,272,180	$58,951,394	0.41	$(34,679,214)
9	$27,428,200	$60,527,790	0.45	$(33,099,590)
10	$30,064,648	$63,739,006	0.47	$(33,674,358)
11	$21,301,394	$58,489,143	0.36	$(37,187,749)
12	$25,691,895	$60,065,539	0.43	$(34,373,644)
132	$29,650,484	$62,756,078	0.47	$(33,105,594)
14	$33,155,064	$68,236,876	0.49	$(35,081,812)
15	$23,619,287	$57,374,999	0.41	$(33,755,712)

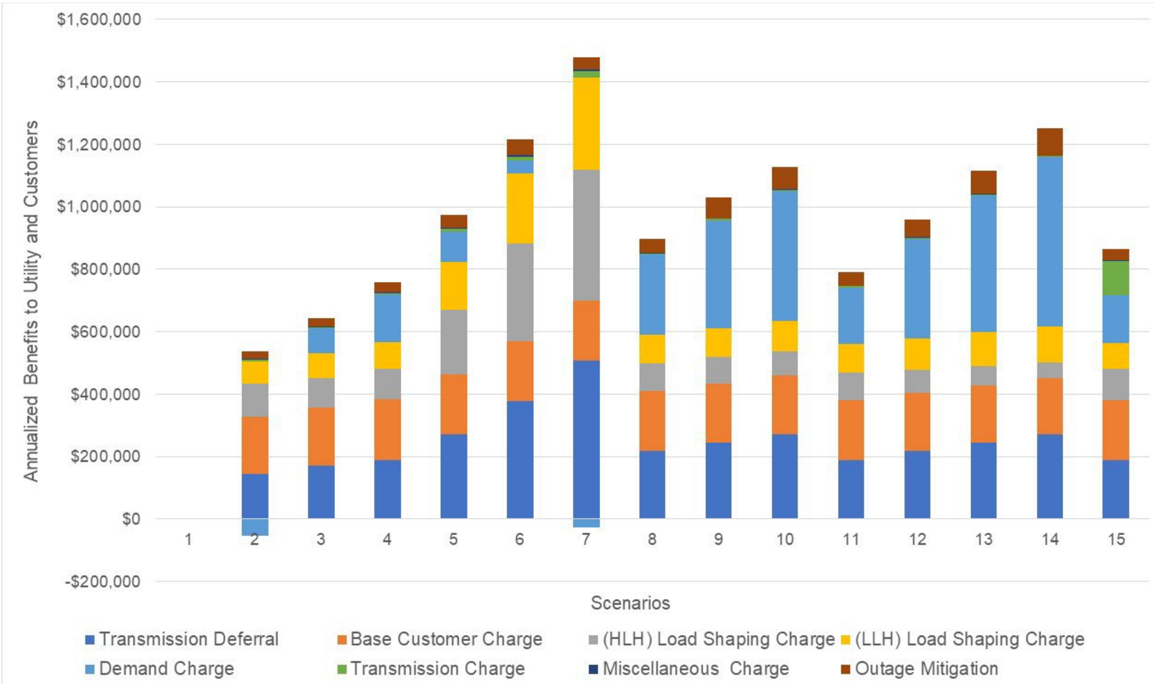

FIGURE 12 Annualized Benefits to OPALCO and Customers

TABLE 16 Benefit-Cost Analysis Results – Utility and Customer Perspectives

Scenario	PV Benefits	PV Costs	BCR	Net Benefits
1	$-	$-	-	$-
2	13,758,792.76	51,983,451.79	0.26	(38,224,659.03)
3	18,289,375.01	53,559,847.32	0.34	(35,270,472.30)
4	21,641,630.64	56,211,131.53	0.39	(34,569,500.89)
5	27,707,510.20	90,259,863.88	0.31	(62,552,353.68)
6	34,595,008.36	127,172,709.25	0.27	(92,577,700.89)
7	41,339,385.56	162,653,498.11	0.25	(121,314,112.55)
8	25,564,093.86	57,787,527.05	0.44	(32,223,433.20)
9	29,358,117.21	59,363,922.58	0.49	(30,005,805.37)
10	32,152,680.80	62,575,138.72	0.51	(30,422,457.91)
11	22,503,769.00	57,325,275.74	0.39	(34,821,506.74)
12	27,321,525.06	58,901,671.26	0.46	(31,580,146.21)
132	31,766,789.29	61,592,210.99	0.52	(29,825,421.70)
14	35,605,770.78	67,073,008.46	0.53	(31,467,237.68)
15	24,607,815.86	56,211,131.53	0.44	(31,603,315.67)

4.4 EVALUATION OF ALTERNATIVE SCENARIOS AND SENSITIVITY ANALYSIS

We evaluated the sensitivity of the results with respect to changes in a number of key assumptions and parameters. The following adjustments are considered:

- BPA energy price inflation is varied by +/- 1% from the 3% baseline
- Discount rate is varied +/- 1% from the 4.77% baseline
- Outage mitigation benefits are improved by bringing each BESS to an 80% SOC prior to reliability events, simulating the use of advanced predictive control methods
- Clean energy investment credits of the IRA are expanded to 40% by meeting all domestic content requirements.

The results of each sensitivity analysis are presented in Tables 17 (utility perspective) and 18 (utility plus customer perspective). The findings of this analysis suggest that the results are somewhat sensitive to all of these assumptions. Varying energy price inflation, meaning the price paid by OPALCO to PNGC Power, has a larger effect than that of varying the discount rate, with impacts reaching -$7.7 million (2% price inflation) to $10.4 million (4% price inflation) when evaluated from a utility perspective. These findings suggest that the microgrid assets would form somewhat of a hedge against future price inflation, with economic performance improving significantly under higher rates of inflation. Scenario 4 reaches a breakeven point with annual energy price inflation of 7.2%. Increasing the clean energy investment credit to 40% for the Orcas BESS and tidal power would improve the economic performance of the microgrid by $4.3-$11.9 million in total PV terms, and setting the BESSs SOC to 80% in advance of reliability events adds $1.0-$4.4 million in additional outage mitigation benefits to customers over the life of the units. Note that scenarios where the duration of energy storage is doubled yield significantly higher outage mitigation benefits.

TABLE 17 Results of Sensitivity Analysis from Utility Perspective

	Energy Price Inflation Rate		Discount Rate			
Scenario	2%	4%	3.77%	5.77%	80% BESS SOC	40% Clean Energy Inv. Credit
1	$-	$-	$-	$-	-	$-
2	$(2,683,948)	$3,605,786	$(2,197,617)	$1,778,177	-	$4,253,880
3	$(3,609,022)	$4,848,590	$(1,383,107)	$1,154,281	-	$4,401,231
4	$(3,710,958)	$4,973,194	$(1,152,647)	$916,394	-	$4,401,231
5	$(4,930,483)	$6,611,581	$(3,123,340)	$2,473,852	-	$6,894,240
6	$(6,295,765)	$8,445,789	$(5,504,640)	$4,380,429	-	$9,387,249
7	$(7,735,500)	$10,380,020	$(7,534,213)	$5,999,434	-	$11,880,258
8	$(4,455,029)	$5,972,826	$(518,026)	$431,339	-	$4,548,581
9	$(5,103,888)	$6,844,545	$21,969	$19,319	-	$4,695,932
10	$(5,645,926)	$7,572,753	$141,196	$(53,675)	-	$4,843,283
11	$(3,844,253)	$5,152,270	$(1,094,291)	$874,715	-	$4,505,373
12	$(4,746,914)	$6,364,963	$(302,056)	$268,012	-	$4,652,724
13	$(5,560,777)	$7,458,358	$327,809	$(210,010)	-	$4,904,217
14	$(6,281,297)	$8,426,351	$327,949	$(177,643)	-	$5,155,711
15	$(4,320,798)	$5,792,491	$(546,562)	$448,607	-	$4,401,231

TABLE 18 Results of Sensitivity Analysis from Utility Perspective plus Customer Perspective

	Energy Price Inflation Rate		Discount Rate			
Scenario	2%	4%	3.77%	5.77%	80% BESS SOC	40% Clean Energy Inv. Credit
1	$-	$-	$-	$-	$-	$-
2	$(2,828,727)	$3,800,292	$(2,053,729)	$1,667,122	$-	$4,253,880
3	$(3,760,188)	$5,051,676	$(1,232,872)	$1,038,327	$950,764	$4,401,231
4	$(3,973,741)	$5,302,101	$(986,218)	$788,975	$1,177,036	$4,401,231
5	$(5,220,850)	$6,977,546	$(2,929,497)	$2,325,275	$1,167,823	$6,894,240
6	$(6,636,879)	$8,879,930	$(5,260,363)	$4,192,925	$976,016	$9,387,249
7	$(8,023,483)	$10,742,783	$(7,342,739)	$5,852,685	$1,276,992	$11,880,258
8	$(4,780,176)	$6,385,517	$(289,617)	$256,083	$1,855,526	$4,548,581
9	$(5,560,205)	$7,433,458	$380,740	$(256,553)	$2,079,011	$4,695,932
10	$(6,134,751)	$8,205,339	$532,274	$(354,482)	$2,719,990	$4,843,283
11	$(4,150,991)	$5,540,230	$(884,177)	$713,580	$1,762,332	$4,505,373
12	$(5,141,494)	$6,870,934	$(4,642)	$39,497	$3,116,000	$4,652,724
13	$(6,055,414)	$8,098,753	$724,665	$(515,276)	$3,906,234	$4,904,217
14	$(6,844,686)	$9,159,111	$793,132	$(535,645)	$4,390,494	$5,155,711
15	$(4,583,571)	$6,121,385	$(380,143)	$321,196	$1,177,083	$4,401,231

5 CONCLUSIONS

OPALCO is developing a diverse set of local renewable energy resources to reduce dependence on mainland Washington State for energy and to reduce the regional need for fossil-fueled power. For this report, the research team at Argonne employed an optimization model to evaluate several economic benefits associated with varying scales of tidal power of between 2.4 and 9.6 MW and other DERs. In addition to existing PV and BESS resources located on Decatur Island, Argonne also evaluated the addition of a BESS on southern Orcas Island with power and energy capacities ranging from 1-4 MW and 2-4 hours in storage duration.

This report evaluates 15 scenarios differentiated based on microgrid asset configuration. The scenarios yield roughly $458.2 thousand to $1.4 million in annual benefits from a utility perspective. Annual demand and transmission charge reductions of up to $542.4 thousand and $110.9 thousand, respectively, were achieved, and are largely driven by the use of BESSs discharging during peak load hours. Transmission deferral ($142.7-$506.5 thousand), base customer charge ($184.9-$194.0 thousand), and load shaping charge reductions of $166.6-$715.1 thousand were driven mostly by tidal energy production.

The results of the BCA from a utility perspective produce BCRs that vary from 0.25 to 0.49, with lifetime net benefits ranging from -$123.6 million to -$33.1 million. Thus, no scenarios yield positive economic returns. Note that total energy production for a 1-year simulation was estimated at 5.7 gigawatt-hours or 2.4% of total OPALCO energy needs. While the benefits of 2.4 MW of tidal power to OPALCO are significant, estimated at $13.1 million in PV terms, they fall $38.9 million short of the breakeven point due in part to high initial capital costs that are estimated at $40 million minus a 30% ($12 million) clean energy investment credit. In addition, annual operating costs, including property taxes and insurance, would reach nearly $550 thousand in the first year of operation. The analysis also demonstrates that additional investments in storage on Orcas Island could yield positive net returns of approximately $3 million in PV terms.

With the addition of tidal power and a BESS on southern Orcas Island in the Olga District, OPALCO could island a significant portion of its system spanning the Olga District to Decatur and Center Islands. Outage data was collected for the 2019-2022 time period for events affecting any of the seven circuits where microgrid assets would be sited in isolation or in combination. Over this time period, there were 30 outages affecting 32,264 customers. Total hours of load interruption were 188.6, and the average outage duration was just over 6 hours. Total customer minutes of outages reached nearly 11 million over the 4-year timeframe. Argonne simulated the use of microgrid assets for reducing outage times and found that BESS investments primarily drove outage mitigation benefits reaching as high as $86.0 thousand annually under one scenario.

The research team evaluated the sensitivity of the results with respect to changes in a number of key assumptions and parameters. Results suggest that the results are somewhat sensitive to several alternative assumptions. Varying energy price inflation, meaning the price paid by OPALCO to PNGC Power, has a larger effect than that of varying the discount rate, with impacts reaching -$7.7 million (2% price inflation) to $10.4 million (4% price inflation) when compared to a 3% price inflation baseline. These findings suggest that the microgrid assets would form somewhat of a hedge against future price inflation, with economic performance improving significantly under higher rates of inflation. The baseline scenario (Scenario 4) reaches a breakeven point when annual energy price inflation reaches 7.2%. Increasing the clean energy investment credit authorized under the IRA of 2022 from 30% to 40% by adding in the bonus for meeting domestic content requirements on the Orcas BESS and tidal power would improve the economic performance of the microgrid by $4.3-$11.9 million in total PV terms, and setting the BESSs SOC to 80% in advance of reliability events adds $1.0-$4.4 million in additional outage mitigation benefits over the life of the units. Finally, scenarios where the duration of energy storage is doubled yield significantly higher outage mitigation benefits.

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