Exploring the Feasibility of

Floating Solar at Lauro Reservoir

April 2022

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JAMES S. BOWER FOUNDATION
Re-envisioning.

Signature Page

Floating Solar in Santa Barbara

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The Group Project is required of all students in the Master of Environmental Science and Management (MESM) Program. The project is a year-long activity in which small groups of students conduct focused, interdisciplinary research on the scientific, management, and policy dimensions of a specific environmental issue. This Group Project Final Report is authored by MESM students and has been reviewed and approved by:

Dr. Roland Geyer	Date

Acknowledgements

Our team would like to thank the following individuals and organizations, without which this Group Project would not have been possible.

Advisors

Dr. Roland Geyer, UC Santa Barbara
Dr. Ranjit Deshmukh, UC Santa Barbara
Dr. Brandi McKuin, UC Santa Cruz
Joel Degner, COMB
Maddie Julian, Mainspring Energy

Clients

Alelia Parentau, City of Santa Barbara
Kristian Hoffland, City of Santa Barbara

Financial Supporters

James S. Bower Foundation

Land Acknowledgement

This project concerns an area located on unceded Chumash land. We acknowledge this fact, and encourage robust engagement with the Chumash peoples as an important project stakeholder and steward of these lands.

Additional Thanks

Joshua Haggmark, City of Santa Barbara
Andrew Rhodes, City of Santa Barbara
Mia Lopez, Wishtoyo Foundation
Byron Pakter, Optony, Inc.
United States Bureau of Reclamation
Southern California Edison
Evan Riley, White Pine Renewables
Terry Crowley, City of Healdsburg
Jeff Rauenhorst, Mission Energy
Connor Haney, Mission Energy
Ned Horneffer, Third Pillar Solar
John McDermott, Third Pillar Solar
Chris Bartle, Ciel & Terre
Mike Gialketsis, Rincon Consultants
Ben Schwartz, Clean Coalition
Gregory Young, Clean Coalition
Annie Secrest, County of San Luis Obispo
Paul Gilman, NREL
Vilayanur Viswanathan, PNNL
Matthew Cimo, Energy Toolbase
Stephen Vicar, Energy Toolbase
Aurora Solar, for Helioscope software

Acronyms and Abbreviations

AC	Alternating current
AF	Acre-foot
BESS	Battery energy storage system
BOS	Balance of systems
BTM	Behind-the-meter
C&I	Commercial and industrial
CAISO	California Independent System Operator
CCA	Community Choice Aggregation
CEQA	California Environmental Quality Act
COMB	Cachuma Operations & Maintenance Board
CPUC	California Public Utilities Commission
DC	Direct Current
DER	Distributed energy resource
DSCR	Debt-service coverage ratio
ETB	Energy Toolbase
FOM	Front-of-meter
FPV	Floating photovoltaic
IRR	Internal rate of return
ITC	Investment tax credit
kPa	kilopascal
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LCOE	Levelized cost of electricity
MACRS	Modified accelerated cost recovery system
MJ	megajoule
MW	megawatt
MWh	megawatt-hour
NBC	Non-bypassable charges
NEM	Net energy metering
NEM 2.0	Net energy metering law – second amendment
NEM 3.0	Net energy metering law – third amendment
NEMA	Net energy metering aggregation
NEPA	National Environmental Policy Act
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PPA	Power purchase agreement
PSPS	Public safety power shutoff
PV	Photovoltaic
RA	Resource adequacy
REC	Renewable energy credit
SAM	System Advisor Model (a tool created by NREL)
SBCE	Santa Barbara Clean Energy
SCE	Southern California Edison
SREC	Solar renewable energy credit
TOU	Time-of-use
TOD	Time-of-delivery
USBR	United States Bureau of Reclamation
WRD	Water Resources Department
WDAT	Wholesale distribution access tariff

Table of Contents

1. Objectives

In this report, we aim to investigate the implications of installing a floating photovoltaic solar system on Lauro Reservoir on behalf of the city of Santa Barbara (the "City"). We developed and analyzed potential system configurations with the goal of maximizing the use of the reservoir according to the goals of various City departments:

1) Maximize local renewable energy resources.
2) Ensure an economically competitive system.

Objective 1: Perform a site analysis and design system configurations given constraints.

A floating solar system, as with any renewable energy project, requires careful consideration of the site. We developed a set of system configurations using the available water surface and surrounding land in different ways, taking into account the priorities of the 'Sustainability and Resilience' and 'Water Resources' departments of the City. To do this, we drew from interviews and site visits by the team to understand the unique physical considerations and constraints at the reservoir. Our report considers how the system connects with the grid, as well as describes possible synergy with adjacent facilities.

Objective 2: Assess potential stakeholders, barriers, and pathways for the project.

Every renewable energy project interacts with multiple stakeholders and faces different challenges. Floating solar has unique considerations and the Lauro Reservoir site also introduces additional stakeholders and complexity. We identified relevant stakeholders of the project, detailed significant barriers to project success, and laid out the basic path required to obtain permits to proceed with the project.

Objective 3: Identify floating solar co-benefits and quantify the benefit of reduced evaporation for inclusion in the report's techno-economic analysis.

We identified numerous co-benefits associated with the implementation of floating solar systems, some of which were quantified. Our co-benefit analysis monetized the benefit of reduced evaporation through a deterministic model and applied the monetized values within a techno-economic analysis.

Objective 4: Conduct a techno-economic analysis of possible system configurations.

Given a set of possible systems designed to satisfy Objective 1, we conducted a 'techno-economic analysis' of each system to inform decision-makers about system performance. This analysis investigated the 'Levelized Cost of Energy' (LCOE), possible 'Power Purchase Agreement' (PPA) prices, and overall electricity generation of these systems.

This analysis also investigated the effects of:

- Including only floating solar in a system compared to choosing hybrid systems that include ground-mounted solar.
- Choosing between connecting the system 'Behind-the-Meter' versus 'Front-of-Meter.'
- Including battery storage as part of the system.
- Adding additional up-front capital costs to certain systems.

2. Significance

California has ambitious climate and air quality goals. To achieve these goals, California needs to complete an 'energy transition' as soon as feasible[1]. This energy transition replaces energy produced via fossil fuels with clean sources of energy, a large part of which likely needs to come from solar projects[1]. However, building new solar projects to produce this renewable energy comes with some challenges, particularly in California. High land costs and a desire to reserve space near electricity load centers for other uses (i.e. near cities) means that solar development is often located in distant desert areas[2]. This increases transmission costs and losses, and these projects also come with both local opposition and concerns about ecological impact[3].

Floating solar (also known as 'Floating Photovoltaics', 'FPV', or 'Floatovoltaics') could help solve these land-use issues and help increase renewable energy generation without some of the drawbacks of conventional solar development[4,2]. A floating solar system at Lauro Reservoir could help the City meet its commitment to reaching 100% renewable energy, with a preference for local energy generation, by 2030. Additionally as incidental water quality benefits, the system could provide reduced evaporation and algae growth on the reservoir. Floating solar as a solution is particularly attractive in Santa Barbara due to the very high cost of land and the isolation of the Santa Barbara area from the wider grid.

Beyond the local impacts of the system itself, this system serves as a case study for future floating solar projects on nearby larger water bodies such as Gibraltar Reservoir or Lake Cachuma, or beyond the Santa Barbara region. This type of operating example is especially valuable for other municipalities, as the barriers to floating solar adoption are often no longer financial but are instead institutional. A literature review and case study detailing floating solar considerations for an US city could be very influential in encouraging wider adoption of this newly matured technology. The opportunity for floating solar is considerable: one recent study conservatively estimated that over 24,000 man-made reservoirs in the US would be suitable for floating solar[5]. However, there are currently only 23 floating solar arrays deployed within the US[6].

Finally, the challenges described above are not unique to California. Other states, and the US as a whole, also have climate and air quality goals, and could benefit from an investigation into floating solar as a potential solution to help achieve such goals. Additionally, this site is managed by the United States Bureau of Reclamation (USBR), a federal agency with significant local interest in solar development. A viable example of a floating solar system on land managed by the USBR could encourage more adoption of this technology on federal lands[7]. This project has salience beyond California and could inform agencies and municipalities about the details of floating solar within the US.

3. Background

Overview:

1. Santa Barbara Clean Energy
2. Lauro Reservoir and Cater Water Treatment Plant
3. History of the Project
4. Floating Solar Technology and Costs
5. Floating Solar Co-Benefits
6. Grid Interconnection
7. Battery Storage
8. Net Energy Metering

3.1 Santa Barbara Clean Energy

The City lies within the 'Goleta Load Pocket,' a section of the California electrical grid minimally connected to the rest of the grid. This relative isolation is compounded by fragile primary connections with the rest of the grid: a set of transmission lines passing through wilderness areas with high earthquake, wildfire, and mudslide risk[8,9]. Loss of any part of this connection with the wider grid would cause significant power outages in Santa Barbara and the surrounding area, and reconnection could be a challenging and lengthy process.

These grid connections have an inherent physical risk that will only be amplified by the growing impacts of climate change[10]. Given this risk and a desire to address climate change, the City has developed a set of goals to improve local energy resilience and develop local renewable energy generation. These goals are laid out in the City's Strategic Energy Plan[11]. They include achieving 100% renewable energy supply by 2030, ideally as much as possible from local sources, as well as developing "Distributed Energy Resources (DERs) & Microgrids at Municipal Facilities"[12].

In 2021, the City took a large step in favor of this plan by creating Santa Barbara Community Energy (SBCE). SBCE is a Community Choice Aggregation (CCA) program that allows the City's municipal government to take control of energy procurement on behalf of all residents and ratepayers. Meanwhile, the City can continue to use the transmission and distribution infrastructure of Southern California Edison (SCE), the local investor-owned utility.

Since SBCE has procurement power over energy generation serving the City, it can place a premium on local renewable energy that might otherwise be too expensive or complicated for SCE to consider purchasing. Further, it can motivate the development of DERs that can establish greater resilience for critical loads in municipal facilities such as the Cater Water Treatment Plant. SBCE has already established its own pricing for energy exported from DERs (such as residential rooftop solar) to further incentivize local renewable energy generation.

Since the City runs its own CCA, it allows for more flexibility for a potential floating solar project – when it comes to supporting larger systems connected directly to Cater.

3.2 Lauro Reservoir and Cater Water Treatment Plant

In looking to meet the local energy and resilience goals outlined in **Section 3.1**, the City has reviewed a number of nontraditional locations that could support local renewable energy development; Lauro Reservoir is one such place.

Located within Santa Barbara city limits, Lauro Reservoir consists of an earthfill dam constructed in 1952, capable of storing 640 acre-feet of water sourced from either Lake Cachuma or Lake Gibraltar[13]. The reservoir water surface level remains generally consistent throughout the year at an average of 549.0 ft in elevation with a total surface area of 857,873 sq ft. This elevation stability is due to its role as essentially a water tank for the Cater Water Treatment Plant[14]. Lauro Reservoir is located on land managed by the US Bureau of Reclamation (USBR) and operated by the Cachuma Operations and Maintenance Board (COMB).

Located across San Roque Road from Lauro Reservoir is the Cater Water Treatment Plant (Cater), which uses and treats water from Lauro Reservoir to deliver a predominant amount of the City's potable water supply. To do so, Cater operates four electrical meters (South Coast Booster Station, Cater Pump, Cater Administration Building, Cross Tie Pump Station). Two of the active meters monitor energy used by Cater's water treatment and distribution systems, and the other two monitor energy used by the administration and operations building.

Located within a high fire-risk zone, Cater is particularly susceptible to public safety power shutoffs (PSPS) and blackout events. Given that much of the City's safe drinking water supply is dependent on this facility, there is significant benefit to ensuring resilience to grid failure at this site. Currently, Cater uses two diesel-powered backup generators and will be installing two Tesla Battery Energy Storage Systems connected to the two most important electrical load accounts – the South Coast Booster Station and the Cross Tie Pump Station. These batteries are intended for 'peak shaving' (which lowers demand charges from SCE) and resilience during power outages. However, these batteries could not power Cater indefinitely, requiring operation of the backup generators in an outage situation. For more information about these batteries, refer to **Section 4.3.7**.

Figure 1: Cater Water Treatment Plant (bottom left) and Lauro Reservoir site location and proximity

3.3 Project History

In the past, City officials from both the 'Water Resources' and 'Sustainability and Resilience' departments have identified this site as a potential source of local clean energy. There have been many options explored, including ground-mounted solar, floating solar, micro-hydro, or even pumped-hydro storage projects. One of these options was a dormant micro-hydro power generator that the City has recently been involved in refurbishing. This facility is located upstream of the reservoir at the Lauro site.

City officials received an unsolicited vendor quote in 2019 for a 1 MW DC behind-the-meter (BTM) system to supply power to the adjacent Cater facility. This proposal only utilized a fraction of the available surface area, and the City did not proceed due to the relatively high cost (due to minimal economies of scale), assumed burdensome regulatory process, and desire to maximize the area on the Lauro site for power generation.

In recent years, the need for local clean power and the ability (via SBCE, managed by the Sustainability and Resilience department) for the City to procure it has grown. In 2021, City officials reached out to the Bren School for Environmental Science and Management in order to determine options that fulfill the goals of the City as economically as possible.

3.4 Floating Solar Technology and Costs

Floating solar systems are very similar to ground-mounted solar systems, except that the solar panels (and sometimes the inverters) are located on floats over a body of water. Usually the chosen project site is a controlled-access freshwater reservoir, although some systems are even installed in marine environments[4].

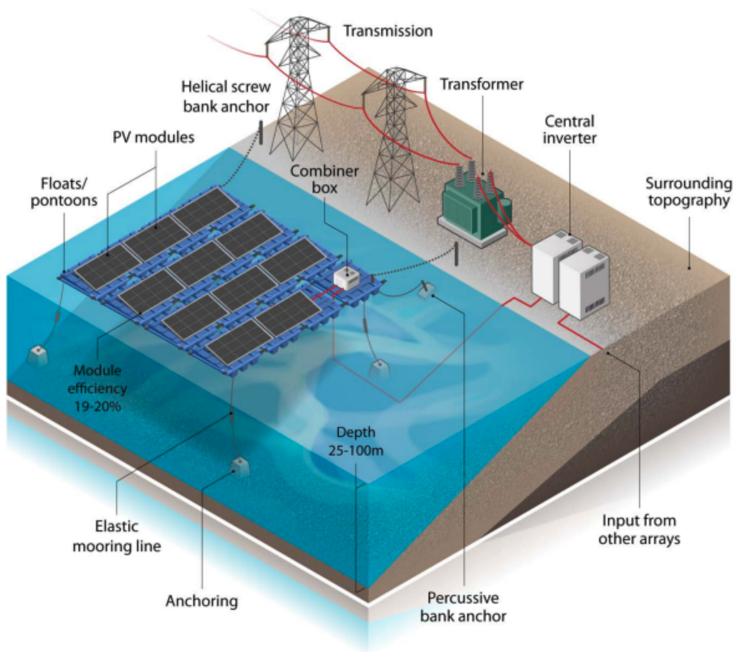

Figure 2: Schematics of a typical large-scale floating solar system and key components, credit to NREL[15].

While very common in East Asia (China, Taiwan, Japan, Vietnam, and South Korea all have many completed projects), floating solar is so far less common so far in the US. As of 2021, there are 2,579 MW of installed capacity globally, increasing from just 2 MW only 14 years ago, yet still only 24 MW total in the United States[16]. There are a number of manufacturers, but the industry leader is Ciel & Terre, a French company that designs the systems but does not develop projects themselves, leaving that to local developers.

The electrical equipment for floating solar (panels, inverters, etc) are identical to ground-mounted systems when procured. However, there are some significant differences between ground-mounted and floating systems, impacting costs and power generation. A recent NREL report surveyed many installers and provides detailed breakdowns of the cost differences between the types of systems as seen in **Figure 3**.

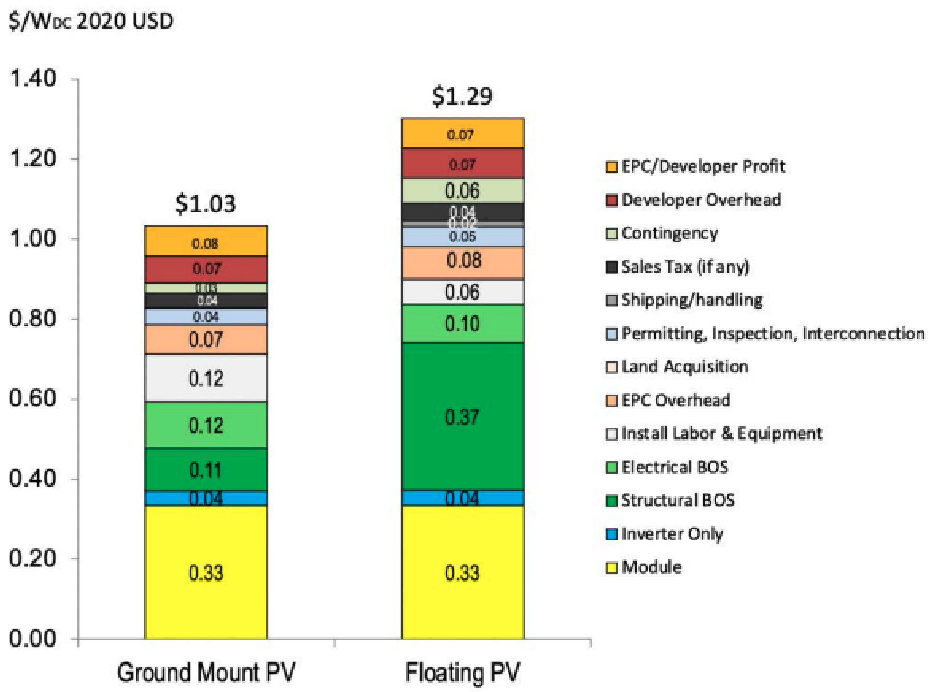

Figure 3. U.S. Installed costs of a 10-MW DC floating solar system and ground-mounted solar system, from the 2021 report from NREL on floating solar costs[15].

3.4.1 Floating Solar Structural Balance-of-System Costs

The structural 'balance of system' (BOS) costs are significantly higher for floating systems than for ground-mounted systems (more than 3x as shown in **Figure 3**)[15]. While floating systems do not require steel posts or new fencing, the high-density polyethylene floats, hardier cabling, and anchoring systems are a significant cost.

3.4.2 Floating Solar Installation Costs

Installation is less costly for floating systems, as there is minimal land preparation, hole-digging, etc. Instead, installation is similar to creating a 'LEGO' set on the shore and pushing it onto a body of water. Installation cost does change based on the design, however – the more 'islands' of solar panels, the higher the installation cost. With more islands, the balance of systems costs are even higher due to more anchors[17].

3.4.3 Floating Solar Operations and Maintenance Costs

Operations and maintenance (O&M) costs are not well understood due to the novelty of the technology and the lack of systems in the US. NREL guidance is as follows regarding O&M costs for floating solar systems (FPV) compared to ground-mounted systems:

> *"Some FPV installers claim fewer O&M occurrences per year due to lack of vegetation and fencing maintenance, leading to O&M savings. However, others say O&M costs are comparable to costs for ground-mounted PV systems, with activities requiring boats to access floating panels away from shore and divers needed to perform preventive maintenance of anchors and mooring lines. In our analysis we assume the FPV O&M cost is equal to the ground-mounted PV O&M cost minus the land leasing cost."*[15]

In the case of the Lauro site, land lease costs would likely be $1 or a similar nominal fee from the USBR, based on preliminary conversations our team had with USBR representatives. In this case, the floating solar system O&M cost would equal the ground-mounted solar system cost.

3.4.4 Floating Solar Power Generation

Due to concerns about wind stress, floating solar system designers typically arrange panels with a maximum tilt of 12°, which would be lower than the ideal for Santa Barbara[18]. Additionally, if an island is significantly longer in the north-south direction than wide, designers must arrange the panels in an east-west orientation on the float, again due to wind stress concerns[17]. Both of these constraints reduce module efficiency compared to the theoretical maximum at the Lauro site.

Meanwhile, the position of modules above a heat sink (the water of the reservoir) decreases module temperature. Solar modules are more efficient at lower temperatures, and thus the floating system gains some efficiency from the location over water[19].

3.5 Co-Benefits

While the costs associated with floating solar technology are overall higher than those of traditional ground-mounted systems, there are a number of additional benefits that increase its relative appeal. These co-benefits can be categorized into five bins; land, economic, power, water, and biological benefits. Understanding these co-benefits is important when assessing the viability of the technology. Some of these benefits have been quantified in the literature and incorporated into our analyses, while others lack sufficient empirical data and must be discussed qualitatively.

3.5.1 Land Use Co-Benefits

Implementing floating solar on a reservoir uses what has previously been an overlooked resource: surface water bodies. Use of these surfaces allows for the conservation of land that would have been otherwise selected for development of ground-mounted solar. This conservation of land may reduce potential land use conflicts derived from competition between development for energy, agriculture, or urban expansion[20]. Reducing land use for energy development also benefits Santa Barbara because of the limited space available and high property costs within the City and surrounding area. Therefore, using surface water bodies for floating solar allows for more space for housing, and can keep solar development away from existing communities[21].

3.5.2 Economic Co-Benefits

Due to the modularity of floating solar systems, system installers do not need to use heavy machinery during installation, simplifying the process. This also reduces installation costs as installers assemble floats on land and simply tow them into the water where they need to be anchored[20]. Site preparation costs, when compared to conventional processes of purchasing and preparing land, may also be reduced. These reductions exist because there is typically no civil engineering work required for floating solar systems and the right to use a water body may be at no or low cost[20].

O&M costs associated with floating solar are also reduced due to the ease of cleaning solar panels when they are located immediately over a body of water. The process is as simple as dipping the panel cleaning device in the water and wiping down the panel. Additionally, floating panels typically accumulate less dust than their ground-mounted counterparts so they require less total maintenance and generate more electricity[20,22].

High transmission losses and new transmission costs associated with solar development located far away from grid infrastructure can also be avoided with most floating solar installations. Instead of transporting electricity from remote areas long distances, locating floating solar on a reservoir with already established hydropower or access to local grid interconnections can reduce development costs and transmission losses[20].

3.5.3 Power Generation Co-Benefits

Deploying solar panels atop a water body leads to a performance benefit in the solar modules due a more favorable operating environment. These performance benefits are borne from a number of factors.

First, the evaporative cooling effect from the water below the panels lowers the operating temperature of the PV modules. This could lead to a 5-10℃ lower module temperature dependent upon air ventilation beneath the floating modules. Higher module temperatures correlate to efficiency losses, specifically, every degree Celsius increase in temperature leads to a 0.45% drop in panel efficiency. Thus, a reduction in temperature could lead to a substantial increase in energy generation from a floating system. Second, wind speeds over open water bodies tend to be higher than over land; this increased wind speed results in more PV module cooling and thus higher efficiency. Third, floating solar installations are rarely shaded by nearby objects and buildings and the characteristically low tilt of floating systems reduces inter-row shading effects. Fourth, the water bodies hosting floating solar are less dusty than traditional solar sites, and these conditions reduce the soiling losses that result from dust gathering on panels[16,20].

With each of these performance benefits in mind, it is worth noting that some floating solar projects have reported improved energy yields of more than 10% when compared to ground-mounted systems. This benefit should also increase in warmer temperature climates[4,20].

Further, siting of floating solar on water bodies that are near already established grid infrastructure reduces transmission losses from lengthy power lines as noted previously. Energy savings attributed to these line loss savings increase the value of the floating solar system. Water reservoirs are also typically located where energy demands are high, therefore allowing floating solar systems to satisfy local energy demands and serving as a DER[22,23]. Additional interconnection synergy can be established when siting floating solar near water treatment plants that can provide on-site self-consumption, further decreasing infrastructure and energy expenses[4,20].

3.5.4 Water Co-Benefits

Noted previously under land-use co-benefits (**Section 3.5.1**), repurposing the surface of a body of water for floating solar increases regional potential generation by using a previously developed area. This is especially useful when using a water body that has limited economic or recreational uses such as Lauro Reservoir[20,22].

Floating solar also shades the water body, lowering the light intensity reaching the water and lowering the temperature of the water. This reduction in irradiance can help prevent algae growth under the floating system, despite the array's constant contact with the water, leading to an improvement in water quality as algae is generally a negative presence in water[20,24,25].

This shading effect leading to a lower temperature is also the main driver of reduced evaporation associated with floating solar[20,24]. In addition to the shading effect, limiting the effects of wind on the water's surface also helps reduce evaporative losses[20,24]. This reduction in evaporation can be important for regions where water is scarce, such as Southern California. However, quantifying these evaporation benefits is difficult because floating solar systems typically only cover a part of a water body and there are many confounding factors to various estimation methods.

The specific amounts of evaporation that floating solar systems reduce vary greatly in the literature. Some literature estimates suggest evaporation reductions of 50% and others report reductions of 90%[24,26]. Despite these uncertainties, there is sufficient empirical evidence and scientific consensus to conclude that reduced evaporation from floating solar systems is a substantial co-benefit.

The materials used for floating solar systems are benign in terms of water quality degradation. The floats themselves are made out of HDPE, the same material used for milk jugs and many municipal water pipes[27]. Previous leaching studies have indicated that the polyethylene plastics used in the floats contain small amounts of aluminum and zinc with concentrations several times lower than drinking water standards and are thus in compliance with water safety regulations[28–30]. Meanwhile, the crystal silicon panels of floating solar only leach lead when lead-based solder is used, and only in cases where structural integrity of the panel itself has been compromised[31].

3.5.5 Biological Co-Benefits

Floating solar systems located atop a surface water body can provide shelter for fish, as well as suitable habitat for perching, loafing, foraging, and basking for various birds, reptiles, and amphibians[24,25]. These benefits can promote a healthy ecosystem in and around the water body in which the floating solar is installed, exhibiting how floating solar minimally degrades the habitat and may even benefit the natural environment.

Unfortunately, as beneficial habitat, floating solar suffers from an increased amount of animal activity on and around the systems. Increased activity may result in increased bird droppings on the panels and a small amount of soiling losses as a result. However, birds are not known to nest on floating solar systems[25], so this increased activity is temporary and soiling losses can be easily abated with regular cleanings any time of year.

3.6 Grid Interconnection

A floating solar system on Lauro Reservoir could interconnect and interact with the greater grid in a number of ways based on the configuration and sizing of the system. According to SCE's 'Integration Capacity Analysis Map', a 16 kV distribution line runs up into Mission Canyon along San Roque Road serving Cater and distributing generation from the micro hydro plant as part of the Hurst Circuit[32].

The most traditional way that a system could distribute its power generation is through an interconnection with the grid, delivering power directly into the Hurst Circuit. This would require the project developer to adhere to SCE's interconnection processes and fees as laid out in **Section 7.1** of this report, and would allow SBCE to purchase the generated electricity at an agreed-upon Power Purchase Agreement (PPA) price based on a third-party ownership contract with that developer. This type of interaction with the grid constitutes a front-of-meter (FOM) system.

Alternatively, the system could be connected directly to Cater. This would necessitate the construction of a new distribution line and trenching under San Roque Road starting from the northern end of the reservoir and extending 0.6 miles to Cater's electric hub. The solar system would be sized to meet the electric load of the plant, provide resilience and could save the City money that it would have otherwise spent purchasing energy from the grid. This type of interaction with the grid constitutes a behind-the-meter (BTM) system.

3.7 Battery Energy Storage Systems

Solar generation is valuable as a source of local renewable energy, but there are clear limitations to any such form of intermittent generation. Solar panels generate energy during the day, and provide peak generation when the sun is shining the strongest, around the middle of the afternoon[33]. This is the time when the grid as a whole is most saturated with energy generation, particularly solar generation. Meanwhile, the time of peak energy demand from the grid is typically from 4pm – 8pm; when many people are returning from work, yet solar panels are generating little or no electricity[34]. Battery storage can shift the electricity generated during non-peak hours, when the electricity is not needed as much, to peak hours in the evening, when there is significantly more demand. This value can be monetized for front-of-meter systems via both time-shifting and resource-adequacy payments, and for behind-the-meter via time-shifting.

3.7.1 Considerations for Front-of-Meter Battery Systems

Adding batteries to a system adds costs, but also adds value streams. In particular, there are four quantifiable and monetizable benefits from the battery for a front-of-meter system:

1. Ability to use 'clipped' DC system energy if the battery is DC-connected (compared to AC-connected). This 'clipped' energy is energy that cannot normally be converted to AC electricity by the inverter, but is able to be used if stored in a battery first.

2. Ability to time-shift the energy from less-valuable peak-insolation times (mid-day) to more valuable early evening times (4 – 8 PM). Note that this time shifting is not pulling energy from the grid, but merely delaying the release of power from the system.

3. Ability to participate in local 'Resource Adequacy' markets, explained below.

4. Ability to participate in ancillary services. This is the only value stream not explored in this report.

The design decisions around battery system configurations come down to two specifications: power factor and energy capacity. Power factor is the power, measured in kilowatts (kW), that the battery provides to the grid. Energy capacity is the amount of energy, measured in kilowatt-hours (kWh) stored within the battery. These two metrics are related by the time it takes the battery to discharge. For instance, a battery with a 1 kW power factor and a 4 kWh energy capacity is referred to as a 'four hour' 1 kW battery, as it can produce for 4 hours continually.

An increase in the power factor tends to increase the cost of a battery system by a small amount, while an increase in the energy capacity tends to increase the cost significantly[35].

Another factor in sizing the battery comes from the amount of energy available from the system itself. The daily production curve is illustrated in **Figure 4**. Note that this curve is different than the energy output would be without a battery. For instance, if a system nameplate capacity is 5.7 MW DC, in practice the amount produced by that system is far less than the nameplate – closer to 5 MW DC at peak. In addition, the inverter nameplate for that system would be ideally sized at 4.8 MW AC, and the system only produces a peak amount in mid-day in the summer in any case. The lost power between the peak produced and the inverter capacity is known as 'clipped' power, and the ability to use this energy is a benefit of battery systems.

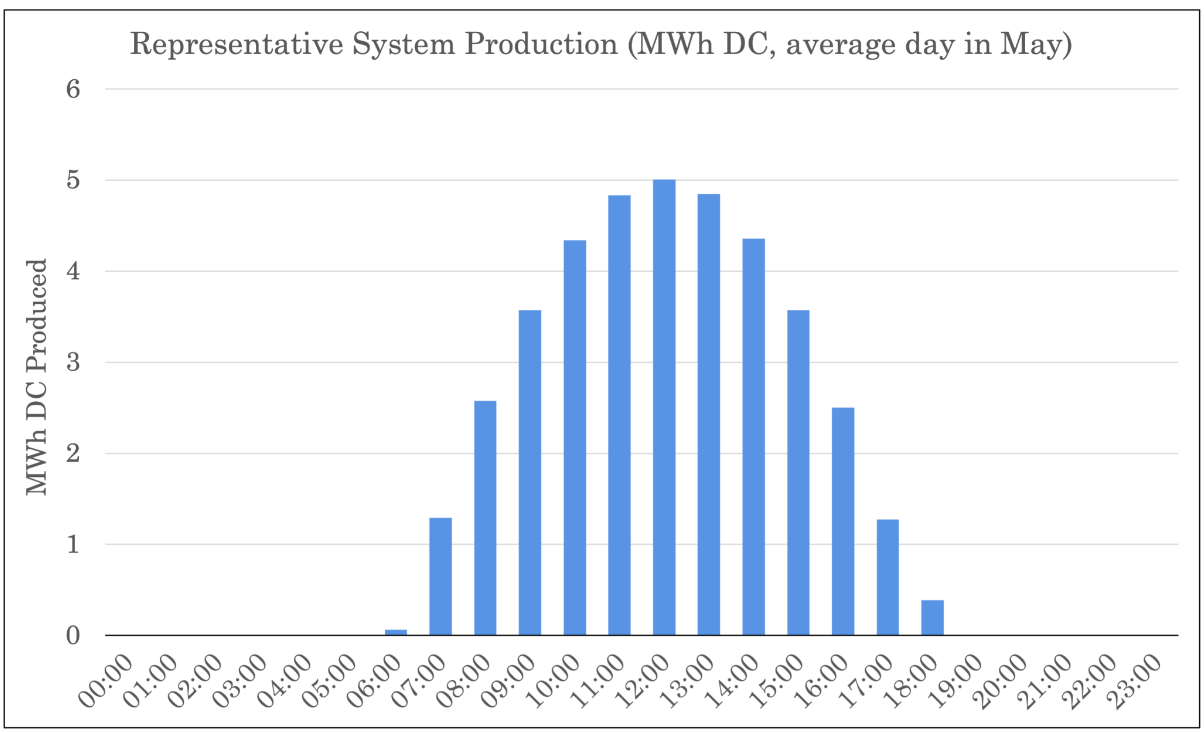

Figure 4. Daily production curve of our largest modeled system (5.7 MW nameplate) on an average day in May, MWh DC. This is the amount of energy actually available to the battery.

Thus, the energy available to store in the battery is the area under this curve. This ranges from about 16.7 MWh DC per day in December to about 33 MWh DC per day in May due to the changes in irradiance (sunlight) from both the length of day over the seasons as well as seasonal weather.

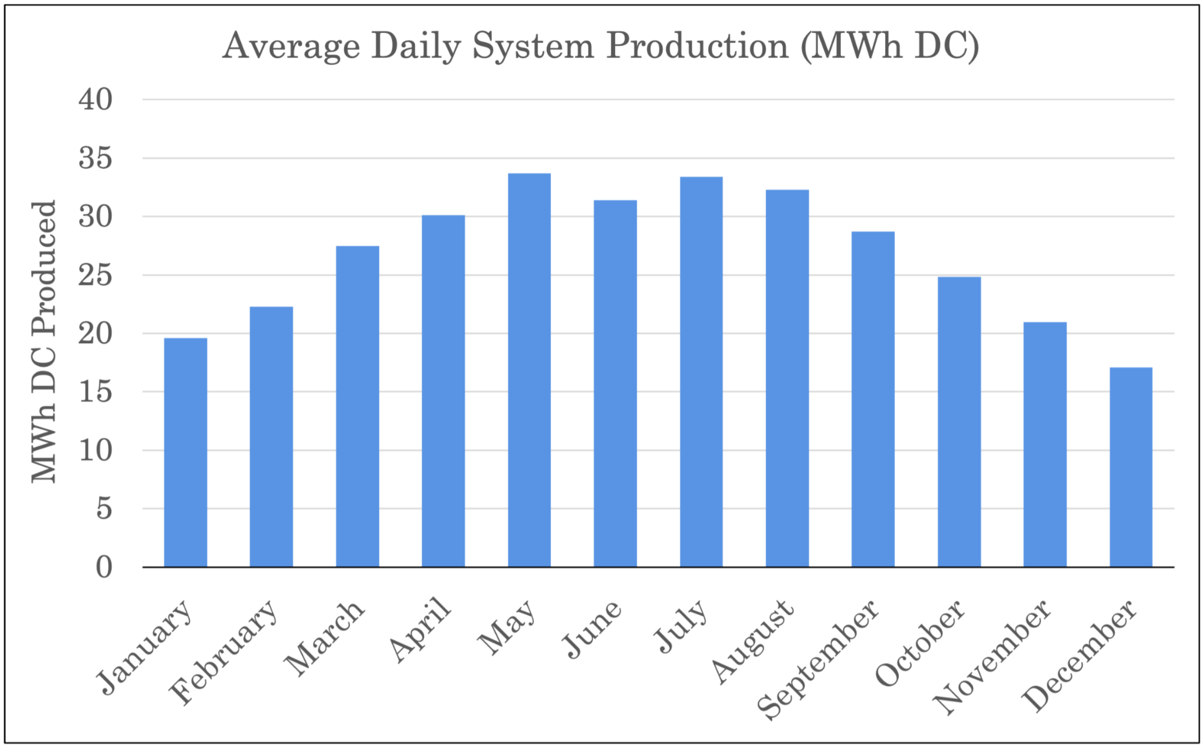

Figure 5. Average daily system production (MWh DC) by month of the largest system configuration. This is the amount available to be stored by a battery storage system.

Time-Shifting Value

Time-shifting value can be calculated from 'Time-of-Delivery' (TOD) multipliers associated with a given PPA. These multipliers incentivize delivery of power at specified times based on market supply and demand. The TOD rate schedule predicted for 2026 by SCE is included in **Figure 6**.

Thus, a 5 ¢/kWh PPA, delivering 1 kWh at noon on a weekend in July would result in a payment of 1¢ (5¢ × 0.20), while delivering 1 kWh at 9 PM of the same day would result in a payment of 8.75¢ (5¢ × 1.75). Accordingly, every kWh 'shifted' from noon to 9 PM on that day by the battery system results in a profit of 7.75¢.

Table 2 Informational TOD Heat Maps (2026) Weekdays and Weekends & Holidays

SCE -WD	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.36	1.34	1.34	1.34	1.37	1.47	1.55	1.54	1.16	0.73	0.48	0.32	0.30	0.39	0.52	0.73	1.43	1.71	1.71	1.57	1.55	1.54	1.51	1.43
2	1.37	1.36	1.36	1.36	1.40	1.45	1.58	1.41	0.88	0.39	0.29	0.19	0.18	0.22	0.23	0.44	1.11	1.64	1.81	1.68	1.57	1.52	1.51	1.45
3	1.37	1.36	1.36	1.37	1.37	1.39	1.52	1.39	0.56	0.17	0.10	0.04	0.02	0.03	0.04	0.08	0.21	0.55	1.47	1.69	1.62	1.45	1.42	1.41
4	1.32	1.31	1.31	1.31	1.31	1.31	1.40	1.11	0.34	0.16	0.13	0.09	0.05	0.07	0.07	0.08	0.14	0.31	1.18	1.62	1.67	1.51	1.35	1.33
5	1.28	1.26	1.26	1.26	1.25	1.27	1.27	0.92	0.26	0.19	0.15	0.09	0.08	0.08	0.09	0.12	0.17	0.32	1.01	1.50	1.65	1.51	1.34	1.30
6	1.29	1.25	1.25	1.25	1.25	1.26	1.20	0.84	0.30	0.29	0.26	0.23	0.19	0.19	0.22	0.26	0.33	0.51	1.03	1.46	1.78	1.63	1.39	1.32
7	1.28	1.23	1.21	1.21	1.21	1.25	1.21	0.96	0.74	0.60	0.56	0.54	0.53	0.58	0.63	0.72	0.81	0.98	1.16	1.54	1.71	1.57	1.43	1.35
8	1.30	1.24	1.23	1.23	1.24	1.28	1.33	1.08	0.85	0.68	0.64	0.60	0.58	0.66	0.72	0.85	0.93	1.06	1.35	1.74	1.74	1.53	1.42	1.37
9	1.30	1.26	1.23	1.24	1.25	1.30	1.38	1.22	0.85	0.58	0.53	0.46	0.41	0.52	0.59	0.69	0.79	1.12	1.60	1.95	1.62	1.47	1.40	1.34
10	1.37	1.33	1.32	1.33	1.35	1.38	1.42	1.41	0.99	0.38	0.33	0.27	0.24	0.29	0.34	0.48	0.73	1.35	1.74	1.69	1.52	1.44	1.42	1.40
11	1.35	1.33	1.32	1.32	1.33	1.37	1.45	1.24	0.69	0.33	0.25	0.22	0.22	0.28	0.46	0.98	1.53	1.73	1.67	1.54	1.52	1.49	1.47	1.41
12	1.39	1.37	1.37	1.37	1.38	1.47	1.55	1.52	1.16	0.76	0.56	0.42	0.34	0.47	0.58	1.08	1.58	1.69	1.66	1.60	1.60	1.59	1.54	1.47

SCE -WE/Hol	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.37	1.35	1.35	1.34	1.34	1.37	1.39	1.37	1.01	0.36	0.26	0.21	0.17	0.19	0.23	0.40	1.41	1.70	1.71	1.57	1.51	1.50	1.47	1.41
2	1.36	1.36	1.36	1.34	1.35	1.37	1.40	1.28	0.24	0.17	0.09	0.05	0.05	0.08	0.10	0.18	1.05	1.57	1.79	1.63	1.54	1.49	1.47	1.45
3	1.38	1.35	1.34	1.34	1.35	1.35	1.35	1.27	0.26	0.05	0.03	0.01	0.00	0.00	0.01	0.04	0.17	0.45	1.46	1.67	1.58	1.45	1.38	1.37
4	1.33	1.31	1.31	1.31	1.30	1.31	1.31	0.89	0.12	0.03	0.02	0.00	0.00	0.00	0.00	0.01	0.03	0.15	1.16	1.62	1.58	1.44	1.35	1.32
5	1.28	1.21	1.21	1.21	1.20	1.20	1.16	0.50	0.15	0.08	0.06	0.03	0.01	0.03	0.03	0.04	0.13	0.20	0.95	1.46	1.58	1.47	1.33	1.28
6	1.27	1.22	1.22	1.22	1.22	1.21	1.09	0.35	0.13	0.08	0.06	0.02	0.01	0.02	0.04	0.07	0.10	0.26	0.91	1.43	1.71	1.63	1.41	1.28
7	1.32	1.24	1.23	1.23	1.23	1.23	1.13	0.75	0.30	0.21	0.25	0.20	0.23	0.25	0.31	0.43	0.66	0.87	1.15	1.59	1.75	1.60	1.37	1.34
8	1.28	1.20	1.19	1.19	1.19	1.19	1.19	1.00	0.32	0.26	0.23	0.19	0.21	0.24	0.30	0.54	0.82	1.03	1.29	1.76	1.70	1.52	1.34	1.33
9	1.27	1.21	1.21	1.22	1.22	1.22	1.22	1.11	0.48	0.25	0.19	0.16	0.16	0.24	0.32	0.39	0.64	0.99	1.61	1.87	1.61	1.40	1.35	1.32
10	1.38	1.34	1.33	1.33	1.33	1.33	1.33	1.31	0.60	0.25	0.17	0.11	0.08	0.14	0.16	0.27	0.44	1.29	1.69	1.68	1.49	1.42	1.41	1.40
11	1.33	1.33	1.32	1.33	1.33	1.33	1.34	1.16	0.39	0.14	0.07	0.05	0.04	0.10	0.18	0.73	1.41	1.65	1.65	1.51	1.49	1.48	1.47	1.44
12	1.39	1.37	1.38	1.38	1.38	1.39	1.41	1.38	1.06	0.30	0.22	0.16	0.15	0.19	0.24	0.89	1.54	1.68	1.65	1.56	1.57	1.56	1.54	1.47

Figure 6. Southern California Edison's (SCE) predicted 2026 Time-Of-Delivery (TOD) heat maps for 'weekday' (WD) and 'weekend / holiday' (WE/Hol) schedules[36].

Resource Adequacy Value

As a way to ensure system reliability across the California grid, all 'Load Serving Entities' (e.g. utilities or CCAs) are required by the California Independent System Operator (CAISO) to procure a certain amount of locally sourced reliability and flexibility supporting generation capacity, known as Resource Adequacy (RA). These 'Load Serving Entities' are required to procure enough energy to meet their expected peak load with a 15% reserve margin[37]. There are several types of RA, but small generation projects like this would fall under the 'flexible local' RA type.

A system only including solar generation on its own does not qualify as 'flexible local' RA because of its intermittent nature. However, when a solar system is paired with a battery system that meets certain criteria, it is eligible for RA payments[38]. Systems with batteries meeting these requirements would receive revenue in the form of regular RA payments and would increase the supply of 'flexible local' power in the market SBCE operates in, thus lowering the cost of procurement. More information on Resource Adequacy value can be found in **Section 4.3.7**.

Ancillary Service Value

Front-of-meter batteries can also be monetized through ancillary service markets. The three ancillary services that are traded in the CAISO market are frequency regulation, non-spinning reserves, and spinning reserves. These services are monetized through contracts with CAISO that require the system to keep a certain amount of battery charge available for a certain amount of time each month. Market prices for these services are difficult to predict into the future, and were too difficult to incorporate into economic modeling for this project. Ancillary services can account for up to 20% of battery revenues streams, so calculations of battery value excluding these revenues are conservative estimates[39].

3.7.2 Considerations for Behind-the-Meter Batteries

In the context of a behind-the-meter system, batteries can have significant benefits to both the grid as a whole and to City facilities. Battery storage reduces the facility's need for electricity from the grid at times of peak demand by 'shifting' the power from times of high utility-wide energy production (midday) times to times of high utility-wide demand (early evening). This allows for savings for the City and benefits for the grid as a whole[39].

For Cater, batteries can help drastically reduce the facility's energy costs. Utility bills are split into a number of different fees, but the bulk of the costs generally come from two items:

1. Energy consumption, based on the amount of kilowatt-hours (kWh) of electricity used during that billing period and the time of that consumption.
2. Peak energy demand, based on the maximum instantaneous energy usage at any point during that billing period.

This demand charge can often represent up to 50% of the total electric bill[39]. Using batteries to shift solar generation to times of peak demand for the facility can drastically reduce this part of the electric bill, a benefit called 'peak shaving'[39]. Meanwhile, the costs of energy consumption can vary based on the Time-of-Use (TOU). The electricity rates that utilities charge facilities like Cater incentivize using energy at times when the energy is cheap for the utility to procure, and vice versa. Thus, if the facility can shift its grid consumption from a time when the facility is charged more for energy to a time when the facility is charged less for energy, the facility saves money. This is possible with a battery system.

3.8 Net Energy Metering

Net Energy Metering (NEM) is a set of rules established by the California Public Utilities Commission (CPUC) that increases the profitability of behind-the-meter systems. These rules allow a customer to monetize the generation of a solar array such that the customer is able to credit the energy produced by the system on their electricity bill over the course of the year. This means that a customer can avoid paying high retail rates for energy even if the energy is pulled from the grid, as long as they have produced a corresponding amount of energy at some point previously. Commercial and industrial (C&I) customers (including municipal customers) have somewhat different rules than residential customers. C&I customers still must pay demand charges (based on the peak kW power pulled from the grid) regardless of their net power usage[40].

To qualify for NEM, customer-generators with systems over 1 MW must pay for all transmission and distribution system upgrades, plus a one-time $800 fee. They must also be under a time-of-use rate, and pay for non-bypassable charges (NBCs) on each kWh of energy that is used/sent to the grid[41].

This basic NEM policy works for many use-cases, but more complicated systems (multiple meters or sites) may require a customer to use parts of the NEM policy that are special cases designed for this complexity. These cases are 'Net Energy Metering Aggregation' and 'Renewable Energy Self-Generation Bill Credit Transfer' as described below. Additionally, the new proposed NEM policy known as 'NEM 3.0' or 'Net Billing' may affect the value of these types of configurations.

3.8.1 Net Energy Metering Aggregation

Typical NEM policies only apply to the electricity usage on a single meter allocated to the solar generation tied to the load. Net Energy Meter Aggregation (NEMA), on the other hand, allows facilities who have multiple meters on attached, adjacent or contiguous properties to aggregate their electrical loads, and receive a financial credit on their electric bills for any surplus energy fed back to their utility[41].
This has the same practical effect of having individual solar systems attached to each meter, but allows the more efficient configuration of just one system and one interconnection.

NEMA is required to enable a behind-the-meter configuration at Cater that can offset loads over all four meters, instead of just one meter. Refer to **Section 4.3.8** for more information on this particular system configuration.

3.8.2 Renewable Energy Self-Generation Bill Credit Transfer

Another kind of NEM policy is the Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) policy. Similar to NEMA, this policy allows distributed energy systems to offset electricity on eligible meters other than the one to which the solar generation is directly connected. This tariff goes a step further, though, allowing the offsetting electricity meter to be completely off site and noncontiguous with the original property, so long as it is under the same utility account. The system size limit under this tariff is 5 MW AC, and bill credits are applied to the generation-only portion of a customer's retail rate. This tariff is particularly helpful for municipalities and local governments who have a number of facilities across a wide geographic range.

However, the RES-BCT tariff itself is only available for bundled large utility customers. To use a similar tariff structure for this project, SBCE would need to establish its own tariff to serve City accounts. Silicon Valley Clean Energy (SVCE) pioneered this kind of feed-in tariff, an example upon which SBCE may be able to model its own implementation of the tariff[42]. If SBCE establishes its own tariff, it may be able to change the structure to suit City needs, for instance increasing the system size limit, although all of the systems investigated in this study are below the 5 MW AC cap. The City would still be restricted to offsetting only generation, however.

This type of tariff is required to enable a large behind-the-meter configuration that can offset loads at both Cater and the Charles E. Meyer Desalination Plant. Refer to **Section 4.3.9** for more information on this particular system configuration.

3.8.3 NEM 3.0 or 'Net Billing'

In 2022, the CPUC released their proposal for a reformed NEM payment system and tariff. This proposal significantly reduces the value of electricity exported by customers to the grid compared with the existing valuation[40]. While this tariff is under intense political scrutiny and pressure particularly regarding residential customer impacts, it is likely that at least for C&I customers the proposal will largely be implemented as-is or close to it.

The rationale behind the CPUC's change comes from a ratepayer fairness question. Customers using NEM to offload excess electricity generation are receiving retail rates for their generation even at times when wholesale prices for the power are very low (e.g. midday at peak solar output). At the same time, residential customers are also not paying for the fixed costs of maintaining the grid — maintenance costs borne by every utility ratepayer. These costs are currently amortized into every kWh of usage on a ratepayer's bill. However, since customers using NEM are purchasing far fewer kWh from the grid, these customers avoid paying for those maintenance fees (this is a similar effect to EV users avoiding the infrastructure taxes embedded in gasoline taxes)[43].

Those fees to maintain the grid, in turn, end up being passed on to other customers in the form of higher electricity rates. These higher rates disproportionately impact lower income individuals for whom their electricity bill is a larger portion of their income. These individuals are also far less likely to own a home and to have rooftop solar, making it far more likely that these individuals bear the full costs[40].

Currently, the CPUC has proposed changing from ‘net-metering’ (calculating the net amount of energy pulled from the grid by a customer) into ‘net billing’ where customers are only able to earn the ‘avoided generation cost’ of the energy that they export to the grid[40]. ‘Avoided generation cost’ is simply the cost that a utility would have to pay for that same energy on the wholesale market. In addition, residential customers would be required to both switch to time-of-use rates and contribute a ‘grid charge’ – similar to the existing C&I customer TOU rates and ‘demand charges’. C&I customers, having already been required to both pay demand charges and use TOU rates in NEM 2.0, are likely less impacted by the CPUC’s proposal[40].

Regardless, this current proposal, as well as any changes which ultimately are adopted, will likely significantly reduce the value of electricity generation exported through NEM. This is particularly the case for residential customers, but is also the case for C&I customers, and will thus impact the value streams of a behind-the-meter system.

4. Methods

The following sections will describe the methodology by which we conducted this analysis. This section describes the various system configurations we used for our economic analysis, as well as the methods behind our physical system designs, economic analyses, and models. We used various tools including industry standard software like Helioscope, System Advisory Model (SAM), and Energy Toolbase (ETB), as well as models within Microsoft Excel.

4.1 System Configurations

As mentioned in **Section 3.6**, there are many different ways a floating solar system at the Lauro site could be sized and could interact with the grid. In this report we conduct a techno-economic analysis for five selected systems at various sizes and configurations.

Of the five systems, three are FOM systems for which all power must traverse the grid. One of these front-of-meter systems would contain a battery, and thus would receive Resource Adequacy capacity and time-shifting revenue. The remaining two systems are BTM systems directly connected to Cater. BTM1.4 would offset the entire Cater aggregated load, while BTM5.7 would offset Cater and an additional 4.3 MW of the Charles E. Meyer Desalination Plant via a custom feed-in tariff.

As a result, we identified the following system configurations:

1. FOM2.5
    a. A 2.5 MW floating solar system
    b. Selected to maximize generation on the surface of the reservoir
    c. All energy is sent directly to the grid
    d. See **Figure 7** for layout

2. FOM5.7
    a. A 2.5 MW floating solar system, plus a 3.2 MW ground-mounted solar system
    b. Selected to maximize use of the site
    c. All energy is sent directly to the grid
    d. See **Figure 8** for layout

3. FOM5.7 + BESS
    a. A 2.5 MW floating solar system, plus a 3.2 MW ground-mounted solar system
    b. Selected to show battery impacts on the largest and most economical system
    c. Includes a lithium-ion based battery system DC-connected to the solar array
    d. All energy is sent directly to the grid
    e. See **Figures 8, 11, and 12** for layout

4. BTM1.4

   a. A 1.4 MW floating solar system sized to Cater's total load across four meters
      i. One interconnection to Cater Cross Tie Pump (paired with existing battery)
      ii. One interconnection to the South Coast Booster (paired with existing battery)
      iii. Remaining Cater meters would need to be under NEMA

   b. Selected to show a traditional net-metering configuration
   c. Requires trenching a cable along and across under San Roque Rd
   d. See **Figure 9** for layout

5. BTM5.7

   a. A 2.5 MW floating solar system, plus a 3.2 MW ground-mounted solar system
      i. One interconnection to Cater Cross Tie Pump (paired with existing battery)
      ii. One interconnection to the South Coast Booster (paired with existing battery)
      iii. Remaining Cater meters would need to be under NEMA

   b. Selected to show a behind-the-meter system at maximum size
   c. Requires trenching a cable along and across under San Roque Rd
   d. Excess energy would offset the desalination plant via RES-BCT.
   e. See **Figure 8** for layout

Figure 7. System design showing full utilization of the reservoir's surface. Blue represents array locations and orange represents a 'keepout buffer' around the intake tower to be avoided. Represents the FOM2.5 system. Colored lines on the reservoir indicate the extent of the reservoir at various surface-level elevations.

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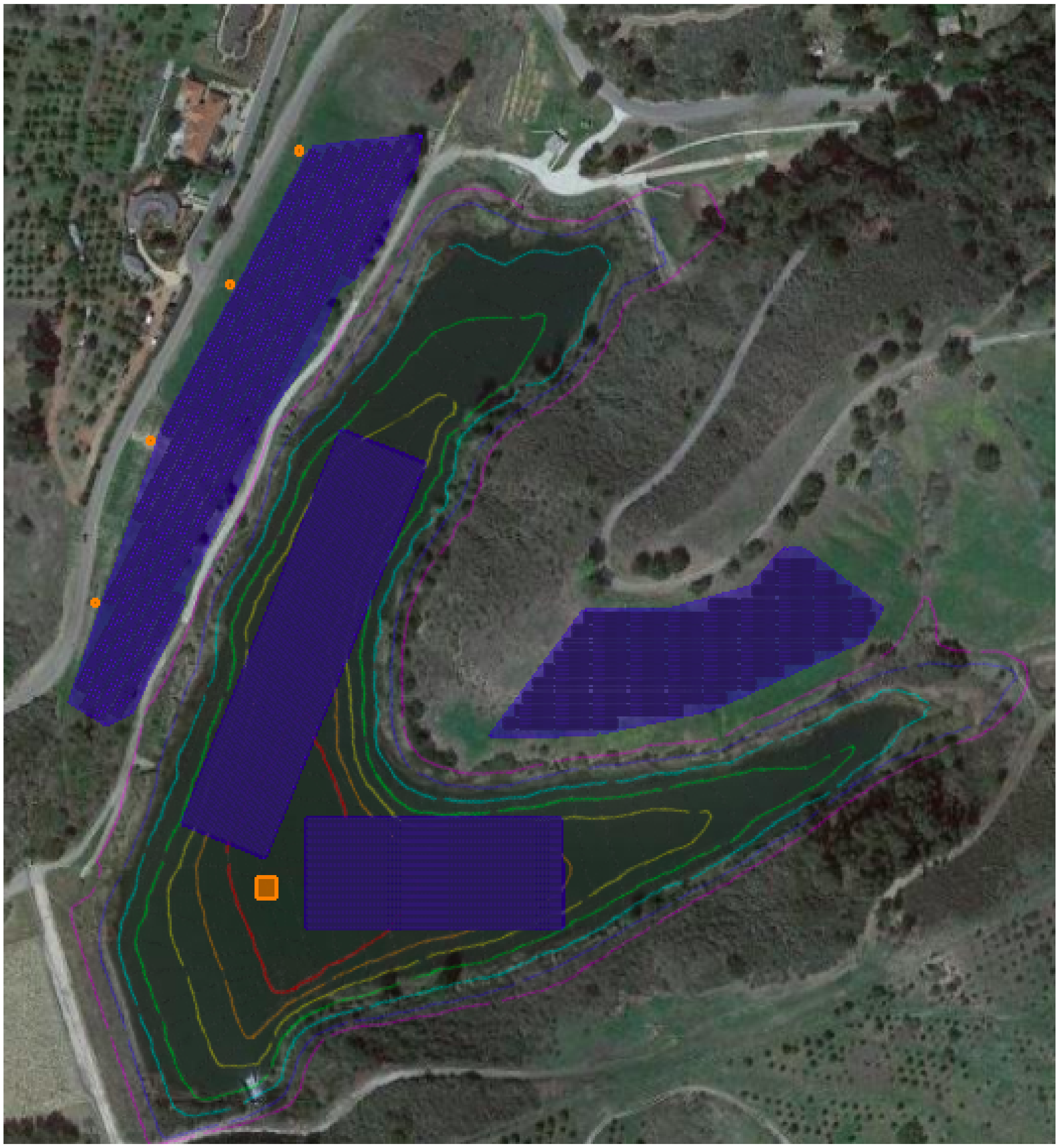

Figure 8. System design showing the full utilization of the site, with ground-mounted and floating systems. Blue represents array locations and orange represents a 'keepout buffer' around the intake tower and electricity poles. Represents the FOM5.7, FOM5.7 + BESS, and BTM5.7 systems.

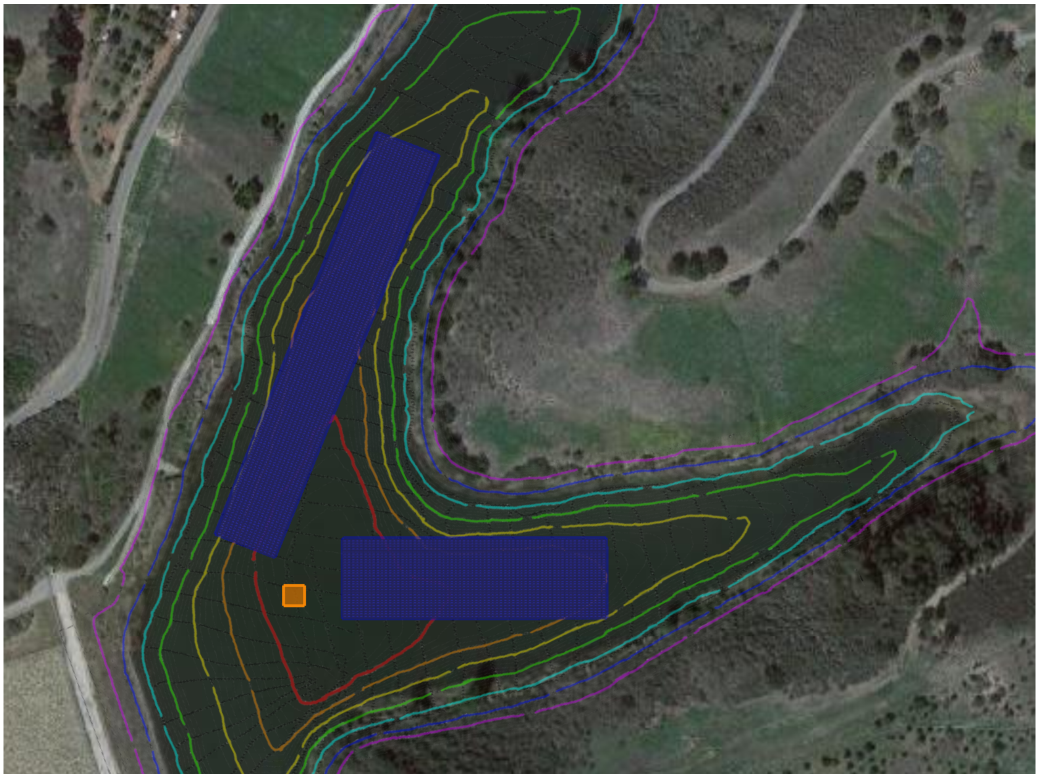

Figure 9. System design showing floating solar exactly sized to Cater's load for a behind-the-meter system. Represents the BTM1.4 system.

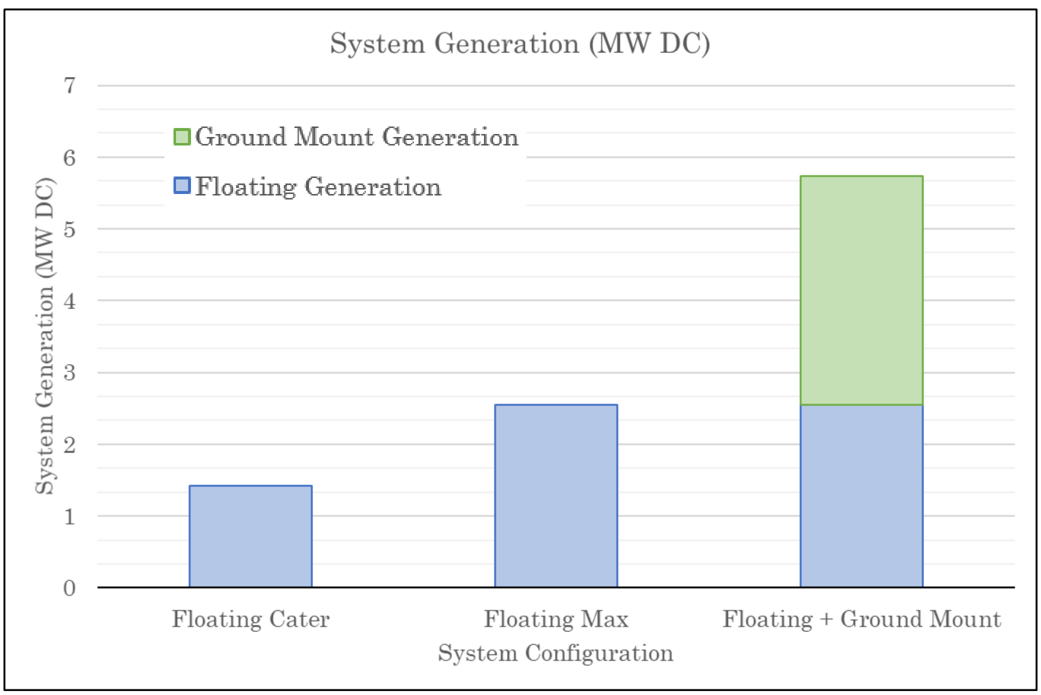

Figure 10. System sizes (MW DC installed) for the three physical configurations developed in this report. Note that one physical system may be configured in different ways – connected directly via trenching to Cater, connected directly to the grid, or including a battery system.

4.2 Physical System Designs

We relied heavily on Helioscope, an industry-standard energy modeling software, to design our systems. Helioscope is software that allows a user to design and evaluate the performance of potential solar projects, including allowing a user to optimize solar arrays overlaid on a site map.

Our main optimization criteria were to produce the most power, at least cost, with minimal disruption to reservoir operations and wildlife. The city of Santa Barbara in particular was interested in producing the most power possible in the space (e.g. the largest feasible fraction of the reservoir) in order to maximize local, clean power.

Based on our discussions with industry experts, we aimed to optimize the following further criteria in service of those goals:

- Maximally-south-facing azimuth angles for our arrays
- Less distance to the inverter pads, if possible
- Avoid curved surfaces for ground-mounted systems

Additional criteria specific to floating systems included:

- The fewest 'islands' of solar panel arrays floating on the surface
- Regular, rectangular configurations of solar panels
- Avoiding placement near the dam or above intake structures
- Ensuring open water near inflow and spillway
- Ensuring CalFire access to the reservoir for fire-fighting purposes
- Avoiding floating inverter pads, if possible, given added complexities
- Ensuring panels remained floating within historical operating water levels of the reservoir (more information in **Section 4.2.4**)

Following these criteria indicated that designs should avoid arrays located in the area in the southwest corner of the reservoir, near the dam and spillway. This open space allows access for CalFire and avoids the dam and spillway hazards, increasing the likelihood of USBR approval. See **Appendix E** for further considerations on solar array row spacing and angle, as well as anchoring considerations.

4.2.1 Inverter and Battery Pads Location

DC power produced by the solar arrays must be 'inverted' into AC power in order to export that power to the grid. Typically, solar systems require an inverter for every 100-200 kW of power[44].

Placing these inverters can be done in three ways:

1. Via a set of inverters placed on a 'pad' (usually concrete) near the edge of the system as a whole.

2. Via a set of inverters placed as close as possible to each 100-200 kW section of a system. In floating systems, these can consist of floating inverter pads.

3. Via 'microinverters' placed on the back of each panel. These are more common in residential settings or where shading is a large concern.

Additional floating pads add complexity and cost to a floating solar system. However, there is limited space available on shore at the site for placing a central inverter pad. After discussions with the city of Santa Barbara, we determined that the ideal location for an inverter pad is near the existing micro-hydro plant located up the hill on the north side of the reservoir (**Figures 11 and 12)**. This avoids the added complexity and cost of floating inverters.

The ideal location for the battery pad (for configurations with batteries) is also located near the micro-hydro facility. The batteries, ideally, should be placed near the inverter for ease of maintenance and to minimize wiring losses. This area in question is currently used by COMB employees to store pipes and can therefore likely be repurposed for this use. Given a power density of 0.182 MWh/m^2, this site of approximately 572.5 m^2 should be able to support up to 125 MWh of energy storage, more than enough to store the daily output of any of our configurations.

Figure 11. Proposed site of inverter pad and battery pad in a site-scale context.

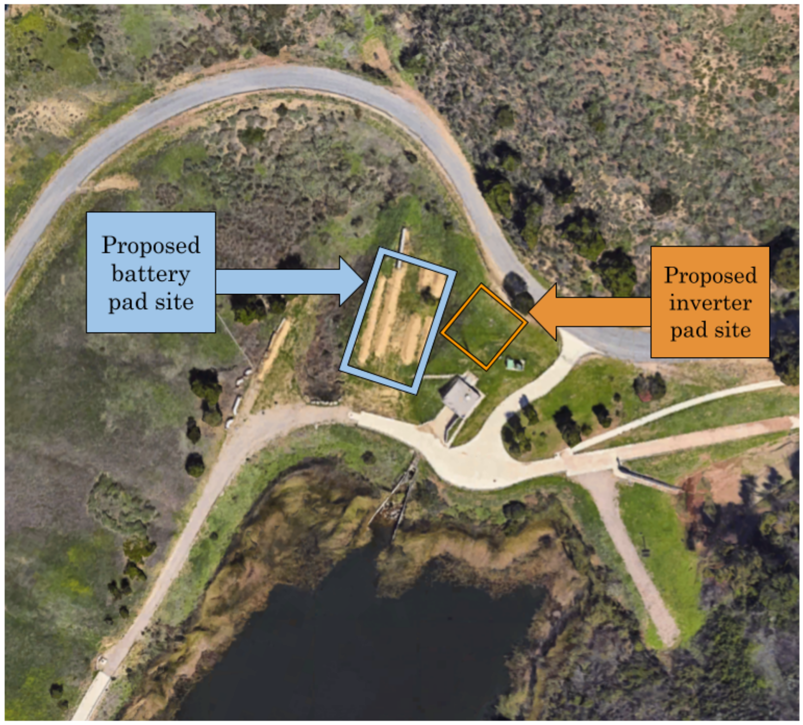

Figure 12. Detail of proposed inverter pad and battery pad sites. Note the locations relative to the existing micro-hydro facility.

4.2.2 Soiling and Temperature Efficiency Effects

The model incorporates improved solar module efficiency at 8% due to local shading and lower operating temperature. Gadzanku et al.'s literature review indicated a range of 5-11% improvement, and the median value of 8% was utilized in this analysis[4]. We modeled improved efficiency in Helioscope and SAM by reporting a -6% soiling loss after summing with a default soiling loss value of 2%.

4.2.3 Power Losses

There are many sources of loss that reduce the actual amount of power delivered to the grid from the amount theoretically produced after considering soiling and temperature losses. These losses occur from line (wiring) loss, module mismatch, and other electrical losses.

We relied on Helioscope's calculation of these losses, given our system configurations, and the results of Helioscope's calculations are included in **Table 1**. Note that we used the same power loss values for both floating-only and combined floating and ground-mounted systems.

Table 1. Losses as reported by the Helioscope tool, used for designing physical configurations.

Parameter	Value	Notes
Module Mismatch	-5.4%	This is fairly high & conservative, incorporating loss due to differing sizes of strings, cloud cover, and edge effects. Therefore, it may be possible for a skilled system designer to reduce this number.
DC Wiring	-4.0%	There is substantial DC wiring loss due to the long cable distance to the central inverter pad.
AC Wiring	-0.5%	
Diodes and Connections	-0.1%	

4.2.4 Lauro Bathymetry

We established suitable boundaries for the floating solar arrays on Lauro Reservoir after consulting reservoir operators and a bathymetry map generated during COMB's 2005 bathymetry study (**Figure 13**). The reservoir elevation of 539 feet above sea level is the historic low point of the reservoir[45]. We therefore designed system configurations to avoid portions of the reservoir bottom exceeding an elevation of 530 feet. This constraint can accommodate a substantial and atypical drop in water level while still maintaining full functionality of the floating system.

An additional boundary for array placement is that of the intake tower supplying water to Cater[46]. To maintain suitable water quality levels and not promote algae growth on or around the intake tower, we designed system configurations with a 'keep out' zone around the buoy designating the intake tower location (see the orange square in **Figure 7**).

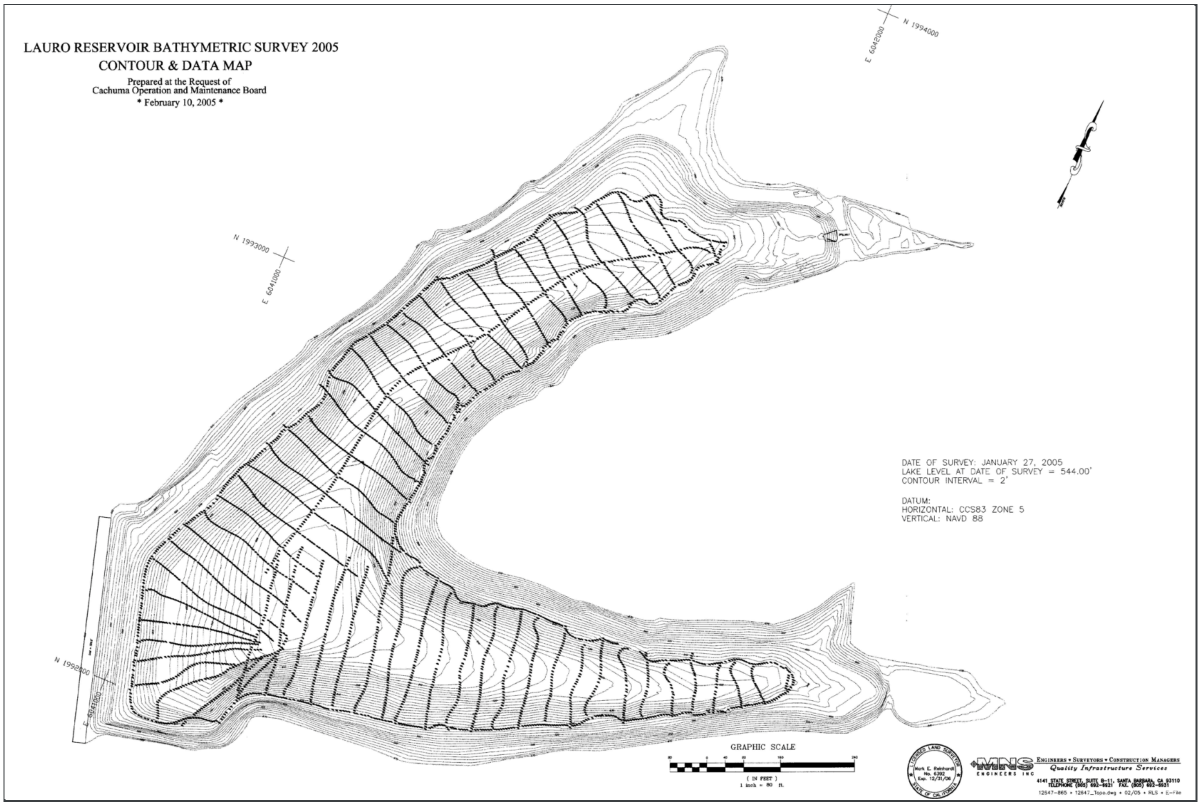

Figure 13: Bathymetric map of Lauro Reservoir.

4.3 Financial Parameters and Economic Modeling

In order to calculate useful metrics like levelized cost of electricity (LCOE) or power purchase agreement (PPA) rates, we needed to determine costs and value streams relevant to the project. Both costs and values are affected by generic financial parameters, and these must be shared between analyses to generate meaningful results.

4.3.1 Financial Parameters

In our analyses, certain financial parameters were required to determine both costs and values. **Table 2** contains the choices made for each financial parameter. Discussion of the more complicated items follows in **Section 4.3.3**.

Table 2. Financial parameters chosen for economic analysis in NREL's SAM modeling tool.

Parameter	Value	Notes
System Lifetime	25 years	Common industry standard[47], this value may be conservative as some sources use 30 years.
Inflation Rate	2.5%	NREL 2021[47].
PPA Escalation Rate	2.5%	Matches inflation rate for simplicity.
Real Discount Rate	4.39%	See discussion below in **Section 4.3.3**.
Electricity Cost Escalation Rate	3%	Floating Solar Solutions estimate.
Nominal Discount Rate	7%	See discussion below in **Section 4.3.3**.
Federal Income Tax Rate	21%	For IRR calculations.
Regional / State Income Tax Rate	8%	This is the case for California, and was confirmed by industry experts[48].
Sales Tax Rate	0%	See discussion below in **Section 4.3.3**.
Salvage Value	0%	Assume no salvage value for the system.
Debt Percent	70%	See discussion below in **Section 4.3.3**.
Investment Tax Credit	26%	Assume the current ITC regime is continued. This is appropriate because continued extensions of sunsetting dates have occurred multiple times in the last 10 years.
Depreciation	100% 5-year MACRS	This is the current regime, which is likely to continue as well. We chose no bonus depreciation (currently available) in order to remain conservative in our estimate. Adding in bonus depreciation would *decrease* the LCOE.

4.3.2 Cost Modeling Sources

While all energy projects are different, there is a body of research by the National Renewable Energy Laboratory (NREL) that attempts to survey the current market and determine costs for all components of renewable energy projects. We relied heavily on their reports to determine approximate costs for our system. In 2021, NREL released reports including cost data for ground-mounted solar systems, floating solar systems, and battery storage paired with solar systems[15,47]. Even with this cost data, modeling is non-trivial as NREL publishes cost data for only certain representative systems, and these systems do not exactly match our proposed systems.

We also relied heavily on NREL's System Advisory Model (SAM) tool. This tool allows users to enter the particulars of their potential system and can use the tool to produce generation profiles and other energy analytics, as well as financial metrics such as LCOE and PPA pricing

Ground-Mount Cost Data

NREL breaks down costs for ground-mounted systems according to sector: Residential, Commercial & Industrial, and Utility[47]. Costs per kWh decline from the residential sector, to commercial & industrial, to utility scale, as representative systems modeled by NREL increase in size (measured in MW DC). Note that there is no municipal sector.

We determined that the 5.7 MW DC system most closely matches the utility sector values, as the size is approximately the size of the smallest utility-scale representative system (5 MW DC). Using the 5 MW DC utility numbers would be a conservative overestimate of the costs of a 5.7 MW DC system, as 5 MW DC systems would generally have larger per-kWh costs than a 5.7 MW DC system due to economies of scale.

Floating Solar Cost Data

In 2021, NREL released a report on floating solar cost benchmarks[15]. This report was not broken down by sectors, likely due to the small size of the sector in the US, so we used NREL's per-kW cost numbers for 2 MW DC systems. This is reasonable and likely conservative for the larger sized array of 2.5 MW DC, but may be optimistic for the 1.4 MW DC smaller system.

Total Cost Data

Table 3. Cost per watt values for floating systems, ground-mounted systems, and a system consisting of 44% floating solar combined with 56% ground-mounted solar (matches our BTM and FOM5.7 systems).

Cost Component	Floating Solar ($/W DC)	Ground-Mount ($/W DC)	Weighted Costs for Combined System ($/W DC)
Inverter	$0.04	$0.04	$0.04
Module cost	$0.33	$0.33	$0.33
Electrical BOS	$0.15	$0.13	$0.14
Structural BOS	$0.47	$0.11	$0.27
Install labor & equipment (Inc. shipping and handling, $0.02/W DC for floating solar)	$0.09	$0.12	$0.11
EPC Overhead / Installer Margin and Overhead	$0.10	$0.08	$0.09
PII (permitting, interconnection, and integration)	$0.12	$0.06	$0.09
Developer Profit	$0.10	$0.08	$0.09
Developer Overhead	$0.14	$0.10	$0.12
Total per watt	**$1.54**	**$1.05**	**$1.28**
Contingency	5%	3%	3.88%
Total with contingency	**$1.62**	**$1.08**	**$1.33**

Floating solar values in **Table 3** were sourced from NREL's floating solar cost report[15] and ground-mounted values were sourced from NREL's 2021 solar cost report[47]. The combined system consists of a simple weighted average of both. Note that contingencies are higher for floating solar due to its novelty and lack of industry experience with the technology.

Further note that the permitting, interconnection and integration line item includes only the paperwork (or 'soft costs') for the permitting, certification, etc. necessary to interconnect. Electrical physical components, or 'hard costs', are included in the 'Electrical BOS' line-item in **Table 3**.

4.3.3 Cost Model

Levelized Cost of Energy (LCOE) Calculations

LCOE calculations are theoretically straightforward – they are simply an output of the SAM model, or a simpler calculation by hand using the following formula[49]:

Eq. 1

$$LCOE = \frac{capital\ cost \cdot CRF}{8{,}760 \cdot capacity\ factor} + \frac{fixed\ O\&M\ cost}{8{,}760 \cdot capacity\ factor} + variable\ O\&M\ cost$$

where, CRF = capital recovery factor, expressed by

$$CRF = \frac{d(1+d)^N}{(1+d)^N - 1}$$

where, d = nominal discount rate
N = number of periods (years), in this case 25 years

The LCOE depends heavily on the choice of the real discount rate and inflation. Inflation is generally straightforward, although it has been more variable recently and this variability could affect the accuracy of this report. To stay consistent with the rest of our cost values, we used the NREL-suggested value of 2.5%[47].

Nominal discount rate is more complicated, and there are a few reasonable choices:

1. Match the inflation rate (2.5%)
2. Choose an intermediate rate (3-5%)
   - This would approximate common municipality discount rates, as the city of Santa Barbara does not have a standard discount rate.
3. Choose the cost of capital for a developer (7%)
   - The amount that a non-profit would have to pay to build this project, or the amount that a developer would require to only just break even.
4. Choose the NREL common developer real discount rate (8.75%)
   - The rate corresponding to a standard minimum profit a developer would need to clear in order to proceed with the project. Calculated from an inflation rate of 2.5% and a real discount rate reported by NREL of 6.1%.

It is likely that the first two values would underestimate the LCOE, while the fourth ‘developer-focused’ rate would overestimate the LCOE as it inherently includes developer profit. We decided that the cost of capital rate of 7% is the most appropriate. This 7% value corresponds to a ‘real discount rate’ of 4.39%.

Debt

Debt affects the LCOE in several ways:

1. Adding debt or leverage reduces the up-front, un-discounted capital cost of the project, and thus reduces the LCOE. Future loan payments are discounted, and as long as the developer's discount rate exceeds the developer weighted average cost of capital, leverage is beneficial.

2. Interest payments are tax-deductible. Since the project will have revenues exceeding costs, and thus have a tax burden, this deduction is a stream of value for the developer that reduces the tax burden. The costs of which are incorporated into the LCOE.

3. Higher revenues (a higher PPA) will increase the amount of revenue used to pay down the balance of the debt and reduce the overall interest paid during the length of the loan (if using a 'Debt Service Coverage Ratio'-based payback). This reduction in cost may then reduce the LCOE compared to a fixed-payment payback scheme.

Note that a Debt Service Coverage Ratio (DSCR) payback scheme is common in the industry. A loan is often sized as large as that which can be serviced by the income from energy sales, with some buffer in case of system underperformance. This buffer is calculated using the DSCR. For instance, a ratio of 1.3 would indicate that the solar system is earning enough revenue to pay its debt service with 30% of a buffer on top. The lender would require only that the system owner achieve a minimum revenue to meet DSCR and pay a minimum payment.

In the SAM tool, there were some technical issues in using the DSCR method. Instead, we chose a 70% debt fraction for our modeling. This may be slightly high – industry experts suggest that 60% is more common, except for certain special lenders like 'green banks' that are willing to take on more risk for a social benefit[50]. Thus, this 70% debt level may reduce the LCOE in this report slightly more than is likely in practice.

The choice to include debt tends to *decrease* the LCOE, and higher debt fractions also tend to *decrease* the LCOE.

Income Taxes

Taxes affect LCOE, as higher taxes will increase costs (while incentives decrease them). Additionally, higher revenues will increase income tax costs and thus will increase the LCOE. This increase in costs from taxes may be confusing and may seem to distract from the overall intention of the LCOE metric, but is more accurate.

The choice to include income taxes tends to have a negligible effect on the LCOE at PPAs that produce little profit for the developer, but a large effect (~1-2 ¢/kWh) at high-profit PPAs.

Sales Taxes

There is a possible sales tax applicable to the direct system costs. This would apply if the developer sold the system to another entity (for instance, an Single-Purpose-Entity tax-equity partnership), and would add 5% to the capital costs of the system. However, not all projects change ownership. For example, the offtaker of power would often be the purchaser of the project, and in this case the city of Santa Barbara is not currently interested in purchasing the system.

The choice to avoid sales taxes tends to *decrease* the LCOE by slightly less than 5%. See **Section 5.1.2** for more information about up-front capital expense effects on the LCOE.

Power Purchase Agreement (PPA) Calculations

PPA calculations are harder to determine as there is a range of possible developer profit. While NREL[47] suggests that 6.1% is a standard 'real discount rate' in industry practice (corresponding to a 8.75% nominal return), We included a few more possibilities in our analysis to show a more reasonable range. These higher profit margins are especially likely due to the novelty of floating solar in the United States and the complexity of this particular project.

To calculate these values we used the 'IRR target' mode in SAM, which performs a numerical analysis to find the PPA value that produces a given IRR at the end of the project lifetime. Note that investors and developers refer to returns in nominal terms, so a 6.1% real discount rate with 2.5% inflation would be referred to as an '8.75% IRR' or '8.75% return' for the developer[49]. These results are shown in **Figure 14**.

4.3.4 BESS Cost Model

Lithium-ion battery systems are complicated, but the two most important features for our economic modeling are the power factor (MW) and the energy capacity (MWh). These describe the battery in enough detail to complete our techno-economic analysis; they are sufficient in conjunction with given battery benchmarks to calculate battery system costs[35].

Given that there are two degrees of freedom for our system, it is useful to find a range of LCOE values for these various parameters to determine the most cost-effective configuration. We were able to use the Parametrics functionality in SAM to run analyses on a range of power and energy configurations for the battery system. The power factors ranged from 1 MW to 6 MW, and the energy capacity from 1 MWh to 20 MWh. These results are found in **Figures 16-20**. Additional parameters were necessary for our battery analysis, and are included in **Table 4**.

Table 4. Battery input parameters for the FOM5.7 + BESS SAM model.

Parameter	**Value**	**Notes**
$/kWh battery cell cost	$174	ESGI report[35].
$/kWh total installed cost	$384	ESGI report.
$/kW power factor additional installed cost	$77	ESGI report.
$/kWh capacity replacement cost	$242	SAM calculated. Included here to show that 'wear and tear' on the battery is included in the model.
$/kWh capacity O&M cost per year	$4.03	ESGI report.
$/MWh discharged O&M cost	$0	The values for variable battery O&M costs are extremely ill-defined. The best available values are averages amongst different *battery chemistries* including high-maintenance lead-acid batteries. The authors of the work cited now report that future variable O&M costs will be $0 via personal communication[51].
Capacity payment amount	$6/kW-month	This equals $72,000/MW-year, which are the units required by SAM. This $6/kW-month value was obtained from the city of Santa Barbara as a reasonable market rate for local RA capacity.
Capacity payment escalation (including inflation)	0%	Given the extreme uncertainty about the value of various forms of energy value in California[34] it is prudent to not assume growth in this value stream. A more conservative assumption would be a slight decline in value (due to inflation) as a result of more short-term storage coming online in California. Future work is needed to more accurately determine this number – industry discussions indicate it may be prudent to reduce the value by 10% every 5 years[52].

4.3.5 Behind-the-Meter Cost Model

Economic modeling for behind-the-meter systems differs from that of front-of-meter systems. In most cases, the sizing of the solar system and any additional BESS is based on site load, as any excess energy beyond site load has no value. This standard design for BTM systems results in the BTM1.4 system, which consists of only floating solar arrays.

However, we also oversized one of the two behind-the-meter configurations (BTM5.7) compared to Cater's load to make full use of the Lauro site. This 'oversizing' for a behind-the-meter system is feasible partly due to SBCE's interest in building out as much local renewable energy as possible. Additionally, the flexibility that SBCE can provide allows for configurations that would otherwise be infeasible due to size and interconnection barriers. The BTM 5.7 system contains a combination of floating solar and ground-mounted solar, the same combination as the FOM5.7 system.

The cost values for these two systems sizes and combinations of array types are explored in **Section 4.3.2**. However, for a behind-the-meter system, there is an additional cost to connect the system directly to Cater via a trench along and then across San Roque Rd. The additional cost of this 'trenching' is shown in **Table 5**.

Estimates of trenching costs are variable, and we examined a number of sources to attribute trenching costs for this project. An Edison Electric Institute study from 2011 was the best source, indicating that the costs of building new underground distribution lines ranged between $297,200/mi and $1,840,000/mi in rural areas[53]. We chose numbers for rural areas rather than suburban areas due to a lack of adjacent houses along the trenching path. These adjacent houses tend to increase costs for trenching in suburban areas, and our path more accurately is represented by the 'rural' values.

We used the mean of these two numbers adjusted for inflation to 2022 dollars for our calculations ($1,308,609/mi). We applied this number to the actual distance that installers would need to trench in project construction (~0.6 miles) to yield the cost of the underground distribution lines: $785,165. We then divided that value by the system size in watts, which resulted in $0.55/W for the BTM1.4 floating system and $0.14/W for the BTM5.7 system.

Table 5. Behind-the-meter system costs after 0.6 miles of trenching

	Small BTM Costs $/W-DC (1.43 MW)	Large BTM Costs $/W-DC (5.74 MW)
Total per watt pre-trenching	$1.54	$1.28
Trenching	$0.55	$0.14
Total per watt post-trenching	$2.09	$1.42
5% contingency	$0.10	$0.07
Total with contingency of 5%	**$2.19**	**$1.49**

This number does not include anticipated soft and administrative costs associated with trenching distribution lines, which do not have known precedence. Determining these soft costs may require additional deliberation with stakeholders like SCE, city, and county officials. See **Section 6.2** for more information.

This estimate is itself highly uncertain; however, there may also be other system upgrades required for the behind-the-meter to connect to the load (moving utility poles, electrical upgrades to infrastructure at Cater, etc.). Therefore, to aid future decision-makers with uncertainty around up-front capital expenditures, we conducted a sensitivity analysis to investigate the effects of capital expenditures on LCOE. This analysis is seen in **Figures 15 and 16**.

4.3.6 Solar Renewable Energy Credit Value

Solar Renewable Energy Credits (SRECs, or more generically RECs) are a valuable source of revenue for a renewable energy project. In our case, the city of Santa Barbara intends to purchase the RECs from any PPA signed with the developer. Thus, we did not include the RECs as a separate value stream in our analysis below. We can still estimate the cost of these RECs, however, as this value is included in any PPA price in which the City receives the RECs and thus should be accounted for.

The value of local, clean energy to SBCE can be quantified by the PPA price premium for local renewable energy over the general wholesale power purchased by SBCE. This value is at least 1.2 ¢/kWh based on SBCE's '100% Green' rate[12]. Note that this may be an underestimate, as this premium would include non-local (i.e. cheaper) sources of green power as well. In general, REC costs in California in 2020 ranged from 1.6 to 1.9 ¢/kWh[54].

4.3.7 Front-of-Meter BESS Value Analysis (FOM5.7 + BESS)

Batteries provide additional value, otherwise their added cost would make these systems uneconomical. This added value can come from Resource Adequacy payments, the ability to 'time-shift' energy, and ancillary service payments. We explored the former two sources of value in our report, as discussed in **Section 3.7.1**.

Resource Adequacy (RA) Capacity Payment Calculations

We calculated resource adequacy capacity payments for various battery system configurations based on the power factor and the energy capacity of the battery. A battery which has enough energy to produce energy at the power factor for 4 hours or more a day is eligible for resource adequacy payments. Batteries of fewer than 4 hours are pro-rated by the fraction of energy these batteries can store, up to a limit of 4 hours of energy[55].

Note that in SAM, the 'capacity credit' is calculated as a fraction of the *solar system nameplate capacity* instead of battery nameplate capacity, requiring another calculation of:

Eq. 2

$$Capacity\ credit\ =\ \frac{battery\ power\ factor}{solar\ system\ nameplate} \cdot min(1,\ \frac{battery\ energy\ capacity}{battery\ power\ factor})$$

Time-Shifting Value Calculations

Calculating the value of time-shifting is difficult given the complexity of the TOD rate schedules (see **Figure 5**). The amount of energy available to time-shift depends on the generation of a given day and the battery size. The change in value depends on the time of day of the energy generation and the TOD rate schedule. To solve this, we calculated the difference in PPA revenue with each battery configuration compared to no battery configuration, and divided it by the total discounted generation yielding revenue per kWh. We obtained the PPA revenues via SAM, which has a built-in battery 'engine' that optimizes battery charging and discharging behavior when given the capacity and power of a provided battery and a TOD rate schedule.

Since this time-shifting value depends on the PPA rate (higher PPAs provide higher value), we needed to choose a rate upon which to calculate the value. To maintain consistency, we chose the PPA rate identified for the system without a battery (FOM5.7) offering a 7% nominal return. This is likely the cost of capital and thus the lowest PPA price. This model is thus *underestimating* the value of these battery configurations, and the true value of the battery may be higher.

4.3.8 Behind-the-Meter 1.4 MW Value Analysis (BTM1.4)

Data

In this model we used Cater Water Treatment Plant's 15-minute interval data from each meter in 2019. Using this data, we determined the behind-the-meter system size that would offset Cater's total annual load combined across all 4 meters.

The 15-minute interval data included information for all meters at the Cater Water Treatment Plant. Along with the interval data, we received Cater's corresponding TOU tariffs for each meter, and additional energy costs that will be charged after SBCE becomes the new Load Serving Entity for Cater, a change scheduled before any solar project could be completed. This data allowed us to fully model the costs of Cater's electricity usage.

Meters

The combined annual total load of the Cater Water Treatment Plant was 2.4 GWh in 2019. Annual per meter loads were calculated as follows:

Table 6. Annual total load in kWh for the 4 meters at the Cater Water Treatment Plant.

Meter	Annual Total Load (kWh)
Cater Cross Tie Pump	742,764
South Coast Booster	259,413
Cater Plant	1,277,801
Cater Administration Building	159,585
Total	**2,439,563**

BESS

The City also provided specifications for the planned BESS installation, which will be complete before any proposed solar system project:

<u>Water Treatment BESS</u>
South Coast Booster Station
Battery output rating: 280 kW
Battery size: 1,392 kWh
Charge/Discharge efficiency: 92%

<u>Water Distribution BESS</u>
Cater Cross Tie Pump Station
Battery output rating: 420 kW
Battery size: 2,320 kWh
Charge/Discharge efficiency: 92%

Model

To provide additional resilience as part of this project, we opted to pair the floating solar system with BESS to show the value that the paired systems could provide. Due to the electrical layout of the site, these loads and systems are connected at two different meters, requiring two system interconnections.

To model accurate generation profiles, we designed two separate arrays within one larger system, and paired the loads and meters as follows:

1. One array would offset both the Cater Cross Tie Pump (interconnection) and Cater Admin (submeter):
    a. Requires yearly generation of at least 902,349 kWh
    b. Helioscope array was sized at 906,206 kWh
    c. System was tied to a 420 kW / 2,320 kWh Tesla Powerpack BESS

2. One array would offset both the South Coast Booster (interconnection) and Cater Plant (submeter):
    a. Requires yearly generation of at least 1,537,214 kWh
    b. Helioscope array was sized at 1,550,011 kWh
    c. System was tied to a 280 kW / 1,392 kWh Tesla Powerpack BESS

To estimate the monetary savings from the solar + BESS system, we used an industry standard tool called Energy Toolbase. In this tool, users enter the details of their solar and BESS systems, along with tariffs, financial parameters, and incentives. The outputs include generation profiles, other energy analytics, and financial metrics such as LCOE, PPA pricing, and monetary savings compared to utility tariffs.

Energy Toolbase is able to fully integrate with solar system design software like Helioscope to minimize errors between the design and economic modeling stages of a project. We were able to upload our BTM1.4 Helioscope system design, and pair it with the given BESS specifications.

To begin modeling the behind-the-meter system, we separated the provided utility interval data for each meter to be uploaded into Energy Toolbase, then created and visualized a full year of energy consumption and load profiles for each meter. For each load, we assigned the given SCE TOU tariffs and modified them to include an additional SBCE premium of $0.012 for 100% carbon-free electricity.

We uploaded the given BESS specifications to the model in Energy Toolbase, and set the batteries at a 5% degradation rate. For our BESS control settings, we used a 70% peak shaving efficiency and utilization rate, and 80% energy arbitrage efficiency per the recommendations of our Energy Toolbase account manager. For developer incentives our analysis used the same values outlined in the financial parameters section (**Section 4.3.2**).

4.3.9 Behind-the-Meter 5.7 MW Value Analysis (BTM5.7)

The BTM5.7 system was conceptually the most difficult to model due to the complexity of two sites and multiple meters. Ultimately, however, we were able to simplify our analysis and calculate the additional energy that the large system would yield after subtracting Cater's usage, and then calculate the value of this excess energy to the City.

SBCE is open to allowing excess energy credits from the Cater-tied system to offset other offsite City loads through a custom feed-in tariff described in **Section 3.8.2**. Based on this opportunity we designed a system that achieves three goals:

1) Gain resilience for Cater through a direct connection with the solar system
2) Maximize generation at the Lauro site
3) Offset other City accounts with remaining energy.

We determined that excess generation from this large system would be best offset from the Charles E. Meyer Desalination Plant, which has a load large enough to offtake all of Cater's excess generation.

Model

Similar to the BTM1.4 system, the Water Resources department would realize some energy savings in this model through meeting Cater's load with solar system generation, thus avoiding generation, transmission, and demand changes from SCE and SBCE. The Water Department would realize additional savings through the offset of the Charles E. Meyer Desalination Plant energy costs.

We calculated excess generation beyond what Cater could use using Cater's 15-minute interval data from 2019. We first transformed this data into an hourly load format and then matched it to the solar system's hourly generation data we had developed from the Helioscope model. We subtracted Cater's load from the system generation for every hour of the year in order to yield the excess generation for the system after usage by Cater.

For each hour of the year, we multiplied this excess generation by the desalination plant's TOU-8-E tariff for each corresponding hour. This allowed us to attribute the excess energy as a credit to the desalination plant's *energy portion* (note that this credit did not cover NBCs) of its utility bill. Note that this tariff is valid for service delivered and metered at voltages of 2 kV to 50 kV and is in effect from March 1, 2022 onwards[36].

We then divided the sum value ($) of the excess generation over a year by the amount of excess generation (kwh) over a year to yield a $/kwh rate that constituted the avoided energy cost to the desalination plant. Finally, we averaged this avoided utility bill cost with the avoided utility bill cost for Cater. Note that Cater's avoided utility bill cost is higher due to the additional avoided NBCs (distribution and transmission charges) as its energy from the solar system avoids SCE's grid altogether.

4.3.10 Behind-the-Meter Value Comparison

Comparing the value between both behind-the-meter systems to both the City as a whole and the Water Resources department is useful. Two items were considered for each system:

1) What is the Water Resources Department willing to pay for the average kWh produced by the solar system?

2) What is the actual savings to the City for the average kWh produced by the solar system?

We calculated the avoided utility bill costs averaged over each site against the system's LCOE. This was complicated as each of the site's TOU tariffs included energy generation charges, demand charges, non-bypassable charges (NBC), and other costs posed by the site's Load Serving Entity. In this analysis we considered only the energy generation charges and NBC costs, which are those that a solar system can primarily help reduce.

Each kWh generated by the solar system will offset a kWh bought from the utility at the TOU tariff cost of the site. Our analysis needed the utility 'energy generation' cost and the utility NBCs for any given kWh to value that energy. The sum of these would be the Water Resources department's 'avoided energy bill cost' or their 'willingness to pay' for a given kWh. The savings from avoided NBCs represent the true savings to the City, as energy generation costs 'saved' by the Water Resources department are 'saved' from SBCE. Including avoided energy generation costs by the Water Resources department (WRD) as 'savings' to the City would be incorrect, as this value is changing hands.

Avoided energy generation cost is the average 'energy generation' part of the utility bill avoided per kWh supplied by the solar system. This avoided energy generation cost was calculated using the TOU tariff for each of the sites as well as the energy generation profile of each system. This is referred to within the following equations as E_C and E_D for Cater and the desalination plant respectively; units are in ¢/kWh.

Avoided NBCs are referred to as 'N' and only apply for power used by Cater, as all power for the desalination plant traverses SCE's grid. This value is 2.5 ¢/kWh on average[56].

These variables allowed us to answer the following questions:

1. How much is the WRD willing to pay for the BTM1.4 system that offsets Cater's load?

Eq. 3

$$Avoided\ Cost\ to\ the\ WRD\ from\ BTM1.4 = N + E_C$$

where, N = avoided Cater NBC charge per kWh
E_C = avoided utility energy generation charge per kWh

This formula shows the simple assertion that the avoided cost of energy for Cater plus the avoided cost of NBCs for Cater equals the total avoided cost to the WRD per kWh. Since all energy is directly used by Cater, the average cost that the WRD can avoid by using one kWh from the system is the avoided utility cost enjoyed by Cater.

2. How much is the WRD willing to pay for the BTM5.7 system offsetting the Cater and desalination plant loads?

Eq. 4

$$Avoided\ Cost\ to\ the\ WRD\ from\ BTM5.7 = (N \cdot F_C) + (E_C \cdot F_C) + (E_D \cdot F_D)$$

where, N = avoided Cater NBC charge per kWh
E_C = Cater's avoided utility energy generation charge per kWh
E_D = the desalination plant's avoided utility energy generation charge per kWh
F_C = the fraction of generated energy used by Cater
F_D = the fraction of generated energy used by the desalination plant

This formula uses the avoided cost of energy for Cater and the desalination plant at 5.7 MW plus the avoided cost of NBCs to find the total avoided cost to the WRD per kWh. This weighs all the costs that the WRD can avoid on average with one kWh from the BTM5.7 system.

3. How much savings per total generated kWh does the BTM1.4 system provide for the City?

Eq. 5

$$Savings\ to\ the\ City\ from\ BTM1.4\ =\ N$$

where, N = avoided Cater NBC charge per kWh

The savings per kWh to the City for BTM1.4 are the NBC charges per kWh, as all generated energy avoids these NBCs.

4. How much savings per total generated kWh does the BTM5.7 system provide for the City?

Eq. 6

$$Savings\ to\ the\ City\ from\ BTM5.7\ =\ (N\ \cdot F_C)$$

where, N = avoided Cater NBC charge per kWh
F_C = the fraction of generated energy used by Cater

The per-kWh savings value here is lower than in **Eq. 5** because there is the same absolute amount of true savings to the City, yet there is a larger amount of system generation. The per-kWh NBC reduction at Cater is reduced proportional to the amount of generation not used by Cater.

4.4 Co-Benefits

Unfortunately, we were limited in our calculations for monetizing co-benefits due as the financial values of many associated floating solar co-benefits are not well-defined. However, we created a deterministic model to estimate the values of potential evaporation reduction for the various system designs.

4.4.1 Evaporation Reduction

Calculating accurate evaporation estimates from an open body of water has many challenges. Precise calculations require both water surface area and evaporation rate data. In our case, estimates for Lauro Reservoir's surface area exist from a bathymetry study completed for COMB in 2005[57]. Due to the age of this data, there may be some inaccuracies due to any physical changes to the reservoir since the study was performed. For example, sedimentation and bank alterations may have changed the capacity and area of the reservoir at certain elevations[58]. The degree of potential data inaccuracies are uncertain, with no other comparable bathymetric records, but we believe this to be the best available data.

COMB also maintains a pan evaporation measuring station at the reservoir. Unfortunately, the data provided from this station does not exist for one whole calendar year and we had to combine the available data into a water year evaporation estimation for 2020-2021. However, pan evaporation data suffers from several well-established issues. For example, the following can affect the evaporation estimates provided from a pan station: differences between the pan's microclimate and that of the reservoir's, failure to account for heat storage effects, extra heat and radiation absorption from the pan, loss of water due to splashing, and pan overflow due to excessive rainfall[58]. Therefore, we also looked to estimate evaporation rates from various meteorological data available.

While there are a number of methods for estimating evaporation and evaporation rates, the Penman equation is one of the most practical. The original Penman equation is a physically-based combination method using meteorological observations to estimate potential evaporation from open water bodies[58–60]. It has been adapted for estimating evapotranspiration or pan evaporation[58], but we used an adapted version of the Penman equation as simplified by Shuttleworth. This simplification allows for easier conversions with SI units[61]. This equation is also used by the floating solar developer Ciel & Terre to estimate evaporation savings produced by the installation of floating solar arrays.

4.4.2 Penman Equation Model

This model was based on a version of the Penman equation as simplified by Shuttleworth (**Eq. 7**) to estimate the mass of water evaporated in kg/m^2/day.

Eq. 7

$$E_{mass} = \frac{mR_n + 6.43(1 + 0.536 \times U_2)\gamma\delta_e}{\lambda_v(m + \gamma)}$$

where, m = slope of the saturation vapor pressure curve in kPa/°C
R_n = incoming solar irradiance in MJ/m^2/day
U_2 = wind velocity in m/s
γ = psychrometric constant in kPa/°C
δ_e = vapor pressure deficit in kPa
λ_v = the latent heat of vaporization in MJ/kg

To calculate the slope of the saturation vapor pressure curve (m) from **Eq. 7**, we used the following **Eq. 8** provided by Allen et al.[62].

Eq. 8

$$m = \frac{4098\left[0.6109e^{\left(\frac{17.27T}{T+237.3}\right)}\right]}{(T+237.3)^2}$$

where, T = air temperature in °C

An average air temperature (T) of 18.73 °C was gathered from the SAM model for use in **Eq. 8** after generating a weather file for the approximate latitude and longitude of Lauro Reservoir. This is a long-term average of air temperature from SAM's weather data sources[63].

To calculate the incoming solar irradiance (R_n) we retrieved an average direct normal irradiance value of 6.33 kWh/m^2/day from the NREL National Solar Radiation Database for Lauro Reservoir in 2019[64]. We converted the data from kWh/m^2/day to MJ/m^2/day for use in **Eq. 7**.

An average wind velocity (U_2) of 2.91 m/s was gathered from the SAM model's weather file for Lauro Reservoir for use in **Eq. 7**. This is a long-term average of wind velocity also from SAM's weather data sources[63].

To calculate the psychrometric constant (ɣ) from **Eq. 7**, we used the following **Eq. 9**[62]:

Eq. 9

$$ɣ = \frac{C_p P}{\varepsilon \lambda}$$

where, C_p = specific heat at a constant pressure in MJ/kg/°C
P = atmospheric pressure in kPa
ε = ratio molecular weight of water vapor to dry air
λ_v = latent heat of vaporization in MJ/kg

The specific heat at a constant pressure (C_p) is a constant value that is representative of the energy required to increase the temperature of a unit mass of air by one degree at a constant temperature. Under normal atmospheric conditions, which we are assuming for Lauro Reservoir, this can be appropriately represented by a value of 1.013 x 10^{-3} MJ/kg/°C in **Eq. 9**[62].

The ratio molecular weight of water vapor to dry air (ε) is a unitless constant represented by a value of 0.622 in **Eq. 9**[62].

To calculate the atmospheric pressure (P) from **Eq. 9**, we used the following **Eq. 10**[62]:

Eq. 10

$$P = 101.3\left(\frac{293 - 0.0065z}{293}\right)^{5.26}$$

where, z = elevation above sea level in m

Elevation of Lauro Reservoir was retrieved from the COMB bathymetry data and an average elevation of 549 ft, or 165.81 m, was used in **Eq. 10**[14].

To calculate the latent heat of vaporization, λ_v from **Eq. 7** and **Eq. 9**, we used **Eq. 11** from Shuttleworth[61]:

Eq. 11

$$\lambda_v = 2.501 - 0.002361\,T$$

where, T = temperature at the surface of the water in °C

For simplification purposes, we chose to use the already established average air temperature of 18.73 °C from the SAM weather files as the surface temperature in **Eq. 11** since λ_v varies only slightly over normal temperature ranges. For example, a value of 2.45 MJ/kg is used for an air temperature of 20 °C and our calculated value of λ_v = 2.457 MJ/kg.

To calculate the vapor pressure deficit (δ_e) from **Eq. 7** we used the following **Eq. 12**[62]:

Eq. 12

$$\delta e = e_s - e_a$$

where, e_s = saturation vapor pressure in kPa
e_a = actual vapor pressure in kPa

To calculate the saturation vapor pressure (e_s) from **Eq. 12**, we used the following **Eq. 13**[62]:

Eq. 13

$$e_s = 0.6108e^{\left(\frac{17.27T}{T + 237.3}\right)}$$

where, T = air temperature in °C

We used the average air temperature of 18.73 °C from the SAM weather file for air temperature in **Eq. 13** to produce a mean saturation vapor pressure.

To calculate the actual vapor pressure (e_a) from **Eq. 12**, we used a modified form of the following **Eq. 14**[62]:

Eq. 14

$$e_a = \frac{RH_{mean}}{100}\left[\frac{e^o\left(T_{max}\right) + e^o\left(T_{min}\right)}{2}\right]$$

where, RH_{mean} = mean relative humidity in %

$e^o(T_{max})$ = saturation vapor pressure at daily max temperature in kPa

$e^o(T_{min})$ = saturation vapor pressure at daily min temperature in kPa

The modification of **Eq. 14** removes the averaging of the maximum and minimum temperature saturation vapor pressure values and replaces this value with the mean saturation vapor pressure value calculated in **Eq. 13**. This modification simplifies **Eq. 14**, removes the need for calculating extra saturation vapor pressure values, and, most importantly, accommodates for the lack of data regarding daily average maximum and minimum temperatures.

We estimated the RH_{mean} value as a long-term mean relative humidity for California Climate Zone 6, which includes Santa Barbara and Lauro Reservoir, from the Pacific Energy Center's Guide to California Climate Zones and Bioclimatic Designs[65].

With all Penman equation inputs calculated, we estimated the mass of water evaporated at Lauro Reservoir in kg/m^2/day. However, the resulting units are difficult to visualize and monetize and are not related to the floating solar system configurations we have developed. We therefore converted the result to show us the total evaporation occurring over the area of a floating solar array each year using the following unit conversions in **Eq. 15**:

Eq. 15

$$E_{system} = E_{mass} \times A \times \frac{1\ m^3}{997\ kg} \times \frac{1\ af}{1233.48\ m^3} \times \frac{365\ days}{1\ year}$$

where, E_{mass} = Penman equation output in kg/m^2/day
A = area of the floating solar array in m^2

Eq. 15 converts the mass flux from the Penman equation into a volume flux relative to the size of the floating solar array and shifts the time scale from days to years. This results in an output of AF/year of water evaporated from the area of the reservoir equal to that of the floating solar array.

4.4.3 Alternate Evaporation Estimations

We compared our modeled evaporation estimate to the other estimations available from both COMB and Ciel & Terre. Unfortunately, each estimation uses different units. COMB data gauges total evaporation from the reservoir per day through the pan evaporation estimation method. Ciel & Terre data estimated evaporation under the area of a proposed floating solar array. Therefore, standardization of evaporation rates was into units of:

$$\frac{AF\ evaporated/year}{Acre\ of\ surface\ water}$$

To make this unit conversion for our evaporation estimate, we normalized our Penman equation output by system size which returned a value in units of AF/year/acre of surface water. This normalization also reduces the need for reporting multiple values as each system configuration's evaporation rate is the same relative to its area.

To make the unit conversion for the COMB evaporation estimate, we took the sum of daily evaporation estimates for water year 2020-2021, in units of AF/year, and normalized it by an approximately average area of Lauro Reservoir. This area is 19.69 acres at 549 feet elevation. This produced a value in units of AF/year/acre of water.

There was no unit conversion necessary for the Ciel & Terre estimate as the value provided by the solar developer was already in units of AF/year/acre.

4.4.4 Evaporation Reduction Monetization

Using the Penman equation model estimations, we estimated the reduction in the volume of water evaporated by applying 50, 70, and 90% evaporation reductions. While the 50 and 90% statistics had been retrieved from the literature[24,26], we decided to include an intermediate value of 70% evaporation reduction to create a high, medium, and low estimate for each floating solar configuration we modeled.

We then monetized these evaporation savings in the model using the avoided cost of water values from both the city of Santa Barbara and COMB. Both the avoided cost values are in units of $/AF so the resulting monetization value is in $/year savings through reduced evaporation. The costs are $865/AF for the City and $1300/AF for COMB[66,67].

Lastly, we 'normalized' the evaporation savings values in the model by dividing the total annual savings by the annual generation of the floating solar array and converting the monetary values from dollars to cents. The result is in the units of ¢/kWh and relates the evaporation savings to an LCOE or PPA price to show how the co-benefits of floating solar, if monetized, reduce the costs of the generated energy.

5. Results

Our analysis yields results for system design and configuration along with the associated economics of those systems, valuation of their co-benefits, and a high level comparison among them.

5.1 System Costs

5.1.1 System LCOE and PPA rates

Figure 14 and **Table 7** illustrate LCOE and PPA price estimates at various developer returns (8.75%, 15%, 20% and 25%).

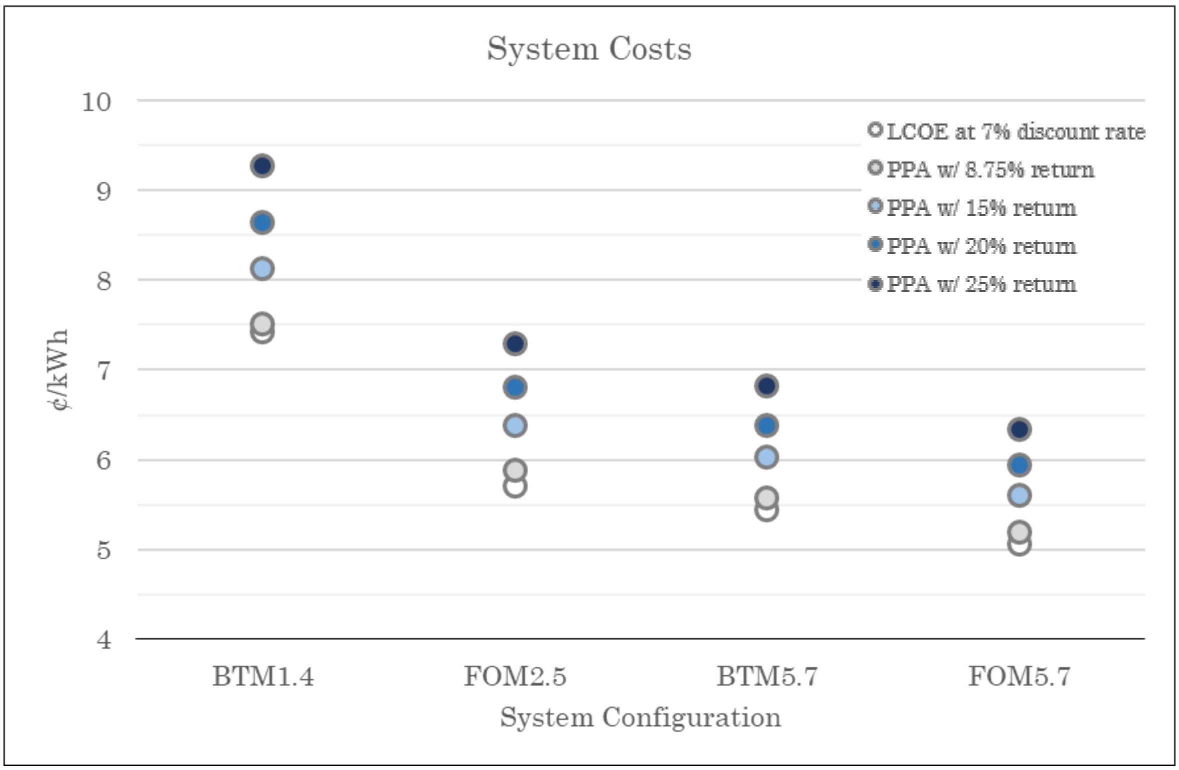

Figure 14. Illustration of LCOE and PPA prices for various systems at different developer returns (8.75%, 15%, 20%, and 25%)

Table 7. LCOE and PPA prices, in ¢/kWh, for various system configurations and developer returns.

System Configuration	LCOE @ 7% discount rate	PPA @ 8.75% return	PPA @ 15% return	PPA @ 20% return	PPA @ 25% return
BTM1.4	7.42	7.52	8.13	8.65	9.28
FOM2.5	5.71	5.89	6.40	6.80	7.30
BTM5.7	5.44	5.58	6.03	6.39	6.83
FOM5.7	5.06	5.19	5.60	5.93	6.33

5.1.2 Up-Front Capital Expense Effects

One major source of uncertainty in this analysis (and in many renewable energy projects) comes from up-front capital expenditures. Variability in up-front capital costs such as grid upgrades, unexpected site preparation costs, and issues during installation can cause significant changes in the LCOE and thus in the PPA price.

In order to aid decision-makers in the future, when required up-front capital expenditures are better understood, this report includes a sensitivity analysis shown in **Figures 15 and 16**. This analysis determines the change in the LCOE for the FOM5.7 system given additional capital cost. Of particular note is the data point at $785,165 in additional expenditure, which is our estimate of trenching costs. This increase in costs is the only difference between the LCOE of the BTM5.7 and of FOM5.7 systems, and yields a 0.40 ¢/kWh increase.

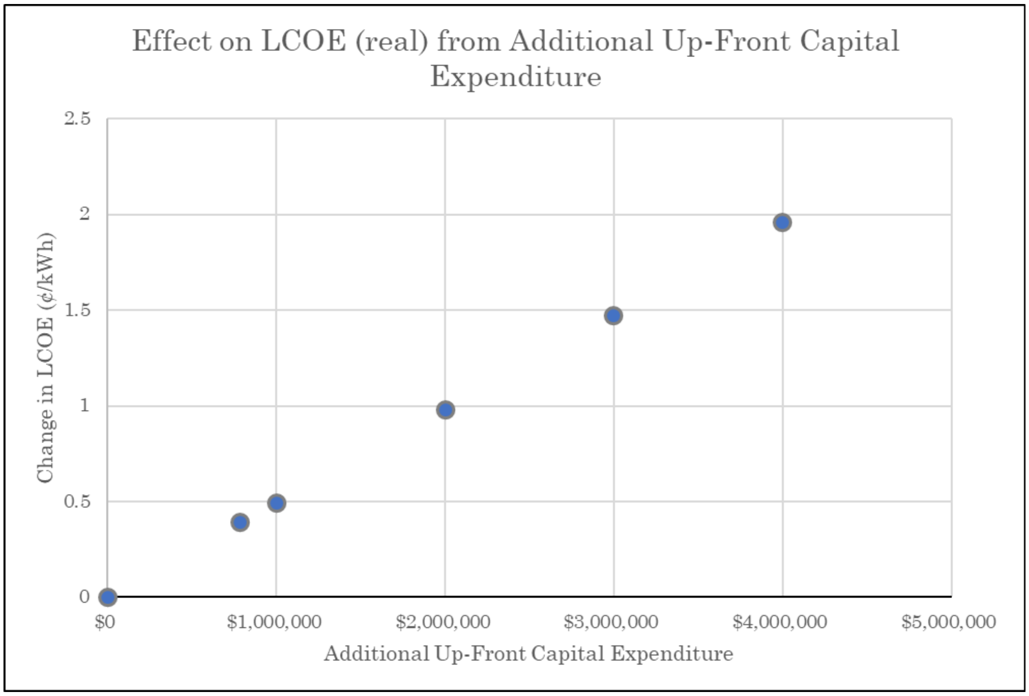

Figure 15. LCOE response to various additional up-front capital expenditures in the construction phase. For instance, the data point at '$785,165' represents the best calculation to trench a line from the proposed inverter pad site (near the micro-hydro site) to the south entrance of Cater Water Treatment Plant. This trenching would increase the LCOE by about 0.40 ¢/kWh.

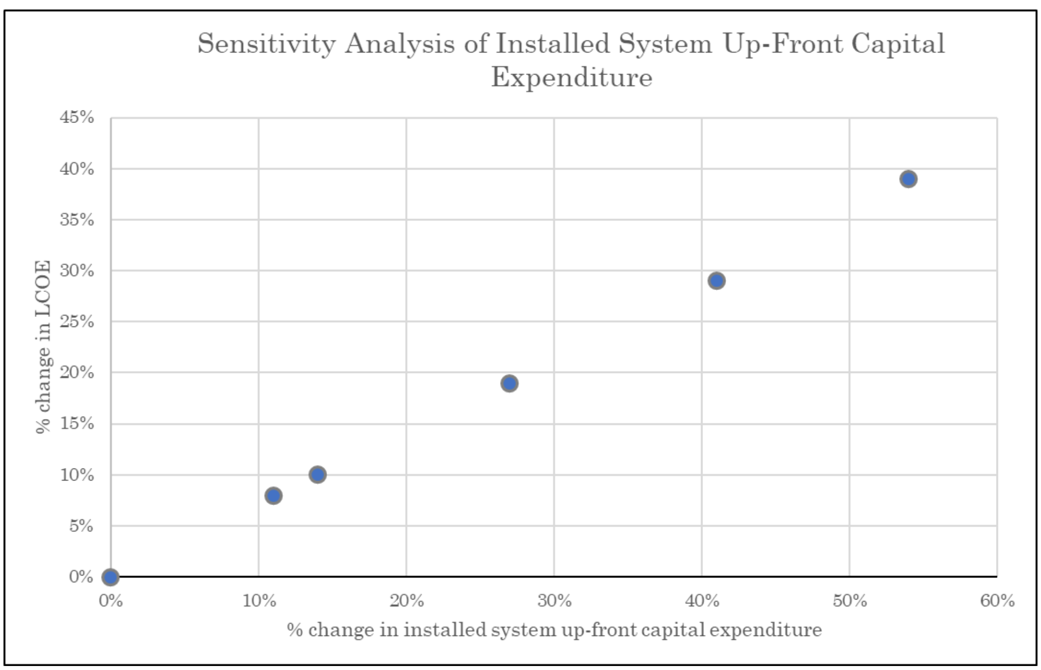

Figure 16. Formal sensitivity analysis results for LCOE response to up-front capital expenditures. Horizontal axis is the percent change in installed system cost for the various capital expenditures. Vertical axis is the percent change in real LCOE based on the change. We see a generally linear trend that shows any increase in install cost of 10% leads to less than a 10% increase in LCOE.

5.2 Co-Benefits – Evaporation Reduction

Table 8 shows the normalized results of each of the evaporation estimation methods in this report. First, it shows the estimated result of our evaporation model using the Penman equation, then the value which was estimated by COMB's Lauro pan evaporation station, and finally, the Ciel & Terre estimate that also used the Penman equation.

Table 8: Results of each evaporation estimation normalized into comparable units of AF per year per acre of surface water.

	Report Output	**COMB**	**Ciel & Terre**
Evaporation (AF/year/acre)	9.3	2.4	7.9

Tables 9 and **10** below show the outputs from the evaporation reduction model. The model explored results from the various system configurations in **Figure 10.**

Table 9: Monetization of evaporation reduction savings in $ per year using both the city of Santa Barbara's and COMB's avoided cost of water values.

System Configuration	**Evaporation Reduction Percentage**	**Evaporation Savings (AF/year)**	**Monetary Savings (City Value) ($/year)**	**Monetary Savings (COMB Value) ($/year)**
BTM1.4	50%	15.25	10,776	16,195
	70%	21.35	15,086	22,673
	90%	27.45	19,397	29,151
FOM2.5	50%	21.54	18,634	28,006
	70%	30.16	26,088	39,208
	90%	38.78	33,542	50,410
FOM & BTM5.7	50%	21.54	18,634	28,006
	70%	30.16	26,088	39,208
	90%	38.78	33,542	50,410

Each system design has three water volume savings; one for each of the three chosen evaporation reduction percentages.We monetized these water volumes using the two different avoided costs of water, or water values, from the city of Santa Barbara and COMB. This results in eighteen monetized results for reduced evaporation in each table. **Table 9** shows total savings per year, whereas **Table 10** shows those annual savings normalized by the estimated annual generation of each system.

Table 10: Monetization of evaporation reduction savings in ¢/kWh after normalizing for system generation per year.

System Configuration	Evaporation Reduction Percentage	Evaporation Savings (AF/year)	Monetary Savings (City Value) (¢/kWh)	Monetary Savings (COMB Value) (¢/kWh)
BTM1.4	50%	15.25	0.44	0.66
	70%	21.35	0.61	0.92
	90%	27.45	0.79	1.19
FOM2.5	50%	21.54	0.39	0.59
	70%	30.16	0.55	0.83
	90%	38.78	0.71	1.07
FOM & BTM5.7	50%	21.54	0.18	0.27
	70%	30.16	0.25	0.38
	90%	38.78	0.33	0.49

Figures 22 and **23** visualize the numerical results from **Tables 9** and **10** in box plots using the evaporation reduction percentages as lower, median, and upper thresholds to compare system designs and water values side by side. **Figure 24** shows the effects on the LCOE after incorporating evaporation savings using the middle value of evaporation reduction (a 70% reduction) and the city of Santa Barbara's avoided cost of water.

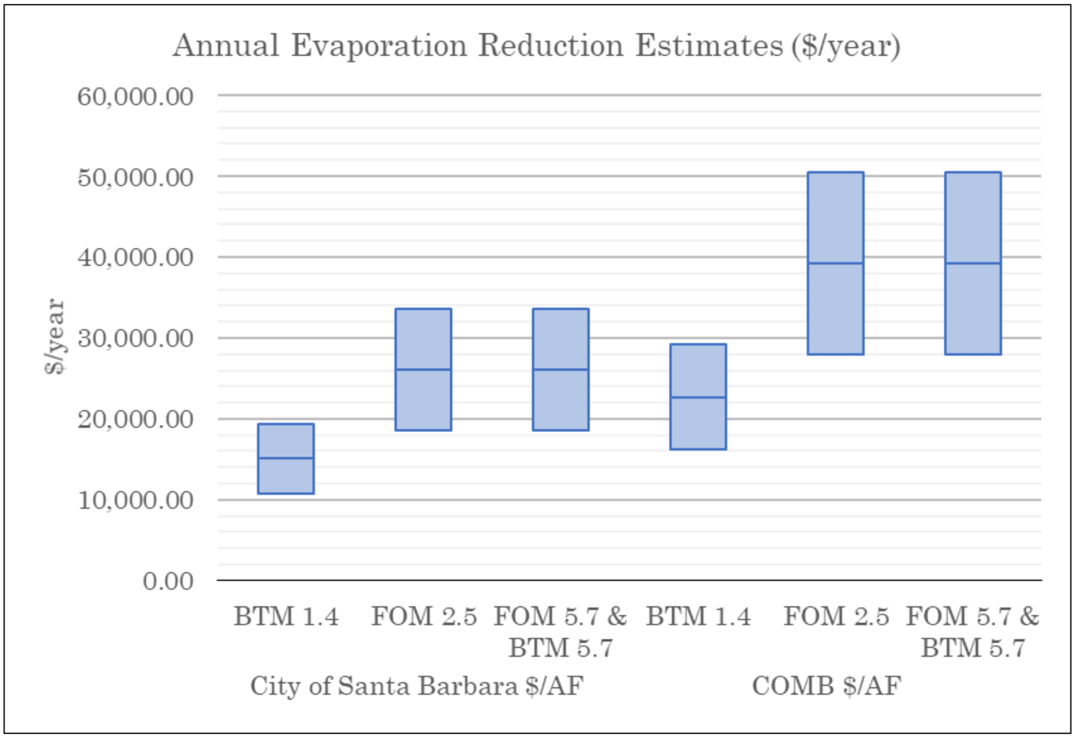

Figure 22. Upper, middle, and lower evaporation reduction estimates based on system type. Monetized in $ per year using both the city of Santa Barbara's and COMB's avoided cost of water values.

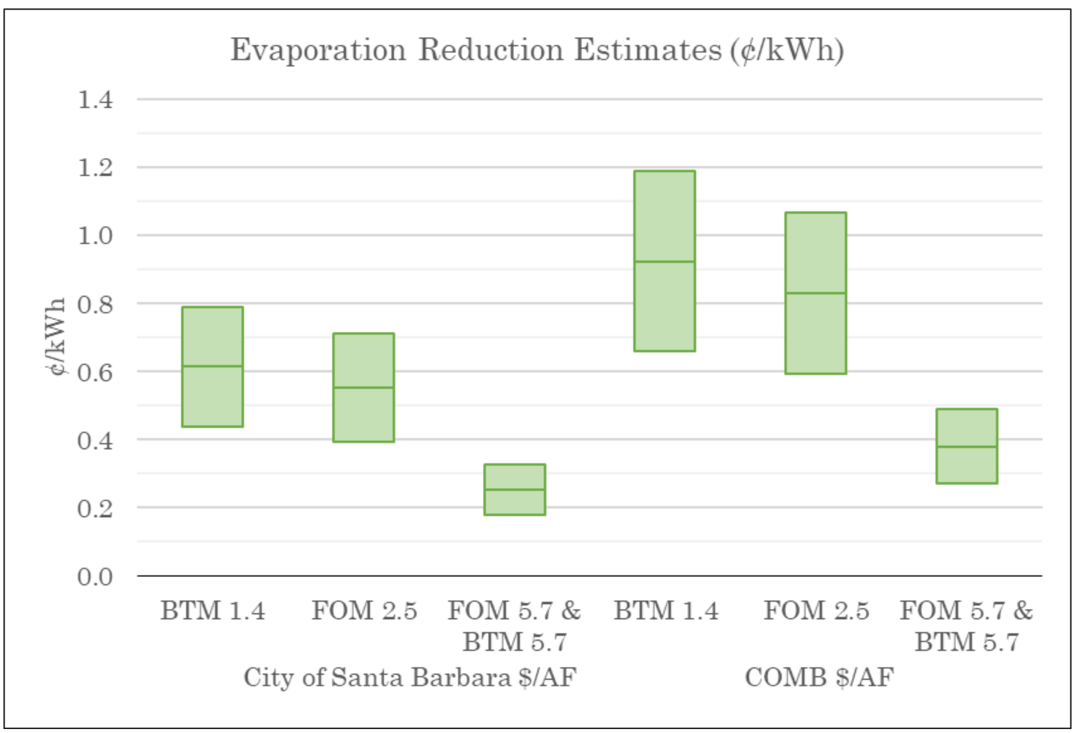

Figure 23. Upper, middle, and lower evaporation reduction estimates based on system type. Monetized in ¢/kWh after normalizing for system generation per year.

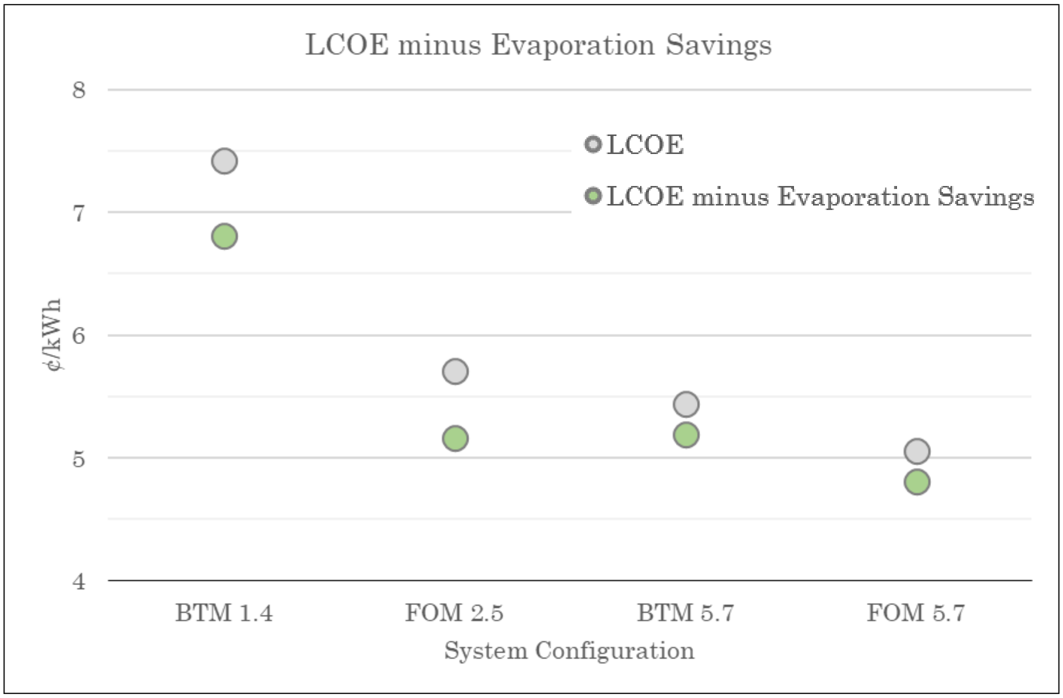

Figure 24. LCOE for each of the PV system configurations, excluding trenching or battery costs, adjusted for value added from reduced evaporation. Evaporation reduction values use the city of Santa Barbara's water value and represent a 70% reduction in evaporation.

5.3 System Comparison

This section compares the value of the systems against each other, in order to help determine which system is optimal. There is no clear 'right answer', as there are complications and considerations for each system. Likely, the 'Effective LCOE' (**Figure 26** and **Table 12)** is the most useful singular metric for comparing between all systems.

5.3.1 Behind-the-Meter System Comparison

Figure 25 and **Table 11** show details of the behind-the-meter systems. These systems are more complicated than the front-of-meter systems – the cost of the system interacts with the value of the energy to the Water Resources department which changes with the size of a BTM system, whereas in a front-of-meter system the value of the energy to SBCE is the same regardless of size. Note that these numbers do not include evaporation savings.

For BTM1.4, all of the system generation offsets the full energy part of the Cater tariff and the NBCs, therefore energy is valued at 9 ¢/kWh –the weighted energy cost for Cater.

The BTM5.7 has a lower LCOE, but also has a lower value per-kWh to the Water Resources department. This lower value is because only some of the energy can be used to offset Cater's energy, and the rest must be used to offset the desalination plant. Since the power must traverse SCE's grid to offset the energy usage of the desalination plant, the energy value is reduced by the amount required to pay SCE for that connection. The combination of this increased transmission and distribution (NBC) charge (2.5 ¢/kWh) and a slightly lower-priced tariff at the desalination plant based on when the leftover power is available sums to 5.96 ¢/kWh. This is the value of energy produced by the BTM5.7 system to the Water Resources department.

Note that these 'savings' are from the perspective of the Water Resources department *only*, and not the savings as seen by the city of Santa Barbara overall. This is because Water Resources purchases power from SBCE – if Water Resources saves money at the expense of SBCE, then the funds are only switching between departments at the City, and are not overall savings. Instead, comparing using the 'Effective LCOE' in **Section 5.3.2** is more useful for understanding the actual cost to the City.

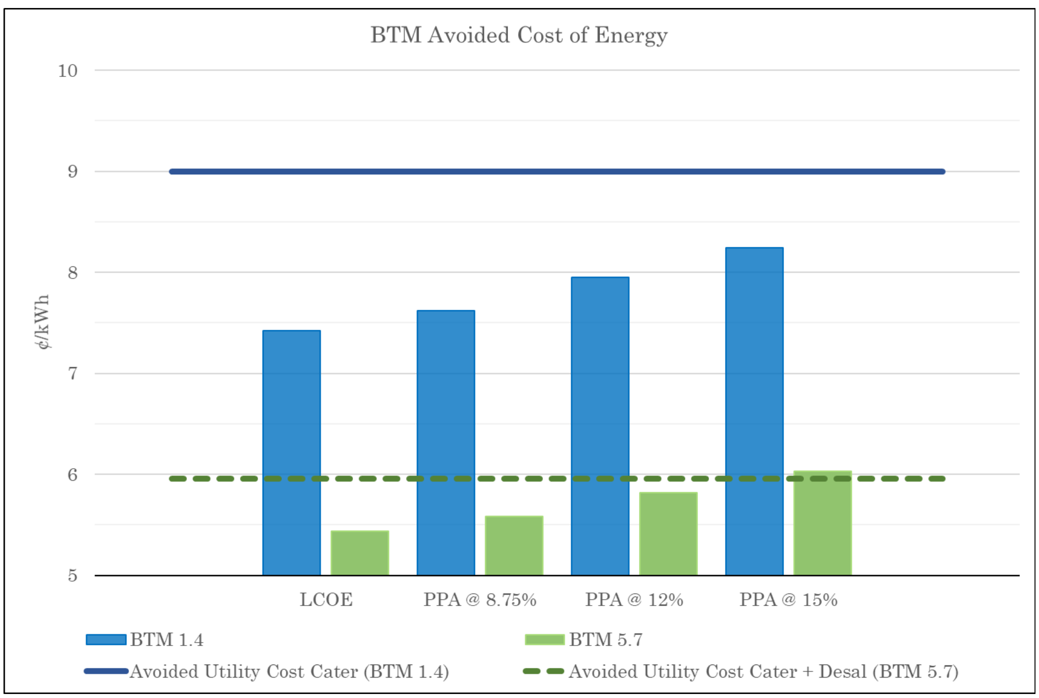

Figure 25. Avoided cost thresholds compared to LCOE and PPA estimates for BTM1.4 and BTM5.7 system designs.

Figure 25 shows that the smaller behind-the-meter system 'BTM1.4' is profitable at any of the selected developer profit margins, while the larger behind-the-meter system 'BTM5.7' is profitable at only a 8.75% return and the LCOE with no developer return.

Table 11. Actual yearly savings (not including evaporation savings) for each behind-the-meter system for the Water Resources department.

System	Total Generation per Year (kWh)	LCOE (¢/kWh)	Avoided cost (Energy and NBCs) (¢/kWh)	Savings (¢/kWh)	Savings between avoided energy cost and LCOE per Year
BTM1.4	2,456,216	7.42	9.01	1.59	**$38,808**
BTM5.7	10,324,379	5.44	5.96	0.52	**$53,552**

As **Table 11** shows, BTM5.7 is actually more profitable for the department, even though the savings per-kWh is lower, due to the larger solar generation of the BTM5.7 system compared to the BTM1.4 system. See note above on how savings numbers are complicated.

5.3.2 Effects from Front-of-Meter Battery Storage

Energy is valued at different amounts throughout the day, week, and even year. This difference in value is driven by both demand and supply, as discussed in **Section 3.7**. We calculated the added cost of a range of possible batteries (**Figure 17**), then the value streams generated by the batteries (**Figure 18**). Together, these comprise the net benefit of incorporating any one of these batteries (**Figures 19 and 20**), and we can determine the optimal battery system by identifying the point on the curve with the maximum benefit.

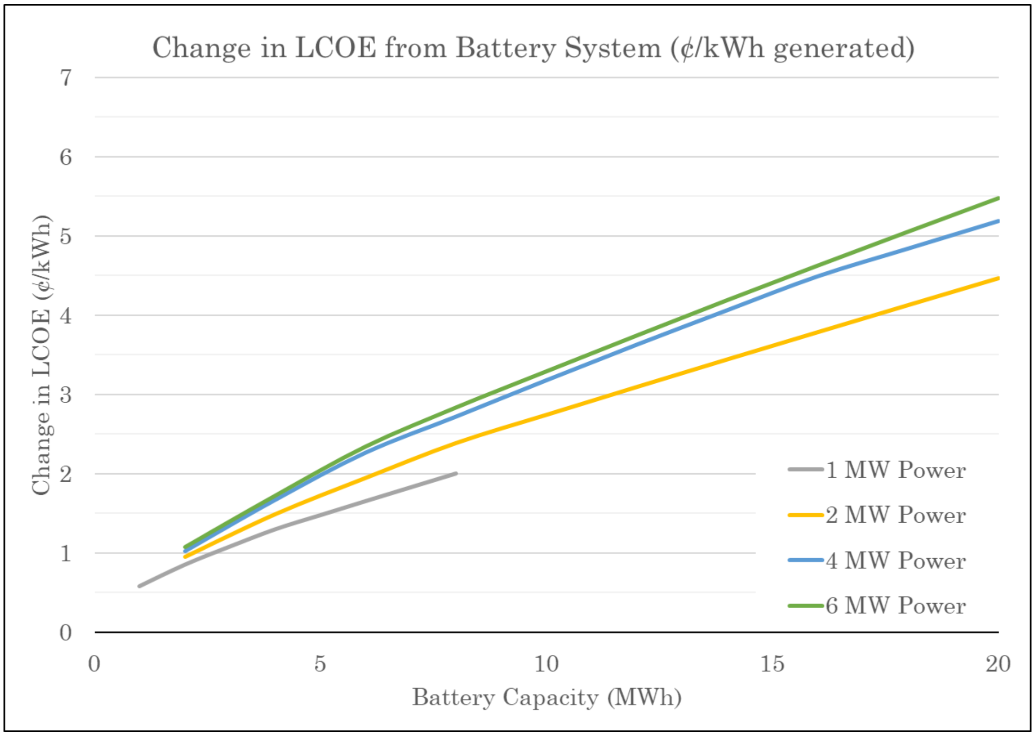

Figure 17. LCOE at a nominal discount rate of 7% for a range of battery power and capacities, as calculated via SAM. This figure looks only at costs, and does not include value streams such as time-shifting or resource adequacy payments.

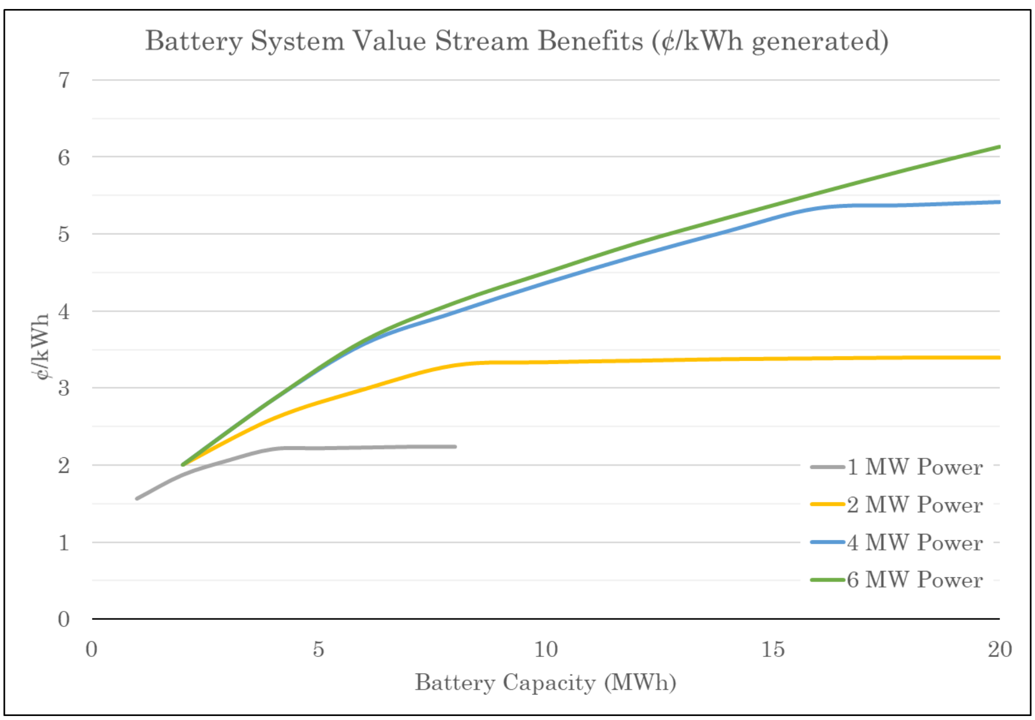

Figure 18. Sum of value streams (time-shifting and resource adequacy payment revenue) for various battery systems. Note that resource adequacy payments max out at 4 hours of charge.

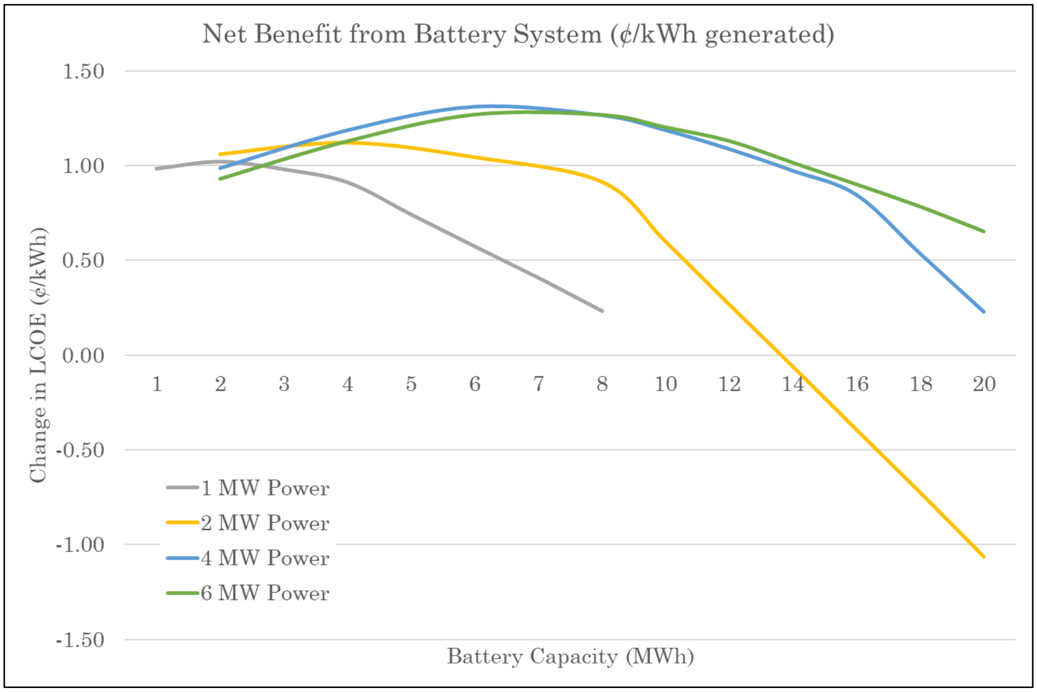

Figure 19. Net benefit of adding a battery to the FOM5.7 system, broken out by battery power and capacity. The maximum benefit occurs at 4 MW power, 6 MWh capacity.

Net benefit from battery system to LCOE, ¢/kWh					
Bank Capacity (MWh)	**0.5 MW Power Factor**	**1 MW Power Factor**	**2 MW Power Factor**	**4 MW Power Factor**	**6 MW Power Factor**
20			1.06	-0.23	-0.65
18			0.72	-0.54	-0.78
16			0.39	-0.85	-0.90
14			0.06	-0.97	-1.02
12			-0.27	-1.09	-1.13
10			-0.60	-1.19	-1.20
8		-0.23	-0.91	-1.27	-1.27
7		-0.41			
6		-0.57	-1.04	-1.31	-1.27
5		-0.74			
4	1.11	-0.91	-1.12	-1.19	-1.13
3	0.96	-0.98			
2	0.82	-1.02	-1.06	-0.99	-0.93
1	0.78	-0.98			

Figure 20. Heat map visualization of the total benefits in ¢/kWh of adding a battery to the FOM5.7 system. The maximum value is achieved at 6 MWh capacity and 4 MW power.

As these figures (**Figure 19 and 20)** show, the most economical battery is clear: a battery with a 4 MW power factor and a 6 MWh energy capacity would provide the most benefit to a FOM5.7 system. **Figure 21** explores these net benefits in more detail.

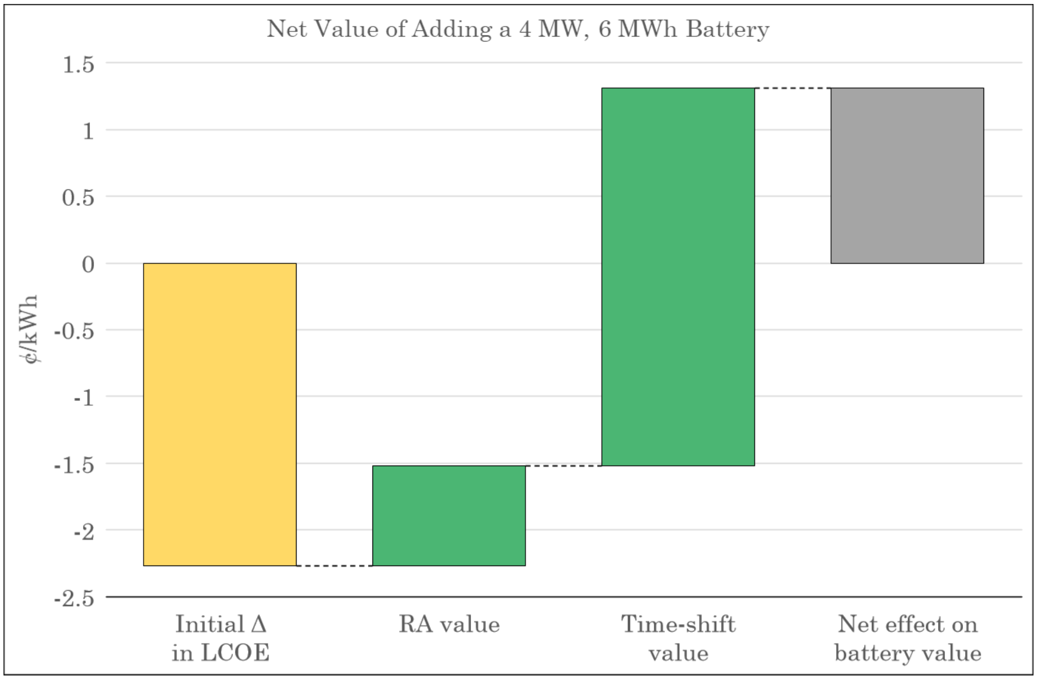

Figure 21. Effects on system value from adding a battery to the FOM5.7 system, specifically for a 4 MW, 6 MWh battery.

5.3.4 Overall System Comparison

Figure 26 and **Table 12** show the LCOE minus all quantifiable benefits including behind-the-meter cost savings, batteries, and evaporation for each configuration. Thus, the graph arrives at an 'Effective LCOE' denoting the value that the city of Santa Barbara would pay for power from a system, assuming no developer profit.

In the values in **Figure 26** and **Table 12**, 'energy bill reduction' refers to the actual savings to the city of Santa Barbara by avoiding paying the SCE grid for some energy, and thus avoiding charges. These savings are not just a transfer from one account to another, but represent real value to the City. See **Section 6.3** for more information.

Note that BTM5.7 could likely benefit from additional BESS as well, but to a smaller extent than FOM5.7. Thus, to compare the overall value of front-of-meter vs behind-the-meter systems, it is ideal to compare the configurations without a BESS.

Behind-the-meter systems are especially likely to encounter unexpected up-front capital expenditures, and this expense is not extensively explored in this report. Every additional $1,000,000 in up-front capital expenditure is estimated to increase the LCOE for the 5.7 MW DC systems by about 0.5 ¢/kWh, as shown via the sensitivity analysis in **Figure 15**. At the time of project development, these values could be used to understand the effects of any additional up-front costs on the various systems without requiring a re-creation of the entire report.

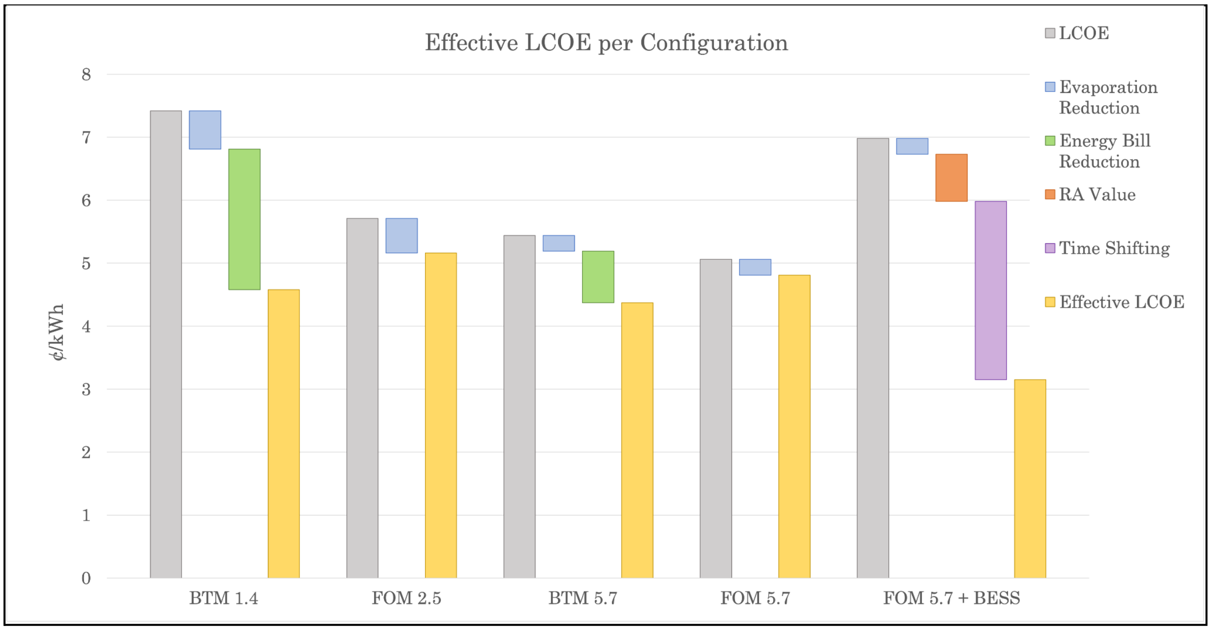

Figure 26. Comparison of expected effective real LCOE. This shows the projected LCOE minus all quantifiable benefits including behind-the-meter cost savings, battery value, and evaporation. When comparing the performance of the various configurations against each other, the yellow bar (Effective LCOE) is likely the most useful metric.

Table 12. Value comparison (in cents/kW) of the 5 configurations explored in this report. Effective LCOE cost includes no developer profit, so actual PPA values will be higher. See **Figure 14** for guidance in approximate PPA increases with various developer returns.

All values in ¢/kWh	**BTM1.4**	**FOM2.5**	**BTM5.7**	**FOM5.7**	**FOM5.7 + BESS**
LCOE	7.42	5.71	5.44	5.06	6.98
Evaporation reduction	0.61	0.55	0.25	0.25	0.25
Energy bill reduction	2.23		0.82		
RA value					0.75
Time-shifting value					2.83
Effective LCOE	**4.58**	**5.16**	**4.37**	**4.81**	**3.15**

6. Discussion

Our results show that there are multiple economically viable configurations to deploy floating solar at Lauro Reservoir. These vary based on system size and position, connection to the grid, and battery size. In particular, the choice of a front-of-meter vs behind-the meter configuration changes the way energy is valued such that it is difficult to directly compare those systems.

Thus, we can identify an optimal front-of meter system and optimal behind-the-meter system while realizing the city of Santa Barbara's goals of:

1) Using the site to maximize local renewable energy generation.
2) Maximizing the economic value of the system to the city of Santa Barbara.

Note that market PPA rates with Load Serving Entities for generated power (i.e. for front-of-meter systems) are in the 2-5 ¢/kWh range. Our behind-the-meter systems have higher anticipated PPA rates than front-of-meter systems, but also provide slightly higher value given that they are offsetting generation, transmission, and distribution – not just generation. To 'break even' for the Water Resources department, the BTM1.4 system would require a PPA of less than 9 ¢/kWh, and the BTM5.7 system a PPA of less than 5.7 ¢/kWh.

When comparing systems without a battery against each other, the BTM5.7 system is slightly more cost effective than an FOM5.7 system (4.81 ¢/kWh vs 4.37 ¢/kWh Effective LCOE), even taking into account the additional trenching costs. However, there is a greater risk of capital expenditure required for the behind-the-meter system, which would increase the LCOE. If that additional capital expenditure exceeds $1 million, then the front-of-meter system would have a lower effective LCOE. In both cases, a battery would likely reduce the effective LCOE due to the value of time-shifting and, for the front-of-meter system, RA capacity. We were not able to include the reduction in effective LCOE for the BTM5.7 system, but we were able to explore that cost reduction as seen in **Figure 26**. Further details, risks, and considerations are elucidated in the following sections.

6.1 Details of Optimal Front-of-Meter System (FOM5.7)

The optimal front-of-meter system is FOM5.7, as shown in **Figure 26**. A front-of-meter system would involve a PPA between SBCE and the solar developer according to a TOD rate structure similar to the SCE 2026 TOD schedule. The system would be owned by the developer. The system's inverters would directly connect to the grid near the micro-hydro plant, with no trenching required. To maximize value and reduce PPA prices as much as possible, a battery with 6-8 MWh of storage at 4-6 MW power factor should be included in the system. However, given the rapid changes in battery costs and battery value streams, choice of specific power and energy values should likely be left to the developer.

The expected effective LCOE would be 3.15 ¢/kWh with a battery, including evaporation savings and before any profit. See **Table 12** for more details.

Risk & Model Limitations

Although the front-of-meter system is straightforward, there are a few risks and items to consider.

1. Risk that our analysis has identified the wrong PPA price

It is possible that developers would require higher returns and thus PPA prices[50]. This could be either due to the complexity of this project (many stakeholders, floating and ground-mounted both, relatively new technology, etc), or due to concerns over future generation or battery revenue changes. For instance, while a 4-hour battery is the optimal choice according to our analysis with projected 2026 TOD rates and current RA value, a developer may decide that this projected value is not likely and require a higher PPA to compensate for the risk that these revenue streams change in the future. Indeed, as more 4-hour battery storage is installed in California, its value decreases – installing 8-hour systems may be more 'future-proof', even if somewhat more expensive right now[34]. TOD rate change risk can be transferred to SBCE *if* SBCE is willing to sign a long-term PPA with fixed TOD rate schedules. However, the risk is then simply moved and not eliminated.

Additionally, a 70% debt fraction may be too high[50]. Many lenders will require a higher equity investment in order to reduce the risk of a developer offloading a project with weak financials. Decreasing the debt fraction to a more realistic 60%, for instance, may increase the PPA price.

2. TOD Rate Model Limitation

If SCBE signs a long-term PPA contract with the developer, the TOD rates are very important to get right. This is a challenge for all LSEs purchasing power, as the wholesale value of power in California is changing rapidly, at 3-5 year timescales compared to the 20-25 year timescale of a standard PPA.

While this analysis uses SCE's expected 2026 TOD rates[36], even the large utilities do not have a strong enough understanding of future TOD rates to sign long-term PPAs[68], and thus these TOD rates are 'informational only' and not binding. If SBCE signs a long-term rate at a given TOD rate, the value of that power in the future may change in an unfavorable way – in the future, power during a specified hour might be vastly cheaper on the wholesale market compared to the long-term PPA. While SBCE can probably recover those higher costs from ratepayers, this would increase the overall cost of power for SBCE ratepayers.

3. Risk of required grid upgrades

It is not clear whether the distribution lines leading to Cater and to the Lauro site can support the electricity produced by the solar system. If not, then costly grid upgrades would be required to complete the system. Preliminary use of the 'DRPEP' map that SCE provides to the public[32] and a preliminary discussion with an SCE grid engineer suggests that the circuit can support about 10 MW AC of generation, given a likely line core composition (a certain common type of aluminum core) that can support up to 450 Amps. Utilities prefer to keep a buffer between total expected power on the line and the line's rated power capacity, and will readily approve additional power generation on a line until about 80% of the line's rated power capacity.

$$Rated\ Power_{kW} = \sqrt{3} \cdot I_A \cdot \frac{V}{1000} = \sqrt{3} \cdot 450\ Amps \cdot \frac{16{,}000\ V}{1000} = 12,471\ kW$$

Using a buffer of 20%, this ~12.5 MW AC power rating means that ~10 MW of generation likely is easily handled by the circuit. There is some existing generation on the circuit that is queued or existing at this time: less than 2 MW worth[32]. Thus, as long as the system does not exceed about 8 MW, it is not likely to require grid upgrades to receive approval from SCE.

While exceeding 80% of rated power via generation on the distribution line is not a big risk, there are other concerns that will need to be cleared via the WDAT / Rule 21 SCE approval process. For instance, it is possible that other types of one-way electrical gear exist on the distribution line between the substation and the site, or that some parts of the distribution line contain a core unable to support 450 Amps. These are less likely and less costly to fix than a full upgrade of the line, but still must be investigated by SCE engineers before proceeding with the project.

If grid upgrades are required, LCOE would increase by about 0.5 ¢/kWh per $1 million in up-front capital costs for the 5.7 MW systems. This analysis is included in **Section 5.1.2,** with results in **Figure 15.**

6.2 Details of Optimal Behind-the-Meter System (BTM5.7)

The optimal behind-the-meter system is BTM5.7. The behind-the-meter system would consist of a PPA between the Santa Barbara Water Resources department and the solar developer. The system would be owned by the developer. Any generation up to Cater's load would be net-metered and thus offset all variable (e.g. bypassable) generation, transmission, and distribution costs (9.0 ¢/kWh). Generation in excess of Cater's load would go to offset other Water Resources loads via a custom feed-in tariff as described in **Section 3.8.2**. A likely load to offset would be the desalination plant, and so we use that facility's tariff to compute avoided generation cost.

The expected effective LCOE would be 4.37 ¢/kWh without a battery, including evaporation savings and before any profit. See **Table 12** for more details. It may be possible to reduce further with a battery, as discussed below in item #4.

Risk & Model Limitations

1. Risk of additional capital expenditures

Grid capacity concerns are less severe for behind-the-meter systems compared to front-of-meter systems, as some power is used by Cater before being exported to the grid and thus total load on the grid is reduced. Instead, a large risk of possible required upgrades at Cater, necessary to properly use this energy and interface with the grid, exists. This could be a significant capital expense, and is one of the largest unexplored considerations of this report. Further, this system would require trenching to connect the Lauro site to Cater, the cost of which is estimated at about $785,000 for 0.6 miles. There is a high degree of uncertainty for this number and the sensitivity analysis illustrated in **Figures 15 and 16** can be used to discern the impacts of different cost numbers on LCOE.

2. Rate Structure Model Limitation

The PPA associated with this system is likely to have a TOD rate structure that matches the weighted rate structure between all Cater meter tariffs and the desalination plant tariff. This rate structure is important to match with Water Resources energy costs, so that the Water Resources department does not take on the risk of purchasing energy from the solar system at a higher PPA price than the energy from the utility which it is replacing. This report does not explore how to structure such a rate structure, nort does it investigate the possible change to PPA price from temporal mismatches between solar production and this TOD rate structure.

3. Trenching approval risk

Any behind-the-meter system connecting the Lauro site to Cater would require trenching, which is estimated at about $785,000 for 0.6 miles. As this is unusual for behind-the-meter systems in general, some negotiation with SCE and perhaps the CPUC may be needed to argue that building an electrical connection under a public road is acceptable by a non-utility entity. This proposal could be highly contentious, and contains the risk that SCE and/or the CPUC would consider the conveyance of electricity across the road as 'distribution' and thus only appropriate for a utility and not a CCA or a municipality. Lack of approval of the trenching feature would eliminate the possibility of a behind-the-meter system at the Lauro site, and would immediately suggest that a front-of-meter system is ideal.

4. Battery Storage

In this analysis, we did not analyze adding additional batteries to the BTM5.7 system. Adding a battery to that behind-the-meter system may make sense, depending on the TOD schedule in the PPA signed with the developer (and thus on the tariff structure applied to Water Resources loads, as that tariff structure would inform the PPA TOD schedule as discussed in item #2). We can assume a similar, yet smaller, reduction to the effective LCOE as that found in the FOM5.7 system. The benefit of adding a battery is likely smaller in a behind-the-meter system as the TOU tariff has a less attractive arbitrage opportunity than the SCE TOD rate structure – the peak cost difference between the most expensive and least expensive time period is smaller for the TOU tariff.

5. Demand Charges

Note that a solar system would not reduce any demand charges at Cater, as Cater's peak loads tend to happen fairly evenly throughout the day. Thus, while solar generation would 'shave' load during the daytime, there would still be peaks just as large as before during times when solar generation from the Lauro site is non-existent. A reduction in Cater's demand charges is therefore not expected from a behind-the-meter system.

6.3 System Value

It is important to highlight that the savings from utility rates in the behind-the-meter system are complicated and can be confusing. Ultimately, the City pays for electricity via SBCE procurement or via the Water Resources budget, but the funds to purchase electricity come from the same place: the city of Santa Barbara's budget.

Thus, higher 'savings' for the Water Resources department from a behind-the-meter system may simply transfer revenue from SBCE, and would not actually be a true savings overall for the city of Santa Barbara. The exception to this issue is in behind-the-meter variable transmission and distribution charges (e.g. non-bypassable charges or 'NBC's) – these are paid to SCE. When these costs can be reduced, this reduction is an actual true source of value to the city of Santa Barbara.

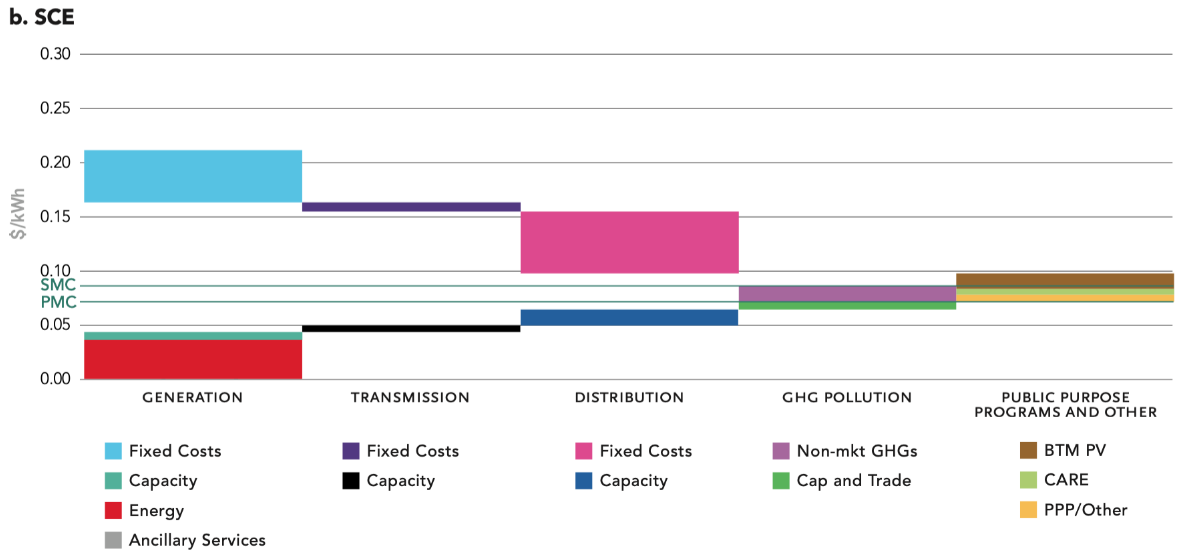

Figure 27. Breakdown of fixed and variable costs for a representative tariff in the SCE service area[69]. Note that this tariff is not that used by Cater, but instead one chosen by the authors of the cited report. Variable costs are those on the bottom half, and are those which can be offset by a solar system.

In our case, behind-the-meter systems would shift the generation cost to the Water Resources department from SBCE. Water Resources would be replacing that energy and capacity (about 5 ¢/kWh as billed by SBCE) via the solar system. Thus, the PPA signed between the Water Resources department and the developer would shift the responsibility of paying that generation cost directly from SBCE to the Water Resources department, but would not truly change the overall costs to the City. This would also be the case for any power offset elsewhere in the system via the custom feed-in tariff (e.g. at the desalination plant).

Given the previous description, it may seem that the *only* benefits from trenching would be resilience benefits. That is not true, however, as any electricity that does not traverse the grid also avoids variable transmission and distribution costs (the black and blue lines in **Figure 27** above). In our case, this electricity would only be that electricity used by Cater itself, and as of NEM 3.0, this would not include 'net-billed' or 'net-metered' electricity[40].

This consideration is explored in **Section 4.3.10.** Our analysis in that section shows the energy and NBC savings for the Water Department at each system size (questions #1 and #2) as well as the NBC savings for the City budget overall (questions #3 and #4). The former two explore the reduction to the Water Department budget from a behind-the-meter system, whereas the latter two explore the actual savings to the City from a behind-the-meter system.

Thus, the increased capital expense and complexity of trenching is *only* worthwhile if the cost is less than the sum of the benefits. These benefits are *only* the avoided *variable* transmission and distribution costs and the difficult-to-quantify resilience benefits, not the full reduction in the Water Department's utility bill. Only the smaller sum of avoided variable costs are the true savings to the city of Santa Barbara as a whole.

6.4 Resilience Discussion

Resilience in our context is the ability for Cater to withstand power outages or shutoffs. This value is difficult to quantify, and is different for behind-the-meter vs front-of-meter systems as discussed below. Even if it is difficult to quantify, resilience may be a significant 'selling point' for the project, and may tip the balance in favor of one type of configuration over the other.

6.4.1 Behind-the-Meter

There would be significant value in connecting Cater directly to the solar array, which would allow Cater to use power in a PSPS or other outage situation. However, this value is difficult to quantify – outages are rare events whose frequency is changing rapidly. However, it is difficult to argue that any solar system would provide full resilience benefits given that there are two existing diesel generators providing backup power at Cater. If the Water Resources department was comfortable removing one or both of those generators in the future, then the avoidance of replacement and O&M costs of those generators could be allocated as benefits to the solar system. However, this is unlikely until the solar system is more established – our conversations with the Water Resources department suggest that this is not a near-term prospect.

One configuration that may make such a replacement more likely would be a behind-the-meter system with a *minimum* 12 MWh battery and at least a 2 MW power factor (although engineers should verify these numbers and properly add error margin / buffer). In the event of an outage, with such a battery configured correctly, Cater could operate without a functioning grid connection continually for an indefinite amount of time.

Such flexibility would allow utility repair crews to focus on other critical parts of the local grid and avoid both air pollution and administrative coordination to resupply diesel fuel for the generator in a crisis situation. This option is a strong selling point of the behind-the-meter systems, and may be enough to justify the higher LCOE / PPA rates required to install a battery with a larger energy capacity than is economically optimal without that flexibility benefit.

6.4.2 Front-of-Meter

Unlike a behind-the-meter system, even with a battery, the front-of-meter system does not provide resilience for Cater in the event of a grid outage. This is due to the way that local grids are constructed – in the event of an outage, power from a distributed generator (i.e. a solar or micro-hydro plant in our case) is not allowed onto the grid. This is to protect utility workers, as well as due to technical challenges in keeping an isolated pocket of the grid operating correctly.

However, in the long term, there could be resilience benefits from a front-of-meter system, especially when paired with the micro-hydro system and a potential pumped hydro storage system at the Lauro site. The City could later create a 'community microgrid' on the circuit that includes both the proposed solar system and the micro-hydro plant, as well as any other future energy infrastructure. This microgrid would require capital expenditure (for special switches and frequency-creating hardware) and would require SCE approval, but would not require any trenching.

With a community microgrid, the circuit itself would be isolated from the rest of the grid in an outage situation, but electricity would still flow on the circuit. Again, with a properly configured and designed battery, Cater would be able to operate continually and indefinitely, pulling power from the locally 'islanded' circuit shared with the solar system and the micro-hydro plant.

The city of Santa Barbara would not get these resilience benefits immediately and would have to wait for the benefits until completing the community microgrid. However, there are two benefits to waiting. The first is that splitting the project into two parts (creating the solar + BESS system first, and then later obtaining approval for resilience infrastructure like trenching or a community microgrid) reduces the risk that the approval process with SCE holds up the entire project and reduces project complexity in general. This staged approach compares with the behind-the-meter system where SCE approval is required to proceed with any part of the project. The second benefit to waiting is that the California legislature may provide financial support for community microgrids, especially in places with high fire risk. If similar to the Self-Generation Incentive Program (SGIP) program, the city of Santa Barbara would be eligible for huge reductions in capital expenditure to achieve these resilience benefits at Cater.

6.5 Co-Benefits Discussion

The discussion of floating solar co-benefits is key to better understanding the values of floating solar systems. This section explores how, despite a majority of the co-benefits lacking proper quantification, these co-benefits can still be recognized as additional value streams for a floating solar system. It also examines one specific co-benefit, reduced evaporation, because comparing the variance in estimations for evaporation helps establish the relationships between the values. Lastly, this section explains the numerous results from Penman equation model calculations of the variety of system configurations, evaporation reduction percentages, and avoided costs of water.

6.5.1 Issues in Co-Benefit Quantification

Quantification and monetization is lacking in the literature, and thus most of the co-benefits of floating solar technology at Lauro Reservoir will have to be considered qualitatively. Their values may be vague, but these co-benefits still exist and still would provide additional value to the floating solar system.

For example, comparing the value of resilience benefits between the behind-the-meter and front-of-meter systems as discussed above is not simple, but we recognize that some systems may have more value than others. The rest of the unquantified co-benefits share a similar story – land-use, water quality, and biological co-benefits. Each provides some additional value to the adoption of floating solar, but the monetary value is simply not calculable at this time.

This inability to calculate could be either due to the current state of understanding of floating solar co-benefits within the literature or the lack of an ability to monetize the co-benefit. As an example, reductions in algae growth are desirable, especially upstream from water treatment plants, and are a well-documented benefit from floating solar systems[20,25]. However, a reduction in algae would not currently cause changes to Cater's operating costs, and thus the co-benefit is not monetizable at Lauro Reservoir, even though it may help to prevent additional operating costs in the future if algae growth becomes a larger problem.

6.5.2 Evaporation Estimation Comparisons

Reduced evaporation was the one co-benefit that could be quantified and monetized independently from those that affect power production. As seen in **Table 8**, the estimated evaporation values vary for each method explored in this report. The difference between our model's estimation and Floating Solar Solution's estimation is approximately 15.5%, likely due to the use of different meteorological data in the two estimations rather than a calculation error from either estimation. For example, where

Floating Solar Solutions used an average solar irradiance of 5.34 kWh/m^2/day, we used a value of 6.6 kWh/m^2/day retrieved from the most recent 2019 local NREL data[64]. Further work could include a sensitivity analysis on the effects of various variables in our estimation to highlight specific variance contributing variables. Even without a sensitivity analysis, the difference between Floating Solar Solutions's estimations and the estimations in this report is not large enough to be concerning.

However, the estimated value from the COMB pan evaporation station is substantially lower than both of the Penman equation estimates. This higher discrepancy of approximately a 74% difference between COMB and our estimation may be due to two potential reasons. First, the COMB empirical data may be inaccurate and could be an underestimate of evaporation from Lauro Reservoir due to a combination of the inaccuracies mentioned in regards to pan evaporation estimates (**Section 4.4.1**). Second, the Penman equation may be an overestimate of evaporation due to the inherent nature of the equation using meteorological data rather than empirical evaporation measurements. This is a fairly large effect, and could benefit from further study.

6.5.3 Evaporation Reductions

This report's evaporation model produces a variety of numbers representing various evaporation statistics and water values. There are differences in the avoided cost of water and the estimated evaporation reduction percentage, differences which then translate to different monetization values.

When it comes to the avoided cost of water, there are two sensible options: the City uses an avoided cost of water of $865/AF while COMB uses an avoided cost of water of $1300/AF. Thus, COMB will always recognize more value from the same amount of reduced evaporation when compared to the City. In our report, the City's value of water will be referenced, with the understanding that COMB would recognize more value from equivalent water savings than what is reported here.

Similarly, there is a range of reasonable evaporation reduction percentages that we explore in the analysis. Evaporation reduction ranges in the literature from 50% to 90%. We chose to split this difference at 70% and treated this as a median estimate for evaporation reduction, while also reporting values for the full range in **Section 5.2**. In this report, the 70% reduction values are used as the default but recognize that savings from evaporation could vary up to 20% in either direction.

With these considerations in mind, we explore the results of the evaporation reduction model as seen in **Section 5.2**.

- The BTM1.4 configuration would save an estimated 21.35 AF of water per year, which translates into a monetary savings of $15,086 per year.

- The FOM2.5 configuration would save an estimated 30.16 AF of water per year, which translates into a monetary savings of $26,088 per year.

- The FOM5.7 & BTM5.7 configurations would save an estimated 30.16 AF of water per year which translates into a monetary savings of $26,088. These values are the same compared to the FOM2.5 system because they both have the same large floating system and therefore reduce the same amount of evaporation.

It may be more useful to normalize these savings by system generation. This normalization turns the annual evaporation savings into a more comparable value of ¢/kWh that can then be applied to the estimated LCOE and PPA values. These normalized values are 0.61, 0.55, and 0.25 ¢/kWh for BTM1.4, FOM2.5, and FOM & BTM5.7 systems respectively. We see the smallest system has the best value per kWh and this is closely followed by the value of the FOM2.5 system. However, the FOM & BTM5.7 configuration savings suffer from a substantially decreased value once normalized. This is due to this system generating more energy because of the added ground-mounted solar without any large corresponding evaporation than the large floating system. Thus, the value of that evaporation is greatly reduced per kWh.

Reduced evaporation would provide observable benefits to the city of Santa Barbara and COMB in both water conservation and monetary savings with a few noteworthy trends. In our model, we see that a larger floating solar system would reduce overall evaporation losses more than a smaller floating system, but the smaller floating system would have a higher value of reduced evaporation when normalized to the generation of the system. This necessitates a weighing of greater overall reduction in evaporation losses against more evaporation reduction value per unit of energy generated.

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8. Appendix

Appendix A: Stakeholder Approval Discussion

A floating solar project installed at Lauro Reservoir would need to be approved by two primary stakeholders, requiring the navigation of key statutes and relevant applications for each. The United States Bureau of Reclamation (USBR) is the lead federal agency concerned with Lauro Reservoir land management, and Southern California Edison (SCE) is the regional utility in charge of approving the interconnection process for this system.

USBR

The USBR established that non-federal development of renewable energy on USBR-owned reservoirs is acceptable, provided that such developments are compatible with underlying, authorized reclamation purposes, are in the best interests of the public, and are consistent with appropriate resource management and environmental considerations[70].

To approve non-federal renewable energy development at the Lauro site, such as floating solar, the USBR requires a Use Authorization[71]. This process requires:

1. A 'Plan of Development' that provides sufficient detail in the potential impacts on environmental resources, water operations, power generation, pumping operations, and transmission infrastructure.

2. A pre-application meeting the 'Plan of Development' data, a summary of changes to the reservoir's surface, and floating solar designs.

3. A safety and hazardous materials plan within the 'Plan of Development' if a floating solar system is on USBR land, which would be the case at the Lauro site.

4. A completed and signed Standard Form (SF) 299 or Form 7-2540, secured project funding (in this case, likely a signed PPA contract), plus a $100 application fee[71,72]. These must be submitted to the USBR California-Great Basin Region, South-Central California Area Office.

If the project is not approved, the City may appeal the decision per statute 43 CFR §429(32-37). Generally, applications with fewer conflicts between the proposed project and the resources and operations of the reservoir will be easier to get approved or to appeal.

Interconnection Process and SCE

In order for the project to start operations it must pass through SCE's process for connecting with the grid. An initial study should first be performed to assess the capacity of the local circuit and the site infrastructure needed to safely connect the solar system to the grid – a 'pre-application interconnection study'.

The front-of-meter configuration modeled in this study would need to seek interconnection service under the Federal Energy Regulatory Commission (FERC) distribution system jurisdictional tariff (the Wholesale Distribution Access Tariff or 'WDAT') via the Independent Study Process. The timeline and total cost of an interconnection study and agreement varies from project to project. However, a deposit of at least $50,000 plus $1,000 for every MW of electrical output is a required input for this track, and the process from application to 'Permission To Operate' can take up to 2 years.

Any behind-the-meter system would need to be interconnected via SCE's Rule 21. The BTM1.4 system would use the NEM Interconnection application (Form 14-957), and the BTM5.7 system would use the Exporting Interconnection Application (Form 14-918). Each of these applications would incur an $800 fee, and would take anywhere from a few months (BTM1.4) to up to 2 years (BTM5.7).

Appendix B: Permitting and Statutes Discussion

National Environmental Policy Act

The National Environmental Policy Act (NEPA) would apply at the Lauro site as any project would require approval from the USBR. This federal action would trigger the NEPA process[31]. The NEPA process would be handled by USBR representatives, and has a range of possible timelines[70]. USBR officials could determine that this project qualifies for a 'categorical exclusion', in which the agency decides that the action does not have a 'significant effect' on the environment. In this case, the process is complete. If the project requires an 'Environmental Assessment' or even an 'Environmental Impact Statement', that would take significantly longer, even up to years.

California Environmental Quality Act

The California Environmental Quality Act (CEQA) requires government agencies to consider the environmental consequences of their actions before approving plans and policies or committing to a course of action on a project. This applies to projects undertaken by the city of Santa Barbara, and thus this project would fall under CEQA's jurisdiction. The full CEQA process can take months or years, sometimes requiring an initial study or a more involved Environmental Impact Report. During the process, the city of Santa Barbara may even need to change the project in order to mitigate environmental effects.

However, if the project qualifies as a 'categorical exclusion', then the length of CEQA review can be reduced by the 'lead agency' (here the city of Santa Barbara) filing a 'Notice of Exemption' (NOE). This is potentially feasible, as the site may count as an 'existing facility' due to either the micro-hydro plant or even the connection to Cater for a behind-the-meter system. A NOE should be filed after the project has been officially approved by the city council[73].

CEQA statute defines an 'existing facility' under §15301(b) as any utility used to provide electric power, natural gas, sewage, or other public utility services. CEQA refers to a 'cogeneration project' under §15329 as the installation of cogeneration equipment with a capacity of 50 MW or less at existing facilities[73]. A floating solar system on Lauro Reservoir may qualify for an Article 19 Categorical Exemption if the cogeneration project results in no net increase in air emissions and complies with all applicable state, federal, and local air quality laws.

As a case study example, a floating solar installation at the Raw Water Ponds in Holtville, California successfully qualified for an Article 19 Categorical Exemption under the same §15329(a) cogeneration project at an existing facility statute, and filed a §15062 Notice of Exemption[74].

Appendix C: Levelized Cost of Energy Calculations

In order to double-check our LCOE values in NREL's SAM tool, we conducted an exercise to calculate the LCOE of two of our systems. The basic LCOE equation is:

Eq. 16

$$LCOE = \frac{capital\ cost \cdot CRF}{8{,}760 \cdot capacity\ factor} + \frac{fixed\ O\&M\ cost}{8{,}760 \cdot capacity\ factor} + variable\ O\&M\ cost$$

where, CRF = capital recovery factor, as described in **Section 4.3.3**.

SAM takes into account taxes and incentives, whereas this simple calculation does not. However, to try to avoid these effects, we ran the analysis with no tax rate. All analysis is in nominal terms. Note that when the analysis was conducted, we included a $0.5125/MWh discharged variable cost term which was later determined to be not well defined or well resolved and has since been removed from our analysis in SAM. This change does not impact the validity of the overall calculation check, however, as we are just investigating the difference between the two calculations, and the overall LCOE values are not important.

Table 13. Double-check of SAM LCOE calculations for two systems.

	Solar Only	**Solar + Battery**	**Δ from Battery**
Installation cost	$8,533,649	$10,209,369	$1,675,720
Calculated 1st term (¢/kWh)	3.995	4.779	0.784
Calculated 2nd term (¢/kWh)	0.928	0.974	0.046
Calculated 3rd term (¢ / kWh)	0	0.051	0.051
Total Calculated LCOE value (¢/kWh)	**4.923**	**5.805**	**0.882**
SAM LCOE value (¢/kWh)	**5.10**	**5.86**	**0.76**
Δ from SAM values	**-3.47%**	**-0.94%**	**16.02%**

Appendix D: Considerations for Anchoring and Panel Orientation

Floating solar systems must be anchored from all sides for each 'island' of floats. This is one reason why fewer floats are optimal: there is an added cost to multiple islands compared to one island with an equivalent number of panels[75].

Each edge of an island can either be anchored via cables to the shore, or via cables to anchors sunk at the bottom of the system. Anchoring via cables to the shore is cheaper and preferred[17], but may not be possible for all edges of a system or for all systems.

Additionally, for long and narrow islands (such as the island on the north-west arm of Lauro Reservoir), the panels must face the long edge of the island to avoid possible failure due to wind stress. Panels can act as a sail, pulling the island in the direction of whichever orientation they are facing, and this 'sail effect' generates stress on the anchors. Less stress occurs at a perpendicular angle to the panel orientation. Thus, to maximize the integrity of each island, if islands are narrow, the panels must only act as sails in an orientation in which there are many anchors by which the energy can be balanced. Thus, the panels must face the long edge of the island[48].

Similarly, wind can cause differential stress on parts of arrays that are not rectangular, potentially causing structural failure in extreme scenarios (e.g. hurricanes). Ciel & Terre (the market leader) will now only design arrays that are rectangular to reduce this risk. However, at the Lauro site, this concern is likely unfounded – the conditions are mild enough that a non-rectangular design could likely be considered without much risk, although decision-makers should consult with any future system developer about this issue.

Appendix E: Calculating Row Spacing for Fixed, Ground-Mounted Arrays

Ground-mount arrays have their own necessary considerations and choices. The terrain only has two slopes that are feasible (somewhat south-facing and not too steep or rugged). These two slopes are a slope on the west side of the site facing southeast henceforth referred to as the 'West Slope' and a southward-facing slope in the center of the site, referred to as the 'South Slope'. While these are steep slopes (19.10° and 22.26° for the West and South slopes respectively, calculated via Google Earth), these are about the same slope as a nearby project by the Santa Barbara County Courthouse and the Santa Barbara County Transfer Station. This nearby project includes array sections on a slope of 21.64°.

We decided to base most of our ground-mounted design decisions on this very similar local project, including the row spacing and the panel orientation. We chose a panel orientation (portrait-orientation, 3 panels high per row) that mimics the courthouse project. We set row spacing to 6 feet in this report, as a conservative estimate; the courthouse project uses 5 foot row spacing, and thus there may be more generation potential at Lauro than this report suggests. We set the tilt angle to the same value as the slope[18].

We discussed whether to rotate the panels to face south on the West Slope with solar developers from Third Pillar Solar. Their guidance recommended against the complexity and shading that comes from trying to go against the 'grain' of the hill, and instead follow the contour of the hill, advice we decided to follow[48].

Note a drawback of our approach: we did not calculate self-shading from each row to the other. This self-shading would reduce power output at the early and late times of day and thus we would be slightly over-underestimated generation in our report compared with reality. Luckily, setting up the panels along the slope helps with avoiding shading, and our row spacing is conservative as well, which should balance the total effect.

Appendix F: Contract PPA Price vs Real PPA Price

One complication of energy markets comes from the fact that the cost of energy in the wholesale market also varies over the course of the day or even over months. Thus, when signing a PPA agreement between the solar system owner and the energy offtaker, two items are required to understand the actual price paid for energy.

First, there is a contract PPA price, the nominal price at which the PPA is set. As an example, we could imagine a PPA contract with a price of 10 ¢/kWh.

Second, there is a time-of-delivery (TOD) rate schedule that specifies the value of a given kWh for every hour of every day of the year. An example of SCE's projected 2026 TOD rate schedule is included as **Figure 28**. TOD factors are based on the contract PPA price, and thus the calculation for the value of any given kWh is shown in **Eq. 17**.

Eq. 17

$$Value\ of\ kWh\ =\ (contract\ PPA\ price)\ \cdot\ (TOD\ rate\ schedule\ factor)$$

Table 2 Informational TOD Heat Maps (2026) Weekdays and Weekends & Holidays

SCE -WD	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.36	1.34	1.34	1.34	1.37	1.47	1.55	1.54	1.16	0.73	0.48	0.32	0.30	0.39	0.52	0.73	1.43	1.71	1.71	1.57	1.55	1.54	1.51	1.43
2	1.37	1.36	1.36	1.36	1.40	1.45	1.58	1.41	0.88	0.39	0.29	0.19	0.18	0.22	0.23	0.44	1.11	1.64	1.81	1.68	1.57	1.52	1.51	1.45
3	1.37	1.36	1.36	1.37	1.37	1.39	1.52	1.39	0.56	0.17	0.10	0.04	0.02	0.03	0.04	0.08	0.21	0.55	1.47	1.69	1.62	1.45	1.42	1.41
4	1.32	1.31	1.31	1.31	1.31	1.31	1.40	1.11	0.34	0.16	0.13	0.09	0.05	0.07	0.07	0.08	0.14	0.31	1.18	1.62	1.67	1.51	1.35	1.33
5	1.28	1.26	1.26	1.26	1.25	1.27	1.27	0.92	0.26	0.19	0.15	0.09	0.08	0.08	0.09	0.12	0.17	0.32	1.01	1.50	1.65	1.51	1.34	1.30
6	1.29	1.25	1.25	1.25	1.25	1.26	1.20	0.84	0.30	0.29	0.26	0.23	0.19	0.19	0.22	0.26	0.33	0.51	1.03	1.46	1.78	1.63	1.39	1.32
7	1.28	1.23	1.21	1.21	1.21	1.25	1.21	0.96	0.74	0.60	0.56	0.54	0.53	0.58	0.63	0.72	0.81	0.98	1.16	1.54	1.71	1.57	1.43	1.35
8	1.30	1.24	1.23	1.23	1.24	1.28	1.33	1.08	0.85	0.68	0.64	0.60	0.58	0.66	0.72	0.85	0.93	1.06	1.35	1.74	1.74	1.53	1.42	1.37
9	1.30	1.26	1.23	1.24	1.25	1.30	1.38	1.22	0.85	0.58	0.53	0.46	0.41	0.52	0.59	0.69	0.79	1.12	1.60	1.95	1.62	1.47	1.40	1.34
10	1.37	1.33	1.32	1.33	1.35	1.38	1.42	1.41	0.99	0.38	0.33	0.27	0.24	0.29	0.34	0.48	0.73	1.35	1.74	1.69	1.52	1.44	1.42	1.40
11	1.35	1.33	1.32	1.32	1.33	1.37	1.45	1.24	0.69	0.33	0.25	0.22	0.22	0.28	0.46	0.98	1.53	1.73	1.67	1.54	1.52	1.49	1.47	1.41
12	1.39	1.37	1.37	1.37	1.38	1.47	1.55	1.52	1.16	0.76	0.56	0.42	0.34	0.47	0.58	1.08	1.58	1.69	1.66	1.60	1.60	1.59	1.54	1.47

SCE -WE/Hol	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.37	1.35	1.35	1.34	1.34	1.37	1.39	1.37	1.01	0.36	0.26	0.21	0.17	0.19	0.23	0.40	1.41	1.70	1.71	1.57	1.51	1.50	1.47	1.41
2	1.36	1.36	1.36	1.34	1.35	1.37	1.40	1.28	0.24	0.17	0.09	0.05	0.05	0.08	0.10	0.18	1.05	1.57	1.79	1.63	1.54	1.49	1.47	1.45
3	1.38	1.35	1.34	1.34	1.35	1.35	1.35	1.27	0.26	0.05	0.03	0.01	0.00	0.00	0.01	0.04	0.17	0.45	1.46	1.67	1.58	1.45	1.38	1.37
4	1.33	1.31	1.31	1.31	1.30	1.31	1.31	0.89	0.12	0.03	0.02	0.00	0.00	0.00	0.00	0.01	0.03	0.15	1.16	1.62	1.58	1.44	1.35	1.32
5	1.28	1.21	1.21	1.21	1.20	1.20	1.16	0.50	0.15	0.08	0.06	0.03	0.01	0.03	0.03	0.04	0.13	0.20	0.95	1.46	1.58	1.47	1.33	1.28
6	1.27	1.22	1.22	1.22	1.22	1.21	1.09	0.35	0.13	0.08	0.06	0.02	0.01	0.02	0.04	0.07	0.10	0.26	0.91	1.43	1.71	1.63	1.41	1.28
7	1.32	1.24	1.23	1.23	1.23	1.23	1.13	0.75	0.30	0.21	0.25	0.20	0.23	0.25	0.31	0.43	0.66	0.87	1.15	1.59	1.75	1.60	1.37	1.34
8	1.28	1.20	1.19	1.19	1.19	1.19	1.19	1.00	0.32	0.26	0.23	0.19	0.21	0.24	0.30	0.54	0.82	1.03	1.29	1.76	1.70	1.52	1.34	1.33
9	1.27	1.21	1.21	1.22	1.22	1.22	1.22	1.11	0.48	0.25	0.19	0.16	0.16	0.24	0.32	0.39	0.64	0.99	1.61	1.87	1.61	1.40	1.35	1.32
10	1.38	1.34	1.33	1.33	1.33	1.33	1.33	1.31	0.60	0.25	0.17	0.11	0.08	0.14	0.16	0.27	0.44	1.29	1.69	1.68	1.49	1.42	1.41	1.40
11	1.33	1.33	1.32	1.33	1.33	1.33	1.34	1.16	0.39	0.14	0.07	0.05	0.04	0.10	0.18	0.73	1.41	1.65	1.65	1.51	1.49	1.48	1.47	1.44
12	1.39	1.37	1.38	1.38	1.38	1.39	1.41	1.38	1.06	0.30	0.22	0.16	0.15	0.19	0.24	0.89	1.54	1.68	1.65	1.56	1.57	1.56	1.54	1.47

Figure 28. A repeat of **Figure 6**. Southern California Edison's (SCE) predicted 2026 Time-Of-Delivery (TOD) heat maps for 'weekday' (WD) and 'weekend / holiday' (WE/Hol) schedules[36].

Thus, if there was a 10 ¢/kWh PPA, delivering 1 kWh at noon on a weekend in July would result in a payment of 2¢ (10¢ × 0.20), while delivering 1 kWh at 9 PM of the same day would result in a payment of 17.50¢ (10¢ × 1.75).

Meanwhile, the actual payments generated by the PPA contract are not simply the average of the TOD rates, as solar power is variable and generates energy at different times of the day, as shown in **Figure 4**. In particular, solar arrays tend to generate power at the times of day with the lowest TOD factors, which is not a coincidence. Thus it can be difficult to determine, given a PPA price, what the actual average transaction price for energy will be – the 'real PPA price'.

As part of our analysis, we determined both the 'contract PPA price' as well as the 'real PPA price' for the FOM5.7 system. These are shown in **Table 14**. Real PPA price matches that in **Figure 14**.

Table 14. Contract PPA price vs real PPA price for the FOM5.7 system at various developer rates of return. Note that these numbers *should not* be used to set prices in PPA contracts without significant additional expert consultation.

PPA Rate of Return	Real PPA Price (¢/kWh)	Contract PPA Price (¢/kWh)
7%	5.06	13.37
8.75%	5.19	13.73
12%	5.41	14.32
15%	5.60	14.83
20%	5.94	16.71
25%	6.34	16.77

These contract rates may seem extreme, but this large gap between contract PPA price and real PPA price makes sense – large amounts of energy would be produced during times when the energy is valued at less than a quarter of the contract PPA price. There are even periods in which the energy's value is zero.

These prices are difficult to calculate, and are changing rapidly. Adding in a battery storage system changes the real PPA price and contract PPA price as well. In order to achieve the same real PPA price with a battery system, the offtaker would need to reduce the contract PPA price, as the battery is able to shift energy from lower-value periods to higher-value periods as discussed in **Section 3.7.1**.

The difficulty of this calculation requires care. Offtakers should seek additional expert consultation before signing any PPA contract.