Stantec

ENERGY SUSTAINABILITY PLAN

REPORT NO. 1630 | VOL 2 | NOV 2020

THE METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA

LIST OF APPENDICES

APPENDIX A

Metropolitan’s Accomplishments in Energy Efficiency

METROPOLITAN'S ACCOMPLISHMENTS IN ENERGY EFFICIENCY

Table A-1 provides a list of Metropolitan's completed and on-going accomplishments in energy efficiency.

Table A-1: Energy Efficiency Accomplishments

Location	Accomplishment	Status
Diamond Valley Lake	Installation of 0.5 MW rooftop solar panels (2006)	Completed
Weymouth WTP	Installation of 3 MW solar farm (2016)	Completed
	Installation of LED lighting:	Completed
	Caustic Ammonia Control Building	Completed
	Ozone area Air Compressor & Dryer pad	Completed
	Coatings Shop storage area	Completed
	Fluoride Tank Farm area	On-going
	Main Plant Switchgear Building #14	On-going
	Auto Shop/ Coatings Shop area	On-going
	Chlorine Building	On-going
	Solids Handling and Sludge Thickener areas	In planning phase
	ODP East Canopy area	In planning phase
	Generator Bldg. #71	In planning phase
	Tank Farm areas (LOX, Caustic Ammonia, Alum, Polymer)	In planning phase
Jensen WTP	Installation of 1 MW solar farm (2018)	Completed
	Installation of LED lighting:	
	Administration Building	Completed
	High bay all lights	Completed
	All street lighting	Completed
	Area lighting around the basins	On-going
	Main switchgear building (SGN-1 and SGN-2)	On-going
	Replacing existing motors with higher energy efficiency motors	
	Pump back motors (5)	In planning phase, to be completed in 2021
	Wash water tank motors, flash mix motors, lift pump motors at WWRP #2 (16)	Evaluation phase
Skinner WTP	Installation of 1 MW Solar Farm (2010)	Completed
	Installation of LED lighting:	
	Electrical buildings 4 and 5, ozone contactor building galleries	Completed

Location	Accomplishment	Status
	High bay lighting in CL2 storage bays	On-going
	Roadway lighting	50% Completed
	Tank farms 3, 4, 6, and 7	In planning phase, to be completed in 2021
	Control roadway and module lighting from RTUs with LED lighting	Evaluation phase
	Replacing existing motors with higher energy efficiency motors	
	Pump back motors (5)	In planning phase, to be completed in 2021
	Wash water tank motors, flash mix motors, lift pump motors at WWRP #2 (16)	Evaluation phase
	Harmonic and Power factor correction	
	Installation of line side harmonic filtering on variable frequency pump drive (5), ozone open loop cooling water pumps and plant 1 jet mix pumps	Completed
	Installation of power factor correction capacitors bank and harmonics mitigation for the unit power centers	Evaluation phase
Diemer WTP	Installation of LED lighting:	
	Administration Building	Completed
	Streetlights	On-going
	Other structures – Replaced with LED when lights are out	On-going
	All underground tunnels	In planning phase
	Replaced pumps/motors with variable frequency drives where applicable	Completed
Mills WTP	Installation of LED lighting:	
	Administration Building.	In planning phase
	Streetlights	On going
OC-88 Pumping Plant	Installation of LED lighting	In planning phase
	Replacement of compressor skid with a centrifugal style compressor which will be much more efficient handlers	Recommended by SCE's Energy Efficiency Audit
	Replacement of outdated HVAC system with higher efficiency equipment. The HVAC system contains 3 chiller skids, circulation pumps, and 4 air handlers	Recommended by SCE's Energy Efficiency Audit
All unmanned conveyance and distribution areas including hydroelectric power plants	Installation of LED lighting in all structures	On-going
CRA Pumping Plants	All Plants: Replace/Rehabilitate pumps/motors with higher efficiency equipment	On-going
	Iron and Eagle pumping plants: Upgrade kitchen and Lodging with higher efficiency equipment	Evaluation phase

In addition to the accomplishments completed thus far, Metropolitan is currently conducting an Energy Efficiency Pilot Program at the Weymouth WTP. Led by a multidisciplinary team, the program will begin with a comprehensive monitoring/reporting system in order to understand the details of Metropolitan's power usage on-site and to develop methods to assist facilities' operations staff making sound decisions to optimize the power consumption, while maintaining the high levels of reliability and safety required by Metropolitan. This will also allow staff to identify processes and equipment that could be improved or upgraded to increase energy efficiency and reduce GHG emissions, while providing performance data that could be utilized as part of on-going, condition-based maintenance efforts. Metropolitan currently monitors many of the internal distribution circuits and meters via supervisory control and data acquisition (SCADA), and uses this data for electricity cost reporting and treatment plant performance metrics. This initial effort would utilize this existing SCADA/data infrastructure and combine it with the various instrumentation currently available on the process equipment to capture data and develop reports to be analyzed and evaluated.

Once this is completed, the energy efficiency team will identify inefficient processes and/or equipment, and make recommendations on upgrading the equipment or processes. The team will then work with operations staff to develop analytical tools for their use in making operational decisions that will optimize the processes from an energy-efficiency perspective, while maintaining or improving the operational integrity of the processes. This system will also assist in improved electricity forecasting and budgeting for all functions and units at the La Verne site.

After the monitoring and reporting system is installed, targeted projects can be prioritized and implemented. Initial targeted projects for the Energy Efficiency Pilot Program are as follows:

- Develop a comprehensive energy monitoring/reporting system for Weymouth WTP and the La Verne Facility using the Metropolitan SCADA system, existing submetering and process controls and instrumentation
- Complete modification of ODP Clearwell Pumping
- Install a combined heat-power system at the Water Quality Laboratory
- Install a site-wide building control system for non-process facilities and equipment at Weymouth/La Verne
- Complete the Outdoor Lighting Retrofit to High Efficiency LED Lighting and Controls
- Optimize HVAC systems and controls throughout La Verne Facility, including potential thermal storage systems
- Retrofit all indoor lighting systems with high-efficiency lighting

Some of these projects are already being evaluated, and the monitoring system would provide validation and on-going verification of any efficiency gains that are realized from implementing the listed projects. It would also be the starting point for any new energy studies (e.g., pump efficiency and process equipment efficiency) that will take place in the future.

APPENDIX B

Compliance with CEQA Appendix F

COMPLIANCE WITH CEQA APPENDIX F

Metropolitan is a public agency and, as such, is subject to California laws governing energy sustainability, including the California Environmental Quality Act (CEQA). CEQA is a statute that requires public agencies, like Metropolitan, to analyze a project's environmental impacts, and identify ways to avoid, reduce, or mitigate any significant environmental impacts from their actions, where feasible. CEQA requires analysis of the potential energy impacts of a proposed project, with particular emphasis on avoiding or reducing wasteful, inefficient, or unnecessary consumption of energy resources during project construction or operation. CEQA also requires Metropolitan to review its actions for consistency with state or local plans for renewable energy or energy efficiency.

The purpose of this CEQA provision is to encourage energy conservation and to implement efficiency measures to avoid fossil fuel usage and other non-renewable energy resources. Webster's Dictionary defines "wasteful" as using more of something than is needed, or causing something valuable to be wasted; "inefficient" is defined as not efficient, or not capable of producing desired results without wasting materials, time, or energy; and "unnecessary" is defined as not necessary, not essential, not needed, or not required.

CEQA Guidelines Appendix F describes various means of achieving energy efficiencies and includes: (1) decreasing overall per capita energy consumption; (2) decreasing reliance on fossil fuels such as coal, natural gas and oil; and (3) increasing reliance on renewable energy sources.

Metropolitan's actions under the ESP generally result in increased reliance on renewable energy resources and decreased dependence on energy derived from fossil fuels, as such, the ESP demonstrates overall compliance with Appendix F. Metropolitan intends to rely on the measures implemented in this plan to demonstrate compliance with CEQA and to serve as important mitigation for energy-related impacts from construction and operations of capital improvement projects identified in the ESP.

APPENDIX C

Peer Review of Energy Sustainability Plans

Stantec

Technical Memorandum No. 1

Peer Review of Energy Sustainability Plans

November 11, 2020

Prepared for:

Metropolitan Water District of Southern California

Prepared by:

Stantec Consulting Services Inc.

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Abbreviations

ACWD	Alameda County Water District
AMP	Asset Management Program
AWA	Amador Water Agency
BESS	Battery Energy Storage Systems
CAP	Central Arizona Project
CapEx	Capital Expenditure
CIP	Capital Improvement Program
CPUC	California Public Utilities Commission
CRA	Colorado River Aqueduct
DA	Direct Access
DERs	Distributed Energy Resources
DR	Demand Response
EMP	Energy Management Plan
EMRS	Energy Management and Reliability Study
EMWD	Eastern Municipal Water District
EPW	El Paso Water
EVWD	East Valley Water District
FERC	Federal Energy Regulatory Commission
FY	Fiscal Year
GHG	Greenhouse Gas
HVAC	Heating, Ventilation, and Air Conditioning
IEUA	Inland Empire Utilities Agency
IRWD	Irvine Ranch Water District
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt-hour
LEAPS	Lake Elsinore Advanced Pump Storage
LED	Light-emitting Diode
MACRS	Modified Accelerated Cost Recovery System
MG	Million Gallon
MW	Megawatt
MWA	Mojave Water Agency
MWh	Megawatt-hour
O&M	Operations & Maintenance
OWASA	Orange Water and Sewer Authority
PAT	Pump-As-Turbine
PPA	Power Purchase Agreement
PV	Photovoltaic
PWRPA	Power and Water Resources Pooling Authority

RFP	Request for Proposal
SA	Sweetwater Authority
SBVMWD	San Bernardino Valley Municipal Water District
SCC	Social Cost of Carbon
SCE	Southern California Edison
SCVWD	Santa Clara Valley Water District
SDCWA	San Diego County Water Authority
SGIP	Self-Generation Incentive Program
SGVWC	San Gabriel Valley Water Company
TBW	Tampa Bay Water
TM	Technical Memorandum
VFD	Variable Frequency Drive
WSSC	Washington Suburban Sanitary Commission
WTP	Water Treatment Plant
WVWD	West Valley Water District
WWTP	Wastewater Treatment Plant

1.0 INTRODUCTION

The purpose of this technical memorandum (TM) is to peer-review Energy Sustainability Plans or similar documents from water agencies across North America to inform Metropolitan Water District of Southern California's (Metropolitan) development of their own Energy Sustainability Plan. This TM will evaluate the overall approach considered in each plan, summarize key components of each plan that may provide useful lessons learned to Metropolitan, and highlight the multicriteria evaluation methodologies used to evaluate a potential projects' contributions to energy sustainability at the selected water agencies. Lastly, the TM will provide a draft outline of Metropolitan's Energy Sustainability Plan.

The documents reviewed for the purposes of this TM were selected based on the following topics with relevance to Metropolitan's Energy Sustainability Plan:

- Geographic proximity;
- Utility size range;
- System configuration and process;
- Energy and carbon neutrality goals and/or greenhouse gas (GHG) emissions reduction;
- Strategic energy planning;
- Energy management strategies and options;
- Renewable energy and energy storage options;
- Other key sustainability initiatives.

The list of documents reviewed for this TM is summarized in Table 1-1.

Table 1-1 List of documents reviewed for the purpose of this TM

Utility	Document Title	Document Type
Inland Empire Utilities Agency (IEUA)	Inland Empire Utilities Agency - 2015 Energy Management Plan	Energy Management Plan
Irvine Ranch Water District (IRWD)	Irvine Ranch Water District – Energy & GHG Master Plan (2012)	Energy Master Plan
El Paso Water (EPW)	Energy Management Master Plan (2017)	Energy Master Plan
Washington Suburban Sanitary Commission (WSSC)	Washington Suburban Sanitary Commission Strategic Energy Plan (2015)	Energy Plan
Orange Water and Sewer Authority (OWASA)	Orange Water and Sewer Authority's Energy Management Plan (2017)	Energy Management Plan

Utility	Document Title	Document Type
Toronto Water	Driving Initiatives - Toronto Water's Twenty-Year Energy Optimization Plan (2018)	WEFTEC 2018 – Conference Proceedings
Philadelphia Water	Philadelphia Water - Utility Wide Strategic Energy Plan Updated Winter 2017	Summary of Energy Management Plan
Tampa Bay Water (TBW)	Tampa Bay Water – Energy Management Program Roadmap (2011)	Energy Management Plan
Central Arizona Project (CAP)	The Water-Energy Nexus Dimension of the Central Arizona Project System Use Agreement (2016)	Report
	Consideration of Action to Approve a Post-2019 Power Portfolio (2018)	Board Meeting Agenda and PowerPoint Presentation
	Power Task Force Recommendations – June 2017	PowerPoint Presentation
Alameda County Water District (ACWD)	Alameda County Water District – Clean Energy Alternatives (2016)	PowerPoint Presentation
San Bernardino Valley Municipal Water District (SBVMWD)	Assessment of Renewable Energy Supply Options (2018)	White Paper
Santa Clara Valley Water District (SCVWD)	Climate Change Mitigation - Update on Progress Towards Carbon Neutrality by 2020 (2017)	Board Agenda Memorandum; PowerPoint Presentation and other
San Diego County Water Authority (SDCWA)	Climate Action Plan 2015	Report
	Energy Management Policy (2013)	Policy
Eastern Municipal Water District (EMWD)	Solar Photovoltaic Renewable Energy Initiative – Phase III (2018)	Report
	Eastern Municipal Water District: A Case Study of Best-In-Class Water-Energy Programs and Practices (2012)	Report
Metropolitan Water District of Southern California (Metropolitan)	Energy Management and Reliability Study (2009)	Energy Management Plan

2.0 OVERVIEW OF ENERGY SUSTAINABILITY INITIATIVES

This section summarizes key components of the energy management plans or energy sustainability initiatives from the selected fifteen utilities. The scope and extent of energy management or energy sustainability initiatives at the reviewed utilities varies, depending on their customer size, regulatory mandate, and location specific social and political factors and incentives. Sections 2.1 through 2.4 synthesize common trends and/or key differences among the reviewed utilities in the areas of 1) purposes and goals, 2) project evaluation and prioritization, 3) scenario analysis, and 4) action plans of their energy sustainability plans.

2.1 GOALS OF ENERGY SUSTAINABILITY INITIATIVES

The purposes and goals of the energy sustainability initiative of a utility vary depending on its long-term vision, mission, implementation strategies, and applicable regulatory requirements. A few utilities have detailed, measurable goals for their energy management plans, while others have more general, statement-type goals. Figure 2-1 summarizes the goals across different utilities, and Table 2-1 presents more specific goals at selected water and wastewater utilities.

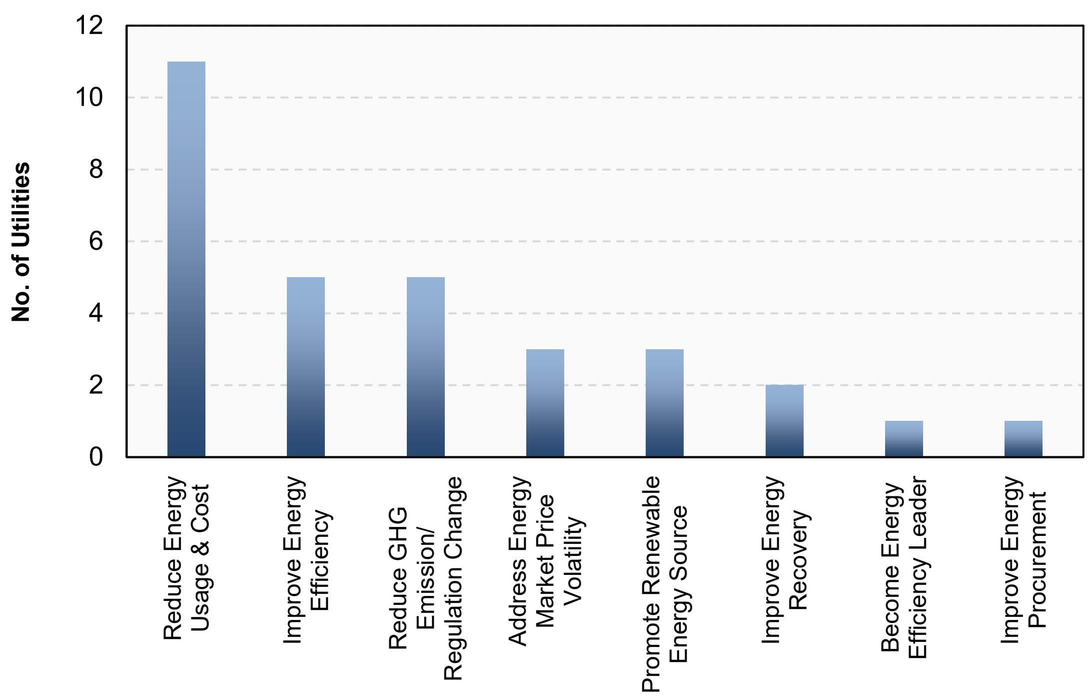

Figure 2-1 Summary of goals for sustainable energy initiatives at selected water and wastewater utilities

Table 2-1 Goals of sustainable energy initiatives in selected water and wastewater utilities

Utility	Selected goals of the Energy Sustainability Initiatives
Inland Empire Utilities Agency	• Achieve grid independence during peak periods; • Procure 100% of IEUA's electricity needs from carbon neutral sources by 2030 through renewable portfolio diversification; • Increase system monitoring, achieve resource optimization and strategic procurement.
Irvine Ranch Water District	• Identify a portfolio of cost-effective projects to reduce the District's existing and future energy usage and costs, and as required under future regulatory conditions, reduce GHG emissions.
El Paso Water	• Maximize process control and minimize resource use. Promote best practices instead of business as usual; • Promote lowest life-cycle cost, instead of lowest initial cost procurement practices; • Provide reliable and timely process performance metrics within all operations sections to benchmark and improve operating efficiency; • Provide key process performance metrics to operations and engineering sections to make informed decisions. Measure return on investment (ROI) of potential adoption of best practices and system improvements and track results before and after improvements; • Quantify actual resource savings from each facility improvement.
Washington Suburban Sanitary Commission	• Create a strategic roadmap for enabling WSSC to become a model energy efficient utility and to formalize the processes for energy management for the next 10 years; • Reduce electrical intensity at wastewater treatment plants (WWTPs) in aggregate by 8%, from 3,308 kWh/MG to 3,030 kWh/MG; • Reduce electrical intensity at water filtration plants in aggregate by 6%, from 1,716 kWh/MG to 1,626 kWh/MG; • Achieve minimum average monthly on peak/off peak usage ratio of 81% at water filtration plants (same as FY 2013 Base Year performance); • Achieve minimum average monthly on peak/off peak usage Ratio of 39% at wastewater treatment plants (same as Fiscal Year (FY) 2013 Base Year performance); • Increase renewable energy portion of total energy consumed at WSSC from 28% to 44%; • Maintain competitive rates, with a target that the total blended wholesale rates (excluding wind power) be within 10% of the published PJM market rates for on- and off-peak power; • Achieve minimum of 50% hedging on electricity energy purchases to minimize volatility risks.

Utility	Selected goals of the Energy Sustainability Initiatives
Orange Water and Sewer Authority	• Reduce use of purchased electricity by 35% by end of calendar year 2020 compared to the calendar year 2010 baseline; • Reduce use of purchased natural gas by 5% by the end of Calendar Year 2020 compared to the calendar year 2010 baseline; • Beneficially use all WWTP biogas by 2022, provided the preferred strategy is projected to have a positive payback within the expected useful life of the required equipment; • Formally engage local governments and partners in discussion about potential development of biogas-to-energy project at the Mason Farm WWTP; • Seek proposals for third-party development of renewable energy projects on OWASA property.
Toronto Water	• Minimize energy use; • Maximize energy recovery; and • Minimize energy cost.
Philadelphia Water	• Strive to maintain a stable energy footprint by increasing energy efficiency at the facilities; • Reduce GHG emissions of 50% by 2030; • Continue to pursue renewable energy generation and resource recovery at the facilities; • Maintain or reduce energy costs and provide budget certainty to the ratepayer.
Tampa Bay Water	• Develop an energy roadmap with the goals to continuously improve efficiency, meet regulatory requirements and manage increasing costs.
Central Arizona Project	• Effectively manage costs; • Maintain existing generation resources until appropriate alternatives are available; • Secure reliable, sustainable, cost-effective generation resources; • Effectively manage transmission costs.
San Bernardino Valley Municipal Water District	• Reduce energy costs, and edge against cost uncertainty perceived as high due to regulatory changes in the market.
Santa Clara Valley Water District	• Achieve carbon neutrality by 2020.
San Diego County Water Authority	• Implement an energy management policy to control and minimize the water authority’s current and future energy costs; • Make purchasing decisions based on available energy-efficient products and maximize energy conservation when purchasing equipment and products; • Operate and maintain facilities in accordance with energy best management practices.

Utility	Selected goals of the Energy Sustainability Initiatives
	• Evaluate investment in metering, building controls, and energy monitoring to enable support of demand response programs; • Maximize off-peak use of gas and electricity; • Develop cost-effective programs, energy projects, and initiatives to control operational costs and move towards increased energy independence; • Pursue a broad, cost effective strategy for energy efficiency that takes into account legislative action, consumer response to water rates, and programmatic approaches that minimize financial impact to the ratepayer; • Pursue additional funding sources as appropriate, including loans, grants, utility incentives, rebates, leases, power purchase agreements, energy services companies, pooled credit, and reinvestment of savings. • Pursue cost effective renewable energy projects that provide alternative revenue streams and contribute to overall energy cost containment; • Pursue innovative and cost-effective applications of new renewable energy sources and cost-effective advances in renewable energy technology; • Periodically review utility rates and tariffs for potential energy savings. • Integrate cost effective energy retrofit projects into Capital Improvement Program (CIP)/Asset Management process; • Periodically review this Energy Management Policy to ensure that the Policy remains efficient, economic, and up-to date.
Eastern Municipal Water District	• Promote various initiatives around the water-energy nexus; • Energy Independence: Plan and cost-effectively implement local renewable energy projects with sufficient generation to meet the District's entire net energy demands while minimizing the District's carbon footprint.
Metropolitan Water District of Southern California	• Update 2009 Energy Management and Reliability Study (EMRS); • Work towards achieving long-term reliable power supply; • Protect against energy market price volatility; • Analyze risks, potential costs and opportunities associated with regulations including laws governing GHG emission reductions and increased use of renewable energy; • Evaluate the basis for hedges against overall cost risks for the operation of all MWD's water distribution system and the Colorado River Aqueduct (CRA).

2.2 PROJECT EVALUATION AND PRIORITIZATION

Several energy management plans and related documents presented in Table 1-1 include information on the approaches used for evaluation and prioritization of energy sustainability initiatives. Information collected from these water and wastewater utilities suggests that an evaluation and prioritization process is generally composed by the steps presented in Figure 2-2:

Figure 2-2 Typical project evaluation and prioritization process

Evaluation and prioritization criteria tend to vary across different utilities, depending on the strategic goals of the utility and drivers of sustainable energy management. A few common criteria could be identified as summarized below:

- Cost and/or cost-effectiveness of the project (e.g., this criterion may be defined as net present value of the life-cycle costs and/or financial payback period);
- Beneficial and/or adverse impacts on existing operations;
- Impacts on carbon footprint or GHG emissions;
- Environmental impacts;
- Social impacts on the community (e.g., public perception, community impacts/benefits).

From the perspective of solicitating and selecting energy suppliers, especially renewable energy suppliers, evaluation criteria used by a few utilities include:

- Life-cycle costs;

- Functional capabilities and past project installation experience;
- Operational reliability;
- Ability to adjust to site variations and supply to electrical loads.
- Relevant market expertise;
- Financial strength (i.e., payback period).

Table 2-2 presents summaries of project evaluation and prioritization methods for selected water and wastewater utilities.

Table 2-2 Project evaluation and prioritization methods at selected water and wastewater utilities

Utility	Project Evaluation and Prioritization Approach
Irvine Ranch Water District	Project evaluation and prioritization through a five-step process: • Baseline and forecast (20 years), including planned projects; • Perform project assessments; • Evaluate and rank the projects; • Perform portfolio and scenario analyses; • Create the master plan report. Evaluation criteria include five major areas: • Cost/cost-effectiveness (compared with other projects); • Operational impacts (adverse and/or beneficial impacts on current operations of the plant. Impacts include general operation and maintenance (O&M) complexity and risk, amount of additional staff required); • Risk and uncertainty (financial risk on estimated capital and O&M costs; regulatory risk of additional permits/approvals; additional political action for implementation; local community support; reliance on other agencies and/or regulators on approval of the project); • GHG Impacts (reduction of GHG compare to other projects and to purchase of electricity); • Environmental impacts (air, land, water, noise, visual and waste by-products impact).
Washington Suburban Sanitary Commission	The project pre-screening and evaluation approach includes: 1) Energy project identification; 2) Initial validation; 3) Conceptual development; 4) Screening and prioritization; 5) Final validation. Prioritization criteria include: • Benefit: impact of implementing the initiative on WSSC's strategic energy plan goals and objectives; • Urgency: immediate benefits or immediate requirement from the business; • Cost: Low (<$100K), medium ($100K-500K) and high (>$500K); • Complexity: involvement required from third-parties, technical challenges, etc.

<table>
<tr><th>Utility</th><th>Project Evaluation and Prioritization Approach</th></tr>
<tr><td>Orange Water and Sewer Authority</td><td>The evaluation and prioritization process include:
1) Establish organizational commitment, including goals and objectives for energy management set by the Board;
2) Develop a baseline of energy use;
3) Evaluate the system;
4) Identify clean energy opportunities;
5) Evaluate and prioritize opportunities for implementation against Board-defined criteria;
6) Create an implementation plan that sets forth the proposed actions, timetable, resource requirements, and expected outcomes for the upcoming year; and
7) Provide for monitoring and reporting level of progress in achieving performance objectives.
The project evaluation criteria include:
• Financial responsibility (public funds; financial viability of similar projects; opportunities for obtaining outside funding/financing);
• Implementability/Realistic (proven at a scale relevant to OWSA's operation; organizational capacity to manage; staff time to implement);
• Operational impacts (consistency with OWASA's operation; improves existing operation problems; impact on safety, comfort and productivity);
• Energy/carbon reduction potential (reduction on OWASA's energy use and/or carbon emissions);
• Coordination with other project(s) (interdependency; potential to leverage on economies of scale for saving money and/or staff time);
• Community impacts (stakeholder interests; coordination with community initiatives).</td></tr>
<tr><td>Toronto Water</td><td>The energy optimization plan development framework includes:
• Establish a consistent vision;
• Identify strategies and goals to meet mission and achieve vision;
• Identify initiatives to meet goals;
• Identify activities to support initiatives;
• Implement strategic measures.
The project evaluation criteria include:
• Technical feasibility: regulatory requirements, ease of implementation, O&M requirements, and facility impacts;
• Economic feasibility: life-cycle cost, payback period (business case assessment);
• Environmental considerations: GHG emissions, footprint;
• Social considerations: public perception, community impacts/benefits</td></tr>
<tr><td>Tampa Bay Water</td><td>The project identification approach includes:
• Review of existing capital and IT projects;
• Identification of gap projects bridging the existing capital projects to the steps identified in the energy roadmap;
• Identify opportunities to expand TBW’s energy efficiency focus on operations;
• Identify project schedules and budgets.</td></tr>
</table>

Utility	Project Evaluation and Prioritization Approach
Central Arizona Project	The evaluation criteria for selecting power suppliers include: • Functional capabilities and experience; • Relevant market expertise; • Financial strength; • Proposed energy supply and delivery, including supply to which CAP facilities, generation technology and plant/fleet size that will be used to serve the CAP load, fuel(s) hedging, and delivery point for the energy; • Indicative pricing.
Alameda County Water District	The project evaluation criteria include: • Feasibility; • Regulatory and land use issues; • Financial issues (life cycle cost; net present value; funding source/incentives); • Pros/cons (maintenance requirements, vendor site visits, operating issues); • Scheduling/Timing with planned capital improvements.

2.3 SCENARIO ANALYSIS

Scenario analysis is often considered as part of a project evaluation and prioritization approach, and subsequent implementation of sustainable energy initiatives, to determine the sensitivity of specific factors to the business or specific project objectives. The parameters that are used to conduct scenario analysis differs across utilities and goals, and may include evaluation of the following:

- Future energy demand (e.g., as a result of anticipated process changes);
- Changes in electric utility programs;
- Changes in price of electricity and/or natural gas;
- Changes in imported water prices;
- Changes in air quality regulations;
- Changes in water quality regulations;
- Changes in groundwater basin rules;
- Availability of financial incentives;
- Unanticipated/unplanned changes (contingency).

It is important to note that additional parameters may be considered depending on the utility system configurations and specific goals of a utility's energy management plan or initiative.

2.4 ACTION PLANS

Once projects are identified and prioritized, utilities select specific action plans or roadmap for project implementation, in relation to timeline (e.g., short versus long-term), budgets, accordance with capital improvement or asset management plans, project approval processes and other factors. These type of action plans vary greatly across different utilities from high-level to more detailed approaches. Table 2-3 presents summary of scenarios and action plans by each utility reviewed.

Table 2-3 Details of action plans for selected water and wastewater utilities

Utility	Key Features of Action Plan
Inland Empire Utilities Agency	Identified projects to undergo more detailed analyses to determine whether they will be implemented into IEUA's Ten Year Capital Improvement Plan.
Irvine Ranch Water District	Action plan based on: • Categorization of Near term versus long term implementation projects; • Priority projects that do not require upfront capital costs; • Priority to projects that provides lower capital expense; • Priority to projects that provides high revenue potential.
Washington Suburban Sanitary Commission	Implementation of the energy projects through the asset management plan (AMP) process. The execution plan is sequenced across several criteria and determining factors: • Prioritized rankings of the initiatives based on the prioritization criteria and prioritization process; • Interdependencies between initiatives that are separate, but related; • Logical sequencing of timing of initiatives to support the strategic energy plan performance related goals • Levelizing of capital cost across the planning horizon (to the extent practicable); and • Levelizing of resource commitments during execution plan. Initiatives are times such that no more than five initiatives will be on-going at any given time.
Orange Water and Sewer Authority	Identified strategies are categorized as: • projects that have already been identified as part of CIP for purposes other than energy management, but that have the potential to reduce the energy required for that facility or function; • strategies are recommended to either be (a) implemented within the upcoming fiscal year or (b) further evaluated to determine their potential savings and associated costs. Projects ranked to either: • Implement; • Study; • Defer until upgrade; or • Defer indefinitely.

Utility	Key Features of Action Plan
Toronto Water	• The identified energy management opportunities were subjected to the decision-making framework based on number of years for opportunity implementation; • Incorporate energy management into the project delivery approach (each capital projects requires a project-specific energy management plan (EMP) related to the scope of the capital project being provided.
Tampa Bay Water	The Energy Roadmap developed 5 steps for the next 10 years (starting from 2011), including: • Path to efficiency: implementation (2011 - 2013), during which TBW would develop action plans with an increased focus on reduced energy use and consider energy factors in decision-making processes. • Understand water and energy relationship (2013 - 2015): during which TBW would collect real time energy and flow data that would support development of analytical tools that can be used to measure performance and study energy efficiency alternatives. • Workforce Initiative (2015 - 2017), during which TBW would provide necessary training and education to its staff on using the tools to make operational decisions that result in reduced energy use. • Total water system management and Broad collaboration (2017-2019), during which TBW would collaborate with external stakeholders to explore options such as strategic storage, system cycle management and better negotiation with power providers • Combined power and water management system (2019-2021), during which TBW would optimize timing between daily demand and supply to promote energy efficiency. Projects are developed as: • Quick hits (short term) • Mid-term changes in capital priority • Long-term strategic needs
Central Arizona Project	The action plan includes: • Portfolio recommendation • Board selects preferred portfolio • Agreements negotiated with power providers • Board approves contracts
Alameda County Water District	Scheduling and timing of projects in accordance to the CIP.

3.0 PRELIMINARY OPTIONS OF ENERGY SUSTAINABILITY INITIATIVES

3.1 RENEWABLE ENERGY OPTIONS

Energy sustainability and energy management plans developed by water and wastewater utilities are increasingly incorporating opportunities for investments and deployments of renewable energy options. Renewable energy options considered by water and wastewater utilities include the following.

- **Solar**: Renewable energy options based on solar energy are largely implemented at water and wastewater utilities. Two forms of solar energy are available: solar photovoltaic (PV) and solar thermal heating. Solar PV involves the installation of PV panels which absorb sunlight to generate electricity; solar thermal heaters harness sunlight to heat a fluid, typically water, for space heating inside buildings. Solar panels typically require utilities to have the availability of a large amount of unobstructed land or roof space.

  Various financing or partnership models are available to utilities installing solar. In particular:

  - Ownership and operation responsibility of the water agency;
  - Power purchase agreements (PPA), in which a contract between two parties is established, one generating the electricity and the other purchasing the electricity. PPAs are often preferred to minimize capital costs and operational concerns to water agencies, in addition to minimize the risks associated to electricity rate structures, size of solar units, and the complexity of power generation and purchasing.
- **Wind Power**: Harnessing wind power as a renewable energy source is dependent on land availability, wind strength and environmental regulations. Unlike solar installations, wind farms can create concerns associated with the visual and ecosystem impacts generated by the height of wind turbines and noise produced by the blades. As previously reported for solar installations, wind power generation was found to be financially feasible for some water agencies, especially when paired with a PPA structure.
- **Large-scale hydropower**: Large hydropower systems, such as hydroelectric generation facilities, utilize the available energy stored in water at different elevations. This type of energy production is common for agencies with large reservoirs and is discussed in more detail in Section 3.2.2.
- **In-conduit hydropower**: In conduit hydropower is defined as the hydroelectric generation potential in man-made conduits such as tunnels, canals, pipelines, aqueducts, flumes, ditches, or similar man-made water conveyance that is operated for the distribution of water for agricultural, municipal and industrial consumption. As turbine technologies have significantly evolved over the last decade, there are multiple alternatives turbines that can be selected depending on the applications. The selection of technologies depends on the water type (potable water or raw

water), available head and flow at the sites, and the tailrace layout (downstream pressure requirement). Most of the water utilities utilize pump-as-turbines (PAT) for systems with downstream pressure requirement, while Pelton turbines are used for systems that discharge pressure to the atmosphere. Table 3-1 presents details on selected in-conduit hydropower projects in California.

There are significant opportunities for in-conduit hydropower in various man-made water conveyance and distribution infrastructure including diversion structures, irrigation chutes, check structures, run-of-river schemes in irrigation systems, pipelines from the source water, inlets to service reservoirs, and along the water distribution network, wastewater treatment plant outfalls, and groundwater recharge sites. The energy potential of the site of interest is determined as a function of the hydraulic head and water flow or based on the hydrokinetics power obtained from harnessing the kinetic energy of flowing water. Generally, the head and flow parameters dictate the type of turbine. Reaction turbines are generally applicable to low head systems, and impulse turbines are more suitable for medium-high head applications. However, some newer generation of impulse turbines, for example, can also operate in low head systems. In addition to reaction and impulse turbines, there is a growing interest in hydrokinetic turbines, although to date their implementation is not as widespread.

Table 3-1 Information on selected in-conduit hydropower projects in California

Case Study Utility/Site	Location of powerhouse	Capacity (kW)	Annual power generation (kWh)	Status	Turbine unit (s)
Amador Water Agency (AWA)	Upstream of Water Treatment Plant (WTP)	110	580,475	In operation	Two PAT units
East Valley Water District (EVWD)	Upstream of WTP	177	1,034,000	In operation	Two PAT units
Mojave Water Agency (MWA)	Upstream of groundwater recharge basin	1100	6,100,000*	Under construction	2-Nozzle Horizontal Pelton
San Bernardino Valley Municipal Water District (SBVMWD)	Upstream of groundwater recharge basin	1059	3,947,000*	Under construction	Pelton
San Gabriel Valley Water Company (SGVWC) – B24	Upstream of water storage facility	72	433,000*	Under construction	One PAT unit
San Gabriel Valley Water Company (SGVWC) – Sandhill	Upstream of WTP	310	1,000,000	In operation	Two PAT units
Sweetwater Authority (SA)	Upstream of WTP	580	3,440,000	In operation	Two PAT units
West Valley Water District (WVWD)	Upstream of WTP	460	2,947,000	In operation	Two PAT units

*Estimated annual power generation

- **Fuel cells**: Fuel cells were only considered by three agencies as an additional renewable energy option. Depending on the power company, fuel cells may not be considered as renewable power sources unless fed by wastewater biogas.
- **Food waste cogeneration (biogas)**: Energy production by means of biogas production, or cogeneration, is considered a viable option for agencies that operate wastewater facilities. To increase the amount of energy generated, options such as co-digestion or thermal hydrolysis processes for sludge pre-treatment have been largely considered by wastewater agencies.
- **Geothermal**: Geothermal heating and cooling systems are viable options for new construction with limited site constraints. However, installations with limited energy use and low energy costs would not benefit from geothermal systems.

Table 3-2 provides a brief overview of renewable energy options considered for implementation or already deployed at the utilities reviewed for the purpose of this TM.

Table 3-2 Renewable energy options at selected water and wastewater utilities

Utility	Solar	Wind	Hydropower	Other
Inland Empire Utilities Agency	3.5 MW (in operation)	1 MW (in operation)	-	1.5 MW food waste cogeneration (in operation)
Irvine Ranch Water District	365 MWh/year (in operation)	-	-	1 MW biosolids energy recovery facility (MWRP plant) (planned)
El Paso Water	-	-	-	Combined Power and Heat systems (planned)
Washington Suburban Sanitary Commission	4 MW (in operation)	29.4 MW (in operation)	2,000 MWh/year (in operation)	Water Resource Recovery Facility Bio-Energy Project (design)
Orange Water and Sewer Authority	up to 5 MW (under evaluation)	-	Future evaluations	Biogas-to-energy project (under evaluation)
Toronto Water	86 kW (in operation)	Under evaluation	-	4 MW Biogas (in operation)
Philadelphia Water	248 kW (in operation)	-	-	5.7 MW Cogeneration (in operation)
Alameda County Water District	286 to1500 kW (in operation and under evaluation)	Under evaluation	In-conduit hydropower (under evaluation)	Fuel Cells (under evaluation)
San Bernardino Valley Municipal Water District	Under evaluation	-	1,059 kW (under construction)	-

Utility	Solar	Wind	Hydropower	Other
Santa Clara Valley Water District	260 KW and 248 KW PV solar (local water utility project); 400 kW and 700 kW allocated from grid utility* (in operation)	-	In operation	-
San Diego County Water Authority	1 MW at TOVWTP and 0.6 MW in office buildings (in operation)	-	4.5 MW of in-conduit hydropower (Rancho Peñasquitos); 40 MW of pumped energy storage (Lake Hodges) (in operation)	-
Eastern Municipal Water District	5 MW (in operation)	-	Nine 60-kw microturbines (in operation)	Fuel Cells (in operation)
Metropolitan Water District of Southern California	5.5 MW (in operation)	-	131 MW (in operation)	-

*through the Power and Water Resources Pooling Authority (PWRPA)

3.2 ENERGY STORAGE OPTIONS

3.2.1 Battery energy storage

To address the challenges associated with the deployment of renewable energy and the continuous escalation of energy prices, Battery Energy Storage Systems (BESSs) have been considered for municipal behind- and in-front of-the-meter applications in municipalities to capture the immediate form of energy generated by renewables or other energy sources and store it in batteries until the energy is needed. Despite several mature technologies are available for battery energy storage, the market has shifted towards lithium-ion batteries due to cost and performance advantages. In addition to batteries, a BESS contains ancillary components such as inverters, battery management systems, thermal management systems, local monitoring panels/remote supervisory capability, power and communication interfaces, fire suppression systems, and HVAC. These components are often in completely modular designs, offering flexibility for installation and short construction cycles in municipal settings. These systems are often accompanied by software with the capability to provide real-time or semi-real-time optimization of the assets based on algorithms developed from historical load profiles, electricity charges, time of operation, weather forecasts, and facility operational constraints. In addition, the software determines battery degradation rates based on various operating and environmental conditions; forecasts and optimizes the consumption, production, storage, or sale of energy; provides remote monitoring of distributed energy resources (DERs) integrated with BESS, tariff management, demand control, and self-consumption; plans optimal operation of the DERs with variable price signals from the market; and leverages weather forecasts to anticipate black-outs and other contingencies.

To date, a growing number of water utilities have deployed BESS projects at their sites and provide a diverse perspective on the type of BESS solutions and integrated DERs, value streams, geography, energy markets, project financing, and partnership models. These BESS projects feature battery solutions with storage capacities that range from 250 kW to approximately 7 MW interconnected with the grid, alone or in combination with other renewable sources (e.g., cogeneration, photovoltaic, wind, etc.) (Table 3-3). Most BESSs connecting to the utility grid must adhere to the interconnection standards and requirements of the local electric grid and vary depending on the behind-the-meter or in front-of-the-meter configuration, the characteristics of the local grid, and the electric system arrangement at the utility. Owners and developers of BESSs must comply with a series of regulations and permits that meet all applicable industry standards and codes, and are required to comply with existing local permits and regulations associated with project construction and the operation of the facility (e.g., land use and zoning laws, building and municipality permits, air and water quality permits, waste program permits, etc.) to limit environmental and human health impacts.

Table 3-3 Selected BESS projects planned or implemented at water and wastewater utilities

Utility	BESS Size	Tangible Benefits	Cost Savings* ($/year)	Status
Inland Empire Utilities Agency, CA	4 MW 8 MWh**	Peak demand and tariff management	$55,000- $230,000	In operation
Irvine Ranch Water District, CA	7 MW 34 MWh**	Peak demand and tariff management; Local Capacity Requirements Program Participation (Southern California Edison (SCE))	$500,000	In operation
Long Beach Water Department, CA	0.5 MW 3 MWh	Peak demand and tariff management; Local Capacity Requirements Program Participation (SCE)	$150,000	In operation
Napa Sanitation District, CA	1 MW 2 MWh	Peak demand and tariff management	$110,000	In operation
Orange County Sanitation District, CA	26 MWh	Peak demand and tariff management; Local Capacity Requirements Program Participation (SCE)	$400,000	Under design
San Diego County Water Authority, CA	1 MW 2 MWh	Peak demand and tariff management	$100,000	Under commissioning
Atlantic County Utilities Authority, NJ	1 MW 1 MWh	Peak Load Contribution Reduction; Frequency Regulation Market Participation (PJM)	$150,000	In operation
University Area Joint Authority, PA	1.5 MW 1.5 MWh	Frequency Regulation Market Participation (PJM)	$80,000	In operation
Suez New Jersey, NJ	1 MW 0.329 MW	Peak demand and tariff management; Frequency Regulation Market Participation (PJM)	N/A	Under design

*Anticipated; **Aggregated

BESS implementations at water and wastewater utilities are anticipated to provide new opportunities for load balancing to address the cost associated with high rate peak power consumption and related demand and peak load contribution charges. BESSs are, in fact, able to store additional energy purchased from the grid during cheap tariff rate periods (e.g., off peak periods) and then release it during periods of high tariff rates (tariff management) and demand charges (peak load management).

Energy storage may also generate income opportunities for water utilities participating in electric utilities' Local Capacity Requirements programs or demand response programs that pay customers when demand is lower during high peak demand periods. Water utilities can also gain revenue by participating in real-time energy markets or by energy arbitrage, allowing storage of energy in periods of low energy prices and the opportunity of selling energy back when energy price is high. For some municipalities, BESS are also installed to be part of grid frequency regulation programs by responding to grid signals to balance in real time local grid demand and supply. BESSs in the municipal sector can, therefore, provide grid services and help stabilize the energy grid, maintaining power quality when peak demands overwhelm the power utility systems or transients occur in the network. Table 3-3 summarizes the cost savings anticipated for selected water utilities through different value streams, including those related to peak demand, tariff management, and reduction of the peak load contribution.

BESSs also have the potential to overcome the availability and intermittency challenges of power from renewable sources and prevent curtailment of periods of oversupply by storing or smoothing renewable energy flows and then releasing energy when the renewable sources are not available. Battery storage can effectively increase utility resiliency and energy reliability, as it supports water utility energy loads by providing backup power during significant power outages or other emergency situations. These energy storage projects present opportunities for developers, investor-owned utilities, and state governments to meet renewable energy goals, make better use of solar and wind resources, and reduce dependence on fossil fuels.

Various financing structures support these BESS deployments, including private-public partnerships, incentives from local electric utilities or regional public utilities (e.g., the California Public Utilities Commission (CPUC)'s Self-Generation Incentive Program (SGIP)), and grants from state organizations, as shown in Table 3-4. In particular, energy storage developers and battery solution providers are generally responsible for the capital investment for the project, and either support or control the operation through the project lifetime. Such partnerships are often based on performance-based service charges and shared savings models, which represent minimal risk for the municipal agencies. As an example, estimated financial benefits from BESS implementation in selected case study utilities are presented in Table 3-3.

Table 3-4 Project funding opportunities and developers for selected BESS projects

Utility	Project Developer	Financial Model	Grants/Incentives
Inland Empire Utilities Agency, CA	Advanced Microgrid Solutions	20-year energy management services agreement with guaranteed savings	Self-Generation Incentive Programs (SGIP) Grant
Irvine Ranch Water District, CA	Advanced Microgrid Solutions	10-year energy management services agreement with guaranteed savings	SGIP Grant; California Energy Commission (CEC)'s Electric Program Investment Charge Funding
Long Beach Water Department, CA	Advanced Microgrid Solutions	10-year energy management services agreement with guaranteed savings	SGIP Grant
Orange County Sanitation District, CA	Advanced Microgrid Solutions	10-year energy management services agreement with guaranteed savings	Southern California Edison Incentive
Napa Sanitation District, CA	Tesla, NextEra Energy	5-year PPA contract on a beta facility and a proof of concept project based on a shared savings model	SGIP Grant ($1.9M)
San Diego County Water Authority, CA	ENGIE Storage Services	10-year power efficiency agreement with shared savings	SGIP Grant ($1M)
Atlantic County Utilities Authority, NJ	Viridity Energy Solutions	10-year lease agreement based on a shared savings model	New Jersey Board of Public Utilities' Grant ($300K)
University Area Joint Authority, PA	PACE Energy, RETTEW	30-years PPA lease agreement with provisions at year 6 and 20	None

3.2.2 Pumped hydroelectric energy storage

Pumped storage is an alternative energy storage solution where energy is stored and generated by moving water between two reservoirs located at different elevations. At times of low electricity demand, when energy is inexpensive or renewable supplies exceed demand (e.g., night or on weekends), the excess energy is used to pump water to an upper reservoir; during periods of high electricity demand or cost (e.g., peak time periods), the stored water is released through turbines from the upper reservoir into the lower one generating clean energy through the operation of turbines. No water consumption is expected in the exchange between the reservoirs.

In California, a few utilities have considered pumped energy storage as part of their energy portfolio or to offset some of their operational energy cost by supporting the local electric grid (Table 3-5).

Table 3-5 Selected pump hydroelectric energy storage projects

Utility	Location	Elevation Difference	Pump Storage Facility Size	Status
San Diego County Water Authority/ City of San Diego	San Vicente	N/A	500 MW (8 hrs) 4,000 MWh (day)	Planned
San Diego County	Lake Hodges/ Olivenhain Reservoir	770 ft	40 MW	Operational since late 2012
Alameda County Water District	Avalon Tank/Rancho Higuera	208 ft	172 kW /135 MWh	Option evaluated
Nevada Hydro Company/ Elsinore Valley Municipal Water District (LEAPS)	Lake Elsinore	180 ft	500 MW (12 hrs)	Planning/FERC approval

It is recognized that the major challenges in implementing pumped energy storage projects in California are associated with the Federal Energy Regulatory Commission (FERC) license process and by the long construction cycles that are typical of such installations. In some cases, building a financial case for these projects may be challenging. As an example, at the Alameda County Water District, the Rancho Higuera to Avalon pump storage options was considered feasible, but the payback period was determined to be approximately the equipment life expectancy.

3.2.3 Other energy storage alternatives

Additional energy storage alternatives that have been considered by water (and electric) utilities in California include the following:

- **Compressed air energy storage**. Burbank Water & Power is interested in developing a large-scale (1,000 MW scale) compressed air energy storage project through partnerships with other utilities in their regional grid. Similarly, LADWP is exploring compressed energy storage in the Utah area with 160 MW units (larger than 8 hour).
- **Energy storage with flow batteries**. LADWP is comparing simultaneously a vanadium flow battery versus a lithium-ion battery in a pilot project in one of the buildings in downtown Los Angeles. The system is a 100 kW – 4 hours for each battery (so 400 kWh), so for a total of 800 kWh among the two batteries. The Vanadium battery is considered safer from a fire safety perspective and the lifecycle is longer (20+ year) compared to the typical 10 year of a Li-ion. However, the vanadium flow battery has lower energy density than the Li-ion counterpart. Although it is safer from a fire perspective, the flow battery still needs some sort of fire protection equipment being an electrical system. The flow battery cost is typically 1.5 times the cost of a Li-ion battery

In addition to compressed air energy storage and flow batteries, thermal energy storage and flywheel, are also being explored, however no implementations of these technologies in the water sector are reported in the literature.

3.3 ENERGY EFFICIENCY OPTIONS AND COST MANAGEMENT STRATEGIES

Energy efficiency and cost management strategies are being largely implemented by water and wastewater agencies, including those reviewed for this TM. Some of the key alternative implemented are:

- **Energy audits** have been conducted to assess facilities energy demand and costs and are intended to provide strategies to reduce energy demand and energy-related costs. Recommendations are typically related to equipment and systems energy efficiencies, and treatment optimization. Energy audits are typically conducted by energy utilities but could be contracted to third-parties or even completed in-house.

- **Equipment and Systems Efficiency:** for water districts, energy efficiency measures can be implemented at the conveyance system and treatment system level, and to reduce energy consumption of administration support facilities.

  For water distribution and conveyance, innovative opportunities are available to make the operation of a pumping system more energy efficient and environmentally sustainable and include a variety of innovative design (e.g., use of variable frequency drives (VFDs) when applicable), operational (e.g. pump sequence that favors the use of most efficient pumps), and maintenance (e.g., predictive rather than reactive maintenance schemes).

  For water treatment, the selection of energy efficient processes (e.g., high-demand processes such as ozone generation where aging equipment can be replaced by higher-efficiency systems) and the optimization of treatment processes or chemical feed pumps can help reducing the use of energy and related cost.

  For administrative and support facilities, energy efficiency measures typically include lighting replacement with light-emitting diode (LED) and HVAC optimization. Programs can also be implemented around vehicle fleet to reduce overall fuel consumption or switch to electrical vehicles to eliminate GHG emissions from vehicle fleet operations.

- **Treatment Process Optimization:** Process optimization is used to reduce overall energy consumption of a treatment process. Given a set of treatment and operational goals, some process can be optimized using specific control strategies to reduce energy consumption. At a water treatment plant, optimization efforts usually focus on ozone dose reduction, and filtration optimization to lower the backwash frequency. At a wastewater treatment plant, energy optimization efforts tend to focus on the aeration process. Biosolids digestion can also be optimized to maximize biogas generation when reciprocating engine co-generation is implemented.

- **Data Collection and Management:** The design of a successful data strategy that supports energy management decisions and other business goals start from the identification of the energy and non-energy related data of importance for energy management, the data acquisition, data transfer, and data storage infrastructure. In addition, data management solutions and analytics for generation of business intelligence, high quality display of data outcomes, and communication of results to the internal and external stakeholders are also an integral part of data management that play a role for energy efficiency and optimization. For example, sub-metering of energy consumption data has also been proven to be invaluable in understanding the details of large facility energy usage and assist facilities managers in optimizing each process and equipment for energy cost reduction and energy efficiency. Energy dashboards also provide an effective and consistent mean by which performance can be displayed and communicated to a utility's management, administration, operation, and maintenance personnel. The dashboard is typically a web page (intranet or internet) connected to a data historian that translates real-time and historic data into useable business information. Various energy dashboards are commercially available or have been developed in-house for different water and wastewater utilities worldwide.

- **Energy cost management strategies** are implemented to reduce associated with the use of energy for water/wastewater distribution/conveyance and treatment. One of the most common strategy is to shift part of the utility energy demand to off-peak hours, when feasible, to take advantage of the cheaper electric tariff rates and avoid high demand charge from the electric utilities. Opportunities to shift the electrical load to low tariff periods can be applied to pumping systems, filter backwashing, chemical feed pumping, sludge handling processes, etc.

- **Participation to electric utility programs and rates optimization:** Demand Response (DR) Programs have been developed by electric utilities to promote an efficient distribution of electricity to end-users while providing incentives for demand reduction. Water utilities are increasingly cooperating with the electricity supplier's DR programs to manage their energy consumption and to balance supply and demand in real-time.

  Rates structure can be negotiated with power providers in order to lower energy costs. In general, it is critical that the electric utility tariff rates and programs are well understood to make the project economical and increase its benefits. In California, for example, several electric tariff alternatives are available, however, the availability of these tariffs and their structures can change over time. Thus, utilities should conduct their feasibility studies on various renewable energy or energy management strategies alternatives to evaluate the project economics and the potential impact on project benefits and revenues of multiple tariff scenarios.

A summary of the energy sustainability management elements related to energy efficiency and cost optimization identified in the peer-review process is provided below in Table 3-2.

Table 3-6 Energy efficiency and cost optimization strategies at selected utilities

Utility	Energy Audits	Equipment/ System Efficiency Programs	Treatment Process Optimization	Data Collection and Management	Energy Cost Optimization	Rate Optimization	Demand Response
Inland Empire Utilities Agency	Yes	Yes	Yes - digesters	Yes – via submetering and dashboards	-	Yes	Yes
Irvine Ranch Water District	Yes	Yes	Yes – aeration	-	-	-	-
El Paso Water	-	Yes	Yes – aeration, new ozone generators	-	-	Yes	-
Washington Suburban Sanitary Commission	Yes	Yes – fleet analysis	-	Yes – sub-metering and dashboards	-	Yes	-
Orange Water and Sewer Authority	Yes	Yes	Yes – nitrification	Yes – system-wide energy model	Yes – reduce peak demand	-	-
Toronto Water		Yes	Yes – aeration	Yes – real-time conveyance optimization tool	Yes – real-time conveyance optimization tool	-	
Philadelphia Water	Yes	Yes	-		Yes – off-peak pumping	-	-
Tampa Bay Water	Yes	Yes	-	Yes – collection of energy data	-	-	-
Central Arizona Project	-	-	-	-	Yes – buy cheap solar power from California at solar peak-hours, edging		
Santa Clara Valley Water District	Yes	Yes	-	-	-	-	-
Eastern Municipal Water District	Yes	-	-	Yes	Yes	Yes	-
Metropolitan Water District of Southern California	Yes	Yes	-	-	-	-	Yes, previously – no longer participating

3.4 OTHER ENERGY MANAGEMENT STRATEGIES ADDRESSING UTILITY CLIMATE ACTION PLANS

Other energy management strategies aimed at addressing climate action plans are all focused on GHG reduction and are detailed below.

- **Alternative Power Sources:** Alternative power sources allow utilities to increase consumption of clean energy, hence decreasing overall GHG emissions. Options available include:
  - Direct Access (DA) via an Electric Service Provider with cleaner power portfolio,
  - Offset power demand with renewable power sources via a power purchase agreements (PPA), if the renewable energy generation facility is owned and operated by a third party or installing and operating agency-owned facilities.
- **Water conservation measures** may allow water utilities to reduce their overall energy consumption, and hence their GHG emissions.

4.0 LESSONS LEARNED FROM UTILITY WORKSHOPS

4.1 WORKSHOP NO. 1 – LONG BEACH WATER DEPARTMENT

The meeting minutes and lessons learned from the workshop held at Long Beach Water Department are attached in Appendix A.1.

4.2 WORKSHOP NO. 2 – INLAND EMPIRE UTILITIES AGENCY

The meeting minutes and lessons learned from the workshop held at Inland Empire Utilities Agency are attached in Appendix A.2.

4.3 WORKSHOP NO. 3 – SAN DIEGO COUNTY WATER AUTHORITY

The meeting minutes and lessons learned from the workshop held at San Diego County Water Authority are attached in Appendix A.3.

4.4 WORKSHOP NO. 4 – LOS ANGELES DEPARTMENT OF WATER AND POWER

The meeting minutes and lessons learned from the workshop held at Los Angeles Department of Water and Power are attached in Appendix A.4.

4.5 WORKSHOP NO. 5 – CALIFORNIA DEPARTMENT OF WATER RESOURCES

The meeting minutes and lessons learned from the workshop held at California Department of Water Resources are attached in Appendix A.5.

5.0 SUMMARY OF FINDINGS AND RECOMMENDATIONS

5.1 SUMMARY OF FINDINGS

Some of the key findings from this TM are the following:

- Only a limited number of water utilities develop energy master plans or have energy and sustainability targets that drive the selection of energy management strategies over a given time horizon.
- Energy management plans are utility- and goal-specific, however they often follow similar approaches used for evaluation and prioritization of energy sustainability initiatives.
- A number of energy management strategies and renewable energy options have been considered by water utilities to reduce energy costs and achieve more sustainable operations.
- An array of renewable energy options is now considered and deployed at water utilities, often through advantageous PPA structures with project developers.
- Battery energy storage options are now being integrated into a water utility energy portfolio to provide opportunities for cost savings, operational flexibility and better management of on-site renewable options.
- Other energy efficiency and cost management strategies are largely helping utilities in achieving energy reduction and cost savings and can be applicable to conveyance/distribution pumping as well as treatment processes.
- Understanding energy use, generation and wastage at water utilities is critical and can be improved through advanced data management options, conducting energy audits and improving data acquisition processes through sub-metering.
- Communication with the electric utilities and understanding of electric utility programs is critical for a cost-effective management of energy use and generation at water utilities.

5.2 PROPOSED ENERGY SUSTAINABILITY MASTER PLAN OUTLINE

Based on the peer-review and understanding of the needs from the Metropolitan, a proposed outline for the Energy Sustainability Plan is presented below.

	EXECUTIVE SUMMARY
1.0	**Energy Sustainability Management Plan Goals and Objectives**
2.0	**System Description**
2.1	Energy Demand Characterization
	2.1.1 Existing Energy Demand
	2.1.2 Future Energy Demand
2.2	GHG Emissions Characterization
	2.2.1 Existing GHG Emissions
	2.2.2 Future GHG Emissions
3.0	**Planning Assumptions**
3.1	Energy Costs
	3.1.1 Wholesale
	3.1.2 Retail
	3.1.3 Energy Cost Scenarios
3.2	GHG Emission Costs
3.3	Scenarios and Planning Horizon
4.0	**Existing Energy Sustainability Management Initiatives**
5.0	**Renewable Energy Options to Achieve Energy Sustainability Goals**
5.1	Potential Energy Sustainability Projects (from TO 5 TM 2)
5.2	Projects Evaluation
	5.2.1 Methodology
	5.2.2 Assumptions
	5.2.3 Evaluation
5.3	Implementation Plan/Roadmap
6.0	**Conclusions and Recommendations**

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APPENDIX A

Workshop Meeting Minutes

Appendix A WORKSHOP MEETING MINUTES

A.1 WORKSHOP NO. 1 – LONG BEACH WATER DEPARTMENT

A.2 WORKSHOP NO. 2 – INLAND EMPIRE UTILITIES AGENCY

A.3 WORKSHOP NO. 3 – SAN DIEGO COUNTY WATER AUTHORITY

A.4 WORKSHOP NO. 4 – LOS ANGELES DEPARTMENT OF WATER AND POWER

A.5 WORKSHOP NO. 5 – CALIFORNIA DEPARTMENT OF WATER RESOURCES

APPENDIX A.1

WORKSHOP NO. 1 – LONG BEACH WATER DEPARTMENT

Appendix A.1

Workshop with Metropolitan Water District, Long Beach Water Department and Stantec

Energy Sustainability Plan – Development of Renewable Energy Options

Date/Time:	March 15, 2019 / 11:00 AM
Place:	2950 Redondo Avenue, Long Beach, CA 90806
Attendees:	Shawn Bailey, Greg de Lamare, Tim Hutcherson, Ha Nguyen, Austen Nelson, Courtnay Roland, Heather Collins, Albrecht Grimm, Simon Calvet, Kyleen Marcella, Carla Cherchi, Yung-Hsin Sun, Tai Tseng, Yan Zhang, Skip Fulton, Kenny Chau
Distribution:	See Attendees

Welcome and Introductions (S. Calvet)

a. Meeting Purpose – The purpose of this meeting is to foster knowledge sharing on the Long Beach Water Department's (LBWD) Energy and Sustainability Management practices to inform Metropolitan Water District's (MWD) Energy and Sustainability Management Plan development effort

b. Workshop Participants Introduction (see Attendees list)

Overview of MWD's Renewable Energy Options Development Effort (G. de Lamare)

c. MWD's objective is to develop an Energy Sustainability Plan to position Metropolitan as a leader in energy sustainability.

d. MWD's interest includes:

   i. Review of Energy Sustainability Plans
   ii. Identify and evaluate Renewable Energy and Energy Storage opportunities:
      1. Renewable energy (solar, in-conduit hydropower)
      2. Energy storage systems (battery energy storage and pump storage)
      3. Emerging technologies
      4. Energy efficiency measures
      5. Operational strategies to manage energy demands and respond to new tariffs
      6. Efforts to reduce GHG emissions and other sustainability practices

LBWD's Battery Energy Storage Project Overview (T. Tseng, Y. Zhang)

e. The overview provided on the battery energy storage project is summarized in Appendix and includes information on the following:

   i. Drivers for battery energy storage at LBWD
   ii. Funding and partnership model
   iii. BESS solution design and grid interconnection
   iv. Operation and performance evaluation
   v. Anticipated benefits

f. Some relevant aspects discussed include:

i. **Project goal and value**: LBWD aims at mitigating the impacts that the changes anticipated in the California energy market may have on the utility financials and operations. LBWD, initially under SCE's TOU-BIP (around 10 cents/kW), started receiving TOU-BIP notifications of interruption at times that were no longer traditional and creating operational challenges. The alternative of leaving the SCE's TOU-BIP, therefore under a higher rate tariff structure, represented a cost disadvantage for LBWD, therefore the utility was looking for alternatives that could address a change in tariff with marginal operational cost and customer rate increases. In pursuing these objectives, the utility has considered a BESS that could help them achieve cost savings and maintain the operational flexibility for operators and staff.

ii. **Project sole source versus release of RFP**: The release of an RFP was a public contracting requirement from the City of Long Beach. Two proposers (AMS and STEM) sent their application. The selection of AMS was based on their experience and previous installations in water utilities and on the operational flexibility that they were able to guarantee to the plant.

iii. **Funding and partnership model**: Advanced Microgrid Solutions (AMS) proposed an agreement based on a shared savings model with no capital outlay for the utility. The agreement lays out AMS' full responsibilities in relation to covering the capital expenses for the project, providing system design, equipment procurement, electrical, construction, and O&M work. The contract is structured on a monthly service fee paid to AMS to manage the system, with a $55,000 per year guarantee of electrical savings. All the savings above $150K per year will be equally shared between AMS and LBWD. The total cost of the project was estimated at approximately $2M. The cost was entirely covered by AMS, and partially offset by a SGIP grant of $400K.

iv. **Role of union in BESS project development**: It is important to understand the implications of the City's requirements on prevailing wage for construction projects and role of labor union staff on the BESS project. The implications of such requirements should be well understood in relation to the BESS projects. Often, developers external to the utility use third-party sub-contractors for the construction work, which may conflict with the City requirements. There may be a possibility of having a project not classified as a public work construction, but still complying with the labor union requirements.

v. **Use of battery for resilience purposes (UPS function)**. Uninterruptible power supply (UPS) capabilities are not yet embedded in the BESS project. Such value stream would have required a different (larger) battery design.

vi. **Reconciliation of benefits at the end of the year**: Although the savings achieved are calculated by AMS, LBWD plans on an independent analysis of the data to determine the savings and to make any necessary reconciliation with AMS at the end of the year.

vii. **Battery system impact to water utility operations**: No negative impacts of the BESS are observed to the water utility operation. An emergency generator was provided by AMS during the interconnection process of the BESS with the electric grid, to avoid power outages to the main treatment plant.

viii. **SOPs for emergency response**: AMS provided a SOP with emergency operating procedures for LBWD's staff. In general, LBWD staff is able to disconnect the BESS in case of emergency and, in case of fire, staff is requested to call 911.

ix. **Maintenance of BESS**: AMS provides quarterly maintenance of the BESS system. Their software also manages the loads to mitigate demands/rates so LBWD staff has minimal involvement in operations.

Site Visit of Battery Energy Storage System

g. A picture from the site visit is presented below. The system is a 500-kW system and occupies about 3-4 parking spaces.

Discussion on LBWD's Energy Management and Sustainability Efforts (T. Tseng)

h. **Solar Project**: LBWD evaluated the feasibility of installing a PV solar at the groundwater treatment plant. However, in order to be cost-effective, the system would have required a large footprint that is not available at the site. Such larch PV solar installation would have interfered with the day-to-day operations. Therefore, the installation of solar was only considered for administrative buildings at different sites and are not integrated with the BESS.

i. **Pump energy storage**: The pumping operation from wells to treatment plant to storage reservoirs are scheduled such that pumping during on-peak times is minimized.

j. **In-conduit hydropower**: Initial evaluations for the installation of in-conduit hydropower systems were made at sites that were considered appropriate for such applications (e.g., flow, head, etc.). However, due to the criticality of the pipe infrastructure for the delivery of water to customers, the project was currently put on hold and will be potentially re-evaluated in the future.

k. **Other key energy management and energy efficiency practices**: Filter backwashing is scheduled outside the peak-period hours. Pump efficiency evaluations are performed every 2 years from Edison.

l. **Efforts to reduce GHG emissions and other sustainability practices**: The City has goals of GHG reduction in place and LBWD is complying with the City mandates (e.g., use of electric cars).

m. **Efforts to reduce grid energy purchases and respond to rate structure changes**: The BESS and the pumping operation of the plant are scheduled such that pumping mostly occurred during mid- and off-peak times.

Stantec

Appendix A.1

Action Items

No.	Item	Owner
1	Schedule meeting with IEUA	Stantec
2	Schedule meeting with DWR	Stantec

The meeting adjourned at 1:30 PM

The foregoing is considered to be a true and accurate record of all items discussed. If any discrepancies or inconsistencies are noted, please contact the writer immediately.

Stantec Consulting Services Inc.

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Long Beach Water Department, CA: Battery Energy Storage Project

Overview

Location	Long Beach, California
Flows	35 MGD (average); 80 MGD (peak)
Power Demand	2,600 MW (on-peak max), 800 kW (mid-peak max)
Energy Cost	$1,500,000/year
Investor-owned Utility	Southern California Edison (SCE)
Battery System	Tesla – PowerPack 2.0
Battery Size	0.5 MW (3 MWh)
Integrated DERs	None
Partners/Developers	Advanced Microgrid Solution (Developer); Macquarie Capital (Owner)

Background

Long Beach Water Department (LBWD) provides its customers with a clean, high-quality and reliable supply of drinking water. The Water Department oversees a large network of water infrastructure that provides water to Long Beach residents through approximately 90,000 individual water connections. The Groundwater Treatment Plant has a capacity of 62.5 million gallons of water per day. The plant receives water pumped from 28 source wells (in unique energy accounts with Southern California Edison), which then flows by gravity through multi-stage treatments, including coagulation, flocculation, sedimentation, chlorine disinfection, and filtration. The water is then pumped from an onsite 13 MG storage reservoir to the 70 MG Alamitos storage tank farm through 11 booster pumps (100 to 300 hp), before final distribution to customers. The plant's load peaks at 2600 kW during on-peak times and it is maintained below 800 kW during mid-/off-peak times, with the majority of the energy demand utilized for the operation of the 11 booster pumps. The peak demand charges at LBWD represent approximately 50% of the monthly energy bill.

Due to the availability of the large onsite storage and the current operational strategy, LBWD is able to optimize the plant's energy consumption by taking advantage of the gravity flows during the day (when tariff and demand charge rates are the highest) and operating the energy-intensive booster pumps starting from 6pm, at the shift between the peak to mid-peak tariff period. Until recently, the plant was under a Time-of-Use Base Interruptible Program (Schedule TOU-BIP) with 30-minute response time and 500 kW of front service load limit. Under this program, SCE sent notification to LBWD to reduce its electrical usage to their specified firm service level within 30 minutes of the notification being sent. LBWD is currently under SCE's TOU-8-B.

Drivers for Battery Energy Storage and Value Proposition

LBWD aims at mitigating the impacts that the changes anticipated in the California energy market may have on the utility financials and operations. Although the low tariff rates associated with the TOU-BIP (around 10 cents/kW), recently TOU-BIP notifications of interruption were sent at times that were no longer traditional due to the effect of the CAISO's duck curve. Earlier interruptions occurred during peak periods, at around 2-3 pm, while were recently received at around 7pm when the availability of staff, to make critical process changes, was limited. In addition, an immediate stop of the flows from 28 wells was challenging and might have created a high risk of overflows, and the onsite storage is near its full capacity. Lastly, the plant supplies the Alamitos storage tanks through a peak flow of 120 MGD (80 MGD from the plant and 40 MGD from the Metropolitan Water District connection) at night while allow the tanks to drain during the day, to maintain an acceptable water turnover in the storage tanks. Alteration of these operating strategies might have impact on the water quality to customers.

The alternative of leaving the TOU-BIP represents a cost disadvantage for LBWD, therefore the utility was looking for alternatives that could address TOU-BIP challenges with marginal operational cost and customer rate increases. LBWD's goal is also to maintain operational flexibility to treat and distribute water to customers. In pursuing these objectives, the utility has considered a BESS that could help them achieve cost savings and maintain the operational flexibility for operators and staff. A critical requirement for the BESS project was a minimal impact to the operations.

Funding and Partnership Model

LBWD released through a competitive process a Request for Proposal to build an advanced energy storage system for the department's Groundwater Treatment Plant. The project was awarded to Advanced Microgrid Solutions (AMS) who proposed an agreement based on a shared savings model with no capital outlay for the utility. The agreement lays out AMS' full responsibilities in relation to covering the capital expenses for the project, providing system design, equipment procurement, electrical, construction, and O&M work. The contract is structured on a monthly service fee of $4,000 paid to AMS to manage the system, with a $55,000 per year guarantee of electrical savings. All the savings above $150K per year will be equally shared between AMS and LBWD. The performance savings were calculated based on the TOU-BIP structure and on the current utility energy profile. LBWD provided the developer with 1 year-15 min interval data of the most recent year of the plant to perform the feasibility study, given its steady operations.

The total cost of the project was estimated at approximately $2M. The cost was entirely covered by AMS, and partially offset by a SGIP grant of $400K.

The agreement with AMS includes various end-of-contract options for LBW after the 10 years operation, which include the following:

- Purchase of the BESS system;
- Extension of the contract with AMS for O&M;
- Decommissioning of the BESS and site restoration.

The contract also includes a number of termination clauses that are based on occurrence of undesirable events (e.g., non-meeting the $55K minimum savings performance, LBWD discretion, etc.). In case the minimum performance savings are not met, that cost would be reduced by the $4,000 monthly service fees. The early contract termination fee to AMS would be $1.4M if termination occurs on the first year and progressively decreases down to $400K at the 10th year.

LBWD's project is part of a LCR (local capacity resource program) contract with SCE for developing 200 MW of behind-the-meter battery energy storage projects. The energy storage project will be part of a series of behind-the-meter installations in the Long Beach area that will provide grid services to SCE, in addition to the financial and operational benefits to LBWD.

BESS Solution Design and Grid Interconnection

The project features a 0.5 MW (3,000 kWh-6 hours) battery energy storage system, utilized for 0.5 MW (2 hours) capacity by LBW for the energy plant needs, and 0.5 MW (4 hours) by AMS for the LCR program with SCE. The system includes Tesla batteries (Powerpack Generation 2) and inverters. The BESS sits on a concrete slab that is placed in a parking lot near the plant perimeter, as showed in the aerial view of Figure A-1. The location of the BESS was selected based on specific criteria, including the following:

- Minimal presence of underground utility services or piping;
- Lack of interferences with daily activities and operations at the plant;
- Proximity to the electrical switchgear center; and
- Absence of truck traffic (e.g., far from chemical storage tanks).

The interconnection occurs at a 480V substation. No improvement on the grid or the utility side was needed to support the interconnection process. An arc flash study to evaluate the hazards and risks in relation to electrical systems was not specifically performed for the BESS project, but old arc flash studies performed on the plant were consulted by the developer. To perform feasibility of the interconnection process, no specific modifications to the switchgear or field outage tests were performed; however, a 10-hour outage was experienced for the interconnection and a temporary mobile (portable) generator was used in outdoor area to support the entire process (e.g., a continuous process that allows the utility to continue its plant operation).

Figure A-1. Aerial view of the LBWD's BESS.

In case of plant outage and power loss from the grid, AMS will receive a hard signal from LBWD and the battery operations will be immediately discontinued. At this time, the operational strategy envisioned will not provide any islanding capability to the BESS; in the future, different control strategies and a different interconnection agreement with SCE may allow the BESS to have an islanding functionality.

In addition to the interconnection requirements, LBWD needed to comply with all the City permits, to which the developer requested approval (e.g., from fire department, etc.). No specific noise protection requirements are needed considering the location of the BESS in an industrial area.

Project Development Project

The agreement anticipated that approximately one-month period was needed from beginning of construction to final inspection of the system, according to the timeline provided in Figure A-2. However, the project was delayed due to the ongoing interconnection process (4 months) and to meet the City requirements on project construction. After the final inspection, the system was commissioned, and came online in December 2018 meeting the SGIP incentive requirements.

Task	Duration
Preliminary Design (CD30)	2-4 weeks
Utility Interconnection	4-6 months
Detailed Drawings (CD70) & Apply for Permit	6 weeks
Permitting	10-12 weeks
Design Complete (IFC)	2 weeks
Contractor Selection & Mobilization	4 weeks
Procurement	4-6 months
Construction & Commissioning	8-11 weeks

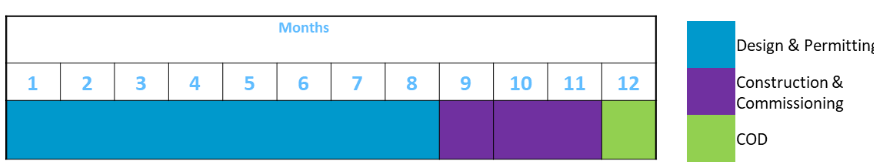

Figure A-2. Projected timeline of BESS implementation at LBWD.

Performance Evaluation

A dashboard developed by AMS compiles information from all the generation sources, the BESSs, the imported energy on a real-time basis and monthly summary information on the savings achieved. The dashboard has also the ability to show California's energy mix from CAISO (e.g., geothermal, solar, etc.) on a real-time basis. An example of the AMS dashboard interface is provided in Figure A-3. The developer provides an annual report with year to date savings, summary performance of the system, battery degradation information, etc. LBWD plans on making reconciliation of the savings estimation provided by the developer on a regular basis (e.g., every 6 months, yearly) through an independent set of calculations.

Figure A-3. AMS dashboard.

Anticipated Benefits

The initial feasibility study anticipated savings of up to $150,000 in annual energy savings to the City of Long Beach, and $1.9 million over 10 years at no upfront cost to the city. These savings are created through a unique combination of energy management and load optimization provided through AMS's data analytic platform. Given the full responsibility of the developer at different life cycle stages of the BESS implementation, no additional utility staff was required to support the project. The level of effort required to support the planning and design phase of the project was approximately 2 hours, every 2-3 weeks. More involvement of the utility staff was needed during construction as is typical for any onsite capital improvement projects.

APPENDIX A.2

WORKSHOP NO. 2 – INLAND EMPIRE UTILITIES AGENCY

Stantec

Appendix A.2

Workshop with Inland Empire Utilities Agency, Metropolitan Water District, and Stantec

Energy Sustainability Plan – Development of Renewable Energy Options

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Date/Time:	April 8, 2019 / 1:00 PM
Place:	6075 Kimball Ave, Chino, CA – Building B, Anza Conference Room
Attendees:	Pietro Cambiaso, Jesse Pompa, Shawn Bailey, Tim Hutcherson, Ha Nguyen, Austen Nelson, Courtnay Roland, Heather Collins, Albrecht Grimm, Salvador Heredia Ibarra, Simon Calvet, Kyleen Marcella, Carla Cherchi
Distribution:	See Attendees

Welcome and Introductions (S. Calvet)

a. Meeting Purpose – The purpose of this meeting is to foster knowledge sharing on the Inland Empire Utilities Agency's (IEUA) Energy and Sustainability Management practices to inform Metropolitan Water District's (MWD) Energy and Sustainability Management Plan development effort

b. Workshop Participants Introduction (see Attendees list)

Overview of MWD's Renewable Energy Options Development Effort (Ha Nguyen)

c. MWD's objective is to develop an Energy Sustainability Plan to position Metropolitan as a leader in energy sustainability.

d. MWD's interest includes:

   i. Review of Energy Sustainability Plans
   ii. Identify and evaluate Renewable Energy and Energy Storage opportunities:
      1. Renewable energy (solar, in-conduit hydropower)
      2. Energy storage systems (battery energy storage and pump storage)
      3. Emerging technologies
      4. Energy efficiency measures
      5. Operational strategies to manage energy demands and respond to new tariffs
      6. Efforts to reduce GHG emissions and other sustainability practices

IEUA's Energy Management Plan Goals (Pietro Cambiaso, Jesse Pompa)

e. **Goals of IEUA's Energy Management Plan**: IEUA focus is to achieve peak energy independence, thus independence from the grid during peak periods, when electricity costs are highest. The peak independence goal replaced the previous "gridless" by 2020 goal (i.e. achieve enough electricity generation on site that IEUA's facilities would be independent from SCE), which was no longer considered feasible at IEUA, because this would have required a daily export of energy back to the grid when generation exceeded demand and made the renewable energy projects economically unattractive. It is important to achieve goals that are realistic and feasible while providing cost effective solutions that will provide savings to IEUA.

The Energy Management Plan developed in 2015 should be considered a working document that will be updated and re-evaluated at appropriate times.

f. **Criteria for project selection and prioritization**: Various criteria are considered for project selection and prioritization at IEUA:

- Cost
- Potential for meeting compliance
- Performance
- Risk on agency or developer
- Sustainability

g. **Cooperation with the electric utility (SCE)**: IEUA's objective is also to become an asset to the electric grid and the State. Therefore, the intent is to cooperate with SCE, understand what they are allowed to do, and engage the electric utility early at each project development stage. It is also important that a person of reference is identified at the electric utility side that can follow the project from beginning to end.

h. **Cooperation with other partners**: Due to the varied portfolio of renewable and energy storage option onsite, IEUA established a thorough communication protocol between the various PPAs, the electric utility and other construction partners each of these projects may require.

IEUA's Facilities and Renewable Energy Projects (Pietro Cambiaso, Jesse Pompa)

i. **IEUA's Regional facilities:** Regional Water Recycling Plant No. 1 (RP-1), Regional Water Recycling Plant No. 4 (RP-4), Regional Water Recycling Plant No. 5 (RP-5), and Carbon Canyon Wastewater Recycling Facility (CCWRF). The biosolids produced at RP-4 and RP-1 are thickened, digested, and dewatered at solids handling facilities located at RP-1. Similarly, the CCWRF and RP-5 biosolids are treated at Regional Water Recycling Plant No. 2 (RP-2). The stabilized and dewatered solids are then transported to the Inland Empire Regional Composting Facility (IERCF) for processing into soil amendment.

j. **Energy Portfolio:** The total energy load of IEUA is 10 MW. The agency's energy portfolio is a combination of imported electricity from the grid and on-site generation, including:

- 3.5 MW of solar PV over 4 different facilities, each ranging from 600 kW to 1 MW, established through a PPA with SunPower, under a fixed energy purchased price;
- 1 MW of wind generation, under a PPA with Sunpower in one facility;
- 2.8 MW of fuel cells from FuelCell Energy in the RP-1 facility, discontinued in 2016 for issues associated with the digestor biogas cleaning system;
- Two-1.5 MW food waste cogeneration powering two engines, through a 10-year PPA (offline for a certain period of time);
- 580 kW engine at RP-2 with the generated biogas used as a fuel for boilers or, if in excess, sent to the grid; the engine was discontinued in 2015; and
- 2.5 MW of back-up diesel emergency generators.
- A total of 4MW (8 MWh) battery energy storage, divided at four different sites, under a shared savings agreement with Advanced Microgrid Solutions (AMS). AMS could not include IEUA's projects under SCE's Local Capacity Requirements (LCR) since Chino's area was excluded. As part of the site agreement, AMS compensates Sunpower (PPA on solar).

All the existing generation assets were installed at IEUA at different times and operate independently.

IEUA currently leases the RP-5 SHF property and equipment to Inland Bioenergy, LLC (IBE), who operates and maintains the facility with the goal of producing sufficient biogas to operate two 1.5 MW cogeneration engines. IEUA has the option to purchase all of the power purchased by the engines. Any excess power produced will be exported to SCE. Currently, RP-5 SHF only processes food waste in two anaerobic digesters. IEUA also encountered difficulties obtaining an interconnection agreement at RP-5 that would allow for export from the REEP ICEs. IEUA initially applied for an interconnection agreement for the ICEs in 2006 under SCE's biogas NEM program, but the agreement was never finalized because the ICEs were never commissioned. As a result, IEUA was required to submit a new application for interconnection under SCE's RES-BCT program, which would allow for exported electricity to be compensated as bill credits on IEUA's other SCE accounts.

IEUA purchases both electricity and natural gas from an Energy Service Provider (ESP) through the Direct Access (DA) program (at two facilities supplied by commodity energy from Shell). These services are procured via an agreement that has a one-year term. The term length is designed to allow the Agency flexibility to adapt to market changes.

k. Battery Energy Storage Projects: A summary of the battery energy storage project, including the drivers, funding and partnership model, implementation/interconnection details, performance evaluation and benefits are reported in the Appendix of this document.

Battery storage is a great option for predictable loads, not for unpredictable loads**.** Batteries also give opportunities to participate in Demand Response (DR) programs. The battery at RP-4 is required to be charged at least for its 75% by solar energy to receive the ITC incentive. Battery storage is kept as third party operated due to knowledge of energy management/operations strategy.

l. Evaluation of Savings: IEUA would prefer having the saving evaluation performed on a monthly basis, having quarterly meeting with other partners and performing a yearly reconciliation of savings with the different parties.

IEUA's Energy Efficiency and Cost Optimization Strategies (Pietro Cambiaso, Jesse Pompa)

m. Centralize data storage in SCADA: IEUA plan is to have all data in SCADA to improve its management, visibility and accessibility**.**

n. **Move budget for electricity** to the facility budget**.** This provides an incentive to manage energy efficiently at a facility level.

o. Participation to The Climate Registry for reporting of annual GHG emissions**.**

It was highlighted that no conflicts exist between water quality and energy management strategies implemented.

IEUA's Data Management Strategy (Pietro Cambiaso, Jesse Pompa)

p. **Data Management:** Data is acquired at each generation or storage source through meters opportunely installed at each location. The data from the solar facility are collected in SCADA, therefore AMS collects the data from SCADA and other plant meters to determine battery dispatch mechanisms.

q. **Energy Data Acquisition:** IEUA has submetering at all facilities, motor control centers (MCC), which cover all large (100-150 hp) and critical equipment.

r. **Data Display.** EnerNOC (a SCE authorized third-party DR provider), a private entity providing energy intelligence software that displays real-time electricity usage. In addition to facilitating DR events, EnerNOC software is used to track consumption from facility processes over time. The plan is to move all energy related data into SCADA.

s. **Energy Metrics**: The Agency has not yet found appropriate energy metrics to evaluate the energy process and portfolio (e.g. MWh/acre-foot is one that could be used).

Future Energy Management Opportunities Under Consideration (Pietro Cambiaso, Jesse Pompa)

t. **Renewable natural gas:** The Agency is considering to potentially implement renewable natural gas in the future.

u. **Biogas Cleaning:** Although IEUA is considering biogas cleaning options, the size of the system seems to be not big enough to make the project economical.

v. **RECs:** IEUA is evaluating options to sell RECs. From a previous analysis it appeared that tracking the RECs is costlier than selling them. IEUA was able to sell some carbon credits through the manure project.

w. **Electric Tariff Rates:** Perhaps in the future, IEUA will considered more aggressive tariff structures, such as the Critical Peak Pricing.

Action Items

No.	Item	Owner
1	Schedule meeting with SDCWA	Stantec
2	Schedule meeting with DWR	Stantec

The meeting adjourned at 3:00 PM

The foregoing is considered to be a true and accurate record of all items discussed. If any discrepancies or inconsistencies are noted, please contact the writer immediately.

Stantec Consulting Services Inc.

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Inland Empire Utilities Agency, CA: Battery Energy Storage Projects

Overview

Location	Chino, California
Average Flows	48 MGD
Energy Consumption	74.3 GWh/year
Energy Cost	$6,500,000/year
Investor-owned Utility	Southern California Edison (SCE)
Battery System	Tesla
Battery Size	1 MW (2 MWh)
Integrated DERs (nominal)	Cogeneration (3 MW), Solar (3.5 MW), Wind (1 MW); Fuel cell (2.8 MW-offline)
Partners/Developers	Advanced Microgrid Solutions

Background

Inland Empire Utilities Agency (IEUA) is a wholesale water agency and regional wastewater district serving 870,000 people over 242 square miles in western San Bernardino, CA. The agency focuses on treating wastewater, developing recycled water, local water resources, and conservation programs to reduce the region's dependence on imported water supplies. IEUA also converts the biosolids and waste produced onsite into a high-quality compost and energy. The agency's energy portfolio is a combination of imported electricity from the grid and on-site generation, including:

- 3.5 MW of solar PV over 4 different facilities, each ranging from 600 kW to 1 MW, established through a PPA with SunPower, under a fixed energy purchased price;
- 1 MW of wind generation, under a PPA with Foundation Windpower in one facility;
- 2.8 MW of fuel cells from FuelCell Energy in the RP-1 facility, discontinued in 2016 for issues associated with the digestor biogas cleaning system;
- Two-1.5 MW food waste cogeneration powering two engines, through a 10-year PPA (offline for a certain period of time);
- 580 kW engine at RP-2 with the generated biogas used as a fuel for boilers or, if in excess, sent to the grid; the engine was discontinued in 2015; and
- 13 MW of back-up diesel emergency generators.

All the existing generation assets were installed at IEUA at different times and operate independently. The power purchased from the grid has a combination of bundle rates from Edison and Direct Access at two facilities supplied by commodity energy from Shell.

Drivers for Battery Energy Storage and Value Proposition

IEUA is a national leader in addressing both water and energy issues. A number of energy efficiency strategies and participation into demand response programs are continuously implemented by the agency to improve operational efficiency and reduce costs. Over a decade ago, the Board moved forward in innovating the agency through investments in renewable energy generation technologies with the goal of reducing GHG emissions and achieving peak energy demand independence by 2020. In particular, an important goal was to reduce the cost associated with energy, representing approximately 50% of the agency's non-labor O&M expenses. Although participation in DR programs was able to save approximately $150K per year to IEUA, it solely could not attain its sustainability goals. In pursuing these objectives, the agency has reached 6 MW of alternative power providing more than 50% of the agency's peak-energy demand for its wastewater treatment plants. In order to reach energy self-sustainability goals and improve management of the renewable sources onsite, the agency believed that battery energy storage needed to be added as a critical component of its energy portfolio.

Funding and Partnership Model

When first considering the possibility of installing a BESS at their facility, IEUA evaluated direct purchase options from vendors, which required unattainable capital outlays and payback periods of 20-30 years. Therefore, in 2015 the agency entered a 10-year agreement with Advanced Microgrid Solutions (AMS) based on a shared savings model with no capital outlay for the agency and guaranteed savings. The agreement lays out AMS's full responsibilities in relation to covering the capital expenses for the projects, provide system design, equipment procurement, electrical, construction and O&M work (either by AMS or subcontracted to a third party). Any capital investment that is needed within the 10-year period (e.g., replacement of the batteries, etc.) will also be covered by AMS.

The performance is calculated considering the net energy cost savings from the operation of the energy storage systems. The feasibility study was based on actual load data, engine data, facility data, tariff structures and peak rates that IEUA provided to AMS to have large visibility of plant operations. During feasibility various scenarios were modelled to evaluate potential impact on the savings of changes in tariff structures (e.g., from TOU-AB to Cree Over Price tariff) or anticipated availability of renewable sources. If any modification to the initial contract terms occur, the agreement can be renegotiated by the two parties.

The length of the permitting and interconnection process with Southern California Edison varied at each of the locations due to several factors, including the capacity of existing self-generation technologies installed, total demand, metering capabilities, and existing tariff structure. At IEUA, the interconnection process required from six to thirty months. For example, although AMS and IEUA anticipated installation of the first BESS system at the end of July 2015, the process was delayed 2 years after planning due to the lengthy interconnection process with SCE and the technical and regulatory challenges related to the following:

- Requirement for a common disconnect for all the onsite DERs, particularly between the battery and the SunPower 0.99 MW solar PV;
- Ineligibility of the battery to the virtual net energy metering tariff (Renewable Energy Self- Generation – Bill Credit Transfer, known as RES-BCT); and
- Conflicts between the Rule 21 interconnection tariff and the RES-BCT tariff. The conflict with RES-BCT was due to one BESS facility being a benefitting account to another, which meant our interconnection options were limited. The battery wasn't ineligible, but the RES-BCT tariff was not an option at the specific battery site because of the benefitting account status.

Information of the total cost of the IEUA battery storage project is currently not available. The cost was entirely covered by AMS, and partially offset by a SGIP grant and participation to demand response programs from the SCE. ITC incentives may also be received depending on the contribution of renewable source to the battery charge. The interconnection cost was also covered by AMS and the sole application was approximately $800. The share of capital expenditure for the implementation of BESS at three IEUA sites (Carbon Canyon, RP1 and RP5) was approximately $200-250K (<1% of the IEUA's yearly capital expenditure), mostly to cover equipment and labor.

The agreement with AMS includes various end-of-contract options for IEUA after the 10 years operation, which include the following:

- Purchase of the BESS system;
- Extension of the contract with AMS to a defined period of time;
- Decommissioning with battery removal and site restoration to its original condition.

IEUA will plan on any of these end-of-contract options or other opportunities toward the end of the agreement period in consideration of the future innovations in the energy storage technologies and the dynamic changes that characterize the California energy market.

Due to the different PPAs on the renewable projects, IEUA manages the communications among the different parties to guarantee no mutual impacts occur from their independent operations.

BESS Solution Design and Grid Interconnection

The project features a total of 4MW (8 MWh) battery energy storage, divided at four different sites, with the following contributions:

- 1.3 MW/2.6 MWh,
- 0.5 MW/1 MWh,
- 0.78 MW/1.56 MWh,
- 1.5 MW/3 MWh

The first 0.5 MW facility at RP-5 was installed in mid-2016, whereas all others finished construction in mid-2018. All sites feature Tesla batteries, particularly Generation 1 at RP-5 and Generation 2 Powerpacks, with twice of the energy density, at all other sites. Generation 1 Powerpacks utilized Dynapower inverters, whereas Generation 2 had both batteries and inverters provided by Tesla. When possible, the location of the battery bank was selected close to the switchgears and, in some cases, underground pipe rerouting was needed to accommodate the batteries.

The interconnection processes of the various BESS at the various locations were different and characterized by different requirements and challenges. Figure B-1 shows a conceptual schematic of the control layout of the various facilities at RP-5. Due to the presence of two cogeneration systems at RP-5, the facility is under a RES-BCT tariff that provides opportunities for exporting to the grid with an export value that is 50% of its generation. Nonetheless, the BESS system at RP-5 is considered a non-export per interconnection requirements. For better management of these assets, SCE installed NGO (net generating output) meters on all IEUA generation sources for tracking of the electron flows and ensure that the export is not associated to the battery operations and that the battery only provides demand management and not an arbitrage value. The interconnection at RP-5 did not require major upgrades on the SCE grid, as the BESS was directly tied to the solar connection. At RP-4, considerations on the liabilities with the battery and wind generation PPAs had to be considered since the interconnection was based on a shared relay.

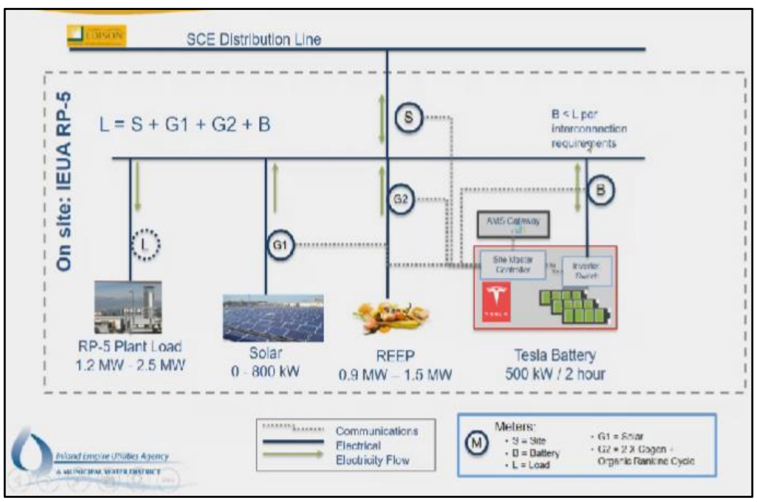

Figure B-1. Control layout and interconnection at RP-5.

Overall, IEUA installed metering at each generation system in the plant in addition to the submetering across the plant to have full visibility of the energy consumption and generation profiles at specific locations.

In addition to the interconnection requirements, IEUA had to receive the inspections of the local fire authority. As a self-permitting agency, IEUA performed all related inspections internally including any building related permitting, the engineering analysis of the plant, and electrical reviews. Compliance to the city permits was needed at RP-4 compost facility, where a solar plus storage project is being installed, since the solar installation is not exempt as the wastewater treatment plants are. The installation of these systems did not provide any concerns over water quality or noise to the surrounding environment.

Project Development Project

Battery operation strategies are based on peak load management, best optimization of other renewable resources onsite and response to utility operating needs and grid requirements. Figure B-2 provides an example on weekly battery operation at IEUA, with battery discharging to offset peak demands from SCE. The figure also shows periods of overgeneration with self-generation sources that exceed the plant's energy load. Over the years of operation, these patterns changed dynamically as a result of the changes occurring at the plant (e.g., downtime of the cogeneration unit, battery and inverter maintenance, etc.). AMS typically runs one event per day, often discharging for 20% of the battery capacity, with no full deep charging/discharging cycles.

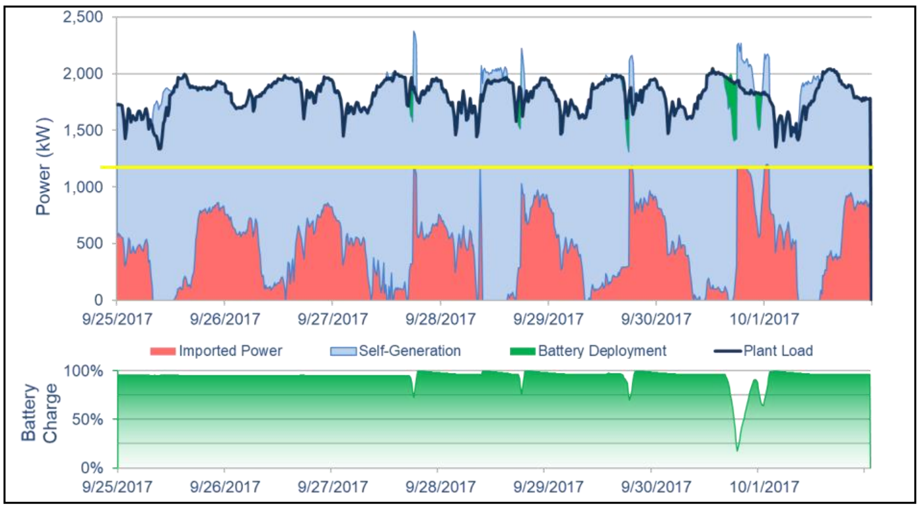

Figure B-2. Typical weekly operation of various energy sources and batteries at IEUA.

IEUA has access to the BESS shut down system only for emergency situations. AT RP-5, due to the battery common coupling interconnection with the 12kV feeder of the solar facility, any downtime of the battery also requires a shutdown of the solar generation. In case of grid outage and operation of the emergency diesel generator, the battery operation is disabled, whereas all other onsite generation sources can continue operation. IEUA is exploring future opportunities to use the batteries for energy resilience and backup power in case of emergency situations, upon appropriate coordination with SCE and an advantageous commercial case.

A dashboard developed by AMS compiles information from all the generation sources, the BESSs, the imported energy on a real-time basis and monthly summary information on the savings achieved. The dashboard has also the ability to show California's energy mix from CAISO (e.g., geothermal, solar, etc.) on a real-time basis. An example of the AMS dashboard interface is provided in Figure B-3.

Figure B-3. AMS dashboard.

Training sessions are also held to operator and maintenance staff, on emergency responses activities related to BESS operations and on the use of the developer dashboard.

Benefits

The initial feasibility study anticipated savings based on an aggregate performance of the four sites of $55K-$250K per year, with the lower bound representing the savings assurance guarantee for IEUA ($80/kW). In consideration of the recent implementation of three of the four available BESS, it is still not possible to determine whether the financial targets are achieved. Nevertheless, it was estimated that during 8 months of good BESS performance at RP-5, with no operational disruptions, a total of $25K of savings were achieved from the operation of only 0.5 MW/1 MWh over a total of 4 MW/8 MWh. In addition to the financial savings, the installation of the BESS allowed a complete integration of the renewable sources in relation to real-time tracking and distribution control. Lastly, IEUA's overall energy management benefitted from the opportunity to immediately respond to adverse operating conditions with more robust operating strategies. The implementation of BESS did not generate increases in rates to IEUA's customers.

Anticipated Benefits

The initial feasibility study anticipated savings of up to $150,000 in annual energy savings to the City of Long Beach, and $1.9 million over 10 years at no upfront cost to the city. These savings are created through a unique combination of energy management and load optimization provided through AMS's data analytic platform. Given the full responsibility of the developer at different life cycle stages of the BESS implementation, no additional utility staff was required to support the project. The level of effort required to support the planning and design phase of the project was approximately 2 hours, every 2-3 weeks. More involvement of the utility staff was needed during construction as is typical for any onsite capital improvement projects.

APPENDIX A.3

WORKSHOP NO. 3 – SAN DIEGO COUNTY WATER AUTHORITY

Stantec

Appendix A.3

Workshop with San Diego County Water Authority, Metropolitan Water District, and Stantec

Energy Sustainability Plan – Development of Renewable Energy Options

Date/Time:	May 20, 2019 / 10:00 AM
Place:	4677 Overland Ave, San Diego, CA 92123 – Library Conference Room
Attendees:	Andrea Altmann, Neena Kuzmich, Nathan Faber, Greg Ortega, Brent Fountain, Jeremy Crutchfield, Greg de Lamare, Shawn Bailey, Ha Nguyen, Austen Nelson, Courtnay Roland, Heather Collins, Albrecht Grimm, Simon Calvet, Kyleen Marcella, Carla Cherchi
Distribution:	See Attendees

Welcome and Introductions (Carla Cherchi)

a. Meeting Purpose – The purpose of this meeting is to foster knowledge sharing on the San Diego County Water Authority's (SDCWA) Energy and Sustainability Management practices to inform Metropolitan Water District's (MWD) Energy and Sustainability Management Plan development effort

b. Workshop Participants Introduction (see Attendees list)

Overview of MWD's Renewable Energy Options Development Effort (Greg de Lamare)

a. MWD's objective is to develop an Energy Sustainability Plan to position Metropolitan as a leader in energy sustainability.

b. MWD's interest includes:

   i. Review of Energy Sustainability Plans
   ii. Identify and evaluate Renewable Energy and Energy Storage opportunities:
      1. Renewable energy (solar, in-conduit hydropower)
      2. Energy storage systems (battery energy storage and pump storage)
      3. Emerging technologies
      4. Energy efficiency measures
      5. Operational strategies to manage energy demands and respond to new tariffs
      6. Efforts to reduce GHG emissions and other sustainability practices

SDCWA's Energy Management Policy and Strategies (Andrea Altmann)

a. In 2013, SDCWA implemented an Energy Management Policy aimed to reduce power costs, maximize use of existing water infrastructure and use of renewables. The plan focused on four key focus areas:

   i. Existing Energy Facilities
   ii. New Energy Initiatives
   iii. Energy Procurement and Transmission
   iv. Regulatory Engagement

b. SDCWA entered into a Water Purchase Agreement with Poseidon in 2012 for the development of the Carlsbad Desalination Plant and has been purchasing desalinated seawater since December 2015. SDCWA is responsible for electricity tariff risk and pays Poseidon for target electricity consumption based on product water flow, source water TDS and source water temperature. Poseidon is responsible for actual electricity costs and can financially benefit when the plant is operated efficiently.

c. SDCWA generates more energy than it is needed to satisfy its system's energy demand (not accounting the energy needs of the desalination plant)

d. SDCWA currently grandfathered with old TOU tariffs but new San Diego Gas & Electric (SDG&E) rates will be applied in 2020, such as those including the new "super off-peak". For example, the Twin Oaks Water Treatment facility is grandfathered at a combined rate of 16 cents/kWh.

SDCWA Energy Generation Facilities

a. Lake Hodges Energy Storage Facility – generates energy as water flows downhill from Olivenhain Reservoir to Lake Hodges. The facility has 40 MW storage capacity and generates approximately 54,000 MWh/year for an estimated annual net revenue of $1.5M. SDCWA is contracted with SDG&E through a Power Purchase Agreement (PPA) at this facility. The project required a 4-year construction period, or 8-10 years if we include all the environmental and permitting process.

b. Rancho Peñasquitos Hydroelectric Facility – generates power as water flows through an aqueduct. The facility has 4.5 MW of renewable energy capacity and when rehabilitated will generate approximately 21,000 MWh/year for an anticipated annual net revenue of approximately $1M through RES-BCT. SDCWA had a PPA with SDG&E at this facility but the contract expired and SDCWA is now selling through the wholesale market (CAISO) to help stabilize water rates to customers. The renewable energy credits generated are sold to a third-party.

c. Three Solar Facilities for an estimated annual savings of $150,000. All facilities are through a PPA with Borrego Solar.

    i. Kearny Mesa – 600 MWh/year;

    ii. Operations Center in Escondido – 250 MWh/year;

    iii. Twin Oaks Valley Water Treatment Plant – 1,850 MWh/year.

SDCWA New Energy Initiatives

a. Alvarado Hydroelectric Facility – built in 1984 with two, 1MW-generators which are now dormant and are undergoing rehabilitation to one, 1.4MW-generator for an estimated 8,000 MWh/year. SDCWA plans to use RES-BCT program for excess energy although currently it does not participate in RES-BCT. Black and Veatch completed a study to evaluate multiple different turbine generators at the site.

b. Twin Oaks Battery System – In May 2016, SDCWA entered into a partnership with Engie for a 1 MW/2 MWh battery system. Engie was the preferred solution provider due to their installation experience at critical facilities. The shared savings agreement is for 10 years and with no capital cost to SDCWA. Without the savings agreement with Engie, the total project cost to SDCWA was estimated to be $2M for the capital costs and annual $30,000 for the O&M costs. The shared savings agreement guarantees SDCWA 46% of the savings, which is higher than the industry standard of 25-30%. With jointly application with Engie, SDCWA's battery storage project received $1M incentive from CPUC (self-generation grant based on lottery system). The system is expected to be operational next month. SDCWA estimates approximately $100,000 annual savings from the operation of the battery storage system. If any changes are experienced in relation to the WTP energy demand or tariff rates, SDCWA will have opportunities to renegotiate the contract with Engie.

c. San Vicente Energy Storage Facility – SDCWA has legislative focus for CAISO to recognize pumped storage as a revenue stream. The potential energy storage facility could store 4,000 MWh/day of energy and have 500 MW of capacity for 8 hours. During off-peak periods, when power is inexpensive and renewable supplies from wind and solar facilities exceed demand, the turbines would pump water to the upper reservoir where it would act as a battery of stored potential energy. During high energy use, the system would create clean energy as water from the upper reservoir flows downhill through the turbines. The potential project will require the construction of a new upper reservoir above the San Vicente Reservoir, along with a tunnel system and an underground powerhouse to connect the two reservoirs, and new pumping facilities. A public private partnership with private developer was established for the project to be a no-cost option to SDCWA. The selected partner was Brookfield, which owns and operates renewable power assets. The anticipated completion date for the project is set to 2030.

   SDCWA prepared and submitted a joint Preliminary Application Document and Notice of Intent to the Federal Energy Regulatory Commission (FERC) in 2015. The potential project is currently at its third FERC renewal. In order to see the advantages of pumped storage modeling should be made up to 2045 model,

SDCWA Energy Procurement and Transmission

a. The Hoover Power allocation is 3,500 MWh/year. SDCWA currently has no opportunities to transmit the power to their service area so it is sold on the CAISO grid. This allocation will require more coordination with SDG&E.

b. SDCWA is evaluating opportunities to receive power through Western Area Power Administration (WAPA).

SDCWA 2018 Legislative and Regulatory Engagement

a. Commented on rulemaking that affects the cost and use of energy.

b. Monitored regulatory activity on 6 energy proceedings.

c. Supported Government Relations Program legislative efforts – 3 energy related senate bills, 5 energy related assembly bills.

SDCWA Climate Action Plan (CAP)

a. SDCWA voluntarily drafted a CAP in 2014 to show GHG accountability. SDCWA is not accountable for Poseidon's Desal Plant GHG emissions.

b. The CAP shows GHG emissions are being minimized and targets are being met.

c. The baseline for CAP was 2009, before solar and other energy efficiency projects were established.

d. SDCWA will be updating its CAP in July 2020. The update reflects new legislation further reducing statewide emission targets and revises emission projections based on the latest operational and planned capital projects.

e. All current and planned energy projects are addressed in the CAP Update.

f. Poseidon desal is required to be carbon-zero, which is met by purchasing RECs and taking account of wheeling from the State Water Project (SWP). Poseidon is also in the process of developing solar generation which will reduce the amount of offsets it has to purchase to achieve carbon-zero.

Other Energy Discussions

a. SDCWA prefers to enter into shorter power contracts due to market volatility.

b. Project evaluation uses flow projections, cost escalations and 2.5% annual increase in electrical rates.

c. Generally, the evaluation criteria for projects is based on years payback and NPV.

d. Small hydropower facility feasibilities increase if able to co-locate with other owned sites, or if a portion of the cost is already incurred as part of another project. The pump station of the Lake Hodge project was already supposed to be built for emergency, so about 50% of the cost was supposed to be incurred anyway by SDCWA.

e. SDCWA has implemented energy efficiency initiatives at Twin Oaks Water Treatment Plant including upgrading compressors and changing operating times of the backwash process and pumping. These strategies helped decrease demand charges. The Authority is looking into more opportunities, such as additional interlocks for operator controls or Energy Management System integrated into SCADA to improve asset visibility and identify potential causes of inefficiencies and increased costs.

f. SDCWA is not on Direct Access but some member agencies, such as Helix, have successfully participated in Direct Access since 1999.

g. SDCWA is monitoring the progress of the Community Choice Aggregation (CCA) activity, but it is not currently active.

h. MWD is currently under Critical Peak Pricing (CPP), therefore the utility is planning on implementing additional demand management strategies. MWD currently has 350 meters and 12 large meters.

i. MWD replaced impellers of constant-speed pumps on the CRA generating about 10% in energy savings.

Action Items

No.	Item	Owner
1	Schedule meeting with LADWP	Stantec
2	Schedule meeting with DWR	Stantec

The meeting adjourned at 12:10 PM

The foregoing is considered to be a true and accurate record of all items discussed. If any discrepancies or inconsistencies are noted, please contact the writer immediately.

Stantec Consulting Services Inc.

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APPENDIX A.4

WORKSHOP NO. 4 – LOS ANGELES DEPARTMENT OF WATER AND POWER

Stantec

Appendix A.4

Workshop with Los Angeles Department of Water and Power, Metropolitan Water District, and Stantec

Energy Sustainability Plan – Development of Renewable Energy Options

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Date/Time:	June 21, 2019 / 10:00 AM
Place:	Room 1471, 14th floor, 111 N. Hope Street, Los Angeles, CA
Attendees:	Shawn Bailey, Ha Nguyen, Austen Nelson, Heather Collins, Albrecht Grimm, Simon Calvet, Kyleen Marcella, Carla Cherchi, Joseph Regala, Giovanni Tek, Ronav Chikhalya, Stephanie Macoritto, Alberto Luna, Hassan Motallebi, Maria Sison-Roces, Theresa Kim
Distribution:	See Attendees

Welcome and Introductions (Stantec)

a. Meeting Purpose – The purpose of this meeting is to foster knowledge sharing on the Los Angeles Department of Water and Power's (LADWP) Energy and Sustainability Management practices to inform Metropolitan Water District's (MWD) Energy and Sustainability Management Plan development effort

b. Workshop Participants Introduction (see Attendees list)

Overview of MWD's Renewable Energy Options Development Effort (MWD)

a. MWD's objective is to develop an Energy Sustainability Plan to position Metropolitan as a leader in energy sustainability.

b. MWD's interest includes:

   i. Review of Energy Sustainability Plans
   ii. Identify and evaluate Renewable Energy and Energy Storage opportunities:
      1. Renewable energy (solar, in-conduit hydropower)
      2. Energy storage systems (battery energy storage and pump storage)
      3. Emerging technologies
      4. Energy efficiency measures
      5. Operational strategies to manage energy demands and respond to new tariffs
      6. Efforts to reduce GHG emissions and other sustainability practices

Pump Operation and Participation to Demand Response Programs (LADWP/MWD)

a. MWD is looking at ways to optimize pumping operations with the dynamic price of the market today, as a consequence of the Duck Curve effect. MWD has a couple of reservoirs that can allow some flexibility for pumping and the degree of this flexibility is being now evaluated.

b. To reduce energy consumption and cost of its pumping operation, MWD is interested in the implementation of soft start systems to reduce wear and tear and in monitoring systems that enable assessment of the condition of the equipment and provide insights into maintenance. Motors of

Colorado River Aqueduct (CRA) pumps at MWD are from the original CRA and of about 7 MW (4300 hp-12500 hp).

c. The water side of LADWP participates in Demand Response (DR) programs, which is a successful program for pump operation (e.g., for efficiency, cycling operations, responding to events). With the DR's 24-hour notice LADWP has the ability to stop pumping, maximize the use of tanks when energy is cheap or at peak time, maximize the use of gravity or cycle the pump to keep the line pressurized.

d. LADWP: Risk analysis evaluation done with respect to the DR program to ensure that LADWP is not adding additional costs that can limit the savings from a DR program. With the DR program LADWP is not cycling the pumps more but is pulling them back (filling the tanks by running the pumps more often, run time is not as important as how many times the pumps starts/stops). That is why it is recommended that pumps have a soft start, so that the speed can be slowed down.

e. MWD pumping load is 180-200 MW at the CRA.

f. MWD pumping strategy is really driven by the water needs; because of the 2 reservoirs MWD can cycle the pumps on a daily basis to reduce the pumping costs.

g. LADWP states that Edison is heavier on solar than LADWP is, so pumping on cheap energy would be mostly during the day. PG&E follows the same trend (of the ISO).

h. MWD has multiple power entities (Edison, LADWP, Riverside) and it is characterized by mixed water supply depending on the supply availability, rights, water resources which are continuously changing. MWD is looking at optimization opportunities at the CRA level, since once the water flows reach the basin, the pumping is minimal as mostly driven by gravity. In the city, opportunities for efficiency are mostly at the treatment plants (e.g., optimizing backwash, etc.).

i. LADWP has a DR program that incentivizes the demand charges. It does not consider the TOU rates, but it is a stand-alone incentive on the kW. LADWP will look at the utility client energy profile, come up with a baseline and, on the day of the event, LADWP can measure how much load the utility client drops compare to its baseline and LADWP provides the incentive based on that.

j. MWD's treatment plant has a 2 MW load at maximum.

k. MWD is seeing the effect of the change in Edison's retail structure, reflecting the shape of the Duck Curve, so the mid-day rates are lower.

l. LADWP suggests referring to their Rate Structure group to know if LADWP is also adopting the change in rate structure as a consequence of the Duck Curve. MWD will follow up with LADWP on it.

m. LADWP's DR program can fit only specific periods of time (at this point is only 12 days), no penalty. The water side of LADWP participating in the DR program usually has the events between 1pm and 5pm, so LADWP is able to modify the load by shifting it to a different period. The incentive depends on the amount of load the customer can curtail.

n. LADWP currently does not have existing customers that use the DR program with energy storage

o. The primary strategy for MWD at the CRA is maintaining the flow.

p. MWD's CRA is a wholesale load, we take credits for the interruptible load.

q. MWD is an ISO participant, with the same resource adequacy requirement; MWD is an active market participant.

r. According to LADPW, a few synergies that MWD should consider are:

- LADWP is part of the Climate Registry as a founding member (MWD is also a founding member). This is a way to keep track of the carbon emissions and related reductions.
- EPRI Energy Nexus Tournament. LADWP is a member of EPRI. The tournament is held in California, and EPRI wants to put together the major players in California tackle some of the major problems that relate to the water-energy nexus. LADWP is looking for collaborative efforts, multi-agency partnerships (including U.S.DOE). On the water side LADWP is trying more and more to use the local water supply. It is important not to impact the energy and GHG reduction efforts of the state.
- MWD is embarking in a recycle water program, and MWD and LADWP are connecting to better understand how the projects can provide regional benefits, and the energy efficiency piece is an important part of it.

s. LADWP by 2030 has to retire all coal units so there will be a lack of capacity, so alternatives such as battery energy storage are considered.

t. MWD's reservoirs are not covered and they are all raw water.

u. LA has the Building Energy and Water Efficiency ordinance and depending on the square footage of the buildings, it may require participation to the energy star portfolio manager, audits, etc.

v. It is the upgraded version of the 2018 Sustainability plan, more aggressive, more ambitious targets in line with the Paris agreement, and has the following targets:
   - Zero carbon grid
   - Zero carbon buildings
   - Zero carbon transportation
   - Zero waste
   - Zero wasted water

w. MWD needs to take into account the risks and well manage the risk when making energy management decisions.

x. EPRI funds research for electric utilities, and LADWP is part of their group with other 45 members (PG&E, Socal Gas, Edison, etc.). EPRI has mechanisms for tailored collaborations where they sustain up 50% of the costs for projects that are of their interest.

y. Is there any incentive for LADWP customers to reduce the retail load by for example installing batteries? LADWP is looking into these types of programs. The first priority for LADWP now is transmission.

z. LADWP has programs that pay customers installing solar based on the load that is generated. In the next years we may incorporate storage as a program to incentive customers. LADWP is still at the early stage of evaluations for these types of programs. As LADWP gets into solar and batteries having a good demand management strategy for customers is critical.

aa. Two groups are in charge of the electrification of transportation for LADWP: Scott Briasco as the Director of EV, and the Chief Sustainability Officer.

bb. MWD is operating the hydro based on the water demand, function of what is coming in and what the minimum flows are needed to run the system.

cc. LADWP has 240 MW of small hydro in the aqueduct and recently shifted the operation to night time, because the large solar penetration and the limited transmission.

Energy Storage Projects (LADWP)

Drivers

a. LADWP has given large focus to energy storage particularly after the SB 100 was passed (100% carbon free by 2045). SB 2514 asked LADWP to set energy storage targets, which are now set at 404 MW by 2025. SB 801 required also LADWP do conduct a cost effectiveness study on the Aliso canyon and if procuring a 100 MW-4 hr battery storage would be cost effective. The study showed that it would be cost effective by 2022.

b. LADWP's 2017 resource stack was:

   - 3800 MW from natural gas;
   - 2000 MW from hydro
   - 1200 MW from for coal
   - 380 MW from nuclear
   - 1300 MW from solar
   - 1000 MW from wind
   - 200 form geothermal

   This portfolio will change in the next years.

c. The goal is to reach 65% renewables by 2036 and perhaps 80 % can be achieved.

Technologies

d. LADWP is exploring various forms of energy storage: chemical with different types of batteries, thermal (ice), pumped storage, flywheel and compressed air. LADWP is evaluating the co-location of these technologies with some of their other generation plants, the related transmission, etc.; evaluating behind the meter and DER resources.

Projects

a. Some of the key projects are:

   - Beacon: 20 MW BESS (lithium ion – Samsung battery) for grid services, October 2018. In that area we have 800 MW of solar plus wind. The BESS is charged with the solar and wind. LADWP owns the system. The cost per MW ($1900-2000/kWh) is high because there was a lot of pressure to commission this project in 2018 rather than 2019, so there was a lot of manpower used. The Beacon battery was a performance battery, so it is fast acting battery discharging a lot of kWh at once, so it needed a lot of inverters (so the price was higher because of that as well). The purpose of the battery was also to provide frequency response services in addition to energy arbitrage and energy shifting. The footprint is about 1.6 kW/sqft.
   - Fire Station Pilot: Solar + Battery. It is a behind the meter system, there is a rooftop solar.
   - Energy storage at LADWP site downtown: It will be commissioned in October 2019. LADWP is simultaneously testing two types of batteries: a lithium-ion and a vanadium flow battery. It is a 100 kW – 4 hours for each system (so 400 kWh), so for a total of 800 kWh among the 2 batteries. The Vanadium battery is considered safer from a fire safety perspective and the lifecycle is longer

(20+ year) compared to the typical 10 year of a li-ion. However, the vanadium has lower energy density than the Li-ion. Although it is safe from a fire perspective it still needs some sort of fire protection equipment being an electrical system. There is one control system for both batteries. The flow battery cost is typically 1.5 times the cost of a Li-ion battery.

- PPA for a 600 MW solar and 300 MW of energy storage, commissioned by 2020. One of the largest in the world.
- Exploring compressed energy storage in the Utah area (160 MW each unit – 8 hour and plus).
- Exploring pumped storage in Boulder Canyon and Hover Dam.

b. For these projects no incentives were received from the government agencies, and that was one of the reasons to consider PPAs for some of these projects. The developers can take the ITC tax credits. The PPAs price is $39/MWh (including solar plus storage) in 2023.

c. Also exploring energy storage (100MW) in behind the meter projects in the downtown area. The target is to achieve 1845 MW of energy storage, which is about 25% of LADWP's peak load (by 2025).

d. A pilot project with EPRI is looking into "inverter control" issues.

e. The return on investment for these storage projects are of about 1-1.2 ratio and there is a positive ratio also for the compressed energy storage.

Other Discussion Items

a. The participation to the EPRI's programs is very advantageous because it includes access to meaningful research for the utility and to published research that is publicly available.

b. LADWP has its own "green team", which partners with other utilities (gas companies, other utilities) and they share best practices of sustainability.

c. In terms of energy efficiency efforts, LADWP has the Building Energy and Water Efficiency plan that tries to have visibility of all energy and water use at all LADWP facilities; submetering is also a very important issue to manage energy and water use. LADWP began to benchmark buildings above 7500 sq ft.

d. Energy use in buildings is reduced through LED lights, energy efficiency programs and getting rebates. LADWP is implementing smart meters at all the facilities and it is a multi-year effort.

e. An important component was the energy monitoring system in the main building, which inspires conservation efforts.

f. In terms of the control system, facility management is separated from the operation team. In 2016, 11 of the LADWP buildings were able to reduce 10-15% of their energy consumption, with simple strategies (shutting off lights, HVAC replaced, etc.).

g. The energy efficiency group tries to promote conservation and incentivize energy efficiency efforts. LADWP helps customers setting a baseline, measure the energy reduction efforts and based on the measures implemented, and will provide incentives based on savings achieved. There are annual awards from the customer service division on the most efficient customers.

h. LADWP is becoming customer-centric and customers have choices. They are bringing new technologies, and they evaluate the impact of repairing and energy efficient strategies to customers. They also try to maintain unvaried rates to customers.

i. In relation to the CCA – community choice- LADWP does not have it, but they are the CCA, they are the local choice.
j. LADWP is working with EPRI on the Water Energy nexus, climate registry, and they started also to look into the supply chain (reporting of carbon from suppliers). This also helps manage the risks, in relation where things come from, which countries, how fair are the employees treated. So, it is a more comprehensive view and energy, water, and carbon emissions are strictly part of it.
k. LADWP is looking at the Encino Reservoir for floating solar as a pilot project and mostly considering raw water reservoirs. All partners that can provide information on these technologies are met through the EPRI meeting.

The meeting adjourned at 12:10 PM

The foregoing is considered to be a true and accurate record of all items discussed. If any discrepancies or inconsistencies are noted, please contact me immediately.

Stantec Consulting Services Inc.

Simon Calvet PE
Civil/Environmental Engineer
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Stantec

Appendix A.4.1

LADWP's Demand Response Program Details

Los Angeles Department of Water & Power

DEMAND RESPONSE PROGRAM

SAVE MONEY & SUPPORT ENERGY RELIABILITY IN LOS ANGELES

DEMAND RESPONSE PROGRAM & HOW DEMAND RESPONSE WORKS

DEMAND RESPONSE PROGRAM

LADWP's Demand Response (DR) is an incentive based, energy savings program that helps customers reduce their energy use and utility bills, while helping to ensure the reliability of our electric grid.

HOW DEMAND RESPONSE WORKS

Participants make temporary adjustments to reduce their energy usage during periods of peak demand to relieve stress on the electric grid and support system reliability. In return, LADWP offers incentives to the participants for their energy savings.

PARTICIPANT REQUIREMENTS

Available to Commercial, Industrial, and Institutional (CII) customers, the Demand Response Program is based on the following parameters:

- Ability of **100 kW** or higher load curtailment
- Ability to adjust energy usage during DR Events
- Ability to adjust operations between **1:00 P.M.** & **5:00 P.M.** PST
- Ability to participate with day-ahead or two hour advance notification
- Existing Building Energy Management System

BUSINESS & SUSTAINABILITY

BUSINESS BENEFITS

- Saves money on your utility bill
- Offers financial incentives
- Increases your control over electric usage
- Creates a positive community impact by supporting a cleaner environment
- Lowers your operating costs
- Optimizes your Building Energy Management System capabilities
- Helps lower chances of black outs

SUSTAINABILITY BENEFITS

- Reduces greenhouse gas emissions and carbon footprint
- Reduces the need for building new power infrastructure – fuel resource, generation plants, transmission and distribution (T&D), and operations and maintenance (O&M)
- Promotes grid integration of renewable energy
- Increases energy reliability

If you are interested in learning more about the LADWP Demand Response Program, please contact the Demand Response Program team at **demand.response@ladwp.com** or by phone at **213.367.3319** or **213.367.2712**. Visit our web page **www.ladwp.com/drprogram**.

Los Angeles Department of Water & Power

Demand Response Commercial and Industrial Program

Terms and Conditions

The Demand Response (DR) Program is designed to help participating customers earn incentives for reducing their electricity use on days when demand is high, which helps reduce LADWP's annual peak electricity demand. The Program's incentive payments share the anticipated savings between the utility and Program Participants.

Through the Program, LADWP will provide monetary incentives to participating customers who are able to reduce their electrical usage when called upon by LADWP during high load periods in the summer. The DR Program Terms and Conditions are outlined below. Interested Participants need to file an application by May 01 in order to be eligible to participate in the Program on its start date of June 15.

1. Defined Terms:

1.1. **Adjusted Baseline:** The Baseline multiplied by a Morning-of Adjustment Factor to capture the anticipated change in the Participant's Baseline usage on the day that LADWP calls for a reduction in energy usage.

1.2. **Baseline:** A Participant's typical hourly energy usage in the absence of a Peak Load Reduction (PLR) Event, calculated from the average daily usage of the three highest of previous ten weekdays, excluding PLR Event Days, weekends and Program Holidays.

1.3. **Incentive Payment**: A capacity payment of **$8** per committed kW per month ($8/kW/month) for day-ahead advance notice or **$12** per committed kW per month ($12/kW/month) for 2-hour advance notice during the curtailment season of June 15 - October 15, and an additional **$0.25/kWh** for demand curtailment, per event.

1.4. **LADWP:** Los Angeles Department of Power and Water.

1.5. **Estimated PLR Quantity:** The amount of load that a Participant commits to curtail during a PLR Event specified in kWs, which is set by a Participant on their application form.

1.6. **Full Performance:** A Peak Load Reduction equal to or greater than the Estimated PLR Quantity for the full PLR Event Duration.

1.7. **Program Holidays:** Memorial Day, Independence Day, and Labor Day.

1.8. **Kilowatt (kW):** Electricity capacity measurement unit.

1.9. **Kilowatt-hour (kWh):** A unit of energy in which one kW of power expended for one hour results in one kWh of energy usage.

1.10. **Demand Response Management System (DRMS):** The LADWP program used to record electricity usage in 15-minute interval data format that can be retrieved and displayed in graphical or tabular format by the customer or by LADWP staff.

1.11. Non-Performance: Failure of a Participant to respond to a PLR Event Notification by 11:30 a.m. Pacific Standard Time for 2 hours advance notification or by 10:00 a.m. Pacific Standard Time for day ahead notification on the day of PLR Event, or a Peak Load Reduction that is less than 50% of the Estimated PLR Quantity.

1.12. Participant: LADWP commercial customer participating in the DR Program.

1.13. Demand Response Season: From June 15 through October 15. The Demand Response Season excludes weekends and Program Holidays.

1.14. Peak Load: Participant's electrical load during the hours of 1 p.m. to 5 p.m. during the Demand Response Season, specified in kWs.

1.15. Peak Load Reduction (PLR): The decrease in a Participant's Peak Load during a PLR Event.

1.16. PLR Event: A LADWP request for Participants to reduce their load for the date and hours specified by LADWP. PLR Events will typically be called for hot summer days when LADWP's load is projected to go above a certain value and /or the annual peak.

1.17. PLR Event Day: The calendar date for which a Peak Load Reduction is requested.

1.18. PLR Event Duration: The number of hours that each PLR Event lasts in any given day.

1.19. Program: DR Program that will be administered by LADWP.

1.20. Participation Period: Participants will be enrolled for **three years** after LADWP accepts the application. Please see 4. Participation in the Program for additional detail.

2. Commercial and Industrial (C&I) Curtailable Load Program Description

C&I customers receive monthly capacity payments in return for providing kW load reduction of a pre-specified amount when requested by LADWP. Additional incentives are provided based on responses to PLR Events.

2.1 Demand Response Season

June 15 through October 15

2.2 Eligibility

Non-residential customers with ability to curtail at least 100 kW of load weekdays between 1 p.m. and 5 p.m., June 15 through October 15, are eligible.

2.3 Notification and Response Time

C&I Curtailable Load: 2-hour or day-ahead advance notification before DR Event.

2.4 Event Limits

Number of events will be limited to a maximum of 12 per year and 4 hours per event, not to exceed 1 event per day. Period of events is limited to weekdays, June 15 through October 15. In certain pre-specified levels of extreme system emergency, LADWP may call the customer to curtail load, even if the customer has already curtailed the maximum number of events per curtailment season or hours per event. The lack of participation in such cases will not count as a non-performance event against the Participant.

2.5 Baseline

The baseline load is calculated from among the 10 similar (e.g., typically non-weekend) preceding days and adjusted prior to event depending on extreme circumstances.

2.6 Customer Incentives

Customers receive two types of financial incentives, based on the calculated load reductions during PLR Events:

- **$8.00/kW** monthly capacity payment during curtailment season, June 15- October 15, for day-ahead notification or **$12.00/kW** monthly capacity payment during curtailment season, June 15- October 15, for 2-hour advance notice
- **$0.25/kWh** for demand curtailment, per event

In keeping with other similar Auto DR programs in California and around the country, LADWP would help reimburse Auto DR Participants for the incremental expenses required to enable their participation, as discussed in the section below.

Failure to reduce load down to or below the committed curtailment level during an event between the peak hours of 1 pm to 5 pm, will result in foregoing a portion of capacity payments for the month. Customers will not receive penalties for opting out of the DR Event. Customers, however, must not opt out more than twice per DR season, if they wish to remain in the program.

LADWP will calculate and finalize the Participants' average and overall performance at the end of the DR season, after October 15. The capacity incentive amount is directly proportional to the Participants' average performance, in kW, during the DR season.

2.7 Dependent Technology

Semi-Auto DR requires a communication channel between LADWP and the customers, which might include text message, email or telephone in order to test the customer's and LADWP's capabilities for Semi-Auto DR. LADWP will semi-automatically send DR event notifications via text message, email, or telephone upon event initiation, and customers will then semi-automatically curtail their energy usage, through their Building Energy Management System (BEMS), after receipt of DR event notification. Semi-Auto DR requires a BEMS, a load control device, or breakers on specific circuits.

3. Notification of a PLR Event

3.1. LADWP will notify the Participant by email by noon Pacific Standard Time, on the business day prior to the PLR Event Day or with two hours advance notice prior to the PLR Event. If Monday is a PLR Event Day, LADWP will notify Participants by noon on the Friday immediately preceding the PLR Event. This notification will contain the following information:

- Date of the PLR Event
- PLR Event Duration

4. Participation in the Program

4.1. C&I customers may enroll in the Program by submitting a completed “Application Form to Participate in Los Angeles Department of Water and Power Demand Response C&I Program” to the LADWP’s DR Team at Demand.Response@ladwp.com.

4.2. After LADWP accepts the application, the Participant is enrolled in the Program for the duration of the Participation Period or until a written notice to exit the Program is provided via e-mail to the LADWP’s DR Team at Demand.Response@ladwp.com, with accordance to Article 5.1.

4.3. During the participation period, the Participant may modify the value of estimated PLR quantity (in kW) by submitting a new, completed application form to the LADWP’s DR Team at Demand.Response@ladwp.com. The participant’s new PLR quantity will become effective starting the following business day after LADWP’s DR Team has received the new application. The Participant may revise the PLR quantity a maximum of one time during each DR season.

4.4. LADWP will notify the Participant of any modifications or addendum to the Terms and Conditions, with the effective date, via email sent to the addresses provided by the Participant.

5. Exiting the Program

5.1. Participant may leave the Program at any time, by providing a written, five-business-day-prior notice to LADWP, via e-mail to the LADWP’s DR Team at Demand.Response@ladwp.com.

5.2. LADWP may terminate a Participant’s involvement in the Program at any time by providing a written, five-business-day-prior notice, via email sent to the address provided by the Participant on its Program Application.

6. Program Administration and Termination

LADWP reserves the right to modify or terminate the Program and any of its Terms and Conditions at any time, for any reason. If LADWP terminates the Program, it will provide all Participants written notice by email and first class mail sent to the addresses provided by the Participants on their Program Applications, of LADWP’s intent to terminate the Program on a set date. LADWP agrees to pay any amounts earned by Participants under the Program within ninety (90) days of the date of Program termination. The DR performance will be calculated after each event and the results will be shared with the participants. The incentives will however be paid at the end of the DR season, after October 15, to the Participants in the form of a check or credit on their utility bill.

Los Angeles Department of Water & Power

LADWP CII DEMAND RESPONSE PROGRAM

POTENTIAL MEASURE GUIDELINE

DR Measures # (DRMs)	Commercial Industrial & Institutional (CII) Measures	Office Building (Property Mgmt.)	Education	Manufacturing	Entertainment	Museum	Aerospace	Healthcare	Retail	Government
DRM-C #1	Elevator Lift Motor Room Space Temperature Setpoint Adjustment (i.e. +2°F | +4°F) - Global Command	✓	✓		✓	✓	✓	✓	✓	✓
DRM-C #2	Air Handling Unit Duct Static Setpoint Adjustment / Reset to 1.0 in IWC	✓	✓	✓	✓	✓	✓	✓	✓	✓
DRM-C #3	Pre - Cooling of the Chilled Water Loop | Disable One (1) Water Cooled Chiller	✓	✓	✓	✓	✓	✓	✓	✓	✓
DRM-C #4	Pre - Cooling of the Chilled Water Loop | Reset Return Chilled Water Temperature Setpoint	✓	✓	✓	✓	✓	✓	✓	✓	✓
DRM-C #5	Parking Garage Lighting Placed Into Egress Mode (Curtail Approx. 40% of Lighting Fixtures)	✓	✓	✓	✓	✓	✓	✓	✓	✓
DRM-C #6	Disable EV Parking Garage Charging Point Stations	✓	✓	✓	✓	✓	✓	✓	✓	✓
DRM-C #7	Parking Garage Exhaust Fan (s) *Purge Mode Disabled	✓	✓	✓	✓	✓	✓	✓	✓	✓
DRM-C #8	Disable Toilet Exhaust (s)	✓	✓	✓	✓	✓	✓	✓	✓	✓
DRM-C #9	Disable Parking Garage Escalator (s)	✓	✓		✓	✓	✓	✓	✓	✓
DRM-C #10	Passenger Elevator (s) Curtailment	✓	✓		✓	✓	✓	✓	✓	✓
DRM-C #11	Elevator Vestibule Room Space Temperature Setpoint Adjustment (+2°F |+4°F) - Global Command	✓	✓		✓	✓	✓	✓	✓	✓
DRM-C #12	Overhead Common Corridor Lighting Fixture (s) Curtailment	✓	✓	✓	✓	✓	✓	✓	✓	✓
DRM-C #13	Disable Central Hot Water Boiler Plant Circulation Pump Motor (s)	✓	✓	✓	✓	✓	✓	✓	✓	✓
DRM-C #14	Dim All Plaza LED Lighting Advertising Boards Down To 75%|50% 30%|15%				✓				✓	
DRM-C #15	Curtail Loading Dock- Exhaust and Supply Air Fan (s)	✓	✓	✓	✓	✓	✓	✓	✓	✓
DRM-C #16	Equipment Processing Delay			✓			✓			
DRM-C #17	Compress Air Plant - Set Point Adjustments			✓			✓	✓		
DRM-C #18	Disable Water Features	✓	✓		✓	✓			✓	✓
DRM-C #19	Global Temperature Set Point Adjustments	✓	✓	✓	✓	✓	✓	✓	✓	✓

Demand Response Program

Frequently Asked Questions

What is Demand Response?

- Energy usage adjustment by customers to reduce their energy load at times of peak demand or other triggering event to relieve stress on the grid and promote system reliability.

What are the Qualifications for the Demand Response Program?

- Existing Building Energy Management System (BEMS)
- Ability to adjust operations between June 15 and October 15
- Ability to adjust operations between 1:00 PM and 5:00 PM PST
- Commitment to a minimum load reduction of 100 kW for each called-for DR Event during the curtailment season of June 15th through October 15th

What are the Demand Response Program Incentives?

- **Event Incentive**: Event Incentive is received based on the number of events and kWh participated within the Demand Response Curtailment Season
- **Capacity Incentive:** Savings by kW per month based on committed curtailment with minimum 50% performance during DR Event to receive this incentive. If no event is called during a given month, Capacity Incentives are guaranteed. It is calculated as 100% performance per committed curtailment
- **Equipment Incentive:** Up to 50% of the program approved Demand Response Automation Server (DRAS) client device (non-labor)after full participation and successful completion of the DR Program

When and how will I see my Demand Response Program Incentive?

- At the end of the curtailment season (June 15th – October 15th), the performance of the participant will be evaluated and calculated per DR Program specifications.

What are examples of Demand Response Measures that our facility could participate in load curtailment during a Demand Response Event?

- Dim or curtail selected lighting zones
- Global Temperature Set Point Adjustment (GTA)
- Pre-cool the building envelope

- Limit demand of electric equipment (ex. Chillers)
- Duty Cycle air-cooled Package Units (ex. 10 min on/10 min off)
- Reset Static Set Point Pressure Controls
- Curtail or disable selected elevators and/or escalators
- Variable Fan Speed Reduction (VSD/VFD)
- Curtail or reset industrial machinery or operations
- Limit or duty cycle garage exhaust fans

How do I Manage my Demand Response Program Participation?

- As a pre-requisite to be a participant, the customer must have a qualified BMS/EMS/BAS/SCADA/BEMS/EMG so the participation during the event can be monitored and managed.*

How do I ensure that Demand Response Events do not interfere with Facility Operations?

- As part of the DR Program you will receive a Complimentary Consultation to review your energy use and areas of possible curtailment specific to your business.
- Participation is voluntary; however the participant may not exceed 2 non-participatory events.
- All Demand Response measures will be identified and approved by you prior to any scope of work being implemented. You always have the option and ability to opt out per Demand Response measure during any DR Event.

Who controls energy curtailment at my facility?

- DWP initiates the notification for a DR Event. The participant then controls, defines and plans the curtailment.

Do we need to shut down our equipment during the DR Event?

- No. The DR Technical Team will work with you to help identify achievable DR load shed opportunities and measures which suit your operations. The Technical Team will also help you determine what level (s) of your DR curtailment (kW Shed) you will be able to comfortably manage during the DR curtailment season.

What type of Notification does the facility receive prior to a Demand Response Event?

- Potential option for one day ahead advance notice
- Potential option for two hour advance notice

How will I be notified when there is a Demand Response Event?

- Semi-Auto DR: Demand Response Event Notification will be passed to Participant via email or phone

What are potential reasons for a Demand Response Event to be called?

- High System Peaks
- Resource Shortage
- System Reliability
- Temperature
- System Contingencies

What is the duration of a Demand Response event?

- A Demand Response Event will not exceed four hours and is limited to one DR Event per day.

How many Demand Response Events will there be during the curtailment season of June 15 – October 15?

- There will be a maximum of 12 DR Events during curtailment season of the Demand Response Program.

What if we cannot participate for a particular Demand Response Event? Are there penalties?

- There are no penalties for non-participation in DR Events.
- The Participant may not exceed two non-participation events during the curtailment season otherwise Participant may not be able to continue with the DR Program.
- During the DR Event, the Participant's curtailment must be at a minimum of 50% committed load shed to be considered as being a valid Event Participation. The incentives received will however be proportional to the percentage of committed participation level.

What is the process for Support during the Demand Response Program?

- Your Premier Account Representative will be your main point of contact and will stay engaged for Support.
- A Demand Response Support number will be provided for use during the DR Event Curtailment Season to provide you with both technical as well as program support.

Can we aggregate multiple sites of a customer to participate?

- Yes

***BMS:** Building Management System	**EMS:** Energy Management System	**BEMS:** Building Energy Management System
BAS: Building Automation System	**EMG:** Energy Management Gateway	**SCADA:** Supervisory Control & Data Acquisition

Los Angeles Department of Water & Power

Demand Response Incentive Calculation Quick Reference Guide

KW Load Curtailed	* Capacity Incentive (2 Hour Notification)	* Capacity Incentive (24 Hour Notification)	** Event Incentive (4 hours)	Total Incentive (2 Hrs. Notification)	Total Incentive (24 Hrs. Notification)
100	$ 4,800	$ 3,200	$ 600	$ 5,400	$ 3,800
150	$ 7,200	$ 4,800	$ 900	$ 8,100	$ 5,700
200	$ 9,600	$ 6,400	$ 1,200	$ 10,800	$ 7,600
250	$ 12,000	$ 8,000	$ 1,500	$ 13,500	$ 9,500
300	$ 14,400	$ 9,600	$ 1,800	$ 16,200	$ 11,400
350	$ 16,800	$ 11,200	$ 2,100	$ 18,900	$ 13,300
400	$ 19,200	$ 12,800	$ 2,400	$ 21,600	$ 15,200
450	$ 21,600	$ 14,400	$ 2,700	$ 24,300	$ 17,100
500	$ 24,000	$ 16,000	$ 3,000	$ 27,000	$ 19,000
550	$ 26,400	$ 17,600	$ 3,300	$ 29,700	$ 20,900
600	$ 28,800	$ 19,200	$ 3,600	$ 32,400	$ 22,800
650	$ 31,200	$ 20,800	$ 3,900	$ 35,100	$ 24,700
700	$ 33,600	$ 22,400	$ 4,200	$ 37,800	$ 26,600
750	$ 36,000	$ 24,000	$ 4,500	$ 40,500	$ 28,500
800	$ 38,400	$ 25,600	$ 4,800	$ 43,200	$ 30,400
850	$ 40,800	$ 27,200	$ 5,100	$ 45,900	$ 32,300
900	$ 43,200	$ 28,800	$ 5,400	$ 48,600	$ 34,200
950	$ 45,600	$ 30,400	$ 5,700	$ 51,300	$ 36,100
1,000	$ 48,000	$ 32,000	$ 6,000	$ 54,000	$ 38,000
1,050	$ 50,400	$ 33,600	$ 6,300	$ 56,700	$ 39,900
1,100	$ 52,800	$ 35,200	$ 6,600	$ 59,400	$ 41,800
1,150	$ 55,200	$ 36,800	$ 6,900	$ 62,100	$ 43,700
1,200	$ 57,600	$ 38,400	$ 7,200	$ 64,800	$ 45,600
1,250	$ 60,000	$ 40,000	$ 7,500	$ 67,500	$ 47,500
1,300	$ 62,400	$ 41,600	$ 7,800	$ 70,200	$ 49,400
1,350	$ 64,800	$ 43,200	$ 8,100	$ 72,900	$ 51,300
1,400	$ 67,200	$ 44,800	$ 8,400	$ 75,600	$ 53,200
1,450	$ 69,600	$ 46,400	$ 8,700	$ 78,300	$ 55,100
1,500	$ 72,000	$ 48,000	$ 9,000	$ 81,000	$ 57,000
1,550	$ 74,400	$ 49,600	$ 9,300	$ 83,700	$ 58,900
1,600	$ 76,800	$ 51,200	$ 9,600	$ 86,400	$ 60,800
1,650	$ 79,200	$ 52,800	$ 9,900	$ 89,100	$ 62,700
1,700	$ 81,600	$ 54,400	$ 10,200	$ 91,800	$ 64,600
1,750	$ 84,000	$ 56,000	$ 10,500	$ 94,500	$ 66,500
1,800	$ 86,400	$ 57,600	$ 10,800	$ 97,200	$ 68,400
1,850	$ 88,800	$ 59,200	$ 11,100	$ 99,900	$ 70,300
1,900	$ 91,200	$ 60,800	$ 11,400	$ 102,600	$ 72,200
1,950	$ 93,600	$ 62,400	$ 11,700	$ 105,300	$ 74,100
2,000	$ 96,000	$ 64,000	$ 12,000	$ 108,000	$ 76,000

1. Capacity Incentive is calculated based on monthly DR performance. There are 4 months during the DR Season. The total numbers shown cover the incentives earned in 4 months.
2. Event Incentive is calculated based on the DR Event and duration (kWh). The event incentive is based on 6 DR Events per season and the duration of 4 hours each.
3. Two-Hour Advance notice participants earn $12/kW per month.
4. Day Ahead Advance notice participants earn $8/kW per month.
5. All participants earn $0.25 per kWh curtailed.

Application Form to Participate in Los Angeles Department of Water and Power Demand Response C&I Program

I have reviewed the Terms and Conditions of Los Angeles Department of Water and Power (LADWP) Demand Response C&I Program (Program) and would like to participate in the Program.

1. Name of Participant's Organization: ______________________
   (This name will appear on the incentive check.)

2. Participant's LADWP Customer Account Number(s): ______________________

3. Participant's Location/Building: ______________________

4. Location of Metering Equipment: ______________________

5. Estimated Peak Load Reduction Quantity in kW (Minimum Quantity is 100kW): ___________

6. Notification Type* (Please choose one):

   ☐ 2-Hour Advance Notification ☐ Day-ahead Advance Notification

   *If the applicant does not choose a notification type, default will be Day-ahead Advance Notification.

7. List Demand Response Measures that may be curtailed upon a Peak Load Reduction (PLR) Event notification:

   ____
   ____
   ____
   ____

8. Provide contact information, including name, address, email, and phone number, for **minimum of three (3) individuals** in the Participant's organization whom LADWP may contact regarding Program eligibility and termination, notice of PLR events, and Program participation results in additional to other general Program information.

	Name	Email Address	Phone Number	Text**
1				☐
2				☐
3				☐
4				☐
5				☐
6				☐
7				☐
8				☐

**The applicant may choose to receive the notifications of planned PLR events via text message, in addition to email.

I understand that participation in Los Angeles Department of Water and Power Demand Response Program is voluntary, and requires compliance with Program Terms and Conditions and LADWP Rules and Regulations. Questions about this Program and its eligibility requirements may be directed to LADWP at (213) 367-2712, or by email at: Hassan.motallebi@ladwp.com.

I state that the information I have provided in this application is true and correct. If LADWP so requests, I agree to provide additional documentation in order for LADWP to determine Program eligibility.

I hereby declare, on this_______day of____________, 20__ that I have read all Program documents provided by LADWP and agree to abide by the Program Terms and Conditions and all applicable Los Angeles Department of Water and Power Rules and Regulations. I certify that I am duly authorized to execute the application form and commit to this Program on behalf of ______________________. I agree to make best efforts to reduce the electrical loads outlined above each time LADWP calls a Peak Load Reduction Event.

Signature: ______________________________

Name: ______________________________ Company: ____________________

Title: ______________________________ Date: ____________________

LADWP Office Use

1. Applicant Number and Received Date:
2. Customer Eligibility: Load and load characteristic, Estimated PLR quantity, metering equipment, etc.
3. Program subscription level: full/ partial/ none
4. Customer Notification (within 3 business days)

Version 5.0 October 2018

Individuals with disabilities who require accommodations to access City facilities, services or programs, or who would like information on the City's compliance with the Americans with Disabilities Act (ADA) of 1990, may contact the City's ADA Coordinator at (213) 202-2764 (voice) or email disability@lacity.org

Submit Form

LADWP’s Energy Storage Projects

Los Angeles Department of Water & Power

CUSTOMERS FIRST

Microgrids and Energy Storage

Board of Water & Power Commissioners
February 12, 2019

Microgrids

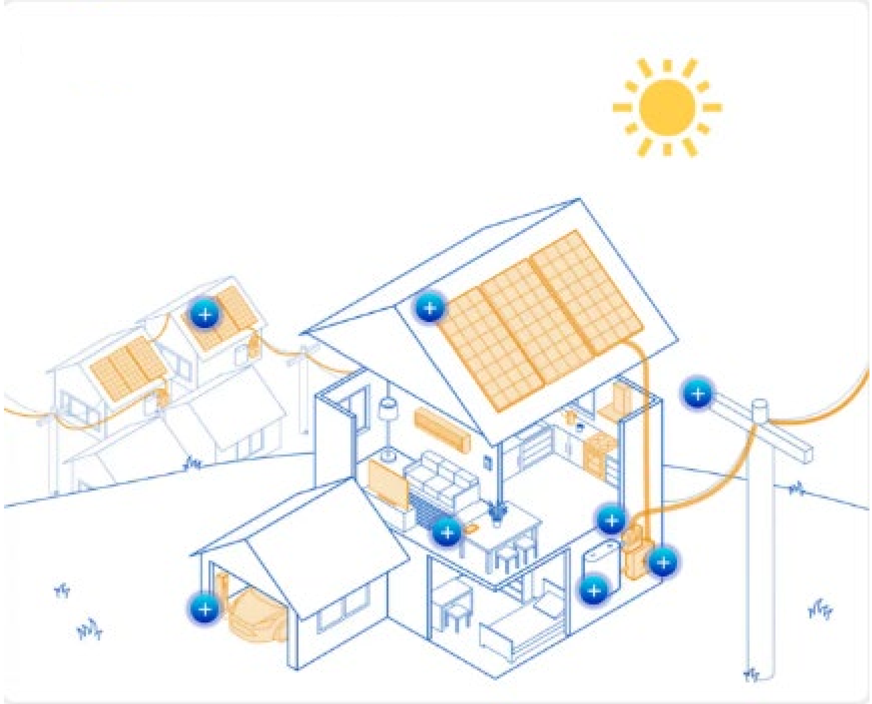
DOE: A group of interconnected loads and distributed energy resources (DER) with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid [and can] connect and disconnect from the grid to enable it to operate in both grid connected or island mode

Microgrid Benefits

- Provide resiliency—by generating or curtailing energy at customer sites and providing backup

- Promotes customer resources and sustainability

- Allows the customer to act as a Prosumer (Consumer and Producer of Energy and Services)



“If you’ve seen one solar plant,
you’ve seen them all.”

“If you’ve seen one microgrid,
you’ve seen one microgrid.”

David Chiesa, S&C Electric
Director, Global Business Development

LA DWP

Challenges & Technical Requirements

Challenges

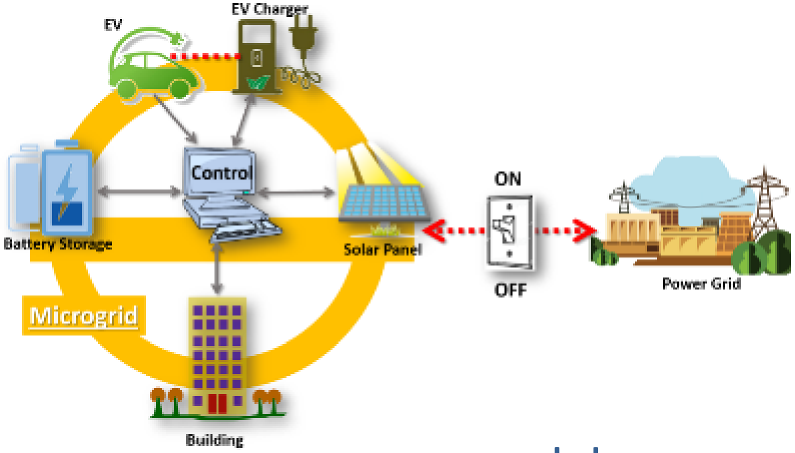
- Microgrids are very specialized and tailored to customer needs
- Microgrids are complex with multiple communication systems, consisting of DERs that need integration and ongoing maintenance

Technical Requirements

- Safe interconnection of microgrids per LADWP Electric Service Requirement and Local and National Codes
- Metering, measurement and verification of multiple components
- Utility communication and control for resource adequacy, deferral, and resiliency

Utility Considerations for Microgrids

- Align community and grid needs with microgrid operations
- Establish monitoring and control system (i.e. Distributed Energy Resource Management System)
- Integrate with other Microgrids and DERs for combined Grid Services
- Promote safety, reliability, resiliency, and potential sustainability



LA DWP

Microgrid Rates

Rates are available to customer based on their microgrid's size and type of resources

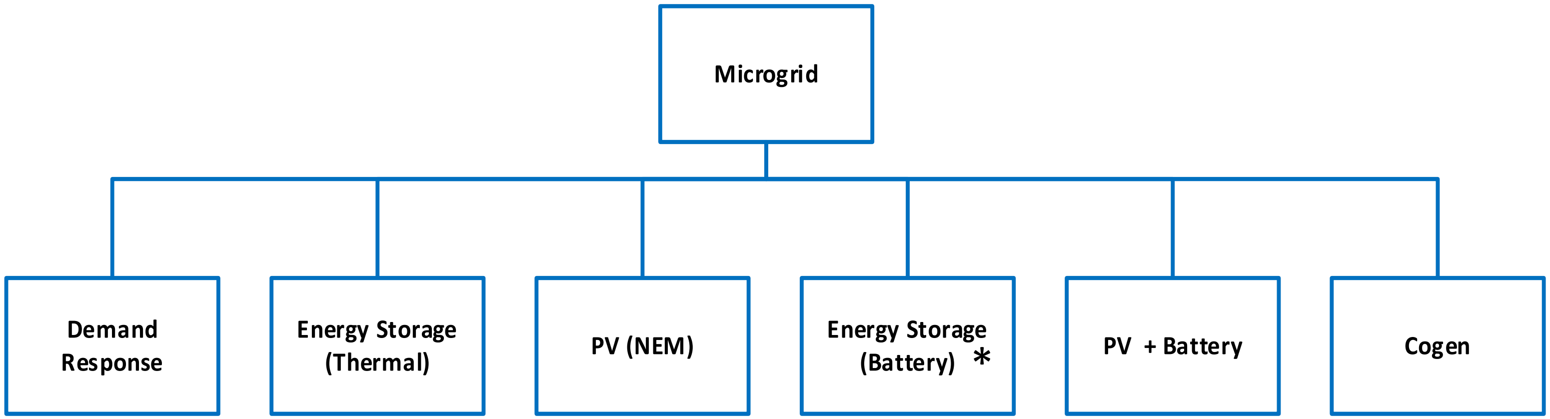
- Net energy metering rates may apply for renewable energy generation systems < 1MW
- Co-generation rate available for non-renewable generation and for renewable generation ≥ 1 MW
- Battery may receive incentive from Small-Generator Incentive Program from California Public Utilities Commission
- Thermal storage will receive appropriate incentives through the Custom Performance Program

Microgrid / Cogeneration Rates

- Allows large commercial generators to supply energy to the grid
- Currently over 300 MW on this co-generation rate (form of microgrid)
- UCLA (Central Plant) – 43.5 MW
- LAWA (Central Utility Plant) – 9.2 MW
- LA Sanitation, Hyperion (Digester Gas Utilization Project) – 23 MW

UCLA Cogeneration Plant

SB 1339 Compliance



	Demand Response	Energy Storage (Thermal)	PV (NEM)	Energy Storage (Battery) *	PV + Battery	Cogen
Interconnection Process	✓	✓	✓	✓	✓	✓
Special Rate or Incentive	✓	✓	✓	✓	✓	✓

✓: Interconnection or special rate/incentive exist

* Incentive available through the California Public Utilities Commission Small-Generation Incentive Program

Fire Station 28 Microgrid, Porter Ranch

- Completed in 2018
- 11 kW rooftop solar
- 12 kW, 40 kWh battery
- Future

  46 kW carport

  EV chargers

La Kretz Innovation Campus

- 170 kW Solar
- 60 kW Battery
- 20+ Level 2 Chargers
- 2 DC Fast Chargers
- Future
  - Additional solar & storage
  - Microgrid controller

LADWP

John Ferraro Building

- 130 kW solar
- Approx 200 EV chargers (fleet, employee & customer)
- 200 kW battery - construction phase
- Future
  - System to manage/optimize EV, solar, and storage resources

Green Meadows Recreation Center

- Backup Power for ADA-Compliant Cooling Center
- Produce Solar Energy for Shared Solar Pilot

- Project Scope
  - Rec & Parks (RAP) Partnership
  - EV chargers
  - 200 kW solar
  - 350 kW, 4 hr battery
- Schedule
  - 11/2018 Engineering Began
  - 4/2019 MOU with RAP
  - 7/2019 Construction Start

ladwp.com

Los Angeles Zoo Microgrid Feasibility

- Exploring Partnership with LA Zoo
- Backup Power for LA Zoo
- Solar, Battery, EV Chargers
- Would require agreement similar to Rec & Parks MOU

Energy Storage Goals & Drivers

- AB 2514 LADWP Board approved procurement target 178 MW by 2021

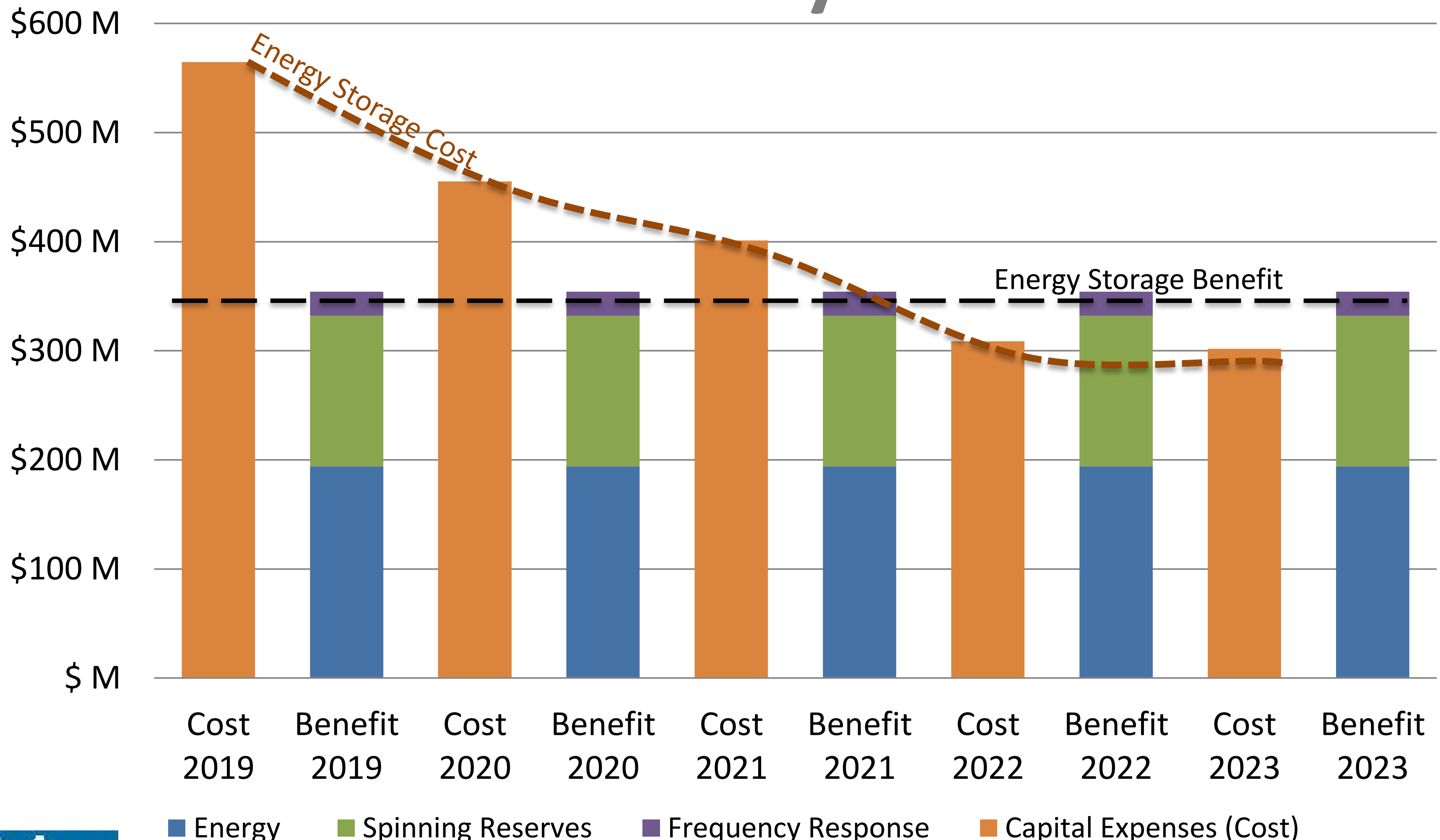
- Strategic Long Term Resource Plan (SLTRP) recommended case 404 MW by 2025

- SB 801 required cost-effectiveness study for 100 MW, 400 MWh storage

Energy Storage Accomplishments

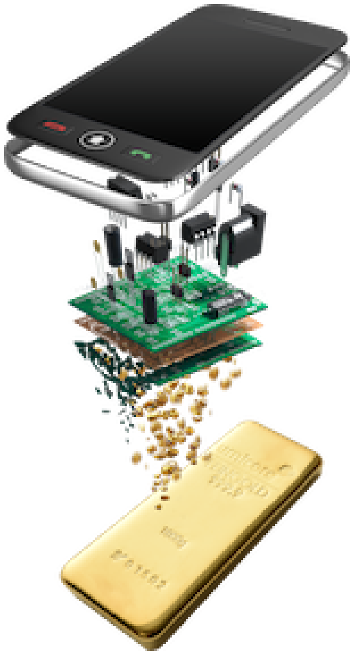
- Customer-owned: Over 500 Interconnection Applications totaling approximately 3.6 MWs
- Beacon Battery Energy Storage System, 20 MW – Completed October 2018
- Upgraded Castaic Power Plant, 21 MW - Completed 2013 – Total Plant Capacity for Storage 1,244 MW.

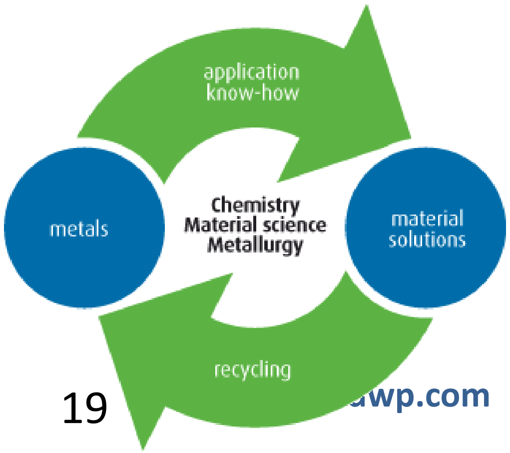
SB 801 Cost-Effectiveness Feasibility Study



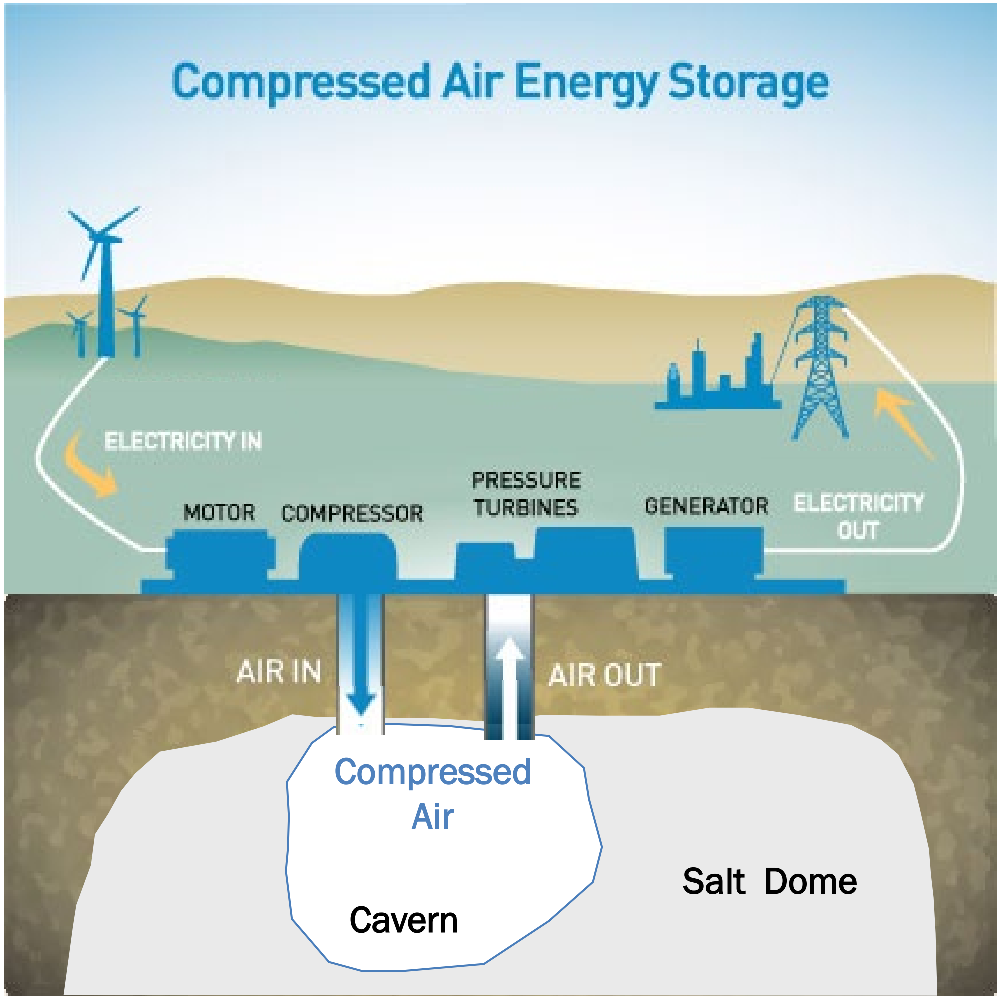
Lithium-Ion Battery End of Life

- Based on degradation and number of cycles, 7-10 yrs
- Potential re-use of battery cells in smaller applications
- Policies incentivize lithium ion recycling plants in parts of Europe
- Limited policy and R&D in United States, 3 recycling plants in North America
- Recycling costs ~$91,500/MWh
  - (Ex: Beacon BESS 20 MW / 10 MWh recycling cost estimate is $1 million to $1.5 million)





CAES Description



Existing CAES – Huntorf, Germany

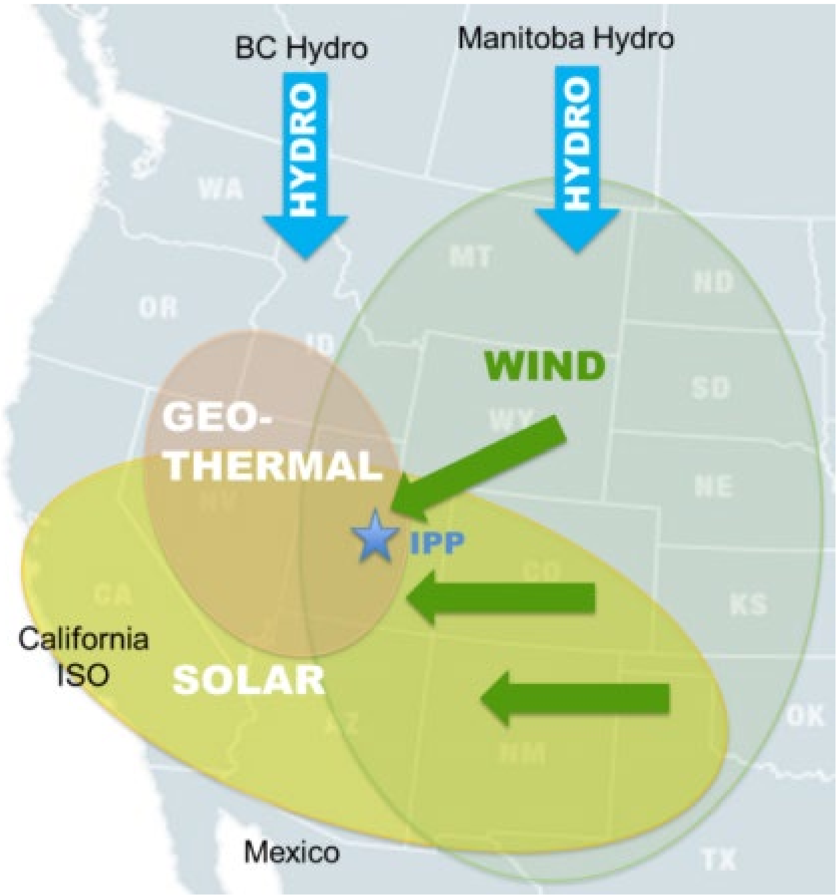
- Commissioned in 1978
- 290 MW; 4 hours duration, 10 hours (reduced load)
- Renewable source is wind
- Equipment by Alstom
- Used for black start, energy time shift, and regulatory requirements

Existing CAES – McIntosh, Alabama

- Commissioned in 1991
- 110 MW; 26 hours duration
- Source is nuclear nighttime power
- Equipment by Dresser Rand
- Used for energy time shift (peak shaving), and regulatory requirements

Compressed Air Energy Storage at IPP

- Need for large scale storage
- Ideal site
- RFP issued through SCPPA
  - Project Size: > 100 MW
  - Potential for multiple CAES Units at site
- Potential joint CAES project with several other IPP Participants



LADWP Next Steps

- Evaluation of Bid Proposals (April 2018 – April 2019)
- Negotiation of PPA (April 2019 – April 2020)
- LADWP Board and LA City Council Consideration of PPA (April 2020 – June 2020)
- Contract Award if Approved (June 2020)
- CAES In Service (November 2025)

LA DWP Los Angeles Department of Water & Power

CUSTOMERS FIRST

APPENDIX A.5

WORKSHOP NO. 5 – CALIFORNIA DEPARTMENT OF WATER RESOURCES

Workshop with Department of Water Resources (DWR) – State of California, Metropolitan Water District, and Stantec

Energy Sustainability Plan – Development of Renewable Energy Options

Date/Time:	June 21, 2019 / 2:00 PM
Place:	Conference Call
Attendees:	Shawn Bailey, Ha Nguyen, Austen Nelson, Heather Collins, Albrecht Grimm, Simon Calvet, Kyleen Marcella, Carla Cherchi, Yung-Hsin Sun, Tuan Bui, Ryan Wilbur, Scott Hunt, Tawnly Pranger
Distribution:	See Attendees

Welcome and Introductions (Stantec)

a. Meeting Purpose – The purpose of this conference call was to foster knowledge sharing on power operation of the State Water Project by California Department of Water Resources (DWR) to inform Metropolitan Water District (MWD or Metropolitan) in developing its Energy and Sustainability Management Plan

b. Call Participants Introduction (see Attendees list)

Overview of MWD's Renewable Energy Options Development Effort (MWD)

a. MWD's objective is to develop an Energy Sustainability Plan to position Metropolitan as a leader in energy sustainability.

b. MWD's interest includes:

   i. Review of available Energy Sustainability Plans and practices by others
   ii. Identify and evaluate renewable energy and energy storage opportunities:
      1. Renewable energy (solar, in-conduit hydropower)
      2. Energy storage systems (battery energy storage and pump storage)
      3. Emerging technologies
      4. Energy efficiency measures
      5. Operational strategies to manage energy demands and respond to new tariffs
      6. Efforts to reduce greenhouse gas (GHG) emissions and other sustainability practices
      7. Efforts to reduce energy consumption from pumping operations of the Colorado River Aqueduct (CRA).

State Water Project (SWP) Power Operation (DWR and group discussion)

a. The power optimization group at DWR for SWP energy management was formed around 2009, when the California Independent System Operator (CAISO) redesigned its market, to improve overall operation and cost efficiency.

i. Many conflicts exist between the price of generation and the price of pumping; therefore, optimization was needed to leverage more the off-peak pricing for pumping than the on-peak, within the water delivery and transmission constraints.

b. An optimization model for the pumping was built in MATLAB® with objective to minimize the cost of moving water.

    i. The model was first developed in 2009 by staff of the power optimization group and improved throughout the years.

    ii. The model was constructed based on a control volume approach with applicable ramping rates for flows and regulatory constraints. However, traveling times and hydraulic properties are not explicated considered.

    iii. The optimization model uses the optimization engine and routines in MATLAB®, looking at the economics of moving water and minimizing the overall costs of operation (i.e., pumping in the least expensive hours and generate in the more expensive).

c. On SWP power operation considerations and requirements

    i. DWR considers the overall conditions in the system, including considerations of high temperature days, the price differences between weekdays and weekends. For example, we tend not to move water during days with over 100 degree in the system (i.e., in Central Valley areas) and leverage the reservoirs for delivery during those days.

    ii. The big challenge is to get the water demands right; the data needed to run the model is built around a variety of Excel files.

    iii. DWR takes the information on the amount of water being released, the amount of water being diverted, and takes into account energy prices on an hourly basis, unit availability and the constraints of the system (e.g., maintenance). DWR has the opportunity also to bid or self-schedule into the market (the last is the most probable).

    iv. DWR participates to the CAISO market, the capacity market (not for all facilities, but only those who have more flexibility), the energy market (bid, load in and the self-schedule). The participation to the market is based on the outcomes of the model. DWR participates into the day ahead market and in the real time market.

    v. Depending on the time and season of the year, CAISO LNP in certain times has two price peaks. So, DWR moves the pumping to the cheapest time of the day.

    vi.

d. On pump unit scheduling

    i. Unit scheduling is one major focus in optimization. Over the past 10 years, DWR has been cycling the pumps based on the economics, while respecting the constraints of the system (physical constraints of the canal, or pump start/stops dictated by other divisions, canal storage capability).

        1. One of the constraints is the number of starts of the pumps. This is a parameter that is decided by various divisions. The design of many facilities was made long ago by the Department of the Interior, Bureau of Reclamation. It is a very inexpensive design; in fact, the pumps do not have a discharge valve. Our federal partners do not like to spend a lot of money on maintenance for those units.

        2. The maintenance keeps track of the number of starts and after a certain target is reached, they schedule a rebuilt of the motor. DWR's system was designed for peaking, so many parts are oversized, and they have extra capacity. Therefore, in case of maintenance DWR is not impacted.

3. DWR does not have a baseline to compare to, since it has operated the pumps with this pumping operation strategy for a long time. Before this current CAISO market, there was not a big change in the number of pump starts that DWR utilized.
4. DWR tries to keep the run hours of the units the same. The experience suggested that there is no efficiency or cost saving gains to run them differently. The schedule is generated and submitted to CAISO. In other words, they do not consider any one unit as a reliable unit, and spread the operations to all units.

ii. Other limiting factors to monitor in the pumps are:

1. Number of starts (some pumps becomes vulnerable after a certain number of starts);
2. Discharge valve constraints (how much leakage collected);
3. Maintenance of the discharge line (every 2-3 years);
4. Maintenance of motors;
5. Storage availability between plants, and the time the water takes to accelerate from one plant to another.
6. Pumps were always set up to do peaking, so they do not have vibration monitoring in it.
7. In the DWR system, if DWR peaks one plant, the other also needs to peak otherwise the water will not stay in the canal (overflow).
8. The field division at Pearblossom Pumping Plant does not like the air system (soft start system), since they claim it does not work properly and seems to be causing more wear and tear of their motors. However, the air system is working well at other sites. These are all original systems, nothing new was installed, and they have maintenance programs scheduled on them.
9. Dos Amigos Pumping System has VFDs, all other systems do not.

e. What may be the priority for system improvement that would benefit power management if not the SWP operation as a whole?

i. Capacity correction – in particular, the portion of the California Aqueduct in the Central Valley

ii. More variable units on the system for additional flexibility

iii. More robust equipment (to replace those installed in the 60's);

iv. The additional offsite storage along the conveyance for operation flexibility. The example was the forebay for the East Branch. Depending on the cost differential on-peak and off-peak, the infrastructure investment for the operation flexibility may not be economically justifiable.

The conference call adjourned at 3:00 PM

The foregoing is considered to be a true and accurate record of all items discussed. If any discrepancies or inconsistencies are noted, please contact me immediately.

Stantec Consulting Services Inc.

Simon Calvet PE
Civil/Environmental Engineer
Phone: +1 626 568 6077
simon.calvet@stantec.com

APPENDIX D

Development of Renewable Energy and Energy Storage Options

DEVELOPMENT OF RENEWABLE ENERGY AND ENERGY STORAGE OPTIONS

Stantec

Technical Memorandum No. 2

Development of Renewable Energy and Energy Storage Options

November 12, 2020

Prepared for:

Metropolitan Water District of Southern California

Prepared by:

Stantec Consulting Services Inc.

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Abbreviations

AEPCO	Arizona Electric Power Cooperative
BESS	Battery Energy Storage System
CAISO	California Independent System Operator
CAP	Climate Action Plan
CARB	California Air Resources Board
CEC	California Energy Commission
CLAP	Custom Load Aggregation Point
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CRA	Colorado River Aqueduct
CRDC	Capacity Reservation Demand Charge
DVL	Diamond Valley Lake
EMMP	Energy Management Master Plan
EMRS	Energy Management and Reliability Study
EMS	Energy Management System
ESP	Energy Sustainability Plan
FRD	Facilities Related Demand
GHG	Greenhouse Gas
HEP	Hydroelectric Plant
IER	Institute of Energy Research
ITC	Investment Tax Credit
KPI	Key Performance Indicator
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LCOE	Levelized Cost of Energy
LED	Light-Emitting Diode
LEED	Leadership in Energy and Environmental Design
LMP	Locational Marginal Pricing
Metropolitan	Metropolitan Water District of Southern California
MG	Million Gallon
MGD	Million Gallon per Day
MW	Megawatt
MWh	Megawatt-hour
NMC	Nickel Manganese Cobalt Oxide
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PCS	Pressure Control Structure
PPA	Power Purchase Agreement
PPI	Pump Performance Indicator
PV	Photovoltaic
RA	Resource Adequacy

REC	Renewable Energy Certificate
RES-BCT	Renewable Energy Self-Generation Bill Credit Transfer
RPS	Renewable Portfolio Standard
RPU	Riverside Public Utilities
SAM	System Advisory Model
SB	Senate Bill
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SoCalGas	Southern California Gas Company
SGIP	Self-Generation Incentive Program
SWP	State Water Project
TM	Technical Memorandum
TOU	Time-of-Use
TRD	Time-Related Demand
VFD	Variable Frequency Drive
VSD	Variable Speed Drive
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WTP	Water Treatment Plant

1.0 INTRODUCTION

Energy management is of critical importance to enabling and furthering the Metropolitan Water District of Southern California's (Metropolitan) mission, which is to provide its service area with adequate and reliable supplies of high-quality water to meet present and future needs in an environmentally and economically responsible way. In this context, the Energy Management Policies adopted by Metropolitan in August 2010 (MWD, 2010) state that any and all future energy-related projects, programs, and initiatives should be based on:

- Containing costs and reducing Metropolitan's exposure to energy price volatility;
- Increasing operational reliability;
- Providing a revenue stream to offset energy costs; and
- Moving Metropolitan towards energy independence and sustainability.

These policies were adopted following Metropolitan's 2009 Energy Management and Reliability Study (EMRS) that served as a blueprint for future energy management strategies and initiatives (MWH, 2009). Metropolitan further solidified the focus and importance on energy management by developing an Energy Management Master Plan (EMMP) and the associated roadmap from which cost-effective projects were brought to Metropolitan's Board on a case-by-case basis for consideration.

1.1 DRIVERS FOR AN ENERGY MANAGEMENT STRATEGY UPDATE

Metropolitan has implemented many of the initiatives recommended in the 2009 EMRS with positive impacts on its energy management and supply portfolio. However, subsequent changes in California's energy market have warranted a review and update of Metropolitan's move-forward strategy for effective and sustainable energy management. The following provides a summary of these changes:

- **California's energy and environmental goals drive changes:** Power utilities are subject to increasing regulations for security and reliability of their supply and their interaction with the electrical grids. In addition, California is leading the nation with energy and environmental policy initiatives that are driving electrical grid changes. Key initiatives include achieving 60 percent of California utility-provided electricity from renewable power sources by 2030, and 100 percent from "carbon free" sources by 2045 under the latest Senate Bill (SB) 100 of 2018 (SB 100, 2018); reducing greenhouse gas (GHG) emissions below 1990 levels; implementing regulations requiring power plants that use coastal water for cooling to either repower, retrofit or retire within the next decade; affirming policies to increase distributed generation; and an executive order for 1.5 million zero emission vehicles by 2025 (CAISO, 2016). In particular, under AB32, the California Air Resources Board (CARB) has implemented a cap and trade system for CO_2 reduction.

These policies and goals are fundamentally changing the electric grid and its operation. The California Independent System Operator (CAISO) identified that the increasing renewable energy entering into the market requires short, steep ramps of flexible generation in response, and mitigates the risks associated with overgeneration and weakened system frequency responses to maintain grid reliability. In 2013, the CAISO published a chart—the “duck curve”—representing the difference between forecasted load and expected electricity production from variable generation resources to illustrate the changing conditions in future “greener” scenarios (CAISO, 2016). This chart shows that in certain times of the year, a significant drop on the load on conventional fossil energy generators is achieved during mid-day, caused by the large power input from solar resources (Figure 1-1). This effect causes a surge in generation demand at sunset when solar facilities go off-line with a corresponding risk of over-generation during the middle of the day, and an increase in the steepness of the load curve for conventional generation (e.g., gas turbines) during the late afternoon and evening. Due to this effect, the volatility of daily wholesale energy market prices has increased, with hourly prices ranging from greater than $1,000/MWh to less than $0/MWh. Thus, the “duck curve” illustrates the potential for solar power generation to provide more energy than can be used by the system, especially considering the host of technical and institutional constraints on power system operation. The volatility of the wholesale energy market will likely increase as time goes on (i.e., a deepening duck curve) as more utility-scale solar energy facilities are brought on-line. While balancing the grid is always a challenge, the duck curve signals an important change in attitude in recognizing the high penetration of variable generation from renewable sources and the need for new operating practices that allow greater system reliability and flexibility. Two types of response have been deployed in the market: The first is to "fatten" the duck by increasing the flexibility of the power system—which means changing operational practices to enable more frequent power plant cycling, starts and stops, and so on. The second is to "flatten" the deepened duck curve by shifting supply and demand so solar can meet parts of the load that would not normally be provided in the middle of the day, e.g., adding energy storage systems to store excess solar generation or demand response.

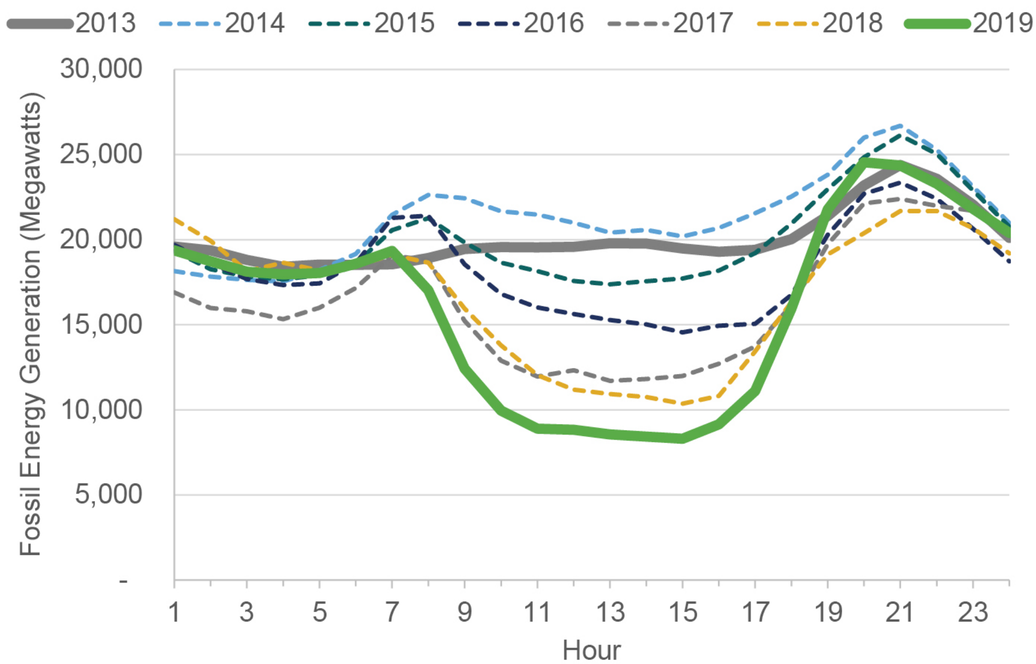

Figure 1-1 CAISO's "duck curve" with net load from fossil fuel generation plotted versus time for a spring day in California (IEA, 2019)

- **Metropolitan's investment preferences in reaction to changing water supply outlook drive operation changes:** Changes in Metropolitan's investment and operation could also impact its strategy for energy management. An example is the recent Metropolitan water reuse initiatives developed over the last decade, including its plan to develop a new regional water reuse facility, to increase regional self-reliance and mitigate the potential water supply impacts by reducing reliance on the State Water Project (SWP) supply (MWD, 2018). This practice could significantly change Metropolitan's energy profile because the required pumping and treatment process will require a higher energy demand. Metropolitan's current energy use and cost is dominated by the energy requirements of SWP (Figure 1-2). However, the new regional water reuse facility is estimated to require approximately 80 megawatts (MW) at full capacity which would increase the electricity requirements of the distribution system to 105 MWh which is 140 percent more than the historical average (MWD, 2016). This project is expected to be phased over multiple years. However, it is assumed that an increase in energy from the recycled water facility would be countered by less imported water.

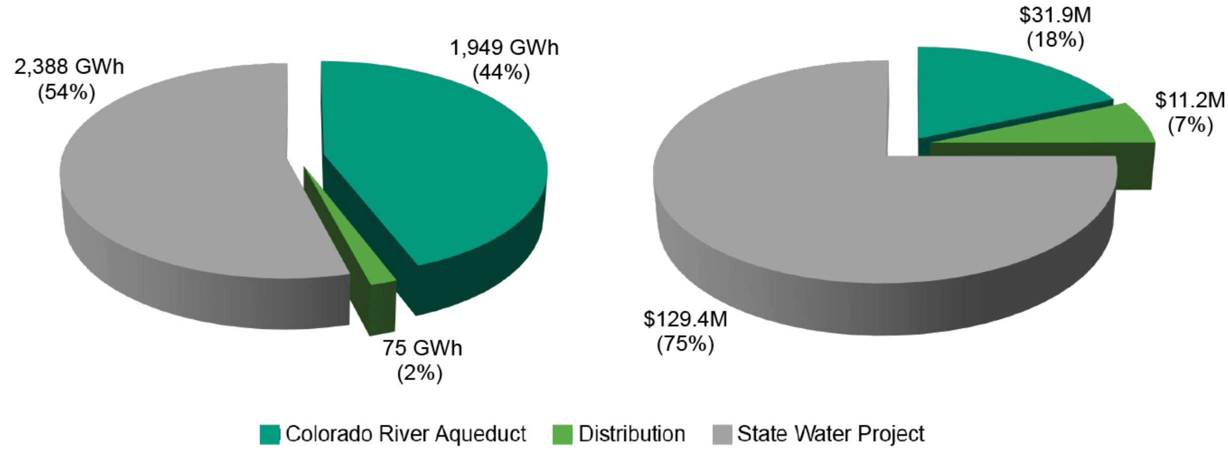

Figure 1-2 Metropolitan's electricity requirements and cost (average 2013-2018)

Additionally, Metropolitan's Colorado River Aqueduct (CRA) power system experienced significant contractual changes recently. The 1987 agreement with Southern California Edison (SCE)— in which SCE provided energy, interconnection and transmission services to Metropolitan—terminated on September 30, 2017 (MWD, 2017a). In addition to its agreement with the Arizona Electric Power Cooperative (AEPCO) and SCE, Metropolitan successfully negotiated, executed, and implemented a new 50-year agreement with the Western Area Power Administration (WAPA) to maintain Metropolitan's interconnection with the Hoover and Parker Power Plants. New long-term agreements with CAISO and AEPCO were executed for CRA power deliveries that began on October 1, 2017. The operating agreement with CAISO establishes the operational relationship between CAISO and Metropolitan, for Metropolitan's operation within the region controlled by CAISO. The agreements with AEPCO provided for energy scheduling and trading services as well as power system operations services. The operations services agreement established AEPCO as the transmission operator for the CRA and identified tasks to be delegated to Metropolitan to comply with the national electricity reliability standards.

The previous Hoover Electric Service Contract terminated on September 30, 2017 (MWD, 2017b). Historically, the power supply from Hoover Dam provides approximately 50 percent of the energy needs for CRA operation. Metropolitan and the other Hoover power contractors successfully negotiated a new contract with WAPA and the Bureau of Reclamation in 2017. The new Energy Service Contract and Implementation Agreement provided Metropolitan with 95 percent of its previous share of the Hoover project, energy, and capacity, for a period of 50 years (2017–2067). While the power allotment percentage is similar, the new contract contains new conditions for voluntary reallocation that allows a number of the contractors to back out of their agreement under certain conditions, creating additional financial risks for others. In addition, there are also concerns over future changes in hydrology which may result in reduction in power generation and thus, increase energy unit costs. The effects of all of these new contractual arrangements may be understood in time; however, they create short-term and medium-term uncertainties for energy costs and associated reliability for CRA operation.

- **New and maturing technologies and market offerings in response to new energy grid operating conditions drive changes and present opportunities:** New technological advancements and improved practices in energy efficiency, renewable energy and energy storage sectors provide additional viable options for Metropolitan's long-term energy management. For example**,** maturing battery energy storage system (BESS) technology provides an option for energy regulation and savings along with the potential for added reliability in a microgrid configuration. In the past several years, Metropolitan has also installed several solar power generating facilities to diversify its energy portfolio, reduce costs, increase Metropolitan's energy independence and lower Metropolitan's overall GHG emissions. The capital costs for installing solar power generating facilities have drastically decreased in recent years but has been countered by other factors. Power utilities have ramped down their incentives for additional solar installation and have modified their tariff rate structures by shifting the peak period to a later part of the day, due to the deepening of the duck curve, resulting in reduction in potential cost savings from self-produced solar energy. Many water utilities in California also installed in-line hydropower units to recover energy in their system to offset energy demand (CEC, 2020). Similarly, pumped-storage systems that fell out of favor in the past decades are now becoming more economically competitive because of the changes in California's energy market rate structure and the need for storing supplies of renewable energy on the market.

1.2 DEVELOPMENT OF AN ENERGY SUSTAINABILITY PLAN

Considering the rapidly changing energy market and related regulations, and new technological opportunities on the horizon, it is an opportune time for Metropolitan to develop a new Energy Sustainability Plan (ESP) and a new roadmap for the upcoming years. The development of the ESP and associated roadmap will be conducted as a multiphase approach, presented in Figure 1-3 and consists of the following:

- Summarize the state of knowledge on energy sustainability practices in the water sector, as documented in technical memorandum (TM)-1;
- Identify renewable energy and energy storage project opportunities and determine their financial feasibility and associated environmental benefits in CO_2 reduction; and
- Develop the ESP and related implementation roadmap using a multicriteria evaluation methodology for project evaluation in its contributions to Metropolitan's long-term energy sustainability.

The ESP will support Metropolitan's Climate Action Plan (CAP), which inventories existing and historical greenhouse gas emissions, setting a target for emissions reductions and developing actions to meet the target. In this context, the purpose of this TM-2 is to identify and select potential renewable and energy storage opportunities at select Metropolitan sites (e.g., water treatment plants [WTPs], CRA).

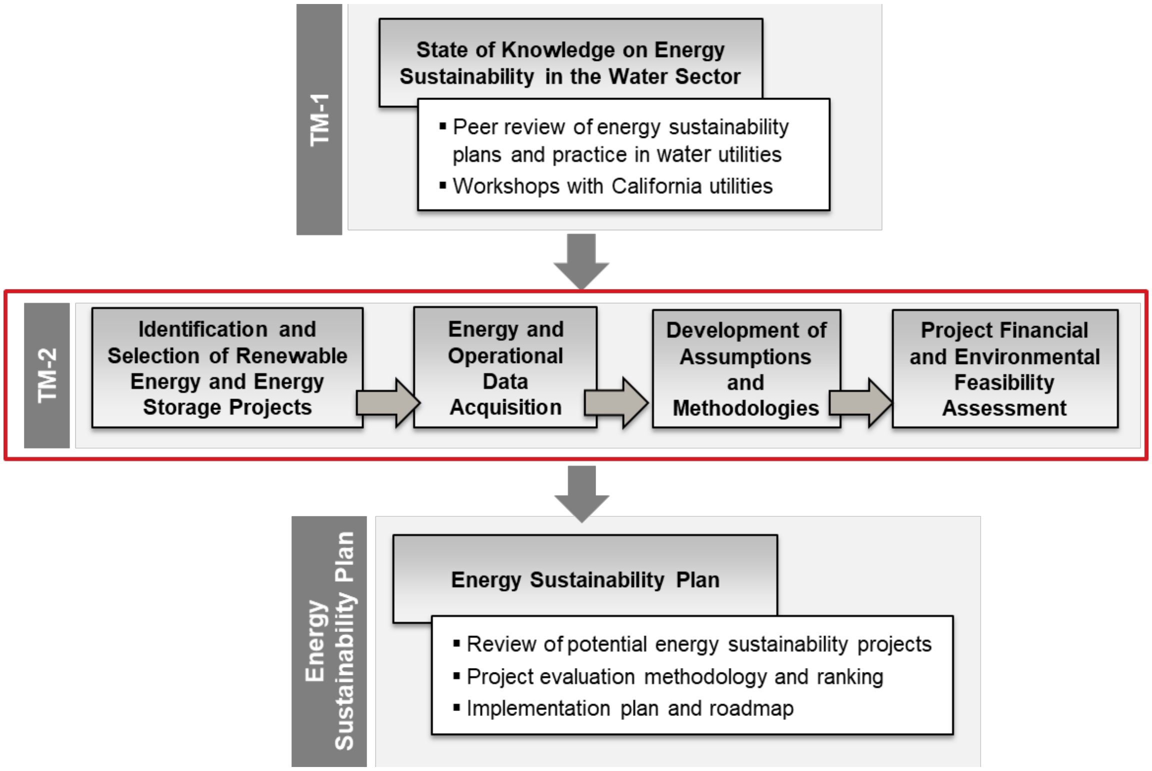

Figure 1-3 Conceptual approach used to develop Metropolitan's Energy Sustainability Plan (topics covered in this TM are highlighted in red)

1.3 OBJECTIVES

The objective of this TM is to assess the financial and environmental feasibility (in terms of carbon emission reduction only) of selected renewable and energy storage projects identified in Metropolitan's facility portfolio. Table 1-1 provides an overview and details of the selected projects. The selection of projects was based on the findings of the previous EMRS and peer-review evaluation of previous energy management efforts at Metropolitan, other proactive peer water and wastewater utilities' activities, and discussions with Metropolitan staff. The projects differ based on the type of facility and energy management project, the retail energy provider versus the wholesale market they participate in, and the type of feasibility assessment conducted (e.g., levelized-cost based assessment, project-based evaluations, or updates of previous studies).

Table 1-1 Renewable and energy storage projects considered for feasibility assessment

Energy Market/ Energy Provider	Project Location	Technology/Project
Retail: Southern California Edison (SCE)	Weymouth WTP	BESS with existing solar or grid
	Skinner WTP	Solar expansion
		BESS with solar expansion
		BESS with existing solar or grid
	Diemer WTP	Yorba Linda connected behind SCE meter
	OC-88 Pumping Plant	BESS (stand-alone)
Retail: Riverside Public Utilities (RPU)	Mills WTP	New solar
		BESS with new solar
		BESS (stand-alone)
Retail: Los Angeles Department of Water and Power (LADWP)	Jensen WTP	BESS with existing solar or grid
Wholesale: California Independent System Operator (CAISO)*	Distribution system	Small-scale hydroelectric facilities
		In-line hydroelectric facilities
		Diamond Valley Lake pumped storage
	CRA	Copper Basin pumped storage
		Third-party developer pumped storage
		Large-scale solar
		Large-scale wind
		BESS (stand-alone)
		Operational flexibility

BESS = battery energy storage system

CRA = Colorado River Aqueduct

WTP = water treatment plant

*CAISO is a public-benefit corporation in charge of operating the wholesale power grid and provides balancing area services to support CRA operations

Other utility-wide energy management initiatives including energy efficiency measures, cost management strategies and best management practices are discussed and recommended but not included on a project-level basis.

1.4 REPORT ORGANIZATION

This TM is organized into the following sections:

- Section 1: Introduction
- Section 2: Methodology
- Section 3: Renewable Energy and Energy Storage Project Opportunities Addressing Retail Electricity Rates
- Section 4: Renewable Hydropower Project Opportunities Addressing Wholesale Electricity Rates for the Distribution System
- Section 5: Renewable Energy and Energy Storage Project Opportunities Addressing Wholesale Electricity Rates for CRA Pumping Operations
- Section 6: Carbon Emissions Reduction Assessment of Renewable Energy and Energy Storage Projects
- Section 7: Other Energy Management Initiatives and Recommended Practices
- Section 8: Summary and Recommendations
- Section 9: References

2.0 METHODOLOGY

This section details the approach used to assess the financial and environmental feasibility of selected renewable and energy storage project opportunities at Metropolitan, within the context of developing an ESP, as presented in Figure 1-3. The methodology used for the purpose of this TM is summarized in Figure 2-1.

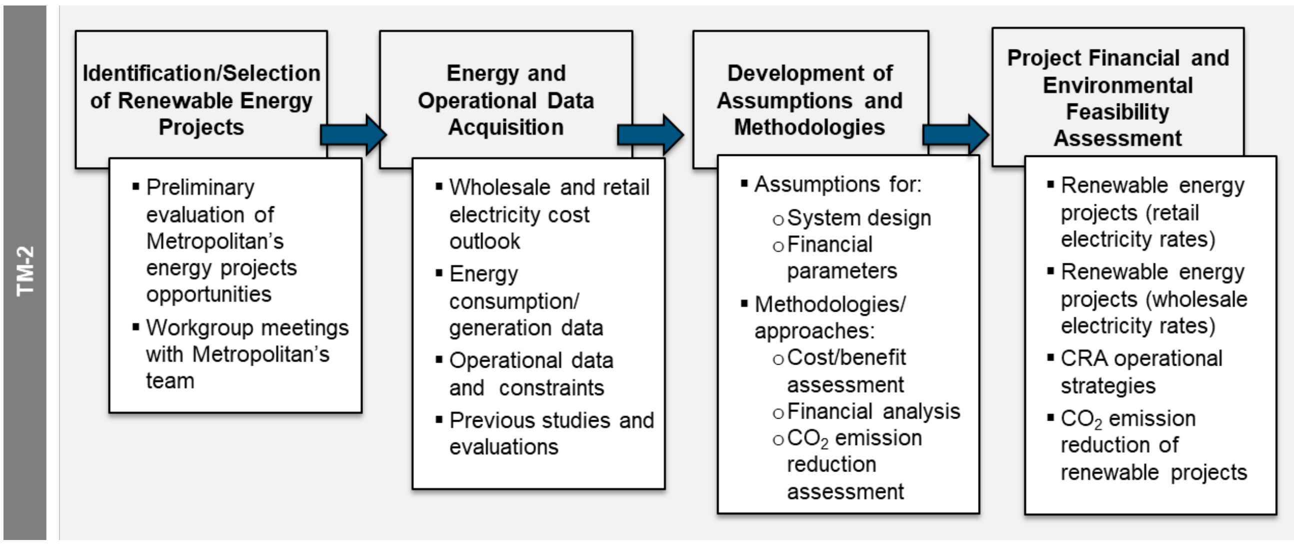

Figure 2-1 Conceptual methodology used for the purpose of this TM

The following subsections present the summary of assumptions and methodologies used in the financial and environmental feasibility assessments, particularly pertaining to the following:

- Energy cost outlook and related assumptions considered for wholesale and retail electricity rates;
- Capital and operations and maintenance (O&M) cost assumptions for various renewable energy and energy storage projects considered to address wholesale and retail electricity rates;
- Financial model assumptions and methodology developed to determine cost feasibility of the identified renewable energy and energy storage options; and
- Carbon emission reduction assessment assumptions and methodology applied to the renewable energy and energy storage alternatives

2.1 ENERGY COST OUTLOOK

Metropolitan purchases both wholesale and retail electricity to meet its energy demand. Energy price outlooks for both wholesale and retail energy were obtained and adapted from the Winter 2018 Wood Mackenzie report and were used to develop the cost feasibility of the various renewable energy and energy storage options for Metropolitan. The report focused on the Western Market Outlook (WECC – Western Interconnection) with North American influencer assumptions. The WECC consists of the provinces of British Colombia (BC) and Alberta, 14 western states and northern Baja Mexico. The outlook considered the energy market and cost aspects and opportunities within all of WECC as well.

Due to the complexities of forecasting wholesale energy prices, Metropolitan obtained a second wholesale energy forecast from S&P Global Platts (Platts) for the years 2025 and 2030 to provide an alternative range of future energy pricing to that provided by Wood Mackenzie, for project opportunities directly affected by this market. A summary of the energy outlook data relevant to the scope of this study is provided in the following sections.

2.1.1 Wholesale electricity cost outlook

The wholesale electricity price in any hour reflects the cost of generating electricity and delivering it over the transmission system, with fluctuations dependent on system conditions (e.g., the amount of consumer demand on the system at a given time, transmission constraints, line losses, and fluctuations in the price of fuel and availability of renewable energy). Wholesale electricity is purchased by Metropolitan in bulk, either from the CAISO at market rates or from the federal government (Hoover and Parker Dams, typically below market rates), to meet the CRA pumping energy demand. Wholesale electricity rates are typically lower than the retail counterparts, as wholesale rates usually include only generation costs. In particular, per its congressional authorization, Metropolitan’s Hoover Dam power contract (which expires in 2067) is strictly cost-based with cost containment provisions.

In addition, Metropolitan owns and operates 15 small hydropower facilities within its distribution system that generate renewable power. These facilities generate Renewable Energy Credits (REC), which can be sold to electric utilities to meet their Renewable Portfolio Standard (RPS) requirements.

2.1.1.1 CAISO SP15 yearly wholesale electricity cost

The CAISO South of Path 15 (SP15) zone wholesale electricity cost outlook was provided by Wood Mackenzie for the 2019–2040 period and is presented in Figure 2-2 (Wood Mackenzie, 2018). It should be noted that these projections assume a federal carbon pricing framework for all power systems in the US starting in 2028 which will increase the cost of fossil fuel generated energy in the wholesale market. The wholesale energy price trend is anticipated to remain fairly stable from 2019 ($33.33/ megawatt-hour [MWh]) to 2027 ($33.81/MWh) due to coincidental growth of renewable penetration and energy demand in California. Prices are anticipated to increase starting in 2028 and to reach $54.26/MWh in 2040 due to anticipated increase in natural gas prices as well as an assumed federal carbon pricing effective from 2028. On an average annual basis, the Platts forecast is not significantly different than the Wood Mackenzie forecast. The differences in the forecasts are more evident for granular time periods (e.g., hourly), as detailed in Section 2.1.1.2.

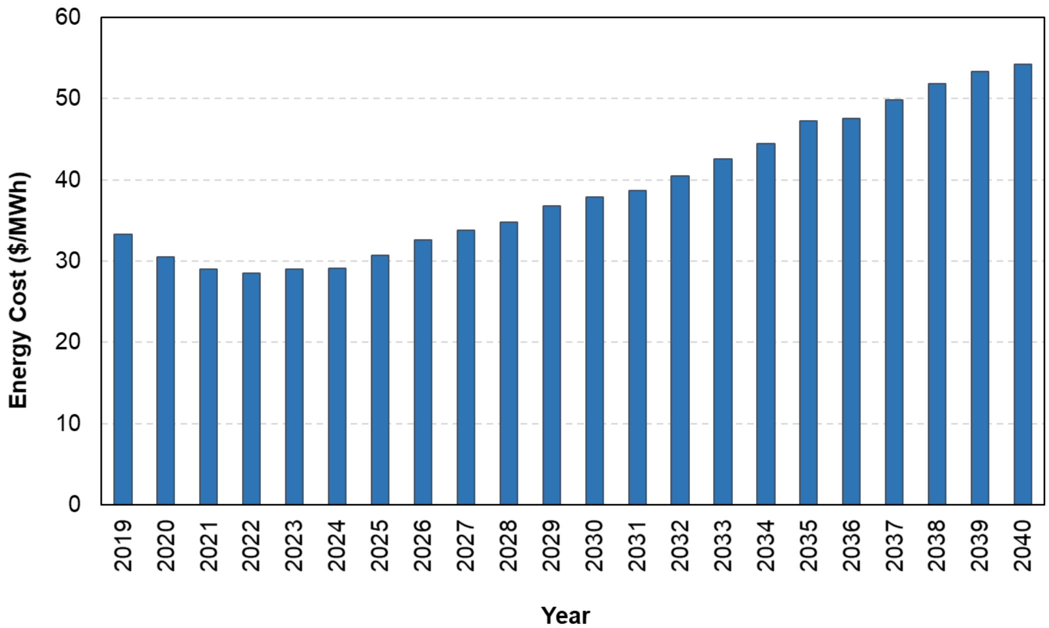

Figure 2-2 CAISO wholesale energy price outlook (in 2019 dollars) for the South of Path 15 (SP15) zone for the period 2019–2040 (Wood Mackenzie, 2018)

Metropolitan also generates renewable energy credits (RECs) when operating its hydropower system. These RECs can be sold, either with the energy as a bundle or separately on the REC market. The REC market price outlook was also provided by the Wood Mackenzie report for the period of 2019–2040 and is summarized in Figure 2-3 (Wood Mackenzie, 2018). The REC price is anticipated to increase in the period between 2019–2025, from $1.39/MWh to $11.32/MWh, and to later decrease to $0.34/MWh in 2040 when the solar penetration at the state level begins to level out. The projected hydropower wholesale selling price outlook presented in Figure 2-4 was calculated by adding the REC prices to the CAISO SP15 wholesale energy price outlook previously presented in Figure 2-2 .

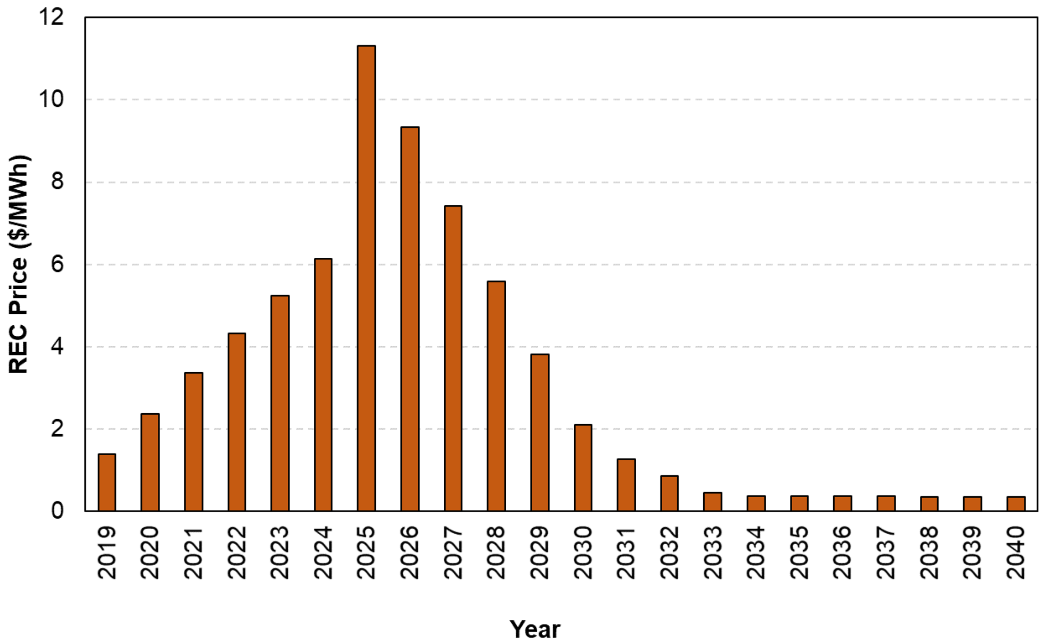

Figure 2-3 RECs market price outlook for the period of 2019–2040 (in 2019 dollars)

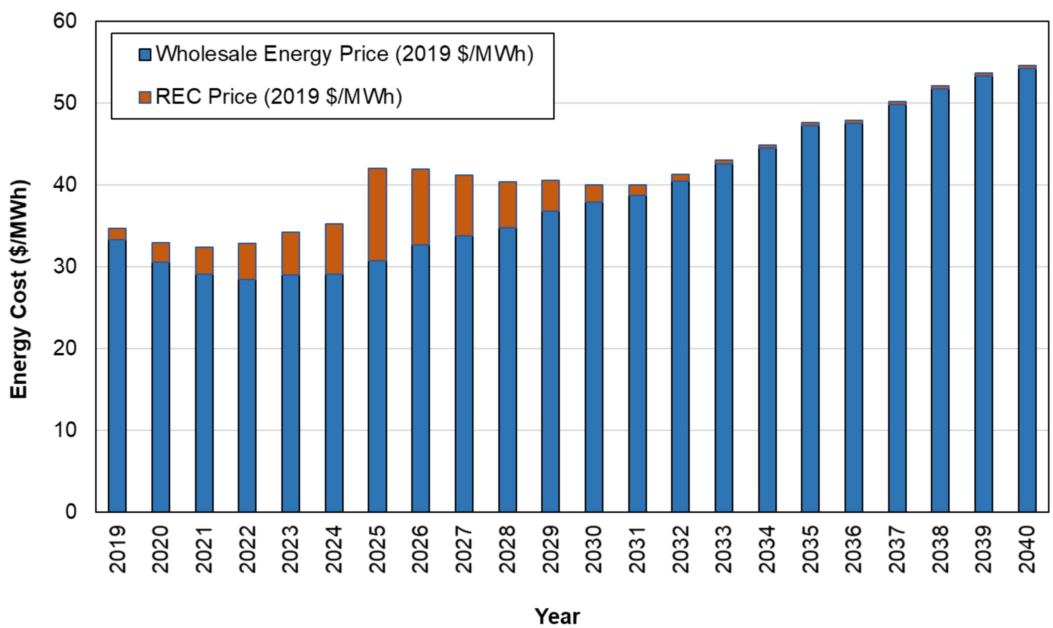

Figure 2-4 Hydropower wholesale selling price outlook for the period 2019–2040 (in 2019 dollars)

It is worth noting that although projections anticipate hydropower energy selling prices of $34.72/MWh in 2019, Metropolitan has observed a higher realized selling price of $54/MWh. To compensate for the difference between the projected and observed hydropower energy selling prices, an adjusted hydropower energy selling price (inclusive of RECs) for a given year was developed by applying an adjustment factor to the 2019 hydropower energy selling price, that is the ratio between the hydropower energy selling price in the given year and that in 2019— both from the Wood Mackenzie wholesale selling price outlook (Figure 2-5). The premium of about $22/MWh that Metropolitan has recently observed may not be realized in the future. Therefore, the economic evaluations of hydropower projects in this study that utilized these rates were assessed using both the marginal renewable energy cost with and without the $22/MWh premium to account for the possible range of outcomes.

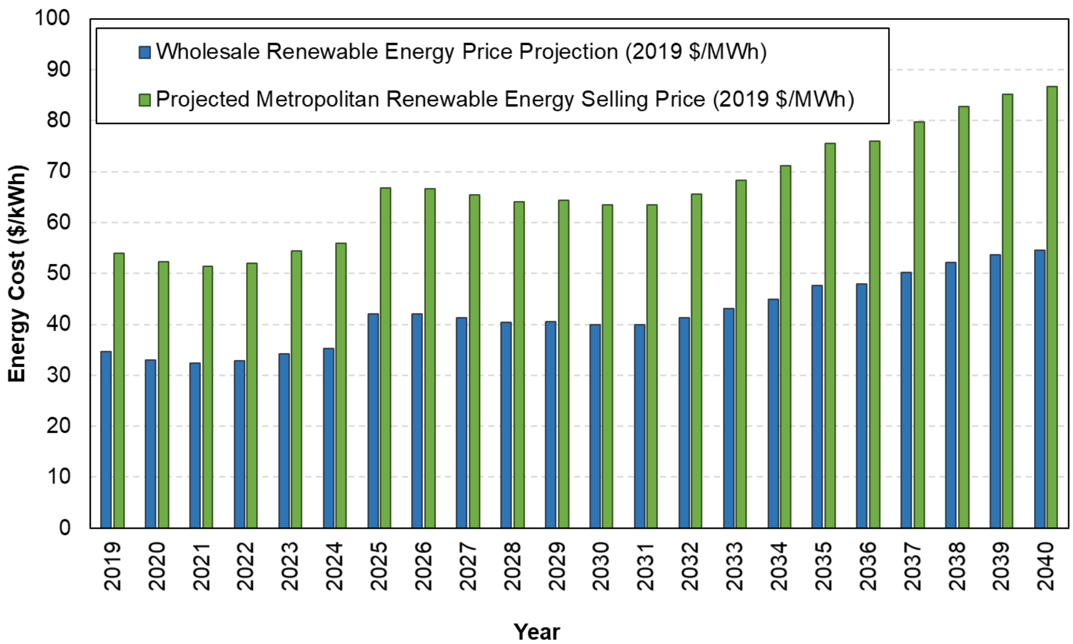

Figure 2-5 The adjusted hydropower wholesale selling price outlook for the period of 2019–2040 (in 2019 dollars)

2.1.1.2 CAISO SP15 average hourly electricity cost

To evaluate the feasibility of renewable energy and energy storage options addressing the wholesale electricity market conditions in Southern California, hourly and seasonal fluctuations of the CAISO SP15 trading hub's electricity prices were evaluated. Figure 2-6 shows the projected hourly fluctuation of the SP15 electricity prices in an average day (calculated as an average of the energy prices at the same hour throughout the year of data) over three years that are representative for this study (i.e., 2023, 2030, and 2040). Lower wholesale energy prices are observed in periods when the solar production in the state is at its maximum (i.e., 11 a.m. to 3 p.m.) and are higher in the evening time when the solar production ends (i.e., 7 p.m. to 10 p.m.). Seasonal variations of the wholesale energy price are also observed in Figure 2-6, with higher energy prices anticipated for the period of July–October and the lower price from April–June. These values were also obtained from the Winter 2018 Wood Mackenzie report.

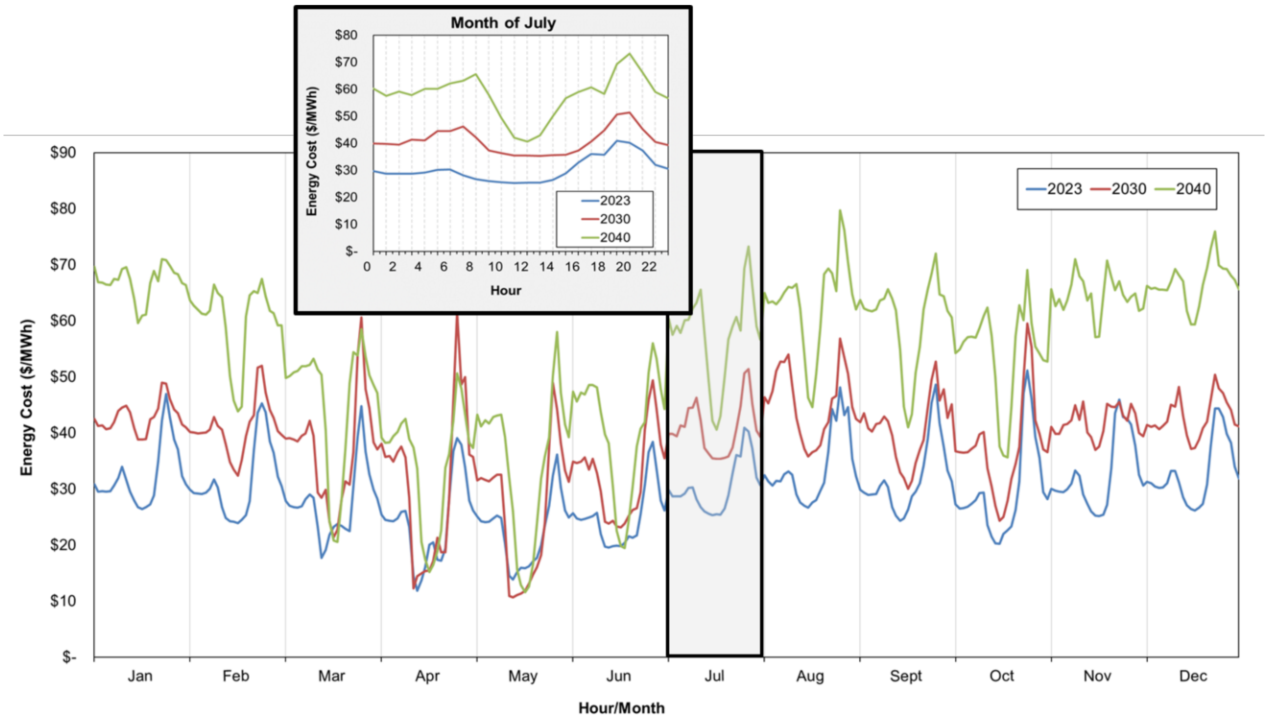

Figure 2-6 CAISO SP15 hourly average wholesale energy cost outlook by month for 2023, 2030, and 2040

The differences between the Wood Mackenzie and Platts forecasts is most apparent when comparing the 2030 average hourly electricity costs. As seen in Figure 2-7, the Wood Mackenzie forecast shows lower variability throughout the year whereas the Platts has significantly greater daily and seasonal fluctuations. These differences stem from the Wood Mackenzie forecast assumption that California will experience swift and large implementation of energy storage, which will help mitigate the hourly variability in wholesale prices. On the other hand, the Platts forecast assumes that the implementation of large-scale energy storage will occur at a slower pace than the continuing implementation of renewables on the market, resulting in a greater volatility of hourly wholesale prices. Both forecasts were used to provide a range of possible outcomes and to weigh the feasibility and risks of projects implemented within the wholesale energy market.

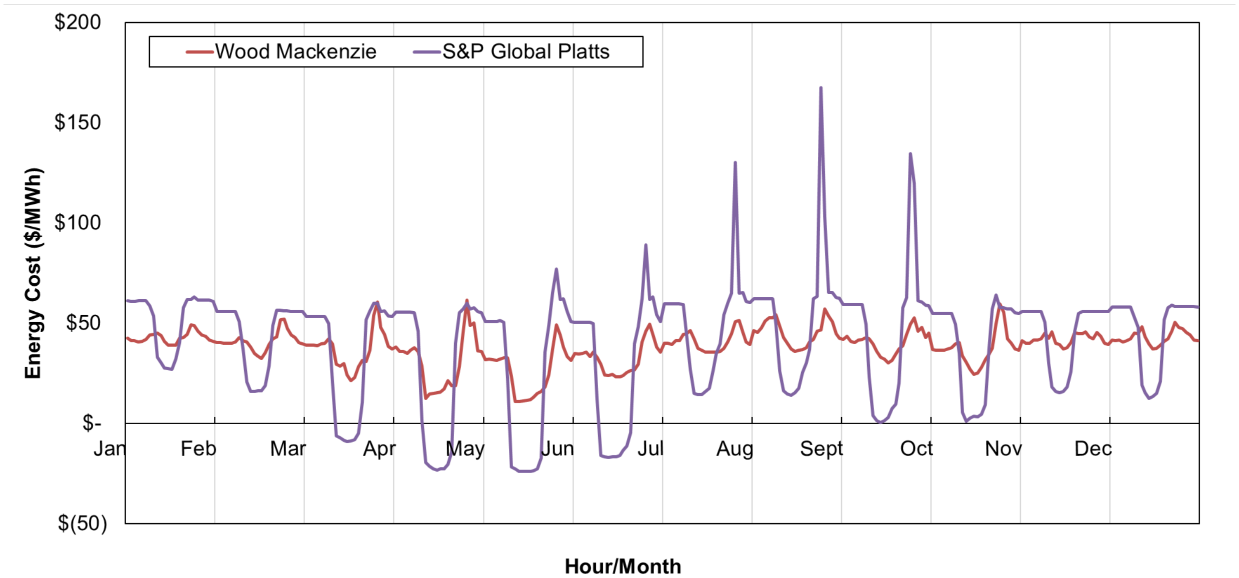

Figure 2-7 CAISO SP15 hourly average wholesale energy cost outlooks from Wood Mackenzie and S&P Global Platts for 2030

2.1.1.3 CAISO SP15 energy price fluctuations at the CRA

The wholesale CAISO SP15 price data from Wood Mackenzie and Platts (Section 2.1.1.2), while adjusted for Southern California conditions, present a general hourly variation for the region. The prices are, in fact, location specific and can vary from the CAISO SP15 averages. Figure 2-8 presents the observed CAISO energy prices from 2015–2019 at the custom load aggregation point (CLAP)_MWD node, a CAISO node representing the weighted average of loads from Metropolitan's pumping plants along the CRA. Historical trends have shown extremely high prices in the summer months, up to almost $1,000/MWh, and some extremely low, often negative, prices.

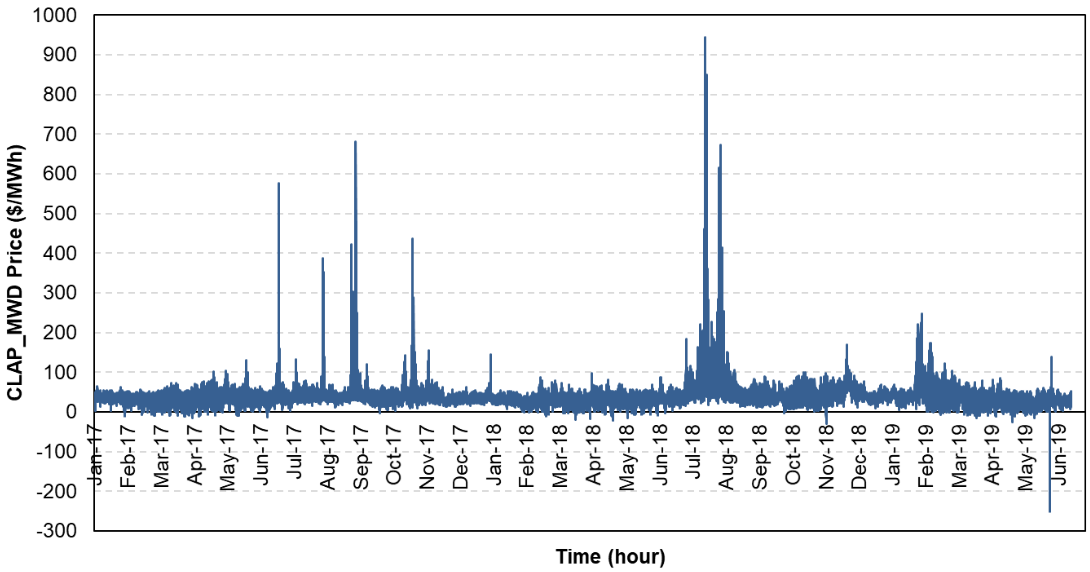

Figure 2-8 CLAP_MWD historical hourly wholesale energy prices observed at the CRA

Although part of the CRA is powered with hydropower (below average market rates) from Hoover and Parker Dams, energy demands above the contractual hydropower amount must be purchased from the wholesale provider. If these demands occur during the summer months, they must be supplemented at the wholesale rate, as the CRA is a critical asset in Metropolitan's distribution system, and it must provide reliable water supplies at all times. Mitigation of these steep energy prices can potentially be achieved by dispatchable storage projects along the CRA—including battery storage and pumped storage—or by the implementation of operational adjustments and energy optimization of pumps. These opportunities are discussed in more detail in Sections 4 and 5.

2.1.2 Retail electricity cost outlook

Metropolitan purchases retail electricity mostly from SCE, Los Angeles Department of Water and Power (LADWP), and Riverside Public Utilities (RPU) for use at Metropolitan's water treatment plants, distribution facilities, office buildings, and other non-CRA facilities. Metropolitan's facilities that were evaluated as part of this study are presented in Table 2-1 with their corresponding energy provider. These six facilities account for approximately 75 percent of Metropolitan's retail electricity purchases.

Table 2-1 Energy providers for Metropolitan facilities

Metropolitan's Facility	Energy Provider
F.E. Weymouth Treatment Plant	SCE
Robert A. Skinner Treatment Plant	SCE
Henry J. Mills Treatment Plant	RPU
Joseph Jensen Treatment Plant	LADWP
Robert B. Diemer Treatment Plant	SCE
OC-88 Pumping Plant	SCE

2.1.2.1 Average retail energy cost outlook

Metropolitan uses industrial-class retail electricity to meet its treatment plant and distribution system needs. The retail electricity rates outlook was provided by Wood Mackenzie for the period of 2019–2040, as shown in Figure 2-9 (Wood Mackenzie, 2018). It should be noted that information provided by SCE indicate an anticipated rate increase of 17.5 percent from 2019 to 2021. For energy cost changes after 2021, the Wood Mackenzie outlooks were used as described in the preceding paragraph.

It should be noted that these projections were made for the entire State of California and do not take into consideration Metropolitan-specific conditions including geographical constraints, rate structures of any electric providers, or time-of-use (TOU) scenarios. Therefore, for each renewable energy and energy storage project considered to address the retail energy rates, the 2019 electricity costs from the different electricity providers were used as a baseline point, and escalated in the future using an adjustment factor that is the ratio between the retail energy price in the given year and the retail energy price in 2019 (both from the Wood Mackenzie retail price outlook according to the shape of the curve presented in Figure 2-9).

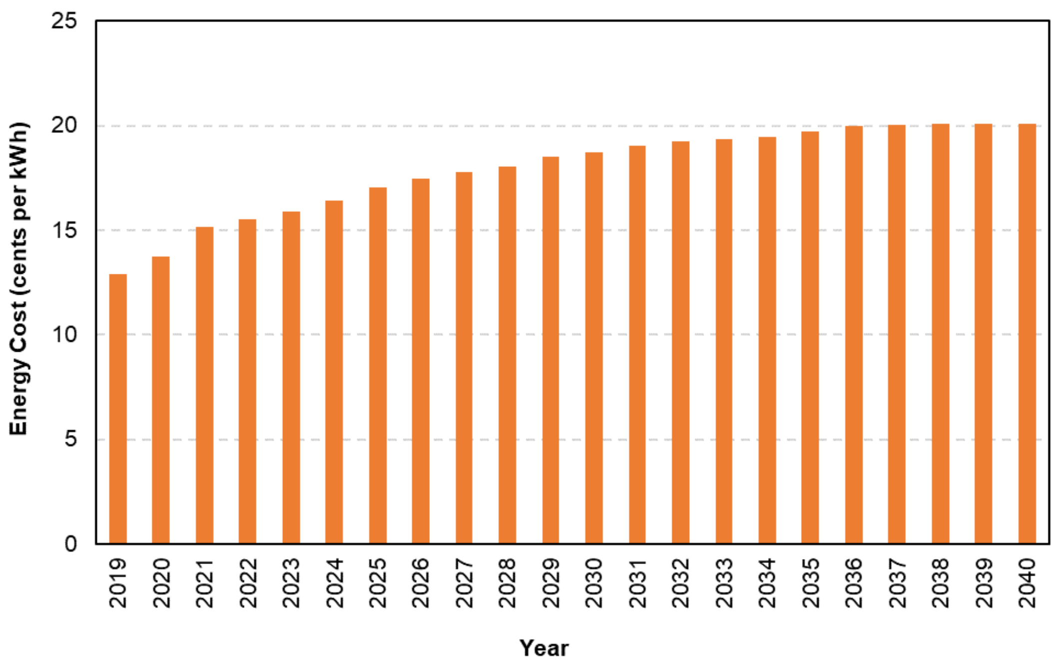

Figure 2-9 Industrial retail energy cost outlook in California (in 2019 dollars)

2.1.2.2 Retail time-of-use structures and electricity costs

Most retail energy providers in California utilize tariff rate structures that are based on TOU schemes, where the cost of electricity varies according to the time of day, day type (weekday or weekend), and season (summer or winter). Conventionally, when the electricity demand is high during the middle of the day, customers are charged by the grid for a higher, on-peak rate, whereas customers are charged a lower rate during low-demand hours. Typically, higher rates are applied on weekdays and during the summer, regardless of the retail electricity provider considered. However, as the wholesale market dynamics are changing due to solar generation penetration, retail energy providers are responding by shifting their TOU rate structures from on-peak rates during the mid-day to evening hours with associated demand charges shifting to evening hours as well. SCE, LADWP, and RPU set the summer period to start on June 1 and end on September 30.

Figure 2-10 and Figure 2-11 provide a summary of the rate structures and associated TOU periods for the three retail electricity providers. In particular, for the purpose of this study:

- SCE retail rates for Metropolitan are based on the application of three TOU tariff rate structures: TOU-8-B-CPP, TOU-8-D-CPP and TOU-8-Standby. Some of the key highlights associated with these rates are:
    - **TOU-8-B-CPP**. TOU-8-B-CPP is a grandfathered SCE rate structure applied only to the Robert A. Skinner Treatment Plant effective June 1, 2019. This rate structure includes the following charges: 1) energy charges based on net energy metered, 2) time-related demand charges based on maximum load during billing period, 3) a facility reliability charge based on overall maximum demand during the billing period 4) reactive energy charges depending on power factor, and 5) a flat monthly customer charge. The Robert A. Skinner Treatment Plant remains under this rate structure through 2026, when it will be transitioned to the TOU-8-D-CPP structure outlined below.
    - **TOU-8-D-CPP.** Effective March 1, 2019, SCE changed their TOU structure and rates to include a new *Super-Off-Peak* period, intended to incentivize customers to transition their power consumption to lower rate periods when renewable generation (e.g., solar) is occurring. SCE rate structure comprises the following charges: 1) energy charges based on net energy metered, 2) time-related demand charges based on maximum load during billing period, 3) a facility reliability charge based on overall maximum demand during the billing period, 4) reactive energy charges depending on power factor, and 5) a flat monthly customer charge. While currently none of Metropolitan's facilities have transitioned to this rate structure yet, the analysis assumes that TOU-8-D-CPP will apply to the Robert B. Diemer Treatment Plant and the OC-88 Pumping Plant upon project startup. As stated above, the Robert A. Skinner Treatment Plant is currently on the TOU-8-B-CPP structure and will transition to TOU-8-D-CPP in 2026 once the grandfathered period is over.
    - **TOU-8-Standby (Option A).** TOU-8-Standby is a grandfathered SCE rate structure applied only to the F.E. Weymouth Treatment Plant effective June 1, 2019. This rate structure includes the following charges: 1) energy charges based on net energy metered, 2) non-time related demand charges, known as Capacity Reservation Charge, based on established Standby Demand for the facility, 3) non-time related Facilities-Related Demand applicable to metered maximum demand in excess of the Standby Demand during the billing period, 4) time related demand charge based on maximum demand during the billing period, 5) reactive energy charges depending on power factor, and 6) a flat monthly customer charge. The F.E. Weymouth Treatment Plant remains under this rate structure through 2026, when it will be transitioned to the new TOU structure outlined below.

- **TOU-8-S Option LG**. TOU-8-S-LG is a new TOU tariff effective March 1, 2019 exclusively for accounts utilizing the Renewable Energy Self-Generation – Bill Credit Transfer (RES-BCT), which allows self-generation customers to receive a credit for any excess power at a facility, and that credit can then be applied to the energy portion of the bill for multiple other accounts within the same utility territory. This rate structure includes the following charges: 1) energy charges based on net energy metered, 2) non-time related demand charges, known as Capacity Reservation Charge, based on established Standby Demand for the facility, 3) non-time related Facilities-Related Demand applicable to metered maximum demand in excess of the Standby Demand during the billing period, 4) time related demand charge based on maximum demand during the billing period, 5) reactive energy charges depending on power factor, and 6) a flat monthly customer charge. For this analysis, it is assumed the F.E. Weymouth Treatment Plant will transition to this tariff structure in 2026 once the grandfathered period is over.

- LADWP rate structure comprises multiple charges, including 1) energy charges based on net energy metered, 2) demand charges based on maximum load during the billing period, 3) a facility charge based on maximum demand during the last 12 months, 4) reactive energy charges depending on power factor, and 5) various billing adjusted factors that depend on season and quarter. These various charge types reported by LADWP became effective on July 1, 2019 and applies to Joseph Jensen Treatment Plant loads.

- RPU rate structure comprises multiple charges, including 1) energy charges based on net energy metered, 2) demand charges based on maximum load during the billing period, 3) a facility reliability charge based on maximum demand during the billing period, 4) a flat monthly customer charge 5) a state-mandated monthly public benefits charge, and 6) state-mandated public benefit charges based on a percentage of the total electricity charge. The various charge types reported by RPU became effective on January 1, 2019 and apply to Henry J. Mills Treatment Plant loads.

Additional details of each rate structure, including specific rates, can be found in Appendix A.

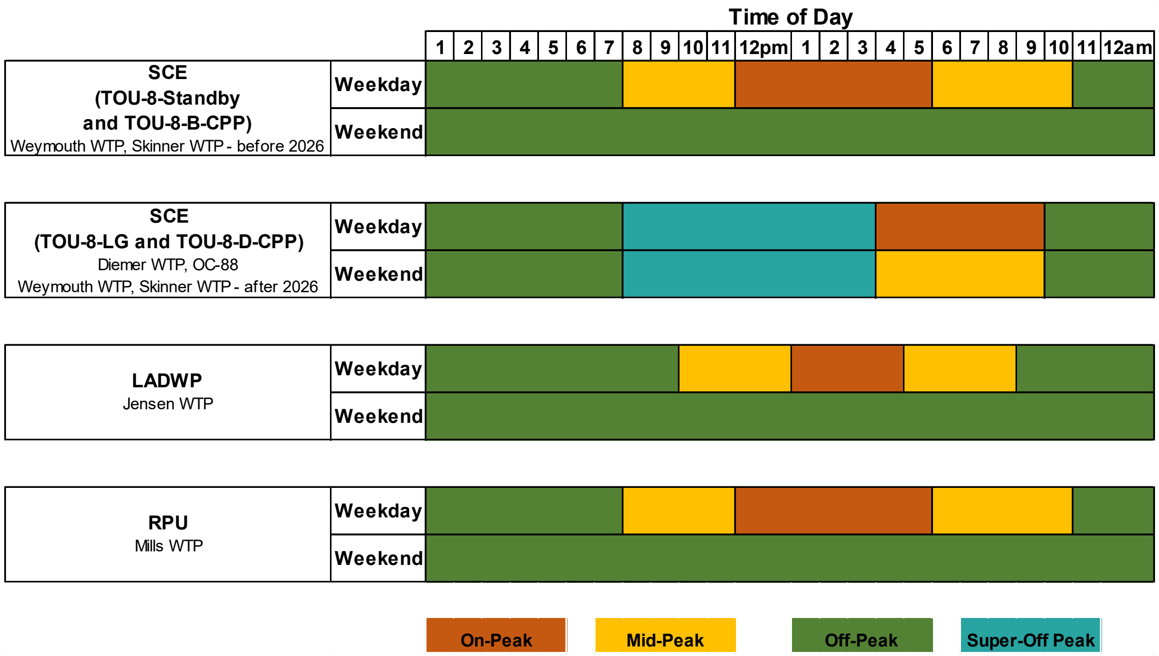

Figure 2-10 Summer TOU periods for SCE, LADWP and RPU

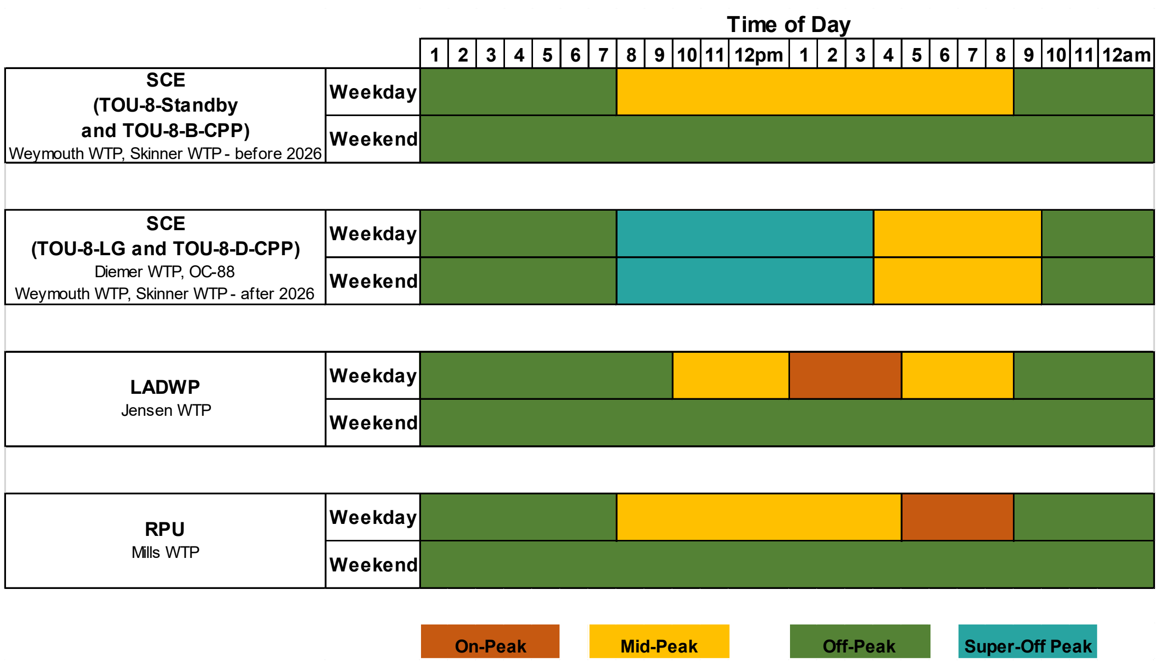

Figure 2-11 Winter TOU periods for SCE, LADWP and RPU

It is important to note that the rate structures presented in Figure 2-10 and Figure 2-11 are those applied by the respective electric utilities at the time this report was prepared. However, following the example of SCE that recently changed its rate structure (i.e., by shifting the on-peak to a later part of the day), LADWP and RPU may also modify their customer charges in the future. The analyses conducted for the purpose of this report assumed that the tariff rate structures remain the same as presented above, as there is no current indication of changes. It is recommended that Metropolitan engages frequently with the different electric utility account representatives to anticipate any potential change in rate structure or release of favorable electric utility programs. Any variation of these rates in the future may impact the outcomes of the evaluations conducted in this study. If changes are made by the electric utilities, the economic analyses presented in this report should be revised accordingly.

2.2 CAPITAL AND O&M COSTS ASSUMPTIONS

The capital and O&M costs for each renewable energy and energy storage project were estimated at a conceptual level using the methodologies and assumptions specified in the sections below. The actual cost will vary as the design is defined in more detail and as it evolves in response to the developing needs of the project's stakeholders. Furthermore, the estimate of costs shown and any resulting conclusions on the project financial, economic feasibility, or funding requirements, have been determined from the information available at the time the estimates were prepared. The final costs of the project and resulting feasibility will depend on actual labor and material costs, competitive market conditions, and other variable factors. Accordingly, the final construction costs may vary from the estimate. Project feasibility, benefit/cost analysis, risk and funding must be carefully reviewed prior to making specific funding decisions and establishing the project budget.

2.2.1 Solar power generation

The viability of a solar energy project depends on the procurement method selected and the associated financial terms. The assumptions used to develop the financial viability of solar power generation projects are summarized in the following sections.

2.2.1.1 Procurement mechanisms

Two procurement mechanisms of solar energy projects were analyzed for the purpose of this study:

- **Power Purchase Agreements (PPA).** Under this agreement, Metropolitan would allow a solar energy developer to install and operate a third-party owned solar generation facility on Metropolitan's land near a Metropolitan-owned load. Metropolitan would then sign an agreement with the developer and commit to buy the solar energy generated at a competitive price that is lower than the retail energy purchase price at that location. On the developer's end, the energy would need to be sold at a price that would cover the asset capital and O&M costs over the facility's lifecycle, plus a profit. A key parameter to model the financial feasibility of a PPA is the solar levelized cost of energy (LCOE), detailed in Section 2.2.1.2. Currently, private investors can also benefit from the Investment Tax Credit (ITC), an incentive mechanism allowing an entity to deduct a percentage of the investment made on solar projects as federal income tax credits, driving prices down and improving PPA financial benefits.

- **Metropolitan-owned solar asset.** Metropolitan would own and operate the solar generating asset; however, as a public entity, it would not be able to benefit from the ITC to reduce the initial capital costs. A key parameter to model the financial feasibility of Metropolitan owning a solar asset is the installation cost (see Section 2.2.1.3).

2.2.1.2 Levelized cost of energy

The LCOE is considered a useful metric to compare the cost of various power generation sources, per the Institute of Energy Research (IER, 2019). An LCOE economic assessment represents the average total cost to build and operate a power-generating asset over its lifetime, divided by the total energy output of the asset over that lifetime. This concept can also be conceived as the minimum price at which electricity must be sold by a power-generating asset owner—a PPA developer for instance—in order to breakeven over the lifetime of the project. In general, solar power generation facilities could be installed at a large scale, referred to as electric utility scale (>5 MW), and at the commercial scale. In particular:

- At large scale, solar facilities (> 5 MW) could possibly be installed over a large available area of land already owned by Metropolitan, along the CRA. The LCOE outlook for solar utility-scale facilities presented in Figure 2-1 was obtained from the *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018* (NREL, 2018a) and forecasted from the period of 2018-2040 using the 2018 Wood Mackenzie study. The National Renewable Energy Laboratory (NREL) price outlook contained median, high, and low LCOE values—the low-price data was used to reflect the low cost of solar in California compared to other states in the US. Selected outlooks show an overall 7 percent per year decrease in LCOE until 2022 due to technology efficiencies, and a further 2 percent decrease per year beyond. Beyond 2022, the effects of the ITC will also step-down to 10 percent[1] of the capital investment from a 30 percent level in 2019. This figure includes all installation costs (e.g., solar panels, inverter, structural/electrical components) but does not include additional markups for site-specific and Metropolitan costs as specified in Table 2-2.

[1] ITC will remain at 30 percent until 2019, and then gradually step-down to 26 percent in 2020, 22 percent in 2022, and 10 percent in 2022 and onward.

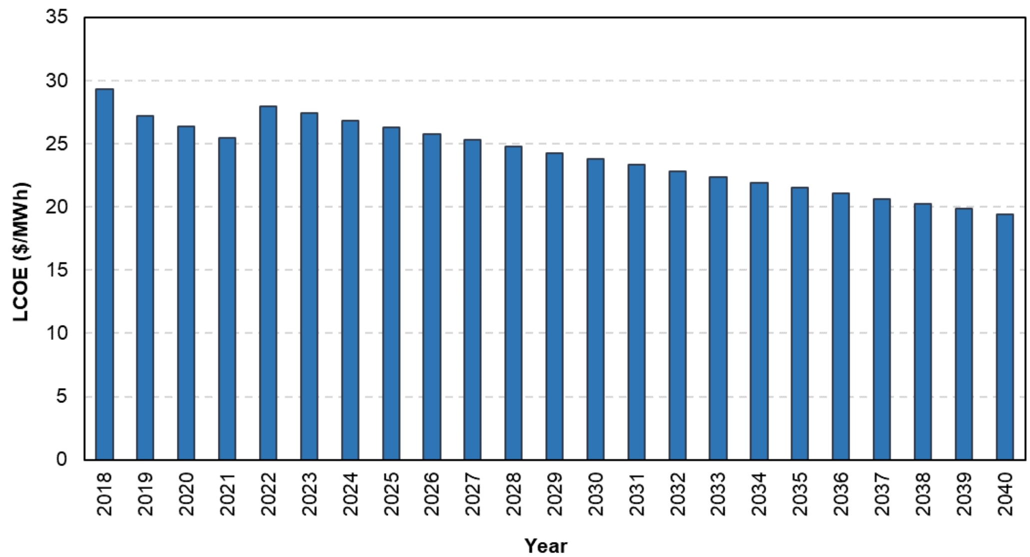

Figure 2-12 California levelized cost of energy (LCOE) for utility-scale solar projects for the period 2018-2040 (in 2019 dollars)

- At the commercial scale, solar facilities (2 MW or less) could possibly be installed to offset the energy demand of Metropolitan's treatment facilities. 2018 LCOE data was obtained for commercial-scale solar from them same study above (NREL, 2018a), and the LCOE outlook was calculated using an adjustment factor that is the ratio between the LCOE in the given year and the LCOE in 2018 (from the Wood Mackenzie solar LCOE outlook, shown in Figure 2-13).

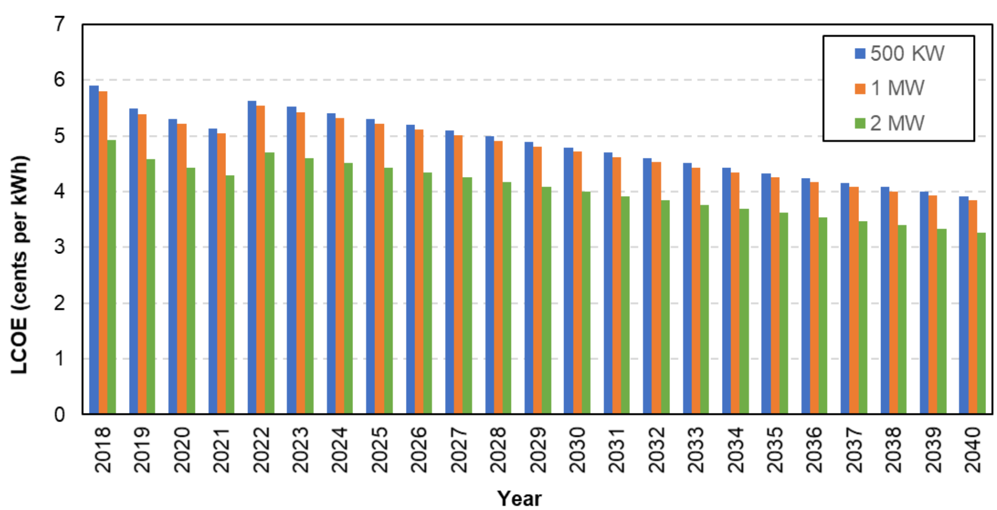

Figure 2-13 California levelized cost of energy (LCOE) for commercial-scale solar for various facility sizes for the period 2018–2040 (in 2019 dollars)

2.2.1.3 Installation cost assumptions

Installation costs should be carefully estimated when planning on owning an asset, as they represent a significant portion of the overall project cost. For the analysis conducted in this study, the installation cost data was obtained for various project scales from the 2018 NREL benchmarking study (NREL, 2018a), and was projected in the future based on the pattern of the LCOE outlook presented previously in Section 2.2.1.2. The installation cost outlook for solar commercial facilities for the period 2018-2040 is presented in Figure 2-14.

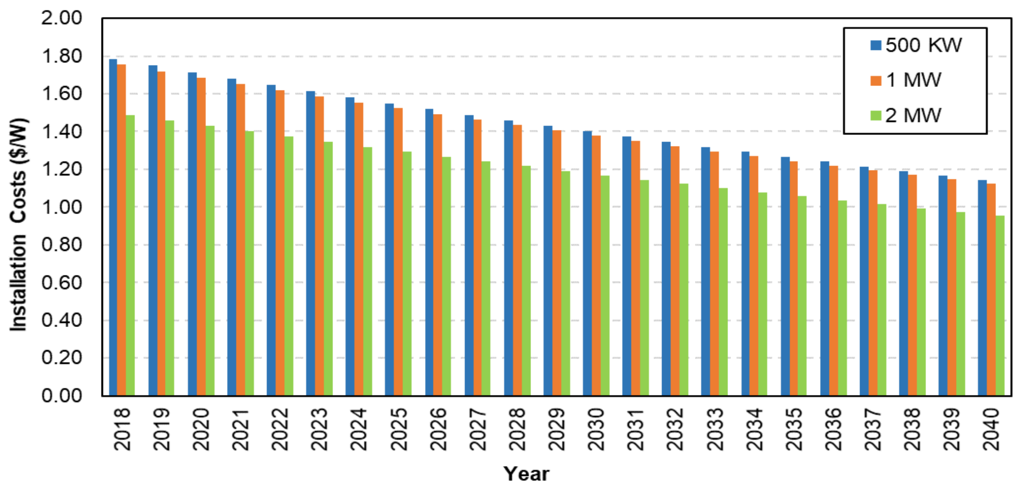

Figure 2-14 Installation costs for commercial-scale solar for various facility sizes for the period 2018-2040 (in 2019 dollars)

2.2.1.4 Solar project cost assumptions

Total project costs for solar generation projects developed for this study were based on the assumptions presented in Table 2-2 for PPA-based projects, and in Table 2-3 for Metropolitan-owned assets.

Table 2-2 Total project cost assumptions for solar energy costs under a PPA (in 2019 dollars)

Parameter	Unit	Value	Notes/References
Energy Cost Items			
LCOE	$/kWh	see Figure 2-13	From NREL, 2018a
Site-specific contingencies	%	30%	Includes site-specific contingencies on civil work (e.g., access, grading, drainage), interconnection requirements specific to Metropolitan, and mobilization

Table 2-3 Total project cost assumptions for Metropolitan-owned solar facilities (in 2019 dollars)

Parameter	Unit	Value	Notes/References
Construction Cost Items			
Installation cost	$/W	See Figure 2-14	From NREL, 2018a
Civil	$/MW	$320,000	Based on previous study (MWH, 2013) escalated numbers
Interconnection	$	$280,000	Based on previous study (MWH, 2013) escalated numbers. Not included at sites that already have infrastructure installed.
Mobilization	$	$55,000	Based on previous study (MWH, 2013) escalated numbers
Contractor Profit	%	10%	10% of construction costs
Engineering, Administration, and Legal	%	30%	30% of construction costs and contractor profit
O&M Costs	$/kW	$18	From NREL, 2018a

2.2.1.5 Solar generation system model

Solar energy generation was modeled on an hourly basis based on location-specific historical weather data and using System Advisor Model (SAM), developed by the NREL. Key inputs in SAM include facility location and solar-generation facility information and configuration. The solar energy generation data was then used to calculate electricity savings for the account, taking into consideration specific electricity rates, TOU, and types of credits received for excess solar energy exported to the grid.

2.2.2 Battery energy storage systems

This study evaluated behind-the-meter battery energy storage as an option for peak load management and energy price arbitrage at Metropolitan's facilities. In addition to potential energy cost-reduction benefits, battery storage could further improve Metropolitan's operational flexibility (i.e., pump optimization at the CRA). This section details the assumptions used for the conceptual design and cost feasibility of BESS developed for the purpose of this study. This section also provides pertinent information on the available grants or incentive programs considered as part of this study that may benefit Metropolitan in offsetting the initial capital investment of these types of installations.

2.2.2.1 Procurement mechanisms

The financial viability of battery energy storage projects is influenced by the procurement mechanism selected. For the purpose of this study, the following three procurement scenarios were considered:

- **Metropolitan-owned and operated BESS.** Under this scenario, Metropolitan would own and finance the battery system, its installation, operation, and maintenance. Metropolitan would not be eligible to claim benefits from the ITC, but it would be eligible to apply to

California Public Utilities Commission's (CPUC) Self-Generation Incentive Program (SGIP) due to its public agency status. Details on the CPUC's SGIP are provided in Section 2.2.2.4.

- **Metropolitan-owned and third-party operated BESS.** In this scenario, Metropolitan would finance the capital and installation costs of the BESS but would contract a third party to operate the battery system (along with other facilities the third-party vendor may have). By financing and owning the battery system, Metropolitan may benefit from the CPUC's SGIP, reducing the initial capital investment. Details on the CPUC's SGIP are provided in Section 2.2.2.4
- **Third-party owned and operated.** Under this scenario, Metropolitan would solicit a third-party developer to own, install, and operate the BESS on Metropolitan-facility land near a Metropolitan-owned energy demand center. Metropolitan would sign an agreement with the BESS developer, where the developer would be responsible for installing and operating the BESS. Terms and conditions of the agreement may vary, but often they contain a payment term where Metropolitan would pay the developer each month for the period of agreement (e.g., a 10-year contract), at a competitive price, in exchange for minimum electricity cost savings guaranteed.

Although it is important to consider the procurement mechanism for a comprehensive evaluation of BESS financial viability, not all three scenarios of procurement mechanisms were modeled for this study. The Metropolitan-owned and operated scenario was modeled for all potential BESS projects identified. However, the remaining scenarios involving third-party operation of the BESS alone, or together with ownership, were not analyzed. Online research, interviews with developers, and workshops with other agencies that have deployed BESS indicate that a contract price for either third-party operation or third-party own-and-operate scenarios is influenced by many factors, including the following:

- Forecast of battery cost and cost reduction potential is highly uncertain as the technology continues to mature; therefore, financial viability of a battery storage system for a BESS developer and/or a BESS private operator is highly dependent on the amount of revenue that can be generated.
- BESSs can provide multiple, stacked services of which several financial benefits are generated. In addition to demand-charge management and/or energy price arbitrage, other services that can generate revenue which can be stacked include frequency regulation, resource adequacy, and spinning/non-spinning reserve (RMI, 2015; Lazard, 2018). BESS developers are likely to design and operate a battery system such that multiple, stacked revenue can be generated to make the battery system financially viable. For the purpose of this study, only behind-the-meter services to reduce energy cost, increase solar self-consumption, and/or TOU price arbitrage were considered. However, financial benefits from other in-front-of-the-meter, local capacity resource, and/or ancillary battery services were not modeled as they are dependent on the BESS developer and/or operator services provided, local regulations, and specific electricity utility programs.

It is suggested that Metropolitan obtain proposals from developers and/or operators in order to conduct detailed assessments to determine the most cost-effective procurement mechanism for a BESS.

2.2.2.2 Battery energy storage system design criteria

Several mature technologies are available today for battery energy storage and their technical characteristics and related performance (capacity, energy and power output, charging and discharging rates, efficiency), which vary depending on the technology, configuration, and supplier. For the purpose of this feasibility study, lithium-ion batteries were selected as the sole option for battery energy storage, based on their high efficiencies and energy densities, their abundant availability in the marketplace, and competitive costs compared to other battery counterparts with different chemistries (e.g., lead acid, sodium sulfur, flow batteries).

The design criteria that are common for all BESS projects evaluated as part of this study are presented in Table 2-4. In addition, site-specific criteria and assumptions were used for specific design parameters (e.g., desired bank capacity, bank power), which, for more clarity, are reported in the related site-specific descriptions of the results presented in Section 3.0.

Table 2-4 Key assumptions used for BESS design

Criteria	Value	Note/Reference
Battery Type	Li-Ion: Nickel Manganese Cobalt Oxide	Typical Li-ion battery chemistry, with demonstrated balanced performance characteristics in terms of energy, power, cost, and cycle life
Charging Rate	1C	C-rating of battery, the acceptable safe rate of battery charge/discharge
Power Converter Type	AC-Coupled	Typical configuration when installed with existing power generation systems
Bank Power Design Margin	15%	Industry standard assumption
AC to DC Conversion Efficiency	96%	Industry standard assumption
DC to AC Conversion Efficiency	96%	Industry standard assumption
Minimum State of Charge	10%	State of charge low limit for Li-ion NMC battery
Maximum State of Charge	90%	State of charge high limit for Li-ion NMC battery
Battery Life	10-Year	Industry standard assumption. End-of-life disposal is assumed to be taken care of by the battery vendor.

2.2.2.3 Battery energy storage cost assumptions for Metropolitan-owned procurement mechanism

A review of key references (PNM, 2017; NREL, 2018b; Lazard, 2018) was conducted to determine the installation, operation, and maintenance costs for stand-alone lithium-ion BESSs at the commercial scale, and later applied in the feasibility cost assessment conducted for this study.

Table 2-5 summarizes the installation cost assumptions used for the battery energy storage projects applied to a scenario that assumed Metropolitan owns and operates the BESS. "Battery pack" cost include cost of batteries, "battery power" cost includes power conversion and control systems, and "balance of plant" includes cost of auxiliary systems and other supporting components for the BESS.

Table 2-5 Battery installation and O&M cost assumptions

Item	Value	Unit	Notes/References
Direct Installation Cost			
Battery pack	$340	$/kWh	In 2017 dollars; cost to be adjusted for inflation and cost reduction for year of construction
Battery power	$150	$/kW	In 2017 dollars; cost to be adjusted for inflation and cost reduction for year of construction
Balance of plant	$170	$/kW	In 2017 dollars; cost to be adjusted for inflation and cost reduction for year of construction. It includes civil and interconnection
Installation labor, margin, and overhead	10	%	Percentage of battery cost (pack, power and balance of plant)
Contingency	4	%	Percentage of battery cost (pack, power and balance of plant)
Cost reduction	8	%	Per year until 2022 (year of installation)
Indirect Installation Cost			
Permitting	0.1	%	Percentage of direct cost
Engineering	10	%	Percentage of direct cost
Grid interconnection fee	$800	$	SCE Rule 21 Interconnection
Interconnection study	$ 2,500	$	SCE Rule 21 Interconnection
Sales tax	5	%	-
Annual O&M Cost			
Fixed cost by capacity	$14	$/kW-yr	In 2017 dollars; cost to be adjusted for inflation for year of operation
Variable cost	$0.03	$/MWh	In 2017 dollars; cost to be adjusted for inflation for year of operation

2.2.2.4 Grants/Incentive programs for battery energy storage

Two incentive programs are available for behind-the-meter customers to install BESSs:

- **Federal Investment Tax Credit (ITC).** Since Metropolitan does not pay federal income taxes, the ITC is not applicable to Metropolitan in a scenario where Metropolitan pays for and owns the BESS. On the other hand, a private energy developer could potentially leverage the ITC program as a cost offset mechanism, and potentially transfer the cost saving to Metropolitan's benefit; the overall financial conditions would be subject to many other factors and agreement negotiations. In order to benefit from the ITC, the BESS would have to be charged a minimum of 75 percent with renewable energy (e.g., solar).

- **California Public Utilities Commission (CPUC) Self-Generation Inventive Program (SGIP).** Metropolitan may obtain grants from the CPUC's SGIP if all required documentation and verification are approved. The application involves three steps, and a detailed description of the application process is described in the *Self-Generation Incentive Program (SGIP) Handbook 2019*. The program administrator for Metropolitan's potential application is SCE for all the SCE accounts and Southern California Gas (SoCalGas) for the LADWP and RPU accounts. The total authorized incentives share for SCE and SoCalGas through the end of 2019 is $169,260,000 and $48,360,000, respectively.

  Within the authorized SCE incentives, 80 percent of the funds are allocated to Energy Storage Technologies. Within the Energy Storage Technologies budget, 75 percent is allocated to the Energy Storage General Budget and 25 percent to the Energy Storage Equity Budget. Nonprofits, small businesses, education institutions, and governments are eligible for incentive budgets from the Energy Storage Equity Budget. Thus, Metropolitan may be eligible for both the Energy Storage General Budget (in the large storage category) and the Energy Storage Equity Budget (in the nonresidential equity category). The CPUC also recently established an Equity Resiliency Budget for communities facing risk of wildfires. Both the Equity Budget and Equity Resiliency Budget are independent of the General Budget and would provide additional incentives for eligible projects. However, for the purposes of this analysis, it is assumed that BESS projects would only receive incentives from the General Budget as a conservative method.

  The total energy storage incentive funds are divided across five steps, with funds allocated to energy storage projects on a first-come first served basis within the limit of each step's pre-defined funding pool. When one step's funding-pool runs out of funds, the program moves to the next step. Both SCE and SoCalGas are currently in Step 3, with an incentive rate of $0.35/Wh. The incentive rates corresponding to each funding step are shown in Table 2-6 below.

Table 2-6 SGIP Incentive Rates

SGIP Step	Rate ($/Wh)	Status
1	*0.50*	*Expired*
2	*0.40*	*Expired*
3	0.35	Active
4	0.30	Pending
5	0.25	Pending

In addition to the incentive declines with each new step of the program, individual projects are limited in the amount of incentives they can receive based on size and storage duration, as shown in Table 2-7. Eligible BESSs may receive incentives for up to 6 MWh of storage, but the rates are reduced by half for all storage capacity above 2 MWh and by half again for capacity over 4 MWh. Incentive rates also decline based on storage duration, defined as the ratio of power output to energy storage of the BESS. These rate reductions compound each other.

Table 2-7 SGIP Incentive Rates for Different Size and Duration BESSs

Duration	Capacity		
	0 - 2 MWh	2 - 4 MWh	4 - 6 MWh
0 - 2 hours	100%	50%	25%
2 -4 hours	50%	25%	12.5%
4 - 6 hours	25%	12.5%	6.25%

Accordingly, the storage and power capacity of each BESS for which Metropolitan may seek incentives must be optimized to balance capital costs and available incentives.

In addition to the decline of incentive amounts based on size and duration, payment of the incentive is performance-based. For BESSs 30 kW or larger, 50 percent of the incentive will be paid upon project completion and verification. The remaining 50 percent will be structured based on annual kWh discharge/offset such that under the expected annual operational requirements, the BESS would receive the entire stream of performance payments in five years. All potential BESS for Metropolitan are expected to be larger than 30kW, and this assumption has been incorporated into the cashflow model used in the financial analyses for this study.

It is worth noting that an application fee of 5 percent of the total cost of the BESS is required when the application is filed. Depending on the size of the BESS, the application fee can be significant. Note that the application fee is not refundable, even if the application is rejected.

The financial feasibility of each BESS, described in Section 3.0, was modeled assuming the above-mentioned incentive.

2.2.2.5 Additional sources of revenue for battery energy storage projects

The CPUC operates the Resource Adequacy (RA) program which ensures load serving entities have sufficient capacity to meet peak loads. If the load serving entity cannot meet their RA requirements with their own facilities, they must procure the remaining capacity from generating resources within the CAISO area. The average capacity price paid by the load serving entities to the generating entities is approximately $3/kW-month for a four-hour duration. This is an additional revenue stream for BESS projects independent from energy cost-reduction. For this analysis, it is assumed that the RA program would apply to all BESS projects.

2.2.2.6 Battery energy storage system model

A simple BESS model was created for each project evaluation. The use case of battery storage systems at different Metropolitan-owned facilities varies. Some facilities have existing onsite solar generation, while others do not. Table 2-8 summarizes battery storage use cases for Metropolitan-owned facilities that were evaluated as part of this study.

Table 2-8 Summary of battery energy storage use case for Metropolitan-owned facilities

Facility	Use Case
F.E. Weymouth Treatment Plant	Stand-alone BESS charged from existing solar generation facility or grid (TOU price arbitrage)
Henry J. Mills Treatment Plant	New solar generation system paired with BESS
	Stand-alone BESS charged from grid (TOU price arbitrage)
Robert A. Skinner Treatment Plant	New solar generation system paired with BESS
	Stand-alone BESS charged from grid (TOU price arbitrage) and/or existing solar generation
Joseph Jensen Treatment Plant	Stand-alone BESS charged from existing solar generation facility or grid (TOU price arbitrage)
OC-88 Pumping Plant	Stand-alone BESS charged from grid (TOU price arbitrage)

A 1MW/2MWh battery size was primarily assumed for all BESS in order to take advantage of the full SGIP incentives. It is assumed that battery sizes would be optimized upon discussion with battery developers. Charging of the battery was modeled to take advantage of off-peak/super-off-peak pricing or solar generation whereas discharge of the battery was modeled to offset demand charges during on-peak/mid-peak hours. Each model was site-specific dependent on the average loads on-site, TOU rate structures and existing solar generation.

Electricity savings were estimated for a typical year. Assuming that the energy demand and energy supply composition remain the same for the period of analysis, electricity cost savings were escalated using the same trend as the retail electricity cost outlook, since it is expected to escalate due to inflation and retail electricity rate increases. To the degree subperiod prices widen to more closely reflect wholesale prices, battery storage benefits would be increased.

2.2.3 Wind power generation

Metropolitan does not currently own a wind power generating facility but it has evaluated its potential in a Navigant 2007 report*, Phase 1 Report on the Feasibility of Wind Power Development at the Julian Hinds Pumping Plant*, and in two subsequent updates made in 2013 and 2018. These assessments developed, at the time they were conducted, optimal design criteria based on available data for modern turbines' performance, and used a project location, size, and interconnection point identified as part of the original 2007 study. Wind data was also collected in 2007 and subsequently used for both report updates. The project was deemed infeasible due to forecasted energy rates not creating enough revenue to recover the incurred project costs.

The intent of this current report is to update the prior studies based on larger, higher-altitude wind turbines and updated market conditions. For this new assessment, the majority of assumptions from the 2007 report remained unchanged and updated levelized costs were calculated to compare to previous update iterations as well as the average wholesale energy price. Existing wind data was also extrapolated to analyze higher-altitude wind turbines. It should be noted that wind generation facilities that begin construction after December 31, 2019 are not eligible to claim the production tax credit, which provided operators tax credits for the first 10 years of operation and was a key incentive for many wind generation projects.

2.2.4 Small and in-line hydropower generation

Metropolitan owns and operates 16 small hydropower facilities within its distribution system, from which the power generated is sold on the wholesale market. The power generated at each hydropower facility site is dependent on flow and pressure availability. Metropolitan has previously completed studies assessing the condition of its existing small hydropower facilities, along with the assessments for potential new locations of hydropower generation. This included adding turbines to existing small hydropower plants and pressure control structures (*2010 Hydroelectric Plant Feasibility Study Project No.103924)* and surveying available equipment for in-line hydroelectric power generation (*2014 In-Line Hydro Study Project No. 104585)*.

The intent of the analysis conducted for this study was not to reanalyze each project based on current flow and head information, but to revisit the conclusions of the previous reports by updating the capital costs and value of the energy selling price based on the wholesale electricity cost outlook presented in Section 2.1.1.1. For this analysis, capital cost values from these two studies were escalated to 2019 dollars using the same design criteria as in the original reports. The cost values for the turbine-generator equipment were estimated based on cost curves provided by turbine manufacturers and in-line hydropower project developers that was collected in 2019. Cost estimations for excavation, shoring, concrete, and piping were escalated from the original report estimations. The approach used for the capital cost escalation is presented in Section 2.3.2. The O&M costs (fixed and variable) for each hydropower project were based on the O&M costs presented in the initial hydropower reports and escalated forward to 2019 dollars.

2.2.5 Pumped storage systems

Pumped storage systems utilize two reservoirs located at different elevations to store and generate energy. This type of project takes advantage of periods of low electricity demand when energy is expensive to pump water to the upper reservoir. During periods of high electricity demand, the stored water is released through turbines that generate clean energy. The amount of energy generated to be sold—and consequently overall cost savings—is highly dependent on the reservoir elevation differences, total flow of water, pumping and generation durations, and hourly wholesale energy prices.

Metropolitan does not currently partake in pumped energy storage but has evaluated potential pumped energy storage projects at two locations:

- **Diamond Valley Lake** - Metropolitan has reviewed various projects to increase hydropower generation at Diamond Valley Lake's Hiram Wadsworth Pumping/Hydro-Generating Facility, the largest of Metropolitan's hydropower facilities (MWD, unknown). For a number of reasons detailed in Section 4.3, pumped storage has been deemed infeasible at Diamond Valley Lake and will not be assessed further within this report.

  Copper Basin and Lake Moovalya (*Evaluation of Hydroelectric Pumped-Storage Power Generation Potential Using Copper Basin, 2002*) (MWD, 2002). This assessment, evaluated in 2002, developed optimal design criteria based on available data for the reservoirs, available storage capacity and capital costs estimated at the time of the report. The project was deemed infeasible due to forecasted energy rates not creating enough revenue to recover the capital or O&M costs. An update of this project opportunity along with other pumped storage alternatives was conducted using the updated energy cost outlooks in Section 2.1.1. A summary of this new analysis is provided in Section 5.1.

2.3 ASSUMPTIONS AND METHODOLOGY FOR FINANCIAL ANALYSIS

A financial analysis of each renewable project option was performed using spreadsheet-based tools or appropriate models with input of the capital and O&M costs, discount and escalation rates, assumed operating life, and the value of energy. Details on each of these financial model elements are reported in the following sections.

2.3.1 Project life-cycle criteria

In order to assess the financial feasibility of energy projects, different planning periods were used for renewable energy and energy storage projects at a commercial scale versus those of larger scale. In particular:

- For commercial-scale projects, the end of construction was set in 2022 with first year of operations in 2023. One year of construction is assumed for all projects for continuity, although it is acknowledged that some projects may take more, or less, than one year. This is the expected earliest year any new project could be implemented. The two-year period before construction takes into consideration Board approval, additional planning efforts, design, bid, and award timing.
- For large-scale projects, the first year of operations was set to 2025.

Each project was assumed to have an operating lifecycle as presented in Table 2-9. These assumptions were based on industry standards and used to calculate each projects' net present value.

Table 2-9 Assumed project lifecycles

Project Type	Assumed Project Lifecycle (years)
Solar	20
Battery	10
Wind	30
Hydropower	40
Pumped energy storage	50

2.3.2 Cost escalation, inflation and discount approach

The capital and O&M cost inputs to the financial model used a 2019 dollar value pricing level. To update the project cost to the initial year of the construction cost (2023 or 2025), an inflation rate of 2 percent was used, and the inflated capital and O&M costs were calculated through the following formula:

$$Pn = P(1 + r)^n$$

where, P = base estimate cost, Pn = total inflated cost, r = inflation rate, and n = difference between base year (2019) and projected year (2023 or 2025).

Costs were then spread (and escalated) over the project development period reported in Table 2-9. The discounted rates assumed in the financial model for the inflation, escalation, and discount are presented in Table 2-10.

Table 2-10 Escalation and discount rates used as assumptions in the financial model

Parameter	Value
Escalation Rate	2%
Discount Rate	4%

2.3.3 Cost feasibility approach

For all renewable options evaluated, the net present value (NPV) was calculated as the value today of the investment based on the discount rate and a series of future payments and income. The NPV was calculated based on the interest and discount rate previously defined using the following formula:

$$NPV\ (i, N) = \sum_{t=1}^{N} \frac{R_t}{(1 + i)^t}$$

where N = number of years of the analysis period for the specific renewable option, i = discount rate, and R_t is the net cash flow (i.e., cash inflow minus cash outflow) at time of t.

In addition to the NPV, the payback period of each renewable project was calculated as the period of time required for the return on an investment to repay the sum of the original investment. The breakeven year is the last year of the payback period. The payback period was calculated as follows:

$$Payback\ (years) = \frac{Initial\ investment}{Net\ cash\ flow\ per\ period}$$

2.4 METHODOLOGY FOR CARBON EMISSIONS REDUCTION ASSESSMENT

Carbon emission reductions associated with each energy generation project analyzed as part of this report was calculated in accordance with CARB and the California Energy Commission (CEC). As reported by the CEC, the historical carbon emissions rate is presented in Figure 2-15 and represents the carbon associated with each MWh of renewable energy generated at Metropolitan.

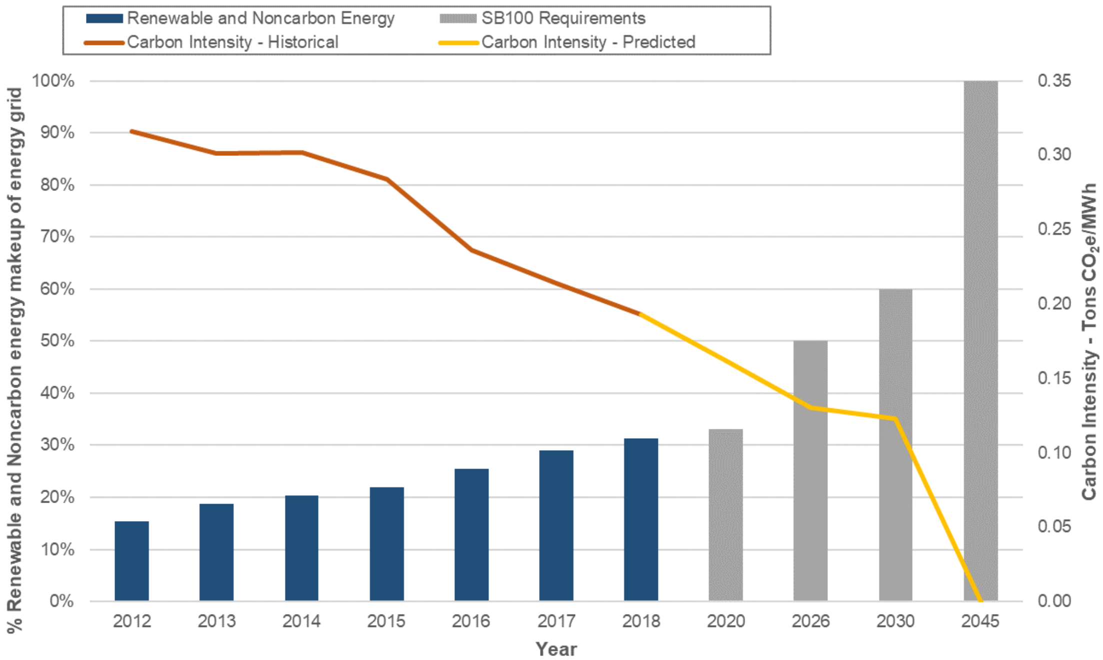

Figure 2-15 Carbon intensity reduction of California's energy grid due to renewable energy growth

It should be noted that SB 100 of 2018 requires retail sellers and publicly owned utilities to procure 60 percent of their electricity from eligible renewable energy sources by 2030 and 100 percent of their electricity from carbon-free energy by 2045 (SB 100, 2018). The measures electric utilities implement to meet the requirements of SB 100 will likely decrease the emission factors of the grid power purchased by Metropolitan over time, and with it the carbon emission reductions associated with implemented renewable energy projects, as shown in Figure 2-15.

Energy storage is not typically associated with carbon emission reduction since it is not generating a new source of carbon-free energy to add to the grid. However, since energy storage utilizes a dispatch strategy to shift renewable energy on the grid, it may indirectly contribute to carbon emission reductions (Figure 2-16).

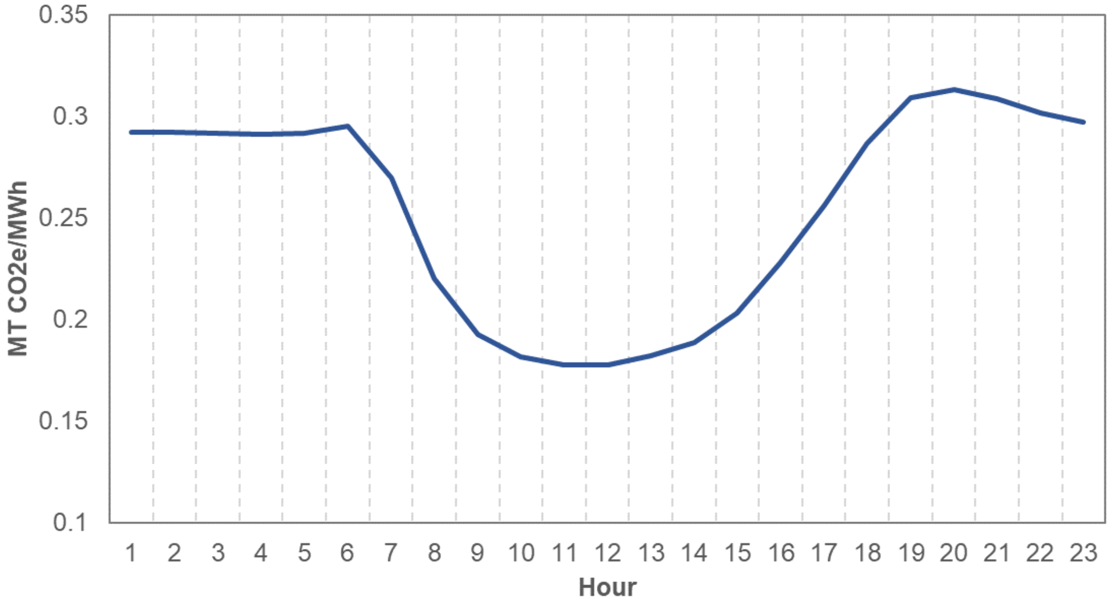

Figure 2-16 2019 Average hourly emission rates

With retail energy providers shifting their TOU structures, it may be beneficial to utilize battery storage to shift the use of solar generated energy from mid-day hours to evening hours which would have the double benefit of cost savings and carbon emissions reductions. The use of real-time emissions monitoring for BESS projects is required to receive the full incentive from SGIP and therefore, emissions reductions for these projects would be quantified and reported for additional reduction value. SGIP mandates a minimum 5 metric tonne CO_2/MWh/year emissions reduction for all projects claiming the incentive so this assumption has been incorporated into the carbon emission reductions analysis provided in Section 6.0. Additional information on GHG reduction forecasting and strategies can be found in Metropolitan's CAP.

3.0 RENEWABLE ENERGY AND ENERGY STORAGE PROJECT OPPORTUNITIES ADDRESSING RETAIL ELECTRICITY RATES

This section details the results of the financial feasibility of selected renewable and energy storage project opportunities at Metropolitan, within the context of developing an ESP, as presented in Figure 2-1, and according to the methodology presented in Section 2.0. The following sections present the feasibility of the select projects at Metropolitan's facilities. In particular, this section includes:

- BESS at Weymouth Treatment Plant
- Solar and/or BESS at Skinner Treatment Plant
- Solar and/or BESS at Mill Treatment Plant
- BESS at Jensen Treatment Plant
- BESS at OC-88 Pumping Plant
- Hydropower at Diemer Treatment Plant

3.1 F.E. WEYMOUTH TREATMENT PLANT

The F.E. Weymouth Treatment Plant (Weymouth) is located in the City of La Verne and serves customers in Los Angeles and Orange Counties. The plant has a capacity of 520 million gallons a day (MGD) of water and treats a blend of water delivered from the CRA and the SWP. The process at Weymouth Treatment Plant consists of conventional treatment (i.e., pretreatment, coagulation/flocculation, sedimentation), direct filtration, and since 2017, ozone treatment has replaced chlorination for primary disinfection. In consideration of its size and the addition of the energy-intensive ozone treatment, the plant experiences high energy demand and retail energy costs. In 2016, to offset some of the energy costs and demand at this facility, Metropolitan installed 3 MW of solar generation.

The following sections provide detailed energy demand and related energy cost information from Weymouth's operations and will provide the results of the feasibility analysis conducted for the integration of a BESS with the existing solar generation at the site.

3.1.1 Weymouth energy demand and electricity cost profiles

Figure 3-1 presents the historical monthly energy demand at Weymouth for the period of 2004–2018. The plant's energy demand was satisfied by SCE alone until 2016, when the 3 MW solar generation system began operation. Energy demand at Weymouth was relatively stable at approximately 10.7 GWh per year between 2004 and 2016. The installation of the ozone treatment in October 2017 resulted in an average 36 percent increase in the plant's energy demand to approximately 14.5 GWh, which was partially offset by the solar previously installed. The energy demand profile presented in Figure 3-1 also shows a seasonal variation with higher consumption occurring during the summer months (i.e., June to August, or September in some cases) and lower consumption during winter time.

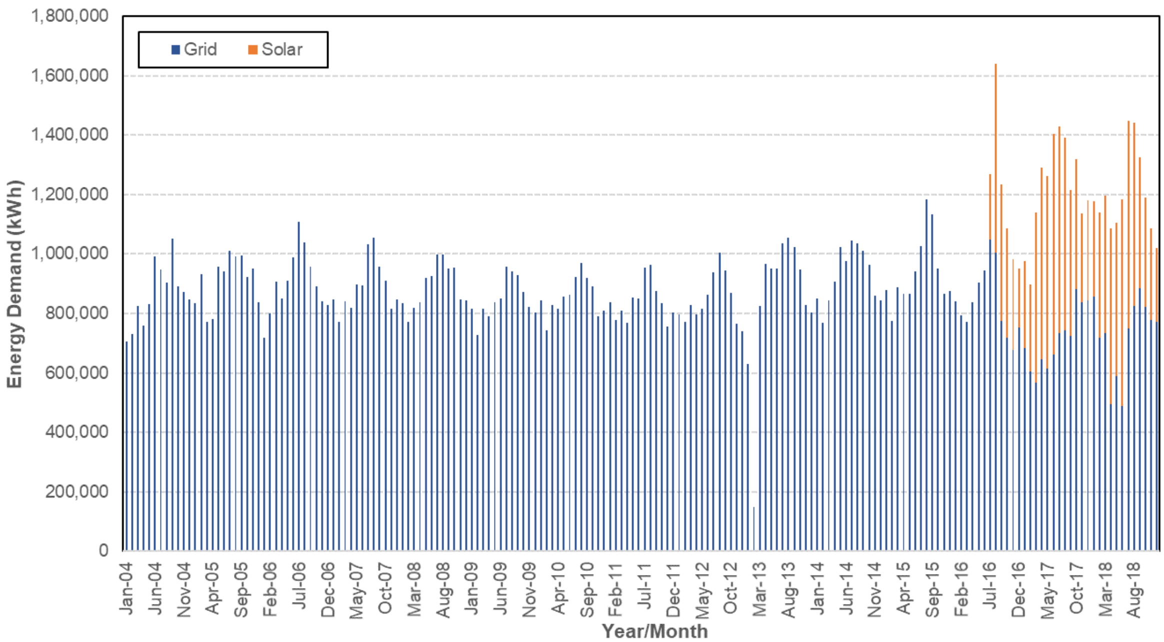

Figure 3-1 Weymouth historical energy demand by source for the period 2004–2018

Weymouth has two meters, a minor meter on SCE's TOU-PA-2-B rate structure and the main meter on SCE's grandfathered TOU-8-A-S standby rate structure. The grandfathered rate plan is applicable for 10 years starting in June 2016 and is subject to standby rate updates during the 10-year term (e.g., the most recent update was effective in June 1, 2019). For the purposes of this analysis, it is assumed that Weymouth's contract will switch over to SCE's LG tariff in 2026, when the TOU-8-A-S grandfathered plan expires.

The energy generated by the behind-the-meter solar facility is used to satisfy the plant demand with the excess energy, if any, sent back to the grid in exchange for credits applied to the monthly electricity bill for the designated account as part of SCE's RES-BCT program. The annual electricity cost between 2004 and 2015 was on average \$1.3 million, resulting in an observed average cost per unit energy of \$0.12 per kWh. After the installation of the solar generating facility in 2016, the average annual electricity cost was reduced to \$790,000 with an average unit cost at \$0.08 per kWh (Figure 3-2).

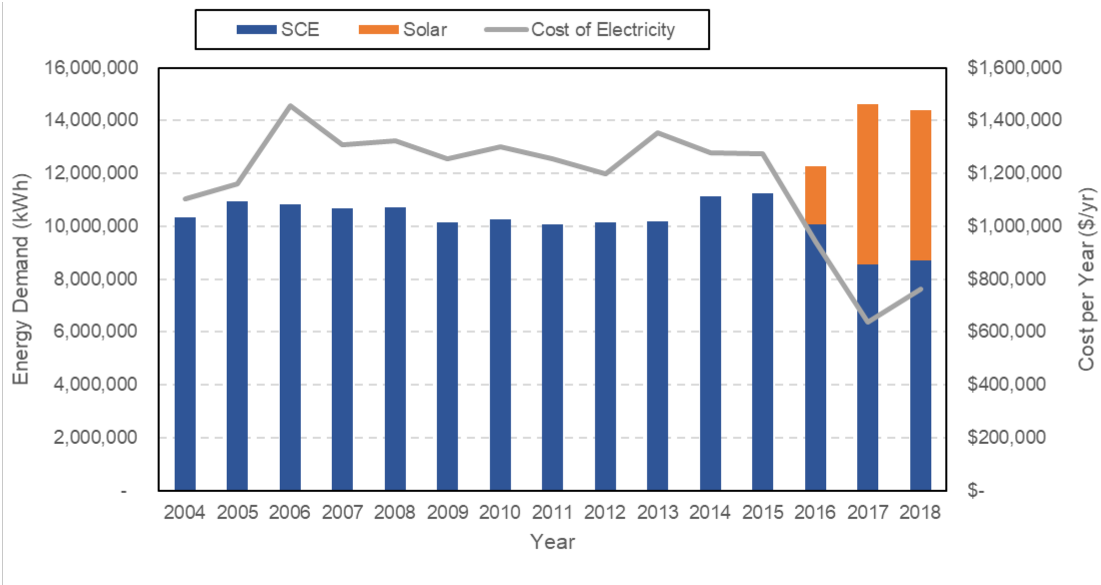

Figure 3-2 Historical energy demand by source and electricity cost at Weymouth

A typical year of energy demand was generated and used as input for the development of the battery energy storage model at Weymouth. To account for the higher energy consumption of the ozone treatment, the estimated demand of the typical year uses an average of the energy demand of 2017 and 2018. Figure 3-3 shows a comparison of the estimated typical year energy demand with the historical demands in 2017 and 2018.

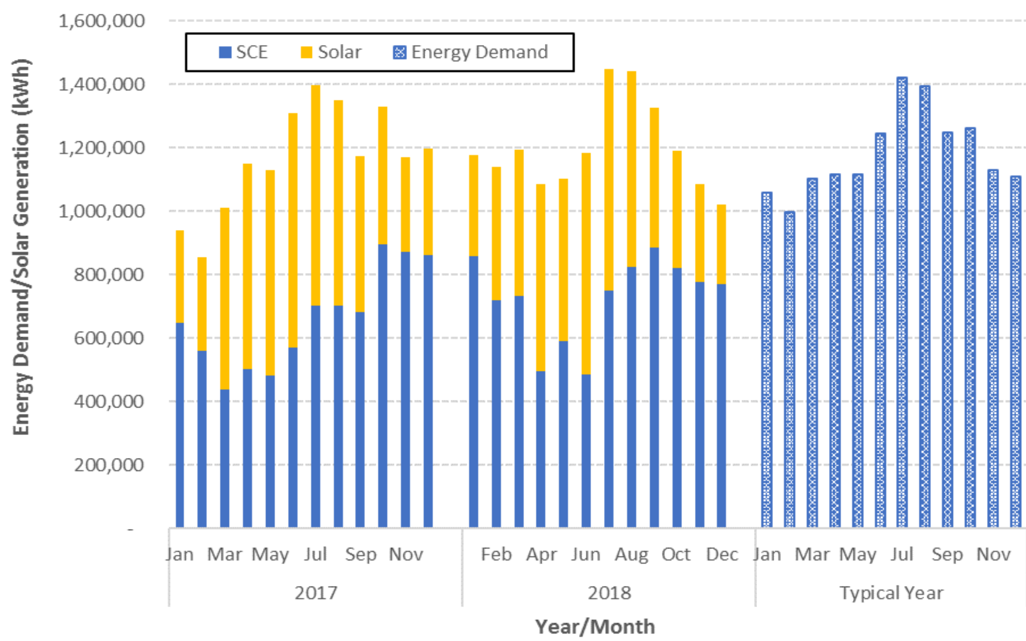

Figure 3-3 Energy demand at Weymouth for the period 2017–2018 by source and for the estimated typical year

Upon completion of 3 MW of solar energy at Weymouth in 2016, there is limited space available at Weymouth for further development of large-scale solar energy. However, there is space available for the implementation of BESS at Weymouth.

3.1.2 Battery energy storage feasibility evaluation at Weymouth

The following sections present key input and outcomes of the battery energy storage feasibility evaluation at Weymouth, particularly in relation to the selection of battery configuration, size, and dispatch model, and the elements of the economic feasibility (i.e., capital and O&M costs, cost benefits, incentives, NPV, and payback analysis).

3.1.2.1 Battery size, configurations and dispatch model

For the purpose of this feasibility analysis for battery energy storage at Weymouth, the following assumptions were considered:

- Stored energy from the battery system can be dispatched to both meters, one of which is connected to the solar generation system.
- The BESS is in a behind-the-meter configuration.

- The BESS is considered a non-exporting asset; therefore, unlike the solar facility, no credits can be gained from exporting the energy stored in the BESS at any point.

A simple model was built to fully assess the potential costs savings through TOU price arbitrage at Weymouth. The BESS was source-agnostic in terms of charging but did remain behind-the-meter and in a non-exporting state. The TOU arbitrage strategy was to charge the BESS during off peak hours and dispatch the stored energy during on peak hours, servicing plant load with energy stored with the BESS when demand and energy charges were highest. Details of this BESS configuration are provided in Table 3-1.

Table 3-1 Details of the BESS evaluated at Weymouth

Parameter	Value/Description
Battery Size	1 MW/2 MWh
Annual energy dispatched by battery	526 MWh
Dispatch Model	Dispatch during peak TOU between 12 p.m. - 6 p.m. summer weekdays on TOU-8-S-A and between 4 p.m. - 9 p.m. summer and winter weekdays on TOU-8-S-LG

Due to Weymouth's grandfathered rate structure, the typical time periods of solar generation coincide with on-peak and most of mid-peak TOU during summer and all of mid-peak TOU during winter, therefore the peak power and energy demand is primarily reduced by solar energy when the electricity rate is high. When Weymouth switches to a new TOU in 2026, it is expected that the on-peaks will shift to evening hours where solar is no longer available and the battery can assist in shifting solar energy to these new peak hours. Thus, while the battery will be more effective with a new TOU, it will still provide some savings on the current, grandfathered rate structure.

3.1.2.2 Economic feasibility of battery energy storage

To assess the economic feasibility of battery energy storage options at Weymouth, the cost of the battery system, the benefits achieved from their operation, and the financial incentives available to offset the initial capital investments were considered. A 1 MW/2 MWh system was chosen to maximize the SGIP incentives received in proportion to capital costs. The capital and O&M costs of the BESS were estimated according to the assumptions previously included in Section 2.0, and are presented in Table 3-2.

Table 3-2 Cost information estimated for BESS at Weymouth

System	First Year of Operation	Capital Cost	Annual O&M Cost	Annual Electricity Savings
1 MW BESS, TOU Demand Arbitrage	2023	$1,100,000	$15,000	$30,000* – $76,000**

*Under the current TOU-8-A-S grandfathered structure
**After 2026, under the TOU-8-LG tariff

The simple arbitrage strategy reduced demand charges every month, as shown in Figure 3-4, and resulted in total annual energy savings of approximately $30,000 compared to the baseline scenario for the grandfathered TOU-8-S-A and approximately $89,000 compared to the baseline scenario for the new TOU-8-S-LG.

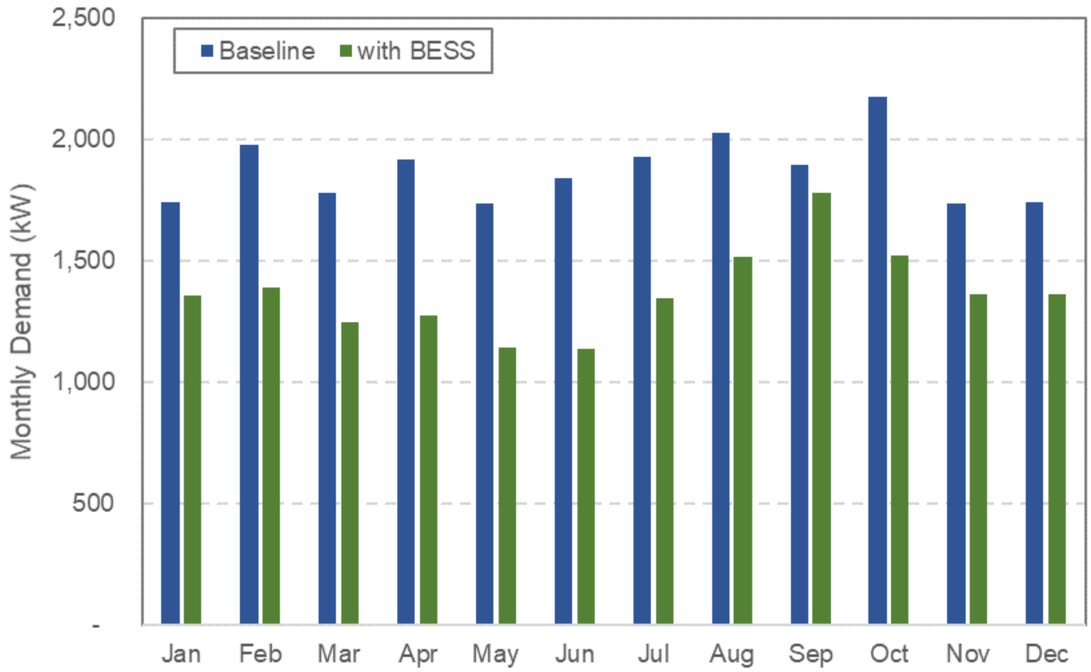

Figure 3-4 Monthly peak demand comparison at Weymouth (TOU-8-S-LG)

As noted above, beginning in 2026, Weymouth will be transitioned from the current grandfathered rate structure to SCE's typical rate structure, assumed in this analysis as the LG tariff. This transition was incorporated into the NPV analysis along with the SGIP Step 3 incentive and RA capacity credit described in Section 2.2.2.4. The results of the analysis are presented in Table 3-3.

Table 3-3 Economic feasibility of BESS at Weymouth

Incentive Scenarios	Incentive Rate ($/Wh)	Capacity Credit ($/kw-month)	10-year* NPV	Payback Period (years)
No incentive	$ -	$ -	($407,000)	>10*
SGIP Step 3 Incentive	$0.35	$ -	$205,000	6
SGIP Step 3 Incentive + RA Capacity Credit	$0.35	$1.50	$345,000	5

*BESS asset life is assumed to be 10 years

The majority of savings from the BESS stem from its use under the LG tariff. Because this study only analyzes the potential returns from incorporating a BESS system at Weymouth, these results are not intended to represent the electricity cost at Weymouth after the introduction of the LG tariff; rather, they simply reflect the difference in cost between Weymouth usage with a BESS and Weymouth usage without a BESS under the assumptions previously introduced. For example, this analysis is based on a standby demand level of 2500 kW at Weymouth; however, while a cursory analysis found that this standby level is optimal for the current plant demand when assessed at an hourly level, changes to usage patterns or an analysis accounting for shorter intervals and the capacity of the treatment plant to shift demand could change the standby demand level at Weymouth.

Before making investment decisions premised on savings under this rate structure, Metropolitan should work closely with SCE to understand any potential future changes to current electricity tariffs. If conversations with SCE and clarifications on future changes to the tariffs seem favorable, Metropolitan should investigate and apply to SGIP’s Step 3 incentive program before depletion of the funding.

3.2 ROBERT A. SKINNER TREATMENT PLANT

The Robert A. Skinner Treatment Plant (Skinner) is located south of the City of Hemet in Riverside County, and it supplies treated water to customers of the Eastern and Western Municipal Water districts in Riverside County and to the San Diego County Water Authority—three of Metropolitan's member agencies. Skinner has the capacity to produce 350 million gallons of water per day, and it treats water from the CRA and the SWP. The treatment facility features conventional and direct filtration process, the latest one not utilizing sedimentation. The facility converted its primary disinfection method to ozone treatment in 2010.

The Skinner plant is located in SCE territory and in 2010, was retrofitted with a 1-MW solar facility that generates renewable energy partially used by the plant (Figure 3-5). To further offset some of the energy costs and demand at this facility, and to improve the benefits of the solar generation currently installed, this study independently evaluated the following renewable energy and energy storage opportunities:

- Solar facility expansion from 1 MW to 2 MW;
- Solar facility expansion from 1 MW to 2 MW coupled with battery energy storage;
- Solar facility expansion from 1 MW to 3 MW;
- Solar facility expansion from 1 MW to 3 MW coupled with battery energy storage;
- New battery energy storage with no solar facility expansion.

The following sections provide detailed energy demand and related energy cost information from the Skinner Treatment Plant's operations, and it provides the results of the feasibility analysis conducted for the solar generation expansion, both with and without integration with BESS, and for the stand-alone BESS.

3.2.1 Skinner energy demand and electricity cost profiles

Figure 3-5 shows the historical monthly energy demand at Skinner for the period of 2014 through the start of 2019. The plant's energy demand is provided by SCE and since 2010, the 1-MW solar generation system. Since 2016, an average of 18 percent of the total energy demand at Skinner has been supplied by solar, although the availability of this renewable energy is heavily localized through time. Overall, the energy demand profile shows a seasonal variation with higher consumption occurring during the summer months (i.e., June to August, or September in some cases) and lower consumption during winter time.

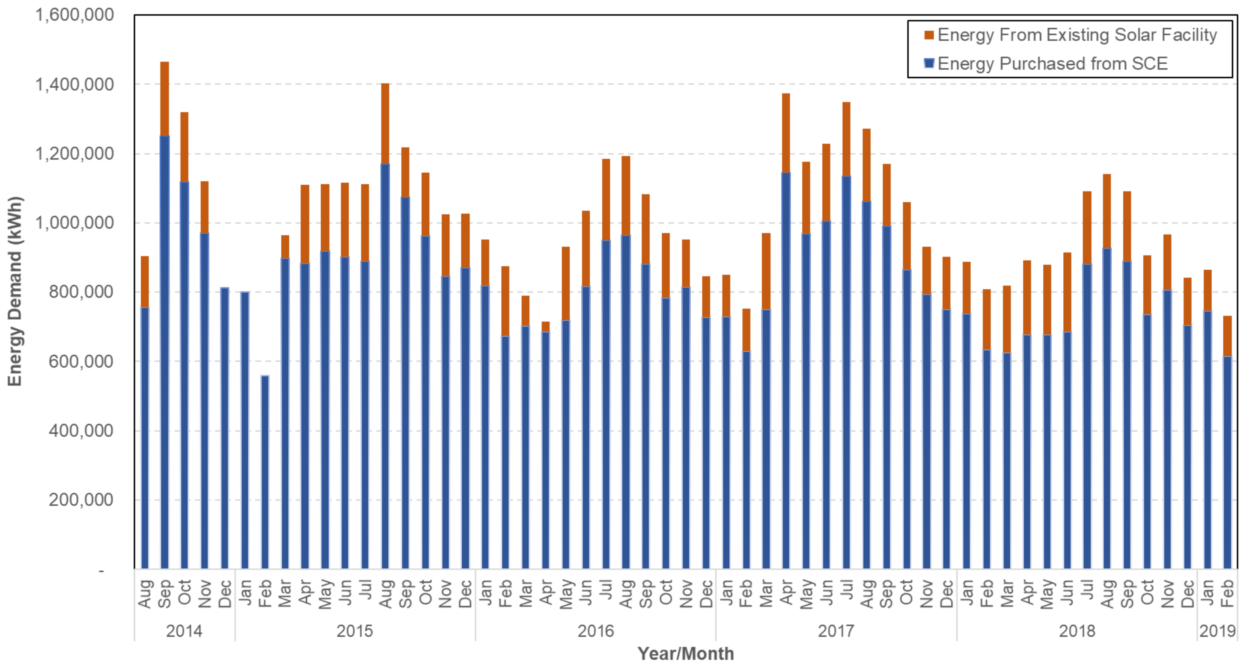

Figure 3-5 Skinner historical energy demand by source for the period 2014-2019

The period of 2015-2018, with an average yearly energy demand of approximately 10.4 GWh, was used to define the typical year for the solar and BESS feasibility evaluation at Skinner. This period was selected based on available 15-minute incremental data.

For Skinner's operation, Metropolitan purchases energy from SCE under the tariff rate structure TOU-8-B-CPP. The average annual electricity cost at Skinner between 2005 and 2017 (2018 electricity costs were not available) was approximately $1.2 million (Figure 3-6).

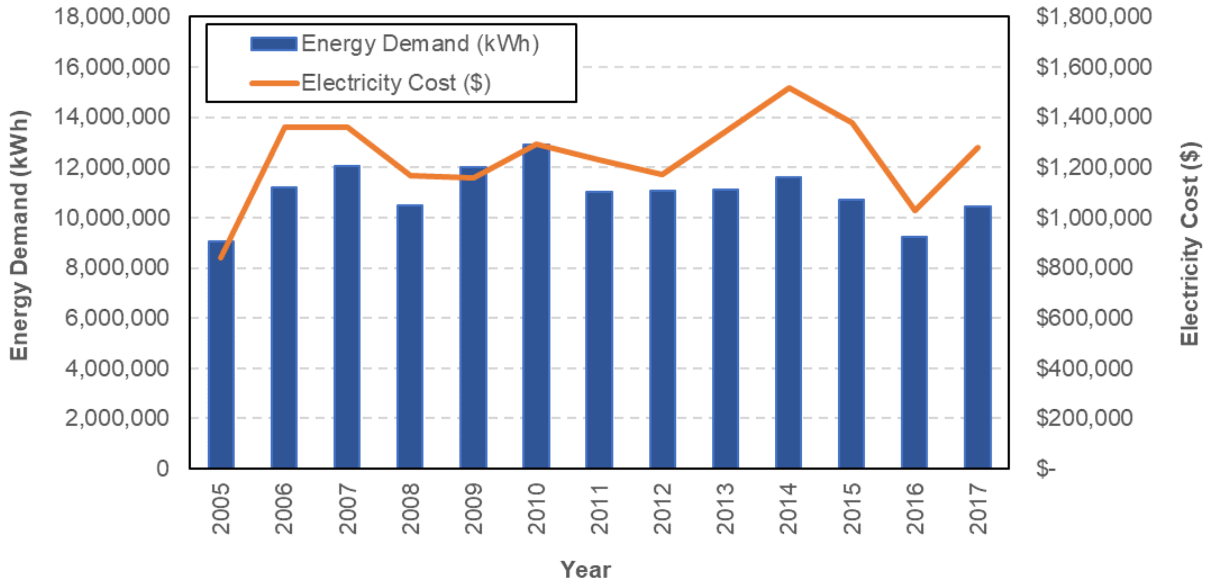

Figure 3-6 Historical annual energy demand and electricity cost at Skinner

3.2.2 Solar generation expansion feasibility evaluation at Skinner

The existing 1 MW solar facility at Skinner was installed in 2010 and was designed to accommodate future expansion. This section evaluates the feasibility of an expansion for two solar facility sizes, 1 MW and 2 MW, and assesses the economics of coupling the new solar generation system with battery energy storage.

3.2.2.1 Solar generation facility expansion

This assessment evaluated a 1 MW and a 2 MW solar facility expansion opportunity located on available land within the facility boundaries near the existing 1 MW solar system. Two procurement mechanisms were considered:

- A Metropolitan-owned solar facility, in which Metropolitan would procure, build, and operate the new solar facility.
- A PPA with a solar developer, in which the solar facility would be owned and operated by a third party, and Metropolitan would commit to buy the power generated at a lower price than on the retail energy market. Based on the methodology described in Section 2.0, PPA prices of 7.87 cents/kWh and 7.57 cents/kWh for the 1 MW and the 2 MW facilities, respectively, were calculated.

It should also be noted that since the existing solar facility at Skinner already offsets part of the facility's electricity demand, the 1 MW or 2 MW solar expansion would generate a surplus of energy than would be needed at the facility during solar hours. In this evaluation, it is assumed that Metropolitan would be fully credited for this surplus energy exported to SCE (net metering).

3.2.2.2 Economic feasibility of solar generation expansion

Project costs for the two solar facility sizes and procurement mechanisms are presented in Table 3-4.

Table 3-4 Cost information estimated for solar generation expansion at Skinner

Solar Facility Size	Procurement Method	Capital Cost ($)	Annual O&M Cost ($)	PPA Electricity Price (cents/kWh)	Renewable Energy Generated (GWh/year)	Renewable Energy Used (GWh/year)
1 MW	Metropolitan-owned	$2,830,000	$18,000	-	2.39	2.26
	PPA	-	-	7.87		
2 MW	Metropolitan-owned	$5,410,000	$36,000	-	4.79	3.13
	PPA	-		7.57		

A financial analysis was performed assuming 2023 as the first year of operation for the system. Results are presented in Table 3-5 and show that a more advantageous NPV is obtained when Metropolitan establishes a PPA with a third-party developer, compared to a Metropolitan-owned solar generation facility. Regardless of the scale, and for the two facility sizes considered, Metropolitan-owned solar at Skinner can be still considered an economically feasible option as it has a positive 20-year NPV achieved with a PPA, for both sizes.

Table 3-5 Economic feasibility of solar generation expansion at Skinner

Solar Facility Size	Procurement Method	Annual electricity cost savings	20-year NPV*	Payback Period (years)
1 MW	Metropolitan-owned	$134, 000	$240,000	14
	PPA	$25, 000	$277,000	-
2 MW	Metropolitan-owned	$267,000	$654,000	14
	PPA	$46,000	$523,000	-

*Solar facility asset life is 20 years

3.2.3 Battery energy storage feasibility evaluation at Skinner

Based on the solar generation expansion projects evaluated above, the addition of a BESS under different conditions was considered for the Metropolitan-owned case only. The BESS was modeled based on a TOU price arbitrage strategy. The three following scenarios were considered:

- BESS integrated with the 1 MW solar expansion;
- BESS integrated with the 2 MW solar expansion;
- A new BESS without additional solar.

3.2.3.1 Battery size, configuration, and dispatch model

For the purpose of this feasibility analysis for battery energy storage in the first two cases, the following assumptions were considered:

- The BESS is in a behind-the-meter configuration;
- The BESS is connected to the solar generation expansion and grid;
- The BESS is considered a non-exporting asset; therefore, unlike the solar facility, no credits can be gained from exporting the energy stored in the BESS at any point.

In order to apply full benefits of the SGIP incentives available to Skinner through SCE, battery sizes for all cases were assumed to be 1MW/2MWh. Further optimization of the battery size may be obtained based on battery developer-specific modeling.

The charge/discharge strategy assumes the BESS is source-agnostic in terms of charging and remains in a behind-the-meter and in a non-exporting state. The strategy schedules charging of the BESS during off-peak or super off-peak hours and dispatches the stored energy during on-peak and mid-peak hours, servicing plant load with energy stored with the BESS when demand and energy charges are highest. This approach utilizes precise knowledge of energy demand through time, which an actual BESS would not have, and therefore represents an upper limit on the savings that could be realized. Table 3-6 presents the key characteristics of the BESSs evaluated at Skinner.

Table 3-6 Details of the BESS evaluated at Skinner

Parameter	Value/Description
Battery Size	1 MW/2 MWh
Annual energy dispatched by battery	526 MWh
Dispatch Model	Dispatch during peak TOU between 12 p.m. - 6 p.m. summer weekdays on TOU-8-B-CPP and between 4 p.m. - 9 p.m. summer and winter weekdays on TOU-8-D-CPP

3.2.3.2 Economic feasibility of battery energy storage

The capital and O&M costs of the BESS systems were estimated according to the assumptions previously included in Section 2.0, and are presented in Table 3-7.

Table 3-7 Cost information estimated for the BESS at Skinner

Parameter	BESS paired with 1 MW new solar*	BESS paired with 2 MW new solar*	BESS stand-alone
Capital cost	$1,100,000	$1,100,000	$1,100,000
Annual O&M cost	$15,000	$15,000	$15,000
Annual electricity cost savings from BESS	$33,000 - $98,000	$28,000 - $98,000	$25,000 - $86,000

* Costs are only reported for the BESS and do not include the cost for the solar expansion

The simple arbitrage strategy reduced demand charges every month, as shown in Figure 3-4, and resulted in total annual energy savings of approximately $30,000 compared to the baseline scenario for the grandfathered TOU-8-B-CPP and approximately $90,000 compared to the baseline scenario for the new TOU-8-D-CPP.

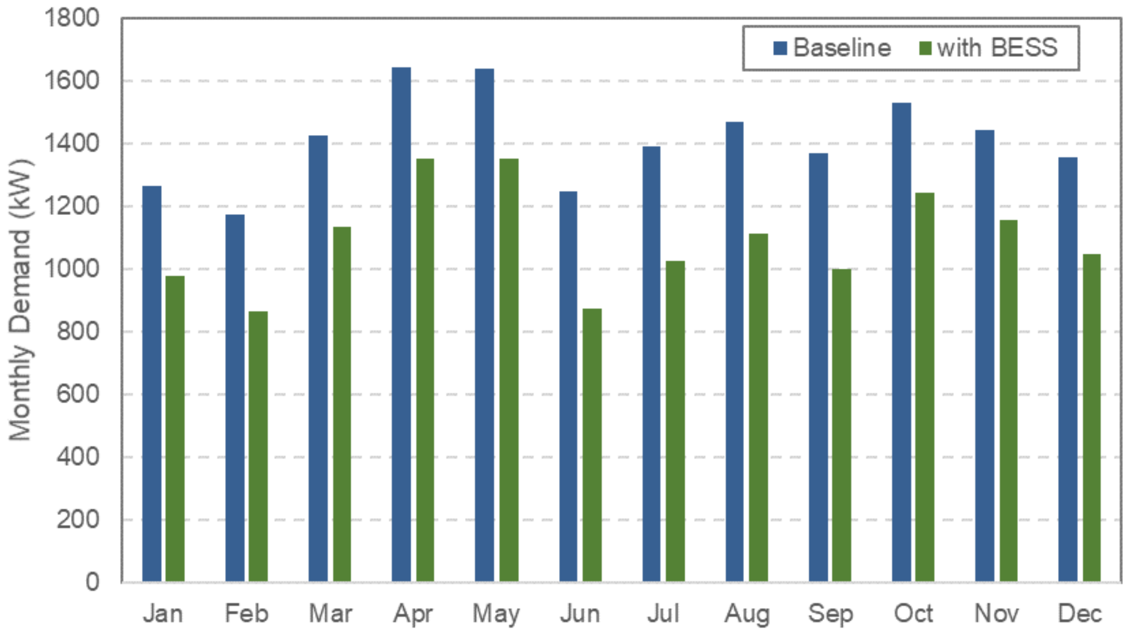

Figure 3-7 Monthly peak demand comparison at Skinner (TOU-8-B-CPP)

The results of the financial analysis are presented alongside the results of the solar-generation expansion only for comparison purposes. It should be noted that these results represent a best-case scenario as they assume that the Step 3 SGIP incentive and RA capacity credits would be obtained and that Metropolitan would get full credit for additional solar exported to the SCE grid (net metering).

Table 3-8 Economic feasibility of solar and BESS options at Skinner

Alternative	Solar Facility Size (MW)	Procurement Method	Battery Storage Sizing (MW/MWh)	Initial Capital Cost ($000s)	20-year NPV ($)	Payback Period (years)	Renewable Energy Generated (GWh/year)	Renewable Energy Used* (GWh/year)
New Solar Only	1	Metropolitan-owned	-	$2,830	$240,000	14	2.39	2.26
		PPA	-	-	$277,000	-		
	2	Metropolitan-owned	-	$5,410	$654,000	14	4.79	3.13
		PPA	-	-	$523,000	-		
New Solar with Battery Storage**	1	Metropolitan-owned	1/2	$3,930	$1,600,000	10	2.39	2.14
	2		1/2	$6,510	$1,993,000	12	4.79	3.56
New Battery Only***	Existing System	Metropolitan-owned	1/2	$1,100	$396,000	5	-	-

* Energy used by the system. When BESS is coupled with solar, assumes some excess solar sent to battery and accounts for losses by the BESS.

** Based on a 20-year lifespan assuming the battery system would be replaced every 10 years but would no longer be eligible for SGIP incentives.

***10-year NPV for BESS since asset life is 10 years

It is recommended that Metropolitan refines the technical and financial analyses of a BESS at Skinner through a battery developer experienced in the SCE market to gain more accurate estimates of the electricity savings that a BESS can reasonably deliver through TOU arbitrage.

3.3 HENRY J. MILLS TREATMENT PLANT

The Henry J. Mills Treatment Plant (Mills) is located in the City of Riverside, and supplies SWP treated water, via gravity flow, to the Eastern and Western Municipal Water Districts of Riverside County. Mills has a capacity of 220 MGD and uses conventional filtration and ozone as the primary disinfectant, followed by the use of chlorination. Mills is located in RPU territory and has the lowest energy demand among all Metropolitan water treatment plants. The plant does not currently have an on-site renewable energy generating facility.

To further offset some of the energy costs and demand at this facility, this study independently evaluated the feasibility of the following renewable energy and energy storage opportunities:

- Battery energy storage only;
- Solar generation only;
- Solar generation coupled with battery energy storage.

The following sections provide detailed energy demand and related energy cost information from the Mills' operations and the results of the feasibility analysis conducted for the three renewable energy and energy-storage alternative scenarios listed above.

3.3.1 Mills energy demand and electricity cost profiles

Figure 3-8 presents the historical monthly energy demand at Mills for the period of 2014 through 2018. Overall, the energy demand profile showed an increasing trend from 2014 to 2018 and a seasonal variation with higher consumption occurring during the summer months (i.e., June to August, or in September) and lower consumption during winter months. For example, in 2019, the approximate 620,500 kWh consumed in the month of July almost halved (350,000 kWh) in the month of December.

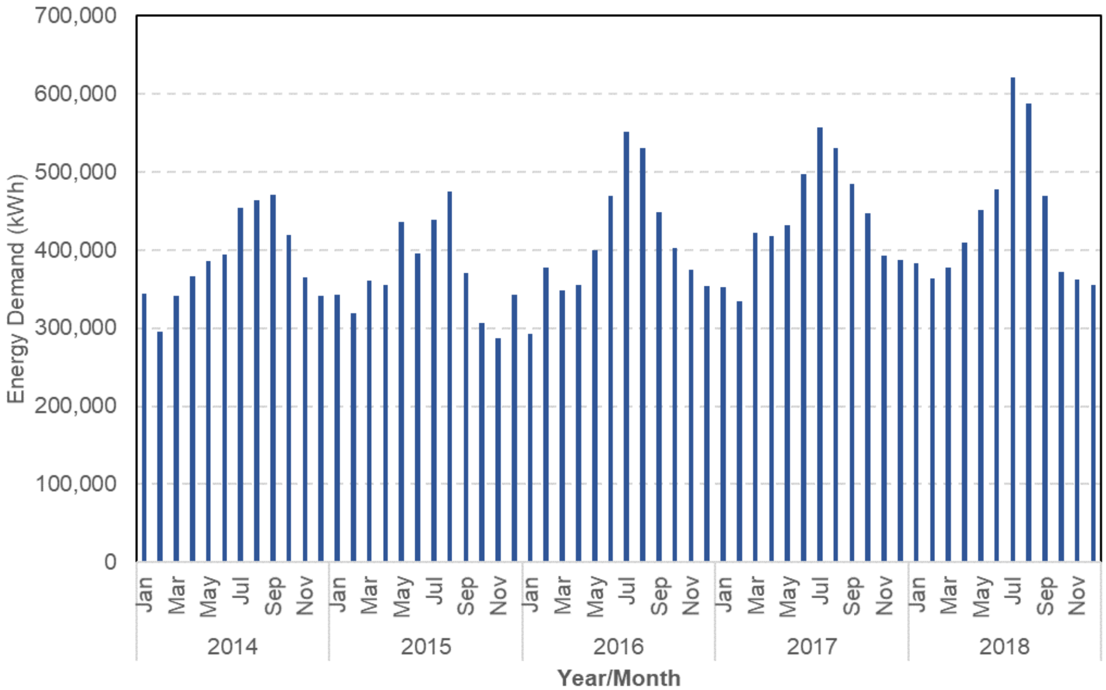

Figure 3-8 Mills historical monthly energy demand by source for the period 2014-2018

Based on the analysis of the historical data, the period 2016-2018, with an average yearly energy demand of approximately 5.0 GWh, was used to define the typical year for the solar and BESS feasibility evaluations at Mills.

For Mills' operation, Metropolitan purchases energy from RPU. The average annual electricity cost at Mills between 2004 and 2017 (2018 electricity costs were not available) was approximately $560,000 (Figure 3-9). Using 2019 RPU electricity rates, the typical year facility electricity cost is approximately $532,000.

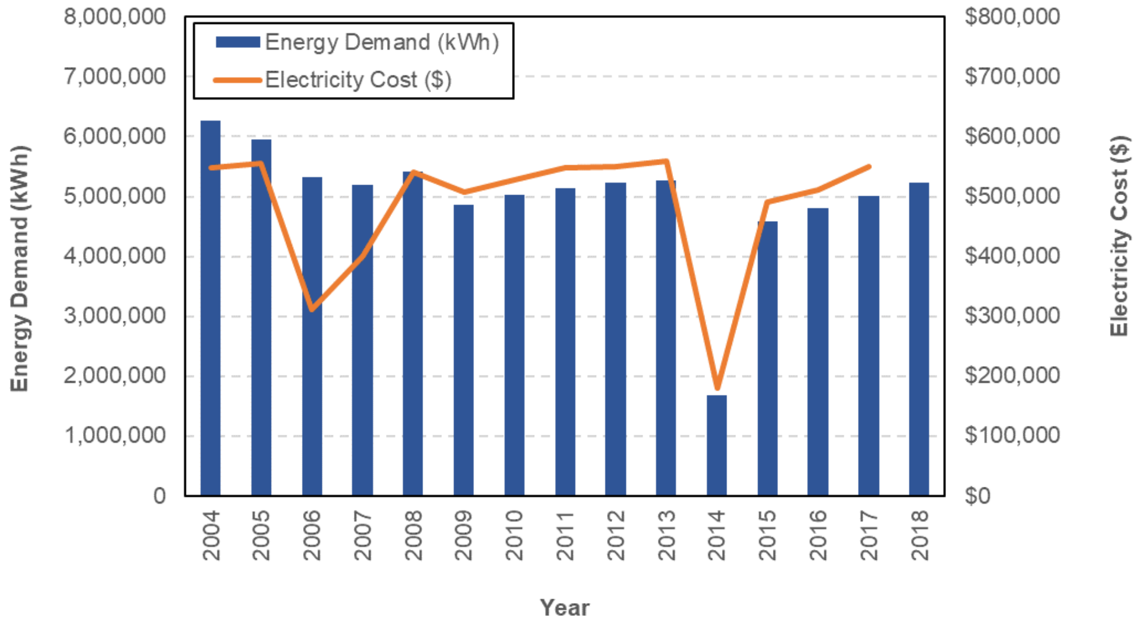

Figure 3-9 Historical energy demand and electricity cost at Mills

3.3.2 Solar generation facility evaluation at Mills

Mills does not currently have any solar generation but there is land available on-site that could be utilized for solar. This section evaluates the feasibility of installing a new 500 kW solar facility at Mills and assesses the economics of coupling the new solar generation system with battery energy storage.

3.3.2.1 New solar generation facility

This assessment evaluated a 500-kW solar facility opportunity located on available land within the Mills' facility boundaries. The size of the storage facility was selected to maximize energy cost offset while minimizing the amount of solar energy exported to RPU. Two procurement mechanisms and the following ownership options were considered:

- A Metropolitan-owned solar facility, in which Metropolitan would procure, build, and operate the new solar facility.
- A PPA with a solar developer, in which the solar facility would be owned and operated by a third party, and Metropolitan would commit to buy the power generated at a lower price than the retail energy market. Based on the methodology described in Section 2.0, a PPA price of 8.00 cents/kWh was calculated. This price was higher than the PPA prices calculated for Skinner due to economy of scale and the lack of existing interconnection infrastructure already installed at Skinner (as part of the existing solar facility).

3.3.2.2 Economic feasibility of solar generation facility

Project costs for both procurement mechanisms are summarized in Table 3-9, in 2019 dollars. A financial analysis was performed assuming 2023 as the first year of operation for the system. Results are presented in Table 3-10 and show that a more advantageous NPV is obtained when Metropolitan establishes a PPA with a third-party developer compared to a Metropolitan-owned solar generation facility.

Table 3-9 Cost information estimated for solar generation at Mills

Solar Facility Size	Procurement Method	Capital Cost	Annual O&M Cost	PPA Electricity Price (cents/kWh)	Renewable Energy Generated (GWh/year)	Renewable Energy Used (GWh/year)
500 kW	Metropolitan-owned	$1,873,000	$10,000	-	1.21	1.21
	PPA	-	-	8.00		

Table 3-10 Economic feasibility of new solar generation facility at Mills

Solar Facility Size	Procurement Method	Annual electricity cost savings	20-year NPV*	Payback Period (years)
500 kW	Metropolitan-owned	$111,000	$140,000	14
	PPA	$54,000	$566,000	-

*Solar facility asset life is 20 years

3.3.3 Battery energy storage feasibility evaluation at Mills

Based on solar generation projects evaluated above, the addition of BESS to a new solar generation facility was considered and detailed in the sections below for the Metropolitan-owned case only. The two following scenarios were considered:

- BESS alongside a new 500 kW solar facility
- A new BESS without additional solar and modeling performance according to a TOU arbitrage strategy

3.3.3.1 Battery size, configuration, and dispatch model

For the purpose of this feasibility analysis for battery energy storage at Mills, the following assumptions were considered:

- The BESS is in a behind-the-meter configuration
- The BESS is connected to the new solar generation facility and the grid
- The BESS is considered a non-exporting asset; therefore, unlike the solar facility, no credits can be gained from exporting the energy stored in the BESS at any point

A conceptual-level optimization of the battery size and dispatch pattern was modeled according to the tariff rate structure plan, the typical year electricity demand, the solar energy generation, and the assumptions previously presented in Section 2.0. Table 3-11 presents the key characteristics of the BESS evaluated at Mills when coupled with solar.

Table 3-11 Details of the BESS evaluated at Mills

Parameter	Value/Description	
	BESS with new 500 kW solar	Stand-alone BESS
Battery Size	300 kW/900 kWh	1 MW/2 MWh
Annual energy dispatched by battery	169 MWh	376 MWh
Dispatch model	Dispatch during peak TOU between 12 p.m. - 6 p.m. summer weekdays and 4 p.m. - 9 p.m. winter weekdays	Dispatch during peak TOU between 12 p.m. - 6 p.m. summer weekdays and 4 p.m. - 9 p.m. winter weekdays

3.3.3.2 Economic feasibility of battery energy storage

The capital and O&M costs of the BESS systems were estimated according to the assumptions previously included in Section 2.0 and are presented in Table 3-12.

Table 3-12 Cost information estimated for the BESS at Mills for solar-coupled system

Parameter	300kW/900 kWh BESS paired with 500 kW new solar*	1 MW/2 MWh BESS stand-alone
Capital cost	$386,000	$1,100,000
Annual O&M cost	$5,000	$15,000
Annual electricity cost savings from BESS	$23,000	$36,000

* Costs are only reported for the BESS and do not include the cost for the solar expansion

The simple arbitrage strategy reduced demand charges every month, as shown in Figure 3-10, and resulted in total annual energy savings of approximately $23,000 for the 200kW/900kWh BESS paired with new solar and $36,000 for the stand-alone 1MW/2MWh BESS.

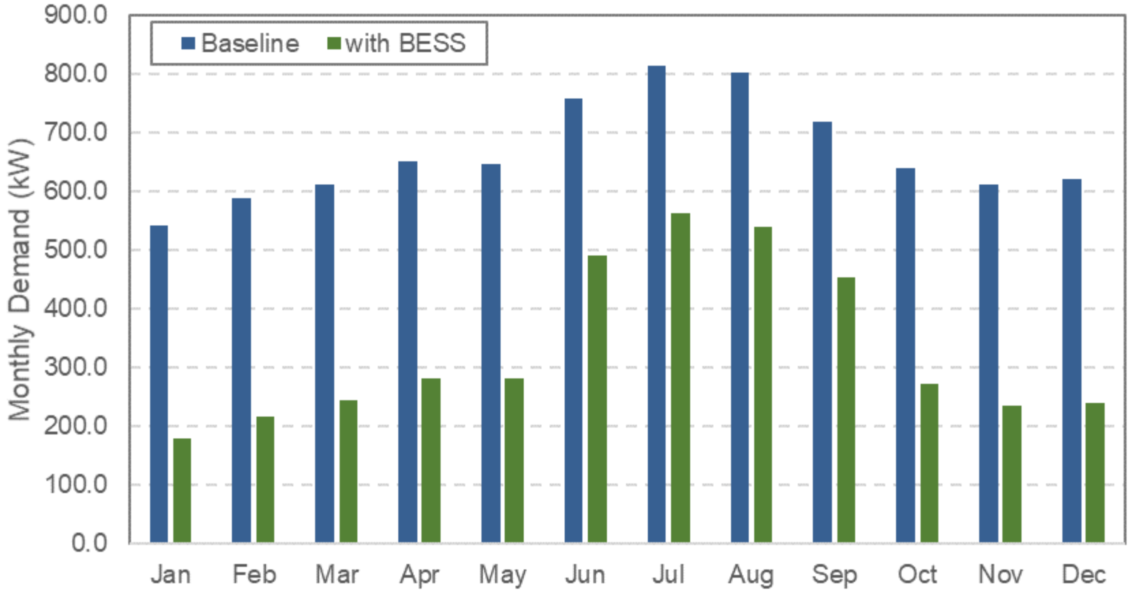

Figure 3-10 Monthly peak demand comparison for Mills (1MW/2MWh BESS)

The results of the financial analysis are presented in Table 3-13, and includes the results of the new solar generation only evaluation for comparison purposes. It should be noted that the results assume that the Step 3 SGIP incentive and RA capacity credits would be obtained for the BESS projects. Without both of these incentives, the stand-alone battery project would have a negative NPV and payback, making it financially unviable.

Table 3-13 Economic feasibility of solar and battery energy storage options at Mills

Alternative	Procurement Method	Solar Facility Sizing (kW-DC)	Battery Storage Sizing (kW/kWh)	Initial Capital Cost ($000s)	20-year NPV	Payback Period (years)	Renewable Energy Generated (GWh/year)	Renewable Energy Used* (GWh/year)
New Solar Only	Metropolitan-owned	500	-	$1,870	$140,000	14	1.21	1.21
New Solar Only	PPA	500	-	-	$566,000	-		
New Solar with Battery Storage**	Metropolitan-owned	500	300/900	$2,260	$356,000	14	1.21	1.09
New Battery Only***	Metropolitan-owned	-	1000/2000	$1,100	$102,000	7	-	-

* Energy used by the system. When BESS is coupled with solar, assumes some excess solar sent to battery and accounts for losses by the BESS.

** Based on a 20-year lifespan assuming the battery system would be replaced every 10 years but would no longer be eligible for SGIP incentives.

***10-year NPV for BESS since asset life is 10 years

3.4 JOSEPH JENSEN TREATMENT PLANT

The Joseph Jensen Treatment Plant (Jensen) is Metropolitan's largest treatment plant, with a capacity of 750 MGD of water. The plant is located in Granada Hills, near San Fernando, and it distributes water to San Fernando Valley, Ventura County, West Los Angeles, the City of Santa Monica, and the Palos Verdes Peninsula. The 125-acre Jensen plant only treats water from the SWP. Jensen's treatment process includes rapid mixing, flocculation, sedimentation, filtration, and disinfection via ozonation that was established in 2005.

In consideration of its size and the presence of energy-intensive treatment processes (i.e., ozone treatment) the plant experiences high energy demand and retail energy costs. In 2018, a 1-MW solar array went online at the site to reduce the amount of power Jensen required from LADWP's electrical grid. Expansion of the existing solar installation at Jensen hasn't been considered due to space limitations and lack of LADWP incentives for solar installations.

To potentially further offset some of the energy costs at Jensen, this study evaluated the feasibility of battery energy storage at this location. The following sections provide detailed energy demand and related energy cost information from Jensen's operations and provides the results of the feasibility analysis conducted for the energy storage alternative scenario.

3.4.1 Jensen energy demand and electricity cost profiles

Figure 3-11 presents the historical monthly energy demand at Jensen for the period of 2004 through 2018. The plant's energy demand was satisfied solely by LADWP until 2018, when the 1 MW solar generation system started operation. The yearly energy demand has fluctuated between 2004 and 2018. In 2004, for example, the total energy demand was 8,500 MWh, then it increased in 2005 with the addition of ozone to 12,600 MWh; a further increase in demand was observed in the following years reaching 16,700 MWh in 2016. Overall, during the 15 years under consideration, Jensen has had an average energy demand of approximately 11,500 MWh per year. The energy demand profile presented in Figure 3-11 also shows a seasonal variation with higher consumption occurring during the summer months (i.e., June to August, or in September in some cases) and lower consumption during wintertime.

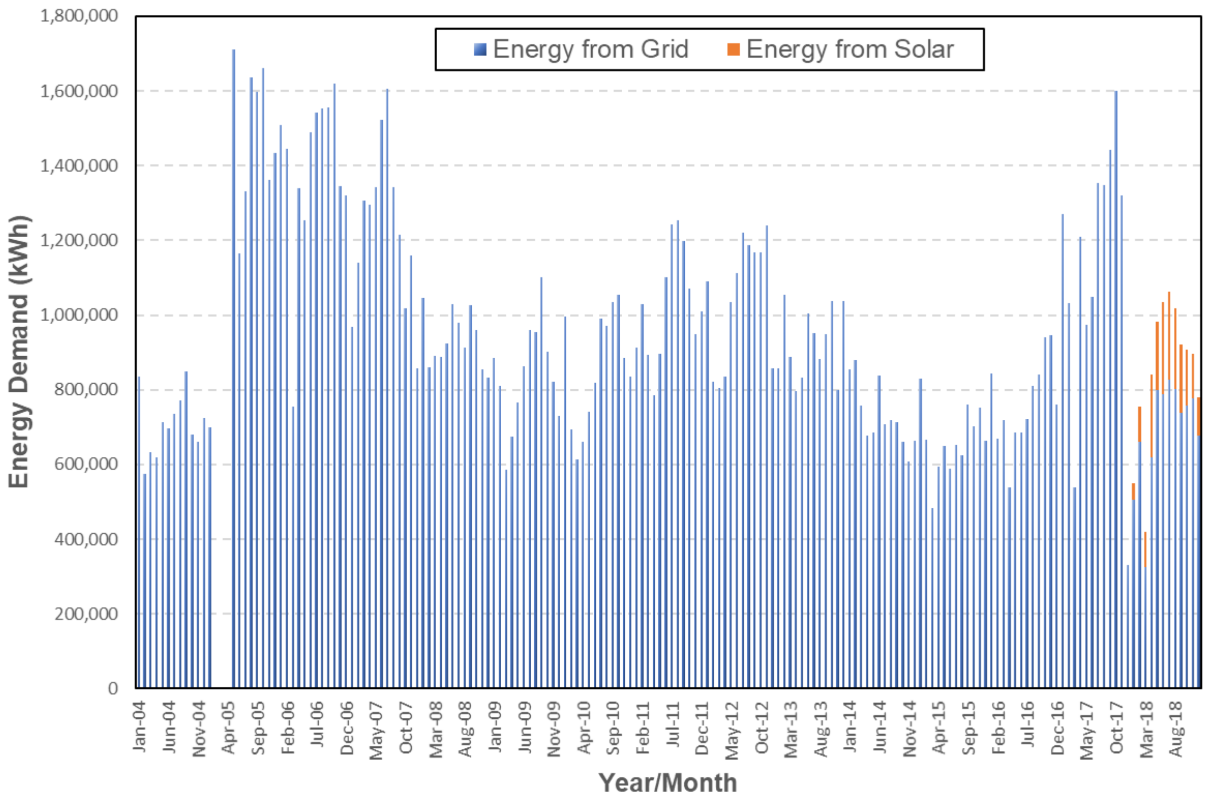

Figure 3-11 Jensen historical energy demand by source during the period 2004-2018

For Jensen's operation, Metropolitan purchases energy from LADWP under the tariff rate structure presented in Section 2.0. The unit cost of electricity has largely increased since 2015, resulting in a total annual electricity cost that is increasing faster than the actual energy demand, as shown in Figure 3-12. As such, there is a growing case for reducing Metropolitan's expenditures on grid electricity at Jensen, either by reducing demand or by optimizing use within the rate structure.

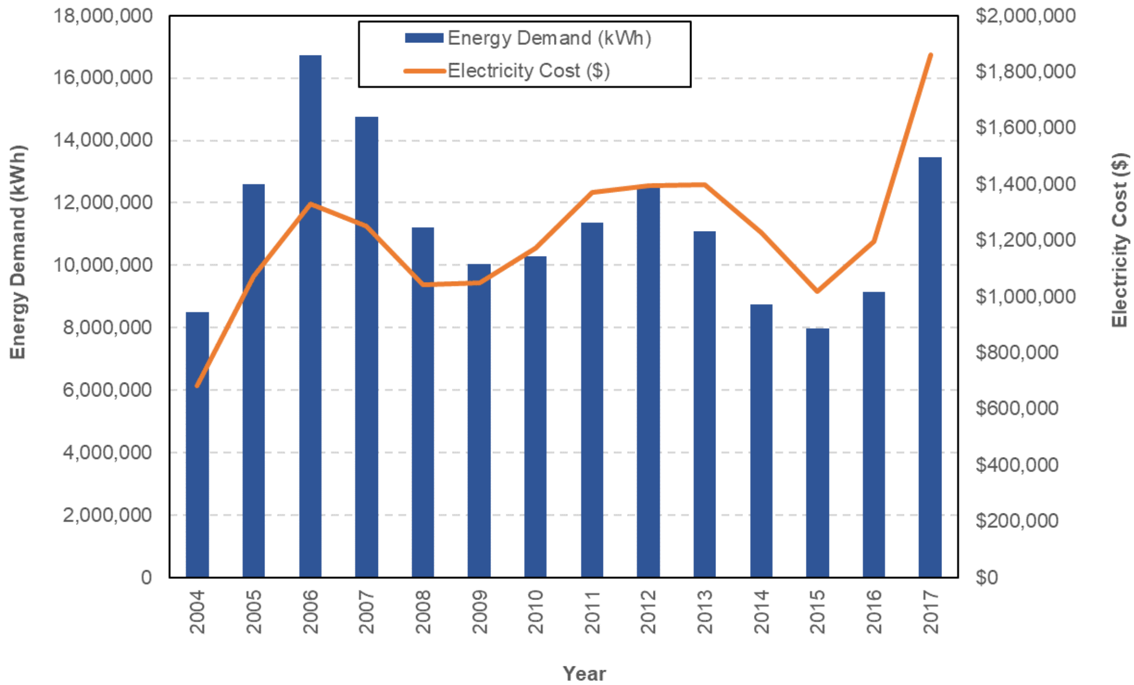

Figure 3-12 Historical energy demand and electricity cost at Jensen

A typical year of energy demand for the solar-connected LADWP account was generated and used as input to develop the battery energy storage model at Jensen. The selection of the typical year was based on the availability of 15-minute-interval energy demand data, only starting from mid-2016; therefore, an average of the 2017 and 2018 energy demand conditions was used to generate the typical-year energy demand at Jensen. The monthly energy demand at both meters during the model year used for the evaluation is shown in Figure 3-13.

Note that March reported very low demand compared to other months. It is unclear what was causing this drop and given that the low demand was a repeated event, the data remained unmodified.

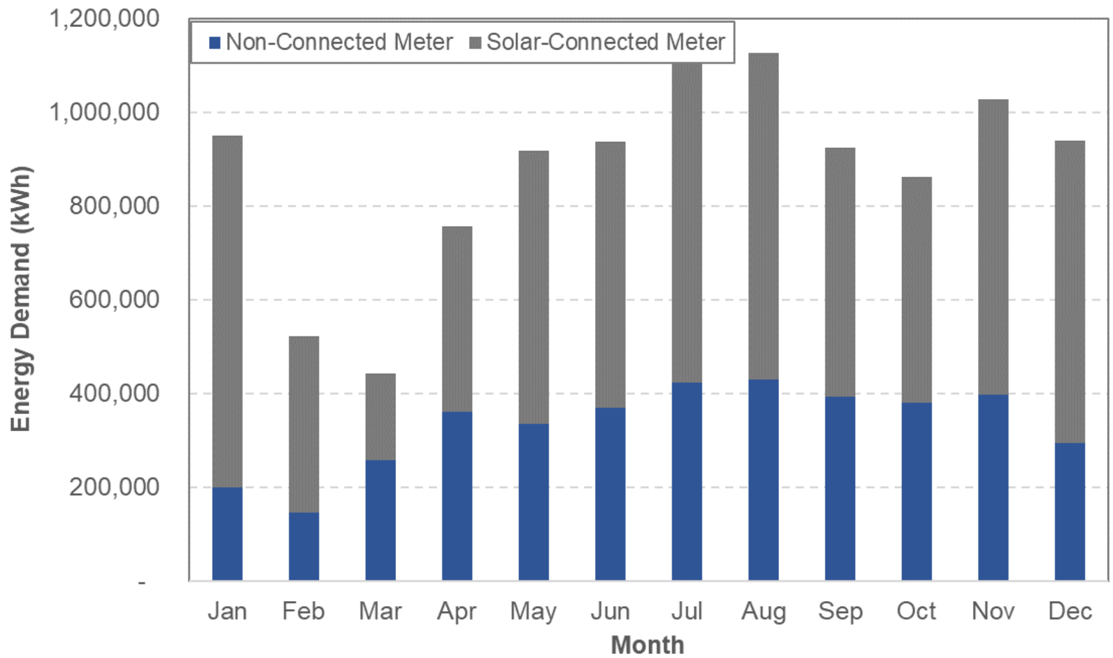

Figure 3-13 Average monthly energy demand on solar-connected meter at Jensen

There is limited space available at Jensen for additional solar generation because space is being reserved for future treatment processed, if needed.

3.4.2 Battery energy storage feasibility evaluation at Jensen

The following sections present key input and outcomes of the battery energy-storage feasibility evaluation at Jensen, particularly in relation to the selection of battery configuration, size and dispatch model, and the elements of the economic feasibility (i.e., capital and O&M costs, cost benefits, incentives, NPV, and payback analysis).

3.4.2.1 Battery size, configuration, and dispatch model

For the purpose of this feasibility analysis for battery energy storage at Jensen, the following assumptions were used:

- Jensen is connected to LADWP's grid through two meters; however, the BESS is only interconnected to the solar-connected LADWP account, which includes the existing solar facility. The total electricity costs were calculated using the electrical load at both meters.
- The BESS is in a behind-the-meter configuration.

- The BESS is considered a non-exporting asset; therefore, unlike the solar facility, no credits can be gained from exporting the energy stored in the BESS at any point.

A simple model was built to fully assess the potential costs savings through TOU arbitrage at Jensen. The BESS was considered source-agnostic in terms of charging but did remain behind-the-meter and in a non-exporting state. The TOU arbitrage strategy was based on charging the BESS during Base hours and dispatching the stored energy during High Peak hours, servicing plant load with energy stored in the BESS when demand and energy charges were highest. Details of this BESS configuration are provided in Table 3-14.

Table 3-14 Details of the demand arbitrage model BESS evaluated at Jensen

Parameter	Value/Description
Battery size	1 MW/2 MWh
Annual energy dispatched by battery	344 MWh
Dispatch model	Dispatch during peak TOU between 1 p.m. - 4 p.m. summer and winter weekdays

3.4.2.2 Economic feasibility of battery energy storage

To assess the economic feasibility of battery energy storage options at Jensen, the cost of the battery system, the benefits achieved from their operation, and the financial incentives available to offset the initial capital investments were considered. A 1 MW/2 MWh system was chosen to maximize the SGIP incentives received in proportion to capital costs. The capital and O&M costs of the BESS was estimated according to the assumptions previously included in Section 2.0, and are presented in Table 3-15.

Table 3-15 Cost information estimated for BESS at Jensen

System	First Year of Operation	Capital Cost	Annual O&M Cost	Annual Electricity Savings
1 MW BESS, TOU Demand Arbitrage	2023	$1,100,000	$15,000	$57,000

The simple arbitrage strategy reduced demand charges every month, as shown in Figure 3-17 and resulted in total annual energy savings of approximately $60,000 compared to the baseline scenario.

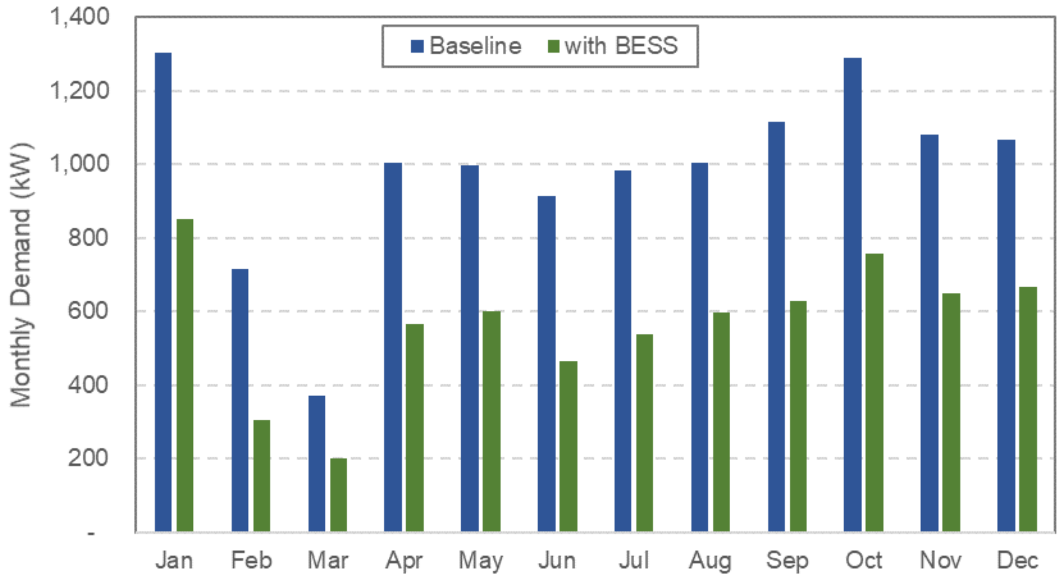

Figure 3-14 Monthly peak demand comparison at Jensen

An NPV analysis was performed following the methodology presented in Section 2.0. As previously discussed, BESSs have the potential to earn revenue through the provision of capacity services to local utilities, and these were also factored into the analysis. The results are presented in Table 3-16.

Table 3-16 Economic feasibility of BESS at Jensen

Scenario	Incentive Rates ($/Wh)	Capacity Credit ($/kw-month)	10-year NPV*	Payback Period (years)
No Incentive	$ -	$ -	($450,000)	>10*
SGIP Step 3 Incentive	$0.35	$ -	$134,000	6
SGIP Step 3 Incentive + RA Capacity Credit	$0.35	$1.50	$275,000	5

*BESS asset life is 10 years

Installation of an SGIP-incentivized BESS at Jensen has the potential to provide positive returns to Metropolitan, especially if combined with capacity credits. It is recommended that a battery developer with experience in the LADWP market be enlisted by Metropolitan to provide more accurate estimates of the electricity savings that a BESS can reasonably deliver through TOU arbitrage.

3.5 OC-88 PUMPING PLANT

The OC-88 Pumping Plant (OC-88) was constructed in 1990 in the City of Lake Forest in Orange County. OC-88 is fed treated water from the Diemer Water Treatment Plant via the Allen McColloch Pipeline and then pumps the treated water into the Municipal Water District of Orange County's South County Pipeline. The energy demand of the pumping plant is currently satisfied by the grid, and no renewable energy sources are present on-site.

To offset some of the energy costs at this facility, this study evaluated independently the feasibility of implementing battery energy storage at this site. The following sections provide detailed energy demand and related energy cost information from OC-88's operations and provides the results of the feasibility analysis conducted for the energy storage alternative scenario.

3.5.1 OC-88 energy demand and electricity cost profiles

Energy-demand data collected from OC-88 during the period of 2014-2018 shows that an average of 4,840 MWh per year is used to sustain pumping operations at this site. The energy demand at OC-88 peaks in July and hits a minimum between December and February, gradually tapering between these two extremes (Figure 3-15).

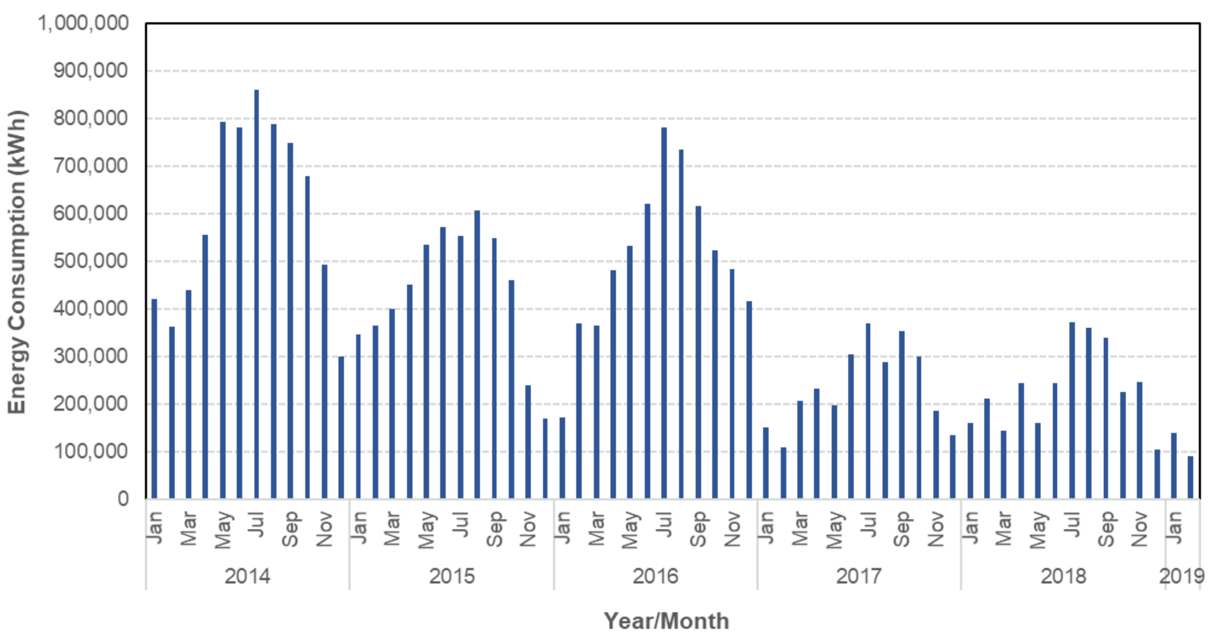

Figure 3-15 Historical monthly energy demand at OC-88 during the period 2014-2018

While there seems to be a downward trend in energy consumption between 2014 and 2018, no information is available explaining the causes of the reduced demands in years 2017 and 2018. The analysis of OC-88 is therefore based on a typical year that is estimated from the average energy demand over the five years of data provided, as shown in Figure 3-16.

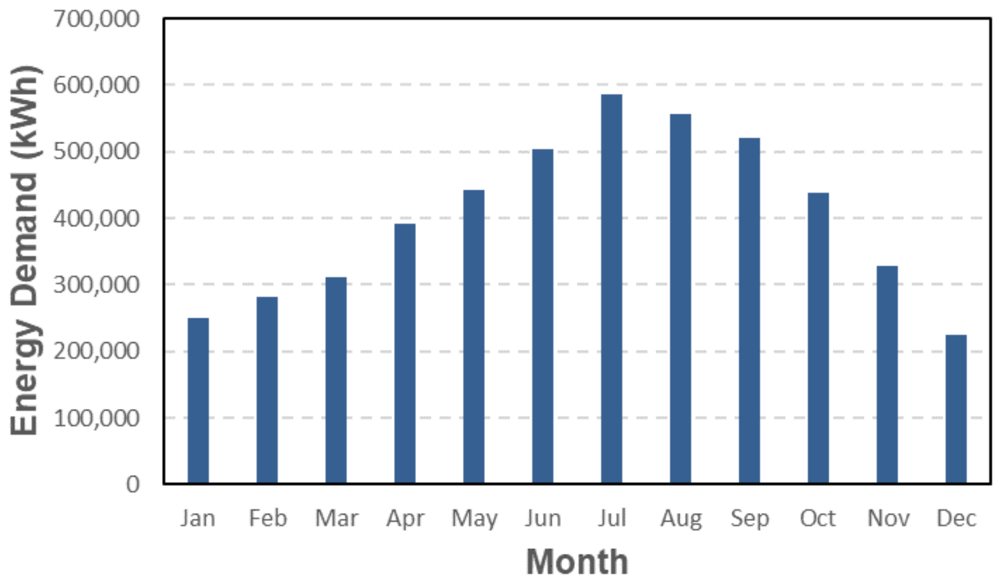

Figure 3-16 Average monthly energy demand at OC-88 during the typical year

Metropolitan has two meters at OC-88, a minor meter on SCE's TOU-PA-3-B rate structure and the main meter on SCE's TOU-8-B rate structure. Historical costs from OC-88 were not available at the time of this analysis, thus assessment of OC-88 historical results were not conducted.

3.5.2 Battery energy storage feasibility evaluation at OC-88

The following sections present key input and outcomes of the battery energy storage feasibility evaluation at OC-88, particularly in relation to the selection of battery configuration, size and dispatch model, and the elements of the economic feasibility (i.e., capital and O&M costs, cost benefits, incentives, NPV, and payback analysis).

3.5.2.1 Battery size, configuration, and dispatch model

A conceptual-level model was built according to the tariff rate structure plan, the typical year energy and power demand, and the assumptions presented in Section 2.0. Table 3-17 shows the key characteristics of the stand-alone BESS evaluated at OC-88. The battery was sized to eliminate peak demand charges during summer and winter months in the model year and by factoring in capacity losses over the 10-year lifetime of the battery.

Table 3-17 Details of the BESS evaluated at OC-88

Parameter	Value/Description
Battery size	1 MW/2 MWh
Annual energy dispatched by battery	526 MWh
Dispatch model	Dispatch during peak TOU between 4 p.m. - 9 p.m. summer and winter weekdays

The BESS would be connected to OC-88's main meter and the analysis assumes that OC-88 would be transitioned to TOU-8-D-CPP upon project startup.

3.5.2.2 Economic feasibility of battery energy storage

To assess the economic feasibility of stand-alone battery energy storage at OC-88, the cost of the battery system, the benefits achieved from its operation, and the financial incentives available to offset the initial capital investment were critical factors to be considered. The capital and O&M costs of the 1-MW BESS were estimated through modeling with Microsoft Excel, according to the assumptions included in Section 2.0, and are presented in Table 3-18.

Table 3-18 Cost information estimated for the BESS at OC-88

System	First Year of Operation	Capital Cost	Annual O&M Cost	Annual Electricity Savings
1 MW BESS, TOU Demand Arbitrage	2023	$1,100,000	$15,00	$57,000

The simple arbitrage strategy reduced demand charges every month, as shown in Figure 3-17 and resulted in total annual energy savings of approximately $57,000 compared to the baseline scenario.

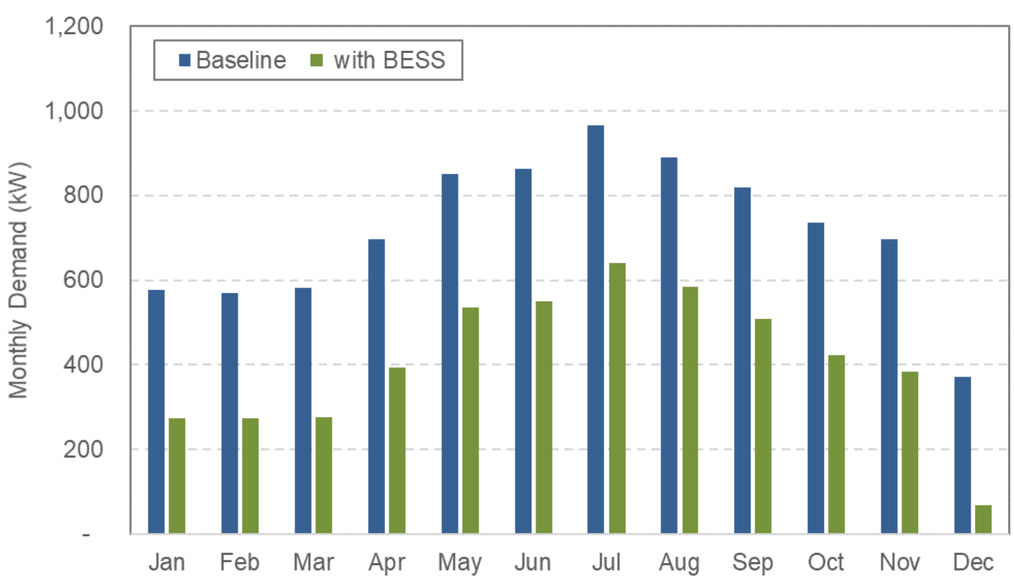

Figure 3-17 Monthly peak demand comparison at OC-88

The SGIP Step 3 incentive and RA capacity credit were considered in the NPV analysis and compared to a condition with no incentive (Table 3-19), according to the details presented in Section 2.0. The NPV analysis shows that a 1MW/2 MWh battery system at OC-88 is only economically feasible if incentives and credits are available to offset the initial capital costs. Due to the variability in BESS performance in different markets and the sensitivity of the analysis to electricity cost changes and the cost of financing, the recommendation to pursue Step 3 funding is contingent on a more detailed analysis being conducted that fully accounts for OC-88's usage patterns and other revenue streams.

Table 3-19 Economic feasibility of BESS at OC-88 with different incentive scenarios

Scenario	Incentive Rates ($/Wh)	Capacity Credit ($/kw-month)	10-year* NPV	Payback Period (years)
No Incentive	$ -	$ -	($420,000)	>10*
SGIP Step 3 Incentive	$0.35	$ -	$166,000	6
SGIP Step 3 Incentive + RA Capacity Credit	$0.35	$1.50	$308,000	5

*BESS asset life is 10 years

3.6 ROBERT B. DIEMER WATER TREATMENT PLANT AND YORBA LINDA HYDROELECTRIC POWER PLANT

The Robert B. Diemer Treatment Plant (Diemer) is located on a hilltop in the City of Yorba Linda and it distributes water from both the CRA and the SWP, via gravity flow, to areas within Los Angeles and Orange Counties. The facility has a treatment capacity of 520 MGD of water and includes coagulation, sedimentation, filtration, and final disinfection as part of its treatment scheme. Similar to other Metropolitan facilities, an ozone treatment was installed in 2012 as a primary disinfectant which is reflected in a commensurate increase in power demand.

The facility includes the 5.1-MW Yorba Linda Hydroelectric Power Plant, which generates hydropower within the pipelines leading to Diemer. Currently, the Yorba Linda hydropower facility sells power on the wholesale market at a price that is lower compared to the SCE retail rate applied to support Diemer's energy demand. Therefore, electricity generated by Yorba Linda Power Plant would have a higher value if potentially used to offset Diemer's energy consumption.

In addition to providing the detailed energy demand and related energy cost information from Diemer's plant operations, the analysis presented in the following sections evaluates the economic feasibility of using the power generated at Yorba Linda Power Plant to support energy requirements of the Diemer facility.

3.6.1 Diemer energy demand and electricity cost profiles

Diemer is located in SCE's services area and has a significant electricity demand. Figure 3-18 presents the historical monthly energy demand at Diemer in the period of 2014 through the initial months of 2019. The energy profile shows a higher overall demand during the summer months and declines, with a few exceptions, during wintertime.

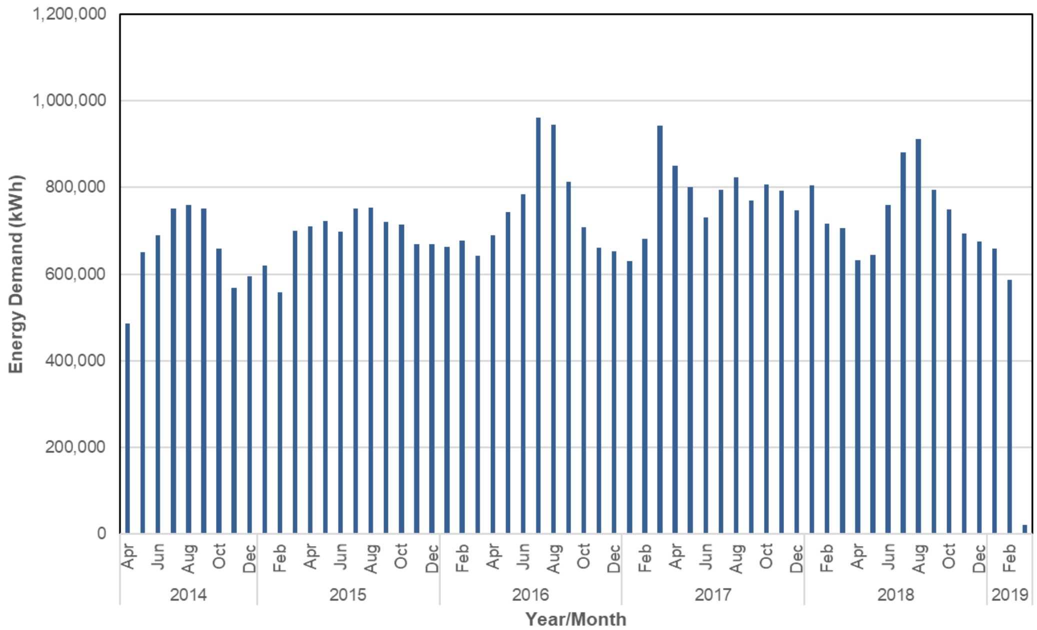

Figure 3-18 Diemer historical energy demand during the period 2014-2019

Similar to the approach used for energy storage evaluations at other Metropolitan facilities, a typical year for Diemer's hourly energy demand was generated using historical data from the year 2015 through 2018, which accounts for an annual electricity consumption of 8.9 GWh/year.

Diemer's yearly electricity cost has been increasing over the past decade (Figure 3-19), due in part to the impact of the energy-intensive ozone treatment operation. Conducting a future energy audit at the treatment facility could be beneficial to clarify the contributing factors to this increasing energy demand trend, which could be used to reduce Metropolitan's overall long-term energy consumption. In 2019, TOU rates at Diemer changed, increasing the electricity cost by approximately 7 percent from that of the typical year (i.e., from $789,000 to $849,000).

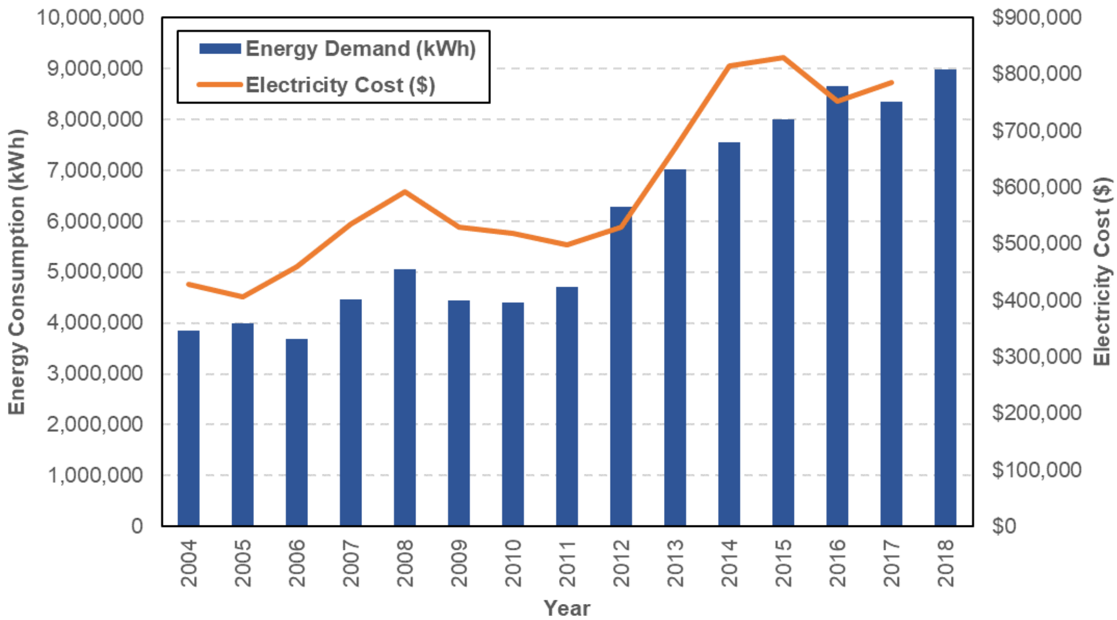

Figure 3-19 Historical energy demand and electricity cost at Diemer

3.6.2 Yorba Linda energy generation

Yorba Linda Power Plant energy generation has been intermittent over the past few years (Figure 3-20). Based on conversations with Metropolitan's engineering and operation staff, the intermittency of operation is due to rain events, low flow and recent improvements and repairs that forced the facility to be off-line for extended periods of time. The majority of these improvements are complete, and further enhancements are planned as part of the Yorba Linda Power Plant Reliability Upgrades Project (e.g., new enclosure to prevent water intrusion/condensation in the high-voltage equipment area during heavy rainfall). For this analysis, it is assumed that all of the enhancements have been completed.

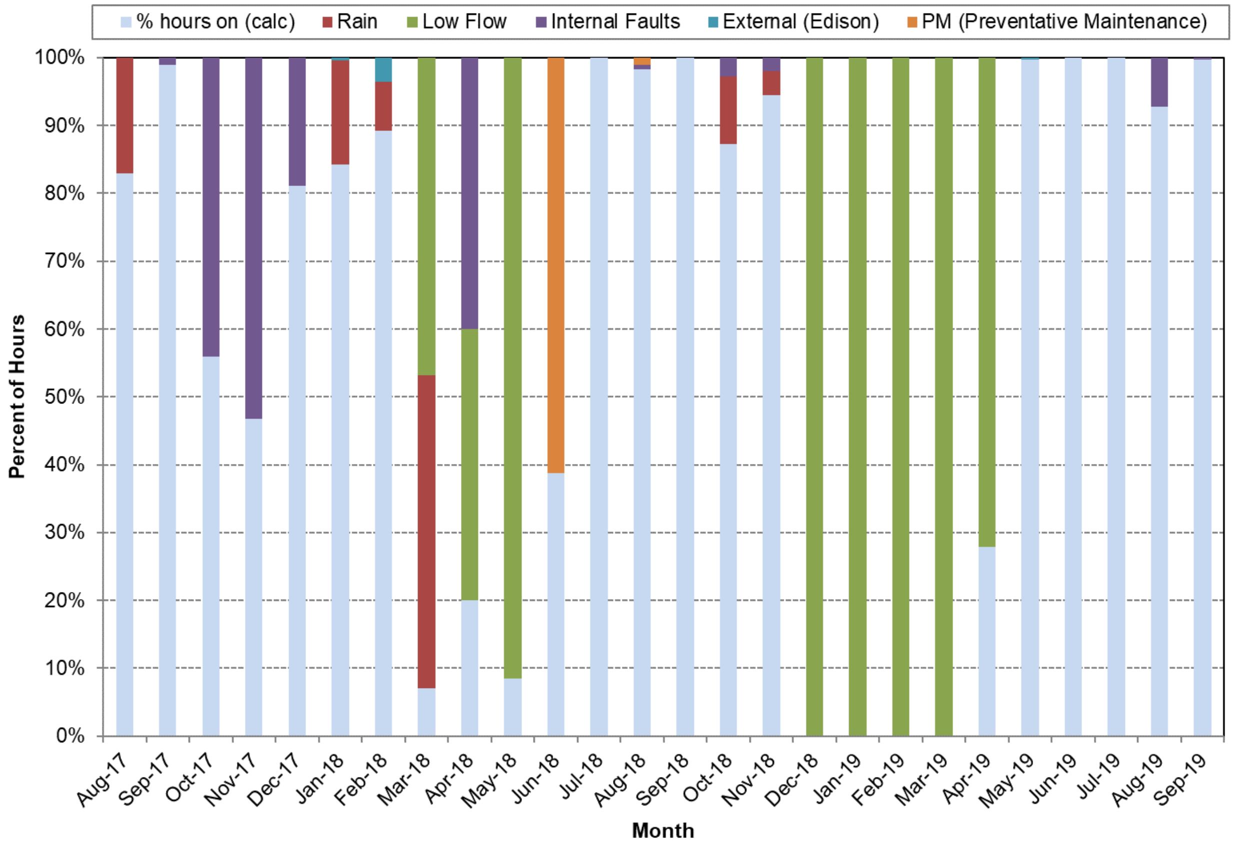

Figure 3-20 Monthly Yorba Linda operating time during the period 08/2017-07/2019

Since the hydropower plant is now operational, available historical data is not representative of the expected future typical electricity generation at Yorba Linda Power Plant. A typical year that is more representative of normal operations was created using the following assumptions:

- The typical year was created for flows based on November 2015–December 2018 data (Figure 3-21). When in operation during this period, Yorba Linda Power Plant generated an average of 3,670 kW.
- The typical-year hourly power was calculated considering the following:
    - 0 kW for flows below 200 cubic feet per second (cfs), as the facility does not generate power when the influent flow is below 200 cfs (Figure 3-21 and Figure 3-22).
    - An average power multiplied by an on-line factor (i.e., 3,670 kW x 80% = 2,936 kW) for flow equal to or above 200 cfs. The on-line factor was assumed to be 80 percent to account for various shutdowns that may be required during the year for facility maintenance and operations.

For the typical year, Yorba Linda Power Plant yearly electricity generation amounts to 25.6 GWh with typical monthly generation shown in Figure 3-23.

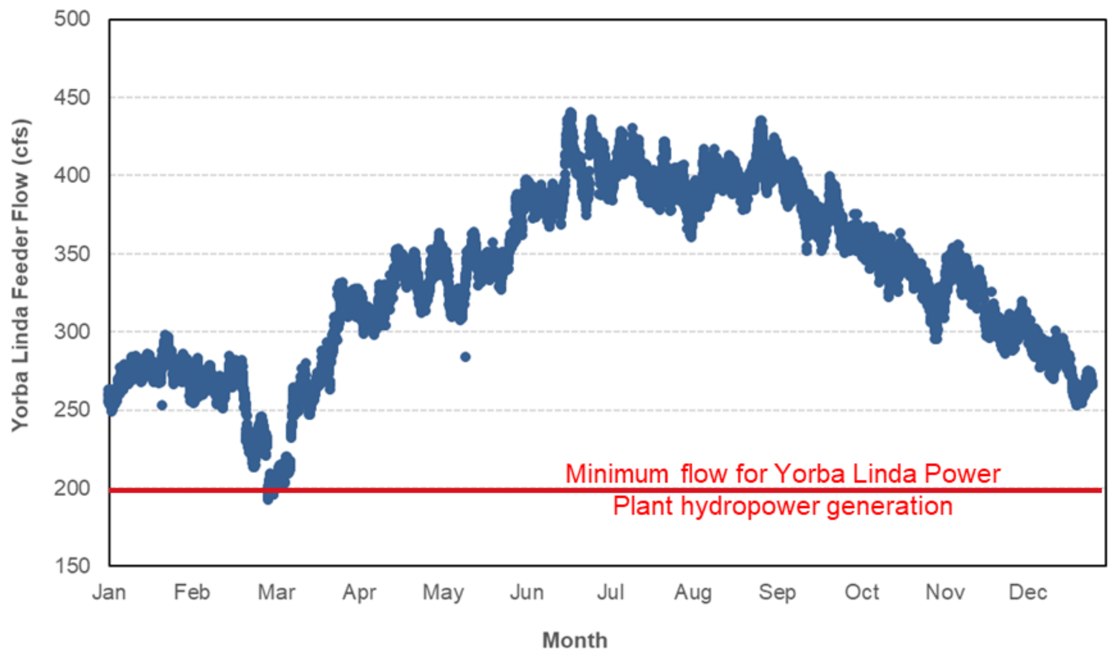

Figure 3-21 Typical year flow (cfs) for the Yorba Linda Power Plant feeder based on November 2015–December 2018 data

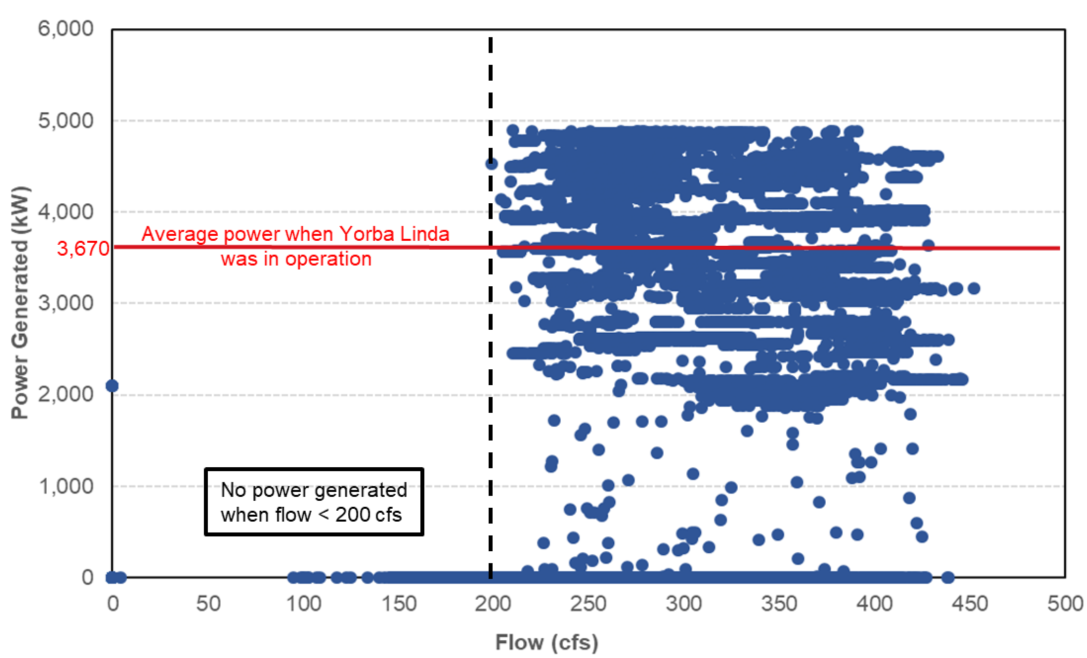

Figure 3-22 Hourly power generated versus flow at Yorba Linda

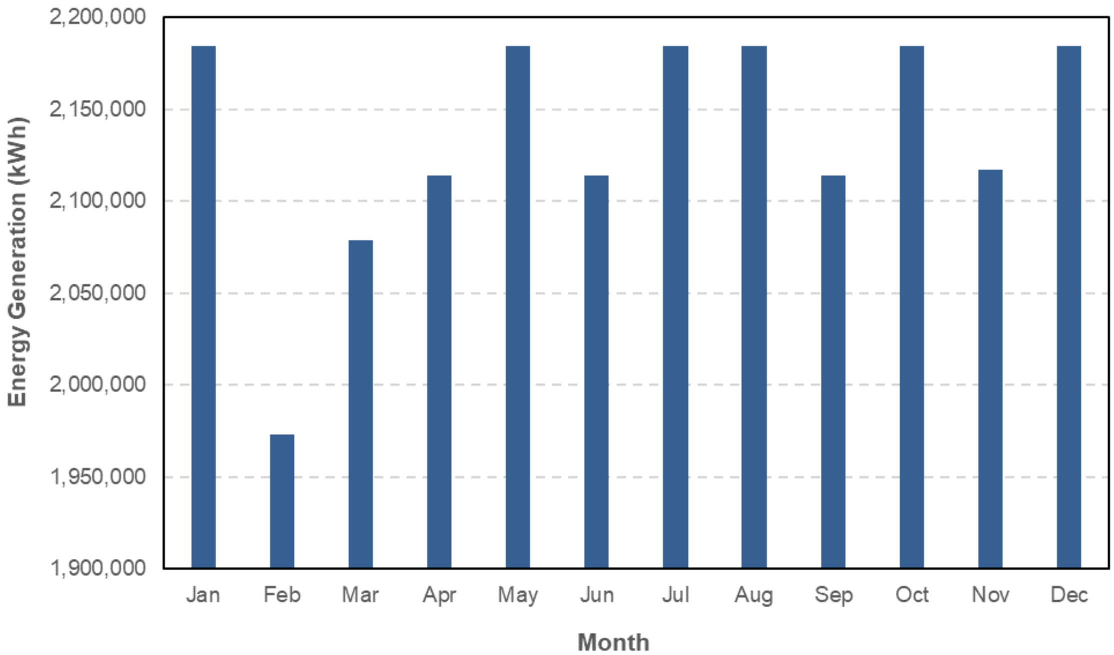

Figure 3-23 Energy generated by Yorba Linda during a typical year

Diemer treatment plant is co-located with the Yorba Linda hydropower facility, which currently sells power on the wholesale market at an average of $54/MWh, including RECs. The energy at Diemer, on average, was purchased from SCE at $94/MWh in 2017. Therefore, the use of the electricity generated by Yorba Linda Power Plant at Diemer would potentially reduce the energy costs at the plant compared to the scenario in which the retail energy is supplied by SCE. The analysis performed in the following section presents and compares the economics of both scenarios.

3.6.3 Cost benefit analysis of using Yorba Linda for Diemer energy demand

Configuring Yorba Linda hydropower generation behind Diemer's SCE meter would meet the entire treatment plant's energy demand when Yorba Linda Power Plant is in operation as the daily Diemer plant demand never exceeds 2,936 kW. Under the assumption that the current rate structure (2019) at Diemer remains unchanged, the monthly energy costs would amount to only $19,000 from customer charges and power factor adjustments required to maintain service from SCE, representing yearly savings of $812,000 from Diemer's energy bill. In case of a rate change triggered by the reduced retail electricity consumption at Diemer, the yearly savings estimated would be potentially impacted. This analysis assumes a change in tariff to TOU-8-D-CPP.

Because the energy generated by Yorba Linda Power Plant for a typical year is consistently above Diemer energy demand, there would be additional excess energy that could potentially be:

- Option A: Sent back to the SCE grid for credit via SCE's RES-BCT program. The credits would be calculated based on the demand portion of the equivalent energy charges for the excess energy and could be allocated to other Metropolitan facilities with SCE accounts.

- Option B: Sold back to SCE at the wholesale price. For the purpose of this study, wholesale prices of $34/MWh and $54/MWh were assumed based on the possible hydropower wholesale rates presented in Section 2.1.1.1.

Table 3-20 summarizes the assumptions and the results of the feasibility assessment of connecting Yorba Linda Power Plant behind Diemer's SCE meter. For the purpose of this study, the cost associated with connecting Yorba Linda Power Plant behind Diemer's SCE meter was assumed to be $1,500,000 and needing to be further defined during the project design phase. No O&M costs are associated with this project. The results showed that both Options A and B would allow a rapid payback (i.e., 2 to 4 years), but the total net savings for either option is dependent on the price of hydropower on the wholesale market. A greater difference between the wholesale and retail energy prices favors the RES-BCT program.

Table 3-20 Feasibility analysis of connecting Yorba Linda behind Diemer's SCE meter (2019 dollars)

Item	Value		Notes
Hydropower Wholesale Price	$34/MWh	$54/MWh	Details presented in Section 2.1.1.1
Yorba Linda Wholesale Revenue Potential	$871,000	$1,383,000	With Yorba Linda selling all of its power on the wholesale market, for a typical year
Energy Generated at Yorba Linda	25.6 GWh		For a typical year
Diemer SCE Electricity Bill Savings	$798,000		With Yorba Linda behind Diemer's SCE meter
Diemer Yearly Energy Demand	8.89 GWh		For a typical year
Project Capital Cost	$1,500,000		Project cost allowance
Project O&M Costs	$0		No changes compared to business as usual
Option A – obtain credits for Yorba Linda excess power via RES-BCT program			
Annual Revenues from RES-BCT ($/year)	$751,000		For excess power not used by Diemer
Total Revenues ($/year)	$1,549,000		Diemer electricity bill savings plus RES-BCT revenues
Yearly Net Savings ($/year)	$678,000	$165,000	-
Simple Payback (years)	2	4	-
Option B – sell excess power at a wholesale market price			
Revenues from Wholesale Market ($/year)	$569,000	$904,000	For excess power not used by Diemer
Total Revenues ($/year)	$1,367,000	$1,702,000	Diemer electricity-bill savings plus wholesale market revenues
Yearly Net Savings ($/year)	$596,000	$318,000	-
Simple Payback (years)	2	4	-

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4.0 RENEWABLE HYDROPOWER PROJECT OPPORTUNITIES ADDRESSING WHOLESALE ELECTRICITY RATES FOR THE DISTRIBUTION SYSTEM

Energy trading in the wholesale market, while highly variable, is a key revenue opportunity for Metropolitan. This section details the results of the financial feasibility of selected renewable and energy storage project opportunities at Metropolitan facilities, utilizing wholesale electricity rates. It is important to note that the majority of these evaluations were performed by updating the outcomes of studies that Metropolitan conducted in previous years, to align with the current electricity market and financial conditions.

Metropolitan owns and operates 15 small hydropower facilities within its distribution system. A summary of Metropolitan's hydropower plants is provided in Table 4-1. Due to their locations within the distribution system, the hydropower plants may receive varying flows from two of Metropolitan's raw-water sources, the CRA and SWP.

Table 4-1 Metropolitan owned hydropower plants

Plant	Feeder	Design Capacity (MW)	Design Head (feet)
Corona	Lower Feeder	2.8	135
Coyote Creek	Lower Feeder	3.1	193
Etiwanda	Etiwanda Pipeline	23.9	625
Foothill	Foothill Feeder	9.0	180
Lake Mathews	Lake Mathews Outlet	4.9	90
Perris	Lake View Pipeline	7.9	160
Red Mountain	San Diego Pipeline #5	5.9	220
Rio Hondo	Middle Feeder	1.9	220
San Dimas	Rialto Feeder	9.9	400
Sepulveda Canyon	Sepulveda Feeder	8.5	300
Temescal	Lower Feeder	2.8	135
Valley View	East Orange County Feeder #1	4.1	421
Venice	Sepulveda Feeder	10.1	280
Wadsworth	DVL Wadsworth Hydroelectric Plant	29.7	235
Yorba Linda	Yorba Linda	5.1	200

The following sections present the feasibility of the renewable hydropower projects around selected Metropolitan's facilities. In particular, this section includes:

- Small hydropower developments at hydropower plants or pressure control structures (PCS);
- In-line hydropower at selected sites;
- Hydropower generation expansion at Diamond Valley Lake;
- Small hydropower plant rehabilitation.

4.1 SMALL HYDROPOWER

In 2010, Metropolitan completed the *Hydroelectric Plant Feasibility Study (Project No. 103924)* that identified 10 potential sites for hydropower development, including both hydropower plants and PCS (MWH, 2010b):

- Carbon Creek PCS
- Collis Avenue PCS
- Covina PCS
- Lake Mathews hydroelectric plant
- Olinda PCS
- Perris hydroelectric plant
- Red Mountain hydroelectric plant
- Santiago Creek PCS
- Sepulveda Canyon hydroelectric plant
- Temescal hydroelectric plant

Flow and pressure data were collected for each site and used to calculate turbine size and annual power generation yield. Powerhouses and other support facilities were established at a conceptual level and the associated, high-level cost estimates developed. The feasibility of these small hydropower facilities has been reassessed by maintaining the original design parameters and updating the costs based on the methodology presented in Section 2.2.4. A summary of this new assessment is presented in Table 4-2 and includes ranges for NPV and payback based on the possible hydropower wholesale rates presented in Section 2.1.1.1. The new analysis shows greater payback periods and NPVs than that assessed by the 2010 report, primarily due to the larger wholesale energy price ($107/MWh) assumed in 2010 compared to the average $54/MWh that is currently observed by Metropolitan.

Table 4-2 Small hydropower reassessment results

Name	Configuration		Installed Capacity (MW)	Annual Energy Generated (MWh)	2010 Study*			Current Assessment		
					Capital Cost ($M)	Payback (years)	NPV ($M)	Capital Cost ($M)	Payback (years)	NPV** ($M)
Carbon Creek	Above ground	Horizontal	1.2	4,200	8	26	1.12	8.7	40+	(-1.84) – (-4.62)
	Above ground	Vertical	1.2	4,200	8.9	30	0.2	9.9	40+	(-2.97) – (-5.74)
Collis Avenue	Above ground	Horizontal	2.5	13,000	10.1	9	19.54	10.2	15 - 24	12.46 - 3.88
	Above ground	Vertical	2.5	13,000	10.9	10	18.76	11.4	17 - 27	11.33 - 2.75
Covina	Above ground	Horizontal	1.6	10,100	9.1	10	13.89	11.9	23 - 35	5.77 – (-0.93)
	Above ground	Vertical	1.6	10,100	10.5	12	12.51	13.1	25 - 38	4.64 – (-2.07)
Olinda	Below ground	Horizontal	1.4	8,400	9.5	13	9.6	9.1	21 - 33	5.43 – (-0.17)
	Below ground	Horizontal	1.4	8,400	10.2	14	8.92	9.9	23 - 36	4.67 – (-0.93)
Red Mountain A	Above ground	Horizontal	4.6	4,900	15.1	40+	-4.03	16.8	40+	(-8.08) – (-11.36)
Red Mountain B	Above ground	Horizontal	5.7	2,400	21.2	40+	-16.03	28.3	40+	(-23.6) – (-25.17)
Lake Mathews A	Above ground	Horizontal	2.4	4,500	8.8	26	1.03	9.5	40+	(-2.11) – (-5.07)
Lake Mathews B	Above ground	Horizontal	1.7	2,600	7.9	40+	-2.47	8.6	40+	(-4.55) – (-6.26)
Santiago	Above ground	Horizontal	1.2	9,500	8.2	10	13.27	9.1	19 - 30	7.24 - 0.97
Sepulveda	Above ground	Horizontal	10.0	15,300	32.3	27	3.2	35.0	40+	(-6.82) – (-16.94)
Perris	Above ground	Horizontal	4.7	13,600	19.2	17	12.07	21.3	29 - 40+	3.06 – (-5.94)
Temescal	Above ground	Horizontal	1.7	1,200	8.3	40+	-6.16	9.2	40+	(-5.21) – (-5.73)

*All reported costs are from the 2010 study without escalation.

**Range based on hydropower selling price of either $34/MWh or $54/MWh

Note: This report assumes a 40-year asset life for hydropower. Any project that exceeds that payback period has been denoted as 40+

4.2 IN-LINE HYDROPOWER

In 2014, Metropolitan assessed the feasibility of installing in-line hydroelectric plants at four selected sites within Metropolitan's distribution system (*2014 In-Line Hydro Study, Project No. 104585)* (MWH, 2014). The four sites investigated for the analysis were:

- Covina PCS
- Influent to Mills Water Treatment Plant
- LA-35 Service Connection
- Perris Hydroelectric Plant

Hydraulic data was collected and reviewed for each site and used to calculate turbine size and annual power generation yield. Designs for the in-line technologies, powerhouses, and other support facilities were established at a conceptual level to develop high-level cost estimates for each site. Francis turbines were selected for analysis at all sites, and a LucidPipe™ system was considered for the Covina and Perris sites. The results from the 2014 study are summarized in Table 4-3 along with the reassessment for this study. It is important to note that this analysis maintained the original design parameters as provided in the 2014 study; however, the costs were updated based on the methodology presented in Section 2.2.4 and include ranges for NPV and payback based on the possible hydropower wholesale rates presented in Section 2.1.1.1.

The results from the updated assessment show, for each site, a similar payback and NPV as resulted in the 2014 study. The 2014 study concluded that the LucidPipe™ technology is not considered viable for any of the sites; the current study validated this earlier conclusion.

Table 4-3 In-line hydropower reevaluation results

Name	Configuration		Installed Capacity (MW)	Annual Energy Generated (MWh)	2014 Study*			Current Assessment		
					Capital Cost ($M)	Payback (years)	NPV ($M)	Capital Cost ($M)	Payback (years)	NPV** ($M)
Covina	Below ground	Horizontal	2.1	11,952	6.8	11	8.6	6.9	11 – 18	14.0 – 6.1
	Below ground	LucidPipeTM	0.7	1,735	10.7	40+	-8.9	12.2	40+	(-10.0) – (-11.2)
Mills WTP	Below ground	Horizontal	0.4	2,198	8.1	40+	-1.6	6.6	40+	(-3.4) – (-4.8)
LA-35	Below ground	Vertical	3.1	15,525	16.5	24	3.1	14.8	19 – 30	11.5 – -1.2
Perris	Below ground	Horizontal	4.9	13,761	10.7	16	6.9	10.3	15 – 24	13.4 – 4.3
	Below ground	LucidPipeTM	1.2	1,390	12.9	40+	-10.8	14.5	40+	(-11.9) – (-12.8)

*All reported costs are from the 2014 study without escalation (MWH, 2014).

**Range based on hydropower selling price of either $34/MWh or $54/MWh

Note: This report assumes a 40-year asset life for hydropower. Any project that exceeds that payback period has been denoted as 40+.

4.3 HYDROPOWER GENERATION EXPANSION AT DIAMOND VALLEY LAKE

Metropolitan has reviewed various projects to increase hydropower generation at Diamond Valley Lake's Hiram Wadsworth Pumping/Hydro-Generating Facility, the largest of Metropolitan's hydropower facilities (MWD, unreported). The facility houses 12 pumps (6,000 horsepower, each) and twelve generators (3.3 MW, each) that produce energy as water is released from Diamond Valley Lake, through the inlet/outlet tower to the Wadsworth facility. From this location, water enters the forebay/afterbay (500 acre-feet capacity) and is typically released through the San Diego Canal to Lake Skinner which feeds the Skinner Water Treatment Plant. It has been proposed for Diamond Valley Lake to utilize a pumped storage scheme by pumping water from the forebay/afterbay through the Wadsworth facility to Diamond Valley Lake when wholesale market prices are low, and then to flow back, generating electricity, when prices are high. This project is not viable due to the following constraints:

- The forebay/afterbay is inadequately sized for this type of operation and would have to be expanded, triggering environmental permitting. Prior studies conducted by Metropolitan concluded that enlarging the forebay would require excavation in extremely hard rock, encroach on environmentally sensitive areas, and result in high costs. Thus, the project was not deemed a viable option for further investigation.
- During pumped storage operations, the forebay/afterbay water levels would be lowered during pumping. If the forebay/afterbay is lowered below certain levels, water from the San Diego Canal could flow in. This is an issue as the San Diego Canal is contaminated with quagga mussels, an invasive species of mussel that alters local ecosystems and clogs water intakes. Diamond Valley Lake has so far remained unaffected by quagga mussels, as it has recently received water only from the SWP. Delivery of water from the CRA to Diamond Valley Lake is not permitted due to the quagga mussel contamination in the CRA.

4.4 SMALL HYDROPOWER PLANT REHABILITATION PROJECT

Metropolitan's current Capital Investment Plan (CIP) includes a project to assess and rehabilitate each of the 16 existing small hydroelectric plants (HEP) in the conveyance and distribution system. The purpose of the project is to develop a rehabilitation plan for each HEP and initiate a multi-phase program to rehabilitate the plants and optimize revenue generation over the next 30 years.

The scope of work for the project will include an initial investigation into the design of the HEP facility versus current operating conditions. Note that due to changes in demand and/or allocation of water from the SWP and CRA over the past 30 years, the current operating conditions may be significantly different than the original design of the existing turbines. Based on the initial evaluation, potential options could include proceeding with rehabilitation and/or modifications of the current turbines if cost effective, evaluating the feasibility and payback of installing new turbines based on the current operating conditions, or do nothing because the current operating conditions will not generate enough power to justify either rehabilitation or installing new turbines.

5.0 RENEWABLE ENERGY AND ENERGY STORAGE PROJECT OPPORTUNITIES ADDRESSING WHOLESALE ELECTRICITY RATES FOR CRA PUMPING OPERATIONS

This section details the results of the financial feasibility of selected renewable and energy storage project opportunities for CRA pumping operations. In particular, this section includes:

- Pumped storage
- Wind power generation
- Solar power generation
- Battery energy storage
- Operational flexibility

The Colorado River Aqueduct consists of 5 pumping plants, 450 miles of high voltage power lines, one electric substation, two regulating reservoirs, and 242 miles of aqueducts, siphons, canals, conduits and pipelines. The first six miles of the CRA contains Whitsett Intake Pumping Plant, the 6,300 acre-feet capacity Gene Wash Reservoir, Gene Pumping Plant, and the 22,000 acre-feet capacity Copper Basin Reservoir (Figure 5-1). Flexible operations combined with stable flow downstream of Copper Basin can be achieved through the flexible storage capacity provided by Gene Wash and Copper Basin Reservoirs.

The Colorado River Aqueduct pumping plants receive power from Hoover and Parker Dams, as well as supplemental energy from the California Independent System Operator (CAISO) or from the Western System Power Pools (WSPP). On October 1, 2017, 11 new agreements and contracts related to Colorado River Aqueduct energy operations went into effect, including: six agreements with SCE, two agreements with AEPCO for transmission operations and power scheduling services, 50-year Energy Services Contract and Implementation Agreements with WAPA for Hoover Dam hydropower, and an operating agreement with CAISO.

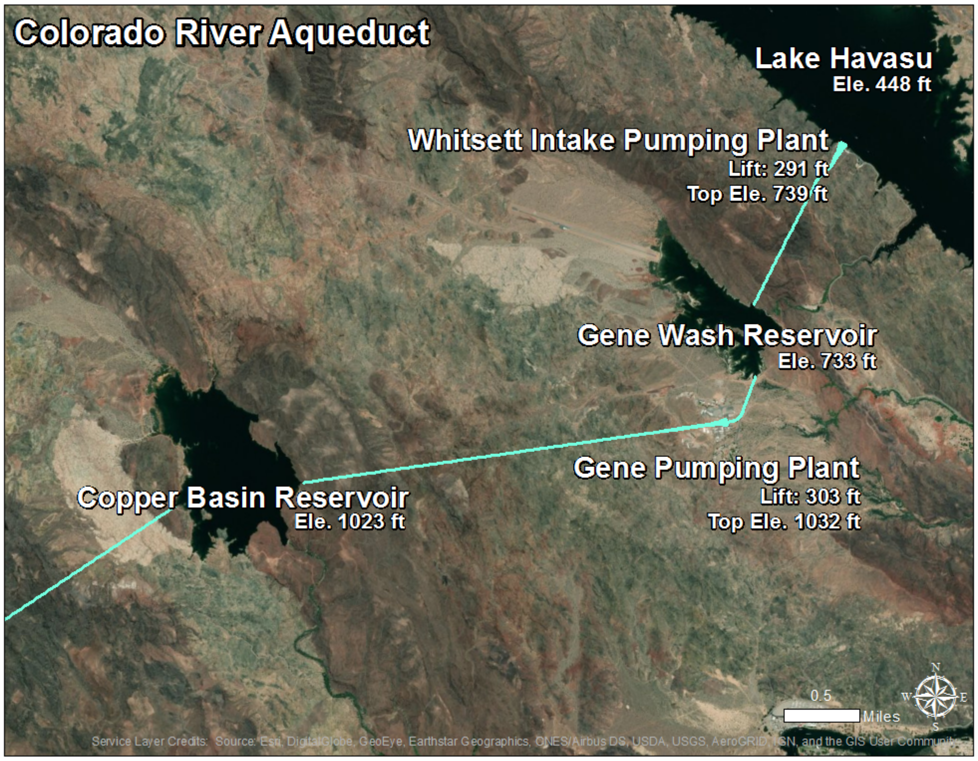


Figure 5-1 Colorado River Aqueduct, Intake Pumping Plant to Copper Basin Reservoir

The full delivery capacity of the CRA is approximately 1.20 million acre-feet per year. As shown in Figure 5-2, annual deliveries of water from the CRA from 2003 to 2019 varied from 0.66 to 1.19 million acre-feet per year, with an average annual delivery of 0.88 million acre-feet.

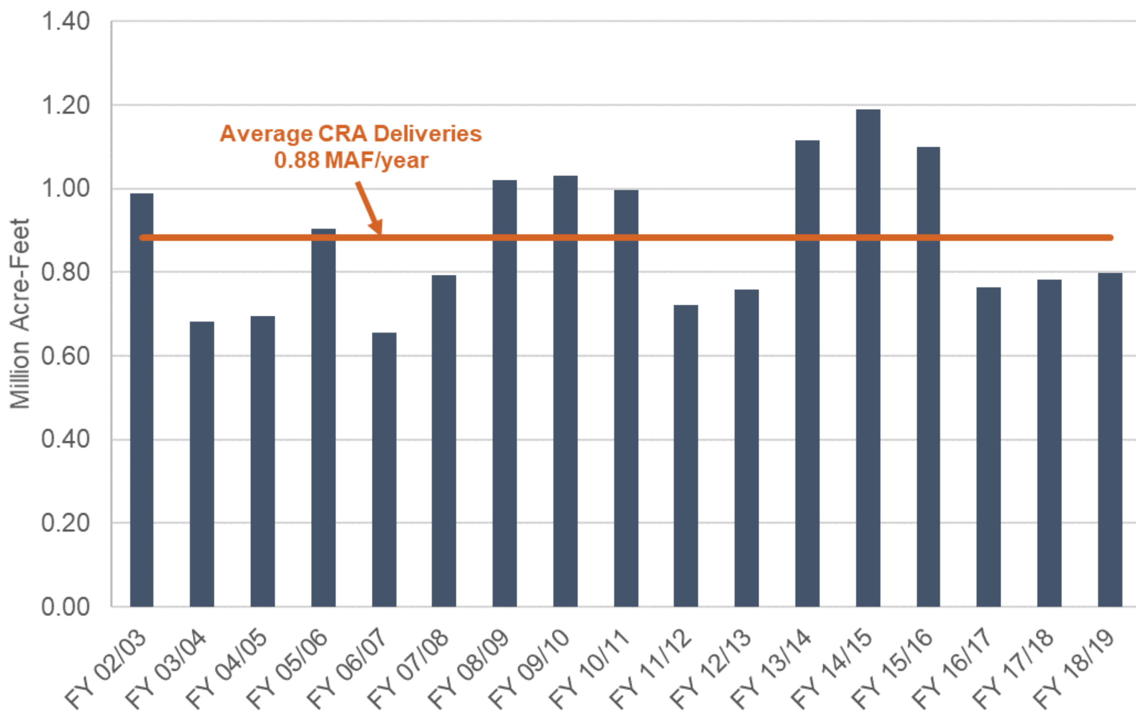


Figure 5-2 Annual CRA water deliveries

During this time period (2003 through 2019), hydropower from Hoover and Parker has supplied approximately 50 percent of the energy required for the pumping plants. Purchases of supplemental energy from CAISO or WSPP supplied the remaining power requirements for the pumping plants.

The 50-year agreement for Hoover Dam hydropower includes 12 percent of the hydroelectric plant's capacity (250MW) and 27.1 percent of the hydroelectric plant's energy (1,277,400 MWh annually). In addition, Metropolitan has a perpetual contract for one-half of all power produced by Parker Dam's hydroelectric plant. The total cost of hydropower from Hoover and Parker will scale with the Bureau of Reclamation's operation, maintenance, and replacement costs.

While Metropolitan has stable and relatively predictable pricing through its hydropower contracts, power from the CAISO and southwest energy market has exhibited significant daily and seasonal price variability. In April 2009, CAISO implemented a new market system based on over 3,000 locational marginal price (LMP) nodes (Figure 5-3). Each node's price is the sum of energy cost, congestion, and losses at each specific node. In 2018, Metropolitan's locational marginal price fluctuated between negative prices and nearly $1,000/MWh (Figure 2-8).

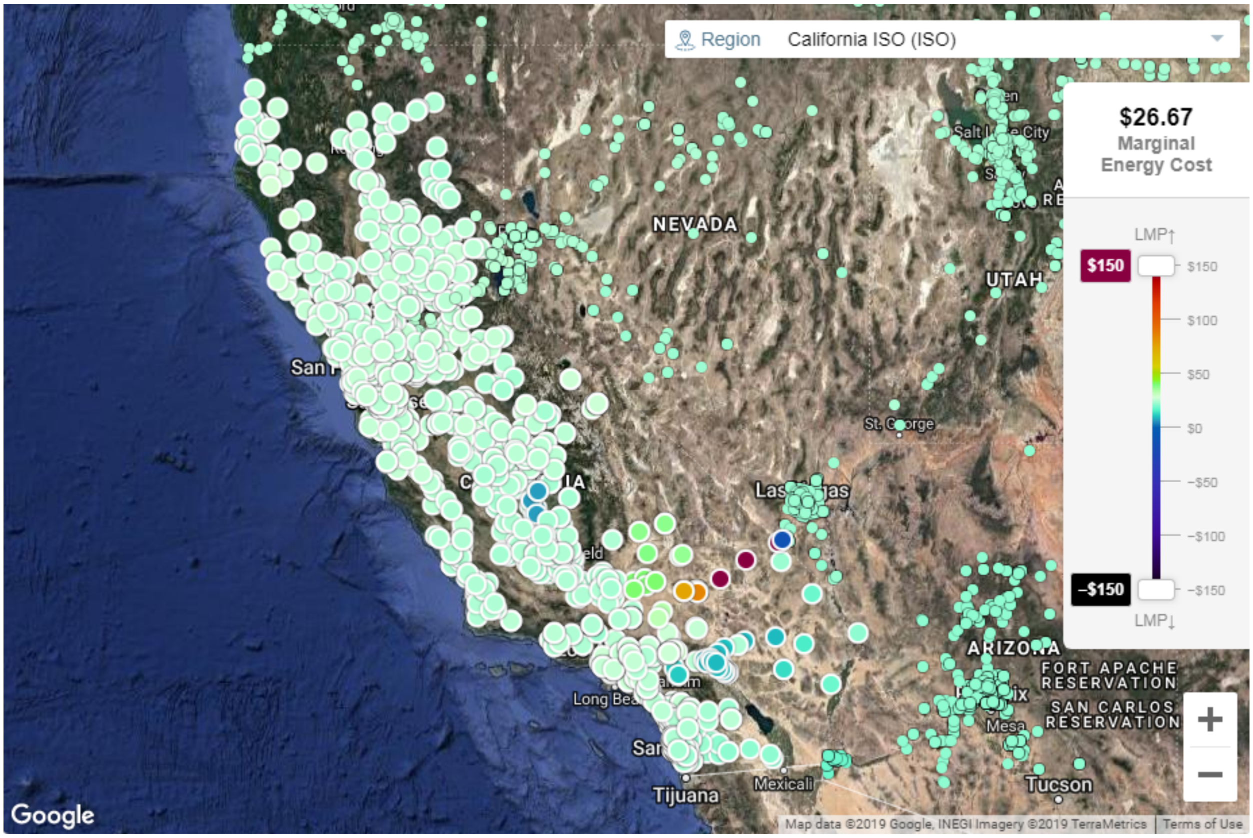


Figure 5-3 CAISO's day-ahead locational marginal price 12-1pm, October 14th, 2019

Water availability in Lake Mead and Lake Powell, power output from Hoover and Parker, and the needs of member agencies combine to determine the supplemental power purchase needs of the CRA. Some years have required little non-hydropower imported energy (FY 2006-2007, 2019), while others have required nearly 50 percent of power from non-hydropower imports (FY 2014-2015). The price dynamic of CAISO fluctuates with supply and demand. Negative prices occur throughout the year, at times and locations when wind and solar produce more energy than customers demand and the system can absorb. High prices, greater than $100/MWh, occur primarily in the early evening hours, when conventional generation ramps up significantly to displace reduced renewable energy production. Although power purchases made up 40 percent of the CRA's electricity consumption in 2018, power purchases made up over 60 percent of the CRA's electricity cost. Figure 5-4 and Figure 5-5 show the monthly power source and cost totals for 2018. As in the case of January-March of 2018, low winter water demands and the annual CRA shutdown resulted in higher sales revenue than purchase expenses.

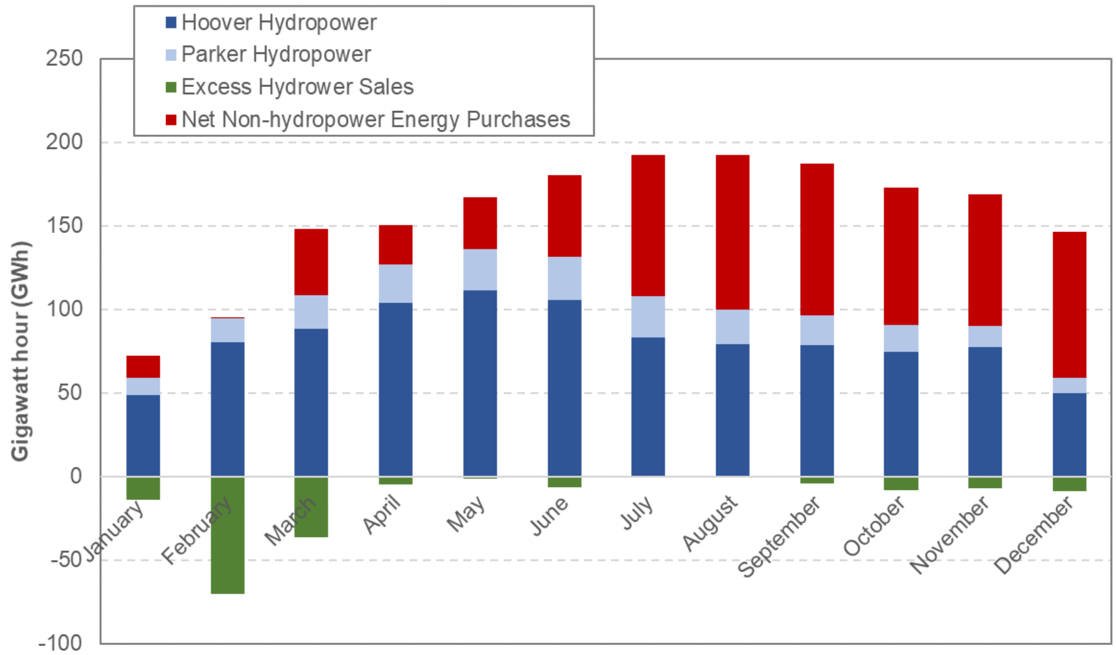


Figure 5-4 Colorado River Aqueduct power sources per month (2018)

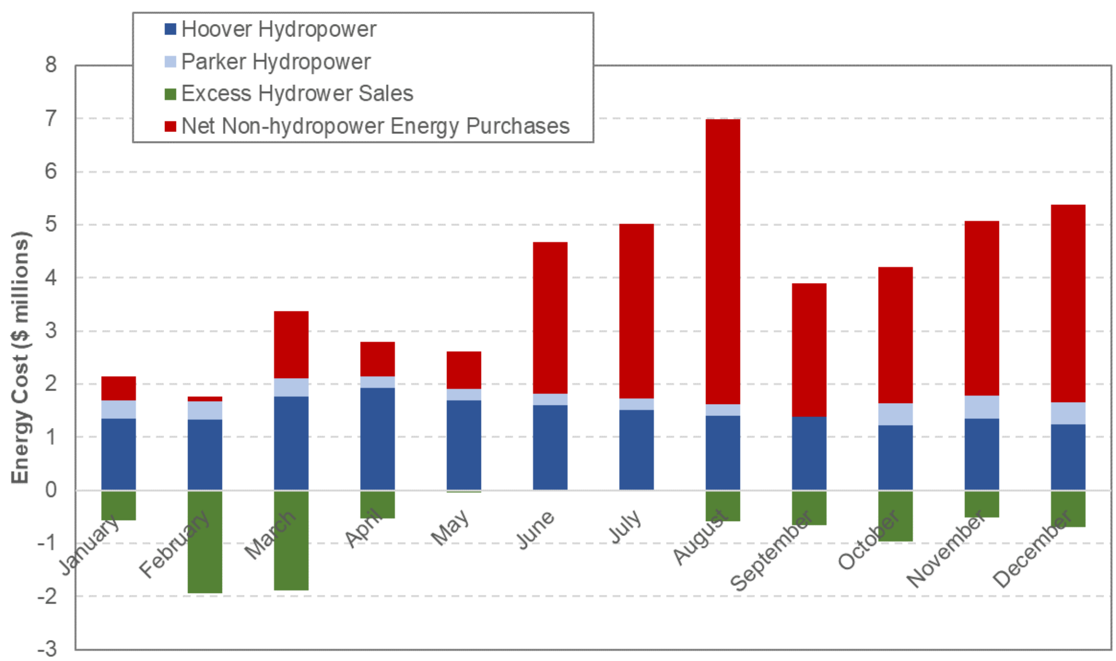


Figure 5-5 Colorado River Aqueduct monthly electricity cost (2018)

Renewable energy projects along the CRA have the potential to 1) provide power for CRA operations in lieu of purchasing energy from the wholesale grid, 2) generate revenue by selling excess generated energy to the grid, or 3) reduce GHG emissions associated with purchase of supplemental energy. Energy storage can produce cost savings through energy arbitrage. These project opportunities include pumped storage, renewable energy (wind and solar), battery storage and reservoir storage. Results from the analysis of these projects is described in detail in the following sections.

5.1 CRA OPERATIONAL FLEXIBILITY TO ADDRESS WHOLESALE ENERGY MARKET VOLATILITY

In July and August of 2018, when CAISO prices regularly increased well above $200/MWh, Metropolitan performed several days of load shedding at Intake and Gene (Figure 5-6 and Figure 5-7). Prior to load shedding, operators filled Gene Wash and Copper Basin to near maximum operational levels. For five days in July and two days in August, between the hours of 4pm and 9pm, operators reduced the number of operating pumps by two at both Intake and Gene. For four days in August, between the hours of 3pm and 10pm, operators reduced the number of operating pumps by three at Intake and two at Gene. Supervisory control and data acquisition (SCADA) data shows that the flow downstream of Copper Basin remained relatively constant during the 5- to 7-hour drawdown time periods.

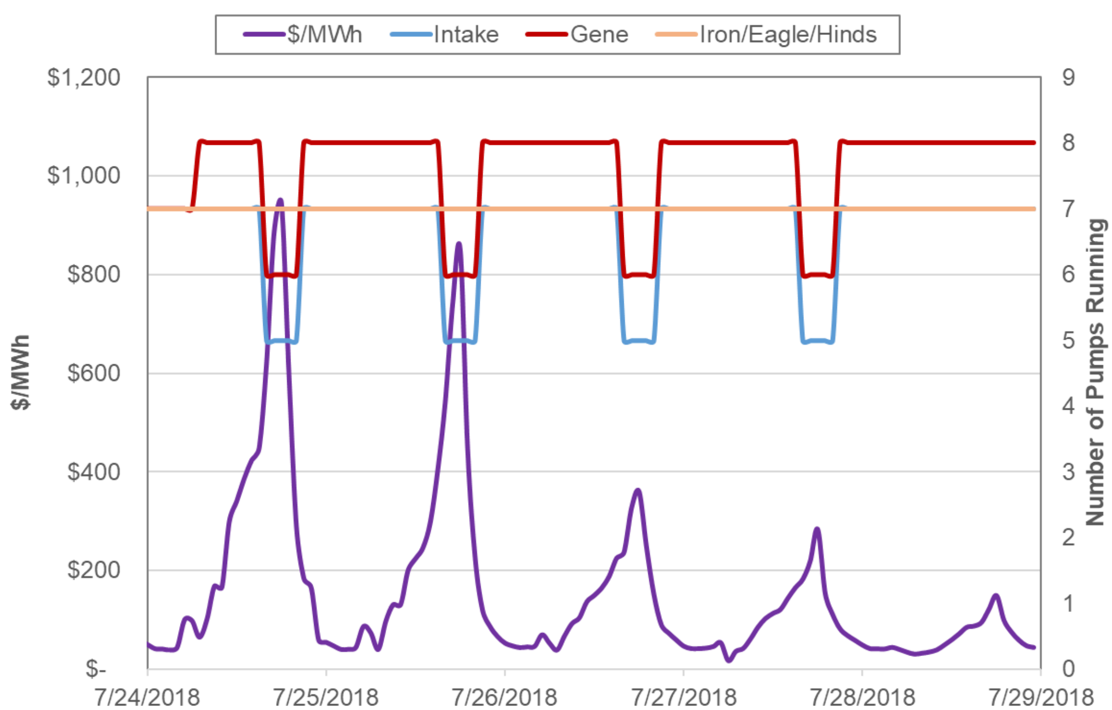


Figure 5-6 Cycling at Gene and Intake pumping plants due to grid stress and resulting high energy prices (July 27, 2018 – July 29, 2018)

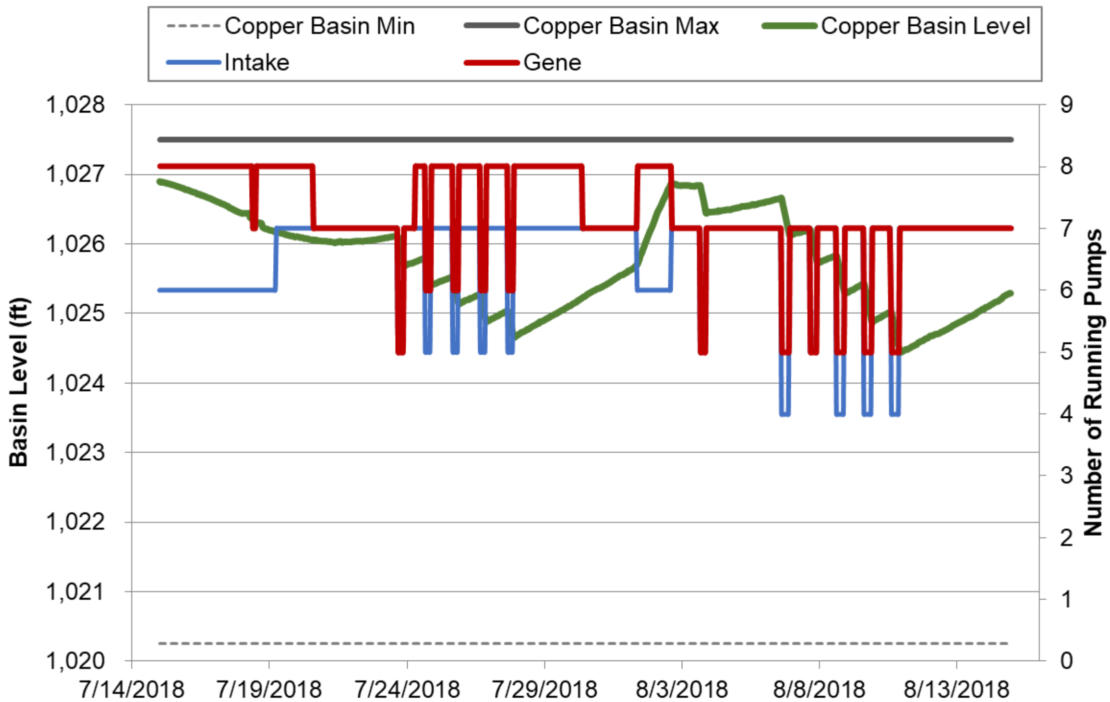


Figure 5-7 CRA Copper Basin response to cycling events (July and August 2018)

In addition to data analysis of past cycling events, Metropolitan utilized its MIKE URBAN water systems modeling software to determine the impacts of cycling at Gene and Intake Pumping Plants on the operation of the entire aqueduct (i.e., from Intake to Lake Matthews). Three cases were analyzed, each with a constant seven pumps at Iron, Eagle, and Hinds Pumping Plants:

- The first case looked at reducing the number of operating pumps at Intake from seven to four and the number of operating pumps at Gene from seven to five for seven hours.
- The second case looked at reducing the number of operating pumps at Intake from seven to three and the number of operating pumps at Gene from seven to four for seven hours.
- The third case looked at reducing both pumping plants from seven pumps to zero pumps for seven hours. In the third case, a fifth day of cycling is not possible.

All cases resulted in minor water level fluctuations downstream of Copper Basin. The drawdown rate at Copper Basin greatly exceeds the recharge rate; nineteen hours of recharge cannot equal five hours of drawdown (Figure 5-7 and Figure 5-8). At seven pump average flow, the CRA cannot safely accommodate more than 3-9 consecutive days of load shedding, depending upon the starting level of Copper Basin, the shutoff duration, and the number of pumps turned off.

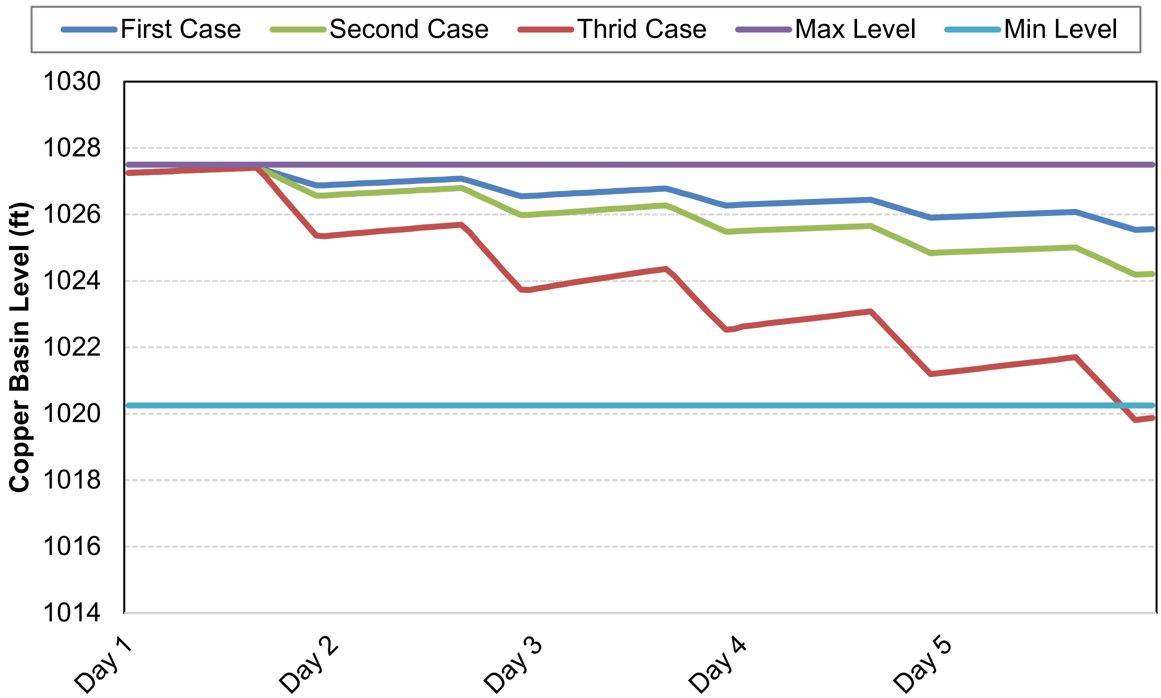


Figure 5-8 MIKE URBAN model of pump cycling impacts to Copper Basin

Cycling pumps at Intake and Gene in July and August of 2018 saved more than $600,000 over eleven days, approximately $10,000 per hour. Deregulation coupled with time dependent solar and wind power generation has resulted in a price dynamic that changes rapidly hour to hour. To shift CRA operations to match hourly prices requires the ability to ramp up pumping as fast as hourly prices decrease and wind down pumping as fast as hourly prices increase. Pump cycling during the October 2017 to June 2019 timeframe could have resulted in approximately 4 million dollars in savings, while maintaining reservoir minimum and maximum level restrictions and meeting the downstream demands of Metropolitan's member agencies and California's state water contractors Figure 5-9). However, the CRA pumps were not designed for frequent cycling to address rapidly fluctuating energy prices, and the pumps would require modifications in order to support hourly changes in pump flow and energy use.

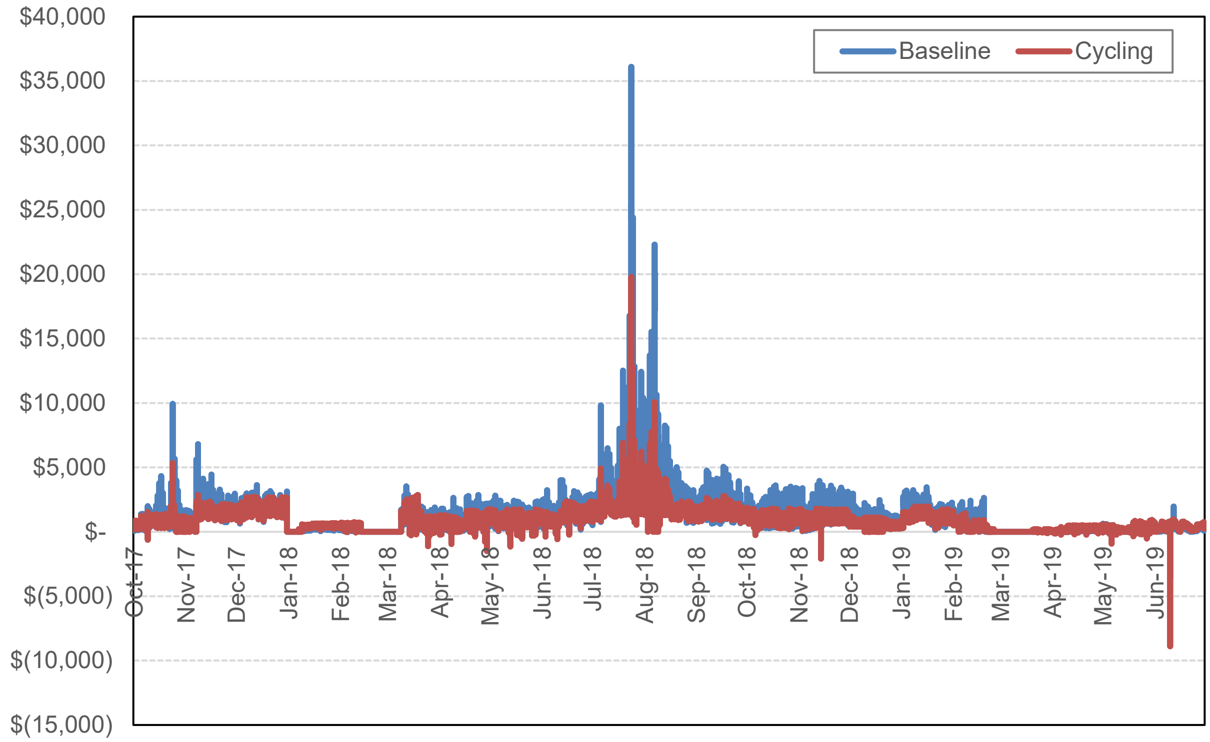


Figure 5-9 Combined Intake and Gene hourly pumping cost with decreased pumping during high price hours (2 pumps) and increased pumping during low price hours (2 pumps)

5.1.1 Potential Impacts of Increased pump cycling

The CRA's five pumping plants, consisting of 45 main pumps and the pump support systems were installed and expanded in phases. Initial construction of the CRA commenced in 1934. The aqueduct was placed into service in 1941 and the final expansion was completed in 1959. The CRA pumps have a capacity of 225 cfs each and are driven by three-phase, 6,900-volt, vertical synchronous motors.

In the mid-1980s, a major rehabilitation project was undertaken on the 45 main pumps. This effort represented the first significant rehabilitation of these units since they were originally installed. While that project successfully extended the service life of the pumps and increased their hydraulic capacity, the pump support systems were not addressed at that time. The pumps are now showing signs of deterioration caused by continuous operation over the past 30 years.

There is a mixed set of pumps and motors at each plant, including pumps from three manufacturers and motors from four manufacturers. Each manufacturer's components are constructed differently and have unique performance characteristics. Intake Pumping Plant currently requires regular cycling of one pump, due to Intake Pumping Plant's greater efficiency over Gene Pumping Plant (Figure 5-10).

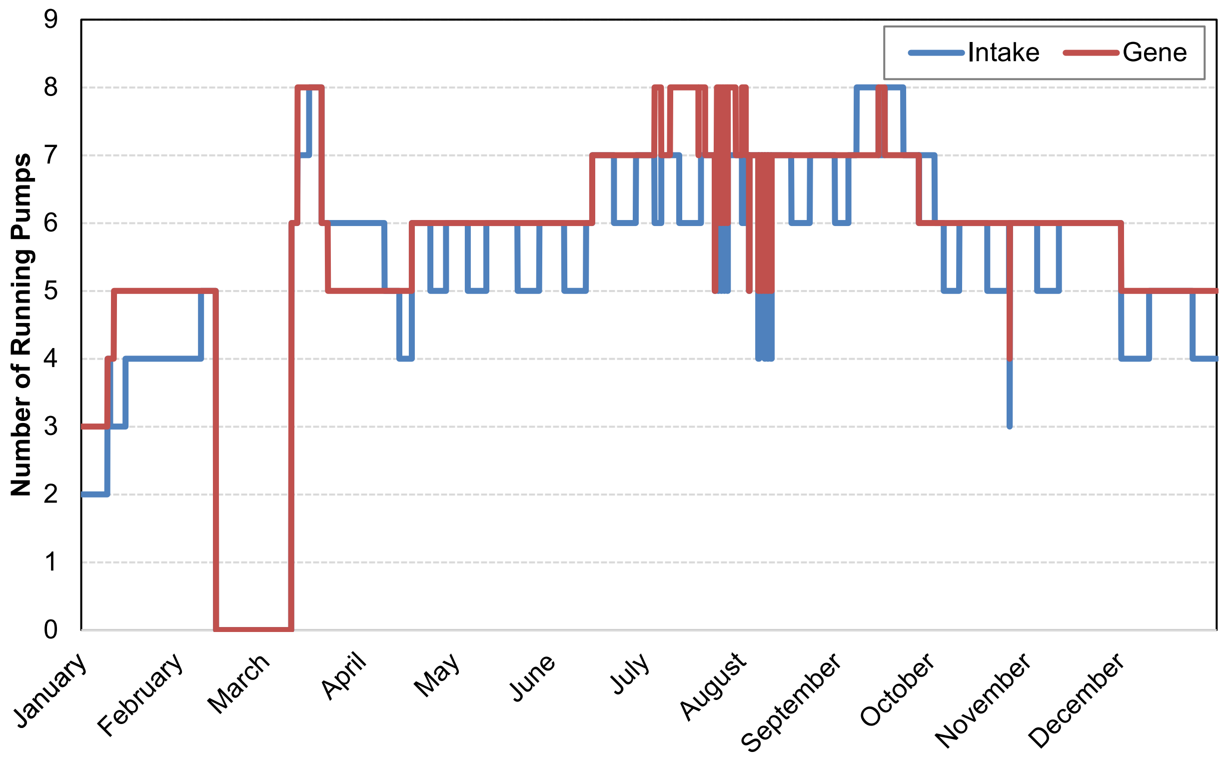


Figure 5-10 Pump cycling at Intake and Gene Pumping Plants (2018)

Additionally, Metropolitan's Operating Agreement with CAISO contains provisions for the emergency interruption of pumps at all five pumping plants, as well as specific provisions pertaining to the limited interruption of pumps at Intake and Gene. Given an imminent system emergency, CAISO may request that Metropolitan interrupt pump loads at Intake and Gene pumping plants for up to 4 hours per each load shedding event (*Public Version Operating Agreement between Metropolitan Water District of Southern California and the California Independent System Operator Corporation*).

Despite the operational need to frequently cycle one pump at Intake and Metropolitan's operating agreement with CAISO, the 70- to 90-year old pumps were not designed to accommodate frequent starts and stops. The energy market has changed significantly since the CRA's pumps became operational. Today's time-of-use price dynamic has resulted in several water utilities' evaluation of the feasibility of daily pump cycling, Metropolitan included. Unfortunately, each pump start greatly increases the wear and tear potential on the motor and it is known to increase the risk of catastrophic failure. Increasing the maintenance frequency in conjunction with increasing pump cycling cannot completely prevent sudden failure upon pump start. Given the size and age of the pump and its components, repair and/or replacement of failed or failing components could take more than a year.

5.1.2 Variable Frequency Drive units at Intake and Gene to allow cycling

VFDs are one means of avoiding failure upon pump start and pump shutoff. VFDs control the rotational speed of a motor by adjusting the voltage and frequency applied to the motor. The precise speed control inherent in VFD operations allows for soft start and soft stop. Instead of cycling one of Intake's pumps every two weeks (Figure 5-9), and therefore greatly increasing the potential for wear and tear on Intake's pumps, Metropolitan operators could instead reduce the flow through two or three VFD controlled pumps. Additionally, with grid stress and grid stability an increasing concern, VFD controlled pumps could provide a better response mechanism to CAISO's mandated load shedding. Finally, while CAISO may not always require load shedding, recent price spikes ranging from 10-50 times the cost of hydropower also provide an incentive to reduce power consumption during timeframes of high system-wide demand. Conversely, CAISO prices routinely drop to low or negative levels; VFDs could allow the ability to ramp up pumping to take advantage of low-price time periods. While hydropower remains a relatively fixed $20/MWh at all hours of the day and all seasons of the year, power in the CAISO marketplace is subject to severe daily and season swings caused by hourly customer demand levels, hourly solar and wind power production levels, routine maintenance, and unscheduled maintenance. VFDs at Gene and Intake would provide operational flexibility to accumulate extensive power savings during low flow/low speed operations as well as during high flow/high speed operations in negative $/MWh time periods. Adding variable frequency drives to two or three of Intake and Gene's pump motors could improve the flexibility to respond to CAISO load shedding, address the efficiency differences between Intake and Gene pumps, and provide flexibility to manage CAISO market volatility and significantly reduce energy costs.

5.1.3 Recommendations

Cycling pumps at Intake and Gene can result in significant electricity cost savings. Coordination with CAISO in alleviating stress on the grid can produce the double economic benefit of reduced energy costs. Eleven days of load shedding in July and August 2018 resulted in a $600,000 savings over the traditional continuous seven-pump flow. Additional cycling during summer 2018 could have resulted in several hundred thousand more in electricity savings.

The age and design of the pumps, however, diminishes the possibility of frequent cycling of Intake and Gene's pumps. Unfortunately, each pump start greatly increases the wear and tear on the motor and increases the risk of catastrophic failure. Given the size and age of the pump and its components, repair and/or replacement of failed or failing components could take more than a year. Nevertheless, CAISO can call for pump load interruptions at Gene and Intake. Such load interruptions are requested in an effort to prevent power grid failure. Moreover, existing efficiency differences between Intake and Gene currently result in forced pump cycling every two weeks at Intake.

Metropolitan is in the planning stages of a multiyear rehabilitation and/or replacement of the Colorado River Aqueduct's 45 pumps and their support systems. Stage 1 of the project, approved by Metropolitan's Board, includes preliminary investigations of all pumps and the design of the rehabilitation of a single pump at Gene. In order to maintain the reliability of the CRA, it is recommended that Metropolitan include an additional assessment of pump modifications at Intake and Gene. Such modifications should ensure that Metropolitan can effectively accommodate load shedding requests in accordance with the agreement with CAISO, as well as improve synchronization between Intake and Gene pumps. The addition of variable frequency drives to a subset of the pumps and motors at Gene and Intake could provide the necessary level of flexibility in today's evolving energy landscape. Metropolitan should prioritize Intake and Gene Pumping Plants in its preliminary investigation of the CRA's pumps and research means of providing additional operational flexibility at those pumping plants.

5.2 PUMPED STORAGE SYSTEMS ALONG THE CRA

In 1983, Metropolitan studied the feasibility and payback of a pumped storage project between Copper Basin and Lake Moovalya, located in the Colorado River between Lake Havasu and Headgate Rock Dam. The 1983 study also investigated two smaller scale pumped storage alternatives – 1) utilizing existing pumping capacity at Intake and Gene Pumping Plants for replenishing storage in Copper Basin, with releases from Copper Basin through a new tunnel, penstock, and powerhouse with turbine generators, and 2) converting a number of existing pumps at Intake and Gene Pumping Plants to also function as turbine generators for reverse flow power generation. A follow-up evaluation was completed in 2002 based on changed assumptions of CRA water delivery requirements and then-forecasted energy rates. The 2002 study concluded the proposed pumped storage project was not economical.

A new analysis has been performed as part of this TM to reevaluate the feasibility of a Metropolitan-owned pumped storage project. Three different pumped storage alternatives, each using Copper Basin Reservoir as the pump-back reservoir (Figure 5-11), were evaluated. Each alternative included the addition of variable frequency drives (VFDs) at Intake and Gene Pumping Plants to provide more flexible management of the pumped storage operation as well as to ensure continuous aqueduct flow deliveries to the remaining downstream pumping plants. The first pumped storage alternative evaluated a pumped storage project using a new conveyance tunnel between Copper Basin Reservoir and Lake Moovalya located on the Colorado River between Parker Dam and Headgate Rock Dam. The second alternative evaluated a pumped storage project using existing Colorado River Aqueduct (CRA) conveyance conduits between Copper Basin Reservoir and Lake Havasu on the Colorado River, and the third pumped storage alternative utilized the same two terminating reservoirs as the second alternative, however, via a new conveyance tunnel and conduits. For each of the three (3) pumped storage alternatives considered, a sub-alternative that assumes an increase in the Copper Basin Reservoir storage capacity resulting from raising its dam by ten (10) feet was also evaluated. More details on each alternative project and assumptions used in this analysis can be found in Appendix B. The results of this analysis are presented in Table 5-1.

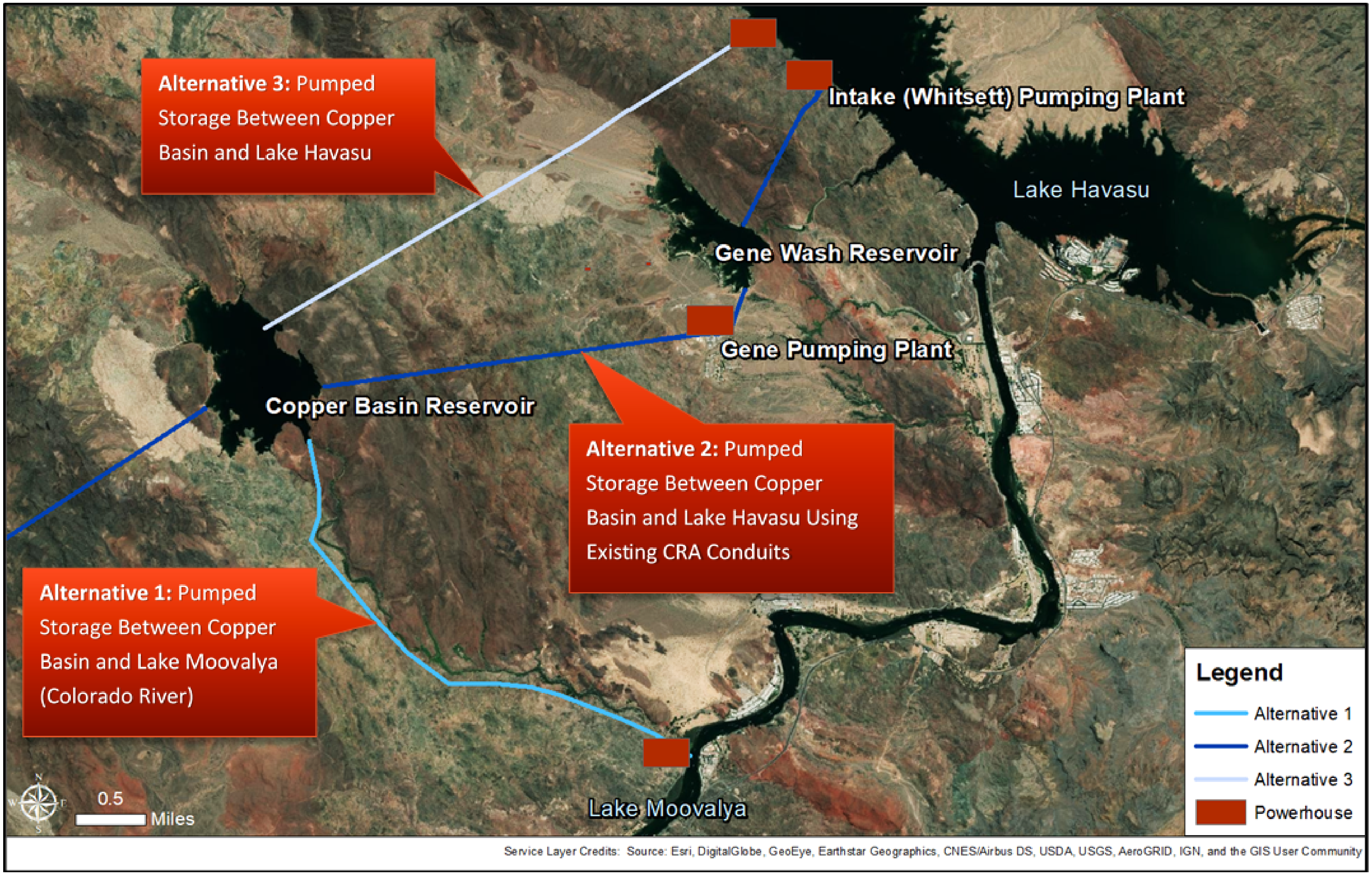


Figure 5-11 CRA pumped storage alternatives

Table 5-1 Metropolitan-owned pumped storage project analysis results

Alternative	Generation Capacity (MW)	Total Project Cost	NPV[1]	Payback (years)
1 – Pumped storage between Copper Basin and Lake Moovalya using new tunnels, penstocks and pump-turbine powerhouse units	360	$1.47 billion	-$568 million	>50
1A - Same as Alternative 1 but increase in Copper Basin storage capacity by raising the dam by ten feet	740	$2.70 billion	-$1.23 billion	>50
2 - Pumped-storage between Copper Basin and Lake Havasu utilizing existing CRA conveyance lines and replacing existing pumping units at Gene and Intake with pump-turbine units	26	$577 million	-$284 million	>50
2A - Same as Alternative 2 but increase in Copper Basin storage capacity by raising the dam by ten feet	60	$710 million	-$302 million	>50
3 - Pumped-storage between Copper Basin and Lake Havasu using new tunnels, penstocks, and pump-turbine powerhouse units	310	$1.75 billion	-$987 million	>50
3A - Same as Alternative 3 but increase in Copper Basin storage capacity by raising the dam by ten feet	620	$2.82 billion	-$1.57 billion	>50

1. Pumped storage asset life is 50 years

Note: Alternatives are based on 550,000 acre-feet annual CRA deliveries. Minimum allocation chosen to increase flexibility and revenue for a pumped storage project with 6-hours of generation and 10-hours of pumping daily

Based on these initial results, a Metropolitan-owned pump storage project is not recommended. However, pumped storage options should be reevaluated based on energy price outlook changes, legislative drivers, new incentive programs, and/or VFD implementation at Intake and Gene Pumping Plants. If later reevaluation deems any pumped storage alternative feasible, additional assessment will be required for more in-depth analysis and could include:

1) Detailed assessment of the impact of the pumped storage project on daily, monthly and annual operation of the CRA. The chosen CRA flow delivery scheme used in the analyses favors energy generation, however, if CRA flow delivery is of priority, then energy generation may be significantly lower.
2) Evaluation of increased O&M costs due to greater complexity in managing CRA deliveries and in addition, managing energy generation.
3) Acquisition of Federal Energy Regulatory Commission (FERC) license.
4) California Division of Safety of Dams (DSOD) review and approval regarding usage of Copper Basin Reservoir for a pumped storage project and in approving raising the dam by ten (10) feet.
5) Approval from United States Bureau of Reclamation (USBR) and coordination with agencies holding water rights along Colorado River downstream of the intake/release structure.
6) Environmental assessment regarding raising of Copper Basin Reservoir dam and construction of tunnel, penstock and powerhouse structure.
7) Tunnel alignment and powerhouse citing study.
8) Determine infrastructure and costs related to power grid connection and transmission lines.

9) Negotiations with power utility regarding firm commitment on purchase of power.

Instead of investing and owning a pumped storage asset, Metropolitan should continue efforts to optimize the use of the CRA's three power sources (hydropower, out of state imports, and CAISO) to minimize the cost to serve the CRA pumping plants. Metropolitan could also contract with a third-party developer for energy benefits from a nearby existing or proposed pumped storage. This type of agreement would be specific to each developer and the benefits and risks should be carefully evaluated by Metropolitan. However, it is recommended that Metropolitan maintains open communications with potential developers with knowledge of upcoming projects and opportunities for pumped storage along the CRA.

5.3 WIND POWER GENERATION ALONG CRA: UPDATE FROM PREVIOUS STUDIES

Metropolitan does not currently own any wind power generating facilities but evaluated the potential in a Navigant 2007 report*, Phase 1 Report on the Feasibility of Wind Power Development at the Julian Hinds Pumping Plant*, and in two subsequent updates made in 2013 and 2018 (Navigant, 2007; Brock, 2013; Brock 2018). An update to these reports was performed to revise the analysis and calculations based on the changes in the wind generation sector since then. Wind power equipment has evolved since 2007: the size of the turbines has increased, whereas the installation cost on a per MW basis (in $/MW) has decreased. Advances in wind technology, including longer blades and increased height, were considered during this analysis. While the analysis did not obtain new wind data at the sites, it used the same wind shear reported from 2007 to extrapolate wind speeds at higher elevations.

The 2007 Study as well as its 2013 and 2018 updates were used as a starting point for the analysis. It should be noted that the previous report does not consider possible incentives that could be available if it were to be developed by a private entity, via a PPA. Although the current study uses the same approach for consistency, it incorporates recent PPA awarded values including current production tax credits and the parameters around them to better represent the most recent wind LCOE.

The complete analysis is provided in Appendix C, and a summary provided in Table 5-2. The new wind LCOE is lower than previous updates due to cost decrease but is higher than wind LCOE reported in literature due to lower capacity factors obtained extrapolating the wind data available from 2007. It should be noted that this analysis does not include additional benefit from carbon emissions reductions for energy purchased for the CRA in meeting any GHG emissions reduction goals.

Table 5-2 Evolution of the levelized cost of wind power along the CRA, based on extrapolated 2007 Navigant report data

Parameter	2007 Navigant report	2013 update by Metropolitan staff	2018 update by Metropolitan staff	2019 update by Stantec
	($/MWh)			
LCOE range	161-166	99-103	65-68	52-75

Wholesale self-generation may only be financially beneficial to Metropolitan if the generated energy was less expensive than purchasing energy in the CAISO market. When comparing these LCOE values to 2019 average CAISO energy price (less than $35/MWh until 2029 in 2019 dollars), and to the Hoover and Parker hydropower bought at $20/MWh, installing wind along the CRA is currently not economically justifiable.

5.4 SOLAR POWER GENERATION ALONG THE CRA

Large utility-scale solar power generation could represent an opportunity to reduce energy costs and GHG emissions along the CRA. This analysis assumes that, if such development is considered viable, due to the size and complexity of operating a utility-scale solar power generation system, Metropolitan would solicit a third-party developer through a PPA and take advantage of the eligibility of the developer for the ITC credit which would provide additional savings to the project.

Current CAISO data was analyzed along with wholesale energy forecasts provided by both Wood Mackenzie and Platts and used to determine the financial viability of solar generation along the CRA. The two forecasts are based on different assumptions related to large-scale implementation of energy storage throughout California, which impact the solar production cost assessment during the mid-day hours between 9 a.m.–3 p.m. (Figure 5-12). The Wood Mackenzie forecast assumes swift and large implementation of energy storage which will help mitigate the hourly variability in wholesale prices. Conversely, the Platts forecast assumes the implementation of large-scale energy storage will be slower than the continuing implementation of renewables on the market. This would result in greater volatility of hourly wholesale prices and extremely low energy prices during solar hours.

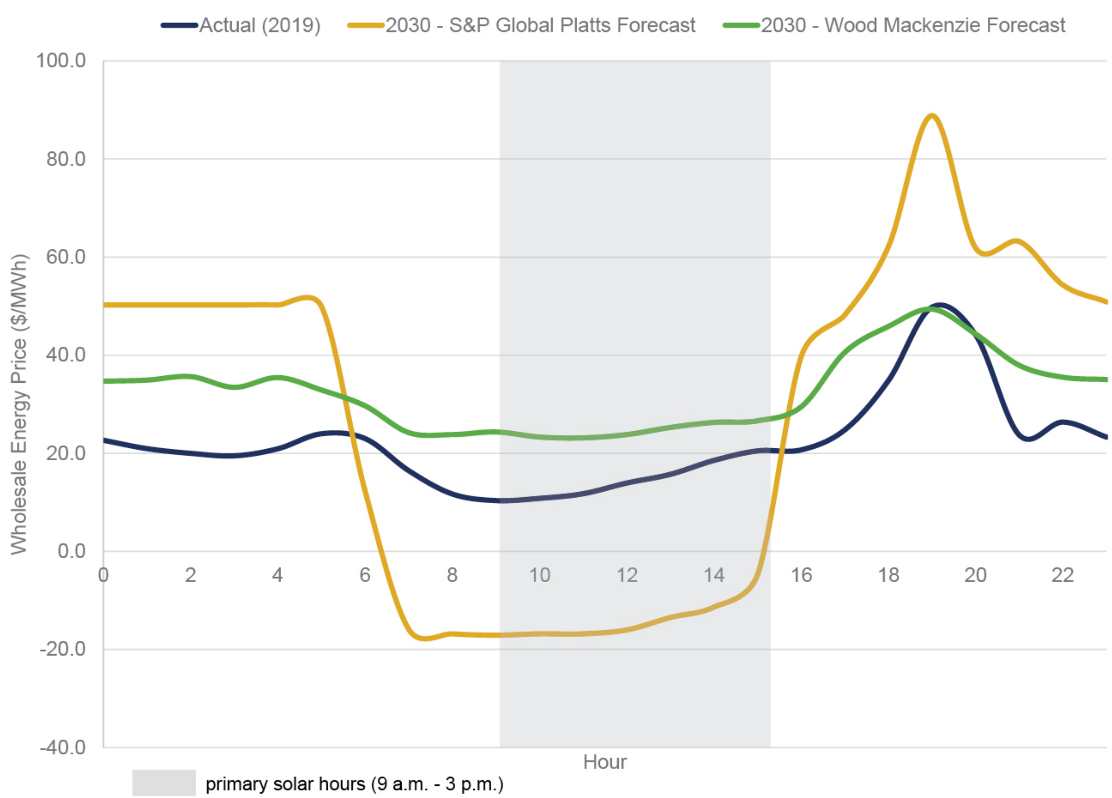
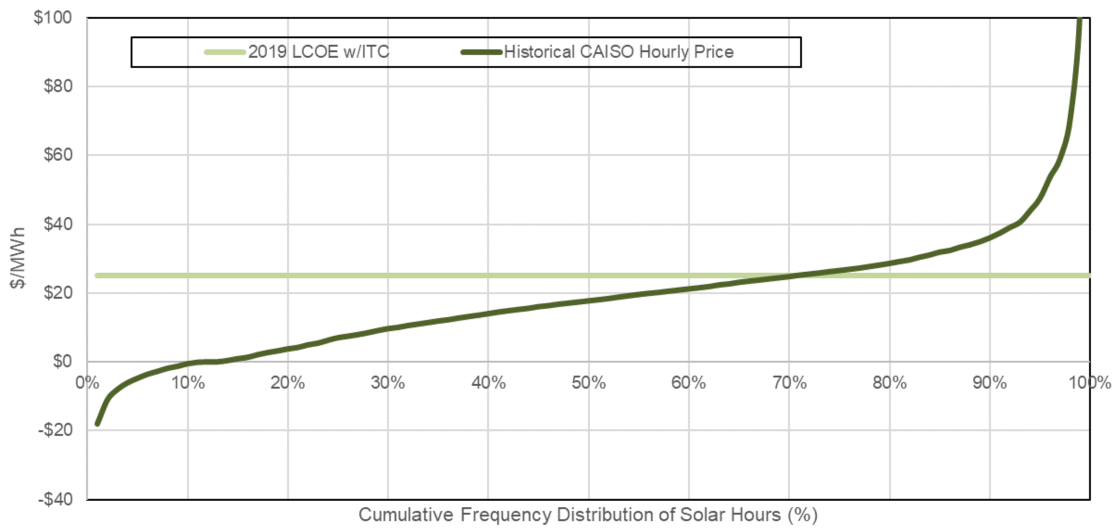


Figure 5-12 Average June day comparing baseline and forecasted wholesale energy prices

The above figure shows the wholesale energy price during an average day in June and does not show seasonal fluctuations. Therefore, actual 2019 hourly energy price data and those predicted for the year 2030 for solar generation were analyzed and zed compared to the expected LCOE of solar in that year, as presented in Figure 5-13. This analysis assumed that solar was generated every day between the hours 9 a.m. and 3 p.m. Solar generation becomes financially viable when the LCOE is less than the cost of energy (i.e. the area under the curve to the right of the intersect should be greater than the area under the curve to the left of the intersect). Using historical CAISO energy prices at nodes near the CRA, 2019 would not have been a net positive year for solar generation. Looking forward, the two energy forecasts result in significantly different future outlooks for solar energy prices which could either be extremely beneficial or of high risk for Metropolitan.



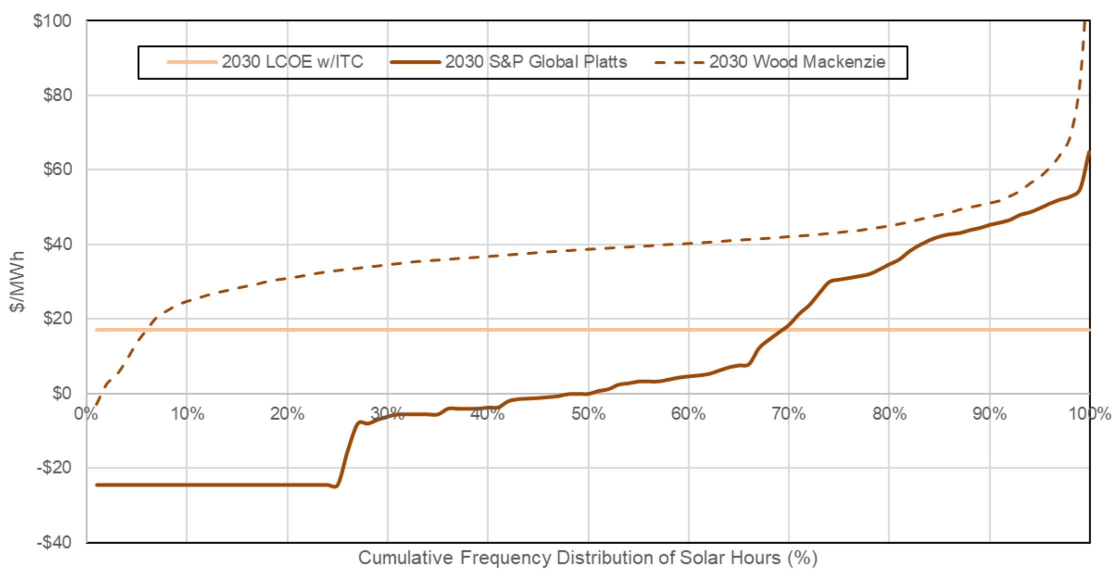


Figure 5-13 Percentile of historical and forecasted CAISO energy prices during solar hours (9a.m. – 3p.m.) compared to expected utility-scale solar LCOE

It should be noted that this analysis does not include additional savings from carbon emissions reductions of energy purchased on the wholesale market for the CRA toward any carbon reduction goal.

This financial analysis only shows at a high level the possible savings and does not include a full and complete specific project component cost and price forecasting for a potential solar generation project. Due to daily variations in the wholesale market, caused by an assortment of variables, future forecasting of the CAISO market along the CRA is difficult to predict. With the increasing construction of renewable energy projects in California, it is expected that CAISO energy prices during solar hours will decrease in the future, similar to the Platts forecast, which will further decrease possible financial viability from a stand-alone solar project. In this scenario, Metropolitan would benefit from reduced wholesale power expenses during mid-day hours without the capital cost of solar development. If Metropolitan were to invest in large-scale solar, the value of that investment would be measured against the low mid-day prices and the value of unbundled RECs. The value of these credits is currently only $1 to $2/MWh. Therefore, considering the volatility of the wholesale market, a large-scale solar energy generation project along the CRA does not appear to be a viable option at this time. It is recommended that Metropolitan continues to monitor wholesale market trends and solar facility LCOEs to determine future project viability. It is also recommended that Metropolitan discusses with potential third-party developers to better understand the benefits and risks of this project.

Large scale solar paired with battery energy storage was not considered for this study due to the wholesale energy pricing uncertainty seen in Figure 5-12. Battery energy storage is, in fact, typically used to store low-cost energy and utilize it during times of high-cost energy. However, the lowest wholesale energy prices are currently seen and predicted to remain during the mid-day (solar) hours for either forecast. Neverthless, a stand-alone battery energy storage project could still help shift these low energy prices to peak times which would take advantage of the solar generation already present in the market without the added costs of implementing a new solar project. More details on a stand-alone battery energy storage project on the wholesale market are presented in Section 5.5.

5.5 BATTERY ENERGY STORAGE ALONG THE CRA

Utility-scale storage represents an opportunity for energy price arbitrage at the CRA to take advantage of the current and predicted volatile wholesale energy market prices. As shown in Figure 5-12, there is an opportunity to capture energy during times of low-cost (typically mid-day when solar energy is available) and dispatch it at times of high cost (late afternoon/evening). As mentioned previously, the “duck curve” effect stemmed from the over-generation of solar power on the grid, driving mid-day prices as low as negative prices in the wholesale energy market. If this trend continues per the Platts forecast, the case for battery storage is potentially beneficial for utilizing the excess renewable energy already on the grid through shifting demand. Implementation of large-scale BESS facilities along the CRA could help Metropolitan mitigate the effects of these large energy price swings for overall energy savings on CRA pumping operations. Specifically, battery storage could be co-located at each of the five pumping plants (Intake, Gene, Eagle, Hinds, Iron) to take advantage of the locational marginal pricing (LMP) of wholesale energy at each site, similar to Figure 2-8. In addition, storing solar energy purchased from the grid during the day and using the stored energy at night in lieu of fossil fuel energy purchased from the grid will also reduce Metropolitan's GHG emissions and obligation to purchase carbon credits through CARB's cap and trade program.

A high-level financial assessment model of BESS implementation at the CRA pumping plants was developed based on historical hourly LMPs at each site. The model uses a simple battery dispatch strategy for a 4-hour battery, assuming the battery charges during the four lowest energy price hours of each day and discharges to the pumping plant during the highest energy price hours of each day. This is a "perfect" assumption since real-time battery usage would not have exact knowledge of when the lowest and highest energy prices would occur each day. It is assumed that if pumping operations are on-hold or less than the capacity of the battery, the battery would be able to discharge back into the grid for energy price arbitrage savings. The difference between the cost of charging and the savings from discharging is considered the net savings for the BESS. Figure 5-14 provides an example of potential energy savings with a 30 MW battery at Hinds Pumping Plant using historical energy prices from 2018 and 2019. This also illustrates the uncertainty of the wholesale market and the major variability between just two consecutive years.

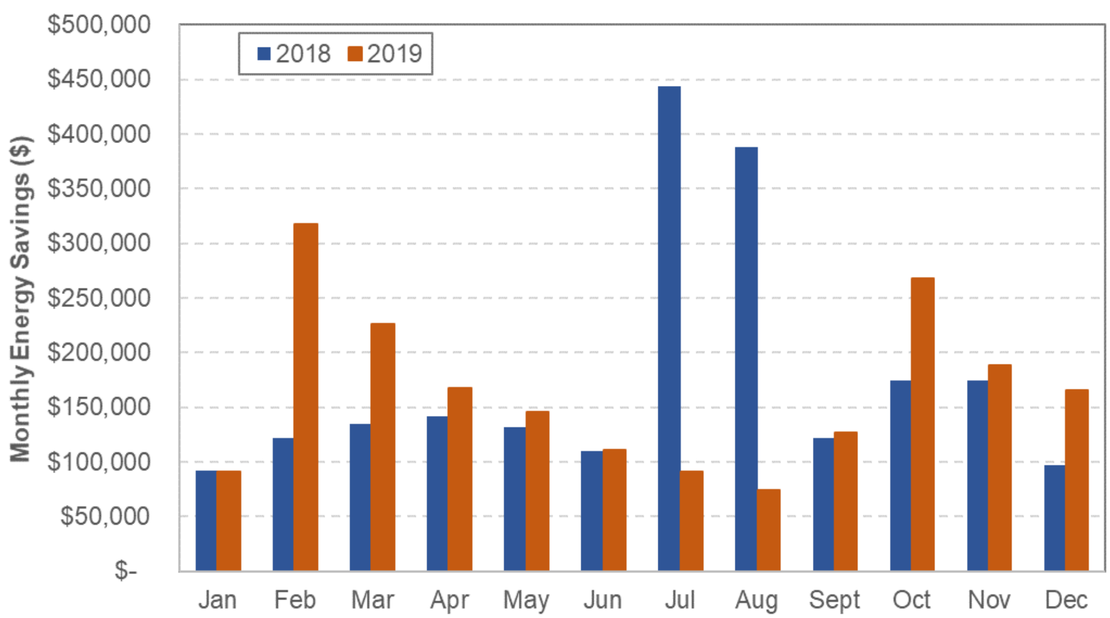


Figure 5-14 Potential Energy Savings of 30MW/156MWh BESS at Hinds Pumping Plant in 2018 and 2019

This net savings was escalated into the future using both the Wood Mackenzie and Platts forecasts to provide a range of energy savings dependent on the shifts in the wholesale market. System installation costs and O&M costs were calculated based on the assumptions in Section 2.2.2 and assumed first year of operation beginning in 2025. While these battery systems would not be eligible for SGIP incentives, the RA capacity credit was included in the cost calculations. A summary of the financial analysis is provided in Table 3-18.

Table 5-3 Cost information estimated for the BESS along the CRA

Location	Battery Size, each site (MW/MWh)	Capital Cost ($M)	Annual O&M Cost ($M)	Capacity Credit ($/kw-month)	Annual Electricity Savings ($M)	20-year NPV* ($M)	Payback Period (years)**
Gene/Intake	30/156	$49	$0.42	$6.00	$1.68	$61.7 - $17.8	11-15
Eagle					$1.93	$77.1 - $22.6	10-14
Hinds					$1.97	$75.2 - $23.5	10-13
Iron					$1.83	$68.7 - $20.8	11-14

*Utility-scale BESS anticipated 20-year life may be reduced if daily cycling of the battery occurs

**Range is based on wholesale energy price forecasts from Wood Mackenzie and S&P Global Platts

For comparison, all batteries were sized the same but exact sizing of this scale of BESS project along with the various dispatch strategies would need further refinement. This financial analysis shows at the high level the possible savings and does not include a full and complete project component costs and price forecasting for a potential BESS project. Due to daily variations in the wholesale market, caused by an assortment of variables, there is no clear pattern of when it is best to operate the battery and future price forecasting of the market along the CRA is difficult to predict. However, based on the above analysis and historical data, it is recommended for Metropolitan to continue analyzing large-scale BESS projects along the CRA including discussions with battery developers to understand the benefits and risks of operating batteries on the wholesale market.

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6.0 CARBON EMISSIONS REDUCTION ASSESSMENT OF RENEWABLE ENERGY AND ENERGY STORAGE PROJECTS

This study assessed the carbon emission reduction and associated carbon cost of the renewable energy and energy storage projects evaluated in Sections 3.0, 4.0 and 5.0. The analysis assumes that carbon emission reduction can be reasonably claimed according to the following criteria:

- For solar generation projects, carbon emission reduction would occur when the renewable energy is used in-lieu of electricity from the grid or from CAISO, regardless of the composition of the energy mix at the generation time. No credit would be obtained for renewable energy exported to the grid.
- For wind projects, carbon emission reduction would occur when renewable energy is used in-lieu of electricity purchased from CAISO, similar to the assumption previously presented for solar generation.
- For BESS projects, carbon emission reduction credit is assumed to be the minimum required to receive incentives. This will require real-time emissions monitoring of the system. Carbon emission credits could also be obtained if the BESS is used to store renewable energy, that would otherwise be exported to the grid, for later use at the facility in lieu of electricity demand from the grid.
- Modifying Yorba Linda configuration to behind the SCE meter at Diemer would reduce carbon emissions proportional to the energy offset since renewable energy would be used in-lieu of electricity from the grid. No credit would be claimed for the remaining renewable energy sent or sold back to the grid.
- Installing new hydropower projects would not offset Metropolitan's carbon emissions as the energy (and the RECs) would be sold back on the wholesale market, instead of offsetting existing Metropolitan electricity demand.

A summary of the carbon emission reduction opportunities associated to each of the projects considered in this analysis is provided in Table 6-1 . When two procurement methods were considered for a given project (e.g., Metropolitan-owned solar and solar PPA), the option with the most favorable NPV is presented.

Table 6-1 Carbon emission reduction of energy projects considered

Project	Carbon emission reduction	Notes
Weymouth stand-alone BESS charged from existing solar generation facility or grid	yes	GHG emission reductions is possible with BESS equipped with real-time tracking of carbon emissions on energy purchased from the grid to charge the battery. If the battery is charging solely from existing solar, no additional reductions would be considered
Skinner stand-alone BESS charged from existing solar generation facility or grid	yes	GHG emission reductions is possible with BESS equipped with real-time tracking of carbon emissions on energy purchased from the grid to charge the battery. If the battery is charging solely from existing solar, no additional reductions would be considered
Skinner 1 MW solar generation system expansion PPA	yes	Carbon emission reduction proportional to the additional solar power used at Skinner
Skinner 1 MW solar generation system expansion PPA with BESS		
Skinner 2 MW solar generation system expansion PPA		
Skinner 2 MW solar generation system expansion PPA with BESS		
Mills stand-alone BESS charged from grid (TOU arbitrage)	yes	GHG emission reductions is possible with BESS equipped with real-time tracking of carbon emissions on energy purchased from the grid to charge the battery.
Mills 500 kW new solar generation facility PPA	yes	Carbon emission reduction proportional to the additional solar power used at Skinner
Mills 500 kW new solar generation facility PPA with BESS		
Jensen stand-alone BESS charged from existing solar generation facility or grid	yes	GHG emission reductions is possible with BESS equipped with real-time tracking of carbon emissions on energy purchased from the grid to charge the battery. If the battery is charging solely from existing solar, no additional reductions would be considered
OC-88 stand-alone BESS charged from grid (TOU arbitrage)	yes	GHG emission reductions is possible with BESS equipped with real-time tracking of carbon emissions on energy purchased from the grid to charge the battery.
Yorba Linda behind Diemer's meter	yes	Carbon emission reduction proportional to the additional hydropower used at Diemer.
Small hydropower projects	no	No carbon emission reduction from sales of hydropower on the wholesale market
In-line hydropower projects		
Pumped storage projects		
Wind along the CRA	yes	Carbon emission reduction if used to offset electricity consumption bought from the wholesale market
Solar along the CRA		
Battery storage along the CRA	yes	GHG emission reductions is possible with BESS equipped with real-time tracking of carbon emissions on energy purchased from the grid to charge the battery.

The annual carbon emission reduction in Table 6-2 was calculated based on the amount of renewable energy used in lieu of grid energy, given an emission factor of 0.12 metric tonnes-CO_2/MWh, as previously described in Section 2.0, assuming project operations begin in 2023.

Table 6-2 Summary of carbon emission reduction by renewable energy and energy storage projects

Project	Additional yearly renewable energy use (GWh)	Annual carbon emission reduction* (metric tonne/year)
Weymouth stand-alone BESS charged from existing solar generation facility or grid	0.08	10
Skinner stand-alone BESS charged from existing solar generation facility or grid	0.08	10
Skinner 1 MW solar generation system expansion	2.26	271
Skinner 1 MW solar generation system expansion with BESS	2.14	256
Skinner 2 MW solar generation system expansion	3.13	375
Skinner 2 MW solar generation system expansion with BESS	3.56	427
Mills stand-alone BESS charged from grid (TOU arbitrage)		10
Mills 500 kW new solar generation system	1.21	145
Mills 500 kW new solar generation system with BESS	1.09	131
Jensen stand-alone BESS charged from existing solar generation facility or grid	0.08	10
OC-88 stand-alone BESS charged from grid (TOU arbitrage)	0.08	10
Yorba Linda behind Diemer's meter	8.85	1,061

** Stand-alone BESS projects are required to reduce GHG emissions by a minimum 5 metric tonne CO_2/MWh/year to receive SGIP benefits.*

Carbon emission reductions for the renewable energy projects along the CRA (wind and solar) are challenging to quantify as the analysis conducted in this study was based on levelized-costs. However, a useful surrogate parameter to consider would be the equivalent cost of carbon calculated by dividing the incremental cost of using the renewable source (compared to business as usual) by the 0.12 metric tonnes-CO_2/MWh emission factor:

$$Equivalent\ cost\ of\ carbon = \frac{LCOE\ \left(\frac{\$}{MWh}\right) - wholesale\ energy\ price\ \left(\frac{\$}{MWh}\right)}{0.12\ metric\ tonnes\ CO_2/MWh}$$

This allows comparison of economically infeasible projects against each other and against the current and future carbon price on the open market. Based on 2019 LMP data, the average price for wholesale energy along the CRA during all hours was \$30/MWh and lowered to \$14/MWh if only the solar hours were considered. Using an LCOE of \$52/MWh and \$20/MWh for wind and solar respectively, the equivalent cost of carbon would amount to \$176 and \$48 per metric tonne of carbon for wind and solar respectively, which are significantly higher than the cost of carbon on the market, as shown in Figure 6-1. Therefore, implementing wind and solar along the CRA for carbon emission reduction is also not economical when compared to the cost of carbon on the open market.

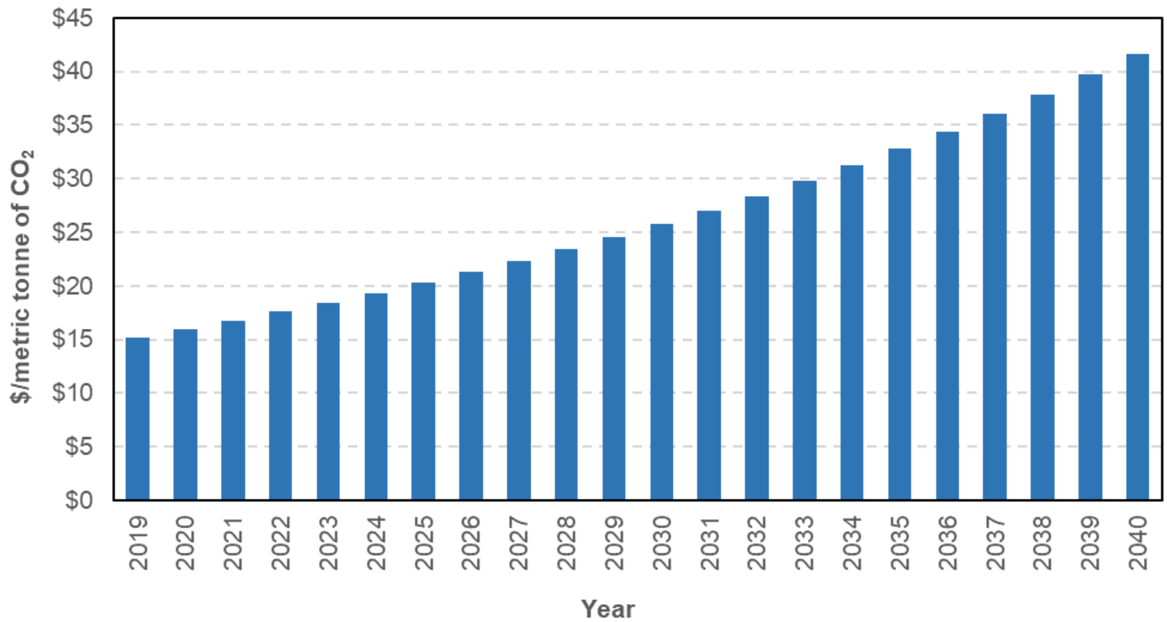

Figure 6-1 Carbon price outlooks in California in 2019 dollars (Wood Mackenzie, 2018)

7.0 OTHER ENERGY MANAGEMENT INITIATIVES AND RECOMMENDED PRACTICES

Other energy management initiatives and best practices were identified as part of TM-1. Several of these initiatives that could be implemented by Metropolitan are presented in the following sections and focus on energy efficiency measures, design practices, and training.

7.1 ENERGY AUDITING, MONITORING AND BENCHMARKING

Metropolitan's energy management efforts should begin with assessing the data needs and data approaches to generate insights for system operation and planning. A data collection plan should be developed and aligned with the end goals of supporting the organizational business strategy and objectives, particularly those in relation to energy management. The following sections provide a brief description of other potential measures Metropolitan should consider for data collection, monitoring and benchmarking for a successful energy management strategy.

7.1.1 Facility energy audits

Energy audits are important components of an energy management and sustainability program that will allow Metropolitan to evaluate energy conservation options and reduce cost, maintain or improve facility energy performance and achieve sustainable operations. Energy audits allow for a detailed inspection and analysis of the energy usage, generation and wastage of Metropolitan facilities which can be conducted at different levels, including:

- A preliminary audit with simple walk through of a total duration between a day to two weeks per site. In this case the audit includes interviews with operators, photo documentation and recording of equipment and/or process upgrades that warrant further investigation. The report will describe the opportunities for conserving energy with very rough cost estimates and will advise on the need of a full scale detailed audit;

- A detailed audit effort involving the evaluation of equipment efficiency, the review of specification and of capital improvement plans, metering equipment set up (i.e., to track pump run times and electric usage to calculate pump efficiencies and replacement equipment paybacks). This level of audit may require several weeks to several months to complete and potentially require on site auditing staff delivering various reports and technical memos.

Facility energy audits can be conducted by a third party (energy provider or outside consultant) and supported by Metropolitan's staff to assess facilities' energy demands and associated costs and provide strategies to their reduction or optimization. In general, due to system changes, new technology innovations, and varying energy costs, it is recommended that energy audits be repeated every three to five years or before a major project.

7.1.2 Energy submetering

Sub-metering of energy consumption data has been proven to be invaluable in understanding the details of large facility energy usage and assist facilities managers in optimizing each process and equipment for energy cost reduction and energy efficiency. Metropolitan currently has several sub-meters at their key facilities but is lacking detailed information about the data collected through submetering and their use. Establishing a dedicated submetering program would allow Metropolitan to measure and record consumption of electric energy usage in hourly intervals or in real-time by allowing collection of consumption, diagnostic, and status data from meters to a central database (i.e., load factor, power factor, demand (kW), and usage (kWh)). Data acquisition should be conducted not only to collect plant-level information but also at the process and equipment level from power-consuming devices (e.g., motors, blowers, aerators, air compressors) and power generating and energy storage units (e.g., generators, turbines, renewable energy sources, energy recovery devices, BESS) and from equipment not directly involved in the movement and treatment of water (e.g., artificial lighting, electrical heaters, ventilation fans). In addition to power and energy monitoring, Metropolitan should also plan on power quality monitoring (power flows quality), which will guarantee energy monitoring and management of the plant.

In general, the submetering program can enable the following practices and functions:

- Verification of utility bills and comparison of utility rates
- Demand response or load shedding when purchasing electricity under time-base rates
- Measurement and verification of energy project performance
- Benchmarking energy use
- Identification of operational efficiency improvement and retrofit project opportunities
- Usage reporting in support of establishing and monitoring utility budgets and costs
- Prolonging equipment life (reducing capital investment requirements) and improving reliability by verifying the efficient operation of equipment

It is important to note that the submetering program should include protocols for instrument calibration and validation or assess needs for instrument redundancy for critical equipment or infrastructure. An adequate level of submetering and related cutoff (e.g., 50 hp, 100 hp) should be also determined depending on Metropolitan's goals as well as limitations (e.g., balancing cost versus value of data). Metropolitan should establish and record all existing sub-metering locations in a location-based system like Geographic Information System (GIS) and review if additional sub-meters are required based on the objectives and anticipated outcomes from energy audits. The transfer, storage and centralization approaches of the collected data through submetering should be established to make informed business decisions in the most reliable and cost-effective way.

7.1.3 Energy key performance indicators and benchmarking

Given that energy management is an integral part of Metropolitan's operations, energy data should be complemented with other enterprise attributes (e.g., operation and maintenance, performance, customers, and finance). Therefore, a successful data management program that supports energy management should be holistic and develop energy key performance indicators (KPI) that support energy benchmarking. Benchmarking can provide Metropolitan with opportunities to document historical system performance trends, quantify relative performance across industry peers, and establish a baseline for determining process or pumping efficiency improvements. In addition, benchmarking activities are recognized to help with the identification of best practices, set targets for future operations and supports asset and operational management practices. Metropolitan already monitors a number of KPIs throughout its' systems but should evaluate these KPIs and identify areas where more useful metrics could be monitored and utilized. These metrics include the following:

- Energy KPIs have been widely developed by the water industry to assess process or pumping system performance. The most commonly used metric for drinking water treatment processes is specific energy (kWh/m3 water treated), which is the ratio between the energy use and the hydraulic capacity of the plant or treated volume. This metric can also be narrowed down to process-specific indicators for various treatment process configurations.

- Energy analysis of pumping systems can be developed using different energy metrics and performance indicators that include the total energy (E) and specific energy (SE) consumption and the water-to-wire efficiency (η_{ww}) although recently, the pump energy indicator (PEI) and pump performance indicators (PPI) were introduced as a more comprehensive metric that normalizes energy consumption against the amount of work done (i.e., energy imparted).

- Energy generation processes using renewable sources, such as solar, can also be described and monitored using KPIs at Metropolitan such as the percentage of renewable production, percentage of energy offset from the grid, and percentage of energy neutrality. The implication of energy consumption, generation or wastage on cost can be reported through KPI, such as in the dollars spent off-peak per dollars spent on-peak, and dollars from energy use per dollar paid by customers.

- In addition to those reported previously, water utilities are also using energy KPIs that represent the relationship between energy and GHG emissions since process optimization for energy management may conflict with GHG emission reductions. KPIs developed around GHG emissions and related savings are particularly meaningful when GHG accounting is based on real-time or semi-real time emission factors capturing the time variation of the energy fuel mix. Metropolitan does not currently participate in real-time GHG accounting, but in coordination with the targets, monitoring, and reporting requirements set by CAP, it is recommended that a real-time or semi-real time emissions factor accounting be put in place.

7.1.4 Display of energy information for business intelligence

Energy dashboards provide an effective and consistent means by which energy performance could be displayed and communicated to Metropolitan's management, administration, operation, and maintenance personnel. The dashboard is typically a web page connected to a data historian that translates the complexity of high volume and variety data (real-time and historical data) into useable business information, for example with the use of KPIs.

An integrated energy dashboard can create a two-way information path, displaying data from the field upwards, while being used by management to communicate energy goals and expectations to staff and other stakeholders downwards. Dashboards should be customized so that the information targets different organizational levels at Metropolitan (e.g., operators, maintenance staff, managers). Operators are generally overloaded with information from SCADA and from the telemetry system, therefore, a dashboard aimed at the operation personnel should refrain from merely supplying additional data as numeric values and instead provide simple and clearly identifiable indicators. For example, a color-coded representation of the information that replaces the numerical values of system performance is generally preferred as it provides a simple visualization of how the equipment is performing against pre-determined benchmark values. Maintenance staff, however, require more detailed information in the form of a mix of indicators and numeric values that provides a quick indication of the location of the issue and the scale of the problem. Managers are more interested in high-level summary information and comparative data related to system performance and its impact on other utility business areas and energy goals.

Most commercial dashboard products have the ability to provide historical trends of multiple data points over any time range and have forecasting capabilities or predictive analytics on future system performance. Some additional analysis or information that an energy dashboard at Metropolitan can include are:

- Temporal plant- or asset-level energy consumption profiles versus influent flows or other normalizing parameters
- Correlations between process metrics (e.g., KPIs), causes of inefficiencies and troubleshooting measures
- Time-of-day process information and its impact on operating costs (e.g., base/night loads)
- Cost savings achieved in real-time (e.g., from previous performance)
- Cost incurred for no taking actions, to drive positive behavior

Dashboards can also provide findings of “big-data” architecture that supports:

- Equipment, process and operations modelling and simulation
- Intelligent model-based data verification and reconciliation for more reliable and robust data
- Intelligent real-time fault diagnosis and alarming
- Predictive analytics
- Multigoal constrained optimization (e.g., minimize energy costs, minimize or limit pump start/stops, minimize GHG footprint)
- Browser-based sharing of data (real-time and historical) with all relevant parties throughout the organization

In general, the development of an energy dashboard obtaining data across multiple sources may encounter many constraints in the alignment of large amounts of complex and disparate data from and within multiple sources, each with their own polling times, record storage and retrieval processes and even possibly inaccurately aligned time clocks. Understanding the data acquisition for dashboards is an opportune time for Metropolitan to review each data source to minimize or avoid data transfer issues and failures as well as any potential communication issues, and to evaluate how the existing data infrastructure (e.g., SCADA, OSIsoft's PI, GIS) can be used and aligned with the concept of an energy dashboard.

A multidisciplinary team at Metropolitan is currently developing an Energy Efficiency pilot program at the Weymouth WTP site that focuses on the development of a comprehensive energy monitoring/reporting system using the SCADA system, existing sub-metering and process controls and instrumentation. This monitoring effort will allow Metropolitan to understand the details of power usage and to develop approaches and methodologies that can translate the data acquired into information and new business intelligence for energy usage and cost reduction, while maintaining the high levels of reliability and safety required by Metropolitan. Metropolitan currently monitors many of the internal distribution circuits and meters via SCADA and uses this data for electricity cost reporting and treatment plant performance metrics. This initial effort would utilize this existing SCADA/data infrastructure and combine it with the various instrumentation currently available on the process equipment to capture the data and develop reports to be analyzed and evaluated.

This pilot project at Weymouth, its lessons learned, and findings will be the starting point for any new energy studies (such as pump efficiency, process equipment efficiency, etc.) that will take place in the future at other Metropolitan's facilities.

7.2 ENERGY AND COST OPTIMIZATION OF PROCESSES AND PUMPING OPERATIONS

Metropolitan has actively managed its energy savings by implementing energy load management programs that take advantage of incentives and rebates from energy providers, shifting power consumption from electricity on-peak to off-peak hours and by adding energy self-generation. This practice should continue and be expanded for even more savings.

For pumping systems where multiple pumps are arranged in parallel that have historically been operated following schedules based on the maximum flow or based on the percent of maximum speed, the combination of pumps can be selected in a manner that minimizes the cost of running those pumps under TOU tariffs or volatile wholesale energy prices or the specific energy consumption of the entire pumping plant, within the system constrains. Evaluating the schedule and timing of pump usage that can lead to significant cost reductions (although perhaps not energy use reductions).

At treatment plant, process optimization based on energy efficiency and cost reduction can be implemented to reduce overall energy consumption and cost within the set of treatment and operational goals and utility constraints. Examples of projects can be the ozone dose reduction and filtration optimization to lower the backwash frequency, or schedule energy intensive processes (e.g., backwash) to low-cost tariff periods.

7.3 ENERGY EFFICIENT DESIGN AND REHABILITATION MEASURES

There are a number of measures Metropolitan could implement for energy efficiency design and rehabilitation. This section discusses these measures pertaining to pumps and motors, administrative and support facilities, and project solicitations.

7.3.1 Variable frequency drives to pumps and motors

At Metropolitan, a high share of energy is required to move water geographically through pumping. Oftentimes, pumping systems follow designs that guarantee capacity for projected demands up to 20 years or more into the future, sacrificing energy efficiency practices. However, deviations of water demand from forecasts results in having pumps with oversized impellers, with oversized motors, and operating away from their optimized range. Additionally, opportunities for pump refurbishing or operational optimization at the CRA is limited and constrained by the age of the assets, as previously reported in Section 5.

Energy efficient design criteria for new or refurbished pumping system should be based on the understanding of the performance of the major components of the pumping system (pump, motor, variable speed drive [VSD] applications, control schemes and the configuration of water system such as pipe size, fittings, and pressure zones).

The addition of variable frequency drives (VFD) to pumps and motors would allow operations of a pumping system more energy efficient and environmentally sustainable. When a pump most regularly operates over a range of flows, a VFD can be used to increase the pumping efficiency over a wider operating range on the system curve and provide speed control and a soft-starting capability that in many cases also provides energy savings. Soft-starting reduces thermal and mechanical stresses on motor windings and couplings. Also, VFDs reduce voltage fluctuations that can occur in starting large motors.

Metropolitan is currently evaluating and have already completed the installation of VFDs on a large number of pumps and motors throughout its system (e.g., Mills, Diemer, Skinner and Jensen). However, additional detailed studies of the system could indicate opportunities for Metropolitan to incorporate more VFDs within the treatment plants and/or in the distribution system (e.g., OC-88 pump station) and provide recommendations for more optimal control utilizing the VFDs for energy efficiency.

7.3.2 Energy efficiency at administrative and support facilities

For administrative and support facilities, energy efficiency measures typically include lighting replacement with light-emitting diode (LED) and HVAC optimization. Programs can also be implemented around vehicle fleet to reduce overall fuel consumption or switch to electrical vehicles to eliminate carbon emissions from vehicle fleet operations. Some of these measures have already been implemented or are planned at Metropolitan facilities.

7.3.3 Energy efficiency practices in project solicitations

Metropolitan should incorporate energy efficiency measures as a requirement in project solicitations to set a greener standard for future projects and meet current and future energy policies. This could also encourage the incorporation of new technologies or strategies as a proactive approach to energy management.

7.4 STAFF AND RESOURCES FOR ENERGY MANAGEMENT

7.4.1 Staff and trainings

Metropolitan should maintain adequacy of staff to support and enable energy management strategies and foster early involvement of key staff members across various groups at Metropolitan (e.g., maintenance, process, data analyst). This is especially important in the process of developing, installing and commissioning data systems or platforms for energy management. It is recommended that Metropolitan establish a dedicated Energy Sustainability team to monitor and implement energy best practices, initiatives and projects.

It is important that the Metropolitan staff be trained on the energy management and related data solutions for the use of the energy and related data infrastructure, use of the interface and control logics. Staff training sessions should be organized at regular intervals to keep the staff up to date on latest developments of the data solution. Trainings should educate Metropolitan staff on operational and maintenance strategies to reduce energy and related costs. Operational strategies could include pump sequencing that favor the use of more efficient pumps (especially during times of high energy prices) or decision matrices based on both process performance and energy costs. Maintenance strategies could include predictive maintenance rather than reactive.

7.4.2 Communication

Metropolitan should facilitate knowledge transfer within and outside the organization on various aspects related to energy management (including the related data management tools) to enable passage of information between different levels of the organizations. It is a critical resource to improve learning about other utility experiences through communication with other agencies and utilities that are able to share lessons learned from their energy management planning and implementation project experience. It is particularly important to keep continuous communication with Department of Water Resources (DWR) and any updates or changes to the energy management of the SWP as this will indirectly affect Metropolitan.

Metropolitan should also keep a continued conversation with the electric utility providers to stay abreast of changes in the energy market that will impact retail or wholesale energy rates or opportunities for incentives or programs that can benefit energy project economics at Metropolitan. In general, it is critical that the electric utility tariff rates and programs are well understood to make the project economical and increase its benefits. Metropolitan’s facilities are under multiple different retail providers and subject to several electric tariff, which are prone to change overtime and change the economics of implemented or anticipated renewable or energy storage projects.

7.5 RECOMMENDATIONS

In addition to Metropolitan's current energy best practices, the following initiatives are recommended to support Metropolitan's goal in becoming a leader in energy sustainability:

- **Energy Audits** - Perform energy audits at critical facilities every three to five years or before a major project.
- **Submetering** - Establish and record all existing sub-metering locations in GIS and review if additional sub-meters are required.
- **Submetering program** - Establish a dedicated submetering program to measure and record consumption of electric energy usage to a central database.
- **KPIs** - Evaluate measured KPIs and identify areas where more useful metrics could be monitored and utilized.
- **Dashboard** - Establish an integrated energy dashboard that can obtain data across multiple sources that can evaluate energy performance or identify energy inefficiencies to assist in operations, maintenance and reporting.
- **Operations** - Evaluate pump scheduling for more optimal timing based on energy prices.
- **Studies** - Initiate process optimization studies at treatment plants to evaluate areas for energy efficiency and cost reduction.
- **VFDs** - Evaluate the additional opportunities to incorporate more VFDs in appropriate locations throughout the entire system.
- **Controls** - Evaluate optimal control strategies for pumping systems, including those utilizing VFDs, for energy efficiency.
- **Vehicles** - Switch vehicle fleet to electrical vehicles.
- **Solicitations** - Incorporate energy efficiency measures as a requirement in project solicitations.
- **Staff** - Train staff on best energy management practices on a regular basis.
- **Knowledge Transfer** - Initiate knowledge transfer within and outside the organization on various aspects related to energy management.
- **Management** – Establish a dedicated Energy Sustainability team to be focused on updates to energy rates, forecasts and technologies while monitoring, expanding and implementing energy best practices, initiatives and projects.
- **Rates** - Continue communications with electric utility providers on optimal rate structures and upcoming changes.

8.0 SUMMARY AND RECOMMENDATIONS

8.1 SUMMARY OF FINDINGS

This study assessed the financial and environmental feasibility (in terms of carbon emission reduction only) of selected renewable energy and energy storage projects identified in Metropolitan's facility portfolio and compatible with the current and foreseeable future energy market and technology advancements. The outcomes of this study will be used by Metropolitan to develop a new ESP and roadmap for the immediate and near future. For this study, the following opportunities were evaluated:

- Solar generation and energy storage projects of various sizes, configurations (e.g., stand alone or integrated), and use cases (e.g., TOU arbitrage, optimization of renewable energy generated), developed through various procurement models (e.g., Metropolitan-owned vs. PPA) at the five WTPs and OC-88 Pumping Plant;
- Change in Yorba Linda's grid interconnection configuration to behind-the-meter at Diemer WTP;
- Small and in-line hydropower at various sites within Metropolitan's distribution system;
- Pumped storage projects;
- Solar and wind generation along the CRA;
- Battery energy storage projects at CRA pumping plants;
- Key strategies that enhance operational flexibility of pumping along the CRA; and
- Other energy management initiatives and best practices.

Table 8-1 summarizes the details and results of the feasibility assessment conducted for all renewable energy and energy storage projects identified at the selected Metropolitan's facilities. The summary also includes carbon emission reductions for eligible projects. Economically feasible projects are those that have a payback period that is less than the asset life. It should be noted that not all economically feasible projects result in carbon emission reductions, such as stand-alone BESS projects. Projects that were not considered economically feasible and were characterized by high payback periods, often larger than the asset lifespan, should be preserved, monitored and revisited as future conditions change.

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Table 8-1 Summary of results of feasibility assessment conducted for renewable energy and energy storage projects at Metropolitan

Project Location	Technology/Project	Project Size	Incentive and Other Revenue Source Considered	NPV	Payback Period (years)	Carbon Emission Reduction* (metric tonne/year)
Weymouth WTP	Stand-alone BESS charged from existing solar or grid (TOU arbitrage)	1 MW/2 MWh	SGIP Step 3 RA Capacity Credit	$345,000	5	10
Skinner WTP	Solar generation system expansion	1 MW - Metropolitan-owned	-	$240,000	14	271
		1 MW - PPA	ITC	$277,000	-	271
		2 MW - Metropolitan-owned	-	$654,000	14	375
		2 MW - PPA	ITC	$523,000	-	375
	BESS paired with new solar generation system	1 MW solar 1 MW/2 MWh BESS	SGIP Step 3 RA Capacity Credit	$1,600,000	10	256
		2 MW solar 1 MW/2 MWh BESS	SGIP Step 3 RA Capacity Credit	$1,993,000	12	427
	Stand-alone BESS charged from grid (TOU arbitrage)	1 MW/2 MWh	SGIP Step 3 RA Capacity Credit	$396,000	5	10
Mills WTP	New solar generation system	500 kW - Metropolitan-owned	-	$140,000	14	145
		500 kW - PPA	ITC	$566,000	-	145
	BESS paired with new solar generation system	500 kW solar 300 kW/900 kWh BESS	SGIP Step 3 RA Capacity Credit	$356,000	14	131
	Stand-alone BESS charged from grid (TOU arbitrage)	1 MW/2 MWh	SGIP Step 3 RA Capacity Credit	$102,000	7	10
Jensen	Stand-alone BESS charged from existing solar generation facility	1 MW/2 MWh	SGIP Step 3 RA Capacity Credit	$275,000	5	10
OC-88	Stand-alone BESS charged from grid (TOU arbitrage)	1 MW/2 MWh	SGIP Step 3 RA Capacity Credit	$308,000	5	10
Diemer WTP	Yorba Linda connected behind SCE meter	-	-	$5,000,000 - $14,000,000	2-4	1,061
Distribution system	Small-scale hydroelectric facilities	Varies, see Table 4-2	-	Varies, see Table 4-2		-
	In-line hydroelectric facilities	Varies, see Table 4-3	-	Varies, see Table 4-3		-
	Diamond Valley Lake pumped storage	Project not feasible				
CRA	Copper Basin Reservoir pumped storage	Varies, see Table 5-1	-	Varies, see Table 5-1	>50	-
	Third-party developer pumped storage	To be determined based on discussion with potential developers				
	Large-scale wind	Levelized-cost based assessment.	-	-	>asset lifespan	-
	Large-scale solar		ITC	-		
	BESS (stand-alone)		RA Capacity Credit	$17,800,000 - $77,100,000	10-15	-
	Operational flexibility	Include option of additional operational flexibility at Gene and Intake Pumping Plants in the preliminary investigation of the CRA's pumps				

** Stand-alone BESS projects are required to reduce GHG emissions by a minimum 5 metric tonne CO_2/MWh/year to receive SGIP benefits.*

8.2 FINAL RECOMMENDATIONS

Based on the above analyses, it is recommended that Metropolitan:

- **Routine rate review** - Engage consistently with the different electric utility account (SCE, LADWP, and RPU) representatives to anticipate any potential change in rate structure or release of favorable electric utility programs. Any variation of these rates in the future may impact the outcomes of the evaluations conducted in this study.
- **SGIP applications** - Begin the SGIP Application process for retail BESS projects to reserve funding. Funds are allocated on a first-come first served basis and the availability of SGIP incentives in the highest step (Step 3 which includes the largest incentive rate of $0.35/Wh) is declining.
- **Solar with BESS at Skinner** – Pursue implementing additional solar with BESS at Skinner WTP including siting the new solar facility and reserving SGIP funds for the BESS.
- **Monitor wholesale energy market** - Continue to track wholesale market trends and forecasts due to their direct impact on CRA energy costs. These trends will also affect the feasibility of utility-scale projects and will have an indirect impact on retail rates and time-of-use schedules.
- **Third-party developer discussions** - Engage in conversations with third-party developers regarding renewable energy and energy storage project opportunities along the CRA. The feasibility of these types of projects is dependent on contract terms surrounding how and when energy would be available for Metropolitan's use, and at prices lower than or equal to the price of energy the spot wholesale market.
- **PPA review** - Pursue PPA agreements from a third-party developer to install and operate a third-party owned solar generation facility on Metropolitan's land near a Metropolitan-owned load for a competitive energy price that is lower than the retail energy purchase price at that location.
- **Yorba Linda hydropower** - Pursue moving Yorba Linda hydropower generation behind Diemer's SCE meter to meet the entire plant's energy demand when Yorba Linda is in operation.
- **Pump modifications assessment** - Include an additional assessment of pump modifications at Intake and Gene Pumping Plants for the addition of VFDs on a subset of pumps and motors to accommodate effective load shedding requests as well as improve synchronization between Intake and Gene pumps.
- **CRA power sources** - Continue efforts to optimize the use of the CRA's three power sources (hydropower, out of state imports, and CAISO) to minimize the cost to serve the CRA pumping plants.

- **Pumped storage** - Re-evaluate pumped-storage options based on energy price outlook changes, legislative drivers, new incentive programs, and/or VFD implementation at Intake and Gene Pumping Plants
- **Energy management practices** - Review existing energy management practices and identify other recommended initiatives around data collection, analysis and visualization for implementation in accordance with Metropolitan's Energy Management Policies.

8.3 NEXT STEPS

The results from this TM will be used in the final ESP to evaluate not only the economic feasibility of each selected project, but also additional benefits such as operational flexibility, reduced exposure to price volatility, increased revenue potential, etc. A multi-criteria analysis will be applied to each project with individual weightings to rank projects based on the additional benefits they provide Metropolitan. In parallel with the multi-criteria decision analysis will be a scenario-based assessment of performance for each project which will identify future conditions to determine vulnerabilities of each project under these various futures. This next phase will provide a strategy for Metropolitan to implement the selected projects, including triggers and optimal timing for implementation.

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APPENDIX A

Energy Rate Structures

Appendix A ENERGY RATE STRUCTURES

The following tables present updated rate structures for SCE, LADWP and RPU used in the financial models of this analysis.

A.1 SCE (TOU-B-D-CPP)

Charge Type	Units	Rate	Notes
Customer Charge	$/meter/month	1,572.7	Monthly fee
Power Factor Adjustment	$/kVar/month	0.6	Monthly fee, depends on facility – assumed 816 kVar
State Tax	$/kWh	$0.00029	
Demand			
Facilities Related Demand Charge	$/kW	17.03	Based on max demand per month
Winter			
Mid Peak	$/kW	0.00	Based on max demand in kW over 15min increments for the month
Off peak	$/kW	0.00	Based on max demand in kW over 15min increments for the month
Super-Off-Peak	$/kW	0.00	Based on max demand in kW over 15min increments for the month
Summer			
On Peak	$/kW	16.56	Based on max demand in kW over 15min increments for the month
Mid Peak	$/kW	5.17	Based on max demand in kW over 15min increments for the month
Off peak	$/kW	0.00	Based on max demand in kW over 15min increments for the month
Energy			
Winter			
Mid Peak – Delivery Charge	$/kWh	0.01429	Consumption based, pay per kWh used
Mid Peak – Generation Charge	$/kWh	0.07128	Consumption based, pay per kWh used
Off Peak – Delivery Charge	$/kWh	0.01429	Consumption based, pay per kWh used
Off Peak – Generation Charge	$/kWh	0.04291	Consumption based, pay per kWh used
Summer			
On Peak – Delivery Charge	$/kWh	0.01429	Consumption based, pay per kWh used
On Peak – Generation Charge	$/kWh	0.05492	Consumption based, pay per kWh used
Mid Peak – Delivery Charge	$/kWh	0.01429	Consumption based, pay per kWh used
Mid Peak – Generation Charge	$/kWh	0.05093	Consumption based, pay per kWh used
Off Peak – Delivery Charge	$/kWh	0.01429	Consumption based, pay per kWh used
Off Peak – Generation Charge	$/kWh	0.04943	Consumption based, pay per kWh used

A.2 SCE (TOU-8-D-CPP)

Charge Type	Units	Rate	Notes
Customer Charge	$/meter/month	1,473.9	Monthly fee
Power Factor Adjustment	$/kVar/month	0.54	Monthly fee, depends on facility – assumed 816 kVar
State Tax	$/kWh	$0.00029	
Demand			
Facilities Related Demand Charge	$/kW	5.92	Based on max demand per month
Winter			
Mid Peak	$/kW	5.87	Based on max demand in kW over 15min increments for the month
Off peak	$/kW	0.00	Based on max demand in kW over 15min increments for the month
Super-Off-Peak	$/kW	0.00	Based on max demand in kW over 15min increments for the month
Summer			
On Peak	$/kW	25.64	Based on max demand in kW over 15min increments for the month
Mid Peak	$/kW	0.00	Based on max demand in kW over 15min increments for the month
Off peak	$/kW	0.00	Based on max demand in kW over 15min increments for the month
Energy			
Winter			
Mid Peak – Delivery Charge	$/kWh	0.01658	Consumption based, pay per kWh used
Mid Peak – Generation Charge	$/kWh	0.05594	Consumption based, pay per kWh used
Off Peak – Delivery Charge	$/kWh	0.01658	Consumption based, pay per kWh used
Off Peak – Generation Charge	$/kWh	0.04715	Consumption based, pay per kWh used
Super Off Peak – Delivery Charge	$/kWh	0.01658	Consumption based, pay per kWh used
Super Off Peak – Generation Charge	$/kWh	0.03018	Consumption based, pay per kWh used
Summer			
On Peak – Delivery Charge	$/kWh	0.01658	Consumption based, pay per kWh used
On Peak – Generation Charge	$/kWh	0.07176	Consumption based, pay per kWh used
Mid Peak – Delivery Charge	$/kWh	0.01658	Consumption based, pay per kWh used
Mid Peak – Generation Charge	$/kWh	0.06465	Consumption based, pay per kWh used
Off Peak – Delivery Charge	$/kWh	0.01658	Consumption based, pay per kWh used
Off Peak – Generation Charge	$/kWh	0.04255	Consumption based, pay per kWh used

A.3 SCE (TOU-8-STANDBY OPTION A)

Charge Type	Units	Rate	Notes
Customer Charge	$/meter/month	1572.69	Monthly fee
Power Factor Adjustment	$/kVar/month	0.54	kVar depends on facility – assumed 1,037 kVar
State Tax	$/kWh	0.00029	
Demand			
Capacity reservation demand charge	$/kW	0.82	Assume 2MW is the established Standby demand value at Weymouth
Facilities Related Demand Charge	$/kW	5.05	Max demand excess of 2MW will be charge per KW at the rate
TRD Back Up (Summer Only)			
Mid Peak	$/kW	0.00	Max recorded demand, excluding weekends, category identified by SCE
Off peak	$/kW	0.00	Max recorded demand, excluding weekends, category identified by SCE
TRD Supplemental (Summer Only)			
On Peak	$/kW	6.97	Max recorded demand, excluding weekends, category identified by SCE
Mid Peak	$/kW	0.00	Max recorded demand, excluding weekends, category identified by SCE
Energy			
Winter			
Mid Peak – Delivery Charge	$/kWh	0.01537	Consumption based, pay per kWh used
Mid Peak – Generation Charge	$/kWh	0.07220	Consumption based, pay per kWh used
Off Peak – Delivery Charge	$/kWh	0.01240	Consumption based, pay per kWh used
Off Peak – Generation Charge	$/kWh	0.04164	Consumption based, pay per kWh used
Summer			
On Peak – Delivery Charge	$/kWh	0.04254	Consumption based, pay per kWh used
On Peak – Generation Charge	$/kWh	0.21303	Consumption based, pay per kWh used
Mid Peak – Delivery Charge	$/kWh	0.02128	Consumption based, pay per kWh used
Mid Peak – Generation Charge	$/kWh	0.08324	Consumption based, pay per kWh used
Off Peak – Delivery Charge	$/kWh	0.01380	Consumption based, pay per kWh used
Off Peak – Generation Charge	$/kWh	0.04695	Consumption based, pay per kWh used

A.4 SCE (TOU-8-STANDBY OPTION LG)

Charge Type	Units	Rate	Notes
Customer Charge	$/meter/month	1473.87	Monthly fee
Power Factor Adjustment	$/kVar/month	0.54	kVar depends on facility – assumed 1,037 kVar
State Tax	$/kWh	0.00029	
Demand			
Capacity reservation demand charge	$/kW	0.69	Assume 2MW is the established Standby demand value at Weymouth
Facilities Related Demand Charge	$/kW	5.05	Max demand excess of 2MW will be charge per KW at the rate
TRD Back Up			
On Peak, summer	$/kW	6.95	Max recorded demand, excluding weekends, category identified by SCE
Mid peak, winter	$/kW	1.35	Max recorded demand, excluding weekends, category identified by SCE
TRD Supplemental			
On Peak, summer	$/kW	6.97	Max recorded demand, excluding weekends, category identified by SCE
Mid Peak, winter	$/kW	0.00	Max recorded demand, excluding weekends, category identified by SCE
Energy			
Winter			
Mid Peak – Delivery Charge	$/kWh	0.03158	Consumption based, pay per kWh used
Mid Peak – Generation Charge	$/kWh	0.10016	Consumption based, pay per kWh used
Off Peak – Delivery Charge	$/kWh	0.01888	Consumption based, pay per kWh used
Off Peak – Generation Charge	$/kWh	0.04722	Consumption based, pay per kWh used
Super Off Peak – Delivery Charge	$/kWh	0.01732	Consumption based, pay per kWh used
Super Off Peak – Generation Charge	$/kWh	0.03025	Consumption based, pay per kWh used
Summer			
On Peak – Delivery Charge	$/kWh	0.03158	Consumption based, pay per kWh used
On Peak – Generation Charge	$/kWh	0.33013	Consumption based, pay per kWh used
Mid Peak – Delivery Charge	$/kWh	0.03158	Consumption based, pay per kWh used
Mid Peak – Generation Charge	$/kWh	0.08486	Consumption based, pay per kWh used
Off Peak – Delivery Charge	$/kWh	0.01888	Consumption based, pay per kWh used
Off Peak – Generation Charge	$/kWh	0.04776	Consumption based, pay per kWh used

A.5 LADWP

Charge Type	Units	Rate	Notes
State Surcharge	$/kWh	0.000300	Total kWh per service period
Energy Charge			
Low Season/Winter			
Energy Charge, high-peak	$/kWh	0.054640	
Energy Charge, low-peak	$/kWh	0.054640	
Energy Charge, base	$/kWh	0.037980	
High Season/Summer			
Energy Charge	$/kWh	0.059910	
Energy Charge	$/kWh	0.053560	
Energy Charge	$/kWh	0.033560	
Demand			
Facility Charge, Capped	$/mo	75.00000	
Facility Charge, Incremental	$/kW	4.560000	Based on max. demand from the last 12 months
Low Season/Winter			
Demand Charge, high-peak	$/kW	4.30000	Based on max. demand from the billing period
Demand Charge, low-peak	$/kW	0.00	
Demand Charge, base	$/kW	0.00	
High Season/Summer			
Demand Charge, high-peak	$/kW	9.70000	Based on max. demand from the billing period
Demand Charge, low-peak	$/kW	3.30000	
Demand Charge, base	$/kW	0.00	

Charge Type	Units	Rate		
Reactive Energy		High-peak	Low-peak	Base
Low Season/Winter				
PF 0.995-1000	$/kvarh	0.00	0.00	0.00
PF 0.950-0.994	$/kvarh	0.000840	0.000840	0.000500
PF 0.900-0.949	$/kvarh	0.001610	0.001610	0.000810
PF 0.800-0.899	$/kvarh	0.004890	0.004890	0.002130
PF 0.700-0.799	$/kvarh	0.008190	0.008189	0.003550
PF 0.600-0.677	$/kvarh	0.011380	0.011380	0.004890
PF 0.000-0.599	$/kvarh	0.012410	0.012410	0.005350
High Season/Summer				
PF 0.995-1000	$/kvarh	0.00	0.00	0.00
PF 0.950-0.994	$/kvarh	0.000960	0.000660	0.000400
PF 0.900-0.949	$/kvarh	0.001820	0.001260	0.000660
PF 0.800-0.899	$/kvarh	0.005560	0.003760	0.001700
PF 0.700-0.799	$/kvarh	0.009310	0.006330	0.002830
PF 0.600-0.677	$/kvarh	0.012940	0.008720	0.003910
PF 0.000-0.599	$/kvarh	0.014110	0.009520	0.004270

Billing Adjustment Factors	Unit	Jan - Mar (Winter)	Apr - May (Winter)	June (Summer)	Jul - Sept (Summer)	Oct - Dec (Winter)
Energy Cost Adjustment (ECA)	$/kWh	0.056900	0.056900	0.056900	0.056900	0.056900
Variable Energy Adjustment (VEA)	$/kWh	0.000180	0.001540	0.001540	0.001560	(0.001550)
Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA)	$/kWh	0.005350	0.005390	0.005390	0.005900	0.005150
Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA)	$/kWh	0.018130	0.020850	0.020850	0.020300	0.017430
Incremental Reliability Cost Adjustment (IRCA)	$/kWh	0.002580	0.002580	0.002580	0.002800	0.002580
Energy Subsidy Adjustment (ESA)	$/kW	0.460000	0.460000	0.460000	0.460000	0.460000
Reliability Cost Adjusted (RCA)	$/kW	0.960000	0.960000	0.960000	0.960000	0.960000
Incremental Reliability Cost Adjustment (IRCA)	$/kW	1.560000	1.560000	1.560000	2.020000	1.560000

A.6 RPU

Charge Type	Units	Rate	Notes
Customer Charge	$/meter/month	691.87	
Reliability Charge			Based on max demand per month
>250-500 kW	$/kW/month	1,100.00	
>500-750 kW	$/kW/month	1,287.50	
>750 kW	$/kW/month	1,487.50	
Electric Public Benefits Charge	--	2.85%	Calculated from total electric charge
State Energy Charge	$/kWh	0.0003	
Demand			Based on max demand per month
On Peak	$/kW	6.97	
Mid Peak	$/kW	2.93	
Off Peak	$/kW	1.42	
Energy			
On Peak	$/kWh	0.105	
Mid Peak	$/kWh	0.085	
Off Peak	$/kWh	0.073	
*All rates are effective for 2019			

APPENDIX B

Evaluation of Pumped Storage Potential Using Copper Basin Reservoir

FINAL
REPORT

EVALUATION OF PUMPED STORAGE POTENTIAL USING COPPER BASIN RESERVOIR

The Metropolitan Water District of Southern California

700 N. Alameda Street, Los Angeles, California 90012

June 2020

Executive Summary

This memorandum provides a brief overview of the feasibility of using Copper Basin Reservoir for a pumped-storage system. Three (3) different pumped-storage alternatives, each using Copper Basin Reservoir as the pump-back reservoir (**Figure 1**), were evaluated. Each alternative included the addition of variable frequency drives (VFDs) at Intake and Gene Pumping Plants to be able to more flexibly manage the pumped-storage operation as well as to ensure continuous aqueduct flow deliveries to the remaining downstream pumping plants. The first pumped-storage alternative evaluated a pumped-storage project using a new conveyance tunnel between Copper Basin Reservoir and Lake Moovalya located on the Colorado River between Parker Dam and Headgate Rock Dam. The second alternative evaluated a pumped-storage project using existing Colorado River Aqueduct (CRA) conveyance conduits between Copper Basin Reservoir and Lake Havasu on the Colorado River, and the third pumped-storage alternative utilized the same two terminating reservoirs as the second alternative, however, via a new conveyance tunnel and conduits. For each of the three (3) pumped-storage alternatives considered, a sub-alternative that assumes an increase in the Copper Basin Reservoir storage capacity resulting from raising its dam by ten (10) feet was also evaluated.

For each alternative, an order of magnitude capital cost estimate was prepared and an estimate of the potential energy costs savings over a fifty-year period was evaluated. The economic feasibility of each alternative is summarized in **Table 1**. For each alternative, the payback is estimated to be greater than 50 years, and each alternative is not economically feasible.

Additional Assessments

Additional assessments and approval will be required if any of the above project alternatives are deemed feasible for more in-depth analysis. Highlighted below are the areas of most interest:

1) Detailed assessment of the impact of the pumped-storage project on daily, monthly and annual operation of the CRA. The chosen CRA flow delivery scheme used in the analyses favors power generation, however, if CRA flow delivery is of priority, then power generation may be significantly lower.
2) Evaluation of increased O&M costs due to greater complexity in managing CRA deliveries and in addition, managing power generation.
3) Acquisition of Federal Energy Regulatory Commission (FERC) license.
4) California Division of Safety of Dams (DSOD) review and approval regarding usage of Copper Basin Reservoir for a pumped-storage project and in approving raising the dam by ten (10) feet.
5) Approval from United States Bureau of Reclamation (USBR) and coordination with agencies holding water rights along Colorado River downstream of the intake/release structure.
6) Environmental assessment regarding raising of Copper Basin Reservoir dam and construction of tunnel, penstock and powerhouse structure.
7) Tunnel alignment and powerhouse citing study.
8) Determine infrastructure and costs related to power grid connection and transmission lines.

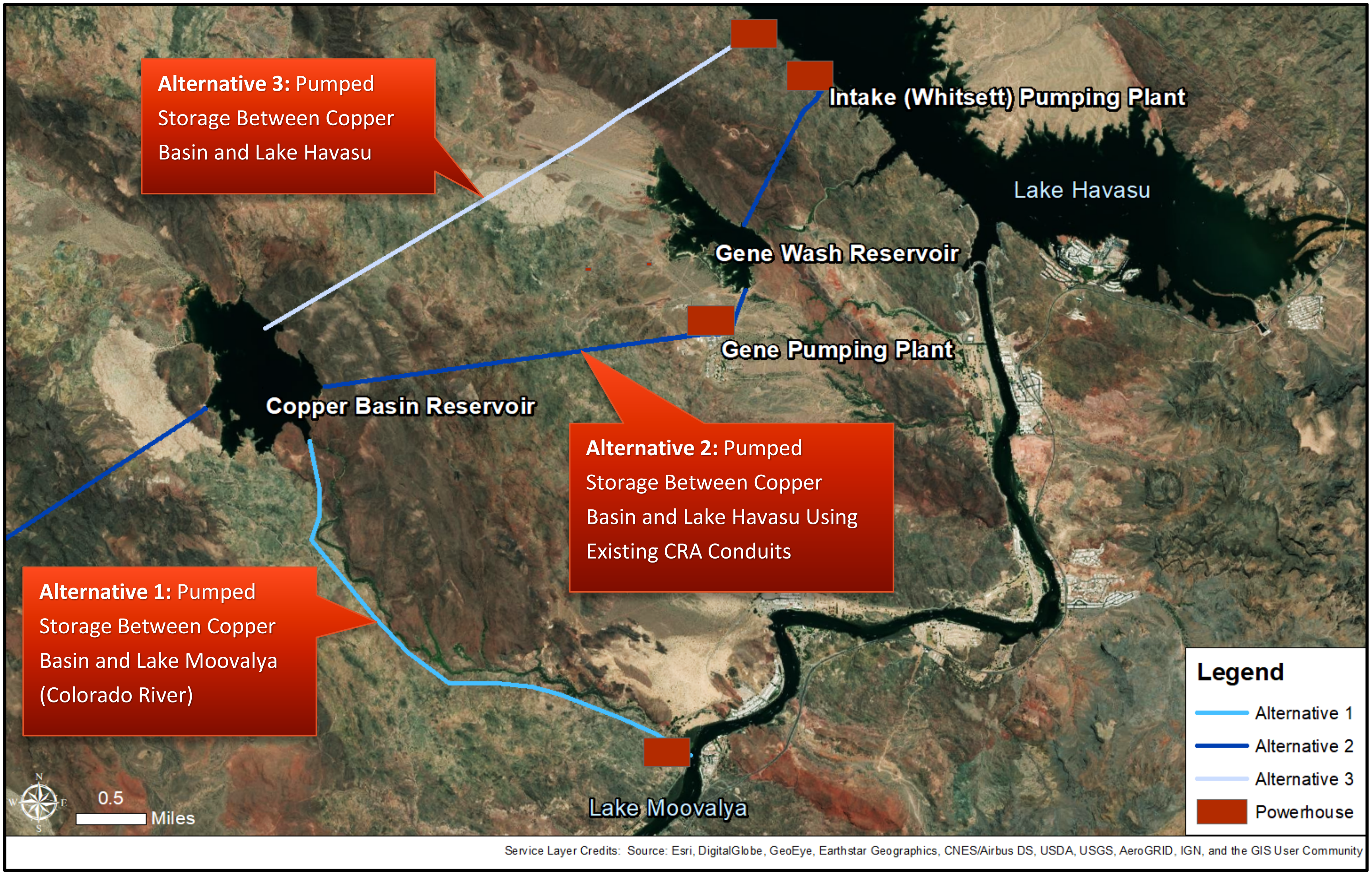


Figure 1: CRA Pumped-Storage Alternatives

Alternative	Generation Capacity (MW)	Total Project Cost[1]	Payback	Notes
1	360	$1.47 billion	>50 years	Based on 550,000 ac-ft annual CRA deliveries. Minimum allocation chosen to increase flexibility and revenue for a pumped-storage project with 6-hours of generation and 10-hours of pumping daily.
1A	740	$2.70 billion	>50 years	
2	26	$577 million	>50 years	
2A	60	$710 million	>50 years	
3	310	$1.75 billion	>50 years	
3A	620	$2.82 billion	>50 years	

[1] ASCE Level 5 Cost estimate includes contingency. engineering, and construction management costs

Table 1: Summary of Alternatives

Background

The Colorado River Aqueduct (CRA) begins at Lake Havasu on the Colorado River and consists of five (5) pumping plants, 450 miles of high voltage power lines, four (4) regulating reservoirs, and 242 miles of aqueducts, siphons, canals, conduits and pipelines. The aqueducts terminal reservoir is Lake Mathews located in Riverside, California. The first roughly 6 miles of the CRA contains the Whitsett Intake Pumping Plant, the 6,300 ac-ft capacity Gene Wash Reservoir, Gene Pumping Plant, and the 22,000 ac-ft capacity Copper Basin Reservoir (**Figure 1**). The two reservoirs have the potential to provide flexible storage capacity favorable to the implementation of VFDs and a pumped-storage project. Changes in California's energy market over the past two decades, including: the deregulation of California's energy market; the introduction of locational marginal pricing (LMP); and the rapid adoption of solar generation have resulted in an energy dynamic in which prices in the California Independent System Operator (CAISO) change significantly throughout the day. Increasing solar generation, particularly in the desert Southwest, has resulted in what CAISO refers to as the "duck curve", in which solar generation eclipses gas-fired generation during the daytime hours (**Figure 2**).

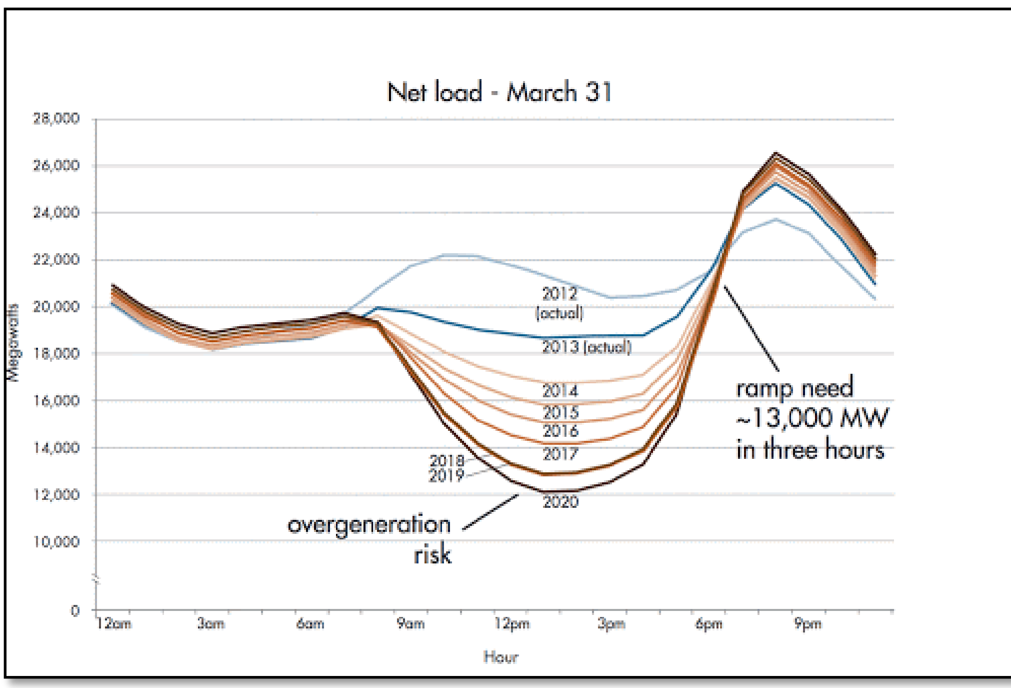


Figure 2: CAISO Duck Curve, Gas-Fired Generation by Hour

Large desert solar farms and transmission congestion often produce negative prices in southeastern California in the vicinity of the CRA. This presents an opportunity for Metropolitan to use pumped storage to shift low priced midday solar energy to high priced evening hours and capture the associated arbitrage revenues. This technical memorandum evaluates the economic feasibility of six potential pumped-storage project alternatives utilizing Copper Basin reservoir based on current and forecasted wholesale electricity market dynamics.

Baseline Operations

For this evaluation, annual deliveries from the CRA were assumed to be 550,000 ac-ft for each pumped storage option in order to maximize the available excess capacity in Copper Basin Reservoir and operational flexibility for a pumped-storage system. This is therefore, considered a highly optimistic scenario for the purpose of defining the maximum value for the pumped storage alternatives. For comparison, CRA flow in 2019 was the lowest in last 65 years at 538,000 ac-ft. Actual annual CRA deliveries vary widely, and during years in which the CRA is operated at maximum capacity, operation of a pumped storage system would be limited.

Figure 3 shows the breakdown in monthly CRA deliveries assumed for this analysis. In general, the highest prices in the CAISO market occur during the summer months. Low flow in the CRA during the summer months would provide maximum flexibility for a pumped-storage operation in this model scenario. Routine maintenance of the CRA is typically performed during the month of February; therefore, zero flow was assumed for the month of February.

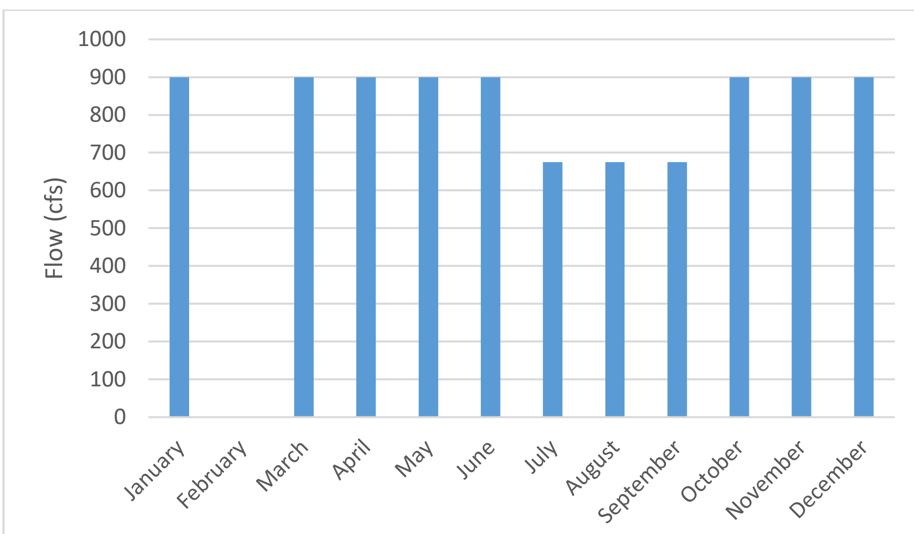


Figure 3: CRA Deliveries by Month (550,00 ac-ft/yr.)

The S&P Global Platts hourly forecast for CAISO's SP15 Hub for the years 2025 and 2030 (**Figure 4**), was used to determine the pumping expenses associated with Intake and Gene Pumping Plants, assuming an annual 2% inflation rate. CAISO pricing contains seasonality as depicted in the quarterly charts in **Figure 4**. Spring (Q2) contains the most pronounced differences in supply and demand, with abundant sunshine for solar production, but low demand throughout Southern

California for heating and air conditioning. In summer (Q3), energy demands for air conditioning raise midday CAISO prices into positive territory and cause energy prices to soar in the evening, as solar production decreases to zero while high energy demands from customers continue past sunset. (**Figure 3**).

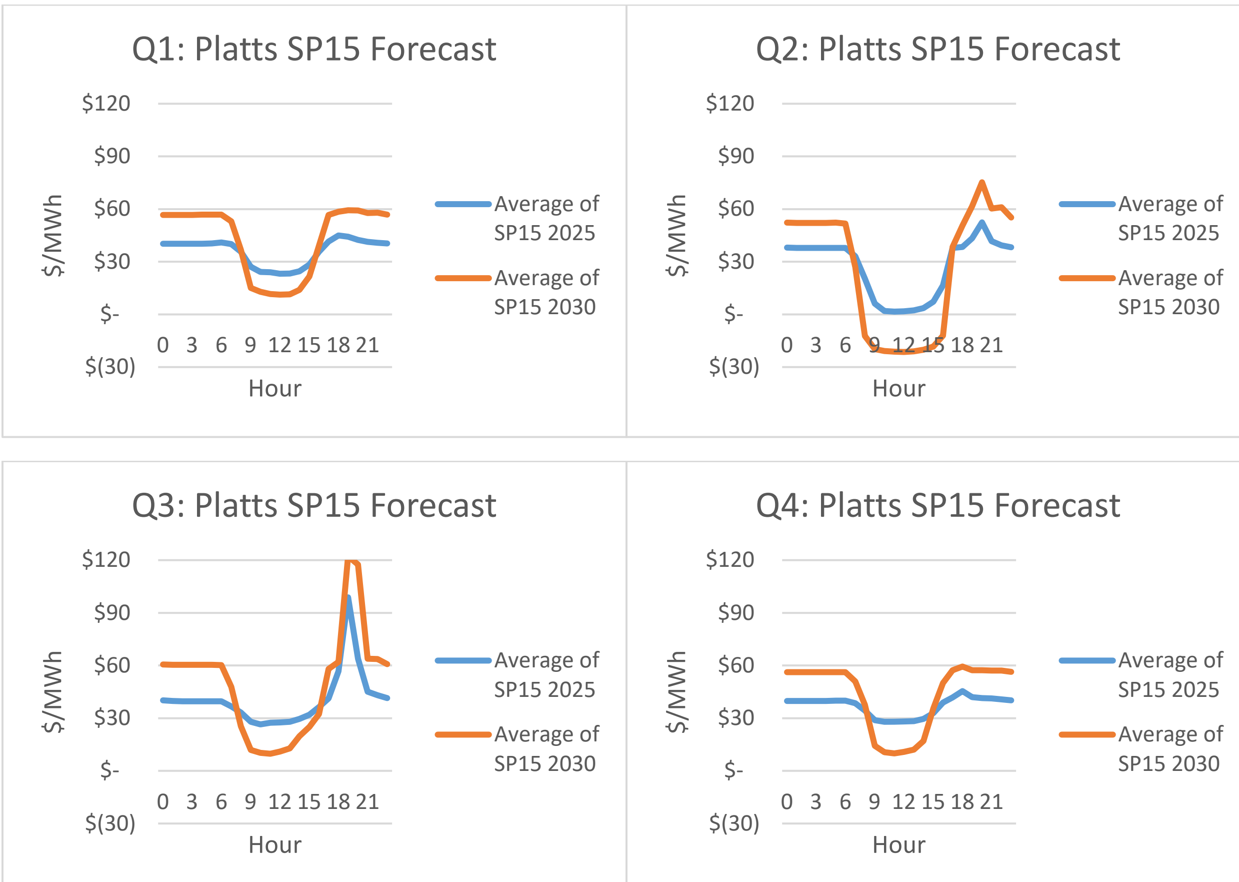


Figure 4: S&P Global Platts Quarterly Forecast for CAISO's SP15

Pumped-Storage

This section presents a high-level review of the infrastructure required to use Copper Basin Reservoir for the three pumped storage alternatives identified in Figure 1. In addition, it also evaluates the benefits, if any, in increasing the cost-effectiveness of the pumped-storage projects by raising Copper Basin Reservoir.

For each alternative, a financial analysis was conducted to identify the revenue and payback period of such projects.

An initial study was done in 1983 that primarily looked at the feasibility and payback of a pumped-storage project between Copper Basin and Lake Moovalya, located on the Colorado River between Lake Havasu and Headgate Rock Dam. A follow-up evaluation was done in 2002 based on an update in assumed CRA delivery requirements and forecasted energy rates. The 2002 study concluded the proposed pumped-storage project was not economical. **Table 2** lists the basic assumptions and the financial findings of the two studies.

Assumption	1983 Study	2002 Study
CRA Annual Delivery	550,000 AF	900,000 TO 1,000,000 AF
Excess Storage Volume in Copper Basin	2,930 AF	1,930 AF
Generation Capacity	260 MW	170 MW
Project Cost[1]	$153 million (1983 dollars)	$215 million (2002 dollars)
On-peak value of Energy	$165.60/MWh	$46-$65/MWh
Off-peak value of Energy	$44.40/MWh	$35-$39/MWh
On-peak/Off-peak Ratio	3.75	1.31 to 1.67
Net Annual Revenue	$10 million	-$19.2 to -$20.9 million

[1]Order of magnitude cost estimate includes engineering and construction management costs

Table 2: Assumptions for Previous Pumped-Storage Evaluations

The 2002 report also performed a cursory evaluation of the pumped-storage project between Copper Basin and Lake Havasu. Its findings were that the capital cost would be higher, and the generation capacity will be approximately 13 percent less than a pumped storage project between Copper Basin and Lake Moovalya. As a result, it did not recommend this alternative.

The 1983 study also investigated two smaller scale pumped-storage alternatives. The first considered using the existing pumping capacity at Intake and Gene pumping plants for replenishing storage in Copper Basin, with releases from Copper Basin through a new tunnel, penstock, and powerhouse with turbine generators. The study did not find this alternative to be cost effective.

The second alternative in the 1983 study considered converting several of the existing pumps at Intake and Gene to also function as turbine generators for reverse flow power generation. It concluded this alternative was cost effective; however, the generation potential would be considerably less since only two units at each plant could be operated due to a conveyance limitation associated with a high point in the Copper Basin Tunnel. The follow-up evaluation in 2002 refined the financial analysis based on updated forecasted energy prices and found this alternative to be no longer financially viable.

This 2020 study re-evaluates the previous alternatives considering the latest information on forecasted energy prices. For each alterative, a sub-evaluation was conducted with an increase in Copper Basin Reservoir storage capacity when the dam is raised by ten (10) feet, which will nearly double the storage capacity of Copper Basin Reservoir. Ten (10) feet was deemed by Metropolitan's Safety of Dams Team as the maximum height increase structurally feasible to the existing dam. Furthermore, greater than 10-ft increase in storage capacity will require construction of a separate dam at another location within Copper Basin Reservoir. Listed below and shown on **Figure 1** are the pumped-storage alternatives evaluated in this study:

1. Alternative 1 – Pumped-storage between Copper Basin and Lake Moovalya using new tunnels, penstocks and pump-turbine powerhouse units.
2. Alternative 1A – Same as Alternative 1 but increase in Copper Basin storage capacity by raising the dam by ten (10) feet.
3. Alternative 2 – Pumped-storage between Copper Basin and Lake Havasu utilizing existing CRA conveyance lines and replacing existing pumping units at Gene and Intake with pump-turbine units.
4. Alternative 2A – Same as Alternative 2 but increase in Copper Basin storage capacity by raising the dam by ten (10) feet.
5. Alternative 3 - Pumped-storage between Copper Basin and Lake Havasu using new tunnels, penstocks, and pump-turbine powerhouse units.
6. Alternative 3A – Same as Alternative 3 but increase in Copper Basin storage capacity by raising the dam by ten (10) feet.

<u>Assumption on CRA Deliveries</u>

For this analysis, based on the recommendation of Metropolitan's Water Operations and Planning Section, the minimum base allotment of 550,000 ac-ft of annual CRA delivery was assumed since low CRA delivery allows more available capacity in Copper Basin Reservoir for pumped-storage. This annual delivery was broken down further on a monthly basis. A monthly distribution was assumed with low CRA delivery during summer months and higher delivery during winter months. This delivery scheme would increase revenue potential from pumped-storage since on-peak prices are significantly higher during summer months and lower during winter months. Note that this selected delivery scheme may not be ideal for meeting demands and/or storing water, and actual CRA deliveries vary greatly each year. Also, the pumped-storage operation will be limited or infeasible during years of high deliveries from the CRA (e.g., 7-8 pump flow years). A limitation on the size of the pumped-storage facility also played a factor in determining the monthly distribution of CRA flow. It was assumed that roughly 8,000 cfs is the maximum feasible discharge into Lake Havasu or Lake Moovalya or the alternatives where Copper Basin Reservoir is not raised (Alternatives 1 and 3). This equates to a storage capacity at Copper Basin Reservoir to accommodate a CRA delivery of 625 cfs. For the two alternatives where the Copper Basin Reservoir can be raised (Alternatives 1a and 3a), it was assumed the Copper Basin Reservoir is predominantly used for pumped-storage activity during the summer months with CRA delivery at its minimum of 225 cfs. This amounts to roughly 16,000 cfs discharged into Lake Havasu and Lake Moovalya during pumped-storage operation. Further assessment needs to be conducted to fully determine the impact of such high discharges to Lake Havasu and Lake Moovalya. As a comparison, the 1983 report had a peak discharge of 5,850 cfs into Colorado River.

Table 3 shows the breakdown in monthly CRA delivery assumed for the two alterative scenarios with and without raising of the Copper Basin Reservoir. Routine maintenance is performed typically during the month of February, therefore, no CRA delivery was assumed during February.

Month	Daily CRA Delivery: Existing Copper Basin (cfs)	Daily CRA Delivery: Raising of Copper Basin (cfs)
January	900	1125
February	0	0
March	900	900
April	900	900
May	900	900
June	900	900
July	675	225
August	675	225
September	675	225
October	900	1350
November	900	1350
December	900	1125

Table 3: Daily Flow Downstream to Iron, Eagle and Hinds by Month

As per the 1983 report, **Table 4** lists the available storage in Copper Basin currently. The last column shows the increase in storage volume after a 10-foot increase in the elevation of the dam.

Flow in Whipple Mt. Tunnel (cfs)	Minimum Required W.S. Elevation in Copper Basin Reservoir (NGVD 29)	Available Storage Space to El. 1028 (ac-ft)	Available Storage Space to El. 1038 (ac-ft)
440	1014.6	5,260	9,260
660	1016.9	4,410	8,410
880	1018.6	3,760	7,760
1100	1020.7	2,950	6,950
1320	1022.9	2,090	6,090
1540	1025.4	1,080	5,080
1760	1028.5	None	4,000

Table 4: Available Storage in Copper Basin

Alternative 1: Pumped-Storage Facility between Copper Basin Reservoir and Lake Moovalya

This alternative evaluates a pumped-storage facility between Copper Basin Reservoir and Lake Moovalya, on the Colorado River between Parker Dam and Headgate Rock Dam. New tunnel, siphons, penstocks, and powerhouse structure will be constructed to run the pumped-storage facility. The powerhouse structure would house the dual-use pump-turbine units which will function both as a pump and a turbine.

The pumped-storage facility was sized to utilize the maximum available volume available at Copper Basin when CRA is at 3-pump flow (675 cfs). This would provide the maximum power generation during summer months when on-peak energy prices are high. Based on the current forecast of the energy prices, the daily on-peak energy prices typically last for 6-hours from 5 pm to 11 pm and the off-peak prices last for 10-hours from 6 am to 4 pm. The 6-hours of generation and 10-hours of pumping are consistent with previous reports. Furthermore, no CRA pumping at Gene and Intake Pumping Plant is assumed during the 6-hour generation window in order to minimize pumping during on-peak energy times. Based on the above assumptions, the available storage at Copper Basin for pumped-storage operation is estimated to be 4,075 ac-ft. For the 6-hr generation period, the generation flow is computed to be 8,200 cfs and for the 10-hr pumping period, the flow is computed to be 4,900 cfs. The generation head and pumping head is assumed to be the same as reported in 1983 report. The average static head between Copper Basin and Lake Moovalya is around 660 feet. Taking into consideration pipe friction and other system losses, the available net generating head would be around 630 feet. Assuming an 85% efficiency in generation yields 360 MW of generation capacity. In the pumping mode, the total dynamic head is estimated to be 690 feet and assuming an 85% pumping efficiency equates to 330 MW in pumping energy required.

Major infrastructure requirements include a 10,900 linear feet of 27-ft diameter tunnel, two 8,000 linear feet of 19-ft diameter penstock and two 180 MW each pumped-turbine units. ASCE Level-5 construction cost estimate for this alternative is roughly $871 million. Incorporating 30% for design and construction management and 30% contingency yields a project cost of roughly $1.47 billion. A detail breakdown of the cost estimate is provided in Appendix A.

Table 5 shows power available for generation and power required for pumping based on the monthly variability in CRA deliveries.

Month	Daily CRA Delivery Flow (cfs)	Power Generated (MW)	Power used for Pumping (MW)
January	900	300	270
February	0	0	0
March	900	300	270
April	900	300	270
May	900	300	270
June	900	300	270
July	675	360	330
August	675	360	330
September	675	360	330
October	900	300	270
November	900	300	270
December	900	300	270

Table 5: Alternative 1 – CRA Flow, Pumped-Storage Generation and Pumping

Metropolitan utilized the S&P Global Platts forecast for years 2025 and 2030 for CAISO's SP15, and current hydropower rates, incorporating 2% inflation, to determine the hourly pumping revenues and expenditures associated with Alternative 1. Estimated pumping expenses for the pumped storage rated capacity are $9.6 million in 2030, escalating with inflation to $43.9 million in 2080. Estimated generation revenue for the pumped storage rated capacity are $42.3 million in 2030, escalating with inflation to $82.6 million in 2080. The project cost of $1.47 billion, associated debt, and O&M expenses result in a project NPV of -$568 million after 50 years, making the project economically not feasible.

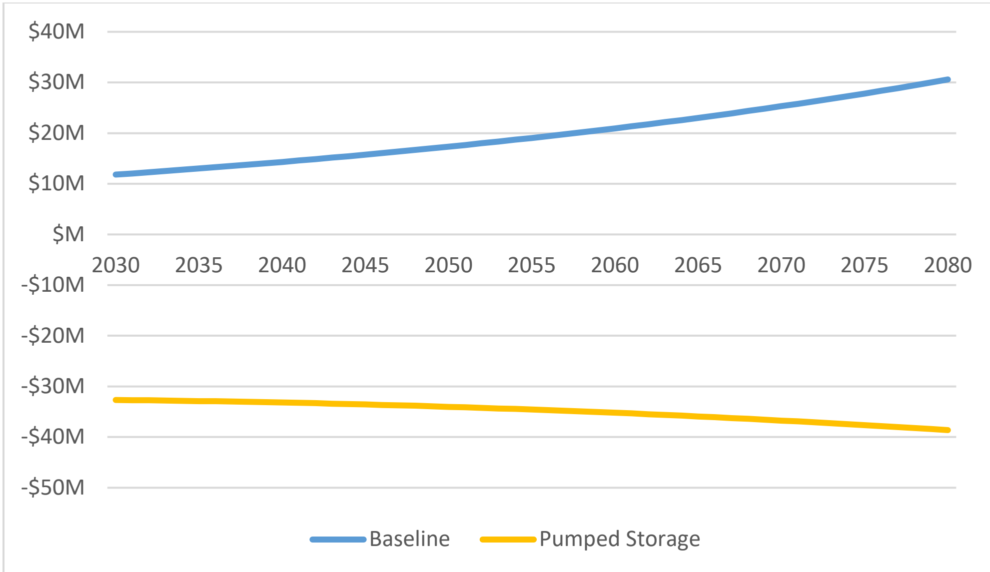


Figure 6: Comparison Between the Baseline Annual Power Expenditures at Intake and Gene for the Delivery of 550,000 Acre-Feet and the Net Annual Power Expenditures of Alternative 1

Alternative 1A: Pumped-Storage Facility between Copper Basin Reservoir and Lake Moovalya with a Ten (10) Foot Increase in Copper Basin Dam Elevation

This alternative is similar to Alternative 1, however, with an increase in storage capacity at Copper Basin from raising the dam elevation by ten (10) feet. The raising of the dam nearly doubles the available storage capacity for a pumped-storage facility from 4,075 ac-ft to 8,075 ac-ft. The computed generation flow is 16,300 cfs, assuming a 6-hr generation window. The computed pumped flow is 9,800 cfs assuming a 10-hr pumping duration. The available generation head is 640-feet and the pumping head requirement is 700-feet. Under these values, the power generated is 740 MW and the power required is 675 MW.

Major infrastructure requirements include two 10,900 linear feet of 27-ft diameter tunnel, four 8,000 linear feet of 19-ft diameter penstock, four 185 MW each pumped-turbine units, and raising of the existing dam and spillway at Copper Basin. The ASCE Level-5 construction cost estimate for this alternative is roughly $1.62 billion. Incorporating 30% for design and construction management and 30% contingency yields a project cost of roughly $2.73 billion. A detailed breakdown of the cost estimate is provided in Appendix A.

Table 6 shows power available for generation and power required for pumping based on the monthly variability in CRA deliveries.

Month	Daily CRA Delivery Flow (cfs)	Power Generated (MW)	Power used for Pumping (MW)
January	900	670	605
February	0	0	0
March	900	670	605
April	900	670	605
May	900	670	605
June	900	670	605
July	675	740	675
August	675	740	675
September	675	740	675
October	900	670	605
November	900	670	605
December	900	670	605

Table 6: Alternative 1A – CRA Flow, Pumped-Storage Generation and Pumping

Metropolitan utilized the S&P Global Platts forecast for years 2025 and 2030 for CAISO's SP15, and current hydropower rates, incorporating 2% inflation, to determine the hourly pumping revenues and expenditures associated with Alternative 1A. Estimated pumping expenses for the pumped storage rated capacity are $23.9 million in 2030, escalating with inflation to $103 million in 2080. Estimated generation revenue for the pumped storage rated capacity are $91.6 million in 2030, escalating with inflation to $179 million in 2080. The project cost of $2.73 billion, associated debt, and O&M expenses result in a project NPV of -$1.23 billion after 50 years, making the project economically not feasible.

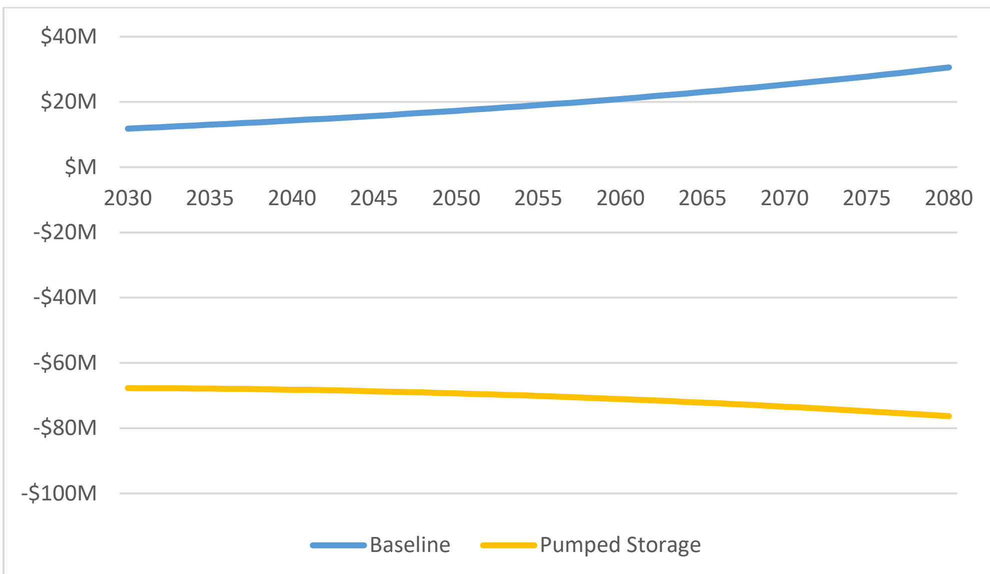


Figure 7: Comparison Between the Baseline Annual Power Expenditures at Intake and Gene for the Delivery of 550,000 Acre-Feet and the Net Annual Power Expenditures of Alternative 1A

Alternative 2: Pumped-Storage Facility between Copper Basin Reservoir and Lake Havasu Using Existing CRA Conduits

This alternative examines conversion of existing pumps at Gene and Intake Pumping Plants to pump-turbine units. Due to a tunnel high point between Gene Pumping Plant and Copper Basin, the maximum reverse flow from Copper Basin to Gene Pumping Plant is a 3-pump flow or 675 cfs. The minimum water surface elevation required is 1025-feet.

The size of new pump-turbine units at Gene Pumping Plant is based on the generated flow of 675 cfs at 275 feet. The generated head is the difference between the static water surface elevation at Copper Basin (wsel. 1025-feet) and Gene Wash (wsel. 736-feet) plus approximately 5% in friction and minor losses. Assuming 85% generation efficiency, the power generated is 13 MW. Similarly, the pump-turbine units at Intake Pumping Plant will generate around 13 MW total since the flow and the available head is the same. The static head at Lake Havasu is assumed to be around 450-feet.

Approximately 335 ac-ft of volume is required for pumped-storage activity and therefore, 225 cfs needs to be pumped for 10-hours to store this amount of volume in Copper Basin prior to generation. Approximate pumped power is 7 MW at both Intake (225 cfs @ 305-feet TDH) and Gene (225 cfs @ 320-feet TDH) Pumping Plants.

Major infrastructure requirements include upgrade of four pumps to pump-turbine units, 3 units and 1 spare, at Gene and Intake Pumping Plants, and structural enhancement of the existing 16-ft horseshoe tunnels between Intake and Copper Basin. ASCE Level-5 construction cost estimate for this alternative is roughly $378 million. Incorporating 30% for design and construction management and 30% contingency yields a project cost of roughly $640 million. A detail breakdown of the cost estimate is provided in Appendix A.

Table 7 shows power available for generation and power required for pumping based on the monthly variability in CRA deliveries.

Month	Daily CRA Delivery Flow (cfs)	Power Generated (MW)	Power used for Pumping (MW)
January	900	26	14
February	0	0	0
March	900	26	14
April	900	26	14
May	900	26	14
June	900	26	14
July	675	26	14
August	675	26	14
September	675	26	14
October	900	26	14
November	900	26	14
December	900	26	14

Table 7: Alternative 2 – CRA Flow, Pumped-Storage Generation and Pumping

Metropolitan utilized the S&P Global Platts forecast for years 2025 and 2030 for CAISO's SP15, and current hydropower rates, incorporating 2% inflation, to determine the hourly pumping revenues and expenditures associated with Alternative 2. Estimated pumping expenses for the pumped storage rated capacity are $0.3 million in 2030, escalating with inflation to $2.5 million in 2080. Estimated generation revenue for the pumped storage rated capacity are $3.4 million in 2030, escalating with inflation to $6.7 million in 2080. The project cost of $577 million, associated debt, and O&M expenses result in a project NPV of -$284 million after 50 years, making the project economically not feasible.

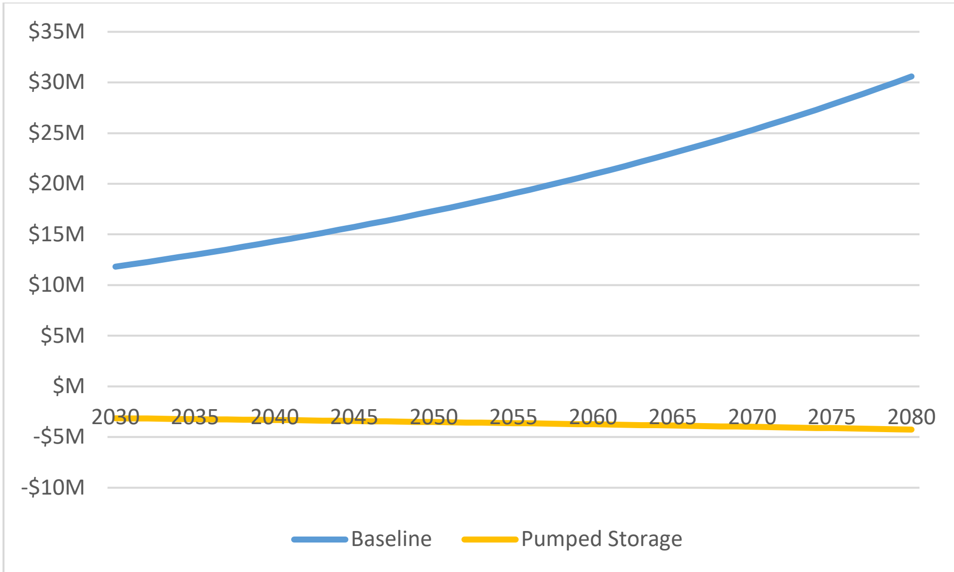


Figure 8: Comparison Between the Baseline Annual Power Expenditures at Intake and Gene for the Delivery of 550,000 Acre-Feet and the Net Annual Power Expenditures of Alternative 2

Alternative 2A: Pumped-Storage Facility between Copper Basin Reservoir and Lake Havasu Using Existing CRA Conduits with a Ten (10) Foot Increase in Copper Basin Dam Elevation

This alternative is similar to alternative 2 however with an increase in storage capacity at Copper Basin from raising the dam elevation by ten (10) feet to a height of 1038 feet. The increase in water surface elevation at Copper Basin allows more flow to be conveyed to Gene Wash Reservoir and overcomes the hydraulic limitation as was the case in Alternative 2. In this case, the maximum generated flow is limited to 1,800 cfs since Gene and Intake Pumping Plants have a maximum of eight (8) working pumps each with a capacity of 225 cfs. The water surface elevation at Copper Basin must be at least 1035-feet to hydraulically convey 1,800 cfs to Gene Pumping Plant. The available storage between 1035-feet and 1038-feet is roughly 1,200 ac-feet which is required to maintain CRA deliveries to Iron Mountain while operating the pump-storage system. Due to a limitation in storage, only 1- and 2-pump CRA delivery can be achieved under 1,800 cfs of generated flow.

At the maximum flow of 1,800 cfs, the generated power is roughly 35 MW each at Gene and Intake Pumping Plants. Under both 3-pump (675 cfs) and 4-pump (900 cfs) CRA delivery, the generated flow is reduced to 1,575 cfs which can generate around 30 MW at each of the two pump-turbine facilities. Approximate pumped power is 16 MW at both Intake (525 cfs @ 305-feet TDH) and Gene (525 cfs @ 320-feet TDH) Pumping Plants.

Major infrastructure requirements include the upgrade of all nine (9) pumps to pump-turbine units at Gene and Intake Pumping Plants, structural enhancement of the existing 16-ft horseshoe tunnels between Intake and Copper Basin and increase in the height of the surge chambers at Gene and Intake Pumping Plants. ASCE Level-5 construction cost estimate for this alternative is roughly $422 million. Incorporating 30% for design and construction management and 30% contingency yields a project cost of roughly $710 million. A detail breakdown of the cost estimate is provided in Appendix A.

Table 8 shows power available for generation and power required for pumping based on the monthly variability in CRA deliveries.

Month	Daily CRA Delivery Flow (cfs)	Power Generated (MW)	Power used for Pumping (MW)
January	900	60	32
February	0	0	0
March	900	60	32
April	900	60	32
May	900	60	32
June	900	60	32
July	675	60	32
August	675	60	32
September	675	60	32
October	900	60	32
November	900	60	32
December	900	60	32

Table 8: Alternative 2A – CRA Flow, Pumped-Storage Generation and Pumping

Metropolitan utilized the S&P Global Platts forecast for years 2025 and 2030 for CAISO's SP15, and current hydropower rates, incorporating 2% inflation, to determine the hourly pumping revenues and expenditures associated with Alternative 2A. Estimated pumping expenses for the pumped storage rated capacity are $0.5 million in 2030, escalating with inflation to $2.8 million in 2080. Estimated generation revenue for the pumped storage rated capacity are $7.9 million in 2030, escalating with inflation to $15.6 million in 2080. The project cost of $710 million, associated debt, and O&M expenses result in a project NPV of -$302 million after 50 years, making the project economically not feasible.

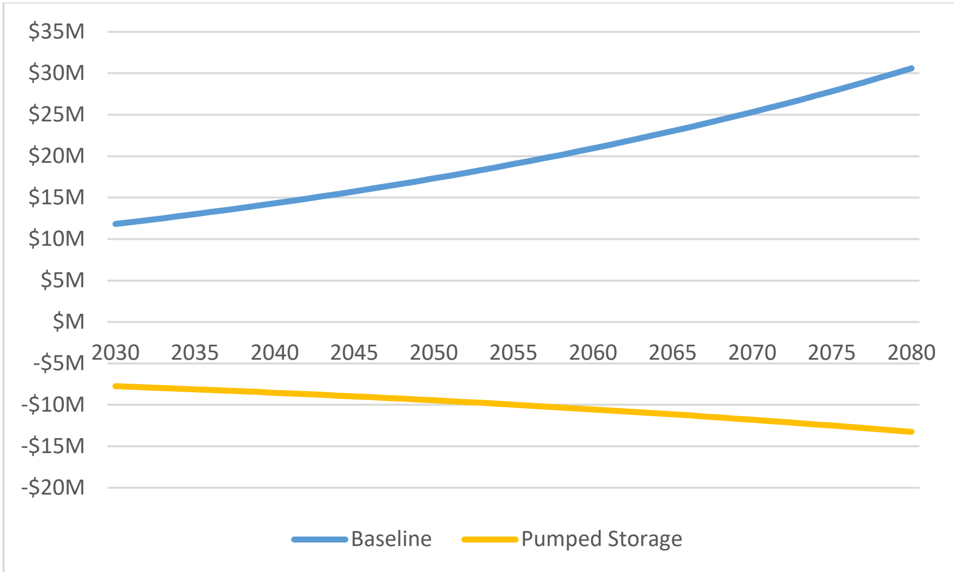


Figure 9: Comparison Between the Baseline Annual Power Expenditures at Intake and Gene for the Delivery of 550,000 Acre-Feet and the Net Annual Power Expenditures of Alternative 2A

Alternative 3: Pumped-Storage Facility between Copper Basin Reservoir and Lake Havasu Using New Conduits

This alternative evaluates a pumped-storage facility between Copper Basin Reservoir and Lake Havasu, on the Colorado River upstream of the existing CRA intake facility. New tunnel, siphons, penstocks and powerhouse structure will be constructed to run the pumped-storage facility. The powerhouse structure would house the dual-use pump-turbine units to function both as a pump and a turbine.

The pumped-storage facility was sized to utilize the maximum available volume available at Copper Basin when CRA is at 3-pump flow (675 cfs). This would provide the maximum energy generation during summer months when on-peak energy prices are high. The generation duration of 6-hours and pumping duration of 10-hours are same as that assumed in previous alternatives. No CRA pumping at Gene and Intake Pumping Plants is assumed during the 6-hour generation window in order to minimize pumping during on-peak energy times. Based on the above assumptions, the available storage at Copper Basin for pumped-storage operation is estimated to be 4,075 ac-ft. For the 6-hr generation period, the generation flow is computed to be 8,200 cfs and for the 10-hr pumping period, the flow is computed to be 4,900 cfs. The available head is lower than Alternative 1 since the water level at Lake Havasu is approximately 100-feet higher than the water level at Lake Moovalya. The static head between Copper Basin and Lake Havasu is around 570 feet assuming Lake Havasu at 450-feet water surface elevation. Allowing for friction and losses, the available net generating head is 540 feet. Assuming an 85% efficiency in generation yields 310 MW of generation capacity. In pumping mode, the total dynamic head would 590 feet and assuming an 85% pumping efficiency equates to 290 MW in pumping energy.

Major infrastructure requirements include a 22,200 linear feet of 27-ft diameter tunnel, two 1,700 linear feet of 19-ft diameter penstock and two 155 MW each pumped-turbine units. ASCE Level-5 construction cost estimate for this alternative is roughly $1.0 billion. Incorporating 30% for design and construction management and 30% contingency yields a project cost of roughly $1.75 billion. A detail breakdown of the cost estimate is provided in Appendix A.

Table 9 shows power available for generation and power required for pumping based on the monthly variability in CRA deliveries.

Month	Daily CRA Delivery Flow (cfs)	Power Generated (MW)	Power used for Pumping (MW)
January	900	250	230
February	0	0	0
March	900	250	230
April	900	250	230
May	900	250	230
June	900	250	230
July	675	310	290
August	675	310	290
September	675	310	290
October	900	250	230
November	900	250	230
December	900	250	230

Table 9: Alternative 3 – CRA Flow, Pumped-Storage Generation and Pumping

Metropolitan utilized the S&P Global Platts forecast for years 2025 and 2030 for CAISO's SP15, and current hydropower rates, incorporating 2% inflation, to determine the hourly pumping revenues and expenditures associated with Alternative 3. Estimated pumping expenses for the pumped storage rated capacity are $7.9 million in 2030, escalating with inflation to $36.9 million in 2080. Estimated generation revenue for the pumped storage rated capacity are $35.7 million in 2030, escalating with inflation to $69.6 million in 2080. The project cost of $1.75 billion, associated debt, and O&M expenses result in a project NPV of -$987 billion after 50 years, making the project economically not feasible.

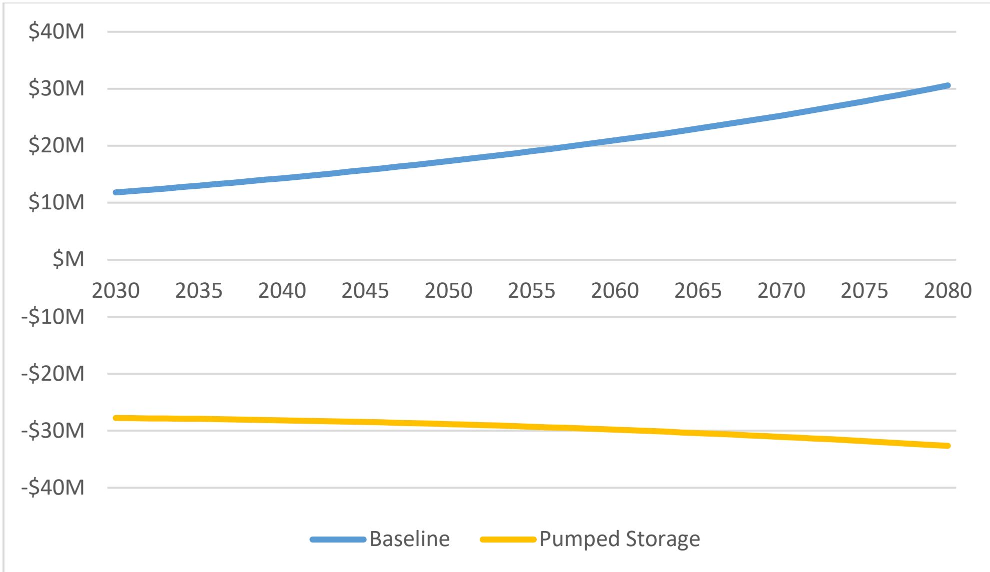


Figure 10: Comparison Between the Baseline Annual Power Expenditures at Intake and Gene for the Delivery of 550,000 Acre-Feet and the Net Annual Power Expenditures of Alternative 3

Alternative 3A: Pumped-Storage Facility between Copper Basin Reservoir and Lake Havasu Using New Conduits with a Ten (10) Foot Increase in Copper Basin Dam Elevation

This alternative is similar to alternative 3, however with an increase in storage capacity at Copper Basin from raising the dam elevation by ten (10) feet. The raising of the dam increases the available storage capacity for a pumped-storage facility from 4,075 ac-ft to 8,075 ac-ft. The computed generation flow is 16,300 cfs, assuming a 6-hr generation window. The computed pumped flow is 9,800 cfs assuming a 10-hr pumping duration. The generation head is 540-feet, and the pumping head requirement is 590-feet. Under these values, the power generated is 620 MW and the power required is 570 MW.

Major infrastructure requirements include two 22,200 linear feet of 27-ft diameter tunnel, four 1,700 linear feet of 19-ft diameter penstocks, four 155 MW each pumped-turbine units and raising of the existing dam and spillway at Copper Basin. ASCE Level-5 construction cost estimate for this alternative is roughly $1.67 million. Incorporating 30% for design and construction management and 30% contingency yields a project cost of roughly $2.82 billion. A detail breakdown of the cost estimate is provided in Appendix A.

Table 10 shows power available for generation and power required for pumping based on the monthly variability in CRA deliveries.

Month	Daily CRA Delivery Flow (cfs)	Power Generated (MW)	Power used for Pumping (MW)
January	900	560	510
February	0	0	0
March	900	560	510
April	900	560	510
May	900	560	510
June	900	560	510
July	675	620	570
August	675	620	570
September	675	620	570
October	900	560	510
November	900	560	510
December	900	560	510

Table 10: Alternative 3A – CRA Flow, Pumped-Storage Generation and Pumping

Metropolitan utilized the S&P Global Platts forecast for years 2025 and 2030 for CAISO's SP15, and current hydropower rates, incorporating 2% inflation, to determine the hourly pumping revenues and expenditures associated with Alternative 3A. Estimated pumping expenses for the pumped storage rated capacity are $19.7 million in 2030, escalating with inflation to $85.8 million in 2080. Estimated generation revenue for the pumped storage rated capacity are $76.6 million in 2030, escalating with inflation to $150 million in 2080. The project cost of $2.82 billion, associated debt, and O&M expenses result in a project NPV of -$1.57 billion after 50 years, making the project economically not feasible.

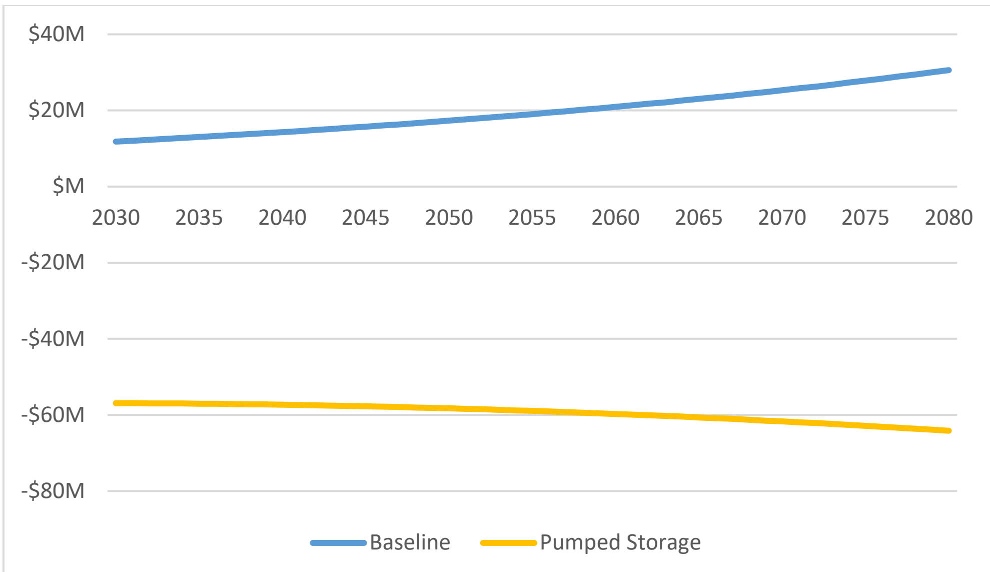


Figure 11: Comparison Between the Baseline Annual Power Expenditures at Intake and Gene for the Delivery of 550,000 Acre-Feet and the Net Annual Power Expenditures of Alternative 3A

Summary of Financial Analysis

The economic feasibility of the six pumped-storage alternatives utilizing Copper Basin Reservoir is summarized in **Table 11** below. Based on these results, which show a payback greater than 50 years for each alternative, none of the pumped storage alternatives are economically feasible at this time.

Alternative	Generation Capacity (MW)	Total Project Cost[1]	NPV[2]	Payback	Notes
1	360	$1.47 billion	-$568 million	>50 years	Based on 550,000 ac-ft annual CRA deliveries. Minimum allocation chosen to increase flexibility and revenue for a pumped-storage project with 6-hours of generation and 10-hours of pumping daily
1A	740	$2.7 billion	-$1.23 billion	>50 years	
2	26	$577 million	-$284 million	>50 years	
2A	60	$710 million	-$302 million	>50 years	
3	310	$1.75 billion	-$987 million	>50 years	
3A	620	$2.82 billion	-$1.57 billion	>50 years	

[1] ASCE Level 5 Cost estimate includes contingency. engineering, and construction management costs
[2] NPV for 50 years of operation

Table 11: Summary of Financial Analysis for the Alternatives Evaluated

Additional Assessments

Additional assessments and approvals would be required if any of the above alternatives are deemed feasible for more in-depth analysis in the future. Highlighted below are the areas of most interest:

1. Detailed assessment of the impact of the pumped-storage project on daily, monthly and annual operation of the CRA. The chosen CRA flow delivery scheme used in the analyses favors power generation, however, if CRA flow delivery is of priority, then power generation may be significantly lower.
2. Evaluation of increased O&M costs due to greater complexity in managing CRA deliveries and in addition, managing power generation.
3. Acquisition of Federal Energy Regulatory Commission (FERC) license.
4. California Division of Safety of Dams (DSOD) review and approval regarding usage of Copper Basin Reservoir for a pumped-storage project and in approving raising the dam by ten (10) feet.
5. Approval from USBR and co-ordination with agencies holding water rights along Colorado River downstream of the intake/release structure.
6. Environmental assessment regarding raising of Copper Basin Reservoir dam and construction of tunnel, penstock and powerhouse structure.
7. Tunnel alignment and powerhouse citing study.
8. Determine infrastructure and costs related to power grid connection and transmission lines.

Recommendations

- Continue efforts to optimize the use of the CRA's three power sources (hydropower, out of state imports, and CAISO) to minimize the cost to serve the CRA pumping plants.
- Perform an in-depth assessment of VFD implementation at Intake and Gene Pumping Plants as part of Metropolitan's Colorado River Aqueduct Main Pump Rehabilitation Program to further optimize Metropolitan's power resources. VFD's at Gene and Intake would allow Metropolitan to cycle pumps daily to fill up the reservoirs when energy prices are low and shut down pumps when energy prices are high and draw down the reservoirs.
- Re-evaluate pumped-storage options based on energy price outlook changes, legislative drivers, new incentive programs, and/or VFD implementation at Intake and Gene Pumping Plants.

Appendix A: Capital Cost Estimates

							Sheet No.	
Title:	Copper Basin						Calc. by	HC
	Pumped Storage						Checked by	
	Order of Magnitude Construction Cost Estimate						Date	3/23/2020 10:00
Project No.:		-	-		-		Bid Date	
Item	Description			Qty	Unit	Unit $	Amount	
Alternative No.1								
1	**Site and Civil**							
2	Site Grading and Site Preparation			1	LS		$ 9,788,000	
3	Access Road to Surge Chamber			1	LS		$ 6,000,000	
4	Access for (2) Penstocks			1	LS		$ 5,000,000	
5	**Outlet Structure at Discharge**							
6	Outlet Structure at Discharge			1	LS		$ 34,281,000	
7	Trash Racks			1	LS		$ 10,584,000	
8	**Outlet Structure at Dam**							
9	Outlet Structure at Dam			1	LS		$ 80,000,000	
10	**Power House**							
11	Power House - superstructure			1	LS		$ 20,888,000	
12	Power House - substructure			1	LS		$ 53,919,000	
13	Pump-Turbine/ Motor Generator	180MW/ ea		2	units	$ 47,000,000	$ 94,000,000	
14	Shutoff Valves			4	ea	$ 2,400,000	$ 9,600,000	
15	Mechanical Piping			1	LS		$ 3,133,000	
16	Switchyard			1	LS		$ 10,250,000	
17	Transmission			2	miles	$ 1,562,500	$ 3,125,000	

18	Electrical & Control			1	LS		$ 6,359,000	
19	Cranes			1	LS		$ 10,000,000	
20	**Tunnel**							
21	27' Dia Tunnel			10900	lf		$ 225,925,000	
22	**Surge Shaft**							
23	Surge Shaft			375	vf		$ 27,721,000	
24	**Siphon and Penstocks**							
25	19' Dia Siphons			2000	lf		$ 52,256,000	
26	19' Dia Penstocks			16000	lf		$ 176,009,000	
27	**Change 6 pumps at Gene and Intake to VFD**			6	ea	$ 3,000,000	$ 18,000,000	
28	**Precise Flow control d/s of Copper Basin to Iron**			1	ls	$ 1,000,000	$ 1,000,000	
29	**Ability to Start/Stop all Gene & Intake Pumps on a daily basis**			18	ea	$ 500,000	$ 9,000,000	
30	**New Control Facility**			1	ls	$ 5,000,000	$ 5,000,000	
31	**FERC License Application and Environmental Document, Land Acquisition**			1	ls			
32	**Admin, Engineering, Inspection**			1	ls			
	Subtotal						$ 871,838,000	
Notes:								
	1. Estimate is based on general layout description, reports, and sketches.							
	2. This is a rough order of magnitude type of estimate. The estimate has an expected accuracy range from +50% to -30%.							
	3. Estimates include contractor's overhead & profit							

							Sheet No.	
Title:	Copper Basin						Calc. by	HC
	Pumped Storage						Checked by	
	Order of Magnitude Construction Cost Estimate						Date	3/23/2020 10:00
Project No.:		-	-		-		Bid Date	
Item	Description			Qty	Unit	Unit $	Amount	
Alternative No.1a								
1	**Site and Civil**							
2	Site Grading and Site Preparation			1	LS		$ 9,788,000	
3	Access Road to Surge Chamber			1	LS		$ 6,000,000	
4	Access for (4) Penstocks			1	LS		$ 5,000,000	
5	**Outlet Structure at Discharge**							
6	Outlet Structure at Discharge			1	LS		$ 43,881,000	
7	Trash Racks			1	LS		$ 10,584,000	
8	**Outlet Structure at Dam**							
9	Outlet Structure at Dam			1	LS		$ 90,000,000	
10	**Power House**							
11	Power House - superstructure			1	LS		$ 27,543,000	
12	Power House - substructure			1	LS		$ 75,856,000	
13	Pump-Turbine/ Motor Generator	180MW/ ea		4	units	$ 47,000,000	$ 188,000,000	
14	Shutoff Valves			8	ea	$ 2,400,000	$ 19,200,000	
15	Mechanical Piping			1	LS		$ 4,717,000	
16	Switchyard			1	LS		$ 14,000,000	
17	Transmission			2	miles	$ 1,562,500	$ 3,125,000	
18	Electrical & Control			1	LS		$ 8,459,000	
19	Cranes			1	LS		$ 12,000,000	
20	**Tunnel**							

21	27' Dia Tunnel			21800	lf		$ 451,849,000	
22	**Surge Shaft**							
23	Surge Shaft			750	vf		$ 55,442,000	
24	**Siphon and Penstocks**							
25	19' Dia Siphons			4000	lf		$ 104,511,000	
26	19' Dia Penstocks			32000	lf		$ 352,018,000	
27	**Change 6 pumps at Gene and Intake to VFD**			6	ea	$ 3,000,000	$ 18,000,000	
28	**Raise Copper Basin and Dam Spillway by 10 feet**			1	ls		$ 33,587,000	
29	**Modiy Outlet Gate Structure**			1	ls		$ 10,500,000	
30	**Precise Flow control d/s of Copper Basin to Iron**			1	ls	$ 1,000,000	$ 1,000,000	
31	**Raise Gene Existing Surge Chamber by 10'**			1	ls		$ 230,000	
32	**Strengthening Exist. 16' Horseshoe Adits**			13000	lf		$ 58,021,000	
33	**Ability to Start/Stop all Gene & Intake Pumps on a daily basis**			18	ea	$ 500,000	$ 9,000,000	
34	**New Control Facility**			1	ls	$ 5,000,000	$ 5,000,000	
35	**FERC License Application and Environmental Document, Land Acquisition**			1	ls			
36	**Admin, Engineering, Inspection**			1	ls			
	Subtotal						$ 1,617,311,000	
Notes:								
	1. Estimate is based on general layout description, reports, and sketches.							
	2. This is a rough order of magnitude type of estimate. The estimate has an expected accuracy range from +50% to -30%.							
	3. Estimates include contractor's overhead & profit							

							Sheet No.	
Title:	Copper Basin						Calc. by	HC
	Pumped Storage						Checked by	
	Order of Magnitude Construction Cost Estimate						Date	3/23/2020 10:00
Project No.:		-	-		-		Bid Date	
Item	Description			Qty	Unit	Unit $	Amount	
Alternative No.2								
1	**Site and Civil**							
2	Site Grading and Site Preparation			1	LS		$ 3,786,000	
3	Access Road to Surge Chamber			1	LS		$ 6,000,000	
4	Access for (4) Penstocks			1	LS		$ 2,000,000	
5	**Outlet Structure at Discharge**							
6	Outlet Structure at Discharge			1	LS		$ 28,583,000	
7	Trash Racks			1	LS		$ 10,290,000	
8	**Outlet Structure at Dam**							
9	Outlet Structure at Dam			1	LS		$ -	
10	**Power House**							
11	Power House - superstructure			1	LS		$ 22,743,000	
12	Power House - substructure			1	LS		$ 56,259,000	
13	Pump-Turbine/ Motor Generator	3.25MW/ ea		8	units	$ 2,500,000	$ 20,000,000	
14	Shutoff Valves			8	ea	$ 1,200,000	$ 9,600,000	
15	Mechanical Piping			1	LS		$ 22,800,000	
16	Switchyard			1	LS		$ 11,500,000	
17	Transmission			2	miles	$ 1,250,000	$ 2,500,000	
18	Electrical & Control			1	LS		$ 9,959,000	

19	Cranes			1	LS		$ 10,000,000	
20	**Tunnel**							
21	Strengthening Exist 16' Horseshoe Adits			20000	lf		$ 89,209,000	
22	**Surge Shaft**							
23	Surge Shaft			375	vf		$ 7,951,000	
24	**Siphon and Penstocks**							
25	19' Dia Siphons			0	lf		$ -	
26	19' Dia Penstocks			0	lf		$ -	
27	**Change 6 pumps at Gene and Intake to VFD**			6	ea	$ 3,000,000	$ 18,000,000	
28	**Precise Flow control d/s of Copper Basin to Iron**			1	ls	$ 1,000,000	$ 1,000,000	
29	**Ability to Start/Stop all Gene & Intake Pumps on a daily basis**			18	ea	$ 500,000	$ 9,000,000	
30	**New Control Facility**			0	ls	$ 5,000,000	$ -	
31	**FERC License Application and Environmental Document, Land Acquisition**			1	ls			
32	**Admin, Engineering, Inspection**			1	ls			
	Subtotal						$ 341,180,000	
Notes:								
	1. Estimate is based on general layout description, reports, and sketches.							
	2. This is a rough order of magnitude type of estimate. The estimate has an expected accuracy range from +50% to -30%.							
	3. Estimates include contractor's overhead & profit							

							Sheet No.	
Title:	Copper Basin						Calc. by	HC
	Pumped Storage						Checked by	
	Order of Magnitude Construction Cost Estimate						Date	3/23/2020 10:00
Project No.:		-	-		-		Bid Date	
Item	Description			Qty	Unit	Unit $	Amount	
Alternative No.2a								
1	**Site and Civil**							
2	Site Grading and Site Preparation			1	LS		$ 3,786,000	
3	Access Road to Surge Chamber			1	LS		$ 6,000,000	
4	Access for (4) Penstocks			1	LS		$ 2,000,000	
5	**Outlet Structure at Discharge**							
6	Outlet Structure at Discharge			1	LS		$ 28,583,000	
7	Trash Racks			1	LS		$ 10,290,000	
8	**Outlet Structure at Dam**							
9	Outlet Structure at Dam			1	LS		$ -	
10	**Power House**							
11	Power House - superstructure			1	LS		$ 22,743,000	
12	Power House - substructure			1	LS		$ 56,259,000	
13	Pump-Turbine/ Motor Generator	3.25MW/ ea		18	units	$ 2,500,000	$ 45,000,000	
14	Shutoff Valves			18	ea	$ 1,200,000	$ 21,600,000	
15	Mechanical Piping			1	LS		$ 22,800,000	
16	Switchyard			1	LS		$ 11,500,000	
17	Transmission			2	miles	$ 1,250,000	$ 2,500,000	
18	Electrical & Control			1	LS		$ 9,959,000	
19	Cranes			1	LS		$ 10,000,000	
20	**Tunnel**							

21	Strengthening Exist 16' Horseshoe Adits			20000	lf		$ 89,209,000	
22	**Surge Shaft**							
23	Surge Shaft			375	vf		$ 7,951,000	
24	**Siphon and Penstocks**							
25	19' Dia Siphons			0	lf		$ -	
26	19' Dia Penstocks			0	lf		$ -	
27	**Change 6 pumps at Gene and Intake to VFD**			6	ea	$ 3,000,000	$ 18,000,000	
28	**Raise Copper Basin and Dam Spillway by 10 feet**			1	ls		$ 33,587,000	
29	**Modiy Outlet Gate Structure**			1	ls		$ 10,500,000	
30	**Precise Flow control d/s of Copper Basin to Iron**			1	ls	$ 1,000,000	$ 1,000,000	
31	**Raise Gene Existing Surge Chamber by 10'**			1	ls		$ 230,000	
32	**Ability to Start/Stop all Gene & Intake Pumps on a daily basis**			18	ea	$ 500,000	$ 9,000,000	
33	**New Control Facility**			0	ls	$ 5,000,000	$ -	
34	**FERC License Application and Environmental Document, Land Acquisition**			1	ls			
35	**Admin, Engineering, Inspection**			1	ls			
	Subtotal						$ 422,497,000	
Notes:								
	1. Estimate is based on general layout description, reports, and sketches.							
	2. This is a rough order of magnitude type of estimate. The estimate has an expected accuracy range from +50% to -30%.							
	3. Estimates include contractor's overhead & profit							

							Sheet No.	
Title:	Copper Basin						Calc. by	HC
	Pumped Storage						Checked by	
	Order of Magnitude Construction Cost Estimate						Date	3/23/2020 10:00
Project No.:		-	-		-		Bid Date	
Item	Description			Qty	Unit	Unit $	Amount	
Alternative No.3								
1	**Site and Civil**							
2	Site Grading and Site Preparation			1	LS		$ 9,788,000	
3	Access Road to Surge Chamber			1	LS		$ 6,000,000	
4	Access for (2) Penstocks			1	LS		$ 5,000,000	
5	**Outlet Structure at Discharge**							
6	Outlet Structure at Discharge			1	LS		$ 43,881,000	
7	Trash Racks			1	LS		$ 10,584,000	
8	**Outlet Structure at Dam**							
9	Outlet Structure at Dam			1	LS		$ 80,000,000	
10	**Power House**							
11	Power House - superstructure			1	LS		$ 27,543,000	
12	Power House - substructure			1	LS		$ 75,856,000	
13	Pump-Turbine/ Motor Generator	155MW/ ea		2	units	$ 40,500,000	$ 81,000,000	
14	Shutoff Valves			4	ea	$ 2,400,000	$ 9,600,000	
15	Mechanical Piping			1	LS		$ 4,717,000	
16	Switchyard			1	LS		$ 10,250,000	
17	Transmission			2	miles	$ 1,562,500	$ 3,125,000	
18	Electrical & Control			1	LS		$ 7,859,000	
19	Cranes			1	LS		$ 12,000,000	
20	**Tunnel**							
21	27' Dia Tunnel			15600	lf		$ 323,455,000	

22	**Surge Shaft**							
23	Surge Shaft			375	vf		$ 27,721,000	
24	**27' Dia Pipeline - Cut and Cover**							
25	27' Dia Pipeline - Cut and Cover			6600	lf		$ 88,945,214	
26	**Siphon and Penstocks**							
27	19' Dia Siphons			2000	lf		$ 52,256,000	
28	19' Dia Penstocks			3400	lf		$ 120,938,000	
29	**Change 6 pumps at Gene and Intake to VFD**			6	ea	$ 3,000,000	$ 18,000,000	
30	**Precise Flow control d/s of Copper Basin to Iron**			1	ls	$ 1,000,000	$ 1,000,000	
31	**Ability to Start/Stop all Gene & Intake Pumps on a daily basis**			18	ea	$ 500,000	$ 9,000,000	
32	**New Control Facility**			1	ls	$ 5,000,000	$ 5,000,000	
33	**FERC License Application and Environmental Document, Land Acquisition**			1	ls			
34	**Admin, Engineering, Inspection**			1	ls			
	Subtotal						$ 1,033,518,000	
Notes:								
	1. Estimate is based on general layout description, reports, and sketches.							
	2. This is a rough order of magnitude type of estimate. The estimate has an expected accuracy range from +50% to -30%.							
	3. Estimates include contractor's overhead & profit							

							Sheet No.	
Title:	Copper Basin						Calc. by	HC
	Pumped Storage						Checked by	
	Order of Magnitude Construction Cost Estimate						Date	3/23/2020 10:00
Project No.:		-	-		-		Bid Date	
Item	Description			Qty	Unit	Unit $	Amount	
Alternative No.3a								
1	**Site and Civil**							
2	Site Grading and Site Preparation			1	LS		$ 9,788,000	
3	Access Road to Surge Chamber			1	LS		$ 6,000,000	
4	Access for (4) Penstocks			1	LS		$ 5,000,000	
5	**Outlet Structure at Discharge**							
6	Outlet Structure at Discharge			1	LS		$ 43,881,000	
7	Trash Racks			1	LS		$ 10,584,000	
8	**Outlet Structure at Dam**							
9	Outlet Structure at Dam			1	LS		$ 90,000,000	
10	**Power House**							
11	Power House - superstructure			1	LS		$ 27,543,000	
12	Power House - substructure			1	LS		$ 75,856,000	
13	Pump-Turbine/ Motor Generator	155MW/ ea		4	units	$ 40,500,000	$ 162,000,000	
14	Shutoff Valves			8	ea	$ 2,400,000	$ 19,200,000	
15	Mechanical Piping			1	LS		$ 4,717,000	
16	Switchyard			1	LS		$ 14,000,000	
17	Transmission			2	miles	$ 1,562,500	$ 3,125,000	
18	Electrical & Control			1	LS		$ 8,459,000	
19	Cranes			1	LS		$ 12,000,000	
20	**Tunnel**							
21	27' Dia Tunnel			31200	lf		$ 646,511,000	

22	**Surge Shaft**							
23	Surge Shaft			750	vf		$ 55,442,000	
24	**27' Dia Pipeline - Cut and Cover**							
25	27' Dia Pipeline - Cut and Cover			6600	lf		$ 88,945,000	
26	**Siphon and Penstocks**							
27	19' Dia Siphons			4000	lf		$ 104,511,000	
28	19' Dia Penstocks			6800	lf		$ 148,409,000	
29	**Change 6 pumps at Gene and Intake to VFD**			6	ea	$ 3,000,000	$ 18,000,000	
30	**Raise Copper Basin and Dam Spillway by 10 feet**			1	ls		$ 33,587,000	
31	**Modiy Outlet Gate Structure**			1	ls		$ 10,500,000	
32	**Precise Flow control d/s of Copper Basin to Iron**			1	ls	$ 1,000,000	$ 1,000,000	
33	**Raise Gene Existing Surge Chamber by 10'**			1	ls		$ 230,000	
34	**Strengthening Exist. 16' Horseshoe Adits**			13000	lf		$ 58,021,000	
35	**Ability to Start/Stop all Gene & Intake Pumps on a daily basis**			18	ea	$ 500,000	$ 9,000,000	
36	**New Control Facility**			1	ls	$ 5,000,000	$ 5,000,000	
37	**FERC License Application and Environmental Document, Land Acquisition**			1	ls			
38	**Admin, Engineering, Inspection**			1	ls			
	Subtotal						$ 1,671,309,000	
Notes:								
	1. Estimate is based on general layout description, reports, and sketches.							
	2. This is a rough order of magnitude type of estimate. The estimate has an expected accuracy range from +50% to -30%.							
	3. Estimates include contractor's overhead & profit							

APPENDIX C

MWD Wind Development Opportunities and Overall Generation Cost Estimates

Stantec

Memo

To:	Metropolitan Water District Los Angeles, CA	From:	Alan Cyr Dartmouth, NS, CA Office
File:	MWD – Wind Generation Cost – TM 20190724	Date:	July 31, 2019

Reference: MWD Wind Development Opportunities and Overall Generation Cost Estimates

Stantec has been tasked by the Metropolitan Water District of Southern California (Metropolitan) to provide an update to the Navigant 2007 Report as well as its 2013 and 2018 updates. The purpose of this update is to revise the report, its analysis, and its calculations based on the changes in the wind generation sector since the report and updates were completed. Equipment manufacturers have evolved, and the size of their units have increased while the overall $/MW of installed capacity has decreased. Stantec reviewed the 2007 report as well as the June 2013 and Feb 2018 reassessment studies as a starting point for this update. Additionally, Stantec provided recent Request for Proposal/Power Purchase Agreements awarded values and the parameters around them to better represent the most recent $/MWh Levelized Cost of Energy (LCOE).

Key Assumptions:

- The initial 2007 assumptions, including wind data and economic model parameters, were retained as a basis of the additional economic analysis and benchmarks (Annual Power Costs and Levelized Cost of Energy). Total installed cost of the wind energy facility was ($1600/kW) in 2007. This was a typical benchmark cost estimate for that time. The report also assumed that Metropolitan would finance the project 100 percent at 5 percent over a 25-year term. Operation and Maintenance (O&M) was estimated at $3 million annually Annual power cost was then calculated based on the annual cost of debt service and O&M divided by the annual energy production. Additional calculations, with an installed cost of $2000/kW, were also included.

- New turbine manufacturer information was added to the analysis and yield estimates were calculated based on wind data and he manufacturers' power curves.

- Stantec used the 2007 report data for the wind shear value to extrapolate wind speeds at higher elevations. It should be noted that using the interpolated values would only be for high-level analysis and should not be used for any project economics based on the annual yields from the calculated speeds at heights.

- Project site, size, and interconnection point and costs remain as initially reported.

Methodology of the Assessment:

- The 2007 wind data was used to determine the annual yield based in the manufacturers' power curve. It should be noted that the 2007 report summarizes wind speed data captured from the metrological towers at 161, 99, and 66 feet (49, 30, and 20 meters, respectively). These observed values were then used to calculate annual yields using the General Electric (GE) SLE 1.5MW unit with hub heights available from 61.4, 64.7, 80, and 85 meters. The 2007 report used a 77 m hub height as opposed to those listed. It is believed that the 77 m rotor-diameter value was used in error. There is a risk in this yield determination as there was no actual observed wind data for the selected turbine hub height. The calculation of wind speed at higher hub heights was done by using the wind shear value provided, and then calculated from the 2007 reported number from the met tower

Reference: MWD Wind Development Opportunities and Overall Generation Cost Estimates

observed data. This wind shear coefficient was used to calculate an extrapolated wind speed at the turbine hub height. Again, it should be noted that the hub height was higher than any of the observed data recorded from the met tower. For example, the 77 m wind speed was calculated as the average of three values based on the shear coefficient and the 20, 30, and 50 m observed data, resulting in the following:

  - From the 20 m observed value of 3.98 m/sec (8.9 mph), the 77 m wind speed of 4.80 m/sec
  - From the 30 m observed value of 3.71 m/sec (8.3 mph), the 77 m wind speed of 4.23 m/sec
  - From the 50 m observed value of 4.02 m/sec (9 mph), the 77 m wind speed of 4.29 m/sec
  - A 4.44 m/sec average, where the equivalent wind speed from the annualized yield was 5.25 m/sec (an 18 percent increase)
  - The 2007 report noted that the wind speed was lower at the middle observation point: *"Wind data analysis results show that the highest average wind speeds during the data collection period were 9.0, 8.3 and 8.9 miles per hour at the 161 foot, 99 foot and 66 foot levels, respectively. A stronger average wind speed at the 66-foot level is likely due to local elevation differences and mountain downwash effects." (p.1-2)*

- Benchmark turbine cost ($/kW) and O&M costs from the November 2018 Lazard Report *Levelized Cost of Energy Analysis – Ver 12*) were used for this analysis. The Stantec values are presented in 2019 dollar values using 2 percent annual inflation The calculations with the new assumptions and reflected 2019 costs are provided in the attached table.

- This memo considers turbines that were recently used in a competitive bid process in Alberta, Canada, where the weighted average-energy costs contracted award was in the $37–$40 Canadian dollar (CDN)/MWh range. Using the last five-year-average exchange rate (with $CDN - $USD at 30 percent), the equivalent values range from $28–$31 USD/MWh. The overall weighted average is $29.64 USD/MWh

Results:

- The results of these calculations were in the $52–$75/MWh range, as summarized in Table 1. Again, the wind shear factor from the 2007 report was used to extrapolate wind speed at hub heights ranging from 100 m to 166 m. For the annual yield determination, the manufacturers' power curves were used along with the X-axis value of 5.0 m/sec. This would provide a slightly higher yield and would result in a lower $/MWh. The yield calculation equates to 22-25 percent capacity factor.

Table 1 Wind Project LCOE Summary

Parameter	2007 Navigant Report	2013 Update	2018 Update	Stantec Update	2018 Lazard Report	2018 Lazard Report with ITC	Recent Bids in Alberta, Canada
LCOE	$161–$166/MWh	$99–$103/MWh	$65–$68/MWh	$52–$75/MWh	$29–$56/MWh	$14–$47/MWh	$28–$31/MWh

Reference: MWD Wind Development Opportunities and Overall Generation Cost Estimates

- Referencing the 2018 Lazard report, the LCOE analysis now places on-shore wind in the $29–$56/MWh range for unsubsidized projects. Subsidies that help reduce the costs to $14–$47/MWh include Investment Tax Credit (ITC) and Production Tax Credit (PTC).. Note that the Lazard report uses a 60/40 debt to equity (D/E) ratio at 8 percent interest and 12 percent cost values. These results, in $/MWh, are lower than the Stantec calculated values as the Lazard uses a 38 percent capacity factor, compared to the 22-25 percent calculated in this memo.

Recommendations:

Based on the reassessments and additional updates, it is not recommended to further evaluate the proposed project based on economics without new wind data being collected at the new hub heights for the larger-scale turbines.

Again, it should be noted that any extrapolations calculated using the wind shear factor to estimate annual yields for taller units, with larger swept areas, should not be used for any economic evaluations.

Stantec Consulting Services Inc.

Alan Cyr
Senior Technical Specialist

Phone: 902-468-7777
Email: alan.cyr@stantec.com

Attachment: Stantec Report Calculations $2019

Table 2 – Estimated Annual Power Cost

	Original Base Case Assumptions	Stantec 2019						
	GE SLE 1.5MW Unit		Vestas V136 3.6MW		Senvion 100 3.4 MW		Enercon E-160 EP5 4.65 MW	
Key Financial Assumptions		Assumptions $2019	$1550/kw & 4.84 m/s (5.0 Used)	$1150/kw & 4.84 m/s (5.0 Used)	$1550/kw & 4.6 m/s (5.0 Used)	$1150/kw & 4.6 m/s (5.0 Used)	$1550/kw & 4.94 m/s (5.0 Used)	$1150/kw & 4.94 m/s (5.0 Used)
Debt / Equity Ratio	*100%*	100%						
Debt Interest rate	*5%*	5%						
Debt Term (yrs)	*25*	25						
Inflation	*2.5%*	2.0%						
Project Life (yrs)	*25*	25						
Estimated Capital Costs ($000s) in $2007		**Estimated Capital Costs ($000s) in $2019**						
Preliminary Studies / Engineering	*$ 245*	$ 311						
Development	*$ 836*	$ 1,060						
Design Engineering	*$ 611*	$ 775						
Wind Turbines	*$ 497,376*	$1550/kw ($2018) High $1150/kw ($2018) Low	$ 569,160	$ 422,280	$ 569,160	$ 422,280	$ 569,160	$ 422,280
Balance of plant	*$ 34,468*	$ 43,714						
Miscellaneous	*$ 43,561*	$ 55,246						
Total	*$ 577,097*		$ 670,266	$ 523,386	$ 670,266	$ 523,386	$ 670,266	$ 523,386
Cost / kwhr	*$ 1,603*							
Estimated Annual Costs ($000s)		**Estimated Annual Costs ($000s) in $2019**						
O&M (Fixed @ 6099)	*$ 6,099*	O&M (20% CAPEX)/year	$ 5,362	$ 4,187	$ 5,362	$ 4,187	$ 5,362	$ 4,187
Debt Service (7.1%)	*$ 40,946*	Debt Service (7.1%)	$ 47,589	$ 37,160	$ 47,589	$ 37,160	$ 47,589	$ 37,160
Total Annual Cost ($000s)			**$ 52,950.97**	**$ 41,347.45**	**$ 52,950.97**	**$ 41,347.45**	**$ 52,950.97**	**$ 41,347.45**
Total Annual Production (MWhrs) (From Manufacturer Power Curve) With Extrapolated Wind Speed at Hub Height			800000	800000	231882	231882	704348	704348
Power Cost ($/MWh) Calculated Based on Turbine Manufacturer Power Curve and extrapolated Wind Speed at hub height.			$ 66.19	$ 51.68	$ 228.35	$ 178.31	$ 75.18	$ 58.70

APPENDIX E

Scenario Narratives

SCENARIO A: STEADY AND PREDICTABLE

Technological breakthroughs in the early 2030s facilitated California's transition to 100 percent renewable energy 10 years earlier than expected. The dreaded "duck curve" has been flattened with vast networks of integrated storage, including utilization of mobile batteries in over 2 million electric vehicles, and the incorporation of Artificial Intelligence (AI) for management of source-of-power controls on most electrical equipment and appliances—a centralized system of highly distributed storage. At the same time, an over $800 billion investment in utility-scale batteries and an even larger investment in transmission upgrades has stabilized the wholesale power market from the Mississippi River to the Pacific coast. Given the complexity associated with cost allocations for new renewable generation, centralized and distributed storage, national electric power transmission upgrades, and AI management services, electric utilities have opted to charge customers a fixed rate, based on expected annual usage and peak power demands.

With the completion of conveyance improvements in the Delta, complementary north-of-Delta and south-of-Delta storage/banking options, and ecosystem restoration in the Sacramento-San Joaquin Delta and the Central Valley Project-State Water Project system, Metropolitan has been successful in integrating various tools to capture the abundant water supply when available. The changes in climate have produced more frequent extremes in temperature and rainfall, but operational improvements have enabled Metropolitan to manage the new peak events, high temperatures, and more frequent droughts. Similarly, the continued investment in regional water supply has created additional redundancy and buffers locally. The drought contingency plan implementation and other water management strategies, including the Intentionally Created Surplus (ICS), have also effectively stabilized the water supply outlook for Metropolitan.

An unexpected consequence of success on both water and energy management has been the "stranding" of assets intended solely to shift energy TOU at specific facilities. For a nominal fee, electric utilities and private aggregators have agreed to take over ownership of the underutilized battery energy storage system (BESS) facilities and incorporate them into the larger integrated networks, but the expected payback on the original investments never materialized.

On the Colorado River Aqueduct (CRA), Metropolitan's operational improvements and investments in energy efficiency have kept the unit cost of power down. Between the plentiful hydropower available from the Hoover Dam and Parker, and the wholesale transition to renewables on the grid, both Metropolitan and electric utilities anticipate a sustainable future—at least until the next surprise disruption occurs.

Potential Implications: Short-term investments would have maximum payback and reduce the possibility of stranded investments.

SCENARIO B: CHAOTIC MARKET

Metropolitan's investments in operational efficiency on the CRA, the completion of Delta conveyance, storage/banking improvements, and the addition of regional recycling and desalination have allowed the agency to take full advantage of the extremely wet weather that has become normal during a period of rising ocean temperatures and year-round storm events. In the meantime, 2040 is approaching and electric utilities are struggling to reduce the energy imbalance. In spite of the successful implementation of over 60 percent renewable energy generation, the lagging availability of utility-scale energy storage and loss of generation facilities throughout the grid due to retirements or energy regulations have exacerbated the challenges in an unpredictable manner that requires frequent attention by regional balancing authorities (e.g., CAISO) individually or collectively. Utilities are paying large-scale solar farms to reduce their generation during long summer days and offering negative power rates (credits) to large power users who can ramp up their daytime use to prevent over generation.

The Legislature has relaxed targets for a 100 percent renewable energy requirement considering the energy market is severely out of balance. Retired natural gas-fired power plants along the California coast are being recommissioned under emergency declarations and executive orders from the Governor's office. The Governor has declared restoration of California's energy reliability her top priority.

Regulators are responding to increased concerns over climate change by setting goals for carbon emissions and aggressively implementing cap-and-trade market pricing for reinforcement. Without the means to store that power and utilize it throughout the day, the energy market continues to become more volatile. Even with a high penalty from cap-and-trade carbon market pricing, utilities and energy users do not have a choice but to continue using energy from non-renewable sources, with pricing controls becoming less effective to shift demands and mandated load-shedding frequency increasing. If water supply and demand remain fairly consistent and reliable, operations can primarily focus on responding to energy market changes, while successfully managing water supplies.

Potential Implications: Flexible CRA pumping operations become critical to responding to shifting market trends.

SCENARIO C: MARKET ADJUSTS TO CLIMATE VARIABILITY

Electric utilities have managed to achieve their 2030 renewable energy targets through new renewable generation, utility-scale and distributed storage, transmission improvements, and AI management services. Water agencies are suffering. Years of extreme drought have resulted in the implementation of dramatic water conservation measures. Local recycling has reached its limits, as wastewater flows decline; and ocean desalination projects, relying on the increasingly stable and reliable energy supply, have appeared all along the Pacific coastline. While the energy market has stabilized, inexpensive hydropower is scarce in the southwest, and Metropolitan's energy allocation from Hoover and Parker Dams continues to decline and become unreliable. Overall, power costs have escalated dramatically.

Success in integration of renewables and utility-scale energy storage projects has smoothed out large swings in the wholesale energy market, but the diminishing Hoover Dam and Parker power generation has driven up energy prices for operating the CRA. Metropolitan is increasingly reliant on energy efficiency and operational flexibility measures to keep operation costs down and maximize the efficiency of the CRA.

Potential Implications: Advances in energy storage technology and pumping operations will be critical.

SCENARIO D: VOLATILE CLIMATE AND MARKET

Climate change continues to inflict chaos on California's water supply. The stalled transition to renewables, combined with reduced hydropower generation and closed coastal power plants, have resulted in regular rolling blackouts and periodic negative power prices. New initiatives to recommission nuclear power plants in other states for energy export to California and provide dry cooling for coastal natural gas generation were initiated in the early 2030s, but the benefits of those investments aren't likely to emerge for 15 to 20 years. Expensive new distributed technologies have allowed wealthy suburban communities and corporations to move off the grid (reliability being the sole driver of investments), leaving aging centralized utilities facing financial failure and dense urban centers suffering the most severe effects of rolling blackouts, water rationing, and skyrocketing rates.

Persistent drought conditions in California resulting from the Ridiculously Resilient Ridge phenomenon have led to increased pumping on the CRA. While at the same time, persistent drought throughout the Colorado River Basin has also limited water availability in the system and reduced power generation at Hoover and Parker Dams. Metropolitan's investment in implementation of the drought contingency plan and ICS had limited success but did provide the portion of water supply needed to compensate for the reduced water supply from Northern California and regional sources. The result has been dramatically higher energy prices for Metropolitan for moving water through the CRA due to diminishing allocation from its Hoover Dam power and the resulting market-based purchase for required energy. High temperatures and drought conditions have also driven up daytime power demands across the state and throughout the west. The frequent use of rolling blackouts to manage imbalances has forced customers to increase backup diesel generation, and consequently, increased GHG emissions on a landscape level that may further exacerbate climate change. While the addition of more renewable generation in the energy market has helped with the increased midday usage, the lack of adequate battery energy storage region-wide has deepened the duck curve further, causing extreme energy market fluctuations. Daily disruptions, electricity price spikes, reduced water revenues, and deteriorating infrastructure leave everyone feeling like "dead ducks."

Potential Implications: Long-term investments will be critical to reduce impacts of hydrology and market volatilities.

APPENDIX F

Multi-Criteria Decision Assessment and Scenario Planning

MULTI-CRITERIA DECISION ASSESSMENT AND SCENARIO PLANNING

The drivers of change affecting energy management go well beyond the basic economics of power generation and transmission. There is an urgent need to both (1) mitigate greenhouse gas emissions, and (2) adapt to the consequences of increased climate extremes and volatility. These parallel demands require a more holistic perspective in energy management strategy than has been practiced in the past. They create a dual responsibility to make decisions that reduce contributions to GHG emissions, while preparing for and adapting to the unpredictable consequences of climate impacts, as well as the interim market disruption of a state-wide transition to renewables.

California's electric system transition from fossil fuels to renewables is a massive undertaking. To accomplish the transition during a period of deep climate uncertainty—with impacts that will severely disrupt both water supply and energy supply reliability—requires a new approach to energy management. In this context, decision-making and strategy development must go beyond the evaluation of the least-cost solutions. Forecasts of cost-effectiveness rely on assumptions based on historical data and predictable future conditions. While historical data is plentiful, predicting future conditions is highly uncertain.

For these reasons, the evaluation of energy management options in both the retail and wholesale markets was undertaken using two alternative decision-making tools:

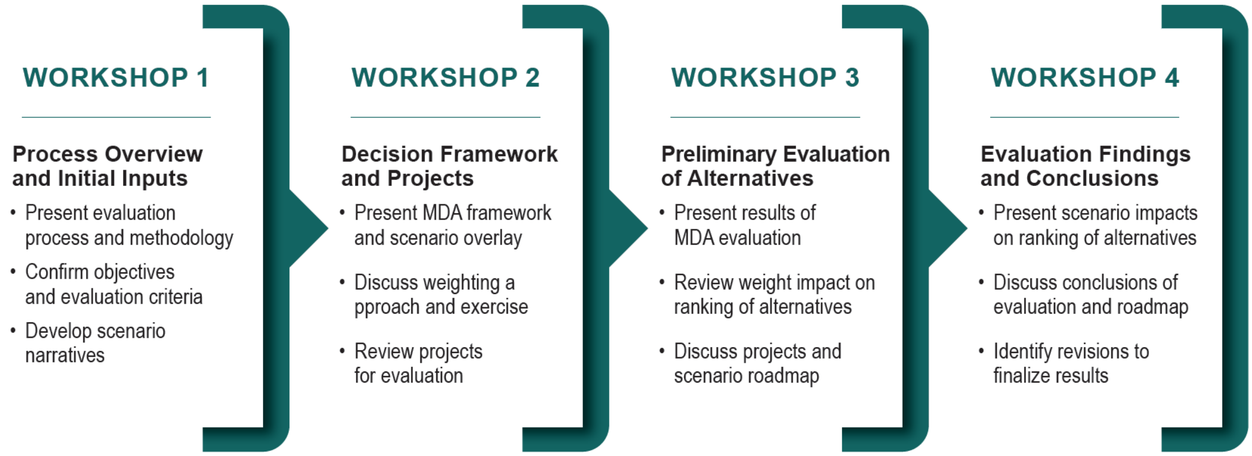
- A detailed scenario analysis that effectively "stress tests" each option under a range of plausible future conditions, and
- A multi-criteria decision analysis that compares the relative performance of options based on considerations that go beyond costs alone.

The combination of these tools affords decision makers the ability to: (1) identify preferred options that achieve sustainability criteria under current assumptions, and (2) assess the resilience of those options under potential future scenarios that radically differ from the base assumptions. In particular, these comparative analyses utilize both quantitative and qualitative criteria for the purpose of ranking the relative performance of options against one another (MDA) and under alternative future scenarios. Options that perform well in both evaluations demonstrate relative strength now as well as robustness in an uncertain future.

The combination of the MDA and scenario assessments is intended to assist in the decision-making process and illustrate trade-offs that should be considered when setting priorities. Further, the scenario exercise allows planners to identify early indicators ("signals") of how the future may be unfolding. Remaining alert to these signals enables decision makers to adapt strategy, correct course, and implement new options that have been prepared in advance for emerging conditions. It is a process of dynamic, adaptive planning that can be coordinated with and complement Metropolitan's other integrated planning efforts.

The planning tools were developed and applied during a series of four interactive workshops that included participation of senior management at Metropolitan. The workshop process, including the topics covered and outcomes, is presented in Figure F-1.

Figure F-1: Overview of Workshop Process, Topics, and Outcomes



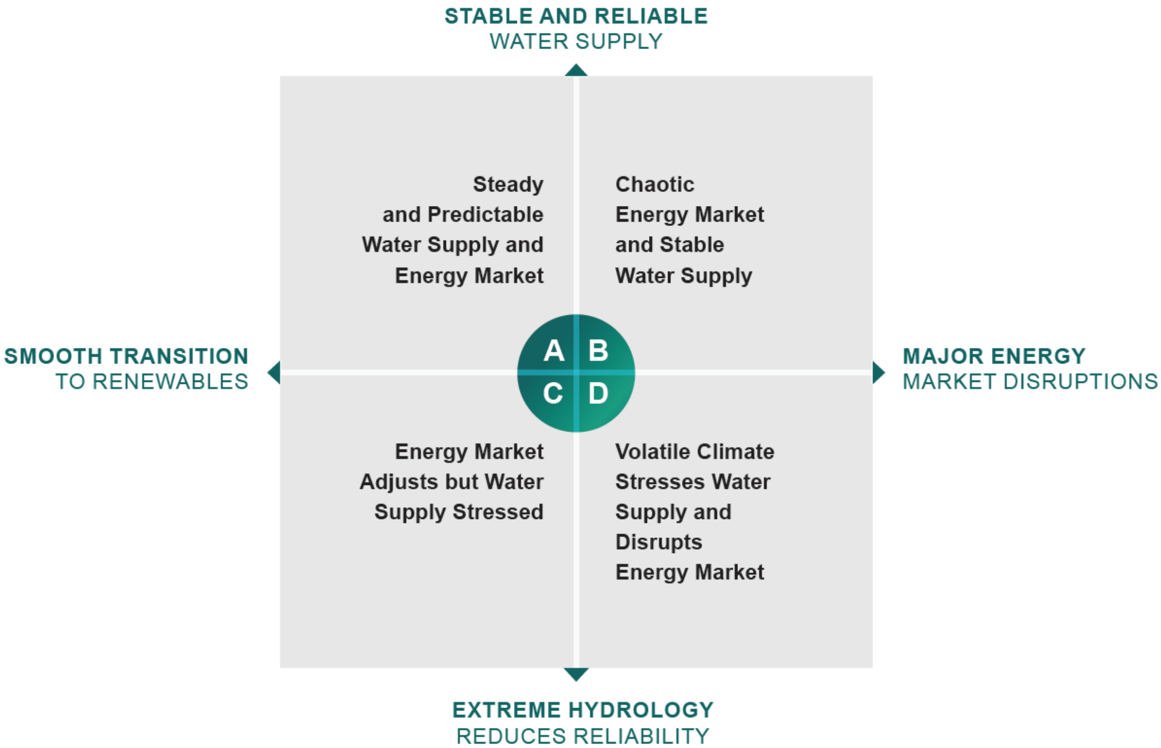
The following sections present the approach and process that was undertaken for project prioritization with detailed description of both the MDA and scenario frameworks explored in parallel. The scenario framework allowed for the introduction of significant uncertainties and possible impacts on project opportunities. The MDA evaluation provided a comparative analytical tool based on available planning data, qualitative assessments, and assumptions regarding expected future conditions. Together, the two approaches highlighted the trade-offs among options under current assumptions, while indicating the robustness of options under plausible future conditions.

F.1 SCENARIO DEVELOPMENT AND APPLICATION

First, a scenario planning tool was applied to assess the expected performance of investment options under conditions significantly different from existing. Scenario-based planning is used in both the public and private sector to evaluate strategies where there is a high level of uncertainty regarding the future conditions within which they will be deployed. In this plan, a scenario planning tool was applied to assess the expected performance of investment options under conditions significantly different from those assumed in the MDA comparisons. The scenario narratives utilized for the evaluation of options were developed through direct input from Metropolitan staff during the workshop process presented in Figure F-1. Following each workshop, additional review and revisions to draft narratives were received from participants and the consultant team.

Scenarios were then developed using a two-by-two matrix constructed based on an assessment of the deepest uncertainties, threatening the greatest impact, on the future context within which options were expected to perform. As shown in Figure F-2, these two axes of impact and uncertainty were identified as (1) the water supply and demand conditions that Metropolitan will be faced with over the next several decades, and (2) the unknown market consequences of implementing the State-mandated transition to renewables. For each axis, best case and worst-case conditions were identified. When combined, the two factors created a four-quadrant matrix created by the best-best outcomes at one extreme and the worst-worst future at the other. Two best-worst combinations were also considered.

Figure F-2: Scenario Matrix and Quadrant Descriptions



With these four quadrants established, participants were asked to imagine how all of the other drivers identified in the study would likely respond to the overall environment conditions created in each quadrant. This exercise was assisted in the development of the scenario narrative for each quadrant.

One of the early observations was related to the possibility of stranded assets under several of the scenarios. For example, any investment designed to provide operational flexibility solely driven by avoiding time of use rate penalties would be vulnerable to changes in rate structures and market conditions that cannot be predicted. It was also observed that serious disruptions of the energy market would likely impose requirements on Metropolitan to share the burden of providing for public needs. In these cases, Metropolitan might be viewed as more than just a large customer in energy markets. Under these circumstances, the frequently cited water-energy nexus would demand energy policy and management changes.

While the scenario planning developed is not designed to predict the future, it can provide insights into the resilience of various options under plausible future conditions. All else being equal, options that can continue to deliver expected performance under all scenarios are preferable to those that only perform under a narrow range of assumptions.

F.1.1 Scenario Signals

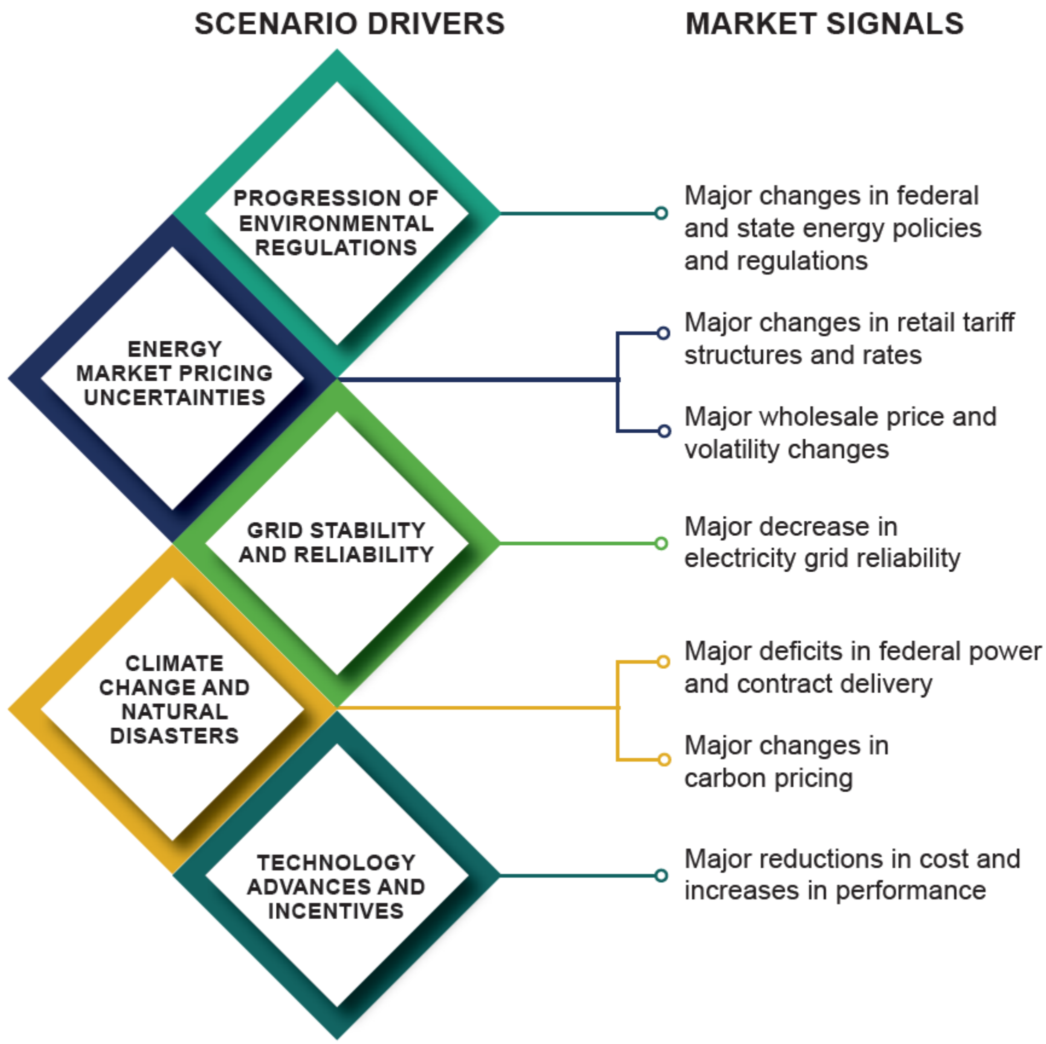
Each of these scenarios is driven by major changes in the energy and water sectors, which will influence the future performance of renewable energy and energy storage project opportunities. At the beginning of the process, potential major drivers were identified (Figure F-3) as affecting the future performance of both retail and wholesale market options.

Figure F-3: Summary of Potential Scenario Drivers

Market Pricing Uncertainties	• Wholesale market stability is subject to renewable generation and storage added to grid • Retail market responds to wholesale market by changing time-of-use (TOU) rates but is overall less variable than wholesale since rates are set.
Grid Reliability	• CRA is dependent on power from Hoover Power Plant and is susceptible to disruptions in the transmission lines. • Potential of future blackouts and Public Safety Power Shutoffs due to increased rise of wildfires.
Regulations	• RPS goals increased renewable energy penetration in the wholesale market leading to duck curve which may continue to deepen if not enough storage is added. • Metropolitan's carbon/GHG goals are expected to be met as the energy grid becomes cleaner but is reliant on other utilities to meet their goals. • Future changes to water quality requirements would lead to increased treatment at WTPs which may increased energy consumption
Technology Advances	• New technologies emerge that are more efficient, cost-effective, etc. than current technologies (i.e. flow through batteries, compressed air, in-line hydro etc.) • Costs of existing technologies decrease faster than expected making them economic sooner • Cost-effective/accessible renewable technologies are changing the grid's profile (i.e. duck curve)
Climate Change	• Decreasing water levels may lead to increased energy prices from the Hoover Power Plant • Climate change may lead to more extreme dry and wet years, changing Metropolitan's water deliveries and fluctuating the rate of energy consumption • Climate change may lead to more wildfires which can cause energy transmission interruptions

In addition to characterizing the performance of retail and wholesale options under the four scenarios, the scenario drivers were also used to identify signals that would potentially indicate significant changes in the energy market and the water supply environment Metropolitan is facing. Figure F-4 provides a list of those signals mapped to the drivers from which they can originate. Each signal may affect only certain energy project opportunities, but all are important from a strategic energy management perspective. Ongoing scanning for these signals could provide Metropolitan with an early warning regarding the unfolding future as configured in the scenario framework.

Figure F-4: Scenario Drivers and Market Signals



F.1.2 Scenario Performance Assessments

For each of the retail and wholesale project options, a performance assessment was developed for each scenario. Where specific options appear vulnerable to the changes imposed under a specific scenario, those weaknesses were flagged. A high-level summary for each option is provided in Table F-1. Acceptable performance of each technology in a scenario is indicated by a green box, yellow indicates an uncertain impact on performance and red indicated poor performance.

Table F-1: Assessment of Technology Options Under Scenario Conditions

Technology Configurations	Scenario A: Steady and Predictable Water and Energy	Scenario B: Chaotic Energy Market and Stable Water Supply	Scenario C: Energy Market Adjusts but Water Supply Stressed	Scenario D: Volatile Climate Stresses Water and Energy Market Disrupted
Retail Market Project Options				
New Solar + Grid	Renewable power production would reduce carbon costs and provide independent energy source off grid	May be producing power when negative prices are available.	Renewable power production would reduce carbon costs and provide independent energy source off grid	May be producing power when negative prices are available.
BESS + Grid	Could become a stranded asset if significant rate restructuring occurs and large peaking is no longer occurring	Provides a predictable means of avoiding peak energy prices	Could become a stranded asset if significant rate restructuring occurs and large peaking is no longer occurring	Provides predictable means of avoiding peak energy prices. Connected to grid and not independent source of energy
BESS + Existing Solar	Provides independence as a generation source owned by MWD and contributes to renewables	Regulatory and utility changes to allow isolation from grid would make this configuration favorable.	Provides independence as a generation source owned by MWD and contributes to renewables.	Regulatory and utility changes to allow isolation from grid would make this configuration favorable.
BESS + New Solar	Provides independence as a generation source owned by MWD and contributes to renewables.	Regulatory and utility changes to allow isolation from grid would make this configuration favorable.	Provides independence as a generation source owned by MWD and contributes to renewables.	Regulatory and utility changes to allow isolation from grid would make this configuration favorable.
New Solar PPA	Provides pricing certainty and transfers some risks to PPA provider.	Depending on levels of energy market disruption, some agreement terms may be renegotiated.	Provides pricing certainty and transfers some risks to PPA provider.	Depending on the levels of disruption, PPA providers may default on their agreements.
Energy Efficiency	Energy and operational efficiency and flexibility measures deliver benefits under all conditions.	Energy and operational efficiency and flexibility measures deliver benefits under all conditions.	Energy and operational efficiency and flexibility measures deliver benefits under all conditions.	Energy and operational efficiency and flexibility measures deliver benefits under all conditions.
Yorba Linda + Diemer	Provides independence as a generation source owned by MWD and contributes to renewables.	Provides independence as a generation source owned by MWD and contributes to renewables.	May be a less reliable generation source under stressed water supply conditions	While less reliable, independence from grid may be highly beneficial.
Wholesale Market Project Options				
Small Hydropower	Fixed energy sale price per contract not affected by changes in energy market	Fixed energy sale price per contract not affected by changes in energy market	Reduced water supply decreases revenue generated from hydro	Reduced water supply decreases revenue generated from hydropower
Pumped Storage - MWD Owned	Steady market conditions lessen savings opportunities for pumped storage	Offsets large margins on energy market	Restraint on pumped storage to allow for more flexible water operations	Offsets large margins on energy market but is limited during grid disruption and to allow flexible water operations

Technology Configurations	Scenario A: Steady and Predictable Water and Energy	Scenario B: Chaotic Energy Market and Stable Water Supply	Scenario C: Energy Market Adjusts but Water Supply Stressed	Scenario D: Volatile Climate Stresses Water and Energy Market Disrupted
Pumped Storage - 3rd Party Owned	Negotiated contract energy purchase price provides pricing certainty and transfers risks to third-party	Depending on levels of market disruption, some agreement terms may be renegotiated	Negotiated contract energy purchase price provides pricing certainty and transfers risks to third-party	Depending on levels of market disruption, third party providers may default on their agreements
CRA Wind Power	Negotiated contract energy purchase price provides pricing certainty and transfers risks to third-party. Contributes to renewables.	Regulatory and utility changes to allow isolation from grid during blackout/disruption would make this configuration more favorable	Negotiated contract energy purchase price provides pricing certainty and transfers risks to third-party. Contributes to renewables.	Depending on the levels of disruption, third party providers may default on their agreements.
CRA Solar Power	Negotiated contract energy purchase price provides pricing certainty and transfers risks to third-party. Contributes to renewables.	Regulatory and utility changes to allow isolation from grid during blackout/disruption would make this configuration more favorable	Negotiated contract energy purchase price provides pricing certainty and transfers risks to third-party. Contributes to renewables.	Depending on the levels of disruption, third party providers may default on their agreements.
CRA BESS	Negotiated contract energy purchase price provides pricing certainty and transfers risks to third-party.	Negotiated contract energy purchase price provides pricing certainty and transfers risks to third-party. Some agreement terms may be renegotiated	Negotiated contract energy purchase price provides pricing certainty and transfers risks to third-party.	Depending on the levels of disruption, third party providers may default on their agreements.
CRA Pump Upgrades	Cost optimization from use of VFDs instead of starts/stops	VFDs will allow pump cycling to take advantage of peak prices	Upgrades will increase flexibility to operate pumps	Upgrades will increase flexibility to operate pumps when/how is most efficient and can mitigate effects from mandatory load shedding

F.2 MULTI-CRITERIA DECISION ANALYSIS (MDA)

MDA is a widely used method for ranking options based on a variety of objective performance criteria and the subjective weightings of decision makers regarding the relative importance of the criteria themselves. The overall process steps undertaken for the MDA included:

1) Establish objectives, evaluation criteria, and performance metrics.
2) Develop quantifiable performance metrics (e.g., cost, GHG emissions data)
3) Develop qualitative performance comparisons (expert ratings of 1-to-5 scale)
4) Apply weightings on an individual and group basis.
5) Identify preferred options and the reasons for preferences.

During the preparation of the MDA evaluation, project evaluation criteria and weighting approach were also discussed, as presented in the section below.

F.2.1 Project Evaluation Criteria and Weighting

The first step in establishing evaluation criteria and associated performance metrics was the review of the overall objectives that Metropolitan's ESP is designed to achieve. Developed from Metropolitan's Energy Management Policies, Table F-2 summarizes the planning objectives and maps them to the specific evaluation criteria and used in the analysis.

Table F-2: Planning Objectives and Evaluation Criteria

Planning Objective	Evaluation Criteria	Definition
Contain costs and reduce exposure to price volatility	Improved cost containment	Predictable annual average energy costs
	Reduced exposure to price volatility	Reduced hourly peak prices
	Increased revenue potential	Ability to produce net revenue within reasonable payback period
Increase operational reliability	Increased operational flexibility	Increased ability to avoid peaks and shed load
	Increased redundancy	Protection from generation and transmission disruptions on grid
Move toward energy independence	Increased energy independence	Power for direct use by Metropolitan outside of the grid
Reduce GHG emissions	Reduced carbon footprint	GHG reduction credited to Metropolitan

F.2.2 Performance Measures

The performance measures used to compare options included a combination of quantitative metrics (e.g., estimated costs and cost savings, estimated GHG emissions), as well as qualitative rankings (e.g., operational flexibility, independence from the grid). The qualitative rankings were based on the expert judgements of the workshop participants and technical staff. In addition, the evaluation separated options in the retail markets (located at WTPs and facilities within the service area), from those in the wholesale market (CRA pumping and storage facilities). Table F-3 presents the combined quantitative metrics and qualitative scores for the retail project options evaluated in the MDA analysis. For comparative purposes redundant metrics associated with the cost containment criterion were combined into a composite score.

Table F-3: Retail Options Criteria and Performance

Evaluation Criteria	Retail Projects														
	1001	1003	1004	1005	1006	1007	1008	1009	1010	1011	1012	1013	1015	1016	1017
Location	Weymouth	Skinner	Skinner	Skinner	Skinner	Skinner	Skinner	Skinner	Mills	Mills	Mills	Mills	Jensen	OC-88	Diemer
Technology	BESS + Existing Solar + Grid	New Solar/Solar Expansion (Owned)	New Solar/Solar Expansion (PPA)	New Solar/Solar Expansion (Owned)	New Solar/Solar Expansion (PPA)	BESS + Existing Solar + Grid	BESS + New Solar	BESS + New Solar	New Solar/Solar Expansion (Owned)	New Solar/Solar Expansion (PPA)	BESS + New Solar	BESS + Grid	BESS + Existing Solar + Grid	BESS + Grid	YL BTM
Battery Power Capacity (MW)	1	0.0	0.0	0.0	0.0	1.0	1.0	1.0	0.0	0.0	0.3	1.0	1.0	1.0	0.0
Battery Energy Capacity (MWh)	2.0	0.0	0.0	0.0	0.0	2.0	2.0	2.0	0.0	0.0	0.9	2.0	2.0	2.0	0.0
Solar Generating Capacity (MW)	0.0	1.0	1.0	2.0	2.0	0.0	1.0	2.0	0.5	0.5	0.5	0.0	0.0	0.0	-
Renewable Energy Generated (GWh/year)	0.0	2.5	0.0	5.0	0.0	0.0	2.5	5.0	1.2	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Energy Used (GWh/year)	0.0	2.3	0.0	3.2	0.0	0.0	2.3	3.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0
Cost Containment - NPV	$345,000	$240,000	$277,000	$654,000	$523,000	$396,000	$1,600,000	$1,993,000	$140,000	$566,000	$356,000	$102,000	$275,000	$308,000	$5,000,000
Cost Containment - Payback (Years)	5	14	0	14	0	5	10	12	14	0	14	7	5	5	4
Cost Containment - Estimated Annual Savings ($000)	$89	$134	$25	$267	$46	$86	$233	$366	$111	$54	$134	$36	$60	$57	$400
Reduced Exposure to Volatility	5	3	3	3	3	5	5	5	3	3	5	5	5	5	5
Operational Flexibility	5	3	3	3	3	5	5	5	3	3	5	4	5	4	5
Increased Redundancy	5	3	3	3	3	5	5	5	3	3	5	5	5	5	5
Increaed Revenue Potential	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Increased Energy Independence	5	5	5	5	5	5	5	5	5	5	5	1	5	1	5
Reduced Carbon Footprint (metric tonnes/year)	10.0	271.0	271.0	375.0	375.0	10.0	256.0	427.0	145.0	145.0	131.0	10.0	10.0	10.0	1061.0

For each of the criteria, a range of dimensionless scores from the highest ranked option (assigned a score of 1.0) to the lowest ranked option (assigned a score of 0.0) was developed. Scores between the highest and lowest performance were assigned a linear distribution of the intermediate values on the scale from 0 to 1. For example, Table F-4 illustrates the conversion of estimated annual savings for each option (presented in thousands of dollars per year) to relative scores from 1 to 0.

Table F-4: Conversion of Performance Metrics to Dimensionless Relative Values

Location	Diemer	Skinner	Skinner	Skinner	Skinner	Mills	Mills	Weymouth	Skinner	Jensen	OC-88	Mills	Skinner	Mills	Skinner
Technology	YL BTM	BESS + New Solar	New Solar/Solar Expansion (Owned)	BESS + New Solar	New Solar/Solar Expansion (Owned)	BESS + New Solar	New Solar/Solar Expansion (Owned)	BESS + Existing Solar	BESS + Existing Solar	BESS + Existing Solar	BESS + Grid	New Solar/Solar Expansion (PPA)	New Solar/Solar Expansion (PPA)	BESS + Grid	New Solar/Solar Expansion (PPA)
Estimated Annual Savings ($000)	$400	$366	$267	$233	$134	$134	$111	$89	$86	$60	$57	$54	$46	$36	$25
Annual Savings (Relative Score)	1.000	0.909	0.645	0.555	0.291	0.291	0.229	0.171	0.163	0.093	0.085	0.077	0.056	0.029	0.000

Note: Columns have been sorted from highest score to lowest score.

This method allows for the comparison of relative performance of options without the need to convert an assortment of diverse quantitative and qualitative performance metrics into a common dollar-denominated quantitative measure. Table F-5 presents each of the criteria performance metrics in Table 2 expressed on a relative score basis. At this stage, the evaluation criteria are equally weighted, and the totals do not reflect the importance of the respective objectives.

Table F-5: Unweighted Partial and Total Retail Scores

Location	Weymouth	Skinner	Skinner	Skinner	Skinner	Skinner	Skinner	Skinner	Mills	Mills	Mills	Mills	Jensen	OC-88	Diemer
Technology	BESS + Existing Solar + Grid	New Solar/Solar Expansion (Owned)	New Solar/Solar Expansion (PPA)	New Solar/Solar Expansion (Owned)	New Solar/Solar Expansion (PPA)	BESS + Existing Solar + Grid	BESS + New Solar	BESS + New Solar	New Solar/Solar Expansion (Owned)	New Solar/Solar Expansion (PPA)	BESS + New Solar	BESS + Grid	BESS + Existing Solar + Grid	BESS + Grid	YL BTM
Cost Containment Composite	0.288	0.106	0.345	0.253	0.381	0.289	0.382	0.479	0.079	0.391	0.114	0.176	0.257	0.257	0.905
Reduced Exposure to Volatility	1.000	0.500	0.500	0.500	0.500	1.000	1.000	1.000	0.500	0.500	1.000	1.000	1.000	1.000	1.000
Operational Flexibility	1.000	0.500	0.500	0.500	0.500	1.000	1.000	1.000	0.500	0.500	1.000	0.750	1.000	0.750	1.000
Increased Redundancy	1.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000
Increased Revenue Potential	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Increased Energy Independence	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	1.000	0.000	1.000
Reduced Carbon Footprint	0.000	0.248	0.248	0.347	0.347	0.000	0.234	0.397	0.128	0.128	0.115	0.000	0.000	0.000	1.000
TOTALS	**4.288**	**2.355**	**2.594**	**2.600**	**2.728**	**4.289**	**4.616**	**4.876**	**2.207**	**2.519**	**4.229**	**2.926**	**4.257**	**3.007**	**5.905**

F.2.3 Criteria Weights

In order to capture the differences in importance placed on objectives by the individual decision-makers, each of the 16 participants in the workshop process was requested to complete a survey used to compute relative weightings of planning objectives. Table 6 presents the total number of weighting points awarded to each criterion and the resulting percentages used to weight the performance scores of each option.

Table 6: Evaluation Criteria Weightings

Evaluation Citiera	Points	Percentage
Improve Cost Containment	57	17%
Reduce Impact of Price Volatility	49	15%
Increase Revenue Creation	24	7%
Increase Operational Flexibility	88	26%
Increase Redundancy	51	15%
Increase Energy Independence	26	8%
Reduce Carbon Footprint	41	12%
Total	**336**	**100%**

When the weightings in Table 6 are applied to the raw scores in Table 5, the resulting weighted scores for each option are presented in Table 7.

Table 7: Weighted Partial and Total Retail Scores

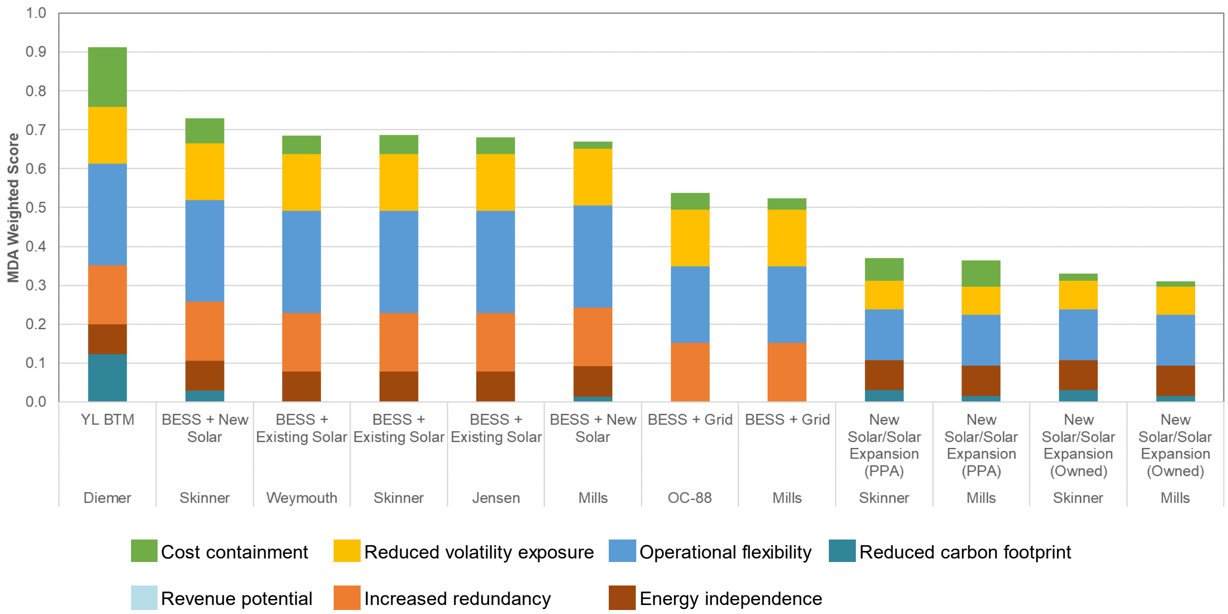
Location	Diemer	Skinner	Skinner	Weymouth	Skinner	Jensen	Mills	OC-88	Mills	Skinner	Skinner	Skinner	Mills	Skinner	Mills
Technology	YL BTM	BESS + New Solar	BESS + New Solar	BESS + Existing Solar	BESS + Existing Solar	BESS + Existing Solar	BESS + New Solar	BESS + Grid	BESS + Grid	New Solar/Solar Expansion (PPA)	New Solar/Solar Expansion (PPA)	New Solar/Solar Expansion (Owned)	New Solar/Solar Expansion (PPA)	New Solar/Solar Expansion (Owned)	New Solar/Solar Expansion (Owned)
Cost Containment Composite	0.153	0.081	0.065	0.049	0.049	0.044	0.019	0.044	0.030	0.065	0.059	0.043	0.066	0.018	0.013
Reduced Exposure to Volatility	0.146	0.146	0.146	0.146	0.146	0.146	0.146	0.146	0.146	0.073	0.073	0.073	0.073	0.073	0.073
Operational Flexibility	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.196	0.196	0.131	0.131	0.131	0.131	0.131	0.131
Increased Redundancy	0.152	0.152	0.152	0.152	0.152	0.152	0.152	0.152	0.152	0.000	0.000	0.000	0.000	0.000	0.000
Increased Revenue Potential	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Increased Energy Independence	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.000	0.000	0.077	0.077	0.077	0.077	0.077	0.077
Carbon Emission Reduction	0.122	0.048	0.029	0.000	0.000	0.000	0.014	0.000	0.000	0.042	0.030	0.042	0.016	0.030	0.016
TOTALS	0.912	0.767	0.730	0.686	0.686	0.681	0.670	0.538	0.524	0.388	0.370	0.366	0.363	0.330	0.310

Note: Columns have been sorted from highest score to lowest score.

F.2.4 Retail Market Project Option Rankings and Preferences

The result of the retail project options ranking and preference of the values presented in Table 7 is presented in Figure 5. The options have been sorted from highest score to lowest. The highest performing retail option is a new direct connection from the Yorba Linda Power Plant to the Diemer WTP (behind the SCE meter). As the figure illustrates, this investment has the potential to offer Metropolitan significant savings and a short payback of the initial capital investment. In addition, this project is anticipated to eliminate exposure to retail price increases of electricity purchased from SCE, allowing Diemer operations to function free from consideration of TOU penalties, and provide an alternative renewable power source to the grid at the Diemer WTP. The potential for the increased revenue criterion is not satisfied by this option since Yorba Linda hydropower is currently sold under a term contract, so utilizing it for Diemer WTP energy demand involves a trade-off of reduced energy sales.

Figure 5: Breakdown of Retail Option Weighted Scores by Criterion



Options with battery energy storage integrated with existing or expanded solar are the next highest performing investments after the Yorba Linda configuration. These projects have somewhat longer payback periods but enable treatment plants to utilize battery energy storage to optimize solar power generation throughout the day, reducing costs and providing TOU flexibility for operations. In addition, batteries charged with renewable energy reduce the potential for GHG emissions. The combination of battery energy storage and solar generation could also offer treatment plants the potential to operate independently from the grid in a microgrid configuration for a limited period, in conjunction with backup emergency generators. However, allowing microgrid (or islanded) operations at Metropolitan facilities has not yet been assessed.

The options that include expanded solar facilities provide the additional benefit of further reducing carbon emissions. Procurement methods involving PPAs versus Metropolitan ownership would transfer project cost risk to the developer and monetize solar tax credits. An evaluation of the actual tradeoffs will require further development of PPA options versus Metropolitan's costs.

Options that utilize stand-alone battery storage to shift power purchases from the grid to off-peak hours can arbitrage TOU pricing periods and provide flexibility for operations relative to hourly pricing differences. However, unlike the combination of battery storage and solar generation, the quantification of the GHG emission reduction potential is challenging and only possible if the batteries are charged from renewable power. New innovative technologies to track the source of GHG emissions could enable both price arbitrage and GHG reduction tracking.

F.2.5 Wholesale Market Project Rankings and Preferences

The MDA evaluation was also applied to the wholesale market project options considered in this study. Unlike the approach used for the retail market project options, the project alternatives considered for the wholesale market were only scored qualitatively, and their ratings were only based on input from the workshop participants. For each criterion, a 1 to 5 scale ranking was established. Table 8 presents the scores for each option and a brief explanation.

Table 8: Evaluation Criteria and Qualitative Scoring

		Small Hydropower (<30 MW)	Pumped Storage - Metropolitan Owned	Pumped Storage - Third-Party Owned	CRA Utility-Scale Wind Power	CRA Utility-Scale Solar Power	CRA Utility-Scale BESS	CRA Operational Flexibility
Contain costs and reduce exposure to price volatility	**Increase Cost Containment**	Sale revenue	Unpredictable costs due to reliance on wholesale market	Negotiated contract energy purchase price	Negotiated contract energy purchase price	Solar hours are already low-priced	Requires additional financial feasilibliy	Cost optimization from energy reductions
		2 - Unlikely	1 - Very Unlikely	4 - Likely	3 - Unknown	3 - Unknown	3 - Unknown	5 -Very Likely
		2	1	4	3	3	3	5
	Reduced Exposure to Price Volatility	None - fixed price contract for hydropower	Can offset large margins on wholesale market	Negotiated contract energy purchase price	Negotiated contract energy purchase price	Negotiated contract energy purchase price - energy only availabe during solar hours	Energy arbitrage	VFDs can allow pump cycling during peaks
		1 - No Reduction	5 - Major Reduction	4 - High Reduction	3 - Some Reduction	3 - Some Reduction	5 - Major	5 - Major Reduction
		1	5	4	3	3	5	5
	Increased Revenue Potential	Generates power for grid	Dependent on wholesale energy prices - could result in stranded asset	None - negotiated contract purchase price	None - negotiated contract purchase price	None - negotiated contract purchase price	None - energy bill savings not revenue	None - energy bill savings not revenue
		5 - Revenue Generator	3 - Limited Revenue	1- No Revenue	1- No Revenue	1- No Revenue	1- No Revenue	1- No Revenue
		5	3	1	1	1	1	1
Increase operational reliability	**Increased Operational Flexibility**	None - not connected to Metropolitan load	DVL - Potential quagga contamination Copper Basin - Requires more operational considerations along the CRA and would reduce operating levels of Copper Basin	Dependent on contract terms of how/when energy is purchased	Dependent on contract terms of how/when energy is purchased	Dependent on contract terms of how/when energy is purchased	Can operate pumpsusing low-cost energy stored in battery. Less concerned about load shedding	Upgrades will increase flexibility of when/how pumps are operated
		2 - No Additional	1 - Reduction in Flexibility	3 - Some Additional	3 - Some Additional	3 - Some Additional	5 - High	5 - High Additional
		2	1	3	3	3	5	5
	Increased Redundancy	Reliant on grid to sell power	May provide minimal backup but still reliant on grid	May provide minimal backup but still reliant on grid	Dependent if disconnect from grid during blackout	Intermittent supply not guaranteed during grid blackout	May provide minimal backup but still grid reliant	Still reliant on grid energy
		1 - No	1 - No	1 - No	3 - Maybe	1 - No	1 - No	1 - No
		1	1	1	3	1	1	1
Move toward energy independence	**Increased Energy Independence**	Non-grid source of energy but not connected to Metropolitan load	Grid-reliant energy source	Dependent if disconnect from grid during blackout	Dependent if disconnect from grid during blackout	Intermittent supply not guaranteed during grid blackout	Not a source of energy	Not a source of energy
		1 - No	1 - No	3 - Maybe	3 - Maybe	1 - No	1 - No	1 - No
		1	1	3	3	1	1	1
Increase energy sustainability	**Reduced Carbon Footprint**	Hydro does not reduce carbon - unless RECS are kept	None - arbitrage only uses grid energy	None - arbitrage only uses grid energy	Renewable energy	Renewable energy	Maybe if real-time,daily carbon emissions are tracked	Pump cycling may lead to energy reduction
		3 - Maybe	3 - Maybe	3 - Maybe	5 - Yes	5 - Yes	3 - Maybe	3 - Maybe
		3	3	3	5	5	3	3

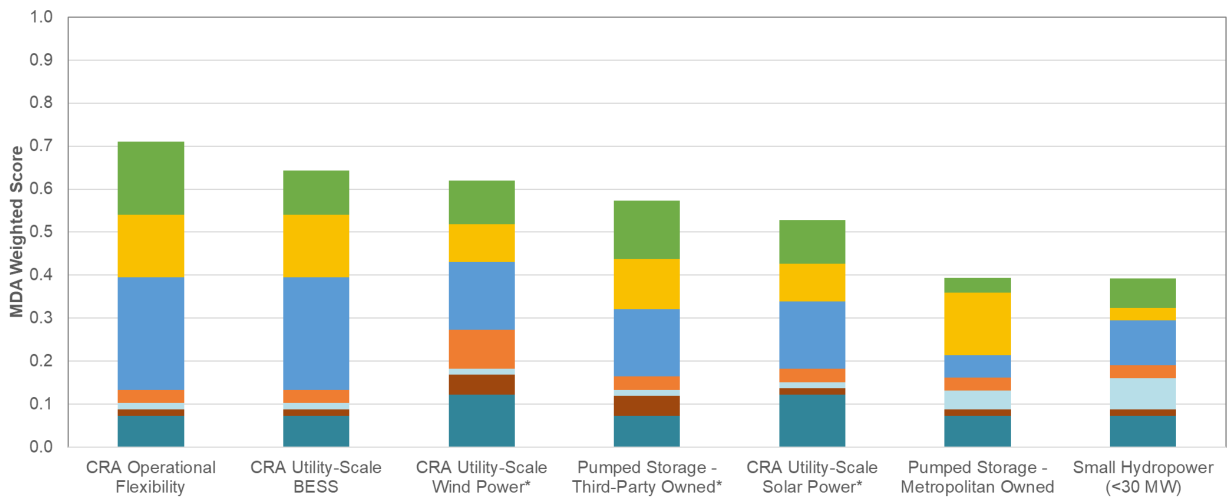
Similar to the process for retail market projects, a range of dimensionless scores from the highest ranked option (assigned a score of 1.0) to the lowest ranked option (assigned a score of 0.0) was developed and weighted per Table 6. Table 9 presents the weighted scores for each of the wholesale market project options, using the same methodology applied to the retail market project evaluation.

Table 9: Weighted Partial and Total Wholesale Option Scores

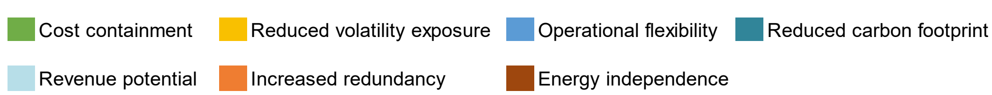
	CRA Operational Flexibility	CRA Utility-Scale BESS	CRA Utility-Scale Wind Power*	Pumped Storage - Third-Party Owned*	CRA Utility-Scale Solar Power*	Pumped Storage - Metropolitan Owned	Small Hydropower (<30 MW)
Increase Cost Containment	0.170	0.102	0.102	0.136	0.102	0.034	0.068
Reduced Exposure to Price Volatility	0.146	0.146	0.088	0.117	0.088	0.146	0.029
Increased Operational Flexibility	0.262	0.262	0.157	0.157	0.157	0.052	0.105
Increased Redundancy	0.030	0.030	0.091	0.030	0.030	0.030	0.030
Increased Revenue Potential	0.014	0.014	0.014	0.014	0.014	0.043	0.071
Increased Energy Independence	0.015	0.015	0.046	0.046	0.015	0.015	0.015
Reduced Carbon Footprint	0.073	0.073	0.122	0.073	0.122	0.073	0.073
TOTALS	0.711	0.643	0.620	0.574	0.529	0.394	0.392

Figure 6 presents a comparison of the wholesale market project options with weighted scores by criterion, sorted from highest score to lowest.

Figure 6: Breakdown of Wholesale Option Weighted Scores by Criterion



**Note: Projects involving third-party developers are subject to large uncertainty due to legal and contract considerations for energy generation along the CRA. Benefits of these projects should be reevaluated once contract conditions are determined.*



As illustrated, the CRA pump upgrades were the highest ranked option due to the high level of importance placed on increased operational flexibility, expected cost savings, and reduced exposure to and the ability to take advantage of price volatility. CRA utility-scale BESS also provides a similar level of operational flexibility, a reduced exposure to price volatility by taking advantage of the depressed prices of the duck curve, and the potential to reduce GHG emissions and obligations to purchase offsets for imported fossil fuel energy. Small hydropower scored lowest for reduced volatility, since Metropolitan-generated hydropower is sold at a contracted price and the counterparty would receive those benefits. Metropolitan-owned pump storage scored lowest for operational flexibility because this asset is relatively high cost and capital intensive and would operate independent of CRA pump operations. Adding pumped storage operations may impair the already limited flexibility

Metropolitan has for CRA pumping and distribution operations. However, this is dependent on the annual supply through the CRA and would require a more detailed study to evaluate impacts to CRA operations.

As indicated in Figure 5, wholesale energy projects involving third-party developers (including wind, solar, and pumped storage) are subject to large uncertainty in the contract terms and conditions for energy generation projects along the CRA. These projects exchange CRA variable costs for fixed costs, but project economic assessment indicates that these options have a long payback and the benefits are uncertain as they are highly dependent on contract conditions with third-party developers. The results presented above are offered for comparison but should be reevaluated once contract conditions are determined.

F.2.6 Energy Management Best Practices Rankings and Preferences

Energy management best practices were not evaluated on a project-level basis and therefore, were not included in the MDA evaluation. In general, energy efficiency improvements (e.g., submetering, energy audits, dashboards) would typically rank high for cost containment, reduced exposure to volatility and carbon emissions reductions due to reductions in overall energy usage through consistent implementation of these practices.

F.3 COMBINED EVALUATION CONCLUSIONS

Table 5 10 below provides a consolidated picture of the retail and wholesale energy market project options, respectively, presenting the ranking of the option in the MDA, as well as an assessment of the performance of the option in each of the four scenario settings. The table also provides, in parallel, the financial and carbon emission reduction assessment results. The vulnerabilities and weaknesses under the four scenario narratives were reported in a color-coded format, with the green square indicating acceptable performance, the red square indicating poor performance or stranded assets, and the yellow square used when the impact on the performance is uncertain.

Both methods produced similar results, in part due to the multiple benefits offered by options that received high rankings in the MDA. For example, an option that significantly increases operational flexibility (i.e. Solar paired with BESS, CRA pumps at Intake and Gene Pumping Plants upgraded with VFDs) is more robust under a wide range of scenarios. It should be noted that while the projects in the above tables are ordered based on the MDA results, this is not the final ranking of project prioritization. The benefits of each project across multiple planning assessments (financial, carbon emission reduction, MDA and scenario analysis) are meant to be used by Metropolitan staff to consider projects that may not have the most optimal financial results but could provide less risk with added benefits in an unknown future.

Both of these evaluation tools, working together, go well beyond a simple cost-benefit calculation and provide a framework for dynamic planning into an uncertain future. They consider benefits beyond cost savings and can guide Metropolitan towards adaptive and sustainable energy management solutions.

Table 10: Retail and wholesale project options and results of financial, MDA, and scenario planning assessments

	NPV ($)	Payback Period (years)	Carbon Emission Reduction (MT CO_2/year)	MDA Ranking	Scenario Assessment Performance			
					A	B	C	D
Retail Project Options								
Yorba Linda behind meter at Diemer	$5,000,000	4	1,061	1				
Skinner – BESS + New Solar	$1,600,000	10	256	2, 3				
Weymouth – BESS + Existing Solar	$345,000	5	10	4				
Skinner – BESS + Existing Solar	$396,000	5	10	5				
Jensen – BESS + Existing Solar	$275,000	5	10	6				
Mills – BESS + New Solar	$356,000	14	131	7				
Skinner – New Solar (PPA)	$277,000	-	271	8, 9				
Skinner – New Solar (Owned)	$240,000	14	271	10, 14				
Mills – New Solar (PPA)	$566,000	-	145	11				
OC-88 – BESS + Grid	$308,000	5	10	12				
Mills – BESS + Grid	$102,000	7	10	13				
Mills – New Solar (Owned)	$140,000	14	145	15				
Wholesale Project Options								
CRA Pump Upgrades	To be determined in the preliminary investigation of the CRA's pumps			1				
Utility-Scale Battery Storage (Owned)	$17,800,000	15	Varies	2				
Utility-Scale Wind Power	To be determined based on discussion with potential developers			3				
Pumped Storage (Third Party)				4				
Utility-Scale Solar Power				5				
Pumped Storage (Owned)	Results pending			6				
Small Hydropower	Varies – see Appendix D			7				

Note: Acceptable performance; Uncertain impact on performance; Poor performance

Scenario: A: Steady and predictable water and energy; B: Chaotic energy market and stable water supply; C: Energy market adjusts but water supply stressed; D: Volatile climate stresses water and energy market disrupted.

THE METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA

Stantec