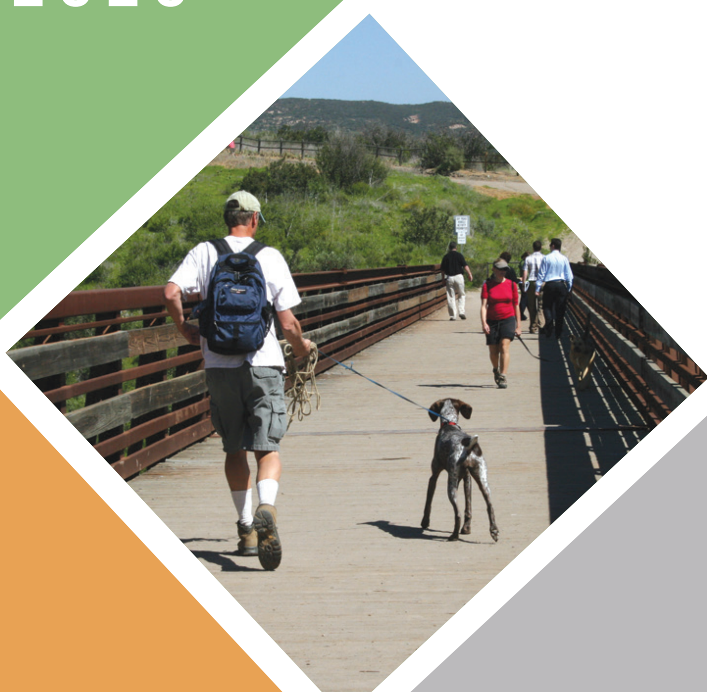
Our Region's Trusted Water Leader
San Diego County Water Authority

2019 CLIMATE ACTION PLAN

JUNE 2020



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LIST OF ACRONYMS

2013 Master Plan Update	**2013 Regional Water Facilities Optimization and Master Plan Update**
2015 UWMP	**2015 Urban Water Management Plan**
AB	**Assembly Bill**
AHEF	**Alvarado Hydroelectric Facility**
BAU	**business-as-usual**
CAFE	**Corporate Average Fuel Economy**
CAP	**Climate Action Plan**
CARB	**California Air Resources Board**
CEQA	**California Environmental Quality Act**
CH4	**methane**
CIP	**Capital Improvements Program**
CO2e	**carbon dioxide equivalent**
CPUC	**California Public Utilities Commission**
ECO	**energy conservation opportunity**
EO	**Executive Order**
GHG	**greenhouse gas**
GWP	**global warming potential**
hp	**horsepower**
HVAC	**heating, ventilation, and air conditioning**
kWh	**kilowatt hour(s)**
LCFS	**Low Carbon Fuel Standard**
LGOP	**Local Government Operations Protocol**
MMT	**million metric tons**
MT	**metric tons**
MW	**megawatt(s)**
MWh	**megawatt hour(s)**
NOC	**notice-of-completion**
PCHF	**Pressure Control and Hydroelectric Facility**
PV	**photovoltaic**
REC	**Renewable Energy Credit**
RPS	**Renewables Portfolio Standard**
SB	**Senate Bill**
SDG&E	**San Diego Gas & Electric**
Water Authority	**San Diego County Water Authority**
WTP	**Water Treatment Plant**

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APPENDICES

EXECUTIVE SUMMARY

The State of California has adopted policies and goals to reduce emissions of greenhouse gases (GHGs). The San Diego County Water Authority (Water Authority), as a local government agency, voluntarily developed a Climate Action Plan (CAP) in 2014 and provides updates every 5 years to look comprehensively at the Water Authority practices and operations, with a goal of minimizing GHG emissions while fulfilling its primary responsibility to provide a reliable, high-quality, and safe water supply to the San Diego region. This CAP, which is an update to the 2014 CAP, allows the Water Authority to look at agency-wide emission and use its unique resources to reduce those emissions. Emissions sources addressed in this CAP include the Water Authority's use of electricity and natural gas; operation of the vehicle fleet, employee commutes, off-road equipment and other stationary sources (e.g., electric generators); solid waste disposal and wastewater discharge; energy use related to water consumption; and refrigerant use.

A GHG emissions inventory provides a snapshot of GHG emissions currently occurring within a region or agency. The inventory is useful in identifying areas that have high emissions or high potential for cost-effective GHG-reduction policies, actions, and control measures. For the CAP, the Water Authority conducted an emissions inventory in calendar year 2009, which serves as the basis for establishing reduction goals and is referred to as the "baseline" emissions inventory.

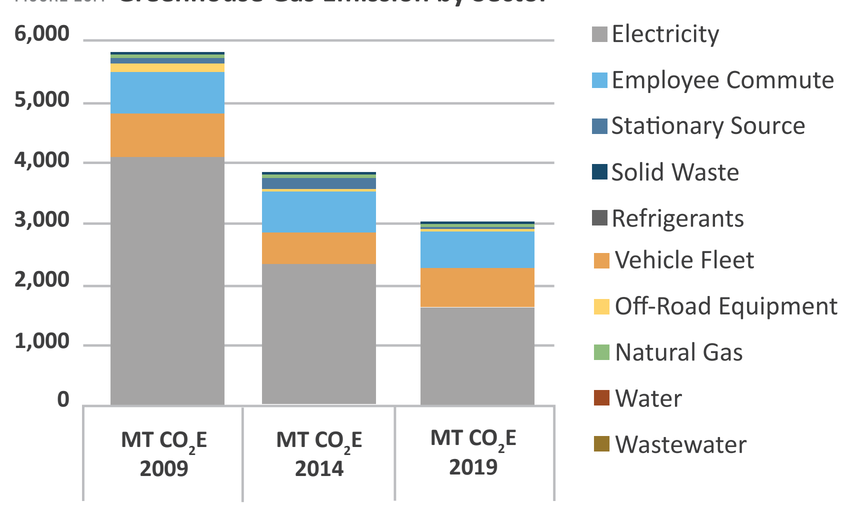
The baseline emissions inventory approximated the Water Authority's GHG emissions to be 5,837 metric tons (MT) of carbon dioxide equivalents (CO2e) in 2009, predominantly from electricity required for water conveyance and treatment. The 2019 emissions inventory update demonstrated an approximately 48% decrease in the GHG emissions from 2009 levels, for a total of 3,024 MT CO2e in 2019; the majority of emissions continue to result from electricity use. Reductions were achieved through successful implementation of GHG-reducing measures, including energy conservation opportunities (ECOs) identified in the 2012 Energy Audit. The audit evaluated energy usage and associated ECOs at nine of the Water Authority's facilities which consume the greatest amount of energy. Figure ES.1 provides a comparison of the Water Authority's 2009, 2014, and 2019 emissions by sector.

This CAP was developed to align with the goals of Assembly Bill (AB) 32 and Senate Bill (SB) 32. To demonstrate consistency with AB 32 GHG target, the Water Authority set a 2020 target (referred to as the 1990 equivalent) to reduce emissions to 15% below baseline 2009 levels to approximate a return to 1990 levels consistent with California's 2008 Climate Change Scoping Plan. This CAP established the Water Authority's goal for 2030, consistent with the statewide target under SB 32, of 40% below the 1990 equivalent (2020 target). A new state-adopted GHG target that expands beyond the targets set in AB 32 and SB 32, includes carbon neutrality by 2045 set forth by EO B-55-18 which was signed on September 2018. Efforts for this CAP began before the signing of EO B-55-18; however, the next 5-year CAP will address this and any other codified targets.

This CAP presents emissions projections for the years 2020 and 2030 to demonstrate how the Water Authority will achieve its state-aligned GHG emissions reduction targets. Table ES.1 and Figure ES.2 illustrate the Water Authority's future emissions and reduction targets with current GHG reduction strategies in place and future reduction opportunities in place.

Through conserving water, implementing GHG-reducing measures, and investing in projects that will ensure reliable water supply and generate renewable energy, the Water Authority is on track to meet its reduction targets for the foreseeable future. To demonstrate a target achievement pathway, this CAP incorporates emissions

FIGURE ES.1 **Greenhouse Gas Emission by Sector**

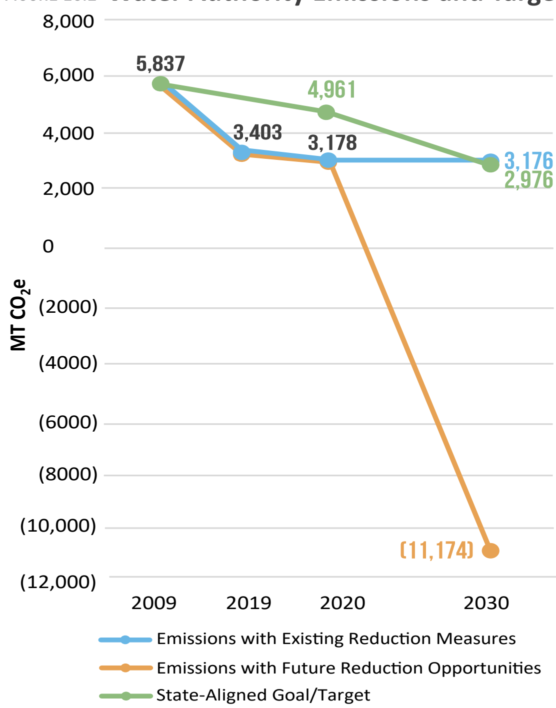


The Water Authority will meet and exceed reduction targets for 2020 and 2030 and will continue to work to reduce or offset its emissions well into the foreseeable future.

reductions expected to result from various regulations and policies and identifies the specific strategies and efforts the Water Authority will take to continue reducing its GHG emissions. These regulatory actions and impacts of the Water Authority's continued implementation of emissions reductions strategies result in a 2020 and 2030 target achievement pathway that can be monitored and revised in future CAP updates.

Emissions projections also allow the Water Authority to see how emissions change over time considering major projects and operational changes. The Water Authority recognizes that the issue of climate change will not end in 2030 and that changing climate conditions have significant implications for long-term water supply planning and the need for energy efficiency and water supply adaptations. As such, the Water Authority has identified additional opportunities for reducing GHG emissions within its operations. Reduction opportunities include the Water Authority's Capital Improvement Program planned projects, ECOs from the 2012 Energy Audit, and renewable energy credits (RECs) for the Rancho Peñasquitos Hydroelectric Facility and the proposed Alvarado Hydroelectric Facility. As shown in Table ES.1 and Figure ES.2, the Water Authority has sufficient existing measures in place to meet 2020 targets and sufficient RECs available to meet 2030 targets. In future CAP updates, the Water Authority will evaluate the use of the available RECs considering projected emissions totals, GHG emissions targets set by regulations such as EO B-55-18 (carbon neutrality by 2045), and financial impacts. This CAP and future updates are part of the Water Authority's agency-wide commitment to energy efficiency and contribution to state goals now and into the future.

FIGURE ES.2 **Water Authority Emissions and Targets**



Note: MT CO_2e = metric tons of carbon dioxide equivalent.

TABLE ES.1 **Summary of Water Authority Greenhouse Gas Emissions and Targets (MT CO_2e)**

	2019 EMISSIONS INVENTORY (MT CO_2E)	2020 PROJECTED EMISSIONS (MT CO_2E)	2030 PROJECTED EMISSIONS (MT CO_2E)
Emissions[1]	3,024	3,047	3,061
Construction Emissions	379	131	596
State and Federal Reductions	0	0	(481)[2]
EMISSIONS WITH EXISTING REDUCTION MEASURES	3,403	3,178	3,176
In-Line Hydropower Generation RECs	0	0	(14,320)
Energy Audit ECOs	0	0	(30)
EMISSIONS WITH FUTURE REDUCTION OPPORTUNITIES	3,403	3,178	(11,174)
STATE-ALIGNED GOAL/TARGET	NA	4,961	2,976

Notes: MT CO_2e = metric tons of carbon dioxide equivalent; REC= Renewable Energy Credit; ECO= Energy Conservation Opportunity. Negative number indicates net emissions reduction. 2009 emissions were baselined at 5,837 MT CO_2e

[1] Excludes construction emissions

[2] State and federal reductions from Renewables Portfolio Standard

01 INTRODUCTION

The Water Authority supports cost-effective sustainability programs that will benefit the environment and promote thoughtful stewardship of natural resources. These programs save ratepayers money, reduce the environmental impacts of Water Authority operations, conserve energy and water, and help the Water Authority better anticipate and adapt to the impacts of climate change.

OUR MISSION

The San Diego County Water Authority (Water Authority) has been delivering safe and reliable water supplies to its member agencies in the San Diego region since 1944. Originally serving nine agencies, the Water Authority is now composed of 24 member agencies consisting of 13 water districts, six cities, three irrigation districts, one public utility district, and one military base (Figure 1.1). The Water Authority works closely with its member agencies to supply water in the most efficient ways possible, both in terms of cost and resource use, and has long been a champion of energy efficiency and sustainability. As part of its sustainability efforts, the Water Authority developed this Climate Action Plan (CAP) to support the state's efforts to reduce greenhouse gas (GHG) emissions and address climate change.

OUR MISSION

- To provide a safe and reliable supply of water to our member agencies serving the San Diego region.

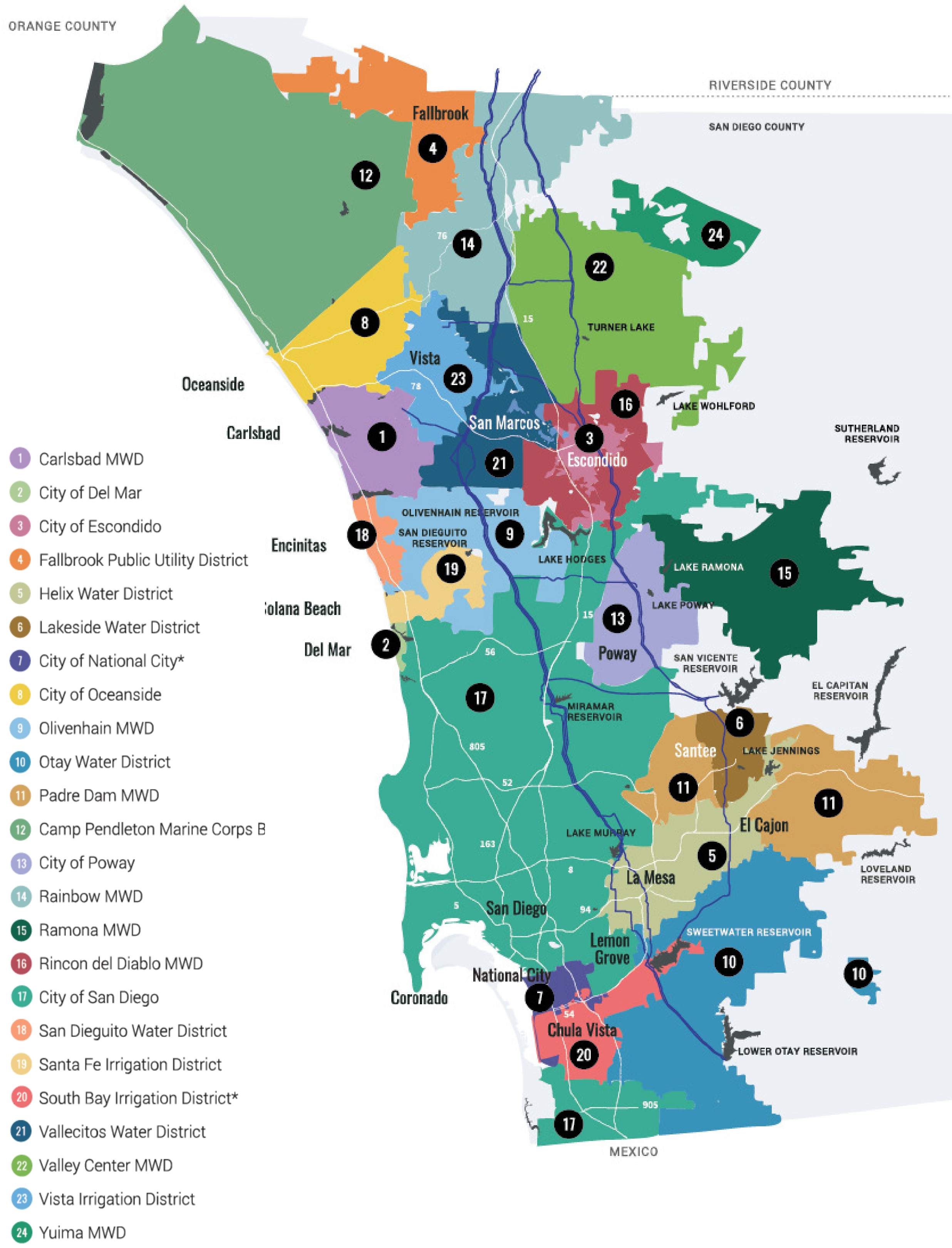
OUR VISION

- To secure our water future and triumph over tomorrow's challenges using a pioneering, visionary, agile, and driven approach. That's who we are. That's what we do.

OUR VALUES

- We will consider our partner agencies' and stakeholders' interests in our decisions.
- We will do our work in the most cost-effective ways.
- We will have open communications with our partner agencies and the public.
- We will have an open and inclusive policy-development process.
- We value diversity in the water supply.
- We value long-range planning.

FIGURE 1.1 **Water Authority Member Agencies**



* The Sweetwater Authority is a service organizat
City of National City and the South Bay Irrigation

PURPOSE OF THIS CLIMATE ACTION PLAN

The Water Authority recognizes climate change as a global issue, but one that must be acted on locally. While the Water Authority provides an essential service to the community, its actions result in emissions of GHGs, which contribute to climate change. Past and current efforts have focused on energy efficiency activities. The original CAP was developed in 2014 in conjunction with the 2013 Regional Water Facilities Optimization and Master Plan Update (2013 Master Plan Update) and updated in 2015 to include projects that further the Water Authority's energy effectiveness. To ensure that the Water Authority is monitoring its GHG emissions reduction efforts relative to its projections documented in the CAP, the Water Authority has committed to track progress on an annual basis and update the CAP every 5 years. This CAP was developed to look comprehensively at the Water Authority's current practices, operations, and progress toward state aligned emissions targets, and identify feasible measures that could be implemented to reduce GHG emissions. The current CAP was updated to establish a new 2030 GHG target aligned with the state's target set in Senate Bill (SB) 32. The future CAP will incorporate new regulatory goals of carbon neutrality and 100% renewable energy by 2045 aligned with Executive Order (EO) B-55-18. To demonstrate a target achievement pathway, this CAP incorporates emissions reductions expected to result from various regulations and policies and identifies the specific strategies and efforts the Water Authority will take to continue reducing its GHG emissions. Combined, these regulatory actions and impact of the Water Authority's continued implementation of identified strategies show a 2030 target achievement pathway that can be monitored and revised in future CAP updates. The CAP also goes further, and quantifies emissions from all GHG-emitting sources and seeks to reduce those emissions wherever feasible. Emissions sources addressed in this CAP include the Water Authority's use of electricity and natural gas; operation of the vehicle fleet, employee commutes, off-road equipment and other stationary sources (e.g., electric generators); solid waste disposal and wastewater discharge; energy use related to water consumption; and refrigerant use (see Chapter 2 for more details).

This CAP was developed to look comprehensively at the Water Authority's current practices, operations, progress toward state aligned emissions targets, and identify feasible measures that could be implemented to reduce GHG emissions and climate change impacts.

The remainder of this chapter consists of a brief description of global climate change; how climate mitigation and adaptation efforts address climate change; and how existing regulation applies to the Water Authority, including SB X7-7, which is a separate but complementary effort for reducing emissions related to water use.

Chapter 2 describes the GHG profile of the Water Authority in detail, including current and future emissions and reduction goals. Chapter 3 provides detail on existing strategies at the federal, state, and local levels that have already reduced the Water Authority's emissions. Chapter 4 identifies additional opportunities for continued reductions. Chapter 5 details how the CAP will be monitored, how progress will be reported over time, when the CAP will be updated, the California Environmental Quality Act (CEQA) process and how it relates to this CAP.

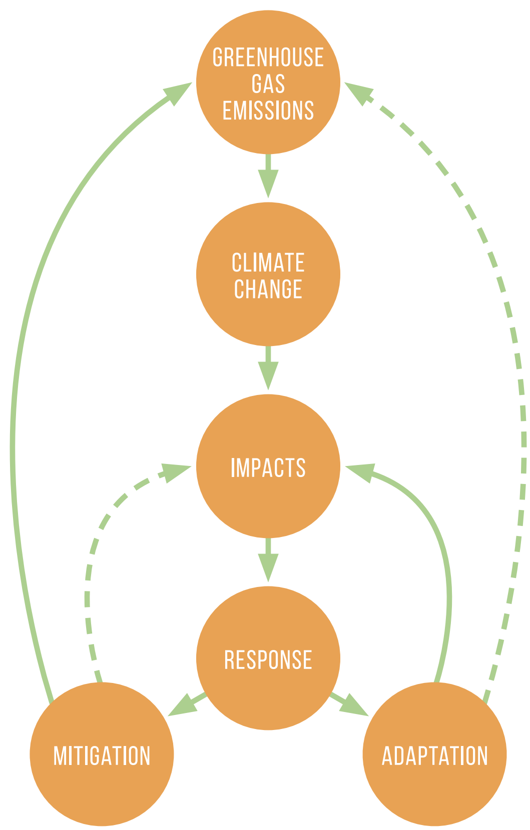
CLIMATE CHANGE SCIENCE

There is near consensus among the scientific community that certain human activities have caused increases in atmospheric GHG concentrations, which in turn have led to changes in climate. Such human activities include land alterations that reduce the Earth's carbon uptake capacity (such as deforestation) and emissions of GHGs into the atmosphere that had previously been stored below ground in the form of fossil fuels and/or in the soil. GHG sources include tailpipe emissions from vehicles, combustion of fossil fuels for home heating and electricity production, and industrial and agricultural practices.

Mitigation and Adaptation

Two potential response paths can address the risks posed by climate change: mitigation and adaptation. Mitigation acts to reduce the magnitude of future climate change, and adaptation acts to adjust to the new conditions or moderate their impacts. Mitigation efforts include reducing GHG-emitting activities and/or increasing carbon sequestration through initiatives such as tree planting, habitat enhancement or expansion, or development of carbon capture systems. This CAP primarily relies on reducing emissions to achieve its targets rather than increasing sequestration activities to offset the Water Authority's emissions. Adaptation actions include limiting vulnerability to climate change impacts through various measures. Adaptation actions can also act to mitigate emissions although that is not their primary intent (Figure 1.2). Efforts to help the Water Authority adapt to future impacts of climate change were addressed in the Water Authority's 2015 Urban Water Management Plan (2015 UWMP) and continue to be addressed in other planning efforts. The purpose of this CAP is to monitor and report the Water Authority's emissions and identify potential emissions reduction measures that can be implemented to achieve the state GHG targets.

FIGURE 1.2 **Mitigation and Adaptation as Complementary Climate Change Planning Efforts**



Notes: Solid line indicates direct link; dashed line indicates indirect link.
Source: AECOM 2020

EXISTING REGULATION

Climate change legislation and policy have been in place at the state level since 2002, with varying levels of authority and implementation. The regulations and policies most relevant to this CAP are described below. Implementing this framework to reduce GHG emissions will reduce the Water Authority's future operational emissions analyzed in this CAP through:

- Decreased electricity emissions from greater use of renewable energy sources,
- Decreased vehicle emissions from Water Authority fleet vehicles and employees' personal vehicles from enhanced vehicle efficiency requirements and reduced transport fuel carbon intensity, and
- Decreased customer water demand from enhanced water conservation programs.

State Level California GHG Target Framework

The state's GHG target setting framework has been established through a series of Executive Orders and adopted Assembly Bills or Senate Bills. In 2005, through EO S-3-05, the governor established the state's first set of GHG goals:

- By 2010, reduce GHG emission to the year 2000 level,
- By 2020, reduce GHG emissions to the year 1990 level, and
- By 2050, reduce GHG emissions to 80% below the 1990 level.

The California Global Warming Solutions Act of 2006, commonly known as AB 32, then codified the 2020 target establishing the state's first adopted GHG target. The Water Authority's first CAP in 2014 was developed to demonstrate consistency with that target.

Then in 2016, SB 32 subsequently established the state's 2030 target to achieve emissions reduction of 40% below 1990 levels, which serves as an interim target between the state's 2020 target and the 2050 goal established in EO S-3-05. This CAP update was designed to be consistent with the state's adopted 2030 target and demonstrate how the Water Authority will do its fair share toward target achievement.

In 2018, EO B-55-18 established a new and more aggressive long-term goal "to achieve carbon neutrality as soon as possible, and no later than 2045, and achieve and maintain net negative emissions thereafter." Because this goal was signed on September 2018, well into the update of this current CAP, this goal is not reflected in this document. In future CAP updates, the Water Authority may adopt this goal and use it for long-term monitoring goals.

In 2018, SB 100 established a stringent renewables portfolio standard (RPS) for California's utility companies, which requires 100% of total retail sales of electricity in California to come from eligible renewable energy resources by 2045. Both SB 100 and EO B-55-18 indicate the level of ambition that will be required in future CAP updates.

California Climate Change Scoping Plan

It is in response to these evolving GHG targets that the state's regulatory framework for climate change has taken shape. The California Air Resources Board (CARB) is charged with monitoring and regulating sources of GHG emissions. To guide its progress toward the state's targets, CARB has developed several iterations of its Climate Change Scoping Plan. The original version was adopted in 2008 and outlined the state's primary strategies to achieve the AB 32 target. The most recent update was released in 2017 to establish a plan of action to achieve the SB 32 target (CARB 2017).

For the water sector specifically, the 2017 Scoping Plan Update includes goals to:

- Develop and support more reliable water supplies provided by a resilient and sustainably managed water resources system;

Water Authority board meeting

- Use and reuse water more efficiently through greater water conservation, climate appropriate landscaping, stormwater capture, water recycling, and reuse;
- Implement programs and projects that increase water energy efficiency and decrease associated GHG emissions;
- Increase use of renewable energy in the water system; and
- Reduce the water system carbon footprint of surface and groundwater supplies through integrated strategies to reduce GHG emissions while meeting needs for population growth, public safety, environmental stewardship, climate adaptation, and economic stability.

Importantly, the 2017 Scoping Plan Update does not include specific mandates for local agencies to reduce water-related GHG emissions. It does identify Potential Additional or Supporting Actions that could help the state achieve its long-term carbon neutrality goals, which would require participation from water agencies. Actions include consideration of long-term goals to reduce GHGs by 80% below 1990 levels by 2050 and then on toward carbon neutrality thereafter, and development of distributed renewable energy resources, where feasible.

Water Authority Energy Policy

The Water Authority adopted an Energy Management Policy in 2013 to reduce energy costs and help stabilize water rates for its 24 member retail water agencies. The energy management policy focus is also being shaped by contemporaneous state legislative activity that is driving the future of the state's energy market. The 2019 Energy Management Policy, adopted by the San Diego County Water Authority Board of Directors in June 2019, provides guidelines to build a robust Energy Program that supports the Water Authority's mission by minimizing energy costs and using existing and new infrastructure to generate revenues to offset water rates. This policy, in conjunction with the Water Authority's CAP, will also provide environmental benefits to the region by helping to reduce GHG emissions associated with energy.

The 2019 Energy Management Policy objectives focus on six areas:

1. Evaluate creative alternatives to procure lower cost energy supplies.

2. Monitor electric power markets and adjust existing system operations to minimize energy costs.

3. Seek new economically sound energy generation and storage opportunities.

4. Incorporate cost effective, energy efficient equipment and features into the Water Authority's Capital Improvement Program (CIP), Asset Management, or facility retrofit projects.

5. Develop collaborative relationships with compatible federal, state and local agencies or private organizations to maximize energy program benefits.

6. Support government relations energy goals as outlined in the current Legislative Policy Guidelines and Federal Legislative Priorities.

This policy will be reviewed and updated biennially.

RELEVANT REGULATIONS AND POLICIES

Overarching State Legislation

- AB 32 (2006), the California Global Warming Solutions Act, established the state's first adopted GHG target to achieve a return to 1990 emissions levels by 2020.
- EO B-30-15 (2015) was signed by Governor Jerry Brown and set an executive GHG emissions target for 2030 at 40% below 1990 levels.
- SB 32 (2016) expanded upon the state's AB 32 GHG target to establish a 2030 target to achieve emissions of 40% below 1990 levels by 2030.
- EO B-55-18 (2018) was signed by Governor Jerry Brown and established a statewide goal to achieve carbon neutrality as soon as possible, and no later than 2045, and to achieve and maintain net negative emissions thereafter.

Emissions Sector-Specific Legislation

- SB X7-7 (2009), the Statewide Water Conservation Strategy, requires the state to achieve a 20% reduction in per-capita urban water use by 2020.
- AB 1668 and SB 606 (2018), Water Conservation and Drought Planning, establish guidelines for efficient water use and a framework for their implementation and oversight, including provisions to establish long-term water use standards, provide incentives to water suppliers to recycle water, support small water suppliers and rural communities in drought planning, and require urban and agricultural water suppliers to set annual water budgets.
- Renewables Portfolio Standard – SB 1078, SB 107, EO S-14-08, SB X1-2, SB 350, and SB 100 have established increasingly stringent renewables portfolio standard (RPS) requirements for California's utility companies. SB 100 (2018) requires that 60% eligible renewable energy sources be provided to electricity customers by 2030, and 100% carbon-free sources by 2045.
- SB 350 (2015), Clean Energy and Population Reduction Act, sets 2030 targets for increasing the state renewable energy mix to 50%, doubling of energy efficiency in existing buildings, and modernizing the electric grid.
- Corporate Average Fuel Economy (CAFE) Standards. The federal CAFE Standards determine the fuel efficiency of certain vehicle classes in the United States.
- Low Carbon Fuel Standard Program – One of the key AB 32 measures identified to reduce statewide GHG emissions, this program requires the carbon intensity of California's transportation fuels to be reduced by at least 20% by 2030.
- Advanced Clean Cars Program – In January 2012, CARB approved the Advanced Clean Cars program, which combines the control of GHG emissions and criteria air pollutants, as well as requirements for greater numbers of zero-emission vehicles, into a single package of standards for vehicle model years 2017 through 2025.
- California Code of Regulations Title 24 Part 6: California's Energy Efficiency – Standards for residential and nonresidential buildings are updated periodically to incorporate new energy efficiency technologies and methods.
- SB 97 (2007) established CEQA Guidelines Amendments for addressing GHG emissions in CEQA documents.
- SB 375 (2008) – Sustainable Communities and Climate Protection Act. Requires regional targets for GHG reductions from passenger vehicles through better land use and transportation planning and a Sustainable Communities Strategy (SCS).
-

WATER CONSERVATION

SB X7-7

In 2009, California passed a package of legislation focused on improving the quality and availability of water for residents and ecosystems of California. One part of this package was SB X7-7, which requires urban retail water suppliers to reduce per-capita water usage by 20% from an established baseline level by December 31, 2020, with an interim goal of 10% reduction by December 31, 2015. Urban retail water suppliers were required to establish baseline per-capita water usage data and develop targets by July 1, 2011. The legislation does not create targets for local retailers but provides several methods that local retailers can use to establish their own targets. The Water Authority is not a retail water supplier, and, therefore, is not directly regulated under this legislation, but it is committed to leading water conservation efforts and assisting local retailers in achieving the water conservation goals mandated by SB X7-7.

Reducing per-capita water demand among end-users within San Diego County will help maintain long-term local and imported supplies in the region. This can already be seen by the reduction in future demand that was detailed in the Water Authority's 2015 UWMP (2020 UWMP will be released by July 2021) and 2018 Demand Forecast Reset. This reduction was a result of multiple factors (see Table 1.2 at end of Chapter 1), including retail water suppliers meeting the goals of SB X7-7, and helped mitigate the need for the Water Authority to develop additional water supplies for the foreseeable future.

To help achieve the goals of SB X7-7, the Water Authority has committed funding, staff, and online resources to achieve communitywide water conservation goals. It also partnered with San Diego Gas & Electric (SDG&E) and member agencies that provide water to San Diego County residents to promote water use efficiency, conduct conservation and education outreach, and provide grants for conservation projects associated with urban water use activities.

Conservation efforts resulting from SB X7-7 have resulted in lower future demand, and helped mitigate the need for the Water Authority to develop additional water supplies for the foreseeable future.

Potential Regulations

In 2018, California passed two bills that are complementary to SB X7-7 and aim to improve the state's water use efficiency and drought planning. The bills amended existing laws and promote permanent changes in water use in the state, and focus on the following four objectives:

1. Use water more wisely.
2. Eliminate water waste.
3. Strengthen drought resilience.
4. Improve agricultural water use efficiency and drought planning.

Specific performance standards for these two bills are currently being developed through a stakeholder participation process. Further details on each piece of legislation are described in the sections below.

AB 1668, Friedman; Water Management Planning

AB 1668 requires the State Water Resources Control Board, in coordination with the Department of Water Resources to:

- Adopt long-term standards for the efficient use of water and performance measures for commercial, industrial, and institutional water use on or before June 30, 2022

- Require the Department of Water Resources to conduct necessary studies and investigations and make recommendations, no later than October 1, 2021, for purposes of these standards and performance measures.
- Set the standard for daily indoor residential water use per capita, summarized in Table 1.1.

AB 1668 requires the Department of Water Resources, in consultation with the State Water Resources Control Board, to issue recommendations and guidance that relate to the development and implementation of countywide drought and water shortage contingency plans to address the planning needs of small water suppliers and rural communities.

Existing law requires an agricultural water supplier to prepare and adopt an agricultural water management plan with specified components. AB 1668 would revise the components of the plan and additionally require a plan to include an annual water budget based on the quantification of all inflow and outflow components for the service area of the agricultural water supplier and a drought plan describing the actions of the agricultural water supplier for drought preparedness and management of water supplies and allocations during drought conditions.

SB 606, Hertzberg; Water Management Planning

SB 606 requires an urban retail water supplier to calculate an urban water use objective no later than November 1, 2023 (and by November 1 every year thereafter) and calculate its actual urban water use by those same dates.

SB 606 would revise and recast the Urban Water Management Planning Act. The bill would require an urban water management plan to:

- Be updated on or before July 1, in years ending in six (6) and one (1), incorporating updated and new information from the five years preceding the plan update; to include a simple lay description of specified information to provide a general understanding of the agency's plan; and to contain a drought risk assessment that examines water shortage risks for a drought lasting the next five consecutive years.

SB 606 would require an urban water supplier to:

- Prepare, adopt, and periodically review a water shortage contingency plan as part of its urban water management plan. A water shortage contingency plan must consist of certain elements, including annual water supply and demand assessment procedures, standard water shortage levels, shortage response actions, and communication protocols and procedures.
- Conduct an annual water supply and demand assessment and submit an annual water shortage assessment report to the department with information for anticipated shortage, triggered shortage response actions, compliance and enforcement actions, and communication actions consistent with the supplier's water shortage contingency plan by June 1 of each year.
- Follow, where feasible and appropriate, the procedures and implement determined shortage response actions in its water shortage contingency plan.

Regional Conservation Program Resources

Table 1.2 provides a partial list of program resources that promote conservation and reduce local water use. For additional information, please visit www.watersmartsd.org.

TABLE 1.1 **Proposed Per Capita Daily Indoor Residential Water Use Standards**

PROPOSED PER CAPITA DAILY INDOOR RESIDENTIAL WATER USE STANDARDS		
Up to January 2025	January 2025 through January 2030	After January 2030
55 gallons	52.5 gallons	50 gallons

TABLE 1.2 **Regional Water Conservation Program Resources**

	WATER CONSERVATION PROGRAM RESOURCE	EDUCATION	TECHNICAL ASSISTANCE	INCENTIVES
AGRICULTURAL	Prop. 84 Electrical Conductivity Mapping & Soil Moisture Sensor Project			X
	Agricultural Water Management Program	X	X	
COMMERCIAL, INDUSTRIAL, & INSTITUTIONAL	Premium High-Efficiency Toilets*			X
	Ultra Low, Zero Water Urinals*			X
	Plumbing Flow Control Valves*			X
	Turf Replacement Program*			X
	Smart Controllers or Soul Moisture Sensor Systems*			X
	Rotating Nozzles for Pop-Up Spray Heads*			X
	Large Rotary Nozzles*			X
	In-Stem Flow Regulators*			X
	Connectionless Food Steamers*			X
	Air-cooled Ice Machines*			X
	Cooling Tower Conductivity Controllers			X
	Cool Tower pH Controllers*			X
	Dry Vacuum Pumps*			X
	Laminar Flow Restrictors*			X
	Water-Energy Nexus Partnership with SDG&E	X	X	X
	Water Savings Incentive Program*			X
	On-Site Retrofit Program (conversion to recycled water)*			X
	Public Agengcy Landscape Program (enhanced incentives)*			X
	Prop. 84 Correctional Facility Retrofit			X
	WaterSmart Field Services (Irrication Checkups and Large Landscape Audits)		X	X X
	Landscape Training for Professionals (Qualified Water Eficient Landscaper)	X		
RESIDENTIAL	Premium High-Efficiency Toilets*			X
	High-Efficiency Clothes Washers*			X
	Smart Irrigation Controllers*			X
	Soil Moisture Sensor Systems*			X
	Rotating Nozzles*			X
	Rain Barrels*			X
	Cisterns*			X
	Turf Replacement Program*			X
	Sustainable Landscape Incentives			X
	Sustainable Landscaping Guidelines	X		
	Sustainable Landscaping Demonstration Garden	X		
	Landscape Classes for Homeowners (Makeover Series and Design for Homeowners Workshops)	X	X	
	Water-Energy Nexus Partnership with SDG&E	X	X	X
	WaterSmart Outreach and Resources (print and online publications, a Water Use Calculator, videos, design database, and community outreach)	X	X	
	WaterSmart Field Services (Indoor and Outdoor Residential Surveys and Irrigation Checkups)	X	X	
OTHER	Innovative Conservation Program*			X
	Community Partnering Program*			X
	Member Agency Administered Program*			X

***Administered by the Metropolitan Water District**

Local Conservation Success

Programs to promote conservation regulations have resulted in lower future water demand and helped mitigate the need for the Water Authority to develop additional water supplies for the foreseeable future.

Conservation programs implemented by the Water Authority and its member agencies reduce per-capita water demand among end-users within San Diego County and help maintain long-term supplies in the region. This can already be seen by the reduction in future demand that was detailed in the Water Authority's 2015 UWMP and further reduction in the 2018 Demand Forecast Reset. This reduction was a result of many factors, including retail water suppliers meeting the conservation goals of existing regulations described in the previous sections.

The Water Authority and its member agencies have committed funding, staff, and online resources to achieve communitywide water conservation goals, and promote water conservation by partnering with other organizations to offer educational resources, technical assistance and financial incentives to agricultural, commercial, industrial, institutional and residential water customers throughout its service areas.

The efforts by the Water Authority and its member agencies to meet water reduction requirements complement the goals of the CAP. Specific reductions in GHG emissions from communitywide conservation programs, such as those described in the previous pages, would be measured through communitywide emissions inventories that account for end-user water consumption rather than in the Water Authority's emissions inventory presented in this CAP. However, the Water Authority's emissions are indirectly affected by these water demand reductions through reductions in operations on the water-supply side.

Conservation Measure: Using Drought-Tolerant Landscaping

REGULATORY IMPLICATIONS FOR THE WATER AUTHORITY

While there is guidance for how local agencies can evaluate their operational GHG emissions, there are no specific requirements for local agencies to do so. As written, this CAP allows the Water Authority to make informed decisions related to its operations and capital improvement program. CAPs can provide detailed information on GHG emissions at the project and agency levels. This allows the Water Authority to evaluate emissions agency-wide, rather than on a project-by-project basis, and to determine the best (e.g., most feasible or cost-effective) method to meet the Water Authority's GHG emissions targets.

It should be noted that this CAP will not be used as an environmental review streamlining tool as outlined in the state's CEQA Guidelines Section 15183.5. However, the information included in the CAP addresses many of the same elements required within such a plan.

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02 GREENHOUSE GAS EMISSIONS: CURRENT AND FUTURE

The purpose of a GHG emissions inventory is to provide a snapshot of GHG emissions currently occurring within a region or agency. The inventory is useful in identifying areas that have high emissions or high potential for cost-effective GHG-reduction policies, actions, and control measures.

STATE AND REGIONAL EMISSIONS LEVELS

The Climate Change Scoping Plan is the state's roadmap to achieving its ambitious GHG reduction goals established in AB 32 and SB 32. The original Climate Change Scoping Plan established the framework to achieve a return to 1990 emissions levels by the year 2020. CARB set the state's 1990 emissions levels at 427 million metric tons (MMT) of carbon dioxide equivalent (CO_2e); in the state's 2017 inventory, emissions totaled 424.1 MMT CO_2e, representing a reduction of 1% below 1990 levels and demonstrating achievement of the AB 32 target 3 years early.

With SB 32, the Legislature passed companion legislation AB 197, which provides additional direction for developing the Scoping Plan. CARB is moving forward with a second update to the Scoping Plan to reflect the 2030 target set by EO B-30-15 and codified by SB 32.

The SB 32 target requires greater action to further reduce statewide emissions to 40% below 1990 levels. As this is a statewide goal, it is essential for agencies, residents, and businesses to do their part to meet the target set by state regulations. Regionally, efforts have been taken by numerous jurisdictions within San Diego County to evaluate and mitigate local emissions contributions. Figure 2.1 shows emissions inventories for some of the larger jurisdictions within San Diego County to provide perspective on the sources and levels of emissions compared to the Water Authority. The emissions year used and inventory methodology may vary within the jurisdictions, so these numbers are not directly comparable; however, they provide context for the level of emissions produced by the Water Authority.

In Figure 2.1, the size of each circle represents the relative emissions level for that jurisdiction and demonstrates the variability in emissions among jurisdictions in San Diego County. A local agency or government operations GHG emissions inventory is like that of a community, but much narrower in scope. For example, both the local agency and community inventories will include emissions from transportation of community members traveling to and from work, but community inventories will also include emissions from travel elsewhere in the community (out of jurisdiction travel). A local agency inventory is generally narrower in scope but represents emissions sources over which the agency has more direct control. Community CAPs rely on all community members to participate toward GHG target achievement; a local agency CAP relies primarily on actions taken by the agency to meet reduction targets.

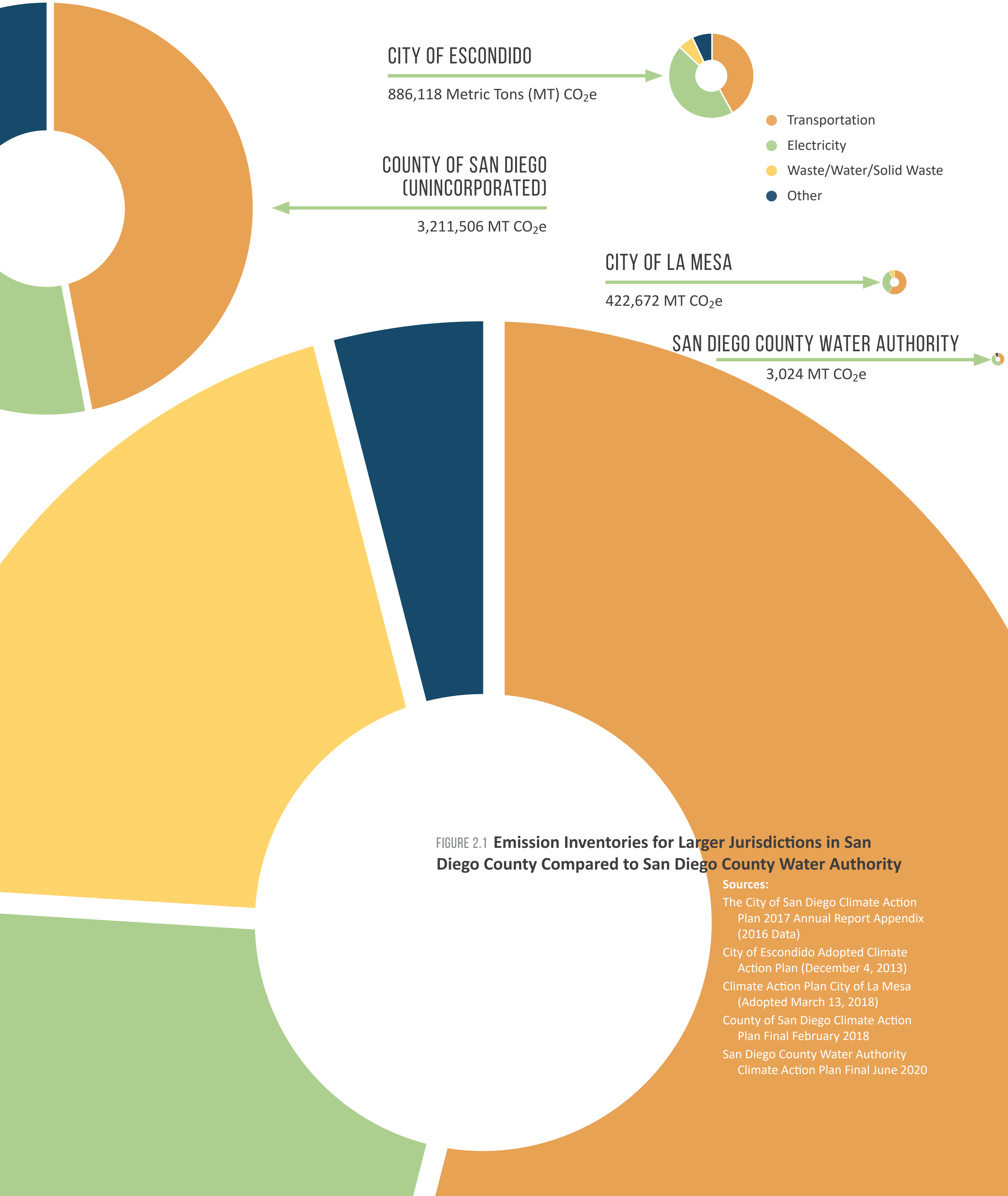


FIGURE 2.1 **Emission Inventories for Larger Jurisdictions in San Diego County Compared to San Diego County Water Authority**

Sources:

The City of San Diego Climate Action Plan 2017 Annual Report Appendix (2016 Data)

City of Escondido Adopted Climate Action Plan (December 4, 2013)

Climate Action Plan City of La Mesa (Adopted March 13, 2018)

County of San Diego Climate Action Plan Final February 2018

San Diego County Water Authority Climate Action Plan Final June 2020

INVENTORY APPROACH

Baseline Year

Best practices dictate that GHG inventories are generally estimated for a single calendar year. Selecting an inventory baseline year will often depend on project objectives, data availability, and/or applicable regulatory guidance. Most entities in California do not have complete or accurate records to calculate GHG emissions for 1990 to align directly with the State's AB 32 and SB 32 targets, which are defined relative to 1990 levels. In these instances, a more recent inventory year can be selected to understand current emissions levels and then an estimate of the relationship to 1990 levels can be made, if necessary. No requirements establish a specific baseline or future year for analysis, and no emissions level must be adhered to at the local level.

In adherence to industry best practice, the Water Authority prepared its original baseline inventory in 2009 directly following the release of the 2008 Scoping Plan. The 2008 Scoping Plan developed as part of the state's AB 32 implementation approach recommended that local governments achieve a 15% reduction from "current" levels by 2020, where current was referenced as a 2005–2008 baseline year. This guidance was provided to help local governments approximate a return to their 1990 emissions levels. In lieu of more directly applicable guidance, many communities and agencies, including the Water Authority, applied this GHG target guidance to their CAPs with baseline years ranging from 2005-2010. For purposes of its CAPs, the Water Authority conducted an emissions inventory for calendar year 2009. This inventory serves as the basis for establishing reduction goals and is referred to as the "baseline" emissions inventory.

Methodology

The Water Authority completed its 2009 GHG emissions inventory in 2011, following the Climate Registry's General Reporting Protocol. As part of the CAP process, the Water Authority and its consultant reviewed the inventory ensuring consistency with current methodologies, practices, and guidance within California. The baseline emissions inventory was updated using the Local Government Operations Protocol (LGOP), which was developed by CARB, the California Climate Action Registry, and ICLEI – Local Governments for Sustainability in collaboration with the Climate Registry (CARB 2010). The LGOP provides a standardized set of guidelines to assist local governments in quantifying and reporting GHG emissions associated with operations; these guidelines are applicable to the emissions of the Water Authority.

In general, estimating GHG emissions requires activity data and emissions factors. Activity data can refer to the amount of energy consumed (kilowatt hours [kWh] or therms), waste produced (tons), and water used (gallons), for example. Emissions factors are a measure of how carbon-intensive an activity is (i.e., the amount of GHGs that are emitted by a unit of activity). The baseline analysis for calendar year 2009 considers the Water Authority's water consumption and wastewater produced for internal operations, number of employees, vehicle fleet, solid waste produced, and consumption of electricity and fossil fuels. The LGOP provided a standard approach to developing GHG inventories and recommended an estimate of CO_2e emissions; both are described in the sections below. Appendix E presents the 2019 emissions inventory calculations, including activity data and emissions factors used to estimate GHG emissions associated with the Water Authority's operations in 2019.

Determining the boundary of emissions can be challenging, since agencies can lease space, have physical locations in different jurisdictions, or be involved in joint development ventures. The LGOP recommends that local agencies define their boundary for emissions reporting by operational control. This approach translates into estimating emissions from any operation over which the agency has control, and, therefore, can effectively implement strategies to reduce those emissions. Operational control is also the approach used by CARB for emissions reporting by large emitters; therefore, the approach used in this CAP provides a consistent approach with other entities, jurisdictions, and agencies in the state. Any infrastructure or program with a shared operational control or financial interest will be evaluated on a case-by-case basis.

GHGs, Global Warming Potential, and CO_2e

CARB identifies six primary compounds as the predominant GHGs found in non-industrial processes. Each type of GHG has a different capacity for contributing to climate change. Therefore, GHG emissions are “equalized” by their global warming potential (GWP) and are reported in this CAP in CO_2e. For example, 1 ton of methane (CH_4) has the same contribution to climate change as approximately 21 tons of CO_2 on a 100-year timescale and would, therefore, have a CO_2e of 21 tons. Table 2.1 lists the primary GHGs, along with their symbols, GWP, and common anthropogenic sources.

TABLE 2.1 **Primary Greenhouse Gases and their Human-Related Sources**

SYMBOL	NAME	GWP[1]	ANTHROPOGENIC SOURCE
CO_2	Carbon Dioxide	1	Fossil fuel combustion, forest clearing, cement production
CH_4	Methane	21	Fossil fuel combustion, landfills, livestock, rice cultivation
N_2O	Nitrous Oxide	310	Fossil fuel combustion, nylon production
HFC	Hydrofluorocarbons	140–14,800	Refrigeration gases, semiconductor manufacturing
PFC	Perfluorocarbons	6,500–12,200	Aluminum production, semiconductor manufacturing
SF_6	Sulfur Hexafluoride	23,900	Electrical transmissions and distribution systems, circuit breakers

1 GWP= global warming potential, based on the UN Intergovernmental Panel on Climate Change, Second Assessment Report

BASELINE AND CURRENT EMISSIONS INVENTORY

The Water Authority's emissions for 2009 were 5,837 metric tons (MT) CO_2e. The results are reported below using several organizational approaches. Reporting emissions by sector, scope, and source provides useful ways to understand the Water Authority's emissions. By better understanding the relative scale of emissions, the Water Authority can more effectively focus emissions reduction strategies to achieve the most cost-effective emissions reductions. Detailed methodology and assumptions for the inventory can be found in Appendix A.

Emissions by Scope

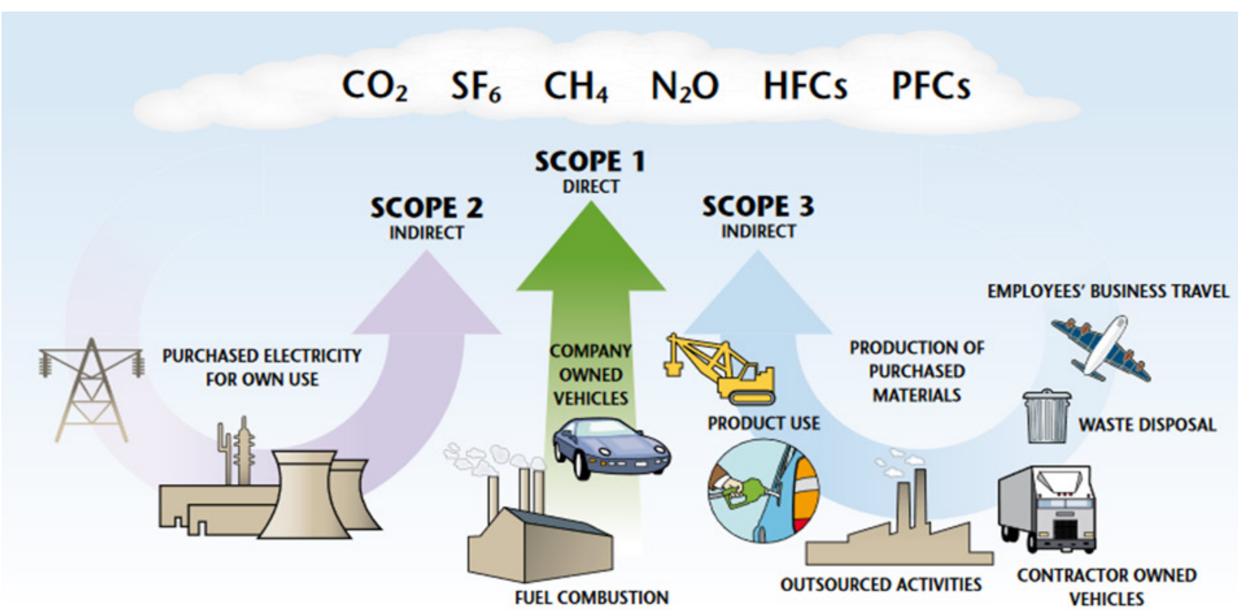
The LGOP recommends organizing emissions inventories using the scope approach to maximize transparency and comparability of emissions inventories with different entities, and to minimize the possibility for double-counting emissions. In other words, if all emissions inventories are developed using the same organizational structure, it is less likely that an inventory will include a sector or activity twice; see Figure 2.2.

Scope 1 emissions consist of all direct GHG emissions. Direct GHG emissions include combustion of fossil fuel and direct release of GHG compounds.

Scope 2 emissions consist of indirect GHG emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling. The descriptor "indirect" indicates that the emissions are being generated at another location other than the entity's operational site.

Scope 3 emissions consist of all other indirect emissions not covered in Scope 2, including employee commutes, wastewater, and solid waste disposal.

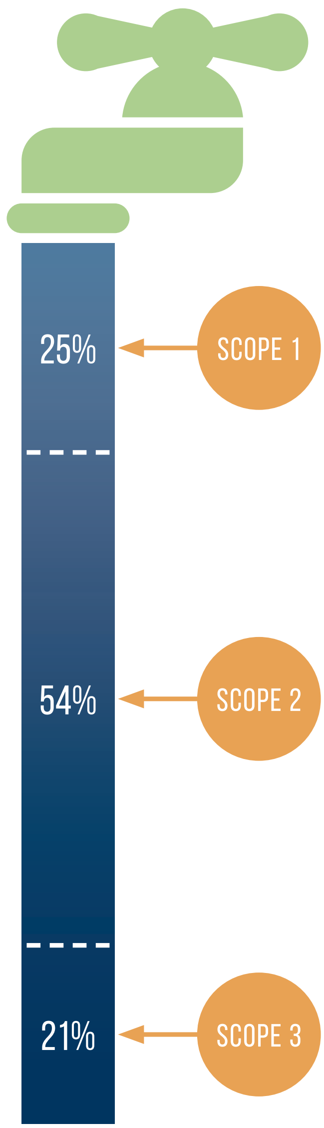
FIGURE 2.2 **Emissions Sources by Scope**



Source: Bhatia and Ranganathan 2004

Figure 2.3 shows that in the Water Authority's 2019 inventory, Scope 2 emissions represented the largest share of total emissions (54%), followed by Scope 1 emissions (25%), and Scope 3 emissions (21%).

FIGURE 2.3 **2019 Greenhouse Gas Emissions by Scope**



Emissions by Sector

Reporting emissions by sector is often the most useful display of information; GHG-reduction measures are often sector-based and understanding the relative emissions by sector helps in the emissions-reduction process. Table 2.2 shows the Water Authority's emissions by sector for 2009 and 2019, which are also detailed below. Appendix E, Table 1, provides emissions by sector for 2009 and annually between 2014 and 2019.

Energy Consumption – Electricity and Natural Gas

The energy consumption sector includes the use of electricity and natural gas at the Water Authority's facilities. GHG emissions may be both direct and indirect. Direct emissions are those generated at the operational site, such as natural gas combustion for space and water heating. Indirect GHG emissions are those generated at a location other than the entity's operational site but as a result of on-site activity, such as electricity used for lighting, pumps, and fans. In 2009, energy consumption (electricity and natural gas) accounted for more than 70% (4,191 MT CO_2e) of the Water Authority's emissions, with electricity representing the majority (4,133 MT CO_2e) of those emissions. In 2019, energy consumption (electricity and natural gas) accounted for approximately 55% (1,677 MT CO_2e) of the Water Authority's emissions, with electricity representing the majority (1,622 MT CO_2e) of those emissions.

TABLE 2.2 **Greenhouse Gas Emissions by Sector**

EMISSIONS SECTOR	2009		2019	
	MT CO_2E	% OF TOTAL	MT CO_2E	% OF TOTAL
Electricity	4,133	70.8%	1,622	53.6%
Vehicle Fleet	694	11.9%	642	21.2%
Employee Commute	685	11.7%	619	20.5%
Off-Road Equipment	143	2.4%	30	1.0%
Stationary Source	89	1.5%	24	0.8%
Natural Gas	58	1.0%	55	1.8%
Solid Waste	27	0.5%	25	0.8%
Water	4	0.1%	3	0.1%
Refrigerants	2	<0.1%	2	0.1%
Wastewater	1	<0.1%	1	<0.1%
TOTAL	5,837	100%	3,024	100%

Notes: Totals may not equal 100% due to rounding.
MT CO2e = metric tons of carbon dioxide equivalent

Vehicle Fleet

Vehicle fleet emissions were estimated based on vehicle fuel use and miles traveled in on-road vehicles owned and operated by the Water Authority. Approximately 694 MT CO_2e emitted in 2009 were from operation of fleet vehicles, representing nearly 12% of the overall emissions profile. In 2019, approximately 642 MT CO_2e came from operation of fleet vehicles, representing about 21% of total emissions. The change is likely due to vehicle replacements with newer, more efficient vehicles included in 2019 that have lower emissions rates than the 2009 vehicle fleet.

Employee Commute

Like vehicle fleet emissions, employee commute emissions accounted for less than 12% of total emissions in 2009 (685 MT CO_2e); in 2019 employee commute emissions accounted for nearly 21% of total emissions (619 MT CO_2e). Employee commutes are influenced by broader transportation and land use issues but the Water Authority promotes alternative commute programs available in the region.

Stationary Sources/Off-Road Equipment

These sectors include stationary-source electrical generators and off-road equipment. The Water Authority owns construction equipment used in the regular maintenance and operation of its facilities; in 2009, emissions from stationary sources and off-road equipment accounted for 4% of total emissions, or 232 MT CO_2e. In 2019, emissions from stationary sources and off-road equipment accounted for less than 2% of total emissions, or 54 MT CO_2e. Although newer off-road equipment will be more efficient and have higher emission standards, this emission sector is expected to vary depending on work activities for the year; continual reductions are not expected and emissions could increase in certain years. Therefore, this sector will need to be closely monitored, and equipment efficiencies will need to be considered during routine maintenance and replacement.

Solid Waste

The solid waste sector includes emissions resulting from the collection, processing, and disposal of solid waste. Solid waste disposal creates CO_2 emissions under aerobic conditions, and CH_4 emissions under anaerobic conditions, primarily at landfills. Solid waste accounts for less than 1% of total emissions in both inventory years (27 MT CO_2e in 2009, 25 MT CO_2e in 2019).

Water

The water sector includes emissions related to water usage by the Water Authority's staff at the Water Authority's facilities. Emissions from energy associated with water treatment, distribution, and conveyance to other entities are captured in the Electricity and Natural Gas categories. Emissions from water conveyance to end-users are captured in communitywide or member-agency inventories, as the Water Authority does not have operational control over those sources. Emissions from water consumption for which the Water Authority is directly responsible represents 0.1% of total emissions in both inventory years (4 MT CO_2e in 2009, 3 MT CO_2e in 2019).

Refrigerants

Although generally a small portion of total emissions, refrigerants consist of high GWP gases. Individual molecules of hydrofluorocarbons, the type of GHG generally emitted by refrigerants, have GWPs ranging from 140 to 14,800 MT CO_2e (see Table 2.1). Refrigerants were responsible for 2 MT CO_2e in each inventory year.

Wastewater

The wastewater sector consists of emissions resulting from wastewater discharge and outside utility, including wastewater collection, septic system management, primary and secondary treatment, solids handling, and effluent discharge. The Water Authority's emissions from wastewater were 1 MT CO_2e in both inventory years.

Emissions by Location

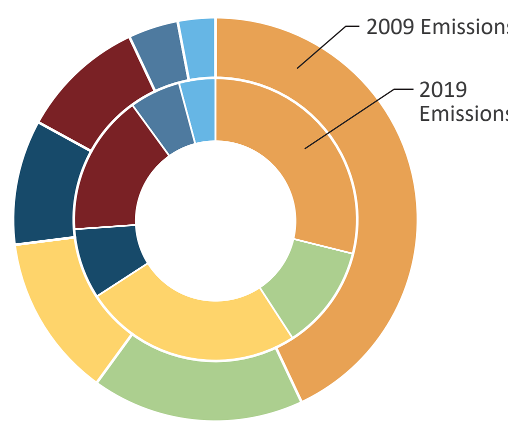
For an agency that has direct control over most of its emissions sources, it is useful to identify which facilities or programs generate the most emissions. Inventories can guide the agency on where to focus energy audits, retrofitting, or retro-commissioning projects. The Water Authority identified seven primary sources of emissions, including major facilities and programs. For the purposes of this organizational approach, employee commute, solid waste, and wastewater are not associated with specific facilities but are called "Combined Other" in Table 2.3 and Figure 2.4. The Twin Oaks Valley Water Treatment Plant (WTP) was responsible for 43% of the Water Authority's emissions in 2009. Pump stations were the next largest source of emissions, accounting for nearly 17% of total emissions, and the San Diego Headquarters Building was responsible for approximately 10% of the 2009 emissions. These three sources represent 70% of all Water Authority facility-related emissions. In 2019, these three sources accounted for approximately 49% of all Water Authority facility-related emissions.

TABLE 2.3 **Greenhouse Gas Emissions by Location**

SOURCE	2009		2019	
	MT CO_2E	% OF TOTAL	MT CO_2E	% OF TOTAL
Twin Oaks Valley Water Treatment Plant	2,513	43.1%	873	28.9%
Pump Stations	980	16.8%	354	11.7%
Combined Other	783	13.4%	745	24.6%
San Diego Headquarters Building	572	9.8%	242	8.0%
Flow Control Facilities	561	9.6%	489	16.2%
Corrosion Monitoring Systems	252	4.3%	188	6.2%
Escondido Operations Center	175	3.0%	133	4.4%
TOTAL	5,837	100%	3,024	100%

Notes: Totals may not equal 100% due to rounding. MT CO2e = metric tons of carbon dioxide equivalent. Corrosion Monitoring System referred to as Aqueduct Protection Program in 2009 Inventory

FIGURE 2.4 **2009 and 2019 Greenhouse Gas Emissions by Source**

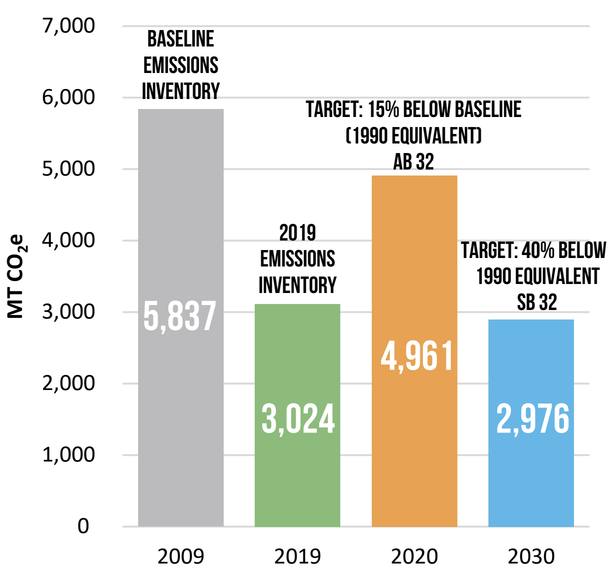


	Source	2009	2019
●	Twin Oaks Valley Water Treatment Plant	43%	29%
●	Pump Stations	17%	12%
●	Combined Other	13%	25%
●	San Diego Headquarters Building	10%	8%
●	Flow Control Facilities	10%	16%
●	Corrosion Monitoring Systems	4%	6%
●	Escondido Operations Center	3%	4%

REDUCTION TARGETS

This CAP was developed to align with the goals of AB 32 and SB 32. To demonstrate consistency with AB 32 GHG target, the Water Authority set a 2020 target to reduce emissions to 15% below 2009 levels, which approximates a return to 1990 levels consistent with the 2008 Scoping Plan developed as part of the state's AB 32 implementation approach. To demonstrate consistency with SB 32, the Water Authority has set a 2030 GHG target that is 40% below the 2020 target (since the 2020 target approximates a return to 1990 emission levels). This is consistent with the Scoping Plan recommendation to local governments to demonstrate consistency with AB 32 and SB 32. These reduction targets are summarized in Figure 2.5.

FIGURE 2.5 **Water Authority Emissions Targets Aligned with State Goals**



Note: MT CO_2e = metric tons of carbon dioxide equivalent

FORECASTING APPROACH

Forecasted business as usual (BAU) is defined as looking at the amount of emissions in the future with out implementation of any additional GHG-reducing measures. Emissions projections also allow the Water Authority to see how emissions may change over time considering major projects and operational changes. For the Water Authority, this includes estimating emissions for projects implemented since the 2009 baseline emissions inventory, such as the San Vicente Pump Station, as well as projects identified in the 2013 Master Plan Update.

Emissions were projected for years 2020 and 2030 to support CAP analysis. AB 32 identifies a strict statewide limit on GHG emissions for 2020, which is set at 431 Million MT CO_2e; SB 32 established a target of 40% below 1990 levels by 2030, which corresponds to a target of 258.6 Million MT CO_2e. Even though the Water Authority's emissions are a small portion of the statewide emissions, the Water Authority has chosen to demonstrate consistency with these targets (see Figure 2.5).

In addition, the Water Authority recognizes that the issue of climate change will not end in 2030. Therefore, the Water Authority will continue to monitor the evolution of the state's GHG planning framework and incorporate applicable changes into future CAP updates.

FUTURE EMISSIONS

Future emissions are those anticipated by the Water Authority because of ongoing facility construction since the 2009 baseline inventory. This section focuses on construction emissions and not operational emissions. Operational emissions are estimated and accounted for in the BAU forecast approach and are captured in Table 2.6 at the end of this chapter.

2014 CAP Process

The 2014 CAP estimated both construction and operational emissions of new projects and their impacts to the emissions inventory. The construction emissions were calculated and amortized over a 20-year period. The emissions amortization has the effect of minimizing the impacts of any one construction project from inflating the emissions totals of years when construction activities occur, usually a 1- to 2-year period. The operational emissions were calculated based on projected annual usage and were assumed to be in addition to the BAU emissions estimates.

2019 CAP Process

The current CAP will continue to estimate construction emissions (see Appendix B) and the construction emissions will be divided into three categories:

- Emissions since the 2014 CAP and the end of calendar year 2019
- Emissions estimates in calendar 2020 (to align with AB 32 – 2020 target year)
- Emissions estimates from 2021–2030 (to align with SB 32 – 2030 target year)

The construction emissions will also no longer be amortized and will be counted on the year where notice of completion for the project has been filed. Construction emissions will now be closely counted when construction emissions are created/emitted versus amortizing the impact over 20 years. This method avoids potential double counting of operational emissions already accounted for in the BAU approach. It is recommended that BAU forecasting be done annually to better gage the impacts of new projects coming online and the impacts it has on the Water Authority meeting its specified GHG emissions goals.

Construction emissions will be calculated using reference projects to develop emissions factors for different types of CIP projects and types of construction. The emission factors will be used along with each project's detailed scope of work to properly scale construction emissions. Emissions ranges will be provided to account for uncertainties and differences between the CIP projects and referenced projects being used. The referenced projects have detailed construction emissions estimates for GHGs as part of their CEQA documentation or developed as part of the 2014 CAP. Five different emission factors will be developed and used to calculate the construction emissions of each individual CIP project based on project scope.

The scope of work, notice-of-completion (NOC) year, emission factors used, major scope items, emissions estimate, and emissions range for each construction project are provided in Appendix B. Total emissions, summarized in the categories below, have been calculated for each year to determine overall construction emissions impacts per calendar year.

Emissions sources constructed 2014–2019

Fourteen major projects have been constructed since the 2014 CAP was approved. The projects from 2014 through 2019 are those that are completed or currently in construction with a NOC before December 2019. These projects were selected to match the timeframe between the 2014 CAP and the current CAP and allowed the Water Authority to historically track construction emissions since the last approved CAP. Construction emissions between 2014 and 2019 range between 113 and 786 MT CO_2e per year and total 3,153 MT CO_2e (see Table 2.4).

Emissions sources constructed 2020

Construction emissions in 2020 include projects expected to issue a NOC between January 1, 2020 and December 31, 2020, which aligns with the 2020 emissions goal timeframe set by AB 32. The CIP schedule as of May 2019 shows only one project scheduled to issue a NOC in 2020. The flow control facility to be constructed under this project was identified as deficient by the Asset Management Program. This project has been awarded with construction scheduled to issue a NOC by September 2020.

The construction emissions for 2020 are estimated to total 131 MT CO_2e. The construction emissions from this project will be used to determine the impacts towards total emissions and how they relate to meeting the 2020 emissions goals set by AB 32. No other CIP project is scheduled to have a NOC issued in calendar year 2020.

Emissions sources constructed 2021–2030

Thirteen projects are presently scheduled to have a NOC between 2021 and 2030. Projects from this category consist of both Master Plan and Asset Management projects that are part of the current CIP schedule. The end of the timeframe for this category coincides with the SB 32 2030 emissions goal. As of May 2019, the CIP schedule only had detailed projects set up to 2024 and it is anticipated that more projects will be scheduled between 2021 and 2030 on a yearly basis.

Projects for this period have a NOC up to 2024, with additional projects expected to be scheduled in the coming years. The construction emissions range from 290 to 904 MT CO_2e (see Table 2.5). The construction emissions for 2025–2030 will be based on an annual average from 2020 to 2024, which is 596 MT CO_2e.

TABLE 2.4 **2014–2019 Construction Emissions**

ESTIMATED CONSTRUCTION EMISSIONS BY CALENDAR YEAR (MT CO_2E)					
2014	2015	2016	2017	2018	2019
755	786	738	113	382	379

Note: MT CO_2e = metric tons of carbon dioxide equivalent

TABLE 2.5 **2021-2024 Construction Emissions**

ESTIMATED CONSTRUCTION EMISSIONS BY CALENDAR YEAR (MT CO_2E)			
2021	2022	2023	2024
791	904	864	290

Note: MT CO_2e = metric tons of carbon dioxide equivalent

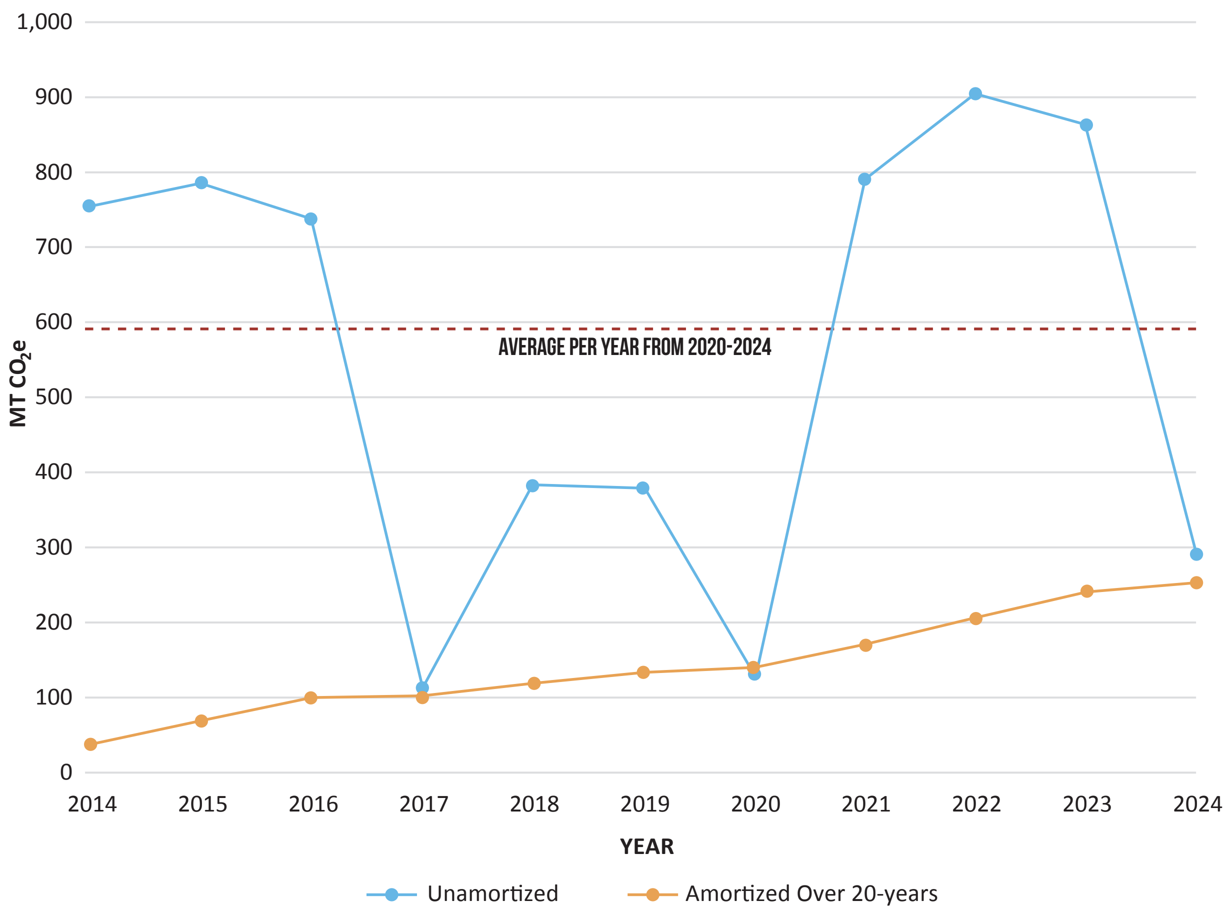
Typical Construction Project - Pipeline Rehabilitation with Steel Liners

Construction Emissions Summary

Changing the way construction emissions are tracked, from amortizing to placing them to a single year, has resulted in more variability of construction emissions totals from year to year; however, tracking construction emissions has been simplified. Under the previous method of amortizing, 2019 would still be accounting for construction emissions from 1999 (assuming a 20-year amortization). Similarly, a project that has a completion date of 2019 would need to have its amortized emissions accounted for until 2039. The change will allow the Water Authority to better track and report construction emissions; it will also be able to better determine the impacts of construction emissions since they are accounted for as they are created and emitted. Figure 2.6 shows a comparison of the two methods (non-amortized vs. amortized); please note that the amortized portion of the graph only accounts for projects starting in 2014 and does not include past projects that were amortized that would count toward emissions totals for 2014–2024.

Typical Construction Project- Excavation and Backfill

FIGURE 2.6 **Construction Emissions Comparison**



SUMMARY

BAU emissions are estimated to be 3,047 MT CO_2e in 2020 with an additional 131 MT CO_2e from construction activity, for a 2020 emissions total of 3,178 MT CO_2e. In compliance with AB 32, the 2020 target is 15% below 2009 baseline emissions, which approximates a return to 1990 levels and is referred to as 1990 equivalent per guidance from the 2008 Scoping Plan. The emissions in 2020 represent approximately 46% reduction below the 2009 baseline emissions and achieves beyond the 2020 target.

The 2030 emissions forecasts are 3,061 MT CO_2e with an estimated 596 MT CO_2e from construction-related activities, for a 2030 emissions total of 3,657 MT CO_2e. In compliance with SB 32, the 2030 target is 40% below 1990 equivalent. The emissions in 2030 represent approximately 26% reduction below the 1990 equivalent and does not achieve the 2030 target. The BAU and construction emissions in 2020 and 2030 are summarized in Table 2.6.

It should be noted that these future emissions values do not include additional actions, measures, or reductions from the Water Authority that are anticipated through full implementation of federal and state measures on renewable energy, which will reduce the emissions factor for electricity use (see Chapter 3). The values also do not include RECs from the Water Authority's existing or future energy generation facilities that could be applied in the future towards emissions reductions (see Chapter 4).

TABLE 2.6 **Emission Goals Summary**

	2020 (MT CO_2E)	2030 (MT CO_2E)
Business-As-Usual Emissions	3,047	3,061
Construction Emissions	131	596*
TOTAL EMISSIONS	3,178	3,657
State-Aligned Goal/Target	4,961	2,976
Meets Goal?	Yes	No**
SURPLUS/SHORTFALL	1,783	(681)**

Notes: MT CO_2e = metric tons of carbon dioxide equivalent; AB= Assembly Bill; SB= Senate Bill
*Used construction emission yearly average from 2020 through 2024
**Does not account for reduction measures and strategies. A separate analysis is presented in Chapters 3 and 4 of this report

03 GREENHOUSE GAS REDUCTION MEASURES

STATE AND FEDERAL EMISSIONS REDUCTIONS

Achieving the targets of AB 32, SB 32, and beyond will require action at the state and local levels from public agencies in collaboration with residents and business owners. GHG reduction measures being implemented at the state level and those already implemented by the Water Authority will help the state meet its emissions targets.

Chapter 1 described state and federal regulations that affect the Water Authority. Some of these regulations set statewide emissions targets (i.e., AB 32 and SB 32); this CAP is designed to demonstrate consistency with these targets. Other regulations have been implemented that will assist in reducing GHG emissions without the Water Authority taking any direct action. Chapter 2 discusses the forecasted BAU approach as if no direct or indirect action are taken. However, federal and state policies/legislation will supplement local measures to meet future emissions targets. These measures are included in the forecast to create an "Emissions with Existing Reduction Measures" scenario (see Table 3.4 at the end of this Chapter), which more accurately reflects expected future conditions. This approach is standard for all local jurisdictions and agencies that undertake a CAP: Apply the anticipated impacts of federal and state policies/legislation and supplement those with local measures to meet future emissions targets.

Low Carbon Fuel Standard and Corporate Fuel Efficiency Standard

The Water Authority's emissions profile is very different from the state's, and even from cities within San Diego County (see Chapter 2). Whereas the transportation sector accounts for the majority of emissions in most communitywide inventories, it accounts for approximately 40% of the Water Authority's emissions profile. This is due to decommissioning vehicles, an increase in use of electric vehicles, and a reduction in the average amount of employee travel. Nevertheless, some of the federal and state regulations related to transportation emissions will result in reductions to the Water Authority, regardless of behavioral or institutional changes within the agency.

The Low Carbon Fuel Standard (LCFS) requires the carbon intensity of California's transportation fuels to be reduced by at least 10% by 2020 and 20% by 2030. The LCFS is a performance standard with compliance mechanisms that incentivize development of a diverse set of clean, low-carbon transportation fuel options to reduce GHG emissions. Although it is applicable to all three transportation-related sectors in the Water Authority (i.e., employee commutes, vehicle fleet, and off-road equipment), emissions reductions from this program were not estimated, as the LCFS requirements may be achieved through actions applicable to various stages of the fuel production lifecycle, and the rate of emissions reductions that would be realized as tailpipe emissions reductions is currently unknown and not substantial relative to the total emissions inventory. However, these reductions will be reflected in future emissions inventories through the use of updated emission factors that account for then-current carbon intensity of California's transportation fuels.

AB 1493, EO B-16-12, and EO R-12-016 align with the US Corporate Average Fuel Economy (CAFE) standards that set fuel-efficiency specifications for new passenger vehicles built between 2012 and 2025. The emissions reductions associated with implementation of this legislation will vary depending on the turnover rate of employee commute vehicles. Therefore, emission reductions associated with this legislation were not estimated for the employee commute sector or the Water Authority's vehicle fleet. However, the Water Authority does have direct control over its vehicle fleet turnover and, as described later, is replacing current vehicles with higher-efficiency models as feasible. In addition, the standards do not apply to off-road equipment and, therefore, emissions reductions were not applied to future emissions estimates associated with off-road equipment use.

Renewables Portfolio Standard

The state's Renewables Portfolio Standard (RPS) requires that the Water Authority's electric utility provider, San Diego Gas & Electric (SDG&E), deliver 33% of its electricity from renewable sources by 2020, 60% from renewable sources by 2030, and 100% from carbon neutral sources by 2045. Renewable energy as a percentage of SDG&E sales was 44% in 2017, exceeding the state's RPS mandate to achieve 33% by 2020 (see Table 3.1).

Utility-scale solar and wind energy make up most of SDG&E's renewable energy mix. Because of this regulation and SDG&E's current compliance with the target for renewables, the Water Authority's Scope 2 emissions from electricity purchased will emit fewer emissions for every kWh used. As SDG&E continues to comply with the state's RPS requirements, its share of renewable energy will grow in the future and further reduce the amount of electricity-related emissions in the Water Authority's inventory (see Table 3.2).

TABLE 3.1 **SDG&E Percentage of Renewable Sources**

RENEWABLE SOURCES OF ELECTRICITY BY SDG&E				
2009	2013	2017	2020**	2030**
10.0%	20.0%	44.0%	44.0%	60.0%

****Estimate % based on current levels and 2030 targets set by SB 100**
Source: SDG&E (U 902 E) Final 2018 Renewables Portfolio Standard Procurement Plan (April 2, 2019)

TABLE 3.2 **Emissions Reductions due to Federal and State Measures for 2020 and 2030**

REDUCTION SOURCE	2020 (MT CO_2E)	2030 (MT CO_2E)
REDUCTIONS FROM LCFS + CAFE		
Transportation	Potential reductions not accounted for in this analysis	
REDUCTION FROM RPS		
Energy	-	(481)
REDUCTIONS FROM SB X7-7, AB 1668, SB 606		
Water	Potential reductions not accounted for in this analysis	
TOTAL REDUCTIONS FROM STATE AND FEDERAL MEASURES	-	(481)

MT CO_2e = metric tons of carbon dioxide equivalent; RPS = Renewable Portfolio Standard; CAFE = Corporate Average Fuel Economy; LCFS = Low Carbon Fuel Standard

WATER AUTHORITY MEASURES AND POLICIES

In addition to federal and state measures that have been implemented to reduce emissions, the Water Authority has already taken measures to reduce energy consumption and GHG emissions. The energy savings and the reduction in GHG emissions are accounted for in the annual updates and reflected in the emission totals for 2019 and prior inventories as well as forecasted GHG totals. Implementation of any new measures (discussed in Chapter 4) can demonstrate reductions towards the 2020 and 2030 targets.


Solar panels at Twin Oaks Valley WTP

Solar Panels

To take advantage of the unique solar potential in Southern California, the Water Authority installed solar panels at three locations in 2011: Twin Oaks Valley WTP (4,844 panels), San Diego Headquarters Building in Kearny Mesa (1,918 panels), and the Operations Center in Escondido (742 panels). These panels have the potential to produce 2.5 million kWh of electricity per year, accounting for 55% of the energy needs at Headquarters, 38% of the energy needs at Escondido, and 31% of energy needs at the Twin Oaks Valley WTP.

The solar energy systems were installed at no cost to the Water Authority through a 20-year contract with CleanCapital. The Company owns and operates the systems and sells the energy to the Water Authority at a reduced and fixed rate with an annual price escalation factor. Power generated by the solar power systems reduces the Water Authority's energy costs, making agency operations more efficient for ratepayers. Combined, they will cut the agency's energy expenses by nearly $3 million over 20 years. Through its agreement, the Water Authority cannot "take credit" for the solar power generated by these systems; however, it is helping SDG&E meet its RPS goal, which indirectly helps the Water Authority's reduction targets by lowering the SDG&E emissions factor. New opportunities for solar panel installations are continually being investigated and considered. As new solar panels are programmed into the CIP, the emissions estimates will be revised accordingly.

Vehicle Fleet

The Water Authority manages a fleet of approximately 90 vehicles used for maintenance and repair of facilities. In parallel with its other sustainability and conservation efforts, the Water Authority has implemented strategies to reduce fuel consumption and vehicle miles traveled. To date, the Water Authority has installed global position system units in most of its fleet to improve vehicle dispatch planning and allow for data collection on vehicle performance. In addition, the Water Authority retires vehicles that are less efficient and/or underused and has replaced some gasoline-powered passenger vehicles with hybrid vehicles to date.

Energy Conservation Opportunities

The Water Authority partners with SDG&E to promote energy conservation among end-users in the region. In 2011, the partnership funded an audit of the Water Authority's operations to identify energy conservation opportunities (ECOs) in its nine highest-energy-consuming facilities (Appendix C). In that report, more than 30 ECOs were identified to reduce energy consumption, improve efficiency, and/or lower costs.

Investment level (no, low, high) and payback period (short-, mid-, and long-term) were identified to help the Water Authority prioritize implementation. Since 2012, 19 ECOs have been implemented (with eight ECOs since 2014), including variable-frequency drive systems for pump operations in the Twin Oaks Valley WTP. Based on the estimated energy savings calculated in the Energy Audit, the Water Authority, since 2014, has already implemented strategies resulting in savings of 197,000 kWh per year. Further development of the remaining ECOs is anticipated to occur along with consideration of conducting a new energy audit (discussed further in Chapter 4).

Table 3.3 lists the ECOs that have been completed from the 2012 Energy Audit.

Solar panels at San Diego Headquarters Building

Solar panels at Twin Oaks Valley WTP

TABLE 3.3 **ECO Implemented since the 2012 Energy Audit**

CLASS	FACILITY	ECO DESCRIPTION	SIMPLE PAYBACK ESTIMATE TERM IN YEARS	COST	ANNUAL ENERGY SAVINGS (KWH)	ESTIMATED ANNUAL SAVINGS	COMPLETION DATE
Lights	Lake Hodges Hydro	T-12 Upgrades	4.7yrs @ 8760hrs 8.7yrs @ 3760hrs	$26,400	33,900	$4,712	FY 2015
Lights	Lake Hodges Hydro	Replace Interior Metal Halide Lights	.5yrs @ 8760hrs 1.1yrs @ 3760hrs	$4,800	23,100	$3,211	FY 2015
Equipment	Valley Center PS	If the pump station will be used in the future, upgrade pumps to improve efficiency (see Pump Test Reports)	Short-term (<5 years)	$10,000			FY 2015
Equipment	Escondido Operations	Warehouse Lighting Upgrade	Short-term (<5 years)	$800	-	$0	10/2014
Process	Escondido Operations	Re-commission (re-balance) new HVAC systems	Short-term (<5 years)	$0			5/2014
Equipment	Twin Oaks Valley WTP	Evaluate continuous recirculation water loop pumps (25-hp constant speed operations)	Short-term (6.9 years)	$41,000	140,160	$26,630	5/2014
Lights & HVAC	Escondido Operations	Evaluate SDG&Es recommendation to change to the ALTOU rate to DGR	Immediate	$0	-	$5,556	2/2014
Process	San Diego Office	Allow setback of hot water system temperature during off-hours from 120F to 90F	5	$0		$0	9/2012
Process	San Vicente PS	Shift all maintenance runs to off-peak weekends	0	$0	-	$331,000	3/2011
Process	Twin Oaks Valley WTP	Shift production of NaClO (sodium hypochlorite) to off-peak periods to the extent possible	5	$0	-	$78,800	9/2012
Process	Twin Oaks Valley WTP	Adjust dewatering operations (centrifuge) to operate during off-peak periods	0	$0	-	$7,670	9/2011
Equipment	Twin Oaks Valley WTP	Sequence and/or install VFDs on Backwash Tank Fill Pumps (20-hp) to pump water to elevated tanks prior to backwash	0	$0	9	$1,224	9/2012
Lights & HVAC	Twin Oaks Valley WTP	Installation of cycle timers on manual light switches	5	$9,000	8,468	$1,800	10/2012

CLASS	FACILITY	ECO DESCRIPTION	SIMPLE PAYBACK ESTIMATE TERM IN YEARS	COST	ANNUAL ENERGY SAVINGS (KWH)	ESTIMATED ANNUAL SAVINGS	COMPLETION DATE
Equipment	Twin Oaks Valley WTP	Evaluate installation of high-efficiency centralized compressed air (screw) configuration in lieu of six separate systems	10	$10,000	48,580	$9,230	3/2013
Equipment	Twin Oaks Valley WTP	SM Blower Room Supply Fan Direct Drive Install		$6,148	21,396	$4,065	11/2013
Equipment	Twin Oaks Valley WTP	Replace SM permeate system air removal vaccum pumps with air actuated educators		$27,670	65,350	$12,416	1/2012
Process	Lake Hodges Hydroelectric Facility	Monitor block loads of support equipment including HVAC, cooling and service water, and compressed air. (Complete an energy assessment after 1-yr of full operation)	Short-term (<5 years)	$0			3/2014
Equipment	Escondido Operations	Main Bldg T12 to T8 & Incandescent cans to CFL			10,363	$1,865	6/2013
Lights & HVAC	Escondido Operations	Reconfigure HVAC ductwork and thermostats in Training Building 2nd floor	Mid-Term (~11.1 years)	$9,000	-	$811	FY 2013

****All cost and energy savings part of the 2012 Energy Audit**

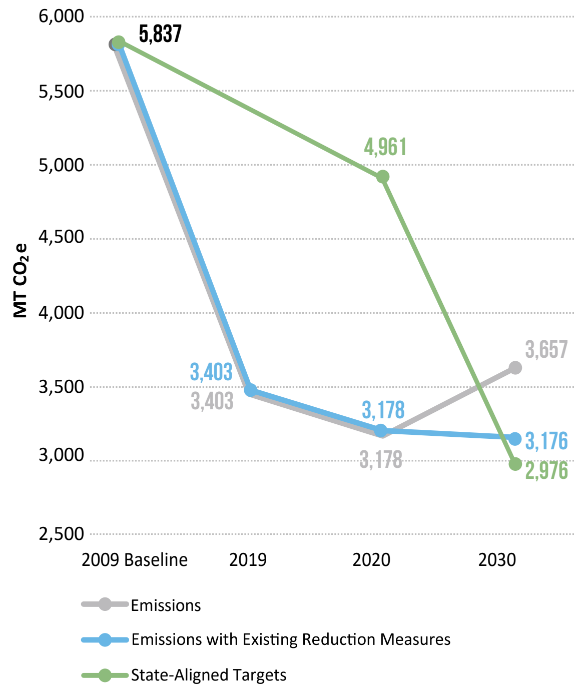
PS=Pump Station; ECO=energy conservation opportunities; kWh=kilowatt-hour; HVAC=heating, ventilation, and air conditioning; SDG&E=San Diego Gas & Electric; WTP=Water Treatment Plant; ALTOU=time-of-use rate schedule; DGR=distributed generation rate schedule; F=Fahrenheit; hp=horsepower; VFDs=variable frequency drives; SM=submerged membrane; CFL=compact fluorescent

CURRENT PROGRESS TOWARD REDUCTION GOALS

Through conserving water, implementing GHG-reducing measures, and investing in projects that will ensure reliable water supply and generate renewable energy, the Water Authority is progressing toward reduction goals for the foreseeable future.

Table 3.4 and Figure 3.1 illustrate the Water Authority's future emissions and reduction targets with current GHG reduction strategies in place. The emissions in 2020 are estimated to be 3,178 MT CO2e and the emissions in 2030 are estimated to be 3,176 MT CO2e with strategies and projects in place today, including the anticipated state and federal reductions. To meet 2030 targets, the Water Authority can implement additional ECOs as well as take RECs for the Rancho Peñasquitos Hydroelectric Facility; these projects along with the proposed Alvarado Hydroelectric Facility have the potential to further reduce emissions below projected levels (see Chapter 4 for more information).

FIGURE 3.1 **Water Authority Emissions and Targets**



MT CO_2e = metric tons of carbon dioxide equivalent. Does not account for future GHG reduction opportunities. A separate analysis is presented in Chapter 4 of this report. Emissions increase or decrease in given years due to construction.

TABLE 3.4 **Summary of Water Authority Emissions and Targets**

	2019 INVENTORY (MT CO_2E)	2020 PROJECTIONS (MT CO_2E)	2030 PROJECTIONS (MT CO_2E)
Business-As-Usual Emissions	3,024	3,047	3,061
Construction Emissions	379	131	596
State and Federal Reductions	0	0	(481)
EMISSIONS WITH EXISTING REDUCTION MEASURES	3,403	3,178	3,176
STATE-ALIGNED GOAL/TARGET	NA	4,961	2,976
SURPLUS/SHORTFALL	NA	1,783	(200)[1]
MEETING TARGET		YES	NO[1]

Notes: MT CO_2e = metric tons of carbon dioxide equivalent. Negative number indicates net emissions reduction. 2009 emissions were baselined at 5,837 MT CO_2e

[1] Does not account for future GHG reduction opportunities. A separate analysis is presented in Chapter 4 of this report

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04 FUTURE GREENHOUSE GAS REDUCTION OPPORTUNITIES

The Water Authority has identified additional opportunities for reducing GHG emissions within its operations. These GHG reduction opportunities were developed in three groups: CIP Planned Projects, energy conservation opportunities from the 2012 Energy Audit, and other opportunities identified by the Water Authority. Table 4.1 summarizes the opportunities, potential GHG savings, initial investment, and payback period; each is described in more detail below.

TABLE 4.1 **Summary of GHG Reduction Opportunities**[1]

MEASURE	GHG REDUCTION POTENTIAL (MT CO_2E PER YEAR)	INITIAL INVESTMENT ($)	PAYBACK PERIOD (YEARS)
MASTER PLAN AND ASSET MANAGEMENT PROJECTS			
All Projects	All projects designed with energy efficiency as a primary design feature	Investment and payback were not assessed separately from the cost of the project	
ENERGY AUDIT ECOS			
Support Operations	20	$0 to >$10,000	0 to 20+ years
Pump Upgrades	10	>$10,000	3 years
OTHER OPPORTUNITIES			
Vehicle Fleet Conversion	Varies	>$10,000	20+ years
Solar PV Installation	Varies	>$10,000	8 to 16 years
In-Line Hydropower Generation (Rancho Peñasquitos)	10,370	>$10,000	13 to 16 years
In-Line Hydropower Generation (Alvarado)	3,950	>$10,000	10 to 13 years

PV = photovoltaic
[1] Projects listed in this table represent opportunities since the Water Authority is currently not taking GHG reduction credits for these projects.

CIP PLANNED PROJECTS

The projects anticipated to be developed are summarized in Chapter 2 of this CAP. The projected water demand through the 2040 planning horizon is anticipated to be met through existing supplies, and additional projects are being developed to better optimize the Water Authority's current delivery system. Therefore, CIP planned projects are inherently focused on improving efficiency and rehabilitating existing infrastructure. The projects primarily involve enhancing current operations and are not anticipated to add long-term GHG emissions. In addition, CIP planned projects were developed to include energy-efficient design features as economically and technically feasible as possible to reduce energy consumption in new facilities (energy efficient windows, high efficiency motors, etc.). Therefore, the projects include measures to minimize GHG emissions as part of their design, so these do not count as specific "reduction measures." The projects within the CIP forecast include features that are consistent with the goals of this CAP.

FUTURE ENERGY AUDIT ECOS

Chapter 3 described ECOs that have already been implemented because of the Energy Audit conducted in 2012 (Appendix C). Additional ECOs identified in the Energy Audit were assessed to determine the feasibility of implementation, the potential for GHG reductions, and the cost and payback period associated with implementation. The ECOs were grouped into the following categories:

- Support Operations
- Pump Upgrades

Only those ECOs that had potential for additional GHG reductions were evaluated. For example, rate optimization and facility operation ECOs were identified in the Energy Audit and have the potential to save the Water Authority energy-related costs by switching operational hours to maximize rate schedules with SDG&E; however, they would not result in GHG reductions for the Water Authority. Similarly, ECOs that have been determined infeasible due to changes in design features (e.g., some pump upgrade measures) were not assessed.

Support Operations

ECOs related to support operations include measures that address heating, ventilation, and air conditioning (HVAC) systems, or that monitor whole-facility energy loads that can help staff identify inefficiencies. Measures vary in their initial cost, payback term, and GHG reduction potential (Table 4.1). For system monitoring, no up-front costs are incurred, but staff time would be required to analyze data and determine how adjustments to energy loads or hot water systems could be made without adversely impacting operations. Demand-management systems are costly but can reduce whole-facility energy loads by 8%. This measure is most effective in facilities with centralized systems and high energy demands, such as the Twin Oaks Valley WTP. Installing HVAC control systems would result in energy reductions and would require an investment of less than $5,000; however, the facilities evaluated would not yield high GHG reductions.

Pump Upgrades

The Energy Audit included several ECOs that would improve pump operations based on current activities or potential future operations; however, many were determined infeasible based on design features or a lack of GHG-reduction potential. Therefore, this measure includes an assessment for the potential GHG reduction and economic analysis of a variable-frequency drive continuous loop pump at the Twin Oaks Valley WTP, which would result in 10 MT CO_2e reduction per year and has a payback term of 3 years, assuming a reduction in flow from 25 horsepower (hp) to 10 hp for 50% of operational time.

OTHER OPPORTUNITIES

In addition to operational energy measures, the Water Authority identified other potential measures, including battery storage, fleet upgrades, solar photovoltaic (PV) installations, pumped storage, and in-line hydropower.

Battery Storage

The Water Authority will save approximately $100,000 per year with commercial-scale batteries installed at the agency's Twin Oaks Valley WTP near San Marcos. The energy storage system is designed to reduce operational costs at the facility by storing low-cost energy for use during high-demand periods when energy prices increase. The battery storage provides a financial incentive and shifts demand from high energy demand periods (on-peak) to low energy.

The batteries were installed at no charge to the Water Authority as part of an agreement with Santa Clara-based ENGIE Storage, a division of ENGIE North America, formerly known as Green Charge. The system charges from either the grid or onsite solar energy production to store low-cost energy. ENGIE Storage's GridSynergy software allows the Water Authority to use that low-cost energy for plant operations during high-demand periods when energy market prices typically peak. Onsite energy is generated by more than 4,800 existing solar panels at the Twin Oaks facility that produce an estimated 1.75 million kWh of electricity each year.

ENGIE Storage installed the 1 MW/2 MWh battery energy storage system at Twin Oaks through a Power Efficiency Agreement with the Water Authority. ENGIE will own, operate, and maintain the $2.6 million system on Water Authority land for 10 years, after which the Water Authority can choose to extend the agreement, purchase the batteries, or have them removed and the site returned to its original condition.

A $1 million incentive from the California Public Utilities Commission (CPUC) helped to fund the project. The incentive, awarded in 2017 under the CPUC's Self Generation Incentive Program, encourages the adoption of energy storage technologies that reduce electricity demand and GHGs.

Vehicle Fleet Conversion

The Water Authority owns and maintains a fleet of vehicles that run primarily on carbon-based fuels. This strategy assumes replacement of existing fleet vehicles with hybrid or lower emitting vehicles. Fully electric vehicles were not considered due to the battery range technology currently available and the lack of recharge infrastructure. Liquid Natural Gas (LNG) vehicles were also not considered given the infrastructure required to fuel the vehicles and the relatively small fleet size. Replacement of vehicles will be done on an as-needed basis. The general assumption is that older, higher GHG-emitting vehicles will be replaced with new vehicles that meet or exceed current state standards for vehicle emissions. The annual reductions in GHG emissions due to vehicle fleet conversion will vary annually.

Solar PV

This potential GHG reduction measure includes the installation of a solar PV system at an existing Water Authority-owned site. There are no solar PV systems as part of the current CIP, but new sites are evaluated as opportunities become available. The estimated size of the system is based on the average size of installations at commercial sites receiving performance-based incentives in the California Solar Initiative database. The estimated annual kWh output is based on the current Escondido Operations facility performance. Emissions benefits based on an estimated electricity generation of 300,000 kWh per year would result in an emissions reduction of 74 MT CO_2 per year. An installation of this size would pay back in 16 years given a cost of approximately $588,270 and incentives paid out over the first 5 years of system operation (see Table 4.2).

TABLE 4.2 **Analysis of Solar PV Measure**

ENERGY GENERATION (KWH/YEAR)	GHG REDUCTION POTENTIAL (MT CO_2E/YEAR)	INITIAL COST	PAYBACK TERM
300,000 kWh/year	74	$600,000	16 years

Notes: GHG reduction potential is based on anticipated 2020 SDG&E emission factor with 33% RPS. KWh = kilowatt hour; MT CO_2e = metric tons of carbon dioxide equivalent; PV = photovoltaic

In-Line Hydropower

Existing Opportunities

In addition, water flowing through pipelines has the potential to generate power within large existing infrastructure. Water distribution pipeline networks can be retrofitted with turbine blades, generally in pipe diameters 24 inches or larger, to exploit the kinetic energy of flowing water. The Water Authority owns and operates the 4.5-megawatt (MW) Rancho Peñasquitos Pressure Control and Hydroelectric Facility (PCHF). This in-line hydroelectric facility was constructed in 2007 to control untreated water flows on the southern portion of the Water Authority's Second Aqueduct and San Vicente Pipeline. The hydroelectric turbine generates approximately 11,000 MWh of GHG emissions-free energy annually. As an in-line hydroelectric turbine, this energy currently qualifies for RECs with associated GHG reductions totaling 5,430 MT CO2e. Previously, energy from the facility was sold into the California Independent System Operator's wholesale energy market with Renewable Energy Credits sold to a third party. In August 2019, the Water Authority obtained approval from the California Public Utilities Commission to bill credit energy generated at the facility towards the energy bill at the Lewis Carlsbad Desalination Plant. The bill credit is realized through SDG&E's Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) tariff. As a result of this decision, RECs are now retained by the Water Authority, but were not used to reduce GHG emissions under this CAP. The Rancho Peñasquitos PCHF is currently off-line due to low flows until Fall 2020 as the Water Authority moves water from the San Vicente Reservoir to the Second Aqueduct. The Water Authority may evaluate using RECs towards its GHG emissions reductions in the future.

Future Opportunities

Due to a reduction in regional water demands, reduced water flows through the Rancho Peñasquitos PCHF have limited hydroelectric generation to less than 60% of its capacity. With the current hydroelectric equipment, forecasted water flows, including the City of San Diego's Pure Water project, are expected to limit hydroelectric generation to less than 50% of its capacity in years with limited local water supplies, and almost no hydroelectric generation in years with ample local water supplies.

As a result, the Water Authority assessed expanding the operating range of the hydroelectric turbine at the Rancho Peñasquitos PCHF to increase run time and electrical generation. The analysis recommended improvements to the facility that are underway and expected to complete by June 2021. When complete, the Rancho Peñasquitos PCHF will have a new hydroelectric turbine, which is anticipated to generate an average annual revenue of $1 Million and additional 10,000 MWh of renewable energy annually for a facility total of 21,000 MWh of renewable energy annually; with a potential of reducing GHG emissions by an additional 4,940 MT CO_2e for a facility total of 10,370 MT CO_2e (greater than Water Authority's current emissions inventory).

The Alvarado Hydroelectric Facility (AHEF) was built in 1984 adjacent to the San Diego 12 Flow Control Facility. The 2.0-MW hydroelectric facility monetizes the potential energy normally consumed at the flow control facility. Staff suspended operation at the AHEF in 2007 due to flood damage. At that time, it was not economical to rehabilitate the facility due to electric market conditions. The 2013 Regional Water Facilities Optimization and Master Plan Update identified the existing hydroelectric facility as potentially viable for producing power. Subsequent analyses confirmed that viability. Once in operation in late 2022, the facility is estimated to generate at least $600,000 in annual net revenue from a new 1.4-MW hydroelectric turbine and 8,000 MWh of clean energy annually. As an in-line hydroelectric turbine, this energy also qualifies for RECs and could reduce GHG emissions by 3,950 MT CO_2e.

The reduction potential from existing and future in-line hydroelectric facilities is summarized in Table 4.3. Currently, all RECs and GHG emission reduction credits from hydroelectric facilities are not being utilized to reduce the overall total GHG emissions by the Water Authority. This is possible since the Water Authority is currently meeting emission goals without using hydroelectric GHG reduction credits. The Water Authority will evaluate the use of hydroelectric RECs to meet GHG emissions goals set by regulations, for example to meet future carbon neutral goals, in the future CAP updates.

The 2013 Master Plan Update provides more detail on system requirements including an evaluation of in-line energy sources at 16 facilities. New potential hydroelectric sites are currently being analyzed by the Water Authority and will be included as potential emissions reduction measures as they are programmed into the CIP.

TABLE 4.3 **Analysis of In-Line Hydropower Measures**

FACILITY	GENERATOR SIZE (MWH)	ENERGY PRODUCTION	GHG REDUCTION POTENTIAL (MT CO_2E/YEAR)	PAYBACK TERM	STATUS
Rancho Penasquitos Pressure Control and Hydroelectric Facility	4.5 megawatt	11,000 MWh/year	5,430	NA	On-line By Fall 2020
		additional 10,000 MWh/year	additional 4,940	13 to 16 years	Improvements by 2021
Alvarado Hydroelectic Facility	1.4 megawatt	8,000 MWh/year	3,950	10 to 13 years	Improvements by 2022

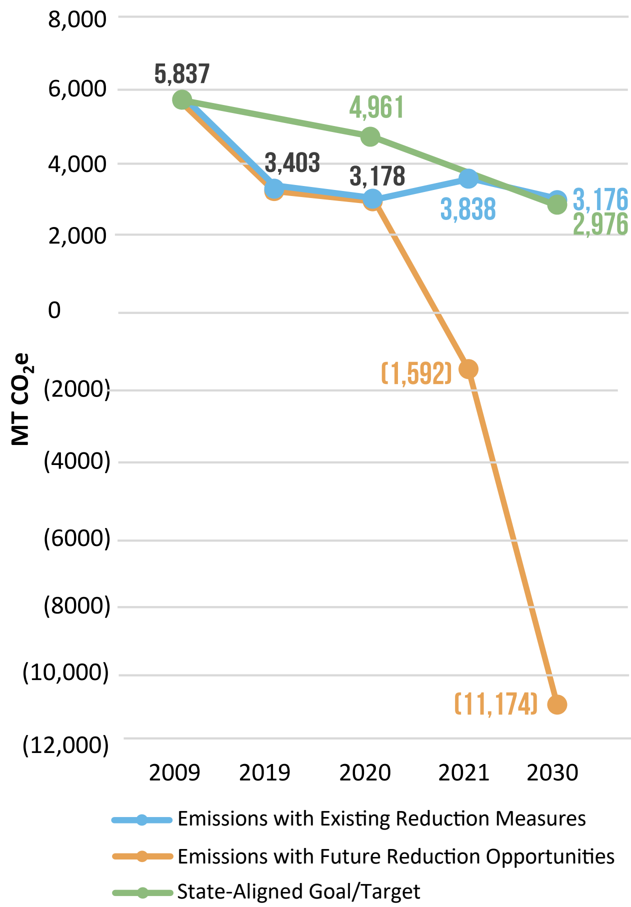
Notes: GHG reduction potential is based on anticipated 2020 SDG&E emissions factor with 33% RPS. MT CO_2e/year = metric tons of carbon dioxide equivalents per year; MWh= megawatt hour(s)

Rancho Penasquitos Pressure Control and Hydroelectric Facility

PROGRESS TOWARDS FUTURE REDUCTION GOALS

The Water Authority has analyzed and implemented measures that resulted in GHG reductions. The measures were developed using information provided in the Energy Audit, actual energy consumption information on a per-facility basis, and assumptions regarding the efficacy and cost of implementing these measures. Future measures are identified as "opportunities," since the timing and level of implementation could vary due to cost, feasibility, or level of GHG reductions. However, the analysis is based on the best available information so that the Water Authority can identify opportunities for immediate implementation and those that warrant further investigation. On February 2020, the Water Authority began conducting energy audits of its top energy-consuming facilities. Results from these audits, including ECOs, will be incorporated into the next 5-year CAP update report. The Water Authority's approach to addressing future GHG emissions reductions within this CAP, is summarized in Table 4.4 and Figure 4.1. In future CAP updates, the Water Authority will evaluate the use of available RECs and ECOs considering projected emissions totals, GHG emissions targets set by regulations such as EO B-55-18 (carbon neutrality by 2045), and financial impacts. The Water Authority will evaluate whether to sell available RECs in the future and to what extent while meeting state-aligned targets.

FIGURE 4.1 **Water Authority Emissions and Targets Aligned with State Goals**



Notes: Assumes existing Rancho Penasquitos PCHF will be online post-2020 and hydropower improvements would be installed post-2021. MT CO_2e = metric tons of carbon dioxide. Emissions increase or decrease in given years due to construction emissions.

TABLE 4.4 **Summary of Water Authority Emissions and Targets**

	2020 PROJECTED (MT CO_2E)	2021 PROJECTED (MT CO_2E)	2030 PROJECTED (MT CO_2E)
Business-As-Usual Emissions	3,047	3,047	3,061
Construction Emissions	131	791	596
State and Federal Reductions	0	0	(481)
EMISSIONS WITH EXISTING REDUCTION MEASURES	3,178	3,838	3,176
In-Line Hydropower RECs – Rancho Peñasquitos PCHF	0	(5,430)	(10,370)
In-Line Hydropower RECs – AHEF	0	0	(3,950)
Energy Audit ECOs	0	0	(30)
EMISSIONS WITH FUTURE REDUCTION OPPORTUNITIES	3,178	(1,592)	(11,174)
State-Aligned Goal/Target	4,961	NA	2,976
Overall MT CO_2e Below Target[1]	1,783	NA	14,150
MEETING TARGET	YES	NA	YES

Notes: MT CO_2e = metric tons of carbon dioxide equivalent; REC=Renewable Energy Credit; ECO= Energy Conservation Opportunity; PCHF= Pressure Control and Hydroelectric Facility; AHEF= Alvarado Hydroelectric Facility. Negative number indicates net emissions reduction. 2009 emissions were baselined at 5,837 MT CO_2e

[1] This indicates the amount of GHGs anticipated to be reduced beyond the target, or the difference between the target and expected emissions.

05 MONITORING AND REPORTING

Although not a GHG reduction plan under CEQA, this CAP will still have a monitoring mechanism. The Water Authority is committed to achieving the 2020 and 2030 emissions reduction targets and has established monitoring mechanisms for accurate reporting. To ensure that the Water Authority is monitoring GHG emissions reduction efforts relative to projections and established targets, progress will be tracked as part of annual and 5-year update reports. Annual CAP update reports were implemented starting in 2014 and 5-year CAPs were implemented starting in 2014.

Future CAP revisions will allow a comprehensive look at how the Water Authority is performing, and the annual CAP reports will be a progress indicator of specific measures. Assessing overall emissions reductions for the Water Authority are important to ensure that progress is being made toward emission goals. If progress is not being made, the review will enable the Water Authority to determine appropriate steps to achieve goals.

Because climate change policy continues to evolve, new information will be available to the Water Authority between 2020 and 2030. Additional reasons to review and update the CAP periodically include:

- New state-implemented GHG-reduction strategies that may achieve even greater reductions than anticipated or change the effectiveness of the opportunities identified.
- New state-adopted GHG targets that expand beyond the targets set in AB 32 and SB 32, including EO B-55-18 which was signed September 2018. Efforts for this CAP began before the signing of EO B-55-18; however, the next 5-year CAP will address this and any other codified targets. As discussed in this report, the Water Authority has sufficient RECs to meet and exceed EO-B-55-18. Other future opportunities identified in an updated Energy Audit will also be considered to reduce GHG emissions.
- Rapidly changing technology that affects the feasibility of opportunities identified in this CAP and/or provides new opportunities
- Additional litigation applicable to future CAP iterations, including new case law
- New funding opportunities identified by the Water Authority that accelerate implementation of GHG reduction opportunities or the completion of feasibility studies that impact current opportunities

Should revisions to the current CAP be necessary in the future, the Water Authority will revise the plan and present it to the Water Authority's Board of Directors for approval.

CEQA

The Water Authority's approach to addressing GHG emissions reductions within this CAP, summarized in Table 4.4 and Figure 4.1 in Chapter 4, is parallel to the climate change planning processes of myriad jurisdictions and agencies throughout California. The process is as follows:

- Complete a baseline GHG emissions inventory and project future emissions.
- Identify future GHG emissions target levels that are consistent with statewide targets and guidance provided for local governments.
- Identify a set of strategies to meet the selected targets.
- Evaluate the environmental impacts of the CAP through an environmental review process pursuant to the State's CEQA Guidelines.
- Adopt the CAP in a public process.

All future projects should demonstrate the impacts on GHG emissions totals and emission targets and include any appropriate mitigation measures as enforceable components of the project. All future projects must also prepare a separate GHG analysis since this CAP is not a tiering document under CEQA Guidelines Section 15183.5.

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Appendix A

2009 GREENHOUSE GAS EMISSIONS INVENTORY

2009 Greenhouse Gas Emissions Inventory

OCTOBER 2012, REVISED DECEMBER 2015

AECOM

San Diego County Water Authority

Contents

Prepared by AECOM

Executive Summary

In 2009, SDCWA generated approximately 5,837 metric tons (MT) of carbon dioxide equivalent (CO2e) emissions. As shown in Table ES1, the largest sector in the inventory was the electricity sector, which accounted for 71% of emissions. The next largest sectors in the inventory were emissions from the vehicle fl eet and employee commute sectors, respectively. These sectors accounted for a combined 24% of the inventory. The remaining sectors accounted for less than 6% of the inventory. This information, along with assumptions regarding future operations, will be used in the next step of the climate action planning process, which is to estimate future emissions and establish a level of emissions reduction the SDCWA hopes to achieve by a future date.

Table ES1: 2009 Greenhouse Gas Emissions Inventory

Sector	MT CO_2e	Percent of Total Emissions
Electricity	4,133.44	70.82%
Vehicle Fleet	694.16	11.89%
Employee Commute	685.34	11.74%
Off-Road Equipment	142.87	2.45%
Stationary Source	88.69	1.52%
Natural Gas	57.75	1.00%
Solid Waste	26.75	0.46%
Water	4.35	<0.1%
Refrigerants	1.78	<0.1%
Wastewater	1.42	<0.1%
Total	**5,836.55**	**100.00%**

Totals may not equal 100% due to rounding. MT CO_2e = metric tons of carbon dioxide equivalent.

Overview

The LGOP is a sector-specific protocol that provides the policy framework, calculation methodologies, and reporting guidance for quantifying GHG emissions developed in partnership with the California Air Resources Board.

A greenhouse gas (GHG) emissions inventory describes the amount of GHGs emitted by various sources over a specific period of time for a certain entity, such as a municipality, agency, or business. A GHG emissions inventory is often used as the first step in developing plans that estimate emissions over time and establish measures that can reduce emissions. In California, these plans (known as GHG reduction plans or climate action plans) are often developed in conformance with the Global Warming Solutions Act of 2006 (Assembly Bill [AB] 32), which requires statewide emissions levels in 2020 to be reduced to 1990 levels.

SDCWA conducted a GHG emissions inventory in 2011 as a member of the Climate Registry, following the Climate Registry's General Reporting Protocol. Currently, SDCWA is developing a CAP and requested a review of the inventory to ensure consistency with current methodologies, practices, and guidance within California.

AECOM had previously reviewed the GHG inventory and recommended the following revisions:

1. Use Local Government Operations Protocol (LGOP) compliant emission factors. These include local emissions factors where available, which provide more accurate GHG emissions and are tied to some of the reduction strategies that will be developed in later CAP-development steps.

2. Add the following GHG emissions sources to conform to LGOP guidance:

   - Employee Commute,
   - Generated Waste Sector,
   - Water Sector, including internal operations,
   - Wastewater Sector, and
   - Stationary refrigerants.

3. Extract the data into a user-friendly Excel format for use in the CAP process. The previous inventory used ICLEI's Clean Air and Climate Protection (CACP) software, which is not as transparent or easily usable for updating the inventory, analyzing future emissions (forecasting), calculating GHG emission reduction measures, or preparing documents.

4. Update the inventory in a fully transparent manner allowing for future consideration of inputting, submitting, and verifying data in The Climate Registry's (TCR) Climate Reporting Information System (CRIS) system.

This memo and inventory address these revisions. The inventory primarily focuses on the three GHGs most relevant to CAP development: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Converting non-CO_2 gases to units of carbon dioxide equivalent (CO_2e) emissions allows GHGs to be compared on a common basis. Non-CO_2 gases are converted to CO_2e using internationally recognized global warming potential (GWP) factors (i.e., on the ability of each GHG to trap heat in the atmosphere). For example, the GWP of CH_4 is 21 because 1 metric ton of CH_4 has 21 times more ability to trap heat in the atmosphere than 1 metric ton of CO_2. The GWP of N_2O is 310.The GWPs are consistent with those used by the California Air Resources Board (ARB) for California statewide emissions.

This memo was originally prepared in October 2012, during the initial stages of CAP preparation. The CAP was finalized in March 2014. While SDCWA was preparing the first CAP annual monitoring report in 2015, staff realized an inconsistency with the 2009 energy usage data, and concluded that the original 2009 inventory and the updated inventory incorporated into the CAP had double-counted certain entries for electricity and natural gas bills. This resulted in an over-estimation of emissions related to energy usage. This memo has been revised to correct that error.

Baseline Emissions Inventory

A baseline inventory is the first step in developing a plan to reduce greenhouse gas emissions.

GHG inventories are generally estimated for a single calendar year, which is considered an international standard. The United Nations Framework Convention on Climate Change, the Kyoto Protocol, The European Union Emission Trading System, The Climate Registry, California Climate Action Registry (CCAR), California's mandatory reporting regulation under AB 32, and the U.S. Environmental Protection Agency's (EPA) GHG reporting program all require GHG inventories to be tracked and reported on a calendar year basis. Determining an appropriate inventory year depends on data availability and regulatory guidance. To comply with AB 32, developing an inventory for emissions in 1990 would provide a straightforward approach to determining the appropriate emissions level necessary in 2020. However, most entities do not have complete or accurate records necessary to calculate GHG emissions in 1990 and a more current inventory is conducted. SDCWA has taken this approach and conducted an emissions inventory for the year 2009. This inventory serves as the basis for estimating future emissions and reduction goals and therefore is referred to as a "baseline" emissions inventory.

Inventory Approach

The baseline emissions inventory was updated using emission factors from the LGOP, which was developed by ARB, CCAR, and ICLEI - Local Governments for Sustainability (ICLEI), in collaboration with The Climate Registry (ARB 2010). The LGOP provides a standardized set of guidelines to assist local governments to quantify and report GHG emissions associated with their operations. To assist SDCWA in making easy future updates to their GHG baseline inventory, as well as future projects, Microsoft Excel spreadsheets were used for the analysis.

Methodology

In general, estimating GHG emissions requires activity data and emission factors. Activity data refers to the amount energy consumed (kWh or therms), waste produced (tons), and water used (gallons). Emission factors are a measure of how carbon-intensive an activity is (i.e., the amount of GHGs that are emitted by a unit of activity). Activity data were obtained from SDCWA, including information related to water consumption for internal operations, number of employees, and electricity and natural gas use. Emissions factors recommended by the LGOP were used to estimate CO_2e emissions; both are described in more detail by sector below. The LGOP provides a conservative approach to developing GHG inventories.

Energy Consumption – Electricity and Natural Gas

The energy consumption sector includes the use of electricity and natural gas at SDCWA facilities. GHG emissions may be both direct and indirect emissions. Direct emissions are those that are generated at the operational site, such as fuel combustion in landscape equipment or for space and water heating. Indirect GHG emissions are those being generated at a location other than the entity's operational site but are a result of on-site activity, such as electricity use.

Utility-specific CO_2 emission factors for electricity were taken from the San Diego Gas and Electric (SDG&E) 2009 Annual Emissions Report for the Climate Action Registry for SDG&E-supplied electricity (SDG&E 2009). SDG&E does not provide CH_4 and N_2O emissions factors; therefore, statewide averages as referenced in the LGOP were applied (ARB 2010). Similarly, statewide average emission factors from the LGOP were used to estimate emissions from natural gas (including CO_2, CH_4, and N_2O).

Baseline energy consumption data was sourced from utility bills for calendar year 2009 at each SDCWA facility with an electricity and natural gas meter. The energy bill data analyzed in the 2015 revision omitted data for two facilities, so assumptions were made to provide reasonable entries for the respective periods, as discussed below.

The 2009 source data for Twin Oaks Valley Water Treatment Plant omitted a May entry for that facility's Meter 1 and omitted January and February entries for Meter 2, even though both meters were known to have been operating during these periods. For May 2009 at Meter 1, staff entered a value of 736,868 kWh, which is the average kWh usage for this facility in the two preceding and succeeding months of March, April, June, and July, accounting for a seasonal fluctuation evident in this meter's activity. For January and February, staff entered a value of 434 kWh, which is the average of the entries for the other 10 months (there was no evident seasonal fluctuation for this meter).

The 2009 source data reviewed in 2015 contained no entries for the Rainbow Chlorine Station, even though this facility was known to be operating during this period. Staff entered a value of 643 kWh for 2009 usage, which is the average of annual data available from fiscal year 2012 through 2015.

Vehicle Fleet

Vehicle fleet emissions were estimated based on vehicle fuel use and miles traveled. CO_2 emissions account for most emissions from mobile sources and are directly related to the quantity of fuel combusted. Thus, CO_2 emissions can be calculated using fuel consumption data. CH_4 and N_2O emissions depend more on the emission control technologies employed in the vehicle and the distance traveled. SDCWA provided total fuel consumption and mileage data for the vehicle fleet in 2009. Emissions factors from the LGOP were used to estimate vehicle fleet emissions (ARB 2010).

Employee Commute[1]

Similar to the methodology for vehicle fleet emissions, employee commute emissions can be estimated based on vehicle fuel use and miles traveled. SDCWA provided information on the number of employees and work schedule (e.g., number of employees working 9/80 schedule). The County of San Diego General Plan Environmental Impact Report reports the average region-wide commute distance, which was used as the average SDCWA employee average commute distance. EMFAC 2007 was used to derive an average fuel consumption rate for light-duty vehicles in San Diego County, which were assumed to be the primary form of transportation for SDCWA employees. Emissions factors from the LGOP were used to estimate vehicle fleet emissions (ARB 2010).

SDCWA emitted 5,837 MT CO2e in 2009. That is about equal to the CO_2 emissions from 533 U.S. homes in a year.

(http://www.epa.gov/cleanenergy/energy-resources/calculator).

1 Emissions related to employee commute, solid waste, and wastewater are considered Scope 3 emissions and could be double-counted as part of other emission inventories. However, SDCWA exerts some influence over the activity that accounts for these emissions and therefore could affect emissions reductions and are included in the inventory. This follows recommended approaches for conducting emissions inventories in California.

Solid Waste

The solid waste sector includes emissions resulting from the collection, processing, and disposal of solid waste. Solid waste disposal creates CO_2 emissions, which occur under aerobic conditions, and CH_4 emissions, which occur under anaerobic conditions, primarily at landfills.

The amount of solid waste was estimated using a per employee disposal rate consistent with the methodology used in the County of San Diego Draft 2009 Greenhouse Gas Emissions Inventory. The average disposal rate is 1.6 pounds per employee per day. The number of employees was provided by SDCWA. GHG emissions resulting from solid waste were estimated using emission factors from the EPA's Waste Reduction Model (EPA 2010) and waste characterization information estimated by the California Department of Resources Recycling and Recovery (CalRecycle) for the Utilities Business Group (CalRecycle 2012).

Wastewater

The wastewater sector includes emissions resulting from wastewater treatment processes, including wastewater collection, septic system management, primary and secondary treatment, solids handling, and effluent discharge. Wastewater treatment processes can encompass many different sources of GHG emissions. GHG emissions from wastewater treatment facilities include CO_2, CH_4, and N_2O; however, CO_2 emissions are biogenic and according to the LGOP are not included in an emissions inventory (ARB 2010). GHG emissions associated with wastewater treatment were calculated using the IPCC methodology for centralized, aerobic wastewater treatment plants (IPCC 2006).

Water Consumption

The water sector includes emissions from energy associated with water treatment, distribution, and conveyance of water to the community. The California Energy Commission has published water-energy intensity studies that estimate the energy required to convey, treat, and distribute water. All water is treated to be potable, but water used in outdoor activities, such as landscape irrigation, is not subject to wastewater treatment. Conveying and distributing water from remote locations involves a considerable amount of electricity to run pumps and other facilities. Water consumption for 2009 was provided by SDCWA through utility bills by facility.

Stationary Sources/Off-Road Equipment

These sectors include stationary source generators and off-road equipment. Fuel consumption associated with generators and off-road equipment was provided by SDCWA. Emissions were estimated based on fuel consumption and emission factors from the LGOP (ARB 2010).

Refrigerants

Although generally a small portion of total emissions, refrigerants consist of high GWP gases. Individual molecules of hydrofluorocarbons (HFCs, the type of greenhouse gas generally emitted by refrigerants) have GWPs ranging from 140–14,800. Information regarding HFC quantities were provided by SDCWA and estimated in the original inventory; additional information was not available and the emissions estimated in the original inventory was considered to account for the majority of refrigerant emissions in 2009.

Results

The results are reported using several organizational approaches. Reporting emissions by sector, scope, facility and source provides useful ways to understand SDCWA's emissions. By better understanding the relative scale of emissions, SDCWA can more effectively focus emissions reduction strategies to achieve the most cost-effective emissions reductions.

Revised GHG Emission Estimates by Sector

Emissions by sector is often the most useful organization of an inventory that will be used in a CAP; GHG-reduction measures are often sector-based and understanding the relative emissions by sector may influence the measure-selection process. As stated above, this memo provides revisions to the previous GHG emissions inventory developed by SDCWA. Table 1 shows the change in emissions from the original inventory, by sector, incorporating the 2012 update by AECOM and corrected energy data identified in 2015.

SDCWA emissions for 2009 were originally estimated to be 8,712 MT CO2e; the revisions from the 2012 update and the 2015 data correction resulted in a 33% decrease (2,875.84 MT CO2e) in emissions, to 5,837 MT CO2e. The 2012 update resulted in a slight increase

Table 1: Original and Revised 2009 Greenhouse Gas Emissions Inventory

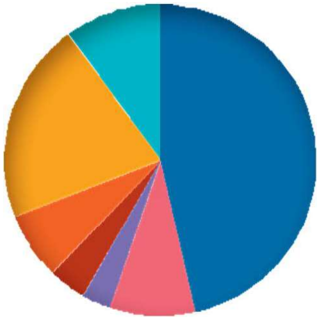
Sector	Original Inventory (MT CO_2e)	Revised Inventory (MT CO_2e)	Net Change (MT CO_2e)
Electricity	7,679.36	4,133.44**	(3,545.92)
Vehicle Fleet	723.00	694.16	(28.84)
Employee Commute		685.34	685.34
Off-Road Equipment*		142.87	142.87
Stationary Source*	265.94	88.69	(177.28)
Natural Gas	42.32	57.75**	15.43
Solid Waste		26.75	26.75
Water		4.35	4.35
Refrigerants	1.78	1.78	
Wastewater		1.42	1.42
Total	**8,712.39**	**5,836.55**	**(2,875.84)**

MT CO_2e = metric tons of carbon dioxide equivalent.

* Stationary Source and Off-Road Equipment emissions were combined into one category in the original inventory. Updated emission factors also resulted in a net change from 265.94 MT CO_2e to 231.56 MT CO_2e for the combined categories in the revised inventory.

** Electricity and Natural Gas emissions were corrected in 2015 based on a refined analysis of SDCWA energy bill data.

Figure 1: GHG Emissions by Facility



in estimated emissions, primarily due to addition of emissions categories for employee commute, water and wastewater, and solid waste disposal. After the 2015 data correction was incorporated into the estimates, overall emissions decreased signifi cantly because of the correction in data inputs for electricity and natural gas bills, eliminating entries that had been double-counted in the original inventory.

Emissions by Facility

For an agency such as SDCWA that has direct control over the majority of its emission sources, it may be useful to identify which facilities generate the most emissions. Often, high-emitting facilities are integral to the agency's mission; however, it can also inform the agency where energy audits, retrofi tting, or retrocommissioning projects may be focused. The majority of the emissions inventory can be associated with specifi c SDCWA facilities. The SDCWA's facilities are comprised of 17 different facilities, including pump stations. For the purposes of this organizational approach, employee commute, solid waste, and wastewater are not associated with specifi c facilities and are considered "Other" in Table 2 and Figure 1. The Twin Oaks Valley Water Treatment Plant is responsible for 43% of SDCWA emissions in 2009. Pump stations are the next largest source of emissions, accounting for 17% of the total emissions, and the San Diego – Headquarters location is responsible for approximately 10% of the 2009 emissions. The three sources represent 70% of all SDCWA facility-related emissions.

Twin Oaks Valley Water Treatment Plant

Table 2: 2009 Greenhouse Gase Emissions by Facility

Facility	MT CO_2e	Percent of Total Emissions
Twin Oaks Valley Water Treatment Plant	2,513	43%
Pump Stations	980	17%
Combined Other	783	13%
San Diego - Headquarters	572	10%
Flow Control Facilities	561	10%
Aqueduct Protection Program	252	4%
Escondido Operations Center	175	3%
Total	**5,837**	**100%**

Table 2 and Figure 1 show that SDCWA has its greatest reduction potential from the Twin Oaks Water Treatment Plant, Pump Stations, and the Headquarters building. However, it is important to understand the existing operational effi ciency of each facility to accurately understand the reduction potential of that sector.

Emissions by Source

Another organizational method to evaluate GHG emission inventories is to identify the different sources of the emissions. In the case of SDCWA, the sources included in the 2009 inventory are: purchased electricity, natural gas, diesel, gasoline and refrigerants as shown in Table 3 below. Purchased electricity accounts for the majority of emissions, followed by gasoline and diesel fuel usage for the vehicle fl eet and generators.

Purchased electricity is the primary source of emissions from the SDCWA.

Table 3: 2009 Greenhouse Gas Emissions by Source

Source	MT CO_2e	Percent of Total Emissions
Purchased Electricity	4,137.79	70.9%
Gasoline fuel	1,172.37	20.1%
Diesel fuel	354.34	6.1%
Distillate Fuel Oil No. 1	84.35	1.4%
Natural Gas	57.75	1.0%
Other	28.18	0.5%
Refrigerants	1.78	0.0%
Total	**5,836.55**	**100%**

MT CO_2e = metric tons of carbon dioxide equivalent.

In 2009, 18% of San Diegans considered water supply/quality/cost to be residents' most important issue.

(http://www.sdcwa.org/sites/default/fi les/fi les/news-center/2012-survey-report.pdf)

Emissions by Scope

The LGOP (ARB 2010) and the Climate Registry's General Reporting Protocol (TCR 2008) recommend organizing emissions inventories using the scope approach in order to maximize transparency and comparability of emission inventories with different entities while minimizing the possibility for double counting emissions. In other words, if all emissions inventories are developed using the same organizational structure, it is less likely that an inventory will include a sector or activity twice.

Scope 1

All direct GHG emissions (with the exception of direct CO_2 emissions from biogenic sources). Direct GHG emissions include combustion of fossil fuel and direct release of GHG emissions. For example, if natural gas is combusted on a SDCWA facility, those GHG emissions would be considered Scope 1 emissions. Direct emissions for the purposes of this memo include natural gas consumption, refrigerants, vehicle fl eet, stationary sources, and off-road equipment.

Scope 2

Indirect GHG emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling. The descriptor "indirect" describes that fact that the emissions are being generated at another location other than the entity's operational site. Scope 2 emissions include electricity and water use.

Scope 3

All other indirect emissions not covered in Scope 2, such as emissions resulting from the extraction and production of purchased materials and fuels, transport-related activities in vehicles not owned or controlled by the reporting entity (e.g., employee commuting and business travel), outsourced activities, waste disposal, etc. Scope 3 emissions include employee commute, wastewater, and solid waste disposal.

When evaluating the 2009 emissions inventory by scope (see Table 4), Scope 2 emissions make up the largest piece of the inventory. No Scope 3 emissions were accounted for in the original 2009 inventory.

Table 4: 2009 Greenhouse Gas Emissions by Scope

Scope	MT CO_2e
Scope 1	958.24
Scope 2	4,137.79
Scope 3	713.52
Total	**5,836.55**

MT CO_2e = metric tons of carbon dioxide equivalent.

References

California Air Resources Board (ARB)

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Appendix A:
Supplemental Tables

Vehicle Fleet Emissions

Highway Vehicles					
	Gasoline	Hybrid	Diesel	Ethanol	Total
# of Vehicles	60	5	31	2	98
Miles driven	695,179	46,814	202,973	30,973	975,939
% of Highway Total	71%	5%	21%	3%	100%
Gal. used	48,723	1,528	23,773	2,186	76,210
% of Highway Total	64%	2%	31%	3%	100%

Fuel Consumption (gallons)					
	Gasoline	Hybrid	Diesel	Ethanol	Total
Passenger Vehicles	14,989	1,528	-	2,186	18,703
Light-Duty Trucks	33,734	-	9,574	-	43,308
Heavy-Duty Trucks	-	-	14,199	-	14,199

Vehicle Miles Traveled					
	Gasoline	Hybrid	Diesel	Ethanol	Total
Passenger Vehicles	260,057	46,814	-	30,973	337,844
Light-Duty Trucks	435,122	-	118,863	-	553,985
Heavy-Duty Trucks	-	-	84,110	-	84,110

Total Emissions

	Gasoline	Diesel	Ethanol	Total
CO2	441	243	-	684
N2O	0.03	0.001	0.0021	0.031
CH4	0.02	0.001	0.0017	0.024
Total	451	243	0.6791	694
% of Total	65%	35%	0%	100%

Note: CO2 Emissions from Ethanol are considered biogenic emissions. Note that the distinction of emissions from biomass combustion applies only to CO2 and not to CH4 and N2O, which are also emitted from biomass combustion. Unlike CO2 emissions, CH4 and N2O emitted from biomass combustion are not of a biogenic origin. This is because no CH4 or N2O would have been produced had the biomass naturally decomposed.

	GWP
GWP - CO2	1
GWP - CH4	21
GWP - N2O	310

Source: ARB. 2010. Local Government Operations Protocol. Version 1.1. Appendix E. Global Warming Potentials.

Stationary Source Emissions

Total Emissions (metric tons)

	Gas	Diesel	Disillate Fuel Oil No. 1	Total
CO2		4	84	88
N2O		0.00	0.00	0.001
CH4		0.00	0.01	0.013
Total		4.33	84	89

Total Emissions by Location (metric tons)

	Gas	Diesel	Disillate Fuel Oil No. 1
NCDP-1/RB-11FCF		0.12	
Escondido Operations Center		2	
Olivenhain Dam		0	58
Rancho Penasquitos Hydro Facility		1	
San Diego - Headquarters		2	
Twin Oaks Valley Water Treatment Plant			26

Emission Factors for Stationary Sources (kg/gal)

	Gas	Diesel	Disillate Fuel Oil No. 1
CO2	8.78	10.21	10.18
N2O	0.0001	0.0001	0.0001
CH4	0.0014	0.0015	0.0015

Source: ARB. 2010. Local Government Operations Protocol. Version 1.1. Table G.1. U.S Default Factors for Calculating Carbon Dioxide Emissions from Fossil Fuel Combustion. Table G.3 Default Methane and Nitrous Oxide Emission Factors by Fuel Type and Sector.

	GWP
GWP - CO2	1
GWP - CH4	21
GWP - N2O	310

Source: ARB. 2010. Local Government Operations Protocol. Version 1.1. Appendix E. Global Warming Potentials.

Off-Road Equipment

Total Emissions (metric tons)

	Gasoline	Diesel	Total
CO2	35.47	106.12	141.59
N2O	0.001	0.003	0.004
CH4	0.002	0.006	0.008
Total	35.78	107.09	142.87

	Gasoline	Diesel	Total
Gal. used	4,039	10,394	14,433
% of Total	28%	72%	100%

		Gas	Diesel	CO2	N2O	CH4	Total
Off Road	NCDP-1/RB-11FCF		1,458	14.89	0.0004	0.0008	15.02
Small Equipment - Diesel	San Diego - Headquarters		4,676	47.74	0.0012	0.0027	48.17
Small Equipment - Dyed Diesel	San Diego - Headquarters		4,146	42.33	0.0011	0.0024	42.72
Small Equipment - Gasoline	San Diego - Headquarters	3,935		34.55	0.0009	0.0020	34.86
Towable Generators - Unit 182 & 183	San Diego - Headquarters		114	1.16	0.0000	0.0001	1.17
Forklift - Unit 152 & Unit 160	Escondido Operations Center	104		0.91	0.0000	0.0001	0.92
Total		4,039	10,394	141.59	0.00	0.01	142.87

Emission Factors for Off-Road Sources (kg/gal)

	Gasoline	Diesel
CO2	8.78	10.21
N2O	0.00022	0.00026
CH4	0.0005	0.00058

Source: ARB. 2010. Local Government Operations Protocol. Version 1.1. Table G.11. Default CO2 Emission Factors for Transport Fuels. Table G.14 Default CH4 and N2O Emission Factors for Non-Highway Vehicles.

	GWP
GWP - CO2	1
GWP - CH4	21
GWP - N2O	310

Source: ARB. 2010. Local Government Operations Protocol. Version 1.1. Appendix E. Global Warming Potentials.

Refrigerants

Location	Type	CO2
NCDP-1/RB-11FCF	HFC-134A	1.48
Aqueduct Protection Program	HFC-134A	0.299
Total		1.78

Appendix B

BUSINESS-AS-USUAL FORECASTING & CONSTRUCTION EMISSIONS FOR 2020 AND 2030

Business-as-Usual Forecasts for 2020 and 2030

Business-as-Usual (BAU) forecasts from the 2018 emissions inventory were developed for the years 2020 and 2030, assuming that neither Climate Action Plan (CAP) measures nor other greenhouse gas (GHG) reducing measures are implemented. The Water Authority's BAU emissions include emission sources from the 2018 inventory scaled to account for changes in water demand, employees, or other activity data, and is inclusive of new emission sources for projects implemented since the 2009 baseline emissions inventory.

The years 2020 and 2030 were chosen to align with the statewide goals for Assembly Bill 32 (2020) and Senate Bill 32 (2030). Note that the emissions estimated in this memo assume current levels of implementation of federal, state, and local measures. Future reductions are anticipated by and beyond 2020.

This appendix was prepared to match the layout of the 2014 Climate Action Plan Appendix B with considerations to new regulations, demand forecasts, and updated capital improvement program forecast.

Emissions sources in place by 2018

Emissions sources in place by 2018 are detailed in the CAP 2018 Annual Update Technical Memorandum (Appendix E) and resulted in 3,099 metric tons of carbon dioxide equivalent (MT CO_2e) emissions in 2018. According to the Water Authority's 2018 Updated Demand Forecast, regional water demand will decrease by 3.0% by 2020 and 2.2% by 2030 from 2018 totals. The downward trend in demand for the region is caused by local member agency supply development and a reduction in per capita water use. The Water Authority has projected a decrease in emissions that is commensurate with the decrease in demand. That is, the Water Authority assumes that emissions from electricity consumption will decrease at the same rate water demand is expected to decrease. While a decrease in demand does not necessarily correlate to an equal decrease in emissions over time, this is a conservative approach to estimate future emissions with future emissions factors held constant for electricity, our largest emissions source, even though they are expected to decrease to meet existing state regulations related renewable energies. Table B-1 details the BAU forecast for emissions sources, anticipating 3,047 MT CO_2e will be emitted by these sources in 2020 and 3,061 MT CO_2e will be emitted in 2030.

Table B-1. Business-as-Usual Emissions Projections (MT CO_2e)

Emissions Sector	2018 Emissions (Actuals)	2020 Estimated Emissions	2030 Estimated Emissions
Electricity	1,728	1,675	1,690
Vehicle Fleet	634	634	634
Employee Commute	607	607	607
Off -Road Equipment	22	22	22
Stationary Source	26	26	26
Natural Gas	54	54	54
Solid Waste	24	24	24
Water	2	2	2
Refrigerants	2	2	2
Wastewater	1	1	1
Total	**3,099**	**3,047**	**3,061**
Total Flow (AF)	**402,820**	**390,560**	**393,890**

MT CO_2e = metric tons of carbon dioxide equivalent; AF = acre-feet
Emission may not add to total due to rounding

Assumptions used to derive the projections are described below.

- Energy consumption was assumed to increase/decrease based on demand growth. Emissions factors were assumed to remain constant over time.
- Vehicle fleet makeup was assumed to remain constant over time.
- Employee commute projections assumes the number of employees, average trip distance, fuel economy and emission factors were assumed to remain constant.
- Off-road equipment and stationary source emissions were assumed to remain constant over time.
- Solid waste emissions projections assume a constant rate of waste generation by employee over time and that the number of employees is the same as projected for Employee Commute.
- Water, refrigerant, and wastewater emissions projections and emissions factors are not substantial and were assumed to remain constant over time; however, these emission sources will be revisited during the next revision of the full 5-year CAP and are mainly minor contributors to total emissions.

Operational and Construction Emissions for New Projects

2014 CAP Process

The 2014 CAP estimated both construction and operational emissions of new projects and their impacts to the emissions inventory. The construction emissions were calculated and amortized over a twenty-year period. The amortizing of emissions has the effect of minimizing the impacts of any one construction project from inflating the emissions totals of years when construction activities occur, usually a 1 to 2-year period. The operational emissions were calculated based on projected annual usage and were assumed to be in addition to the BAU emissions estimates in Table B-1. The previous emissions estimates were updated to reflect the impacts of new construction and operational emissions of new CIP projects.

2019/2020 CAP Process

The CAP continues to estimate construction emissions but does not estimate individual operational emissions for CIP projects. The construction emissions are divided into three categories:

- Emissions since the 2014 CAP and the end of calendar year 2019
- Emissions estimates in calendar 2020 (to align with AB 32 - 2020 requirement)
- Emissions estimates from 2021-2030 (to align with SB 32 – 2030 requirement)

The construction emissions are no longer amortized and are accounted for on the year where notice of completion (NOC) for the project has been filed. Construction emissions will now be counted when construction emissions are created/emitted versus amortizing the impact over 20 years. This method makes tracking of emissions totals easier and accurately identifies future potential impacts associated with construction activities. Operational emissions will no longer be calculated for each individual CIP project to avoid potential double counting of operational emissions already accounted for in the BAU approach. It is recommended that BAU forecasting be done annually to better gage the impacts of new projects coming online and the impacts it has on the Water Authority meeting its specified GHG emissions goals.

Construction emissions were calculated using reference projects to develop emissions factors for different types of CIP Projects and types of construction. The emission factors were used along with the projects detailed scope of work to properly scale construction emissions. The referenced projects have a detailed construction emissions estimate for GHG as part of their CEQA documentation or developed as part of the 2014 CAP. Five different emissions factors were developed and used to calculate the construction emissions of each individual CIP project based on project scope (see Table B-2).

Table B-2. Emission Factors and Reference Projects

Factor Name/ Project Type	Factor Description	Emissions Factor ($MT\ CO_2e$)	Referenced Project
Pipeline Lining	Lining emissions per inch per foot	0.000313784	Based on P3-Lake Murray to Sweetwater and P4-San Luis Rey project averages
New Pipeline Installation	New pipeline emissions per inch per foot	0.001529536	San Vicente Bypass Pipeline
Mechanical Structure	Emissions per mechanical structure	71.25	Based on System Isolation Valves (vault, valves, I &C), per structure
Storage Reservoir	Emissions per MG of storage	45.92	Mission Trails Flow Regulating Structure (Master Plan Scope)
Flow Control Facility	Emissions per 30 cfs of flow capacity	178.13	Based on System Isolation Valves and Carlsbad 6 FCF
Pump Station	Emissions per 30 cfs of pumping capacity	884	Based on North County ESP Pump Station

Note: $MT\ CO_2e$ = metric tons of carbon dioxide equivalents; cfs = cubic feet per second

Emissions sources constructed 2014-2019

Fourteen major projects have been constructed since the 2014 CAP was approved. A scope of work, notice-of-completion (NOC) year, emission factors used, major scope items, emissions estimate, and emissions range will be provided for each project. Emissions ranges are provided to account for uncertainties and differences between the CIP projects below and refenced projects being used. Totals will then be calculated for each year to determine overall construction emissions impacts per calendar year.

See below for project details and emissions estimates (MT CO_2e):

Project No. 1	**Title: San Marcos Vent Desal Modifications**	Emissions Estimate = 71
NOC: 2014	Major Scope Items: Small Mechanical Structure	Emissions Range = (53 - 89)
The project consists of constructing a 54-inch interconnect between Pipelines 3 and 4 and a passive hydraulic grade-control weir and vent structure on Pipeline 4 at the San Marcos Vent site. The San Marcos Vent modifications component consists of a passive weir and vent structure constructed just north of the existing San Marcos Vent to boost the pressure within Pipeline 4 enough to refill Pipeline 3 and maintain current service conditions. The reinforced concrete structure will be separated into two chambers by an intermediate weir with upstream and downstream connections to Pipeline 4.Work activities include, but are not limited to, environmental fencing, clearing and grubbing, blasting, excavation, shoring and bracing, temporary erosion control, spoil hauling, cutting and demolition of existing steel pipe, material delivery, reinforced concrete placement, fabrication and installation of steel pipe, welding, placing field-applied cement mortar lining, modifications to the existing San Marcos Vents, backfill, grading, permanent fence/wall installation, hydroseeding and all other appurtenant work.		
Project No. 2	**Title: Pipeline 3 Relining Sweetwater to Lower Otay**	Emissions Estimate = 683
NOC: 2014	Major Scope Items: 28,400' of 69" Reline 680" of 66" new PL	Emissions Range = (513 - 854)
The Work includes relining approximately 28,400 feet of Pipeline 3, an existing 69 inch diameter prestressed concrete cylinder pipe; fabricating steel liners; fabricating and installing approximately 680 feet of 66-inch outside diameter welded steel pipe at 17 access portals; installing, maintaining and removing environmental fencing and flagging; installing and maintaining storm water pollution prevention measures; clearing and grubbing; fabricating, installing and removing an interior bulkhead; dewatering; providing traffic control; excavating and backfilling; providing excavation support systems; improving the access road between Portals 1 and 2; installing and removing temporary sound walls and fencing; cutting, demolishing and disposing prestressed concrete cylinder pipe; welding; grouting between liners and PCCP; placing field-applied cement mortar lining; installing cathodic protection systems; placing reinforcing steel and encasing welded steel pipe in concrete; removing, rehabilitating, and replacing the pipeline's structures and outlets; acoustic fiber optic system modifications; Otay vents 1 and 2 replacement; removing the carbon fiber lined pipe spool at Portal 5		
Project No. 3	**Title: Pipeline 3 Desal Relining San Marcos to Twin Oaks**	Emissions Estimate = 655

<table>
<tr><td>NOC: 2015</td><td>Major Scope Items: 12,750' of 75" Reline
15,740' of 72" Reline</td><td>Emissions Range = (492 - 820)</td></tr>
<tr><td colspan="3">The purpose of the Pipeline 3 Relining Twin Oaks to San Marcos is to rehabilitate approximately 27,100 feet of existing 75-inch and 72-inch inside diameter gasketed steel pipe with 72-inch and 69-inch outside diameter welded steel liners. Relining 12,750 feet of 75-inch pipeline and 15,740 of 72-inch pipeline.</td></tr>
<tr><td>Project No. 4</td><td>Title: Pipelines 3, 4 & 5 Relining at the San Luis Rey River</td><td>Emissions Estimate = 130</td></tr>
<tr><td>NOC: 2016</td><td>Major Scope Items: 259' of 72" reline
64' of 68 new PL
3,276 of 90" reline
96' of 86" new PL
252' of 96" reline
36' of 92" new PL</td><td>Emissions Range = (98 - 163)</td></tr>
<tr><td colspan="3">The Work includes relining approximately 259 feet of Pipeline 3, an existing 72-inch diameter untreated water steel pipeline; fabricating and installing steel liners; fabricating and installing approximately 64 feet of 68-inch outside diameter welded steel pipe at one access portal; relining approximately 3,276 feet of Pipeline 4, an existing 90-inch diameter treated water PCCP pipeline; fabricating and installing steel liners; fabricating and installing approximately 96 feet of 86-inch outside diameter welded steel pipe at two access portals; relining approximately 252 feet of Pipeline 5, an existing 96 inch diameter untreated water PCCP pipeline; fabricating and installing steel liners; fabricating and installing approximately 36 feet of 92-inch outside diameter welded steel pipe at one access portal; installing, maintaining and removing environmental fencing and flagging; maintaining existing Water Authority access roads, installing and maintaining water pollution prevention measures; clearing and grubbing; fabricating, installing and removing interior bulkheads; dewatering; providing traffic control;</td></tr>
<tr><td>Project No. 5</td><td>Title: Ramona Pipeline Pump Well</td><td>Emissions Estimate = 71</td></tr>
<tr><td>NOC: 2016</td><td>Major Scope Items: Small Mechanical Structure</td><td>Emissions Range = (53 - 89)</td></tr>
<tr><td colspan="3">The project includes removing an existing 20 feet section of 36-inch diameter concrete bar-wrapped cylinder pipe of Ramona Pipeline and replaced with a steel pipe section with an outlet for the pump well. Construct a street type pump well concrete vault.</td></tr>
<tr><td>Project No. 6</td><td>Title: Twin Oaks Valley Water Treatment Plant Expanded Service Area</td><td>Emissions Estimate = NA</td></tr>
<tr><td>NOC: 2016</td><td>Major Scope Items: PS upgrade from 20 to 41 cfs</td><td>Emissions Range = NA</td></tr>
</table>

The project consists of design and construction of the VCPS to expand its pumping capacity from 20 cfs to 41 cfs, by replacing the two existing 10 cfs pumps (P-1 and P-2) with 13.7 cfs pumps and installing a third, 13.7 cfs pump (P-3) in the existing can. The pumps will operate through new variable frequency drives (VFD) for operational flexibility. Other improvements to support the rehabilitated pump station operations include installation of three 24-inch resilient gate valves, a 48-inch plunger valve and a 10-inch plunger valve, upgrade of ventilation, electrical and control/communication systems, roof reinforcement, and security upgrades, such as fire and intrusion alarms and new site perimeter fencing to meet the Water Authority standards.

Project No. 7	**Title: Miramar Pump Station Rehabilitation**	Emissions Estimate = NA
NOC: 2017	Major Scope Items: PS Upgrade	Emissions Range = NA

The project consists of the rehabilitation of the Miramar Pump Station and its various components including selective demolition of existing facilities, earthwork and installation of three (3) new vertical turbine pumps and motors. Demolish three (3) existing pumps at P-1, P-3, and P-4, base plates, piping and appurtenances. Remove and dispose of four (4) plug valves and hydraulic actuators, fittings, piping and appurtenances including P-2 spool piece. Modify existing suction barrels (pump cans) and excavate to proposed suction barrel invert elevation, slip-line existing suction barrels with 38-inch steel cylinder pipe. Remove and dispose of four (4) existing ultrasonic flow meters and replace with pipe spool pieces. Install three (3) new 300 HP vertical turbine pumps as specified and shown on plans over proposed train P-100, P-200 and P-300. Install three (3) new metal seated butterfly control valves. Install four (4) exhaust ventilation fans and HVAC improvement accessories. Install four (4) filtered supply air fans, 24-inch x 24-inch ductwork and accessories. Furnish and install air conditioner in the control room. Provide seismic strengthening improvements to the pump stations internal walls.

Project No. 8	**Title: Pipeline 4 Relining at Lake Murray**	Emissions Estimate = 51
NOC: 2017	Major Scope Items: 5,381 ' of 72" reline	Emissions Range = (38 - 64)

The purpose of the R0306 project is to increase Pipeline 4 reliability by rehabilitating approximately 5,381 feet of existing 72-inch inner diameter PCCP with 69-inch outside diameter welded steel liners, from the Lake Murray Interconnect at Station 4362+28.04 to the Pipeline 4 turnout at the Alvarado Water Treatment Plant at Station 4416+08.97. Structures along the alignment will be rehabilitated as part of the relining effort.

Project No. 9	**Title: Nob Hill Improvements**	Emissions Estimate = 62
NOC: 2017	Major Scope Items: 1,600 of paved roads 458' of 98" new PL 120' of 69" new PL	Emissions Range = (47 - 78)

Constructing approximately 1,600 lineal feet of permanent access road from Scripps Lake Drive for use to construct the tunnel and pipeline under this contract and for future operation and maintenance activities at various appurtenant structures and paving approximately 230 lineal feet of existing access road to existing appurtenant structures. Constructing Reach 1at the south portal for tunneling that is approximately 136 feet long. Portions of the existing Pipeline 3, a 72-inch prestressed concrete cylinder pipe with and without welded steel lining, will need to be demolished and supported and protected in place to construct the portal. Constructing Reach 2, which is required to be tunneled over approximately 458 lineal feet to install 98-inch OD welded steel pipe. Constructing Reach 3 at the

North portal that is approximately 281 feet long by combination of trenching and tunneling. Portions of the existing Pipeline 3, a 72-inch prestressed concrete cylinder pipe with welded steel lining, will need to be demolished and supported and protected in place to construct the portal. Installing approximately 821 feet of 98-inch OD welded steel pipe within the three tunnel and portal reaches and connecting to the existing 69-inch OD welded steel liner inside the existing 72-inch ID prestressed concrete cylinder pipe at the north and south ends of Pipeline 3. Constructing approximately 120 lineal feet of trenched 69-inch OD welded steel pipe to connect Pipeline 4, a 72-inch ID prestressed concrete cylinder pipe with 69-inch OD welded steel lining, to the 98-inch OD welded steel pipeline.		
Project No. 10	**Title: Carlsbad 6 Flow Control Facility**	Emissions Estimate = 178
NOC: 2018	Major Scope Items: 30 cfs FCF	Emissions Range = (134 - 223)
This project consists of excavation and disposal of lead-contaminated soils, construction of new Carlsbad 6 Flow Control Facility (FCF, 30 cfs), rehabilitation of existing Pipeline 3 and Pipeline 4 Turnout Structures (TOS), demolition of existing Carlsbad 1 FCF, and all other appurtenant work as required by the Contract Documents. Form and place approximately 150-cubic-yard concrete for construction of the new FCF building, retaining wall, new roof for the existing Pipeline 3 TOS (off-street), and replacement of access hatch for the existing Pipeline 4 TOS (in-street). Construct approximately 100 linear feet of 20- to 24-inch diameter steel pipe with cement mortar lining and coating, and field weld interconnection pipes.		
Project No. 11	**Title: Pipeline 3 Relining Lake Murray to Sweetwater Reservoir**	Emissions Estimate = 204
NOC: 2018	Major Scope Items: 22,800' of 68" equivalent reline	Emissions Range = (153 - 255)
The project rehabilitated (lined) approximately 22,800 feet of 66-inch and 69-inch diameter pipe. Construction crews conducted most of the work underground, inside the pipe. They access the pipe by excavating, establishing, and entering the pipeline through access sites, or portals. Most construction activities occur at the portals, which are spaced approximately 525 to 2,500 feet apart. Portals 4, 6, 7, 9, and 11 have been repurposed to serve primarily as pipeline access and staging areas for construction equipment and materials. Existing pipeline access structures are also being rehabilitated and some flow control facilities abandoned as part of the project. The portals are 25-foot-by-60-foot excavated areas.		
Project No. 12	**Title: San Vicente Marina Facilities**	Emissions Estimate = 435
NOC: 2016	Major Scope Items: Marina	Emissions Range = (326 - 544)
Work consists of the construction of San Vicente Marina Facilities and off-site improvements. The work includes grading, paving, striping and signage, and the construction and installation of site amenities, site utilities, yard security system, landscape, groundwater monitoring wells, potable water main and piping appurtenances, sewer holding tank, meter station, building, site and interpretive signage, booster pump stations, water storage tank(s), comfort station, concession building, office building, boat ramp, boat docks, boat slips, and buoy system, and accessible equipment (pontoon boat, ADA shuttle, and wheelchair lift. The work also includes improvements to enhance the traffic pattern of the Moreno/Vigilante Intersection, improve the access roads to various San Vicente facilities, improve the drainage at the San Vicente Pump Station, remove San Vicente Creek crossing, and provide a secured parking area for the Water Authority's lab.		
Project No. 13	**Title: San Vicente Bypass Pipeline**	Emissions Estimate = 232
NOC: 2016	Major Scope Items: SV Bypass Pipeline	Emissions Range = (174 - 290)

This project replaced the existing San Vicente Bypass Pipeline that will be inundated by the expanded San Vicente Reservoir, replaced the terminal structure at the end of the First San Diego Aqueduct, constructed a new access road to the terminal structure, and constructed other site improvements necessary for operation of the replacement pipeline. Approximately 3,160 feet of 48-inch diameter reinforced concrete pipe extending from the marina area to a terminal structure located at the end of the San Vicente Tunnel of the First San Diego Aqueduct, of which approximately 2,230 feet is trench construction and approximately 930 feet is tunnel construction; Appurtenant structures for the 48-inch diameter pipe, including a 69-inch diameter vent pipe, manways, and corrosion monitoring system; Connection of the 48-inch diameter pipe to the existing San Vicente Bypass Pipeline, and to the ends of 48-inch diameter pipe installed as part of the marina construction; Replacement of an access road from the marina area to the terminal structure, including storm water drainage structures; Rip rap erosion protection on the reservoir shoreline.		
Project No. 14	**Title: Pipeline 5 Relining Delivery Point to Sage Road**	Emissions Estimate = 297
NOC: 2019	Major Scope Items: 9,850' of 96" Reline	Emissions Range = (223 - 371)
The purpose of this project is to rehabilitate approximately 9,850 feet of existing 96-inch pre-stressed concrete cylinder pipe (PCCP) along Pipeline 5 (P5), at the northern end of the Water Authority's service area. The project area starts at the point of delivery with the Metropolitan Water District (Sta 2060+60) and ends at Sage Road in Fallbrook (Sta 2158+98). The project is in the unincorporated community of Fallbrook. The rehabilitation of the pipeline will consist of installing welded steel liners inside the existing PCCP through two excavated access portals measuring approximately 60 feet long by 20 feet wide. Personnel and equipment access will also be made through structures along the alignment to support the work. In addition to pipeline relining, the project includes work to rehabilitate existing appurtenances such as blowoffs and combination air release/ air vacuum valves.		
Project No. 15	**Title: Padre Dam 7 FCF**	Emissions Estimate = 83
NOC: 2019	Major Scope Items: 13.9 cfs FCF	Emissions Range = (62 - 103)
Build a 9 MGD PD 7 FCF and associated equipment, pipelines, traffic control and appurtenant work.		

2014-2019 Summary

The projects from 2014 to 2019 are projects that were complete with a NOC before December 2019. These projects were selected to match the timeframe between the 2014 CAP and current CAP and allowed the Water Authority to historically track construction emissions since the last approved CAP. As shown in Table B-3, construction emissions between 2014 and 2019 range between 113 and 786 MT CO_2e per year and total 3,154 MT CO_2e.

Table B-3. 2014-2019 Construction Emissions

Estimated Construction Emissions by Calendar Year (MT CO_2e)					
2014	**2015**	**2016**	**2017**	**2018**	**2019**
755	786	738	113	382	379

Emissions sources to be constructed in 2020

This section will include projects expected to issue a NOC between January 1, 2020 and December 31, 2020, which aligns with the 2020 emissions goal timeframe set by AB 32. A detailed scope of work, NOC, emission factors used, major scope items, emissions estimate, and emissions range will be provided for each project. Emissions ranges are provided to account for uncertainties and differences between the CIP projects below and refenced projects being used. Totals will then be calculated for each year to determine overall construction emissions impacts per calendar year. The CIP schedule as of May 2019 shows only one project is scheduled to issue a NOC in 2020. The flow control facility to be constructed under this project was identified as deficient by the Asset Management Program. This project has been awarded with construction scheduled to issues a NOC by September 2020.

Project No. 1	**Title: Vallecitos Water District 11/Vista Irrigation District 12 Flow Control Facility**	Emissions Estimate = 131
NOC: 2020	Major Scope Items: 12 cfs FCF & 10 cfs FCF	Emissions Range = (98 - 163)
Construct the Vallecitos 12 cfs/Vista ID 10 cfs flow control facility. The Water Authority currently meters and controls the delivery of treated water from Water Authority Pipelines 1 and 2 to Vallecitos Water District (Vallecitos) and Vista Irrigation District (Vista) through the existing flow control facility, which was built in 1954 and is in the city of Escondido. As part of the Asset Management Program, staff performed a facility condition assessment and found that the piping and valves are at the end of their service life and the building does not comply with current seismic code and safety requirements. Therefore, the existing facility needs to be replaced to ensure reliable deliveries to those member agencies.		

2020 Summary

The construction emissions for the project to be completed in 2020 are estimated to total 131 MT CO_2e. The construction emissions from this project will be used to determine the impacts to total emissions and how it relates to meeting the 2020 emissions goals set by AB 32. No other CIP project is scheduled to have a NOC issued in calendar year 2020.

Emissions sources to be constructed 2021-2030

There are thirteen (13) projects presently scheduled to have a NOC between 2021 and 2030. A detailed scope of work, NOC, emission factors used, major scope items, emissions estimate, and emissions range will be provided for each project. Emissions ranges are provided to account for uncertainties and differences between the CIP projects below and refenced projects being used. Totals will then be calculated for each year to determine overall construction emissions impacts per calendar year. Projects from this category are comprised of both Master Plan and Asset Management projects that are part of the current CIP schedule. The end of the timeframe for this category coincides with SB 32 2030 emissions goal. The CIP schedule only has detailed projects set up to 2024 and it is anticipated that more projects will be scheduled between 2021-2030 on a yearly basis. Currently, only the Northern First Aqueduct Structures and Lining Rehabilitation project has been awarded. Any changes to the schedule (adding projects, deleting projects, delays, etc.) will have a direct impact on yearly construction emission estimates which could impact the Water Authority's ability to meet emissions goals. Additional projects from the Asset Management Program have been identified but have not been programmed. It is anticipated that 0.75 miles of relining and one (1) FCF will be scheduled on an annual basis.

Project No. 1	**Title: San Diego 28 FCF**	Emissions Estimate = 388
NOC: 2021	Major Scope Items: 150 cfs FCF	Emissions Range = (291 - 485)
New FCF for the Alvarado WTP at a rated capacity of 150 cfs.		
Project No. 2	**Title: Northern First Aqueduct Structures and Lining Rehabilitation**	Emissions Estimate = 84

NOC: 2021	Major Scope Items: 5,600 of lining removal & rehab 61 small structures	Emissions Range = (63 - 105)

The objective of the project is to rehabilitate PL 1 and PL 2 and extend the service lives of both pipelines by 50 years. The general project scope includes the following:

- Evaluate the condition of the existing PL 1 and PL 2 structures and mechanical components.
- Evaluate the condition of the coal tar lining for the steel portions of PL 1 and PL 2 in the San Luis Rey Canyon and PL 1 in the Couser Canyon.
- Rehabilitate or abandon a total of 61 manway, air valve, blow off, and pump well structures, with 31 structures on PL 1 and 30 structures on PL 2. See Table 1, Summary of First Aqueduct Structures.
- Remove coal tar lining from approximately 4,800 linear feet from both PL 1 and PL 2 in the San Luis Rey Canyon, assess and repair the steel as necessary, and replace with cement mortar.
- Remove coal tar lining from approximately 800 linear feet from PL 1 in Couser Canyon, assess and repair the steel as necessary, and replace with cement mortar.

Project No. 3	**Title: ESP - Valley Center Improvements**	Emissions Estimate = 89
NOC: 2021	Major Scope Items: 7.2 cfs FCF 7.8 cfs FCF	Emissions Range = (67 - 111)

Improvements to the VCMWD system, including expansion and upgrades to VCMWD's San Gabriel Pump Station, a new Lilac road pipeline, a new FCF with pressure reduction, a new connection to the YMWD system, and improvements to other ancillary components. The flows to VCMWD and YMWD would be delivered from the Second Aqueduct to the First Aqueduct via the Valley Center Pipeline and Valley Center Pump Station (VCPS). The added capacity to be provided through these improvements is 15 cfs (7.2 cfs for YMWD and 7.8 cfs for VCMWD).

Project No. 4	**Title: Mission Trails FRS II and Flow Control Facility**	Emissions Estimate = 230
NOC: 2021	Major Scope Items: 5 MG Reservoir	Emissions Range = (172 - 287)

5 MG flow regulatory structure with a new flow control facility located near the existing Flow Balancing Structure (FBS) in MTRP. The existing tunnels will connect to P3 and P4 at the north end and will connect to P3 just upstream of the FBS at the south end. Relocating the FCF from Lake Murray to MTRP just downstream of the FBS eliminates the need for an isolation valve vault at this location.

Project No. 5	**Title: ESP - Pipeline 4 Meter Vault**	Emissions Estimate = 143
NOC: 2022	Major Scope Items: Two small mechanical structures	Emissions Range = (107 - 178)

The North County ESP Pump Station project is part of the final phase of the Water Authority's Emergency Storage Project (ESP), extending ESP service to the northernmost areas of San Diego County that are beyond the reach of current Water Authority facilities. A new MWD- or Water Authority-owned FCF with two parallel, metered trains serving the proposed FPUD and RMWD pump stations listed below. Meter 1 will be rated for 7.2 cfs (Rainbow PS). Meter 2 will be rated for 13.5 cfs (Fallbrook).

Project No. 6	**Title: ESP - Pipeline 4 Turnout & Rainbow MWD Pump Station**	Emissions Estimate = 212
NOC: 2022	Major Scope Items: 7.2 cfs PS	Emissions Range = (159 - 265)

A new RMWD-owned 7.2 cfs East Mission Road Pump Station located on an undeveloped and cleared parcel of land owned by SDG&E along East Mission Road, just east of Interstate 15 (I-15). The preliminary pump station layout includes two 200 hp pumps with a total dynamic head of 225 feet. Delivery will be directly to RMWD distribution

system via existing RMWD pipelines in East Mission Road. The existing 24-inch Fallbrook Aqueduct owned by FPUD will be used to convey suction from the new Pipeline 4 connection and FCF (listed above) to the East Mission Road Pump Station.		
Project No. 7	**Title: ESP - Fallbrook PUD Pump Station**	Emissions Estimate = 398
NOC: 2022	Major Scope Items: 13.5 cfs PS	Emissions Range = (298 - 497)
A new FPUD-owned 13.5 cfs Red Mountain Pump Station located on a portion of a parcel owned by FPUD south of Red Mountain Reservoir. The preliminary pump station layout includes three 250 hp pumps with a design TDH of 280 feet. Delivery will be directly to FPUD distribution system including the De Luz service area.		
Project No. 8	**Title: Hauck Mesa Storage Reservoir and Pipeline Surge Protection Project**	Emissions Estimate = 151
NOC: 2022	Major Scope Items: 1) 1.1 MG Reservoir 2) Small Mechanical Structure 3) 5 cfs FCF	Emissions Range = (114 - 189)
The project scope includes the following primary elements. •Demolition of the existing tank and appurtenant piping at Hauck Mesa. •New storage tank -Provides First Aqueduct flow regulatory storage. -Provides Valley Center Pipeline and Pump Station flow regulatory storage. -Provides passive (non-mechanical) surge control protection for the Valley Center Pump Station and Valley Center Pipeline. -Sized for a volume of 1.1 million gallons and located within the existing Hauck Mesa parcel. -Includes tank appurtenances including inlet and outlet steel piping, tank and Valley Center Pipeline isolation valves with electric actuators, and overflow facilities. -Includes supervisory control and data acquisition communication using existing Valley Center Pipeline fiber optic system and new fiber optic system, as required, and develop and integrate new HMI screens and controls. -Includes a new 20-foot-wide access road around tank. •New flow control facility -Includes isolation valves, plunger or cone flow control valve and venturi meter. -Includes electric actuators for valves. -Located in below grade concrete vault.		
Project No. 9	**Title: Fallbrook 7 / Rainbow 14 Flow Control Facility**	Emissions Estimate = 297
NOC: 2022	Major Scope Items: 20 cfs FCF & 30 CFS FCF	Emissions Range = (223 - 371)
Work to be completed under this Contract consists of the construction of one new Fallbrook 7 (20 cfs) /Rainbow 14 (30 cfs) Flow Control Facility, including an above grade masonry structure; installation of mechanical and electrical equipment; replacement of three 90-inch ID PCCP segments with 90-inch ID WSP; replacement of existing turnout and blowoff; temporary piping modifications for Fallbrook 4 and Rainbow 7 Flow Control Facility; demolition of two existing Flow Control Facilities, FB4 and RB7; installation of cathodic protection system; installation of gravel infiltration pit; installation of 20-inch, 24-inch, and 30-inch CMLC WSP; installation of 12-inch PVC drain pipe; trees and brush removal; site grading; installation of AC pavement; installation of one precast and two cast-in-place vault; and all other appurtenant work as required by the Contract Documents.		

Project No. 10	**Title: Alvarado Hydroelectric Facility Rehabilitation**	Emissions Estimate = 422
NOC: 2023	Major Scope Items: 1.4 MH hydro = 90 cfs PS	Emissions Range = (316 - 527)
Construction of a new hydroelectric facility at the Alvarado WTP near SD 12 FCF. Potential power is 1.4 MW.		
Project No. 11	**Title: Carlsbad 5 FCF and Pressure Reducing Valve**	Emissions Estimate = 61
NOC: 2023	Major Scope Items: 10.2 cfs FCF	Emissions Range = (45 - 76)
The Carlsbad 5 Flow Control Facility is a new facility that would provide Carlsbad Municipal Water District (CMWD) direct access to treated water from the Carlsbad Seawater Desalination Plant through an existing turnout off the 54-inch Desalination Conveyance Pipeline in Lionshead Avenue. A steady state hydraulic analysis was performed to determine the pipe diameter and flow control valve size and type to operate over the design flow range, which consists of a maximum flow of 6.6 MGD (10.2 cfs), an average flow of 2.2 MGD (3.4 cfs), and a minimum flow of 0.6 MGD (1 cfs). The average day flow through the CR5FCF is expected to be at a relatively consistent rate of 2.2 MGD (3.4 cfs) with peak flows of 6.6 MGD (10.2 cfs). Selection of the pipe diameter was based on maintaining the velocity at an acceptable level at the maximum design flow. A steel pipe with a diameter of 14-inch was selected having a ½-inch cement mortar lining.		
Project No. 12	**Title: First Aqueduct Structures Rehabilitation Hubbard Hill South**	Emissions Estimate = 84
NOC: 2023	Major Scope Items: Evaluate 105 small structures 7 & some removal of coal tart lining	Emissions Range = (63 - 105)
The Asset Management Program identified repairs required for the First Aqueduct, Pipelines 1 and 2, from the Hubbard Hill overflow at South Station 1073 to the upstream side of the San Vicente tunnel at South Station 34. Evaluate the condition of the 105 existing PL 1 and PL 2 structures and mechanical components, and rehabilitate or abandon the man-way, air valve, blow off, and pump well structures. See Table 1, Summary of First Aqueduct Structures. Coal tar lining on the steel portion of Pipeline 1 in the Lake Hodges river bed will be removed as part of the Q0204 project. Repair or replace 35 structures (air valves, blow-offs, manholes).		
Project No. 13	**Title: Crossover Pipeline**	Emissions Estimate = 290
NOC: 2024	Major Scope Items: 4,200' of 66" Reline 1,700' of 78" new PL	Emissions Range = (217 - 362)
Relining the existing Crossover Pipeline from Station 144+00, just northwest of the Deer Springs Road crossing, to approximate Station 186+00 where the Crossover intersects Mesa Rock Road (66-inch PL, 4,200 feet). Constructing a new 5,800 feet of 72 to 78-inch pipeline from Crossover Station 186+00 to approximately 1,700 feet north of the Frontage Road highway overpass along Mesa Rock Road. A tunnel would be built at the end of the new pipeline and connect to the existing Crossover on the east side of I-15. This option will require a Caltrans permit for the I-15 tunnel crossing. Secure member agency agreements and build improvements to allow for a 10-week shutdown (40 feet of 36-inch pipeline, plus isolation valves).		

2021-2030 Summary

Projects for this period have a NOC up to 2024, with additional projects expected to be scheduled in the coming years. This will inflate the construction emissions for this timeframe. The construction emissions range from 290 to 904 MT CO_2e. As shown in Table B-4, the construction emissions for 2025-2030 will based on an annual average from 2020 to 2024, which is 596 MT CO_2e.

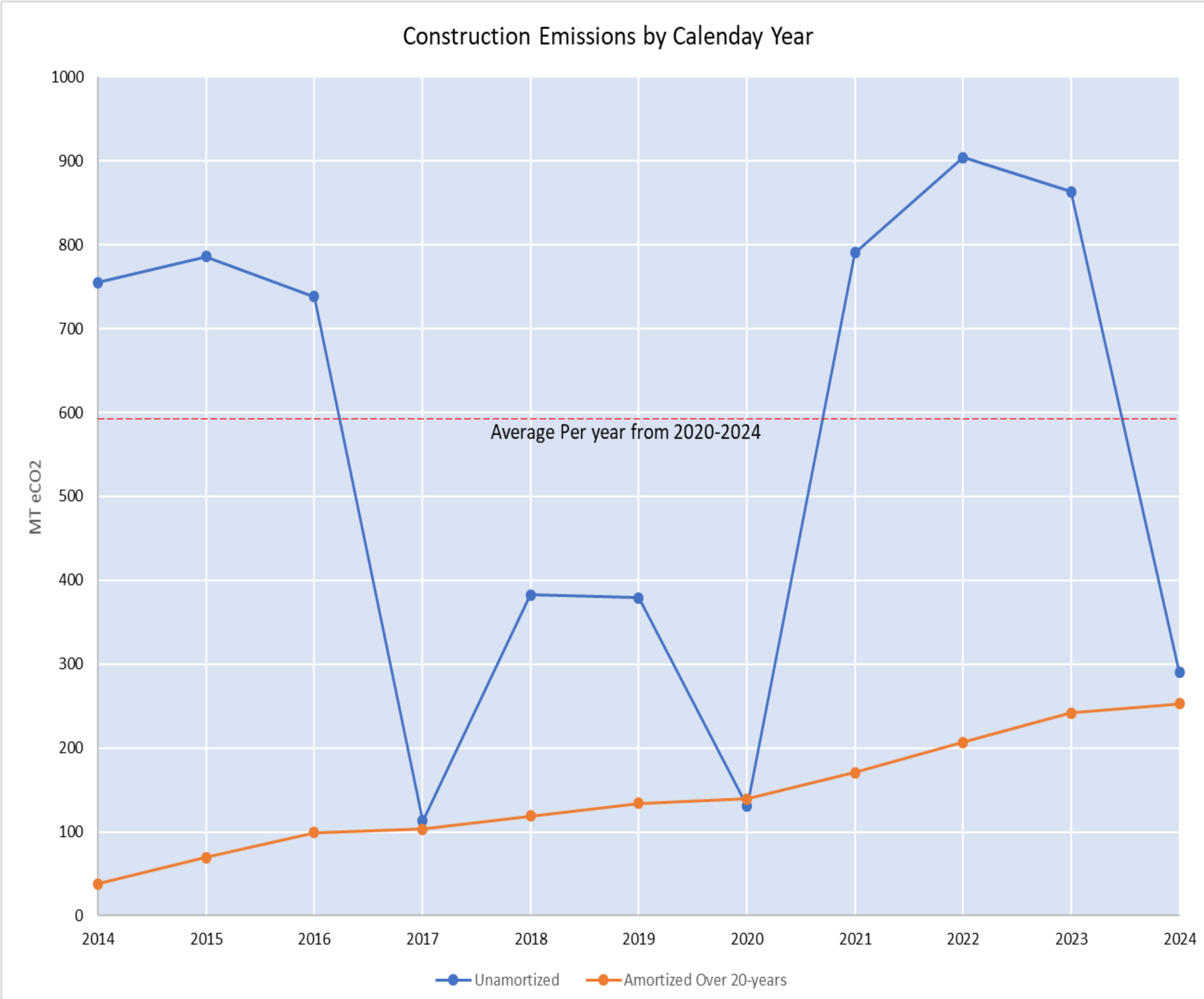
Table B-4. 2021-2024 Construction Emissions

Estimated Construction Emissions by Calendar Year (MT CO_2e)			
2021	**2022**	**2023**	**2024**
791	904	864	290

Construction Emissions Summary

Changing the way construction emissions are tracked, from amortizing to placing them to a single year, has resulted in more variability of construction emissions totals from year to year; but tracking of construction emissions has been simplified. Under the old method of amortizing, 2019 would still be accounting for construction emissions from 1999 (assuming 20-year amortization). Similarly, a project that has a completion date of 2019 would need to have its amortized emissions accounted for until 2039. The change will allow the Water Authority to better track and report construction emissions; it will also be able to better determine the impacts of construction emissions since they are accounted for as they are created and emitted. The graph below shows a comparison of the two methods (non-amortized vs. amortized), please note that the amortize portion of the graph only accounts for projects starting in 2014 and does include for past projects that were amortized that would count towards emissions totals for 2014-2024.

Figure B-1. Construction Emissions Comparison



Emissions Targets

The Water Authority set an agency-wide reduction goal of 15% below 2009 levels by 2020. This is consistent with the Scoping Plan recommendation to local governments to demonstrate consistency with AB 32 and approaches taken by other local agencies for California Environmental Quality Act (CEQA) streamlining purposes. The Water Authority has also set a goal for 2030 consistent with SB 32 of 40% below 2009 levels. Currently, the Water Authority emissions targets are 4,961 MT CO_2e in 2020 and 3,502 MT CO_2e in 2030, under the BAU approach.

Summary

Total future BAU emissions will result in 3,047 MT CO_2e in 2020 and 3,061 MT CO_2e in 2030.

This represents approximately a 47.75% reduction and a 47.5% reduction from baseline emissions in 2020 and 2030, respectively. It should be noted that this does not include additional reductions anticipated through full implementation of federal and state measures. In addition, the Water Authority can use credits from energy generation facilities including future facilities to further reduce total emissions (see Chapter 3 and 4 of the CAP).

Table B-5 Emission Goals Summary

Category	2020 MT CO_2e (AB 32)	2030 MT CO_2e (SB 32)
BAU	3,047	3,061
Construction Estimates	131	596*
Total	3,178	3,657
Emission Goals	4,961	3,502
Meets Goal	Y	N**
Surplus/Shortfall	-1,783	155

***Used construction emission yearly average between 2020-2024**

****Does not account for emission factor reductions and credits for renewables energies. A separate analysis is in Chapter 3 and 4 of this CAP considering reduction measures and strategies.**

References

San Diego County Water Authority. 2014 Climate Action Plan Appendix B

San Diego County Water Authority. 2019 CIP Schedule

San Diego County Water Authority. 2018 Revised Forecast

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Harvey-Meyerhoff Consulting Group. 2013. Assessment of Greenhouse Gas Emissions for the Olivenhain-Hodges Pumped Storage Hydroelectric Project.

HMCG see Harvey-Meyerhoff Consulting Group.

San Diego County Water Authority. 2011. 2010 Urban Water Management

Plan. San Diego County Water Authority. 2012. Energy Audit Summary

Report Phase 2.

SANDAG. 2012. 2050 RTP/SCS EIR, Appendix F-1. Available at http://www.sandag.org/index.asp? projectid=349&fuseaction=projects.detail.

Appendix C

2012 ENERGY AUDIT

San Diego County Water Authority

ENERGY AUDIT SUMMARY REPORT

PHASE 2

Escondido Operations Building
Escondido Pump Station
Lake Hodges Pump Station
Olivenhain Pump Station
Rancho Penasquitos PCHF
San Diego Office
San Vicente Pump Station
Twin Oaks Valley Water Treatment Plant
Valley Center Pump Station

Prepared for

San Diego County Water Authority
4677 Overland Drive
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September 2012

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ACRONYMS AND ABBREVIATIONS

η	efficiency (motor)
A	Amperes or Amps
CPP	Critical Peak Pricing (also CPP-D)
CSP	constant speed (pump)
CWA	County Water Authority (see also SDCWA)
DAF	dissolved air flotation
DHK	DHK Engineers, Inc.
ECO	energy conservation opportunity
gpm	gallons per minute
HVAC	heating/ventilation and air conditioning
hp	horsepower
hr	hours (also hrs)
kW	kiloWatt (also real or resistive power)
kWh	kiloWatt · hours
kV	kiloVolt
kVA	kiloVolt · Amps, apparent power demand
kVAR	reactive power
MW	MegaWatt
MWh	MegaWatt · hours
LGPP	Local Government Partnership Program
MGD	million gallons per day
MGY	million gallons per year
PF	power factor
PS	pump station
RHC	Redhorse Corporation
R/O	reverse osmosis
RPM	revolutions per minute
SDG&E	San Diego Gas & Electric
SDCWA	San Diego County Water Authority
V	Volts
VFD	variable frequency drive
WTP	water treatment plant
yr	year

Note: Not all acronyms and abbreviations may be used in this report

1. INTRODUCTION

This report summarizes and describes overall trends from a San Diego County Water Authority (Water Authority)-wide perspective based on data collected at nine Water Authority facilities during the energy audit conducted from December 2011 through February 2012. The report should provide the Water Authority with an understanding about which facilities are using the most energy, which facilities cost the most to operate, and which facilities have the opportunity to achieve the best results if the recommended energy conservation opportunities (ECOs) are performed. The information in this summary report calls upon information located within the individual facility reports. The facility reports are provided as attachments to this summary and are intended to be stand-alone in nature. The attached facility reports provide an in-depth discussion regarding each facility's operations, equipment, energy rate schedules, current energy use and trends, and potential ECOs.

Energy audits of selected Water Authority facilities were performed by DHK Engineers, Inc. (DHK). The audits were funded by the Local Government Partnership Program (LGPP) between San Diego Gas and Electric (SDG&E) and the Water Authority. DHK, the Water Authority, and SDG&E staff collectively prioritized energy consuming facilities and selected those that represent the greatest opportunity for energy conservation. Nine facilities were selected for auditing. The Water Authority's total annual 2011 energy costs for these facilities are summarized in Table 1-1.

Table 1-1: San Diego County Water Authority Facilities Selected for Energy Auditing

Facility Name	2011 Energy Cost
Escondido Operations Building	$74,820
Escondido Pump Station	$2,349
Lake Hodges Pump Station	See Notes
Olivenhain Pump Station	$2,422
Rancho Penasquitos Hydroelectric Facility	$22,569
San Diego Office	$174,588
San Vicente Pump Station	$934,822
Twin Oaks Valley Water Treatment Plant	$690,967
Valley Center Pump Station	$5,107
Total	**$1,907,632**

Notes: Under construction as of December 2011.

Section 2 provides an overview of the auditing process. Section 3 provides information on SDG&E rates and incentives. Section 4 and 5 summarize the facility audits and ECO's identified. The individual Phase 1 energy audits are attached for reference.

Overview of the San Diego County Water Authority

The San Diego County Water Authority is a public agency serving the San Diego region as a wholesale supplier of water from the Colorado River and Northern California. The Water Authority's mission is to provide a safe and reliable supply of water to its 24 member agencies serving the San Diego region (SDCWA 2012). In this capacity, the Water Authority has been importing up to 80 percent of the total water needed to meet the region's needs for more than 60 years. As a wholesale agency, the Water Authority purchases and imports about 30 percent of its water from Metropolitan Water District of Southern California. The Water Authority obtains the remainder of its water via long-term Colorado River water conservation and transfer agreements with agencies in the Coachella Valley and Imperial County. The Water Authority sells this water to its 24 member retail agencies, which in turn provide water to retail residential, commercial, and industrial customers in San Diego County.

The mission of the Water Authority is to meet the region's water supply needs, in partnership with member agencies and stakeholders, by:

- Providing a safe and reliable water supply
- Diversifying the region's water supply sources
- Building, maintaining, and operating critical water facilities in a cost-effective and environmentally sensitive manner

The Water Authority operates and maintains the San Diego region's aqueduct delivery system which consists of approximately 300 miles of large-diameter pipeline in two aqueducts, 1,600 aqueduct-related structures, and over 100 flow-control facilities, occupying 1,400 acres of right-of-way.

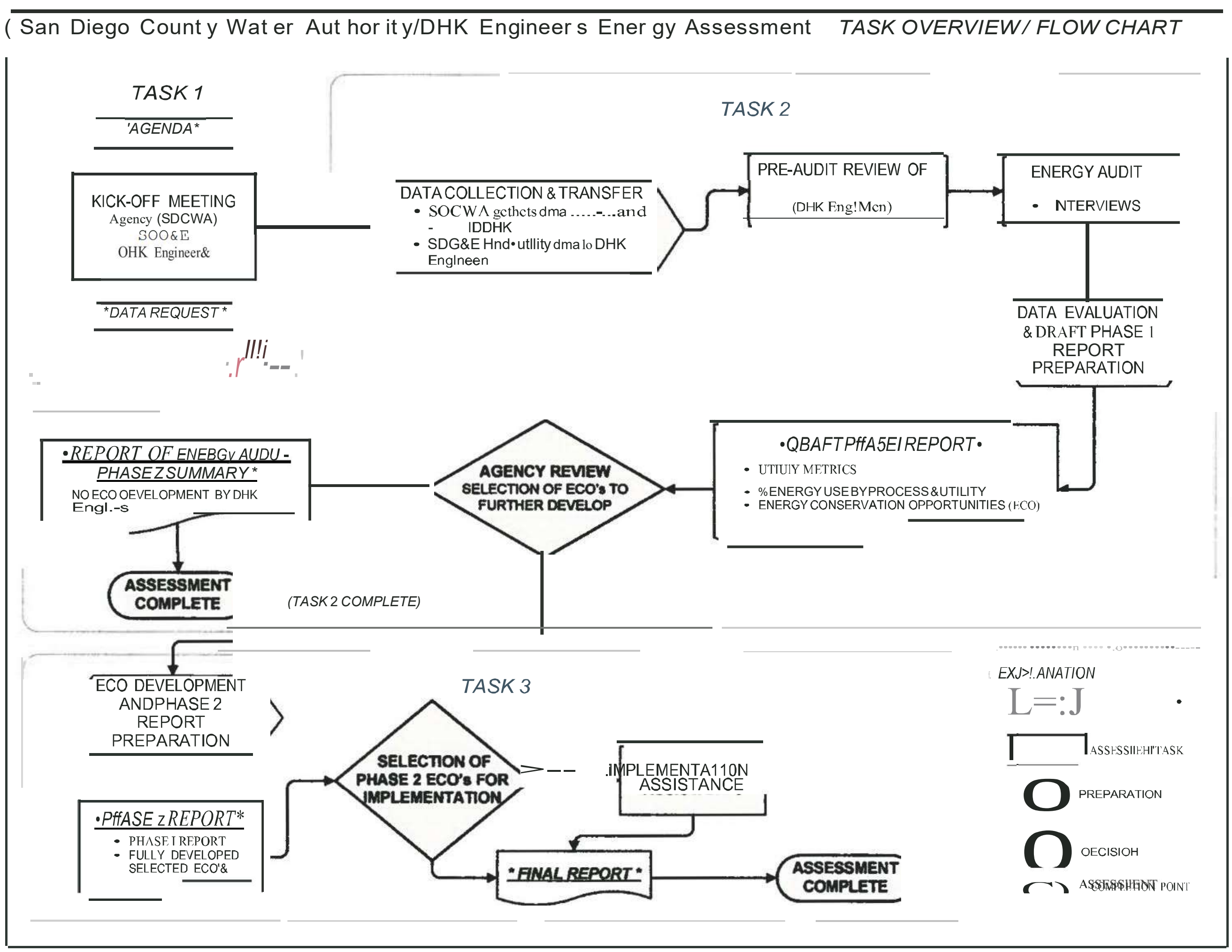
Imported water flows to San Diego County through five large-diameter pipelines. The Water Authority takes ownership of these pipelines just south of the Riverside-San Diego county line. The main pipelines range in size from 48 to 108 inches and carry either fully treated potable water or untreated water that is then treated within the county. The system has the capability of delivering more than 900 million gallons per day. The pipelines and associated facilities run north to south along two routes known as the First and Second aqueducts.

In addition to the main pipelines, there are several interconnecting pipelines. These interconnecting pipelines have been built to ensure the ability to move stored water in the event of an emergency such as an earthquake. As an added feature, these pipelines have been designed to allow for system flexibility and alternative deliveries during maintenance activities.

2. ENERGY AUDIT PROCESS

The purpose of the energy audit is to assess the energy consuming processes at the selected facilities, provide the agency with energy use and cost metrics, and identify potential ECOs. It is the goal of DHK to educate agency staff during the audit process so they may better understand energy consumption at their facilities and be better prepared to make informed decisions regarding energy use in the future. The energy audit process consists of three tasks as shown on Figure 2-1 below. Each of the three tasks is discussed in further detail below.

Figure 2-1: Energy Assessment Program - Task Overview/Flow Chart



2.1 TASK 1

The kick-off meeting is the main component of Task 1. The kick-off meeting is held by DHK and attended by representatives of SDG&E and the agency being audited. The main objective of the kick-off meeting is to educate the agency on the energy audit process and request the pertinent data required for a successful audit. At a minimum, the following data is requested during the kick-off meeting:

- Equipment List
- Equipment Use Profiles
- Equipment Nameplate Data (for equipment over 5 horsepower)
- Total Run-Time Hours
- Electrical One-Line Drawing
- Electrical Bills (at least the previous 12 months)
- Electrical Rate Schedule
- Natural Gas, Propane, Diesel, and Potable Water Use
- Previous Energy Conservation Studies
- Renewable Energy Sources (Solar, Wind, etc.)
- Discharge Permit Constraints
- Regional Issues
- Projects in Development
- Photographs

2.2 TASK 2

Subsequent to the kick-off meeting, the agency transfers the requested data to DHK. A pre-audit review of the data is performed and is followed by an on-site energy audit. During the on-site energy audit, DHK conducts interviews with agency staff and performs a field audit of the facility.

2.2.1 Energy Audit

Interviews with agency staff typically include discussions regarding operational control strategies; historical operations; and recent modifications, repairs, replacements, and/or maintenance issues that may impact energy use. If needed, DHK attempts to retrieve any requested data that may not have been previously provided.

During the field audit, DHK observes, photographs, and documents the facility. The number, location, identifier, and current reading of all on-site SDG&E meters are documented. Nameplate data for electrical motors rated above 5 horsepower (hp) is recorded; nameplate data typically includes motor type, hp, voltage, power factor, etc. DHK also identifies potential ECOs during the audit and gathers pertinent data/information required to develop each ECO.

2.2.2 Draft Phase 1 Report

Following the energy audit, DHK compiles the information obtained from the data transfer, interviews, and field audit. A Draft Phase 1 Report is prepared to present detailed information regarding each facility's bills, utility metrics, baseline energy use, and potential ECOs. The ECOs presented in the Draft Phase 1 Report are preliminary in nature and only include a simple payback range estimate and a capital investment range estimate. Simple payback ranges are describes as short (less than 5 years), medium (5 to 10 years), or long (more than 10 years). Capital investment ranges are described as a no cost measure, low cost measure (less than $10,000), or investment grade measure (greater than $10,000). The Draft Phase 1 Reports for each selected facility are included in this report as attachments.

2.2.3 Agency Review

After reviewing the Draft Phase 1 Report, the agency selects the ECOs they would like further developed and the project moves to Task 3. If there weren't any ECOs identified, or if the agency does not choose to further develop any of the identified ECOs, the assessment is complete.

2.3 TASK 3

During Task 3, DHK prepares Phase 2 and Final Reports, and completes the assessment.

2.3.1 Phase 2 Report

The Phase 2 report is similar to the Phase 1 report, but summarizes the Phase 1 findings and if requested, includes more detail and further develops the selected ECOs. A detailed description of each ECO is prepared and the estimated implementation cost and simple payback is calculated. The steps required to implement the ECO are presented and the facility staffing impact is assessed. Based on the data presented, DHK provides a recommendation to either consider implementation of the ECO or not.

2.3.2 Final Report

Similarly to Task 2, the agency reviews the Phase 2 report. Based on the estimated implementation costs and simple payback periods calculated, the agency determines which ECOs it would like to implement. DHK then finalizes the development of each selected ECO. At the agency's request, DHK can assist with the design and implementation of each ECO. Once the Final Report is delivered, the assessment is complete.

3. INCENTIVES AND RATE SCHEDULES

San Diego Gas & Electric incentives and rate schedules are summarized in this section. Only the rate schedules the Water Authority uses to purchase energy from SDG&E are provided.

3.1 INCENTIVES

Incentives are provided by SDG&E in three categories of "solutions:

- Demand Response Solutions
- Financial Solutions
- Energy-Efficiency Solutions

Demand Response Solutions consist of programmatic incentives that reward customers for demand reduction during "critical peak" periods by load shedding, transferring load from the grid to standby generators, and/or demand reduction during predetermined periods. Penalties can be assessed for excessive energy use during "events." For each case, customers are provided advance notice of critical events ranging from 15 minutes to 24 hours.

Financial Solutions include interest free loans for the purchase and installation of energy efficient equipment and other energy saving projects. Offsets are also provided for installation of demand response equipment.

Energy-Efficiency Solutions consist of incentives for large energy-efficient retrofit projects, installation of high-efficiency equipment or systems, rebates for installation of energy-efficient lighting, refrigeration, food service, natural gas, and other technologies. Details of each program are provided in tables 3-1, 3-2, and 3-3 (SDG&E 2012).

Table 3-1: San Diego Gas and Electric Demand Response Solutions

Program	Description
Critical Peak Pricing (CPP)	A dynamic pricing rate which features increased prices during "critical peak" periods and lower commodity rates the rest of the year. This incentive rewards customers who shed load during event days by lowering the commodity rates during non-event days throughout the year. Customers receive a 1-day notification.
Peak Generation	Customers can receive incentives for transferring load from the SDG&E system to a standby generator. Customers must be able to achieve at least 15% demand reduction or more than 50kW. Customers receive a 15-minute notification.
Base Interruptible Program	Customers can receive incentives for predetermined reduction during events. Customers are penalized for excess energy use during events. Customers receive either a 30-minute or 3-hour notification.

Source: SDG&E 2012a

Table 3-2: San Diego Gas and Electric Financial Solutions

Program	Description
On-Bill Financing	Customers may receive interest free financing through SDG&E for qualified energy efficient projects. The loan is repaid as a line item on the customer's monthly bill.
Technology Incentives	Helps offset the installation of demand response equipment.

Source: SDG&E 2012a

Table 3-3: San Diego Gas and Electric Energy-Efficiency Incentives

Program	Description
Energy Savings Bid	Offers incentives for installing large, energy efficient retrofit projects.
Energy Efficiency Business Incentives	Offers incentives for installing new, high-efficiency equipment or systems.
Energy Efficiency Business Rebates	Offers rebates for installing energy-efficient lighting, refrigeration, food service, natural gas, and other technologies.
Optimization Pump Utilization Systems	Provides a no-cost pump test and evaluation.

Source: SDG&E 2012a

3.2 RATE SCHEDULES

The Water Authority purchases electricity from SDG&E for the subject facilities based on the rate schedules shown in Table 3-4. A summary of the SDG&E rate schedules in use for the facilities audited are presented in tables 3-5 through 3-8. Detailed descriptions of each rate schedule are provided after the tables.

Table 3-4: Rate Schedules for Selected San Diego County Water Authority Facilities

Facility	SDG&E Rate Schedule
Escondido Operations Building	AL-TOU
Escondido Pump Station	PAT-1
Lake Hodges Pump Station	AL-TOU
Olivenhain Pump Station	PAT-1-CP2
Rancho Penasquitos Hydroelectric Facility	AL-TOU-CP2
San Diego Office	AL-TOU-CP2
San Vicente Pump Station	PAT-1
Twin Oaks Valley Water Treatment Plant	AL-TOU
Valley Center Pump Station	A

Table 3-5: SDG&E Rate Schedule: A

Period	Schedule A Energy ($/kWh)	Schedule A Demand ($/kW)
Summer (May 1 to Sept. 30)	0.18031	--
Winter (Oct. 1 to April 30)	0.15519	--

Source: SDG&E 2012b

Table 3-6: SDG&E Rate Schedule: AL-TOU

Period		AL-TOU Energy ($/kWh)	AL-TOU Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.09907	12.86
	Semi-Peak	0.07979	--
	Off-Peak	0.05942	--
Winter (Oct. 1 to April 30)	On-Peak	0.09320	4.92
	Semi-Peak	0.08491	--
	Off-Peak	0.06475	--
Non-Coincident		--	13.57
CPP Event Days		**1.06282**	**Current Market Rate**
Capacity Reservation Charge		**--**	**6.42**

Source: SDG&E 2012b

Table 3-7: SDG&E Rate Schedule: AL-TOU with CPP-D

Period		AL-TOU with CPP-D Energy ($/kWh)	AL-TOU with CPP-D Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.08123	12.86
	Semi-Peak	0.06467	--
	Off-Peak	0.04552	--
Winter (Oct. 1 to April 30)	On-Peak	0.07692	4.92
	Semi-Peak	0.07024	--
	Off-Peak	0.05084	--
Non-Coincident		--	13.57
CPP Event Days		**1.06282**	**Current Market Rate**
Capacity Reservation Charge		**--**	**6.42**

Source: SDG&E 2012b

Table 3-8: SDG&E Rate Schedule: PAT-1 Option D

Period		PAT-1 Option D	
		Energy ($/kWh)	Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.09848	11.36
	Semi-Peak	0.08024	8.91
	Off-Peak	0.05902	--
Winter (Oct. 1 to April 30)	On-Peak	0.09364	5.24
	Semi-Peak	0.08539	8.91
	Off-Peak	0.06435	--

Source: SDG&E 2012b

Table 3-9: SDG&E Rate Schedule: PAT-1 Option D with CPP-D

Period		PAT-1 Option D with CPP-D	
		Energy ($/kWh)	Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.09202	11.36
	Semi-Peak	0.07386	8.91
	Off-Peak	0.05311	--
Winter (Oct. 1 to April 30)	On-Peak	0.08771	5.24
	Semi-Peak	0.07943	8.91
	Off-Peak	0.05843	--
CPP Event Days		**1.06282**	**Current Market Rate**
Capacity Reservation Charge		**--**	**6.42**

Source: SDG&E 2012b

3.2.1 Rate Schedule A

This schedule is SDG&E's standard tariff for commercial customers with a maximum monthly demand of less than 20 kW. Along with the Basic Service Fees, customers are charged for the energy they use (kWh). There are several components that make up the energy rates charged by SDG&E: Commodity Costs, Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component. Demand charges do not apply to this rate schedule.

3.2.2 Rate Schedule AL-TOU

Rate Schedule AL-TOU is an optional time-of-use schedule available to common use and metered non-residential customers whose monthly maximum demand exceeds 20 kW. The "A" is a designation for industrial users and the "L" denotes a rate structure. TOU stands for *Time of Use*, which refers to the fact that energy and demand charges are based on the time of day electricity is used: On-Peak, Semi-Peak, and Off-Peak demand. This schedule charges customers based on the following seasonal time periods:

	May 1 – September 30	**All Other**
On-Peak	11 am – 6 pm Weekdays	5 pm – 8 pm Weekdays
Semi-Peak	6 am – 11 am Weekdays	6 am – 5 pm Weekdays
	6 pm – 10 pm Weekdays	8 pm to 10 pm Weekdays
Off-Peak	10 pm – 6 am Weekdays	10 pm – 6 am Weekdays
	Plus Weekends and Holidays	Plus Weekends and Holidays

Along with the Basic Service Fees, customers are charged for the energy they demand (kW) and use (kWh). Demand is the amount of energy a customer is using at any one time. There are several components that make up the Demand and Energy rates charged by SDG&E: Commodity Costs, Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component. It should be noted that, under the AL-TOU rate schedule, Non-Coincident demand charges are based on the higher of the maximum monthly demand or 50 percent of the maximum annual demand. This can severely affect a facility that has one month of excessive demand because Non-Coincident charges are $13.57/kW.

3.2.3 Rate Schedule CPP-D

The Critical Peak Pricing-Default (CPP-D) rate schedule provides customers with the opportunity to manage their electricity costs by either reducing load during peak pricing periods or shifting load from peak pricing periods to lower cost periods. When electric supplies are anticipated to be low, SDG&E contacts the customers enrolled in this plan and requests a reduction in energy consumption. Up to 18 CPP events can be called in a year. SDG&E may call a CPP event when reductions in electricity use by customers are needed during periods of high electric demand or when electric system reliability is in jeopardy. The most dominant triggers are based on *system load* and *temperature*. Customers are notified no later than 3 pm the day before a CPP event will be in effect. CPP events are effective from 11 am to 6 pm during the CPP Event Day.

3.2.4 Rate Schedule PAT-1 Option D

The PAT-1 rate schedule is an optional time-of-use schedule available to agriculture and water pumping customers whose maximum monthly demand exceeds 500 kW. "Time-of-use" refers to the fact that energy and demand charges are based on the time of day electricity is used. The PAT-1 schedule allows customers to choose a Demand Charge Option (C through F) which determines when they are charged for On-Peak, Semi-Peak, and Off-Peak demand. Option D of this schedule, which the facility is currently enrolled, charges customers based on the following seasonal time periods:

Option D	**May 1 – September 30**	**All Other**
On-Peak	1 pm – 3 pm Weekdays	5 pm – 8 pm Weekdays
Semi-Peak	6 am – 1 pm Weekdays	6 am – 5 pm Weekdays
	4 pm – 10 pm Weekdays	8 pm to 10 pm Weekdays

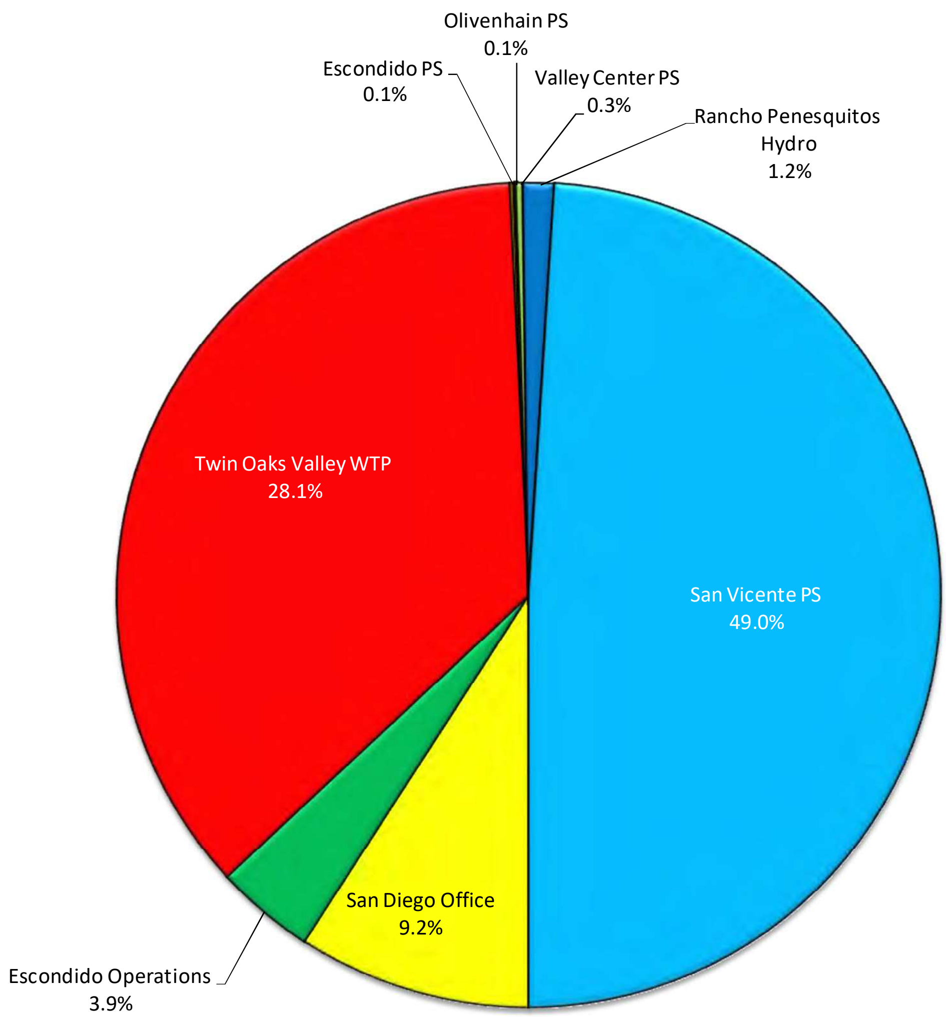
Along with the Basic Service Fees, customers are charged for the energy they demand (kW) and use (kWh). Demand is the amount of energy a customer is using at any one time. There are several components that make up the Demand and Energy rates charged by SDG&E: Commodity Costs, Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component.

4. ENERGY AUDIT SUMMARY

4.1 SUMMARY OF ENERGY METRICS

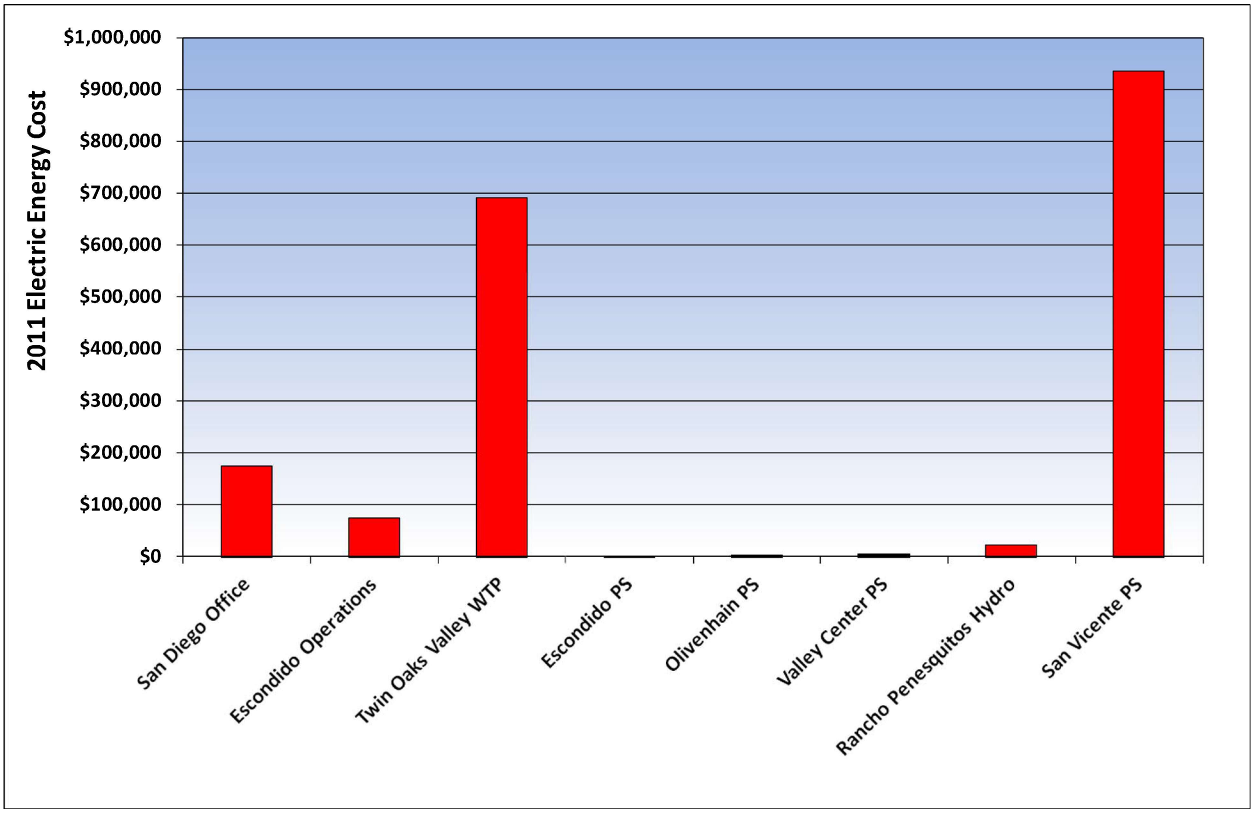
Electricity usage data and bills from 2010 to present were reviewed. According to these data, the Water Authority currently consumes approximately 13.4 GigaWatt-hours of electricity and spends just over $1,900,000 annually for electrical energy. Figure 4-1 shows the percent total annual energy use per facility audited. The San Vicente Pump Station and Twin Oaks Valley Water Treatment Plant consume over 75 percent of the energy delivered to the Water Authority each year.

Figure 4-1: Total Annual Energy Cost per Facility by Percentage



As illustrated in Figure 4-2 below, the Water Authority spends at least $100,000 per year to operate each the San Diego Office, Twin Oaks Valley WTP, and the San Vicente Pump Station.

Figure 4-2: Annual Energy Cost for Selected San Diego County Water Authority Facilities



4.2 *ANNUAL ENERGY COSTS BREAKDOWN*

Figure 4-2 presents a breakdown of the annual operating cost for each facility. This figure illustrates which facilities are charged for demand and may benefit from the implementation of demand response strategies. The table following Figure 4-2 presents the metrics discussed in each of the attached Phase 1 facility audit reports.

Figure 4-3: Annual Energy Cost Breakdown for Selected San Diego County Water Authority Facilities

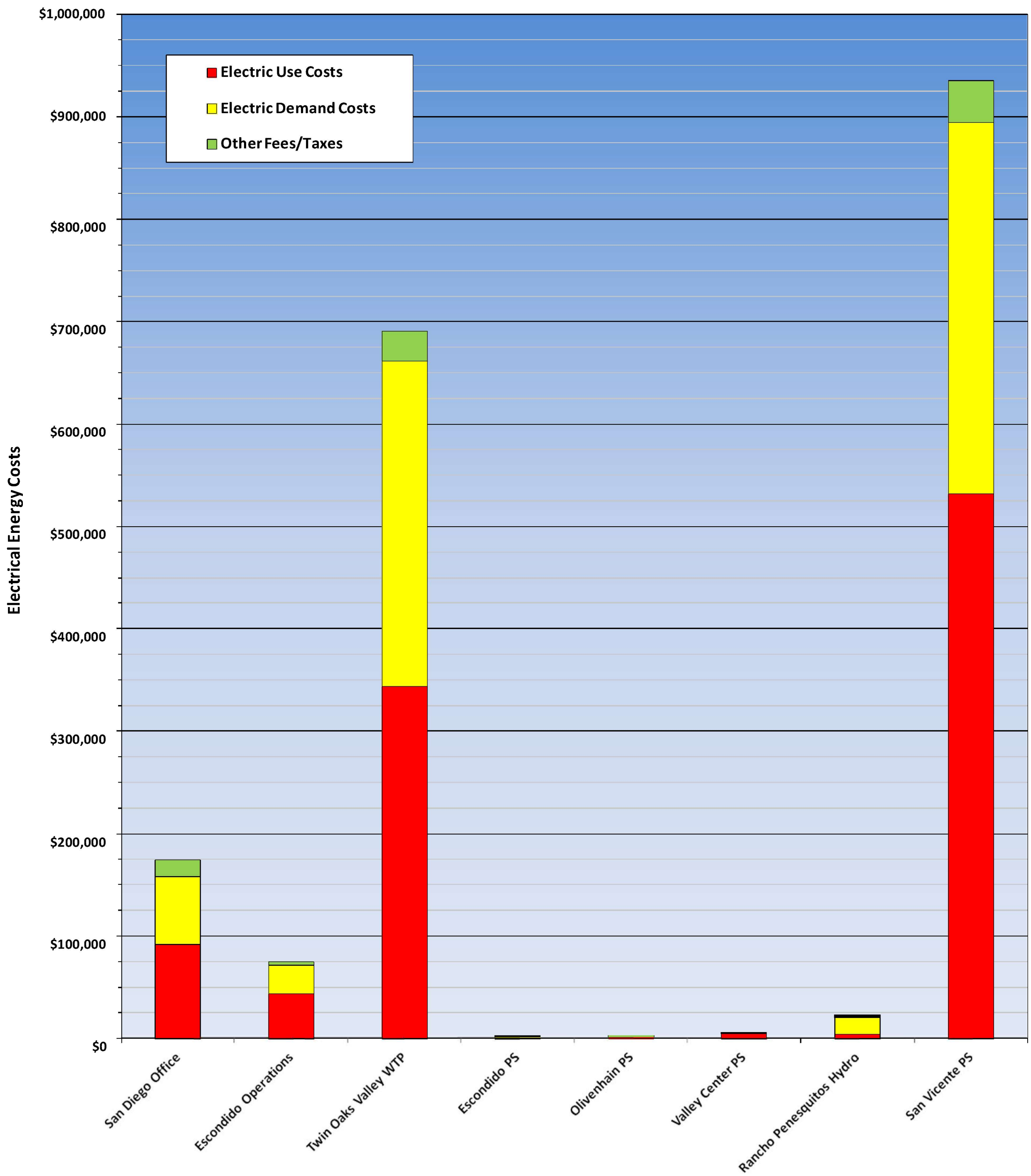


Table 4-1: Summary of Energy Metrics for Selected San Diego County Water Authority Facilities

Facility	SDGE Rate Schedule	Annual Flow (MG)	Avg. Daily Flow (MGD)	Electric Use (kWh/Year)	Avg. Max. Demand (kW)	Electric Use Cost ($)	Demand Cost ($)	Fees & Taxes ($)	Total Electricity Cost ($)	Avg. Energy Cost/Day ($/Day)
Offices										
San Diego Office	ALTOUCP2	--	--	1,085,608	272	$91,792	$66,296	$16,501	$174,588	$478
Escondido Operations	ALTOU	--	--	514,400	112	$43,208	$27,936	$3,676	$74,820	$205
	Totals	--	--	***1,600,008***	--	***135,000***	***94,231***	***20,177***	***249,407***	***683***
Water Treatment Plants										
Twin Oaks Valley WTP	ALTOU	17,657	43.38	4,668,508	1,239	$343,867	$29,468	$690,6967	$1,893	$39
	Totals	***17,657***	***43.38***	***4,668,508***	--	***343,867***	***29,468***	***690,967***	***1,893***	***39***
Potable Water Pump Stations										
Escondido PS	PAT1	0	0.00	6,400	10	$493	$1,121	$735	$2,349	$6
Olivenhain PS	PAT1	0	0.00	20,551	115	$1,488	$115	$819	$2,422	$7
Valley Center PS	A	0	0.00	30,560	63	$4,817	$0	$290	$5,107	$14
Rancho Penesquitos PHCF	ALTOUCP2	0	0.00	59,893	32	$4,335	$15,960	$2,273	$22,569	$62
San Vicente PS	PAT1	0	0.00	6,996,732	2,231	$531,992	$362,222	$40,597	$934,811	$2,561
	Totals	***0***	***0***	***7,114,136***	--	***543,126***	***379,417***	***44,714***	***967,258***	***2,650***
	Total	--	--	***13.4 GWh***	--	***1,022,001***	***791,271***	***94,360***	***1,907,632***	***5,226***

Notes:

Avg	average
GWh	gigaWatt-hours
kW	kiloWatts
kWh	kiloWatt-hours
MG	million gallons
MGD	million gallons per day
MWh	megaWatt-hour
PCHF	pressure control hydroelectric facility
PS	pump station
WTP	water treatment plant

5. ENERGY CONSERVATION OPPORTUNITIES

The recommended Energy Conservation Opportunities (ECOs) identified for the facilities audited are presented in Table 5-1 by facility. The ECOs are discussed in further detail within each attached facility report. During the ECO review meeting, several ECOs were selected by the Water Authority for further development and specific assignments were requested.

Table 5-1: Energy Conservations Opportunities

Facility and ECO Number	ECO Description	Simple Payback Term (Estimate)	Investment Measure Type (Cost Estimate)
Escondido Operations-1	Re-commission (re-balance) new HVAC systems (Cost $3,000/ Savings $600/year)	Short-term (<5 years)	Low Cost Measure (<$10,000)
Escondido Operations-2	Install Energy Management System (EMS) similar to San Diego Office to monitor building loads. (Cost $5,000/ Savings $1,000)	Short-term (<5 years)	Low Cost Measure (<$10,000)
Escondido Operations-3	Add motion sensors and/or timers to lighting controls (Cost $2,500/ Savings $400/year)	Short-term (<5 years)	Low Cost Measure (<$10,000)
Escondido Operations-4	Investigate retrofit of current lighting configuration to extend time between bulb replacements (currently replacing every 6 months) (Study cost $5,000/ Savings TBD)	Short-term (<5 years)	Low Cost Measure (<$10,000)
Escondido Operations-5	Lighting retrofit and controls for VMF (100 light bulbs on from 6:00 am to 4:30 four days per week; possible task lighting (Cost $20,000/ $3,500/year)	Mid-Term (>5 to <10 years)	Investment Grade Measure (>$10,000)
Escondido Operations-6	Reconfigure HVAC ductwork and thermostats in Training Building 2nd floor (Cost $2,000/ $150/hr)	Mid-Term (>5 to <10 years)	Low Cost Measure (<$10,000)
Escondido Operations-7	Complete lighting retrofit within Administration Building; currently about 50% complete on de-lamping (Cost $5,000/ $750/year)	Mid-Term (>5 to <10 years)	Low Cost Measure (<$10,000)
Escondido PS-1	Evaluate SDG&Es recommendation to change to the PA, CPP-D rate schedule (Cost $0/ Savings $0)	Short-Term (<5 years)	No Cost Measure
Escondido PS-2	If the pump station will be used in the future, upgrade pumps to improve efficiency (see Pump Test Reports) (Currently, PS seldom used)	Short-Term (<5 years)	Investment Grade Measure (>$10,000)
Escondido PS-3	Install timers on light switches (Cost $250/ Savings $30/year)	Short-Term (<5 years)	Low Cost Measure (<$10,000)
Olivenhain PS-1	Adjust HVAC and lighting controls for as-needed operations	Short Term (<5 years)	No Cost Measure
Lake Hodges PS-1	Monitor block loads of support equipment including HVAC, cooling and service water, and compressed air. (Complete an energy assessment after 1-yr of full operation)	Short-term (<5 years)	No Cost Measure

Facility and ECO Number	ECO Description	Simple Payback Term (Estimate)	Investment Measure Type (Cost Estimate)
Rancho Penasquitos PCHF-1	Evaluate the need to continuously operate cooling and service water loops for turbine; possibly consider jockey pump if concerned about a no-flow condition (Cost $10,000/ Savings $2,000)	Short-term (<5 years)	Investment Grade Measure (>$10,000)
Rancho Penasquitos PCHF-2	Install cycle timers for manual light switches (Cost $1,000/Savings $200/year)	Short-term (<5 years)	Low Cost Measure (<$10,000)
San Diego Office-1	Install boiler hot water low-flow (jockey) pump (2-hp) to circulate minimal flow during building off-hours (Cost $12,000/ Savings $3,000)	Short-term (<5 years)	Investment Grade Measure (>$10,000)
San Diego Office-2	Allow setback of hot water system temperature during off-hours from 120oF to 90oF (Cost $0/ $600/year)	Short-term (<5 years)	No Cost Measure
San Vicente PS-1	Evaluate SDG&Es recommendation to change to the PA, CPP-D rate schedule	Short-term (<5 years)	No Cost Measure
San Vicente PS-2	Adjust HVAC and lighting controls for as needed operations (Cost $3,000/ Savings $1,000)	Short-term (<5 years)	Low Cost Measure (<$10,000)
San Vicente PS-3	Evaluate the need for continuous operation of cooling and service water loops; possible jockey pump installation if concerned about a no-flow condition (Construction cost of jockey pump or VFD $20,000/ Savings $3,000)	Mid-Term (>5 to <10 years)	Investment Grade Measure (>$10,000)
Twin Oaks Valley WTP-1	Shift production of NaOCl (sodium hypochlorite) to off-peak periods to the extent possible	Short-term (<5 years)	No Cost
Twin Oaks Valley WTP-2	Confirm and modify SDG&E Rate Schedule (AL-TOU vs. A6-TOU)	Short-term (<5 years)	No Cost
Twin Oaks Valley WTP-3	Adjust dewatering operations (centrifuge) to operate during off-peak periods	Short-term (<5 years)	No Cost
Twin Oaks Valley WTP-4	Sequence and/or install VFDs on Backwash Tank Fill Pumps (20-hp) to pump water to elevated tanks prior to backwash	Short-term (<5 years)	No Cost
Twin Oaks Valley WTP-5	Evaluate continuous recirculation water loop pumps (25-hp constant speed operations)	Short-term (<5 years)	No Cost
Twin Oaks Valley WTP-6	Installation of cycle timers on manual light switches	Short-term (<5 years)	Low Cost Measure (<$10,000)
Twin Oaks Valley WTP-7	Evaluate installation of high-efficiency centralized compressed air (screw) configuration in lieu of six separate systems	Mid Term (5 to 10 years)	Investment Grade Measure (>$10,000)
Twin Oaks Valley WTP-8	Evaluate air receiver for use with air scour blower	Mid-Term (5 to 10 years)	Investment Grade Measure (>$10,000)
Twin Oaks Valley WTP-9	Evaluate installation of VFD for Return Water Pumps during low flow operations	Mid-Term (5 to 10 years)	Investment Grade Measure (>$10,000)

Facility and ECO Number	ECO Description	Simple Payback Term (Estimate)	Investment Measure Type (Cost Estimate)
Twin Oaks Valley WTP-10	Investigate and implement Demand Management Strategies including addition of Energy Management System (EMS)	Short-Term (<5 years)	Low Cost Measure (<$10,000)
Valley Center PS-1	If the pump station will be used in the future, upgrade pumps to improve efficiency (see Pump Test Reports)	Short-term (<5 years)	Investment Grade Measure (>$10,000)
Valley Center PS-2	Install timers on light switches (Cost $250/ Savings $30/year)	Short-term (<5 years)	Low Cost Measure (<$10,000)

In addition to the ECOs listed in Table 5-1, the Water Authority requested these additional items:

- Development of alternative types of Strategic Energy Plans including annotated outlines, table of contents, mission statements, etc.
- Utility Rate Guidance Table including an easy to read rate schedule and a breakdown of demand and consumption charges
- DG-R versus AL-TOU rate analysis with photovoltaic system overlay to determine the overall benefits of the Water Authority's solar program
- Input to Pump Station Operations versus Rate Schedule Interface including independent review of the Operational Assessment Tool developed by the Water Authority

Table 5-2 provides a color-coded illustration of the selection status and potential energy and fiscal savings associated with each ECO. During the development phase, additional workshops, field inspections, data gathering, and analysis were completed. Each ECO selected for further development is discussed in further detail in Attachment 10, ECO Development.

Table 5-2: Summary of ECOs Selected for Development

Facility and ECO Number	ECO Description	Estimated Energy Savings	Estimated Payback Term	Estimated Investment Cost
Escondido Operations-2	Install Energy Management System (EMS) similar to San Diego Office to monitor building loads.	40,000 kWh/yr	3.7 yrs	$ 21,250
Escondido Operations-5	Lighting retrofit and controls for VMF (100 light bulbs on from 6:00 am to 4:30 four days per week; possible task lighting	4,700 kWh/yr	11.1 yrs	$ 7,500
San Diego Office-1	Install boiler hot water low-flow (jockey) pump (2-hp) to circulate minimal flow during building off-hours	20,000 kWh/yr	4.7 yrs	$ 13,500
Twin Oaks Valley WTP-4	Sequence and/or install VFDs on Backwash Tank Fill Pumps (20-hp) to pump water to elevated tanks prior to backwash	6,500 kWh/yr 8.5 kW	12.3 yrs	$ 39,000
Twin Oaks Valley WTP-5	Evaluate continuous recirculation water loop pumps (25-hp constant speed operations)	41,000 kWh/yr	6.9 yrs	$ 41,000
Twin Oaks Valley WTP-9	Evaluate installation of VFD for Return Water Pumps during low flow operations	0 kWh/yr 10 kW	33.4 yrs	$ 63,000
Twin Oaks Valley WTP-10	Investigate and implement Demand Management Strategies including addition of Energy Management System (EMS)	100 kW	1.6 yrs	$42, 500

6. REFERENCES

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ATTACHMENT 1: ESCONDIDO OPERATIONS BUILDING

Phase 1 Energy Audit Report

Report of Energy Audit – Phase 1 Summary

Escondido Operations Facility

San Diego County
Water Authority

February 15, 2012

Prepared for San Diego County Water Authority
4677 Overland Drive
San Diego, California 92123

1.Introduction

On December 6, 2011, an energy audit of San Diego County Water Authority's (Water Authority) Escondido Operations Facility was conducted by Greg Ortega (Water Authority) and was led by Donald King of DHK Engineers, Inc (DHK). The Escondido Operations Facility is located at 610 5th Avenue in Escondido, California.

The main function of the Water Authority's Escondido Operations Facility is to provide administration offices for staff, training, maintenance, and repair resources, as well as a vehicle maintenance facility. Based on data reviewed, the major equipment types typically associated with Operation Buildings are categorically summarized in Table 1.

Table 1. Major Equipment Inventory

No.	Equipment Description	Equipment Size (hp)
1	HVAC units	Various
2	Lighting	Various
3	Light industrial equipment (compressor)	Various

2. Utility Analysis

2.1 *Current Utility Use*

Electricity and natural gas usage data and bills from 2009 to present were reviewed. A solar system was installed in July 2011. Since this energy audit is focused on optimizing energy demand and consumption, energy data from July 2010 to June 2011 was utilized for this study. According to this data, it costs the Water Authority approximately $76,000 annually to operate the facility. Typical annual electricity and natural gas use and costs are summarized in Table 2 and are described in more detail below.

Table 2. Annual Utility Summary

Utility	Site Utility Use (common units)	Site Utility Costs	% of Costs
Electricity	514,400 kWh	$74,820	99%
Natural Gas	683 therms	$709	1%
Total		**$75,528**	**100%**

As presented in Table 2, electricity accounts for 99 percent of the annual energy costs at the facility, and therefore, will be the focus of this report. As previously noted, the facility installed a 170.7-kilowatt (kW) solar system that went online in July 2011. Since this energy audit is focused on optimizing energy demand and consumption at the facility, the solar system is not considered in this report. However, the solar system is projected to provide 252.15 megawatt-hours (MWh) of electricity per year.

San Diego Gas & Electric (SDG&E) provides electrical energy to the Escondido Operations Facility. The electrical energy is delivered through one onsite transformer and one meter (SDG&E Meter Number 1980295). Table 3 provides a monthly summary of the electrical energy purchased from SDG&E by the facility for the 12-month period of July 2010 through June 2011(prior to solar system being placed online).

Table 3. 2010/2011 Electrical Energy Use

Billing Period	Electrical Energy Use (kWh)	Max Demand (kW)	Electrical Energy Cost ($)
Jul-10	41,120	114	$6,618
Aug-10	53,600	138	$8,434
Sep-10	47,520	136	$7,851
Oct-10	45,920	136	$7,623
Nov-10	41,600	120	$5,940
Dec-10	41,280	125	$5,890
Jan-11	45,600	96	$5,948
Feb-11	42,080	98	$5,431
Mar-11	39,200	86	$4,942
Apr-11	38,720	98	$5,068
May-11	38,400	106	$5,329
Jun-11	39,360	91	$5,744
Total (12 months)	**514,400**	**--**	**$74,820**
Average (12 months)	**42,867**	**112**	**$6,235**

2.2 *ELECTRICITY RATE SCHEDULE*

The Escondido Operations Facility purchases electricity from SDG&E based on their AL-TOU rate schedule. AL-TOU is an optional time-of-use schedule available to common use and metered non-residential customers whose monthly maximum demand exceeds 20 kW. The "A" is a designation for industrial users and the "L" denotes a rate structure. TOU stands for *Time of Use*, which refers to the fact that energy and demand charges are based on the time of day electricity is used: On-Peak, Semi-Peak, and Off-Peak demand. This schedule charges customers based on the following seasonal time periods:

	May 1 – September 30	All Other
On-Peak	11 am – 6 pm Weekdays	5 pm – 8 pm Weekdays
Semi-Peak	6 am – 11 am Weekdays	6 am – 5 pm Weekdays
	6 pm – 10 pm Weekdays	8 pm to 10 pm Weekdays
Off-Peak	10 pm – 6 am Weekdays	10 pm – 6 am Weekdays
	Plus Weekends and Holidays	Plus Weekends and Holidays

Along with the Basic Service Fees, customers are charged for the energy they demand (kW) and use (kWh). Demand is the amount of energy a customer is using at any one time. There are several components that make up the Demand and Energy rates charged by SDG&E: Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component. It should be noted that, under the AL-TOU rate schedule, Non-Coincident demand charges are based on the higher of the maximum monthly demand or 50 percent of the maximum annual demand. This can severely

affect a facility that has one month of excessive demand because Non-Coincident charges are $13.63/kW, nearly double the amount of summer on-peak demand charges ($7.67/kW).

Table 4. SDG&E Rate Schedule: AL-TOU

		AL-TOU	
		Energy ($/kWh)	Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.01138	7.67
	Semi-Peak	0.00874	--
	Off-Peak	0.00799	--
Winter (Oct. 1 to April 30)	On-Peak	0.01035	4.75
	Semi-Peak	0.00874	--
	Off-Peak	0.00799	--
Non-Coincident		**--**	**13.63**
Source: SDG&E website, January 2012			

An Energy Rate Analysis was performed by the Water Authority and SDG&E in 2011 for Water Authority facilities that typically consume large amounts of energy. The purpose of the study was to analyze SDG&E rate alternatives for each facility to determine whether or not the facility could benefit from changing rate schedules. The Energy Rate Analysis recommended that the Escondido Operations Facility considers changing to the AL-TOU, CPP-D rate schedule.

An all-inclusive average electrical energy rate was calculated by dividing the previous 12 months of electrical energy costs by the previous 12 months of electrical energy use. An all-inclusive average energy rate of $0.145/kWh was calculated for the facility and is presented in Table 5. The all-inclusive average electrical energy rate will be utilized in Energy Conservation Opportunity (ECO) calculations.

Table 5. 2010/2011 Electrical Energy Use and Rates to Be Utilized for ECO Cost Impact for the Site

	Electrical Energy Use & Costs	Electrical Energy Demand Use & Costs	Other Costs	Total Electric Use & Costs
2010/2011 Use (12 months)	514,400 kWh/yr	--	--	--
2010/2011 Cost (12 months)	$43,208 /yr	$27,936 /yr	$3,676 /yr	$74,820 /yr
All Inclusive Rate Used for ECO Calculations	**$0.145 /kWh**			

2.3 *ENERGY BASELINE*

Figure 1 illustrates the facility's actual energy use for the 12-month period from July 2010 through June 2011. Figure 1 shows that energy use and costs are relatively consistent throughout the year with slight seasonal variations.

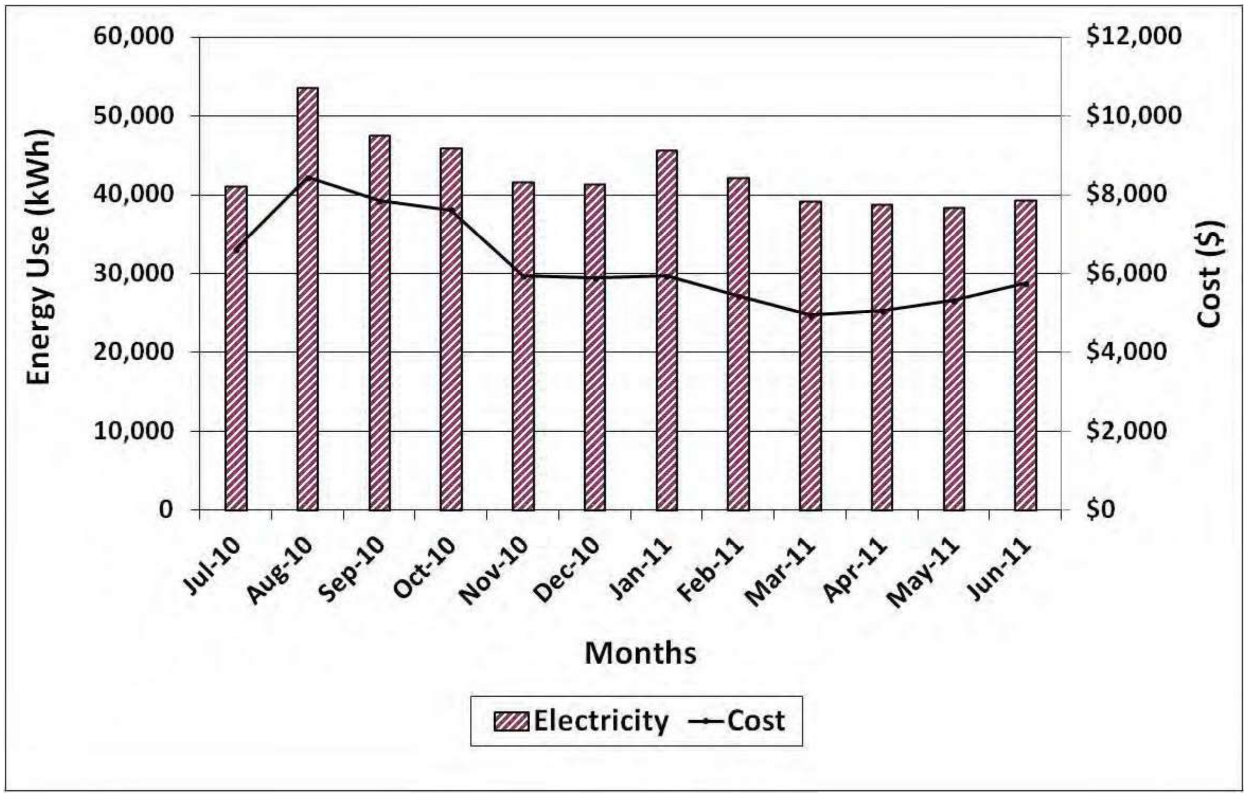

Figure 1. 2010/2011 Energy Use and Cost Breakdown

Figure 2 illustrates the facility's energy costs for the 12-month period from July 2010 through June 2011. As seen in Figure 1, the energy use and demand costs are relatively consistent throughout the year with slight seasonal variations.

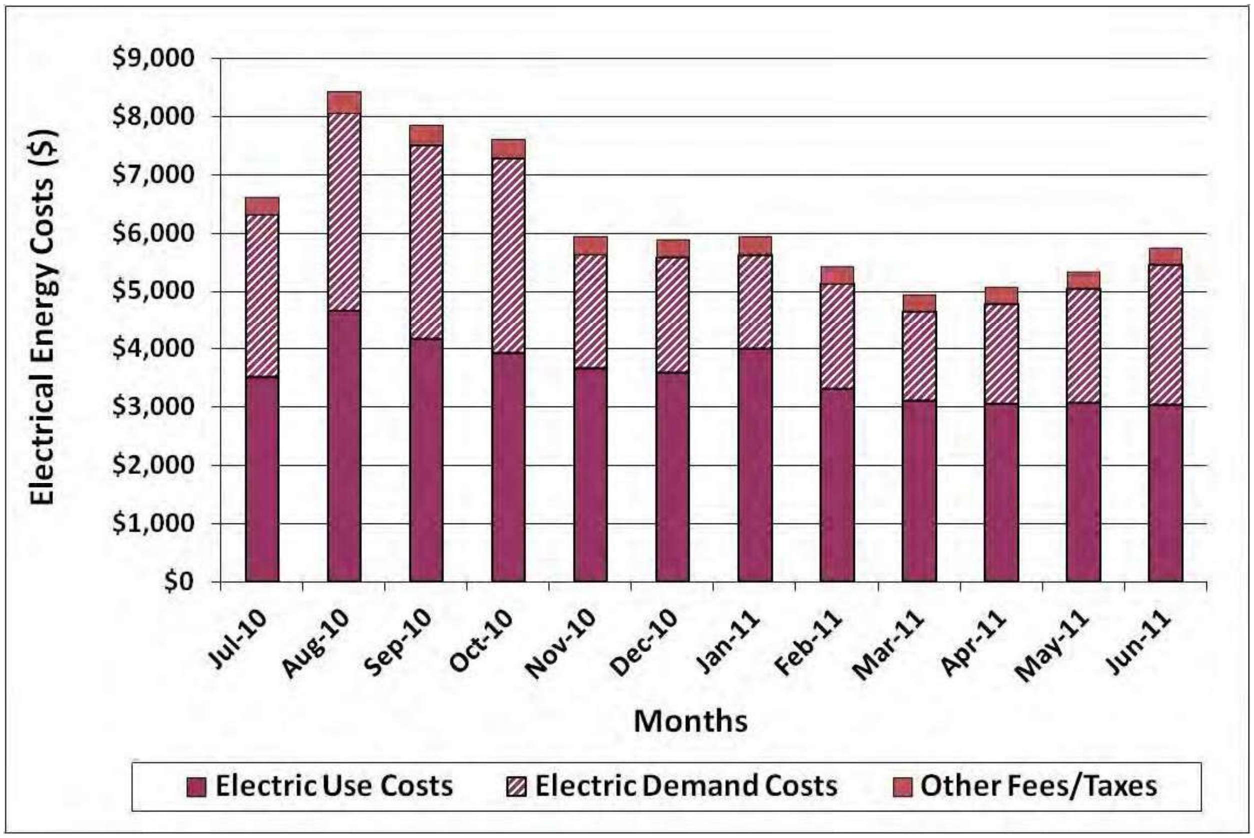

Figure 2. 2010/2011 Energy Cost Breakdown

3. Energy Conservation Opportunities

Table 6 lists potential ECOs recommended for further evaluation.

Table 6. Recommended Energy Conservation Opportunities

ECO Opportunity	ECO Description	Simple Payback Estimate	Investment Cost Estimate
1	Re-commission (re-balance) new HVAC systems (Cost $3,000/ Savings $600/year)	Short Term (<5 years)	Low Cost Measure = <$10,000
2	Install Energy Management System (EMS) similar to San Diego Office to monitor building loads. (Cost $5,000/ Savings $1,000)	Short Term (<5 years)	Investment Grade Measure (>$10,000)
3	Add motion sensors and/or timers to lighting controls (Cost $2,500/ Savings $400/yr)	Short Term (<5 years)	Low Cost Measure (<$10,000)
4	Investigate retrofit of current lighting configuration to extend time between bulb replacements (currently replacing every 6 months) (Study cost $5,000/ Savings TBD)	Short Term (<5 years)	Investment Grade Measure (>$10,000)
5	Lighting retrofit and controls for VMF (100 light bulbs on from 6:00 am to 4:30 four days per week; possible task lighting (Cost $20,000/ $3,500/yr)	Mid Term (>5 - <10 years)	Investment Grade Measure (>$10,000)
6	Reconfigure HVAC ductwork and thermostats in Training Building 2nd floor (Cost $2,000/ $150/hr)	Mid Term (>5 - <10 years)	Low Cost Measure (<$10,000)
7	Complete lighting retrofit within Administration Building; currently about 50% complete on de-lamping (Cost $5,000/ $750/yr)	Mid Term (>5 - <10 years)	Low Cost Measure (<$10,000)

Table 6. Notes

1. Payback Range Estimate: Short Term = <5 years; Mid Term = 5 years to 10 years; Long Term = > 10 years
2. Capital Investment Range Estimate: No Cost Measure = $0; Low Cost Measure <$10,000; Investment Grade Measure >$10,000

4.Photographs

	
Exterior View	**Solar System**

	
Lighting	**Rooftop Mechanical Equipment**

ATTACHMENT 2: ESCONDIDO PUMP STATION

Phase 1 Energy Audit Report

Report of Energy Audit – Phase 1 Summary

Escondido Pump Station

San Diego County
Water Authority

February 15, 2012

Prepared for San Diego County Water Authority
4677 Overland Drive
San Diego, California 92123

1. Introduction

On December 6, 2011, an energy audit of San Diego County Water Authority's (Water Authority) Escondido Pump Station was conducted by Greg Ortega (Water Authority) and was led by Donald King of DHK Engineers, Inc (DHK). The Escondido Pump Station is located at 1220 Hubbard Avenue in Escondido, California. The pump station is designed to convey raw water from Escondido Connection No. 4 at the Crossover Pipeline to Dixon Reservoir via Escondido Pipeline No. 2. The pump station includes two vertical diffusion vane pumps, a 48-inch suction can for a future pump, an air compressor assembly, a submersible sump pump, flow metering equipment, butterfly valves, a ball valve, a 600-volt class motor control center assembly, and miscellaneous devices. Based on data reviewed, the major equipment (5 hp or greater) is summarized in Table 1.

Table 1. Major Equipment Inventory

No.	Equipment Description	Equipment Size (hp)
1	Pump #1	100
2	Pump #2	100

2.Utility Analysis

2.1 Current Utility Use

Electricity is the only utility consumed at the Escondido Pump Station. Electricity usage data and bills from 2009 to present were reviewed. According to this data, it costs the Water Authority approximately $2,400 annually to operate the pump station. Typical annual electricity use and costs are summarized in Table 2 and are described in more detail below. Flow data for the pump station was available; however, flows can be conveyed through the pump station by gravity. Since the pump station wasn't operational for eleven of the twelve months reviewed, the flow data for the pump station was not included in this study.

Table 2. Annual Utility Summary

Utility	Site Utility Use (common units)	Site Utility Costs	% of Costs
Electricity	6,400 kWh	$2,349	100%
Total		**$2,349**	**100%**

San Diego Gas & Electric (SDG&E) provides electrical energy to the Escondido Pump Station. The electrical energy is delivered through one onsite transformer and one meter (SDG&E Meter Number 1931356). Table 3 provides a monthly summary of the electrical energy purchased from SDG&E by the pump station for the 12-month period of November 2010 through October 2011.

Table 3. 2010/2011 Electrical Energy Use

Billing Period	Electrical Energy Use (kWh)	Max Demand (kW)	Electrical Energy Cost ($)
Nov-10	640	2	$126
Dec-10	480	2	$119
Jan-11	480	3	$126
Feb-11	480	0	$96
Mar-11	480	0	$96
Apr-11	480	2	$118
May-11	640	2	$115
Jun-11	480	2	$107
Jul-11	480	2	$129
Aug-11	640	101	$984
Sep-11	640	2	$143
Oct-11	480	10	$188
Total (12 months)	**6,400**	**--**	**$2,349**
Average (12 months)	**533**	**10**	**$196**

2.2 *ELECTRICITY RATE SCHEDULE*

The Escondido Pump Station purchases electricity from SDG&E based on the PAT-1, Option D rate schedule. PAT-1 is an optional time-of-use schedule available to agriculture and water pumping customers whose maximum monthly demand exceeds 500 kW. "Time-of-use" refers to the fact that energy and demand charges are based on the time of day electricity is used. The PAT-1 schedule allows customers to choose a Demand Charge Option (C through F) which determines when they are charged for On-Peak, Semi-Peak, and Off-Peak demand. Option D of this schedule, which the pump station is currently enrolled, charges customers based on the following seasonal time periods:

Option D	May 1 – September 30	All Other
On-Peak	1 pm – 3 pm Weekdays	5 pm – 8 pm Weekdays
Semi-Peak	6 am – 1 pm Weekdays	6 am – 5 pm Weekdays
	4 pm – 10 pm Weekdays	8 pm to 10 pm Weekdays

Along with the Basic Service Fees, customers are charged for the energy they demand (kW) and use (kWh). Demand is the amount of energy a customer is using at any one time. There are several components that make up the Demand and Energy rates charged by SDG&E: Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component. A summary of the PAT-1 Option D rate schedule is presented in Table 4.

Table 4. SDG&E Rate Schedule: PAT-1 Option D

		PAT-1 Option D	
		Energy ($/kWh)	Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.01079	5.80
	Semi-Peak	0.00919	--
	Off-Peak	0.00759	--
Winter (Oct. 1 to April 30)	On-Peak	0.01079	5.06
	Semi-Peak	0.00919	--
	Off-Peak	0.00759	--
Source: SDG&E website, January 2012			

An Energy Rate Analysis was performed by the Water Authority and SDG&E in 2011 for Water Authority facilities that typically consume large amounts of energy. The purpose of the study was to analyze SDG&E rate alternatives for each facility to determine whether or not the facility could benefit from changing rate schedules. The Energy Rate Analysis recommended that the Escondido Pump Station considers changing to the PA, CPP-D rate schedule.

An all-inclusive average electrical energy rate was calculated by dividing the previous 12 months of electrical energy cost by the previous 12 months of electrical energy use. An all-inclusive average energy rate of $0.348/kWh was calculated for the pump station and is presented in Table 5. The all-inclusive average electrical energy rate will be utilized in Energy Conservation Opportunity (ECO) calculations.

Table 5. 2010/2011 Electrical Energy Use and Rates to Be Utilized for ECO Cost Impact for the Site

	Electrical Energy Use & Costs	Electrical Energy Demand Use & Costs	Other Costs	Total Electric Use & Costs
2010/2011 Use (12 months)	6,400 kWh/yr	--	--	--
2010/2011 Cost (12 months)	$493 /yr	$1,121 /yr	$735 /yr	$2,349 /yr
All Inclusive Rate Used for ECO Calculations	**$0.348 /kWh**			

2.3 *ENERGY BASELINE*

Figure 1 illustrates the pump station's energy use and total cost for the 12-month period from November 2010 through October 2011. As discussed above, electricity is the pump station's only energy supply. Figure 1 shows that the pump station is rarely used. Based on discussion with Water Authority staff, pump tests were conducted for two days during August 2011. This figure shows that the baseline energy use for the pump station is about 500 kWh per month, costing the Water Authority Approximately $100 per month.

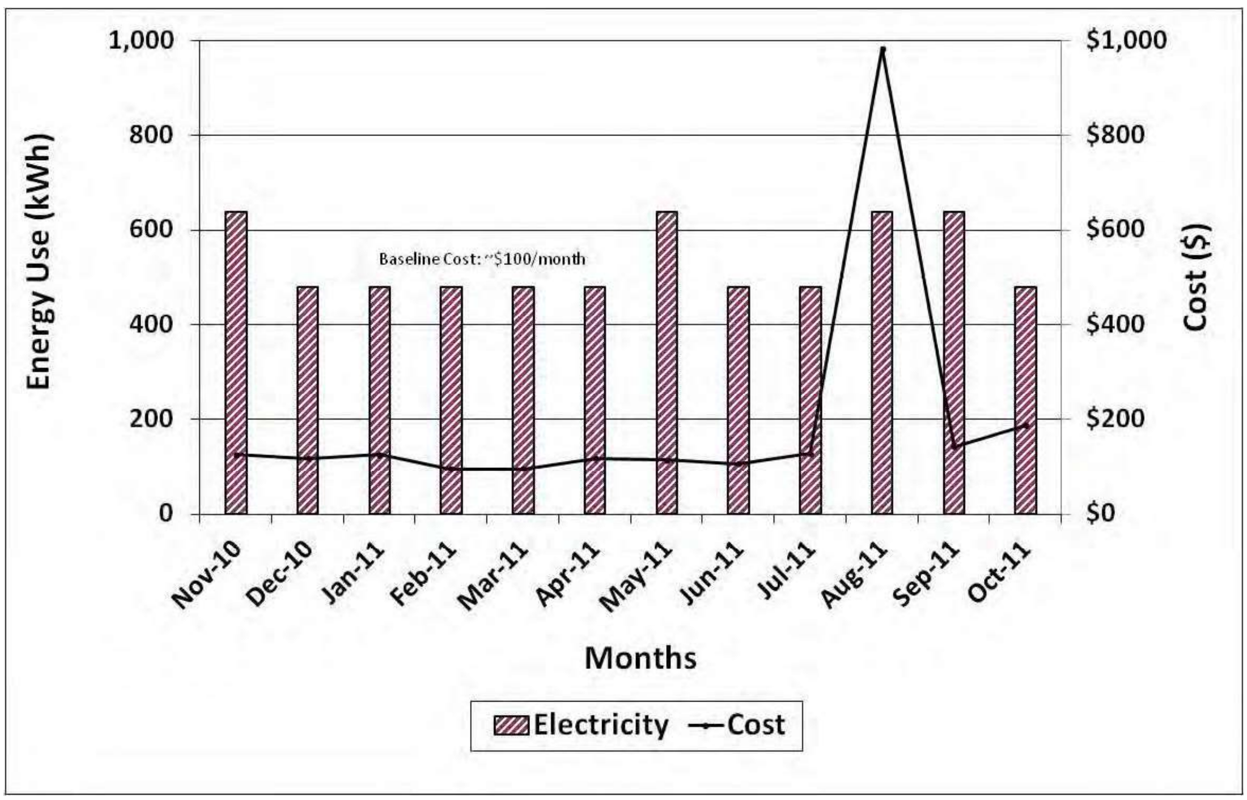

Figure 1. 2010/2011 Energy Use and Cost Breakdown

Figure 2 illustrates the pump station's energy costs for the 12-month period from November 2010 through October 2011. This figure shows that the pump station energy charges were consistent throughout the 12-month period, except for the month of August 2011 when costs jumped to almost $1,000 due to demand charges. As presented in Table 3 above, the pump station usually demands about 2 kW; however, that rose to 101 kW during the month of August. As previously stated, pump tests were conducted for two days during August 2011.

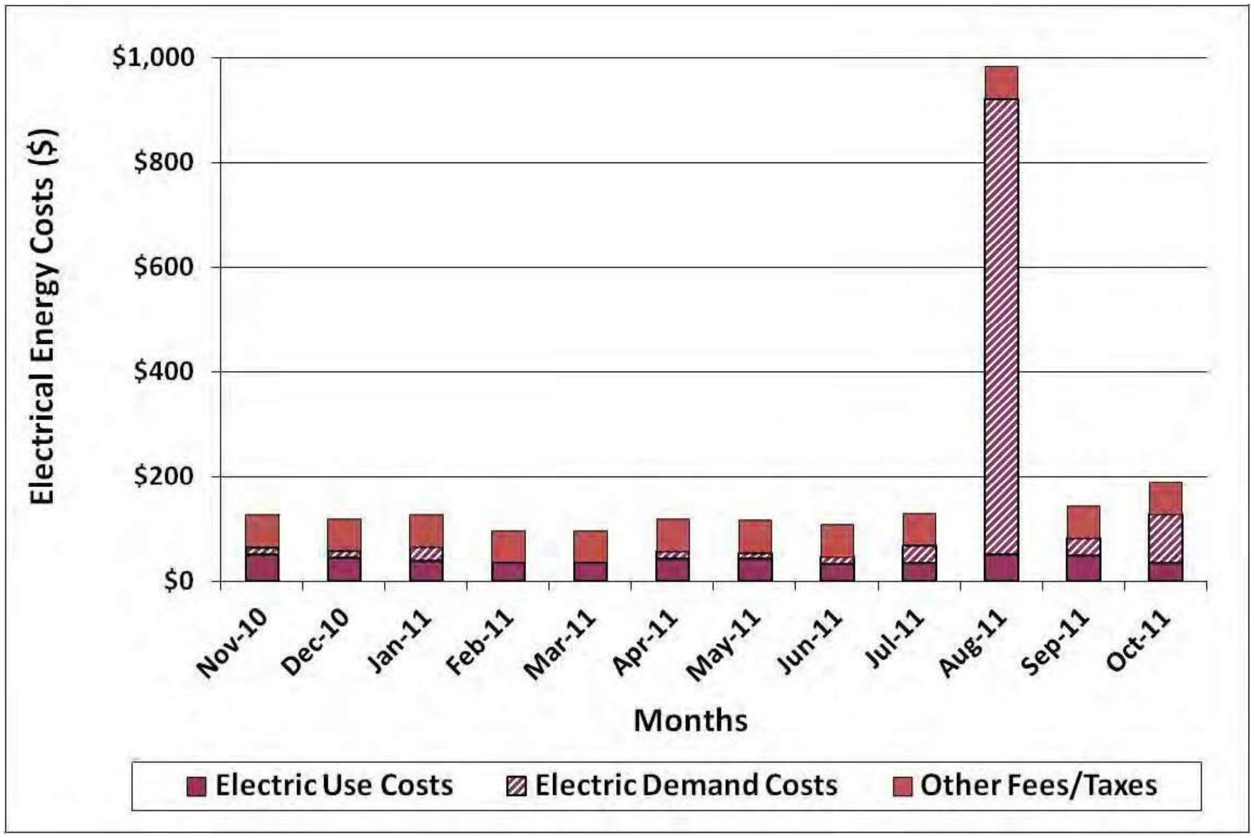

Figure 2. 2010/2011 Energy Cost Breakdown

3. Energy Conservation Opportunities

Table 6 lists potential ECOs recommended for further evaluation.

Table 6. Recommended Energy Conservation Opportunities

ECO Opportunity	ECO Description	Simple Payback Estimate	Investment Cost Estimate
1	Evaluate SDG&Es recommendation to change to the PA, CPP-D rate schedule (Cost $0/ Savings $0)	Short Term (<5 years)	No Cost Measure
2	If the pump station will be used in the future, upgrade pumps to improve efficiency (see Pump Test Reports) (Currently, PS seldom used)	Short Term (<5 years)	Investment Grade Measure (>$10,000)
3	Install timers on light switches (Cost $250/ Savings $30/yr)	Short Term (<5 years)	Low Cost Measure (<$10,000)

Table 6. Notes

1. Payback Range Estimate: Short Term = <5 years; Mid Term = 5 years to 10 years; Long Term = > 10 years
2. Capital Investment Range Estimate: No Cost Measure = $0; Low Cost Measure <$10,000; Investment Grade Measure >$10,000

4.Photographs

	
Exterior View	**Booster Pumps**

ATTACHMENT 3: LAKE HODGES PUMP STATION

Phase 1 Energy Audit Report

Report of Energy Audit – Phase 1 Summary

Lake Hodges Pump Station

San Diego County
Water Authority

February 15, 2012

Prepared for San Diego County Water Authority
4677 Overland Drive
San Diego, California 92123

1.Introduction

On December 13, 2011, an energy audit of San Diego County Water Authority's (Water Authority) Lake Hodges Pump Station was conducted by Water Authority staff (Greg Ortega) and was led by Donald King of DHK Engineers, Inc (DHK). The Lake Hodges Pump Station is located at 18962 Lake Drive in Escondido, California and is part of the Water Authority's Emergency Storage Project (ESP). Construction of the facility is scheduled for completion in 2012. Once completed, the pump station will be equipped with two 28,000-horsepower (hp) reversible pump/turbines capable of pumping raw water from Lake Hodges to Olivenhain Reservoir or generating up to 40-megawatts (MW) of electricity while raw water is gravity fed from Olivenhain Reservoir to Lake Hodges.

2. Utility Analysis

2.1 ELECTRICITY RATE SCHEDULE

The Lake Hodges Pump Station purchases electricity from SDG&E based on their AL-TOU rate schedule. AL-TOU is an optional time-of-use schedule available to common use and metered non- residential customers whose monthly maximum demand exceeds 20 kW. The "A" is a designation for industrial users and the "L" denotes a rate structure. TOU stands for *Time of Use*, which refers to the fact that energy and demand charges are based on the time of day electricity is used: On-Peak, Semi-Peak, and Off-Peak demand. This schedule charges customers based on the following seasonal time periods:

	May 1 – September 30	All Other
On-Peak	11 am – 6 pm Weekdays	5 pm – 8 pm Weekdays
Semi-Peak	6 am – 11 am Weekdays	6 am – 5 pm Weekdays
	6 pm – 10 pm Weekdays	8 pm to 10 pm Weekdays
Off-Peak	10 pm – 6 am Weekdays	10 pm – 6 am Weekdays
	Plus Weekends and Holidays	Plus Weekends and Holidays

Along with the Basic Service Fees, customers are charged for the energy they demand (kW) and use (kWh). Demand is the amount of energy a customer is using at any one time. There are several components that make up the Demand and Energy rates charged by SDG&E: Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component. A summary of the AL-TOU rate schedule is presented in Table 1. It should be noted that, under this rate schedule, Non-Coincident demand charges are based on the higher of the maximum monthly demand or 50 percent of the maximum annual demand. This can severely affect a facility that has one month of excessive demand because Non-Coincident charges are $15.20/kW, nearly double the amount of summer on-peak demand charges ($7.92/kW).

Table 1. SDG&E Rate Schedule: AL-TOU

		AL-TOU	
		Energy ($/kWh)	Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.01138	7.67
	Semi-Peak	0.00874	--
	Off-Peak	0.00799	--
Winter (Oct. 1 to April 30)	On-Peak	0.01035	4.75
	Semi-Peak	0.00874	--
	Off-Peak	0.00799	--
Non-Coincident		--	13.63
Source: SDG&E website, January 2012			

3. Energy Conservation Opportunities

Table 2 lists potential ECOs recommended for further evaluation.

Table 2. Recommended Energy Conservation Opportunities

ECO Opportunity	ECO Description	Simple Payback Estimate	Investment Cost Estimate
1	Monitor block loads of support equipment including HVAC, cooling and service water, and compressed air. (Complete an energy assessment after 1-yr of full operation)	Short Term (<5 years)	No Cost Measure

Table 2. Notes

1. Payback Range Estimate: Short Term = <5 years; Mid Term = 5 years to 10 years; Long Term = > 10 years
2. Capital Investment Range Estimate: No Cost Measure = $0; Low Cost Measure <$10,000; Investment Grade Measure >$10,000

4.Photographs

Top Hatch of Pump/Generator Station

Sleeve Valve

Support Equipment - Compressed Air System

ATTACHMENT 4: OLIVENHAIN PUMP STATION

Phase 1 Energy Audit Report

Report of Energy Audit – Phase 1 Summary

Olivenhain Pump Station

San Diego County
Water Authority

February 15, 2012

Prepared for San Diego County Water Authority
4677 Overland Drive
San Diego, California 92123

1. Introduction

On December 13, 2011, an energy audit of San Diego County Water Authority's (Water Authority) Olivenhain Pump Station was conducted by DHK Engineers, Inc (DHK). The Olivenhain Pump Station is located between the Olivenhain Dam and the Olivenhain Water Treatment Plant at 19086 Via Ambiente in Escondido, California. The pump station is an integrated part of the Water Authority's Emergency Storage Project (ESP) and is designed to remain operational after a major earthquake. The primary function of the pump station is to provide untreated water stored in the Olivenhain Reservoir to the Water Authority's Pipeline 5 when imported water supplies are cut off by a major earthquake or other event. Since the pump station's main duty is to operate during an emergency situation, the pump station is rarely operational.

The Olivenhain Pump Station operates three split-case pump trains, each driven by a 2,500-horsepower (hp) medium voltage induction motor. Pump speeds are adjusted by means of variable frequency drives (VFD) driving each motor. The pump station also includes a heating, ventilation, and air conditioning (HVAC) system consisting of two, continuous operation ventilation fans and three high-capacity supply fans operated by VFD. Power at the pump station is backed by a 350-kilowatt (kW) diesel standby generator and an automatic transfer switch. Based on data reviewed, the major equipment (5 hp or greater) is summarized in Table 1.

Table 1. Major Equipment Inventory

No.	Equipment Description	Equipment Size (hp)
1	Pump #1 w VFD (P-100)	2,500
2	Pump #2 w VFD (P-200)	2,500
3	Pump #3 w VFD (P-300)	2,500
4	Sump Pump (SP-3)	10
5	Supply Fan #1 w VFD (SF-1)	30
6	Supply Fan #2 w VFD (SF-2)	30
7	Supply Fan #3 w VFD (SF-3)	30
8	Air Compressor	15
9	Air Compressor	15

2. Utility Analysis

2.1 CURRENT UTILITY USE

Electricity is the only utility consumed at the Olivenhain Pump Station. Electricity usage data and bills from 2009 to present were reviewed. According to this data, it costs the Water Authority approximately $2,500 annually to operate the pump station. Typical annual electricity use and costs are summarized in Table 2 and are described in more detail below. As previously discussed, the pump station's main duty is to operate during an emergency situation and is, therefore, rarely operational. Because of this, flow data for the pump station was not utilized for this study.

Table 2. Annual Utility Summary

Utility	Site Utility Use (common units)	Site Utility Costs	% of Costs
Electricity	20,551 kWh	$2,422	100%
Total		**$2,422**	**100%**

San Diego Gas & Electric (SDG&E) provides electrical energy to the Olivenhain Pump Station. Electrical energy is delivered to the pumps through one onsite transformer and one meter. (SDG&E Meter Number 1823383). Table 3 provides a monthly summary of the electrical energy purchased from SDG&E by the pump station for the 12-month period of November 2010 through October 2011.

Table 3. 2010/2011 Electrical Energy Use

Billing Period	Electrical Energy Use (kWh)	Max Demand (kW)	Electrical Energy Cost ($)
Nov-10	0	0	$58
Dec-10	19,271	816	$1,690
Jan-11	0	0	$58
Feb-11	0	0	$58
Mar-11	0	0	$58
Apr-11	1,280	560	$150
May-11	0	0	$58
Jun-11	0	0	$58
Jul-11	0	0	$58
Aug-11	0	0	$58
Sep-11	0	0	$58
Oct-11	0	0	$58
Total (12 months)	**20,551**	**--**	**$2,422**
Average (12 months)	**1,713**	**115**	**$202**

2.2 *ELECTRICITY RATE SCHEDULE*

The Olivenhain Pump Station purchases electricity from SDG&E based on the PAT-1 Option D, CPP-Default rate schedule, which is a combination of the two rate schedules. PAT-1 is an optional time-of-use schedule available to agriculture and water pumping customers whose maximum monthly demand exceeds 500 kW. "Time-of-use" refers to the fact that energy and demand charges are based on the time of day electricity is used. The PAT-1 schedule allows customers to choose a Demand Charge Option (C through F) which determines when they are charged for On-Peak, Semi-Peak, and Off-Peak demand. Option D of this schedule, which the pump station is currently enrolled, charges customers based on the following seasonal time periods:

Option D	**May 1 – September 30**	**All Other**
On-Peak	1 pm – 3 pm Weekdays	5 pm – 8 pm Weekdays
Semi-Peak	6 am – 1 pm Weekdays	6 am – 5 pm Weekdays
	4 pm – 10 pm Weekdays	8 pm to 10 pm Weekdays

Along with the Basic Service Fees, customers are charged for the energy they demand (kW) and use (kWh). Demand is the amount of energy a customer is using at any one time. There are several components that make up the Demand and Energy rates charged by SDG&E: Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component. A summary of the PAT-1 Option D rate schedule is presented in Table 4.

The Critical Peak Pricing-Default (CPP-D) rate schedule provides customers with the opportunity to manage their electricity costs by either reducing load during peak pricing periods or shifting load from peak pricing periods to lower cost periods. When electric supplies are anticipated to be low, SDG&E contacts the customers enrolled in this plan and requests a reduction in energy consumption. Up to 18 CPP events can be called in a year. SDG&E may call a CPP event when reductions in electricity use by customers are needed during periods of high electric demand or when electric system reliability is in jeopardy. The most dominant triggers are based on *system load* and *temperature*. Customers are notified no later than 3 pm the day before a CPP event will be in effect. CPP events are effective from 11 am to 6 pm during the CPP Event Day. A summary of the PAT-1 Option D with CPP-D rate schedule is presented in Table 4. Note that on CPP event days, energy use is $1.03692/kWh, while on non-event days it is $0.01079/kWh.

Table 4. SDG&E Rate Schedule: PAT-1 Option D with CPP-D

		PAT-1 Option D		CPP-D	
		Energy ($/kWh)	Demand ($/kW)	Energy ($/kWh)	Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.01079	5.80	0.08123	--
	Semi-Peak	0.00919	--	0.06467	--
	Off-Peak	0.00759	--	0.04552	--
Winter (Oct. 1 to April 30)	On-Peak	0.01079	5.06	0.07692	--
	Semi-Peak	0.00919	--	0.07024	--
	Off-Peak	0.00759	--	0.05084	--
CPP Event Days				**1.06282**	--
Capacity Reservation Charge				--	**6.42**
Source: SDG&E website, January 2012					

Customers are provided the option to self-select and reserve a level of generation capacity that would protect that portion of their load from the CPP Event rate. The capacity is reserved at the listed Capacity Reservation Charge rate. All usage that is protected under the customer's capacity reservation is billed at the PAT-1 On-Peak rate for CPP Events occurring on weekdays and the PAT-1 Off-Peak rate for CPP Events occurring on Saturdays, Sundays, and holidays. All usage during a CPP Event that is not protected under the customer's capacity reservation is billed at the CPP-D Period rates. For example, if a customer has a reserved capacity of 300 kW under the CPP-D rate schedule and uses 500 kW during a CPP Event that has occurred on a weekday, the customer would be charged $6.42 for the first 300 kW plus $0.01079/kWh for consumption and the current market rate for the extra 200 kW plus $1.06282/kWh for consumption.

An Energy Rate Analysis was performed by the Water Authority and SDG&E in 2011 for Water Authority facilities that typically consume large amounts of energy. The purpose of the study was to analyze SDG&E rate alternatives for each facility to determine whether or not the facility could benefit from changing rate schedules. The Energy Rate Analysis recommended that the Olivenhain Pump Station remain on its current rate schedule.

An all-inclusive average electrical energy rate was calculated by dividing the previous 12 months of electrical energy costs by the previous 12 months of electrical energy use. An all-inclusive average energy rate of $0.118/kWh was calculated for the pump station and is presented in Table 5. The all-inclusive average electrical energy rate will be utilized in Energy Conservation Opportunity (ECO) calculations.

Table 5. 2010/2011 Electrical Energy Use and Rates to Be Utilized for ECO Cost Impact for the Site

	Electrical Energy Use & Costs	Electrical Energy Demand Use & Costs	Other Costs	Total Electric Use & Costs
2010/2011 Use (12 months)	20,551 kWh/yr	--	--	--
2010/2011 Cost (12 months)	$1,488 /yr	$115 /yr	$819 /yr	$2,422 /yr
All Inclusive Rate Used for ECO Calculations	**$0.118 /kWh**			

2.3 *ENERGY BASELINE*

Figure 1 illustrates the pump station's energy use and total cost for the 12-month period from November 2010 through October 2011. A brief reliability check was performed on the pumps during December of 2010, which can be seen on the figure. This figure also shows that the baseline energy cost for the pump station is about $58 per month, which represents the Basic Service Fee ($58.22/month) charged by SDG&E under the PAT-1 rate schedule.

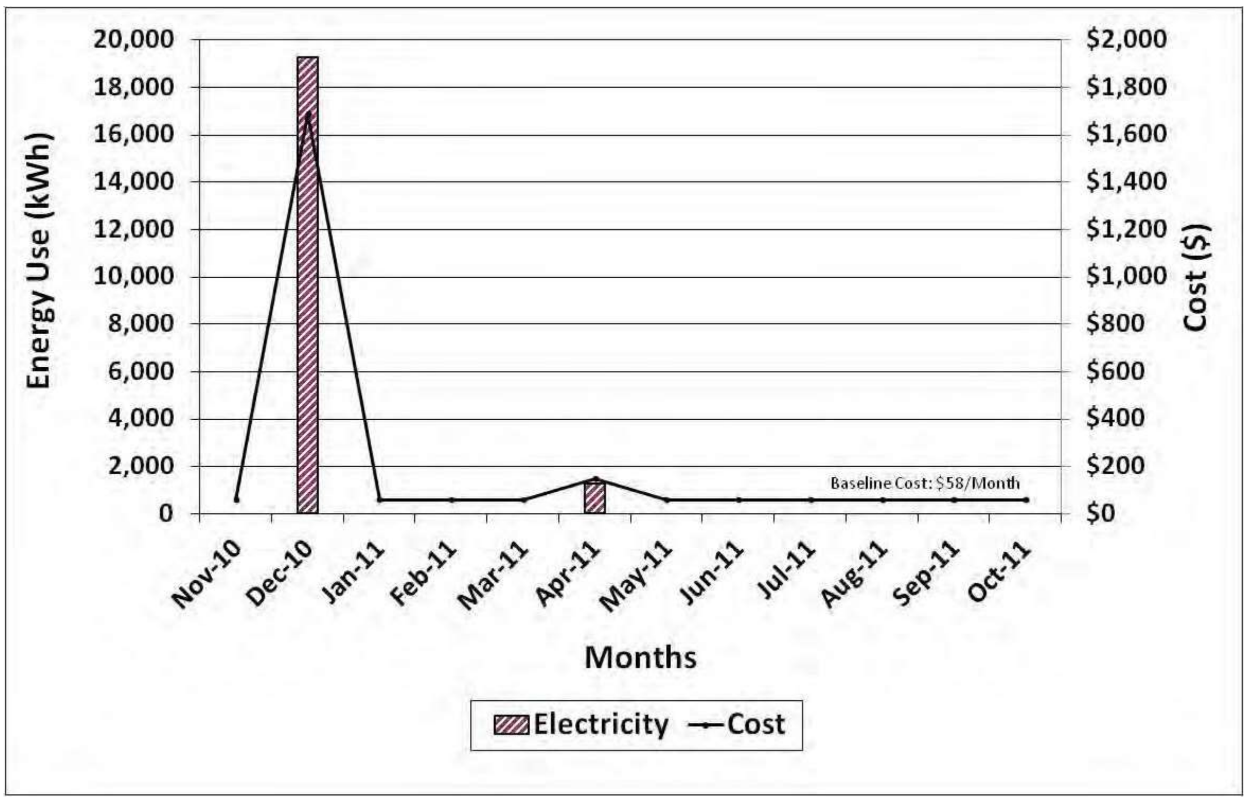

Figure 1. 2010/2011 Energy Use and Cost Breakdown

Figure 2 illustrates the pump station's energy costs for the 12-month period from November 2010 through October 2011. Similar to Figure 1, this figure shows that the pump station was rarely operational during the 12-month period reviewed.

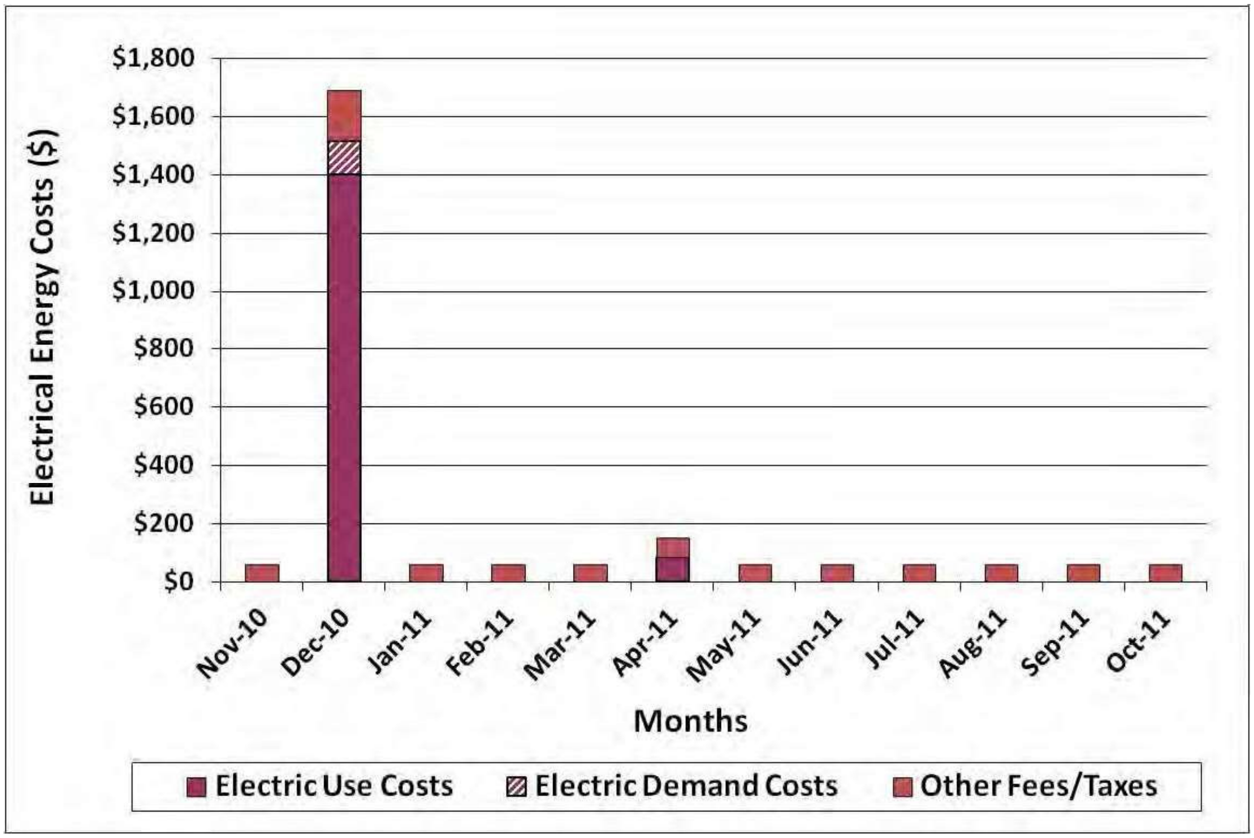

Figure 2. 2010/2011 Energy Cost Breakdown

3. Energy Conservation Opportunities

Table 6 lists potential ECOs recommended for further evaluation.

Table 6. Recommended Energy Conservation Opportunities

ECO Opportunity	ECO Description	Simple Payback Estimate	Investment Cost Estimate
1	Adjust HVAC and lighting controls for as-needed operations	Short Term (<5 years)	No Cost Measure

Table 6. Notes

1. Payback Range Estimate: Short Term = <5 years; Mid Term = 5 years to 10 years; Long Term = > 10 years
2. Capital Investment Range Estimate: No Cost Measure = $0; Low Cost Measure <$10,000; Investment Grade Measure >$10,000

4.Photographs

Pump/Motor

Pressure Control Valve

Cooling Water System

ATTACHMENT 5: RANCHO PENASQUITOS PRESSURE CONTROL/HYDROELECTRIC FACILITY

Phase 1 Energy Audit Report

Report of Energy Audit – Phase 1 Summary

Rancho Penasquitos Pressure Control Hydro Electric Facility

San Diego County Water Authority

February 15, 2012

Prepared for San Diego County Water Authority
4677 Overland Drive
San Diego, California 92123

1.Introduction

On December 7, 2011, an energy audit of San Diego County Water Authority's (Water Authority) Rancho Penasquitos Pressure Control Hydro-Electric Facility (PCHF) was conducted by Water Authority staff (Greg Ortega) and was led by Donald King of DHK Engineers, Inc (DHK). The Rancho Penasquitos PCHF is located at 12298 Alemania Road in San Diego, California. The facility pressurizes a 22-mile-long section of the Water Authority's Pipeline 5 between San Marcos and Mira Mesa.

Pipeline 5 is a 108-inch diameter pipeline that conveys imported water in one direction only, from north to south, by the force of gravity. This limits the Water Authority's ability to move water around the county when imported supplies are curtailed. Enhancements to the pipeline system, including control valves in the Rancho Penasquitos PCHF, a new pump station at San Vicente, and the San Vicente Pipeline, allows Pipeline 5 to transport water either north or south using water stored at the San Vicente Reservoir, improving pipeline operations and keeping water flowing to member agencies.

The high-pressure flows in Pipeline 5 provide an opportunity to generate a clean renewable energy resource for San Diego County. The Rancho Penasquitos PCHF's 4.5-megawatt turbine/generator is capable of operating year-round; however, since flows must be flowing through the turbine in a specific direction, it is only available for generation during four of the facility's nine operating modes. Based on data reviewed, the major equipment (5 hp or greater) is summarized in Table 1.

Table 1. Major Equipment Inventory

No.	Equipment Description	Equipment Size (hp)
1	Cooling Water Pump #1 (CWP-111)	10
2	Cooling Water Pump #2 (CWP-112)	10
3	Drainage Pump	10
4	Supply and Exhaust Fans	1,2

2. Utility Analysis

2.1 CURRENT UTILITY USE

Electricity is the only utility consumed at the Rancho Penasquitos PCHF. Electricity usage data and bills from 2009 to present were reviewed. According to this data, it costs the Water Authority approximately $23,000 annually to operate the facility. Typical annual electricity use and costs are summarized in Table 2 and are described in more detail below. Since the facility only generates energy during four of its nine operating modes, monthly energy generation is inconsistent; therefore, energy generated by the facility was not taken into consideration for this report.

Table 2. Annual Utility Summary

Utility	Site Utility Use (common units)	Site Utility Costs	% of Costs
Electricity	59,893 kWh	$22,569	100%
Total		**$22,569**	**100%**

San Diego Gas & Electric (SDG&E) provides electrical energy to the Rancho Penasquitos PCHF. The electrical energy is delivered through one onsite transformer and one meter (SDG&E Meter Number 1852060). Table 3 provides a monthly summary of the electrical energy purchased from SDG&E by the facility for the 12-month period of November 2010 through October 2011.

Table 3. 2010/2011 Electrical Energy Use

Billing Period	Electrical Energy Use (kWh)	Max Demand (kW)	Electrical Energy Cost ($)
Nov-10	5,000	29	$1,121
Dec-10	5,030	24	$1,057
Jan-11	9,115	173	$3,440
Feb-11	7,072	19	$2,092
Mar-11	6,930	24	$2,060
Apr-11	8,934	24	$2,210
May-11	8,879	24	$2,255
Jun-11	7,754	24	$2,208
Jul-11	0	0	$1,405
Aug-11	0	0	$1,405
Sep-11	321	24	$1,625
Oct-11	858	19	$1,691
Total (12 months)	**59,893**	**--**	**$22,569**
Average (12 months)	**4,991**	**32**	**$1,881**

2.2 Electricity Rate Schedule

The Rancho Penasquitos PCHF purchases electricity from SDG&E based on their AL-TOU, CPP-Default rate schedule, which is a combination of two rate schedules. AL-TOU is an optional time-of-use schedule available to common use and metered non-residential customers whose monthly maximum demand exceeds 20 kW. The "A" is a designation for industrial users and the "L" denotes a rate structure. TOU stands for *Time of Use*, which refers to the fact that energy and demand charges are based on the time of day electricity is used: On-Peak, Semi-Peak, and Off-Peak demand. This schedule charges customers based on the following seasonal time periods:

	May 1 – September 30	All Other
On-Peak	11 am – 6 pm Weekdays	5 pm – 8 pm Weekdays
Semi-Peak	6 am – 11 am Weekdays	6 am – 5 pm Weekdays
	6 pm – 10 pm Weekdays	8 pm to 10 pm Weekdays
Off-Peak	10 pm – 6 am Weekdays	10 pm – 6 am Weekdays
	Plus Weekends and Holidays	Plus Weekends and Holidays

Along with the Basic Service Fees, customers are charged for the energy they demand (kW) and use (kWh). Demand is the amount of energy a customer is using at any one time. There are several components that make up the Demand and Energy rates charged by SDG&E: Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component. It should be noted that, under the AL-TOU rate schedule, Non-Coincident demand charges are based on the higher of the maximum monthly demand or 50 percent of the maximum annual demand. This can severely

affect a facility that has one month of excessive demand because Non-Coincident charges are $13.63/kW, nearly double the amount of summer on-peak demand charges ($7.67/kW).

The Critical Peak Pricing-Default (CPP-D) rate schedule provides customers with the opportunity to manage their electricity costs by either reducing load during peak pricing periods or shifting load from peak pricing periods to lower cost periods. When electric supplies are anticipated to be low, SDG&E contacts the customers enrolled in this plan and requests a reduction in energy consumption. Up to 18 CPP events can be called in a year. SDG&E may call a CPP event when reductions in electricity use by customers are needed during periods of high electric demand or when electric system reliability is in jeopardy. The most dominant triggers are based on *system load* and *temperature*. Customers are notified no later than 3 pm the day before a CPP event will be in effect. CPP events are effective from 11 am to 6 pm during the CPP Event Day. A summary of the AL-TOU with CPP-D rate schedule is presented in Table 4. Note that on CPP event days, energy use is $1.06282/kWh, while on non-event days it is $0.01138/kWh.

Table 4. SDG&E Rate Schedule: AL-TOU with CPP-D

		AL-TOU		CPP-D	
		Energy ($/kWh)	Demand ($/kW)	Energy ($/kWh)	Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.01138	7.67	0.08123	--
	Semi-Peak	0.00874	--	0.06467	--
	Off-Peak	0.00799	--	0.04552	--
Winter (Oct. 1 to April 30)	On-Peak	0.01035	4.75	0.07692	--
	Semi-Peak	0.00874	--	0.07024	--
	Off-Peak	0.00799	--	0.05084	--
Non-Coincident		**--**	**13.63**		
CPP Event Days				**1.06282**	**--**
Capacity Reservation Charge				**--**	**6.42**
Source: SDG&E website, January 2012					

Customers are provided the option to self-select and reserve a level of generation capacity that would protect that portion of their load from the CPP Event rate. The capacity is reserved at the listed Capacity Reservation Charge rate. All usage that is protected under the customer's capacity reservation is billed at the PAT-1 On-Peak rate for CPP Events occurring on weekdays and the PAT-1 Off-Peak rate for CPP Events occurring on Saturdays, Sundays, and holidays. All usage during a CPP Event that is not protected under the customer's capacity reservation is billed at the CPP-D Period rates. For example, if a customer has a reserved capacity of 300 kW under the CPP-D rate schedule and uses 500 kW during a CPP Event that has occurred on a weekday, the customer would be charged $6.42 for the first 300 kW plus $0.01138/kWh for consumption and the current market rate for the extra 200 kW plus $1.06282/kWh for consumption.

An Energy Rate Analysis was performed by the Water Authority and SDG&E in 2011 for Water Authority facilities that typically consume large amounts of energy. The purpose of the study was to analyze SDG&E rate alternatives for each facility to determine whether or not the facility could benefit from changing rate schedules. The Energy Rate Analysis recommended that the Rancho Penasquitos PCHF remain on its current rate schedule.

An all-inclusive average electrical energy rate was calculated by dividing the previous 12 months of electrical energy costs by the previous 12 months of electrical energy use. An all-inclusive average energy rate of $0.922/kWh was calculated for the facility and is presented in Table 5. The all-inclusive average electrical energy rate will be utilized in Energy Conservation Opportunity (ECO) calculations.

Table 5. 2010/2011 Electrical Energy Use and Rates to Be Utilized for ECO Cost Impact for the Site

	Electrical Energy Use & Costs	Electrical Energy Demand Use & Costs	Other Costs	Total Electric Use & Costs
2010/2011 Use (12 months)	59,893 kWh/yr	--	--	--
2010/2011 Cost (12 months)	$4,335 /yr	$15,960 /yr	$2,273 /yr	$22,569 /yr
All Inclusive Rate Used for ECO Calculations	**$0.922 /kWh**			

2.3 *ENERGY BASELINE*

Figure 1 illustrates the facility's energy use and total cost for the 12-month period from November 2010 through October 2011. The figure shows that the facility typically consumed 5,000 to 9,000 kWh of electricity during most of the year. This consumption can be attributed to the turbine's cooling water system which operates continuously, rather the turbine is operational or not.

This figure also shows that the baseline energy cost for the facility is approximately $1,500 per month, even when the facility doesn't consume any energy (as seen in July and August 2011). The reason for this baseline cost is the AL-TOU rate schedule. Based on the rate schedule, the facility is charged a Non-Coincident demand charge which is based on the higher of the maximum monthly demand or 50 percent of the maximum annual demand.

In this case, the facility demand in January 2011 was 173 kW (see Table 3). Based on the rate schedule, the facility was charged for 50 percent of this demand (86 kW) for the rest of the year, even though it never used more than 24 kW the rest of the year.

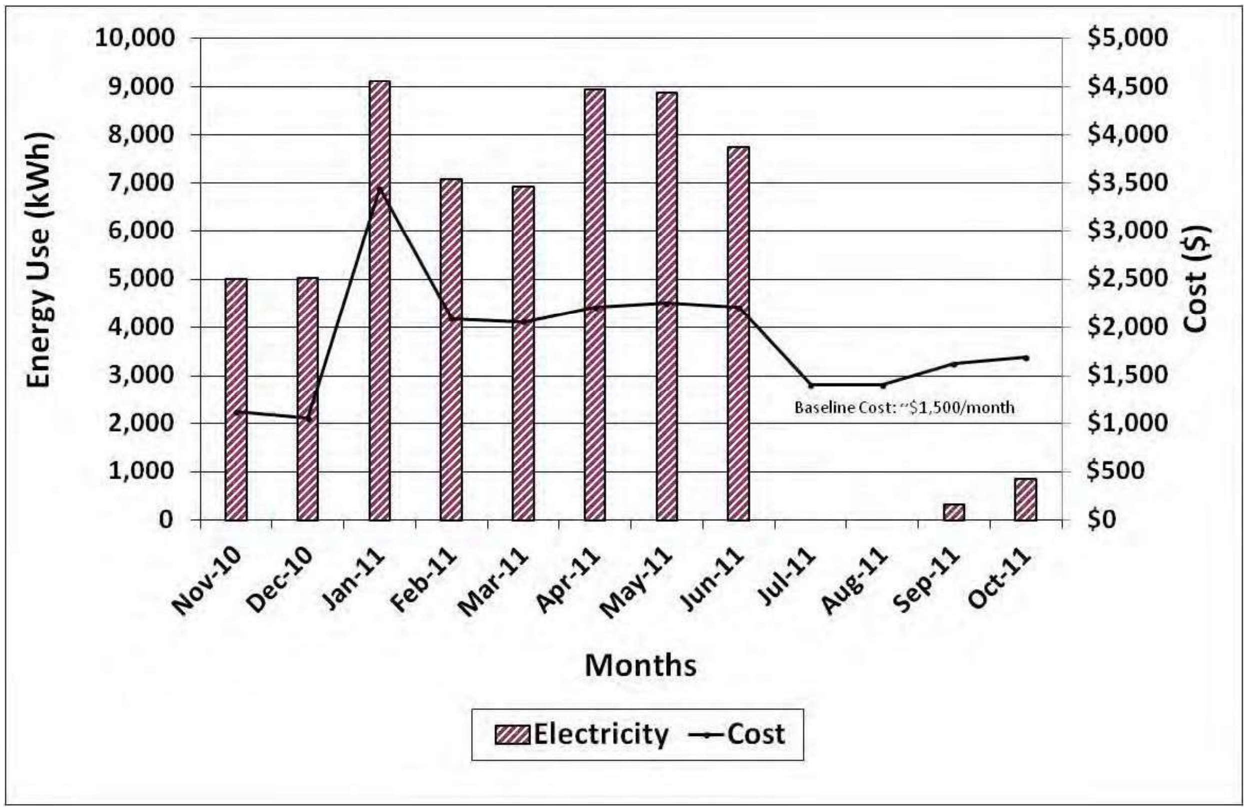

Figure 1. 2010/2011 Energy Use and Cost Breakdown

Figure 2 illustrates the facility's energy costs for the 12-month period from November 2010 through October 2011. This figure further illustrates the effect of the Non-Coincident demand charges discussed above.

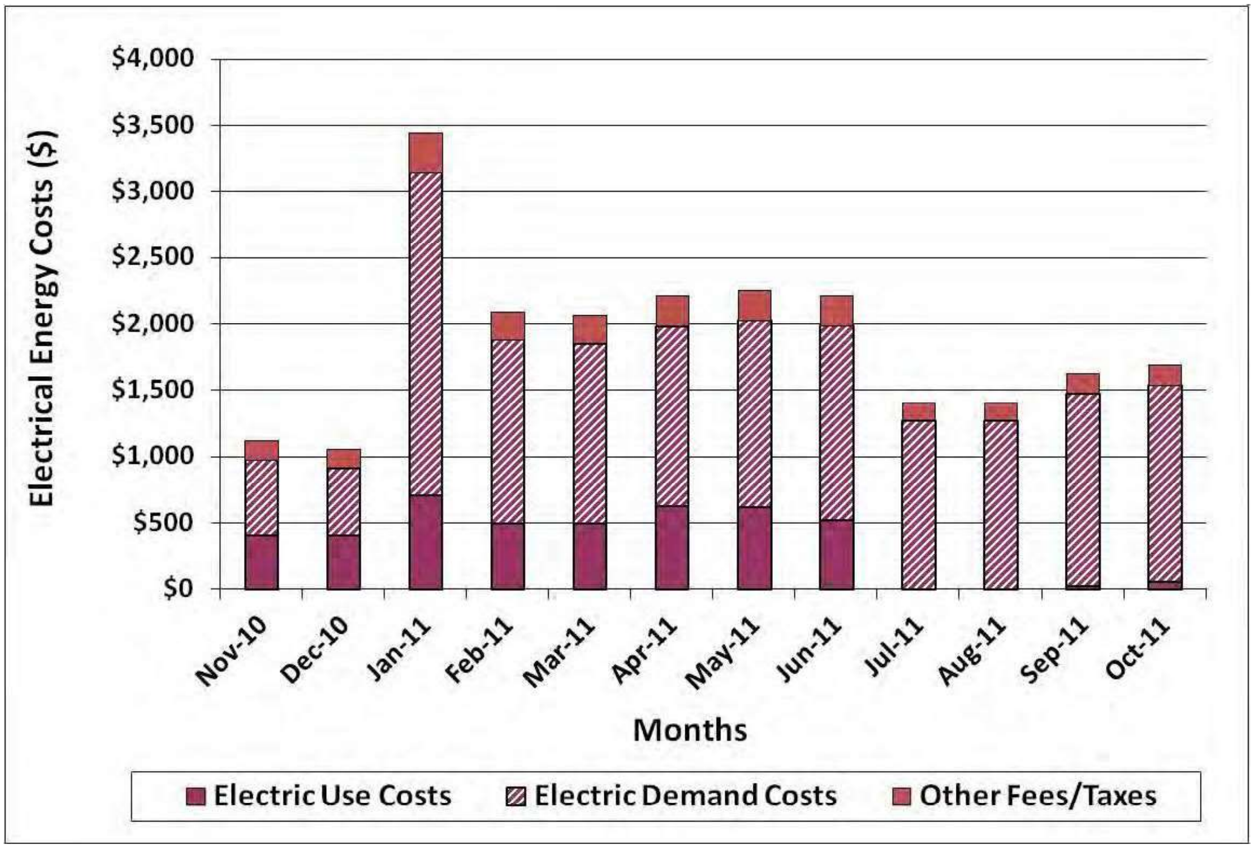

Figure 2. 2010/2011 Energy Cost Breakdown

3.Energy Conservation Opportunities

Table 6 lists potential ECOs recommended for further evaluation.

Table 6. Recommended Energy Conservation Opportunities

ECO Opportunity	ECO Description	Simple Payback Estimate	Investment Cost Estimate
1	Evaluate the need to continuously operate cooling and service water loops for turbine; possibly consider jockey pump if concerned about a no-flow condition (Cost $ 10,000/ Savings $ 2,000)	Short Term (<5 years)	Investment Grade Measure (>$10,000)
2	Install cycle timers for manual light switches (Cost $1,000/ Savings $200/yr)	Short Term (<5 years)	Low Cost Measure (<$10,000)

Table 6. Notes

1. Payback Range Estimate: Short Term = <5 years; Mid Term = 5 years to 10 years; Long Term = > 10 years
2. Capital Investment Range Estimate: No Cost Measure = $0; Low Cost Measure <$10,000; Investment Grade Measure >$10,000

4.Photographs

	
Interior View	**Turbine**

ATTACHMENT 6: SAN DIEGO OFFICE

Phase 1 Energy Audit Report

Report of Energy Audit – Phase 1 Summary

San Diego Office

San Diego County
Water Authority

February 15, 2012

Prepared for San Diego County Water Authority
4677 Overland Drive
San Diego, California 92123

1. Introduction

On December 15, 2011, an energy audit of San Diego County Water Authority's (Water Authority) San Diego Office was conducted by Gary Tannahill (Water Authority) and was led by Donald King of DHK Engineers, Inc (DHK). The San Diego Office is located at 4677 Overland Avenue in the Kearny Mesa neighborhood of San Diego, California.

The main function of the Water Authority's San Diego Office is to provide administration and training facilities for its staff. The facility has a facility manager and energy management system to support their energy efficiency efforts. Based on data reviewed, the major equipment consists of HVAC, lighting and miscellaneous small load equipment that is categorically summarized in Table 1.

Table 1. Major Equipment Inventory

No.	Equipment Description	Equipment Size (hp)
1	HVAC units	Various
2	Hot water heating	Various
3	Lighting	Various

2. Utility Analysis

2.1 *Current Utility Use*

Electricity and natural gas usage data and bills from 2009 to present were reviewed. A solar system was installed in July 2011. Since this energy audit is focused on optimizing energy demand and consumption, electric data from July 2010 to June 2011 was utilized for this study. According to this data, it costs the Water Authority approximately $184,000 annually to operate the facility. Typical annual electricity and natural gas use and costs are summarized in Table 2 and are described in more detail below.

Table 2. Annual Utility Summary

Utility	Site Utility Use (common units)	Site Utility Costs	% of Costs
Electricity	1,085,608 kWh	$174,588	95%
Natural Gas	9,666 therms	$8,557	5%
Total		**$183,145**	**100%**

As presented in Table 2, electricity accounts for 95 percent of the annual energy costs at the facility, and therefore, will be the focus of this report. It should be noted that the facility installed a 441.1-kilowatt (kW) solar system that went online in July 2011. Since this energy audit is focused on optimizing energy demand and consumption at the facility, the solar system is not considered in this report. However, the solar system is projected to provide approximately 676 megawatt-hours (MWh) of electricity per year.

San Diego Gas & Electric (SDG&E) provides electrical energy to the San Diego Office. The electrical energy is delivered through one onsite transformer and one meter (SDG&E Meter Number 1969028). Table 3 provides a monthly summary of the electrical energy purchased from SDG&E by the facility for the 12-month period of July 2010 through June 2011.

Table 3. 2010/2011 Electrical Energy Use

Billing Period	Electrical Energy Use (kWh)	Max Demand (kW)	Electrical Energy Cost ($)
Jul-10	94,821	302	$15,493
Aug-10	95,692	304	$18,248
Sep-10	102,121	343	$20,730
Oct-10	88,552	262	$13,805
Nov-10	89,803	292	$14,050
Dec-10	84,014	243	$12,917
Jan-11	84,533	256	$12,810
Feb-11	89,360	231	$12,653
Mar-11	83,797	250	$12,531
Apr-11	85,396	245	$12,591
May-11	98,136	270	$14,736
Jun-11	89,383	262	$14,023
Total (12 months)	**1,085,608**	**--**	**$174,588**
Average (12 months)	**90,467**	**272**	**$14,549**

2.2 *ELECTRICITY RATE SCHEDULE*

The San Diego Office purchases electricity from SDG&E based on their AL-TOU, CPP-Default rate schedule, which is a combination of two rate schedules. AL-TOU is an optional time-of-use schedule available to common use and metered non-residential customers whose monthly maximum demand exceeds 20 kW. The "A" is a designation for industrial users and the "L" denotes a rate structure. TOU stands for *Time of Use*, which refers to the fact that energy and demand charges are based on the time of day electricity is used: On-Peak, Semi-Peak, and Off-Peak demand. This schedule charges customers based on the following seasonal time periods:

	May 1 – September 30	All Other
On-Peak	11 am – 6 pm Weekdays	5 pm – 8 pm Weekdays
Semi-Peak	6 am – 11 am Weekdays	6 am – 5 pm Weekdays
	6 pm – 10 pm Weekdays	8 pm to 10 pm Weekdays
Off-Peak	10 pm – 6 am Weekdays	10 pm – 6 am Weekdays
	Plus Weekends and Holidays	Plus Weekends and Holidays

Along with the Basic Service Fees, customers are charged for the energy they demand (kW) and use (kWh). Demand is the amount of energy a customer is using at any one time. There are several components that make up the Demand and Energy rates charged by SDG&E: Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component. It should be noted that, under the AL-TOU rate schedule, Non-Coincident demand charges are based on the higher of the maximum monthly demand or 50 percent of the maximum annual demand. This can severely

affect a facility that has one month of excessive demand because Non-Coincident charges are $13.63/kW, nearly double the amount of summer on-peak demand charges ($7.67/kW).

The Critical Peak Pricing-Default (CPP-D) rate schedule provides customers with the opportunity to manage their electricity costs by either reducing load during peak pricing periods or shifting load from peak pricing periods to lower cost periods. When electric supplies are anticipated to be low, SDG&E contacts the customers enrolled in this plan and requests a reduction in energy consumption. Up to 18 CPP events can be called in a year. SDG&E may call a CPP event when reductions in electricity use by customers are needed during periods of high electric demand or when electric system reliability is in jeopardy. The most dominant triggers are based on *system load* and *temperature*. Customers are notified no later than 3 pm the day before a CPP event will be in effect. CPP events are effective from 11 am to 6 pm during the CPP Event Day. A summary of the AL-TOU with CPP-D rate schedule is presented in Table 4. Note that on CPP event days, energy use is $1.06282/kWh, while on non-event days it is $0.01138/kWh.

Table 4. SDG&E Rate Schedule: AL-TOU with CPP-D

		AL-TOU		CPP-D	
		Energy ($/kWh)	Demand ($/kW)	Energy ($/kWh)	Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.01138	7.67	0.08123	--
	Semi-Peak	0.00874	--	0.06467	--
	Off-Peak	0.00799	--	0.04552	--
Winter (Oct. 1 to April 30)	On-Peak	0.01035	4.75	0.07692	--
	Semi-Peak	0.00874	--	0.07024	--
	Off-Peak	0.00799	--	0.05084	--
Non-Coincident		--	13.63		
CPP Event Days				**1.06282**	**--**
Capacity Reservation Charge				**--**	**6.42**
Source: SDG&E website, January 2012					

Customers are provided the option to self-select and reserve a level of generation capacity that would protect that portion of their load from the CPP Event rate. The capacity is reserved at the listed Capacity Reservation Charge rate. All usage that is protected under the customer's capacity reservation is billed at the PAT-1 On-Peak rate for CPP Events occurring on weekdays and the PAT-1 Off-Peak rate for CPP Events occurring on Saturdays, Sundays, and holidays. All usage during a CPP Event that is not protected under the customer's capacity reservation is billed at the CPP-D Period rates. For example, if a customer has a reserved capacity of 300 kW under the CPP-D rate schedule and uses 500 kW during a CPP Event that has occurred on a weekday, the customer would be charged $6.42 for the first 300 kW plus $0.01138/kWh for consumption and the current market rate for the extra 200 kW plus $1.06282/kWh for consumption.

An Energy Rate Analysis was performed by the Water Authority and SDG&E in 2011 for Water Authority facilities that typically consume large amounts of energy. The purpose of the study was to analyze SDG&E rate alternatives for each facility to determine whether or not the facility could benefit from changing rate schedules. The Energy Rate Analysis recommended that the San Diego Office remain on its current rate schedule.

An all-inclusive average electrical energy rate was calculated by dividing the previous 12 months of electrical energy costs by the previous 12 months of electrical energy use. An all-inclusive average energy rate of $0.161/kWh was calculated for the facility and is presented in Table 5. The all-inclusive average electrical energy rate will be utilized in Energy Conservation Opportunity (ECO) calculations.

Table 5. 2010/2011 Electrical Energy Use and Rates to Be Utilized for ECO Cost Impact for the Site

	Electrical Energy Use & Costs	Electrical Energy Demand Use & Costs	Other Costs	Total Electric Use & Costs
2010/2011 Use (12 months)	1,085,608 kWh/yr	--	--	--
2010/2011 Cost (12 months)	$91,792 /yr	$66,296 /yr	$16,501 /yr	$174,588 /yr
All Inclusive Rate Used for ECO Calculations	**$0.161 /kWh**			

2.3 ENERGY BASELINE

Figure 1 illustrates the facility's actual energy use for the 12-month period from July 2010 through June 2011. Figure 1 shows that energy use is relatively consistent throughout the year. Electric costs are also relatively consistent throughout the year with the exception of August and September of 2010. As seen in Table 3, Maximum Demand for the facility increased during these months, causing the energy costs to increase as well.

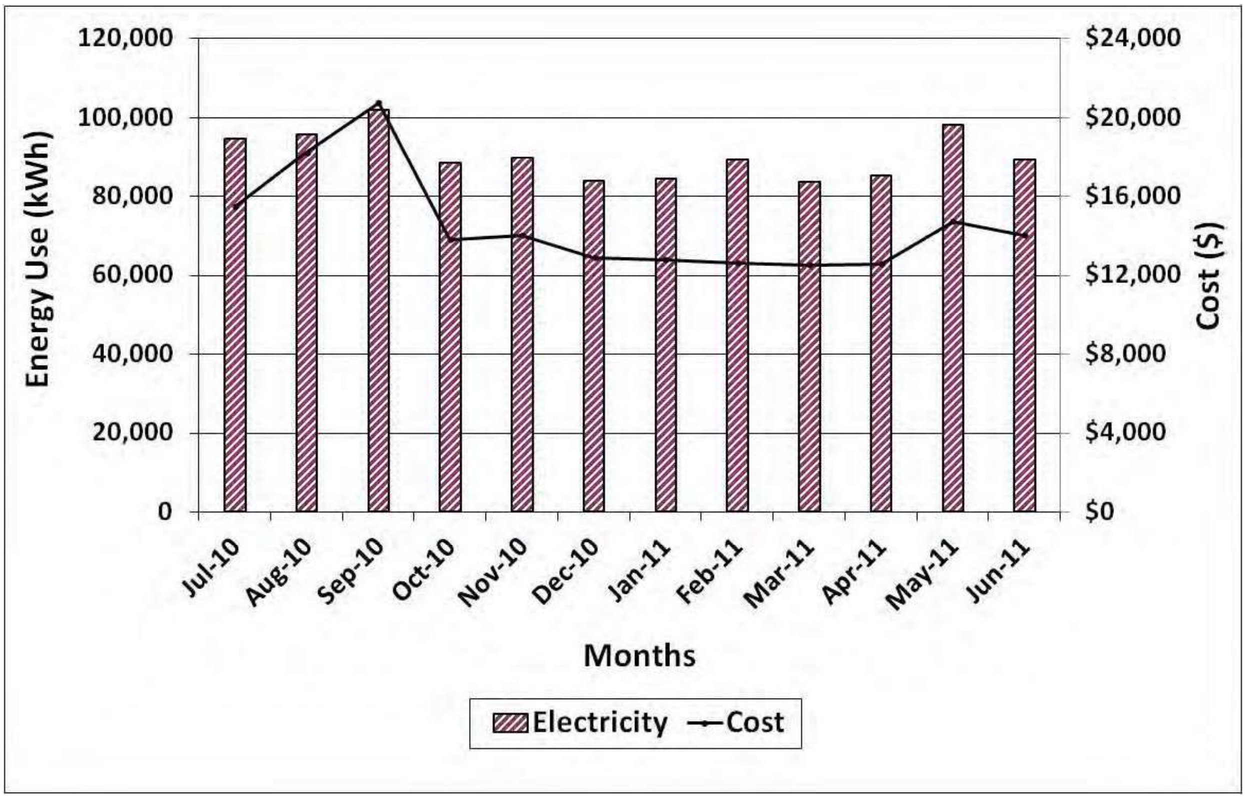

Figure 1. 2010/2011 Energy Use and Cost Breakdown

Figure 2 illustrates the facility's energy costs for the 12-month period from July 2010 through June 2011. This figure shows that the facility energy charges were consistent throughout the 12-month period, except for the months of August and September 2010. As seen in Table 3, Maximum Demand for the facility increased during these months, causing the energy costs to increase as well.

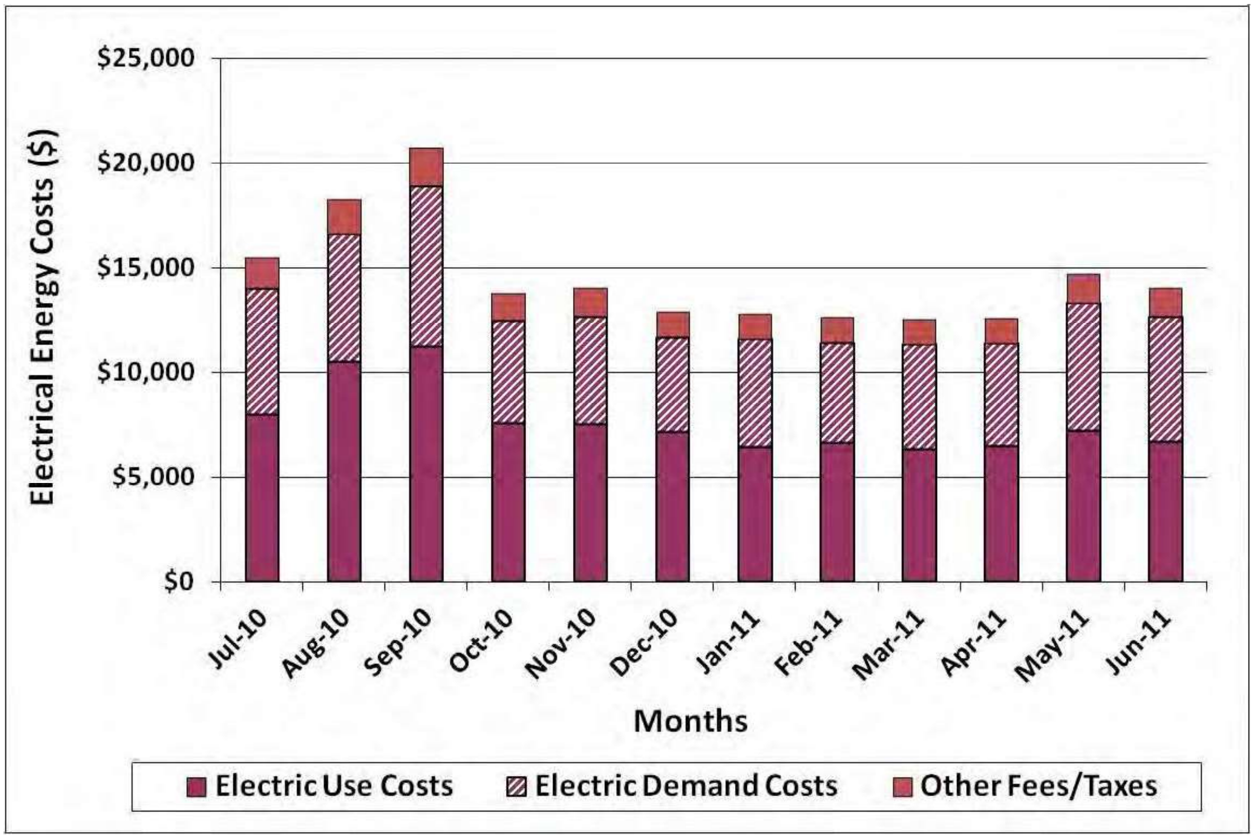

Figure 2. 2010/2011 Energy Cost Breakdown

3. Energy Conservation Opportunities

Table 6 lists potential ECOs recommended for further evaluation.

Table 6. Recommended Energy Conservation Opportunities

ECO Opportunity	ECO Description	Simple Payback Estimate	Investment Cost Estimate
1	Install boiler hot water low-flow (jockey) pump (2-hp) to circulate minimal flow during building off-hours (Cost $ 12,000/ Savings $3,000)	Short Term (<5 years)	Investment Grade Measure (>$10,000)
2	Allow setback of hot water system temperature during off-hours from 120°F to 90°F (Cost $0/ $600/yr)	Short Term (<5 years)	No Cost Measure

Table 6. Notes

1. Payback Range Estimate: Short Term = <5 years; Mid Term = 5 years to 10 years; Long Term = > 10 years
2. Capital Investment Range Estimate: No Cost Measure = $0; Low Cost Measure <$10,000; Investment Grade Measure >$10,000

4.Photographs

	
Exterior View	**Solar System**

	
Rooftop Air Conditioner	**Hot Water Recirculation Pumps**

ATTACHMENT 7: SAN VICENTE PUMP STATION

Phase 1 Energy Audit Report

Report of Energy Audit – Phase 1 Summary

San Vicente Pump Station

San Diego County
Water Authority

February 15, 2012

Prepared for San Diego County Water Authority
4677 Overland Drive
San Diego, California 92123

1. Introduction

On December 7, 2011, an energy audit of San Diego County Water Authority's (Water Authority) San Vicente Pump Station was conducted by Greg Ortega (Water Authority) and was led by Donald King of DHK Engineers, Inc (DHK). The San Vicente Pump Station is located at 12393 Moreno Avenue in Lakeside, California. The pump station draws raw water from the San Vicente Reservoir and discharges it to the Surge Control Facility, where it is distributed to downstream users. The pump station is an integrated part of the Water Authority's Emergency Storage Project (ESP) and is designed to remain operational after a major earthquake. The primary function of the pump station is to provide untreated water stored in the San Vicente Reservoir when imported water supplies are cut off by a major earthquake or other event. Since the pump station's main duty is to operate during an emergency situation, the pump station is rarely operational.

The San Vicente Pump Station consists of three 7,000 horsepower (hp) horizontal, split case, centrifugal pumps controlled by two variable frequency drives (VFD). The pump station is designed for operating conditions at 44 cubic feet per second (cfs) at a pumping head of 350 feet. A closed-loop cooling water system and service water system provide cooling for the VFDs, motors, pump bearings, and supply fans for the heating, ventilation, and air conditioning (HVAC) system. Based on data reviewed, the major equipment (5 hp or greater) is summarized in Table 1.

Table 1. Major Equipment Inventory

No.	Equipment Description	Equipment Size (hp)
1	Pump #1 w VFD (P-100)	7,000
2	Pump #2 w VFD (P-200)	7,000
3	Pump #3 w VFD (P-300)	7,000
4	Cooling Water Pump #1 (CWP-515)	10
5	Cooling Water Pump #2 (CWP-525)	10
6	Cooling Water Pump #3 (CWP-535)	10
7	Cooling Water Pump #4 (CWP-545)	10
8	Service Water Pump #1 (SWP-510)	7.5
9	Service Water Pump #2 (SWP-520)	7.5
10	Service Water Pump #3 (SWP-530)	7.5
11	Service Water Pump #4 (SWP-540)	7.5
12	Supply Fan #1 (SF-610)	5
13	Supply Fan #2 (SF-620)	5
14	Supply Fan #3 (SF-630)	5
15	Supply Fan #4 (SF-640)	5

No.	Equipment Description	Equipment Size (hp)
16	Exhaust Fan #1 (EF-641)	10
17	Exhaust Fan #2 (EF-642)	10
18	Exhaust Fan #3 (EF-680)	10
19	Air Compressor #1 (CMP-801)	15
20	Air Compressor #2 (CMP-802)	15

2. Utility Analysis

2.1 CURRENT UTILITY USE

Electricity is the only utility consumed at the San Vicente Pump Station. Electricity usage data and bills from 2009 to present were reviewed. According to this data, it costs the Water Authority approximately $935,000 annually to operate the pump station. Typical annual electricity use and costs are summarized in Table 2 and are described in more detail below.

Table 2. Annual Utility Summary

Utility	Site Utility Use (common units)	Site Utility Costs	% of Costs
Electricity	6,996,732 kWh	$934,811	100%
Total		**$934,811**	**100%**

San Diego Gas & Electric (SDG&E) provides electrical energy to the San Vicente Pump Station. The electrical energy is delivered through one onsite transformer and one meter (SDG&E Meter Number 1838375). Table 3 provides a monthly summary of the electrical energy purchased from SDG&E by the pump station for the 12-month period of November 2010 through October 2011.

Table 3. 2010/2011 Electrical Energy Use

Billing Period	Electrical Energy Use (kWh)	Max Demand (kW)	Electrical Energy Cost ($)
Nov-10	17,928	2,976	$26,002
Dec-10	14,048	64	$2,095
Jan-11	736,284	3,248	$105,779
Feb-11	1,566,164	7,808	$214,962
Mar-11	26,948	64	$3,152
Apr-11	12,976	64	$1,911
May-11	2,774,956	6,864	$323,480
Jun-11	1,748,424	5,456	$245,196
Jul-11	20,916	48	$2,656
Aug-11	24,784	64	$3,319
Sep-11	25,480	48	$3,041
Oct-11	27,824	64	$3,219
Total (12 months)	**6,996,732**	**--**	**$934,811**
Average (12 months)	**583,061**	**2,231**	**$77,901**

2.2 ELECTRICITY RATE SCHEDULE

As described above, the San Vicente Pump Station purchases electricity from SDG&E based on the PAT-1 Option D rate schedule, which is a combination of the two rate schedules. PAT-1 is an optional time-of-use schedule available to agriculture and water pumping customers whose maximum monthly demand exceeds 500 kW. "Time-of-use" refers to the fact that energy and demand charges are based on the time of day electricity is used. The PAT-1 schedule allows customers to choose a Demand Charge Option (C through F) which determines when they are charged for On-Peak, Semi-Peak, and Off-Peak demand. Option D of this schedule, which the pump station is currently enrolled, charges customers based on the following seasonal time periods:

Option D	**May 1 – September 30**	**All Other**
On-Peak	1 pm – 3 pm Weekdays	5 pm – 8 pm Weekdays
Semi-Peak	6 am – 1 pm Weekdays 4 pm – 10 pm Weekdays	6 am – 5 pm Weekdays 8 pm to 10 pm Weekdays

Along with the Basic Service Fees, customers are charged for the energy they demand (kW) and use (kWh). Demand is the amount of energy a customer is using at any one time. There are several components that make up the Demand and Energy rates charged by SDG&E: Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component. A summary of the PAT-1 Option D rate schedule is presented in Table 4.

Table 4. SDG&E Rate Schedule: PAT-1 Option D

		PAT-1 Option D	
		Energy ($/kWh)	Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.01079	5.80
	Semi-Peak	0.00919	--
	Off-Peak	0.00759	--
Winter (Oct. 1 to April 30)	On-Peak	0.01079	5.06
	Semi-Peak	0.00919	--
	Off-Peak	0.00759	--
Source: SDG&E website, January 2012			

An Energy Rate Analysis was performed by the Water Authority and SDG&E in 2011 for Water Authority facilities that typically consume large amounts of energy. The purpose of the study was to analyze SDG&E rate alternatives for each facility to determine whether or not the facility could benefit from changing rate schedules. The Energy Rate Analysis recommended that the San Vicente Pump Station considers changing to the PAT-1, CPP-D rate schedule.

An all-inclusive average electrical energy rate was calculated by dividing the previous 12 months of electrical energy costs by the previous 12 months of electrical energy use. An all-inclusive average energy rate of $0.241/kWh was calculated for the pump station and is presented in Table 5. The all-

inclusive average electrical energy rate will be utilized in Energy Conservation Opportunity (ECO) calculations.

Table 5. 2010/2011 Electrical Energy Use and Rates to Be Utilized for ECO Cost Impact for the Site

	Electrical Energy Use & Costs	Electrical Energy Demand Use & Costs	Other Costs	Total Electric Use & Costs
2010/2011 Use (12 months)	6,996,732 kWh/yr	--	--	--
2010/2011 Cost (12 months)	$531,992 /yr	$362,222 /yr	$40,597 /yr	$934,811 /yr
All Inclusive Rate Used for ECO Calculations	**$0.241 /kWh**			

2.3 *Energy Baseline*

Figure 1 illustrates the pump station's energy use and total cost for the 12-month period from November 2010 through October 2011. This figure shows that the baseline energy cost for the pump station is about $3,000 per month when the pump station isn't in operation.

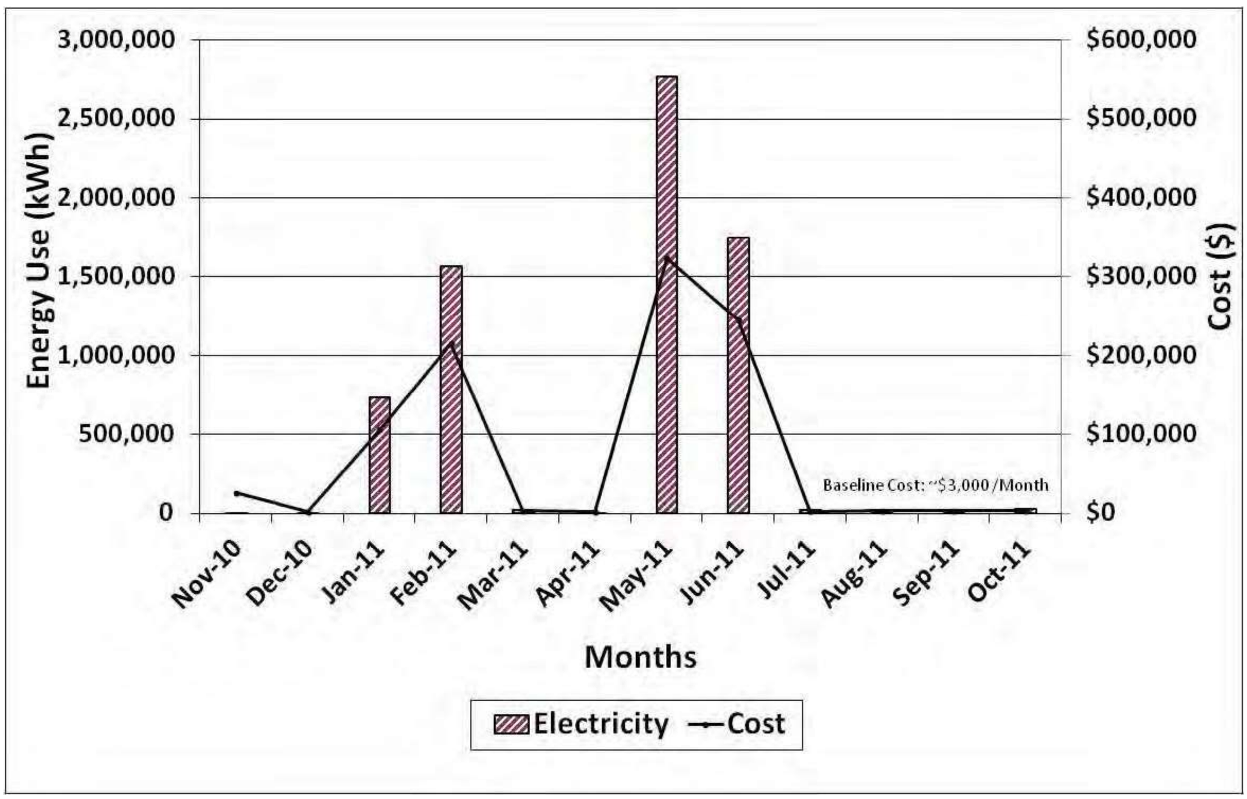

Figure 1. 2010/2011 Energy Use and Cost Breakdown

Figure 2 illustrates the pump station's energy costs for the 12-month period from November 2010 through October 2011. This figure shows the pump station energy charges based on usage, demand and other fees. The operational strategy for the pump station is to pump as much water as possible during the billing cycle once the pump station is called into service and the "demand charge" as been tripped for the month. When the station is in idle mode, a base demand charge of 48/64 is assessed. The base load is a combination of pump cooling and service water pump operations. This figure illustrates the On-Off nature of the pump station and the four months during the year that the pump station was operational.

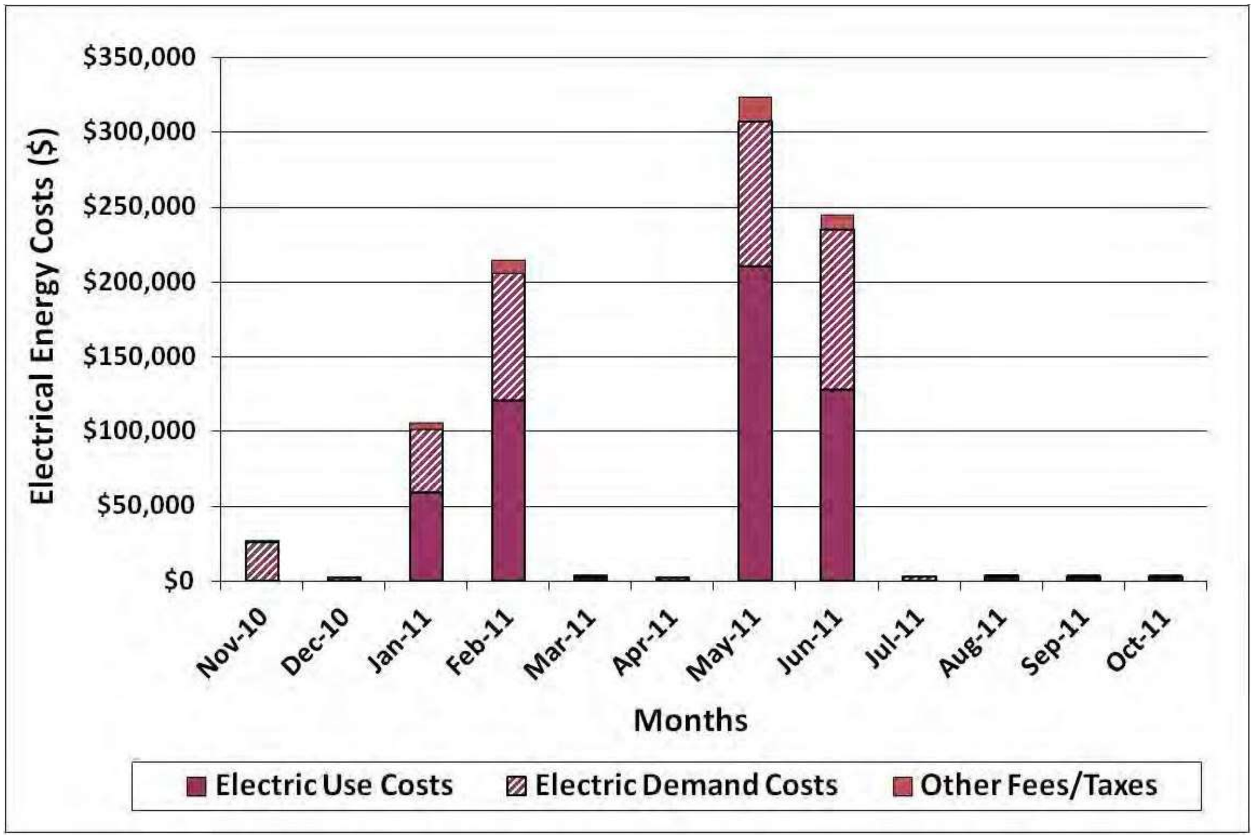

Figure 2. 2010/2011 Energy Cost Breakdown

3. Energy Conservation Opportunities

Table 6 lists potential ECOs recommended for further evaluation.

Table 6. Recommended Energy Conservation Opportunities

ECO Opportunity	ECO Description	Simple Payback Estimate	Investment Cost Estimate
1	Evaluate SDG&Es recommendation to change to the PA, CPP-D rate schedule	Short Term (<5 years)	No Cost Measure
2	Adjust HVAC and lighting controls for as needed operations (Cost $3,000/ Savings $ 1,000)	Short Term (<5 years)	Low Cost Measure (<$10,000)
3	Evaluate the need for continuous operation of cooling and service water loops; possible jockey pump installation if concerned about a no-flow condition (Cost Study $5,000 SDGE funded) (Construction cost of jockey pump or VFD $20,000/ Savings $3,000)	Mid Term (5years to 10 years)	Investment Grade Measure (>$10,000)

Table 6. Notes

1. Payback Range Estimate: Short Term = <5 years; Mid Term = 5 years to 10 years; Long Term = > 10 years
2. Capital Investment Range Estimate: No Cost Measure = $0; Low Cost Measure <$10,000; Investment Grade Measure >$10,000

4.Photographs

Booster Pumps

Service Water Pump

Service/Cooling Water Panel

ATTACHMENT 8: TWIN OAKS VALLEY WATER TREATMENT PLANT

Phase 1 Energy Audit Report

February 2012

San Diego County Water Authority
4677 Overland Drive
San Diego, California 92123

Subject: **Report of Energy Audit – Phase 1**
Twin Oaks Valley Water Treatment Plant

DHK Engineers, Inc. has performed a Phase 1 Energy Audit for the Twin Oaks Valley Water Treatment Plant (TOVWTP) located in San Marcos, California. The purpose of the energy audit was to assess the energy consuming processes at the facility, provide San Diego County Water Authority (Water Authority) with energy bill and power use metrics, and identify potential Energy Conservation Opportunities (ECOs). The following table summarizes the recommended ECOs for the TOVWTP. Full details can be found within the attached report.

ECO Opportunity	ECO Description
1	Shift production of NaOCl (sodium hypochlorite) to off-peak periods to the extent possible
2	Confirm and modify SDG&E Rate Schedule (AL-TOU vs. A6-TOU)
3	Adjust dewatering operations (centrifuge) to operate during off-peak periods
4	Sequence and/or install VFDs on Backwash Tank Fill Pumps (20-hp) to pump water to elevated tanks prior to backwash
5	Evaluate continuous recirculation water loop pumps (25-hp constant speed operations)
6	Installation of cycle timers on manual light switches
7	Evaluate installation of high-efficiency centralized compressed air (screw) configuration in lieu of six separate systems
8	Evaluate air receiver for use with air scour blower
9	Evaluate installation of VFD for Return Water Pumps during low flow operations
10	Investigate and implement Demand Management Strategies including addition of Energy Management System (EMS)

Please do not hesitate to call if you have any questions or require further information. Thank you for the opportunity to assist with this project.

Sincerely,

Donald H. King

Donald King, P.E.
DHK Engineers, Inc.

DLP/DHK sky

February 2012

Report of Energy Audit – Phase 1

Twin Oaks Valley Water Treatment Plant
3566 Twin Oaks Valley Road
San Marcos, California 92069

Prepared for San Diego County Water Authority
4677 Overland Drive
San Diego, California 92123

Table of Contents

1. Introduction

The Twin Oaks Valley Water Treatment Plant (TOVWTP) is one of the largest submerged membrane water treatment plants in the world and the first treatment plant built by the San Diego County Water Authority (Water Authority). Construction of the facility began in 2005 and was completed in April 2008. Located next to the Water Authority's aqueduct north of the city of San Marcos, the high-capacity treatment plant can produce up to 100 million gallons (MG) of treated water per day - enough to supply up to 220,000 typical four-person households each year.

Water from rivers and reservoirs can contain a variety of organisms and inorganic material that must be removed at a water treatment plant before the water is safe for drinking and other uses. Treatment plants vary in the specific processes they use, but they generally follow the same basic steps. Larger particles such as sand, vegetation, and other materials must be screened out first. Smaller particles are removed in a later, separate process. To eliminate organisms that can cause disease or unpleasant odors and taste in water, disinfecting chemicals are added. In many treatment plants, water passes through an additional filtering medium such as sand, gravel, carbon, or anthracite, to remove any remaining tiny particles. The last step is to apply an additional, long-lasting disinfectant that will keep water safe and healthy for the days or weeks it may travel through pipelines to reach homes and businesses.

The Water Authority selected the submerged membrane method for treating water at the plant. This method of separating water molecules from contaminants is safe and highly effective in producing high-quality treated water. The membrane treatment, in conjunction with the other processes at the plant, has such a high degree of contaminant removal that the plant will be able to meet increasingly rigorous state and federal water quality regulations.

Water treated at the Twin Oaks Valley Water Treatment Plant is drawn through very fine pores in membrane fibers. The pores are just large enough for water to pass through, but small enough to leave behind contaminants and particles, such as dirt, dust, bacteria, cryptosporidium, giardia, and others. The contaminants that do pass through are eliminated in a disinfection process. In addition, as part of the treatment process, fluoride is added to the treated water.

Treatment Plant Benefits

The TOVWTP is a project with many benefits beyond the high-quality water it produces. Its strategic location, creative design, and use of membrane technology make it an efficient, money-saving facility. Some of the benefits of the TOVWTP include:

- High Volume – Each day 100-million gallons of water can be treated at the facility.
- Scarcely a Drop Wasted – Nearly all water entering the plant leaves as high-quality drinking water.
- Energy and Money Savings – The plant's location next to the Water Authority's existing pipelines made pumping and new pipeline construction unnecessary.
- High Quality – The facility not only meets current regulations, but is prepared to meet more rigorous water quality regulations anticipated in the future.

- Emergency Water Availability – The plant can supply treated water to the region's emergency water system if catastrophe strikes (no water boiling required).

Solar Power

With the tremendous cost associated with the treatment and distribution of water, many water districts are going solar for protection from rising electricity costs. However, while solar electric installations generate significant long-term savings, and material and installation costs have plummeted recently, the initial investment can still be too much for many water districts, big and small. As an alternative to up- front purchases, many organizations are opting for a Power Purchase Agreement (PPA) to finance solar energy projects. Through a PPA, a third-party investor takes on all finance, design, installation, and ownership and maintenance (O&M) costs, and the water district agrees to buy the power back, at a pre- determined and reduced rate. Water districts enjoy the immediate cost-savings and environmental benefits, without paying a dime upfront, while third-party investors bear all financial risk associated with the system. At the end of the contract, the water district has the opportunity to renew the contract or purchase the system outright.

In June 2011, the Water Authority entered into a PPA with Borrego Solar. Enough solar panels to generate over 1-megawatt (MW) of electricity were installed several water storage structures. As part of the agreement, Borrego Solar will continue to maintain, operate and repair the systems as needed, and sell the clean renewable power they produce back to the Water Authority at a set rate (currently $0.14/kWh) with a pre-determined escalator over the course of the 20-year PPA term.

Sustainability

The Water Authority has been on the forefront of energy management and sustainability initiatives. The Water Authority has developed and implemented a comprehensive energy management strategy at the TOVWTP and throughout their distribution systems. Over the past several years, numerous initiatives, projects, and process optimization programs have been successfully executed, resulting in decreasing energy demands and associated costs. Several of the projects and initiatives include:

- Ongoing process adjustments to optimize the various operations and minimize the energy and chemical consumption.
- Initiated a predictive and re-purposed program to evaluate each process area and provide improvement plans to best use and maintain existing Water Authority assets.
- Electrical sub-meter monitoring for several process areas to assist in energy management activities.
- Developed and implemented standard operating procedures (SOP) and highly trained and aware operators proficient in starting and stopping large electrical loads.
- The Water Authority has an excellent relationship with the San Diego Gas and Electric (SDG&E) account representatives and staff closely monitoring rebate and incentive programs.
- Designed the new TOVWTP with a high level of energy and sustainability features as well as a fully integrated solar energy project.

2. Utility Analysis

2.1 *Current Utility Use*

The TOVWTP currently consumes and is billed for two types of utilities: purchased electricity and third party funded solar. Electricity usage data and bills from 2010 to present were reviewed. According to this data, current electrical energy use costs the TOVWTP approximately $825,000 annually.

Based on data reviewed, purchased electrical energy from SDG&E accounts (November 2010 - October 2011) for approximately 84% of the utility bills, while solar generated energy (June - October) accounts for the remaining 16%. Typical annual utility use and costs are summarized in Table 1 and are described in more detail below.

Table 1. Annual Utility Summary

Utility	Site Utility Use (common units)	Site Utility Costs	% of Costs
Electricity (SDG&E)	4,668,508 kWh	$690,967	84%
Electricity (Solar June - October 2011)	942,439 kWh	$131,941	16%
Total	**5,610,947 kWh**	**$822,908**	**100%**

Plant Average Daily Treatment Flow	**50 MGD**
Plant Annual Treatment Flow	**18,000 MGY**
Plant Average Energy Cost Per Million Gallons Treated	**$45 / MG**

SDG&E provides electrical energy to the TOVWTP. The electrical energy is delivered through one onsite transformer and two meters. As indicated in Table 1, the TOVWTP typically consumes approximately 5,610,947 kWh annually at a cost of approximately $825,000 per year. Table 2 provides a monthly summary of the electrical energy demand and energy purchased from SDG&E by the TOVWTP as well as onsite power generation via the solar facility for the 12-month period of November 2010 through October 2011.

Table 2. 2010/2011 Electrical Energy Use

Billing Period	Electrical Energy Use (kWh)	Onsite Solar Production (kW)	Peak/ Max NC Demand (kW)	Electrical Energy Cost ($)
Nov-10	368,652	--	880 / 1,088	$51,491
Dec-10	306,084	--	544 / 912	$41,790
Jan-11	244,772	--	880 / 1,120	$40,384
Feb-11	377,980	--	1,088 / 1,312	$55,151
Mar-11	351,716	--	864 / 1,200	$50,170
Apr-11	514,192	--	944 / 1,328	$64,928
May-11	558,576	--	1,360 / 1,360	$80,685
Jun-11	436,140	200,437	1,200 / 1,344	$67,810 + $28,061
Jul-11	409,748	205,082	960 / 1,216	$60,022 + $28,712
Aug-11	419,968	206,729	1,056 / 1,280	$63,470 + $28,942
Sep-11	404,400	169,524	1,328 / 1,424	$68,152 + $23,733
Oct-11	276,280	160,667	1,200 / 1,280	$46,913+ $22,493
Total (12 months)	**4,668,508**	**942,439**	**--**	**$690,967+ $ 131,941 (Total $822,908)**
Average (12 months)	**389,042**	**188,488**	**1,025/1,239**	**$68,576**

2.2 *ELECTRICITY RATE SCHEDULE*

The TOVWTP purchases electricity from SDG&E based on their AL-TOU rate schedule. AL-TOU is an optional time-of-use schedule available to common use and metered non-residential customers whose monthly maximum demand exceeds 20 kW. The "A" is a designation for industrial users and the "L" denotes a rate structure. TOU stands for *Time of Use*, which refers to the fact that energy and demand charges are based on the time of day electricity is used: On-Peak, Semi-Peak, and Off-Peak demand. This schedule charges customers based on the following seasonal time periods:

	May 1 – September 30	All Other
On-Peak	11 am – 6 pm Weekdays	5 pm – 8 pm Weekdays
Semi-Peak	6 am – 11 am Weekdays	6 am – 5 pm Weekdays
	6 pm – 10 pm Weekdays	8 pm to 10 pm Weekdays
Off-Peak	10 pm – 6 am Weekdays	10 pm – 6 am Weekdays
	Plus Weekends and Holidays	Plus Weekends and Holidays

Along with the Basic Service Fees, customers are charged for the energy they demand (kW) and use (kWh). Demand is the amount of energy a customer is using at any one time. There are several components that make up the Demand and Energy rates charged by SDG&E: Commodity Costs, Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component. A summary of the AL-TOU rate schedule is presented in Table 3. It should be noted that, under this rate schedule, Non-Coincident demand charges are based on the higher of the maximum monthly demand or 50 percent of the maximum annual demand. This can severely affect a facility that has one month of excessive demand because Non-Coincident charges are $13.57/kW.

Table 3. SDG&E Rate Schedule: AL-TOU

		AL-TOU	
		Energy ($/kWh)	Demand ($/kW)
Summer (May 1 to Sept. 30)	On-Peak	0.09907	12.86
	Semi-Peak	0.07979	--
	Off-Peak	0.05942	--
Winter (Oct. 1 to April 30)	On-Peak	0.09320	4.92
	Semi-Peak	0.08491	--
	Off-Peak	0.06475	--
Non-Coincident		--	13.57
Source: SDG&E website, January 2012			

An Energy Rate Analysis was performed by the Water Authority and SDG&E in 2011 for Water Authority facilities that typically consume large amounts of energy. The purpose of the study was to analyze SDG&E rate alternatives for each facility to determine whether or not the facility could benefit from changing rate schedules. The Energy Rate Analysis recommended that the TOVWTP consider the A6-TOU, CPP-D rate schedule.

An all-inclusive average electrical energy rate was calculated by dividing the previous 12 months of electrical energy costs by the previous 12 months of electrical energy use. An all-inclusive average energy rate of $0.14/kWh was calculated for the TVOWTP and is presented in Table 4. This cost is representative of both the purchased electricity and the solar (the current cost per kWh for solar generated energy is $0.14 by contract). As illustrated below 39% of the facility's electrical cost is associated with demand charges and not sensitive to utilization. The all-inclusive average electrical energy rate was used to complete the electrical energy balances presented in Section 3.

Table 4. 2010/2011 Electrical Energy Use and Rates to Be Utilized for ECO Cost Impact for the Site

	Electrical Energy Use & Costs	Electrical Energy Demand Use & Costs	Other Costs ($)	Total Electric Use & Costs
2010/2011 Use (12 months)	4,668,508 kWh/yr	--	--	--
2010/2011 Cost (12 months)	$475.817 /yr	$317.623	$29.468	$822.908 /yr
Percentage of Total Cost	58%	39%	3%	100%
All Inclusive Rate Used for Electrical Energy Balance and ECO Calculations	**$0.14 /kWh**			

2.3 ENERGY BASELINE

Figure 1 illustrates the TOVWTPs actual energy use (purchased and generated) and water treated over the 12-month period from November 2010 through October 2011. As discussed above, all of the plant's energy supply is electricity (either purchased from SDG&E or generated by solar). Figure 1 shows that TOVWTPs energy usage varies seasonally with flow.

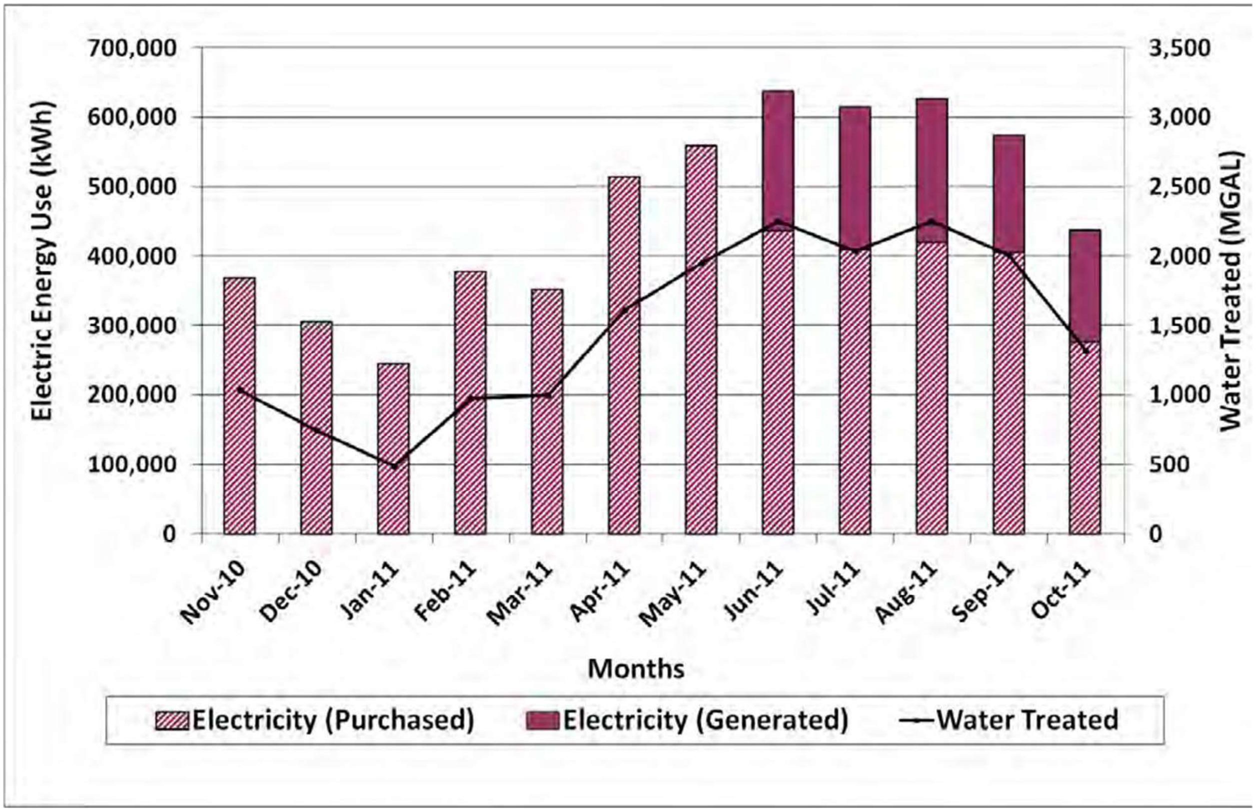

Figure 1. 2010/2011 Energy Use and Flow Breakdown

Figure 2 illustrates the plant's energy use and costs over the same 12-month period from November 2010 through October 2011. This figure shows that the electricity use varies similarly to costs, and that the plant used more energy during the summer months (April through September).

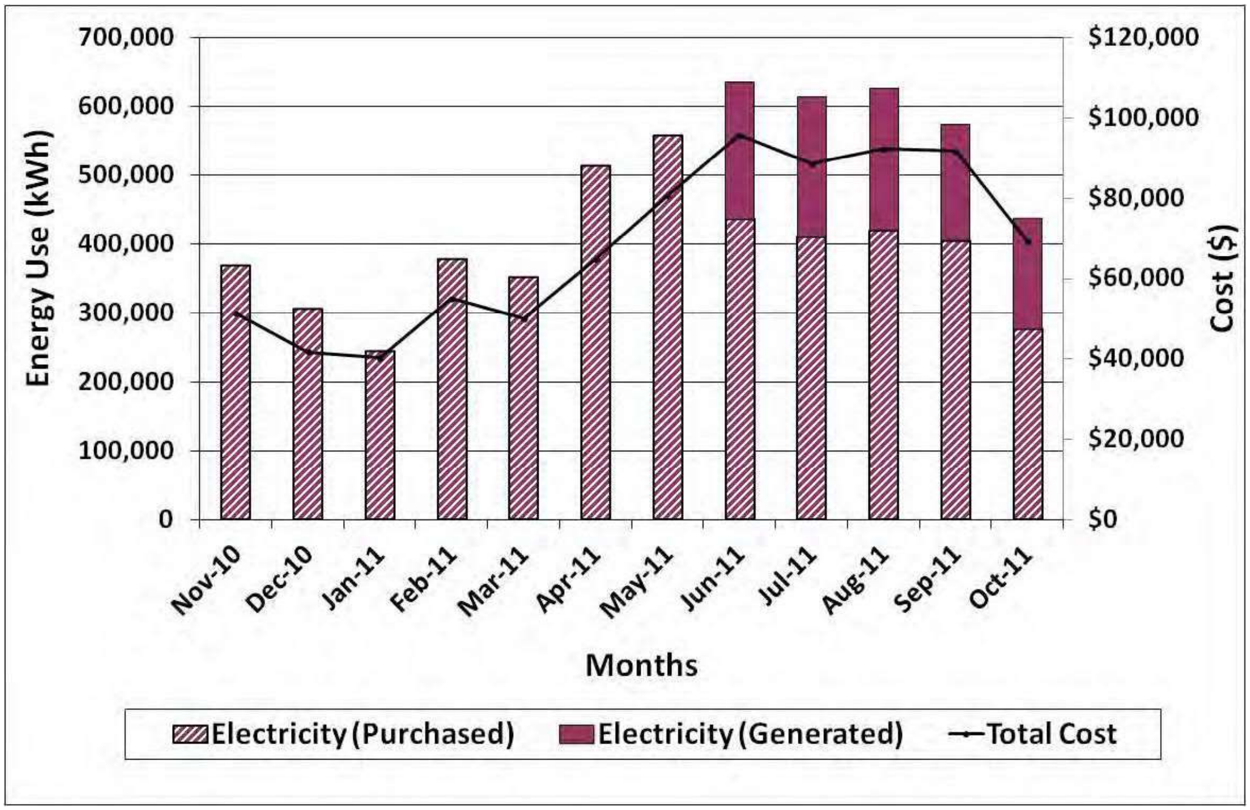

Figure 2. 2010/2011 Energy Use and Cost Breakdown

Figure 3 illustrates the plant's energy costs over the same 12-month period from November 2010 through October 2011. This figure shows that the costs associated with demand stay relatively constant throughout the year and do not appear to be production sensitive, nor impacted by the addition of the solar facility.

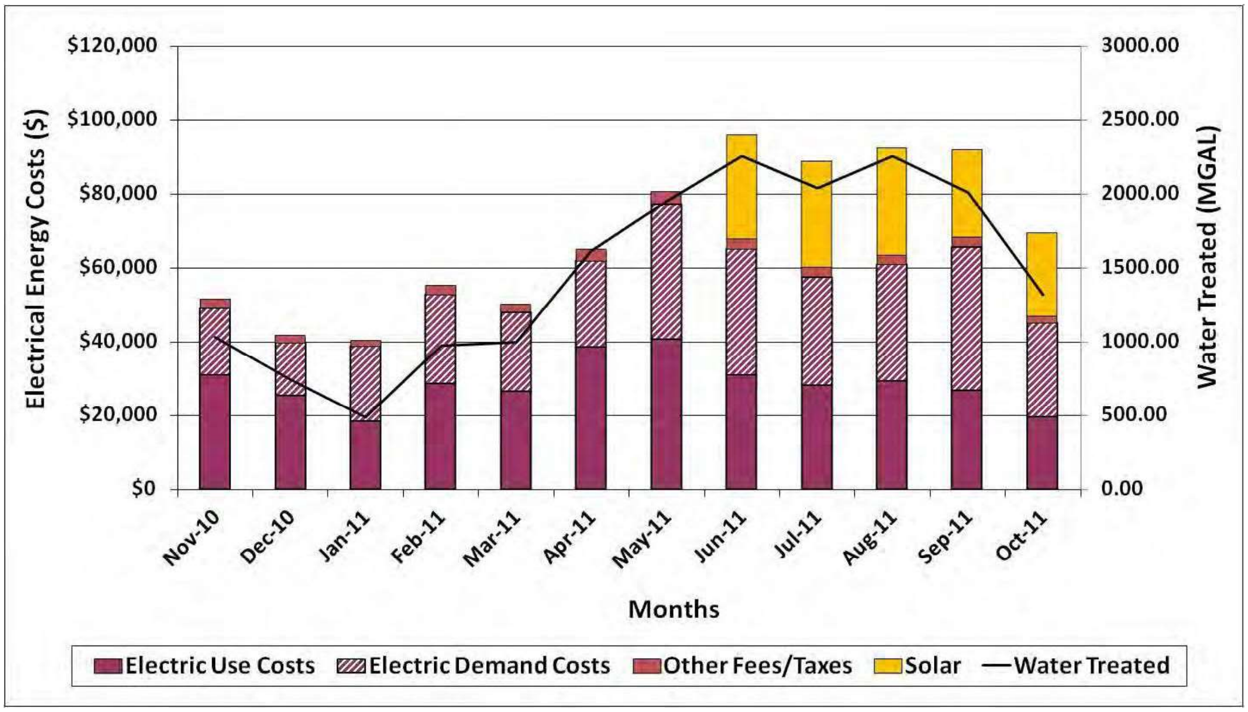

Figure 3. 2010/2011 Energy Cost and Flow Breakdown

Figure 5 presents the plant's energy demand and effluent flow over the same 12-month period from November 2010 through October 2011. This figure shows that plant's On-Peak demand is typically just slightly less than its maximum/Non-Coincident demand.

Under the AL-TOU rate schedule, only On-Peak ($12.86) and Non-Coincident ($13.57) demand charges apply. As discussed above, Non-Coincident demand charges are based on the higher of the maximum monthly demand or 50 percent of the maximum annual demand. This means that if the plant's maximum demand for a given month occurs during the On-Peak period, the plant is charge for both On-Peak and Non-Coincident demand ($12.86 + $13.57 = $26.43).

This figure also shows that the costs associated with demand do not appear to be production sensitive. It should also be noted that the monthly demands do not appear to be impacted by the addition of the solar facility (June through October 2011).

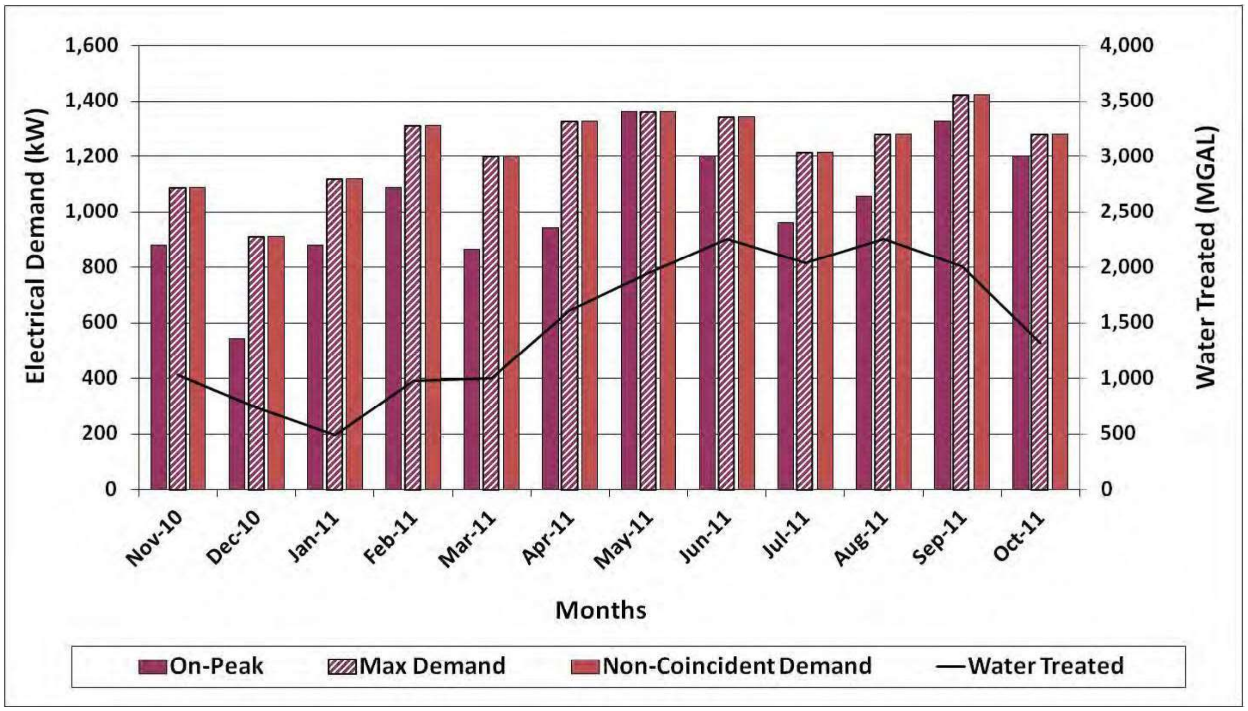

Figure 4. 2010/2011 Energy Demand and Flow Breakdown

Figure 5 provides normalized electrical energy costs per million gallons of wastewater treated for the 12-month period from November 2010 through October 2011 and can better demonstrate electrical energy efficiency over time. There are advantages and disadvantages in comparing month-to-month energy efficiency, so this plot should not be used as a sole source of comparison.

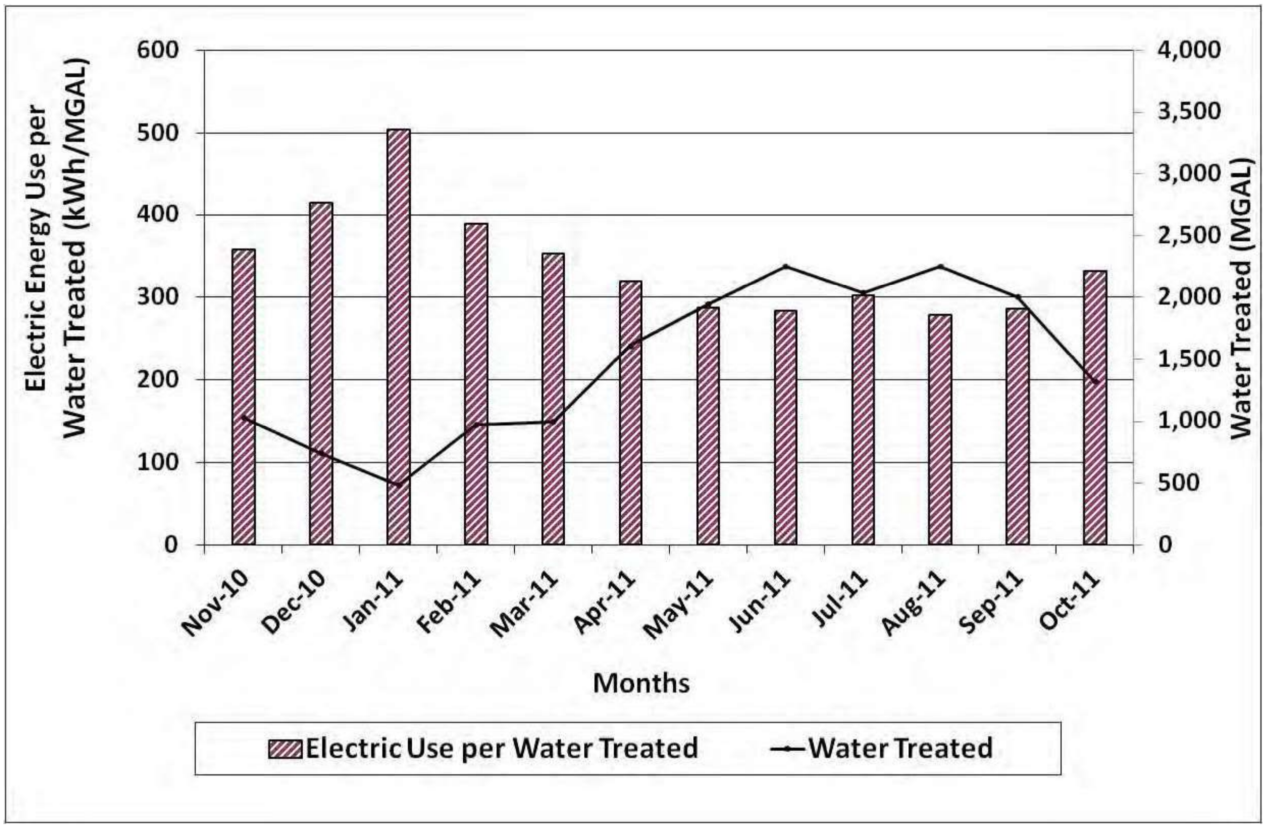

Figure 5. 2010/2011 Electric Energy Use per Million Gallons of Water Treated

As clearly evident, the water production profile fluctuates based on customer demand: during the summer months, the plant is producing more treated water than during winter season. The above figures illustrate the variation of energy consumption per million gallons produced. The higher the production rate the lower the overall utilization rate (kWh/MG) rate. Additionally, the costs associated with demand <u>do not appear to be production sensitive nor impacted by the addition of the solar facility.</u>

3. Electrical Analysis

3.1 Electrical Energy Balance

Based on data reviewed for the TOVWTP, an electrical energy balance for major equipment (7.5 hp or greater) was developed for two different scenarios: high and low production rates. It is understood that the treatment plant production rates can and do vary greatly and operated on customer demand daily requests. The estimated electrical energy balance for each scenario is summarized in Tables 5 and 6 below based on a six month operating profile (4,380 operating hours).

Table 5. High Production – Major Equipment Inventory and Electrical Energy Balance

No.	Equipment Description	Equipment Size / Load[1] (kW)	Estimate Operational Hours[2] (hrs/yr)	Est. Energy Use[3] (kWh/yr)	Est. Energy Cost[4] ($/yr)	Est. Energy %[5] (%)
1	Membrane Blower #1	25/15	3,800	57,000	$7,980	2%
2	Membrane Blower #2	25/15	0	0	$0	0%
3	Permeate Pump #1	100/50	3,800	190,000	$26,600	5%
4	Permeate Pump #2	100/50	3,800	190,000	$26,600	5%
5	Permeate Pump #3	100/50	3,800	190,000	$26,600	5%
6	Permeate Pump #4	100/50	3,000	150,000	$21,000	4%
7	Permeate Pump #5	100/50	3,000	150,000	$21,000	4%
8	Permeate Pump #6	100/50	2,250	112,500	$15,750	3%
9	Permeate Pump #7	100/50	2,250	112,500	$15,750	3%
10	Permeate Pump #8	100/50	2,250	112,500	$15,750	3%
11	Permeate Pump #9	100/50	2,250	112,500	$15,750	3%
12	Permeate Pump #10	100/50	2,250	112,500	$15,750	3%
13	Permeate Pump #11	100/65	0	0	$0	0%
14	Permeate Pump #12	100/65	0	0	$0	0%
15	Permeate Pump #13	100/65	0	0	$0	0%
16	Permeate Pump #14	100/65	0	0	$0	0%
17	Vacuum Pump	30/20	3,800	76,000	$10,640	2%
18	Vacuum Pump	30/20	0	0	$0	0%
19	Instrument Air Compressor	30/20	2,000	40,000	$4,000	1%
20	Instrument Air Compressor	30/20	0	0	$0	0%
21	MIT Air Compressor	15/10	2,000	20,000	$2,800	1%
22	MIT Air Compressor	15/10	0	0	$0	0%

No.	Equipment Description	Equipment Size / Load[1] (kW)	Estimate Operational Hours[2] (hrs/yr)	Est. Energy Use[3] (kWh/yr)	Est. Energy Cost[4] ($/yr)	Est. Energy %[5] (%)
23	BAC Scour Blower #1	125/90	150	13,500	$1,890	0%
24	BAC Scour Blower #2	125/90	0	0	$0	0%
25	Ozone Generator #1- 75% Load	--/225	4,380	985,500	$137,970	27%
26	Ozone Generator #2	--/225	0	0	$0	0%
27	Ozone Generator #3	--/225	0	0	$0	0%
28	Ozone Destruct Unit #1	--/10	4,380	43,800	$6,132	1%
29	Ozone Destruct Unit #2	--/10	0	0	$0	0%
30	Agitation Water Pump #1	25/16	4,380	70,080	$9,811	2%
31	Agitation Water Pump #2	25/16	0	0	$0	0%
32	Plant Water #1	25/16	4,380	70,080	$9,811	2%
33	Plant Water #2	25/16	0	0	$0	0%
34	Sodium Hypochlorite Generator #1	150/120	4,380	525,600	$73,584	14%
35	Sodium Hypochlorite Generator #2	150/120	0	0	$0	0%
36	Equalization Pump #1	50/30	2,250	67,500	$9,450	2%
37	Equalization Pump #2	50/30	0	0	$0	0%
38	Equalization Pump #3	50/30	0	0	$0	0%
39	Backwash Return Pump #1	40/25	1,000	25,000	$3,500	1%
40	Backwash Return Pump #2	40/25	0	0	$0	0%
41	Backwash Return Pump #3	40/25	0	0	$0	0%
42	Solids Feed Pump #1	7.5/5	1,125	5,625	$788	0%
43	Solids Feed Pump #2	7.5/5	0	0	$0	0%
44	Solids Feed Pump #3	7.5/5	0	0	$0	0%
45	Centrifuge #1	65/45	1,000	45,000	$6,300	1%
46	Centrifuge #2	65/45	0	0	$0	0%
47	Balance of Plant - Misc. Loads	100/60	3,000	180,000	$25,200	5%
	Estimated Annual Electric Use		**--**	**3,657,185**	**$510,406**	**100%**

Notes

1. Equipment size includes nameplate horsepower (hp) rating of the equipment, and the estimated average power load in kilowatts (kW) considering the efficiency rating if available and operating characteristics. Major equipment is defined as 7.5 hp or greater
2. Plant equipment estimated operating hours per year (hrs/yr) and discussions with plant personnel.

3. Estimated electrical energy use in kilowatt-hours per year (kWh/yr) is based on equipment and operating conditions. Due to truncating, energy use may not equal the product of equipment load (kW) and operating hours per year (hrs/yr).
4. Estimated electrical energy cost in dollars per years ($/Yr) is based upon using an all-inclusive average electric rate of $0.14/kWh.
5. Estimated equipment electrical energy use and cost as a percentage of total plant use and costs.

Table 6. Low Production – Major Equipment Inventory and Electrical Energy Balance

No.	Equipment Description	Equipment Size / Load[1] (kW)	Estimate Operational Hours[2] (hrs/yr)	Est. Energy Use[3] (kWh/yr)	Est. Energy Cost[4] ($/yr)	Est. Energy %[5] (%)
1	Membrane Blower #1	25/15	3,800	57,000	$7,980	2%
2	Membrane Blower #2	25/15	0	0	$0	0%
3	Permeate Pump #1	100/50	3,800	190,000	$26,600	7%
4	Permeate Pump #2	100/50	3,800	190,000	$26,600	7%
5	Permeate Pump #3	100/50	3,800	190,000	$26,600	7%
6	Permeate Pump #4	100/50	3,000	150,000	$21,000	6%
7	Permeate Pump #5	100/50	3,000	150,000	$21,000	6%
8	Permeate Pump #6	100/50	2,250	112,500	$15,750	4%
9	Permeate Pump #7	100/50	0	0	$0	0%
10	Permeate Pump #8	100/50	0	0	$0	0%
11	Permeate Pump #9	100/50	0	0	$0	0%
12	Permeate Pump #10	100/50	0	0	$0	0%
13	Permeate Pump #11	100/65	0	0	$0	0%
14	Permeate Pump #12	100/65	0	0	$0	0%
15	Permeate Pump #13	100/65	0	0	$0	0%
16	Permeate Pump #14	100/65	0	0	$0	0%
17	Vacuum Pump	30/20	3,800	76,000	$10,640	3%
18	Vacuum Pump	30/20	0	0	$0	0%
19	Instrument Air Compressor	30/20	2,000	40,000	$4,000	2%
20	Instrument Air Compressor	30/20	0	0	$0	0%
21	MIT Air Compressor	15/10	2,000	20,000	$2,800	1%
22	MIT Air Compressor	15/10	0	0	$0	0%
23	BAC Scour Blower #1	125/90	150	13,500	$1,890	1%
24	BAC Scour Blower #2	125/90	0	0	$0	0%

No.	Equipment Description	Equipment Size / Load[1] (kW)	Estimate Operational Hours[2] (hrs/yr)	Est. Energy Use[3] (kWh/yr)	Est. Energy Cost[4] ($/yr)	Est. Energy %[5] (%)
25	Ozone Generator #1- 75% Load	--/150	4,380	657,000	$91,980	25%
26	Ozone Generator #2	--/150	0	0	$0	0%
27	Ozone Generator #3	--/150	0	0	$0	0%
28	Ozone Destruct Unit #1	--/10	4,380	43,800	$6,132	2%
29	Ozone Destruct Unit #2	--/10	0	0	$0	0%
30	Agitation Water Pump #1	25/16	4,380	70,080	$9,811	3%
31	Agitation Water Pump #2	25/16	0	0	$0	0%
32	Plant Water #1	25/16	4,380	70,080	$9,811	3%
33	Plant Water #2	25/16	0	0	$0	0%
34	Sodium Hypochlorite Generator #1	150/120	2,350	282,000	$39,480	11%
35	Sodium Hypochlorite Generator #2	150/120	0	0	$0	0%
36	Equalization Pump #1	50/30	2,250	67,500	$9,450	3%
37	Equalization Pump #2	50/30	0	0	$0	0%
38	Equalization Pump #3	50/30	0	0	$0	0%
39	Backwash Return Pump #1	40/25	1,000	25,000	$3,500	1%
40	Backwash Return Pump #2	40/25	0	0	$0	0%
41	Backwash Return Pump #3	40/25	0	0	$0	0%
42	Solids Feed Pump #1	7.5/5	1,125	5,625	$788	0%
43	Solids Feed Pump #2	7.5/5	0	0	$0	0%
44	Solids Feed Pump #3	7.5/5	0	0	$0	0%
45	Centrifuge #1	65/45	1,000	45,000	$6,300	2%
46	Centrifuge #2	65/45	0	0	$0	0%
47	Balance of Plant - Misc. Loads	100/60	3,000	180,000	$25,200	7%
	Estimated Annual Electric Use		**--**	**2,635,085**	**$367,312**	**100%**

Notes

1. Equipment size includes nameplate horsepower (hp) rating of the equipment, and the estimated average power load in kilowatts (kW) considering the efficiency rating if available and operating characteristics. Major equipment is defined as 7.5 hp or greater
2. Plant equipment estimated operating hours per year (hrs/yr) and discussions with plant personnel.
3. Estimated electrical energy use in kilowatt-hours per year (kWh/yr) is based on equipment and operating conditions. Due to truncating, energy use may not equal the product of equipment load (kW) and operating hours per year (hrs/yr).

4. Estimated electrical energy cost in dollars per years ($/Yr) is based upon using an all-inclusive average electric rate of $0.14/kWh.
5. Estimated equipment electrical energy use and cost as a percentage of total plant use and costs.

3.2 MAJOR ENERGY USERS

Similar to the major equipment balances in Section 3.1, a major users pie chart was developed for two scenarios: high and low flow. As illustrated in Figure 6 and 7 below, the submerged membrane facility, ozone generation, chemical mixing, equalization pumping, backwash return, solids processing, and gravity thickening consume the majority of the electrical energy at the facility during high flow conditions. All other electrical energy use systems at the plant were combined under "Small Loads - Balance of Plant". The submerged membrane facility, ozone generation, and chemical mixing account for about 90% of the electrical energy use at the site during high flow conditions.

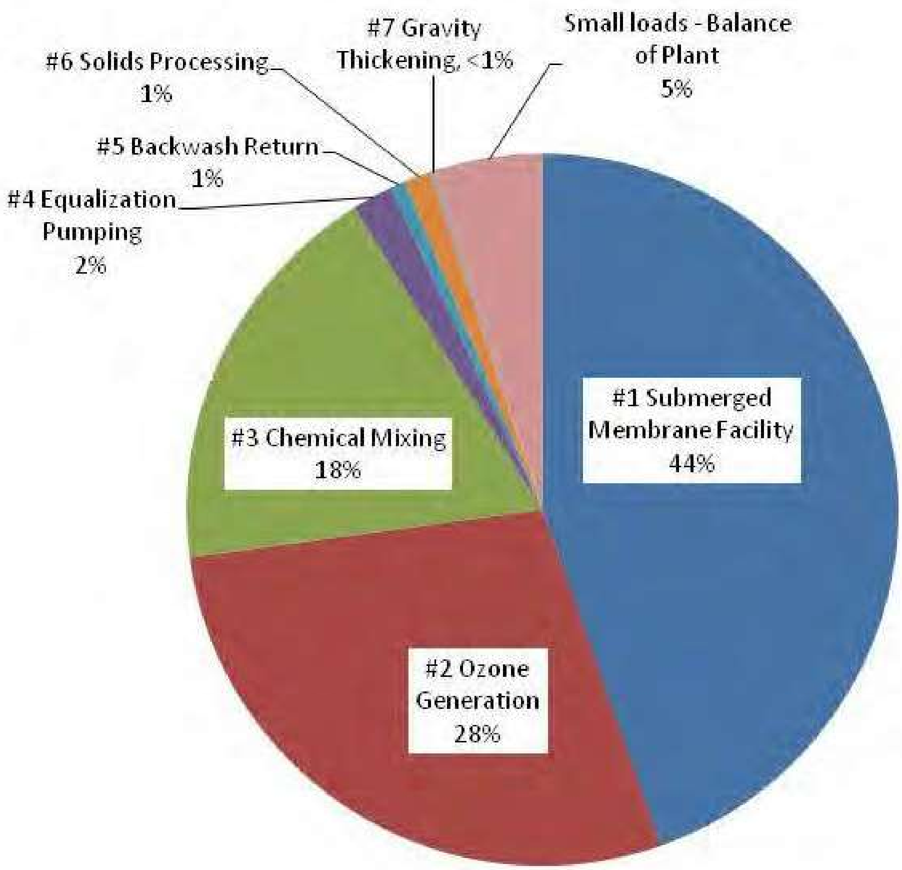

Figure 6. High Production – Major Electrical Users

The submerged membrane facility, ozone generation, and chemical mixing account for about 88% of the electrical energy use at the site during low flow conditions.

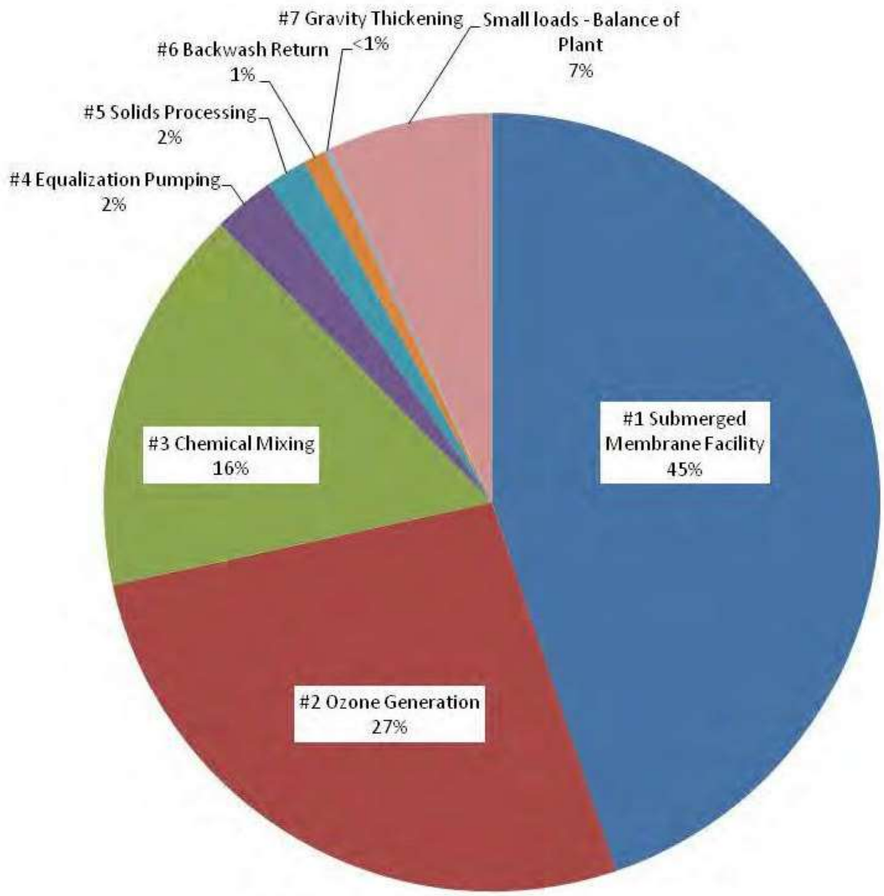

Figure 7. Low Production – Major Electrical Users

4. Energy Conservation Opportunities

Table 7 lists potential Energy Conservation Opportunities recommended for further evaluation.

Table 7. Recommended Energy Conservation Opportunities

ECO Opportunity	ECO Description	Simple Payback Term Estimate	Investment Cost Estimate
1	Shift production of NaOCl (sodium hypochlorite) to off-peak periods to the extent possible	Short Term (<5 years)	No Cost
2	Confirm and modify SDG&E Rate Schedule (AL-TOU vs. A6-TOU)	Short Term (<5 years)	No Cost
3	Adjust dewatering operations (centrifuge) to operate during off-peak periods	Short Term (<5 years)	No Cost
4	Sequence and/or install VFDs on Backwash Tank Fill Pumps (20-hp) to pump water to elevated tanks prior to backwash	Short Term (<5 years)	No Cost
5	Evaluate continuous recirculation water loop pumps (25-hp constant speed operations)	Short Term (<5 years)	No Cost
6	Installation of cycle timers on manual light switches	Short Term (<5 years)	Low Cost Measure (<$10,000)
7	Evaluate installation of high-efficiency centralized compressed air (screw) configuration in lieu of six separate systems	Mid Term (5 to 10 years)	Investment Grade Measure (>$10,000)
8	Evaluate air receiver for use with air scour blower	Mid Term (5 to 10 years)	Investment Grade Measure (>$10,000)
9	Evaluate installation of VFD for Return Water Pumps during low flow operations	Mid Term (5 to 10 years)	Investment Grade Measure (>$10,000)
10	Investigate and implement Demand Management Strategies including addition of Energy Management System (EMS)	Short Term (<5 years)	Low Cost Measure (<$10,000)

Notes

1. Payback Range Estimate: Short Term = <5 years; Mid Term = 5 years to 10 years; Long Term = > 10 years
2. Capital Investment Range Estimate: No Cost Measure = $0; Low Cost Measure <$10,000; Investment Grade Measure >$10,000

5. Photographs


Permeate Pumps


Centrifuge


Chemical Water Mixing Pumps


Sodium Hypochlorite Generation System

Compressor Station

ATTACHMENT 9: VALLEY CENTER PUMP STATION

Phase 1 Energy Audit Report

Report of Energy Audit – Phase 1 Summary

Valley Center Pump Station

San Diego County Water Authority

February 15, 2012

Prepared for San Diego County Water Authority
4677 Overland Drive
San Diego, California 92123

1. Introduction

On December 6, 2011, an energy audit of San Diego County Water Authority's (Water Authority) Valley Center Pump Station was conducted by Greg Ortega (Water Authority) and was led by Donald King of DHK Engineers, Inc (DHK). The Valley Center Pump Station is located at 31145 Rodriquez Road in Valley Center, California. The pump station has two continuous-duty 125-horsepower (hp) pumps. The station operates in gravity mode (most of the time) to feed the Valley Center area. The station can be configured to convey water in two directions by using the two pumps. Discussions with pump station operators indicated a potential future need for a third pump and possible upgrade of the constant speed motors to variable frequency drives (VFD). Based on data reviewed, the major equipment is summarized in Table 1.

Table 1. Major Equipment Inventory

No.	Equipment Description	Equipment Size (hp)
1	Pump #1	125
2	Pump #2	125
3	Fan #1	2
4	Fan #2	2

2. Utility Analysis

2.1 CURRENT UTILITY USE

Electricity is the only utility consumed at the Valley Center Pump Station. Electricity usage data and bills from 2009 to present were reviewed. According to this data, it costs the Water Authority approximately $5,200 annually to operate the pump station. Typical annual electricity use and costs are summarized in Table 2 and are described in more detail below. Flow data for the pump station was not available; however, based on electrical data reviewed, it appears that the pump station was operational only during five of the twelve months reviewed below.

Table 2. Annual Utility Summary

Utility	Site Utility Use (common units)	Site Utility Costs	% of Costs
Electricity	30,560 kWh	$5,107	100%
Total		**$5,107**	**100%**

San Diego Gas & Electric (SDG&E) provides electrical energy to the Valley Center Pump Station. The electrical energy is delivered through one onsite transformer and one meter (SDG&E Meter Number 1666035). Table 3 provides a monthly summary of the electrical energy purchased from SDG&E by the pump station for the 12-month period of November 2010 through October 2011.

Table 3. 2010/2011 Electrical Energy Use

Billing Period	Electrical Energy Use (kWh)	Max Demand (kW)	Electrical Energy Cost ($)
Nov-10	5,280	106	$846
Dec-10	1,600	3	$238
Jan-11	11,680	106	$1,859
Feb-11	2,400	10	$382
Mar-11	1,120	101	$183
Apr-11	960	3	$158
May-11	800	3	$158
Jun-11	640	10	$164
Jul-11	2,720	206	$504
Aug-11	1,120	5	$195
Sep-11	960	3	$165
Oct-11	1,280	205	$254
Total (12 months)	**30,560**	**--**	**$5,107**
Average (12 months)	**2,547**	**63**	**$426**

2.2 *ELECTRICITY RATE SCHEDULE*

The Valley Center Pump Station purchases electricity from SDG&E based on their A rate schedule. This schedule is SDG&E's standard tariff for commercial customers with a maximum monthly demand of less than 20 kW. Along with the Basic Service Fees, customers are charged for the energy they use (kWh). There are several components that make up the energy rates charged by SDG&E: Transmission Charges, Distribution Charges, Public Purpose Program Charges, Nuclear Decommissioning Charge, Ongoing Competition Transition Charges, Reliability Services, and Total Rate Adjustment Component. A summary of the A rate schedule is presented in Table 4. It should be noted that demand charges do not apply to this rate schedule.

Table 4. SDG&E Rate Schedule: A

	Schedule A	
	Energy ($/kWh)	Demand ($/kW)
Schedule A Rates	0.09297	--
Source: SDG&E website, January 2012		

An Energy Rate Analysis was performed by the Water Authority and SDG&E in 2011 for Water Authority facilities that typically consume large amounts of energy. The purpose of the study was to analyze SDG&E rate alternatives for each facility to determine whether or not the facility could benefit from changing rate schedules. The Energy Rate Analysis recommended that the Valley Center Pump Station remain on its current rate schedule.

An all-inclusive average electrical energy rate was calculated by dividing the previous 12 months of electrical energy costs by the previous 12 months of electrical energy use. An all-inclusive average energy rate of $0.178/kWh was calculated for the pump station and is presented in Table 5. The all-inclusive average electrical energy rate will be utilized in Energy Conservation Opportunity (ECO) calculations.

Table 5. 2010/2011 Electrical Energy Use and Rates to Be Utilized for ECO Cost Impact for the Site

	Electrical Energy Use & Costs	Electrical Energy Demand Use & Costs	Other Costs	Total Electric Use & Costs
2010/2011 Use (12 months)	30,560 kWh/yr	--	--	--
2010/2011 Cost (12 months)	$4,817 /yr	--	$290 /yr	$5,107 /yr
All Inclusive Rate Used for ECO Calculations	**$0.178 /kWh**			

2.3 *ENERGY BASELINE*

Figure 1 illustrates the pump station's actual energy use for the 12-month period from November 2010 through October 2011. As discussed above, electricity is the pump station's only energy supply. Figure 1 shows that the pump station is rarely used. Although flow data was not available, November 2010 and January 2011 are probably the only months when the pump station was operational. The slightly elevated electrical use in November 2010 and January 2011 probably represent equipment reliability checks. The small increase in July was caused by a short-term pump efficiency test.

The baseline energy use of approximately 1,000 kWh per month can be seen in Figure 1 also. This baseline energy use costs the Water Authority approximately $200 per month. The baseline energy use is probably due to the supply and exhaust fans within the facility.

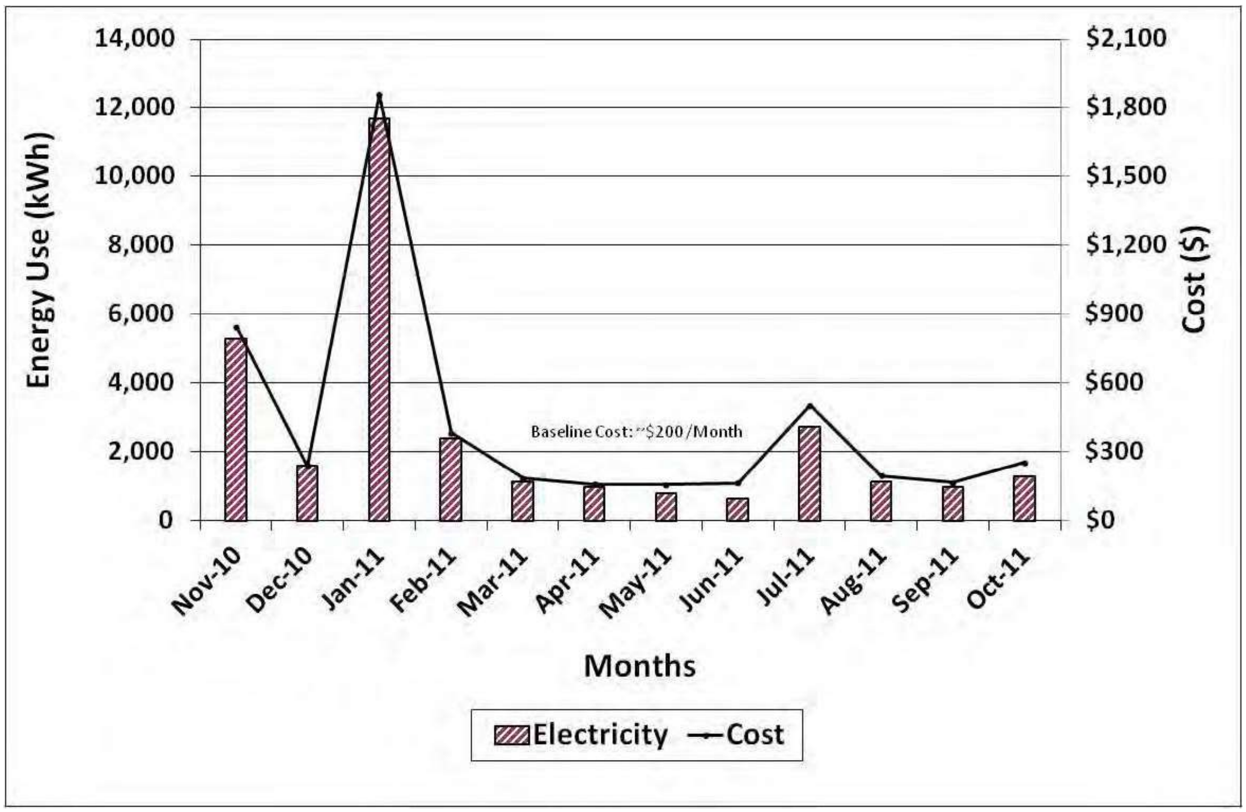

Figure 1. 2010/2011 Energy Use Breakdown

3. Energy Conservation Opportunities

Table 6 lists potential ECOs recommended for further evaluation.

Table 6. Recommended Energy Conservation Opportunities

ECO Opportunity	ECO Description	Simple Payback Estimate	Investment Cost Estimate
1	If the pump station will be used in the future, upgrade pumps to improve efficiency (see Pump Test Reports)	Short Term (<5 years)	Investment Grade Measure (>$10,000)
2	Install timers on light switches (Cost $250/ Savings $30/yr)	Short Term (<5 years)	Low Cost Measure (<$10,000)

Table 6. Notes

1. Payback Range Estimate: Short Term = <5 years; Mid Term = 5 years to 10 years; Long Term = > 10 years
2. Capital Investment Range Estimate: No Cost Measure = $0; Low Cost Measure <$10,000; Investment Grade Measure >$10,000

4. Photographs

Exterior View

Booster Pumps

ATTACHMENT 10: ECO DEVELOPMENT

ESCONDIDO OPERATIONS CENTER

ECO 2: Install Energy Management System (EMS) similar to San Diego Office to monitor building power loads

	
Rooftop HVAC Units	**HVAC Units**

Overview of ECO:
Having tools to monitor real time operations has been very helpful in providing information to staff that can be directly/immediately connected to real time situations. Water treatment and distribution has sophisticated systems that provide the “eyes and ears” on each system. An Energy Management System (EMS) is an extension to this concept that allows for instantaneous monitoring of energy systems, which may lead to positive changes in operational behaviors. In office and maintenance type operations, EMS technology as demonstrated that 5 to 15% energy and costs savings can be expected just by understanding the connection between operations and energy use.

Existing Conditions:
Currently, the Escondido Operations Center has a campus setting with multiple structures including administration offices, training, warehouse, vehicle maintenance and storage. Each building is independently operated using a combination of thermostats, timers, and manual on-off switches. The campus has recently been equipped with a photovoltaic system to offset the energy purchased from SDG&E.

Proposed Changes:
Incorporate an EMS to monitor and track building loads to allow adjustment of utilities during peak periods, track PV generation, and confirm most appropriate rate schedule.

Install sub-metering on each building as well as the PV system and incorporate into web-based SCADA screen to allow on-site and remote monitoring.

Benefit or Effect on Operations:
Allows periodic oversight of energy utilization for each structure, track trends, investigate unusual usage, and allows optimization of space and utilities.

Environmental Benefits or Consequences:
Reduction in electrical consumption would reduce energy purchase and greenhouse gas emission.

Calculations:

Assumptions:
Office Building benefits and associated reduction of usage seen with EMS typically between 5 to 15%

Existing campus usage: 500,000 kWh

Estimated reduction: 8%

Electrical cost: $0.145/kWh (purchase price for PV)

Existing energy consumption:

Estimate Energy Costs based on metrics: 500,000 kWh * $0.145 = $72,500

Enhanced condition energy consumption:

Estimated Energy Costs based on enhanced case: 500, 000 kWh *0.92 * $0.145 = $66,700

Yearly Savings Summary:
Annual Savings = Base Case – Enhanced Case: $72,500 – 66,700 = $5,800/year

Estimated Implementation Cost:
Installation of sub-metering (four buildings): $6,500

EMS Software package and SCADA interface $10,500

Training Optimization of Systems: $2,500

Annual review of data/report: $1,750

Total: $21,250

Payback:
Payback = Capital cost/annual savings = $21,250/ $5,800 = 3.7 years

Recommendations:
Request proposals from HVAC/Energy Service contractors for sub metering and EMS package for the four major buildings

ESCONDIDO OPERATIONS CENTER

ECO 5: Lighting and Sensor Retrofit of Vehicle Maintenance Facility (VMF)

Garage (Canopy) Lighting

Indoor Garage Lighting

Existing Conditions:

Currently, the Escondido Operations Vehicle Maintenance Facility (VMF) has several garage, parts warehouse areas, and offices. All areas are equipped for Super Saver 34 watt fluorescent bulb (4' to 8') double lamped fixtures with wall switches. A site inspection was conducted to review the operating philosophy, lighting controls, and interview staff on utilization of space and possible reduction or repositioning of lighting fixtures.

The facility is operated Monday through Thursday from 6:30 am to 4:30 pm. All lighting fixtures are turned-on manually and remain on for the entire work day. Several garage areas are provided with canopy roof structures with continuous exposure to outdoor sunlight.

Table 1. VMF Lighting Summary

Area	Number of Fixtures	Type of Fixture	Number of Bulbs	Control
Garage (canopy)	48	4' reflective	96	Manual Wall switch
Garage (indoors)	36	4' reflective	72	Manual Wall switch
Tool Room(s)	9	4' reflective	18	Manual Wall Switch
Repair/Welding Garage	12	8' reflective	24	Manual Wall Switch
Offices and Miscellaneous	12	4' reflective	24	Manual Wall Switch(es)

Proposed Changes:
In combination with ECO #2 – Energy Management System installation, it is proposed to separate the lighting circuits on various combinations of high lighting, sensor times, and focused bench lighting to improve the overall lighting in the work areas and to turn off or eliminate several fixtures. The specific modifications would include:

- Reconfigure canopy garage with three lighting circuits equipped with light sensors on outer systems.
- Upgrade electrical service to existing lighting circuits to eliminate electrical arcing in local control panel.
- Install workbench lighting with timers to allow focused light on work benches.
- Install new energy efficient fixtures/ballasts and bulbs for VMF
- Add motion/light/timer sensors on all other lighting including parts storage areas.

Benefit or Effect on Operations:
Improved lighting in work spaces.

Reduction in energy use required by lighting.

Improve electrical safety by eliminating arcing at electrical panel.

Environmental Benefits or Consequences:
Reduction in electrical consumption would reduce energy purchase and greenhouse gas emission.

Calculations:
<u>Assumptions:</u>
Operations: 4 days/week * 52 weeks/year = 208 days/year

Lights are on an average of 8 hours/day

4' bulbs = 34 watts, 8' bulbs = 60 watts

210 4' bulbs * 0.034kWh/bulb * 1 hour = 7.14 kWh

24 4' bulbs * 0.060 kWh/bulb * 1 hour = 1.44 kWh

Total kWh/hour of operation: 7.14 kWh + 1.44 kWh = 8.5 kWh

Yearly consumption: 208 days/year * 8 hours/day * 8.5 kWh = 14,144 kWh/year

Estimated energy cost/year (exclusive of bulb replacement): 14,144 kWh * $0.145/kWh = $2,050/year

Table 2. Proposed VMF Lighting Summary

Area	Number of Fixtures	Type of Fixture	Number of Bulbs	Control
Garage (canopy)	30 18	4' reflective 4' reflective	60 36	Manual Wall switch Light Switch Activated (on 2 hours/day)
Garage (indoors)	36	4' reflective	72	Manual Wall switch
Tool Room(s)	9	4' reflective	18	Manual Wall Switch Sensors (on 2 hours/day)
Repair/Welding Garage	8 (4 fixtures removed)	8' reflective	16	Manual Wall Switch Sensor (on 2 hours/day)
Offices and Miscellaneous	6 6	4' reflective 4' reflective	12 12	Manual Wall Switch Manual Wall Switch Sensor (on 2 hours/day)

Operations: 4 days/week * 52 weeks/year = 208 days/year

Lights are on an average of 8 hours/day

4' bulbs = 34 watts, 8' bulbs = 60 watts

210 4' bulbs * 0.034kWh/bulb * 1 hour = 7.14 kWh (for 2 hours/day)

144 4' bulbs * 0.034kWh/bulb * 1 hour = 4.98 kWh (for 6 hours/day)

24 4' bulbs * 0.060 kWh/bulb * 1 hour = 0.96 kWh (for 2 hours/day)

Total kWh/hour of operation:

2 hours/day * 7.14 kWh + 6 hours/day * 4.98 kWh + 2 hours/day * 0.96 kWh = 45.6 kWh

Yearly consumption: 208 days/year * 45.6 kWh/day = 9,485 kWh/year

Estimated energy cost/year (exclusive of bulb replacement): 9,485 kWh * $0.145/kWh = $1,375/year

Yearly Savings Summary:
Annual Savings = Base Case – Enhanced Case: $2,050 - $1,375 = $675/year

Estimated Implementation Cost:
Wiring sensors to existing lighting fixtures $ 7,500

Total: $7,500

Payback:
Payback = Capital cost/annual savings = $7,500/ $675 = 11.1 years

Recommendations:
Investigate electrical circuit arcing situation and install new/additional circuits and sensors in garage (canopy). If upgrades to the VMF are planned in the near future, incorporate half lighting, motion/light sensors as part of the upgrade project

SAN DIEGO OFFICE - ADMINISTRATION BUILDING (KEARNY MESA)

ECO 1: Add VFD to existing hot-water circulation pump or install a low-flow jockey pump

Hot Water Pump Control Panels

Hot Water Recirculation Pumps

Existing Conditions:
Currently, the Administration Building is equipped with a boiler and hot water loop for heating. Two 10-hp hot water recirculation pumps (each with a rating of 129 gpm at 130 ft of head) operate in a lead/lag configuration. One pump operates 24 hours per day, 7 days a week to maintain a constant temperature within the piping system, even during summer periods. Discussions regarding turning off the hot water system when not in use noted that if the hot water loop cools, the piping joint will be begin to leak and thus presents a maintenance issue.

Building staff have recently lowered the circulating water temperature to reduce the natural gas use by the boiler.

Proposed Changes:
In order to maintain a consistent temperature within the circulation loop, it is proposed to add a VFD to one of the existing pumps or install a smaller low-flow jockey pump to operate when heating demands are low.

Benefit or Effect on Operations:
Reduction of the hot water recirculation rate during low heating periods will reduce energy use and potentially save money in operating costs.

Environmental Benefits or Consequences:
Reduction in electrical consumption would reduce energy purchase and greenhouse gas emission.

Calculations:
Assumptions:
Hot Water Pump operate 8,760 hours/year

Existing pumps: 10 hp @ 129 gpm @ 56 psig

Energy use per hour: 6.5 kwH

Energy Cost offset: $0.145/ kWh (purchase price for PV)

Acceptable flow for reduced rate: 50 gpm @ 40 psig (3 hp) 2 kW

Number of hours at reduced flow 50% (4,380 hrs/ yr)

Existing Energy Consumption:

8,760 hours/yr * 6.5 kWh = 56,940 kWh/yr

Cost per yr= 56,940 kWh * $0.145= $8,256/yr

Enhanced Condition Energy Consumption:

Half time at existing recirculation rate: = 8,760 * 0.5 * 6.5 kWh = 28,470 kWh

Half time at reduced flow rate= 8,760 * 0.5 * 2 kW= 8,760 kWh

Total for the year: 37,230 kWh @ 0.145/kWh = $5,400

Yearly Savings Summary:
Annual Savings = Base Case – Enhanced Case: $8,256 - $5,400 = $2,856/year

Estimated Implementation Cost:
Estimated construction costs (Option A- Jockey Pump):

Purchase and install 3 hp rated 40 gpm @ 100ft: $ 4,500

Add starter circuit, control panel, and SCADA/EMS connection: $ 3,250

Piping/check valves, installation start-up: $ 3,500

Miscellaneous: $2,000

Total: $13,250

Estimated construction costs (Option B- Add VFD to existing Pumps)

2- VFD for 10 HP pumps with NEMA 4 enclosure: $6,500

Installation of VFD, control panel tie-in, cross-over controls: $ 5,500

SCADA modifications and temperature control loop: $1,500

Total: $13,500

Payback:
Payback = Capital cost/annual savings = $13,500 / $2,856 = 4.7 years

Recommendations:
Conduct a site walk with an HVAC/electrical contractor to confirm budgetary costs and selection of VFD option.

TWIN OAKS VALLEY WATER TREATMENT PLANT

ECO 4: Demand Management Strategy – Install VFD on Backwash Water Fill Cycle

Existing Conditions:
Twin Oaks Valley Water Treatment Plant uses a slightly elevated backwash tank for the "backwash" operation. The backwash operation consists of a storage tank, level monitoring system, and 20-hp constant speed fill pumps. The Backwash tank is filled prior to each backwash cycle and emptied during the cycle.

Typically, the backwash fill pumps are activated based on the level within the backwash tank, which would signal a fill cycle immediately after/during a backwash cycle.

Proposed Changes:
Investigate the potential to manage the demand response of the backwash fill pumps with other batch-type operations. For instance, the backwash recovery pumps pump the backwash waste to the front end of the facility after each cycle. If both the backwash recovery pumps and the backwash tank fill pumps are operating at the same time, the combined demand impact could affect the monthly demand readings and associated costs.

In addition to demand management, installation of VFD's and/or a smaller jockey pump to reduce the water pumping rate during long periods between backwash cycles may provide some demand and energy use savings .

Benefit or Effect on Operations:
Reduction of pump rates during backwash cycles will reduce energy use and potentially save money in operating costs.

Environmental Benefits or Consequences:
Reduction in electrical consumption would reduce energy purchase and greenhouse gas emission.

Calculations:
<u>Assumptions:</u>
Shift backwash fill pumps to non-impact periods of the day

Demand savings one pump: 15 kW

Savings (Peak and Non-coincident): Summer $26.43; winter $18.49

Time periods: Summer 5 months, Winter 7 months

Existing pumps: 20 hp

Energy use per hour: 15 kWh

Energy Cost offset: $0.145/ kWh (purchase price for PV)

Acceptable flow for reduced rate: 10 hp

Energy use per hour: 6.5 kWh

Number of hours at 20 hp per year

Number of hours at full flow 25% (2,190 hrs/ yr)

Number of hours using at 10 hp per year

Number of hours at reduce flow extended time (4,050 hr/yr)

<u>Existing Energy Consumption:</u>

Consumption Impact:

2,190 hours/yr * 15 kWh = 32,850 kWh/yr

Total Consumption Impact: 32,850 kWh/yr * $0.145/kWh = $4,763/yr

Demand Impact:

Summer: 5 months * 15 kW * $26.43/kW/month = $1,982/yr

Winter: 7 months * 15 kW * $18.49/kW/month = $1,941/yr

Total Demand Impact: $1,982/yr + $1,941/yr = $3,923/yr

<u>Enhanced Condition Energy Consumption:</u>

Consumption Impact:

4,050 hours/yr * 6.5 kWh = 26,325 kWh/yr

Total Consumption Impact: 26,325 kWh/yr * $0.145/kWh = $3,817/yr

Demand Impact:

Summer: 5 months * 6.5 kW * $26.43/kW/month = $860/yr

Winter: 7 months * 6.5 kW * $18.49/kW/month = $841/yr

Total Demand Impact: $860/yr + $841/yr = $1,701/yr

Yearly Savings Summary:
Annual Savings = Base Case – Enhanced Case:

Energy Consumption Savings: $4,763 - $3,817 = $946/year

Demand Savings based on VFD and full impact (no demand management)

Demand Savings: $3,923 - $1,701 = $2,222/yr

Demand Savings with Energy Management Strategy: $946 + $2,222 = $3,168

Estimated Implementation Cost:
<u>Estimated construction costs (Add VFD to existing pumps):</u>

Two VFDs for 20-hp pumps with NEMA 4 enclosure: $17,500

Installation of VFD, control panel tie-in, cross-over controls: $ 12,500

SCADA modifications and temperature control loop: $4,500

Design/CM: $4,500

Total: $39,000

Payback:
Payback = Capital cost/annual savings = $39,000 / $3,168 = 12.3 years

Recommendations:
Incorporate backwash fill and backwash return pumps into the demand response management program. VFD's are not recommended.

TWIN OAKS VALLEY WATER TREATMENT PLANT

ECO 5: Continuous Operation of Loop Pumps – Install VFD on Loop Pumps

Existing Conditions:
Twin Oaks Valley Water Treatment Plant uses a continuous operating water loop which provides water service throughout the facility including chemical addition/mixing, chemical carrier water, and other services. The system has multiple 25-hp pumps operating on a full-time basis (24 hours per day 365 days per year).

Proposed Changes:
Investigate the potential to install VFD's and/or a smaller jockey pump to reduce the water circulation rate during low operating periods. The reduction in flow rate would allow energy and cost savings. Confirmation of the minimum circulation flow will dictate the possible turn-down ratio of the existing pumps and VFD applications.

Benefit or Effect on Operations:
Reduction of loop pump rates will reduce energy use and potentially save money in operating costs.

Environmental Benefits or Consequences:
Reduction in electrical consumption would reduce energy purchase and greenhouse gas emission.

Calculations:
<u>Assumptions:</u>
One Recirculation Pump on 8,760 hours / year

Existing pumps: 25 hp

Energy use per hour: 16 kWh

Energy Cost offset: $0.145/ kWh (purchase price for PV)

Acceptable flow for reduced rate: 10 hp

Energy use per hour: 6.5 kWh

Number of hours at reduced flow 50% (4,380 hrs/ yr)

<u>Existing Energy Consumption:</u>

Consumption Impact:

8,760 hours/yr * 16 kWh = 140,160 kWh/yr

Total Consumption Impact: 140,160 kWh/yr * $0.145/kWh = $20,325/yr

Enhanced Condition Energy Consumption: Consumption Impact:

Half time at existing recirculation rate: 8,760 hours/yr * 0.5 * 16 kWh = 70,080 kWh/yr

Half time at reduced recirculation rate: 8,760 hours/yr * 0.5 * 6.5 kWh = 28,470 kWh/yr

Total Consumption per year: 70,080 kWh/yr + 28,470 kWh/yr = 99,270 kWh/yr

Total Consumption Impact: 99,270 kWh/yr * $0.145/kWh = $14,395/yr

Yearly Savings Summary:
Annual Savings = Base Case -Enhanced Case:

Energy Consumption Savings: $20,325- $14,395= $5,930/year

Estimated Implementation Cost:
Estimated construction costs (Add VFD to existing pumps):

Two VFDs for 25-hp pumps with NEMA 4 enclosure: $19,500

Installation of VFD, control panel tie-in, cross-over controls: $ 12,500

SCADA modifications and temperature control Joop: $4,500

Design/CM: $4,500

Total: $41,000

Payback:
Payback = Capital cost/annual savings = $41,000 / $5,930 = 6.9 years

Recommendations:
Conduct a site walk with an HVAC/electrical contractor to confirm budgetary costs and selection of VFD option.

TWIN OAKS VALLEY WATER TREATMENT PLANT

ECO 9: Demand Management Strategy – Install VFD on Backwash Return Pumps

Existing Conditions:
Twin Oaks Valley Water Treatment Plant uses an elevated backwash tank for the backwash operation. Each backwash is conveyed to a backwash recovery process. Following each backwash cycle, three 40-hp backwash recovery pumps return the backwash to the influent structure of the facility. Typically, the backwash fill pumps are activated based on the level within the backwash tank, which would signal a fill cycle immediately after/during a backwash cycle. It is estimated the recovery pumps operate approximately 1,000 hours per year.

Proposed Changes:
Investigate the potential to manage the demand response of the backwash recovery pumps with other batch type operations. For instance, the backwash recovery pumps pump the backwash waste to the front end of the facility after each cycle. If both the backwash recovery and the backwash tank fill pumps are operating at the same time, the combine demand impact could affect the monthly demand readings and associated costs.

In addition to demand management, installation of VFD's and/or a smaller jockey pump to reduce the water pumping rate during long periods between backwash cycles may provide some demand and energy use savings .

Benefit or Effect on Operations:
Reduction of pump rates during backwash cycles will reduce energy use and potentially save money in operating costs.

Environmental Benefits or Consequences:
Reduction in electrical consumption would reduce energy purchase and greenhouse gas emission.

Calculations:
Assumptions:
Shift backwash recovery pumps to non-impact periods of the day

Demand savings one pump: 25 kW

Savings (Peak and Non-coincident): Summer $26.43; winter $18.49

Time periods: Summer 5 months, Winter 7 months

Existing pumps: 40 hp

Energy use per hour: 25 kWh

Energy Cost offset: $0.145/ kWh (purchase price for PV)

Acceptable flow for reduced rate: 25 hp

Energy use per hour: 15 kWh

Number of hours at 40 hp per year

Number of hours at full flow 15% (1,000 hrs/ yr)

Number of hours using at 25 hp per year

Number of hours at reduce flow extended time (2,000 hr/yr)

<u>Existing Energy Consumption:</u>

Consumption Impact:

1,000 hours/yr * 25 kWh = 25,000 kWh/yr

Total Consumption Impact: 25,000 kWh/yr * $0.145/kWh = $3,625/yr

Demand Impact:

Summer: 5 months * 25 kW * $26.43/kW/month = $3,305/yr

Winter: 7 months * 25 kW * $18.49/kW/month = $3,235/yr

Total Demand Impact: $3,305/yr + $3,235/yr = $6,540/yr

<u>Enhanced Condition Energy Consumption:</u>

Consumption Impact:

2,000 hours/yr * 15 kWh = 30,000 kWh/yr

Total Consumption Impact: 30,000 kWh/yr * $0.145/kWh = $4,350/yr

Demand Impact:

Summer: 5 months * 15 kW * $26.43/kW/month = $1,985/yr

Winter: 7 months * 15 kW * $18.49/kW/month = $1,941/yr

Total Demand Impact: $1,985/yr + $1,941/yr = $3,926/yr

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Yearly Savings Summary:
Annual Savings = Base Case -Enhanced Case:

Energy Consumption Savings: $3,625 - $4,350= - $725/year

Demand Savings based on VFD and full impact (no demand management)

Demand Savings: $6,540 - $3,926 = $2,614/yr

Demand Savings with Energy Management Strategy: - $725 + $2,614 = $1,889

Estimated Implementation Cost:
Estimated construction costs (Add VFD to existing pumps):

Two VFDs for 40-hp pumps with NEMA 4 enclosure: $28,500

Installation of VFD, control panel tie-in, cross-over controls: $ 17,500

SCADA modifications and temperature control loop: $8,500

Design/CM: $8,500

Total: $63,000

Payback:
Payback = Capital cost/annual savings = $63,000 / $1,889 = 33.4 years

Recommendations:
Incorporate backwash fill and backwash return pumps into the demand response management program. VFD's are not recommended.

TWIN OAKS VALLEY WATER TREATMENT PLANT

ECO 10: Demand Management Strategy – Entire Plant

Existing Conditions:
Twin Oaks Valley Water Treatment Plant is a facility with a combination of continuous and semi-continuous processes. In addition, the plant throughput varies based upon system demand. The combination of variable flow requirements and a carefully crafted operational sequence results in excellent treated water at the right time. The facility is equipped with electrical monitoring systems (sub- metering) on several of the larger Motor Control Centers (MCC). The facility is operated by an outside contractor under contract to the Water Authority. The operational contract specifies energy related metrics and "incentives" based upon the following metrics:

- Guaranteed Electrical Usage(kWh/MG),
- Guaranteed Electrical Usage (kWh),
- Guaranteed Maximum Electrical Demand (kW), and
- Guaranteed Electrical Cost ($)

Proposed Changes:
Investigate the potential to manage demand response of all variable and batch load operations including:

- Sodium hypochlorite production,
- Backwash recovery pumps,
- Backwash Tank Fill Pumps
- Sludge Dewatering
- Water Pumps

Benefit or Effect on Operations:
Reduction of energy use and potentially save money in operating costs.

Environmental Benefits or Consequences:
Reduction in electrical consumption would reduce energy purchase and greenhouse gas emission.

Calculations:
Assumptions:
Shift batch and semi-continuous loads to non-impact periods of the day

Demand savings: 100 kW; 200 kW, and 300kW

Savings (Peak and Non-coincident): Summer $26.43; Winter $18.49

Time periods: Summer - 5 months, Winter - 7 months

Enhanced Condition Energy Consumption:

100 kW Demand Impact (12 Months):

Summer: 5 months * 100 kW * $26.43/kW/month = $13,215/yr

Winter: 7 months * 100 kW * $18.49/kW/month = $12,943/yr

Total Demand Impact: $13,215/yr + $12,943/yr = $26,158/yr

200 kW Demand Impact (12 Months):

Summer: 5 months * 200 kW * $26.43/kW/month = $26,430/yr

Winter: 7 months * 200 kW * $18.49/kW/month = $25,886/yr

Total Demand Impact: $26,430/yr + $25,886/yr = $52,316/yr

300 kW Demand Impact (12 Months):

Summer: 5 months * 300 kW * $26.43/kW/month = $39,645/yr

Winter: 7 months * 300 kW * $18.49/kW/month = $38,829/yr

Total Demand Impact: $39,645/yr + $38,829/yr = $78,474/yr

Estimated Implementation Cost:
Estimated Costs for integration of Demand Response into SCADA (Assume 100kW Scenario):

Supplemental sub-metering: $20,000

Demand Response Software and Integrator: $ 25,000

Design/CM: $7,500

Rebate from SDG&E $100/kW reduction: $100* 100 kW= $10,000 (incentive)

Total: $ 52,500 - $10,000 Rebate = $42,500

Payback:
Payback = Capital cost/annual savings = $42,500 / $26,158 = 1.6 years

Recommendations:
Implement Demand Response Program and request SDG&E incentive to partially offset implementation costs.

Appendix D

EMISSIONS REDUCTIONS FOR 2020 AND 2030: EXISTING MEASURES AND ADDITIONAL OPPORTUNITIES

Emissions Reductions for 2020 and 2030: Existing Measures and Additional Opportunities

Greenhouse gas (GHG) emissions reductions include those that have been implemented since the 2009 baseline emissions inventory and those anticipated to be implemented by 2020 and 2030. These consist of reduction strategies put in place by federal or state agencies or that the Water Authority has implemented since 2009. These strategies will result in a different emissions profile than the BAU scenario detailed in Appendix B and is referred to as an "adjusted BAU" scenario. Reduction measures implemented by federal, state, and local measures from 2009-2018 are accounted for in the 2018 annual emissions inventory. This appendix estimates the reduction potential of these actions from 2018 to 2020 and 2030.

Additional opportunities are those that the Water Authority is evaluating and may implement in the future, which would lead to even greater emissions reductions. This appendix details the existing strategies that will result in GHG emissions reductions and analysis of additional opportunities.

This appendix was originally prepared in 2012 during the initial stages of CAP preparation. The CAP was finalized in March 2014. While the Water Authority was preparing the first CAP annual monitoring report in 2015, an inconsistency with the 2009 energy usage data was identified, and it was determined that the original 2009 inventory and the updated inventory incorporated into the emissions reduction projection had double-counted certain entries for electricity and natural gas bills. This resulted in an over-estimation of emissions related to energy usage. This version considers the error found in the original appendix and has updated all numbers accordingly.

Existing Measures

State and Federally Implemented Measures

Existing measures include federal and state regulation that will be implemented by 2020 and 2030. As described in Appendix B, regulations in place could be quantified as "business-as-usual (BAU)" or as future reductions. Both approaches result in the same amount of emissions reductions. The Water Authority has identified them as reduction strategies, including renewable energy production, water conservation, and transportation-related measures. However, as described in the CAP, due to uncertainties about how some of these programs will be implemented and/or would be reflected in the Water Authority's emissions profile, only the state's Renewables Portfolio Standard (RPS) has been separately quantified and included as a reduction for CAP target achievement purposes. Note that previous versions of the CAP included reduction estimates associated with implementation of the state's Low Carbon Fuel Standard (LCFS), but due to methodological changes in evaluating how implementation of that program will occur, those reductions have conservatively been omitted from this CAP.

Table D-1 summarizes the state and federal regulations that are likely to result in emissions reductions in the Water Authority's future GHG inventories and includes the quantified reductions from implementation of the RPS.

Table D-1. Emissions Reductions from Federal and State Measures

Reduction Source	2020 MT CO_2e	2030 MT CO_2e
Reductions from RPS		
Energy	-	(481)
Reductions from SB X7-7, AB 1668, SB 606		
Water	Potential reductions not accounted for in this analysis	
Reductions from CAFE + LCFS		
Transportation	Potential reductions not accounted for in this analysis	
Total Reductions from State and Federal Measures	**-**	**(481)**

Notes: Negative number indicates GHG reduction.

Renewables Portfolio Standard

California has required increasingly stringent requirements for utilities to generate electricity with renewable sources in a group of legislation collectively known as the Renewables Portfolio Standard (RPS). Currently, utilities are required to generate 33% of their energy through renewables by 2020, and 60% by 2030. San Diego Gas and Electric (SDG&E), which is the utility that serves the Water Authority, has attained 44% renewable generation through a variety of projects as of 2017, including major solar installations (https://webarchive.sdge.com/renewables). SDG&E has exceeded their 33% goal by 2020, which will result in GHG reductions to the Water Authority by reducing the emission factor of electricity consumption. Emission factors indicate the level of GHG intensity in an activity, such as the GHG emitted per kilowatt-hour (kWh) of electricity use. The Water Authority anticipates 481 MT CO_2e reductions in 2030 below the 2030 BAU estimated levels due to full implementation of this measure (Table D-1). The Water Authority has conservatively assumed 0 MT CO_2e of reductions in 2020 associated with RPS implementation because SDG&E had already achieved the 2020 RPS requirements as of the 2018 inventory year. The Water Authority has assumed that SDG&E will not increase its RPS position beyond its 2018 levels until after the 2020 RPS target year.

Transportation Measures

California and the federal government agreed on a single set of fuel-efficiency standards for passenger vehicles manufactured between 2012 and 2025; these standards are increasingly stringent each year. These are referred to as the Corporate Average Fuel Economy (CAFE) Standards and apply only to on-road vehicles. As drivers purchase newer vehicles with better fuel economy, emissions will decrease even under static estimates of total vehicle miles traveled (VMT). The emissions reductions associated with implementation of this legislation will vary depending on the turnover rate of employee commute vehicles. Due to the relatively small employee vehicle fleet compared to the statewide total vehicle fleet, future emissions reductions associated with this legislation were conservatively omitted from this analysis for the employee commute sector of the Water Authority's inventory. However, average fleet emissions factors will be collected during future inventories when estimating emissions from this source and will therefore reflect implementation of this legislation at that time.

The Low Carbon Fuel Standard (LCFS) requires the carbon intensity of California's transportation fuels to be reduced by at least 10% by 2020 and 20% by 2030. The LCFS is a performance standard with compliance mechanisms that incentivize development of a diverse set of clean, low-carbon transportation fuel options to reduce GHG emissions. Although it is applicable to all three transportation-related sectors in the Water Authority's inventory (i.e., employee commutes, vehicle fleet, and off-road equipment), emissions reductions from this program were not estimated as the LCFS requirements may be achieved through actions applicable to various stages of the fuel production lifecycle. Therefore, the rate of emissions reductions that would be realized as tailpipe emission reductions is currently unknown. However, these reductions will be reflected in future emissions inventories through use of updated emissions factors that account for the most current carbon intensity of California's transportation fuels.

Federal and State Summary

Because of full implementation of federal and state strategies already in place, the Water Authority will realize a net GHG reduction of 481 MT CO_2e in 2030 (Table D-1).

Locally Implemented Measures

The Water Authority has long been concerned with energy efficiency and sustainability. As a result, it has implemented strategies since the 2009 baseline emissions inventory; these strategies resulted in GHG reductions, including solar panel installation, vehicle fleet upgrades, and energy efficiency measures in Water Authority operations.

Solar Panels

The Water Authority entered into a power purchase agreement with CleanCapital to install, operate, and maintain solar photovoltaic (PV) systems at three locations: Twin Oaks Valley Water Treatment Plant (WTP), Headquarters in Kearny Mesa, and the Operations Center in Escondido. The solar energy systems were installed at no cost to the Water Authority through a 20-year contract with CleanCapital. The Company owns and operates the systems and sells the energy to the Water Authority at a reduced and fixed rate with an annual price escalation factor. Power generated by the solar power systems reduces the Water Authority's energy costs, making agency operations more efficient for ratepayers. Combined, they will cut the agency's energy expenses by nearly $3 million over 20 years. Through its agreement, the Water Authority cannot "take credit" for the solar power generated by these systems; however, it is helping SDG&E meet its RPS goal, which indirectly helps the Water Authority's reduction targets by lowering the SDG&E emissions factor. Combined, the solar panels produce nearly 2.5 million kWh of electricity per year, accounting for 55% of the energy needs at Headquarters, 38% of the energy needs at Escondido, and 31% of energy needs at the Twin Oaks Valley WTP.

Vehicle Fleet

The Water Authority manages a fleet of approximately 90 vehicles used for maintenance and repair of facilities. In parallel with its other sustainability and conservation efforts, it has implemented strategies to reduce fuel consumption and VMT. To date, the Water Authority has installed Global Positioning System (GPS) units in most of its fleet to improve vehicle dispatch and allow for data collection on vehicle performance. In addition, the Water Authority retired vehicles that were less efficient and underutilized and has replaced three passenger vehicles with hybrid vehicles. The Water Authority has replaced 61 vehicles since 2014 and have resulted in better fuel economy. No specific analysis was done to determine savings in fuel or reduction of GHG emissions by the turnover of fleet vehicles.

Energy Conservation Opportunities

The Water Authority conducted an Energy Audit in 2012 that detailed several opportunities to reduce energy or energy-related costs, referred to as energy conservation opportunities (ECOs) (see Appendix C). Since 2012, 49 ECOs have been implemented, 8 ECOs since 2014, including variable-frequency drive systems for pump operations in the Twin Oaks Valley WTP (see Table D-2). Based on the estimated energy savings calculated in the Energy Audit, the Water Authority has already implemented strategies resulting in savings of 197,000 kWh per year since 2014, which translates in lower GHG emissions.

Table D-2. Energy Conservation Opportunities (ECO) Implemented since 2014

Class	Facility - ECO Description	Simple Payback Term (Estimate)Yrs.	Cost	Annual Energy Savings (kWh)	Estimated Annual Savings	Completed
Lights & HVAC	Escondido Ops Center - Evaluate SDG&Es recommendation to change to the ALTOU rate to DGR.	Immediate	$0	0	$5,556	2014
Process	Lake Hodges Hydroelectric Facility - Monitor block loads of support equipment including HVAC, cooling and service water, and compressed air. (Complete an energy assessment after 1-yr of full operation).	Short-term (<5 years)	$0			2014
Process	Escondido Ops Center - Re-commission (re-balance) new HVAC systems.	Short-term (<5 years)	$0			2014
Equipment	TOWTP - Evaluate continuous recirculation water loop pumps (25-hp constant speed operations).	Short-term (6.9 years)	$41,000	140,160	$26,630	2014
Lights	Lake Hodges Hydroelectric Facility - T-12 Upgrades.	4.7yrs @ 8760hrs 8.7yrs @ 3760hrs	$26,400	33,900	$4,712	2014-2015
Lights	Lake Hodges Hydroelectric Facility -Replace Interior Metal Halide Lights.	.5yrs @ 8760hrs 1.1yrs @ 3760hrs	$4,800	23,100	$3,211	2014-2015
Equipment	Valley Center PS - If the pump station will be used in the future, upgrade pumps to improve efficiency.	Short-term (<5 years)	$10,000			2014-2015

Class	Facility - ECO Description	Simple Payback Term (Estimate)Yrs.	Cost	Annual Energy Savings (kWh)	Estimated Annual Savings	Completed
Equipment	Escondido Ops Center - Warehouse Lighting Upgrade.	Short-term (<5 years)	$800	-	$0	2014

Summary of Existing Measures

Measures and strategies being implemented today through 2030 by federal, state, and local actions will result in reductions totaling 634 MT in 2020 and 1,276 MT in 2030 (Table D-5). This results in an adjusted BAU scenario in which the Water Authority is offsetting enough emissions in 2020 and 2030 to meet the state aligned goals of AB 32 and SB 32.

Table D-3. Summary of Water Authority Emissions and Targets

	2018 MT CO2e	2020 MT CO2e	2030 MT CO2e
Business-As-Usual Emissions	3,099	3,047	3,061
State and Federal Reductions	0	0	(481)
Local Reductions	No Estimate Developed		
Emissions w/ Existing Reduction Measures	**3,099**	**3,047**	**2,580**
State Aligned Target	**NA**	**4,961**	**2,976**
Overall MT CO_2e Below Target	**0**	**1,914**	**396**
Meeting Target		YES	YES

Estimated construction emissions for 2018 and 2020 are 382 and 131 MT CO_2e, respectively; the construction emissions for 2030 are based on an annual average from 2020 to 2024, which is 596 MT CO_2e. Adding the BAU and construction emissions provides the total emissions produced for the year. Subtracting federal, state, and local emissions due to reduction measures per table D-3 shows the Water Authority meeting the goals for 2020 and not meeting goals for 2030 (see Table D-4 for details). This excludes additional measures that can be implemented by the Water Authority to reduce emissions.

Table D-4. Summary of Water Authority Emissions and Targets Accounting for Construction Emissions

	2018 MT CO_2e	2020 MT CO_2e	2030 MT CO_2e
Business-As-Usual Emissions	3,099	3,047	3,061
Construction Emissions	382	131	596
Federal, State, and Local Reduction Measures	0	0	(481)
Emissions w/ Existing Reduction Measures	**3,481**	**3,178**	**3,176**
State Aligned Target	**NA**	**4,961**	**2,976**
Overall MT CO_2e Below Target	**0**	**1,783**	**(200)**
Meeting Target		YES	NO

References

California Air Resources Board (ARB). 2010. Local Government Operations Protocol, version 1.1 .

California Public Utilities Commission (CPUC). 2013. California Renewables Portfolio Standard (RPS). Available at: http://wym.cpuc.ca.gov/PUC/energy/Renewables/index.htm. Last accessed October 9, 2013.

U.S. Environmental Protection Agency (EPA). 2013 Office of Transportation and Air Quality. Fuel Economy. Available at http://fueleconomy.gov/.

Appendix E

CLIMATE ACTION PLAN 2019 ANNUAL UPDATE TECHNICAL MEMORANDUM

June 2020

CLIMATE ACTION PLAN

2019 ANNUAL EMISSIONS INVENTORY UPDATE TECHNICAL MEMORANDUM

Our Region's Trusted Water Leader
San Diego County Water Authority

The San Diego County Water Authority (Water Authority) adopted a Climate Action Plan (CAP) in March 2014, updated the CAP in 2015, and is currently developing a CAP update. As part of the CAP process, the Water Authority developed a greenhouse gas (GHG) inventory for the year 2009, which serves as the baseline for establishing reduction goals and is referred to as the “baseline” emissions inventory. The CAPs establish emissions reduction targets and projected GHG emissions for the years 2020 and 2035. To ensure that the Water Authority is monitoring its GHG emissions reduction efforts relative to its projections documented in the CAP, the Water Authority has committed to track progress on an annual basis starting in 2014 and update the CAP every 5 years starting in 2014.

This annual report includes (1) a summary of the 2009 baseline emissions, (2) an estimate of emissions for 2014 through 2019 calendar years, and (3) an assessment of progress toward the 2020 emission reduction goals. The updated emission estimates for the 2019 calendar year included operational emissions and sectors consistent with the GHG inventory in the CAP to understand the relative change for each sector since the baseline year. In addition, the update provides comparisons to previous years and tracks yearly emissions trends.

Emission Sources

The Water Authority CAP and annual report include the following emission sources:

- Electricity
- Natural Gas
- Vehicle Fleet
- Employee Commute
- Off-Road Equipment
- Stationary Source
- Water
- Solid Waste
- Wastewater
- Refrigerants

The emission estimates for the 2019 calendar year included updates to energy consumption (electricity and natural gas), vehicle fleet, employee commute, off-road equipment, stationary sources, water, solid waste, and wastewater. The additional sector mentioned above (refrigerants) are not substantial sources of emissions and not updated for the annual report. For purposes of calculating total estimated emissions, the sources for which 2019 emissions were not obtained (refrigerants) were assumed to be consistent with the 2009 baseline numbers listed in the CAP. Difficult to obtain emission sources (refrigerants) will be revisited during the next annual inventory and are mainly minor contributors to total emissions.

Summary of 2009 Emissions

In 2009, the Water Authority generated approximately 5,837 metric tons (MT) of carbon dioxide equivalent (CO_2e) emissions. Electricity and natural gas consumption (4,191 MT CO_2e) accounted for approximately 72% of the Water Authority’s emissions in 2009. The next largest sectors in the inventory were emissions from the vehicle fleet and employee commute sectors, respectively. Approximately 694 MT CO_2e emitted in 2009 were from operation of fleet vehicles, representing less than 12% of the overall emissions. Employee commute (685 MT CO_2e) accounted for approximately 12% of total emissions. Additional sectors from the CAP that are responsible for the remaining 4% of the emissions include stationary sources, off-road equipment, solid waste, water consumption, refrigerants, and wastewater. Water consumption, refrigerants, and wastewater combined only contributed 0.12% of total emissions for 2009.

Methodology

The 2019 emissions inventory was updated using the same methodology as the CAP and was based on the Local Government Operations Protocol (LGOP)[1]. The LGOP provides a standardized set of guidelines to assist local governments in quantifying and reporting GHG emissions associated with operations; these guidelines are applicable to the emissions of the Water Authority.

Water Authority staff provided the necessary data for estimating the 2019 GHG emissions. Energy consumption data from utility bills at each Water Authority facility with an electricity and natural gas meter was used for the annual report. Total fuel consumption and mileage data were provided for all light-duty and heavy-duty on-road vehicles operating in 2019. The Water Authority also provided information on the number of employees and work schedule (e.g., number of employees working 9/80 schedule) to estimate employee commute emissions. Annual fuel consumption, including gallons of gasoline and diesel, was used to estimate emissions from off-road equipment and stationary sources (e.g., generators). Water consumption data from utility bills at each Water Authority facility with a water meter was used for the annual report.

2019 Emissions Inventory Update

As discussed in the CAP, reporting emissions by sector is useful in understanding the impact of GHG-reduction measures and the process to meet emission reduction goals in the CAP. Table 1 shows the Water Authority's emissions by sector from the 2009 CAP and the 2014-2019 annual reports.

[1] The Water Authority completed its 2009 GHG emissions inventory in 2011, following the Climate Registry's General Reporting Protocol. As part of the CAP process, the Water Authority and its consultant reviewed the inventory ensuring consistency with current methodologies, practices, and guidance within California. The 2009 baseline emissions inventory was updated in 2015 using the Local Government Operations Protocol (LGOP).

Table 1. Greenhouse Gas Emissions by Sector (MT CO_2e)

Emissions Sector	2009 Baseline	2014 Annual Report	2015 Annual Report	2016 Annual Report	2017 Annual Report	2018 Annual Report	2019 Annual Report
Electricity	4,133	2,432	2,343	1,938	2,457	1,728	1,622
Vehicle Fleet	694	509	976	694	1,027	634	642
Employee Commute	685	655	558	562	572	607	619
Off-Road Equipment	143	32	33	29	34	22	30
Stationary Source	89	204	17	61	86	26	24
Natural Gas	58	58	58	59	19	54	55
Solid Waste	27	26	23	24	22	24	25
Water	4	4	4	4	4	2	3
Refrigerants[1]	2	2	2	2	2	2	2
Wastewater	1	1	1	1	1	1	1
Total[2]	5,837	3,924	4,016	3,375	4,225	3,099	3,024

[1] Emissions estimates for these sources are based on 2009 for refrigerants.
[2] Emissions may not add to total due to rounding.

As shown in Table 1, total GHG emissions decreased from an estimated baseline of 5,837 MT CO_2e in 2009 to an estimated 3,024 MT CO_2e in 2019 but increased from years 2014-2017, with a decrease in 2016. The total GHG for 2019 decreased nearly 28% from 2017, mainly due to a decrease in electricity and vehicle fleet emissions. The sectors with the highest percentage in the inventory continue to be electricity, vehicle fleet, and employee commute. Electricity emissions still make up the majority of emissions (nearly 54% of total emissions in 2019) but are account for a lower percentage than 2009 levels (70%). This overall reduction stems from a combination of reduced emission factors and measures implemented by the Water Authority. As San Diego Gas & Electric (SDG&E) increases the incorporation of renewable energy sources for electricity in its energy portfolio the emission factors associated with SDG&E-provided electricity consumed by the Water Authority decrease. Reduced electricity consumption, and therefore reduced emissions, has also been achieved through various energy conservation opportunities (ECOs) implemented by the Water Authority throughout their system including the installation and operation of solar panels at Twin Oaks Valley Water Treatment Plant, the San Diego Headquarters Building in Kearny Mesa, and the Escondido Operations Center, which are designed to produce nearly 2.5 million kilowatt hours of electricity per year. Vehicle fleet emissions in 2019 decreased from 2017 by approximately 38%; a result of a newer vehicle fleet and lower miles driver per vehicle for the year. Employee commute in 2019 shows a slight increase in emissions from 2017 (8%), but an overall decrease from 2009 (nearly 10%).

Emissions by Scope

Consistent with the LGOP and the CAP, the 2019 annual report also organizes the GHG emissions by scope. Scope 1 emissions include all direct GHG emissions, such as the combustion of fossil fuel. Direct GHG emissions include natural gas consumption, vehicle fleet, off-road equipment, stationary sources, and refrigerants. Scope 2 emissions include indirect GHG emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling. Scope 2 emissions also include electricity and water use. Scope 3 emissions include all other indirect emissions not covered in Scope 2, such as emissions resulting from the transport-related activities in vehicles not owned or controlled by the reporting entity. Scope 3 emissions include employee commute, wastewater, and solid waste disposal. Estimated GHG emissions broken down by scope are shown below in Table 2.

Table 2. Greenhouse Gas Emissions by Scope (MT CO_2e)

Emissions Source	2009 Baseline	2014 Annual Report	2015 Annual Report	2016 Annual Report	2017 Annual Report	2018 Annual Report	2019 Annual Report
Scope 1	985	805	1,086	845	1,168	737	753
Scope 2	4,138	2,436	2,347	1,942	2,461	1,730	1,625
Scope 3	714	683	583	587	596	633	645
Total	5,837	3,924	4,016	3,375	4,225	3,099	3,024

Note: Emissions may not add to total due to rounding.

As shown in Table 2, estimated emissions were reduced for all scopes (Scope 1, 2, and 3) from 2009 to 2019. The estimated emissions for Scope 3 did increase from 2017 to 2019, primarily due to an increase in employee commute. Scope 2 emissions make up the largest percentage of the inventory in 2009 and 2014-2019.

Emissions by Source

The emissions sources included in the 2009 inventory and the 2014-2019 annual reports are purchased electricity, gasoline fuel, diesel fuel, distillate fuel oil, natural gas, other, and refrigerants. As shown in Table 3, purchased electricity accounts for most of emissions in 2009 and 2014-2019, followed by gasoline and diesel fuel use.

Table 3. Greenhouse Gas Emissions by Source (MT CO_2e)

Emissions Source	2009 Baseline	2014 Annual Report	2015 Annual Report	2016 Annual Report	2017 Annual Report	2018 Annual Report	2019 Annual Report
Purchased Electricity	4,138	2,436	2,347	1,942	2,461	1,730	1,625
Gasoline fuel	1,172	969	1,302	1,084	1,388	1,044	1,081
Diesel fuel	354	230	272	263	309	244	235
Distillate Fuel Oil No. 1	84	202	10	-	23	-	-
Natural Gas	58	58	58	59	19	54	55
Other	28	27	24	25	24	26	26
Refrigerants	2	2	2	2	2	2	2
Total	5,837	3,924	4,016	3,375	4,225	3,099	3,024

Note: Emissions may not add to total due to rounding.

Progress toward 2020 Goals

To demonstrate consistency with the AB 32 GHG target, the Water Authority set a 2020 target (referred to as the 1990 equivalent) to reduce emissions to 15% below baseline 2009 levels, which approximates a return to 1990 levels. The current CAP was developed to establish a new 2030 GHG target to achieve emissions reductions of 40% below the 1990 equivalent (2020 target), aligned with the state's target set in 2016 in Senate Bill (SB) 32. Table 4 compares 2009 baseline emissions and the 2014-2019 estimates in comparison to the 2020 goal established in the CAP.

Table 4. Total GHG Emissions (MT CO_2e)

	2009 Emissions	2014 Emissions Estimates	2015 Emissions Estimates	2016 Emissions Estimates	2017 Emissions Estimates	2018 Emissions Estimates	2019 Emissions Estimates	2020 Goal
Total Emissions	5,837	3,924	4,016	3,375	4,225	3,099	3,024	4,961

As shown in Table 4, estimated Water Authority emissions in 2019 have already met the 2020 emissions goal stated in the CAP. Figure 1 is a line graph showing progress toward this goal. The upward trend from 2016 to 2017 was due to an increase of fleet vehicles, higher miles driven per vehicle, and higher electricity use.

Figure 1. Comparison of Estimated Emissions to CAP Goals