FINAL
MARCH 2014

San Diego County Water Authority

San Diego County
Water Authority

CLIMATE ACTION PLAN

ACKNOWLEDGMENTS

Board of Directors

Thomas V. Wornham (Chair)
Mark Weston (Vice Chair)
Michael T. Hogan (Secretary)
Gary Arant
David Barnum
Brian J. Brady
Gary Croucher
Farrah G. Douglas
Betty Evans
Ed Gallo
Frank Hilliker
Bill Horn
Jerome M. Kern
Keith Lewinger
John B. Linden
Jim Madaffer
Marty Miller
Ron Morrison
Vincent Mudd
Mark Muir
James Murtland
Ken Olson
Bud Pocklington
Dennis Sanford
Javier Saunders
Elsa Saxod
John Simpson
Fern Steiner
Bob Topolovac
Yen C. Tu
DeAna Verbeke
Ron Watkins
Mark Watton
Barbara Wight
Kenneth Williams
Doug Wilson

San Diego County Water Authority Staff

Dave Chamberlain
Gary Eaton
Kelley Gage
Greg Ortega
Larry Purcell
Ken Weinberg

San Diego County
Water Authority

LIST OF ACRONYMS

2010 UWMP	2010 Urban Water Management Plan
2013 Master Plan Update	2013 Regional Facilities Optimization and Master Plan Update
AB	Assembly Bill
AF	acre feet
ARB	California Air Resources Board
BAU	business as usual
CAFE	Corporate Average Fuel Economy
CAP	Climate Action Plan
CCAR	California Climate Action Registry
CEQA	California Environmental Quality Act
cfs	cubic feet per second
CH_4	methane
CIP	capital improvement program
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CPUC	California Public Utilities Commission
ECO	energy conservation opportunity
EIR	environmental impact report
ESP	Emergency Storage Project
GHG	greenhouse gas
GWP	global warming potential
HFC	hydrofluorocarbon
HOA	homeowner's association
hp	horsepower
HVAC	heating, ventilation, and air conditioning
ICLEI	International Council for Local Environmental Initiatives
kWh	kilowatt hour
LCFS	Low Carbon Fuel Standard
LGOP	Local Government Operations Protocol
MMT	million metric tons
MT	metric ton
MTFRSII	Mission Trails Flow Regulatory Structure II
MW	megawatt
MWh	megawatt hour
N_2O	nitrous oxide
PCHF	pressure control and hydroelectric facility
PFC	perfluorocarbon
PV	photovoltaic
REC	renewable energy credit
RPS	Renewable Portfolio Standard
SB	Senate Bill
SDG&E	San Diego Gas & Electric
SF_6	sulfur hexafluoride
SUV	sport utility vehicle
UWMP	Urban Water Management Plan
VFD	variable-frequency drive
Water Authority	San Diego County Water Authority
WTP	water treatment plant

TABLE OF CONTENTS

APPENDICES

EXECUTIVE SUMMARY

The State of California has adopted policies and goals to reduce human emissions of greenhouse gases (GHGs). In response, the San Diego County Water Authority (Water Authority), as a local government agency, has voluntarily developed a Climate Action Plan (CAP). This CAP examines Water Authority activities, with a goal of minimizing GHG emissions in fulfilling its primary responsibility to provide a reliable, high-quality, and safe water supply to the San Diego region. The Water Authority has already taken great strides in reducing emissions, optimizing efficiency, and providing a leadership role for energy management in the community.

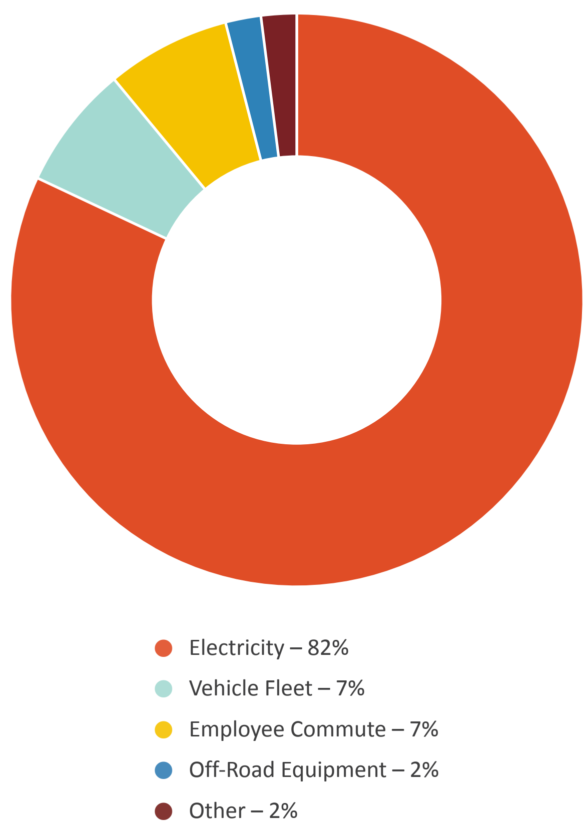
The Water Authority is one of the first local agencies to undertake a GHG emissions inventory and develop a CAP that identifies emissions reduction strategies consistent with state goals for attainment by 2020. This CAP allows the Water Authority to look at agency-wide emissions and use its unique resources to reduce those emissions. In addition, this CAP fulfills the requirements of a qualified GHG reduction plan under the California Environmental Quality Act (CEQA) by including the following:

- current and future GHG emissions estimates,
- GHG reduction goals,
- measures to meet those goals, and
- a mechanism to monitor progress.

Assessment of the potential impacts resulting from the CAP pursuant to CEQA is presented in a Supplemental Program Environmental Impact Report.

The Water Authority's GHG emissions inventory for 2009 totaled 9,325 metric tons, predominately from electricity required for water conveyance and treatment (see Figure ES.1). Consistent with adopted state policy, a goal to reduce those emissions by at least 15% by 2020 is established in the CAP, and it is recognized that there is a need to continue to manage and reduce or offset emissions, if possible, beyond 2020.

FIGURE ES.1 **2009 Baseline Emissions by Sector**

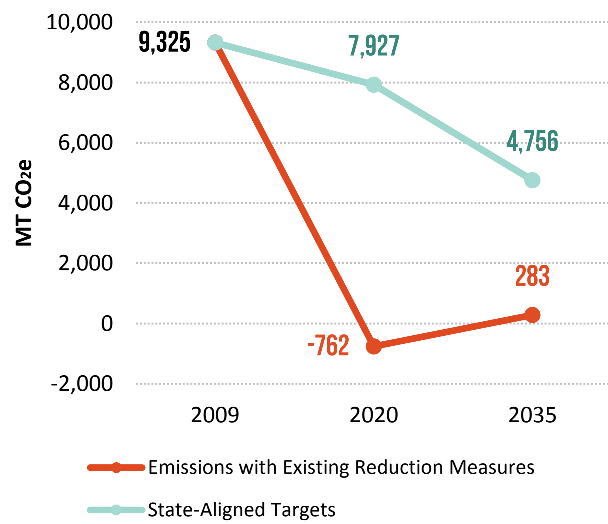


The Water Authority will meet and exceed reduction targets for 2020 and will offset its emissions well into the foreseeable future.

The CAP demonstrates how the Water Authority will achieve and surpass the state-aligned 2020 reduction goal, offsetting all operational emissions and demonstrate ongoing GHG reductions beyond 2020 (Figure ES.2 and Table ES.1). This will be achieved through operation of the Lake Hodges Pumped Storage hydroelectric project, working with its member agencies to meet water conservation goals, and operational changes. The CAP also identifies future opportunities to further reduce and offset emissions through development of solar and in-line hydro projects, and possibly additional pumped-storage hydroelectric projects.

The Water Authority understands that changing climate conditions has significant implications for long-term water supply planning, and the need for energy efficiency and water supply adaptations. This CAP is part of the Water Authority's commitment to energy efficiency and a contribution to attainment of state goals.

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 Emissions and Targets**

	2009 (MT CO_2E)	2020 (MT CO_2E)	2035 (MT CO_2E)
Business-as-Usual Emissions	9,325	8,295	9,916
State and Federal Reductions		(9,052)	(9,629)
Local Reductions		(4)	(4)
EMISSIONS WITH EXISTING REDUCTION MEASURES	9,325	(762)	283
STATE-ALIGNED GOAL/TARGET	9,325	7,927	4,756
OVERALL MT CO_2E BELOW TARGET[1]		8,689	4,473
MEETING GOAL/TARGET?		YES	YES

Notes: MT CO_2e = metric tons of carbon dioxide equivalent. Negative numbers (in parentheses) indicate net emissions reduction.

1 This number indicates the amount of greenhouse gases anticipated to be reduced beyond the goal, or the difference between the goal and expected emissions.


San Diego County Water Authority
4677

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.

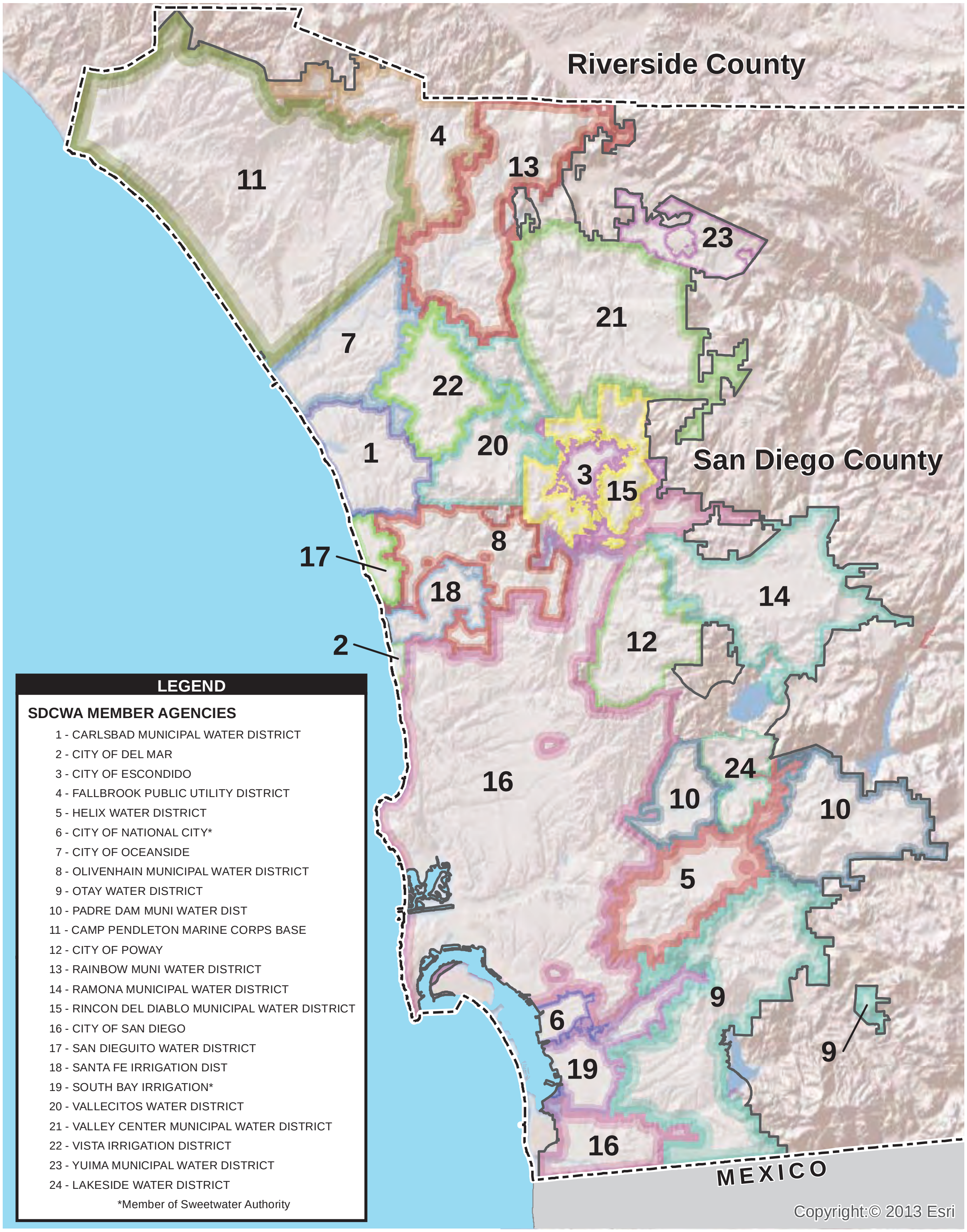
OUR MISSION

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 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**



Source: Esri 2013; SDCWA 2011, 2012; SanGIS 2013

Scale: 1:538,560; 1 inch = 8.5 miles

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. This CAP was developed in conjunction with the 2013 Regional Water Facilities Optimization and Master Plan Update (2013 Master Plan Update), which includes projects that further the Water Authority's cost- and energy-effectiveness. But the CAP goes further, quantifying emissions from all GHG-emitting sources and seeking to reduce those emissions wherever feasible.

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 Senate Bill (SB) 7X-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, and when the CAP will be updated. Chapter 6 describes the California Environmental Quality Act (CEQA) process and how this document fulfills the requirements for a GHG reduction plan under CEQA Guidelines Section 15183.5.

This CAP was developed to look comprehensively at the Water Authority's current practices and operations, and identify feasible measures that could be implemented to reduce greenhouse gas emissions and climate change impacts.

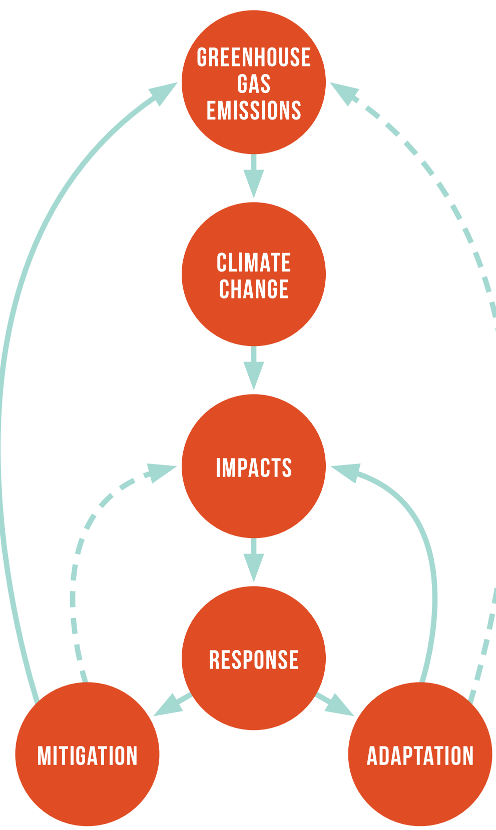
CLIMATE CHANGE SCIENCE

There is general consensus among the scientific community that certain human activities have caused increases in atmospheric GHG concentrations, which in turn have lead 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. 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 or developing additional GHG capture systems (such as tree-planting); these efforts are the focus of this CAP. Adaptation actions include limiting vulnerability to climate-change impacts through various measures, while not necessarily dealing with the underlying cause of those impacts. Adaptation actions can also act to mitigate emissions, but 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 2010 Urban Water Management Plan (2010 UWMP); the purpose of this CAP is to reduce GHG emissions.

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 2013

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.

State policy on climate change is continually evolving. The California Air Resources Board (ARB), the agency responsible for implementing Assembly Bill (AB) 32 (see box below), released a draft of the first update to the Scoping Plan in October 2013. The 2013 Draft Scoping Plan Update identifies the need to look beyond 2020 for additional reductions, but states that "2050 is too distant to form the basis for a credible policy regime for ongoing emission reductions." The Scoping Plan Update identifies 2030 as an interim planning year, with reduction levels between 33 and 44% below 1990 levels to keep the state on the path toward the 2050 goal. For the water sector specifically, the Scoping Plan Update recommends continuing water conservation strategies, developing local sources, and facilitating interagency partnerships; it does not include specific mandates or guidance for local agencies for reducing water-related GHG emissions.

RELEVANT REGULATIONS AND POLICIES

- Assembly Bill (AB) 1493 (2002) states that greenhouse gas (GHG) emissions must be reduced from passenger vehicles, light-duty trucks, and other non-commercial vehicles for personal transportation for the years 2009 through 2016.
- Executive Order S-3-05 (2005), the Greenhouse Gas Initiative, sets statewide GHG emissions targets to 2000 levels by 2010, 1990 levels by 2020, and 80% below 1990 levels by 2050.
- AB 32 (2006), the Global Warming Solutions Act, establishes that the state must reduce GHG emissions to 1990 levels by 2020.
- Senate Bill (SB) 97 (2007) established CEQA Guideline Amendments for addressing GHG emissions in CEQA documents.
- Executive Order S-1-07 (2007), the Low Carbon Fuel Standard, requires the carbon intensity of California's transportation fuels to be reduced by at least 10% by 2020.
- The AB 32 Scoping Plan (2008) describes the approach California will take to reduce GHGs to achieve the goal of reducing emissions to 1990 levels by 2020.
- SB 7X-7 (2009), the Statewide Water Conservation Strategy, requires the state to achieve a 20% reduction in per-capita urban water use by 2020.
- SB X1-2 (2011), the Renewable Portfolio Standard, states that California investor-owned utilities must provide at least 33% of their electricity from renewable resources by 2020.
- Executive Order R-12-016 (2012), the Advanced Clean Cars Package, establishes GHG emissions standards for new passenger motor vehicles for model years 2017 through 2025.

Water Authority board meeting

Regulatory Implications for the Water Authority

There are no specific GHG requirements for local agencies, but the CEQA Guidelines (as amended in 2010 from SB 97) incentivize development of plans that look comprehensively at the issue of GHG emissions, and establish goals, policies, and actions to reduce emissions. The CEQA Guidelines allow lead agencies to analyze and mitigate GHG emissions at a programmatic level such that later projects may tier from a qualified emissions reduction plan and associated environmental impact report (EIR) analysis. The later projects may find that their incremental contribution to a cumulative effect is not cumulatively considerable if the project complies with the emissions reduction plan (CEQA Guidelines Section 15183.5). 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 GHG emissions standards, such as those listed in Appendix G of the CEQA Guidelines. For a CAP to qualify as a streamlining tool, it must do the following:

- quantify GHG emissions for a baseline and future year;
- estimate the emissions level that would not be exceeded and not be considered cumulatively considerable;
- identify and analyze GHG emissions resulting from specific actions;
- develop measures that would achieve the emissions level;
- establish a mechanism to monitor progress toward achieving the emissions level and, if not met, a mechanism to require amending the CAP; and
- adopt the CAP in a public process following environmental review.

SB 7X-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 7X-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 7X-7.

SAN DIEGO LEADS THE WAY IN WATER CONSERVATION

According to a recent survey, residents in the San Diego region are the best in the country when it comes to reducing water use at home. A recent survey of respondents who said they regularly "use less water at home" found the following:

1. San Diego/Carlsbad/San Marcos: 58.8%
2. El Paso, Texas: 57.9%
3. San Francisco/Oakland/Fremont: 57.7%
4. Austin/Round Rock/San Marcos, Texas: 56.1%
5. Durham/Chapel Hill, North Carolina: 55.1%

Source: Scarborough Research, as reported in U-T San Diego 2013.

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

Reducing per-capita water demand among end-users within San Diego County will 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 2010 UWMP. This reduction was a result of many factors, including retail water suppliers meeting the goals of SB 7X-7, and helped mitigate the need for the Water Authority to develop additional water supplies for the foreseeable future (Water Authority 2011).

Although a per-capita reduction goal does not ensure overall demand reductions (total demand could still increase given population increase), conservation efforts do lower GHG emissions over a business-as-usual (i.e., no SB 7X-7) scenario. Therefore, efforts by the Water Authority's member agencies to meet SB 7X-7 requirements complement the goals of the CAP. Specific reductions in GHG emissions from conservation programs, such as those listed in the box on the opposite page, would be measured through communitywide emissions inventories that account for end-user water consumption rather than the Water Authority's emissions inventory as outlined in this CAP. However, the Water Authority's emissions will be indirectly affected by the reduction in operations on the water-supply side.

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.


Conducting a soil moisture test at a conservation nursery

REBATES, PROGRAMS, AND RESOURCES

The Water Authority is committed to conservation in all sectors. Below are some of the rebates, programs, and resources available to residents, homeowner's associations (HOAs), businesses, and the public sector.

	BUSINESS	HOA	RESIDENTIAL	PUBLIC
Agricultural Water Management	Program			
Best Management Practices	Tools & Resources			
Gardening and Landscaping Resources	Tools & Resources	Tools & Resources	Tools & Resources	Tools & Resources
High-Efficiency Clothes Washers			Rebate	
High-Efficiency Toilets	Rebate		Rebate	
Irrigation Management System and Information	Tools & Resources	Tools & Resources	Tools & Resources	Tools & Resources
Landscape Irrigation Survey	Program	Program		Program
Landscape Training Classes			Program	
Process Water Improvement Services	Program			
Recycled and Gray Water Information	Tools & Resources		Tools & Resources	Tools & Resources
Rotating Sprinkler Nozzles			Rebate	
Water-Use Calculator			Tools & Resources	
Water$mart Checkups	Program	Program	Program	Program
Water$mart Upgrades	Rebate	Rebate		Rebate
Water Savings Incentive		Program		Program
Water$mart Turf Replacement	Program	Program	Program	Program
Weather-Based Irrigation Controllers			Rebate	

PROGRAM TYPE

- Rebate
- Program
- Tools & Resources

Notes: For more information about these or other resources, see www.watersmartsd.org.

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. An accurate inventory is necessary to understand which sectors comprise the largest portion of the GHG inventory, have the most reduction potential, and can be effectively influenced by policies and actions.

STATE AND REGIONAL EMISSIONS LEVELS

The state has determined that emissions in 2020 cannot exceed 1990 levels. It has been estimated that 1990 emissions levels were 427 million metric tons (MMT) of carbon dioxide equivalent (CO_2e); in 2009, emissions were 455 MMT CO_2e. As this is a statewide goal, it is essential for residents, businesses, and agencies to do their part to meet the target. Efforts are underway within San Diego County to understand and mitigate emissions. The figure to the right shows emissions inventories for some of the larger jurisdictions within San Diego County to provide perspective on the sources and levels of emissions. The baseline emissions year used (described in the next section) and methodology may vary, so these numbers are not directly comparable; however, they provide a context for the emissions produced by the Water Authority.

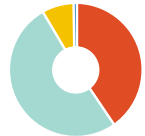
The size of each circle represents the relative emissions level for that jurisdiction and demonstrates the variability in emissions among jurisdictions in San Diego. A local agency or government operations GHG emissions inventory is similar to that of a community, but much narrower in scope. For example, 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. A local agency inventory is generally narrower in scope (of sources from which to reduce emissions), but has more control over those emissions. Community CAPs rely on all community members to participate; a local agency CAP relies on actions taken by the agency to meet reduction goals.

2008 CITY OF SAN DIEGO

12,900,000 MT CO_2e

2005 CITY OF ESCONDIDO

927,266 Metric Tons (MT) CO_2e



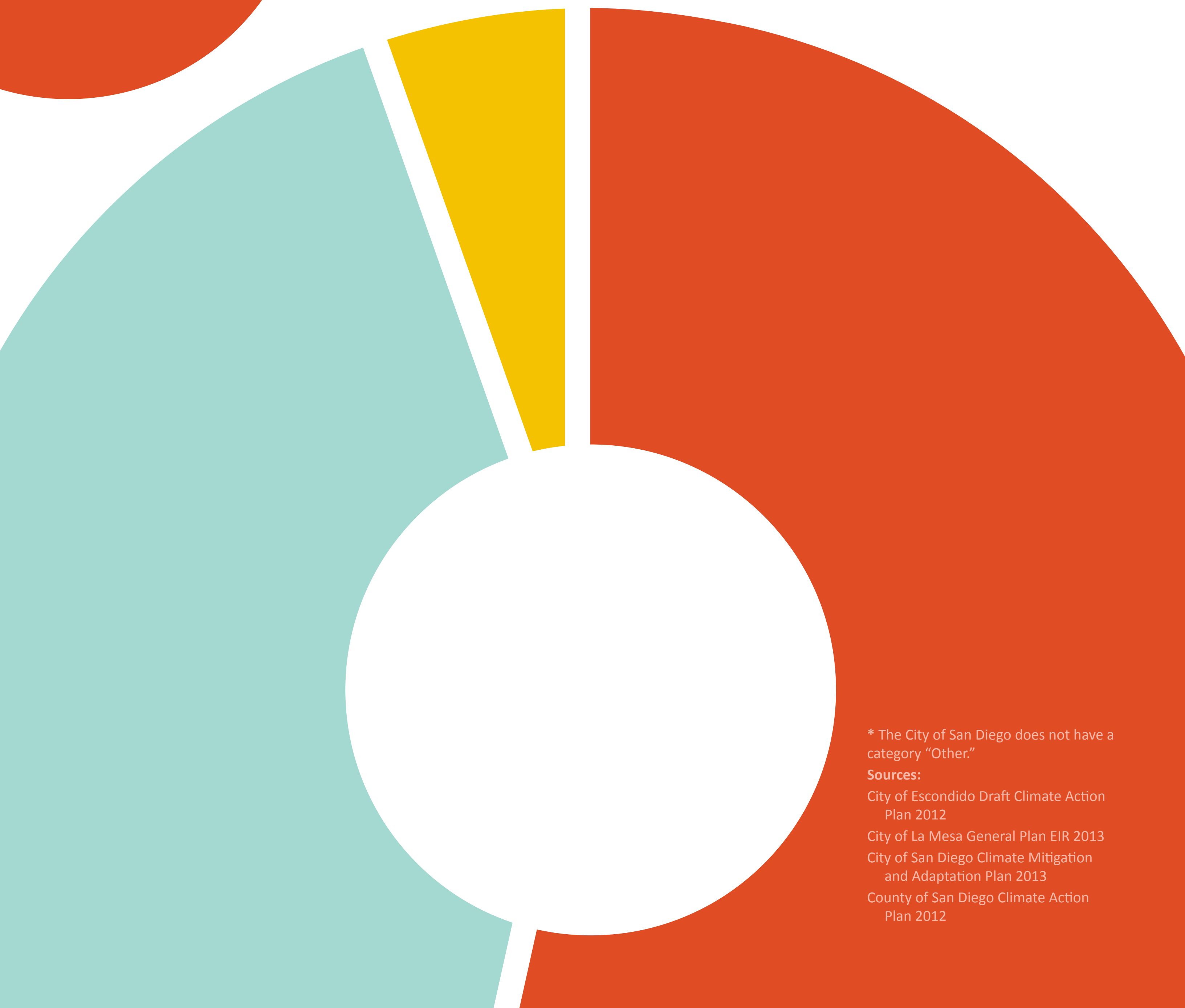
- Transportation
- Energy
- Waste & Water
- Other*

2005 COUNTY OF SAN DIEGO (UNINCORPORATED)

4,512,580 MT CO_2e

2005 CITY OF LA MESA

278,096 MT CO_2e



* The City of San Diego does not have a category "Other."

Sources:

City of Escondido Draft Climate Action Plan 2012

City of La Mesa General Plan EIR 2013

City of San Diego Climate Mitigation and Adaptation Plan 2013

County of San Diego Climate Action Plan 2012

INVENTORY APPROACH

Baseline Year

GHG inventories are generally estimated for a single calendar year, which is an international standard. Determining an appropriate inventory year depends on data availability and regulatory guidance. To demonstrate consistency with AB 32, developing an inventory for emissions in 1990 would provide a straightforward approach to determining the appropriate emissions level necessary by 2020. However, most entities do not have complete or accurate records to calculate GHG emissions from 1990, so a more current inventory is conducted. No requirements establish a specific baseline or future year for analysis, and no emissions level must be adhered to at the local level. However, the Scoping Plan developed as part of implementation of AB 32 recommends that local governments achieve a 15% reduction from "current" levels by 2020. Current levels are generally understood to be for the years 2005 through 2009, although some CAPs have used baseline years of 2004 and 2010. The Water Authority conducted an emissions inventory for 2009. This inventory serves as the basis for estimating future emissions and reduction goals, and, therefore, is referred to as the "baseline" emissions inventory.

Methodology

As a member of the Climate Registry, 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 inventory was reviewed to ensure 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 ARB, the California Climate Action Registry (CCAR), and the International Council for Local Environmental Initiatives (ICLEI) – Local Governments for Sustainability in collaboration with the Climate Registry (ARB 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 refers to the amount of energy consumed (kilowatt hours [kWh] or therms), waste produced (tons), and water used (gallons). 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 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 for calendar year 2009. 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 standard approach to developing GHG inventories.

Determining the boundary of emissions can be challenging, since agencies can lease space, be located 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 ARB for emissions reporting by large emitters; therefore, this approach, used in this CAP, provides a consistent approach with other entities, jurisdictions, and agencies in the state.

GHGs, Global Warming Potential, and CO_2e

ARB 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 "carbon dioxide (CO_2) equivalents" (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	ANTHROPOGENIC SOURCES
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

GWP = global warming potential

BASELINE EMISSIONS INVENTORY

The Water Authority's emissions for 2009 were 9,325 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.

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.

Evaluated by scope, the Water Authority's primary emissions are from Scope 2 (Figure 2.1). Scope 2 sources account for 82% of all emissions, Scope 1 sources account for 10% of emissions, and Scope 3 sources account for 8% of emissions.

Figure 2.2 illustrates emissions sources by scope.

FIGURE 2.1 **2009 Greenhouse Gas Emissions by Scope**

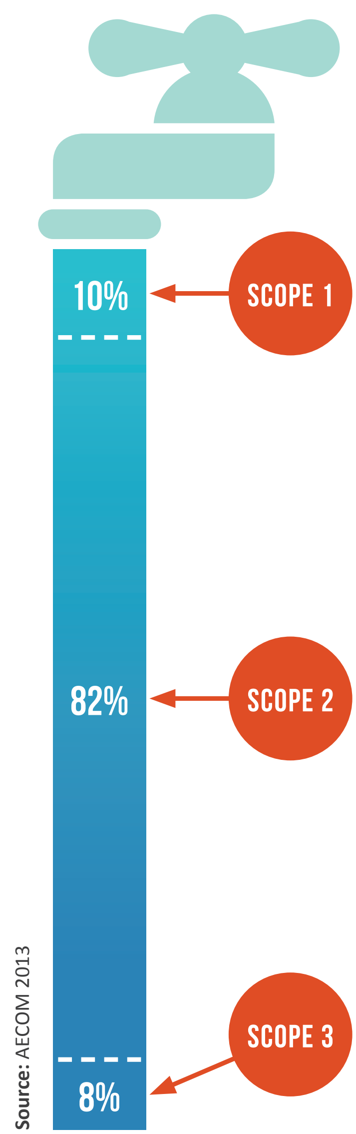
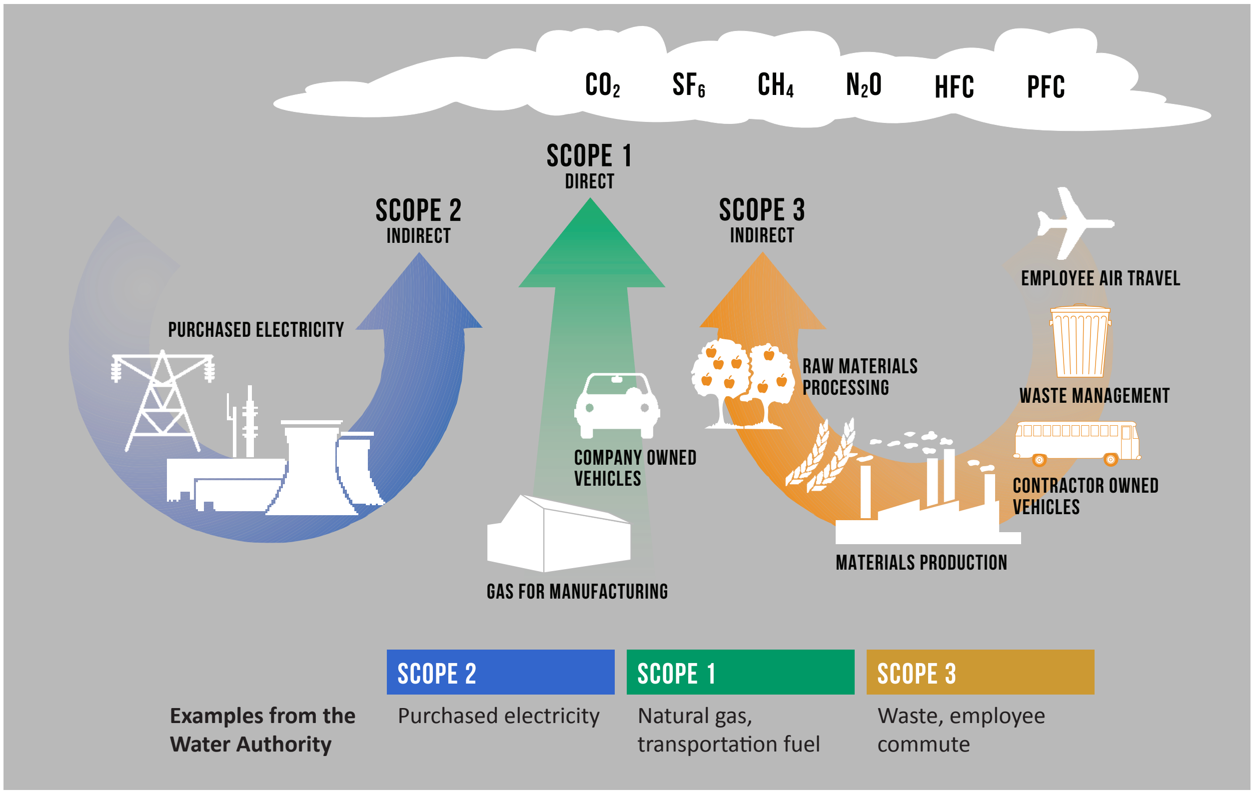


FIGURE 2.2 **Emissions Sources by Scope**



Source: Modified from New Zealand Business Council 2002

Emissions by Sector

Reporting emissions by sector is often the most useful inventory; 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, which are also detailed below.

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 that are generated at the operational site, such as natural gas combustion 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 used for lighting, pumps, and fans. Energy consumption accounted for more than 82% (7,680 MT CO_2e) of the Water Authority's emissions, with electricity representing the majority (7,638 MT CO_2e) of those emissions.

TABLE 2.2 **2009 Greenhouse Gas Emissions by Sector**

EMISSIONS SECTOR	MT CO_2E	PERCENT OF TOTAL
Electricity	7,638	81.9%
Vehicle Fleet	6948	7.4%
Employee Commute	6858	7.4%
Off-Road Equipment	143	1.5%
Stationary Source	89	1%
Natural Gas	42	0.5%
Solid Waste	27	0.3%
Water	4	< 0.1%
Refrigerants	< 2	< 0.1%
Wastewater	< 2	< 0.1%
TOTAL	9,325	100.00%

Notes: Totals may not equal 100% due to rounding.
MT CO_2e = metric tons of carbon dioxide equivalent
Source: AECOM 2013

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 less than 8% of the overall emissions profile.

Employee Commute

Similar to vehicle fleet emissions, employee commute emissions accounted for less than 8% of total emissions in 2009 (685 MT CO_2e). Employee commutes are not directly under the Water Authority's purview, but are generally included in emissions inventories because the employer can offer programs and incentives to affect changes in the type of transportation taken by employees, such as transit vouchers.

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; emissions from these sources accounts for less than 2% of total emissions, or 143 MT CO_2e.

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. Solid waste accounts for less than 1% (27 MT CO_2e) of emissions in the Water Authority's baseline inventory.

Water Consumption

The water sector includes emissions from energy associated with water treatment, distribution, and conveyance to other entities. 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 that the Water Authority is directly responsible for accounts for 4 MT CO_2e, or less than 1% of its total emissions profile.

Refrigerants

Although generally a small portion of total emissions, refrigerants consist of high GWP gases. Individual molecules of hydrofluorocarbons (HFCs), the type of GHG generally emitted by refrigerants, have GWPs ranging from 140 to 14,800 MT CO_2e (Table 2.1). Refrigerants constituted a very small (less than 1%; 2 MT CO_2e) portion of overall Water Authority emissions in 2009.

Wastewater

The wastewater sector consists of emissions resulting from wastewater treatment processes, including wastewater collection, septic system management, primary and secondary treatment, solids handling, and effluent discharge. The Water Authority's emissions from wastewater were less than 2 MT CO_2e in 2009, or less than 1% of total emissions.

Emissions by Source

For an agency that has direct control over the majority 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, programs, and pump stations. 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 2.3. The Twin Oaks Valley Water Treatment Plant (WTP) was responsible for 47% of the Water Authority’s emissions in 2009. Pump stations were the next largest source of emissions, accounting for 21% of total emissions, and the San Diego Headquarters Building location was responsible for approximately 10% of the 2009 emissions. These three sources represent 78% of all Water Authority facility-related emissions.

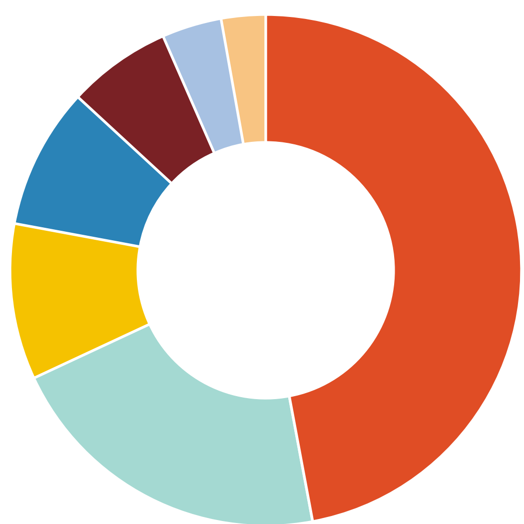
The Water Authority also owns the Rancho Peñasquitos pressure control and hydroelectric facility (PCHF). The Rancho Peñasquitos PCHF is an in-line hydroelectric facility that generates an average of 44 megawatt hours (MWh) of electricity on an annual basis. This equates to 15 MT CO_2e of clean emissions. Through a power purchase agreement with SDG&E, the renewable energy credits (RECs) that the facility produces are currently retained by SDG&E. However, the agreement expires in 2017, and affords the Water Authority an opportunity to retain the RECs to use toward its own GHG reductions.

TABLE 2.3 **2009 Greenhouse Gas Emissions by Source**

SOURCE	MT CO_2E	% OF TOTAL
Twin Oaks Valley Water Treatment Plant	4,388	47%
Pump Stations	1,960	21%
San Diego Headquarters Building	919	10%
Combined Other	832	9%
Flow Control Facilities	612	7%
Escondido Operations Center	353	4%
Aqueduct Protection Program	261	3%
TOTAL	9,325	100%

Notes: Totals may not equal 100% due to rounding.
MT CO_2e = metric tons of carbon dioxide equivalent
Source: AECOM 2013

FIGURE 2.3 **2009 Greenhouse Gas Emissions by Source**

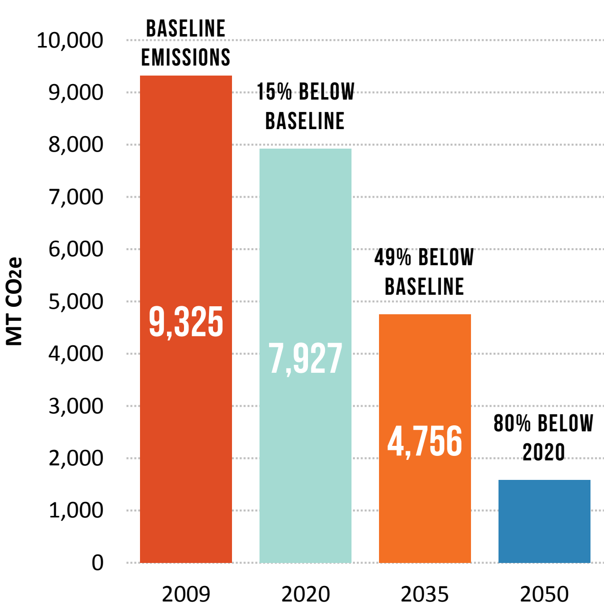


- Twin Oaks Valley Water Treatment Plant – 47%
- Pump Stations – 21%
- San Diego Headquarters Building – 10%
- Combined Other – 9%
- Flow Control Facilities – 7%
- Escondido Operations Center – 4%
- Aqueduct Protection Program – 3%

REDUCTION TARGETS

This CAP was developed to align with the goals of AB 32. To demonstrate that the Water Authority will not hinder the state in achieving its statewide target, the Water Authority has set a goal to reduce its emissions to 15% below 2009 levels by 2020. This is consistent with the Scoping Plan recommendation to local governments to demonstrate consistency with AB 32. This CAP is being completed in tandem with the 2013 Master Plan Update, which has a planning horizon of 2035, so this date was also chosen as the longer-term analysis year for the CAP. There is no guidance for local governments or agencies regarding an emissions-reduction target beyond 2020. The Water Authority is not mandated to achieve the 2050 goals set forth by Executive Order S-3-05, and the 2035 target is based on a simple linear projection between the 2020 and 2050 state targets.

FIGURE 2.4 **Water Authority Emissions Targets Aligned with State Goals**



Notes: MT CO_2e = metric tons of carbon dioxide equivalent
The 2050 state goal is 80% below 1990 levels. Because emissions in 2020 should equal 1990 levels, a target of 80% below the 2020 target is consistent with the state goal.

FORECASTING APPROACH

Estimating future emissions under a "business-as-usual" (BAU) scenario allows the Water Authority to understand the type and amount of emissions that are likely to occur in the future without implementation of 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 Lake Hodges Pumped Storage Facility and San Vicente Pump Station, as well as future projects identified in the 2013 Master Plan Update.

Emissions were projected for years 2020 and 2035. AB 32 identifies a strict state limit on GHG emissions for 2020, which is 427 MMT 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 this goal.

In addition, the Water Authority recognizes that the issue of climate change will not end at 2020. Although there is a lack of specific guidance for state-level emissions goals beyond 2020, standard practice for CAPs has been to evaluate emissions for a future year beyond 2020. (Figure 2.4). Although Executive Order S-3-05 identifies an emissions level of 80% below 1990 levels by 2050, this is generally considered too far into the future to be able to realistically estimate emissions and reductions.

For CAPs being developed in conjunction with another programmatic document, such as a General Plan or Master Plan, the typical approach is to evaluate the horizon year of the associated document. As described earlier, the Water Authority is developing this CAP alongside the 2013 Master Plan Update, which has a horizon year of 2035. Since the Master Plan includes the projects that will be needed to fulfill supply to its member agencies, it is reasonable to include 2035 as a longer-term evaluation year in this CAP. At this time, the level of demand and the supply needed to meet that demand are unknown beyond 2035. Therefore, the projects that may be developed after 2035 are also unknown, and attempting to estimate emissions beyond the horizon year of the 2013 Master Plan Update would be beyond the ability to reasonably forecast. However, as the Master Plan is updated in the future and the horizon date is extended, so too can the analysis in this CAP.

FUTURE EMISSIONS

Future emissions are those anticipated by the Water Authority as a result of ongoing facility operations since the 2009 baseline inventory; emissions that have been added since the inventory, such as new facilities; and emissions associated with future projects, both operational and construction-related. The following sections detail how the Water Authority analyzed future emissions, which fall into the following four categories:

- Sources in place by 2009
- Sources implemented 2010 through 2013
- Sources anticipated for construction 2014 through 2020
- Sources anticipated for construction 2021 through 2035

Sources in Place by 2009

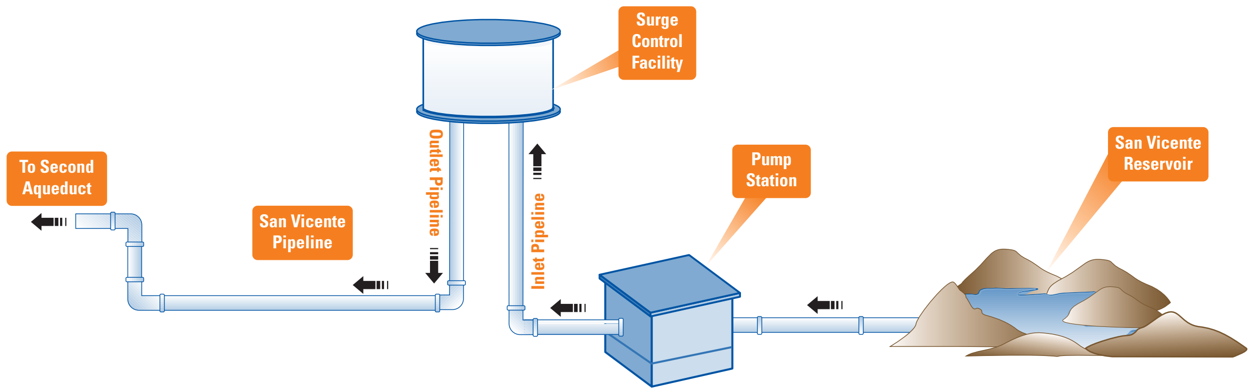
Emissions were estimated for sources in place by 2009; that is, those sources that were accounted for in the baseline emissions inventory. These facilities and resources are expected to continue operation into the future, and increase emissions at a rate consistent with the anticipated change in demand as assumed in the 2010 UWMP. The 2010 UWMP shows that the Water Authority's service area used 643,900 acre-feet (AF) of water in 2009, and projected a demand of 675,089 AF in 2020, assuming water conservation targets are met by the member agencies. This represents a 4.84% increase in demand by 2020. Similarly, the 2010 UWMP projected water usage to 2035, and estimated that demand would reach 785,685 AF, or a 22% increase from 2009 demand. Although increases in demand generally do not correlate to a 1-to-1 increase in operations, the Water Authority conservatively applied this growth rate for existing facilities and resources (Table 2.4). Emissions associated with sources existing at the time of the baseline emissions inventory are expected to increase to 9,754 MT CO_2e by 2020 and 11,338 MT CO_2e by 2035. Detailed assumptions can be found in Appendix B.

TABLE 2.4 **Projected Emissions for Resources in Operation by 2009**

EMISSIONS SOURCE	2009 EMISSIONS (MT CO_2E)	2020 ESTIMATED EMISSIONS (MT CO_2E)	2035 ESTIMATED EMISSIONS (MT CO_2E)
Electricity	7,638	8,007	9,318
Vehicle Fleet	694	728	847
Employee Commute	685	696	801
Off-Road Equipment	143	150	174
Stationary Source	89	93	108
Natural Gas	42	44	52
Solid Waste	27	28	28
Water	4	5	5
Refrigerants	2	2	2
Wastewater	1	1	2
TOTAL	9,325	9,754	11,338

MT CO_2e = metric tons of carbon dioxide equivalent

FIGURE 2.5 **San Vicente Pump Station and Appurtenance Structures**



Sources Constructed 2010 through 2013

Two major facilities have been constructed since the 2009 baseline emissions inventory: the San Vicente Pump Station (Figure 2.5) and the Lake Hodges Pumped Storage facility (Figure 2.6). Therefore, actual energy consumption information is available for these projects, as they are now operational and current GHG emissions can be calculated.

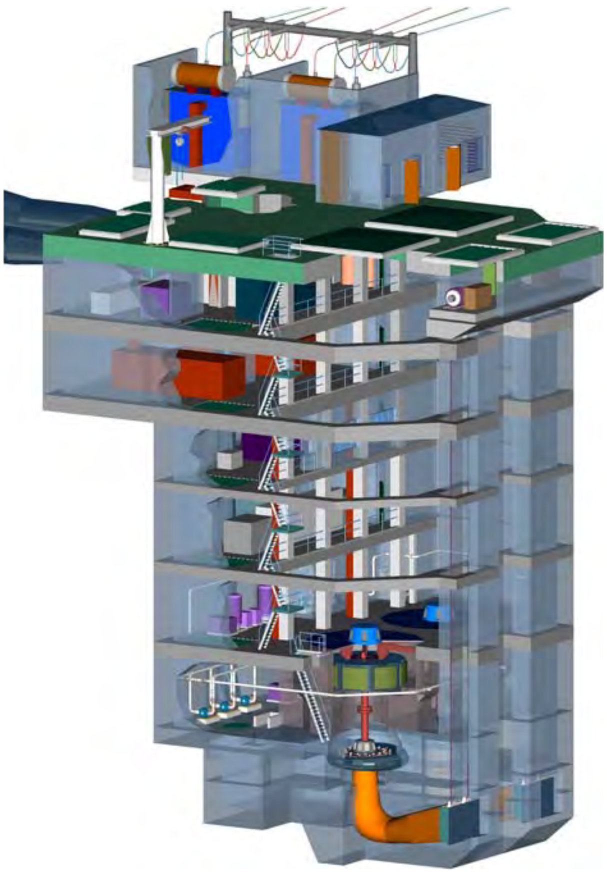
San Vicente

Construction of the San Vicente Pump Station began in 2007 and ended in late 2010. 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 part of the Water Authority's Emergency Storage Project (ESP) and is designed to provide untreated water from the San Vicente Reservoir in case imported water supplies are interrupted due to a natural disaster or to meet operational demands. In 2011, its first year of operations, the San Vicente Pump Station consumed nearly 7,000 MWh of energy, resulting in an additional 2,316 MT CO_2e of emissions. Future energy use may vary annually based on demand, but it could consume 20,000 MWh per year in 2020 and 2035, which would result in 6,620 MT CO_2e based on current SDG&E emissions factors (Table 2.5).

Lake Hodges

The Lake Hodges Pumped Storage facility represents a key element of the Water Authority's ESP, and has an added benefit of generating hydroelectric power, which is sold to SDG&E to offset operational costs. The facility began operations in late 2012 and is currently fully operational. The Lake Hodges Pumped Storage facility stores energy by pumping water up from Lake Hodges to the Olivenhain Reservoir during off-peak energy demand periods, and then using the 770 feet of elevation difference to generate electricity during peak energy demand periods, when water is released from Olivenhain Reservoir, flowing downhill through two electricity-generating turbines before being released back into Lake Hodges.

FIGURE 2.6 **Lake Hodges Pumped Storage Pump House Rendering**



The Water Authority conducted an analysis of the emissions required to pump water up to the Olivehain Reservoir, and the emissions offset by hydroelectric energy generated by releasing the water back into Lake Hodges. The analysis assumes an average of 6 hours of generation time per day with 78% efficiency (Appendix E). According to the California Public Utilities Commission (CPUC), the agency overseeing implementation of Renewable Portfolio Standards (RPSs) that apply to the state's regulated utilities, SDG&E currently has attained its goal of 20% renewable energy in its generation portfolio (CPUC 2013). Therefore, Lake Hodges could displace up to 8,907 MT CO_2e per year and SDG&E would still be in compliance (Table 2.5).

As SDG&E's electricity-generation portfolio becomes more renewables-based, the energy required for pump-back operations will become even less GHG energy-intensive, further augmenting the benefit of the renewable energy. By 2020, with SDG&E meeting its 2020 RPS goal of 33% renewable sources, the 40-megawatt (MW) capacity Lake Hodges facility could displace as much as 14,032 MT CO_2e per year, or 5,125 MT CO_2e more than the current estimate. These additional anticipated benefits are accounted for as state and federal regulations in Chapter 3 of this CAP. If SDG&E increases its percentage of renewables beyond 33%, whether mandated or voluntary, the Water Authority could realize even greater GHG benefit from this project.

Table 2.5 summarizes the current and future emissions for these facilities, and shows a net GHG benefit to the Water Authority of 2,287 MT CO_2e per year, which could increase as SDG&E augments its renewable mix.

TABLE 2.5 **Emissions Estimates for Projects Implemented 2010–2013**

NEW PROJECTS	"CURRENT" (MT CO_2E)	2020 (MT CO_2E)	2035 (MT CO_2E)
Lake Hodges Pump Station	(8,907)	(8,907)	(8,907)
San Vicente Pump Station	2,316	6,620	6,620
TOTAL	(6,591)	(2,287)	(2,287)

Notes: Negative number indicates net emissions reduction. "Current" indicates the year with the most applicable data for the project indicated. For Lake Hodges, data are from 2012 (see Appendix E); for San Vicente, data are from 2011.
MT CO_2e = metric tons of carbon dioxide equivalent

Sources Anticipated for Construction by 2020

Additional projects are anticipated to be built to meet the needs of the Water Authority, including projects in the current capital improvement program (CIP) and projects identified in the 2013 Master Plan Update. Projects anticipated to be constructed by 2020 are described below.

Master Plan Projects

System Isolation Valves

System isolation valve projects serve many purposes, including isolating the aqueduct system from areas at risk of outages (e.g., from flood or seismic events); addressing potential water quality concerns during low-flow periods; and allowing for segment repairs, maintenance, and inspection. Currently, four projects are being considered as part of the 2013 Master Plan Update:

- P4 South of the San Luis Rey River Crossing
- P4 at the Twin Oaks Valley WTP
- P3 at Mission Trails
- P4 at State Route 125

The exact construction dates are unknown at this time, but could occur anytime from 2014 through 2025; therefore, they are conservatively included as though constructed by 2020. Details regarding construction and operational assumptions can be found in Appendix B.

Asset Management Projects

Asset management projects are ongoing efforts focused on establishing a priority for rehabilitation, repair, or replacement of infrastructure components based on the probability of that component failing to meet operational requirements. Two proposed asset management projects are part of the 2013 Master Plan Update:

- P3 Relining – Lake Murray to Sweetwater Reservoir
- P4 Relining – At San Luis Rey River

The projects are anticipated to be completed by 2017. Additional details regarding construction and operational assumptions can be found in Appendix B.

Working on pipeline relining

Inside the P2A Pump Station

Capital Improvement Program Projects

Mission Trails

The Mission Trails suite of projects, located in Mission Trails Regional Park, is envisioned to meet expected untreated water demand increases resulting from improvements to expand the capacity at several central and south county water treatment plants. The projects will also relieve an existing hydraulic capacity constraint at the interconnection between Pipelines 3 and 4 located in the Lake Murray area. The suite of projects includes Mission Trails Flow Regulatory Structure II (MTFRSII), Mission Trails Tunnel, and Lake Murray Control Valve. MTFRSII would be connected to and operated in combination with the completed Mission Trails Tunnel. Currently, two project alternatives are being considered; the alternative with the greater emissions was used for estimating future GHG emissions.

North County ESP Pump Station

The North County ESP Pump Station, located near the Red Mountain Reservoir, will be used to deliver water to portions of the North San Diego County service area during an emergency condition and when imported supplies are curtailed during outages of the aqueduct system. The intermittently used pump station would send treated water north from the Twin Oaks Valley WTP to member agencies. Expected usage would require 218 MWh per year, equating to 54 MT CO_2e in operational emissions annually.

Valley Center Pump Station (P2A Pump Station)

The P2A Pump Station is an existing facility located in the Valley Center area. Pumping capacity will be expanded from 20 cubic feet per second (cfs) to 40 cfs. The pump station will be used to convey treated water from Pipeline 4 in the Second Aqueduct to Pipelines 1 and 2 in the First Aqueduct, allowing for increased utilization of the Twin Oaks Valley WTP. The expansion will be operational in 2016, and expected usage would require 2,550 MWh, or 631 MT CO_2e per year. Construction required for the expansion will be minimal.

Nob Hill Improvements

This project will replace two approximately 800-foot-long sections of existing pipelines with one pipeline at a lower elevation in the Nob Hill area of Scripps Ranch. The new pipeline will be constructed by tunneling or open-trench construction, and will improve the Water Authority's ability to operate and maintain its pipelines and structures, eliminating the likelihood of a future uncontrolled release of water in this area.

Additionally, the Water Authority is designing a new access road to Nob Hill from Scripps Lake Drive along the Water Authority's right-of-way, west of Miramar Dam. The new access road will reduce construction traffic and operations and maintenance traffic through the Nob Hill community. It will also give easier access to other Water Authority structures.

San Vicente Bypass Pipeline

The Water Authority will replace the portion of the existing San Vicente Bypass Pipeline that will be inundated by the expansion of San Vicente Reservoir. The project will include construction of approximately 5,500 linear feet of new pipeline and ancillary facilities to replace the existing pipeline, modification to the First Aqueduct Terminal Structure, and construction of a new access road from the future Marina area to the Terminal Structure, which will include 40,000 cubic yards of excavation and more than 6,000 linear feet of unpaved road.

TABLE 2.6 **Emissions Estimates for Projects Anticipated 2014 through 2020**

PROJECTS	EXPECTED OPERATIONAL YEAR	2020 EMISSIONS (CO_2E)	2035 EMISSIONS (CO_2E)
MASTER PLAN			
System Isolation Valves	2014	14	0
Asset Management			
Pipeline 4	2017	7	7
Pump 3	2016	14	14
CAPITAL IMPROVEMENT PROGRAM			
Mission Trails	2016	28	28
North County ESP Pump Station	2016	98	98
Nob Hill[1]	2015	3	3
San Vicente Marina	2014	22	0
San Vicente Bypass	2014	12	0
Valley Center (P2A) Pump Station[1]	2015	631	631
TOTAL		**828**	**781**

Notes: MT CO_2e = metric tons of carbon dioxide equivalent per year
Emissions estimates include construction emissions (except P2A, which are considered minimal). North County ESP Pump Station and P2A also include new operational emissions. Construction emissions are amortized over 20 years.
[1] Construction-related emissions are included in the 2035 emissions estimate to allow for a 1-year delay.

San Vicente Reservoir Marina Facility

This project will replace the demolished marina facilities as part of the San Vicente Dam Raise project, address impacts resulting from previous construction projects, and construct other site improvements necessary to re-open the San Vicente Reservoir for public recreational use. The project is anticipated to be constructed in 2014. The City of San Diego reviewed the marina facilities for compliance with the mandatory CalGreen requirements as part of the building permit process. Emissions associated with the operation and maintenance of these facilities, as well as emissions associated with the recreational activities that will occur after project completion, will be part of the City of San Diego's emissions, as the city will be the owner of the facilities and be responsible for ongoing operation as a recreational area.

All of the projects listed in the 2013 Master Plan Update and the CIP will result in construction-related emissions. Although construction emissions are short-term and cease once the project is operational, they do contribute to the cumulative impact of climate change. Therefore, construction-related emissions are amortized over the reasonable lifetime of the project, which is 20 years in this case. For example, San Vicente Marina and Bypass are expected to be constructed in 2014, so those emissions would be amortized from 2014 through 2033 and would not appear as emissions in the 2035 emissions forecast. Emissions for Nob Hill were included in 2035 to allow for a 1-year project construction delay. Operational emissions occur yearly and may be affected by federal, state, and local regulations; therefore, a change in emissions may occur over time, although the level of operation may remain constant. Table 2.6 summarizes the emissions anticipated as a result of implementing 2013 Master Plan Update and CIP projects from 2014 through 2020.

San Vicente Marina Facilities Rendering

Sources Anticipated for Construction by 2035

Projects that are expected to be built after 2020 are also identified in the 2013 Master Plan Update. Because the Water Authority has emissions goals for 2020 and 2035, it is appropriate to differentiate those projects that will add emissions after 2020. Details about the projects are provided in the 2013 Master Plan Update and summarized below, along with their anticipated GHG emissions.

Master Plan Projects

Pipeline 3/4 Switch

The proposed Pipeline (P) P3/P4 conversion project would alleviate a projected untreated water conveyance constraint at the Metropolitan Water District Delivery Point. The project is intended to increase untreated water conveyance capacity in the Second Aqueduct north of Twin Oaks Valley by converting a portion of the existing P4 (capacity 470 cfs) to untreated water service, and converting a similar portion of the existing P3 (capacity 280 cfs) to treated water service. The proposed project would increase the total untreated water delivery capacity to 970 cfs (the combined capacity of P4 and P5), and reduce the total treated water delivery capacity to 470 cfs (the combined capacity of P1, P2, and P3). The proposed P3/P4 conversion project would not increase total conveyance capacity.

System Regulatory Storage

The system regulatory storage projects would provide new water storage for improved operation of the aqueduct system. Regulatory storage is needed to manage daily flow changes, provide storage for unanticipated flow interruptions that otherwise may cause pipelines to drain or vent structures to spill, provide hydraulic control for segments of the aqueduct system, dampen hydraulic transient pressures, and serve as a pump station afterbay. The project includes two possible locations for new regulatory storage facilities: at the Twin Oaks Diversion Structure and near the First Aqueduct and Valley Center Pipeline connection. Both alternatives were evaluated for their potential environmental impacts in the Supplemental Program EIR; however, because this CAP is concerned with total emissions resulting from new projects, the highest-emitting alternative was used in the GHG analysis.

San Vicente 3rd Pump Drive and Power Supply

The San Vicente 3rd Pump Drive and Power Supply project would provide station upgrades and a new power supply to allow the existing San Vicente Pump Station to be operated at full design capacity. The project would allow full use of the expanded San Vicente Reservoir for emergency storage operation. This proposed project would upgrade the existing San Vicente Pump Station by adding a third pump drive and an electrical transformer within the existing pump station structure. The new power supply options to operate the third pump may include a new 12-kilovolt overhead power line (to be implemented by SDG&E) or on-site power generation using diesel- or natural-gas-powered generator sets. For on-site power generation, the existing fence line would be demolished, and new fencing would be provided to expand the site by approximately 2 to 3 acres for the new on-site generators.

The on-site generators would be sized to operate one pump, requiring a rated load capacity equal to approximately 6 MW. The rated load capacity would typically be met by installing either three 2-MW diesel generators or one 6-MW natural gas generator. Additional yard switchgear and ancillary equipment would also be required for the on-site generation options.

In addition, for the natural gas generators, a new natural gas feed line (to be implemented by SDG&E) would be constructed from the nearest gas service to the project site. For the diesel generators, on-site fuel storage would be required. The diesel fuel storage tank would be sized to provide sufficient fuel to conduct periodic monthly maintenance testing of the generators. The monthly maintenance testing would require the generators to operate at approximately 30% of rated load for a minimum of 30 minutes. For continuous operation during an emergency event, diesel fuel would need to be delivered to the site on a daily or as-needed basis.

The projects listed above will result in construction-related emissions. As described in the previous section, construction emissions contribute to the cumulative impact of climate change and are included as amortized annual emissions over 20 years. Operational emissions occur yearly and may be affected by federal, state, and local regulations, such as the RPS; therefore, a change in emissions may occur over time, although the level of operation may remain constant. If major projects are added in the future outside of what is identified in the 2013 Master Plan Update, the Water Authority may need to review the post-2020 emissions estimates in the CAP. Table 2.7 summarizes the emissions anticipated as a result of implementing 2013 Master Plan Update projects from 2021 through 2035.

TABLE 2.7 **Construction Emissions Estimates for Projects Anticipated 2021–2035**

PROJECTS	EXPECTED OPERATIONAL YEAR	2035 EMISSIONS (MT CO_2E)
MASTER PLAN		
Pipeline 3/ 4 Switch	2021	27
System Regulatory Storage	2021	41
San Vicente 3rd Pump Drive[1]	2020	17
TOTAL		**85**

Notes: MT CO_2e=metric tons of carbon dioxide equivalent per year
Construction emissions are amortized over 20 years. For projects with alternative options in the 2013 Master Plan Update, the more GHG-intensive alternative was modeled.

[1] Additional operational emissions are accounted for in Table 2.5.

SUMMARY OF FUTURE EMISSIONS

Table 2.8 summarizes the Water Authority's future emissions as a result of implementing projects anticipated through 2035. The net emissions in 2020 and 2035 are estimated to be 8,295 MT CO_2e and 9,916 MT CO_2e, respectively. These represent an 11% reduction and a 6% increase from 2009 baseline levels by 2020 and 2035, respectively.

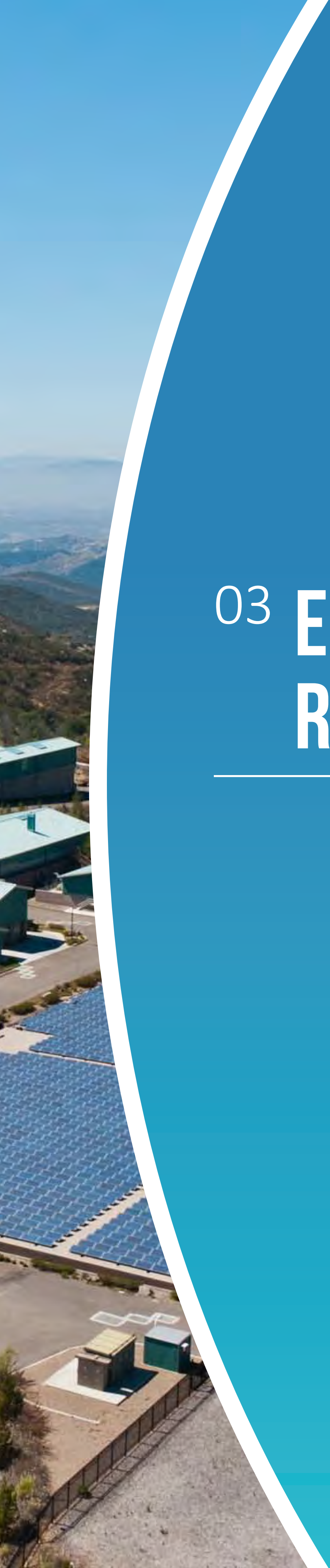
The following chapters discuss reduction measures that have been implemented (Chapter 3) or may be implemented (Chapter 4) to demonstrate how the Water Authority will meet its 2020 target and demonstrate ongoing GHG-reduction opportunities beyond 2020.

TABLE 2.8 **Business-as-Usual Emissions for 2020 and 2035**

EMISSIONS SOURCE	2009 EMISSIONS (MT CO_2E)	2020 BAU PROJECTION (MT CO_2E)	2035 BAU PROJECTION (MT CO_2E)
Sources in Place by 2009	9,325	9,754	11,338
Emissions Sources Constructed 2010—2013	NA	(2,287)	(2,287)
New Emissions Sources Anticipated 2014—2020	NA	828	781
New Emissions Sources Anticipated 2021—2035	NA	NA	85
TOTAL	9,325	8,295	9,916

Notes: MT CO_2e = metric tons of carbon dioxide equivalent; NA = not applicable
Sources anticipated to be built between 2014 and 2035 include construction-related GHG emissions, which are amortized over the lifetime of the project, estimated to be 20 years. See Appendix B for additional details.

Page intentionally left blank



03 EXISTING GREENHOUSE GAS REDUCTION MEASURES

STATE AND FEDERAL EMISSIONS REDUCTIONS

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

Chapter 1 described state and federal regulations that affect the Water Authority. Some of these regulations set statewide emissions goals (i.e., AB 32); this CAP is designed to demonstrate consistency with these goals. Other regulations have been implemented that will assist in reducing GHG emissions without the Water Authority taking any direct action.

These measures are included in the forecast to create an "Emissions with Existing Reduction Measures" scenario, which more accurately reflects expected future conditions within the Water Authority. This approach is standard for all local jurisdictions and agencies that undertake a CAP: Apply the relevant federal- or state-implemented reductions and supplement those with local measures to demonstrate meeting future emissions goals.

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 most communitywide inventories have a majority of emissions from transportation, less than 10% of the Water Authority's profile is from the transportation sector. Nevertheless, some of the federal and state regulations will result in emissions 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. 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. It is applicable to all three transportation-related sectors in the Water Authority: employee commutes, vehicle fleet, and off-road equipment.

AB 1493 and Executive Order R-12-016 align with the U.S. 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. However, this CAP assumes that the turnover rate will be consistent with that of San Diego County.[1] Emissions reductions were only taken for the employee commute sector, as the Water Authority has direct control over vehicle fleet turnover and, as described later, is replacing current vehicles with higher-efficiency models as feasible. In addition, the standards apply to on-road passenger vehicles and, therefore, do not apply to off-road equipment.

These two regulations will reduce emissions by 234 MT CO_2e in 2020 and by 479 MT CO_2e in 2035 (Table 3.1).

1 Turnover rates are established by ARB on a per-county basis in the emissions model EMFAC. They are based on vehicle registration records and historic trends in vehicle turnover.

Renewable Portfolio Standard

The state's RPS requires that the Water Authority's utility provider, SDG&E, deliver 33% of its electricity from renewable sources by 2020. At the time of the baseline emissions inventory, SDG&E had approximately 10% renewable sources; currently, it has the highest percentage of the three major investor-owned utilities in the state, at 20.31% (CPUC 2013). Because of this regulation and SDG&E's current compliance with the interim goal of 20% renewables by December 31, 2013, the Water Authority's Scope 2 emissions from electricity purchased will be less GHG-emitting for every kilowatt-hour used. Based on projected electricity consumption, the Water Authority will have 8,819 MT CO_2e reductions in 2020 and 9,150 MT CO_2e reductions in 2035, accounting for sources constructed through 2013 (Table 3.1). If RSP regulations become increasingly stringent after 2020, the Water Authority may achieve even greater reductions.

TABLE 3.1 **Emissions Reductions due to Federal and State Measures for 2020 and 2035**

REDUCTION SOURCE	2020 (MT CO_2E)	2035 (MT CO_2E)
SOURCES IN PLACE BY 2009		
Reduction from RPS		
Water	(3)	(3)
Energy	(2,021)	(2,351)
Reduction from CAFE + LCFS		
Employee Commute	(146)	(377)
Vehicle Fleet	(73)	(85)
Off-Road Equipment	(15)	(17)
SOURCES CONSTRUCTED 2010–2013		
Reduction from RPS		
Lake Hodges	(5,125)	(5,125)
San Vicente	(1,670)	(1,670)
TOTAL REDUCTIONS FROM RPS	**(8,819)**	**(9,150)**
TOTAL REDUCTIONS FROM CAFE + LCFS	**(234)**	**(479)**
TOTAL REDUCTIONS FROM STATE AND FEDERAL MEASURES	**(9,052)**	**(9,629)**

Notes: Totals may not add due to rounding.
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 steps to reduce energy consumption and GHG emissions (Table 3.2). Activities implemented through 2009 would have been captured in the baseline emissions inventory, but those implemented after 2009 can demonstrate reductions toward the 2020 and 2035 goals.

Solar Panels

To take advantage of the unique solar potential in Southern California, the Water Authority has installed solar panels at three locations: Twin Oaks Valley WTP, Headquarters in Kearny Mesa, and the Operations Center in Escondido. These produce nearly 3 million kWh of electricity per year, accounting for more than one-half of the energy needs at Headquarters and Escondido, and 25% of energy needs at the Twin Oaks Valley WTP.

Solar panels at Twin Oaks Valley WTP

The Water Authority fully financed the solar power installation through a power purchase agreement. Its partner, Borrego Solar Systems, installed the systems and will operate and maintain them for 20 years at no capital cost to the Water Authority. In return, the Water Authority purchases the clean renewable energy produced at a predetermined below-the-grid rate, resulting in a savings of more than $88,000 in 2012 alone.

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 does indirectly help the Water Authority's reduction goals by lowering SDG&E emissions factor. The amount of renewable energy produced by the Water Authority in 2012 was equivalent to 972 MT CO_2e of emissions.

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 GPS 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 three gasoline-powered passenger vehicles with hybrid vehicles to date.

TABLE 3.2 **Local Measures and Reductions Implemented 2010–2013**

REDUCTION SOURCE	2020 (MT CO_2E)	2035 (MT CO_2E)
Solar Panels	NA	NA
Vehicle Fleet	2	2
Energy Conservation Opportunities	2	2
TOTAL REDUCTIONS FROM LOCAL MEASURES	**4**	**4**

Notes: MT CO_2e = metric tons of carbon dioxide equivalent; NA = not applicable (see text for details)
Reductions assume all measures are implemented by 2020; therefore, annual emissions reductions remain constant in 2035.

TABLE 3.3 **Energy Conservation Opportunities (ECOs) Implemented**

FACILITY AND ECO NUMBER	ENERGY CONSERVATION OPPORTUNITY DESCRIPTION	ESTIMATED ENERGY SAVINGS	ESTIMATED PAYBACK TERM	ESTIMATED INVESTMENT 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	6,500 kWh/yr 8.5 kW	12.3 years	$39,000
Twin Oaks Valley WTP – 9	Evaluate installation of VFD for return water pumps during low-flow operations	0 kWh/yr 10 kW	33.4 years	$63,000

Notes: WTP = Water Treatment Plant; VFD = variable-frequency drive; hp = horsepower; kWh/yr = kilowatt hours per year
Source: 2012 Energy Audit

Energy Conservation Opportunities

As described in Chapter 1, the Water Authority partners with SDG&E to promote water 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, two ECOs have been implemented, 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 has already implemented strategies resulting in more than 6,500 kWh savings per year, or approximately 2 MT CO_2e reduction (Table 3.3).

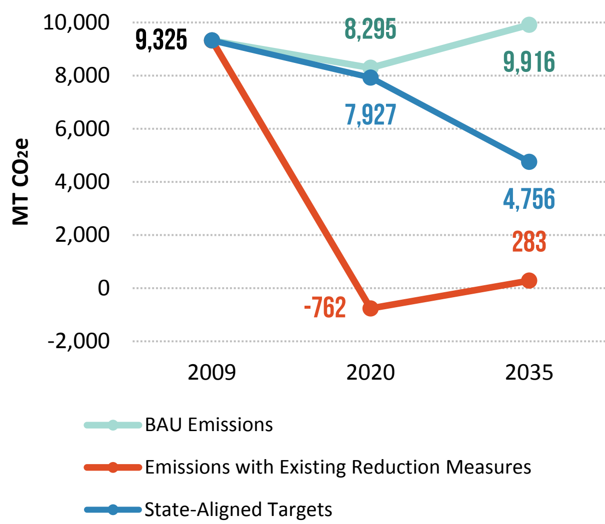
Further development of the remaining ECOs is anticipated to occur through an additional audit to be completed in partnership with SDG&E.

CURRENT PROGRESS TOWARD REDUCTION GOALS

Figure 3.1 illustrates the Water Authority's future emissions and reduction goals with current GHG reduction strategies in place. The emissions in 2020 are estimated to be –762 MT CO_2e and the emissions in 2035 are estimated to be 283 MT CO_2e. With strategies and projects in place today, and accounting for additional emissions from future projects, the Water Authority will meet and exceed state emissions goals. Moreover, the Water Authority more than mitigates all of its operational emissions in 2020, indicated by the negative emissions shown in Figure 3.1 and Table 3.4.

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 exceeding its reduction goals for the foreseeable future.

FIGURE 3.1 **Water Authority Emissions and Targets**



MT CO_2e = metric tons of carbon dioxide equivalent
BAU = business as usual

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

	2009 (MT CO_2E)	2020 (MT CO_2E)	2035 (MT CO_2E)
Business-As-Usual Emissions	9,325	8,295	9,916
State and Federal Reductions		(9,052)	(9,629)
Local Reductions		(4)	(4)
EMISSIONS WITH EXISTING REDUCTION MEASURES	9,325	(762)	283
STATE-ALIGNED GOAL/TARGET	9,325	7,927	4,756
OVERALL MT CO_2E BELOW TARGET[1]		8,689	4,473
MEETING GOAL/TARGET?		YES	YES

Notes: MT CO_2e = metric tons of carbon dioxide equivalent. Negative number indicates net emissions reduction.
[1] This indicates the amount of GHGs anticipated to be reduced beyond the goal, or the difference between the goal and expected emissions.

Page intentionally left blank

04 LOCAL GREENHOUSE GAS REDUCTION MEASURES AND QUANTIFICATION

The Water Authority has identified additional opportunities for reducing GHG emissions within its operations. These GHG reduction opportunities were developed in three groups: 2013 Master Plan Update project energy efficiency, 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**

MEASURE	GHG REDUCTION POTENTIAL (MT CO_2E PER YEAR)	INITIAL INVESTMENT ($)	PAYBACK PERIOD (YEARS)
MASTER PLAN PROJECTS			
All Projects	All projects were 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			
Lighting Upgrades	17	<$1,000 to >$10,000	3 to 20+ years
Support Operations	20	$0 to >$10,000	0 to 20+ years
Pump Upgrades	10	>$10,000	3 years
OTHER OPPORTUNITIES			
Vehicle Fleet Conversion	4	>$10,000	20+ years
Solar PV Installation	145	>$10,000	17 years
In-Line Hydropower Generation	8,156	>$10,000	3 to 12 years

PV = photovoltaic

MASTER PLAN PROJECTS

The projects anticipated to be developed in the 2013 Master Plan Update are summarized in Chapter 3 of this CAP. As described earlier in this document, the water demand anticipated through the 2035 planning horizon is being met through existing supplies, and additional projects are being developed to better optimize the Water Authority's current delivery system. Therefore, 2013 Master Plan Update projects are inherently focused on improving efficiency. The projects primarily involve enhancing current operations, and are not anticipated to add long-term GHG emissions. In addition, 2013 Master Plan Update projects were developed to include energy-efficient design features as economically and technically feasible as possible to reduce energy consumption in new facilities. 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 2013 Master Plan Update include features as listed below, and are consistent with the goals of this CAP.

ENERGY AUDIT ECOS

Chapter 3 described ECOs that have already been implemented as a result 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:

- Lighting Upgrades
- 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 operation 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 to be infeasible due to changes in design features (e.g., some pump upgrade measures) were not assessed.

Lighting Upgrades

The Water Authority conducted lighting retrofits and delamping to reduce its GHG emissions. Additional ECOs include installing motion sensors and/or timers to lighting controls, and retrofitting lighting to more energy-efficient options. Electricity usage related to lighting, especially for office buildings, can be significant, and can comprise up to 25% of the total usage for a building or facility. Based on current energy consumption in major facilities, lighting measures could account for less than 1 MT CO_2e to 10 MT CO_2e reduction per year (Table 4.2). Installation costs are reflective of the amount of lighting used in the facility, and can range from less than $1,000 to more than $14,000 for lighting and to install timers on light switches, depending on the size of the facility. Based on a 25% reduction in electricity use related to indoor lighting, facilities consuming greater than 100,000 kWh per year in lighting would have a short payback period (1 to 3 years), and facilities with indoor electricity consumption of less than 1,000 kWh per year would have longer (10 to 20 years) payback periods.

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 4.3). 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 Escondido Operations Center. 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 a number of ECOs that would improve pump operations based on current activities or potential future operations; however, many were determined to be 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 WTP facility, 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 (Table 4.4).

TABLE 4.2 **Analysis of Indoor Lighting Control Measures Warranting Further Investigation**

INDOOR LIGHTING ENERGY USAGE (KWH/YEAR)	GHG REDUCTION POTENTIAL (MT CO_2E/YEAR)	INITIAL COST	PAYBACK TERM	EXAMPLE FACILITIES
<1,000 kWh/year	<1 MT CO_2e/year	<$5,000	10 to 20+ years	Escondido PS3, Valley Center PS
10,000 to 15,000 kWh/year	1 to 2 MT CO_2e/year	$5,000 to $10,000	10 to 15 years	Escondido Vehicle Maintenance Facility
>100,000 kWh/year	5 to 10 MT CO_2e/year	$8,000 to $15,000	1 to 5 years	Escondido Operations Center, Twin Oaks Valley WTP

Notes: GHG reduction potential is based on anticipated 2020 SDG&E emissions factor with 33% RPS. Detailed analyses are provided in Appendix D. KWh = kilowatt hours; MT CO_2e = metric tons of carbon dioxide equivalent; PS = pump station; WTP = water treatment plant

TABLE 4.3 **Analysis of Support Operations Measures Warranting Further Investigation**

SUPPORT MEASURE	ENERGY USE (KWH/YEAR)	GHG REDUCTION POTENTIAL (MT CO_2E/YEAR)	INITIAL COST	PAYBACK TERM	EXAMPLE FACILITIES
Demand Management Systems	200,000 kWh/year	4 to 10 MT CO_2e/year	$20,000 to $50,000	4 to 20+ years	Twin Oaks Valley WTP, Escondido Operations Center
HVAC Control Systems	10,000–15,000 kWh/year	1 to 2 MT CO_2e/year	<$5,000	20+ years	Olivenhain PS, San Vicente PS
System monitoring and evaluation of block loads and hot water temperature usage	10,000–25,000 kWh/year	1 to 2 MT CO_2e/year	$0	Immediate	San Diego HQ, Lake Hodges PS

Notes: GHG reduction potential is based on anticipated 2020 SDG&E emissions factor with 33% RPS. Detailed analyses are provided in Appendix D. Energy usage indicates the assumption of energy load that the reductions were based on. KWh = kilowatt hours; MT CO_2e = metric tons of carbon dioxide equivalents; PS = pump station; WTP = water treatment plant

TABLE 4.4 **Pump Upgrade Measures Warranting Further Investigation**

ENERGY USE (KWH/YEAR)	GHG REDUCTION POTENTIAL (MT CO_2E/YEAR)	INITIAL COST	PAYBACK TERM	EXAMPLE FACILITY
140,160 kWh/year	10 MT CO_2e/year	>$10,000	3 years	Twin Oaks Valley WTP

Notes: Energy use taken from 2012 Energy Audit report, page 136. GHG reduction potential is based on anticipated 2020 SDG&E emissions factor with 33% RPS. Detailed analyses are provided in Appendix D. KWh = kilowatt hours; MT CO_2e = metric tons of carbon dioxide equivalent; WTP = water treatment plant.

OTHER OPPORTUNITIES

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

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 vehicles. Fully electric vehicles were not considered due to the battery range technology currently available and the lack of recharge infrastructure. Only vehicles with high mileage and that would result in perceptible GHG reductions were considered as potentially financially feasible for replacement. Of the approximately 90 on-road vehicles maintained by the Water Authority, 12 fit this profile: two sport utility vehicles (SUVs) and 10 trucks. The replacement analysis assumed vehicles would be replaced by vehicles with hybrid electric engines in same class (i.e., SUVs will be replaced with SUVs). Table 4.5 shows the potential GHG reduction, cost, and payback term on a per-vehicle- type basis. If all 12 vehicles were replaced with hybrids, the net GHG benefit would be approximately 30 MT CO_2e per year in 2020, with a payback of more than 20 years. Other assumptions are provided in Appendix D.

Solar PV

This potential CAP measure includes the installation of a solar PV system at an existing Water Authority-owned site. 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 annual kilowatt-hour output is proportional to 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 in 2020. 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 (Table 4.6).

TABLE 4.5 **Vehicle Fleet Conversion Measures**

VEHICLE TYPE	FUEL REDUCTION (GALLONS/YEAR)	GHG REDUCTION POTENTIAL (MT CO_2E/YEAR)	INITIAL COST	PAYBACK TERM
SUV	90	<1 MT CO_2e/year	<$10,000	20+ years
Truck	320	3 MT CO_2e/year	>$10,000	20+ years

Notes: Initial cost indicates premium cost of hybrid versus purchase of a standard vehicle. Assumes vehicles are driven 10,000 miles per year on average. Estimates are per vehicle. MT CO_2e = metric tons of carbon dioxide equivalent; SUV = sport utility vehicle

TABLE 4.6 **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. Detailed analyses are provided in Appendix D. KWh = kilowatt hour; MT CO_2e = metric tons of carbon dioxide equivalent; PV = photovoltaic

In-Line Hydropower

Generating electricity using water is already occurring in facilities such as the Lake Hodges Pumped Storage facility, which takes advantage of height differentials by pumping water uphill during non-peak hours and releasing the water downhill via gravity during peak or carbon-intensive periods to create zero-GHG-emitting electricity. In addition, water flowing through pipelines has the potential to generate power within largely existing infrastructure. Water distribution pipeline networks can be retrofitted with turbines blades, generally in pipes 24 inches or larger in diameter, to exploit the kinetic energy of flowing water. The Water Authority also owns and operates the Rancho Peñasquitos PCHF, a 4.5-MW hydroelectric generating system that was completed in 2006. Through a power purchase agreement with SDG&E, RECs are generated by the facility and are retained by SDG&E. However, the agreement expires in 2017, and affords the Water Authority an opportunity to retain these RECs to use toward its own GHG reductions.

The 2013 Master Plan Update provides more detail on system requirements and the efficiency of additional in-line energy sources. For purposes of identifying all potential measures available to the Water Authority, Table 4.7 describes several in-line power potential opportunities, the energy production potential, and an estimated payback term based on information available to date. Systems between 200 and 2,000 kW have payback periods of less than 10 years and can create substantial alternative energy. If all seven of the installations analyzed in the CAP were implemented, in-line hydropower generation would result in a reduction of approximately 8,156 MT CO_2e per year (Appendix D). This presents another significant water-based energy production opportunity that could further offset emissions.

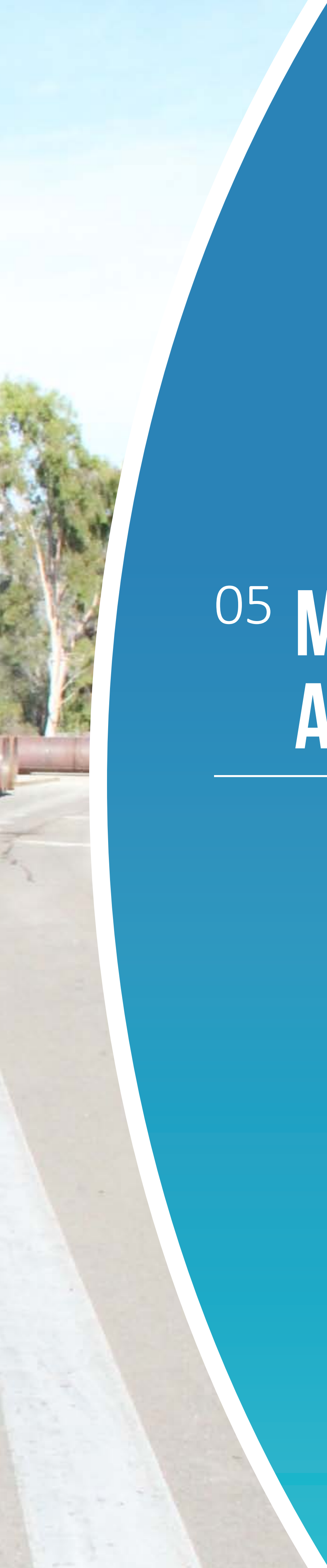
Summary

The Water Authority has identified and analyzed the measures described above that would result in GHG reductions beyond those already implemented. 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. The 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.

TABLE 4.7 **Analysis of In-Line Hydropower Measures**

GENERATOR SIZE (KW)	ANNUAL ENERGY PRODUCTION (KWH/YEAR)	GHG REDUCTION POTENTIAL (MT CO_2E/YEAR)	INITIAL COST	PAYBACK TERM	EXAMPLE FACILITIES
120 kW	900,000 kWh/year	220 MT CO_2e/year	$980,000	10 to 15 years	Oceanside 5 FCF
530 kW	2,100,000 kWh/year	>500 MT CO_2e/year	$3.2 million	15 to 20 years	Miramar
2,000 kW	16,500,000 kWh/year	>4,000 MT CO_2e/year	$6.5 million	<5 years	Twin Oaks Flow Regulatory Structure
200–1,200 kW	1,700,000–8,000,000 kWh/year	400–2,000 MT CO_2e/year	$1.25 million–$5.2 million	5 to 10 years	Otay 12 FCF, Oceanside 6 FCF, Alvarado, Crossover Pipeline Terminal Structure

Notes: GHG reduction potential is based on anticipated 2020 SDG&E emissions factor with 33% RPS. Detailed analyses are provided in Appendix D. MT CO_2e/year = metric tons of carbon dioxide equivalents per year; kW = kilowatt; kWh = kilowatt hours; FCF = Flow Control Facility



05 MONITORING AND REPORTING

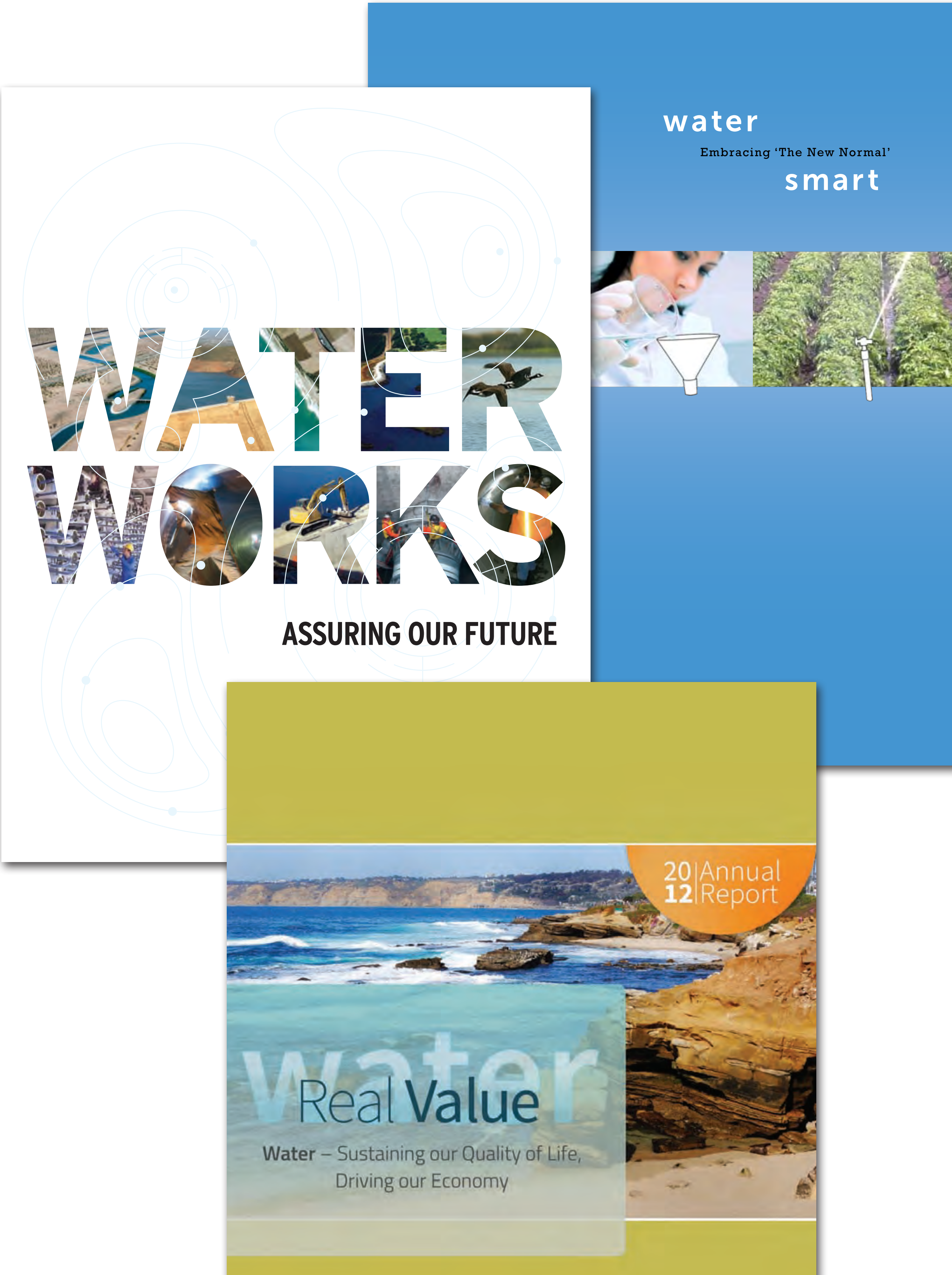
To qualify as a GHG reduction plan under CEQA, a CAP must have a monitoring mechanism. The Water Authority is committed to achieving the 2020 emissions reduction target, and has established monitoring mechanisms for accurate reporting. To ensure that the Water Authority is monitoring GHG emissions reduction efforts, progress will be tracked as part of an annual CAP report.

In addition, the CAP will be reviewed prior to 2020. Reviewing the CAP will allow a comprehensive look at how the Water Authority is performing, and the annual CAP report will be a progress indicator of specific measures. Since the CAP is a programmatic document that later projects can tier from for CEQA review, assessing overall emissions reductions for the Water Authority is important to ensure that progress is being made. If progress is not being made, the review will enable the Water Authority to determine appropriate steps to achieve goals.

Since climate change policy continues to evolve, new information will be available to the Water Authority before 2020. Following are more reasons to review and update the CAP periodically:

- New state-implemented GHG-reduction strategies may be implemented that achieve even greater reductions than anticipated or change the effectiveness of the opportunities identified in Chapter 4.
- The Scoping Plan will have its second update prior to 2020, and may include additional guidance for local agencies for establishing reduction goals beyond 2020.
- Technology is rapidly changing and could affect the feasibility of opportunities identified in this CAP or identify new opportunities.
- Case law is being established for horizon years evaluated in CAPs and target-setting on a local level. Additional litigation is likely, and may affect future CAP iterations.
- Internally, the Water Authority may identify funding opportunities that accelerate implementation of GHG-reduction opportunities or complete feasibility studies that impact current opportunities.

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


water
Embracing 'The New Normal'
smart
WATER
WORKS
ASSURING OUR FUTURE
20 Annual
12 Report
water
Real Value
Water – Sustaining our Quality of Life,
Driving our Economy

06 CEQA

The Water Authority's approach to addressing GHG emissions reductions within this CAP is parallel to the climate change planning process being followed by dozens of jurisdictions and agencies throughout California. The process is as follows:

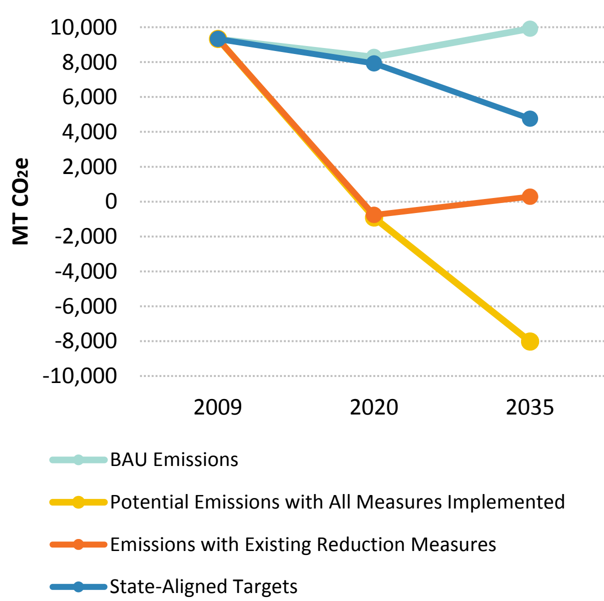
- Completing a baseline GHG emissions inventory and projecting future emissions.
- Identifying a future GHG emissions level consistent with statewide goals and guidance set by the state for local governments.
- Identifying a set of strategies to meet the targets.
- Evaluating the environmental impacts of the CAP through CEQA; in this case, through a Supplemental Program EIR.
- Adopting the CAP in a public process following environmental review.

This process is also consistent with the CEQA Guidelines Section 15183.5 that allows agencies to analyze and mitigate significant GHG impacts at a programmatic level. Later, project-specific environmental documents may tier from and incorporate by reference the Supplemental Program EIR in the cumulative GHG impact analysis. Specific projects, such as the 2013 Master Plan Update projects, were included in the CAP analysis and reviewed in the Supplemental Program EIR; as long as these projects do not change substantially from the description evaluated, they may rely on this analysis for their GHG impact analysis.

Additional projects that were not evaluated in this CAP or the EIR would have to demonstrate compliance with the CAP and include any appropriate mitigation measures as enforceable components of the project. Otherwise, future projects must prepare a separate GHG analysis. For example, later revisions to the Master Plan may include new projects that may require updates to the CAP and additional environmental documentation for tiering purposes.

Figure 6.1 shows how the Water Authority's current emissions targets align with state goals. Table 6.1 summarizes the Water Authority's emissions to date, and lists future reduction opportunities.

FIGURE 6.1 **Water Authority Emissions and Targets Aligned with State Goals**



Notes: Assumes in-line hydropower would be installed post-2020.
MT CO_2e = metric tons of carbon dioxide
BAU = business as usual

TABLE 6.1 **Summary of Water Authority Emissions, Reductions to Date, and Additional Reduction Opportunities**

	2009 (MT CO_2E)	2020 (MT CO_2E)	2035 (MT CO_2E)
Business-as-Usual Emissions	9,325	8,295	9,916
Existing Reduction Measures			
Federal and State Reductions		(9,052)	(9,629)
Local Reductions		(4)	(4)
EMISSIONS WITH EXISTING REDUCTION MEASURES	**9,325**	**(762)**	**283**
Additional Local Reduction Opportunities			
ECOs – Lighting Measures		(17)	(17)
ECOs – Support Operations		(20)	(20)
ECOs – Pump Upgrades		(10)	(10)
Vehicle Fleet Conversion		(30)	(30)
Solar PV Installation		(74)	(74)
In-Line Hydropower			(8,156)
POTENTIAL EMISSIONS WITH ALL MEASURES IMPLEMENTED	**9,325**	**(913)**	**(8,024)**
STATE-ALIGNED TARGETS		**7,927**	**4,756**

Notes: Assumes all additional opportunities are implemented prior to 2020 except in-line hydropower, which would be installed 2021–2035.
MT CO_2e = metric tons of carbon dioxide equivalent; ECO = energy conservation opportunity; PV = photovoltaic

REFERENCES

ARB, see *California Air Resources Board.*

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://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm.
Last accessed October 9, 2013.

City of Escondido. 2012. Draft Climate Action Plan.
Available at www.escondido.org/Data/Sites/1/media/PDFs/Planning/GPUpdate/DraftClimateActionPlan.pdf.
Last accessed October 12, 2013.

City of La Mesa General Plan Environmental Impact Report. 2013. Chapter 4.5 - Green House Gas Emissions.
Available at http://www.cityoflamesa.com/DocumentCenter/View/5882.
Last accessed October 12, 2013.

City of San Diego Climate Mitigation and Adaptation Plan. 2013.
Available at www.sandiego.gov/environmental-services/pdf/sustainable/finalcmap.pdf.
Last accessed October 12, 2013.

County of San Diego Climate Action Plan. 2012.
Available at http://www.sdcounty.ca.gov/dplu/advance/Climate_Action_Plan.pdf.
Last accessed October 12, 2013.

CPUC, see *California Public Utilities Commission.*

New Zealand Business Council for Sustainable Development. 2002. The Challenge of Greenhouse Gas Emissions.

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

Union Tribune San Diego. 2013. San Diego Loves Merlot, not Michelob.
Available at http://www.utsandiego.com/news/2013/Sep/04/san-diego-scarborough-rankings-2013.

Water Authority, see *San Diego County Water Authority.*

Page intentionally left blank

Appendix A

2009 GREENHOUSE GAS EMISSIONS INVENTORY

2009 Greenhouse Gas Emissions Inventory

OCTOBER 2012

San Diego County Water Authority

Contents

Prepared by AECOM

Executive Summary

In 2009, SDCWA generated approximately 9,325 metric tons (MT) of carbon dioxide equivalent (CO_2e) emissions. As shown in Table ES1, the largest sector in the inventory was the electricity sector, which accounted for 82% of emissions. The next largest sectors in the inventory were emissions from the vehicle fleet and employee commute sectors, respectively. These sectors accounted for a combined 15% of the inventory. The remaining sectors accounted for less than 3% 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	7,637.76	81.90%
Vehicle Fleet	694.16	7.44%
Employee Commute	685.34	7.35%
Off-Road Equipment	142.87	1.53%
Stationary Source	88.69	0.95%
Natural Gas	42.29	0.45%
Solid Waste	26.75	0.29%
Water	4.35	0.05%
Refrigerants	1.78	0.02%
Wastewater	1.42	0.02%
Total	**9,325.42**	**100%**

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.

Baseline Emissions Inventory

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

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

SDCWA emitted 9,325 MT CO_2e in 2009. That is about equal to the CO_2 emissions from 807 U.S. homes in a year.

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

from the LGOP were used to estimate emissions from natural gas (including CO_2, CH_4, and N_2O).

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).

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;

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.

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 previous inventory, by sector.

SDCWA emissions for 2009 were originally estimated to be 8,712 MT CO_2e; the revisions resulted in a 7% increase (613 MT CO_2e) in emissions, or 9,325 MT CO_2e. The increase was largely a result of the addition of emissions from employee commutes, water and wastewater, and solid waste disposal. Minor changes resulted to the other sections based on revisions to emission factors and other updates to the methodology.

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	7,637.76	(41.60)
Vehicle Fleet	723.00	694.16	(28.83)
Employee Commute	-	685.34	685.34
Off-Road Equipment	-	142.87	142.87
Stationary Source	265.94	88.69	(177.25)
Natural Gas	42.32	42.29	(0.03)
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**	**9,325.42**	**613.03**

Totals may not equal 100% due to rounding. 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.

Emissions by Facility

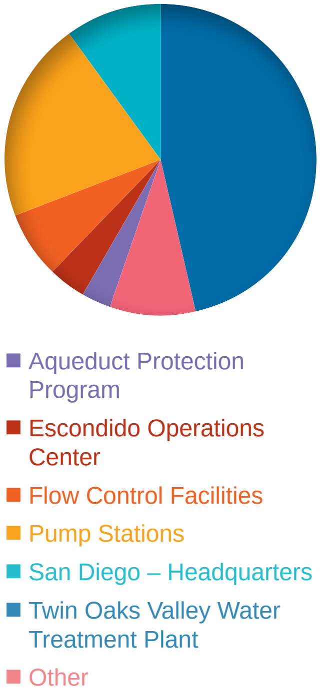
For an agency such as SDCWA that has direct control over the majority of its emission sources, it may be useful to identify which facilities generate the most emissions. Often, high-emitting facilities are integral to the agency's mission; however, it can also inform the agency where energy audits, retrofitting, or retrocommissioning projects may be focused. The majority of the emissions inventory can be associated with specific 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 specific facilities and are considered "Other" in Table 2 and Figure 1. The Twin Oaks Valley Water Treatment Plant is responsible for 47% of SDCWA emissions in 2009. Pump stations are the next largest source of emissions, accounting for 21% of the total emissions, and the San Diego – Headquarters location is responsible for approximately 10% of the 2009 emissions. The three sources represent 78% of all SDCWA facility-related emissions.

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 efficiency of each facility to accurately understand the reduction potential of that sector.

Table 2: 2009 Greenhouse Gase Emissions by Facility

Facility	MT CO_2e	Percent of Total Emissions
Twin Oaks Valley Water Treatment Plant	4,388.25	47%
Pump Stations	1,959.79	21%
San Diego - Headquarters	919.41	10%
Combined Other	832.01	9%
Flow Control Facilities	611.93	7%
Escondido Operations Center	353.01	4%
Aqueduct Protection Program	261.00	3%
Total	**9,325.42**	**100%**

Figure 1: GHG Emissions by Facility



Twin Oaks Valley Water Treatment Plant

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

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 fleet and generators.

Table 3: 2009 Greenhouse Gas Emissions by Source

Source	MT CO_2e	Percent of Total Emissions
Purchased Electricity	7,642.11	81.9%
Gasoline fuel	1,172.37	12.6%
Diesel fuel	354.34	3.8%
Distillate Fuel Oil No. 1	84.35	0.9%
Natural Gas	42.29	0.5%
Other	28.18	0.3%
Refrigerants	1.78	0.0%
Total	**9,325.42**	**100%**

MT CO_2e = metric tons of carbon dioxide equivalent.

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 fleet, 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.

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

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

Table 4: 2009 Greenhouse Gas Emissions by Scope

Scope	MT CO_2e
Scope 1	969.79
Scope 2	7,642.11
Scope 3	713.52
Total	**9,325.42**

MT CO_2e = metric tons of carbon dioxide equivalent.

References

California Air Resources Board (ARB)

2010 Local Government Operations Protocol for the Quantification and Reporting of Greenhouse Gas Emissions Inventories. Version 1.1. May. Available at http://www.arb.ca.gov/cc/protocols/localgov/pubs/lgo_protocol_v1_1_2010-05-03.pdf. Accessed August 2012.

CalRecyle

2012 Solid Waste Characterization Database. Detailed Waste Composition by Selected Business Group by Jurisdiction. Available at http://www.calrecycle.ca.gov/WasteChar/wcabscrn.asp. Accessed August 2012.

County of San Diego

2011 Draft County of San Diego GHG Inventory. Available at http://www.sdcounty.ca.gov/dplu/gpupdate/docs/BOS_Aug2011/EIR/Appn_K_GHG.pdf. Accessed August 2012.

Environmental Protection Agency (EPA)

2010 Waste Reduction Model (WARM). Available at http://www.epa.gov/climatechange/waste/calculators/Warm_home.html. Accessed August 2012.

Intergovernmental Panel on Climate Change (IPCC)

2006 IPCC Guidelines for National Greenhouse Gas Inventories. Chapter 6 – Wastewater Treatment and Discharge.

San Diego Gas & Electric (SDG&E)

2009 2009 Annual Entity Emissions: Electric Power Generation/Electric Utility Sector.

The Climate Registry (TCR)

2008 General Reporting Protocol. Version 1.1. Available at http://www.theclimateregistry.org/downloads/GRP.pdf. Accessed August 2012.

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

EMISSIONS FORECASTS AND REDUCTION TARGETS

Business-as-Usual Forecasts for 2020 and 2035

Business-as-Usual (BAU) forecasts were developed for the years 2020 and 2035 using the scenario that neither a Climate Action Plan (CAP) nor other greenhouse gas (GHG)-reducing measures are implemented. For the Water Authority, BAU emissions include:

1. Emission sources in place at the time of the baseline inventory, with appropriate scaling of emissions to account for changes in water demand, employees, or other activity data;
2. Emission sources for projects implemented since the 2009 baseline emissions inventory, such as the Lake Hodges Pumped Storage Facility and San Vicente Dam (i.e., constructed between 2010 and 2013);
3. Projects anticipated to be constructed by 2020, such as those identified in the Master Plan and Capital Improvement Program (CIP); and
4. Projects anticipated to be constructed between 2021 and 2035.

The years 2020 and 2035 were chosen to align with the statewide goals for Assembly Bill 32 (2020) and the horizon year of the Master Plan (2035). Anticipating emissions beyond 2035 is considered speculative, because the level of supply and demand beyond 2035 has not been fully established at the time of the CAP development.

Note that the emissions estimated in this memo assume current levels of implementation of federal, state, and local measures. Additional reductions are anticipated by 2020 and 2035 due to existing legislation, and are accounted for in an “adjusted BAU” scenario, described in Appendix D.

1. Emissions sources in place by 2009

Emissions sources in place by 2009 are detailed in Appendix A and resulted in 9,325 metric tons of carbon dioxide equivalent (MT CO_2e) emissions in 2009. According to the Water Authority’s 2010 Urban Water Management Plan (SDCWA 2011), regional water demand will increase by 4.84% by 2020 and 22% by 2035. The Water Authority has projected an increase in emissions commensurate with the increase in demand. That is, the Water Authority assumes that all emissions sources described in Appendix A will increase at the same rate water demand is expected to increase. While an increase in demand does not necessarily correlate to an equal increase in emissions over time, this is a conservative approach to estimating future emissions. Table B-1 details the BAU forecast for emissions sources in place by 2009, anticipating 9,754 MT CO_2e will be emitted by these sources in 2020 and 11,338 MT CO_2e will be emitted in 2035.

Table B-1. Business-as-Usual Emissions Projections for Sources in Place by 2009

Emissions Source	2009 Emissions ($MT\ CO_2e$)	2020 BAU Projection ($MT\ CO_2e$)	2035 BAU Projection ($MT\ CO_2e$)
Electricity	7,637.76	8,007.43	9,318.07
Vehicle Fleet	694.16	727.76	846.88
Employee Commute	685.34	695.58	801.43
Off-Road Equipment	142.87	149.79	174.30
Stationary Source	88.69	92.98	108.20
Natural Gas	42.29	44.34	51.59
Solid Waste	26.75	27.97	27.97
Water	4.35	4.56	5.31
Refrigerants	1.78	1.86	2.17
Wastewater	1.42	1.49	1.74
Total	**9,325**	**9,754**	**11,338**

Note: Emissions may not add to total due to rounding.

Assumptions used to derive the projections are described below.

- Energy consumption (kilowatt hours [kWh] and therms) was assumed to increase by 4.84% between 2009 and 2020 and 22% between 2009 and 2035. Emissions factors were assumed to remain constant over time.
- Vehicle fleet makeup was assumed to remain constant over time; mileage and fuel consumption were assumed to increase.
- Employee commute projections assumed the number of employees grew relative to the growth in water demand. Average trip distance was assumed to remain constant but the mode share was adjusted according to the San Diego Association of Governments (SANDAG) projections for worker trip commute mode (SANDAG 2012). Fuel economy and emission factors were assumed to remain constant.
- Off-road equipment and stationary source emissions were assumed to increase relative to the increase in demand projected by the 2010 Urban Water Management Plan (UWMP).
- 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 emissions projections assumed that water usage increased 4.84% by 2020 and 22% by 2035, relative to 2009. Emissions factors were assumed to remain constant over time.
- Wastewater emissions projections assumed that influent and effluent increased 4.84% by 2020 and 22% by 2035, relative to 2009. Emissions factors were assumed to remain constant over time.
- Refrigerant emissions projections assumed that influent and effluent increased 4.84% by 2020 and 22% by 2035, relative to 2009. Emissions factors were assumed to remain constant over time.

2. Emissions sources constructed 2010–2013

Two major projects have been constructed since the 2009 baseline inventory was conducted. The San Vicente Pump Station and Lake Hodges Pumped Storage began operation in 2010 and 2012, respectively.

2.1 San Vicente Pump Station

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 provides untreated water stored in the San Vicente Reservoir when imported water supplies are cut off or to meet operational demands. Since operation of the pump station will depend on emergency situations and demand, energy consumption may vary considerably annually. During 2011, its first operational year, the facility consumed 6,996,732 kWh of energy (SDCWA 2012), which represents 2,316 MT CO_2e emissions for the year. Future energy use may reach 20,000 MWh per year, or 6,620 MT CO_2e based on current SDG&E emission factors (assuming 20% renewables). Emissions for 2020 and 2035 from the facility used the higher energy estimate as a conservative approach. As SDG&E meets the 33% target by 2020, the emissions estimate will be lower than 6,620 MT CO_2e. In addition, as the facility is operational longer, better data will be available to estimate "typical" annual conditions.

2.2 Olivenhain- Hodges Pumped Storage

The Olivenhain-Hodges Pumped Storage hydroelectric power project (Lake Hodges) is owned by the Water Authority and its priority purpose is water storage and distribution. However, the facility can also be operated within defined limits pursuant to a Master Power Purchase Agreement with SDG&E to produce peak power by utilizing the 770 feet of elevation difference between Olivenhain Reservoir and Lake Hodges to generate electricity. The pump-back power required is greater than the power that is generated by the facility. However, due to the timing and sources of power from which pump-back power is derived and the displacement of higher-emission natural gas-fired peaker plant-generated power, overall net emissions of CO_2 are reduced by the system operation. In addition, because the power is not being supplied to a utility provider to meet renewable energy-production requirements set by the state, the Water Authority may use the credits to offset other operational emissions.

As of 2012, SDG&E produced 20% of their electricity with renewable sources. Based on analysis of energy usage and pump-back power generated, the Water Authority has estimated that the facility could displace 8,907 MT CO_2 more emissions than it generates per year (HMCG 2013). Because this is a new facility, similar to the San Vicente Pump Station, several years of data will allow the Water Authority to evaluate typical conditions. As SDG&E's renewable portfolio increases, so too will the amount of emissions displaced by operation of the Lake Hodges Pumped Storage facility.

2.3 Summary

Emissions since 2009 have resulted in displacing 6,591 MT CO_2 as of 2012. As discussed, San Vicente will likely have higher emissions in 2020 and 2035 and the net emissions displaced by the two facilities are estimated to be 2,287 MT CO_2e in 2020 and 2035 that can be used to offset other Water Authority emissions sources. The displaced emissions could be even greater as SDG&E meets its renewable energy goals set for 2020. These additional GHG reductions are accounted for in the CAP as State and Federal reductions, since the Water Authority does not control SDG&E's portfolio.

3. New Emissions sources anticipated 2014–2020

Future projects likely to be constructed by 2020 include Master Plan projects and CIP projects. Master Plan projects include system isolation valve construction, which increases security of the network. The projects require construction, which are short-term emissions, but will not increase operational emissions. A variety of CIP projects are also scheduled to occur by 2020 and would result in construction and operational emissions.

3.1.1 Construction Emissions

Construction-related GHG emissions are short term, as opposed to ongoing operational emissions; therefore, they may be amortized over the lifetime of the project (County of San Diego 2012). For purposes of estimating emissions for emissions projection purposes, project lifetimes are considered to be 20 years. As the 20-year period expires for projects, those amortized emissions are no longer part of the Water Authority's profile. For example, projects constructed in 2014 will have amortized emissions added to the Water Authority's annual emissions profile from 2014 through 2033 and would not be included in the 2035 emissions projections. Table B-2 shows the estimated construction emissions by project, which are anticipated to be 143 MT CO_2e in 2020 and 96 MT CO_2e in 2035 when amortized.

3.1.2 Operational Emissions

Three project anticipated for construction between 2014 and 2020 will result in additional operational emissions: San Vicente Marina, Valley Center (P2A) Pump Storage, and North County Pump Station. The Water Authority is constructing the San Vicente Marina as part of the San Vicente Dam Raise project. However, once built, the operation and related emissions will be under the jurisdiction of the City of San Diego and therefore the emissions associated with the marina would be accounted for by the City of San Diego. The North County Emergency Storage Project (ESP) Pump Station (PS) will serve portions of the North County during emergencies and planned outages of the aqueduct system. The energy consumption therefore will be intermittent and is estimated will consume 218 MWh per year, resulting in 54 MT CO_2e operational emissions per year. The Valley Center (P2A) Pump Station project will expand the current facility from 20 cubic feet per second (cfs) to 40 cfs, which will require additional power. The estimated energy consumption is 2,550 MWh, or 651 MT CO_2e, per year.

Table B-2 shows the total emissions for projects anticipated to be constructed between 2014 and 2020 would result in 828 MT CO_2e per year in 2020 and 781 MT CO_2e in 2035.

Table B-2. Emissions from New Sources Constructed 2014– 2020

Projects	2020 and 2035 Operational Emissions ($MT\ CO_2e/yr$)	2020 Construction Emissions ($MT\ CO_2e$)	2035 Construction Emissions ($MT\ CO_2e$)
Master Plan			
System Isolation Valves (2014)	NA	285	0
Asset Management			
Pipeline 4 (2017)	NA	144	144
Pump 3 (2016)	NA	272	272
CIP			
Mission Trails (2015–2016)	NA	551	551
North County Pump Station (2015–2016)	54	884	884
Nob Hill (2015)	NA	62	62
San Vicente Marina (2014)	NA	435	0
San Vicente Bypass (2014)	NA	232	0
Valley Center (P2A) Pump Station (2016)	631	NA	NA
Total	**685**	**2,865**	**1,913**
Amortized (20 years)		**143**	**96**
Total Annualized Emissions (Operation + Amortized Construction)		**828**	**781**

Notes: $MT\ CO_2e$ = metric tons of carbon dioxide equivalent per year. Assumes life of project to be 20 years for amortization purposes. Year in parenthesis indicates construction year(s). Emissions for projects anticipated for construction in 2015 were included in the 2035 emissions estimate, allowing for a 1-year delay in construction.

4. New Emissions sources anticipated 2021–2035

Additional projects included in the Master Plan are expected to be constructed between 2021 and 2035. Similar to emissions constructed by 2020, the Pipeline 3/4 Switch and System Regulatory Storage projects are expected to increase system efficiency and therefore only have construction emissions. The San Vicente 3rd Pump Drive and Power project is part of the San Vicente project described in Section 2.1. That analysis (estimating up to 20,000 MWh energy consumption per year) includes the potential energy consumption of the overall project and therefore only construction emissions are estimated for this phase of the project below. Amortized over 20 years, these projects would emit 85 MT CO_2e per year in 2035 (Table B-3).

Table B-3. Emissions from New Sources Constructed 2021–2035

Projects	2035 Construction Emissions (MT CO_2e)
Master Plan	
Pipeline 3/ 4 Switch (2020–2021)	542
System Regulatory Storage (2020–2021)	816
San Vicente 3rd Pump Drive and Power (2020)	349
Total	**1,707**
Amortized (20 years)	**85**

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. In addition, the Water Authority Master Plan anticipates projects to be constructed through 2035; therefore, emissions through 2035 can be estimated. Although no guidelines are available for addressing emissions reductions goals beyond 2020, the Water Authority has determined that a straight-line path toward the 2050 goals identified in Executive Order S-3-05 would lead to a reduction target of 49% below 2009 levels by 2035. The Water Authority identified this as a longer-term target in lieu of more specific guidance. Should more specific guidance become available, the Water Authority may revisit this target. Currently, the 2020 emissions goal for the Water Authority is 7,927 MT CO_2e and a longer-term target of 4,756 MT CO_2e in 2035.

Summary

Total future BAU emissions will result in 8,295 MT CO_2e in 2020 and 9,916 MT CO_2e in 2035 (Table B-4). This represents an 11% reduction and 6% increase from baseline emissions in 2020 and 2035, respectively. It should be noted that this does not include additional reductions anticipated through full implementation of federal and state measures, such as SDG&E achieving 33% renewables by 2020. Those reductions are quantified in Appendix D.

Table B- 4. Summary of Business-as-Usual Emissions Projections

Emissions Source	2009 Emissions (MT CO2e)	2020 BAU Projection (MT CO2e)	2035 BAU Projection (MT CO2e)
Sources in Place by 2009	9,325	9,754	11,337
Emissions sources constructed 2010–2013	NA	(2,287)	(2,287)
New Emissions sources anticipated 2014–2020	NA	828	781
New Emissions sources anticipated 2021–2035	NA	NA	85
Total	**9,325**	**8,295**	**9,916**
Percent Change from Baseline	NA	**-11%**	**+6%**
Meeting Goal/Target?	NA	**No**	**No**

References

County of San Diego. 2012. County of San Diego Guidelines for Determining Significance for Climate Change. Available at http://www.sdcounty.ca.gov/pds/advance/climateactionplan.html.

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.

SDCWA see San Diego County Water Authority.

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

Appendix C

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
San Diego, California 92123

September 2012

Prepared by

DHK ENGINEERS, INC.

1851 Skyhill Place
Escondido, California 92026

Redhorse Corporation
363 5th Avenue, Suite 201
San Diego, California 92101

TABLE OF CONTENTS

TABLES

FIGURES

ATTACHMENTS

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.

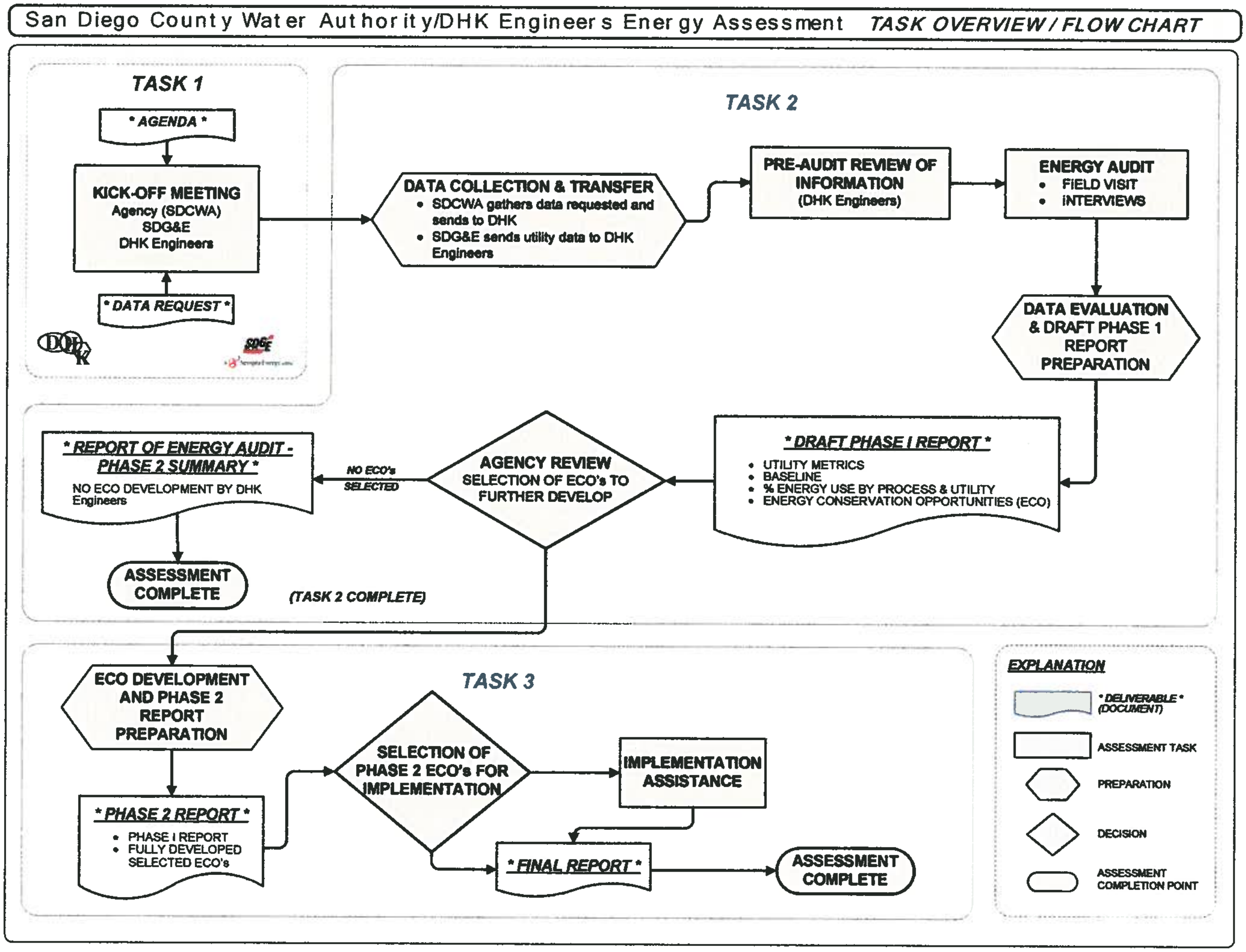
Imported water flows to San Diego County through five large-diameter pipelines. The Water Authority takes ownership of these pipelines just south of the Riverside-San Diego county line. The main pipelines range in size from 48 to 108 inches and carry either fully treated potable water or untreated water 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

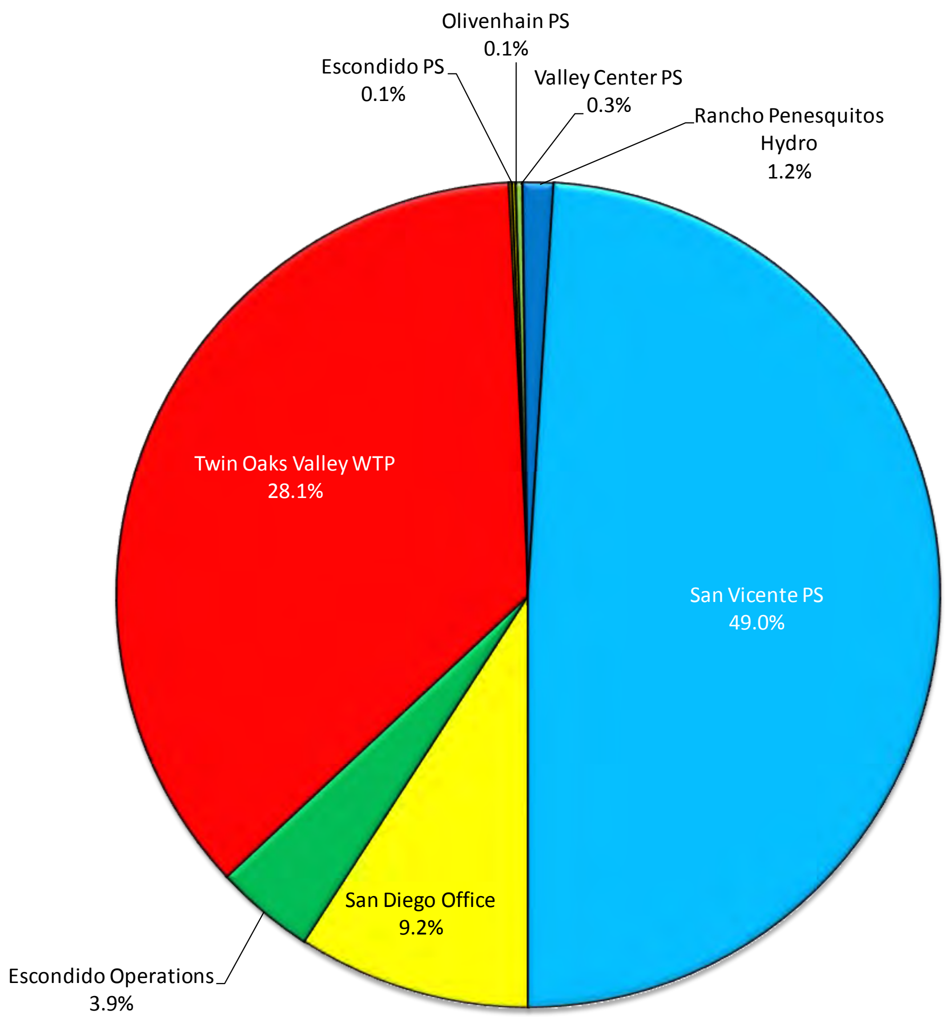
Along with the Basic Service Fees, customers are charged for the energy they demand (kW) and use (kWh). Demand is the amount of energy a customer is using at any one time. There are several components that make up the Demand and Energy rates charged by SDG&E: Commodity Costs, Transmission Charges, Distribution 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

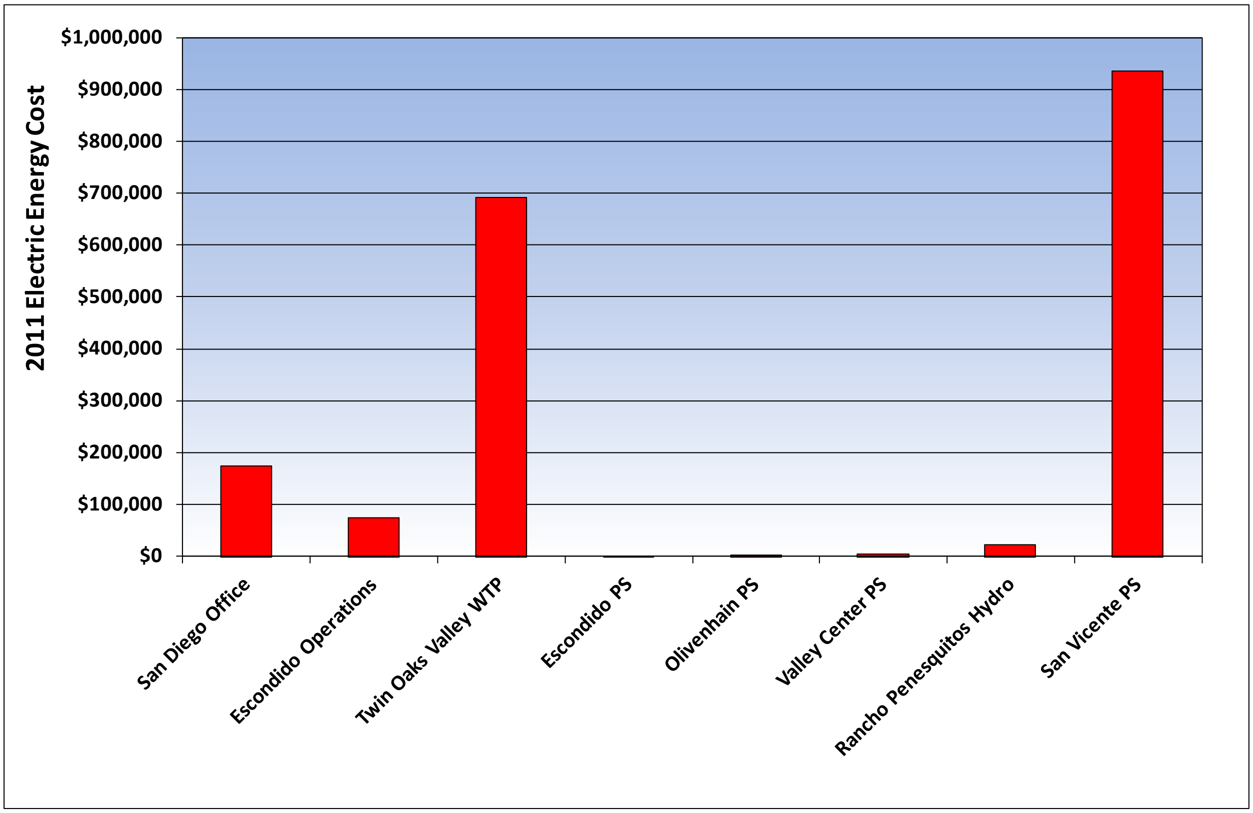
Electricity usage data and bills from 2010 to present were reviewed. According to these data, the Water Authority currently consumes approximately 13.4 GigaWatt-hours of electricity and spends just over $1,900,000 annually for electrical energy. Figure 4-1 shows the percent total annual energy use per 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

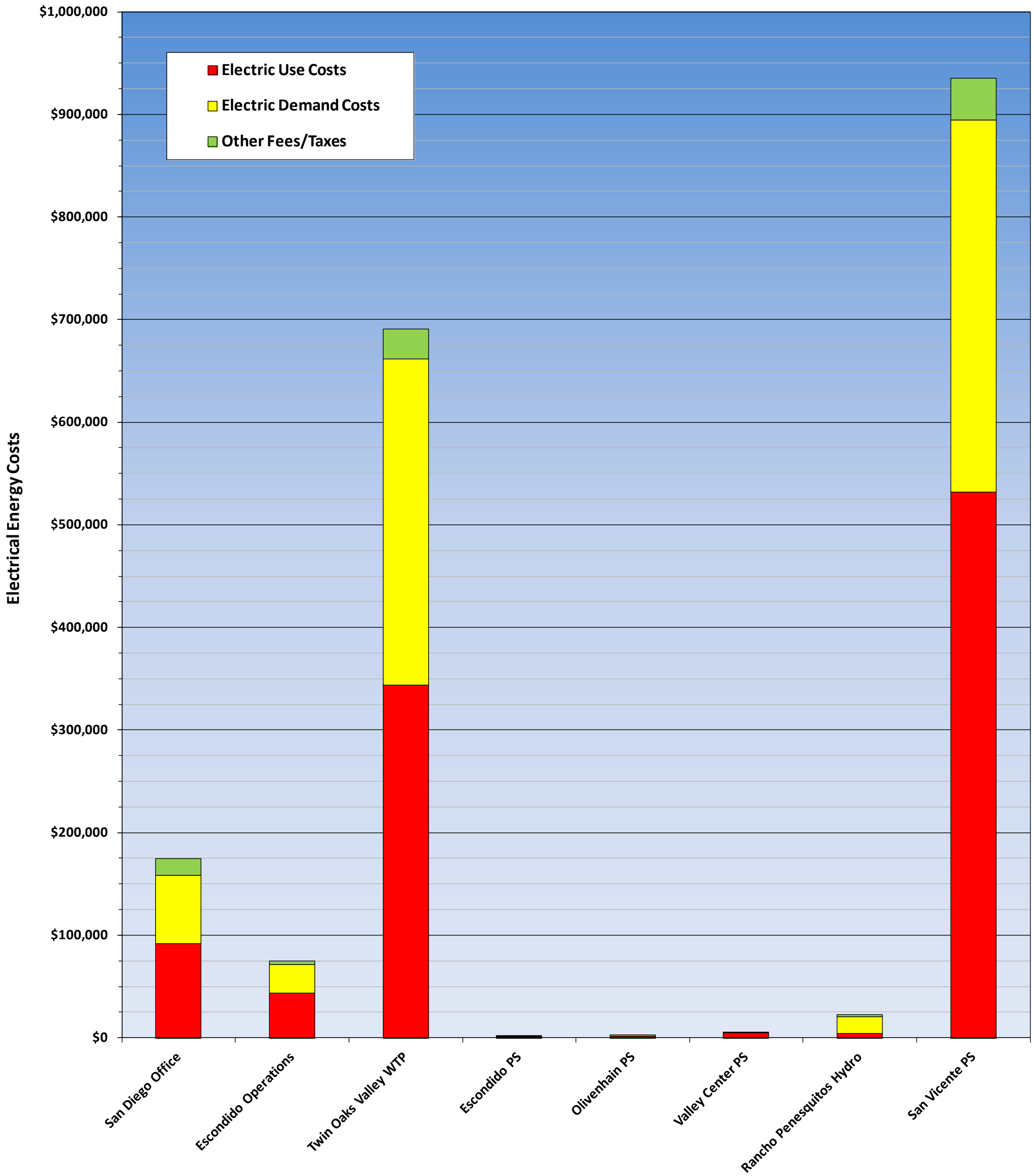


Table 4-1: Summary of Energy Metrics for Selected San Diego County Water Authority Facilities

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

San Diego County Water Authority. 2012. Website accessed on August 27-29, 2012. http://www.sdcwa.org.

San Diego Gas & Electric (SDG&E). 2012a. Tariff Information Index Page. http://sdge.com/electric-tariff-book-commercialindustrial-rates. Accessed July 15, 2012.

San Diego Gas & Electric (SDG&E). 2012b. Rate Schedules. http://sdge.com/rates-regulations/tariff-information/miscellaneous-rate-related-information. Accessed January-August, 2012.

ATTACHMENT 1: ESCONDIDO OPERATIONS BUILDING

Phase 1 Energy Audit Report

Report of Energy Audit – Phase 1 Summary

Escondido Operations Facility

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.

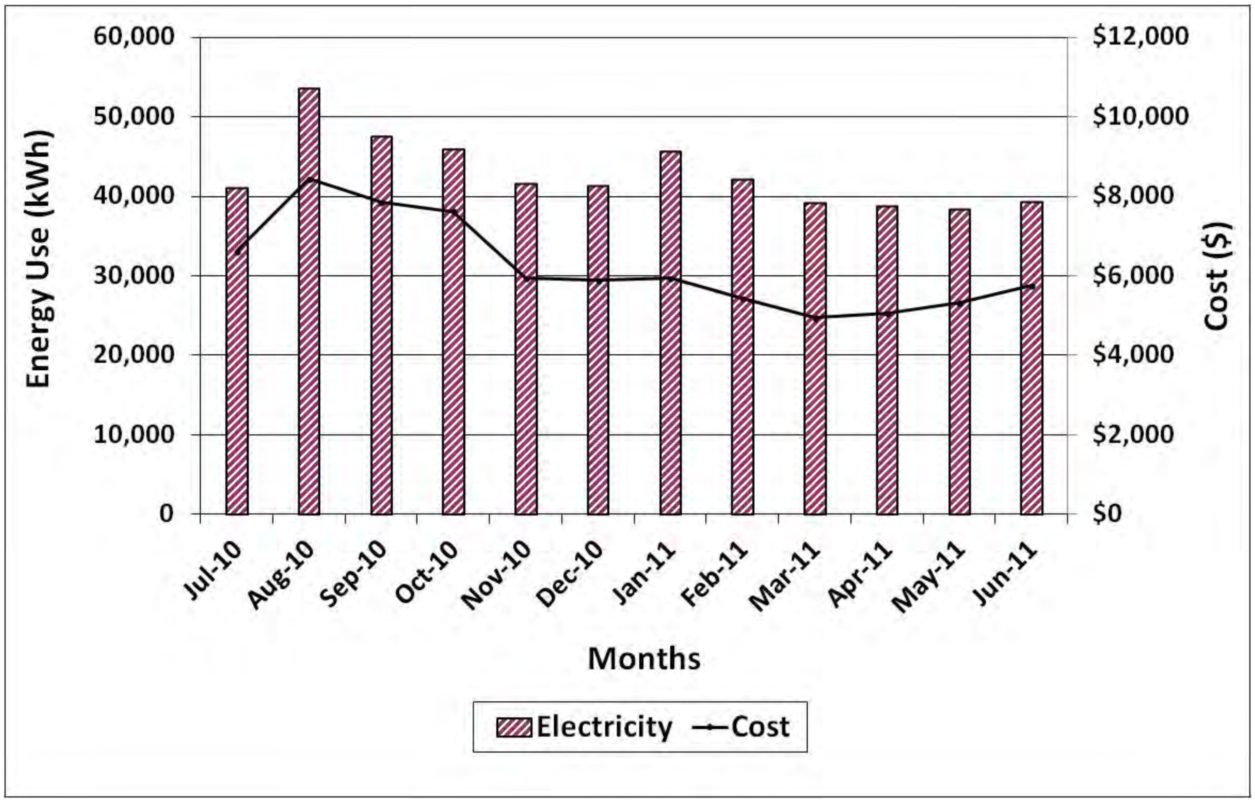


Figure 1. 2010/2011 Energy Use and Cost Breakdown

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.

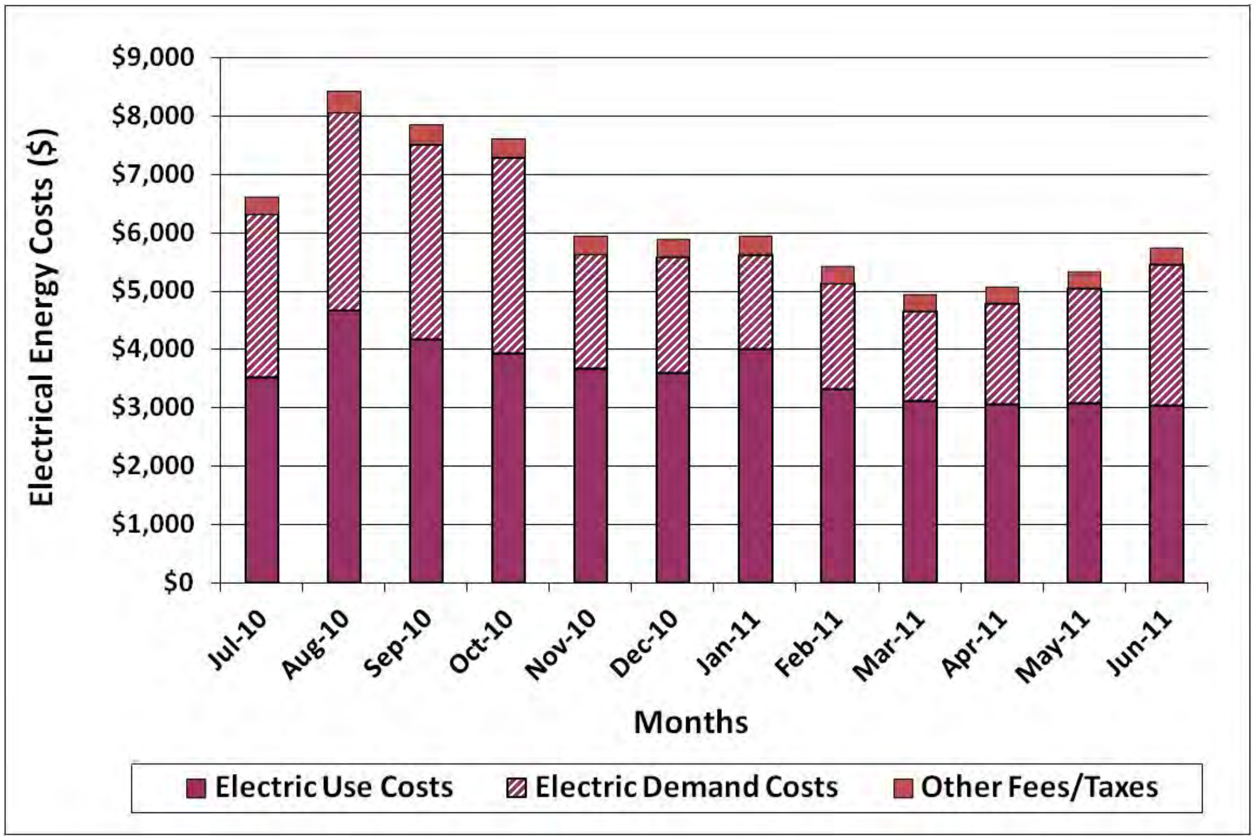


Figure 2. 2010/2011 Energy Cost Breakdown

3. Energy Conservation Opportunities

Table 6 lists potential ECOs recommended for further evaluation.

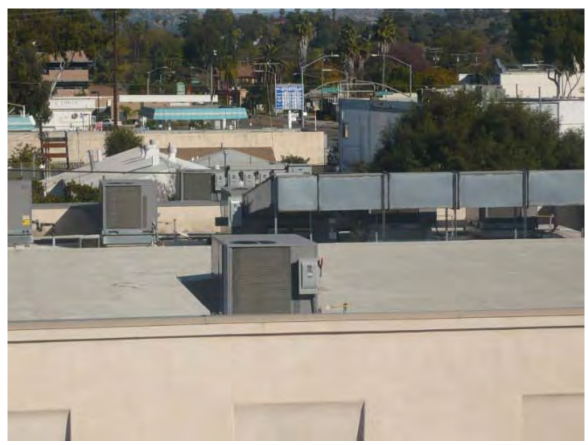
Table 6. Recommended Energy Conservation Opportunities

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.

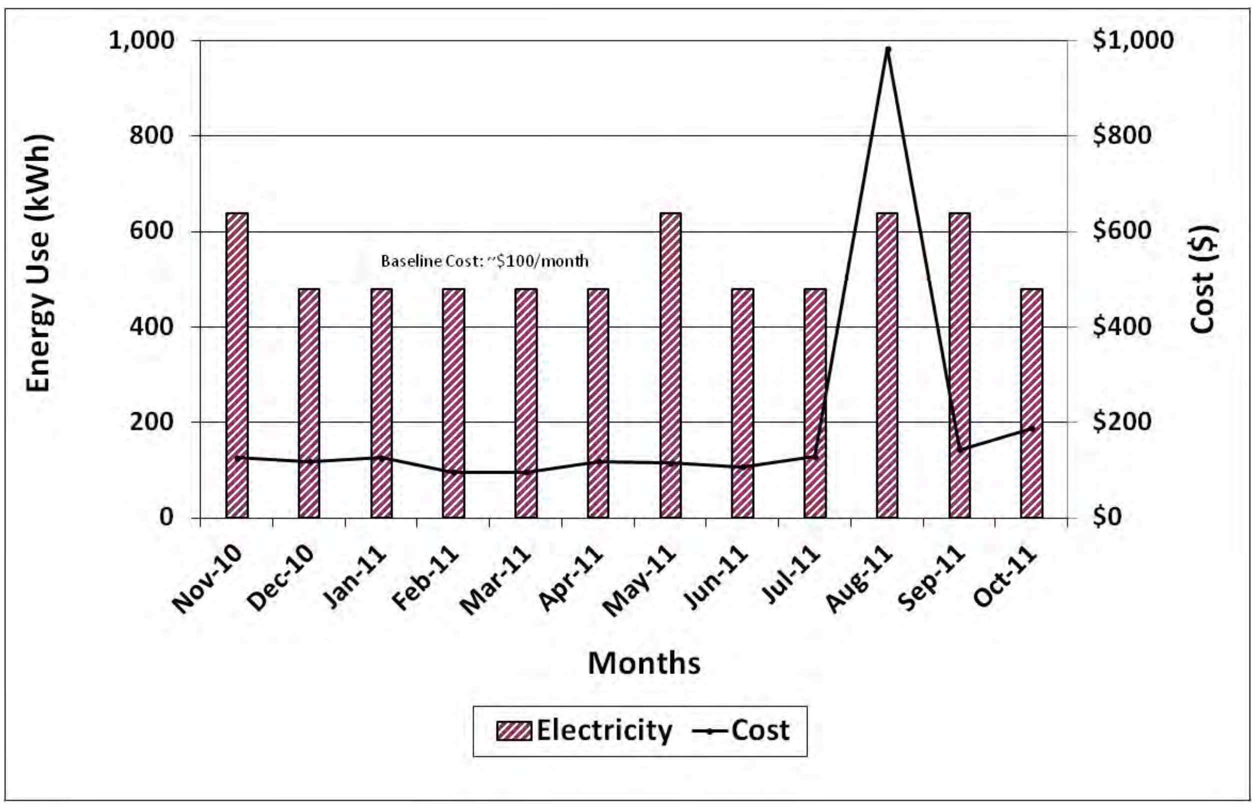


Figure 1. 2010/2011 Energy Use and Cost Breakdown

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.

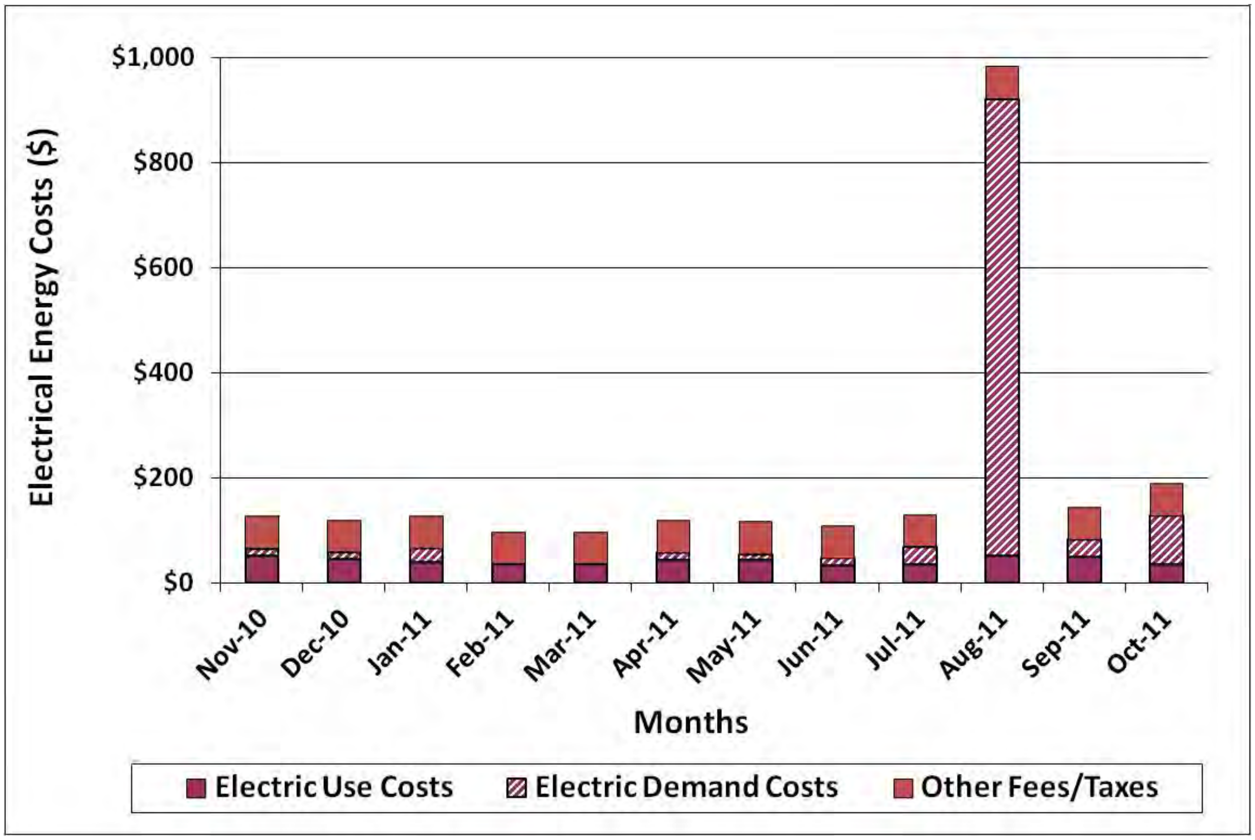


Figure 2. 2010/2011 Energy Cost Breakdown

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

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.

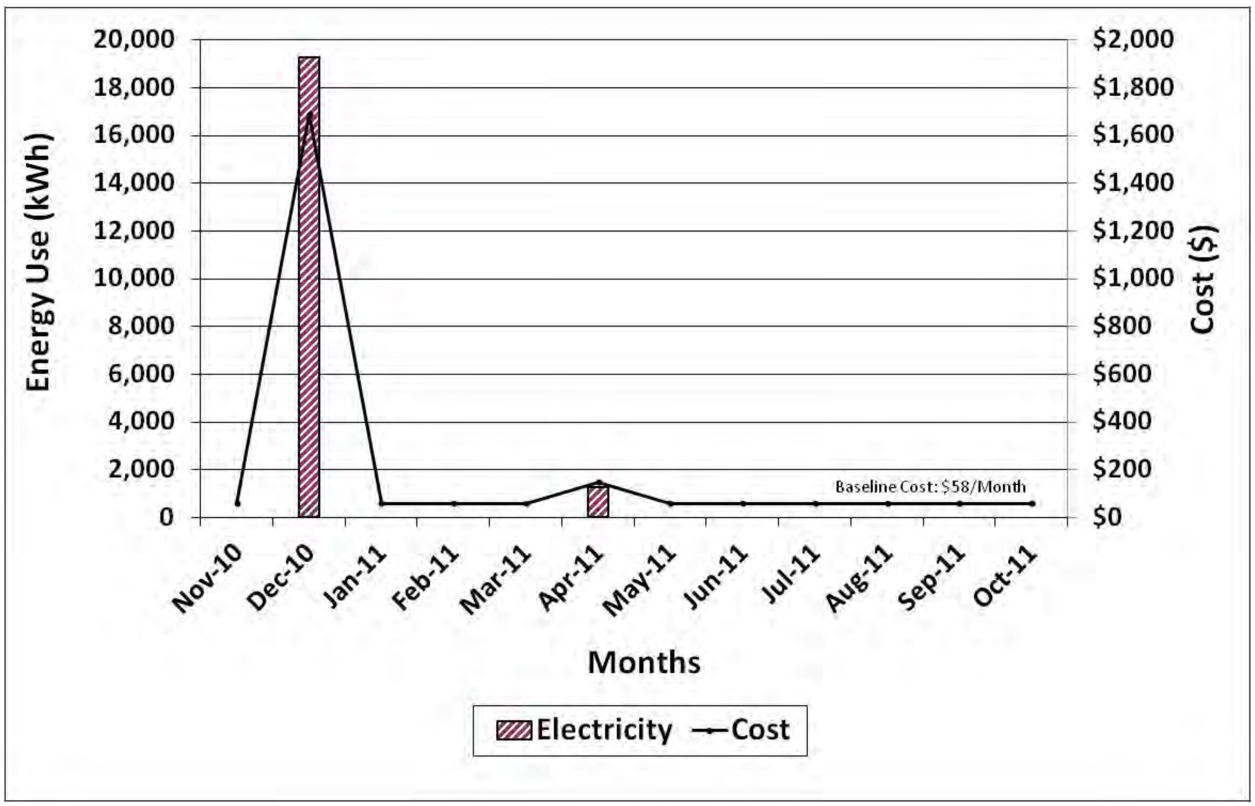


Figure 1. 2010/2011 Energy Use and Cost Breakdown

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.

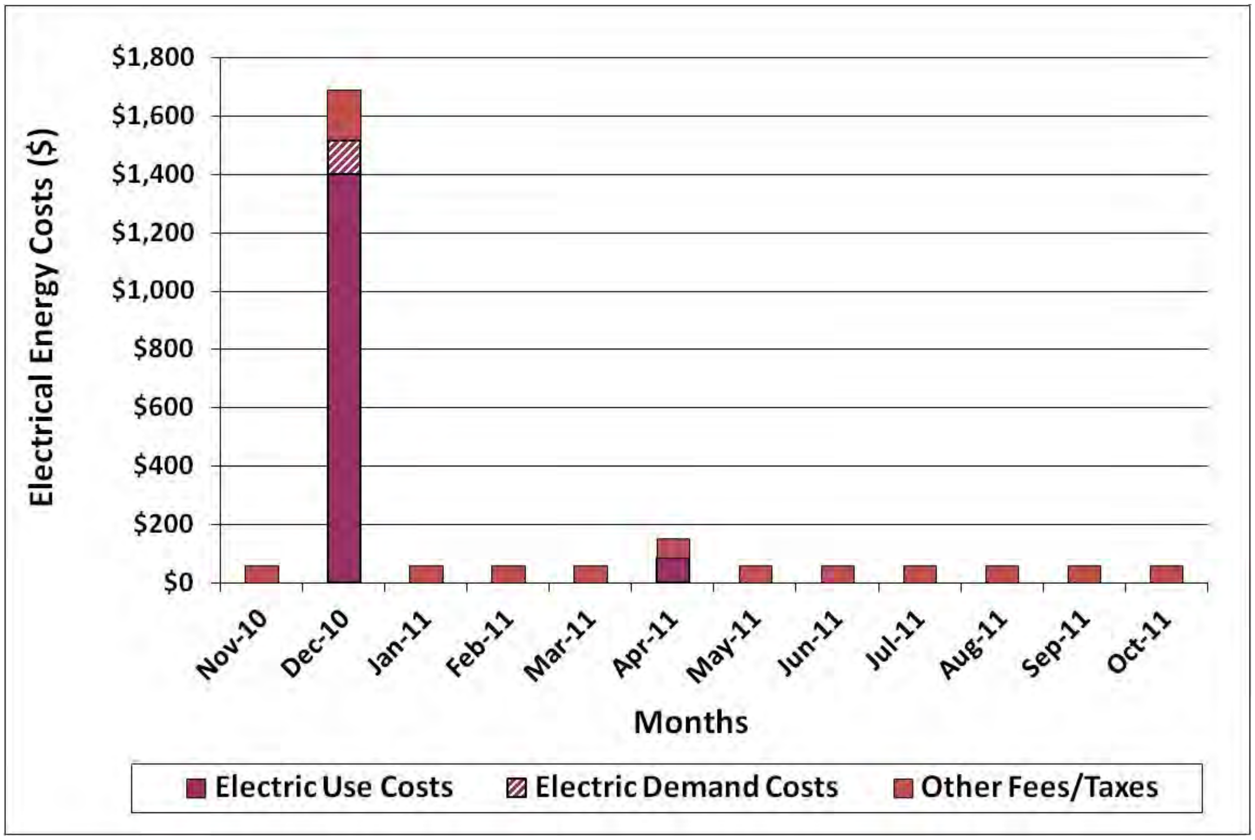


Figure 2. 2010/2011 Energy Cost Breakdown

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.

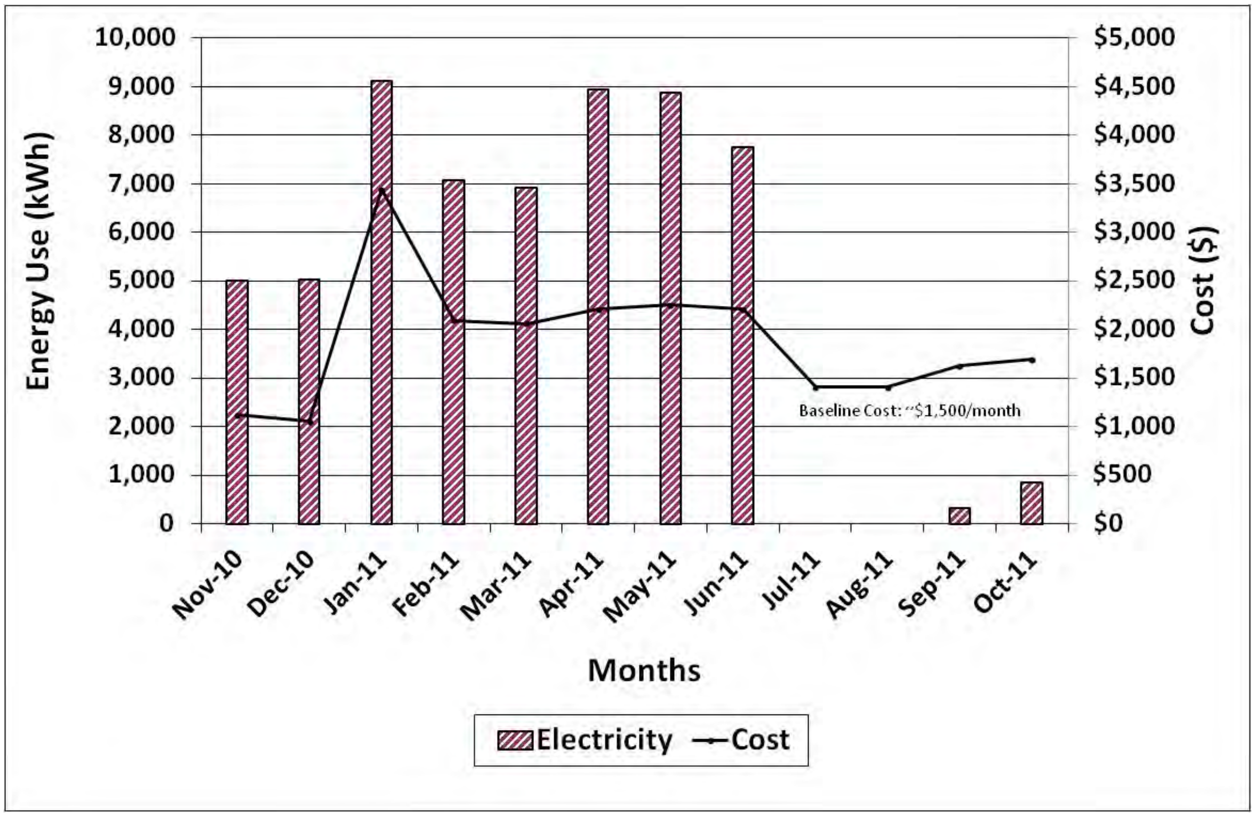


Figure 1. 2010/2011 Energy Use and Cost Breakdown

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.

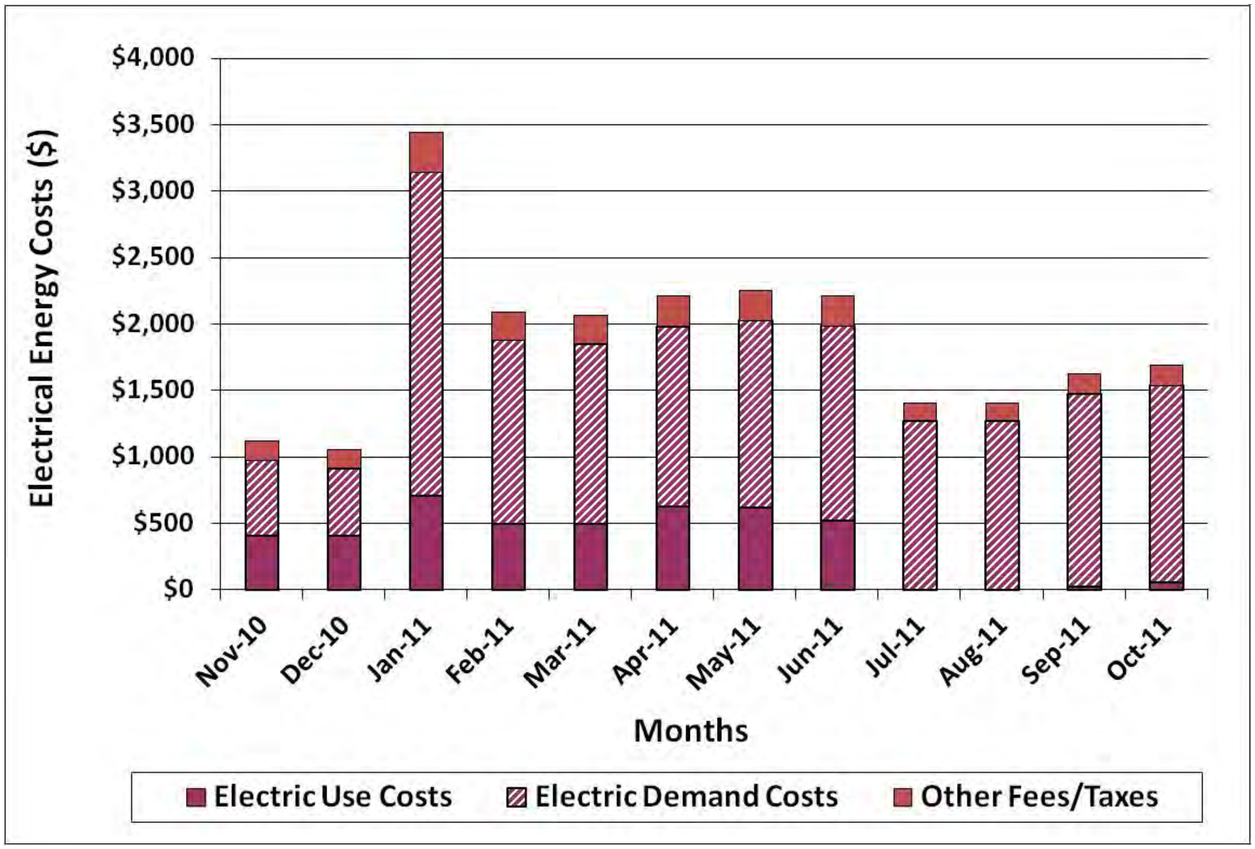


Figure 2. 2010/2011 Energy Cost Breakdown

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.

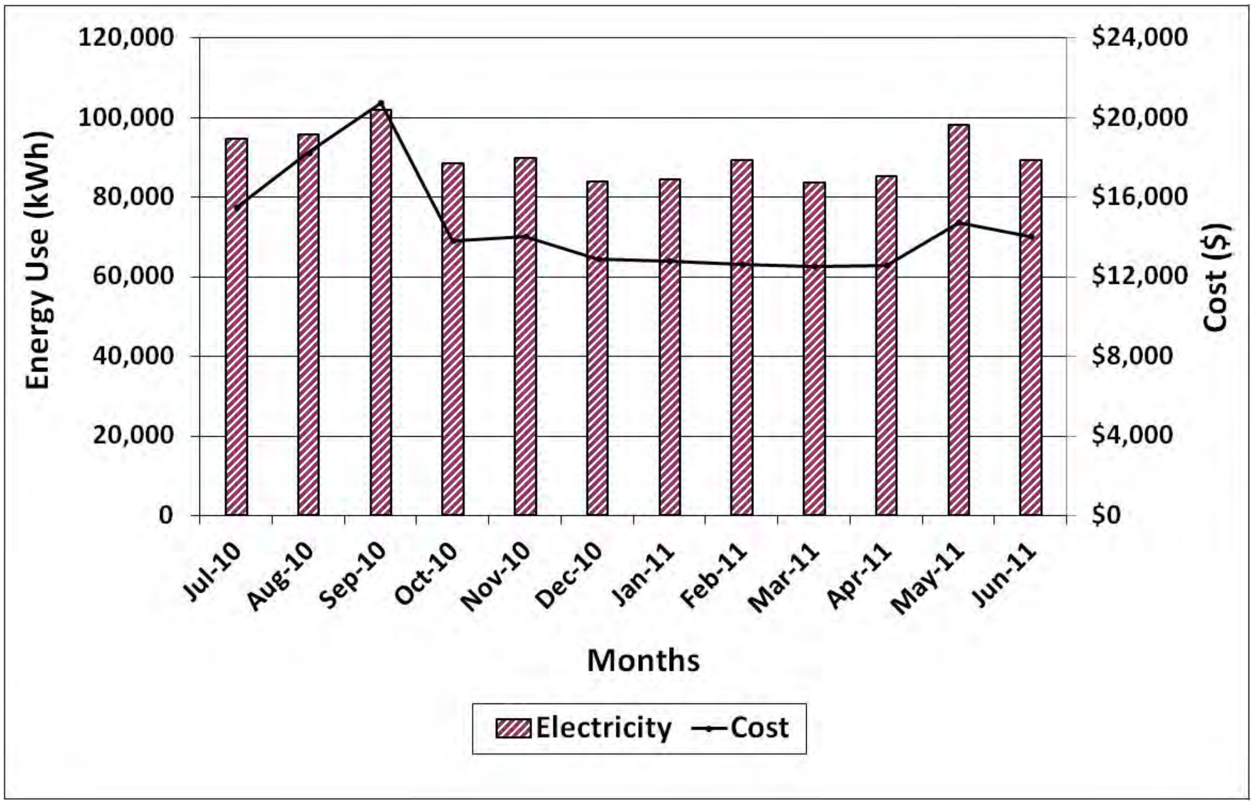


Figure 1. 2010/2011 Energy Use and Cost Breakdown

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.

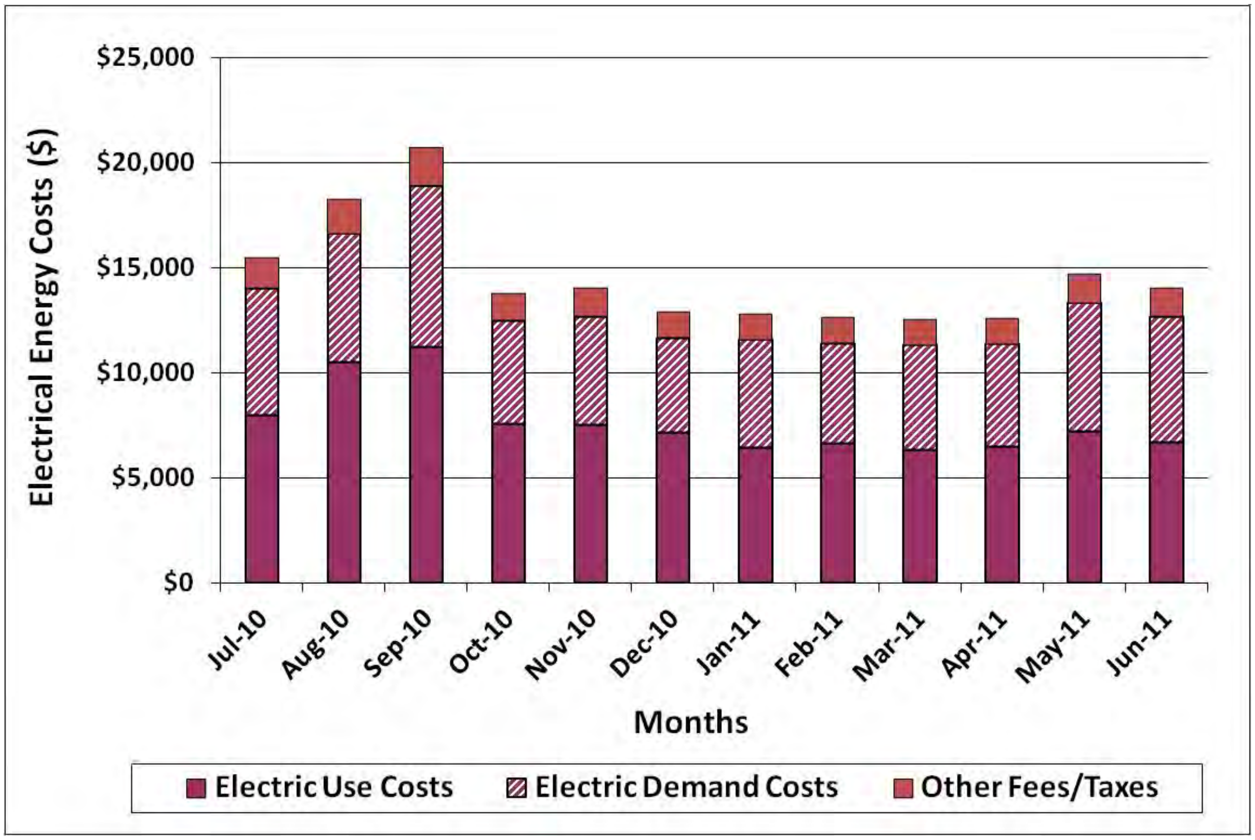


Figure 2. 2010/2011 Energy Cost Breakdown

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

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	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 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.

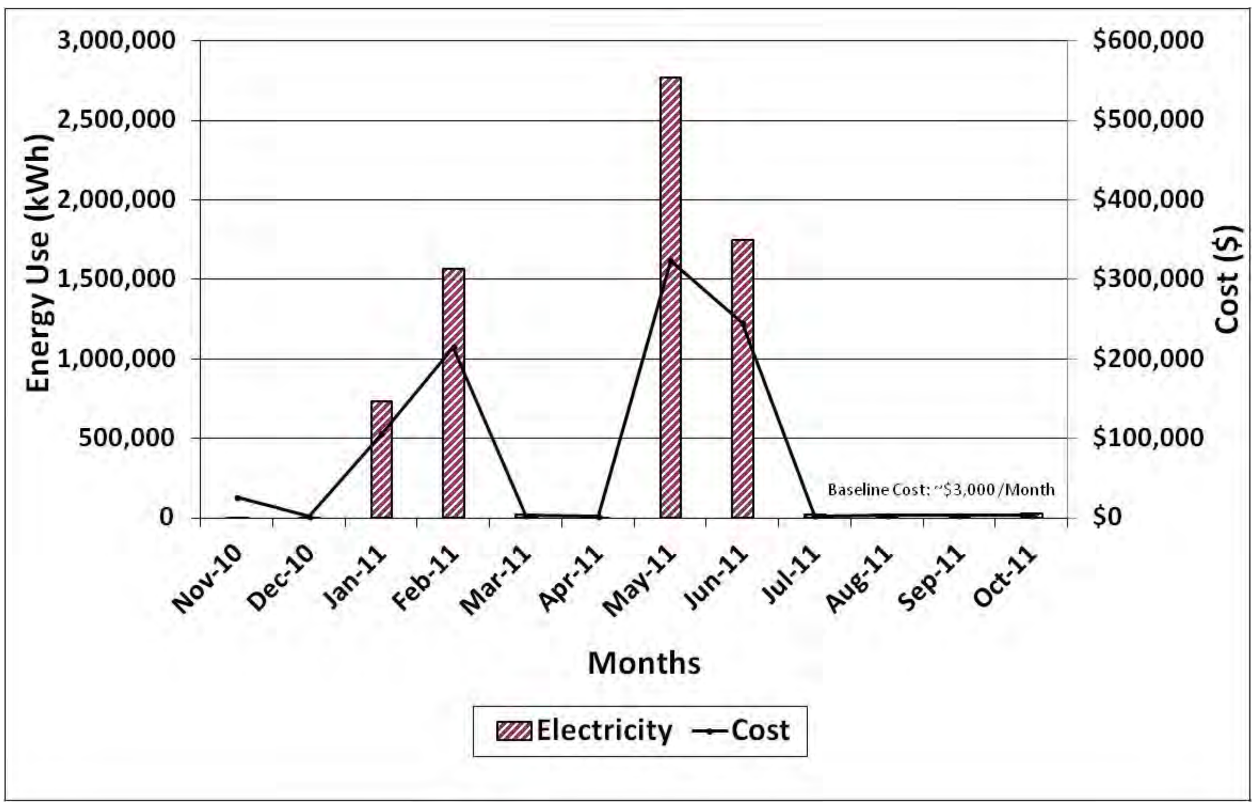


Figure 1. 2010/2011 Energy Use and Cost Breakdown

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.

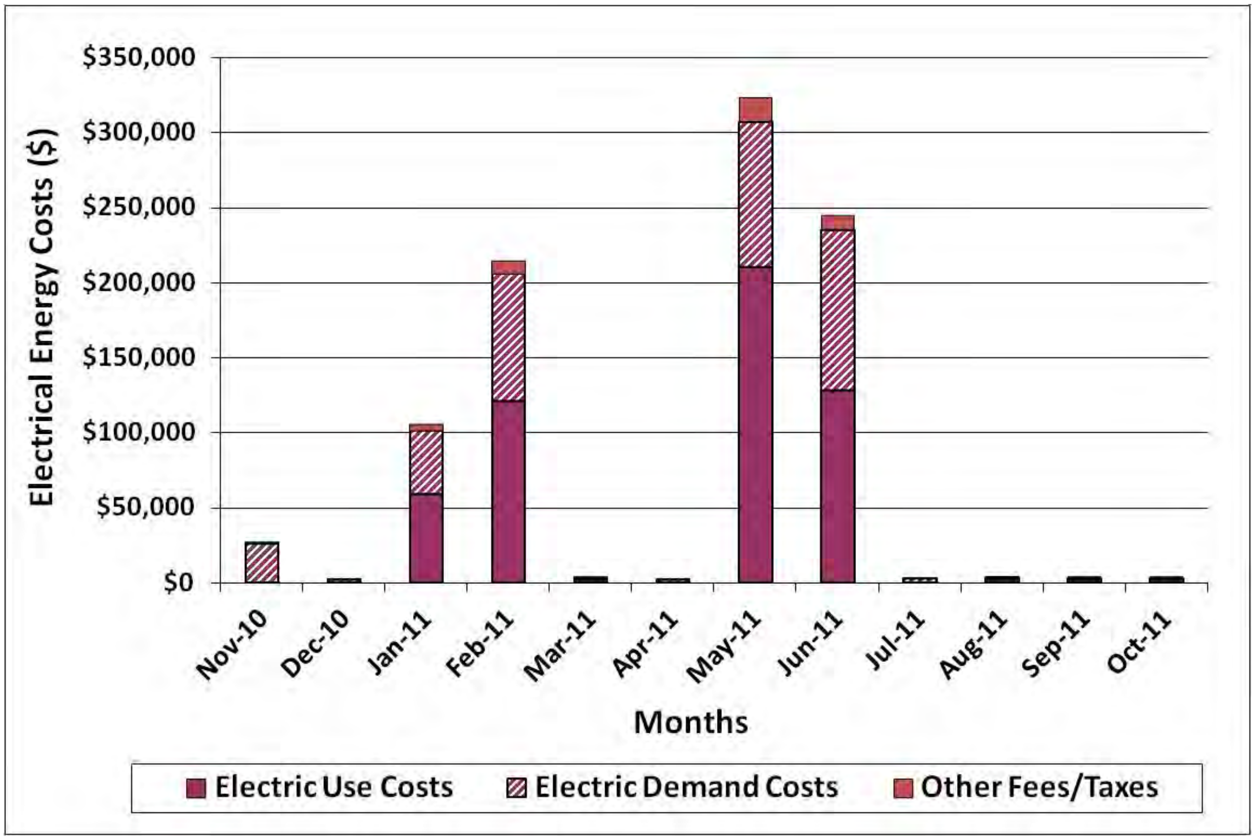


Figure 2. 2010/2011 Energy Cost Breakdown

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.

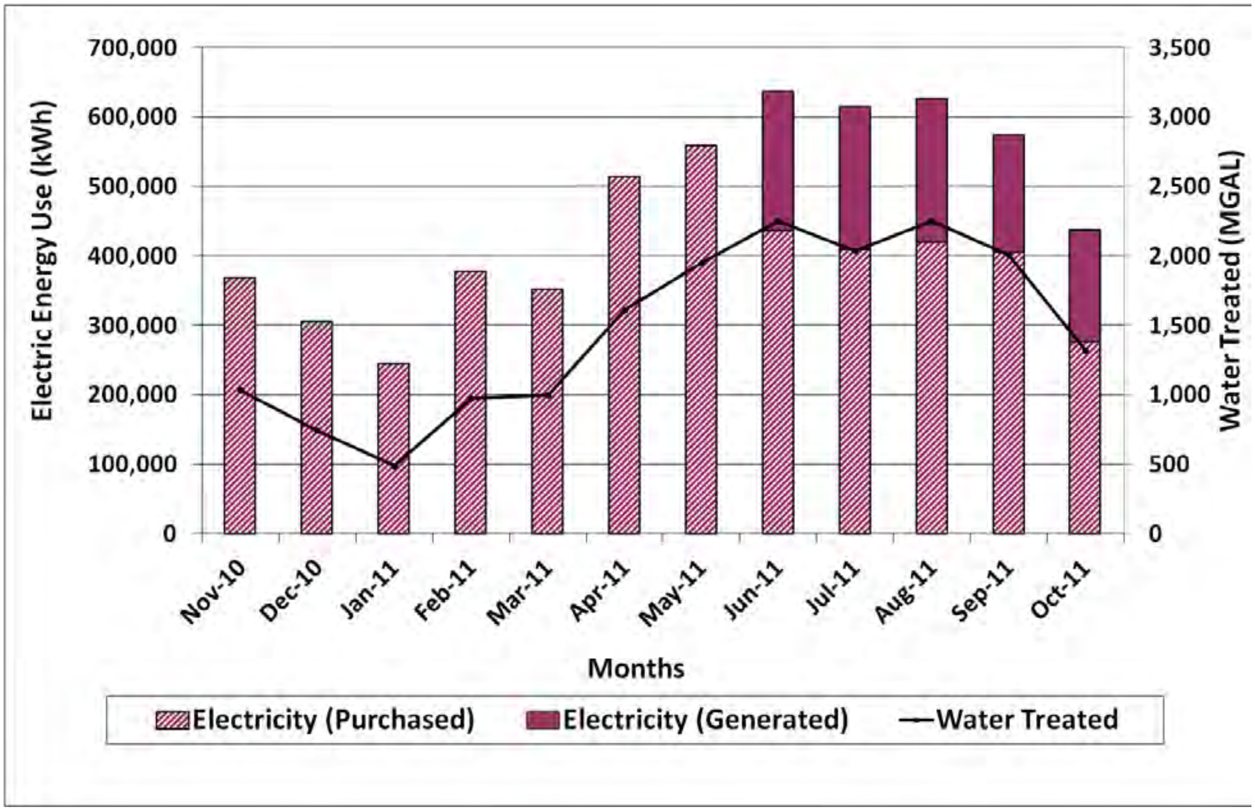


Figure 1. 2010/2011 Energy Use and Flow Breakdown

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).

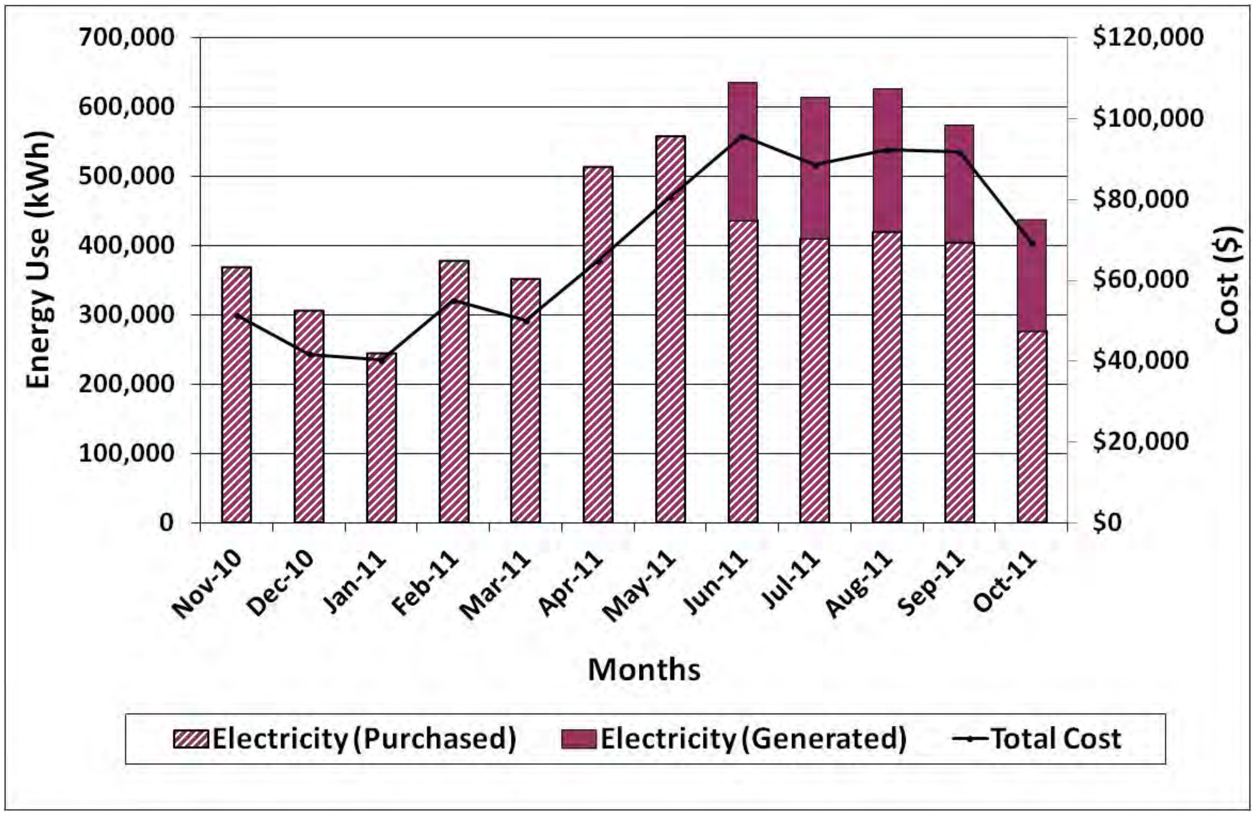


Figure 2. 2010/2011 Energy Use and Cost Breakdown

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.

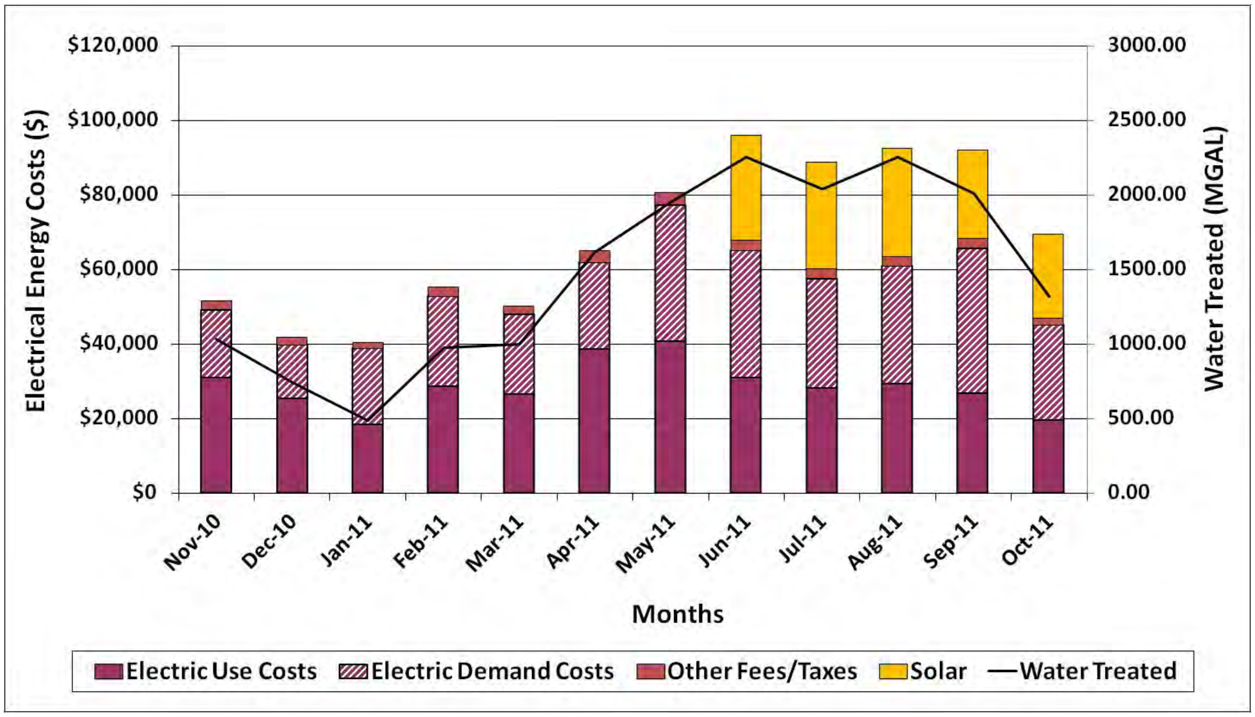


Figure 3. 2010/2011 Energy Cost and Flow Breakdown

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).

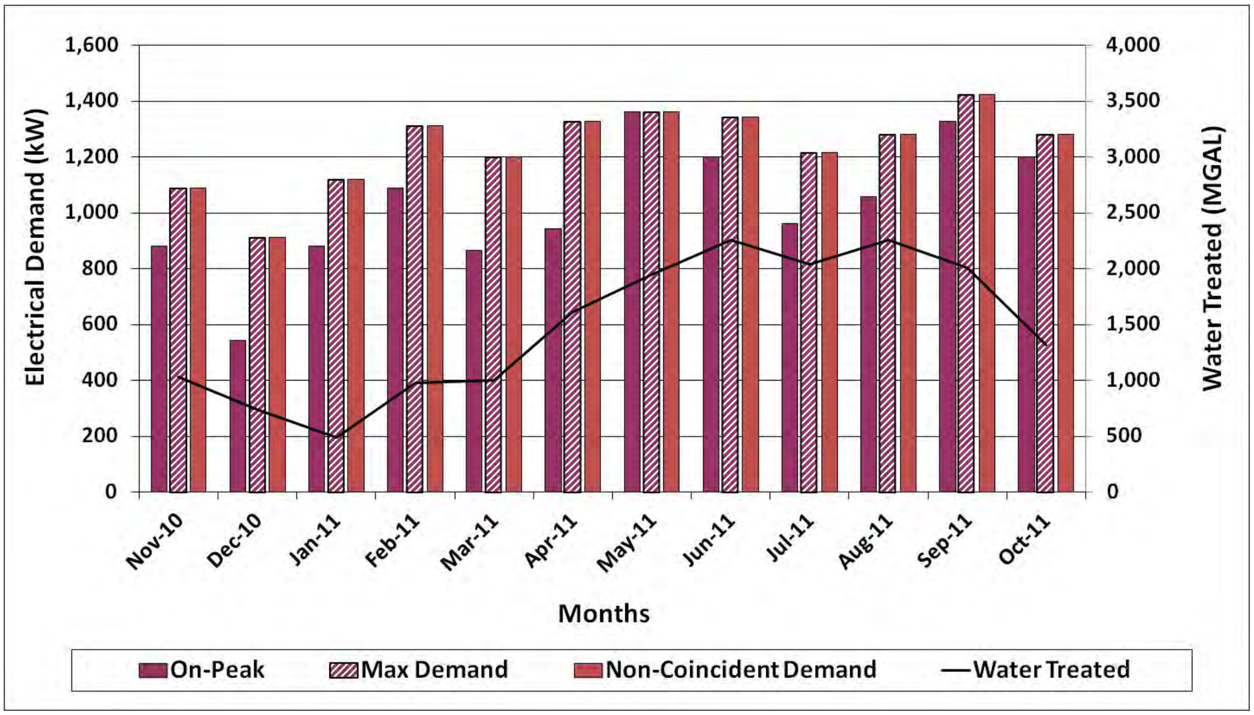


Figure 4. 2010/2011 Energy Demand and Flow Breakdown

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.

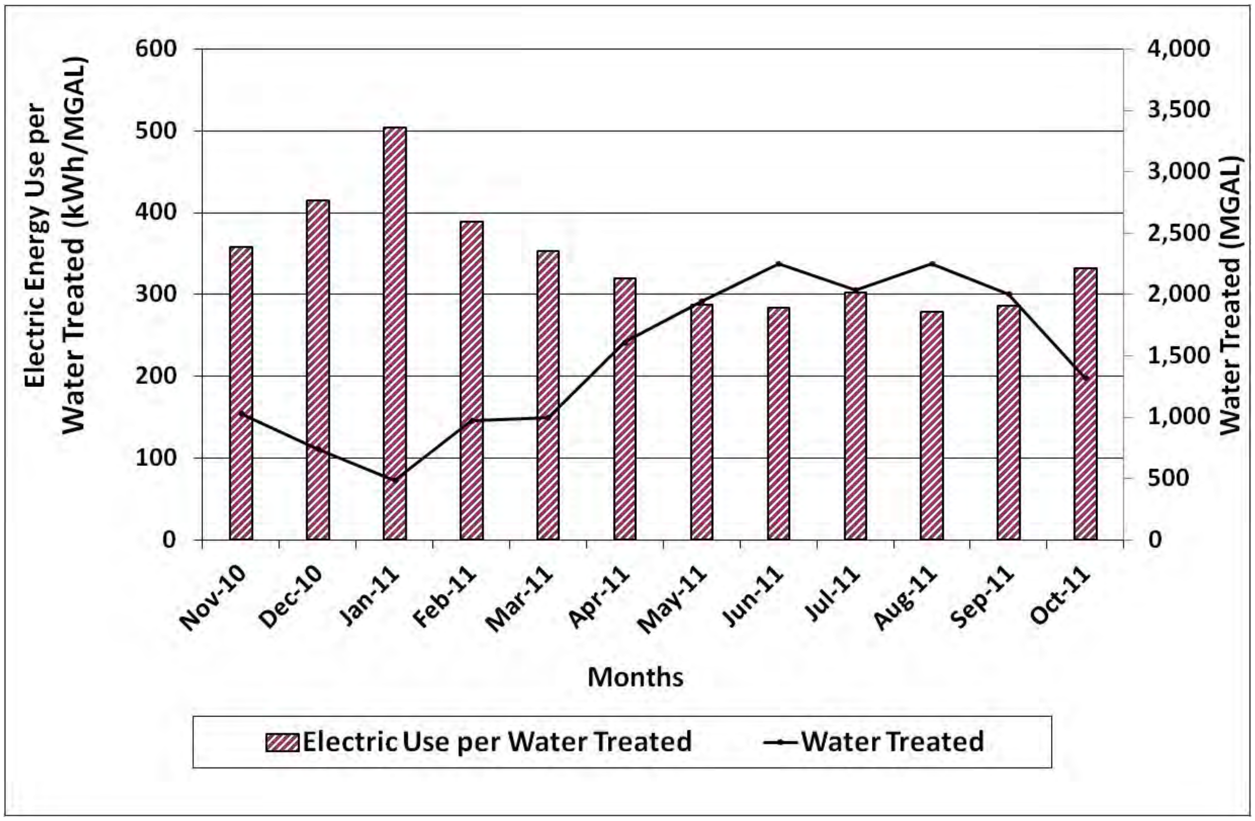


Figure 5. 2010/2011 Electric Energy Use per Million Gallons of Water Treated

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.

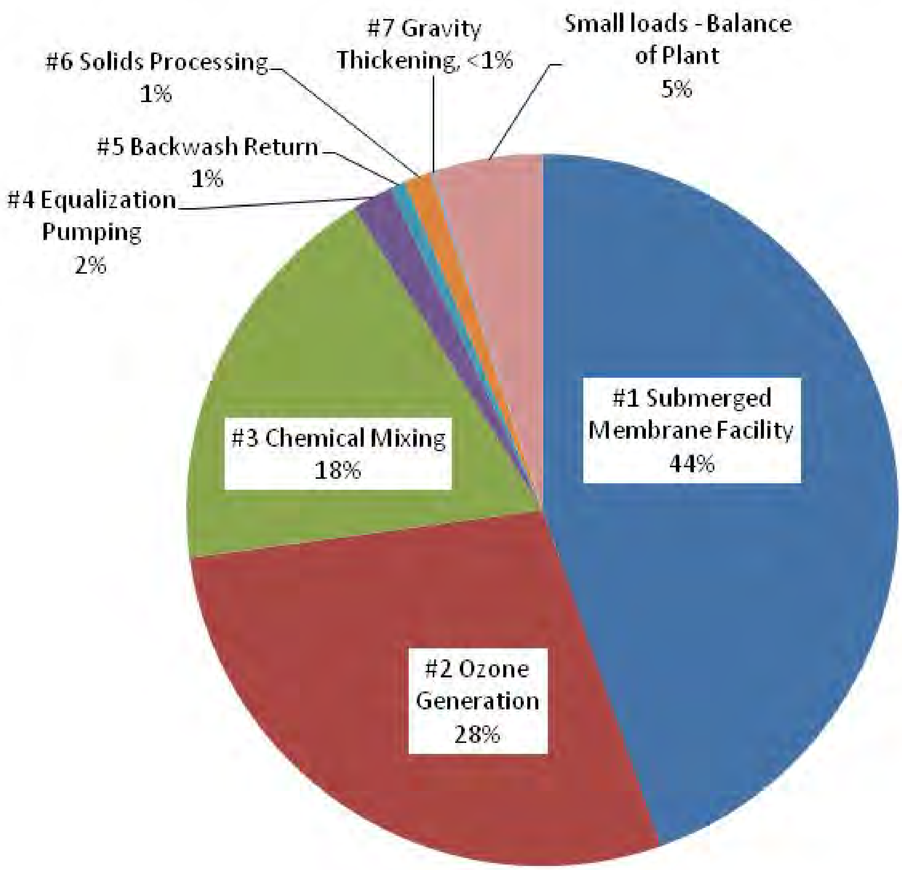


Figure 6. High Production – Major Electrical Users

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.

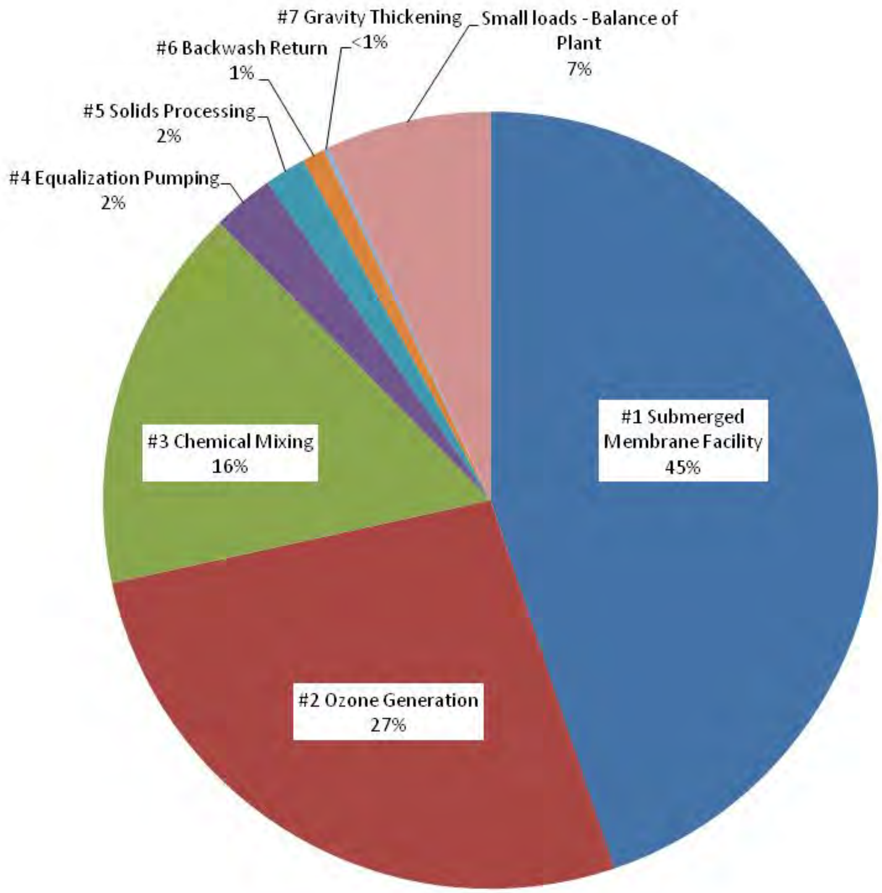


Figure 7. Low Production – Major Electrical Users

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.

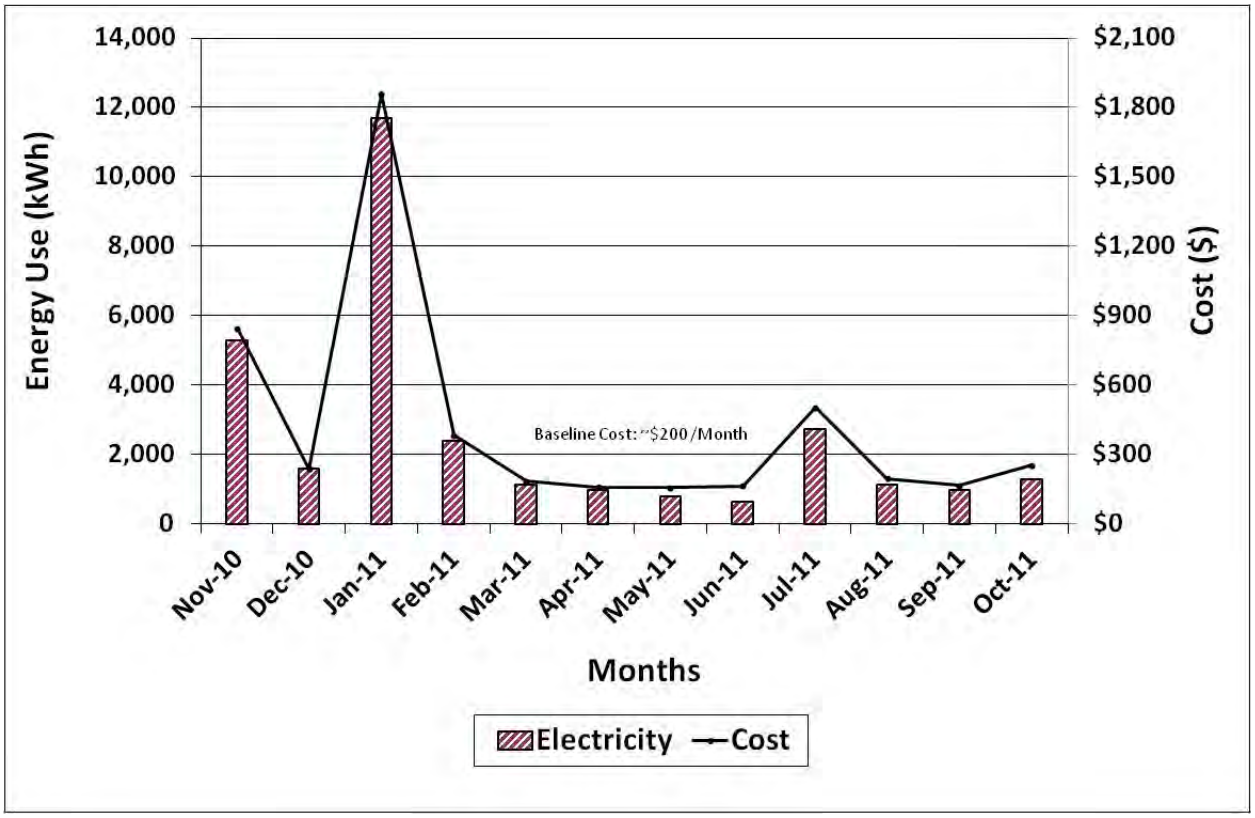


Figure 1. 2010/2011 Energy Use Breakdown

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)

<u>Existing energy consumption</u>:

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

<u>Enhanced condition energy consumption:</u>

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

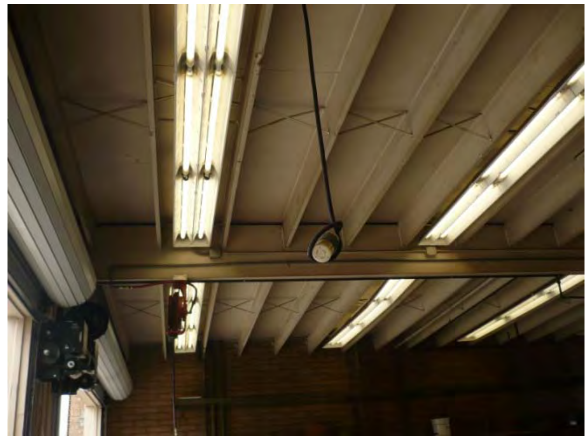
Total: $21,250

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:
Assumptions:
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:
Estimated construction costs (Add VFD to existing pumps):

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:
Assumptions:
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)

Existing Energy Consumption:

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

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

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

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 loop: $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:
<u>Assumptions:</u>
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

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:
<u>Assumptions:</u>
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

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

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:
<u>Estimated Costs for integration of Demand Response into SCADA (Assume 100kW Scenario):</u>

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

GREENHOUSE GAS REDUCTION MEASURES

Emissions Reductions for 2020 and 2035: 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 2035. 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.

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, including a cost assessment that may help the Water Authority prioritize future actions.

1. Existing Measures

1.1 State and Federally Implemented Measures

Existing measures include federal and state regulation that will be implemented by 2020 and 2035. As described in Appendix B, regulation 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 incorporated them as reduction strategies, including transportation and renewable energy production measures.

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 lower even under static vehicle miles traveled (VMT). For purposes of quantifying reductions due to this measure, the Water Authority assumed the turnover rate of vehicles used for the employee commute would reflect that of the general population. The California Air Resources Board (ARB) provides an Emission Factor model Postprocessor[1] that quantifies the level of GHG reductions anticipated through implementation of this measure by county. Reductions were modeled for San Diego County. Reductions were not assumed for the Water Authority’s Vehicle Fleet sector because the Water Authority has direct control over their vehicle turnover and therefore can more accurately account for changes in GHG emissions, as described in Section 2.2.

The Low Carbon Fuel Standard (LCFS) requires that the carbon intensity of California’s transportation fuels be reduced by at least 10% by 2020. This measure applies to all emissions derived from transportation fuels, including employee commute, vehicle fleet, and off-road equipment. ARB’s Postprocessor quantifies the level of GHG reductions anticipated through implementation of this measure by county, and reductions were modeled for San Diego County.

---

[1] *ARB’s Postprocessor was modified by AECOM to reflect the final rules for reductions associated with model years 2012–2025. The original Postprocessor included assumptions prior to the unified standards between ARB and the federal government.*

Reductions for these measures will result in 234 and 479 metric tons of carbon dioxide (MT CO_2e) in 2020 and 2035, respectively (Table D-1).

Table D-1. Emissions Reductions from Federal and State Measures

Measure and Sector	2020 MT CO_2e	2035 MT CO_2e
CAFE and LCFS		
Employee Commute	(146.07)	(376.67)
Vehicle Fleet	(72.78)	(84.69)
Off-Road Equipment	(14.98)	(17.43)
RPS		
Water	(2.72)	(3.16)
Electricity of Sources in place by 2009	(2,020.54)	(2,351.26)
Electricity of Lake Hodges Pumped Storage	(5,125.00)	(5,125.00)
Electricity of San Vicente Pump Station	(1,670.36)	(1,670.36)
Total	**(9,052.44)**	**(9,628.72)**

Notes: Negative number indicates GHG reduction.

Renewable Energy-Production Measure

California has required increasingly stringent requirements for utilities to generate electricity with renewable sources in a group of legislation collectively known as the Renewable Portfolio Standard (RPS). Currently, utilities are required to generate 33% of their energy through renewables by 2020. An interim goal established a 20% renewable requirement by 2012. San Diego Gas and Electric (SDG&E), which is the utility that serves the Water Authority, has attained 20% renewable generation through a variety of projects, including major solar installations (CPUC 2013). SDG&E is on target to meet their 33% goal by 2020, which would result in GHG reductions to the Water Authority by lowering 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 8,819 MT CO_2e reductions in 2020 and 9,150 MT CO_2e reductions in 2035 due to full implementation of this measure (Table D-1).

Federal and State Summary

As a result of full implementation of federal and state strategies already in place, the Water Authority will realize a net GHG benefit of 9,052 MT CO_2e in 2020 and 9,629MT CO_2e in 2035 (Table D-1).

1.2 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 Borrego Solar Systems 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 project was fully funded by Borrego Solar Systems, and the Water Authority uses the electricity on-site at a rate lower than what would have been paid through the grid (i.e., through direct service by SDG&E). 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 does indirectly help the Water Authority’s reduction goals by lowering SDG&E’s emissions factor. The amount of renewable energy produced by the Water Authority in 2012 was the equivalent of 972 MT CO_2e emissions if the energy had come from SDG&E directly. Combined, the solar panels produce nearly 3 million kWh of electricity per year, accounting for more than half of the energy needs at Headquarters and the Operations Center, and 25% 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. Analysis of the typical usage of vehicles owned by the Water Authority demonstrates that conversion of a single sport utility vehicle to a hybrid model would result in approximately 0.78 MT CO_2e reductions per year (Table D-2). For the three vehicles converted to date, this results in 2.34 MT CO_2e per year emissions reductions (Table D-4).

Table D-2. Analysis of Vehicle Fleet Conversion by Vehicle Type

Fuel Consumption (gallons)	SUV	Truck
Standard (gallons/year)	625	1,000
Hybrid (gallons/year)	536	682
Net Reduction (gallons/year)	89	318
CO_2 Emission Factor (kg/gal)	8.78	8.78
Annual Emissions (MT CO_2)	**0.78**	**2.79**

Notes:
Assumes replacement of vehicles over 100,000 miles and driven 10,000 miles per year
Truck replacement: 2012 Chevrolet Silverado 15 Hybrid 2-Wheel Drive (2WD) and 2012 Chevrolet Silverado 15 2WD
Sport Utility Vehicle (SUV) replacement: 2012 Ford Escape Hybrid All-Wheel Drive (AWD), 2012 Ford Escape AWD
Source: ARB 2010. Local Government Operations Protocol. Version 1.1

Energy Conservation Opportunities

The Water Authority conducted an Energy Audit in 2012 that detailed more than 30 opportunities to reduce energy or energy-related costs, referred to as energy conservation opportunities (ECOs) (Appendix E). To date, two ECOs have been implemented, relating to Variable Frequency Drive (VFD) system upgrades and efficiency for pump operations (Table D-3). Based on the estimated energy savings calculated in the Energy Audit, the Water Authority has already implemented strategies resulting in more than 6,500 kWh savings per year, equating to 2 MT CO_2e per year in emissions reductions in 2020 and 2035.[2]

[2] *Energy savings assumed an emissions factor consistent with full implementation of the RPS by SDG&E.*

Table D-3. Energy Conservation Opportunities (ECO) Implemented to Date

Facility	ECO Description	Estimated Energy Savings	Estimated Payback Term	Estimated Investment Cost
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	6,500 kWh/yr 8.5 kilowatts (kW)	12.3 yrs	$39,000
Twin Oaks Valley WTP	Evaluate installation of VFD for return water pumps during low-flow operations	0 kWh/yr 10 kW	33.4 yrs	$63,000

Source: Energy Audit, Appendix E

Local Measure Summary

Through actions taken by the Water Authority since 2009, emissions will be reduced by 4 MT CO_2e in 2020 and in 2035 (Table D-4).

Table D-4. Emissions Reductions from Local Measures, 2020 and 2035

Measure	MT CO_2e 2020	MT CO_2e 2035
Solar PV	NA	NA
Vehicle Fleet	(2.34)	(2.34)
ECOs	(2.12)	(1.58)
Total	**(4.46)**	**(3.92)**

Notes: NA = not applicable, see Section 2.1 for details. Negative number indicates emissions reductions.

1.3 Summary of Existing Measures

Measures and strategies being implemented today through 2035 by federal, state, and local actions will result in reductions totaling 9,057 MT CO_2e in 2020 and 9,632 MT CO_2e in 2035 (Table D-5). This results in an adjusted BAU scenario in which the Water Authority is more than offsetting all of its emissions in 2020 (reducing emissions 108% from baseline) and nearly offsetting all of its emissions in 2035 (reducing emissions 97% from baseline). Compared with a goal of 15% reduction from baseline by 2020, the Water Authority will meet and exceed its 2020 goal.

Table D-5. Emissions with Existing Measures, 2020 and 2035

Emissions/Reduction Source	2009 Emissions (MT CO_2e)	2020 BAU Projection (MT CO_2e)	2035 BAU Projection (MT CO_2e)
Sources in place by 2009	9,325	9,754	11,337
Emissions sources constructed 2010–2013	NA	(2,287)	(2,287)
New emissions sources anticipated 2014–2020	NA	828	781
New emissions sources anticipated 2021–2035	NA	NA	85
Federal and state measures	NA	(9,052)	(9,629)
Local measures	NA	(4)	(4)
Adjusted BAU Emissions	**9,325**	**(762)**	**283**

Emissions/Reduction Source	2009 Emissions ($MT\ CO_2e$)	2020 BAU Projection ($MT\ CO_2e$)	2035 BAU Projection ($MT\ CO_2e$)
Percent Change from Baseline[1]	NA	-108%	-97%
Percent Reduction Goal/Target	NA	-15%	-49%
Meeting Goal/Target?	NA	**Yes**	**Yes**

Notes: NA = not applicable.

1: Percent Change from Baseline is calculated as: (Adjusted BAU Emissions – 2009 Baseline Emissions) / 2009 Baseline Emissions.

2. Additional Local Opportunities

Through the measures described above, the Water Authority will exceed its goals (see Appendix B) and more than offset all of its operational emissions (Table D-5). The Water Authority would not need to implement any additional measures to demonstrate consistency with state reduction goals. However, the Water Authority evaluated additional opportunities to estimate the GHG reduction and cost implications of going even further. Opportunities that are cost-effective are likely to be implemented sooner than other opportunities evaluated, but all would depend on funding and prioritization of the needs and resources of the Water Authority. The analysis of additional opportunities provides information in determining implementation.

2.1 Energy Conservation Opportunities

Section 2.3 described two ECOs that have already been implemented and have demonstrated GHG reductions. Other ECOs were identified that could provide additional GHG benefit, including lighting upgrades, operational upgrades, and pump upgrades. The Water Authority analyzed five additional ECOs for their GHG benefit and cost-effectiveness. ECOs that would not result in GHG reductions, such as timing operations to take advantage of SDG&E rate schedules, or that were determined to no longer be applicable, such as certain pump upgrades, were not evaluated. ECOs were grouped into three categories: lighting upgrades, support operations, and pump upgrades.

<u>Methodology</u>

The Energy Audit evaluated specific facilities ECOs at major facilities to estimate potential energy savings. This analysis used that and other information to conduct an assessment of potential GHG reduction and economic impact of implementing the ECOs. Neither the 2009 emissions inventory nor the Energy Audit included energy consumption by end use (e.g., lighting, office equipment, etc.); therefore, specific facility profiles were developed based on data from the California Energy Commission (CEC) for offices and Water Authority documents for other facility types (e.g., pump stations).

To estimate GHG emissions reductions in 2020 and 2035 resulting from the proposed measures, a carbon dioxide (CO_2) emission factor was calculated that forecasts the emission factor in 2020, assuming SDG&E meets its 33% RPS goal. Methane (CH_4) and nitrous oxide (N_2O) emission factors based on California grid average electricity emission factors from the ARB Local Government Operations Protocol were used for all emission estimates (ARB 2010).

To estimate implementation costs for ECOs, information from the Energy Audit cost estimates and Water Authority reporting of expenditures were used where available. Where data were not available from these sources, cost estimates from research entities such as the National Renewable Energy Laboratory and industry sources such as equipment vendors were used. ECO-specific assumptions are listed below.

2.1.1 Lighting Upgrades

Lighting Upgrade ECOs include installing motion sensors and/or timers to lighting controls, and retrofitting lighting to more energy-efficient options. Electricity usage related to lighting, especially for office buildings, can be a significant end use, and requires up to 25% of the total usage for a building or facility. Based on current energy consumption in major facilities, lighting measures could account for less than 1 to 10 MT CO_2e reduction per year (Table 4.2). Installation costs are reflective of the amount of lighting used in the facility and can range from less than $1,000 to install timers on light switches for facilities with low indoor lighting requirements to $14,000 at larger facilities. Based on a 25% reduction in electricity use related to indoor lighting, facilities consuming greater than 100,000 kWh per year in lighting would have a short payback period (1 to 3 years), and facilities with indoor electricity consumption of less than 1,000 kWh per year would have longer (10 to 20 years) payback periods. For economic analysis, installation of timers or sensors were applied at a rate of 1 per 1,000 square feet of the facility, with square footage estimates based on aerial measurements from Google Earth. Table D-6 describes the specific ECOs evaluated along with the GHG reduction potential, installation cost, and payback term. If all measures are implemented, 17 MT CO_2e per year reductions could be achieved through lighting upgrades.

The analysis detailed above includes assumptions that may change over time as the exact specifications of implementation are not currently known. The analysis was conducted to estimate approximate GHG and cost indicators so that all additional opportunities could be evaluated for feasibility, reduction potential, and payback time, which will help the Water Authority prioritize implementation. In addition, the Energy Audit evaluated major facilities only, and the opportunities may be generalized to Water Authority facilities. Therefore, the information is summarized in Table D-7.

2.1.2 Operational Upgrades

ECOs related to support operations include measures that address energy demand optimization and heating, cooling, and ventilation (HVAC) systems. For HVAC-related measures, facilities of smaller size were estimated at 50% of full-size HVAC needs for larger facilities listed in the Energy Audit. For operational costs, energy consumption and energy savings from the GHG analysis were incorporated to estimate the energy cost savings. Table D-8 describes the specific ECOs evaluated along with the GHG reduction potential, installation cost, and payback term. The GHG benefit of the measures is relatively small, but some measures are no cost to implement (monitoring block loads), low cost (<$5,000), or have a relatively short (<10 years) payback period. If all measures are implemented, 20 MT CO_2e per year reductions could be achieved through operational upgrades.

Similar to the lighting upgrades, the analysis detailed above includes assumptions that may change over time as the exact specifications of implementation are not currently known. The analysis was conducted to estimate approximate GHG and cost indicators so that all additional opportunities could be evaluated for feasibility, reduction potential, and payback time, which will help the Water Authority prioritize implementation. In addition, the Energy Audit evaluated major facilities only, and the opportunities may be generalized to Water Authority facilities. Therefore, the information is summarized in Table D-9.

Table D-6. Lighting Upgrade ECO analysis

ECO	ECO Description	Energy Benefits	GHG Benefits (MT CO_2/year)	Installation Cost ($)	Payback Term (years)
Escondido Operations Center – 3	Add motion sensors and/or timers to lighting controls	25% reduction in electricity use related to indoor lighting	7.40	$13,869	3
Escondido Operations Center – 5	Lighting and Sensor Retrofit of Vehicle Maintenance Facility	33% reduction (Phase 2 Energy Audit estimate) in electricity usage for lighting	1.15	$7,978	14
Escondido PS3	Install timers on light switches	25% reduction in electricity use related to indoor lighting	0.05	$3,750	20+
Rancho Peñasquitos PCHF-2	Install cycle timers for manual light switches	25% reduction in electricity use related to indoor lighting	0.06	$800	10
Twin Oaks Valley WTP-6	Installation of cycle timers on manual light switches	25% reduction in electricity use related to indoor lighting	7.83	$8,832	1
Valley Center PS-2	Install timers on light switches	25% reduction in electricity use related to indoor lighting	0.05	$300	10

Table D-7. Summarized Lighting Upgrade Analysis

Indoor Lighting Energy Usage (kWh/yr)	GHG Reduction Potential (MT CO_2e/yr)	Initial Cost ($)	Payback Term	Example Facilities
<1,000 kWh/yr	<1 MT CO2e/yr	<$5,000	10–20+ years	Escondido PS3, Valley Center PS
10,000—15,000 kWh/yr	1–2 MT CO2e/yr	$5,000--$10,000	10–15 years	Escondido Vehicle Maintenance Facility
>100,000 kWh/yr	5–10 MT CO2e/yr	$8,000--$15,000	1–5 years	Escondido Operations Center, Twin Oaks Valley WTP

Table D-8. Operations Upgrade ECO Analysis

ECO	ECO Description	Energy Benefits	GHG Benefits (MT CO_2/year)	Installation Cost ($)	Payback Term (years)
Escondido Operations – 2	Install EMS similar to San Diego Office to monitor building loads.	Estimates consistent with ECO Development (Phase 2 Energy Audit Summary, Page 125)	9.86	$21,250	4
Olivenhain PS-1	Adjust HVAC and lighting controls for as-needed operations	8% reduction consistent with ECO Development (Phase 2 Energy Audit Summary, Page 125)	0.25	$3,750	20+
San Diego Office – 1	Install boiler hot water low-flow (jockey) pump (2 horsepower) to circulate minimal flow during building off-hours	Estimates consistent with ECO Development (Phase 2 Energy Audit Summary, Page 125)	4.93	$13,500	5
San Diego Office – 2	Allow setback of hot water system temperature during off-hours from 120º F to 90º F	12% reduction based on assumption of achieving 3% to 5% reduction for every 10˚F reduction in temperature.	0.33	$0	0
San Vicente PS-2	Adjust HVAC and lighting controls for as-needed operations	8% reduction consistent with ECO Development (Phase 2 Energy Audit Summary, Page 125)	0.22	$3,750	20+
Lake Hodges PS-1	Monitor block loads of support equipment including HVAC, cooling and service water, and compressed air.	8% reduction consistent with ECO Development (Phase 2 Energy Audit Summary, Page 125)	0.43	$0	0
Twin Oaks Valley WTP-10	Demand Management Strategy – Entire Plant	8% reduction consistent with ECO Development (Phase 2 Energy Audit Summary, Page 125)	4.07	$51,574	20+

Table D-9. Summarized Operational Upgrade Analysis

Support Measure	Energy Usage (kWh/yr)	GHG Reduction Potential (MT CO2e/yr)	Initial Cost ($)	Payback Term	Example Facilities
Demand Management Systems	>200,000 kWh/yr	4 MT CO2e/yr	>$20,000	4-20+ years	Twin Oaks Valley Waste Treatment Plant, Escondido Operations Center
HVAC Control Systems	10,000—15,000 kWh/yr	1–2 MT CO2e/yr	<$5,000	20+ years	Olivenhain Pump Station, San Vicente Pump Station
System monitoring and evaluation of block loads and hot water temperature usage	10,000—25,000 kWh/yr	1–2 MT CO2e/yr	$0	Immediate	San Diego Headquarters, Lake Hodges Pump Station

2.1.3 Pump Upgrades

The Energy Audit Summary included a number of ECOs that would improve pump operations based on current activities or potential future operations; however, only one ECO was considered in this analysis. Other ECOs would not result in GHG reductions (e.g., the pump station at Escondido is not currently operational; therefore, upgrades would not result in GHG reductions) or were considered infeasible due to changes in operational parameters of the facilities (e.g., the Rancho Peñasquitos facility is being redesigned and would not include a jockey pump). Table D-10 shows that the ECO evaluated would result in 10 MT CO_2e reduction per year and have a relatively short (3-year) payback period.

As with the other ECOs, this was generalized to reflect potential cost, payback term, and GHG reductions (Table D-11). More specific analysis may be needed if this measure will be implemented to identify costs, payback term, energy benefits, and GHG reduction at the time of implementation.

2.2 Vehicle Fleet Conversion

The Water Authority owns and maintains a fleet of vehicles that are run primarily on carbon-based fuels. This strategy assumes replacement of existing fleet vehicles with hybrid vehicles. Fully electric vehicles were not considered at this time due to the lack of recharge infrastructure or battery range technology currently available. The following assumptions were used in the analysis:

- Fleet vehicles with 100,000 lifetime miles and driven 10,000 or more miles per year would be replaced. This results in a replacement of 12 fleet vehicles.
- Vehicles identified will be replaced by vehicles with hybrid electric or standard engines in same class (i.e., Sport Utility Vehicles [SUVs] will be replaced with SUVs).
    - 2 SUVs replaced with either Ford Escape All-Wheel Drive (AWD) or Ford Escape Hybrid AWD.
    - 10 trucks replaced with either Chevrolet Silverado 15 Hybrid 2-Wheel Drive (2WD) or Chevrolet Silverado 15 2WD.
- Combined miles per gallon based on 60% highway and 40% city driving (EPA 2013).
- Maintenance costs for standard and hybrid vehicles are the same.

Table D-2 shows the per-vehicle GHG reduction that would likely occur as a result of converting the vehicles meeting the above criteria to hybrid vehicles, which is 0.78 and 2.79 MT CO_2e per year for SUVs and trucks, respectively. The cost estimate is the premium of purchasing a hybrid vehicle instead of a traditionally fueled vehicle, not the total purchase price. Given the high price premium of hybrid electric vehicles over standard fuel vehicles and a lack of incentives for purchase, the payback date for both types of vehicles would be 20+ years (Table D-12). If all 12 vehicles were converted to hybrids, the Water Authority would reduce emissions by approximately 30 MT CO_2e per year.

Table D-10. Pump Upgrade ECO Analysis

ECO	ECO Description	Energy Benefits	GHG Benefits ($MT\ CO_2$/year)	Installation Cost ($)	Payback Term (years)
Twin Oaks Valley WTP-5	Continuous Operation of Loop Pumps – Install VFD on Loop Pumps	29% reduction in energy used based on Phase 2 Energy Audit Summary (Page 136)	10.08	$35,441	3

Table D-11. Summarized Pump Upgrade Analysis

Energy Use (kWh/yr)	GHG Reduction Potential (MT CO2e/yr)	Initial Cost ($)	Payback Term	Example Facilities
100,000–200,000 kWh/yr	10 MT CO_2e/yr	>$10,000	3 years	Twin Oaks Valley WTP

Table D-12. Vehicle Fleet Conversion Analysis

Vehicle Type	Fuel Reduction (gallons/year)	GHG Reduction Potential (MT CO2e/yr)	Initial Cost ($)	Payback Term
SUV	90	<1 MT CO2e/yr	<$10,000	20+ years
Truck	320	3 MT CO2e/yr	>$10,000	20+ years

2.3 Solar Panels

The Water Authority currently has solar installations generating nearly 3 million kWh of electricity per year through a power purchase agreement (see Section 2.1). This analysis estimates the GHG reduction potential and cost benefit of the Water Authority installing another solar PV system and operating it internally, to reap the GHG reduction credits the renewable power source would generate. No current plans exist for implementation and therefore no specific site has been established. The estimated size of the system is based on average size of installations by commercial entities at commercial sites receiving performance-based incentives (PBIs) in current incentive step using California Solar Initiative database (181 kilowatts [kW]). The annual kilowatt (kWh) output is proportional to Escondido Operations Facility performance and would be installed and operational in 2014. Emissions benefits are based on an estimated electricity generation of 300,503 kWh per year. The proposed solar PV installation would result in an emissions reduction of 74 MT CO_2 per year in 2020 or 2035 (Table D-13). To develop costing estimates for the solar PV installation, data from the California Solar Initiative were examined for commercial customers owning and installing on commercial sites in the current incentive step in the County of San Diego with pending or installed application status. The average values for nameplate rating, CSI performance rating and installation cost were obtained from this group. In addition, it was assumed that there would be no cost to acquire land for the PV installation as it would be constructed on land currently owned by the Water Authority and no cost for installation of transmission infrastructure. For operational estimates, California Solar Incentive payments in the current step were applied, assuming full performance levels at CSI rating using the 5-year PBI structure and rate escalation based on the CEC commercial rate forecast were applied. 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.

Table D-13. Solar PV Installation Analysis

Energy Generation (kWh/yr)	GHG Reduction Potential (MT CO2e/yr)	Initial Cost ($)	Payback Term (years)
300,000 kWh/yr	74	<$600,000	16

2.4 In-Line Hydropower

Seven installation sites were examined for new hydropower generation via inline hydro installations. Sites currently being considered are Oceanside 5 Flow Control Facility (FCF), Oceanside 6 FCF, Twin Oaks Flow Regulatory Structure, Crossover Pipeline Terminal Structure, Miramar, Alvarado, and Otay 12 FCF. The Water Authority is currently conducting feasibility studies on this opportunity and no system would be installed prior to 2021. All data for the inline hydro installations were provided by the Water Authority in an email dated August 23, 2013, titled, “RE: Master Plan enviro team meeting 8/20 - action items,” listing average flow, average head, annual production, generator size, capital cost, annual revenues, and generator class for the seven potential sites. No displacement of current consumption or additional costs for transmission of power generated were assumed. If all seven systems were installed, inline hydropower generation would result in a reduction of approximately 8,156 MT CO_2e per year in 2035 and costs for installation at each site range from just under $1 million to approximately $6.5 million (Table D-14).

Table D-14. Detailed In-Line Hydropower Analysis

ECO	Generator Size (kW)	Annual Production (kWh)	GHG Benefits (MT CO_2/year)	Initial Cost ($)	Payback Term (years)
Oceanside 5 FCF	120	900,000	221.76	$980,000	12
Oceanside 6 FCF	200	1,700,000	418.88	$1,260,000	7
Twin Oaks Flow Regulatory Structure	2,000	16,500,000	4,065.56	$6,440,000	3
Crossover Pipeline Terminal Structure	1,120	7,800,000	1,921.90	$5,130,000	6
Miramar	530	2,100,000	517.43	$3,150,000	18
Alvarado		2,300,000	566.71	$1,590,000	7
Otay 12 FCF	230	1,800,000	443.52	$1,370,000	7

Again, because the analysis is based on estimated energy production, the measures have been somewhat generalized in Table D-15 to show estimated GHG benefits, costs, and payback periods, rather than stating exact figures.

Table D-15. Summarized In-Line Hydropower Analysis

Generator Size (kW)	Annual Energy Production (kWh/yr)	GHG Reduction Potential (MT CO_2e/yr)	Initial Cost ($)	Payback Term	Example Facilities
120	900,000	220	$980,000	10–15 years	Oceanside 5 FC
530	2,100,000	>500 MT CO2e/yr	$3.2 million	15–20 years	Miramar
2,000	16,500,000	>4,000 MT CO2e/yr	$6.5 million	<5 years	Twin Oaks Flow Regulatory Structure
200-1,200	1,700,000–8,00,000	400-2,000 MT CO2e/yr	$1.25 million–$5.2 million	5–10 years	Otay 12 FCF, Oceanside 6 FCF, Alvarado, Crossover Pipeline Terminal Structure

2.5 Summary of Additional Opportunities

Table D-16 summarizes the total GHG benefit from installing all additional opportunities. The installation date of all measures is uncertain and depends on a variety of factors; however, for purposes of this evaluation, all opportunities were assumed to be implemented by 2020 except in-line hydropower projects, which were assumed to be installed by 2035. The net GHG benefit by 2020 would be 151 MT CO_2e and by 2035 would be 8,307 MT CO_2e.

Table D-16. Summary of Additional Opportunities

Additional Local Reduction Opportunities	2020 (MT CO2e)	2035 (MT CO2e)
ECOs – Lighting Measures	(17)	(17)
ECOs – Support Operations	(20)	(20)
ECOs – Pump Upgrades	(10)	(10)
Vehicle Fleet Conversion	(30)	(30)
Solar PV Installation	(74)	(74)
In-Line Hydropower		(8,156)
Total	**(151)**	**(8,307)**

3. Conclusion

This analysis demonstrates the Water Authority's ability to surpass the 2020 target and be on track toward longer-term goals, such as an intermediate target in 2035, more than offsetting its 2020 emissions through strategies already in place (Table D-17). The Water Authority is also committed to water conservation (and therefore GHG reductions) in the community, and continues to provide opportunities and education to member agencies and end-users to reduce water consumption. By working within its own operations and within the community, the Water Authority is leading the way toward a more efficient and climate-stable future.

Table D-17. Summary of Greenhouse Gas Emissions and Reduction Potential

	2009 (MT CO_2e)	2020 (MT CO_2e)	2035 (MT CO_2e)
BAU Emissions	9,325	8,295	9,916
Existing Reduction Measures			
Federal and State Reductions		(9,052)	(9,629)
Local Reductions		(4)	(4)
Adjusted BAU Emissions	**9,325**	(762)	283
Additional Local Reduction Opportunities		(151)	(8,307)
Emissions with Existing Measures and Additional Opportunities	**9,325**	**(913)**	**(8,024)**

4. 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://www.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

LAKE HODGES PUMPED STORAGE ANALYSIS

Technical Memorandum

Date: October 23, 2013

To: Ms. Kelley Gage, Senior Project Manager
San Diego County Water Authority

From: Jeffrey G. Harvey, Ph.D., Senior Scientist
Paul Miller, Senior Environmental Scientist

Re: Updated Assessment of Greenhouse Gas Emissions for the Olivenhain-Hodges Pumped Storage Hydroelectric Project (***V3 – Final***)

Introduction

The San Diego County Water Authority (Water Authority) is developing a Climate Action Plan (CAP) as a part of its 2013 Regional Water Facilities Optimization and Master Plan Update (Master Plan Update). The completed 2009 baseline emissions inventory for the CAP is intended to capture all significant elements of the Water Authority's operations that have potential to produce residual greenhouse gas emissions (GHG)[1]. It is also intended to identify projects and operational strategies that have been undertaken since the 2009 baseline year that may reduce or offset GHG.

The Olivenhain-Hodges Pumped Storage hydroelectric power project was completed in 2012. It is owned by the Water Authority, and is operated under contract by SNC-Lavalin Operations & Maintenance, Inc. The priority operation of the project is water storage and distribution, however, it is also operated within defined limits pursuant to a Master Power Purchase Agreement with SDG&E to produce peak power, and to provide ancillary services when

[1] GHG emissions account for multiple gases including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (SF_6). The reference gas used in measuring GHG is CO_2, with total GHG expressed as CO_2-equivalents (CO_2e).

requested by the California Independent System Operator (CAISO), the State's transmission grid operator. Because it is part of the Water Authority's facilities, it is one of the projects to be accounted for as a part of the Water Authority's emissions inventory.

The Olivenhain-Hodges Pumped Storage facilities utilize the 770-feet of elevation difference between Olivenhain Reservoir and Lake Hodges to generate electricity. A tunnel system and powerhouse connect the two reservoirs. Water is pumped from Lake Hodges up to Olivenhain Reservoir during off-peak energy demand periods, and stored for use during peak energy demand periods when water is released from Olivenhain Reservoir back down to Lake Hodges. Power generation and return pumping operations are conducted to balance out flows between the two reservoirs on a weekly basis such that there is no net transfer of water between the reservoirs.

Pumped storage hydroelectric systems are net energy consumers since more power is required to pump water to the upper reservoir than can be generated when the water is released back to the lower reservoir. By utilizing lower cost off-peak power at nights and over weekends, and generating power during peak demand higher cost periods, pumped storage systems are economical to operate. They are also unique in providing on-demand instantly dispatchable power that is valuable for providing ancillary transmission grid support services. These include voltage regulation and load following that are essential for stable and reliable electric transmission grid operations.

Emissions for a pumped storage system are normally associated with the source of pump-back power, and vary regionally according to available power sources. In generation mode the water is released and flows by gravity, producing zero GHG emissions compared to other sources of peak demand power. Therefore, actual net emissions are the sum of the emissions associated with the pump-back power generation source(s), and the emissions associated with the power source(s) that are displaced by the project's generation. Pump-back operations are conducted during off-peak evening and weekend hours, and utilize baseload power sources. In the San Diego region this is derived primarily from combined-cycle natural gas generation. (Prior to the shutdown of the San Onofre Nuclear Generating Station (SONGS), baseload power also included some nuclear generation.) Project operations generate electricity during peak demand periods and as needed to support transmission grid operations. Typically, peaking power is provided by simple-cycle natural gas generating plants (also known as "gas peaker plants"). Electrical generation from the pumped storage project displaces electrical generation from these natural gas fueled peaker plants[2].

---

[2] Assumptions for source power and displaced sources were confirmed in consultation with SDG&E (Daniel L. Sullivan, Senior Energy Administrator, Electric and Fuel Procurement, SDG&E, October 10, 2013) and the California Independent System Operator (CAISO), (Linda Wright, Senior Interconnection Specialist, October 17, 2013).

Operational Parameters

The typical generation and pump-back operations for the project are defined for purposes of a Master Power Purchase and Sales Agreement with SDG&E, and were subject to environmental review in an Addendum EIR document in 2008[3]. The weekly transfer rates of water volumes between Lake Hodges and Olivenhain Reservoir are a maximum of 3,100 acre-feet. Allowable hours per dispatch include up to 16 hours of pumping up to Olivenhain Reservoir for 657.4 acre-feet at approximately 500 cubic feet per second (cfs); (*Addendum EIR*, page 12, Table 2). Water is pumped up to Olivenhain Reservoir at a rate of approximately 500 to 600 cfs and is released down to Lake Hodges at a rate of approximately 700 cfs. Pumping water up to the reservoir is only conducted during the regional electric grid off-peak hours at night and on weekends.

Project operations include an average 7.75-hour pump-back period at night to transfer flows from Lake Hodges to Olivenhain Reservoir. This pump-back period supports an average 6-hour daytime generation period when water is released from Olivenhain Reservoir back down to Lake Hodges. The Lake Hodges Pump Station is equipped with two 20 MW pump/turbines for a total pump/generation capacity of 40 MW. The measured average efficiency rate of the two units is approximately 77.5%.[4] For purposes of assessment of the net GHG emissions on an annual basis, approximately 107 GW-hours/year of electricity would therefore be required for pumping, and approximately 83 GW-hours/year of electricity would be generated.

Emissions Inventory

Annual emissions of CO_2e comparing power generation and pump-back power under several scenarios are given in Table 1 below. Due to the timing and sources of power from which pump-back power is derived (i.e., combined-cycle natural gas-fired plants[5] and renewable energy plants with lower GHG emissions), and the displacement of higher emission natural gas-fired peaker plant-generated power, overall net emissions of CO_2e are reduced by the system operation.

---

[3] *Addendum EIR (PEA-19) to the Emergency Water Storage Project Final Environmental Impact Report / Environmental Impact Statement (SCH #93011028)*, San Diego County Water Authority, December 16, 2008.

[4] Unit 1 test results: Generate Mode: 1.4785 AF to generate 1 MW-hr; Pump Mode: 1.1513 AF are pumped per 1 MW-hr. Efficiency calculation is 1.1513/1.4785 = 0.7787 or 78%. Unit 2 test results: Generate Mode: 1.4750 AF to generate 1 MW-hr; Pump Mode: 1.1418 AF are pumped per 1 MW-hr. Efficiency calculation is 1.1418/1.4750 = 0.7741 or 77%. Average efficiency for the two units combined is 77.5%. Source: Tim Suydam, SDCWA Operations Manager, October 2013.

[5] In a combined-cycle power plant a gas turbine generator generates electricity and the waste heat is used to make steam to generate additional electricity via a steam turbine; this last step enhances the efficiency of electricity generation. These types of plants are expensive to build and are generally used as base load plants, generating power during both peak and off-peak time periods.

As shown in Table 1, if there were no renewable energy sources in the SDG&E generation portfolio used to pump water back to the upper reservoir, the annual net CO_2e emissions that would be displaced by the Olivenhain-Hodges Pumped Storage Project would be approximately 1,022 metric tons. However, SDG&E's current energy portfolio includes approximately 20% renewable energy sources.[6] Accounting for these renewable energy sources (and not including any nuclear generation), which generate negligible CO_2e emissions, it is estimated that the project currently results in a net displacement of up to 8,907 metric tons CO_2e per year.

In addition, per Executive Order S-14-08, which establishes a Renewable Portfolio Standard (RPS) for all retail sellers of electricity in California, SDG&E will be required to serve 33% of its electricity load with renewable energy sources by 2020. Accounting for attainment of this RPS, the project would be expected to result in a net displacement of up to 14,032 metric tons CO_2e at the 33 percent renewable level by 2020. Therefore, the Olivenhain-Hodges Pumped Storage Project produces a net benefit for the region and State with regard to the generation of CO_2e pollutant emissions.

Table 1: Olivenhain-Hodges Pumped Storage Project CO_2e Emissions Assessment

Source	**Pump-back or Energy Generation**	**Energy Source Mix**	**Annual GWh**	**Emissions Factor CO_2e[*] (lbs/GWh)**	**Annual CO_2e (metric tons/year)**
A	Pump-back (consumed energy)	100% Combined-Cycle Natural Gas	107	815,000[a]	39,423
B	Pump-back (consumed energy)	80% Combined-Cycle Natural Gas and 20% Renewable Energy Sources	107	652,000[b]	31,538
C	Pump-back (consumed energy)	67% Combined-Cycle Natural Gas and 33% Renewable Energy Sources	107	546,050[b]	26,413
D	Generation (displaced energy)	Simple-Cycle Natural Gas	83	1,080,000[a]	40,445
Net Displaced Emissions assuming no renewable power generation sources (D-A)					1,022
Net Displaced Emissions with 20% renewable power sources[c] for pump-back (D-B)					8,907
Net Displaced Emissions assuming 33% renewable power sources for pump-back (D-C)					14,032

See notes below.

[6] SDG&E's renewable procurement for 2012 was 20.31% according to the California Public Utilities Commission (CPUC), (rounded to 20% for purposes of these calculations). CPUC. 2013. California Renewables Portfolio Standard (RPS). Available at: http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm. Accessed October 9, 2013.

Table 1 Notes: The analysis assumes 83 GWh of annual electrical generation for the 40 MW Project (6 hours per day at 344 days generation; accounting for 21 days maximum downtime for annual maintenance). The measured average pump-back efficiency for the two units is 77.5%.

a These emissions factors are from *Comparative Costs of California Central Station Electricity Generation* (CEC, 2010) for conventional simple-cycle and combined-cycle power plants.

b These emissions factors are based on emissions factors for combined-cycle power plants from CEC, 2010, adjusted to account for the applicable mix of renewable energy generation sources.

c Actual attained renewable energy percentage for 2012 as reported by SDG&E to the California Energy Commission – see footnote number 6.

Conclusions

When fully operational at a total of 40 MW of generating capacity, utilization of the Olivenhain-Hodges Pumped Storage Project results in a regional net CO_2e emissions reduction of up to 8,907 metric tons annually within the San Diego region. For purposes of the emissions inventory and the Water Authority's CAP, the pumped storage project is accounted for as a net benefit for offsetting other GHG emissions associated with operation of the regional water and electricity supply systems. This benefit may be adjusted in future years to account for a greater percentage of total SDG&E power derived from renewable energy sources as RPS goals are achieved. For purposes of accurate accounting, actual operations should be monitored annually and the total offset recalculated to account for changing percentages of renewable generation available, and actual hours of operations of the Olivenhain-Hodges Pumped Storage Project.