The Residential Runoff Reduction Study

Municipal Water District of Orange County

Irvine Ranch Water District

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Study Participants

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Southern California Coastal Water Research Project

State Water Resources Control Board

United States Department of the Interior Bureau of Reclamation

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Executive Summary

Study Background and Rationale

In 2001, the Irvine Ranch Water District (IRWD), the Municipal Water District of Orange County (MWDOC), and the Metropolitan Water District of Southern California (MWD) completed a small-scale study of weather-based evapotranspiration (ET) irrigation controllers. This study, known as the "Westpark Study," tested the effectiveness of ET controller technology in residential applications. After 40 such controllers were installed in the Westpark neighborhood of Irvine, California, water demand and runoff in the study area were measured. The resulting average water savings for this study were 37 gallons per day, or 7 percent of total household water use and 18 percent of irrigation water use.

Based upon the findings of the Westpark Study, IRWD and MWDOC partnered on new research, the Residential Runoff Reduction (R3) Study, in which the number of sites studied was increased, a baseline area where no changes were made was included, and an "education only" area where printed educational materials were distributed was also included. This made the R3 Study one of the first studies to attempt to quantify the effectiveness of public education alone versus a technology-based plus education approach to reducing residential irrigation water usage. Figure ES-1 presents the study participants and their respective roles within the R3 Study.

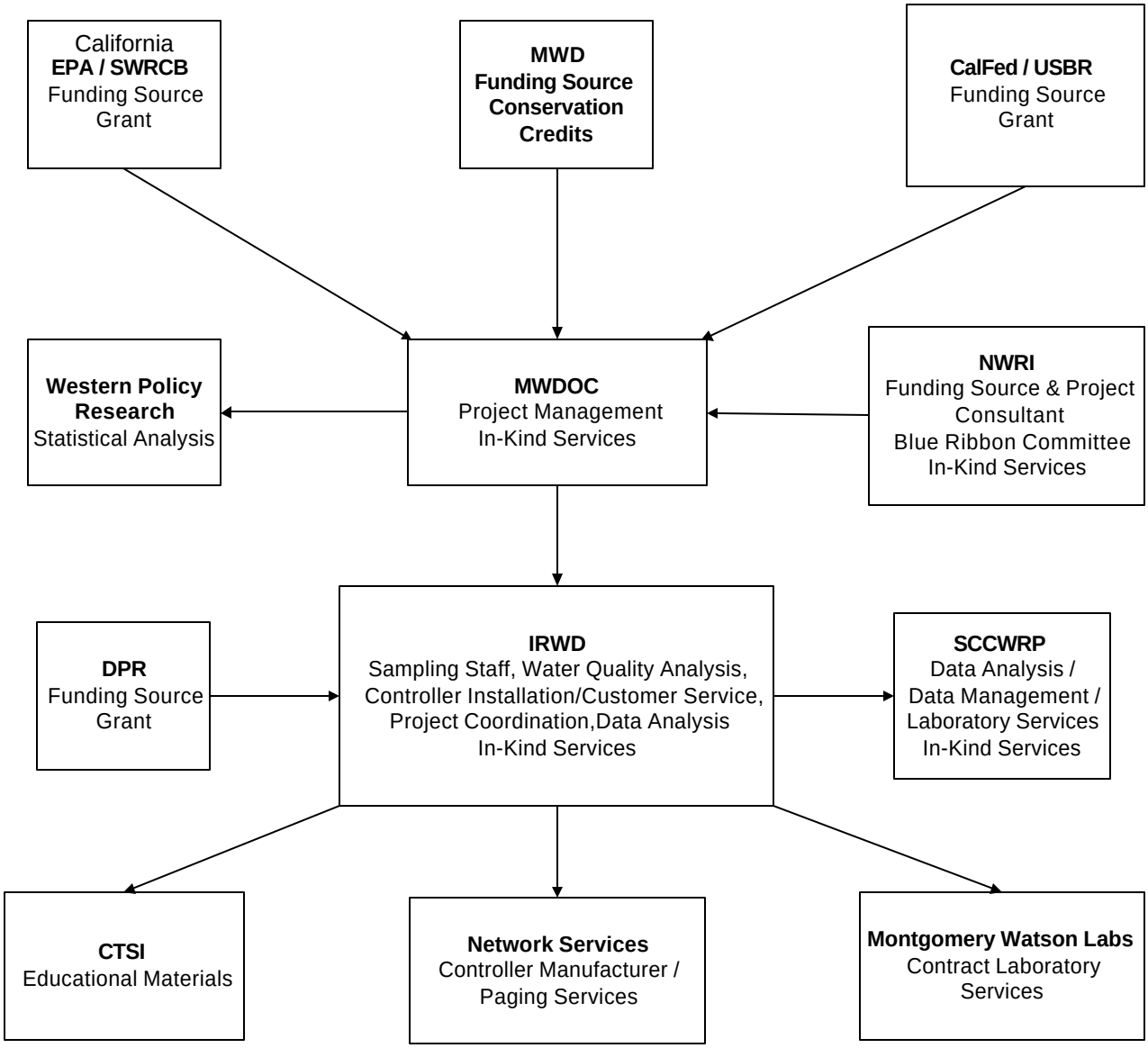
The R3 Study had four primary purposes:

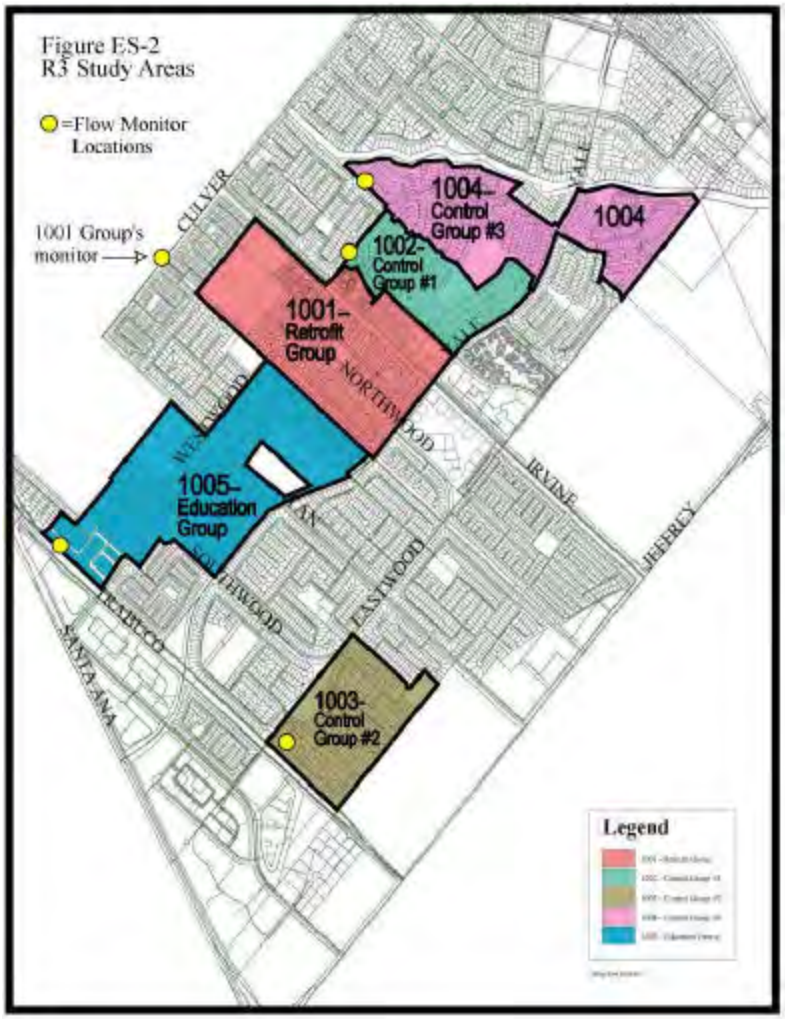
1) To test the use of weather-based irrigation technology, also known as ET controllers, to manage irrigation water for residential homes and large landscape areas;
2) To evaluate the effectiveness of a targeted education program on residential homeowners;
3) To determine the correlation between proper water application in landscape irrigation and the quantity and quality of urban dry-season runoff; and
4) To gauge the acceptance of water management via the controller technology.

Study Methodology

The R3 Study area included five similar neighborhoods (Sites 1001 through 1005) in Irvine, California, each with its own single point of discharge into the urban storm drain system. The five sites are shown on Figure ES-2. At these points of discharge from each study area, the runoff volume was monitored and water quality samples were taken. The five sites were divided into three separate areas. The first area, Site 1001 (retrofit group), used ET controller technology and public education. The second area, Site 1005 (education group), received educational materials, but did not receive controllers. The third area (control group) consisted of three separate neighborhoods (Sites 1002, 1003, and 1004), which received neither ET controllers nor educational materials.

Figure ES -1
R3 Study Participants





Evaluation Results

After the initial 18-month study period was completed, the data was compiled and evaluated for water conservation savings, dry season runoff changes, and changes in the quality of the dry season runoff water. The following summarizes the results:

a) Water Conservation Savings

Water conservation savings from the typical participant in the retrofit group were 41 gpd, or approximately 10 percent of total household water use. The bulk of the savings occurred in the summer and fall (Figure ES-3. Residential Water Savings: Technology + Education). The education group residential customers saved 26 gpd, or about 6 percent of total water use. The savings from this group were more uniform throughout the year (Figure ES-4, Residential Water Savings, Education Only). The retrofit group also included 15 dedicated landscape accounts (ranging in size from 0.14 acres to 1.92 acres), which showed average water savings of 545 gpd. The net result was eight times more water savings than with the single-family residential controller, strongly indicating that the larger the landscape, the better the savings per controller.

Figure ES -3
Residential Water Savings: Technology + Education

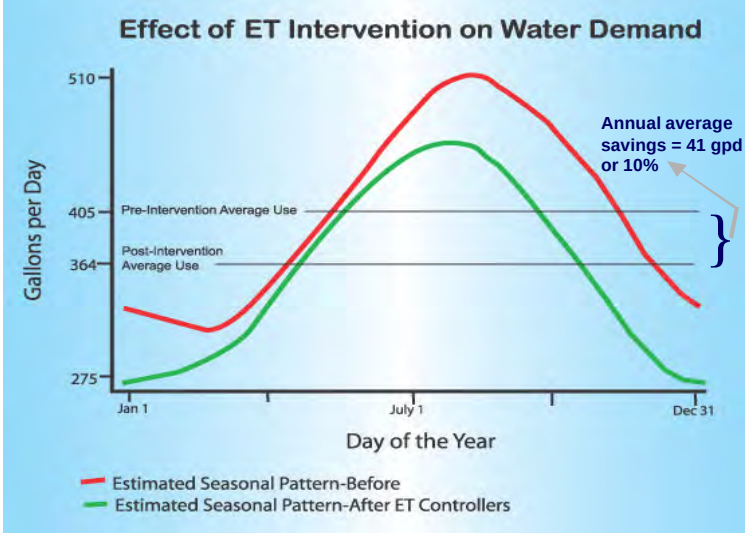


Figure ES -4
Residential Water Savings: Education Only

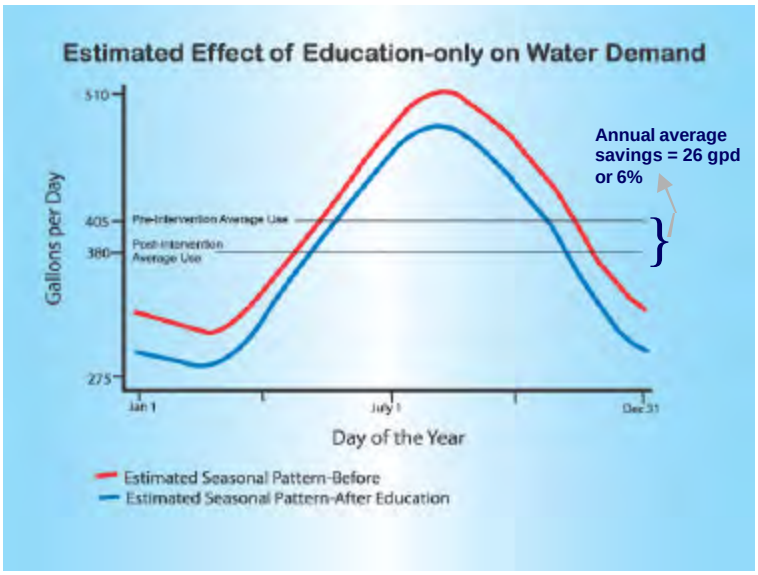


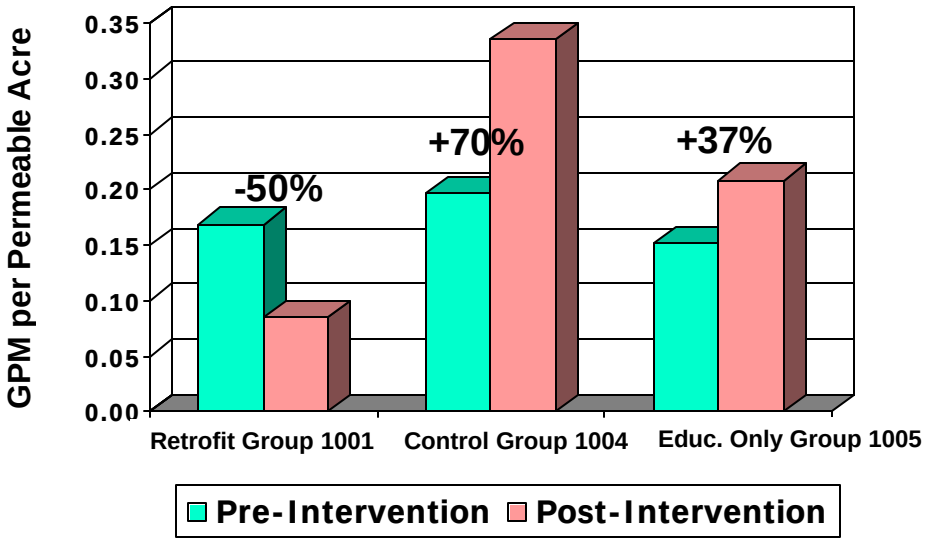
Figure ES -5
Changes in Runoff Within Each Site

b) Dry Season Runoff Changes

The retrofit group experienced a 50 percent direct reduction in water runoff (pre-intervention runoff compared to post-intervention runoff) during dry season periods. When the retrofit group is compared to the control group, the dry season runoff shows a statistical reduction of approximately 71 percent. In contrast, a comparison of direct pre-intervention and post-intervention runoff from the education group increased 37 percent, while runoff increased 70 percent within the control group. Other than the presence of an

ET controller, the primary difference between these groups is the participation of the 15 landscape accounts in the retrofit group. These accounts irrigated approximately 12 acres of landscape versus between 4 to 5 acres of total irrigated area for the 112 residential homes. Figure ES-5 presents R3 Study changes in runoff within sites.

Figure ES -5
Changes is Runoff Within Each Site



Note: It is also possible to compare post-intervention runoff *between* the study sites. These comparisons suggest a higher reduction in runoff for Site 1001 (between 64 and 71 percent) than was observed for the "within site" pre and post comparison, and a reduction in runoff of 21 percent for Site 1005. However, as described more fully in the text, these comparisons are less reliable than the "within site" pre and post comparisons shown here.

c) Changes in Runoff Water Quality

The study gathered a great deal of information on the water quality constituents present in urban runoff. In almost all cases, the data showed no changes in the concentration of these constituents in the runoff. The most significant fact to come out of the urban runoff water quality data is that the decrease in runoff volume from the retrofit group did not appear to result in an increase in the concentration of pollutants in the runoff. Thus, it is probable that a reduction in total pollutant migration could be achieved by reducing total dry season urban runoff.

d) Public Acceptance of Water Management

While there were some customer service-related issues, the retrofit group had a generally positive response to the ET controller, with 72 percent of participants indicating that they liked the controllers. The retrofit group also found that the controller irrigation either maintained or improved the appearance of the landscape. This has very positive implications. The water district customers receive a desired benefit of a healthy landscape, and the community receives several important environmental benefits from

the conservation of valuable and limited water resources and the reduction in dry season urban runoff.

Findings, Conclusions, and Recommendations

The R3 Study showed that weather-based irrigation controllers, which provide proper landscape water management, resulted in water savings of 41 gpd in typical residential settings and 545 gpd for larger dedicated landscape irrigation accounts. The observed reduction in runoff from the retrofit test area was 50 percent when comparing pre-intervention and post-intervention periods and 71 percent in comparison to the control group. The education group saw reductions in water use of 28 gpd, and a reduction in runoff of 21 percent in comparison to the control group. Water quality parameters in both study areas were highly variable, and very few differences in the level of monitored constituents were detected. In terms of water savings per controller (and cost-effectiveness), the study clearly indicated that larger landscape areas (parks and street medians) should provide the initial targets for the expansion of similar programs.

Chapter 1: Introduction

1.1 Overview

Weather-based evapotranspiration (ET) irrigation control has long been a tool of large agricultural operations, maximizing crop yields through pinpoint management of crop watering. The Residential Runoff Reduction (R3) Study was conducted to evaluate the applicability of ET technology for other uses. This chapter of the study report presents the following:

- Background information on study rationale;
- Specific study goals and objectives;
- Identification of study partners and their roles/contributions to the study.

The organization of this report is also described, and commonly-used abbreviations and acronyms are listed. References used during the study are presented in Appendix A.

1.2 Background

Approximately 58 percent of residential water demand is used for outdoor purposes, primarily for home landscape irrigation (AWWARF Residential End Uses of Water, 1999). Excess irrigation results in inefficient use of valuable water supplies and increased runoff that is the transport mechanism of pollutants that enter natural waterways and, ultimately, the Pacific Ocean for areas along the west coast.

Landscape water use efficiency/water conservation and watershed management in the urban sector are linked. Water agencies throughout the state are implementing 14 Best Management Practices (BMPs) to increase the efficient use of urban water supplies including landscape irrigation efficiency. Cities and counties are also implementing National Pollutant Discharge Elimination System (NPDES) permit requirements containing BMPs for watershed management focused on runoff reduction.

Recent studies in Orange County have had promising results. In 1998-1999, Irvine Ranch Water District (IRWD), Municipal Water District of Orange County (MWDOC), and the Metropolitan Water District of Southern California (MWD) conducted a study that evaluated the use of weather-based ET irrigation control technology at 40 residential homes in the Westpark area of Irvine. The report from this research, entitled "Residential Weather-Based Irrigation Scheduling: Evidence from the Irvine 'ET Controller' Study," showed water savings that translated to 37 gallons per day (gpd), or 7 percent of total household water use/16 percent of irrigation water use.

In April 2001, water savings from the ET Controller study in Westpark were evaluated through September 2000, or the second post-retrofit year. This evaluation confirmed the persistence of water savings observed during the initial evaluation. More specifically, this evaluation concluded that ET Controllers were able to reduce total household water consumption by roughly 41 gallons per household per day, representing an 8 percent reduction in total household use, or an 18 percent reduction in estimated landscape water use.

The R3 Study represents the next phase of research associated with the new irrigation control technology linking benefits to watershed management.

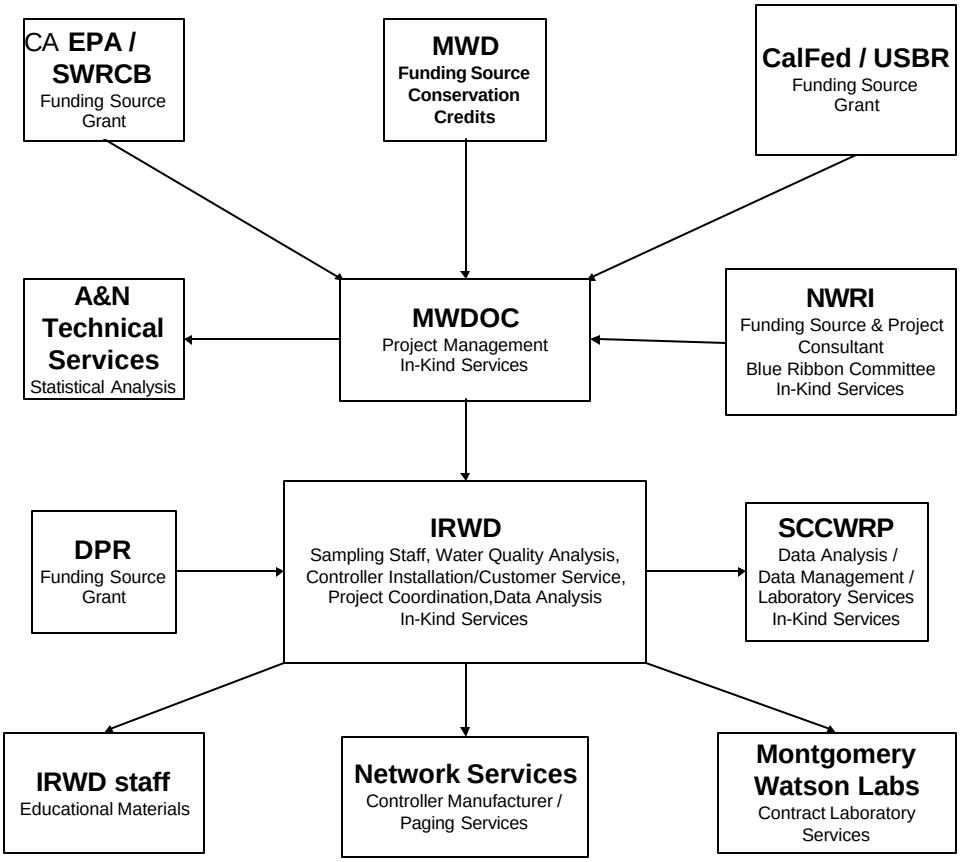
1.3 Study Goal and Objectives

The goal of the R3 Study was to quantify ET Controller savings for single-family residences and large landscape users. The study had four primary purposes: 1) to develop and expand the application and use of pager-signal (electronic controller) technology to manage irrigation water for residential homes and large landscape areas; 2) to evaluate the effectiveness of a targeted education program; 3) to determine the connection between proper water use in the landscape and the quantity and quality of dry weather runoff; and 4) to gauge the acceptance of water management via the controller technology.

1.4 Study Partners

The R3 Study was made possible through a partnership of agencies and organizations committed to improved water use efficiency and watershed management. The members of the partnership are shown on Figure 1-1. The figure also indicates the roles played by each study partner.

Figure 1-1
R3 Study Partners



As shown on Figure 1-1, the R3 Study involved a diverse mix of study participants and funding agencies bringing equally diverse interests and visions to the project. In general, the study was based on the premise that runoff from poor irrigation practices from urban areas in the San Diego Creek watershed constitutes non-point source pollution and contributes to water quality problems both in the Creek and in Newport Bay, the receiving water for the Creek. Although water quality problems in the Creek and Bay have been well documented, data on the specific sources of these pollutants is limited.

The R3 Study was intended to focus on and analyze both the quality and quantity of runoff from relatively small sub-areas of the watershed to provide insight into the sources of pollution in the Creek and Bay. In addition to providing this baseline information, the study was intended to evaluate the effectiveness of two methods of reducing runoff and improving water quality: 1) education; and 2) education combined with ET controller technology. Furthermore, since irrigation runoff is 100 percent water waste, the water agency participants were very interested in the ability of the study intervention methods to reduce customer water usage.

The R3 Study presented a good opportunity to develop valuable information about the relative effectiveness of structural (retrofit) versus non-structural (public education) controls. A technology + education (retrofit group) BMP was applied in one neighborhood, an education-only BMP was applied in a second neighborhood, and a control was established through three additional neighborhoods.

A more detailed discussion of the study participants is provided below. For purposes of simplicity, the organizations are categorized as agencies responsible for water quality, agencies responsible for water supply, and "supporting participants." However, in many cases, these objectives are overlapping and are not mutually exclusive.

1.4.1 Agencies Responsible for Water Quality

Study participants whose major area of responsibility is water quality include the California Environmental Protection Agency (CAEPA), the State Water Resources Control Board (SWRCB), the Regional Water Quality Control Board (RWQCB), the California Department of Pesticide Regulation (DPR), the County of Orange, and the Southern California Coastal Water Research Project (SCCWRP). These agencies are charged with regulating, enforcing, implementing, or researching and monitoring federal and state laws pertaining to water quality and the control of constituents which may degrade water quality. For example, the RWQCB is responsible for establishing limits on the amount of pollutants that can be discharged to Newport Bay. These limits are defined as "Total Maximum Daily Load" (TMDL). The County of Orange, which provided indirect funding to the study through DPR, is the primary permittee on the Municipal Separate Storm Sewer System (MS4) Permit issued by the RWQCB. The County's primary interest in the study relates to their efforts to implement a comprehensive program of BMPs to meet the TMDLs as required by the MS4 permit. In addition to providing improved baseline water quality and runoff information, these agencies focus on gauging the

effectiveness of the two study intervention methods in reducing the quantity of runoff and improving the quality of the water that does run off.

1.4.2 Water Agencies

IRWD and MWDOC are water districts whose primary mission is to provide safe and reliable water service to customers within their respective service areas. The reliability of water service, in particular, is directly related to the efficiency of water use. In other words, since supplies of reasonably priced water are essentially fixed, increases in efficiency can result in additional supplies being available for storage until they are needed during periods of supply shortages.

Both IRWD and MWDOC, as well as MWDOC's "parent" agency, MWD, operate various water efficiency/conservation programs within their service areas. Some progress has been made on increasing water use efficiency from programs targeting outside use for landscape irrigation (which generally accounts for about 50 percent of total urban water use). However, water use in this sector remains closely linked to the ability and responsiveness of landscape personnel with responsibility for controlling and adjusting irrigation control timers.

Two basic issues are associated with this "people to water use efficiency" link. First, there is a wide variation in the abilities of personnel to properly set baseline irrigation schedules based on site factors (type of plant material, soil, exposure, slope, irrigation equipment, etc.). Second, for various reasons, it is believed that very few of these timers are adjusted on a sufficient frequency to promote optimum water use efficiency. Consequently, the water agencies are very interested in technologies such as the irrigation controller tested as a part of the R3 study. This technology allows irrigation schedules to be automatically adjusted based on real-time weather conditions. Equally important, the technology provides the ability to set appropriate base irrigation schedules by site conditions, particularly the soil type (infiltration capacity) and slope. This capability is critical to reducing runoff.

In addition to the potential effectiveness of the water management/irrigation controller program, IRWD and MWDOC were also very interested in determining if the focused educational and communication efforts tested in the study could yield customer water savings. This is particularly important since these efforts can be a very cost-effective way to achieve water savings.

In addition to water conservation, water agencies are becoming increasingly aware of their role as providers of water which, if not used efficiently, may ultimately become a nuisance or source/carrier of non-point source pollution. Consistent with its vision to optimize the use of resources as demonstrated by its globally-recognized recycled water reuse program, IRWD in particular has taken a leadership role in addressing irrigation runoff/non-point source pollution within its service area, which covers a majority of the San Diego Creek watershed. In addition to the current study focusing on potential source control measures, IRWD has prepared a master plan outlining a system of constructed wetlands which will capture and treat runoff and improve water quality in the watershed and Newport Bay.

1.4.3 Supporting Participants

The remaining study participants provided vital support for various aspects of the study. Network Services Corporation (now HydroPoint Data Systems, Inc.) manufactured the ET controllers used in the study and was responsible for compiling weather data and transmitting this information to the controllers. The National Water Research Institute (NWRI) provided input on the study design and evaluation, and A&N Technical Services prepared the detailed analysis of water savings and runoff reduction under a contract. Similarly, a portion of the water quality analysis was conducted under a contract by Montgomery Watson.

1.5 Report Organization

The R3 Study report is organized into two main parts: a body, consisting of seven chapters, followed by eight Appendices containing references and the analyses prepared by the study partners and presented in their entirety.

The first two sections of this report (Chapters 1 and 2) present general information about study goals and methodology. Chapter 1 presents study rationale, goals and objectives, and participating organizations. Chapter 2 describes how the study area was developed and presents the methodology used to develop information on the four main study areas: water conservation savings, dry season runoff/reduction savings, water quality impacts, and customer acceptance/public education.

Chapters 3 through 6 present the evaluations for the four main study areas, respectively, water conservation, dry season runoff, water quality, and customer acceptance. Each chapter provides an overview, summarizes the evaluation approach, presents results, and summarizes major conclusions. More detailed information on the evaluations is presented in the Appendices.

The final section of this report (Chapters 7) integrates study results and describes relevance for future planning and policy. Key findings, conclusions, and recommendations are presented.

The Appendices to this report contain eight sections. Appendix A, References, lists reports, articles, and other documents utilized during the R3 Study. Appendix B, Study Design, provides support information for Chapter 2, Study Methodology, and provides details on the techniques and methods used for data collection, sampling, and analysis. Appendix C, Water Conservation, presents the detailed water conservation evaluation conducted by A&N Technical Services, Inc., and includes detailed information on data models developed for the analysis. Appendix D1, Statistical Analysis of Urban Runoff Reduction, and Appendix D2, 2003 Runoff Data, present the detailed statistical analysis of runoff reduction. These analyses were also prepared by A&N Technical Services, Inc., and include detailed information on the data collection and analysis approach. Appendix E1 and E2 present Water Quality information. E1 was prepared by SCCWRP, and E2 was prepared by GeoSyntec Consultants. Finally, Appendix F, Public Education, presents information on customer acceptance and public involvement.

1.6 Abbreviations and Acronyms

The following abbreviations and acronyms are used in this report:

ADP	antecedent dry period
ANOVA	analysis of variance between groups
AWWA	American Water Works Association
AWWARF	American Water Works Association Research Foundation
BACI	before-after control impact
BMPs	Best Management Practices
CAEPA	California Environmental Protection Agency
Calfed	consortium of state and federal agencies who address California and San Francisco Bay-Delta water issues
cfs	cubic feet per second
CIMIS	California Irrigation Management Information System
CTR	California Toxic Rule
DPR	California Department of Pesticide Regulation
ET	evapotranspiration
fps	feet per second
GIS	geographic information system
gpd	gallons per day
HOA	homeowners association
IRWD	Irvine Ranch Water District
K-W	Kruskal-Wallis
mgd	million gallons per day
mg/acre/day	milligrams per acre per day
mg/L	milligrams per liter
mL	milliliters
MPN	most probable number
MS4	Multiple Separate Storm Sewer System
MWD	Metropolitan Water District of Southern California
MWDOC	Municipal Water District of Orange County
NPDES	National Pollutant Discharge Elimination System
NWRI	National Water Research Institute
OCPFRD	Orange County Public Facilities and Resources Department
OP	organophosphorus
ng/L	nanograms per liter
PCF	pressure control facility
R3	Residential Runoff Reduction Study
RWQCB	Regional Water Quality Control Board
SCCWRP	Southern California Coastal Water Research Project
SWRCB	State Water Resources Control Board
TIN	total inorganic nitrogen
TKN	total Kjeldahl nitrogen
TMDL	total maximum daily load
TN	total nitrogen

TP	total phosphorous
ug/L	micrograms per liter
USBR	United States Bureau of Reclamation
USEPA	Untied States Environmental Protection Agency

Chapter 2: Study Methodology

2.1 Overview

Historically, water agencies have utilized educational programs and in some cases allocation-based rate structures to achieve improved irrigation efficiency in urban landscapes. With the introduction of "smart" weather-based irrigation controller technology, which in early studies generated quantifiable and reliable irrigation water savings over time, water agencies may now have a new and effective management tool to introduce to residential and other customers. The R3 Study compared, in a controlled setting, water savings and watershed management benefits of a remote, weather-based "ET" automated irrigation controller technology. This chapter of the report presents information on the methodology used in the following areas:

- Study design, including study area development, flow monitoring and water quality sampling procedures, and determination of a viable ET irrigation controller operation and selection process.
- Evaluation of water conservation savings.
- Quantification of dry season runoff reduction savings.
- Assessment of water quality impacts.
- Approach to public acceptance/public education.

More information on study design is presented in Appendix B. Evaluation-specific information on study design, data collection/analysis, and results is presented in Chapters 3 through 6 for water conservation, dry season runoff reduction, water quality, and public education, respectively. Additional details are provided in Appendices C through F.

2.2 Study Design

Study design included developing a viable study area, which provided for accurate data collection and comparison. Identifying appropriate flow monitoring equipment and determining an effective ET irrigation controller operation and selection were also important.

The goal of this study is to compare the effectiveness of technological BMPs versus public education for reducing the volume, concentrations, and mass emissions of potential pollutants in dry weather runoff from irrigated landscapes. The technological BMP consisted of ET controllers that communicate with irrigation systems of individual households and selected large landscapes, such as street medians, parks, etc. This technology is designed to optimize watering times for landscaped areas, hence reducing over-watering and resultant runoff. (See Section 2.2.3.) The public education campaign focused both on appropriate watering times and on the correct application of pesticides, herbicides, and fertilizers. (See Section 2.3.4.) These two types of BMPs were tested in residential neighborhoods, typically the most common land use in urban watersheds (Wong et al.1997). The goal was to determine if technology or education provides more pollutant reduction so that urban runoff managers can select optimal runoff pollutant minimization strategies.

2.2.1 Development of the Study Area

When developing the R3 Study area, the study partners focused on identifying watersheds with similar characteristics that would enable them to confirm water savings identified in the previous "Westpark" study, a water conservation evaluation (IRWD, MWDOC and MWD, 200l). Because a parallel purpose was to expand upon the findings of the Westpark study by measuring changes in dry weather volume (dry season runoff evaluation) and pollutant content of residential runoff (water quality evaluation) associated with improved irrigation management practices, both single-family residences and medium-size landscapes were considered. The R3 Study area is located within IRWD's service area as shown on Figure 2-1.

The R3 Study involved data collection and evaluation not previously attempted at such a large scale. In order to ensure reliable and accurate results, the study team sought to minimize the effects of outside variables that might produce "skewed" results. The team designated a study area that included five similar neighborhoods in Irvine, California. The study area was configured so that meaningful data could be provided for the water conservation, dry weather runoff reduction, and water quality evaluations. Runoff from each of the neighborhoods could be isolated and sampled at a single point from within the municipal sewer system, enabling each neighborhood to be treated individually. At these points of drainage, the runoff volume was monitored, and water quality samples were taken. The five neighborhoods are summarized in Table 2-1 and depicted graphically on Figure 2-2.

Table 2-1
Summary of Neighborhoods

Name	Description/Purpose	Comments
Site 1001 Retrofit Group	The homes in this group were retrofitted with an ET controller and also received education information.	The Retrofit Group area consisted of: • 112 residential landscapes • 12 City of Irvine streets • 2 condominium associations • 1 homeowners association
Sites 1002 – 1004 Control Groups	The homes in this group were monitored as experimental control groups and received no ET controller and no public education materials.	The Control Group area had evaluation-specific variations in size and configuration. In addition, some evaluations assessed "matched" and "unmatched" controls from within and outside of the study area.
Site 1005 Education Group	The homes in this group received information materials only (the same education information as supplied to the Retrofit Group).	The Education Group consisted of 225 homes identified by visual selection. This area also included one large school site.

Figure 2-1
Location of R3 Study Area Within Southern California

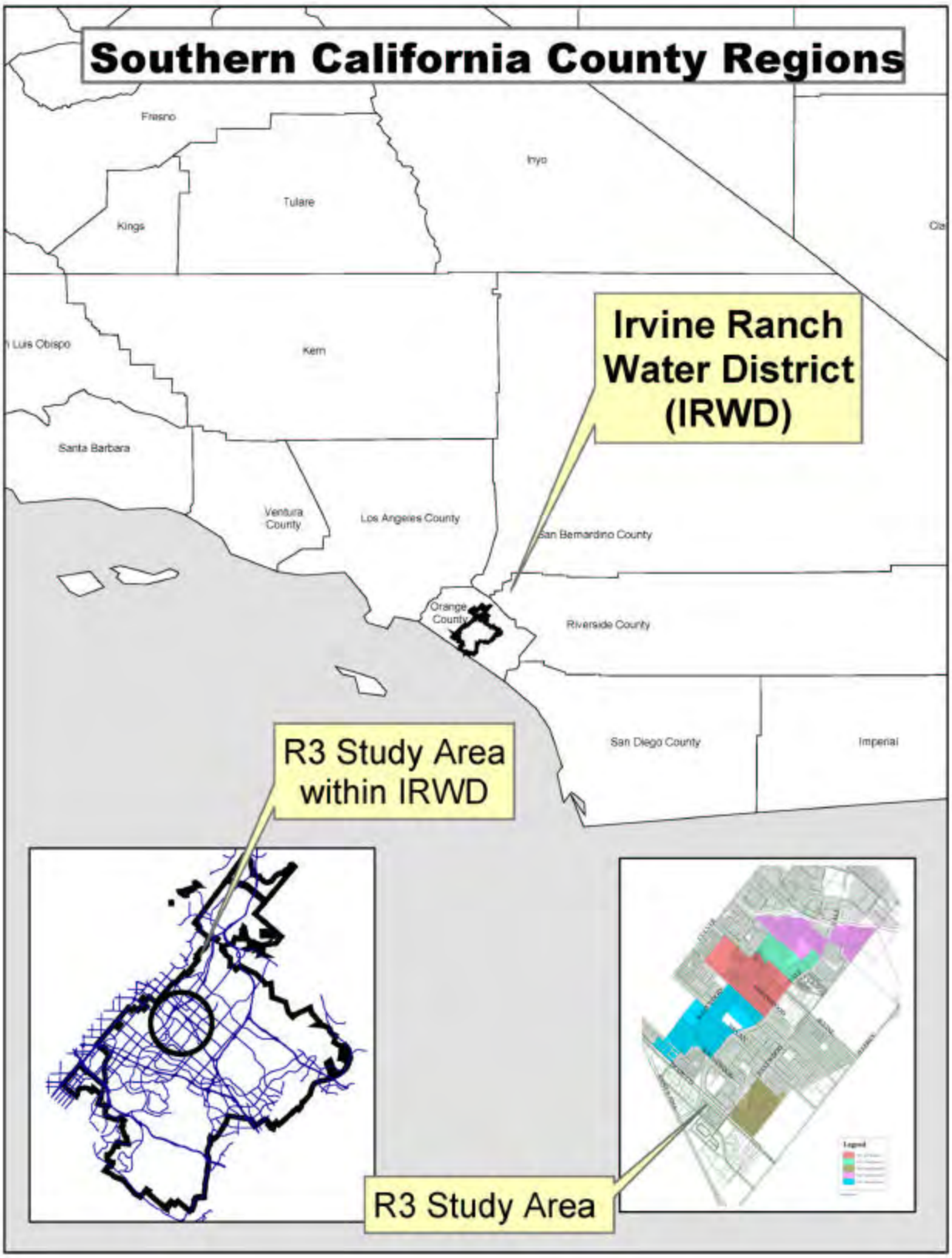
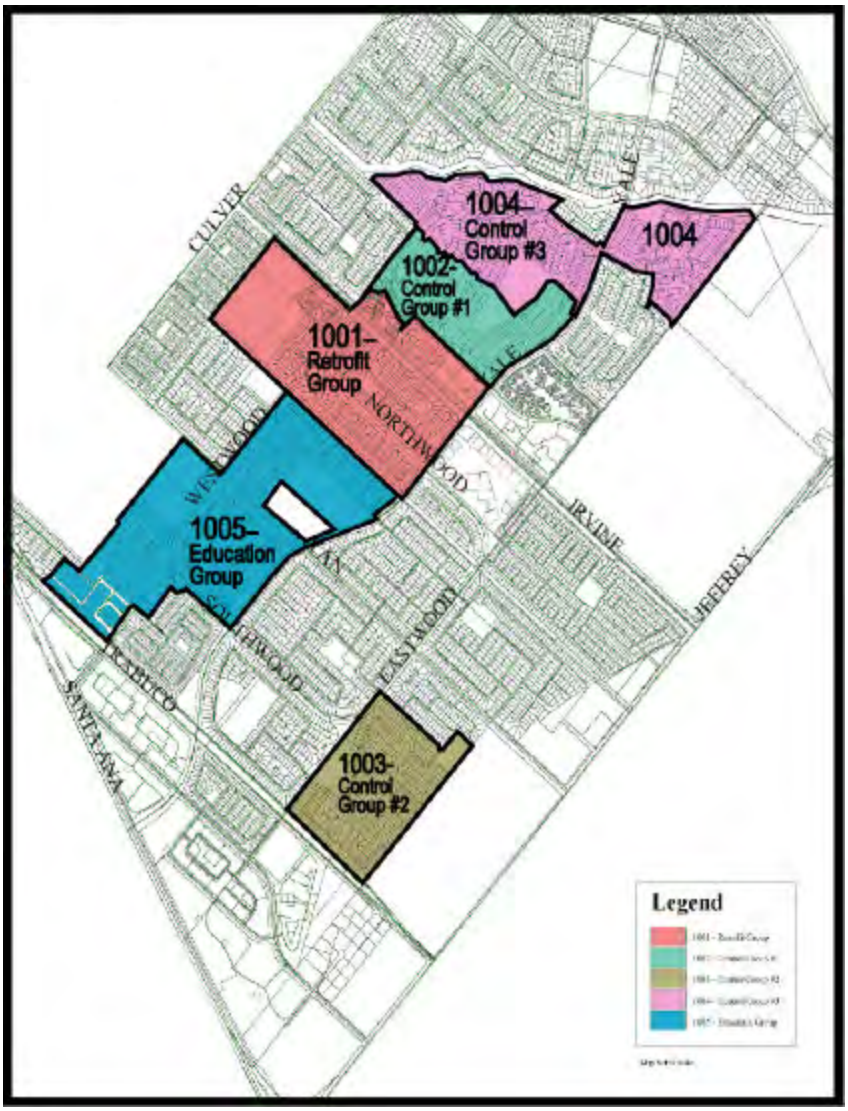


Figure 2-2
R3 Study Neighborhood Areas



In the first of the neighborhoods (Site 1001 or retrofit group), participating homes received a site evaluation and installation of an ET controller to automatically adjust irrigation schedules. Additionally, the residents at these homes received information regarding environmentally-sensitive landscape maintenance practices. The controllers were installed in 112 residential homes, 12 city street landscapes in the City of Irvine, two condominium associations' landscapes, and one homeowners association (HOA) landscape. The HOA landscape had three distinctive sites: 1) pool/park/tennis courts, 2) park, and 3) streetscapes.

The second neighborhood (Site 1005, or education group) received the same environmentally-sensitive landscape maintenance information as the first group, as well as a suggested irrigation schedule.

The three remaining neighborhoods (Sites 1002 – 1004, or control group) did not receive ET controllers and were not provided educational materials. Residents in the control groups had no knowledge of the study and were used only for comparison purposes. The make-up of the control group varied depending upon the evaluation. In the water conservation evaluation, "matched controls" were used in addition to the control group sites. In the water conservation and the dry weather runoff evaluations, only data from Site 1004 was used, as discussed in Sections 2.3.1 and 2.3.2. Data from all three sites was used in the water quality evaluation.

The five neighborhoods were selected based on the following criteria: 1) isolation from other neighborhood watersheds, 2) climate, 3) land use, 4) development age, and 5) irrigation water management techniques. These parameters are described in greater detail in Appendix B.

2.2.2 Flow Monitoring / Water Quality Sampling

This section summarizes the approach to flow monitoring and water quality sampling.

2.2.2.1 Flow Monitoring

Two main criteria were established for the study's flow monitoring equipment. First, the monitor could not alter the pipe or channel. Second, the monitoring had to be sufficiently accurate to distinguish seasonal flow changes and any flow change that resulted from the two study treatments (retrofit and education). Because the storm drain systems used for flow monitoring are designed to convey peak storm flows, and the focus of the R3 study was on changes in dry season (low flow) runoff associated with the treatments, the flow monitors had to be able to detect relatively small differences in low volume flows in large diameter storm drains. This situation was exacerbated by the fact that only a portion of each tributary neighborhood received the study treatments. Two flow monitoring technologies were determined to meet these criteria:

- Manning's equation plus a level sensor
- Velocity sensor and level monitor (area-velocity)

The area-velocity method was chosen due to lack of slope information for the storm drain system. The selected equipment was an American Sigma 950, which is battery-operated and can record data every minute. The equipment has an ultrasonic transmitter and a velocity sensor, both of which were installed in the storm drain. The ultrasonic transmitter establishes the water surface level and area, while the velocity sensor determines the velocity of the water in the pipe. Flow is calculated by the equation:

- Flow = Area x Velocity

Because four of the five monitoring locations were in a pipe, several variations on the ultrasonic transmitter / velocity sensor were tested before the combination of sonic and velocity wafer were finalized.

The accuracy of the flow monitoring equipment was tested at all study sites. This was accomplished by metering flow (at three different levels) from a fire hydrant within each tributary watershed and comparing these metered flows to flows measured at the flow monitoring locations. As expected, the accuracy of the flow monitors varied from site to site depending on the nature and condition of each storm drain. For example, some settling of the storm drain was noted near the flow monitor for Site 1002, resulting in an accumulation of sediment. This physical "anomaly" altered the hydraulic characteristics of the pipe and affected the accuracy of flow measurements. However, based on the flow test results, it was believed that these issues were manageable. The subsequent analysis of flow data as presented in Chapter 4 of this report suggests that this belief was partially correct; although flow monitoring problems required data from two of the three control sites to be discarded, the data from the other three sites (two treatments and one control) was sufficiently accurate to allow for the determination of meaningful statistical results.

2.2.2.2 Water Quality Sampling

The water quality sampling program quantified constituents found in residential runoff flows. This program consisted of two phases: 1) pre-study and 2) dry weather sampling. More information about water quality sampling and analysis is provided in Section 2.3.3, Chapter 5 and Appendices B and E.

2.2.3 ET Irrigation Controller Operation and Selection Process

The technology-based BMP consisted of an ET controller + education. The ET controller selected was similar to most automatic sprinkler timers available at home improvement stores and nurseries, but with the capacity to receive radio signals that will alter sprinkler timing based on current weather conditions. If the weather is hot and dry, the radio signal calls for longer or more frequent irrigation. If the weather is cool and moist, such as recent precipitation, the radio signals call for shorter or less frequent irrigation. For the R3 Study, the existing sprinkler timers that are set manually by the homeowner were replaced with the radio-controlled ET controller systems. Trained technicians were used to ensure successful installation because the ET controller requires programming for each valve including area (size of yard or planter per valve), soil type (clay, sand, etc.), and landscape type (turfgrass, shrubbery, etc.). The remaining irrigation system was unchanged, including piping and sprinkler head configuration.

Since residential areas include landscapes other than the homeowners, these "common area" and streetscape landscape areas ("medium-size" landscapes) were included in the water management component of the R3 Study. As shown in Table 2-2, the medium-size landscapes accounted for an estimated 70 percent of the total landscape area treated in the retrofit group (Site 1001). The installation process for both residential and medium-size landscapes is described in Appendix B.

2.2.3.1 Controller Installation

The study evaluated the performance of the engineering of irrigation management techniques to reduce the consumption and residential runoff while maintaining the quality of the landscape. A typical irrigation controller is difficult to program and limited in the scope of the scheduling

ability. Proper scheduling requires calculations based on real time ET data, landscape topography, and plant type, which are beyond the capabilities of typical controllers. The landscaper in the field is left to guess or rely on past experience as to the correct amount of water, the correct runtime to prevent runoff, and the correct number of days of the week to water.

The controllers were installed following the general principle that an ET controller is a water management tool and that professional operation should result in conservation and reduction of runoff. A picture of the controller is shown on Figure 2-3. More information is provided in Appendix B.

Figure 2-3
ET Controller

2.2.3.2 ET Controller Operation

The operation of the ET controller in this study was optimized by proper irrigation scheduling. As discussed further in Chapter 4 and Appendices B, D1 and D2, the ET controller must meet three key criteria: cost, ease of operation, and ability to conserve water and reduce runoff.

2.3 Study Evaluations

This section summarizes the water conservation evaluation, the quantification of changes in dry season runoff reduction savings, the analysis of water quality impacts, and the approach to customer acceptance / public education.

Table 2-2
Study Sites Land Use and Treatment Summary

Site 1001

Land Use	No. of Lots	Acres	Treatment Sites	Treatment Acreage*	No. of Controllers
SFR	565	66.8	112	6.6	112
Condo	109	10.3	2	1.9	8
HOA	4	5.9	1	0.9	3
School	2	4.6			
Landscape	10	19.4	12	11.2	15
Street	97	49.7			
Unmetered	64	11.5			
Total	**851**	**168.1**	**127**	**20.5**	**138**

***Note: All acreage except SFR were considered "medium-size" landscapes.**

Site 1002

Land Use	No. of Lots	Acres	Treatment Sites	Treatment Acreage	No. of Controllers
SFR	-	-	control	control	control
Condo	-	-	control	control	control
HOA	-	-	control	control	control
School	-	-	control	control	control
Landscape	-	-	control	control	control
Street	-	-	control	control	control
Unmetered	-	-	control	control	control
Total	**-**	**-**			

Table 2-2 (continued)
Study Sites Land Use and Treatment Summary

Site 1003

Land Use	No. of Lots	Acres	Treatment Sites	Treatment Acreage	No. of Controllers
SFR	-	-	control	control	control
Condo	-	-	control	control	control
HOA	-	-	control	control	control
School	-	-	control	control	control
Landscape	-	-	control	control	control
Street	-	-	control	control	control
Unmetered	-	-	control	control	control
Total	**-**	**-**			

Site 1004

Land Use	No. of Lots	Acres	Treatment Sites	Treatment Acreage	No. of Controllers
SFR	417	47.8	control	control	control
Condo	-	-	control	control	control
HOA	1	0.9	control	control	control
School	1	8.0	control	control	control
Landscape	2	0.0	control	control	control
Street	42	25.0	control	control	control
Unmetered	61	7.1	control	control	control
Total	**524**	**88.8**			

Site 1005

Land Use	No. of Lots	Acres	Treatment Sites	Treatment Acreage	No. of Controllers
SFR	559	67.9	225	13.0	n/a
Condo	-	-	-	-	n/a
HOA	1	1.5	-	-	n/a
School	2	12.1	-	-	n/a
Landscape	2	0.0	-	-	n/a
Street	45	0.0	-	-	n/a
Unmetered	8	2.7	-	-	n/a
Total	**617**	**84.2**	**225**	**13.0**	**0**

2.3.1 Water Conservation Evaluation

The water conservation evaluation was conducted by A&N Technical Services, Inc. The firm performed a statistical analysis of historical water consumption records from, roughly, July 1997 to August 2002. Two main types of water use were reviewed: single-family residences and medium-size landscapes. For the single-family residences, data was compared among the retrofit group, the education group, and the control group. For the medium-size landscape accounts, a slightly different approach was used. Accounts within the study area were compared to "matched" and "unmatched" controls in the City of Irvine, both within and outside of the study

area. Matched controls were similar in sun exposure, irrigation type, soil type, etc. Unmatched controls were areas not similar enough to be used for direct comparison but areas that could be used for weather normalization. A detailed description of the methods used to evaluate water savings for the single-family residence and medium-size landscape sites is provided in Chapter 3 and Appendix C of this report.

2.3.2 Dry Season Runoff Reduction Savings Quantification

In addition to the water conservation evaluation, A&N Technical Services, Inc., performed a statistical analysis of the reduction of runoff induced by ET controller and irrigation education. With the assistance of IRWD staff, who collected runoff data, A&N developed regression models to estimate mean runoff by site.

Two of the control sites (1002 and 1003) had recurring measurements issues that produced generally unreliable data. Site 1002 was found to have a physical hydraulic jump, which caused sediments to build in such a way that flows avoided the monitor. At Site 1003, there was an occurrence of illegal dumping of cement into the storm drain. This event reshaped the monitoring area, led to continuous collection of debris, and caused the monitor to perform erratically. Thus, it was only possible to use data from Site 1004. More details are provided in Chapter 4 and Appendices D1 and D2.

2.3.3 Water Quality Impacts Assessment

As described in Section 2.2.2.2, the water quality sampling program quantified constituents found in residential runoff flows. Two independent reviews of the water quality data were performed. The initial review, conducted by SCCWRP, used parametric statistical techniques (t-test; analysis of variance [ANOVA]), which provide a good descriptive review of the study. However, these techniques are generally considered to have less power for detecting differences in data than other statistical tests. A subsequent statistical overview was performed by Geosyntec Consultants to review alternative and possibly more “robust” data analysis techniques. This work, which included the review of only a portion of the data set, focused on additional descriptive techniques (time series plots; box plots; probability distributions) and the use of non-parametric statistical techniques (rank-sum test; Kruskal-Wallis [K-W]). The SCCWRP and Geosyntec Consultants reports are presented in Appendix E-1 and E-2, respectively.

2.3.4 Public Acceptance / Public Education Approach

The public acceptance evaluation was conducted to compare the effectiveness of proposed BMPs for ET controller technology + education and education only. The participating ET technology retrofit group homes received a site evaluation and installation of an ET controller to manage the irrigation system. Additionally, the residents of these homes received information regarding environmentally-sensitive landscape practices. The education-only group received an initial informational packet containing three items: an introductory letter, an informational booklet, and a soil probe to measure the water content of landscaped soils.

In addition to the initial packet, monthly reminders were mailed to each homeowner that included tips for maintaining the irrigation system. Suggested sprinkler run times (for the non-ET controller neighborhood) and tips on fertilizer or pesticide application usage, including non-toxic alternatives, were also provided in the monthly newsletter. A telephone log was kept to monitor incoming customer calls relating to the R3 Study, and a pre- and post-program survey was developed to measure customer impact of the study. More details are provided in Chapter 6 and Appendix F.

Chapter 3: Water Conservation

3.1 Overview

This chapter describes the statistical analysis of water savings (water conservation) among customers who installed ET controllers and customers given irrigation education in the study area. Specific information includes:

- A summary of study methods and evaluation approach.
- Evaluation results for large landscape customers and for single-family residences.
- Effect of ET controllers on seasonal peak demand.

More detailed information is provided in Appendix C.

3.2 Evaluation Approach

This section summarizes the overall evaluation approach, the records, review process, and data assessment techniques.

3.2.1 Overall Evaluation Approach

Historical water consumption records for a sample of participants and for a sample of nonparticipating customers were examined statistically. The hypothesis was that installation of new irrigation technology or better management of existing equipment would reduce the observed water consumption of customers participating in this program. This study empirically estimates the water savings that resulted from two types of "interventions"—1) customers receiving both ET controllers and follow-up education and 2) customers receiving an education-only intervention. Both single-family residences and medium-size landscapes were evaluated. (See Tables 3-1 and 3-2.)

Table 3-1
Summary of Water Conservation Evaluation Approach for Single-family Residences

Site	Number of Usable Accounts	
Site 1001 Retrofit Group	Retrofit Non Participants	97* 213
Site 1004 Control Group		264
Site 1005 Education Group	Education Non Participants .	192* 346

*Note: These sample numbers are smaller than the total number of original participants in each group due to changes in tenants, anomalous data, and other data quality issues.

Table 3-2
Summary of Water Conservation Approach for Medium-size Landscapes

Type	Number of Usable Accounts	Average Acres Per Account
Participating Landscapes	15*	0.93
Matched Controls	76	0.92
Unmatched Controls	895	0.96

Note: This sample number is smaller than the total number of original study participants due anomalous data, and other data quality issues.

Since installation of ET controllers required the voluntary agreement of the customer to participate, this sample of customers can be termed "self-selected." Customers in the education–only group were initially approached by mail about their interest in participating in the study. 137 customers initially expressing interest were included in the study group. However, because sufficient interest in the study was not generated through this mailing to meet the study saturation goals for this group, the remaining 112 participants self selected. While this analysis does quantitatively estimate the reduction of participant's water consumption, one may not directly extrapolate this finding to nonparticipants. This is because self-selected participants can differ from customers who decided not to participate.

The explanatory variables in these models include:

- Deterministic functions of calendar time, including
    - the seasonal shape of demand
- Weather conditions
    - measures of air temperature
    - measures of precipitation, contemporaneous and lagged
- Customer-specific mean water consumption
- "Intervention" measures of the date of participation and the type of intervention

3.2.2 Records Review Process

Consumption records were compiled from IRWD's customer billing system for customers in the study areas. Billing histories were obtained from meter reads between July 1997 and August 2002. It is important to note that a meter read on August 1 will largely represent water consumption in July. Since the ET controllers were installed in May and June of 2001, the derived sample contained slightly more than one year of data for each participant. More information is presented in Appendix C.

The landscape-only customers (15 accounts) were handled separately. Two control groups were developed for these irrigation accounts: A matched control group was selected by IRWD staff by visual inspection, finding three-to-five similar control sites for each participating site. Similarity was judged by irrigated area and type of use (HOA, median, park, or streetscape). Since the City of Irvine was improving irrigation efficiency on the City-owned sites during the post-intervention period, this matched control group also had potential water savings. A second control group was developed where the selection was done solely based on geographic area. In this way, the statistical models could separately estimate the water savings effects for each group. (See Appendix C.)

3.2.3 Data Assessment Techniques

The first major issue with using meter-read consumption data is the level and magnitude of noise in the data. The second major issue is that records of metered water consumption can also embed non-ignorable meter mis-measurement. To keep either type of data inconsistencies from corrupting statistical estimates of model parameters, the modeling effort employed a sophisticated range of outlier-detection methods and models. These are described in Appendix C.

Daily weather measurements—daily precipitation, maximum air temperature, and evapotranspiration—were collected from the California Irrigation Management Information System (CIMIS) weather station located in Irvine. Daily weather histories were collected as far back as were available (January 1, 1948) to provide the best possible estimates for "normal" weather through the year. Thus, 54 observations were available upon which to judge "normal" rainfall and temperature for January 1^{rst} of any given year.

Robust regression techniques were used to detect which observations were potentially data quality errors. This methodology determines the relative level of inconsistency of each observation with a given model form. A measure is constructed to depict the level of inconsistency between zero and one; this measure is then used as a weight in subsequent regressions. Less consistent observations are down-weighted. Other model-based outlier diagnostics were also employed to screen the data for any egregious data quality issues.

3.3 Evaluation Results

This section presents evaluation results for single-family residences and landscape-only customers. The effect of ET controllers on peak demand is also discussed.

3.3.1 Estimated Single-family Residential Water Demand

Table 3-3 presents the estimation results for the model of single-family water demand in the R3 study sites. Twenty-one variables are listed. This sample represents water consumption among 1,525 single-family households between June 1997 and July 2002. This sample contains 97 ET controller/education participants (in Site 1001) and 192 education-only participants (in Site 1005). This sample is smaller than the total number of participants in each group due to changes in tenants and anomalous data.

The constant term (1) describes the mean intercept for this equation. (A separate intercept is estimated for each of the 1,525 households, but these are not displayed in Table 3-3 for reasons of brevity.) The independent variables 2 to 8—made up of the sines and cosines of the Fourier series described in Appendix C (Equation 2)—are used to depict the seasonal shape of water demand.

Table 3-3
Single-family Residential Water Demand Model

Dependent Variable: Average Daily Metered Water Consumption in gallons per day (gpd)		
Independent Variable	**Coefficient**	**Std. Error**
1. Constant (Mean intercept)	405.6593	3.1660
2. First Sine harmonic, 12 month (annual) frequency	-45.4215	0.9636
3. First Cosine harmonic, 12 month (annual) frequency	-89.1494	0.9629
4. Second Sine harmonic, 6 month (semi-annual) frequency	3.6549	0.6798
5. Second Cosine harmonic, 6 month (semi-annual) frequency	1.0709	0.6733
6. Third Cosine harmonic, 4 month frequency	1.7312	0.7151
7. Fourth Sine harmonic, 3 month (quarterly) frequency	4.4016	0.7403
8. Fourth Cosine harmonic, 3 month (quarterly) frequency	3.3491	0.7865
9. Interaction of contemporaneous temperature with annual sine harmonic	48.7897	17.1559
10. Interaction of contemporaneous temperature with annual cosine harmonic	-72.4672	22.3626
11. Deviation from logarithm of 31 or 61 day moving average of maximum daily air temperature	284.7163	13.542
12. Interaction of contemporaneous rain with annual sine harmonic	10.1102	1.8546
13. Interaction of contemporaneous rain with annual cosine harmonic	5.9969	2.6904
14. Deviation from logarithm of 31 or 61 day moving sum of rainfall	-34.0117	1.8931
15. Monthly lag from rain deviation	-13.3173	1.0549
16. Average Effect of ET controller/Education (97 participants)	**-41.2266**	**4.0772**
17. Interaction of ET intervention with annual sine harmonic	38.9989	5.3327
18. Interaction of ET intervention with annual cosine harmonic	-6.3723	4.8980
19. Average Effect of Education-only intervention (192 participants)	**-25.5878**	**2.8081**
20. Interaction of Ed.-only intervention with annual sine harmonic	6.0357	3.5870
21. Interaction of Ed.-only intervention with annual cosine harmonic	-3.0703	3.3826
Number of observations	94,655	
Number of customer accounts	1,525	
Standard Error of Individual Constant Terms		120.85
Standard Error of White Noise Error		129.81
Time period of Consumption	June 1997 - July 2002	

The predicted seasonal effect is the shape of demand in a normal weather year. This seasonal shape is important because it represents the point of departure for the estimated weather effects (expressed as departure from normal). The effect of the landscape interventions on this seasonal shape was also tested.

The estimated weather effect is specified in "departure-from-normal" form. Variable 11 is the departure of monthly temperature from the average temperature for that month in the season. (Average seasonal temperature is derived from a regression of daily temperature on the seasonal harmonics.) Rainfall is treated in an analogous fashion (Variable 14). One month lagged rainfall deviation is also included in the model (Variable 15). It is also noted that the contemporaneous weather effect is interacted with the harmonics to capture any seasonal shape to both the rainfall (Variables 12 and 13) and the temperature (Variables 9 and 10) elasticities. Thus, departures of temperature from normal produce the largest percentage effect in the spring growing season. Similarly, an inch of rainfall produces a larger effect upon demand in the summer than in the winter.

The effect of the landscape conservation program interventions is captured in the following rows. The parameter on the indicator for ET controllers/education (Variable16) suggests that the mean change in water consumption is 41.2 gpd (reduction) while the education only participants (Variable 19) saved approximately 25.6 gpd. Because residential meters serve both outdoor and indoor demand, the model cannot say whether education-only participants saved this water through improved irrigation management or by also reducing indoor water consumption. Since the sample includes only one year of post-intervention data, the model cannot say how persistent either effect will be in future years.

3.3.2 Estimated Landscape Customer Water Demand

Table 3-4 presents the estimation results for the model of medium-size landscape (irrigation-only) customer water demand in the R3 study sites. Seventeen variables are listed. This sample represents water consumption among 992 accounts between June 1997 and August 2002 and contains 21 ET controller accounts, 76 matched control accounts, and 895 unmatched control accounts.

The constant term (1) describes the intercept for this equation. The independent variables 2 to 9—made up of the sines and cosines of the Fourier series described in Appendix C (Equation 2)—are used to depict the seasonal shape of water demand. The estimated weather effect is specified in "departure-from-normal" form. Variable 10 is the departure of monthly temperature from the average temperature for that month in the season. (Average seasonal temperature is derived from a regression of daily temperature on the seasonal harmonics.) Rainfall is treated similarly (Variable 11). One month lagged rainfall deviation is also included in the model (Variable 12). The next variable accounts for the amount of irrigated acreage on the site. (Note that while measured acreage is available for all irrigation-only accounts, this is not true for single-family accounts.)

The effect of the landscape conservation program interventions is captured in the following rows. The parameter on the indicator for ET controllers (Variable 14) suggests that the mean change in water consumption is 545 gpd (reduction), approximately 21 percent of the pre-intervention water use. The matched control group (Variable 16) did experience water savings, approximately 241 gpd or 8.7 percent of their pre-intervention water use. As noted previously, this group included City of Irvine landscape accounts for which a parallel water efficiency program was

conducted. The variables testing for differences in pre-intervention use cannot distinguish any differences between the different types of accounts.

Table 3-4
Landscape Customer Water Demand Model

Dependent Variable: Average Daily Metered Water Consumption (in gallons per day)		
Independent Variable	**Coefficient**	**Std. Error**
1 Constant (Mean intercept)	2624.0890	235.5602
2. First Sine harmonic, 12 month (annual) frequency	-810.6712	26.4690
3. First Cosine harmonic, 12 month (annual) frequency	-1979.1650	26.1149
4. Second Sine harmonic, 6 month (semi-annual) frequency	103.7890	26.7195
5. Second Cosine harmonic, 6 month (semi-annual) frequency	-18.6126	27.1067
6. Third Sine harmonic, 4 month frequency	-123.5511	28.2926
7. Third Cosine harmonic, 4 month frequency	106.4412	28.6328
8. Fourth Sine harmonic, 3 month (quarterly) frequency	38.3819	30.6999
9. Fourth Cosine harmonic, 3 month (quarterly) frequency	-61.4848	30.9128
10. Deviation from logarithm of 31 or 61 day moving average of maximum daily air temperature	6293.6890	565.6084
11. Deviation from logarithm of 31 or 61 day moving sum of rainfall	-748.2235	52.1792
12. Monthly lag from rain deviation	-209.9027	46.5477
13. Irrigated Acreage (in acres)	485.1284	140.1746
14. ET controller sites, test for difference in pre-intervention use	-327.6321	1511.6870
15. Average Effect of ET controller (21 accounts)	-545.3841	330.3669
16. Matched accounts, test for difference in pre-intervention use	-166.6455	693.9447
17. Average Effect of city efficiency improvements (76 accounts)	-240.4067	148.4015
Number of observations		56666
Number of customer accounts		977
Standard Error of Individual Constant Terms		5766.8
Standard Error of White Noise Error		4189.5
Time period of Consumption	June 1997 - July 2002	

3.3.3 Effect of ET Controllers on Seasonal Peak Demand (Single-family Residential)

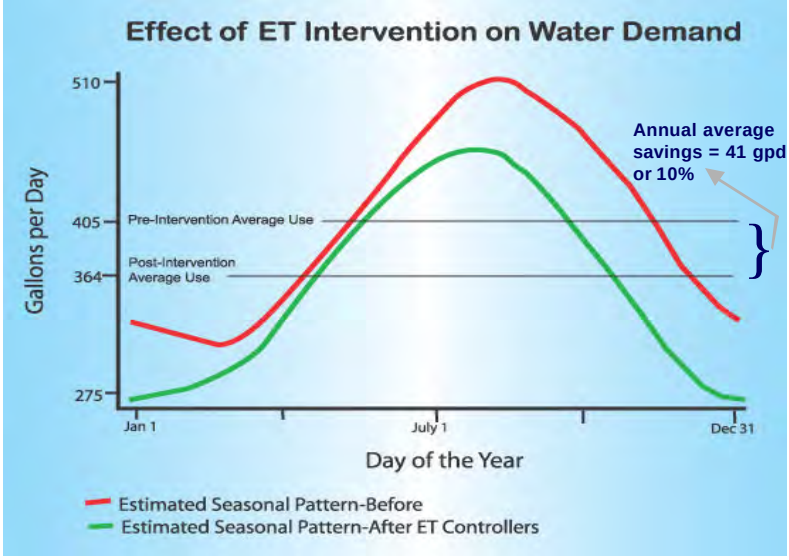
The question of how these programs affected the seasonal shape of water demand can be interpreted from the remaining interactive effects—the indicators interacted with the first sine and cosine harmonics.

When the pre / post seasonal patterns are combined with their pre / post mean water consumption, the following before and after picture can be seen throughout the year.

On Figure 3-1, several observations should be made. First, the difference between the two horizontal lines corresponds to the estimated mean reduction of approximately 41 gpd. Second,

the assumption of a constant 41 gpd effect does not hold true throughout the year. The reduction is barely noticeable in the spring growing season and is much larger in the fall.

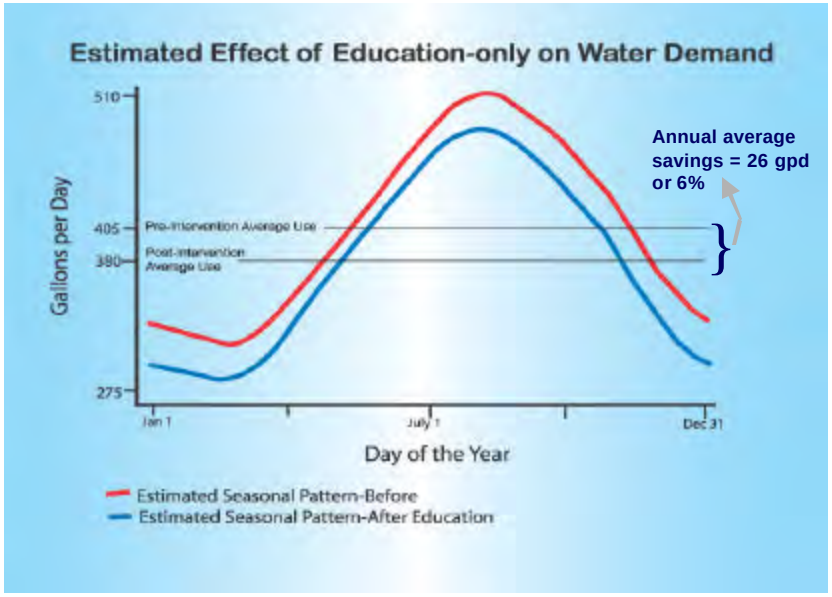
Figure 3-1
Effect of ET Intervention on Seasonal Water Demand for Single-family Residential



The reduction in peak demand—though dependent upon how the seasonal peak is defined—is greater than the average reduction. The estimated peak day demand, occurring on August 8, is reduced by approximately 51 gallons. This "load-shaping" effect of the ET controller intervention can translate into an additional benefit to water agencies. The benefits from peak reduction derive from the avoided costs of those water system costs driven by peak load and not average load—the costs for new treatment, conveyance, and distribution all contain cost components driven by peak capacity requirements

Figure 3-2 plots the corresponding estimates for the education-only intervention. The reduction in average demand is less—approximately 25 gpd. The effect upon the estimated seasonal shape of demand is much more muted. In fact, the change to the estimated seasonal shape of demand induced by the education-only intervention is not significantly different from zero at classical levels of significance.

Figure 3-2
Estimated Effect of Education-only on Seasonal Water Demand for Single-family Residential



3.4 Conclusions

This modeling effort focused on developing the best depiction of net changes in water consumption due to the landscape interventions of ET controllers and / or education. Much of the modeling effort was expended on data cleaning, diagnosis, and validation. The most serious data issues were identified and appropriately handled. To the extent that future data quality can be improved, future work could provide several statistical refinements in model specification. These are described in Appendix C.

The documentation provided in this report describes the shape of water savings achieved by the landscape interventions of ET controllers and / or education. Households participating in these programs saved significant amounts of water. Savings for the education-only program were less than for the retrofit group, but were still significant. The ET controller / education program changed both the level and shape of water demand.

Chapter 4: Runoff

4.1 Overview

This chapter presents the statistical analysis of the reduction of runoff induced by ET controllers and irrigation education. Specific information includes:

- Description of flow meters used and the data collection approach
- Discussion of the runoff analysis and analytical methods
- Presentation of evaluation results

More detailed information is provided in Appendices D1 and D2.

4.2. Evaluation Approach

The evaluation approach is summarized in Table 4-1 and discussed in more detail below.

Table 4-1
Summary of Dry Weather Runoff Evaluation Approach

Site	Description/Purpose	Controllers	Measuring Points
Site 1001 Retrofit Group	The study site contained 565 single-family residences. Of these, 112 participated in the ET/education program. In addition, 15 medium-size landscape sites also received ET controllers.	The accounts listed in Table 2-1 were allocated controllers as follows: • 112 for residential landscapes • 15 for 12 City of Irvine streets • 8 for the condominium associations • 3 for the HOA	1
Sites 1004 Control Group	This site contained 417 single-family residences and 44 large landscapes.	Not Applicable	1
Site 1005 Education Group	At this site, 225 residential customers participated in the irrigation education program.	Not Applicable	1

4.2.1 Data Collection

To measure dry weather runoff, flow monitors were installed at the five locations shown on Figure 4-1. The study used Sigma 950 flow monitors manufactured by Hach. The flow monitor applies an area-velocity calculation. The basic formula for flow is: flow (Q) equals the velocity (V) of the water multiplied by the area (A) of the water (Q=VA).

The first variable in the equation, velocity, was measured by velocity wafers placed below the surface of the runoff stream to measure the velocity of the water. These electronic devices were attached to metal plates positioned at the bottom of the concrete pipes that carried runoff. Each velocity wafer was centered to the width of the water flowing in the pipe. Once it is correctly

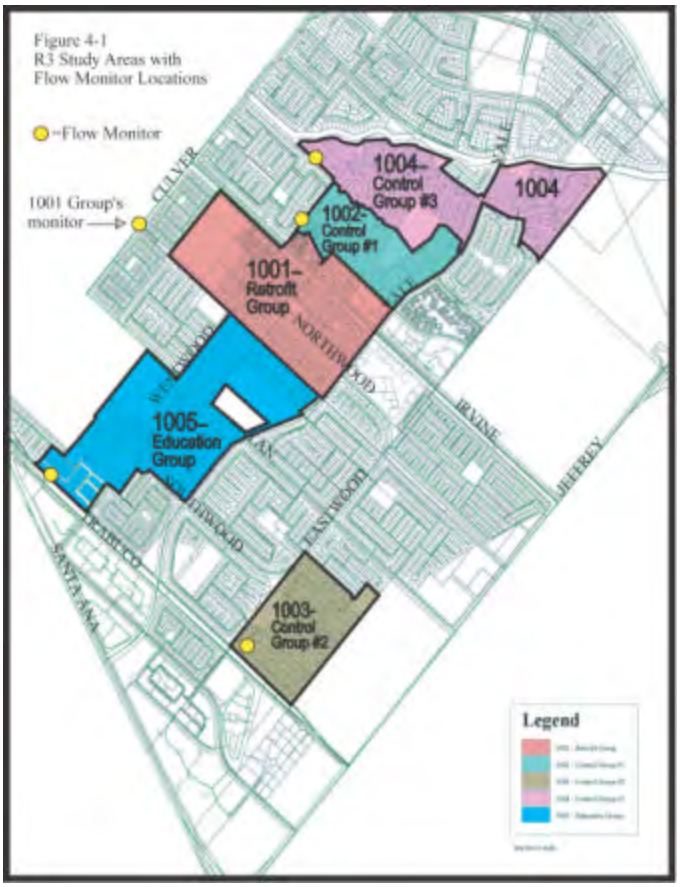
positioned, the wafer measures the velocity of the water by measuring the speed of the particles in the water. This information is then transmitted via cable to the Sigma 950.

The second variable in the water flow equation, the area of the water, also referred to as the cross sectional area, was obtained by multiplying the depth of the water by its width. This calculation is based on geometry, the diameter of the pipe, and the depth of the water. Since the geometry of the area is the arc of a circular pipe of known diameter, the Sigma 950 was able to internally calculate this measurement using data from a sonic sensor. The sonic sensor measures the depth of the water by hanging above the water surface and sending out a sonic pulse that reflects off the surface of the water.

The Sigma 950 contains a central processing unit that recorded the time, water depth, water velocity, and flow every five minutes.

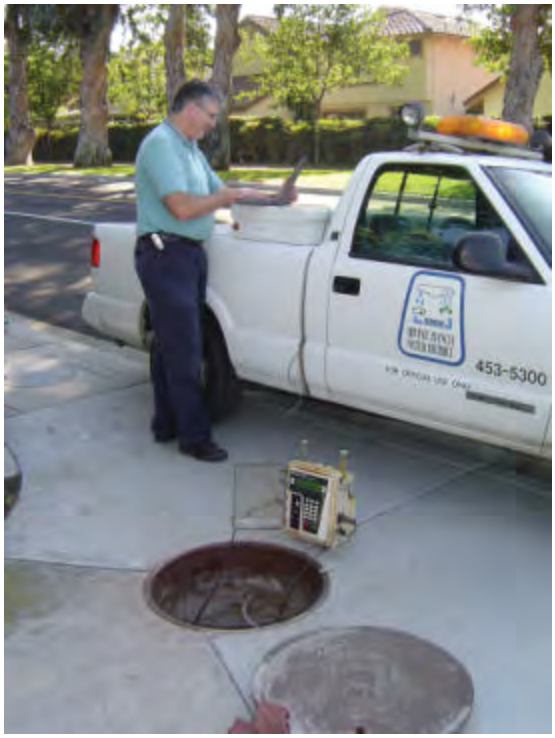
Maintaining the flow monitors in good working order required an R3 Study field staff member to visit each of the five data collection locations twice per week. At each site, staff would open the manhole and lift out the monitor. Then, the storm drainpipe would be inspected for any obstruction or interference with the flow or with the devices (velocity wafer and sonic sensor) used to measure flow.

Figure 4-1
Flow Monitor Locations



Next, staff would measure the depth of the water with a tape measure and recalibrate the flow monitor to this measurement. The velocity wafers could not be calibrated. They were adjusted for accuracy, however, during low flow and low velocity periods. To accomplish this, staff would observe an object on the surface of the water. As the object moved with the flow, staff would estimate its speed as feet per second (fps). This speed was compared to the value simultaneously registered on the flow monitor. If the observed velocity was much slower than that recorded by the monitor, staff would disconnect the velocity wafer. This action would usually reset the velocity wafer. If the problem persisted, the wafer would be replaced.

Figure 4-2:
Downloading Data from Sigma 950 Flow Monitor to Laptop



4.2.2 Ranking Collected Data

Twice per week during each site visit, data was downloaded from the flow monitor to a laptop computer. This process is depicted on the adjacent figure (Figure 4-2). When staff returned to IRWD's operations building, the data was downloaded to the District's central computer. Here the data was transferred from a text file to an excel file. At this point, staff would rank the data for each download of each site. After observing the site, recalibrating the flow monitor, and reviewing the data graphs, staff would add ranking to each site's data. The following process assigned these ranks: a) if staff observed nothing unusual and had no reason to suspect any data collection problems, the flow, depth and velocity received a ranking of "zero," b) if one of these factors was suspect or the data graph had an unusual jump in value, the rank indicator was a "one," c) if staff noted a problem which may have affected the data and changed its values beyond the tolerances of the equipment, the data was ranked with a "two."

4.2.2 Data Methods

Robust regressions techniques were used to detect which observations were potentially data quality errors. This methodology determines the relative level of inconsistency of each observation with a given model form. A measure is constructed to depict the level of inconsistency between zero and one; this measure is then used as a weight in subsequent regressions. Less consistent observations are down-weighted. Other model-based outlier diagnostics (Cook's distance, DFBETA statistics, and residual diagnostics) were also employed to screen the data for any egregious data quality issues

After screening for the known data quality problems, using the "rank" indicator, all raw meter reads were first converted to average hourly values. These were then aggregated by date to convert to daily runoff, available in both mean hourly flow and total daily volume.

Precipitation taken from the Irvine weather station was matched to the daily data and used to separate wet from dry days. It should be noted that wet weather flows were monitored and evaluated in a parallel study that assessed pesticide contributors from residential land use during dry and wet weather (SCCWRP, 2003). However, the focus of the R3 study was runoff reduction during the peak irrigation season (i.e., dry weather).

Wet weather storm flow can be a more complicated phenomenon to predict, as it depends on the timing and magnitude of the rainfall event, the moisture deficit of soils, and other factors. The relative lack of large storm events in the post-intervention period precluded examination of these more complicated forces and the effect that the landscape interventions might have on wet day runoff.

Area-standardized measures of site runoff were also created for dry/wet days, where total daily volume was divided by the estimated permeable/total area. Estimates of area for the study sites were derived from the IRWD geographic information system (GIS) system. The GIS system was queried to produce estimates of the number of lots and total area for the different land use classifications (single family residence, condo, HOA, school, landscape, street, and unknown). The GIS system also provided an estimate of the number of buildings, and building area. The area taken up by buildings is treated as impermeable. The remaining area was separated into permeable and impermeable area using a land use classification- specific assumption of impermeability. Table 4-2 provides the raw data used to construct the estimated site area. (Due to lack of usable flow measures, Sites 1002 and 1003 are not separately reported.) Table 4-3 aggregates the data by site.

Table 4-2
Estimated Area of Study Sites by Land Use

R3 GROUP	#Lots	Classification	Total Area in square feet. (sq. ft.)	Building Area in sq. ft.	Assumed Impermeable Coefficient %	Estimated Impermeable Area in sq. ft.	Estimated Permeable Area in sq. ft.
1001	64	Unmetered	499885		0	0	499885
1001	565	SFR	2911227	976574	0.5	1943900	967326
1001	109	Condo	447096	189721	0.9	421358	25738
1001	4	HOA	255208		0.75	191406	63802
1001	2	School	198676		0.9	178808	19868
1001	10	Landscape	845529		0	0	845529
1001	97	Street	2163105		1	2163104	0
1004	61	Unmetered	307556		0.0	0	307556
1004	417	SFR	2081636	719485	0.5	1400560	681076
1004	1	HOA	40165		0.8	30123	10041
1004	1	School	348739		0.9	313865	34874
1004	2	Landscape	1136		0.0	0	1136
1004	42	Street	1089143		1.0	1089143	0
1005	8	Unmetered	118370		0.0	0	118370
1005	559	SFR	2957363	1033197	0.5	1995280	962083
1005	1	HOA	66421		0.8	49816	16605
1005	1	School	264236		0.9	237812	26424
1005	1	School	261089		0.9	234980	26109
1005	2	Landscape	773206		0.0	0	773206
1005	45	Street	1736098		1.0	1736098	0

Table 4-3
Estimated Area of Study Sites

R3 Group	Estimated Impermeable Area sq.ft.	acres	Estimated Permeable Area sq. ft.	acres	Total Area sq. ft.	acres
1001	4,898,578	112.5	2,422,148	55.6	7,320,724	168.1
1004	2,833,691	65.1	1,034,683	23.8	3,868,374	88.9
1005	4,253,986	97.7	1,194,553	44.1	6,176,783	141.8

4.3 Evaluation Results

Table 4-4 presents the robust regression estimation results for the model of dry day runoff in R3 study Site 1001 (containing some customers receiving the ET controller/education intervention), Site 1004 (whose customers received no treatment), and Site 1005 (containing some customers receiving the education-only treatment). This sample represents metered dry day runoff, standardized by estimated site permeable area, between February 2001 and June 2002.

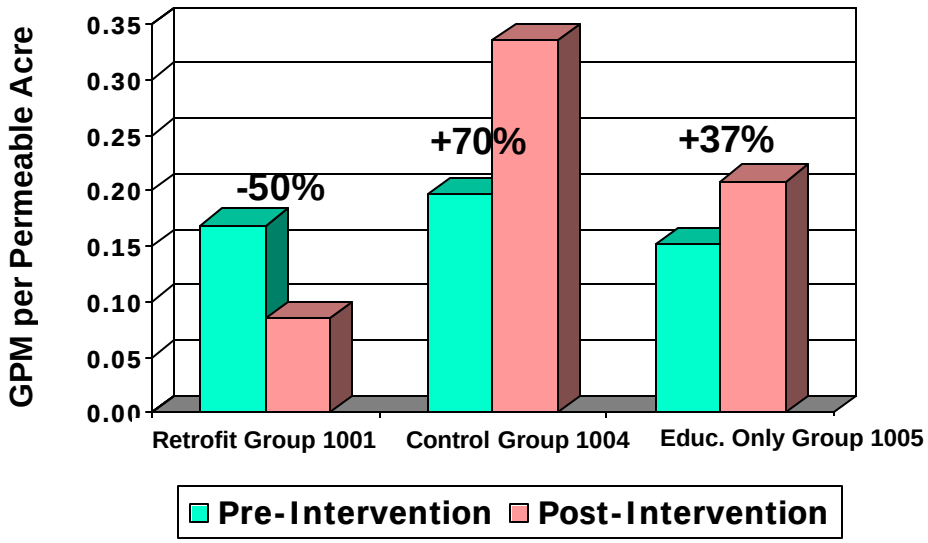
The changes in runoff estimated during the R3 study are summarized on Figure 4-3 and described in more detail below. Additional descriptions of the regression models are presented in Appendices D1 and D2.

Table 4-4
Robust Regression Estimates of Mean Dry Day Runoff

Dependent Variable: Dry Day Runoff Height (in hundredths inches per unit area)
(Height=Runoff Volume/Site Area)

Variable	Coefficient	Std. Error	t	Prob.>|t|
Mean Runoff: Feb-May 2001				
1. Intercept (1001 mean runoff)	0.898563	0.120838	7.44	0
2. Difference of Site1004 in pre-period	0.143721	0.157245	0.91	0.361
3. Difference of Site1005 in pre-period	-0.092260	0.151479	-0.61	0.543
Change in Runoff: June 2001-June2002				
4. Change of Site 1001 in post-period	-0.445390	0.134540	-3.31	0.001
5. Change of Site 1004 in post period	0.878089	0.113737	7.72	0
6. Change of Site 1005 in post period	0.202553	0.106973	1.89	0.059
Number of observations	950			
F (5, 944)	74.92			
Prob. > F	0			
Quasi-R-Squared	0.35			

Figure 4-3
R3 Study's Changes in Runoff (Within Sites)



4.3.1 Pre-intervention Period

The constant term (Variable 1) in Table 4-4 defines the intercept for the model equation and can be interpreted as the mean daily runoff in Site 1001—about 0.898 hundredths of an inch per permeable acre (equal to 0.00898 inches). Variables 2 and 3, the indicators for Sites 1004 and 1005 in the pre-period, suggest that estimated difference in mean runoff is not statistically distinguishable from zero (standard error > coefficient). The estimated pre-period site mean runoff for these sites can also be inferred from these coefficients:

$$m_{4,\mathrm{Pre}} \equiv m_1 + d_{4,\mathrm{Pre}} \approx 0.899 + 0.144 = 1.042 \text{ hundredths of an inch and}$$

$$m_{5,\mathrm{Pre}} \equiv m_1 + d_{5,\mathrm{Pre}} \approx 0.899 - 0.092 = 0.806 \text{ (See Table 4-5.)}$$

Table 4-5
Study Site Comparisons of Pre Period Flow vs. Post Period Flow

	1001 Pre	1001 Post	1004 Pre	1004 Post	1005 Pre	1005 Post
Permeable Square feet	2,422,148	2,422,148	1,034,683	1,034,683	1,922,797	1,922,797
Permeable Acres (Table 4-3)	55.6	55.6	23.8	23.8	44.1	44.1
Coefficient from Table 4-4 (Hundredths of in/day/perm acre)	0.899	-0.445	0.144	0.878	-0.092	0.203

Table 4-5 (continued)

	1001 Pre	1001 Post	1004 Pre	1004 Post	1005 Pre	1005 Post
Hundredths of in/day/perm acre flow	0.899	0.453	1.042	1.777	0.806	1.101
in/day/perm acre flow	0.0090	0.0045	0.0104	0.0178	0.0081	0.0110
feet/day	0.04164	0.02063	0.0081	0.0178	0.0081	0.0110
Raw GPM	9.42	4.75	4.67	7.96	6.71	9.71
GPM/perm acre	0.169	0.085	0.197	0.335	0.152	0.208
Percent change in flow (Pre to Post)	**-50%**		**+70%**		**+37%**	

4.3.2 Post-intervention Period

The formal test for the change in runoff in the post-intervention period (June 2001-June 2002) can be found in the following three terms: variables 4, 5 and 6 as shown in Table 4-4. The estimated change in dry day runoff for Site 1001 (Variable 4 in Table 4-4), is -0.44 hundredths of an inch. In relative terms, this works out to approximately a 50 percent reduction. The implied mean post-intervention dry day runoff for Site 1001, is 0.89-0.44˜0.45 hundredths of an inch. This reduction in runoff is statistically distinguishable from zero at classical levels of confidence.

It should be noted that the pre- and post- periods are not comparable. The post-intervention period, June 2001 to June 2002, includes 13 months, but would be fairly close to an annual average. The period of time covered by the pre-intervention period for all sites, February to May 2001, includes at most four months. For Site 1001, the pre-intervention period only includes the months of April and May in 2001 because the flow meter produced enough invalid reads in February and March to necessitate its relocation to a new site in April. Since these are not the highest months for urban runoff, it would be reasonable to expect runoff in the post-intervention period to increase. For this reason, the reduction of 50 percent from the pre-intervention period would be a lower bound on the true estimate of runoff reduction. An examination of the other two valid sites would provide insight into how much runoff would have increased in the post-intervention period.

The estimated change in dry day runoff for Site 1004 (Variable 5 in Table 4-4) is +0.88 hundredths of an inch. This increase in runoff is statistically distinguishable from zero at classical levels of confidence. The implied mean post-intervention dry day runoff for Site 1004, is (0.89+0.88˜) 1.77 hundredths of an inch. In relative terms, this works out to a fairly large (1-{1.77-1.03}/1.03˜) 70 percent increase in the post-intervention period.

The estimated change in dry day runoff for Site 1005 (Variable 6 in Table 4-4) is +0.20 hundredths of an inch. This increase in runoff is statistically distinguishable from zero at close to classical levels of confidence. The implied mean post-intervention dry day runoff for Site 1005, is (0.89+0.20˜) 1.09 hundredths of an inch. In relative terms, this works out to a more modest (1-{1.09-0.80}/0.80=) 37 percent increase in the post-intervention period.

4.3.3 Comparison Across Sites

The last and potentially most vulnerable inference compares the time change in runoff across sites. If Site 1001 had experienced the same change in runoff as its neighbor sites 1005 or 1004, then dry day runoff would have increased from 37 to 70 percent in the post-intervention period. In absolute terms, this would imply a prediction of non-intervention runoff of 1.24 to 1.53 hundredths of inches per acre. Compared to the realized 0.45 hundredths of inches of runoff in the post-intervention period, this reduction would translate to reduction in runoff from 64 to 71 percent.

A similar counterfactual exercise for Site 1005 would require assuming that Site 1004 is a good matched control site. Then dry weather runoff in Site 1005 would have increased by 72 percent in the post-intervention period, a level of 1.38 hundredths of inches per acre. Compared to the realized 1.09 hundredths of inches of runoff in the post-intervention period, the reduction would translate into a modest but non-ignorable 21 percent decrease in runoff.

Both of these exercises require use of Site 1004 as a control site. While the unadjusted flow measures for Sites 1001 and 1005 are fairly close in the pre-intervention period, the same cannot be said for the flow measures from Site 1004. There are uncertainties as to which of the three estimates of reduction runoff for Site 1001 should be used. The direct within-site estimate of a 50 percent runoff reduction is likely biased low; runoff in the post-intervention period should have increased. The estimate of 64 percent, based on Site 1005 as a control site, may also be biased on the low side. Though Site 1005 did have pre-intervention runoff that reasonably matched Site 1001, Site 1005 also contained more than 200 homes that participated in the education-only intervention with monthly follow-up. These homes did have quantified water savings, some of which is likely to have resulted from reduced runoff. Site 1004 did not receive any treatment, but did have measurement issues. Thus, the estimate of a 71 percent reduction, using Site 1004 as a control site, has an unknown bias.

The bigger inferential uncertainties lie in how these conservation interventions will work as they are scaled in a larger program or in how implementations of these programs would work in other areas.

4.4 Conclusions

The difficulties encountered in calibrating custom configured equipment to measure dry season / low flow runoff limited the amount of pre-intervention data. This in turn precluded simple before and after comparisons of mean runoff flow. Nonetheless, a sufficient length of baseline data was collected to allow quantitative estimates of runoff reduction. If additional flow data can be collected, additional analysis would be possible: 1) the runoff reduction under wet conditions

could be examined, and 2) an estimate of the seasonal shape of runoff could be included in the models to improve the precision of the estimated runoff reduction.

Because the runoff measurement is not at a customer level, it was not possible to distinguish the relative contribution of different customers to urban runoff reduction. Thus, for Site 1001, it was not possible to determine how much the single-family ET controller/education contributed relative to the ET controller intervention with medium-size landscape customers.

However, because the medium-size landscapes accounted for an estimated 70 percent of the area "treated" with ET controllers (Table 2-2), on strictly a proportional basis it is likely that the medium-size landscapes contributed to the majority of the observed runoff reduction for Site 1001.

Chapter 5 Water Quality and Watershed Implications

5.1 Overview

This chapter describes the water quality evaluations conducted as a part of the R3 Study and outlines the potential implications of these evaluations on the San Diego Creek Watershed. Specific information includes:

- A discussion of two approaches to the evaluation of water quality
- A summary of the study methods relating to water quality
- Development of "before and after" assessments of water quality to evaluate the effectiveness of ET technology and public education
- Detailed discussions of the evaluation approaches and findings based on these approaches
- A discussion of the implications of the findings for water quality in the San Diego Creek Watershed, focusing on TMDL constituents

More detailed information is provided in Appendices E1 and E2.

5.2 Introduction

Two independent reviews of water quality measurements were conducted as a part of this study. The initial review was conducted by SCCWRP as a part of its participation in the R3 Study and is included in its entirety as Appendix E1. This review used parametric statistical techniques (t-test; ANOVA), which provide a good descriptive review of the study data, but are generally considered to have less statistical power for detecting differences in data than other statistical tests. In general, because of the variability of the data and limitations in sample quantities, this review concluded that there was virtually no difference in either the concentration or "flux" (concentration times flow) of pollutants over time or between study treatments.

A subsequent statistical overview by Geosyntec Consultants was commissioned by IRWD to review alternative and possibly more "robust" data analysis techniques that might identify differences in study data not uncovered during the initial review. This work, which included the review of only a portion of the data set, focused on additional descriptive techniques (time series plots; box plots; probability distributions) and the use of non-parametric statistical techniques (rank-sum test; K-W). For some of the parameters reviewed, these techniques suggest that differences in measured water quality did occur across time and between study treatments. The entire Geosyntec report is provided in Appendix E2.

As noted above, both of the completed statistical reviews of the study data are included in the Appendices of this report. The remainder of this chapter of the report discusses the key findings of each review.

5.3 SCCWRP Water Quality Review

This section describes the SCCWRP evaluation approach, sampling and laboratory analysis, data analysis, and interpretations of the results. Watershed implications are also discussed.

5.3.1 Evaluation Approach

A before-after, control-impact (BACI) design was used to evaluate the effectiveness of both the sprinkler technology and public education. Each neighborhood was sampled every other week between December 2000 and June 2001. In June 2001, homes in one of the neighborhoods were outfitted with the ET controllers. Since homeowners with the retrofitted ET controllers were simultaneously being educated, a well-defined public education campaign was also begun with these homeowners. To ascertain the difference between education and ET technology, homeowners in a second neighborhood were targeted with an identical public education campaign, but without effect of the ET retrofit technology. There was no education or technology intervention in the remaining three neighborhoods, which served as control neighborhoods to document the effect of no treatment. Sampling at the five neighborhoods continued every other week from June 2001 to June 2002.

5.3.2 Sampling and Laboratory Analysis

Each neighborhood was hydrologically self-contained and drained to a single underground pipe. At each of these five locations, samples were collected for flow and water quality. Stage (water depth) and velocity were recorded at 5-minute intervals using an ultrasonic height sensor mounted at the pipe invert and a velocity sensor mounted on the floor of the pipe. Flow was calculated as the product of velocity and wetted cross-sectional area as defined by the stage and pipe circumference. Despite the relatively continuous measurement of flow, many of the flow measurements were excluded due to faulty readings. Synoptic flow and water quality measurements were only available for two sites over the course of the entire study (i.e. before and after intervention), including the ET controller + education and education only sites. Flow measurements at the time of water quality sampling for the three control sites were considered faulty and discarded.

Grab samples for water quality were collected just downstream of the flow sensors in the early morning using peristaltic pumps and pre-cleaned Teflon tubing. Samples were placed in individual pre-cleaned jars, placed on ice, and transported to the laboratory within one hour. Each sample was analyzed for 19 target analytes, five microbiological parameters, and four toxicity endpoints (Table 5-1). Target analytes included trace metals, nutrients, and organophosphorus (OP) pesticides. Microbiological parameters included fecal indicator bacteria and bacteriophage. Toxicity was evaluated using two marine species, the purple sea urchin *Strongylocentrotus purpuratus* and the mysid *Americamysis bahia*. All of the laboratory methodologies followed standard protocols developed by the USEPA or Standard Methods.

5.3.3 Data Analysis

Data analysis consisted of five steps: 1) comparison of water quality among the five neighborhoods prior to intervention; 2) comparison of water quality concentrations over time by neighborhood; 3) comparison of water quality concentrations before and after intervention by

treatment type; 4) comparison of pollutant flux before and after intervention by treatment type; and 5) correlation of toxicity measures with potential toxicants in dry weather runoff.

Comparison of water quality concentrations among the five neighborhoods prior to intervention was conducted to assess if there were inherent differences among treatment sites for each

Table 5-1
Reporting Level and Method for Target Parameters

	Reporting Level	Method
Metals (ug/L)		
Antimony	0.2	EPA 200.8
Arsenic	1.5	EPA 200.8
Barium	0.2	EPA 200.8
Cadmium	0.2	EPA 200.8
Chromium	0.3	EPA 200.8
Cobalt	0.1	EPA 200.8
Copper	1.5	EPA 200.8
Lead	0.3	EPA 200.8
Nickel	0.2	EPA 200.8
Selenium	5.0	EPA 200.8
Silver	0.4	EPA 200.8
Zinc	5.0	EPA 200.8
Nutrients (mg/L)		
Ammonia as N	5.0	EPA 350.1
Nitrate/Nitrite as N	5.0	EPA 353.2
Total Kjeldahl Nitrogen	10.0	EPA 351.2
Ortho-Phosphate as P	0.5	EPA 365.1
Total Phosphorus	1.0	EPA 365.4
OP Pesticides (ng/L)		
Chlorpyrifos	20.0	IonTrap GCMS
Diazinon	20.0	IonTrap GCMS
Microbiology		
Enterococcus (MPN/100 mL)	2	SM9230B
Fecal Coliform (MPN/100 mL)	2	SM9221B
Total Coliform (MPN/100 mL)	2	SM9221B
MS2 Phage (PFU/100 mL)	2	EPA 1602
Somatic Phage (PFU/100 mL)	2	EPA 1602
Toxicity (% effluent)		
Sea Urching Fertilization EC50	NA	EPA 1995
Sea Urching Fertilization NOEC	NA	EPA 1995
Mysid EC50	NA	EPA 1993
Mysid NOEC	NA	EPA 1993

Note: ug/L = micrograms per liter; MPN/100 mL=most probable number per 100 milliliters; PFU/100mL=plaque forming units per 100 milliliters; mg/L=milligrams per liter; ng/L=nanograms per liter.

constituent. This analysis was conducted using ANOVA using Tukey's post hoc test for identifying the significantly different neighborhoods. All data was tested for normality and homogeneous variance prior to testing. Only the microbiological data was determined to be non-normally distributed, so these results were log transformed prior to data analysis.

Comparison of water quality concentrations over time was accomplished by creating temporal plots of monthly mean concentration. Comparisons of water quality concentration before and after intervention by treatment type were accomplished using a standard t-test of the mean concentration before versus mean concentration after intervention. The mean concentrations for ET controller + education, education only, and ET controller + education – education only for each sampling event were normalized by the grand mean of the control sites for the same sampling event.

Pollutant flux estimates were calculated by the product of the concentration and volume at the time of sampling and then normalized to the area of the sampled neighborhood. Pollutant flux before and after treatment was compared somewhat differently since the lack of flow data at the control sites did not permit an estimate of flux for these neighborhoods. Mean pollutant flux before and after intervention was compared using standard t-tests at the ET controller + education and education only neighborhoods without normalization to control values.

Correlation of toxicity with toxicant concentrations was accomplished using a Pearson product moment correlation. These correlations are inferential only and do not presume resulting correlations automatically identify the responsible toxicants. In order to help identify potential causative toxic agents, concentrations of the correlated constituents were compared to concentrations known to induce toxicity in the respective test organisms.

5.3.4 Evaluation Results

There were significant differences in water quality among sites prior to intervention (Appendix E1, Table WQ3). Site 1004, the control site, had the greatest mean concentrations for 15 of the 24 constituents evaluated prior to the ET controller intervention. In particular, all of the mean nutrient concentrations were greater at Site 1004 than the other sites. On the other hand, Sites 1001 and 1002 generally had the lowest average concentrations prior to the ET controller intervention. Cumulatively, these sites had the lowest mean concentrations for 17 of the 24 constituents evaluated. Site 1002 also had the least toxicity, on average, of all five sites. Finally, Site 1003 had an intermediate status. Mean concentrations of enterococcus and fecal coliforms at this site were greater than any other site (fecal coliforms significantly greater than Sites 1001 and 1002), but the mean concentrations of five trace metals (chromium, copper, cobalt, nickel, selenium) were lowest at this site.

Water quality concentrations and toxicity were highly variable over time during the study period. Temporal plots of concentrations and toxicity for each site demonstrated that there was no seasonal trend and no overall trend with time. There were, however, occasional spikes in concentrations for many constituents that appeared to fall into one of two categories. The first

category was recurring spikes in concentration that were unpredictable in timing and location. The second category of concentration spike was single or infrequent peaks. Occasionally these spikes would occur across multiple sites, without commensurate changes in concentration at the treatment sites (1001 or 1005). More often, infrequent spikes were isolated to a single site. For example, concentrations of chlorpyrifos climbed to over 10,000 ng/L in July 2001, but averaged near 50 ng/L the remainder of the year at site 1005. Similarly, concentrations of ammonia and total phosphorus spiked 10 and 25-fold prior to June 2001 at the control site (1004) with less variability and overall lower concentrations the remainder of the study.

There were few significant differences that resulted from the intervention of education, ET controller + education, or ET controller + education – education only, relative to control sites (Table 5-2). Only six of the 24 constituents evaluated showed a significant difference between pre and post-intervention concentrations after normalizing to mean control values. These significant differences were a net increase in concentrations of ammonia, nitrate/nitrite, total phosphorus, chlorpyrifos, diazinon, and fecal coliforms. These statistical analyses were the result of one of two circumstances. In the first circumstance, there were individual large spikes in concentration at treatment sites, but not at control sites following intervention. Therefore, the net difference in concentrations between controls and treatments increased following the intervention. In these cases, removal of the outlier samples resulted in no significant difference among treatment effects relative to controls before intervention compared to after intervention. In the second circumstance, there were large spikes in concentrations at control site(s) prior to the intervention that later subsided, while treatment site concentrations and variability remained steady. Therefore, the difference between treatments and controls changed following interventions, although it was not a result of the education or technology.

Although there were no significant differences in pollutant flux as a result of the intervention, significant differences were noted in pollutant flux among sites prior to intervention. Site 1001, the ET controller + education site, had the greatest mean flux for 22 of the 24 constituents evaluated prior to the ET controller intervention. The mean flux for 20 of these 22 constituents was significantly greater at Site 1001 than the mean flux at Site 1005 (t-test, $p<0.05$). Site 1005 had greater mean fluxes only for MS2 phage and ammonia. The differences among the fluxes prior to (and after) intervention were the result of two factors: greater flow and, at times, greater concentrations at Site 1001 compared to Site 1005. Mean dry weather flow at the time of water quality sampling was nearly three times greater at Site 1001 than Site 1005.

Toxicity was inconsistently found at all five of the sampling sites, and there was no change in toxicity as a result of the intervention (Table 5-3). The two species tested did not respond similarly either among sites, among treatments, or over time. Correlation of toxicity with constituent concentrations yielded few significant relationships for either species (Table 5-3). Mysid toxicity was correlated with diazinon and several trace metals, but the strongest relationship was with diazinon concentration. Moreover, the concentrations of diazinon were well above the levels known to cause adverse effects in mysid, while trace metals were not. Sea urchin fertilization toxicity was only correlated with concentrations of zinc. The concentrations of zinc were well above the level known to induce adverse effects in this species.

Table 5-2
Significance of ANOVA Results for the Effect of ET Controller + Education, Education Alone, and the Difference Between ET Controller + Education and Education Alone Relative to Control Concentrations. (No data indicates p > 0.05)

	Effect of ET Controller + Education	Effect of Education Alone	Difference Between ET Controller + Education and Education Alone
Metals			
Antimony			
Arsenic			
Barium			
Cadmium			
Chromium			
Cobalt			
Copper			
Lead			
Nickel			
Selenium			
Silver			
Zinc			
Nutrients			
Ammonia as N	0.03	0.02	
Nitrate/Nitrite as N	0.02		
Total Kjeldahl Nitrogen			
Ortho-Phosphate as P			
Total Phosphorus		0.03	
OP Pesticides			
Chlorpyrifos	<0.01	<0.01	<0.01
Diazinon		<0.01	
Microbiology			
Enterococcus			
Fecal Coliform	0.04		
Total Coliform			
MS2 Phage			
Somatic Phage			
Toxicity			
Fertilization EC50			
Fertilization NOEC			
Mysid EC50			
Mysid NOEC			

Table 5-3
Correlation Coefficients (and p value) of Constituent Concentrations with Toxicity Endpoints (No Observed Effect Concentration, NOEC and Median Effect Concentration, EC50) in Dry Weather Discharges from Residential Neighborhoods in Orange County, CA. (No data indicates p > 0.05)

	Sea Urchin Fertilization NOEC	Mysid Survival NOEC	Sea Urchin Fertilization EC50	Mysid Survival EC50
Antimony		-0.273 (0.009)		
Arsenic		-0.3396 (0.001)		
Barium				
Cadmium				
Chromium		-0.244 (0.021)		-0.219 (0.044)
Cobalt		-0.330 (0.002)		-0.279 (0.010)
Copper				
Lead		-0.215 (0.042)		
Nickel				
Silver		-0.260 (0.013)		-0.229 (0.035)
Zinc	-0.277 (0.005)		-0.274 (0.006)	
Chlorpyrifos				
Diazinon		-0.426 (0.001)		-0.468 (0.001)
Ammonia				

5.3.5 Interpretation of Results

The evaluation was unable to find large, significant reductions in concentration or pollutant flux as a result of education and/or ET controller retrofit technology. This may indicate that the technology and/or education are inefficient for improvements in water quality. Equally as important, however, was the absence of meaningful increases in concentrations. Of the small number of concentrations that showed significant increases, most could be explained by highly variable spikes in concentrations reminiscent of isolated entries to the storm drain system, as opposed to ongoing chronic inputs or the effects of best management practices evaluated in this study.

If significant changes did occur, the evaluation design may not have detected these changes due to two factors. First, the variability in concentrations within and between sites is naturally high and the evaluation simply collected too few samples. After taking into account the variability and relative differences in mean concentrations, zinc was used as an example constituent to determine what sample sizes would be required to detect meaningful differences. Assuming that the sampling yielded the true mean and variance structure that actually existed at the five sites, power analysis indicated that a minimum sample size of no less than five-fold would have been required to detect the differences observed in zinc concentrations during this study.

The second factor that could have hindered the ability to detect meaningful differences in water quality is that the technology and education treatments were applied at the spatial scale of individual homes, while the evaluation design sampled at the neighborhood scale. This problem was exacerbated because only a fraction (approximately one-third) of the homes within the

neighborhoods sampled had the technological or educational treatments. Therefore, the treatments were effectively diluted, decreasing the ability to detect differences in water quality.

5.3.6 Watershed Implications

It appears that residential dry weather flows measured in the R3 Study may contribute significant proportions of some constituents to overall watershed discharges. The study sites were located within the San Diego Creek watershed, the largest tributary to Newport Bay. The Orange County Public Facilities and Resources Department (OCPFRD) publishes monitoring data on San Diego Creek to provide environmental managers the information they need to properly manage the Bay (OCPFRD 2002). The dry weather monitoring data was compiled at the mouth of San Diego Creek from OCPFRD during 2001-2002 and compared the concentrations to our results from residential neighborhoods (Table 5-4). Mean concentrations of chlorpyrifos, diazinon, copper and zinc were much higher in upstream residential neighborhoods than concentrations measured at the mouth of San Diego Creek. These residential dry weather contributions were amplified by the fact that the San Diego Creek watershed is primarily composed of residential land uses. In contrast, concentrations of selenium, arsenic, and total phosphorus in the residential dry weather discharges were much lower than the cumulative dry weather discharges from San Diego Creek, indicating that residential areas may not be the primary source of these constituents.

Table 5-4
Comparison of Mean Concentrations (95% Confidence Intervals) in Residential Dry Weather Discharges from this Study Compared to Concentrations in Dry Weather Discharges from San Diego Creek at Campus Drive During 2001-2002. (Data from OCPFRD)

	San Diego Creek	Residential
Parameter	**Mean (95% CI)**	**Mean (95% CI)**
Nitrate	5.16 (0.72)	4.76 (1.96)
Phosphate	1.98 (0.07)	1.16 (0.20)
Diazinon	0.13 (0.07)	1.52 (0.52)
Chlorpyrifos	0.05 (0.01)	0.35 (0.44)
Copper	11.59 (2.83)	23.59 (5.65)
Arsenic	6.58 (0.40)	2.68 (0.26)
Selenium	21.22 (2.65)	2.46 (0.03)
Zinc	22.08 (2.75)	60.09 (8.26)

5.4 Geosyntec Water Quality Review

This section presents examples of alternative approaches to data analysis, data analysis methods, example results, and watershed implications.

5.4.1 Examples of Alternative Approaches to Data Analysis

These example analyses focus on TMDL constituents: nutrients (total nitrogen [TN] and total phosphorus [TP]), metals (copper, lead, zinc, cadmium), pesticides, and pathogens (fecal coliform). The analyses also focus on dry weather flows, as reduction of these flows was a major objective of the R3 Study.

5.4.2 Data Analysis Methods

Exploratory Data Analysis
Visual inspection of data and exploration of factors that could potentially influence data (e.g. seasonal trends, rain events)

1. Divide data into pre and post- intervention groups.
2. Construct time series plots to visually inspect data and visually examine for seasonal trends. Overlay storm event markers to identify any relation to rainfall volume or antecedent dry period (ADP).
3. Investigate normality or log normality of data sets. Select appropriate statistical tests.
4. Construct probability plots for pre-intervention and post-intervention periods.
5. Prepare quantile plots.
6. Prepare side-by-side box plots.
7. Calculate descriptive statistics

Hypothesis Testing
Test data for skewness, normality, and statistically significant differences. Skewness and normality tests are only needed if parametric approaches are conducted. Use of non-parametric approaches is recommended for consistency because normality will not be met in all cases. Nonetheless, examples are provided to show that several of the data sets do not come from a normal distribution.

1. Skewness hypothesis test for symmetry.
2. Shipiro-Wilkes normality test.
3. Mann-Whitney rank-sum test.
4. For the data sets that have greater than 50 percent censored data (i.e., data only known to be less than the detection limit), hypothesis tests for differences in proportions.

5.4.3 Example Results

The first step in the data analysis was to construct individual time-series plots for each site to identify seasonal periodicity, step-trends, and monotonic trends. Plotting each site individually reveals more information than plotting all sites together. Also, by overlaying storm events, the role of rainfall volumes and the ADP may be more apparent and may indicate whether additional analyses are warranted (e.g., correlating ADP with concentration). Figure 5-1 is an example

time-series plot with storm event markers overlain for TP for Site 1001. As shown on the figure, the pre-intervention period had much more rainfall, which likely added to the variability in runoff concentrations and fluxes. However, it is apparent that the winter and spring concentrations appear to be lower and less variable during the post-intervention period. The irrigation controllers may have had an effect on the runoff concentrations by reducing the amount of irrigation during moister weather conditions (i.e., high soil moisture). A similar effect for TN is shown on Figure 5-2. Additional time-series plots are provided in Appendix E2.

Figure 5-1
Example Time-series Plot of Total Phosphorus with Storm Event Markers.

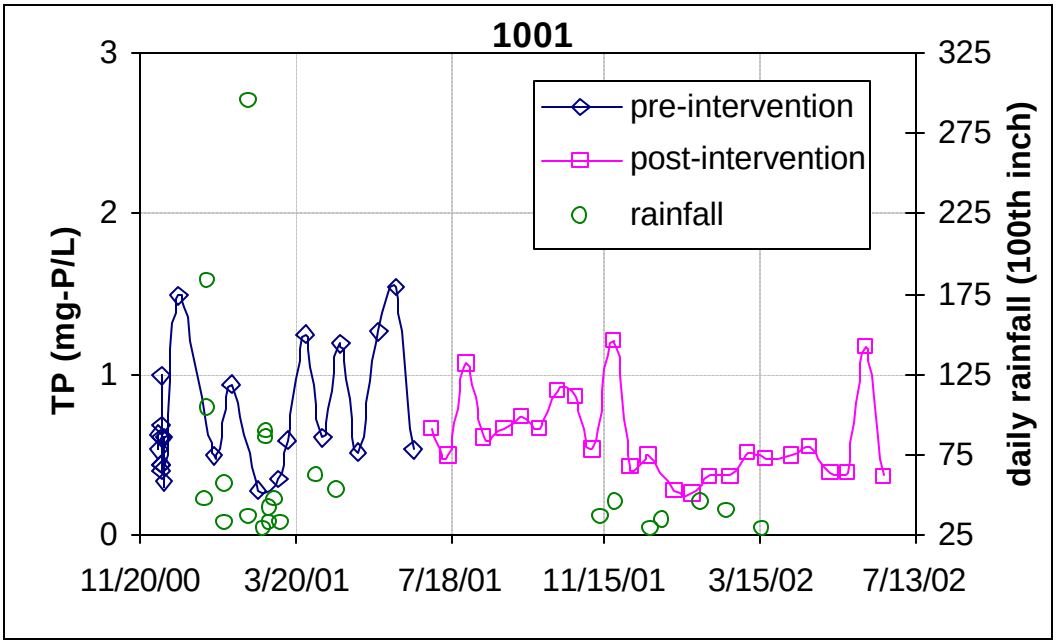
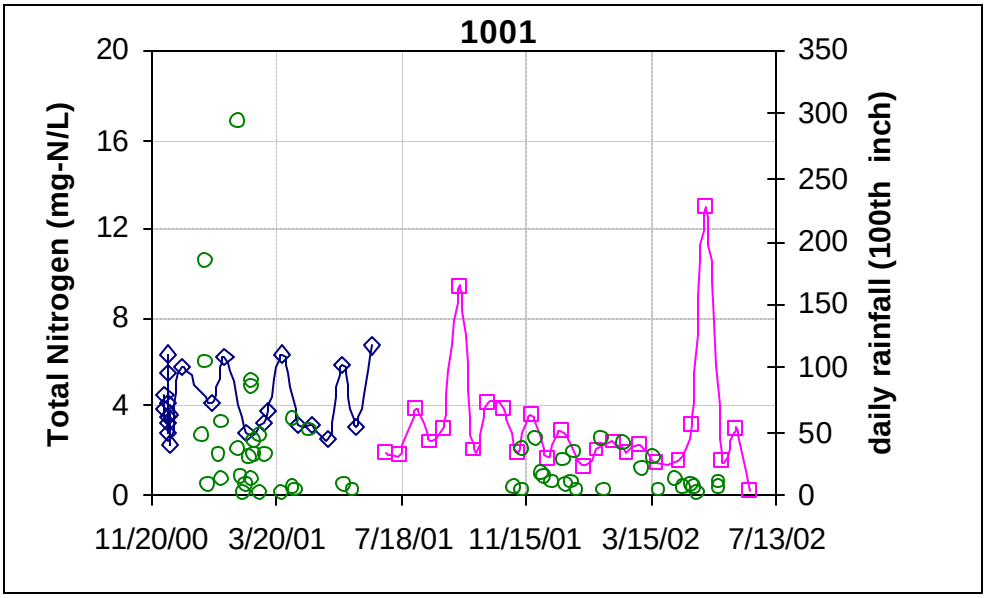


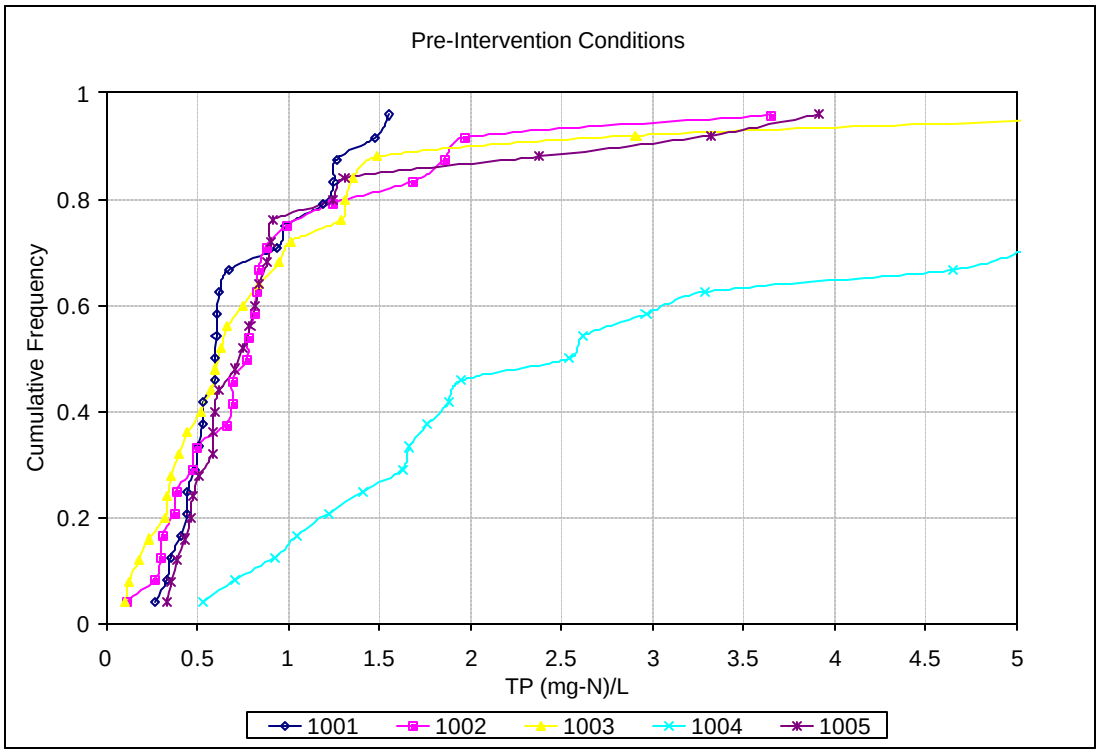
Figure 5-2
Example Time-series Plot of Total Nitrogen with Storm Event Markers.



5.4.3.1 Comparison of Water Quality Data Prior to Intervention

To visually investigate whether the test sites have similar runoff characteristics, probability plots were constructed. Figure 5-3 is an example of a probability plot for TP for all of the test sites. The figure shows that all of the sites have a similar distribution except for Site 1004.

Figure 5-3
Example Probability Plot of Total Phosphorus for All Sites Prior to Intervention.



The next step in the data analysis was to calculate parametric and non-parametric descriptive statistics. Table 5-5 is an example table of descriptive statistics for TN for all sites for both the pre- and post-intervention periods. (Additional descriptive statistics are included in Appendix E2). Table 5-5 includes the number of data points (n), the detection percent (%>MDL/RL), the mean, median, 25 percent trimmed mean, min, max, 25th percentile, 75th percentile, standard deviation, interquartile range (IQR), and the coefficient of skewness (g_s). Also included in the table are critical skewness coefficients (g_{cr}), which are readily available in statistics texts. If the coefficients of skewness are less than these critical values, then the data is symmetric. It should be noted that the measures of central tendency (mean and median) and variability (standard deviation) of the sites during the pre-intervention period are quite different, indicating the data arises from different distributions. The median values are consistently smaller than the mean (in some cases substantially smaller), demonstrating the influence of the outliers on the measure of central tendency. Only three pre-intervention data sets are symmetric, and none of the post-intervention data sets are. Failure to pass the symmetry test indicates the data is not normal. However, passing the symmetry test does not indicate the data is normal; this requires a normality test. The symmetry test, which is easier to conduct than normality tests, serves as an initial screen for normality to reduce the number of data sets needing further investigation.

Table 5-5
Example Table of Descriptive Statistics for Total Nitrogen for Each Site for Pre- and Post-intervention.

		1001		1002		1003		1004		1005	
Parameter	**Statistic**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
TN (calculated)	**n**	23	25	23	25	23	25	23	25	23	25
(mg-N/L)	**% > MDL/RL**	100%	80%	98%	90%	98%	96%	98%	96%	100%	98%
	Mean	4.24	3.09	5.31	3.44	3.66	4.42	48.00	10.18	6.89	7.74
	Median	3.84	2.27	3.95	2.55	2.66	2.50	19.01	5.57	5.06	4.36
	Trimmed mean	3.94	2.40	4.53	2.76	2.93	3.01	33.11	6.47	5.08	4.42
	min	2.30	0.30	1.50	0.78	1.46	0.45	3.28	0.74	2.48	1.07
	max	6.76	12.99	13.83	11.40	12.12	19.91	141.06	40.80	20.41	67.12
	25th percentile	3.20	1.79	2.27	2.10	2.11	2.04	9.05	2.71	3.52	3.47
	75th percentile	5.68	3.13	8.02	4.36	4.81	5.17	94.79	19.18	7.07	5.62
	St Dev	1.41	2.67	3.56	2.51	2.48	4.39	49.17	10.73	5.29	12.85
	IQR	2.48	1.34	5.75	2.26	2.70	3.13	85.74	16.47	3.55	2.15
	Skewness, g_s	0.55	2.82	0.84	1.87	2.13	2.27	0.74	1.37	1.88	4.46
	g_{cr}	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92
	Symmetric ($g_s < g_{cr}$)?	Y	N	Y	N	N	N	Y	N	N	N

The non-parametric equivalent to the ANOVA test is the K-W test, which tests for a difference between the medians of independent data groups. The K-W test will also test whether the datasets are derived from the same distribution.

Comparison of the mean ranks in Table 5-6 provides an indication of whether the data groups are derived from the same distribution. A p values < 0.05 indicates that two or more of the data groups have different distributions. Examination of the mean ranks in Table 5-6 shows that Sites 1001, 1002, and 1005 have somewhat similar mean ranks, and Sites 1003 and 1004 have somewhat different mean ranks. This suggests that Sites 1003 and 1004 have a different distribution than the other sites. Thus, the K-W test was performed on just Sites 1001, 1002, and 1005. These results are shown in Table 5-7. The p-value is now greater than 0.05, so the distributions of the TN data are not significantly different. Based on this analysis, Site 1002 was determined to be the only control site for comparison of TN data. Furthermore, it is clear that Site 1004 should not be considered as a control site for TN, and Site 1003 should be used with caution.

Table 5-6
Example of Kruskal-Wallis Test Results for Total Nitrogen at the Test Sites Prior to Intervention.

Test:	**Kruskal-Wallis ANOVA**		
Comparison:	**Total Nitrogen: 1001, 1002, 1003, 1004, 1005**		
Performed by:	**GeoSyntec Consultants**		
n	115		
Total Nitrogen	**n**	**Rank sum**	**Mean rank**
1001	23	1128.0	49.04
1002	23	1162.0	50.52
1003	23	774.0	33.65
1004	23	2150.0	93.48
1005	23	1456.0	63.30
Kruskal-Wallis statistic	41.71		
p	<0.0001	(chisqr approximation)	

Table 5-7
Example of Kruskal-Wallis Test Results for Total Nitrogen at Sites 1001, 1002, and 1005 Prior to Intervention.

Test:	**Kruskal-Wallis ANOVA**		
Comparison:	**Total Nitrogen: 1001, 1002, 1005**		
Performed by:	**GeoSyntec Consultants**		
n	69		
Total Nitrogen	**n**	**Rank sum**	**Mean rank**
1001	23	710.0	30.87
1002	23	761.0	33.09
1005	23	944.0	41.04
Kruskal-Wallis statistic	3.27		
p	0.1948	(chisqr approximation)	

5.4.3.2 Comparison of Water Quality Data Before and After Intervention

Side-by-side box plots and probability plot comparisons of pre-intervention and post-intervention were constructed to identify any apparent differences in the central tendency and concentration distributions between the two data sets. Figure 5-4 shows side-by-side box plots of total nitrogen at all of the test sites. Site 1004 was omitted due to its high variability. The figure shows that Site 1001 has a distinct decrease in TN while the other sites do not. However, other sites do show a decreasing trend in median concentration and inter-quartile ranges.

Figure 5-4
Side-by-side Box Plots of Pre- versus Post-Intervention for Total Nitrogen at All Sites.

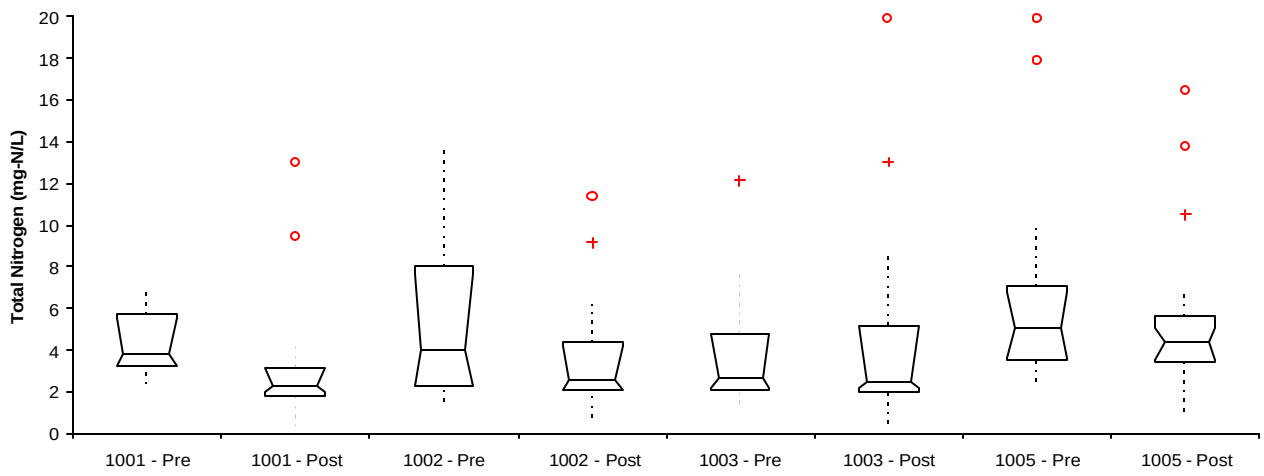
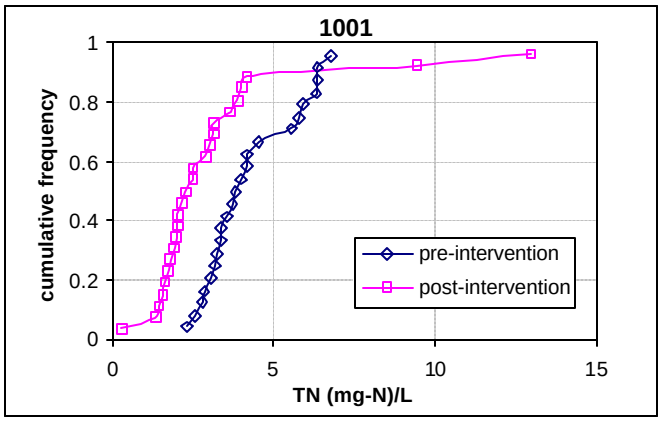


Figure 5-5 is a probability plot of TN for Site 1001 before and after intervention. (Additional probability plot comparisons are included in Appendix E2.) This figure shows a distinct reduction in TN at the site. However, since the data is from different time-periods, this difference could be related to temporal variability.

Figure 5-5
Example Probability Plot of Pre- versus Post-intervention for Total Nitrogen at Site 1001.



To evaluate if temporal variability caused by the different monitoring periods has anything to do with the difference in TN concentrations, the probability plots of the pre- and post-intervention period for Site 1001 were plotted with those for Site 1002 and Site 1005 (as these were determined to be the only valid control sites). These comparison plots are shown on Figure 5-6 and Figure 5-7. For pre-intervention, the distribution of Site 1001 more closely follows the distribution of Site 1005 than that of Site 1002, and for post-intervention the opposite is true. This indicates that the year-to-year variability alone cannot explain the reduction in TN at Site 1001.

Figure 5-6
Example Probability Plot for Total Nitrogen of Site 1001 versus Site 1002 for the Pre- and Post-Intervention Periods.

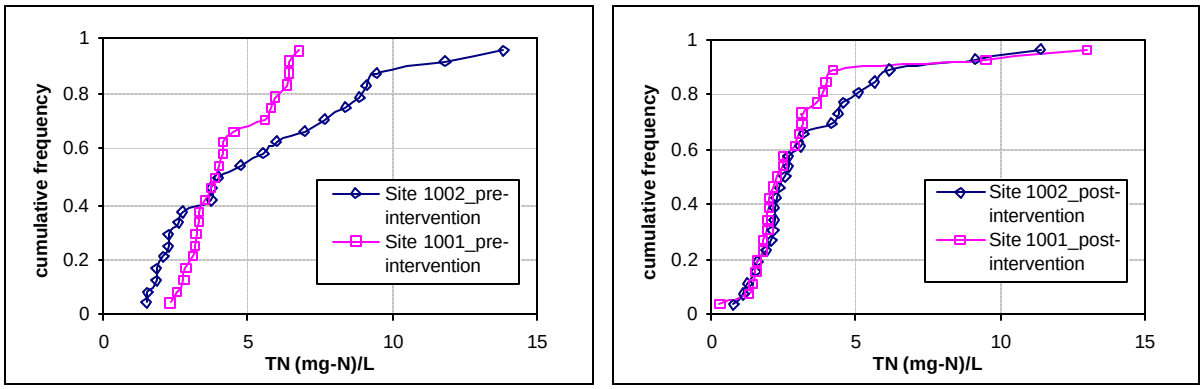
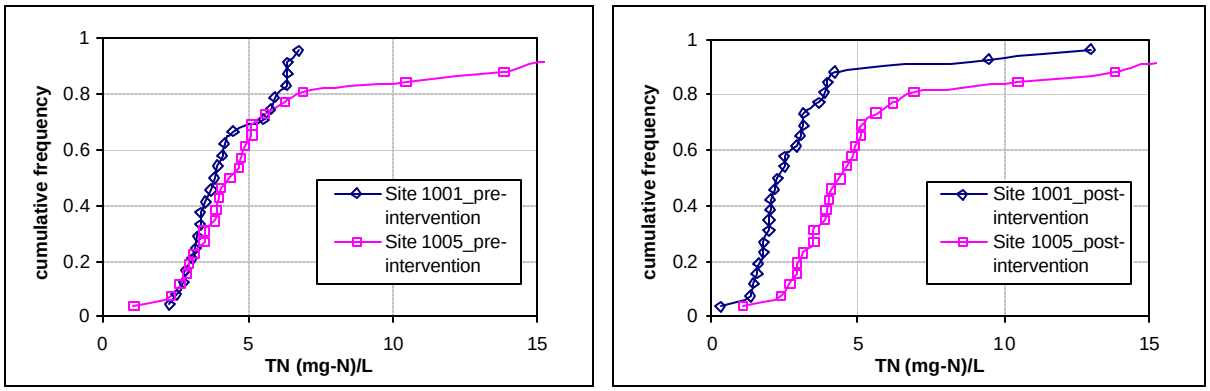


Figure 5-7
Example Probability Plot for Total Nitrogen of Site 1001 versus Site 1005 for the Pre- and Post-Intervention Periods.



The Mann-Whitney test (rank-sum) was used to determine if there is a statistical difference in the median values of two independent data sets (by rejecting the hypothesis that they are the same). Tables 5-8 through 5-10 show the output of the Mann-Whitney tests on Sites 1001, 1002, and 1005, respectively. The tables show a statistically significant difference ($p<0.05$) in the medians between the pre- versus post-intervention TN data at both Sites 1001 and 1002, but not at Site 1005. Furthermore, the difference in the medians at Site 1001 is at a higher level of confidence (more statistically significant) than the difference at Site 1002 (i.e., greater than 99 percent

significant compared to about 96 percent significant). The magnitudes of these differences (Hodges-Lehmann estimator) are about 1.5 and 1.3 milligrams of nitrogen per liter (mg-N/L) for Sites 1001 and 1002, respectively. These tests indicate that the difference in the TN medians at Site 1001 from pre-intervention to post-intervention cannot be explained by the year-to-year variation alone (e.g., the intervention appears to have had an effect). It also indicates that the public education applied to Site 1005 did not appear to make a significant difference.

Table 5-8
Example Mann-Whitney Test for Difference in Medians for Total Nitrogen at Site 1001 from Pre- Versus Post-intervention.

Test :	**Mann-Whitney test**			
Alternative hypothesis	**1001: Pre versus Post**			
Performed by:	**GeoSyntec Consultants**			
n	48			
1001	**n**	**Rank sum**	**Mean rank**	**U**
Pre	23	736.0	32.00	115.0
Post	25	440.0	17.60	460.0
Difference between medians	1.497			
95.2% CI	0.883	to +?	(normal approximation)	
Mann-Whitney U statistic	115			
1-tailed p	0.0002	(normal approximation)		

Table 5-9
Example Mann-Whitney Test for Difference in Medians for Total Nitrogen at Site 1002 from Pre- Versus Post-Intervention.

Test:	**Mann-Whitney test**			
Alternative hypothesis:	**1002: Pre versus Post**			
Performed by:	**GeoSyntec Consultants**			
n	48			
1002	**n**	**Rank sum**	**Mean rank**	**U**
Pre	23	651.0	28.30	200.0
Post	25	525.0	21.00	375.0
Difference between medians	1.289			
95.2% CI	0.065	to +?	(normal approximation)	
Mann-Whitney U statistic	200			
1-tailed p	0.0355	(normal approximation)		

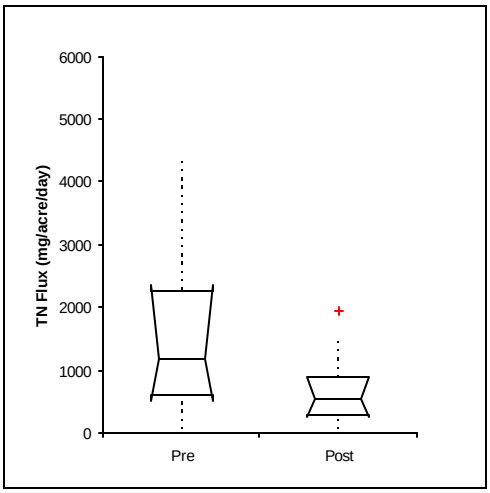
Table 5-10
Example Mann-Whitney Test for Difference in Medians for Total Nitrogen at Site 1005 from Pre- Versus Post-intervention.

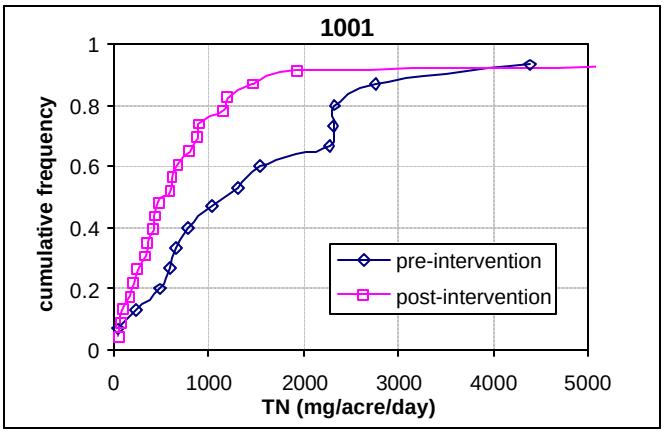
Test:	**Mann-Whitney test**			
Alternative hypothesis:	**1005: Pre versus Post**			
Performed by:	**GeoSyntec Consultants**			
n	48			
1005	**n**	**Rank sum**	**Mean rank**	**U**
Pre	23	610.0	26.52	241.0
Post	25	566.0	22.64	334.0
Difference between medians	0.530			
95.2% CI	-0.446	to +?	(normal approximation)	
Mann-Whitney U statistic	241			
1-tailed p	0.1686	(normal approximation, corrected for ties)		

5.4.3.3 Comparison of Constituent Fluxes Before and After Intervention

The statistical procedures applied to the concentrations examples above were also applied to the constituent fluxes (mass loadings). For completeness, an abridged example analysis is provided here. Figure 5-8 includes side-by-side box plots and probability plots of total nitrogen flux data milligrams per acre per day (mg/acre/day) for Site 1001 at pre- and post-intervention. There appears to be a significant decrease in the median, as well as an overall reduction in the distribution of values.

Figure 5-8
Side-by-side Box Plot and Probability Plots of Pre- Versus Post-Intervention for Total Nitrogen Flues at Site 1001.





Table

Table 5-11 shows the results of the Mann-Whitney test (rank-sum) for the total nitrogen flux at Site 1001. The medians from pre- to post-intervention are statistically significantly different at the 95 percent confidence level ($p<0.05$). The magnitude of the difference (the Hodges-Lehmann estimator) is approximately 530 mg/acre/day, indicating a relatively large reduction in total nitrogen loads from the neighborhood. However, as discussed below, the extent to which the ET controllers contributed to this reduction is unclear.

The nitrogen fluxes used in this analysis were computed as the product of the measured concentration and the average daily flow. Therefore, the reduction in TN flux could be due to a reduction in flow, a reduction in concentration, or a combination of both. Analyses presented earlier showed a statistically significant reduction in median TN concentration at Site 1001 between the pre- and post-intervention periods. Similarly, analyses discussed elsewhere in this report indicate that there was a statistically significant reduction in flow at Site 1001 between the pre- to post-intervention periods; however, it was cautioned that the pre- and post-intervention periods are not comparable due to seasonal differences in the data collection period. Thus, observed reductions in flow in 1001 could be influenced by seasonal factors. Therefore, the extent to which the ET controllers contributed to a reduction in flow is unknown. Consequently, reductions in TN flux could be attributed to a combination of TN reduction, flow reduction, and/or seasonal factors.

Table 5-11
Example Mann-Whitney Test for Difference in Medians for Total Nitrogen Flux at Site 1001 from Pre- Versus Post-intervention.

Test :	**Mann-Whitney test**			
Alternative hypothesis	**1001 flux (mg/acre/day): Pre vs. Post**			
Performed by:	**GeoSyntec Consultants**			
n	36			
1001_flux (mg/acre/day)	**n**	**Rank sum**	**Mean rank**	**U**
Pre	14	320.0	22.86	93.0
Post	22	346.0	15.73	215.0
Difference between medians	529.389			
95.1% CI	115.985	to +?	(normal approximation)	
Mann-Whitney U statistic	93			
1-tailed p	0.0239	(normal approximation)		

The above results suggest that it would be valuable to complete a more robust statistical evaluation of the data because some significant management implications could be determined.

5.4.4 Watershed Implications

The water quality evaluation results were examined in the context of existing TMDLs in the San Diego Watershed. Most of the existing TMDLs are reviewed below, and possible inferences and implications of the R3 Study data for TMDL compliance are discussed. The sediment and organophosphorus pesticide TMDLs were not reviewed because sediment data was not collected

(the vast majority of sediments are transported by storm flows) and because Schiff and Tiefenthaler (SCCWRP, 2003) have previously conducted an extensive analysis of the OP pesticide data.

5.4.4.1 Comparisons with Regulatory Requirements

Mean dry-season concentrations for nutrients, toxics, metals, and pathogens at the R3 Study Sites were compared with regulatory objectives including TMDL's, California Toxics Rule (CTR) criteria, and Basin Plan objectives in Tables 5-12 and 5-13. These comparisons are strictly descriptive and provide a rough sense of dry-season residential water quality in comparison to regional water quality objectives. This comparison shows substantial variability between neighborhoods and among constituents.

Table 5-12
Comparison of Dry Season Concentrations of Nutrients and Toxics at R3 Study Sites with Regulatory Objectives

Parameter/Location	Objective	Site 1001	Site 1002	Site 1003	Site 1004	Site 1005
TIN (San Diego Creek Reach 1 / Reach 2)	13 mg/L / 5 mg/L (RWQCB-TMDL)	4.079 mg/L	0.464 mg/L	2.18 mg/L	18.16 mg/L	4 mg/L
		Percent of Samples above Toxics TMDL				
		Site 1001	**Site 1002**	**Site 1003**	**Site 1004**	**Site 1005**
Chlorpyriphos -Acute (San Diego Creek Reach 1)	18 ug/L (RWQCB-TMDL)	36.59	N/A	N/A	22.76	43.9
Chlorpyriphos - Chronic- (San Diego Creek Reach 1)	12.6 ug/L (RWQCB-TMDL)	46.34	N/A	N/A	26.02	49.59
Diazinon - Acute- (San Diego Creek Reach 1)	72 ug/L (RWQCB-TMDL)	70.73	N/A	N/A	69.11	73.17
Diazinon - Chronic- (San Diego Creek Reach 1)	45 ug/L (RWQCB-TMDL)	74.80	N/A	N/A	75.61	77.24

Table 5-13
Comparison of Dry Season Concentrations of Metals and Pathogens at R3 Study Sites with Regulatory Objectives

		Percent of Samples above CTR Criteria				
Parameter	**Objective**	**Site 1001**	**Site 1002**	**Site 1003**	**Site 1004**	**Site 1005**
Copper -Acute	13 ug/L (CTR Criteria for Metal Toxicity*)	43.59	43.59	46.14	46.15	71.79
Copper - Chronic	9 ug/L (CTR Criteria for Metal Toxicity*)	74.36	56.41	76.92	74.36	87.18
Lead -Acute	65 ug/L (CTR Criteria for Metal Toxicity*)	0	0	0	0	0
Lead -Chronic	2.5 ug/L (CTR Criteria for Metal Toxicity*)	10.26	28.21	10.26	12.82	28.21
Zinc -Acute	120 ug/L (CTR Criteria for Metal Toxicity*)	0	7.69	5.13	7.69	15.38
Zinc -Chronic	120 ug/L (CTR Criteria for Metal Toxicity*)	0	7.69	5.13	7.69	15.38
		Median Dry Season Fecal Coliform				
Parameter	**Objective**	**Site 1001**	**Site 1002**	**Site 1003**	**Site 1004**	**Site 1005**
Fecal Coliform	200 MPN/100 mL (RWQCB Basin Plan)	1400 MPN/100 mL	3000 MPN/100 mL	5000 MPN/100 mL	13000 MPN/100 mL	65000 MPN/100 mL

5.4.4.2 Nitrogen

Nitrogen Water Quality Objectives and TMDLs – The Basin Plan water quality objectives for nitrogen in San Diego Creek are 13 milligrams per liter (mg/L) Total Inorganic Nitrogen (TIN) in Reach 1, and 5 mg/L TIN in Reach 2 (RWQCB, 1995). Reach 1 extends from Newport Bay to Jeffrey Road, and Reach 2 extends from Jeffrey Road to the headwaters. There is no numeric standard for nitrogen in Upper Newport Bay in the Basin Plan.

The nitrogen TMDL for Upper Newport Bay is based on the general goal of reducing nutrient loads to Newport Bay by 50 percent, to levels observed in the early 1970s (USEPA, 1998b). The nitrogen TMDL sets phase-in limits on TN loads to Newport Bay (see Table 5-14). Separate loads are established for the dry and wet seasons (dry season is from April 1 to September 30). In addition, the winter load is exclusive of storm flows with an average daily flow greater than 50 cubic feet per second (cfs) in San Diego Creek at Campus Drive.

There is no TMDL for nitrogen loads in San Diego Creek, Reach 1 because it was reasoned that attainment of the 50 percent reduction in nitrogen loads to Newport Bay would result in compliance with the Basin Plan in-stream water quality standard for Reach 1 (13 mg/L TIN). However, for Reach 2, it was determined that the average in-stream nitrogen concentrations would likely remain close to or above the Basin Plan in-stream water quality standard (5 mg/L TIN), even with attainment of the Newport Bay TMDLs. Therefore a TMDL of 14 lbs/day TN

was established for Reach 2 (see Table 5-14) and is applicable for all flows exclusive of storm flows greater than an average daily flow of 25 cfs in San Diego Creek at Culver Drive.

Table 5-14
Summary of Nutrient TMDLs for Upper Newport Bay and San Diego Creek

TMDL	Dec 31, 2002	Dec 31, 2007	Dec 31, 2012
Newport Bay Watershed, TN – Summer load (4/1 to 9/30)	200,097 lbs	153,861 lbs	
Newport Bay Watershed, TN – Winter load (10/1 to 3/31; non-storm)			144,364 lbs
Newport Bay Watershed, Total Phosphorus – Annual Load	86,912 lbs	62,080 lbs	
San Diego Creek, Reach 2, daily load			14 lbs/day
Urban Runoff Allocation for the Newport Bay Watershed Summer load Winter load	22,963	11,481	38,283

Study Data Comparison with Nitrogen Water Quality Objective – The Basin Plan water quality objectives are expressed in terms of TIN, which is comprised of nitrate/nitrite nitrogen and ammonia. By far the majority of the TIN in San Diego Creek is comprised of nitrate/nitrite nitrogen, as measured ammonia concentrations were typically quite low with a majority below the detection limit. For this reason, only the nitrate/nitrate concentration data is compared to the Basin Plan objectives in this report.

Table 5-15 shows the mean and median nitrate/nitrite concentrations measured in the five study sites. The mean and median nitrate/nitrite concentration of all sites except 1004 was below the Reach 2 Basin Plan objective of 5 mg/L TIN. As discussed previously, Site 1004 may not be a representative control site because the underlying distribution of pre-intervention nitrogen data appears to be different from the other sites. Similar arguments may also be true for Site 1003. With the exception of Site 1004, mean nitrate/nitrite concentrations suggest that, on average, residential runoff from these sites does not contribute to the exceedance of Basin Plan standards for TIN in receiving waters in San Diego Creek, Reach 1 and 2. The Reach 2 water quality objective was occasionally exceeded in all sites, except for the post intervention conditions in 1001 and 1002.

Table 5-15
Mean and Median Nitrate/Nitrite Concentration (mg/l) by Site (all data).

	1001		1002		1003		1004		1005	
	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post
n	23	25	23	25	24	25	23	25	24	25
Mean	2.56	1.47	2.57	1.07	2.13	1.71	36.50	6.61	2.61	4.13
Median	2.32	1.38	1.56	0.93	1.68	0.94	16.88	2.29	2.45	1.48
n>5 mg/L	1	0	4	0	1	2	18	8	2	1
n>13 mgL	0	0	0	0	0	0	12	4	0	1

The mean and median nitrate/nitrate concentrations in Sites 1004 and 1005 exhibit exceedances of the 5 mg/L standard during pre- and/or post intervention conditions. Site 1004, in particular, had high levels of measured nitrate/nitrite concentrations, especially during the pre-intervention period. A number of these high readings exceed the Reach 1 water quality objective of 13 mg/L TIN. The results from Site 1004 are not consistent with those from the other four study sites, and the source of the high readings is unknown. Localized conditions involving excessive fertilizer usage by a few users could possibly be a factor in these elevated readings. In particular, the R3 Study mentions an unknown connection to a neighboring watershed, which could explain the source of elevated nutrient levels.

The Mann-Whitney (rank-sum) test was performed to compare the statistical difference between median concentrations during pre- and post-intervention periods. The median nitrate/nitrite in the post-intervention period was lower at all sites, and the difference was statistically significant at the 0.05 confidence level. As the control stations exhibited this trend, the data (i.e. entire data sets with unequal seasonal coverage) cannot be used to ascertain if the structural and educational BMPs were effective in reducing the runoff concentrations of nitrate/nitrite.

Clearly another factor is contributing to reduced concentrations in the post-intervention period. One possibility that was investigated is differences in seasons, year-to-year variability, and sampling times of the pre- and post-intervention data. Table 5-16 presents mean and median concentrations for comparable seasons and sampling times. The table shows that there are still noticeable reductions in all of the median concentrations, except Site 1005. Applying the Mann-Whitney (rank-sum) test to the data, it was found that statistically significant differences between median nitrate/nitrite concentrations in the pre- and post-intervention periods occurred only at Sites 1001 and 1004, as compared to all sites when all data is considered. These results indicate that seasonal effects are present in the data and should be considered in the study evaluation. It may be inferred from these results that there were significant reductions in the nitrate/nitrite concentration in the intervention site during the wet season that may, in part, be attributable to the structural BMPs. It is unknown whether similar reductions would occur in dry weather runoff during the dry season because such data was not collected during the pre-intervention period.

Table 5-16
Mean and Median Nitrate/Nitrite Concentration (mg/l) by Site for Comparable Seasons and Sampling Times[1]

	1001		**1002**		**1003**		**1004**		**1005**	
	Pre	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
n	18	14	18	14	19	14	18	14	19	14
Mean	2.38	1.43	1.95	0.95	2.17	1.66	26.24	6.57	2.24	6.27
Median	2.22	1.48	1.16	0.96	1.50	1.02	8.94	2.06	2.03	1.96
n>5 mg/L	0	0	2	0	1	1	13	4	1	1
n>13 mg/L	0	0	0	0	0	0	7	3	0	1

1 – evening samples were deleted from the pre-intervention data. The post-intervention data include only those data collected in months identical to the pre-intervention period.

Study Data Comparison with Nitrogen TMDLs - The nitrogen TMDL is expressed in terms of total nitrogen TN loads. TN concentrations were calculated from the monitoring data as the sum

of the nitrate/nitrite nitrogen and total Kjeldahl nitrogen (TKN) nitrogen. Table 5-17 shows the mean and median TN concentrations measured in the five study sites. The mean and median TN concentration in dry weather runoff are generally in the range of 2 to 5 mg/L, with the exception of Site 1004 where substantially higher concentrations were measured. The rank sum tests indicated that median TN concentrations were significantly lower (in a statistical sense) in the post-intervention period in Site 1001 (structural BMPs, see Table 5-8), and at Site 1002 (control, see Table 5-9). Based on the probability plots in Appendix E2, Site 1004 is expected to as well. However, Sites 1003 and 1005 did not show statistically significant reductions. These results did not change when only subsets of the data were used to consider possible effects stemming from the sampling time and sampling months.

Table 5-17
Mean and Median TN Concentration (mg/l) by Site

	1001		**1002**		**1003**		**1004**		**1005**	
	Pre	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
All Data										
n	23	25	23	25	23	25	23	25	23	25
Mean	4.24	3.09	5.31	3.44	3.66	4.42	48.00	10.18	6.89	7.74
Median	3.84	2.27	3.95	2.55	2.66	2.50	19.01	5.57	5.06	4.36
Subsets[1]										
n	18	14	18	14	18	14	18	14	18	14
Mean	4.18	2.78	4.51	2.63	3.71	3.71	33.99	8.91	6.98	9.91
Median	3.62	2.02	3.22	2.21	2.51	2.47	12.14	3.74	4.17	3.96

1 – Data subsets with comparable sampling time and seasons. Evening samples were deleted from the pre-intervention data. The post-intervention data include only those data collected in months identical to the pre-intervention period.

TN flux estimates were calculated for Sites 1001 and 1005 (Table 5-18). The flow measurements at Sites 1002 to1004 are not reliable. Therefore, flux estimates were not calculated for these sites. Flux estimates were calculated as the product of the constituent concentration and the average daily flow occurring on the day of the sample collection. The flux estimates were found to be quite variable as they depend on both flow and concentration measurements. Table 5-18 shows that median TN flux estimates decreased from the pre- to post-intervention periods for both sites. Mann-Whitney (rank sum) tests show the reductions to be statistically significant (Table 5-11). Because comparable data is not available for the control sites, it is not possible to infer whether these reductions are influenced by the ET controllers in the intervention site (1001). Also, as previously discussed, the reduction in TN flux may be attributable to a reduction in flow, a reduction in concentration, seasonal factors, or a combination of these.

Table 5-18
Mean and Median TN Flux (mg-N/acre/day) by Site

	1001		1005	
	Pre	**Post**	**Pre**	**Post**
All data				
n	14	22	10	21
Mean	1476	1667	2104	6537
Median	1164	530	1568	1177
Subset[1]				
n	12	14	10*	8
Mean	1384	587	2104	1716
Median	902	497	1568	960

1 – Data subsets with comparable sampling time and seasons. Evening samples were deleted from the pre-intervention data. The post-intervention data include only those data collected in months identical to the pre-intervention period.
* – Same as the all data case

Although the flux estimates in Table 5-18 are limited in number, duration, and location, they can be used to speculate about the magnitude of the urban area contribution of TN loads to Newport Bay and the potential reduction in loads from structural and nonstructural BMPs. Based on the limited flux data, the annual TN load to Newport Bay in dry weather runoff from urban areas in the San Diego Creek Watershed is estimated to range between 37,000 to 50,000 lbs per year under existing land-use conditions (see Table 5-19). This is for the most part below the 2012 urban runoff allocation of 49,764 lbs. The annual TN load is estimated to increase to 50,000-67,000 lbs per year under build-out conditions.

According to the 2001 report on the nutrient TMDL (OCPFRD, 2001), the average daily TN load in San Diego Creek at Campus Drive was 540 lbs/day between July 2000 and June 2001. This converts to an annual load of about 197,000 lbs, which is below the 2007 TMDL (note: San Diego Creek is the majority but not sole contributor of TN loads to Newport Bay). Estimates in Table 5-19 suggest that dry weather runoff from urban areas account for about 20 to 25 percent of the annual TN in the San Diego Creek Watershed. If it is assumed that flux reductions observed in the post intervention period are attributable to the structural and nonstructural BMPs, and if similar interventions could hypothetically be implemented on a watershed-wide basis, then the potential reduction in annual dry weather TN loads is estimated to range between 12,500-20,000 lbs. This would represent a reduction of about 6-10 percent of the current TN loads and about 30-40 percent of the estimated current dry weather urban loads. These estimates are based on few data collected in a limited area and should therefore be considered preliminary in nature.

Table 5-19
Estimated Annual TN Loads in Dry Weather Runoff from Urban Areas in the San Diego Creek Watershed

	TN flux (mg-N/acre/d)	Annual TN Load to Newport Bay (lbs) Existing land-use[1]	Annual TN Load to Newport Bay (lbs) Built-out land-use[2]
Pre-intervention conditions	1160 – 1560	37,300 – 50,500	50,000 – 67,000
Post-intervention conditions	530 – 1180	17,000 – 38,000	23,000 – 51,000
Potential reduction		~12,500 – 20,000	~16,000 – 27,000

1 –Used 40000 acres or about 53% of the San Diego Creek Watershed area (IRWD, 2003). For comparison, urban land use in 1999 use was estimated at 35,500 acres of the watershed area at Campus Drive (Tetra-Tech, 2000).
2 – Used 53500 acres or about 71% of the San Diego Creek Watershed area (IRWD, 2003).

The following conclusion can be made based on the analyses above:

- Average and median nitrate/nitrite concentrations in dry weather runoff are below the Reach 2 water quality objective (5 mg/L), for most but not all study sites.
- Occasional exceedance of the Reach 2 water quality objective occurred in all study sites.
- The majority of measured nitrate/nitrite concentrations at Site 1004 during the pre-intervention period were greater than the Reach 2 water quality objective of 5 mg/L. The data is not consistent with those from the other sites. The cause is unknown, but could possibly be related to the unknown connection to the neighboring nursery discussed in the R3 report.
- Sampling periods (months) and sampling time (morning versus evening) were found to affect the statistical significance of differences between pre- and post- intervention median nitrate/nitrate concentration in some of the sites. The sampling period and sampling time did not affect the statistical significance of differences between pre- and post-intervention median TN concentrations.
- Median TN fluxes at Sites 1001 and 1005 were statistically smaller in the post-intervention period. The extent to which the structural and nonstructural BMPs contributed to these reductions cannot be determined due to the lack of reliable flow data in the control sites.
- Preliminary estimates of annual TN loads to Newport Bay in dry weather runoff from urban sources range between 37,000 to 50,000 lbs per year, or about 20 to 25 percent of the current TN loads.
- The potential reductions in annual dry weather TN loads due to implementation of BMPs on a watershed basis is estimated to range between 12,500-20,000 pounds per year. This would represent a reduction of about 6-10 percent of the current TN loads and 30-40 percent of the urban loads.

5.4.4.3 Phosphorus

The majority of the annual TP load in the San Diego Creek Watershed occurs in the wet season, and has been correlated with sediment loads generated by storm events (USEPA, 1998b). This

correlation suggests that a majority of phosphorus occurs in particulate form attached to sediments. The main sources of the TP are in Peters Canyon Wash and San Diego Creek above Culver Drive (USEPA, 1998b).

Phosphorus TMDL – There is no numeric objective for phosphorus for San Diego Creek in the Basin Plan. Because measured TP and sediment loads are correlated, it was determined in the TMDL that a 50 percent reduction in TP loads would be achieved through compliance with the sediment TMDL (USEPA, 1998a). Accordingly, the TMDL for TP was based on a 50 percent reduction of average annual load estimated at 124,160 lbs (USEPA, 1998b). The TMDLs are applicable for all flow conditions. The target compliance date was set for December 31, 2007.

The annual TP load allocation for urban areas is 4102 lbs by 2002, reducing to 2960 lbs by 2007. According to the USEPA (1998b), the TP is allocated in the same proportion as sediments. The annual urban area (stabilized vs. construction) sediment allocation for the Newport Bay Watershed is 50 tons distributed over 95.3 square miles (see Table 5 in USEPA, 1998a). This is a very small allocation over a large area. By contrast, the annual construction allocation is 6500 tons distributed over the assumed 3.0 square miles under construction in any one year. Using the same proportions of sediment load allocations, the TP load rate based on the 2007 urban allocation is 2960 lbs/95.3 square miles = 0.0485 lbs/acre/yr. If the construction and urban allocations are combined, the TP load rate based on the combined 2007 urban and construction allocations is (2960+12810) lbs/(95.3+3.0) square miles = 0.251 lbs/acre/yr.

Study Data Comparison with TMDLs – Similar to the nitrogen TMDL, the phosphorus TMDL is expressed in terms of total annual TP loads. Table 5-20 shows the mean and median TP concentrations measured in the five study sites. The mean and median TP concentrations in dry weather runoff are below 1.2 mg/L in all sites, with the exception of Site 1004, where substantially higher concentrations were measured. Comparison of the pre- and post-intervention median TP concentrations in all data (Table 5-20) reveals an increase in the median TP concentration during the post-intervention period for all sites except the intervention Site 1001 and Site 1004. In contrast, when subsets of the data with similar seasons and sampling times are considered (Table 5-20), there is a decrease in the median TP concentration at all sites except 1005. This indicates that there are seasonal influences in the data, which presumably are related to rainfall. Unfortunately, no data is available to permit comparison of pre- and post-intervention concentrations for dry weather flows during the dry season.

Table 5-20 Mean and Median TP Concentration (mg/l) by Site

	1001		**1002**		**1003**		**1004**		**1005**	
	Pre	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
All Data										
n	23	25	23	25	24	25	23	24	24	25
Mean	0.73	0.60	0.92	0.84	0.98	1.21	3.33	1.50	1.01	1.19
Median	0.60	0.51	0.77	0.82	0.62	0.67	2.54	1.05	0.73	0.85
Subsets[1]										
n	18	14	18	14	19	14	18	13	19	14
Mean	0.78	0.47	0.91	0.67	1.13	0.57	2.62	1.33	0.93	1.24
Median	0.61	0.41	0.73	0.56	0.75	0.58	1.82	1.07	0.75	0.83

1 – Data subsets with comparable sampling time and seasons. Evening samples were deleted from the pre-intervention data. The post-intervention data include only those data collected in months identical to the pre-intervention period.

TP flux estimates were calculated for Sites 1001 and 1005 using the approach discussed in the nitrogen section above. Table 5-21 shows that median TP flux estimates decrease from the pre- to post-intervention periods at the intervention site (1001), but not in the education only site (1005). Mean fluxes increased at both sites. However, as discussed earlier, the mean values are strongly influenced by outliers and do not provide a good measure of central tendency for the data. Application of the Mann-Whitney (rank sum) test shows the reduction in median TP flux at Site 1001 is statistically significant. This suggests that the structural BMPs had a positive influence in reducing the TP fluxes. However, because comparable data is not available for the control sites, it is not possible to ascertain the extent to which the ET controllers contributed to these reductions. Also, as discussed previously, reductions in flux could be influenced by several factors: reduction in concentration, reduction in flow, and/or seasonal variability.

Table 5-21
Mean and Median TP Flux (mg-P/acre/day) by Site (all data)

	1001		**1005**	
	Pre	**Post**	**Pre**	**Post**
All data				
n	14	22	10	21
Mean	265	370	473	1327
Median	164	109	219	219

Similar to the previous analyses of TN loads, the TP flux estimates in Table 5-21 can be used to speculate about the magnitude of the urban area contribution of TP loads to Newport Bay and the potential reduction in loads from structural BMPs. Based on the limited flux data, the annual TP load to Newport Bay in dry weather runoff from urban areas in the Newport Bay Watershed is estimated to range between about 5,000 to 11,000 lbs per year (see Table 5-22), assuming a total urban area of 95.3 square miles obtained from Table 5 of the sediment TMDL (USEPA, 1998a). These estimated annual TP loads are greater than the urban allocation (for both dry and wet weather) and are less than the combined urban and construction allocations (Table 5-22). However, these estimates are based on dry weather data only, and it is expected that a major portion of the TP loads will occur in runoff from winter storms. Therefore, actual annual TP loads would be expected to be greater. If it is hypothesized that flux reductions observed at the intervention site (1001) could be realized over the entire watershed, then the potential reduction in annual dry weather TP loads from urban areas is estimated at 2700 lbs. As stated previously, these estimates are based on few data collected in a limited area and should therefore be considered preliminary in nature.

Table 5-22
Estimated Annual TP Loads in Dry Weather Runoff from Urban Areas in the San Diego Creek Watershed

	TP flux (mg-P/acre/d)	Annual TP Load Rate to Newport Bay (lbs/acre/year)[1]	Annual TP Load to Newport Bay (lbs/year)
2007 Urban Area Allocation for Newport Bay		0.0485	2960
2007 Combined Urban and Construction Area Allocation for Newport Bay		0.251	15770
Pre-intervention conditions (median fluxes)	164 – 219	0.132 – 0.176	8049 – 10748
Post-intervention conditions (median fluxes)	109 – 219	0.088 – 0.176	5350 – 10748
Potential reduction			2700

1 - urban area is 95.3 square miles and the construction area is 3.0 square miles based on Table 5 in USEPA,1998a

5.4.4.4 Metals

Metals TMDLs – The USEPA (June 2002) determined that TMDLs are required for dissolved copper, lead, and zinc in San Diego Creek, Upper Newport Bay, and Lower Newport Bay, and that TMDLs are required for cadmium in San Diego Creek and the Upper Newport Bay. The TMDLs for San Diego Creek are expressed as concentration limits, based on the California Toxic Rule (CTR) criteria at various hardness values that are associated with different flow regimes (Table 5-23). The flow regimes are based on 19 years of flow measurements in San Diego Creek at Campus Drive. The concentration-based TMDLs apply to all freshwater discharges to San Diego Creek, including discharges from agricultural, urban, and residential lands, and storm flow discharges. The applicable flow regime at any location in the entire watershed is determined on the basis of discharge at Campus Drive.

Table 5-23
Summary of Dissolved Metal TMDLs for San Diego Creek

Dissolved Metal (?g/l)	Base flow (0–20 cfs) hardness @ 400 mg/L		Small flows (21-181 cfs) hardness @ 322 mg/L		Medium flows (182-814 cfs) hardness @ 236 mg/L		Large flows (>814 cfs) hardness @ 197 mg/L
	Acute	**Chronic**	**Acute**	**Chronic**	**Acute**	**Chronic**	**Acute**
Cadmium	19.1	6.2	15.1	5.3	10.8	4.2	8.9
Copper	50	29.3	40	24.3	30.2	18.7	25.5
Lead	281	10.9	224	8.8	162	6.3	134
Zinc	379	382	316	318	243	244	208

Metals Sources – The USEPA (June 2002) conducted a source analysis as part of the TMDL preparation. Surface runoff is the largest contributor of metals loads in the San Diego Creek watershed, which includes natural and man made sources (USEPA, June 2002). Much of the metals loads are from natural sources. The estimated anthropogenic contributions are metal specific and range from about 33 percent for zinc to 63 percent for cadmium (USEPA, June 2002). A primary anthropogenic source of heavy metals is runoff from urban roads, which contributes to sources of cadmium (tire wear), copper (brakes, tires), lead (brakes, tires, fuels and oils), and zinc (tires, brakes, galvanized metals). Use of copper sulfate by nurseries may also be a minor source of copper loads. Other copper and zinc uses in building materials (roofing and roof drains) may be another source.

The USEPA found that metal inputs were heavily influenced by rainfall and stream flow rates. Monitoring results were reported to be highly variable due to different rainfall amounts and flows during each water year. The USEPA estimated that base flows account for 25 percent of the total metal loadings, with the remainder from low, medium and large flows caused by storms.

The USEPA's preliminary analyses suggest that: 1) a primary source of metals in dry weather runoff in the study watershed is from roads (i.e. wash off of metals in driveways, parking lots, streets, gutters, etc.); 2) the runoff concentrations will be influenced by rainfall which result in wash off of accumulated metals; and 3) the concentrations can be variable depending on the amount of rainfall.

Study Data Comparison with Base Flow TMDLs – The metals TMDLs for base flow conditions are based on meeting the CTR criteria at a total hardness of 400 mg/L. The CTR criteria express maximum allowable concentrations in receiving waters for acute (short term) and chronic (4-day) exposure periods. The acute and chronic criteria are expressed as values that cannot be exceeded more that once in three years. Although the criteria are applicable in the receiving waters and not in the urban runoff per se (i.e. the measured dry weather discharge), exceedance of the CTR in the urban discharge would suggest a potential for the discharge to contribute to an exceedance in the receiving waters.

Table 5-24 shows the mean and median heavy metal concentrations in the five study sites. With the exception of mean copper concentrations in some of the sites, all mean and median concentrations were below the chronic and acute CTR criteria. Copper, lead, and zinc concentrations occasionally exceeded the chronic CTR criteria, and copper and zinc concentrations occasionally exceeded the acute criteria. These exceedances suggest that the dry weather runoff can potentially contribute to an exceedance in the receiving waters. However, if intervention is determined to be effective in reducing runoff flows, then the BMPs would help to reduce impacts of these potential exceedances by allowing for greater dilution with the in-stream flows.

Table 5-24
Mean and Median Metal Concentrations (mg/L) by Site (all data)

	1001		1002		1003		1004		1005	
	Pre	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
Cadmium										
n	23	25	23	25	24	25	23	25	24	25
Mean	0.26	0.14	0.47	0.44	0.27	0.17	0.64	0.22	0.21	0.29
Median	0.27	0.10	0.24	0.10	0.10	0.10	0.36	0.10	0.10	0.10
n>6.2 ? g/l	0	0	0	0	0	0	0	0	0	0
n>19.1 ? g/l	0	0	0	0	0	0	0	0	0	0
Copper										
n	23	25	23	25	24	25	23	25	24	25
Mean	13.5	16.9	27.3	30.3	11.5	26.6	21.8	17.7	32.1	30.8
Median	11.5	11.4	10.9	14.0	11.1	14.3	12.7	11.4	12.3	20.4
n>29.3 ? g/l	2	2	3	7	0	2	5	4	3	5
n>50 ? g/l	0	1	3	3	0	2	2	3	3	2
Lead										
n	23	25	23	25	24	25	23	25	24	25
Mean	0.8	1.6	5.9	4.7	0.8	1.6	3.5	1.5	1.0	3.2
Median	0.6	0.6	0.9	1.2	0.6	0.8	0.7	0.7	0.7	1.3
n>10.9 ? g/l	2	1	2	3	0	0	2	0	0	1
n>281 ? g/l	0	0	0	0	0	0	0	0	0	0
Zinc										
n	23	25	23	25	24	25	23	25	24	25
Mean	58.7	37.2	115.2	86.3	56.3	56.8	83.6	40.9	74.0	75.0
Median	56.0	50.2	53.4	57.2	50.7	53.9	50.8	43.8	52.4	54.5
n>382 ? g/l	0	0	1	2	0	0	1	0	0	0
n>379 ? g/l	0	0	1	2	0	0	1	0	0	0

Dry weather metals monitoring information in the Central Irvine Channel, the immediate receiving water of the study watersheds, was unavailable. OCPFRD dry weather monitoring data is available in San Diego Creek at Campus Drive, which is quite a way downstream from the study sites. Data collected between December 2001 and June 2002 (Table 5-25) shows that average dry weather concentrations at Campus Drive are well below mean and median concentrations measured in dry weather runoff from the study watershed. Similar comparisons cannot be made for lead and cadmium because the method detection limits in the OCPFRD data are greater than those in the R3 data. None of the OCPFRD dry weather data exceeded the chronic or acute criteria.

Table 5-25
Summary of OCPFRD Dry Weather Monitoring Data of San Diego Creek at Campus Drive (12/01 to 6/02)

	Cadmium	**Copper**	**Lead**	**Zinc**
Sample number	24	24	24	24
Range	All < 1 ?g/l	<2 – 16 ?g/l	<2-2.4 ?g/l	<10-16
Mean		7.4 ?g/l	most <2 ?g/l	most <10
Median-		6.8?g/l		

These comparisons suggest that metal loads in dry weather runoff from the study (urban) watersheds could be a contributing factor to dry weather copper and zinc loads measured at Campus Drive. These dry weather discharges do not result in non-compliance of the base flow metal TMDL at Campus (based on the reviewed data only). It is unknown if the elevated

concentrations measured in the dry weather urban runoff result in exceedance of the CTR criteria in the immediate receiving waters. If flow reductions observed in the intervention watershed are attributable to the ET controllers, then these controllers would help to reduce impacts from any potential exceedances of the TMDL because the discharges would be subject to greater dilution by the in-stream flows.

5.4.4.5 Pathogens

Pathogens are agents or organisms that can cause diseases or illnesses, such as bacteria and viruses. Fecal coliform bacteria are typically used as an indicator organism because direct monitoring of human pathogens is generally not practical. Fecal coliform are a group of bacteria that are present in large numbers in the feces and intestinal tracts of humans and animals, and can enter water bodies from human and animal waste. The presence of fecal coliform bacteria implies the water body is potentially contaminated with human and/or animal waste, suggesting the potential presence of associated pathogenic organisms.

Fecal Coliform TMDL – The RWQCB has adopted phased TMDL criteria for pathogens, with the initial focus on additional monitoring and assessment to address areas of uncertainty. The goal of the Newport Bay TMDL is compliance with water contact recreational standards by 2014:

- Fecal coliform concentration of not less than five samples per 30 days shall have a geometric mean less than 200 MPN/100 ml, and not more than 10 percent of the samples shall exceed 400 MPN/100ml for any 30-day period.

A second goal is to achieve the shellfish harvesting standards by 2020:

- The monthly median fecal coliform concentration shall be less than 14 MPN/100 ml, and not more than 10 percent of the samples shall exceed 43 MPN/100 ml.

The TMDLs are applicable for all flow regimes.

Study Data Comparison with Fecal Coliform TMDLs – Table 5-26 shows the mean and median fecal coliform concentrations measured in the five study watersheds. From 70 percent to 100 percent of all fecal coliform measurements were greater than 400 MPN/ml in all study watersheds. This level of exceedance is substantially greater than the allowable 10 percent. The mean and median fecal coliform concentrations also exceed the 400 MPN/100ml criterion in all study watersheds. There was insufficient data to calculate the 30-day geometric mean (a minimum of 5 samples per 30 days needed). However, the TMDL criterion (30-day geometric < 200 MPN/100 ml) would likely be exceeded, assuming that any additional data would be of the same magnitude as those collected. Exceedance of the TMDL criteria in all study watersheds suggests that urban dry weather runoff is likely a contributing factor to any dry weather exceedance of the TMDL in the receiving waters.

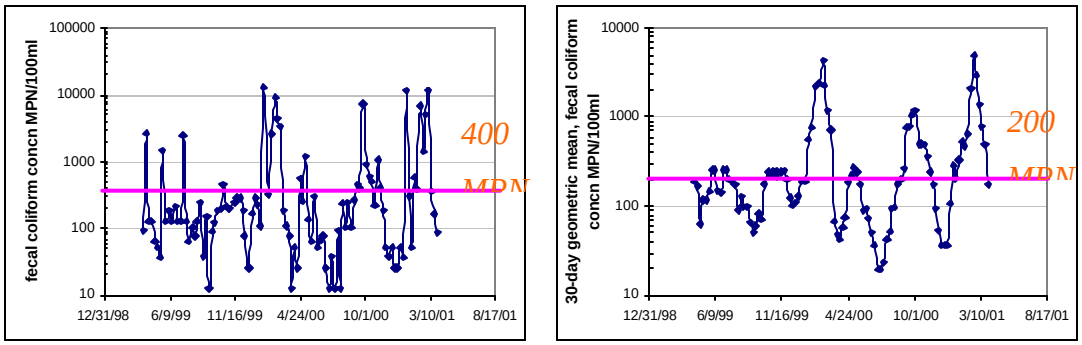
Table 5-26
Mean and Median Fecal Coliform Concentration (MPN/100ml) by Site

	1001		1002		1003		1004		1005	
	Pre	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
All Data										
n	22	24	21	24	23	24	21	24	23	24
Mean	4921	3003	5582	128193	34526	28980	28205	34185	17976	10326
Median	2300	1400	1700	3000	13000	4000	13000	13000	8000	8000
% > 400 MPN/100ml	82%	67%	86%	79%	100%	88%	95%	83%	92%	93%
Subsets[1]										
n	17	14	17	14	18	14	17	14	18	14
Mean	2545	3054	3090	5074	13783	37479	23312	20166	8524	6109
Median	2200	950	1400	1400	8000	2650	8000	6500	4000	2900
% > 400 MPN/100ml	100%	71%	82%	79%	100%	86%	94%	79%	100%	93%

1 – Data subsets with comparable sampling time and seasons. Evening samples were deleted from the pre-intervention data. The post-intervention data include only those data collected in months identical to the pre-intervention period.

Dry weather coliform monitoring information in the Central Irvine Channel was not available. Therefore, it is unknown if elevated fecal coliform concentrations measured in the study watershed contribute to an exceedance of the TMDL in the immediate receiving waters. The OCPFRD has collected dry and wet weather *E. coli* monitoring information in San Diego Creek at Campus Drive (OCPFRD, September 2001), which is considerably downstream from the study watersheds. A plot of the equivalent fecal coliform concentration (assuming an 80 percent *E. coli* content) shows exceedance of the TMDL occurs primarily during the wet season, although dry season exceedances are also evident (see Figure 5-9). This suggests that dry weather urban runoff is potentially a contributing factor to exceedance of the TMDL in dry weather flows at Campus Drive. The ET controllers would reduce the impacts from these potential exceedances if they were determined to be effective in reducing the dry weather runoff volumes.

Figure 5-9
Time Series of Fecal Coliform Levels of San Diego Creek at Campus Drive (converted from measured E. *coli* concentrations)



Median fecal coliform concentrations presented in Table 5-26 may be used to evaluate the influence of the structural and non-structural BMPs. When all monitoring data sets are

considered, the median fecal coliform concentrations are equivalent or increase from pre- to post- intervention conditions in all sites except the 1001 (intervention site) and 1003 (a control site). Based on the Mann-Whitney (rank-sum) test, the reduction in median concentrations at Site 1001 and 1003 is significant at the 95 percent confidence level. Thus the site with the irrigation controllers corresponded to a significant reduction in median fecal coliform concentrations, in comparison to two of the three control sites, while the education only watershed exhibited no discernable reduction in median concentrations.

When subsets of the data with similar seasons and sampling times are considered (Table 5-26), there is a decrease in the median fecal coliform concentration at all sites except 1002. However, because of the smaller sample sizes, the decrease is median concentration is statistically significant only at Site 1003. This suggests that there could be seasonal influences in the monitoring data, but the data is not sufficient to determine if there are statistically significant differences in the median concentrations.

5.5 Conclusions

The initial review of water quality data from the study found virtually no difference in concentrations or pollutant flux over time. The technological and education treatments provided essentially no detectable increase or decrease in water quality following the intervention.

The follow-up review utilizing more robust statistical methods on a sample of study data suggests that the interventions did result in changes in water quality. TN levels in the retrofit neighborhood following intervention were found to be significantly lower than levels before intervention, whereas no detectable differences were noted before and after intervention in the education neighborhood. Relatively large observed reductions in TN flux in the retrofit neighborhood could be influenced by seasonal factors, and the extent to which the ET controller contributed to the reduction is unknown. Similarly, although reductions in TP flux were observed in the retrofit neighborhood, the effect of the ET controllers cannot be determined.

Chapter 6: Public Education

6.1 Overview

This chapter discusses issues pertaining to public acceptance of water conservation and runoff reduction measures. Specific information is provided on:

- Evaluation approach, including development of ET controller + education and education-only BMPs
- Customer interaction
- Evaluation results, as measured through responses to pre- and post-intervention customer surveys

More detailed information is provided in Appendix F.

6.2 Evaluation Approach

The public acceptance evaluation was conducted to compare the effectiveness of proposed BMPs for ET controller technology + education and education only. There were three groups of R3 Study participants: 1) participants who had their home irrigation controllers replaced with an ET controller and who received educational materials, 2) participants who received educational materials only, and 3) control groups, who received no interventions. The retrofit participants were selected through random "cold knocking" and through letter solicitations that explained the study. The education group was self and randomly selected. Some of the education group participants voluntarily chose to participate in the study by replying to a letter. However, the majority was randomly selected through a door-to-door campaign.

6.2.1 ET Technology + Education (Retrofit Group)

For the R3 Study, existing sprinkler timers that are set manually by the homeowner were replaced with the radio controlled ET controller systems. Trained technicians were used to ensure successful installation because ET controllers require programming for each valve including area (size of yard or planter per valve), soil type (clay, sand, etc.), and landscape type (turfgrass, shrubbery, etc.). The remaining irrigation system was unchanged, including piping and sprinkler head configuration.

The participating ET technology retrofit group homes received a site evaluation and installation of an ET controller to manage the irrigation system. Additionally, the residents of these homes received information regarding environmentally sensitive landscape practices. The controllers were installed in 112 residential homes, two condominium associations' landscapes, two HOA landscapes, one pool/park setting, and 12 city street landscapes.

Public education materials were also provided, as described in Section 6.2.2.

6.2.2 Education Only

Educational materials were provided to both the retrofit and education-only groups. Public education consisted of an initial informational packet containing three items. The first item was an introductory letter that described the purpose of the packet. The second item was a booklet with irrigation, fertilization, and weed and pest control information. The centerfold of the booklet was a month-by-month guide to irrigating, fertilizing, and pesticide application suitable for posting near the sprinkler timer. Third, each homeowner was supplied a soil probe for measuring the water content of the landscaped soils. In addition to the initial packet, monthly reminders were mailed to each homeowner including landscape maintenance tips about irrigation system, watering schedule, fertilizing, and weed and insect control. Suggested sprinkler run times (for the non-ET sprinkler neighborhood) and fertilizer or pesticide application usage, including non-toxic alternatives, were also provided in the monthly newsletter. A representative collection of the public information tools used for the R3 Study is provided in Exhibits A through D at the end of this section.

6.2.3 Customer Interaction

Home residents were advised that if they had any problems with the controller or if the controller required any adjustments, they should call the water district for assistance. IRWD's customer service department telephone number was left on a sticker on the ET controller. All calls related to the ET controller were logged in separately and routed to the appropriate staff member for assistance. Table 6-1 shows the number of calls that were received from residential residents during the R3 study period.

Table 6-1
Calls from Residential Customers in R3 Study

April 2001	1	August 2001	13	December 2001	1	April 2002	2
May 2001	12	September 2001	4	January 2002	4	May 2002	3
June 2001	7	October 2001	5	February 2002	9	June 2002	6
July 2001	13	November 2001	3	March 2002	4	July 2002	2

Generally, there were four common types of calls: 1) customer misunderstanding the way the ET controllers were supposed to operate, 2) installation-related issues, 3) maintenance or system design issues, and 4) ET controller malfunctioning. These issues were addressed and resolved. (See Appendix F.)

.

6.3 Customer Surveys

This section describes pre-and post-intervention surveys developed to measure public acceptance.

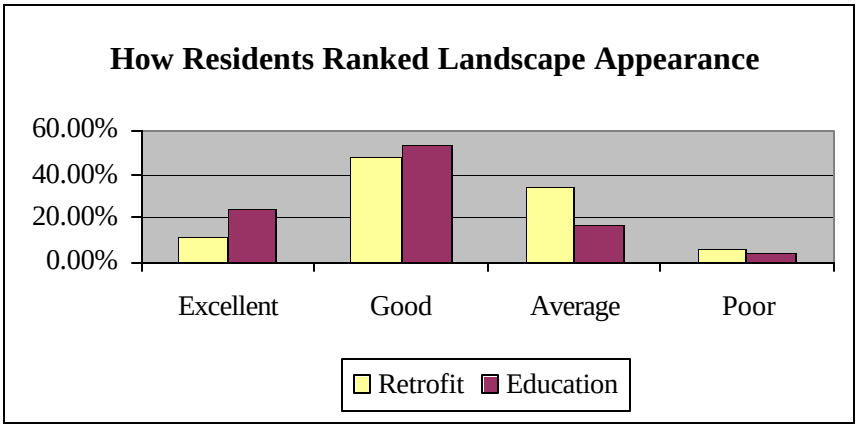
6.3.1 Pre-survey

The purpose of the pre-survey was to determine if the retrofit group and the education group had similar irrigation practices and attitudes. The pre-survey was distributed to the retrofit group while installation of the controller was taking place. Retrofit study participants were asked to fill

out the survey while staff was installing the controller. The education group received their survey as part of the initial educational packet that was randomly distributed to residents. Education group participants were provided a stamped addressed envelope to return their survey to the IRWD. Ninety-seven percent (109/112) of those that received a survey from the retrofit group mailed the survey back. Twenty-four percent (53/225) of residents in the education group mailed back a survey. Pre-survey results are tabulated in Appendix F and summarized below.

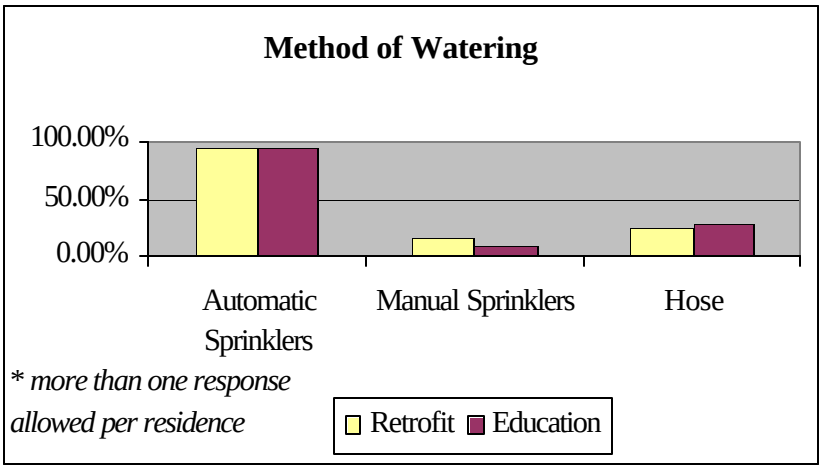
Figure 6-1 shows the responses of both of the groups. Similar responses were given. A majority of the residents in both groups believed that the appearance of the yard is average to good. It should be noted that the "excellent" response was selected by more of the education group than the retrofit group. One possible explanation for this response is that the staff was on-site while people were filling out their survey in the retrofit group.

Figure 6-1



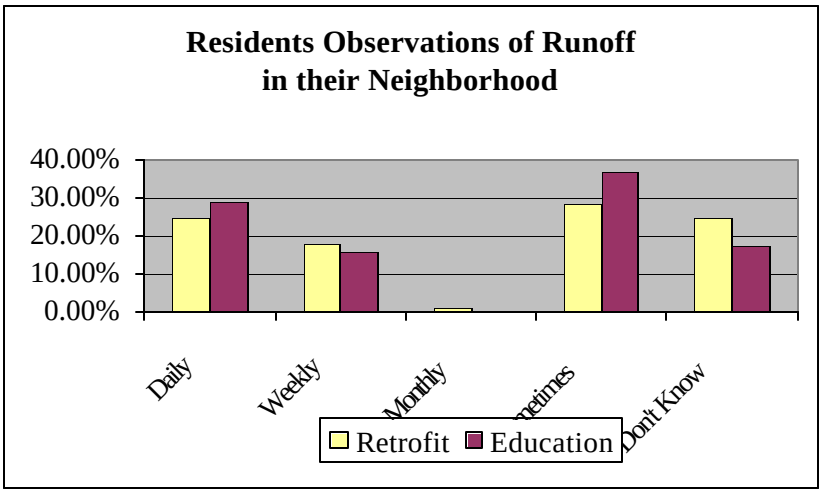
When residents were asked how they watered their lawn, the responses across groups were very similar. The percentage of people in the retrofit and education group that use automatic sprinklers, manual sprinklers, or a hose are similar. The survey shows that the retrofit and education groups have similar watering behaviors. As shown on Figure 6-2, the majority of the participants used automatic sprinklers. This is important because the R3 Study focuses on retrofitting the automatic irrigation controllers as a water management tool.

Figure 6-2



Residents were asked how often they observed runoff in their neighborhood. As presented on Figure 6-3, the data shows that residents in both groups have similar attitudes and views of urban runoff.

Figure 6-3



Residents were asked if they used fertilizers in their landscape, and chemicals to control pests or weeds. As shown on Figure 6-4, fertilizer use in both groups is almost the same. Results for chemical use were also similar for both groups. (See Figure 6-5.)

Figure 6-4

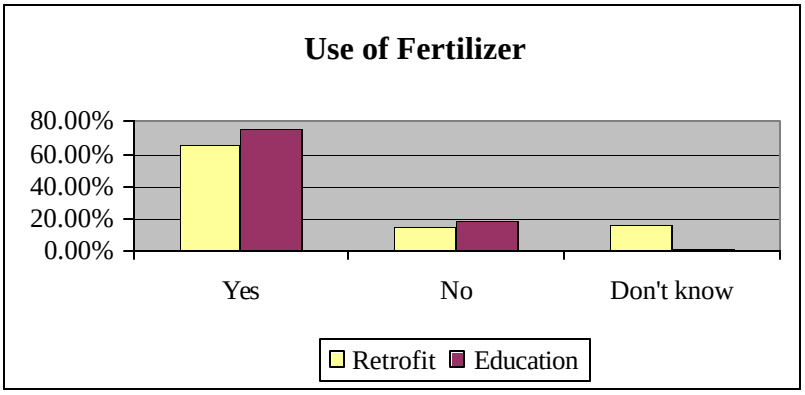
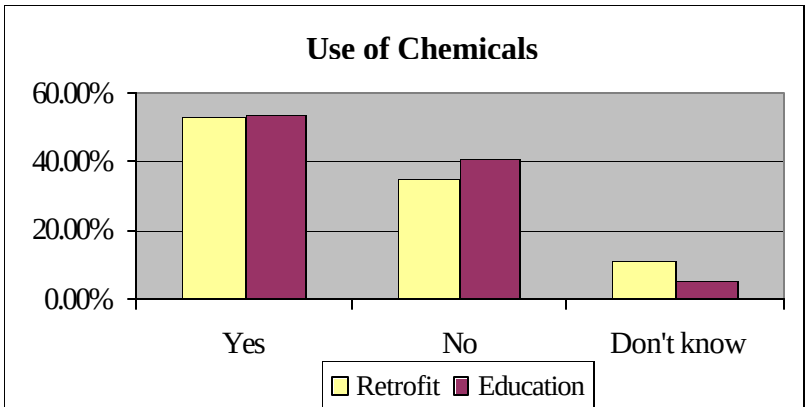


Figure 6-5



The purpose of the post-survey was to determine the attitudes of the study participants towards the ET controller and to determine if the education material had an impact on modifying behavior of the recipients. The post-survey was distributed to both of the groups through the mail. Twenty-three percent (52/225) of the education group participants responded to the survey, and forty-five percent (50/112) of the retrofit group participants responded. Post survey results are tabulated in Appendix F and summarized in the tables and text below.

6.3.2 Post-survey

Table 6-1 summarizes responses of the retrofit group compared to responses from the education group. The majority of the retrofit households acknowledged their satisfaction with the ET controller's performance and agreed that they would recommend the ET controller to their friends. It appears that the residents liked the controller and did not mind having someone else manage their irrigation-watering schedule. Data shows that households accepted the controller as a method of saving water, reducing runoff, and watering their landscapes. The survey shows that twice the number of retrofit households observed a decrease in their water bill than the education households did. A majority of the education households did not observe a change in their water bills. Data appears to show that the appearances of the retrofit landscapes were ranked equally with those landscapes that were part of the education group. It can therefore be concluded that the survey showed that the lower use of water did not create landscapes that were inferior to the education group. The customer's perception of a lower bill is important for the success of any long-term conservation program.

The retrofit and education group were asked if they were willing to pay for an ET controller signal. A majority of the households in both of the groups would not be willing to pay for an ET signal. The ET controller costs approximately $150.00 and the signal fee is $48 per year. The ET controller would be able to save less than 2 ccfs per month, which is a savings of about $14 per year. It appears that the savings in water use per year is not large enough for the water customer to pay for an ET signal.

Table 6-2
ET Controller Selected Responses

Responses to select survey questions	Retrofit group	Education group
Were satisfied with the ET controller	72 percent	n/a
Would recommend use of the ET controller to others	70 percent	n/a
Ranked the appearance of their yard as good to excellent	70 percent	69 percent
Not willing to pay for an ET signal	58 percent	69 percent
Saw decrease in water bills	44 percent	23 percent
Saw water bills unchanged	38 percent	63 percent

6.3.3 Education Only and Retrofit Group Responses

Table 6-3 summarizes the responses to the educational material by the retrofit group compared to the responses by the education group. Samples of these educational materials provided for participants in the R3 Study are presented on the following pages as Exhibit A through Exhibit D. Only half of the education households acknowledged that they sometimes or most of the time would change the settings on their controller according to ET via the monthly letter's (Exhibits A and B) suggested schedule. Monthly mailings also provided monthly landscape maintenance tips (Exhibits C and D). Here, the majority of the households in both of the groups liked the tips on the irrigation checks and fertilization sections. Although most people read these sections, a vast majority (80 percent) of households in both of the groups did not change their use of pesticides, herbicides, or fertilizers.

In addition to the education materials, a soil probe was given to both groups at the beginning of the study. A soil probe is a tool that takes a soil sample and enables the user to see the amount of moisture available to the plants and its depth. This allows the user of the soil probe to determine if the plants require more or less irrigation. More than half of the households in both groups only used the soil probe once or not at all. The majority of the people never used the soil probe at all. From a program point of view, people enjoy the education materials, but they appear to have little effect on modifying behavior.

Table 6-3
Education Material Selected Responses

Responses to select survey questions	Retrofit group	Education group
Have not changed their use of pesticides and herbicides	82 percent	81 percent
Have not changed their use of fertilizers	80 percent	73 percent
Did not use the soil probe or used it only once	76 percent	62 percent
Believed fertilization checks (part of monthly tips) were helpful	58 percent	44 percent
Believed irrigation checks (part of monthly tips) were helpful	42 percent	58 percent

6.4 Conclusions

While there were some customer service-related issues, the response to the ET controller was generally positive with 72 percent of participants indicating that they liked the controllers. This group also found that the controller irrigation either maintained or improved the appearance of their landscape. This is a classic win-win situation. The water district customers receive a desired benefit of a healthy landscape, and the community receives several important environmental benefits from the conservation of valuable and limited water resources and the reduction in dry season urban runoff.

Exhibit A
Monthly Landscape Maintenance Tips Letter Sent to "retrofit" customers in group 1001

May Landscape Maintenance Tips

The weather is getting warmer, the days are longer, and most of your plants are well into their growth stage. This is also the season for weeds and garden pests.

Irrigation System

- Watch for grass or plant growth that blocks sprinkler heads.
- Look for overspray onto streets and sidewalks and realign the sprinkler head.
- Look for dry spots and find the sprinkler problem to fix, such as a clogged head.
- Look for wet spots and potential sprinkler problems, such as a broken head.

Watering Schedule

- The Run-off Study Controller will adjust watering times as the weather changes.

Fertilizing

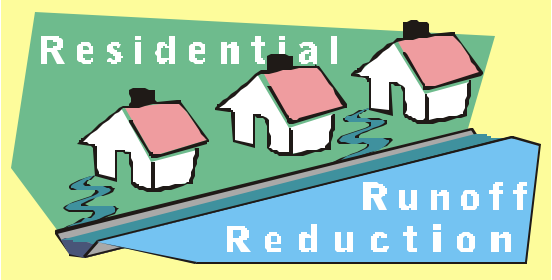
- Time to apply a slow release Nitrogen fertilizer to turf (apply only as directed on the bag or container).
- Keep fertilizer off of sidewalks, patio and streets.
- Do not wash fertilizer into drains or gutters.

Weed and Insect Control

- Watch for aphids and whiteflies. Wash insects off of leaves with a hard spray of water or spray with diluted soap solution.
- Apply mulch to control weeds, improve moisture retention and restore nutrients to the soil.
- Pick weeds now while they're still small.
- Use weed and insect chemicals only as directed on the containers.

This is a guide only. This guide does not hold public agencies responsible for the health and appearance of your home landscape.

Exhibit B
Monthly Landscape Maintenance Tips Letter (Sent to "education only" customers in group 1005)



May Landscape Maintenance Tips

The weather is getting warmer, the days are longer, and most of your plants are well into their growth stage. This is also the season for weeds and garden pests.

Irrigation System

- Watch for grass or plant growth that blocks sprinkler heads.
- Look for overspray onto streets and sidewalks and realign the sprinkler head.
- Look for dry spots and find the sprinkler problem to fix, such as a clogged head.
- Look for wet spots and potential sprinkler problems, such as a broken head.

Watering Schedule

- Start with this suggested schedule:
  Turf: 3 days per week, 3 cycles* of 3 minutes
  Shrubs and groundcover: 2 days per week, 3 cycles* of 3 minutes
- Reduce this amount in shaded areas.
- Use the soil probe to check the level of moisture beneath the surface before you water. If the soil is still moist 2 or more inches below the surface, wait another day to water.

Fertilizing

- Time to apply a slow release Nitrogen fertilizer to turf (apply only as directed on the bag or container).
- Keep fertilizer off of sidewalks, patio and streets.
- Do not wash fertilizer into drains or gutters.

Weed and Insect Control

- Watch for aphids and whiteflies. Wash insects off of leaves with a hard spray of water or spray with diluted soap solution.
- Apply mulch to control weeds, improve moisture retention and restore nutrients to the soil.
- Pick weeds now while they're still small.
- Use weed and insect chemicals only as directed on the containers.

This is a guide only. This guide does not hold public agencies responsible for the health and appearance of your home landscape.

*By "cycling" your irrigation timer to turn on for the suggested number of minutes about an hour apart, you reduce runoff and gain deeper watering and healthier root growth.

Exhibit C
Monthly Landscape Maintenance Calendar (Provided for "retrofit" and "education only" customers)
(Actual size: 8.5 in. x 11in.)

Monthly Landscape Maintenance Guide for Water Use Efficiency & Runoff Reduction

Seasons	Fall		Winter			Early Spring		Late Spring		Summer		
Month	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Irrigation System												
Check for: Runoff, from broken, blocked, clogged heads or overspray	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Check for Misting	✓				✓		✓		✓		✓	
Check for Dry Spots	✓							✓	✓	✓	✓	✓
Watering Schedule If two numbers are shown (i.e. 3▶2) adjust the number of days as indicated sometime during the month.												
Turf (grass) or Annuals Days to water per week	3▶2	2▶1	1	1	1▶2	2▶3	3	3	4	4▶5	4	4▶3
Trees, Shrubs Groundcovers	2▶1	1	1	1	1	1▶2	2	2	2	2	2	2
Deep Watering (trees)									●	●	●	●
Root zone watering: Use the soil probe any time you think there is too much or too little water in the yard. If soil is moist in the plant root zone, irrigation level is OK. If the soil is very wet, reduce your watering.												
Rain potential: Turn controllers to "rain pause" or off. Use a soil probe to determine when to turn controllers back on.	✓	✓	✓	✓	✓	✓	✓					
Fertilizing (specialty plants like roses or annuals may have different fertilizer requirements)												
Turf	✓ Balanced slow release					✓ Nitrogen slow release		✓ Nitrogen slow Release			✓ Nitrogen slow release	
Groundcovers	✓ Balanced slow release					✓ Balanced slow release			✓ Balanced slow release			
Shrubs							✓ Balanced slow release					✓ Balanced slow release
Trees						✓ Balanced slow release						✓ Balanced slow release
Weed/Insect Control												
Mulch	✓							✓				
Pesticides (insects)						✓	✓		✓			✓
Herbicides (weeds)					✓		✓				✓ Optional	

Exhibit D
Monthly Landscape Maintenance Guide
Provided for "retrofit" and
"education only" customers
(Actual size 5.5 in. x 8.5 in)

Chapter 7: Findings, Conclusions, and Recommendations

7.1 Overview

The previous chapters of this report evaluate changes in water usage, dry weather runoff, water quality, and customer attitudes and awareness related to irrigation practices associated with the R3 Study. The intent of this chapter is to "integrate" these findings and outline their context as they relate to the interests and goals of the study participants and provide guidance for future efforts to improve water quality in the San Diego Creek watershed and in other areas of the county and state. Information is provided on:

- Findings and conclusions related to study methods for the water conservation, runoff reduction, water quality, and customer acceptance evaluations
- Findings and conclusions related to key results from the four study evaluations
- Recommendations related to future planning and policy

7.2 Study Methods

As noted in Chapters 3 through 6 of this report, study assumptions and methods demonstrated varying degrees of success. This section presents findings and conclusions regarding the degree of reliability of certain evaluation approaches and provides a foundation for future studies to build upon.

7.2.1 Water Conservation

Findings and conclusions regarding the study method for the water conservation evaluation portion of the R3 Study focused on three major areas.

First, the empirical effort used in the study quantified the change in mean water consumption and the shift in seasonal consumption. The models were not extended to document how water savings vary across households, for example, how savings are decreased/increased among lower/higher water use households. Such information could be useful in future studies.

Second, the study evaluated only about one year of post installation data. Thus, the statistical models can say little about the persistence of water savings. Additional follow-up quantification of water savings in subsequent years would be desirable.

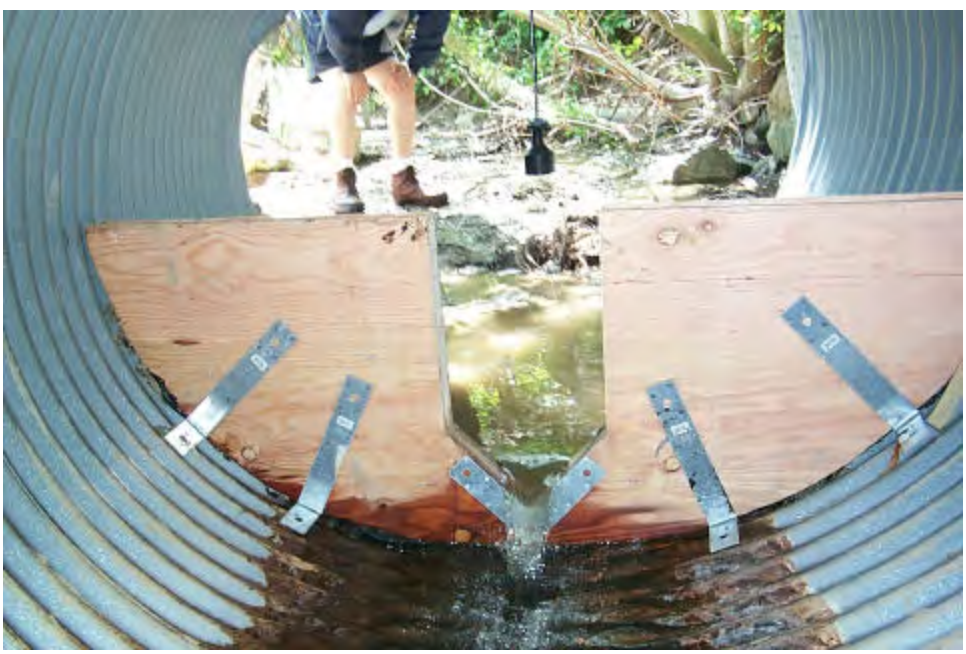
Third, the modeling effort did not estimate the effect of self-selection by the participants in the education-only group. Thus, no attempt was made to extend the inference from the existing sample of participants to: 1) the rest of the service area; or 2) other service areas. The error component of the estimated models could be improved by specifying a function form to explain the variance. This should only be attempted after all major data issues have been resolved.

7.2.2 Runoff Reduction

As discussed in Chapters 2 and 4, significant measurement and data quality issues were associated with the enacted real-time measurement of urban runoff. The technology employed involved custom configurations and numerous needed calibration adjustments. Debris build-up was an early, ongoing, and possibly unavoidable issue that interfered with the calibration of the flow meters. Some of the original locations selected were more prone to this type of problem, and the flow meters were necessarily relocated. Although flow-monitoring problems required data from two of the three control sites to be discarded, the data from the other three sites (two treatments and one control) was sufficiently accurate to allow for the determination of meaningful statistical results.

To minimize the data collection issues experienced during the R3 Study, it would be helpful to install a V-notch weir in the storm drain. (See figure 7-1.) This would enable low flows to be captured and measured more precisely. It should be noted, however, that installation in an underground drain (as opposed to the surface drain shown on the figure) would require protective gear to be worn by the data collectors. Full gear (breathing apparatus) could become cost prohibitive for an aggressive (bi-weekly) monitoring program.

Figure 7-1
Detail of Diversion V-notch Design of Weir Installed in Large Drainage Pipe
(Note: Black sonic sensor hanging directly over V-notch to measure water flow levels.)



7.2.3 Water Quality

As discussed in Chapter 5, two independent reviews of water quality measurements were conducted as part of the R3 Study. Because of the variability of the data and limitations in sample quantities, the first review, which used parametric statistical techniques, provided less definitive results that the second review, which used more robust data analysis techniques. For

some of the parameters reviewed, the robust analytical techniques were able to identify and measure differences in water quality across time and between study treatments.

7.2.4 Public Acceptance

As discussed in Chapter 6, pre- and post- intervention surveys were given to both the retrofit group and the education group. The pre-intervention survey was given to assess and document the prevailing landscape maintenance attitudes and behaviors of both participating groups. The post- intervention survey was given to determine 1) whether or not there was an acceptance of the ET controller as a way of managing landscape irrigation and 2) if exposure to the educational materials and monthly landscape maintenance tips had led to a change in irrigation practices and landscape management behaviors in either study group.

The survey responses indicate that, while 82 to 90 percent of the retrofit and education-only group reported to have read the educational materials, reading these materials did not cause their landscape maintenance habits to change. These responses suggest that future surveys should be designed to capture a measurement of the changes in the study subjects' consumer attitudes and behaviors in greater detail.

Future projects could benefit from using a marketing research firm specializing in the use of polls and surveys to measure residential consumers' attitudes and behaviors. The wording of each pre- and post- intervention survey question can be very carefully crafted in order to target, capture, and quantify each specific pre- and post- intervention behavioral change that is being measured. Identical or one-to-one correspondence between the pre- and post- survey questions is another effective marketing research technique. By documenting customers' changing responses, over time, to identical questions, behavioral shifts can be tracked and quantified.

7.3 Study Results

Key results of the four R3 Study evaluations are summarized below. Because the water conservation and runoff reduction evaluations were interrelated, the results from these evaluations are discussed together below.

7.3.1 Water Conservation and Runoff Reduction

As discussed in Chapter 3, water consumption by residential customers in the retrofit group was reduced by 41.2 gallons per day per household, with a reduction for the education group of 25.6 gallons per day per household. In contrast, whereas the runoff flows for the retrofit group were reduced during the study, flows in the education group increased (Chapter 4). There are three related explanations for this dichotomy: 1) the inclusion of small to medium size "common area" landscapes in the retrofit group and the exclusion of this group from the education group; 2) differences in irrigation scheduling between the residential homes in the two groups; and 3) proximity and relative flow volumes of the landscapes to the storm drain system.

7.3.1.1 Dedicated Landscapes

The retrofit group common areas averaged 0.8 acres in size and encompassed 15 sites/irrigation controllers including city landscape medians, HOA greenbelts, and a park. It is estimated that these sites account for more than 75 percent of the total area under treatment in the Site 1001 area. More specifically, these 15 sites totaled about 12 acres. The remaining 112 irrigation controllers installed on single-family residential lots are estimated to encompass 3.5 to 4 acres. The proportion of residences receiving educational materials including irrigation scheduling information was chosen to match the number receiving retrofit treatment. However, the total treated acres for the two groups varied considerably.

As was the protocol for all retrofit sites, irrigation schedules for these sites were established based on valve-by-valve evaluations of plant, soil, and irrigation system parameters. These schedules resulted in significantly more start times and shorter run times than that observed in these areas prior to the study.

More specifically, prior to installation of the retrofit treatment, each valve was turned on for two minutes to determine the flow. In this brief period, runoff was observed for many of the valves. This relates to the predominant clay soils, where runoff can exceed 90 percent of applied water after short periods due to the low infiltration rates. It is believed that the more frequent, short duration irrigation schedules developed by the treatment irrigation technology is the primary mechanism to reduce runoff from irrigation sites. In addition, these sites were closely monitored and incorporated suggested BMPs such as weekly meter readings. These sites were also used to develop the protocol for the midweek scheduling changes for all of the retrofit area and when to terminate a rain pause for the region.

In contrast to the retrofit group, the controllers on comparable common area landscapes in the education group are assumed to have continued with typical irrigation schedules that likely result in higher levels of runoff. If this is the case, and the common areas account for a similar percentage of irrigated area, this could explain the observed differences in runoff between the retrofit and education groups.

7.3.1.2 Differences in Irrigation Schedules

In addition to the runoff differences likely stemming from the inclusion of the nonresidential landscapes in the retrofit group, irrigation scheduling differences also existed for the residential homes between the retrofit and education groups. The education group households received a suggested irrigation schedule that provided the number of days per week to run the irrigation system, the number of minutes per cycle (start time), and a maximum of three start times. As noted above, short run times and multiple start times are believed to be the key element in reducing irrigation runoff.

Although the post-study survey indicated that about 60 percent of those in the education group changed their controller's irrigation schedule at least "sometimes," it is not clear how closely they followed the suggested schedule, including the recommendation on start times. Inasmuch as programming many controllers for multiple start times can be challenging, it is possible these

instructions were generally overlooked. In contrast, the weather-based irrigation controller used on the retrofit homes automatically reduced the run time for slope, soil, and sprinkler precipitation rate. This will likely reduce runoff even in the absence of direct water savings. This difference may also be a consideration in the dissimilar runoff results in the two treatment sites.

7.3.1.3 Proximity to Storm Drains and Flow Volumes

The final consideration is the location and relative flow volumes of the common area landscapes relative to location and flow volumes of the residences. The common area landscapes were typically located closer to storm drain catch basins (and the study flow monitors) than most residential lots and also had much higher flow volumes on the individual irrigation valves. Runoff from most residential lots had to travel a signficant distance through surface street gutters before reaching catch basins and were subject to both evaporation and seepage in route. In addition, the limited drainage associated with many residential back yards could have further reduced the quantity of water reaching the storm drain from these areas in both the retrofit and education groups. Consequently, the reduction in runoff from treated retrofit common area landscapes and the presumed lack of similar reductions for the education group common areas, combined with the high valve flow volumes, likely explain the differences in observed runoff for the two treatment groups.

7.3.2 Water Quality

As described in Chapter 5, water quality samples were taken twice per month, resulting in a total of 39 samples over an 18-month period. One of the simplest and most straightforward methods to review these samples is to compare them to established water quality objectives for the San Diego Creek watershed. The subsections below address water quality and flow, and runoff water quality.

7.3.2.1 Water Quality and Flow

Chapter 5 of this report also describes issues with the reliability of study flow data during certain study periods and with certain monitoring locations. Because of the temporal relationship of these issues, integrating the water quality and flow data to determine changes in the mass loading of water quality constituents is difficult from a statistical standpoint. However, certainly, the water quality and flow data from the study provide some useful qualitative insight into the impacts of the interventions and may be instructive for future water quality improvement efforts.

7.3.2.2 Runoff Water Quality

Analyses utilizing ore robust statistical methods suggest that the intervention did result in changes in water quality. TN levels in the retrofit neighborhood following intervention were found to be significantly lower than levels before intervention, whereas no detectable differences were noted before and after intervention in the education neighborhood. Relatively large observed reduction in TN flux in the retrofit neighborhood could be influenced by seasonal factors, and the extent to which the ET controller contributed to the reduction is unknown.

7.3.3 Public Education

Data issues discussed previously make it difficult to quantify the impact of public education on reduced water usage and reduced dry season runoff. However, pre- and post-surveys of the retrofit + education and education only groups showed a positive response to the concepts of the irrigation tips. More than 70 percent of the retrofit group participants indicated that they liked the ET controllers, and the group also found that controller irrigation either maintained or improved the landscape. However, it appears that the savings in water use per year is not large enough for the water customers to be willing to pay for an ET signal.

7.4 Recommendations

The application of data from this study will influence future programs and efforts to improve water quality. The application of the irrigation management program focusing on using automatic real-time weather-based irrigation scheduling not only resulted in reductions in onsite/customer water use, but also reduced runoff. With the quality of runoff essentially unchanged, this reduction in runoff should result in a decrease in the total mass of non-point source pollutant loading to the watershed. The relative cost-effectiveness of this program should be evaluated in comparison to other existing or proposed BMPs to improve watershed water quality.

Although not directly determined from the study, the results suggest that the common area landscape sites will provide the most cost-effective application of the water management program. Additional empirical verification of this relative cost-effectiveness supposition is likely warranted.

An additional issue related to the water management program is the availability and viability of the irrigation controllers tested as a part of the study. Although the tested controllers operated reasonably well, occasionally glitches occurred, which necessitated either telephone or onsite intervention by study personnel. For the number of controllers installed for the study, these maintenance issues were manageable. However, the wide-scale use of these controllers would require a significant commitment from the water purveyor or the controller manufacturer to address maintenance issues. At this time, it is not believed that the controller manufacturer has established infrastructure to support a large number of controllers. In addition, the viability of the tested water management program is completely dependent on the regular transmission of data signals from the controller manufacturer to adjust irrigation schedules. Assurances on the long-term viability of signal transmission are imperative to the expansion of the tested program.

In contrast to the water management program, the educational program implemented as a part of the R3 Study reduced customer water use, but did not reduce measured runoff from the study area. Consequently, again assuming no change in runoff quality, this treatment would not appear to provide pollutant mass loading benefits to the watershed. However, the relationship between the observed water savings for the treated portion of the study area and increased runoff for the entire study area is unclear. Because of the clear relative cost advantages of educational programs, additional and more focused studies should be conducted to more fully understand this

relationship and determine the viability of educational programs in reducing non-point source pollution.

Appendix A: References

The Residential Runoff Reduction Study

Appendix A: References

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Appendix B: Study Design

The Residential Runoff Reduction Study

Appendix B: Study Design

Introduction

In 1999, the Municipal Water District of Orange County (MWDOC) and Irvine Ranch Water District (IRWD), in partnership with other national, state, and local agencies and organizations began developing a project to accomplish two goals:

1) Measure changes in the dry weather volume and pollutant content of residential runoff associated with improved irrigation management practices.
2) Confirm residential irrigation water savings identified in a previous study evaluating an automated residential irrigation controller system (the "Westpark Study").

This Appendix presents detailed information on the general study design framework described in Chapter 2. Subjects discussed include watershed selection, flow monitoring, water quality sampling, ET controller operation and selection process, and controller installation and operation.

Watershed Selection

Five watersheds were selected for the study area, based on five criteria: 1) Isolation from other watersheds, 2) climate, 3) land use, 4) development age, 5) irrigation water management techniques.

Isolation from Other Watersheds:

A watershed consists of a region of land, which drains through a single point. The five study watersheds were located in the Northwood Village subdivision in the IRWD service area. Each watershed drains through a single point and is isolated from other sources of runoff. This enabled the runoff flow and water quality to be free of interference from other sources.

Climate

While most of Southern California and Northwood Village have a similar climate, the five watersheds share the same ET zone. They are located within 5 miles of CIMIS station #75, which provides local ET_o information. The ET_o (reference evapotranspiration, the amount of water utilized by plants and lost to evaporation) is the same throughout the Northwood region and most of the central section of the IRWD service area. The plant water requirements of ET_g, which is the standard of turfgrass for cool season turfgrass and is often referred to as simply ET, are the same for all five watersheds.

Due to the close proximity of the all the homes and the lack of any physical or geographical separation of the five watersheds, the study team relied on the CIMIS station #75 for ET_o data.

Land Use

The Northwood section of IRWD's service area was selected because the predominant land use is single-family residence. There are also local parks, common city streetscapes, two condominium associations and one homeowners association (HOA). Several of the watersheds contained townhouses, apartments or condominiums. However, these types of multi-family units were limited in each of the watersheds; no single watershed had a large number of multi-family units.

Development Age

Northwood's neighborhoods were created during two distinct periods of home development. The first phase of development began in the late 1970s and finished in the early 1980s. The second phase started in 2000 and continues to the present. The study excluded the newer section of Northwood for two reasons. First, the newer homes and their HOA are not typical of Southern California. Second, IRWD has monthly water bill information dating back to the late 1980s on homes in the older section of Northwood.

Irrigation Water Management Factors

In addition to ET_o, other basic factors of irrigation water management are precipitation rate, soil type, and plant type. This study implemented real time ET scheduling through a commercially-available signal and distributed educational material to improve water management. Other water management factors are described below.

Precipitation rates vary from irrigation valve to irrigation valve, and most of the homes applied the water with spray heads operating off the pressure provided by IRWD. The individual homeowners installed most of the irrigation systems after the purchase of their houses. The technology used in these irrigation systems was of the same approximate age and featured similar types of equipment. The irrigation systems installed in the study area were also representative of a common irrigation set-up presently in use in Southern California. .

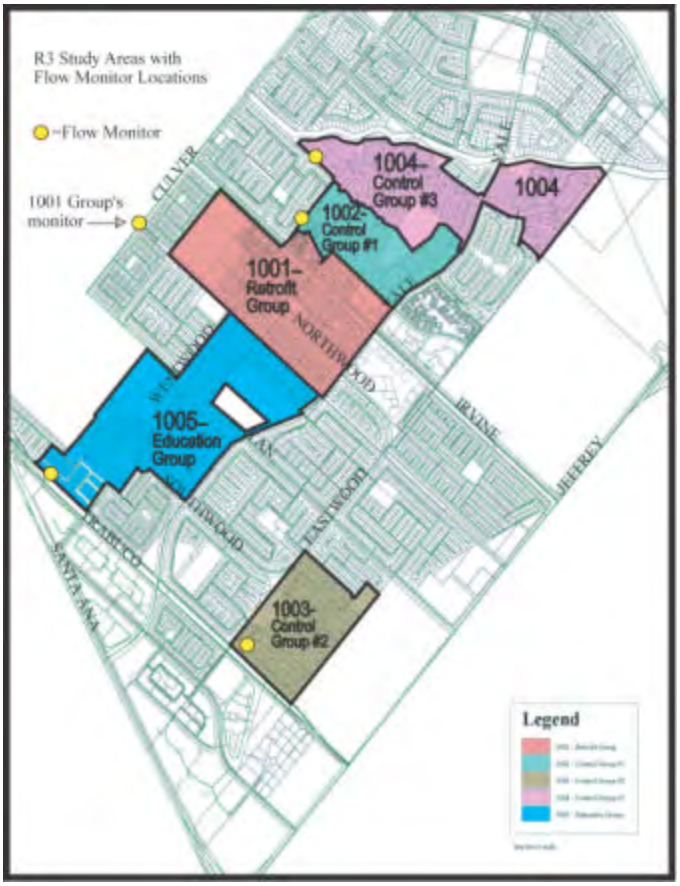
The soil type in the study area is not typical of Southern California and consists of heavy clay. Clay has the lowest infiltration rate and requires the highest level of water management.

The landscapes have sufficiently similar plant material. Although there was no data available to perform a numerical comparison, the study team field surveyed each of the potential watersheds. The majority of landscaping of all homes in the study area consisted of turfgrass. To varying extent, the outside edges, fence, building and walkways areas were lined with shrubs and plant materials other than turfgrass. The best estimate of the ratio of turfgrass to other landscaping is approximately 70 percent. While some of the homes in each of the watersheds may not have followed this construct, the vast majority of landscapes were laid out in this fashion, which allowed the study team to determine which plant materials were mostly consistently found throughout the five watersheds.

Results

After determining that large sections of Northwood were similar and after locating safe monitoring sites, the study team traced the storm drains. The selection of the monitoring site determined the shape and contents of the watershed. The study was able to isolate five watersheds with similar characteristics. The areas of the five watersheds are outlined and labeled in Figure B-1 below.

Figure B-1
Five watershed areas and their corresponding Control groups



Flow Monitoring

The two main criteria for the study's flow monitoring equipment were: 1) the monitor could not alter the pipe or channel and 2) the monitoring must be able to distinguish the seasonal flow changes and any flow change that resulted from the three different treatments (i.e., retrofit group treatment, education-only group treatment, and control group treatment).

Two technologies were suitable for this application: Manning's equation plus a level sensor, or velocity sensor and level monitor (area-velocity). The area-velocity method was chosen due to lack of slope information for the storm drain system. The selected equipment was a Sigma 950, manufactured by Hach. The equipment was battery operated, could record data every minute, and included an ultrasonic transmitter and a velocity sensor located in the storm drain. The ultrasonic transmitter established the water surface level and area, while the velocity sensor determined the velocity of the water in the pipe.

Flow was calculated by the equation: Flow = Area x Velocity. Because four of the five monitoring locations (see Figure B-1 above) were located in pipes, several variations on the ultrasonic transmitter / velocity sensor were tested before the combination of sonic and velocity wafer were selected.

Water Quality Sampling

The water quality sampling program quantified constituents found in residential runoff flows. Because a typical residential neighbor includes more than single-family lots, the concept of water management through an ET signal technology expanded to include common area landscapes.

The water quality sampling program consisted of two phases: 1) pre-study and 2) dry weather sampling.

Pre-study

Based on water level elevation provided by the flow monitors, the study team developed a plan for sampling water quality during dry weather runoff periods. In the early evening (7 to 10 pm) and again in the early morning (3 to 6 am), the water level would rise, indicating an increase in runoff flow. While the amount of change varied by location and date, the pattern was common to all of the watersheds.

The study team performed a weeklong test to determine the most representative sampling time. The team sampled all five study areas every day at 4 am and 7 pm. The constituents sampled were fecal coliform, nutrients, and trace metals.

The test results showed neither differences nor patterns in concentrations between sites, days, and sample times.

Dry Weather Sampling Duration

The final sampling program consisted of bi-weekly sampling of all five sites. During sampling weeks, all five sites were sampled for all analyses listed in Table B-1 on Tuesday, and three sites were sampled for pesticides two additional days. Toxicity samples were collected once per month at all five sites.

Table B-1
Routine Water Quality Analysis Responsibilities

Responsible Lab	Water Quality Parameter	Bottle Type
IRWD	NO_2, NO_3, NH_3, T-PO_4, TKN, O-PO_4, EC, pH, Trace Metals, Total / Fecal Coliform	(2) 1-L Cubitainer (1) 250 ml Sterile
SCCWRP	Toxicity (Sea Urchin Fertilization)	
SCCWRP	Pesticides	
MWL	MS-2 Phage	(1) 1-L (from MWL)
MWL	Enterococcus	(1) 250 mL (from MWL)

The study team collected the biweekly Tuesday samples beginning in January of 2001 and continuing through the next 18 months. The first months of sampling occurred before or during the installation of the ET controllers in the residences and the common landscape. The last 12 months, starting in July 2001 and finishing in June 2002, became the post retrofit samplings. The pesticide sampling continued for an additional six months through December 2002. Table B-2 provides outlines the water quality and data collection schedule for each group in the study.

Table B-2. Water Quality and Data Collection Schedule

Sample Site	Site ID	Cross Streets	Atlas Page	Parameter	Frequency
Group A Education Site Control Site	 1005 1003	 Shadwell/Westmoreland Carver/Carver	 84w – C1 105w – A1	Flow WQ	Weekly Bi-weekly
Group B Control Site Control Site Retrofit Site	 1004 1002 1001	 Hicks Canyon/Park Place La Paloma/Park Place Culver/Florence	 83w – D2 83w - D1 84n – A3	Flow WQ	Weekly Bi-weekly

ET Irrigation Controller Operation and Selection Process

To meet the R3 Study objectives, it was necessary to install as many ET controllers as possible in the retrofit group. Providing the fullest coverage of the watershed with proper irrigation water management generated the best chance of changing the runoff flows. Since residential areas include landscapes other than those of the homeowners, these landscape areas were included in the water management component of the R3 Study. This represents a 3 to 1 ratio of medium-size landscapes to residential landscapes. A description of the installation process for both residential and medium-size landscapes follows:

Residential Landscapes

The IRWD staff attempted to reach as many of the 334 residences in the retrofit watershed as possible. These targeted residents received three letters which informed them of the following:

1) If selected to participate in the study, they would receive a free controller that would automatically adjust the landscape watering.
2) Their participation would be part of an environmental study aimed at preventing runoff from reaching the ocean.
3) They would be saving water without having to program an irrigation controller.
4) They were provided instructions for participating in the study along with a phone number to call to sign-up, as well as a form with a stamped and addressed envelope (for returning the form).

Additionally, IRWD staff hosted a function for the HOA in which staff demonstrated the ET controller to the residents and helped them to complete the sign-up form. Lastly, IRWD staff walked the Northwood neighborhood and hung flyers on the study candidates' front doors. These flyers contained statements from the homeowners in Westpark that had participated in the original ET Controller study. The flyers also described the ET controllers' overall customer satisfaction and ease with which the irrigation system worked.

In all, 137 residents responded to the various communication efforts by agreeing to participate in the study and installing the ET controller on their property. Of the 137 positive responses, 112 homes were equipped with proper automatic valves.

The installation of controllers began in April 2001 and continued through June 2001. A full team of IRWD staff worked weekdays, Saturdays and evenings to complete the installations. Additionally, educational materials were distributed to the retrofit group during installations.

Medium-size Landscapes

In addition to the single-family residences, the retrofit watershed contains 2 condominium complexes, and one HOA with three distinct land use types. The area also contained 12 city streetscapes. The City of Irvine agreed to change out the existing manual controllers with the ET controllers. All of the HOAs agreed to change out their controllers for the ET controllers.

The only major landscape not replacing its existing controller with an ET controller was the park-playground area of the school. The school landscape area consisted of a single meter with two separate controllers and more than 50 valves. This would require at least six ET controllers. Given the limitation in the controller and the high number of cycles that would be required to correctly irrigate the school site, IRWD was not confident that the ET controllers could be programmed in a manner that would avoid conflicting runtimes.

Controller Installation and Operation

The study evaluated the performance of the engineering of irrigation management techniques to reduce the consumption and residential runoff while maintaining the quality of the landscape. A typical irrigation controller is difficult to program and limited in the scope of the scheduling ability. Proper scheduling requires calculations based on real time ET data, landscape topography, and plant type, which are beyond the capabilities of typical controllers. The landscaper in the field is left to guess or rely on past experience as to the correct amount of water, the correct runtime to prevent runoff, and the correct days of the week to water.

The operation of the ET controller in this study was optimized by: 1) weekly maintenance, and 2) proper irrigation scheduling. IRWD staff programmed the controllers, which were operated by a combination of IRWD staff and HydroPoint consultants. (HydroPoint Data Systems, also known as HydroPoint, developed and supplied the ET controllers used in the R3 Study.)

During the prior study in Westpark, the programming was calculated based on a design precipitation rate suggested for spray heads. That study received numerous complaints that too much water was being applied and an effort was undertaken to conduct an area/flow measurement to determine the actual precipitation rate. These measurements indicated an average precipitation rate of 3.98 inches per hour while the design precipitation rate for the spray heads was 1.80 inches per hour. The measured rates varied from as low as 1.4 inches per hour to as high as 9 inches per hour. This suggested that standard settings in which a homeowner would program the controller are unlikely to efficiently run the irrigation. Because of this and other important factors, trained staff preformed the installations

Appendix C: Statistical Analysis of Water Savings

The Residential Runoff Reduction Study

Appendix C - Statistical Analysis of Water Savings

Prepared for
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Summary

Findings

$ **Single Family Residences:** Households receiving an evapotranspiration (ET) controller and education were found to save approximately 41.2 gallons per day on average (33.2 gpd – 49.2 gpd is the 95 percent confidence level). Households receiving the education treatment alone were found to save approximately 25.6 gallons per day on average (20.1 gpd – 31.1 gpd is the 95 percent confidence level). This sample compared 93 ET controller/education participants and 192 education-only participants to 1236 nonparticipating single family customers.

A secondary finding in this sample related to seasonal shape in this average savings effect. For the one year of post-intervention consumption data within our sample, the water savings was not constant. The ET controller/education intervention, in particular, saved more water in the autumn and less in the spring growing season.

$ **Landscape-Only Accounts:** Among a smaller sample of 21 landscape-only accounts, significant water savings (16 percent) were obtained from the use of ET controllers. A sample of 76 matched sites (similar in landscaped area and type of use) also showed the effects of City water efficiency improvements. Since both of these samples contain a large number of medians and streetscapes, it is possible that each gallon saved from irrigation-only sites contributes more to runoff

reduction than a gallon saved at a single family site. Since the runoff reduction was not measured by customer account, this study will not be able to confirm or deny this hypothesis.

Introduction

The purpose of this work is a statistical analysis of water savings among customers who installed evapotranspiration (ET) controllers and customers given irrigation education in the Irvine Ranch Water District. This report documents a careful statistical analysis of historical water consumption data to derive estimates of the net water savings from these interventions.

Approach

Historical water consumption records (July 1997 to August 2002) for a sample of participants and for a sample of nonparticipating customers were examined statistically. The hypothesis was that installation of new irrigation technology or better management of existing equipment would reduce the observed water consumption of customers participating in this program. This study empirically estimates the water savings that resulted from both types of interventions—(1) customers receiving both ET controllers and follow-up education and (2) customers receiving an education-only intervention.

Since installation of ET controllers required the voluntary agreement of the customer to participate, this sample of customers can be termed "self-selected." Customers were randomly chosen to receive the education-only treatment. While this analysis does quantitatively estimate the reduction of participant's water consumption, one may not directly extrapolate this finding to nonparticipants. This is because self-selected participant can differ from customers that decided not to participate.

The explanatory variables in these models include

- Deterministic functions of calendar time, including
  - The seasonal shape of demand
- Weather conditions
  - measures of air temperature
  - measures of precipitation, contemporaneous and lagged
- Customer-specific mean water consumption
- "Intervention" measures of the date of participation and the type of intervention

Data and Methods

Consumption records were compiled from the IRWD customer billing system for customers in the study areas. Billing histories were obtained from meter reads between July 1997 and August 2002. It is important to note that a meter read on August 1 will largely represent water consumption in July. Since the ET controllers were installed in May and June of 2001, the derived sample will only contain slightly more than one year of data for each participant. Table 1 presents descriptive statistics on the sample.

Table 1: Single Family Residential Sample Descriptive Statistics

	Site 1001		Site 1004	Site 1005	
	ET Controller Participant	Non-Participant	Control	Education Participant	Non-Participant
Number of Usable Accounts	97	213	264	196	346
Pre-period: July 1997-May 2001					
Mean Use (gpd)	375	371	405	390	418
No. of observations	4,504	9,860	12,452	9,251	16,364
Post-period: June 2001-August2002					
Mean Use (gpd)	366	379	427	395	421
No. of observations	1,358	2,982	3,694	2,744	4,856

The landscape-only customers (21 accounts) were handled separately. Two control groups were developed for these irrigation accounts: A matched control group was selected by IRWD staff by visual inspection, finding 3-5 similar control sites for each participating site. Similarity was judged by irrigated area and type of use (Home Owner Association, Median, Park, or Streetscape). Since the City of Irvine was improving irrigation efficiency on the City-owned sites during the post-intervention period, this matched control group also had potential water savings. A second control group was developed where the selection was done solely located by geographic area. In this way, the statistical models can separately estimate the water savings effects for each group.

Table 2: Landscape Accounts Descriptive Statistics

	Participant	Matched Control	Unmatched Control
Number of Usable Accounts	21	76	895
Acres per Account	0.93	0.92	0.96
Type of Account (if known)			
HOA	3	13	
Median	3	11	
Park	1	6	
Streetscape	14	47	
Pre-period: July 1997-June 2001			
Mean Use (gpd)	2,948	2,768	3,042
Mean Use per Acre (inches/day)	0.11702	0.11823	0.12893
No. of observations	967	3,503	39,352
Post-period: July 2001-August2002			
Mean Use (gpd)	2,845	2,990	3,271
Mean Use per Acre (inches/day)	0.10813	0.12012	0.13013
No. of observations	293	1,052	12,121

The first major issue with using meter-read consumption data is the level and magnitude of noise in the data. The second major issue is that records of metered water consumption can also embed non-ignorable meter mis-measurement. To keep either type of data inconsistencies from corrupting statistical estimates of model parameters, this modeling effort employed a sophisticated range of outlier-detection methods and models. These are described in the next section.

Daily weather measurements—daily precipitation, maximum air temperature, and evapotranspiration—were collected from the CIMIS weather station located in Irvine. The daily weather histories were collected as far back as were available (January 1, 1948) to provide the best possible estimates for "normal" weather through the year. Thus we have at least 54 observations upon which to judge what "normal" rainfall and temperature for January 1^{rst} of any given year.

Robust regression techniques were used to detect which observations are potentially data quality errors. This methodology determines the relative level of inconsistency of each observation with a given model form. A measure is constructed to depict the level of inconsistency between zero and one; this measure is then used as a weight in subsequent regressions. Less consistent observations are down-weighted. Other model-based outlier diagnostics were also employed to screen the data for any egregious data quality issues.

Specification

A Model of Water Demand

The model for customer water demand seeks to separate several important driving forces. In the short run, changes in weather can make demand increase or decrease in a given year. These models are estimated at a household level and, as such, should be interpreted as a condensation of many types of relationships—meteorological, physical, behavioral, managerial, legal, and chronological. Nonetheless, these models depict key short-run and long-run relationships and should serve as a solid point of departure for improved quantification of these linkages.

Systematic Effects

This section specifies a water demand function that has several unique features. First, it models seasonal and climatic effects as continuous (as opposed to discrete monthly, semi-annual, or annual) function of time. Thus, the seasonal component in the water demand model can be specified on a continuous basis, then aggregated to a level comparable to measured water use (e.g. monthly). Second, the climatic component is specified in different form as a similar continuous function of time. The weather measures are thereby made independent of the seasonal component. Third, the model permits interactions of the seasonal component and the climatic component. Thus, the season-specific response of water demand can be specific to the season of the year.

The general form of the model is:

Equation 1

$$Use = m_i + S_t + W_t + E_{i,t}$$

where ***Use*** is the quantity of water demand within time *t*, the parameter $\boldsymbol{\mu_i}$ represents mean water consumption per meter *i*, $\boldsymbol{S_t}$ is a seasonal component, $\boldsymbol{W_t}$ is the weather component, $\boldsymbol{E_{i,t}}$ is the effect the landscape interventions for meter *i* at time period *t*. Each of these components is described below.

Seasonal Component : A monthly seasonal component can be formed using monthly dummy variables to represent a seasonal step function. Equivalently, one may form a combination of sine and cosine terms in a Fourier series to define the seasonal component as a continuous function of time.[1] The following harmonics are defined for a given day *T*, ignoring the slight complication of leap years:

Equation 2

$$S_t \equiv \sum_{1}^{6}\left[b_{i,j} \cdot \sin\left(\frac{2p \cdot jT}{365}\right) + b_{i,j} \cdot \cos\left(\frac{2p \cdot jT}{365}\right)\right] = Z \cdot b_S$$

[1] The use of a harmonic representation for a seasonal component in a regression context dates back to *Hannan* [1960]. *Jorgenson* [1964] extended these results to include least squares estimation of both trend and seasonal components.

where T = (1,...365) and j represents the frequency of each harmonic.[2] Because the lower frequencies tend to explain most of the seasonal fluctuation, the higher frequencies can often be omitted with little predictive loss.

To compute the seasonal component one simply sums the multiplication of the seasonal coefficient with its respective value. This number will explain how demand changes due to seasonal fluctuation.

Weather Component: The model incorporates two types of weather measures into the weather component–maximum daily air temperature and rainfall.[3] The measures of temperature and rainfall are then logarithmically transformed to yield:

Equation 3

$$R_t \equiv \ln\left[1+\sum_{t=T}^{T_d} Rain_t\right], A_t \equiv \ln\left[\sum_{t=T}^{T_d} \frac{AirTemp_t}{d}\right]$$

where d is the number of days in the time period. For monthly aggregations, d takes on the values 31, 30, or 28, ignoring leap years; for daily models, d takes on the value of one. Because weather exhibits strong seasonal patterns, climatic measures are strongly correlated with the seasonal measures. In addition, the occurrence of rainfall can reduce expected air temperatures. To obtain valid estimates of a constant seasonal effect, the seasonal component is removed from the weather measures by construction.

[2] If measures of water demand are available on a daily basis, the harmonics defined by Equation 2 can be directly applied. When measures of water demand are only observed on a monthly basis, two steps must be taken to ensure comparability. First, water demand should be divided by the number of days in the month to give a measure of average daily use. Otherwise, the estimated seasonal component will be distorted by the differing number of days in a month. The comparable measures of the seasonal component are given by averaging each harmonic measure for the number of days in a given time period.

[3] Specifically it uses the maximum daily air temperature and the total daily precipitation at the Irvine weather station. This station was selected due to its proximity to the study area.

Specifically, the weather measures are constructed as a departure from their "normal" or expected value at a given time of the year. The expected value for rainfall during the year, for example, is derived from regression against the seasonal harmonics. The expected value of the weather measures ($\hat{\boldsymbol{A}}=\boldsymbol{Z}\bullet$) is subtracted from the original weather measures:

Equation 4

$$W_t \equiv (R_t - \hat{R}_t)\cdot b_R + (A_t - \hat{A}_t)\cdot b_A$$

The weather measures in this deviation-from-mean form are thereby separated from the constant seasonal effect. Thus, the seasonal component of the model captures all constant seasonal effects, as it should, even if these constant effects are due to normal weather conditions. The remaining weather measures capture the effect of weather departing from its normal pattern.

The model can also specify a richer texture in the temporal effect of weather than the usual fixed contemporaneous effect. Seasonally-varying weather effects can be created by interacting the weather measures with the harmonic terms. In addition, the measures can be constructed to detect lagged effects of weather, such as the effect of rainfall one month ago on this month's water demand.

Effect of Landscape Interventions: Information was compiled on the timing and location of each ET controller installation and education-only customer participation. The account numbers from these data were matched to meter consumption histories going back to 1997. All raw meter reads were converted to average daily consumption by dividing by the number of days in the read cycle. Using these data, relatively simple

"intervention analysis" models[4] were statistically estimated where, in this case, the intervention is ET controller installation and/or participation in the landscape education program. The form of the intervention is:

Equation 5

$$E_{i,t} \equiv I_{ET} \cdot b_{ET} + I_{Ed} \cdot b_{Ed}$$

The indicator variable I_{ET} takes on the value one to indicate the presence of a working ET controller and is zero otherwise. The indicator variable I_{Ed} takes on the value one if a household agreed to participate in the education program and is zero otherwise.

The parameter $\hat{b}_{ET}$ represents the mean effect of installing an ET controller and is expected to be negative (installing an ET controller reduces water consumption.) The parameter $\hat{b}_{Ed}$ has a similar interpretation for the education-only participants.

This formulation also permits formal testing of the hypothesis that landscape interventions can affect the seasonal shape of water consumption within the year. Since numerous studies have identified a tendency of customers to irrigate more than ET requirements in the fall and somewhat less in the spring, it will be informative to examine the effect of ET controllers designed to irrigate in accord with ET requirements. The formal test is enacted by interacting the participation indicators with the sine and cosine harmonics.

[4]See Box and Tiao, "Intervention Analysis with Applications to Economic and Environmental Problems" *Journal of the American Statistical Association*, Vol 70,No. 349, March 1975, pp. 70-70.

Stochastic Effects

To complete the model, we must account for the fact that not every data point will lie on the plane defined by **Equation 1**. This fundamental characteristic of all systematic models can impose large inferential costs if ignored. Misspecification of this "error component" can lead to inefficient estimation of the coefficients defining the systematic forces, incorrect estimates of coefficient standard errors, and an invalid basis for inference about forecast uncertainty. The specification of the error component involves defining what departures from pure randomness are allowed. What is the functional form of model error? Just as the model of systematic forces can be thought of as an estimate of a function for the "mean" or expected value, so too can a model be developed to explain departures from the mean—i.e., a "variance function" If the vertical distance from any observation to the plane defined by **Equation 1** is the quantity **e**, then the error component is added to **Equation 1**:

Equation 6

$$Use = \mathbf{f}(\mathbf{S}_t, \mathbf{C}_t, \mathbf{T}_t) + e$$

The error structure is assumed to be of the form:

Equation 7

$$e_{it} = m_i + x_{it}$$
$$where$$
$$m_i \sim N(0, s_m^2)$$
$$x_{it} \sim N(0, s_x^2)$$

The X and $?$ are assumed to be independent of each other and of μ. The individual component μ represents the effects of unmeasured household characteristics on household water use. An example of such an unmeasured characteristic might be the water use behavior of household members. This effect is assumed to persist over the estimation period. The second component $?$ represents random error. Because μ and $?$ are independent, the error variance can be decomposed into two components:

Equation 8

$$s_e^2 = T \cdot s_m^2 + s_x^2$$

This model specification is accordingly called an error components or variance components model. The model was estimated using maximum likelihood methods.

Estimation Results

Estimated Landscape Customer Water Demand Model

Table 3 presents the estimation results for the model of landscape (irrigation-only) customer water demand in the R3 study sites. This sample represents water consumption among 992 accounts between June 1997 and August 2002. This sample contains 21 ET controller accounts, 76 matched control accounts, and 895 unmatched control accounts.

The constant term (1) describes the intercept for this equation. The independent variables 2 to 9—made up of the sines and cosines of the Fourier series described in Equation 2—are used to depict the seasonal shape of water demand. The estimated weather effect is specified in "departure-from-normal" form. Variable 10 is the departure of monthly temperature from the average temperature for that month in the season. (Average seasonal temperature is derived from a regression of daily temperature on the seasonal harmonics.) Rainfall is treated similarly (Variable 11). One month lagged rainfall deviation is also included in the model (Variables 12). The next variable accounts for the amount of irrigated acreage on the site. (Note that while measured acreage is available for all irrigation-only accounts, this is not true for single family accounts.)

The effect of the landscape conservation program interventions is captured in the following rows. The parameter on the indicator for ET controllers (15) suggests that the mean change in water consumption is 472 gallons per day, approximately 16 percent of the pre-intervention water use. The matched control group (17) did experience water savings, approximately 241 gallons per day or 8.7 percent of their pre-intervention water use. The variables testing for differences in pre-intervention use cannot distinguish any differences between the different types of accounts.

Table 3: Landscape Customer Water Demand Model Dependent Variable: Average Daily Metered Water Consumption (in gallons per day)		
Independent Variable	**Coefficient**	**Std. Error**
1. Constant (Mean intercept)	2619.0670	234.8112
2. First Sine harmonic, 12 month (annual) frequency	-811.6864	26.3271
3. First Cosine harmonic, 12 month (annual) frequency	-1984.6310	25.9776
4. Second Sine harmonic, 6 month (semi-annual) frequency	104.1141	26.5769
5. Second Cosine harmonic, 6 month (semi-annual) frequency	-18.5088	26.9614
6. Third Sine harmonic, 4 month frequency	-124.1069	28.1396
7. Third Cosine harmonic, 4 month frequency	107.1129	28.4812
8. Fourth Sine harmonic, 3 month (quarterly) frequency	39.5420	30.5372
9. Fourth Cosine harmonic, 3 month (quarterly) frequency	-62.1012	30.7453
10. Deviation from logarithm of 31 or 61 day moving average of maximum daily air temperature	6306.4130	562.5547
11. Deviation from logarithm of 31 or 61 day moving sum of rainfall	-747.0860	51.9108
12. Monthly lag from rain deviation	-209.8997	46.2994
13. Irrigated Acreage (in acres)	490.5891	139.6673
14. ET controller sites, test for difference in pre-intervention use	-46.2624	1278.0470
15. Average Effect of ET controller (21 accounts)	-472.1763	279.4630
16. Matched accounts, test for difference in pre-intervention use	-166.3042	691.8883
17. Average Effect of city efficiency improvements (76 accounts)	-240.9208	148.0551
Number of observations		57017
Number of customer accounts		983
Standard Error of Individual Constant Terms		5749.64
Standard Error of White Noise Error		4179.81
Time period of Consumption	June 1997 - July 2002	

Estimated Single Family Residential Water Demand Model

Table 4 presents the estimation results for the model of single family water demand in the R3 study sites. This sample represents water consumption among 1,525 single family households between June 1997 and July 2002. This sample contains 97 ET

controller/education participants (in Site 1001) and 192 education-only participants (in Site 1005).

The constant term (1) describes the mean intercept for this equation. (A separate intercept is estimated for each of the 1,525 households but these are not displayed in Table 4 for reasons of brevity.) The independent variables 2 to 8—made up of the sines and cosines of the Fourier series described in Equation 2—are used to depict the seasonal shape of water demand. The predicted seasonal effect (that is, $Z \cdot \hat{b}_S$) is the shape of demand in a normal weather year. This seasonal shape is important in that it represents the point of departure for the estimated weather effects (expressed as departure from normal). We will also test to see if the landscape interventions have any effect on this seasonal shape.

The estimated weather effect is specified in "departure-from-normal" form. Variable 11 is the departure of monthly temperature from the average temperature for that month in the season. (Average seasonal temperature is derived from a regression of daily temperature on the seasonal harmonics.) Rainfall is treated in an analogous fashion (Variable 14). One month lagged rainfall deviation is also included in the model (Variables 15). The reader should also note that the contemporaneous weather effect is interacted with the harmonics to capture any seasonal shape to both the rainfall (Variables 12 and 13) and the temperature (Variables 9 and 10) elasticities. Thus, departures of temperature from normal produce the largest percentage effect in the spring growing season. Similarly, an inch of rainfall produces a larger effect upon demand in the summer than in the winter.

The effect of the landscape conservation program interventions is captured in the following rows. The parameter on the indicator for ET controllers/education (16) suggests that the mean change in water consumption is 41.2 gallons per day while the education only participants (19) saved approximately 25.6 gallons per day. The model cannot say whether education-only participants saved this water through improved irrigation management or by also reducing indoor water consumption. Since the sample includes only one year of post-intervention date, the model cannot say how persistent either effect will be in future years.

Table 4: Single Family Residential Water Demand Model Dependent Variable: Average Daily Metered Water Consumption (in gallons per day)		
Independent Variable	**Coefficient**	**Std. Error**
1. Constant (Mean intercept)	405.6593	3.1660
2. First Sine harmonic, 12 month (annual) frequency	-45.4215	0.9636
3. First Cosine harmonic, 12 month (annual) frequency	-89.1494	0.9629
4. Second Sine harmonic, 6 month (semi-annual) frequency	3.6549	0.6798
5. Second Cosine harmonic, 6 month (semi-annual) frequency	1.0709	0.6733
6. Third Cosine harmonic, 4 month frequency	1.7312	0.7151
7. Fourth Sine harmonic, 3 month (quarterly) frequency	4.4016	0.7403
8. Fourth Cosine harmonic, 3 month (quarterly) frequency	3.3491	0.7865
9. Interaction of contemporaneous temperature with annual sine harmonic	48.7897	17.1559
10. Interaction of contemporaneous temperature with annual cosine harmonic	-72.4672	22.3626
11. Deviation from logarithm of 31 or 61 day moving average of maximum daily air temperature	284.7163	13.542
12. Interaction of contemporaneous rain with annual sine harmonic	10.1102	1.8546
13. Interaction of contemporaneous rain with annual cosine harmonic	5.9969	2.6904
14. Deviation from logarithm of 31 or 61 day moving sum of rainfall	-34.0117	1.8931
15. Monthly lag from rain deviation	-13.3173	1.0549
16. Average Effect of ET controller/Education (97 participants)	-41.2266	4.0772
17. Interaction of ET intervention with annual sine harmonic	38.9989	5.3327
18. Interaction of ET intervention with annual cosine harmonic	-6.3723	4.8980
19. Average Effect of Education-only intervention (192 participants)	-25.5878	2.8081
20. Interaction of Ed.-only intervention with annual sine harmonic	6.0357	3.5870
21. Interaction of Ed.-only intervention with annual cosine harmonic	-3.0703	3.3826
Number of observations	94,655	
Number of customer accounts	1,525	
Standard Error of Individual Constant Terms		120.85
Standard Error of White Noise Error		129.81
Time period of Consumption	June 1997- July 2002	

How ET Controllers Affect Peak Demand

The question of how these programs affected the seasonal shape of water demand can be interpreted from the remaining interactive effects—the indicators interacted with the first sine and cosine harmonics. For example, the seasonal shape of demand can be derived before and after ET controller/education participation:

$$\text{Pre_Intervention}: S_t = Z \cdot \hat{b}_S \approx -45.4 \cdot \sin_1 - 89.1 \cdot \cos_1 + 3.6 \cdot \sin_2 + 1.1 \cdot \cos_2 + \ldots + 3.4 \cos_4$$

$$\text{Post_ETIntervention}: S_t^{'} \approx Z \cdot \hat{b}_S + 39 \cdot I_{ET} \cdot \sin_1 - 6.4 \cdot I_{ET} \cdot \cos_1$$

When the pre/post seasonal patterns are combined with their pre/post mean water consumption, the following before and after picture can be seen throughout the year.

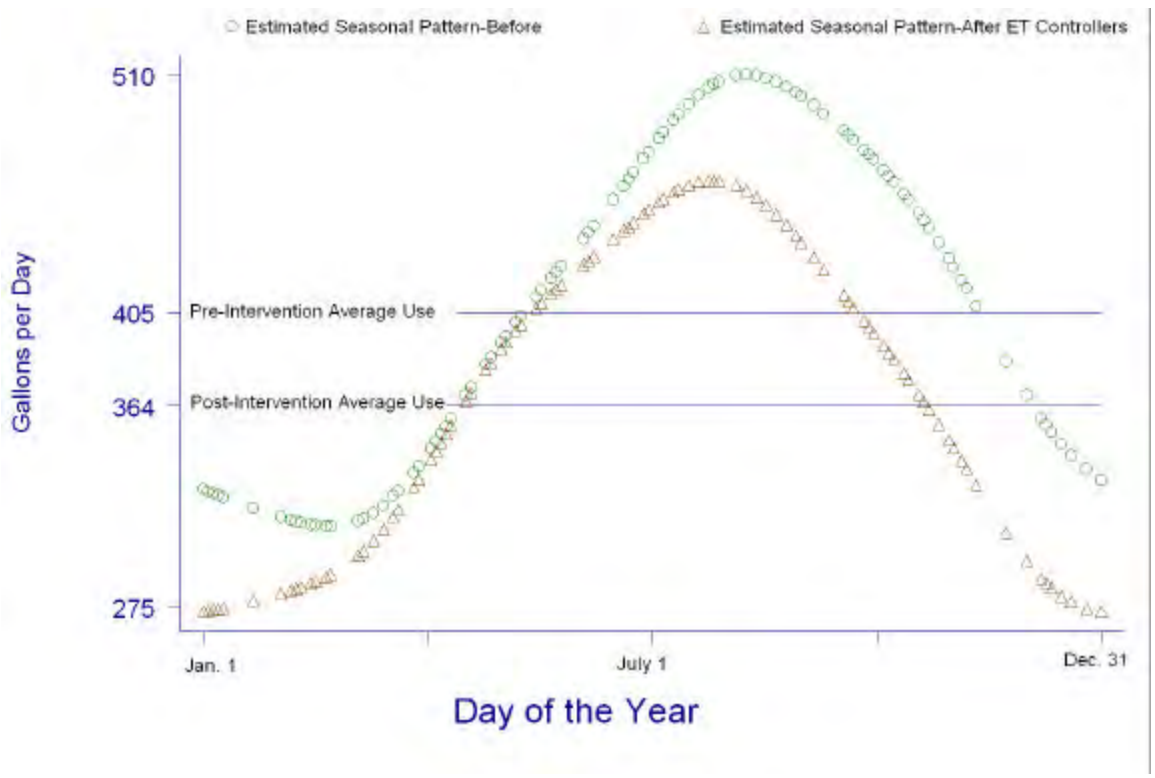

Figure 1-Effect of ET intervention on Water Demand

In Figure 1, several observations should be made. First, the difference between the two horizontal lines corresponds to the estimated mean reduction of approximately 41 gallons

per day. Second, the assumption of a constant 41 gallon per day effect does not hold true throughout the year. The reduction is barely noticeable in the spring growing season and is much larger in the fall.

The reduction in peak demand—though dependent upon how the seasonal peak is defined[5]—is greater than the average reduction. The estimated peak day demand, occurring on August 8, is reduced by approximately 51 gallons. This "load-shaping" effect of the ET controller intervention can translate into an additional benefit to water agencies. The benefits from peak reduction derive from the avoided costs of those water system costs driven by peak load and not average load—the costs for new treatment, conveyance, and distribution all contain cost components driven by peak capacity requirements.

Figure 2 plots the corresponding estimates for the Education-only intervention. The reduction in average demand is less—approximately 25 gallons per day. The effect upon the estimated seasonal shape of demand is much more muted. In fact, the change to the estimated seasonal shape of demand induced by the education-only intervention is not significantly different from zero at classical levels of significance.

[5] This is the issues of "coincident" versus "noncoincident" peak demand: the extent to which the peak load of a customer coincides with the system peak. Water systems by their nature have a strong and predictable tendency to peak seasonally—for Southern California, this occurs in the summer. Given the predictability of system peaks, and the attendant costs, the empirical case for the contribution of ET controller load shaping to the reduction of systems cost is relatively straightforward. The additional value of peak reduction--over and beyond reductions in average consumption--require careful specification of the additional incremental costs necessitated by peak flow requirements.

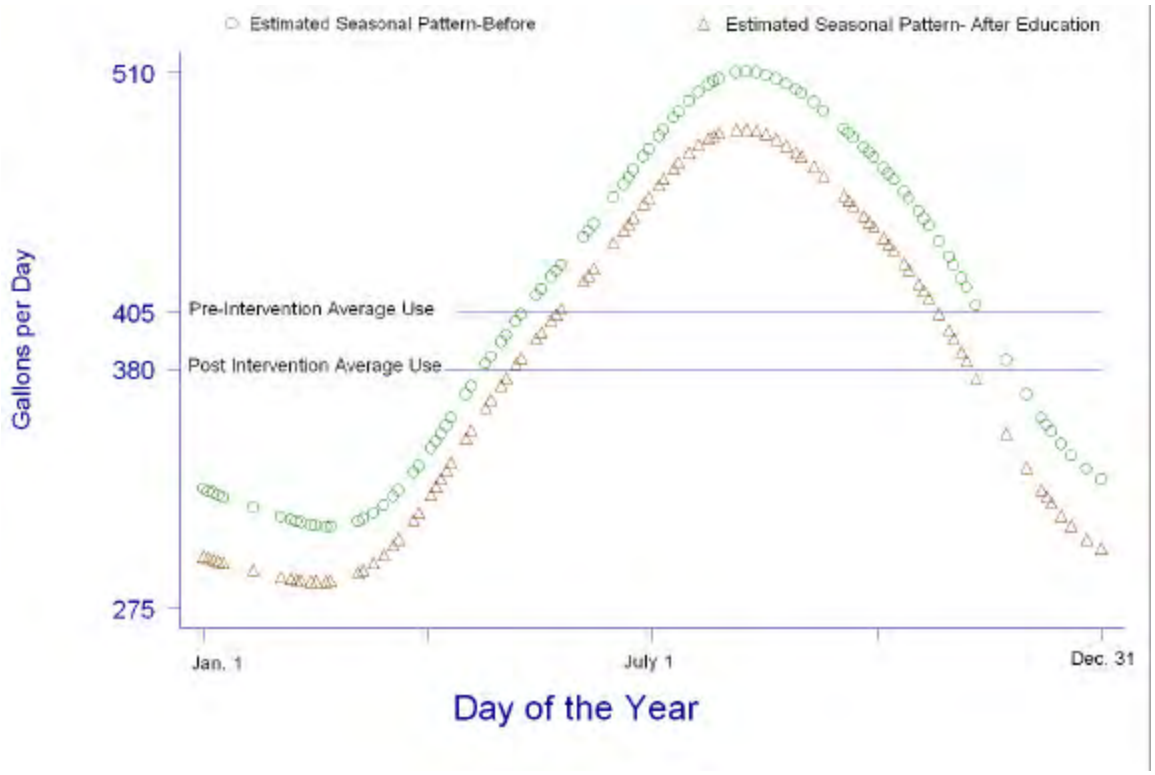

Figure 2-Estimated Effect of Education-only on Water Demand

Caveats and Additional Work

This modeling effort focused on developing the best depiction of net changes in water consumption due to the landscape interventions of ET controllers and/or education. Much of the modeling effort was expended on data cleaning, diagnosis, and validation. We believe that the most serious data issues were identified and appropriately handled. To the extent that future data quality can be improved, future work could provide several statistical refinements in model specification:

- The empirical effort has quantified the change in mean water consumption and the shift in seasonal consumption. The models have not been extended to document how water savings vary across households—how are savings decreased/increased among lower/higher water use households?
- Since the sample only contains about one year of post installation data, the statistical models can say little about the persistence of water savings. Additional follow-up quantification of water savings in subsequent years is required.
- The modeling effort to date has *not* attempted to estimate the effect of self-selection. Thus, we make no attempt to extend the inference from the existing sample of participants to (1) the rest of the service area or (2) to other service areas.
- The error component of the estimated models could be improved by specifying a function form to explain the variance. This should only be attempted after all major data issues have been resolved.

Conclusion

This report documents the shape of water savings achieved by the landscape interventions of ET controllers and/or education. Households participating in these programs saved significant amounts of water. The education-only program showed less water savings than the ET controller/education program, but were still significant. The ET controller/education program changed both the level and shape of water demand.

Appendix D1: Statistical Analysis of Urban Runoff Reduction

The Residential Runoff Reduction Study

Appendix D1 - Statistical Analysis of Urban Runoff Reduction

Prepared for
Municipal Water District of Orange County and
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Summary

$ **Data Reliability and Validity:** There were significant measurement and data quality issues with the enacted real-time measurement of urban runoff. The technology employed involved custom configurations and numerous needed calibration adjustments. Debris build-up was an early, ongoing, and possibly unavoidable issue that interfered with the calibration of the flow meters. Some of the original locations selected were more prone to this type of problem and the flow meters were necessarily relocated. Careful attention was paid to documenting data quality issues in ways that did allow for quantitative evaluation of runoff. Nonetheless, the intrinsic data reliability constrain the inference that can be drawn.

$ **Control Study Sites 1002 and 1003:** The measured runoff for the study sites 1002 and 1003—potential control sites—had recurring measurement issues that produced generally unreliable runoff data. We were unable to use the runoff data from either of these sites to serve as a match to either of the sites receiving landscape interventions (ET controllers and/or education).

$ **Control Site (1004):** The unadjusted runoff flow at Site 1004 contained some elevated and likely invalid flow recordings in the pre-intervention period; that is prior to May 2001. Using robust statistical modeling methods, the spurious flow observations were identified and "quarantined." It is possible that these high flow

measures were completely accurate measures of real runoff within Site 1004; perhaps one or more customers experienced undetected leaks. If this is the case, then Site 1004 could not serve as a good "matched" control site. The runoff in the post-intervention period for the Control Site 1004 increased 63 percent from the pre-intervention period.

$ **Effect of Education-only Intervention (Site 1005):** Study site 1005 contained approximately 565 single family residences. Of these, 225 residential customers agreed to participate in the irrigation education program. Study site 1005 was found to have post-intervention runoff (after May 2001) that was 36 percent higher than pre-intervention runoff (May 2001 and before). The question of how much higher runoff might have been without the education intervention necessitates comparisons to comparable sites that did not receive any intervention.

Comparison across sites can, in theory, control for time-varying covariance in runoff. That is, measured runoff from a matched control group could be used to estimate how runoff increases in the summer period. Comparing across sites, however, will also require standardizing for the different areas across sites and testing for how well matched the sites are in the pre-intervention period. These results are presented in the body of this chapter. If one is willing to accept the Control Site as a matched control, Site 1005's post-intervention runoff is 21 percent less than expected.

$ **Effect of Evapotranspiration Controller/Education Intervention:** Study site 1001 contained 565 single family residences. Of these, 114 agreed to participate in the evapotranspiration (ET) controller/education program. In addition, approximately 26 landscape sites (HOA, City median, parks, and school sites) also received ET controllers.

Study site 1001 was found to have post-intervention runoff (after May 2001) that was approximately 49 percent less than pre-intervention runoff (May 2001 and before). These two time periods are not equivalent as valid pre-intervention measures include less than four months of data. Since urban runoff derives from outdoor water use, it generally increases in the spring and summer and declines in the autumn and winter. Hence, the 49 percent runoff reduction is likely to be an underestimate of the level of runoff reduction that would be estimated on comparable time periods.

Using either Site 1005 or 1004 as matched controls implies that the observed post-intervention runoff was 64 to 71 percent less than expected.

Introduction

The purpose of this work is a statistical analysis of the reduction of runoff induced by Evapotranspiration (ET) controllers and irrigation education in the Irvine Ranch Water District. This report documents a careful statistical analysis of measured runoff in residential areas to derive estimates of the runoff reduction from these interventions.

Data and Methods *THIS INFO NEEDS TO BE ADDED BY IRWD STAFF*

Data collection (by IRWD staff)

Description of flow meters and how they work
Description of staff meter checking
Description of QA/QC on data (flagging suspect data through "rank" indicator)
Description of calibration tests - measurement issues at high (wet day) flow rates

Methods

Robust regressions techniques were used to detect which observations are potentially data quality errors. This methodology determines the relative level of inconsistency of each observation with a given model form. A measure is constructed to depict the level of inconsistency between zero and one; this measure is then used as a weight in subsequent regressions. Less consistent observations are down-weighted. Other model-based outlier diagnostics (Cook's distance, DFBETA statistics, and residual diagnostics) were also employed to screen the data for any egregious data quality issues.

Results

Descriptive Statistics

Raw flow rates

After screening for the known data quality problems, using the "rank" indicator, all raw meter reads were first converted to average hourly values. These were then aggregated by date to convert to daily runoff—the runoff measures are available in both mean hourly flow and total daily volume. Precipitation taken from the Irvine weather station was matched to the daily data and used to separate wet from dry days. Wet weather storm flow can be a more complicated phenomenon to predict, as it depends on the timing and magnitude of the rainfall event, the moisture deficit of soils, and other factors. The relative lack of large storm events in the post-intervention period precluded examination of these more complicated forces and the effect that the landscape interventions might have on wet day runoff.

Standardizing for area

Area-standardized measures of site runoff were also created for dry/wet days, where total daily volume was divided by the estimated permeable/total area. Estimates of area for the study sites were derived from the IRWD GIS system. The GIS system was queried to produce estimates of the number of lots and total area for the different land use classifications (single family residence, condo, HOA, school, landscape, street, and unknown). The GIS system also provided an estimate of the number of buildings, and building area. The area taken up by buildings is treated as impermeable. The remaining area was separated into permeable and impermeable area using a land use classification-specific assumption of impermeability. Table 1 provides the raw data used to construct the estimated site area. (Due to lack of usable flow measures, Sites 1002 and 1003 are not separately reported.) Table 2 aggregates these data by site.

Table 1: Estimated Area of Study Sites by Land Use

R3 GROUP	#Lots	Classification	Total Area	Building Area	Assumed Impermeable Coefficient	Estimated Impermeable Area	Estimated Permeable Area
1001	64	?	499885		0	0	499885
1001	565	SFR	2911227	976574	0.5	1943900	967326
1001	109	Condo	447096	189721	0.9	421358	25738
1001	4	HOA	255208		0.75	191406	63802
1001	2	School	198676		0.9	178808	19868
1001	10	Landscape	845529		0	0	845529
1001	97	Street	2163105		1	2163104	0
1004	61	?	307556		0.0	0	307556
1004	417	SFR	2081636	719485	0.5	1400560	681076
1004	1	HOA	40165		0.8	30123	10041
1004	1	School	348739		0.9	313865	34874
1004	2	Landscape	1136		0.0	0	1136
1004	42	Street	1089143		1.0	1089143	0
1005	8	?	118370		0.0	0	118370
1005	559	SFR	2957363	1033197	0.5	1995280	962083
1005	1	HOA	66421		0.8	49816	16605
1005	1	School	264236		0.9	237812	26424
1005	1	School	261089		0.9	234980	26109
1005	2	Landscape	773206		0.0	0	773206
1005	45	Street	1736098		1.0	1736098	0

Table 2: Estimated Area of Study Sites (in sq. ft.)

R3 Group	Estimated Impermeable Area	Estimated Permeable Area	Total Area
1001	4,898,578	4,246,905	7,320,726
1004	2,833,692	572,686	3,868,375
1005	4,253,986	1,194,553	6,176,782

Robust Analysis of Runoff

Form of the Model

Using the runoff flow data, regression models were used to estimate mean runoff by site. A regression framework allows for (1) hypothesis testing within or across sites and (2) use of robust modeling techniques to identify and minimize the influence of spurious or outlying observations. Sites 1002 and 1003 contained too few valid observations to be included in this analysis. The form of the model is specified to have a single pre-intervention mean (μ_1) and to allow for tests of changes in this mean over time and across sites:

Equation 1

$$\frac{RunoffVolume_{i,t}}{SiteArea_i} \equiv m_1 + I_{4,\mathrm{Pre}} \cdot d_{4,\mathrm{Pre}} + I_{5,\mathrm{Pre}} \cdot d_{5,\mathrm{Pre}} + I_{1,Post} \cdot d_{1,Post} + I_{4,Post} \cdot d_{4,Post} + I_{5,Post} \cdot d_{5,Post}$$

The indicator variable $I_{i,\,t}$ takes on the value one to indicate that an observation comes from site i and the time period t (pre/post). Thus, the indicator variable $I_{4,Pre}$ takes on the value one for Site 1004 in the pre-period (Feb.2001-May 2001) and is zero otherwise. The parameter $d_{4,\mathrm{Pre}}$ is the estimate of how runoff in Site 1004 differs from the common mean μ_1 in the pre-period. The parameter $d_{5,\mathrm{Pre}}$ has a similar interpretation for Site 1005. The common intercept will, by construction, pick up the estimate of Site 1001 pre-period mean runoff, since the parameters $d_{4,\mathrm{Pre}}$ and $d_{5,\mathrm{Pre}}$ absorb any differences in the other sites.[1] The indicator variable $I_{,1Post}$ takes on the value one for Site 1001 in the post-period

[1] The choice of Site 1001 as the reference site—implied by excluding a Site 1001 change indicator—is not required. Choosing another site would generate an essentially

(June 2001 -June 2002); its parameter is interpreted as the estimated change to the pre-period mean runoff. The parameters $d_{4,Post}$ and $d_{5,Post}$ have similar interpretations for Site 1004 and Site 1005.

Table 3: Robust Regression Estimates of Mean Dry Day Runoff

Dependent Variable: Dry Day Runoff Height (in inches per unit area) (Height=Runoff Volume/Site Area)

Variable	Coefficient	Std. Error	t	Prob.>|t|
Mean Runoff: Feb-May 2001				
1. Intercept (1001 mean runoff)	0.898563	0.120838	7.44	0
2. Difference of Site1004 in pre-period	0.143721	0.157245	0.91	0.361
3. Difference of Site1005 in pre-period	-0.092260	0.151479	-0.61	0.543
Change in Runoff: June 2001-June2002				
4. Change of Site 1001 in post-period	-0.445390	0.134540	-3.31	0.001
5. Change of Site 1004 in post period	0.878089	0.113737	7.72	0
6. Change of Site 1005 in post period	0.202553	0.106973	1.89	0.059
Number of observations	950			
F(5, 944)	74.92			
Prob. > F	0			
Quasi-R-Squared	0.35			

Robust Regression Results

Table 2 presents the robust regression estimation results for the model of dry day runoff in R3 study Site 1001 (containing some customers receiving the ET controller/education intervention), Site 1004 (whose customers received no treatment), and Site 1005 (containing some customers receiving the education-only treatment). This sample represents metered dry day runoff, standardized by estimated site permeable area, between Feb. 2001 and June 2002.

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equivalent model that is one that generates identical predictions, but would change the interpretation of the coefficients.

Differences among Sites in the Pre-Intervention Period. The constant term (1) defines the intercept for this equation and can be interpreted as the mean daily runoff in Site 1001—about 0.898 hundredths of an inch per permeable acre. The following two variables (2) and (3), the indicators for Sites 1004 and 1005 in the pre-period, suggest that estimated difference in mean runoff is not statistically distinguishable from zero; The standard errors of the estimated coefficients are larger than the estimated coefficients. The estimated pre-period site mean runoff for these sites can also be inferred from these coefficients: $m_{4,\mathrm{Pre}} \equiv m_1 + d_{4,\mathrm{Pre}} \approx 0.89 + 0.14 = 1.03$ hundredths of an inch and $m_{5,\mathrm{Pre}} \equiv m_1 + d_{5,\mathrm{Pre}} \approx 0.89 - 0.09 = 0.80$.

Change in Runoff in the Post-Intervention Period: The formal test for the change in runoff in the post-intervention period (June 2001-June 2002) can be found in the following three site-specific terms: variables 4, 5 and 6 as shown in Table 3. The estimated change in dry day runoff for Site 1001 (4), is -0.44 hundredths of an inch. In relative terms, this works out to approximately a 49 percent reduction. The implied mean post-intervention dry day runoff for Site 1001, is 0.89-0.44˜0.45 hundredths of an inch. This reduction in runoff is statistically distinguishable from zero at classical levels of confidence.

The reader should be careful in interpreting this result as the pre- and post- periods are not comparable. The post-intervention period, June 2001 to June 2002, includes 13

months but would be fairly close to an annual average. The period of time covered by the pre-intervention period for all sites, February to May 2001, includes at most 4 months. For Site 1001, the pre-intervention period only includes the months of April and May in 2001, because the flow meter produced enough invalid reads in February and March to necessitate its relocation to a new site in April. Since these are not the highest months for urban runoff, it would be reasonable to expect runoff in the post-intervention period to increase. For this reason, the reduction of 49 percent from the pre-intervention period would be a lower bound on the true estimate of runoff reduction. We can examine the other two valid sites for insight into how much runoff would have increased in the post-intervention period.

The estimated change in dry day runoff for Site 1004 (5), is +0.88 hundredths of an inch. This increase in runoff is statistically distinguishable from zero at classical levels of confidence. The implied mean post-intervention dry day runoff for Site 1004, is (0.89+0.88˜) 1.77 hundredths of an inch. In relative terms, this works out to a fairly large (1-{1.77-1.03}/1.03=) 72 percent increase in the post-intervention period.

The estimated change in dry day runoff for Site 1005 (6), is +0.20 hundredths of an inch. This increase in runoff is statistically distinguishable from zero at close to classical levels of confidence. The implied mean post-intervention dry day runoff for Site 1005, is (0.89+0.20˜) 1.09 hundredths of an inch. In relative terms, this works out to a more modest (1-{1.09-0.80}/0.80=) 36 percent increase in the post-intervention period.

Comparing Post-Intervention Change in Runoff across Sites. The last and potentially most vulnerable inference compares the time change in runoff across sites. If Site 1001 had experienced the same change in runoff as its neighbor sites 1005 or 1004, then dry day runoff would have increased from 36 to 72 percent in the post-intervention period. In absolute terms, this would imply a prediction of non-intervention runoff of 1.24 to 1.53 inches per acre. Compared to the realized 0.45 inches of runoff in the post-intervention period, this reduction would translate to 64 to 71 percent reduction in runoff.

A similar counterfactual exercise for Site 1005, would require assuming that Site 1004 is a good matched control site. Then dry weather runoff in Site 1005 would have increased by 72 percent in the post-intervention period, a level of 1.38 inches per acre. Compared to the realized 01.09 inches of runoff in the post-intervention period, the reduction would translate into a modest but non-ignorable 21 percent decrease in runoff.

Both of these exercises require use of Site 1004 as a control site. While the unadjusted flow measures for Sites 1001 and 1005 are fairly close in the pre-intervention period, the same cannot be said for the flow measures from Site 1004. Perhaps the question would be best put, “Given the three estimates of reduction runoff for Site 1001, which should be used?” The direct within-site estimate of a 49 percent runoff reduction is likely biased low; runoff in the post-intervention period should have increased. The estimate of 64 percent, based on Site 1005 as a control site, may also be biased on the low side. Though Site 1005 did have pre-intervention runoff that reasonably matched Site 1001, Site 1005 also contained more than 200 homes who participated in the education-only intervention

with monthly follow-up. These homes did have quantified water savings, some of which is likely to have resulted from reduced runoff. Site 1004 did not receive any treatment but did have measurement issues. Thus the estimate of a 71 percent reduction, using Site 1004 as a control site, has an unknown bias.

The bigger inferential uncertainties lie in how these conservation interventions will work as they are scaled in a larger program or in how other implementations of these programs would work in other areas.

Caveats and Additional Work

- The difficulties encountered in calibrating custom configured equipment to measure runoff limited the amount of pre-intervention data. This in turn precluded simple before and after comparisons of mean runoff flow. Nonetheless, a sufficient length of baseline data was collected to allow quantitative estimates of runoff reduction. If additional flow data can be collected, additional analysis would be possible: (1) the runoff reduction under wet conditions could be examined and (2) an estimate of the seasonal shape of runoff could be included in the models to improve the precision of the estimated runoff reduction.

- Because the runoff measurement is not at a customer level, we cannot distinguish the relative contribution of different customers to urban runoff reduction. Thus, for Site 1001, we cannot state how much the single family ET controller/education contributed relative to the ET controller intervention with landscape customers.

Appendix D2: Residential Runoff Reduction Study Update – 2003 Runoff Data

The Residential Runoff Reduction Study

Memorandum

To: Dick Diamond, IRWD

From: Thomas W. Chesnutt, Ph.D.

Date: August 31, 2004

Re: Residential Runoff Reduction Study Update – 2003 Runoff Data

Finding

The 2003 measures of runoff from the Residential Runoff Reduction Sites 1001, 1004, 1005 support the findings of the earlier data: Site 1001 has a consistently lower mean level of urban runoff *and* a smaller variation in runoff.

Approach

A & N Technical Services performed data manipulation, collation, and validation on 2003 flow data collected in the R3 Study. The raw flow measures were provided in spreadsheet form. First, the spreadsheets of flow data from three study sites were incorporated into database form. This entailed the writing of a program for each site to convert the spreadsheets that also accounted for variations of form. Second, we performed validation checks on the estimated flow rates to check for consistency problems. Where correctable, revisions will be performed to the flow estimates. Last, these raw data exhibit an inconsistent time step, varying from 5-30 minutes. The raw data for each site was converted into their consistent daily basis—mean flow and total daily volume. The consistent time series version of flow data in the three study sites was then combined into a single consistent database with a consistent time series across sites. A consistent time-step, in term, allows valid comparisons across sites.

An attached spreadsheet contains the raw estimated daily runoff data–mean daily flow, total daily volume, and an indicator measure of data quality. As was experienced with the earlier data, there were considerable measurement issues that the IRWD team had to overcome to obtain consistent measures of flow. The project team coded a data quality indicator ("rank") for each subcomponent of the flow measure—instantaneous velocity and flow height. A combined indicator was also developed. The data quality indictor was set to 2 for measures that were known to be bad (rank=2). The data quality indictor was set to 1 for measures of questionable data quality (rank=1). Thus, the data quality indicator rank would take on the value 222 if all three measures (velocity, height, and estimated flow) were known to be bad and would take on the value 111 if all three were of questionable data quality. A value of zero was assigned to measures having no known or suspected data quality issues.

The data are summarized in two ways. First, the descriptive statistics of the mean daily flow volume (adjusted by site area) at each of the three sites in this post-installation period are examined. The

estimated mean daily runoff flow is expressed in inches per acre. Second, a graph of 2003 runoff data is developed for each site that displays the raw data and a lowess-smoothed line of central tendency. (Lowess smoothers are a robust data analytic technique that can convey a sense of the level of runoff.)

Table 1 provides the descriptive statistics of mean dry day runoff height at the three sites. (Note that the number of observations per site are reduced due to the exclusion of flow measures on wet days and exclusion of flow measures due to data quality concerns.) The 2003 flow data were also graphed for the three sites. These figures follow. Site 1001 that received the ET controller and education intervention consistently displays both lower levels of runoff and lower variability in runoff. Site 1004 displays very large variability in runoff; this level of variability is the norm rather than the exception. The months of May and June in 2003 did experience wetter than normal (May) and cooler than normal (June) weather patterns.

Table 1: Estimated Mean Dry Day Runoff Height

January 2003 – August 2003

(in inches per unit area)

(Height=Runoff Volume/Site Permeable Area)

Site	Obs	Mean	Std. Dev.	Min	Max
Site 1001 (ET controllers +ed.) Runoff Height	136	1.03	0.72	0	3.90
Site 1005 (Education only) Runoff Height	160	1.79	2.75	0	27.29
Site 1004 ("Control") Runoff Height	136	2.29	2.83	0	14.25

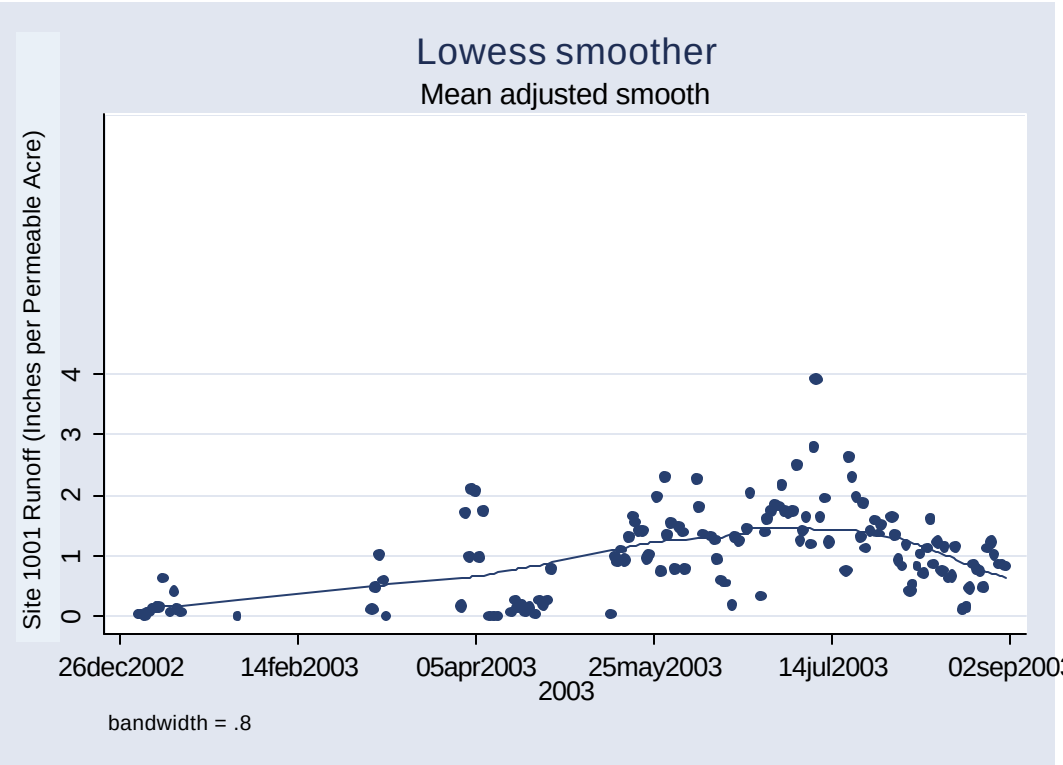

Figure 1: Site 1001 ET Control and Education Intervention

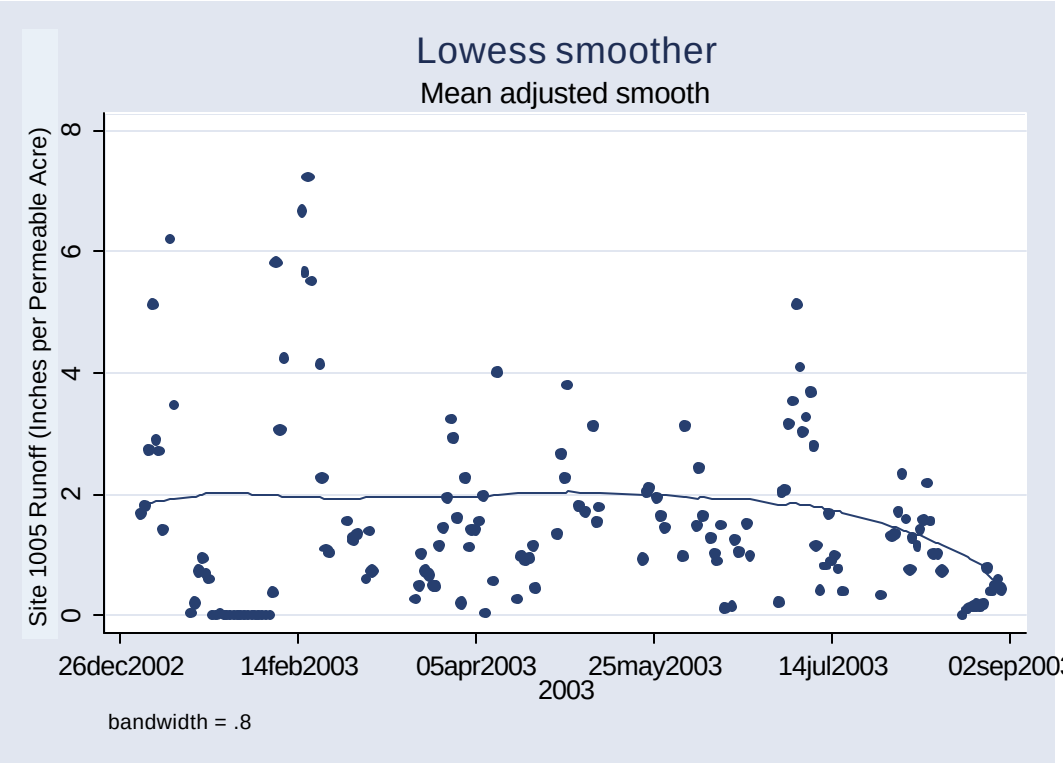

Figure 2: Site 1005 Education Only Site

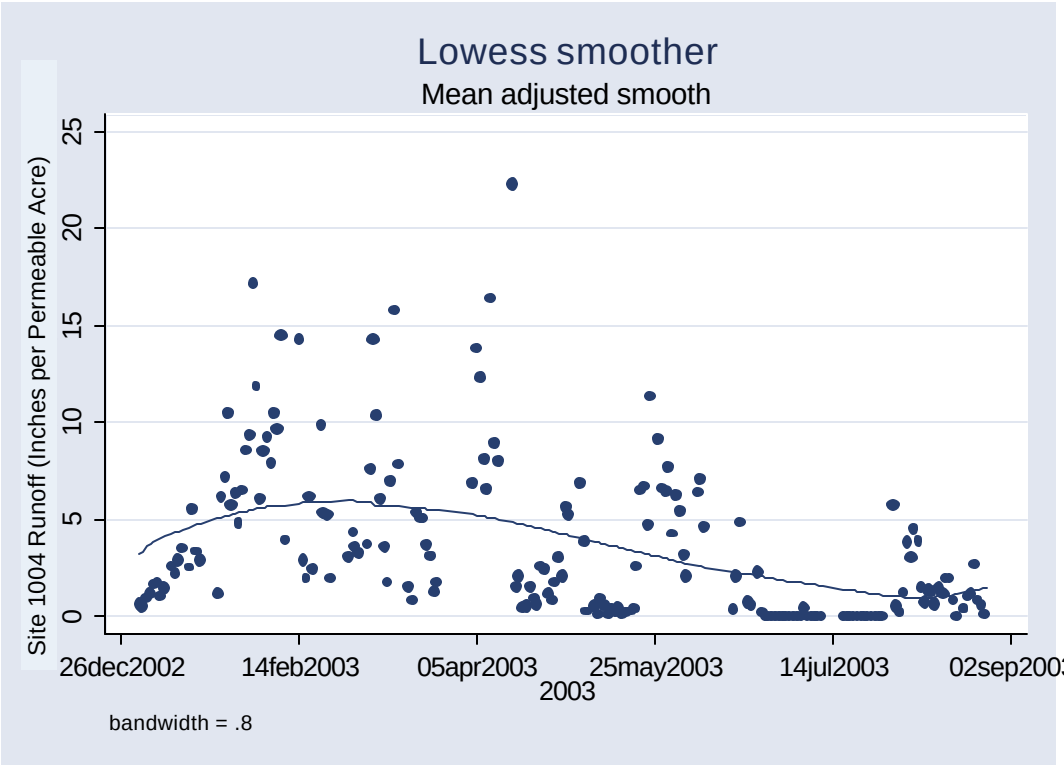

Figure 3: Site 1004 "Control" site

Appendix E1: The Effect of Technology and Public Education on the Water Quality of Dry Weather Runoff from Residential Neighborhoods

The Residential Runoff Reduction Study

Appendix E1

The Effect of Technology and Public Education on the Water Quality of Dry Weather Runoff from Residential Neighborhoods

Prepared by Kenneth C. Schiff,
Southern California Coastal Water Research Project

May 2003

ABSTRACT

Urban runoff is one of the largest contributors of pollutants to impaired surface waters in the United States, however little is known about effectiveness of potential best management actions (BMPs) to improve water quality. The goal of this study was to quantify the effectiveness of a technological BMP compared to public education as a BMP. The technological BMP consisted of a new evapotranspiration (ET) sprinkler controller that automatically changes sprinkler timing based on weather conditions using remotely controlled radio signals at a nearby weather station. Water quality (nutrients, trace metals, bacteria, pesticides, toxicity) was measured every two weeks for six months at five similar residential neighborhoods, then the technology plus education or education only treatments were applied to one neighborhood each, and measurements continued for another year. At the end of one year post intervention, there was virtually no difference in concentrations or pollutant flux over time. The technological and education treatments provided essentially no detectable increase or decrease in water quality following the intervention. The lack of detectable differences in water quality was a result of a combination of factors including large variability among measurements within a neighborhood and insufficient sample sizes to detect small changes in concentration or pollutant flux.

INTRODUCTION

Urban runoff has been identified as a major contributor to water quality problems throughout the United States (EPA 2000). Runoff from urban areas contains numerous potential pollutants including nutrients, trace metals, pesticides, and/or bacteria (US EPA 1987, Wong et al 1997, Smullen et al 1999, Ackerman and Schiff in press). These discharges have resulted in water quality impairments such as excessive blooms of algae (Bricker et al 1999), toxicity to aquatic organisms (deVlaming et al 2000, Bay et al 1996, closures of recreational shoreline for protection of human health (Noble et al 2000).

As managers become aware of the environmental concerns resulting from discharges of urban runoff, they are seeking methods and technologies for reducing or eliminating these discharges. Best management practices (BMPs) come in a variety of forms, including structural and non-structural control measures. Structural BMPs typically include technologically driven management actions that either reduce or eliminate runoff volume and/or attempt treatment of runoff prior to discharge. Non-structural BMPs typically are aimed at changing peoples attitudes or behavior that reduce the use of potential pollutants or limit their entry into the storm drainage systems. The most commonly cited form of non-structural BMPs is public education, which often consists of advertising campaigns, mailers, and other widely distributed educational materials.

The problem with both structural and nonstructural BMPs is that the efficiency and effectiveness of these BMPs are largely unknown. There is no uniform manner or standard method for independently testing these BMPs. Manufacturer information is occasionally available for some structural BMPs, but these data are looked upon suspiciously by most urban runoff managers as a result of their potential conflict of interest. Nonstructural BMPs, such as public education, are almost entirely without rigorous evaluation of their effectiveness. Hence, managers struggle with which BMPs to select, and in which environmental application, to achieve the greatest reduction in pollutant concentrations or mass emissions. At the same time, regulatory mechanisms like National Pollutant Discharge Elimination System (NPDES) Permits for municipal

separate storm sewer systems or total maximum daily loads (TMDLs) continue to push the regulatory obligation of urban runoff managers to reduce concentrations and mass emissions of many potential pollutants.

The goal of this study is to compare the effectiveness of technological BMPs versus public education for reducing concentrations or mass emissions of potential pollutants in dry weather discharges. The technological BMP consisted of evapotranspiration (ET) controllers that communicate with landscape irrigation systems of individual households. This technology is designed to optimize watering times for landscaped areas, hence reducing overwatering and resultant runoff. The public education campaign focused on not just appropriate watering times, but also minimization of pesticide, herbicide, and fertilizer usage. These two types of BMPs were tested in residential neighborhoods, typically the most common land use in urban watersheds (Wong et al. 1997). Our goal was to determine if technology or education provides more pollutant reduction so that urban runoff managers can select optimal runoff pollutant minimization strategies.

METHODS

We used a before-after, control-impact (BACI) design for evaluating the effectiveness of both the sprinkler technology and public education. Each neighborhood was sampled every other week between December 2000 and June 2001. In June 2001, homes in one of the neighborhoods were outfitted with the ET sprinkler controllers. Since homeowners with the retrofitted sprinkler controllers were simultaneously being educated, a well-defined public education campaign was also begun with these homeowners. To ascertain the difference between education and ET sprinkler technology, homeowners in a second neighborhood were targeted with an identical public education campaign, but without effect of the ET sprinkler retrofit technology. There was no education or technology intervention in the remaining three neighborhoods, which served as control neighborhoods to document the effect of no treatment. Sampling at the five neighborhoods continued every other week from June 2001 to June 2002.

ET Sprinkler Controller and Public Education

The ET controller is described in detail elsewhere (*see Chapter 2 – Study Methods*). It is similar to any automatic sprinkler timer available at most home improvement stores and nurseries, but with the capacity to receive radio signals that will alter sprinkler timing based on current weather conditions. If weather is hot and dry, the radio signals call for longer or more frequent irrigation. If the weather is cool and moist, such as recent precipitation, the radio signals call for shorter or less frequent irrigation. For this study, the existing sprinkler timers that are set manually by the homeowner were replaced with the radio controlled ET controller systems. Trained technicians were used to ensure successful installation; ET controller requires programming for each valve including area (size of yard or planter per valve), soil type (clay, sand, etc.), and landscape type (turfgrass, shrubbery, etc.). The remaining irrigation system was unchanged, including piping and sprinkler head configuration.

Public education consisted of an initial informational packet containing three items. The first item was an introductory letter that described the purpose of the packet. The second item was a booklet with irrigation, fertilization and weed and pest control information. The centerfold of the booklet was a month-by-month guide to irrigating, fertilizing and pesticide application suitable for posting near their sprinkler timer. Third, each homeowner was supplied a soil probe for measuring the water content of their landscaped soils. In addition to the initial packet, monthly reminders were mailed to each homeowner including landscape maintenance tips such as irrigation system, water schedule, fertilizing, and weed and insect control. Suggested sprinkler run times (for the non-ET sprinkler neighborhood) and fertilizer or pesticide application usage, including non-toxic alternatives, were also provided in the monthly newsletter.

Treatment Neighborhoods

The five neighborhoods were located within a three mile radius in Irvine, CA. The selection criteria for the neighborhoods included similarity in: 1) age of neighborhood (approximately 20 years old); 2) primary land use (single family residential); 3) irrigation management factors (precipitation rate, soil type, plant type, slope and sun exposure); 4) proximity to radio signal for ET controller (all neighborhoods used the same signal). The five neighborhoods were designated 1001 (sprinkler retrofit + education), 1002 (control), 1003 (control), 1004 (control), and 1005 (education only). Although each of the five neighborhoods met the selection criteria, there were some differences worth noting (Table WQ1). First, the two treatment neighborhoods were larger, up to twice as large as the control neighborhoods. Second, the two treatment neighborhoods were more impervious, up to two twice as much impervious area, as the control neighborhoods. Third, the two treatment neighborhoods had greater proportions of landscaped common areas than any of the control neighborhoods.

The treatments were not uniformly applied to all homeowners in either the 1001 or 1005 neighborhoods. In the case of sprinkler + retrofit neighborhood (1001), roughly one third of the pervious area actually retrofit their sprinkler systems. These homeowners, condominium complexes, school and city landscaped areas were recruited by trained personnel. In order to keep the relative percentages approximately the same between treatment neighborhoods, homeowners representing roughly 30% of the pervious area were selected to receive the education materials in the education only neighborhood (1005). These homeowners were selected at random.

Sampling and Laboratory Analysis

Each of the five neighborhoods were hydrologically self-contained and drained to a single underground pipe unique to each neighborhood. At each of these five locations, samples were collected for flow and water quality. Stage (water depth) and velocity were recorded at 5 min intervals using an ultrasonic height sensor mounted at the pipe invert and a velocity sensor mounted on the floor of the pipe. Flow was calculated as the

product of velocity and wetted cross-sectional area as defined by the stage and pipe circumference. Despite the relatively continuous measurement of flow, many of the flow measurements were excluded due to faulty readings. Synoptic flow and water quality measurements were only available for two sites over the course of the entire study (i.e. before and after intervention), including the sprinkler + education and education only sites. Flow measurements at the time of water quality sampling for the three control sites were considered faulty and discarded.

Grab samples for water quality, collected just downstream of the flow sensors in the early morning, were collected using peristaltic pumps and pre-cleaned Teflon tubing. Samples were placed in individual pre-cleaned jars, placed on ice, and transported to the laboratory within one hour. Each sample was analyzed for 19 target analytes, five microbiological parameters, and four toxicity endpoints (Table WQ2). Target analytes included trace metals, nutrients, and organophosphorus (OP) pesticides. Microbiological parameters included fecal indicator bacteria and bacteriophage. Toxicity was evaluated using two marine species, the purple sea urchin *Strongylocentrotus purpuratus* and the mysid *Americamysis bahia*. Toxicity endpoints included the median effects concentration that estimates the concentration at which 50% of the sample population is affected (EC50) and the no effect concentration that estimates the highest concentration at which no effect is observed (NOEC). All of the laboratory methodologies followed standard protocols developed by the US EPA (1995, 1993, 1983) or Standard Methods (APHA 2001).

Data Analysis

Data analysis consisted of five steps. These steps included: 1) comparison of water quality among the five neighborhoods prior to intervention; 2) comparison of water quality concentrations over time by neighborhood; 3) comparison of water quality concentrations before and after intervention by treatment type; 4) comparison of pollutant flux before and after intervention by treatment type; and 5) correlation of toxicity measures with potential toxicants in dry weather runoff.

Comparison of water quality concentrations among the five neighborhoods prior to intervention was conducted to assess if there were inherent differences among treatment sites for each constituent. This analysis was conducted using an analysis of variance (ANOVA) using Tukey's post hoc test for identifying the significantly different neighborhoods. All data were tested for normality and homogeneous variance prior to testing. Only the microbiological data were determined to be non-normally distributed, so these results were log transformed prior to data analysis

Comparison of water quality concentrations over time was accomplished by creating temporal plots of monthly mean concentration. Comparisons of water quality concentration before and after intervention by treatment type were accomplished using a standard t-test of the mean concentration before versus mean concentration after intervention. The mean concentrations for sprinkler+education, education only, and sprinkler+education – education only for each sampling event were normalized by the grand mean of the control sites for the same sampling event.

Pollutant flux estimates were calculated by the product of the concentration and volume at the time of sampling and then normalized to the area of the sampled neighborhood. Pollutant flux before and after treatment was compared somewhat differently since the lack of flow data at the control sites did not permit an estimate of flux for these neighborhoods. Mean pollutant flux before and after intervention was compared using standard t-tests at the sprinkler+education and education only neighborhoods without normalization to control values.

Correlation of toxicity with toxicant concentrations was accomplished using a Pearson product moment correlation. These correlations are inferential only and do not presume resulting correlations automatically identify the responsible toxicants. In order to help identify potential causative toxic agents, concentrations of the correlated constituents were compared to concentrations known to induce toxicity in the respective test organisms.

RESULTS

There were significant differences in water quality among sites prior to intervention (Table WQ3). Site 1004, the control site, had the greatest mean concentrations for 15 of the 24 constituents evaluated prior to the sprinkler intervention. Mean concentrations for seven of the 15 constituents were significantly greater at site 1004 than mean concentrations at least one other site (ANOVA, $p<0.05$). In particular, all of the mean nutrient concentrations were greater at site 1004 than the other sites. Mean ammonia, nitrate/nitrite, and TKN were a factor of 13, 11, and 2.5-fold greater at site 1004 than the mean concentrations at the next greatest site, respectively. On the other hand, sites 1001 and 1002 generally had the lowest average concentrations prior to the sprinkler intervention. Cumulatively, these sites had the lowest mean concentrations for 17 of the 24 constituents evaluated. Site 1002 also had the least toxicity, on average, of all five sites. Finally, site 1003 had an intermediate status. Mean concentrations of enterococcus and fecal coliforms at this site were greater than any other site (fecal coliforms significantly greater than sites 1001 and 1002), but the mean concentrations of five trace metals (chromium, copper, cobalt, nickel, selenium) were lowest at this site.

Water quality concentrations and toxicity were highly variable over time during the study period (Figure WQ1). Temporal plots of concentrations and toxicity for each site demonstrated that there was no seasonal trend and no overall trend with time. There were, however, occasional spikes in concentrations for many constituents that appeared to fall into one of two categories. The first category was recurring spikes in concentration that were unpredictable in timing and location. For example, both fecal coliform and enterococcus consistently varied by more than an order of magnitude from month to month during the study period and there was no similarity in pattern between the sites. The second category of concentration spike was single or infrequent peaks. Occasionally these spikes would occur across multiple sites, such as the peak in both lead and zinc at all three control sites (1002, 1003, and 1004) in October 2001, without

commensurate changes in concentration at the treatment sites (1001 or 1005). More often, infrequent spikes were isolated to a single site. For example, concentrations of chlorpyrifos climbed to over 10,000 ng/L in July 2001, but averaged near 50 ng/L the remainder of the year at site 1005. Similarly, concentrations of ammonia and total phosphorus spiked 10 and 25-fold prior to June 2001 at the control site (1004) with less variability and overall lower concentrations the remainder of the study.

There were few significant differences that resulted from the intervention of education, sprinkler retrofit and education, or sprinkler retrofit minus education, relative to control sites (Table WQ4). Only six of the 24 constituents evaluated showed a significant difference between pre and post-intervention concentrations after normalizing to mean control values. These significant differences were a net increase in concentrations of ammonia, nitrate/nitrite, total phosphorus, chlorpyrifos, diazinon, and fecal coliforms. These statistical analyses were the result of one of two circumstances. In the first circumstance, there were individual large spikes in concentration at treatment sites, but not at control sites following intervention (i.e. chlorpyrifos and diazinon at sites 1001 and 1005). Therefore, the net difference in concentrations between controls and treatments increased following the intervention. In these cases, removal of the outlier samples resulted in no significant difference among treatment effects relative to controls before intervention compared to after intervention. In the second circumstance, there were large spikes in concentrations at control site(s) prior to the intervention (i.e. ammonia, nitrate/nitrite, and total phosphorus at site 1004) that later subsided while treatment site concentrations and variability remained steady. Therefore, the difference between treatments and controls changed following interventions, although it was not a result of the education or technology.

Although there were no significant differences in pollutant flux as a result of the intervention, there were significant differences in pollutant flux among sites prior to intervention (Table W5). Mean flux did not change at either site from before to after the installation of technology or initiation of education. Site 1001 however, the sprinkler+education site, had the greatest mean flux for 22 of the 24 constituents

evaluated prior to the sprinkler intervention. The mean flux for 20 of these 22 constituents was significantly greater at site 1001 than the mean flux at site 1005 (t-test, $p<0.05$). Site 1005 had greater mean fluxes only for MS2 phage and ammonia. The differences among the fluxes prior to (and after) intervention was the result of two factors; greater flow and, at times, greater concentrations at site 1001 compared to site 1005. Mean dry weather flow at the time of water quality sampling was nearly three times greater at site 1001 than 1005.

Toxicity was inconsistently found at all five of the sampling sites (Table WQ3, Figure WQ4) and there was no change in toxicity as a result of the intervention (Table WQ4). The two species tested did not respond similarly either among sites, among treatments, or over time. Correlation of toxicity with constituent concentrations yielded few significant relationships for either species (Table WQ6). Mysid toxicity was correlated with diazinon and several trace metals, but the strongest relationship was with diazinon concentration. Moreover, the concentrations of diazinon were well above the levels known to cause adverse effects in this species while trace metals were not (Table WQ7). Sea urchin fertilization toxicity was only correlated with concentrations of zinc. The concentrations of zinc were well above the level known to induce adverse effects in this species (Table WQ7).

DISCUSSION

This study was unable to find large, significant reductions in concentration or pollutant flux as a result of education and/or sprinkler retrofit technology. This may indicate that the technology and/or education are inefficient for improvements in water quality. Equally as important, however, was the absence of meaningful increases in concentrations. Of the small number of concentrations that showed significant increases, most could be explained by highly variable spikes in concentrations reminiscent of

isolated entries to the storm drain system as opposed to ongoing chronic inputs or the effects of best management practices evaluated in this study.

If significant changes did occur, our study design may not have detected these changes due to two factors. First, the variability in concentrations within and between sites are naturally high and our study simply collected too few samples. After taking into account the variability and relative differences in mean concentrations, we used zinc as an example constituent to determine what sample sizes would be required to detect meaningful differences. Assuming that our sampling yielded the true mean and variance structure that actually existed at the five sites, power analysis indicated that a minimum sample size of no less than five-fold would have been required to detect the differences we observed in zinc concentrations during this study.

The second factor that could have hindered our ability to detect meaningful differences in water quality is that the technology and education treatments were applied at the spatial scale of individual homes, while our study design sampled at the neighborhood scale. This problem was exacerbated in this study because only a fraction (approximately one-third) of the homes within the neighborhoods we sampled had the technological or educational treatments. Therefore, the treatments were effectively diluted, decreasing our ability to detect differences in water quality.

It appears that residential dry weather flows measured in our study may contribute significant proportions of some constituents to overall watershed discharges. Our study sites were located within the San Diego Creek watershed, the largest tributary to Newport Bay. San Diego Creek is routinely monitored to provide environmental managers the information they need to properly manage the Bay (OCPFRD 2002). We compiled the dry weather monitoring data at the mouth of San Diego Creek from OCPFRD during 2001-2002 and compared the concentrations to our results from residential neighborhoods (Table wq5). Mean concentrations of chlorpyrifos, diazinon, copper and zinc were much higher in upstream residential neighborhoods, than concentrations measured at the mouth of San Diego Creek. These residential dry weather contributions

are amplified by the fact that the San Diego Creek watershed is primarily composed of residential land uses. In contrast, concentrations of selenium, arsenic, and total phosphorus in the residential dry weather discharges were much lower than the cumulative dry weather discharges from San Diego Creek, indicating that residential areas may not be the primary source of these constituents.

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Table WQ1. Characteristics of the five treatment[a] study neighborhoods.

	Neighborhood				
	1001	1002	1003	1004	1005
Total Area (ft^2)	5,174,861	2,145,864	2,426,731	3,868,375	6,176,782
Impervious Area (%)	64.3	30.3	33.6	54.8	82.2
Land Use (%)					
Single Family Res	34.4	52.8	65.4	53.8	47.9
Condo	7.7	2.2	0.0	0.0	1.1
Homeowners Assoc	1.6	8.1	0.0	1.0	4.3
School	3.8	0.0	0.0	9.0	4.2
Landscape	16.3	0.1	6.6	0.0	12.5
Street	29.2	30.4	28.1	28.2	28.1
Unknown	7.0	6.5	0.0	8.0	1.9

[a] 1002, 1003, 1004=control, 1005=education, 1001=education + sprinkler retrofit

Table WQ2. Reporting level and method for target analytes.

	Reporting Level	Method
Metals (ug/L)		
Antimony	0.2	EPA 200.8
Arsenic	1.5	EPA 200.8
Barium	0.2	EPA 200.8
Cadmium	0.2	EPA 200.8
Chromium	0.3	EPA 200.8
Cobalt	0.1	EPA 200.8
Copper	1.5	EPA 200.8
Lead	0.3	EPA 200.8
Nickel	0.2	EPA 200.8
Selenium	5.0	EPA 200.8
Silver	0.4	EPA 200.8
Zinc	5.0	EPA 200.8
Microbiology		
Enterococcus (MPN/100 mL)	2	SM9230B
Fecal Coliform (MPN/100 mL)	2	SM9221B
Total Coliform (MPN/100 mL)	2	SM9221B
MS2 Phage (PFU/100 mL)	2	EPA 1602
Somatic Phage (PFU/100 mL)	2	EPA 1602
Nutrients (mg/L)		
Ammonia as N	5.0	EPA 350.1
Nitrate/Nitrite as N	5.0	EPA 353.2
Total Kjeldahl Nitrogen	10.0	EPA 351.2
Ortho-Phosphate as P	0.5	EPA 365.1
Total Phosphorus	1.0	EPA 365.4
OP Pesticides (ng/L)		
Chlorpyrifos	20.0	IonTrap GCMS
Diazinon	20.0	IonTrap GCMS
Toxicity (% effluent)		
Sea Urchin Fertilization EC50	NA	EPA 1995
Sea Urchin Fertilization NOEC	NA	EPA 1995
Mysid EC50	NA	EPA 1993
Mysid NOEC	NA	EPA 1993

Table WQ3. Mean concentration (and 95% confidence interval) of constituents in dry weather discharges collected before and after intervention[a] at five residential neighborhoods in Orange County, CA.

Parameter	Site 1001				Site 1002				Site 1003				Site 1004				Site 1005			
	Pre-Intervention		Post-Intervention		Pre-Intervention		Post-Intervention		Pre-Intervention		Post-Intervention		Pre-Intervention		Post-Inter vention		Pre-Intervention		Post-Intervention	
	Mean	95% CI	Mean	95% CI	Mean	95% CI	Mean	95% CI	Mean	95% CI	Mean	95% CI	Mean	95% CI	Mean	95% CI	Mean	95% CI	Mean	95% CI
Metals (ug/L)																				
Antimony	3.28	0.52	3.09	0.51	2.90	0.29	3.49	0.73	3.33	0.60	3.71	0.72	2.98	0.33	3.46	0.51	2.66	0.30	3.11	0.58
Arsenic	2.19	0.64	2.61	0.95	1.99	0.41	2.87	1.25	1.58	0.35	2.38	0.94	4.06	0.85	3.07	0.95	2.44	0.60	3.02	0.97
Barium	80.91	11.61	93.04	10.97	87.39	9.00	105.12	23.99	88.34	6.09	80.12	11.72	79.22	21.23	82.01	13.16	94.36	13.93	104.55	17.74
Cadmium	0.26	0.09	0.15	0.07	0.26	0.11	0.42	0.38	0.25	0.12	0.23	0.18	0.37	0.14	0.21	0.12	0.28	0.12	0.28	0.18
Chromium	2.49	0.98	1.97	0.59	3.74	1.53	4.72	3.35	1.96	0.41	2.70	1.25	3.31	1.41	2.44	0.82	4.01	2.79	3.89	2.01
Cobalt	0.43	0.11	0.50	0.21	0.65	0.28	1.19	0.81	0.40	0.11	0.53	0.26	0.97	0.49	0.73	0.25	0.64	0.19	1.08	0.54
Copper	13.91	4.31	16.14	7.27	31.50	30.24	27.12	17.30	11.82	2.57	24.30	15.41	24.02	12.64	16.81	6.71	33.98	39.62	29.67	14.38
Lead	0.57	0.18	1.63	1.15	6.95	9.32	4.23	2.90	0.88	0.40	1.45	0.88	4.09	4.84	1.34	0.69	0.79	0.23	3.09	1.98
Nickel	9.28	0.91	9.32	1.87	9.40	1.58	10.94	4.14	7.76	0.72	7.87	2.06	11.18	1.94	9.11	1.60	9.97	1.46	10.23	2.33
Selenium	2.43	0.13	2.50	0.00	2.43	0.13	2.50	0.00	2.30	0.26	2.50	0.00	2.43	0.13	2.50	0.00	2.30	0.26	2.50	0.00
Silver	0.13	0.05	0.14	0.07	0.11	0.02	0.18	0.10	0.17	0.09	0.17	0.15	0.12	0.03	0.16	0.17	0.16	0.09	0.17	0.15
Zinc	58.75	7.13	40.57	10.49	130.25	115.77	65.28	29.77	59.33	14.92	53.58	16.10	93.40	50.30	40.80	12.22	73.08	31.52	75.74	35.18
Microbiology (Log)																				
Enterococcus (MPN/100 mL)	3.95	0.43	3.24	0.18	3.80	0.38	4.16	0.35	4.36	0.68	4.22	0.24	4.49	0.61	4.35	0.25	4.34	0.31	4.37	0.29
Fecal Coliform (MPN/100 mL)	3.45	0.31	2.94	0.27	3.15	0.37	3.50	0.45	4.13	0.33	3.67	0.32	4.08	0.35	3.84	0.32	3.88	0.33	3.67	0.23
Total Coliform (MPN/100 mL)	4.16	0.27	3.82	0.24	4.30	0.30	4.51	0.46	4.70	0.33	4.36	0.26	5.04	0.39	4.50	0.27	4.53	0.34	4.51	0.24
MS2 Phage (PFU/100 mL)	-0.30	0.00	0.02	0.55	-0.30	0.00	-0.09	0.52	-0.19	0.14	0.02	0.53	0.30	0.44	0.05	0.52	0.05	0.43	0.33	0.54
Somatic Phage (PFU/100 mL)	2.00	0.35	2.02	0.49	1.84	0.42	1.81	0.69	2.59	0.40	2.24	0.62	2.88	0.32	2.52	0.54	2.16	0.46	2.37	0.47
Nutrients (mg/L)																				
Ammonia as N	0.17	0.15	0.08	0.03	0.17	0.07	0.39	0.51	0.23	0.11	0.28	0.23	7.32	4.93	0.31	0.26	0.65	0.32	0.42	0.24
Nitrate/Nitrite as N	2.72	0.50	1.48	0.28	3.00	1.14	1.00	0.33	2.35	0.96	1.63	0.78	38.71	18.21	9.29	6.58	2.94	0.61	3.70	4.48
Total Kjeldahl Nitrogen	1.62	0.51	1.87	1.20	1.75	0.62	2.38	0.92	1.96	1.33	2.61	1.75	11.18	5.71	3.60	2.03	4.49	2.64	3.51	1.65
Ortho-Phosphate as P	0.65	0.15	0.64	0.12	0.80	0.25	0.73	0.14	0.79	0.39	1.21	0.75	2.93	0.90	1.55	0.57	0.87	0.25	1.00	0.22
Total Phosphorus	0.79	0.21	0.63	0.16	0.78	0.25	0.82	0.23	1.22	0.83	1.19	1.07	3.30	1.37	1.46	0.73	0.96	0.39	1.16	0.40
OP Pesticides (ng/L)																				
Chlorpyrifos	22.66	9.27	442.78	827.29									45.54	33.48	11.34	6.31	75.27	64.41	803.44	1433.34
Diazinon	1680.45	1379.39	829.56	338.72									3265.38	3277.20	1650.50	1540.87	1159.12	553.01	1738.58	721.44
Toxicity (% effluent)																				
Fertilization EC50	47.26	8.89	53.73	6.17	57.37	3.48	51.94	9.85	41.60	8.94	49.58	10.17	49.79	8.96	55.91	6.48	43.81	9.26	58.35	2.98
Fertilization NOEC	25.36	8.61	44.62	10.32	35.00	8.54	46.23	11.11	32.07	13.27	37.69	11.15	32.50	9.66	51.92	7.67	22.00	9.31	42.88	9.76
Mysid EC50	46.76	25.04	60.00	0.00	56.32	10.22	39.04	35.71	39.10	24.16	51.94	22.38	54.28	15.88	49.36	25.33	39.32	25.25	60.00	0.00
Mysid NOEC	90.71	17.23	104.00	9.49	82.14	18.13	95.00	16.20	95.71	12.20	77.50	17.53	64.29	16.73	68.50	22.30	53.86	14.81	83.00	17.96

[a] 1002, 1003, 1004=control, 1005=education, 1001=education + sprinkler retrofit

Table WQ4. Significance of ANOVA results for the effect of sprinkler + education, education alone, and the difference between sprinkler + education and education alone relative to control concentrations. No data indicates p > 0.05

	Effect of Sprinkler + Education	Effect of Education Alone	Difference Between Sprinkler + Education and Education Alone
Metals			
Antimony			
Arsenic			
Barium			
Cadmium			
Chromium			
Cobalt			
Copper			
Lead			
Nickel			
Selenium			
Silver			
Zinc			
Microbiology			
Enterococcus			
Fecal Coliform	0.04		
Total Coliform			
MS2 Phage			
Somatic Phage			
Nutrients			
Ammonia as N	0.03	0.02	
Nitrate/Nitrite as N	0.02		
Total Kjeldahl Nitrogen			
Ortho-Phosphate as P			
Total Phosphorus		0.03	
OP Pesticides			
Chlorpyrifos	<0.01	<0.01	<0.01
Diazinon		<0.01	
Toxicity			
Fertilization EC50			
Fertilization NOEC			
Mysid EC50			
Mysid NOEC			

Table WQ5. Mean flux (and 95% confidence interval) of constituents in dry weather discharges collected before and after intervention[a] at two residential neighborhoods in Orange County, CA.

Parameter	Site 1001				Site 1005			
	Pre-Intervention		Post-Intervention		Pre-Intervention		Post-Intervention	
	Mean Flux	95% CI	Mean Flux	95% CI	Mean Flux	95% CI	Mean Flux	95% CI
Metals (ug/hr/km^2)								
Antimony	1564	740	920	410	167	99	1756	1666
Arsenic	1476	1006	741	427	164	107	2610	2425
Barium	41644	18423	29241	11384	6537	4624	83266	71121
Beryllium	43	17	36	15	7	5	94	79
Cadmium	157	97	40	17	13	5	207	189
Chromium	880	474	562	264	155	86	3199	2810
Cobalt	273	166	131	57	41	21	958	854
Copper	4738	2383	3600	1587	2233	1178	13717	11137
Lead	1149	861	253	133	81	52	1475	1270
Nickel	4287	2096	2743	1249	636	465	7319	6221
Selenium	1075	420	910	367	177	132	2045	1894
Silver	58	19	49	35	13	8	64	73
Zinc	28968	13481	11264	9171	5589	3276	39966	39179
Microbiology (Log)								
Enterococcus (MPN/hr/km^2)	1771	768	1437	624	281	208	1822	1464
Fecal Coliform (MPN/hr/km^2))	1254	567	955	418	234	170	3393	3251
Total Coliform (MPN/hr/km^2)	1628	607	1264	489	284	193	3902	3687
Somatic Phage (PFU/hr/km^2)	976	480	650	282	57	32	748	550
Nutrients (mg/hr/km^2)								
Ammonia as N	584	324	339	260	1145	1236	2466	2475
Nitrate/Nitrite as N	12981	6366	4316	2174	1849	1706	12102	9812
Total Kjeldahl Nitrogen	8144	4881	3621	1893	3083	2614	18149	13628
Ortho-Phosphate as P	4822	2535	1516	679	504	279	6735	6634
Total Phosphorus	4875	2573	1645	657	477	308	7782	8007
Pesticides (ng/hr/km^2)								
Chlorpyrifos	8	8	7	4	3	5	26	20
Diazinon	467	606	234	185	56	36	822	579

[a] 1005=education, 1001=education + sprinkler retrofit

Table WQ6. Correlation coefficients (and p value) of constituent concentrations with toxicity endpoints (No Observed Effect Concentration, NOEC and Median Effect Concentration, EC50) in dry weather discharges from residential neighborhoods in Orange County, CA. No data indicates p > 0.05

	Sea Urchin Fertilization NOEC	Mysid Survival NOEC	Sea Urchin Fertilization EC50	Mysid Survival EC50
Antimony		-0.273 (0.009)		
Arsenic		-0.3396 (0.001)		
Barium				
Cadmium				
Chromium		-0.244 (0.021)		-0.219 (0.044)
Cobalt		-0.330 (0.002)		-0.279 (0.010)
Copper				
Lead		-0.215 (0.042)		
Nickel				
Silver		-0.260 (0.013)		-0.229 (0.035)
Zinc	-0.277 (0.005)		-0.274 (0.006)	
Chlorpyrifos				
Diazinon		-0.426 (0.001)		-0.468 (0.001)
Ammonia				

Table WQ7. Comparison of median effect concentrations for the mysid survival (*Americamysis bahia*) and sea urchin (*Strongylocentrotus purpuratus*) fertilization tests.

Constituent (µg/L)	Mysid Survival (EC50)	Sea Urchin Fertilization (EC50)
Antimony	>4150	-
Arsenic	1390-2725	-
Barium	>500,000	>1500
Cadmium	16.5-90.2	1,272
Chromium	1560-2450	-
Cobalt	-	-
Copper	267	30
Lead	3130	>4,000
Nickel	387-635	-
Silver	220-283	-
Zinc	400	29
Chlorpyrifos	0.04	-
Diazinon	4.5	>1,000
Ammonia	-	69

- indicates no data available

Table WQ8. Comparison of mean concentrations (95% confidence intervals) in residential dry weather discharges from this study compared to concentrations in dry weather discharges from San Diego Creek at Campus during 2001-2002 (Data from OCPFRD).

	San Diego Creek	Residential
Parameter	Mean(95% CI)	Mean(95% CI)
Nitrate	5.16(0.72)	4.76(1.96)
Phosphate	1.98(0.07)	1.16(0.20)
Diazinon	0.13(0.07)	1.52(0.52)
Chlorpyrifos	0.05(0.01)	0.35(0.44)
Copper	11.59(2.83)	23.59(5.65)
Arsenic	6.58(0.40)	2.68(0.26)
Selenium	21.22(2.65)	2.46(0.03)
Zinc	22.08(2.75)	60.09(8.26)

Figure WQ1. Monthly average concentrations in dry weather discharges from five residential neighborhoods in Orange ounty, CA.

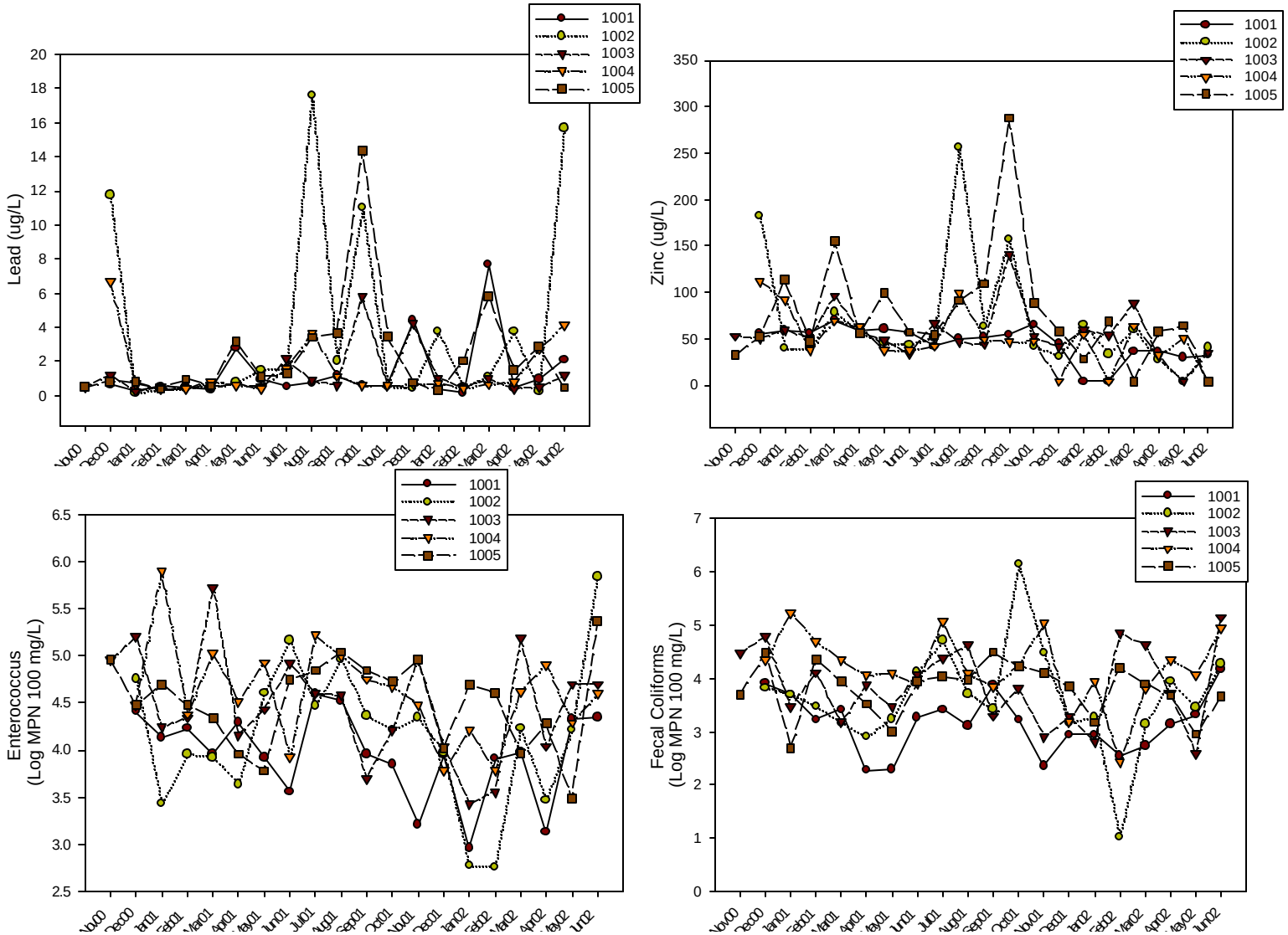


Figure WQ1 continued.

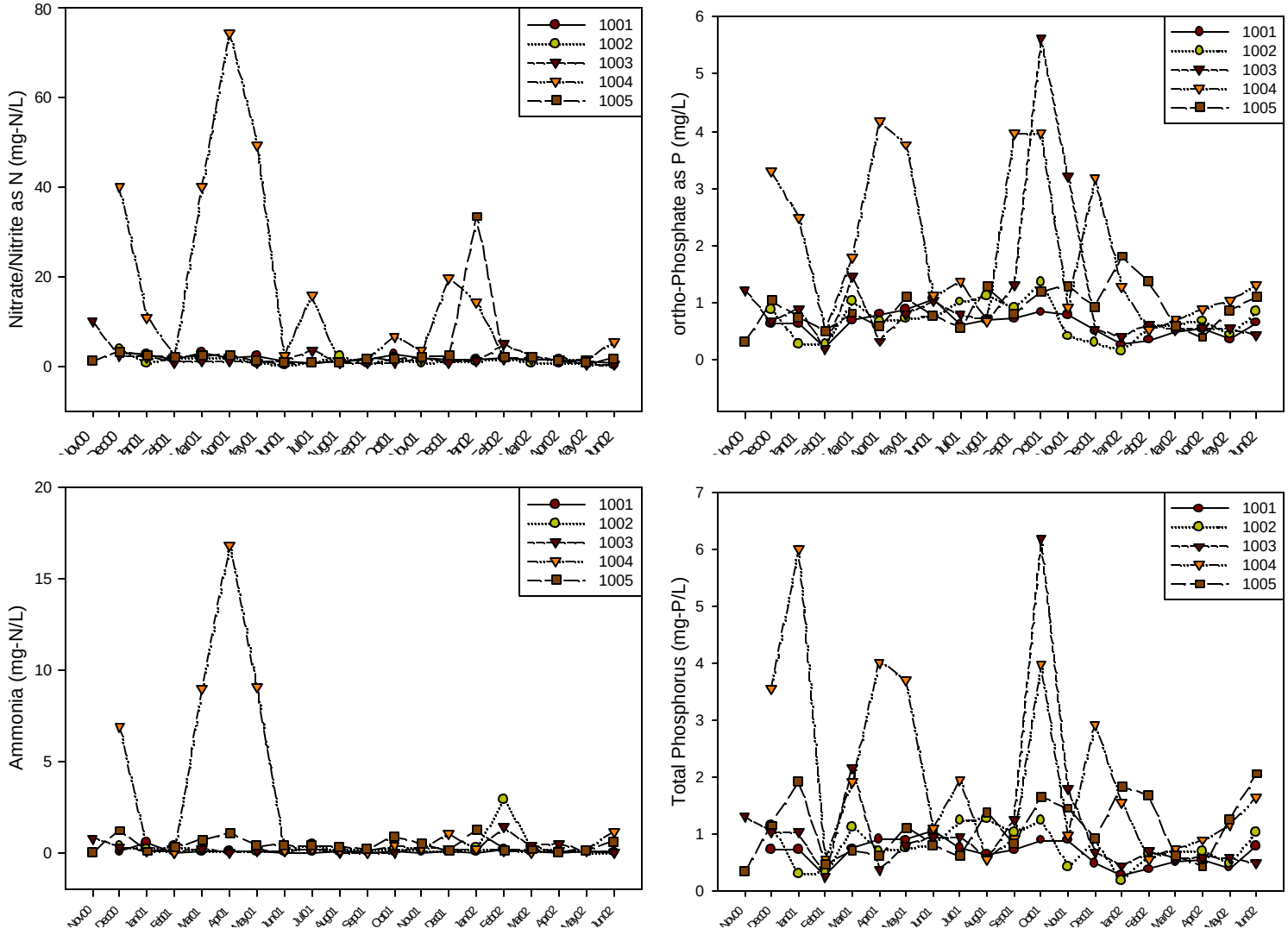
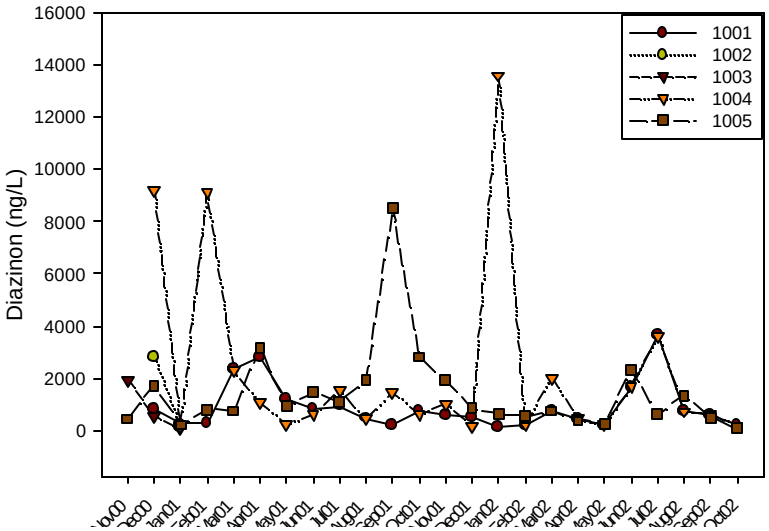


Figure WQ1 continued



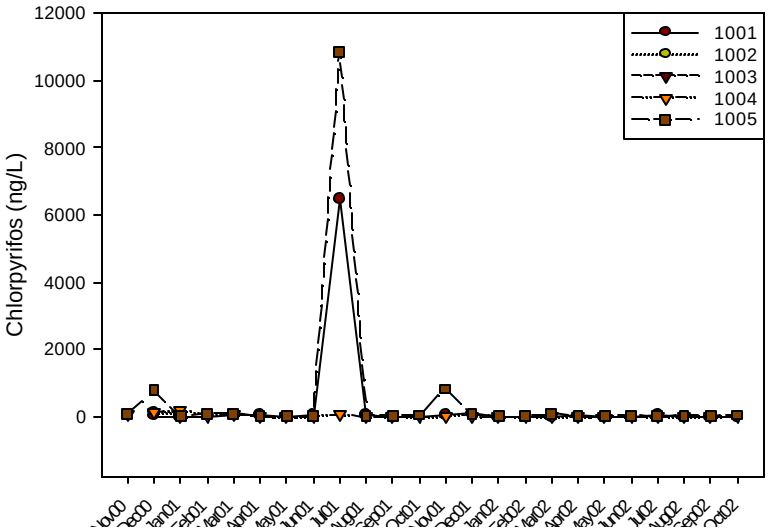
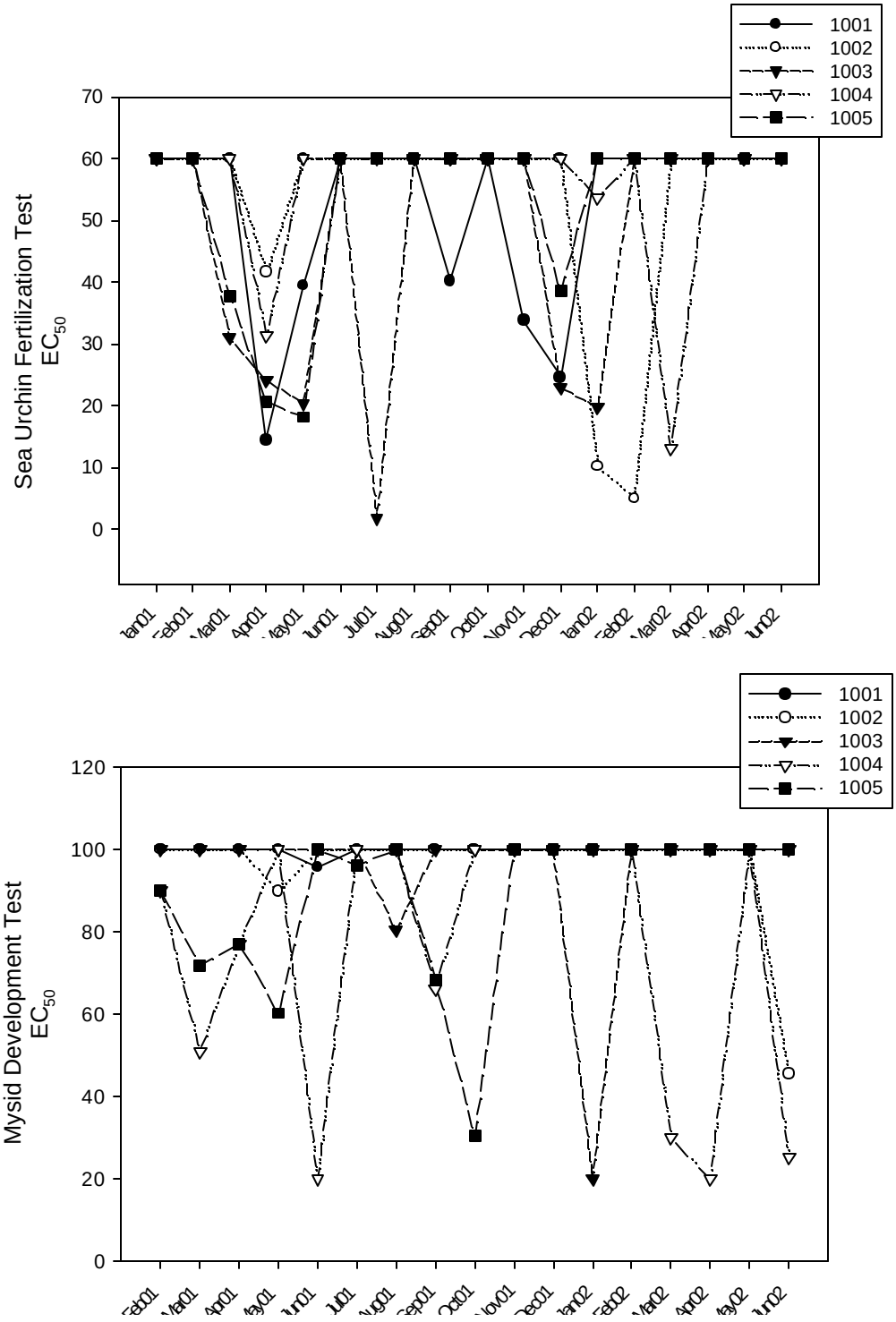


Figure WQ2. Toxicity of dry weather discharges from five residential neighborhoods in Orange County, CA



Appendix E2: Technical Assistance

The Residential Runoff Reduction Study

Appendix E2: Technical Assistance for the Residential Runoff Reduction (R3) Report

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1. Introduction

This report describes analyses and results of work conducted by GeoSyntec Consultants for the Irvine Ranch Water District (IRWD) to assist in the completion of the Residential Reduction Runoff (R3) Study. The R3 Study is an ambitious investigation to quantify the effectiveness of BMPs in reducing dry weather discharges and associated pollutants.

GeoSyntec Consultants completed the following tasks:

1. Review and Analysis of Water Quality Data. We reviewed the analyses described in Chapter 5 of the R3 report and conducted additional analyses of the water quality data and flux calculations to explore and potentially enhance the interpretation of the monitoring results.
2. Evaluation of Possible Implications on TMDL Compliance. We reviewed and summarized applicable TMDLs in the San Diego Creek Watershed. Results from Task 1 were compared with the TMDLs to evaluate whether the BMPs are beneficial to achieving the TMDL objectives.

2. GeoSyntec Review of Section 5 of the R3 Study Report

Section 5 in the R3 report describes the water quality monitoring data and analyses. The following are GeoSyntec review comments of Section 5.

- **Abstract and Introduction**. The abstract and introduction section provides a recap of the entire study, including a description of the study motivation and objectives. This suggests that this section of the report was originally written as a stand-alone report. In the final report we recommend that most of this information should be integrated into an earlier overall report introductory chapter. The introduction of Section 5 should be limited to a recap of the water quality and flow data, and to present the purpose/goals of the data analysis described in this section.
- **Methods**. The methods section similarly presents much of the study details (watershed descriptions, intervention description-BMPs applied-, etc). We recommend this information be presented in an earlier chapter in the report that describes the study design and procedures in a high degree of detail. This study description chapter could then be referenced as needed throughout the report.
- **Data Analysis and Results**. The 5 data analysis steps are logical and reasonable, however, the procedures, assumptions made, and results are, in some cases, unclear as discussed below. Additional details of the procedures and assumptions made, as well as the use of alternative, possibly more appropriate statistical procedures could enhance the interpretation and usefulness of the monitoring data. Some specific suggestions and comments are discussed below:

1. **Comparison of water quality data prior to intervention**. ANOVA tests were used to test for differences among the treatment sites for each constituent prior to intervention. ANOVA is a parametric test, which is identical to the t-test when comparing only two groups of data. This test assumes that all data sets are normally distributed and have equal variance. The t-test has limitedpower todetect small differences among data sets if they are not normally distributed. Currently the report states that the "data were tested for normality and homogeneous variance prior to testing...[and] only the microbiological data were determined to be non-normally distributed..." However, the results of the normality tests were not included, nor were any descriptive statistics that may indicate normality. Our analyses suggest that many of the data groups are not normally distributed. In addition the mean is not considered a good measure of central tendency for many of R3 data, because mean values can be strongly influenced by outlier values, which were frequently observed. Much of our analyses, therefore, are based on the evaluation of median concentrations. Median values are resistant to the influence of outlier values, and may therefore be a more appropriate measure of central tendency in the R3 data.

   Table WQ3 includes means and 95% confidence intervals for the water quality data before and after intervention (BMPs applied). These descriptive statistics only show part of the story. At the very least, other parametric descriptive statistics, such as the standard deviation and the coefficient of skewness should be included, as well as non-parametric (i.e., resistant to outliers) descriptive statistics, such as the median, interquartile range, and the quartile skew. These will aid in interpreting the central tendency, variation, and skewness of the data. A test on the coefficient of skewness will indicate whether the data are symmetric or not. If the null hypothesis that the data are symmetric cannot be rejected, normality tests are warranted. Otherwise, it can be safely assumed that the data do not come from a normal distribution and alternative non-parametric statistical procedures that do not require normality should to be used.

   The standard methods for calculating the 95% confidence interval about the mean (based on t-distribution) are symmetric confidence intervals that require normality, especially with small data sets. While the report does not state the method used for calculating the 95% confidence intervals, it is likely that the standard method was employed since normality was assumed for the ANOVA analysis. When data are non-normal, alternative methods for calculating the 95% confidence intervals could be used, such as the non-parametric interval estimate for the median (no specific data distribution assumed) or an asymmetric confidence interval about the mean (a specific distribution is assumed, such as the lognormal distribution). However, it should be noted that 95% confidence intervals, are appropriate, but not necessary for testing whether there are significant differences between data sets. Hypothesis tests can be used to detect differences. It is recommended that confidence intervals be reserved for showing the uncertainty in an estimate of central tendency (e.g. mean or median) to determine the likelihood for a threshold to be exceeded, such as a water quality criterion.

If one or more of the pre-intervention data sets are determined to be non-normal or unequal in variance, alternatives to the single-factor ANOVA test can be used, such as the Kruskal-Wallis (K-W) test. The K-W test will determine if all of the data sets have the same distribution and if the medians are equivalent within a specified level of confidence.

2. **Comparison of water quality concentrations over time.** Monthly mean concentrations over time were included in the report. While this is a valid approach to analyzing data, it has a tendency to mask the data's true variability, and since there were generally only two samples per month, there is no apparent advantage to averaging for this exploratory data analysis. Also, Site 1004 had large spikes in the nutrient values that when plotted on the same graph as the other sites tends to dampen and make less apparent the variability in monitoring results from the other sites. It is recommended that all data are initially plotted on separate time-series graphs to identify seasonal periodicity, step-trends, or monotonic trends for each sampling site. Time series plots are an excellent approach for presenting the data and an appropriate first step for understanding the characteristics of the data. Note that unless there are obvious trends (step or monotonic), the time-series plots should probably be placed in an appendix rather than the main body of the report, as there will be a number of them and the information provided is primarily to aid the investigator in determining the next step in the analysis.

   In addition to time series plots, other plotting procedures are available that can be useful in the visual inspection of the data. Plots that should be considered for inclusion in the report include box plots that show side-by-side comparisons of central tendency and variability, and side-by-side quantile (cumulative probability distribution) plots that give an indication of the underlying distribution and any apparent differences in those distributions. These should be included in the main body of the report.

3. **Comparison of water quality data before and after intervention.** Standard t-tests were used to compare mean concentrations before and after intervention. The report states that only 6 out of 24 constituents showed significant differences, and the differences showed a net increase from pre- to post treatment. Removing the outlier points did not affect this result. As stated above, the t-test assumes that both groups of data are normally distributed about their respective means and that they have constant variance. There is no indication that the data meet these strict requirements (water resources data rarely do). The report also states that the data were "normalized" to the grand mean of the control sites, but there is no justifiable reason for doing so, especially since the control sites varied greatly amongst themselves.

   A limitation in the comparison of mean concentrations, such as through the use of the t-test, is that the mean of the concentration data is heavily influenced by outlier values. Given that outlier values were identified and recognized to influence the results, alternative measures of central tendency that are more resistant to the influence of the outliers (e.g. median) should be investigated and presented in the report. The rank-sum test, or Mann-Whitney test, is a non-parametric test that tests whether the median of one

group is significantly different from the median of another group. The rank-sum test does not assume any particular distribution or even that the two data sets come from the same distribution. Also, it has the power to detect small differences among data sets and will even work on censored data (data only known to be below the detection limit) as long as less than 50% of the data are censored. The rank-sum test is equivalent to the Kruskal-Wallis test discussed above, but applied to only two data sets. Based on the relative strengths of the rank-sum test as compared to the t-test, and for consistency in the data analysis (as it is highly unlikely the assumptions of the t-test could be met for all, if any of the data sets), it is recommended that the rank-sum (or Krsuskal-Wallis) tests be performed on all data sets.

Once it is determined that a significant difference in the medians exists, the magnitude of the difference can be calculated using the Hodges-Lehmann estimator, which is the median of all possible pair-wise differences between the two data sets. Note that this is often significantly different than the simple difference in medians. A confidence interval about the Hodges-Lehmann estimator can then be calculated to illustrate the variability of the estimate.

4. **Comparison of constituent fluxes (Mass loadings per time) before and after intervention**. Similar to the analysis of concentration data discussed above, mean fluxes for the pre- and post-intervention cases were compared using standard t-tests (for 2 sites only). In general, no difference in the mean flux was found between the pre- and post-intervention data.

   Similar to the analysis of the concentration data, the mean of the flux data is heavily influenced by outliers. Therefore, alternative measures of the central tendency should be calculated and compared. The rank-sum test could be used here as well.

5. **Correlation of toxicity measures with potential toxicants in dry weather runoff**. Correlations between toxicity data and concentration data were investigated using a Pearson product moment correlation. Based on this analysis, no correlations were found to be significant. The first and foremost step in investigating whether one variable is associated with another is to plot the two variables on opposite axes (scatterplot). This step was presented in the report and should be included. A scatterplot matrix helps to identify the nature of the correlation between several variables in one concise graph. A scatterplot will also indicate whether the use of Pearson's correlation coefficient is even appropriate, as it only tests whether there is a <u>linear</u> association between two variables. Due to the nature and complexity of biotic systems, the relationship between toxicity and constituent concentration are likely to be nonlinear. Therefore, an alternative measure of association should be used such as Kendall's Tau or Spearmans Rho. Both of these statistics measure the strength of the <u>monotonic</u> relationship between two variables.

- **<u>Discussion and General Review Comments</u>**. The primary conclusions drawn from the investigation were that there is no statistically significant reductions in pollutant concentration or flux (loadings) as a result of the education and/or sprinkler retrofit

technology. While this may be the case, the data analysis described and presented may have had limited ability to detect differences for the particular data sets. The discussion section included two possible explanations for not being able to detect changes between pre- and post-intervention: 1) the data had too much variability and not enough samples were taken, and 2) the treatments were applied at only about one-third of the individual homes within the test watersheds, which effectively diluted the effects of the intervention. Both of these are logical explanations and should be considered in the design of future studies. A helpful assessment would be to evaluate how much data would be needed to detect levels of differences desired to be detected. This information would be valuable for planning of future studies.

Another possible explanation for having difficulty in detecting differences that was not mentioned in the report is the difference in time periods for the pre-intervention and the post-intervention. The pre-intervention period was from December 2000 to June 2001 and the post-intervention period was from July 2001 to June 2002. In other words, the post-intervention period includes summer and fall data, while the pre-intervention period does not. Moreover, there was considerably more rainfall during the pre-intervention wet season than the post intervention wet season (see Table 1).

Based on this it may be desirable to analyze differences using a truncated post-intervention data set with only winter and spring data. The downside of this approach is that it reduces the number of data points to include in the analysis. However, it is justifiable in that in the summer and fall the observed dry-weather flows are likely more associated with irrigation practices and in the winter and spring the observed dry-weather flows are likely more associated with the leaching of saturated soils. We recommend that the use of a truncated data set should be considered if additional analyses of the data using the approaches recommended above do not reveal statistically significant differences.

Table 1: Daily Rainfall Data at the Tustin-Irvine Rain Gauge (100th of inches)

		2001												2002											
	Dec 00	Jan 01	Feb 01	Mar 01	Apr 01	May 01	Jun 01	Jul 01	Aug 01	Sep 01	Oct 01	Nov 01	Dec 01	Jan 02	Feb 03	Mar 02	Apr 02	May 02	Jun 02	Jul 02	Aug 02	Sep 02	Oct 02	Nov 02	Dec 02
1																									
2							5						15												
3																									
4				47	7							6		5											
5																									
6				3	61												12								
7																22									
8		47																							
9				33	5																				
10													10											163	
11		184										4													
12		105	36									36													
13		8	295																						
14			14																						
15																	7								
16																									99
17															40	29									8
18			3																						
19																		7							
20			9															10							85
21					52								28												
22													8												
23			29													4									9
24		32	12									46					9								
25			85																						
26		57	90	3		8											7						5		
27		13	42											46			3								
28			32											5										3	
29												18	10												13
30													35											54	
31																									
total	0	446	647	86	125	8	5	0	0	0	0	110	106	56	40	55	38	17	0	0	0	0	5	220	214

Pre-intervention period (13.2 inches from12/00-6/01) Post-intervention period (3.1 inches from12/01-6/02)

3. Examples of Recommended Approaches to Data Analysis for Chapter 5

These example analyses focus on TMDL constituents: nutrients (total nitrogen and total phosphorus), metals (copper, lead, zinc, cadmium), pesticides, and pathogens (fecal coliform). The analyses also focus on dry weather flows, as reduction of these flows was the objective of the R3 study.

Recommended Data Analysis Methods

Exploratory Data Analysis

Visual inspection of data and exploration of factors that could potentially influence data (e.g. seasonal trends, rain events)

1. Divide data into pre and post- intervention groups.
2. Construct time series plots to visually inspect data and visually examine for seasonal trends. Overlay storm event markers to identify any relation to rainfall volume or antecedent dry period (ADP).
3. Investigate normality or log normality of data sets. Select appropriate statistical tests.
4. Construct probability plots for pre-intervention and post-intervention periods.
5. Prepare quantile plots.
6. Prepare side-by-side box plots.
7. Calculate descriptive statistics

Hypothesis Testing

Test data for skewness, normality, and statistically significant differences. Note that the skewness and normality tests are only needed if parametric approaches are conducted. It is our recommendation to use non-parametric approaches for consistency because normality will not be met in all cases. Nonetheless examples have been provided to show that several of the data sets do not come from a normal distribution.

1. Skewness hypothesis test for symmetry.
2. Shipiro-Wilkes normality test.
3. Mann-Whitney rank-sum test.
4. For the data sets that have greater than 50% censored data (i.e. data only known to be less than the detection limit), hypothesis tests for differences in proportions.

Example Results

The first step in the data analysis is to construct time-series plots. Time-series plots are constructed to identify seasonal periodicity, step-trends, and monotonic trends. The original report included monthly average time-series plots with all sites included per plot. The authors noted that periodicity and trends were not apparent. However, plotting all sites on one graph tends to hide much of the information. For instance, Site 1004 had much higher nutrient concentrations than the other sites, so by including this site, the minor fluctuations in data from

the other stations are less apparent. Individually plotting the time-series plots reveals more information. Also, by overlaying storm events the role of rainfall volumes and the antecedent dry period (ADP) may be more apparent and may indicate whether additional analyses are warranted (e.g., correlating ADP with concentration). Figure 1 is an example time-series plot with storm event markers overlain for total phosphorus for Site 1001. Notice the pre-intervention period had much more rainfall, which likely added to the variability in runoff concentrations and fluxes. However, it is apparent that the winter and spring concentrations appear to be lower and less variable during the post-intervention period. The irrigation controllers may have had an affect on the runoff concentrations by reducing the amount of irrigation during moister weather conditions (i.e. high soil moisture). Notice a similar effect for total nitrogen in Figure 2. Additional time-series plots are provided in Appendix A.

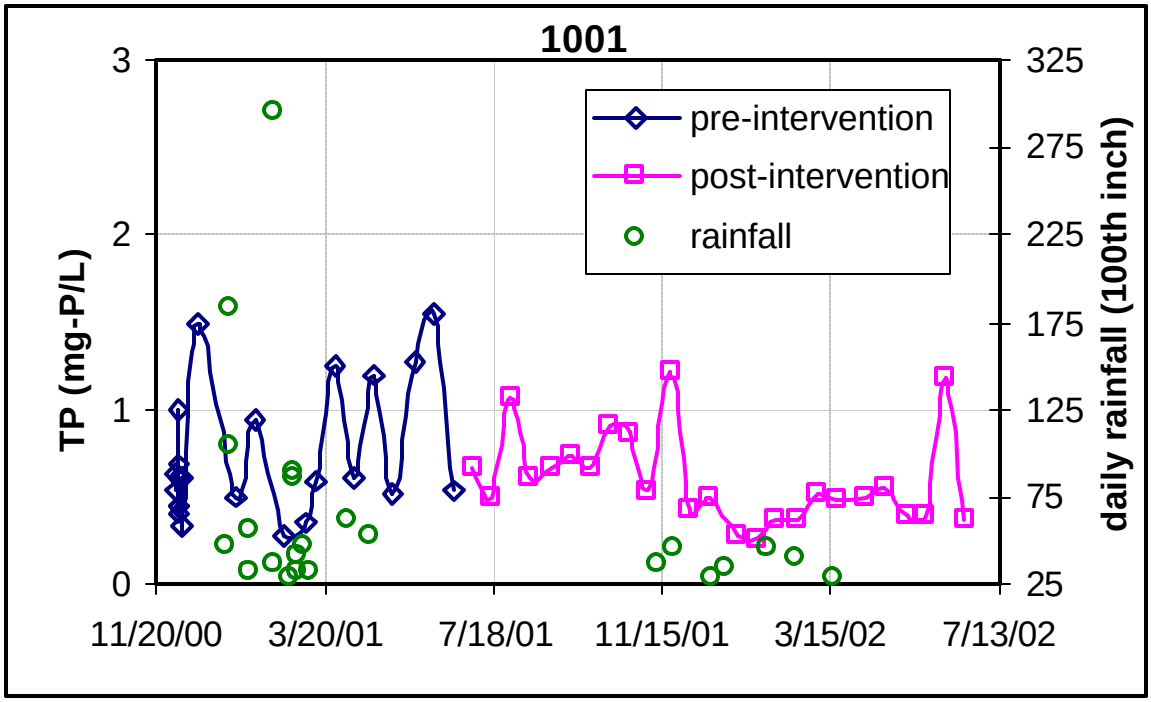


Figure 1. Example time-series plot of total phosphorus with storm event markers.

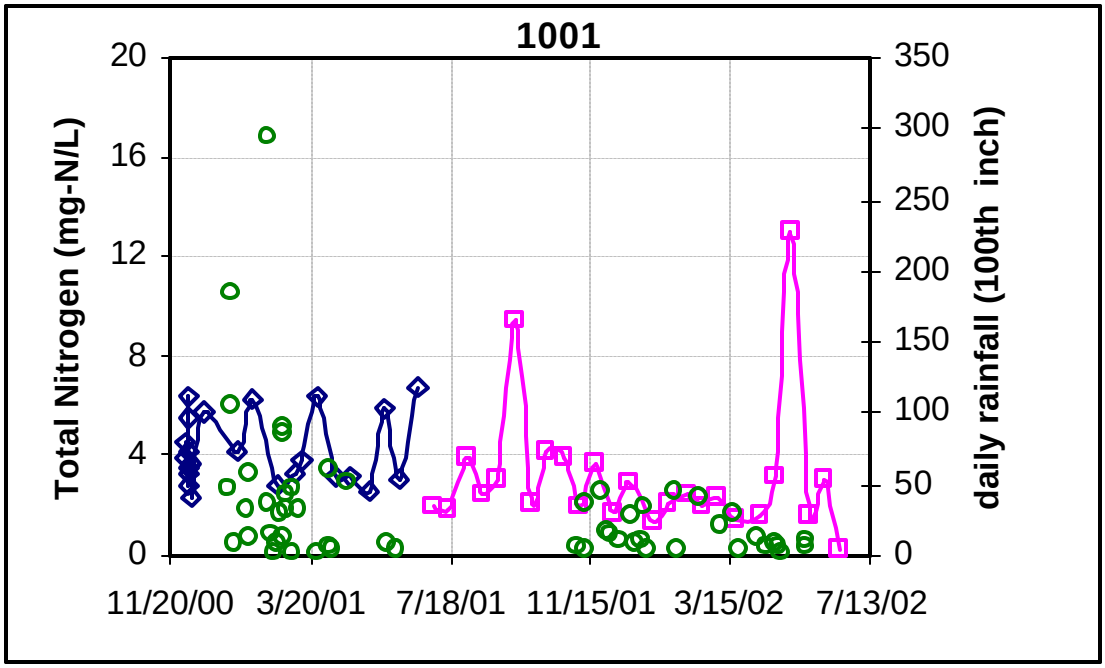


Figure 2. Example time-series plot of total nitrogen with storm event markers.

Comparison of Water Quality Data Prior to Intervention

To visually investigate whether the test sites have similar runoff characteristics, probability plots should be constructed. Figure 3 is an example of a probability plot for total phosphorus for all of the test sites. Notice that all of the sites have a similar distribution except for Site 1004. This suggests that Site 1004 should not be used for "normalizing" of the intervention sites (other information in the report indicating an unknown connection to a nursery further suggests the exclusion of site 1004). However, as mentioned above there is no advantage to normalizing the data using the control sites even if all of the sites had similar distributions.

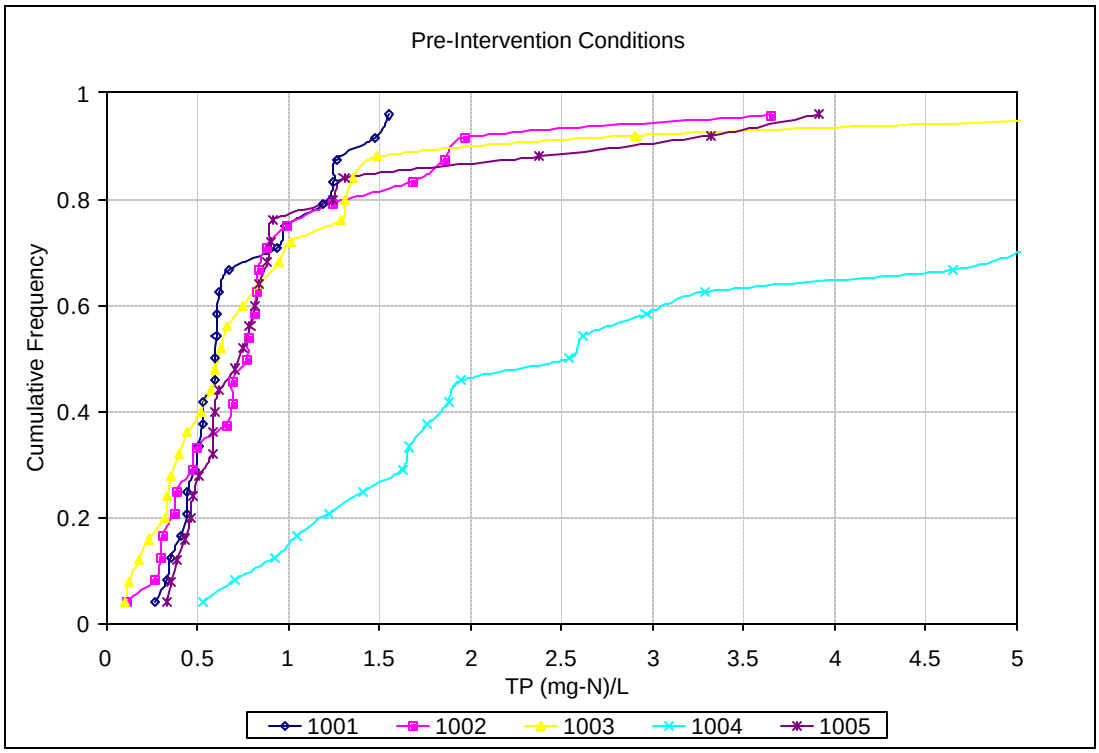


Figure 3. Example probability plot of total phosphorus for all sites prior to intervention.

The next step in the data analysis is to calculate parametric and non-parametric descriptive statistics. Table 2 is an example table of descriptive statistics for total nitrogen for all sites for both the pre- and post-intervention periods. (Additional descriptive statistics are included in Appendix B.) Table 2 includes the number of data points (n), the detection percent (%>MDL/RL), the mean, median, 25% trimmed mean, min, max, 25th percentile, 75th percentile, standard deviation, interquartile range (IQR), and the coefficient of skewness (g_s). Also included in the table are critical skewness coefficients (g_{cr}), which are readily available in statistics texts. If the coefficients of skewness are less than these critical values, then the data are symmetric. Notice that the measures of central tendency (mean and median) and variability (standard deviation) of the sites during the pre-intervention period are quite different, indicating the data arise from different distributions. The median values are consistently smaller than the mean (in some cases substantially smaller) demonstrating the influence of the outliers on the measure of central tendency. Also note that only three pre-intervention data sets are symmetric and none of the post-intervention data sets are. Failure to pass the symmetry test indicates the data are not normal. However, passing the symmetry test does not indicate the data are normal; this requires a normality test. The symmetry test, which is easier to conduct than normality tests, serves as an initial screen for normality to reduce the number of data sets needing further investigation.

Table 2. Example table of descriptive statistics for total nitrogen for each site for pre- and post-intervention.

		1001		1002		1003		1004		1005	
Parameter	**Statistic**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
TN (calculated) (mg-N/L)	**n**	23	25	23	25	23	25	23	25	23	25
	% > MDL/RL	100%	80%	98%	90%	98%	96%	98%	96%	100%	98%
	Mean	4.24	3.09	5.31	3.44	3.66	4.42	48.00	10.18	6.89	7.74
	Median	3.84	2.27	3.95	2.55	2.66	2.50	19.01	5.57	5.06	4.36
	Trimmed mean	3.94	2.40	4.53	2.76	2.93	3.01	33.11	6.47	5.08	4.42
	min	2.30	0.30	1.50	0.78	1.46	0.45	3.28	0.74	2.48	1.07
	max	6.76	12.99	13.83	11.40	12.12	19.91	141.06	40.80	20.41	67.12
	25th percentile	3.20	1.79	2.27	2.10	2.11	2.04	9.05	2.71	3.52	3.47
	75th percentile	5.68	3.13	8.02	4.36	4.81	5.17	94.79	19.18	7.07	5.62
	St Dev	1.41	2.67	3.56	2.51	2.48	4.39	49.17	10.73	5.29	12.85
	IQR	2.48	1.34	5.75	2.26	2.70	3.13	85.74	16.47	3.55	2.15
	Skewness, g_s	0.55	2.82	0.84	1.87	2.13	2.27	0.74	1.37	1.88	4.46
	g_{cr}	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92
	Symmetric ($g_s < g_{cr}$)?	Y	N	Y	N	N	N	Y	N	N	N

Non-parametric tests are recommended for all data analyses for consistency since all data sets do not meet the required assumptions for parametric tests (i.e. normality and constant variance). Non-parametric tests are not based on the assumption of normally distribution; therefore, normality tests were not warranted. It is important to note that if the data sets that passed the initial symmetry screening (Sites 1001, 1002, and 1004 in the table above) also passed a normality test, it does not indicate the data follow a normal distribution, especially for small data sets. The test simply indicates that normality cannot be rejected for the data.

As mentioned above, the non-parametric equivalent to the ANOVA test is the Kruskal-Wallis test, which tests for a difference between the medians of independent data groups. The K-W test will also test whether the datasets are derived from the same distribution. Several statistical packages will perform this test. Results of the K-W test shown in Table 3 was generated from a statistical add-on to Microsoft Excel® called Analyse-It™.

Comparison of the mean ranks in Table 3 provides an indication of whether the data groups are derived from the same distribution. A p values < 0.05 indicates that two or more the data groups have different distributions. Examination of the mean ranks in Table 3 shows that Sites 1001, 1002, and 1005 have somewhat similar mean ranks and Sites 1003 and 1004 have somewhat different mean ranks. This suggests that Sites 1003, 1004 have a different distribution than the other sites. Therefore, it is determined that the K-W test should be performed on just Sites 1001,

1002, and 1005. These results are shown in Table 4. Notice that the p-value is now greater than 0.05, so the distributions of the total nitrogen data are not significantly different. Based on this analysis, Site 1002 should be used as the only control site for comparison of total nitrogen data. These analyses will need to be repeated for the other water quality constituents.

Table 3. Example of Kruskal-Wallis test results for total nitrogen at the test sites prior to intervention.

Test	**Kruskal-Wallis ANOVA**
Comparison	Total Nitrogen: 1001, 1002, 1003, 1004, 1005
Performed by	GeoSyntec Consultants
n	115

Total Nitrogen	n	Rank sum	Mean rank
1001	23	1128.0	49.04
1002	23	1162.0	50.52
1003	23	774.0	33.65
1004	23	2150.0	93.48
1005	23	1456.0	63.30

Kruskal-Wallis statistic	41.71	
p	<0.0001	(chisqr approximation)

Table 4: Example of Kruskal-Wallis test results for total nitrogen at the Site 1001, 1002, and 1005 prior to intervention.

Test	**Kruskal-Wallis ANOVA**
Comparison	Total Nitrogen: 1001, 1002, 1005
Performed by	GeoSyntec Consultants
n	69

Total Nitrogen	n	Rank sum	Mean rank
1001	23	710.0	30.87
1002	23	761.0	33.09
1005	23	944.0	41.04

Kruskal-Wallis statistic	3.27	
p	0.1948	(chisqr approximation)

Based on these example analyses of the pre-intervention TN data, it is clear that Site 1004 should not be considered as a control site for total nitrogen, and Site 1003 should be used with caution.

Comparison of Water Quality Data Before and After Intervention

Side-by-side box plots and probability plot comparisons of pre-intervention and post-intervention were constructed to identify any apparent differences in the central tendency and concentration distributions between the two data sets. Figure 4 shows side-by-side box plots of total nitrogen at all of the test sites. Site 1004 was omitted due to its high variability. Notice that Site 1001 shows a distinct decrease in total nitrogen, while the other sites do not. However, other sites do show a decreasing trend in median concentration and inter-quartile ranges.

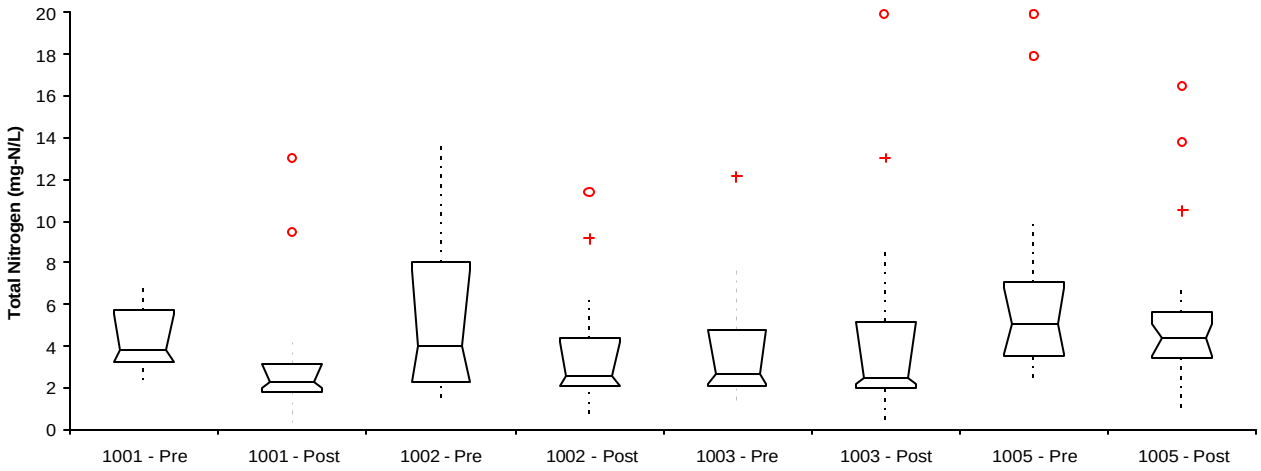


Figure 4. Side-by-side box plots of pre- versus post-intervention for total nitrogen at all sites.

Figure 5 is a probability plot of total nitrogen for Site 1001 before and after intervention. (Additional probability plot comparisons are included in Appendix C.) Notice that there is a distinct reduction in total nitrogen at the site. However, since these data are from different time-periods, this difference could be related to temporal variability.

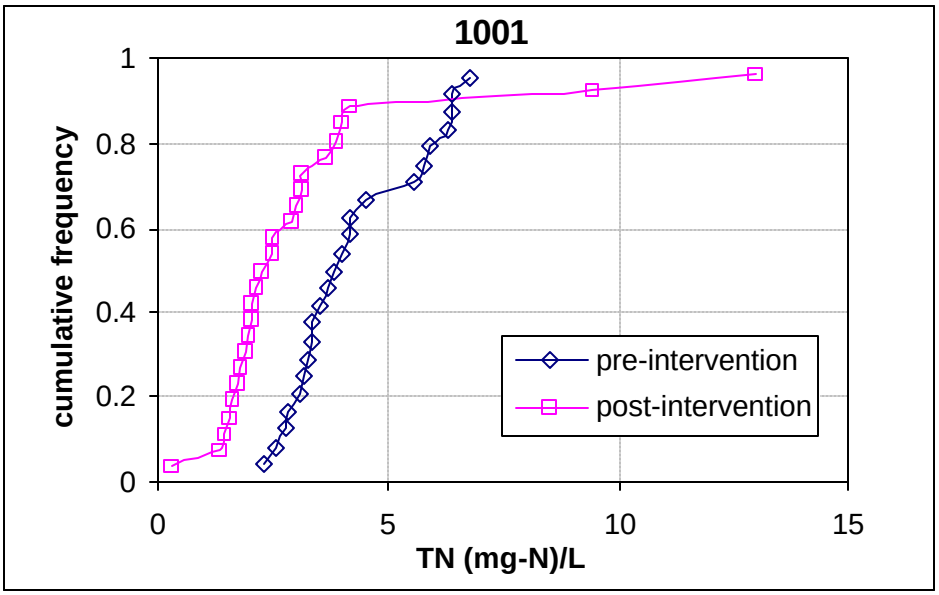


Figure 5. Example probability plot of pre- versus post-intervention at Site 1001 for total nitrogen.

To evaluate if temporal variability caused by the different monitoring periods has anything to do with the difference in total nitrogen concentrations, the probability plot of the pre- and post-intervention period for Site 1001 is plotted with those for Site 1002 and Site 1005 (as these were determined to be the only valid control sites). These comparison plots are shown in Figure 6 and Figure 7. Notice that for pre-intervention, the distribution of Site 1001 more closely follows the distribution of Site 1005 than that of Site 1002, and for post-intervention the opposite is true. This indicates that the year-to-year variability alone cannot explain the reduction in total nitrogen at Site 1001. However, this would need to be statistically verified.

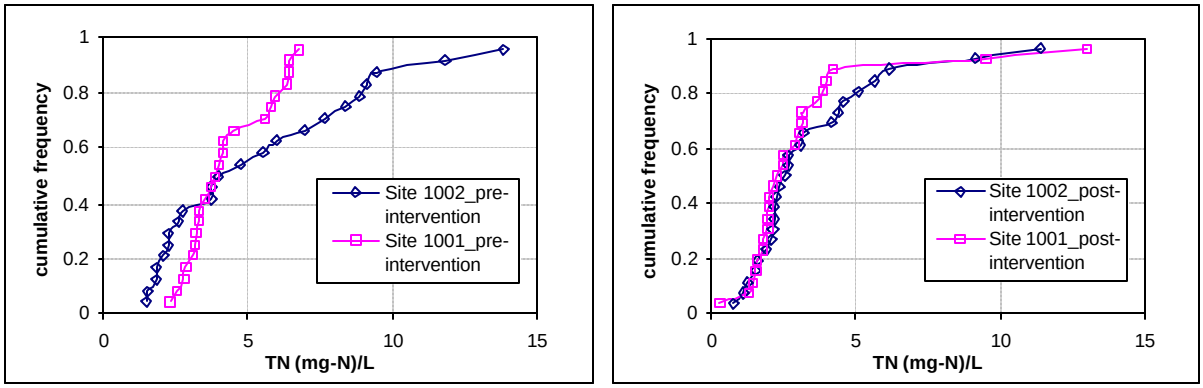


Figure 6. Example probability plot for total nitrogen of Site 1001 versus Site 1002 for the pre- and post-intervention periods.

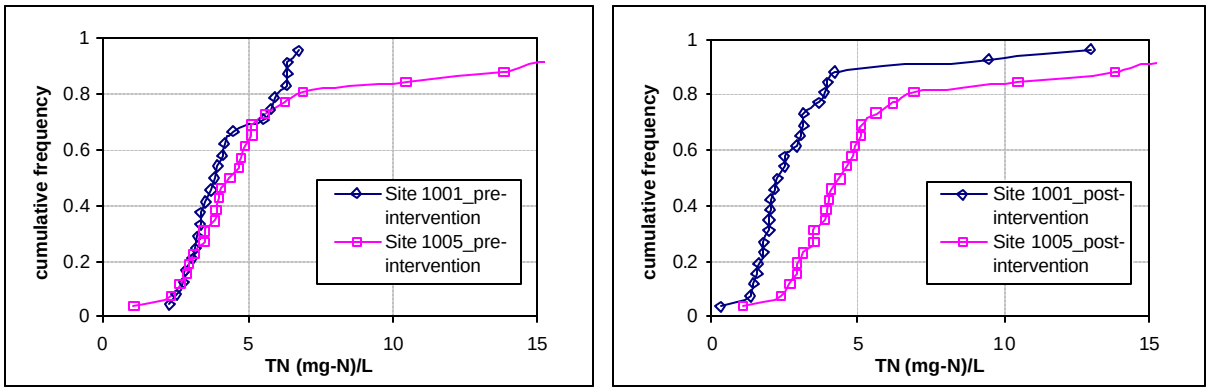


Figure 7. Example probability plot for total nitrogen of Site 1001 versus Site 1005 for the pre- and post-intervention periods.

As mentioned earlier, the Mann-Whitney test (rank-sum) can be used to determine if there is a statistical difference in the median values of two independent data sets (by rejecting the hypothesis that they are the same). Table 5, Table 6, and Table 7 show the output of the Mann-Whitney tests from the Analyse-It™ statistical package on Sites 1001, 1002, and 1005, respectively. Notice that there is a statistically significant difference ($p<0.05$) in the medians between the pre- versus post-intervention total nitrogen data at both Sites 1001 and 1002, but not at Site 1005. Furthermore, the difference in the medians at Site 1001 is at a higher level of confidence (more statistically significant) than the difference at Site 1002 (i.e., greater than 99% significant compared to about 96% significant). The magnitudes of these differences (Hodges-Lehmann estimator) are about 1.5 and 1.3 mg-N/L for Sites 1001 and 1002, respectively. These tests indicate that the difference in the total nitrogen medians at Site 1001 from pre-intervention to post-intervention cannot be explained by the year-to-year variation alone (e.g., the intervention appears to have had an effect). It also indicates that the public education applied to Site 1005 did not appear to make a significant difference.

Table 5: Example Mann-Whitney test for difference in medians for total nitrogen at Site 1001 from pre- versus post-intervention.

Test	**Mann-Whitney test**			
Alternative hypothesis	1001: Pre ≥ Post			
Performed by	GeoSyntec Consultants			
n	48			
1001	**n**	**Rank sum**	**Mean rank**	**U**
Pre	23	736.0	32.00	115.0
Post	25	440.0	17.60	460.0
Difference between medians	1.497			
95.2% CI	0.883	to +∞	(normal approximation)	
Mann-Whitney U statistic	115			
1-tailed p	0.0002	(normal approximation)		

Table 6. Example Mann-Whitney test for difference in medians for total nitrogen at Site 1002 from pre- versus post-intervention.

Test	**Mann-Whitney test**			
Alternative hypothesis	1002: Pre ≥ Post			
Performed by	GeoSyntec Consultants			
n	48			
1002	**n**	**Rank sum**	**Mean rank**	**U**
Pre	23	651.0	28.30	200.0
Post	25	525.0	21.00	375.0
Difference between medians	1.289			
95.2% CI	0.065	to +∞	(normal approximation)	
Mann-Whitney U statistic	200			
1-tailed p	0.0355	(normal approximation)		

Table 7. Example Mann-Whitney test for difference in medians for total nitrogen at Site 10052 from pre- versus post-intervention.

Test	**Mann-Whitney test**			
Alternative hypothesis	1005: Pre ≥ Post			
Performed by	GeoSyntec Consultants			
n	48			
1005	**n**	**Rank sum**	**Mean rank**	**U**
Pre	23	610.0	26.52	241.0
Post	25	566.0	22.64	334.0
Difference between medians	0.530			
95.2% CI	-0.446	to +∞	(normal approximation)	
Mann-Whitney U statistic	241			
1-tailed p	0.1686	(normal approximation, corrected for ties)		

Comparison of Constituent Fluxes Before and After Intervention

The statistical procedures applied to the concentrations examples above should also be applied to the constituent fluxes (mass loadings). For completeness, an abridged example analysis will be provided here. Figure 8 includes side-by-side box plots and probability plots of total nitrogen flux data (mg/acre/day) for Site 1001 at pre- and post-intervention. Note there appears to be a significant decrease in the median, as well as an overall reduction in the distribution of values.

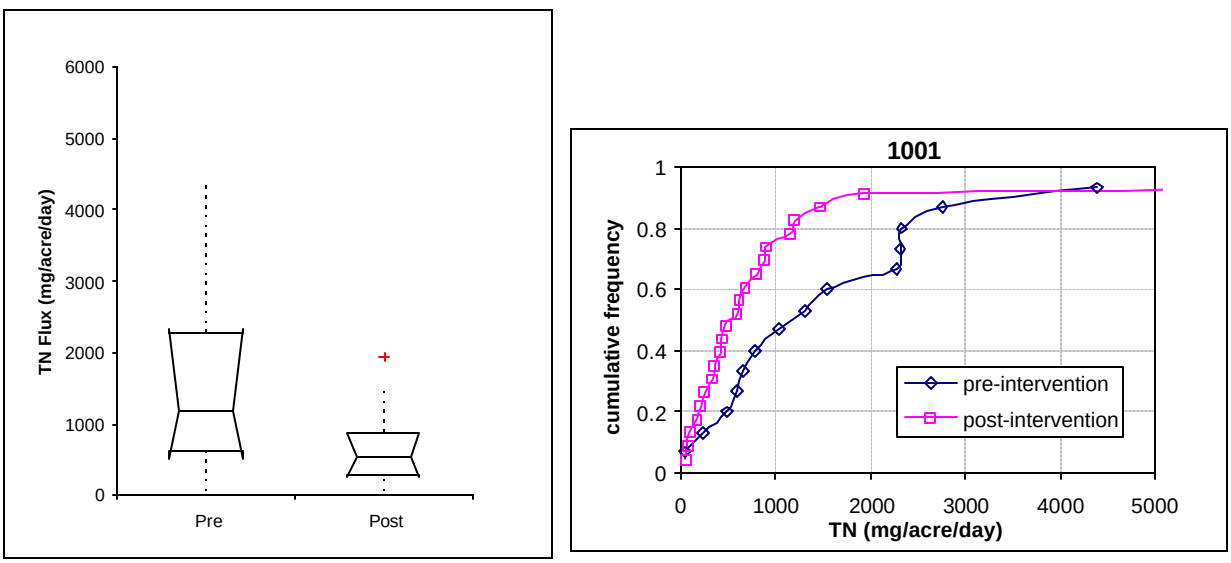


Figure 8. Side-by-side box plot and probability plots of pre- versus post-intervention for total nitrogen flues at Site 1001.

Table 8 shows the results of the Mann-Whitney test (rank-sum) for the total nitrogen flux at Site 1001. Notice the difference in the medians from pre- to post-intervention are statistically significantly different at the 95% confidence level ($p<0.05$). The magnitude of the difference (the Hodges-Lehmann estimator) is approximately 530 mg/acre/day, indicating a relatively large reduction in total nitrogen loads from the neighborhood. However, as discussed below, the extent to which the ET controllers contributed to this reduction is unclear.

The nitrogen fluxes used in this analysis were computed as the product of the measured concentration and the average daily flow. Therefore, the reduction in TN flux could be due to a reduction in flow, a reduction in concentration, or a combination of both. Analyses presented earlier showed a statistically significant reduction in median TN concentration at site 1001 between the pre- and post-intervention periods. Similarly, analyses discussed in the R3 report indicate that there was a statistically significant reduction in flow at site 1001 between the pre- to post-intervention periods; however, it was cautioned that the pre- and post-intervention periods are not comparable due to seasonal differences in the data collection period. Thus, observed reductions in flow in 1001 could be influenced by seasonal factors, and therefore the extent to which the ET controllers contributed to a reduction in flow is unknown. Consequently, reductions in TN flux could be attributed to a combination of TN reduction, flow reduction, and/or seasonal factors.

Table 8. Example Mann-Whitney test for difference in medians for total nitrogen flux at Site 1001 from pre- versus post-intervention.

Test	**Mann-Whitney test**			
Alternative hypothesis	1001_flux (mg/acre/day): Pre ≥ Post			
Performed by	GeoSyntec Consultants			
n	36			
1001_flux (mg/acre/day)	**n**	**Rank sum**	**Mean rank**	**U**
Pre	14	320.0	22.86	93.0
Post	22	346.0	15.73	215.0
Difference between medians	529.389			
95.1% CI	115.985	to +∞	(normal approximation)	
Mann-Whitney U statistic	93			
1-tailed p	0.0239	(normal approximation)		

Based upon the above results, we believe that it would be valuable to complete a more robust statistical evaluation of the data, as we believe that some significant management implications could be determined.

4. Possible Implications for TMDL Compliance.

The R3 Study results were examined in the context of existing TMDLs in the San Diego Watershed. Most of the existing TMDLs are reviewed below and possible inferences and implications of the R3 Study data for TMDL compliance are discussed. The sediment and organophosphorus pesticide TMDLs were not reviewed because sediment data were not collected (the vast majority of sediments are transported by storm flows) and because Schiff and Tiefenthaler (2003) have previously conducted an extensive analysis of the organophosphorus pesticide data.

4.1. Nitrogen

Nitrogen Water Quality Objectives and TMDLs – The Basin Plan water quality objectives for nitrogen in San Diego Creek are 13 mg/L Total Inorganic Nitrogen (TIN) in Reach 1, and 5 mg/L TIN in Reach 2 (RWQCB, 1995). Reach 1 extends from Newport Bay to Jefferey Road, and Reach 2 extends from Jefferey Road to the headwaters. There is no numeric standard for nitrogen in Upper Newport Bay in the Basin Plan.

The nitrogen TMDL for Upper Newport Bay is based on the general goal of reducing nutrient loads to Newport Bay by 50 percent, to levels observed in the early 1970's (USEPA, 1998b). The nitrogen TMDL sets phase-in limits on total nitrogen (TN) loads to Newport Bay (see Table 9). Separate loads are established for the dry and wet seasons (dry season is from April 1 to September 30). In addition, the winter load is exclusive of storm flows with an average daily flow greater than 50 cfs in San Diego Creek at Campus Drive.

There is no TMDL for nitrogen loads in San Diego Creek, Reach 1 because it was reasoned that attainment of the 50 percent reduction in nitrogen loads to Newport Bay would result in compliance with the Basin Plan in-stream water quality standard for Reach 1 (13 mg/l TIN). However, for Reach 2 it was determined that the average in-stream nitrogen concentrations would likely remain close to or above the Basin Plan in-stream water quality standard (5 mg/L TIN), even with attainment of the Newport Bay TMDLs. Therefore a TMDL of 14 lbs/day TN was established for Reach 2 (see Table 9) and is applicable for all flows exclusive of storm flows greater than an average daily flow of 25 cfs in San Diego Creek at Culver Drive.

Table 9: Summary of Nutrient TMDLs for Upper Newport Bay and San Diego Creek

TMDL	Dec 31, 2002	Dec 31, 2007	Dec 31, 2012
Newport Bay Watershed, TN – Summer load (4/1 to 9/30)	200,097 lbs	153,861 lbs	
Newport Bay Watershed, TN – Winter load (10/1 to 3/31; non-storm)			144,364 lbs
Newport Bay Watershed, Total Phosphorus – Annual Load	86,912 lbs	62,080 lbs	
San Diego Creek, Reach 2, daily load			14 lbs/day
Urban Runoff Allocation for the Newport Bay Watershed Summer load Winter load	22,963	11,481	38,283

Study Data Comparison with Nitrogen Water Quality Objective – The Basin Plan water quality objectives are expressed in terms of total inorganic nitrogen (TIN), which is comprised of nitrate/nitrite nitrogen and ammonia. By far the majority of the TIN in San Diego Creek is comprised of nitrate/nitrite nitrogen, as measured ammonia concentrations were typically quite low with a majority below the detection limit. For this reason, only the nitrate/nitrate concentration data are compared to the Basin Plan objectives in this report.

Table 10 shows the mean and median nitrate/nitrite concentrations measured in the five study watersheds. The mean and median nitrate/nitrite concentration in all watersheds except 1004 are below the Reach 2 Basin Plan objective of 5 mg/l TIN. As discussed previously, Site 1004 may not be a representative control site because the underlying distribution of pre-intervention nitrogen data appears to be different from the other sites. Similar arguments may also be true Site 1003. With exception of Site 1004, mean nitrate/nitrite concentrations suggests that, on average, residential runoff from these watersheds do not contribute to the exceedance of Basin Plan standards for TIN in receiving waters in San Diego Creek, Reach 1 and 2. The Reach 2 water quality objective was occasionally exceeded in the all watersheds, except for the post intervention conditions in 1001 and 1002.

The mean and median nitrate/nitrate concentrations in watershed 1004, and 1005 exhibit exceedances of the 5 mg/l standard during pre- and/or post intervention conditions. Watershed 1004, in particular, had high levels of measured nitrate/nitrite concentrations, especially during the pre-intervention period. A number of these high readings exceed the Reach 1 water quality objective of 13 mg/l TIC. The results from watershed 1004 are not consistent with those from the other four study watersheds, and the source of the high readings is unknown. Localized conditions involving excessive fertilizer usage by a few users could possibly be a factor in these elevated readings. In particular, the R3 mentions an unknown connection to a neighboring watershed, which could explain the source of elevated nutrient levels.

Table 10: Mean and Median Nitrate/Nitrite Concentration (mg/l) by Watershed (all data)

	1001		1002		1003		1004		1005	
	Pre	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
n	23	25	23	25	24	25	23	25	24	25
Mean	2.56	1.47	2.57	1.07	2.13	1.71	36.50	6.61	2.61	4.13
Median	2.32	1.38	1.56	0.93	1.68	0.94	16.88	2.29	2.45	1.48
n>5 mg/l	1	0	4	0	1	2	18	8	2	1
n>13 mg/l	0	0	0	0	0	0	12	4	0	1

The Mann-Whitney (rank-sum) test was performed to compare the statistical difference between median concentrations during pre- and post-intervention periods (see example in Section 3 above). The median nitrate/nitrite in the post-intervention period was lower in all watersheds, and the difference was statistically significant at the 0.05 confidence level. As the control stations exhibited this trend, these data (i.e. entire data sets with unequal seasonal coverage) cannot be used to ascertain if the structural and educational BMPs were effective in reducing the runoff concentrations of nitrate/nitrite.

Clearly there is another factor contributing to reduced concentrations in the post intervention period. One possibility that was investigated is differences in seasons, year-to-year variability, and sampling times of the pre- and post-intervention data. Table 11 shows mean and median concentrations for comparable seasons and sampling times. Note there are still noticeable reductions in all of the median concentrations, except Site 1005. Applying the Mann-Whitney (rank-sum) test to these data it was found that statistically significant differences between median nitrate/nitrite concentrations in the pre- and post-intervention periods occurred only in watersheds 1001 and 1004, as compared to all watershed when all data are considered. These results indicate that seasonal effects are present in these data and should be considered in the study evaluation. It may be inferred from these result that there were significant reductions in the nitrate/nitrite concentration in the intervention watershed during the wet season that may, in part, be attributable to the structural BMPs. It is unknown whether similar reductions would occur in dry weather runoff during the dry season because such data were not collected during the pre-intervention period.

Table 11: Mean and Median Nitrate/Nitrite Concentration (mg/l) by Watershed for Comparable Seasons and Sampling Times[1]

	1001		1002		1003		1004		1005	
	Pre	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
n	18	14	18	14	19	14	18	14	19	14
Mean	2.38	1.43	1.95	0.95	2.17	1.66	26.24	6.57	2.24	6.27
Median	2.22	1.48	1.16	0.96	1.50	1.02	8.94	2.06	2.03	1.96
n>5 mg/l	0	0	2	0	1	1	13	4	1	1
n>13 mg/l	0	0	0	0	0	0	7	3	0	1

1 – evening samples were deleted from the pre-intervention data. The post-intervention data include only those data collected in months identical to the pre-intervention period.

Study Data Comparison with Nitrogen TMDLs **-** The nitrogen TMDL is expressed in terms of total nitrogen (TN) loads. TN concentrations were calculated from the monitoring data as the sum of the nitrate/nitrite nitrogen and TKN nitrogen. Table 12 shows the mean and median TN concentrations measured in the five study watersheds. The mean and median TN concentration in dry weather runoff are generally in the range of 2 to 5 mg/l, with the exception of watershed 1004 where substantially higher concentrations were measured. The rank sum tests indicated that median TN concentrations are significantly lower (in a statistically sense) in the post-intervention period in watershed 1001 (structural BMPs, see Table 5), and in watershed 1002 (control, see Table 6), and based on the probability plots in Appendix C, Site 1004 is expected to as well. However, sites 1003 and 1005 did not show statistically significant reductions. These results did not change when only subsets of the data were used to consider possible affects stemming from the sampling time and sampling months.

Table 12: Mean and Median TN Concentration (mg/l) by Watershed

	1001		1002		1003		1004		1005	
	Pre	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
All Data										
n	23	25	23	25	23	25	23	25	23	25
Mean	4.24	3.09	5.31	3.44	3.66	4.42	48.00	10.18	6.89	7.74
Median	3.84	2.27	3.95	2.55	2.66	2.50	19.01	5.57	5.06	4.36
Subsets[1]										
n	18	14	18	14	18	14	18	14	18	14
Mean	4.18	2.78	4.51	2.63	3.71	3.71	33.99	8.91	6.98	9.91
Median	3.62	2.02	3.22	2.21	2.51	2.47	12.14	3.74	4.17	3.96

1 – Data subsets with comparable sampling time and seasons. Evening samples were deleted from the pre-intervention data. The post-intervention data include only those data collected in months identical to the pre-intervention period.

TN flux estimates were calculated for watersheds 1001 and 1005 (Table 13). The draft R3 report indicates that the flow measurements in watershed 1002-1004 are not reliable and therefore flux estimates were not calculated for these watersheds. Flux estimates were calculated as the product of the constituent concentration and the average daily flow occurring on the day of the sample collection. The flux estimates were found to be quite variable as they depend on both flow and concentration measurements. Table 13 shows that median TN flux estimates decrease from the pre- to post-intervention periods for both watersheds. Mann-Whitney (rank sum) tests show the reductions to be statistically significant (Table 8). Because comparable data are not available for the control sites, it is not possible to infer whether these reductions are influenced by the ET controllers in the intervention watershed (1001). Also, as previously discussed, the reduction in TN flux may be attributable to a reduction in flow, a reduction in concentration, seasonal factors, or a combination of these.

Table 13: Mean and Median TN Flux (mg-N/acre/day) by Watershed

	1001		1005	
	Pre	**Post**	**Pre**	**Post**
All data				
n	14	22	10	21
Mean	1476	1667	2104	6537
Median	1164	530	1568	1177
Subset[1]				
n	12	14	10*	8
Mean	1384	587	2104	1716
Median	902	497	1568	960

1 – Data subsets with comparable sampling time and seasons. Evening samples were deleted from the pre-intervention data. The post-intervention data include only those data collected in months identical to the pre-intervention period.
* – Same as the all data case

Although the flux estimates in Table 13 are limited in number, duration, and location, they can be used to speculate about the magnitude of the urban area contribution of TN loads to Newport Bay and the potential reduction in loads from structural and nonstructural BMPs. Based on the limited flux data, the annual TN load to Newport Bay in dry weather runoff from urban areas in the San Diego Creek Watershed is estimated to range between 37,000 to 50,000 lbs per year under existing land-use conditions (see Table 14). This is for the most part below the 2012 urban runoff allocation of 49,764 lbs. The annual TN load is estimated to increase to 50,000-67,000 lbs per year under built-out conditions.

According to the 2001 report on the nutrient TMDL (OCPFED, 2001), the average daily TN load in San Diego Creek at Campus Drive was 540 lbs/day between July 2000 and June 2001. This converts to an annual load of about 197000 lbs, which is below the 2007 TMDL (note: San Diego Creek is the majority but not sole contributor of TN loads to Newport Bay). Estimates in Table 14 suggest that dry weather runoff from urban areas account for about 20 to 25% of the annual TN in the San Diego Creek Watershed. If it is assumed that flux reductions observed in the post intervention period are attributable to the structural and nonstructural BMPs, and if similar interventions could hypothetically be implemented on a watershed-wide basis, then the potential reduction in annual dry weather TN loads is estimated to range between 12,500-20,000. This would represent a reduction of about 6-10% of the current TN loads and about 30-40% of the estimated current dry weather urban loads. Note these estimates are based on few data collected in a limited area, and should therefore be considered preliminary in nature.

Table 14: Estimated Annual TN Loads in Dry Weather Runoff from Urban Areas in the San Diego Creek Watershed

	TN flux (mg-N/acre/d)	Annual TN Load to Newport Bay (lbs) Existing land-use[1]	Annual TN Load to Newport Bay (lbs) Built-out land-use[2]
Pre-intervention conditions	1160 – 1560	37,300 – 50,500	50,000 – 67,000
Post-intervention conditions	530 – 1180	17,000 – 38,000	23,000 – 51,000
Potential reduction		~12,500 – 20,000	~16,000 – 27,000

1 –Used 40000 acres or about 53% of the San Diego Creek Watershed area (IRWD, 2003). For comparison, urban land use in 1999 use was estimated at 35,500 acres of the watershed area at Campus Drive (Tetra-Tech, 2000).
2 – Used 53500 acres or about 71% of the San Diego Creek Watershed area (IRWD, 2003).

The following conclusion can be made based on the analyses above:

- Average and median nitrate/nitrite concentrations in dry weather runoff are below the Reach 2 water quality objective (5 mg/l), for most but not all study watersheds.
- Occasional exceedance of the Reach 2 water quality objective occurred in all study watersheds
- The majority of measured nitrate/nitrite concentrations in watershed 1004 during the pre-intervention period were greater than the Reach 2 water quality objective of 5 mg/l. These data are not consistent with those from the other watersheds. The cause is unknown, but could possibly be related to the unknown connection to neighboring nursery discussed in the R3 report.
- Sampling periods (months) and sampling time (morning versus evening) was found to affect the statistical significance of differences between pre- and post- intervention median nitrate/nitrate concentration in some of the watersheds. The sampling period and sampling time did not affect the statistical significance of differences between pre- and post-intervention median TN concentrations.
- Median TN fluxes in watershed 1001 and 1005 were statistically smaller in the post-intervention period. The extent to which the structural and nonstructural BMPs contributed to these reductions cannot be determined due to the lack of reliable flow data in the control sites.
- Preliminary estimates of annual TN loads to Newport Bay in dry weather runoff from urban sources range between 37,000 to 50,000 lbs per year, or about 20 to 25% of the current TN loads.
- The potential reductions in annual dry weather TN loads due implementation of BMPs on a watershed basis is estimated to range between 12,500-20,000 pounds per year. This would represent a reduction of about 6-10% of the current TN loads and 30-40% of the urban loads.

4.2. Phosphorus

The majority of the annual TP load in the San Diego Creek Watershed occurs in the wet season, and has been correlated with sediment loads generated by storm events (USEPA, 1998b). This correlation suggests that a majority of phosphorus occurs in particulate form attached to sediments. The main sources of the total phosphorus (TP) are in Peters Canyon Wash and San Diego Creek above Culver Drive (USEPA, 1998b).

Phosphorus TMDL – There is no numeric objective for phosphorus for San Diego Creek in the Basin Plan. Because measured TP and sediment loads are correlated, it was determined in the TMDL that a 50 percent reduction in TP loads would be achieved through compliance with the sediment TMDL (USEPA, 1998a). Accordingly, the TMDL for TP was based on a 50 percent reduction of average annual load estimated at 124,160 lbs (USEPA, 1998b). The TMDLs are applicable for all flow conditions. The target compliance date was set for December 31, 2007.

The annual TP load allocation for urban areas is 4102 lbs by 2002, reducing to 2960 lbs by 2007. According to the USEPA (1998b) the TP is allocated in the same proportion as sediments. The annual urban area (stabilized vs. construction) sediment allocation for the Newport Bay Watershed is 50 tons distributed over 95.3 square miles (see Table 5 in USEPA, 1998a). This is a very small allocation over a large area. By contrast, note that the annual construction allocation is 6500 tons distributed over the assumed 3.0 square miles under construction in any one year. Using the same proportions of sediment load allocations, the TP load rate based on the 2007 urban allocation is 2960 lbs/95.3 square miles = 0.0485 lbs/acre/yr. If the construction and urban allocations are combined, the TP load rate based on the combined 2007 urban and construction allocations is (2960+12810) lbs/(95.3+3.0) square miles = 0.251 lbs/acre/yr.

Study Data Comparison with TMDLs – Similar to the nitrogen TMDL, the phosphorus TMDL is expressed in terms of total annual (TP) loads. Table 15 shows the mean and median TP concentrations measured in the five study watersheds. The mean and median TP concentrations in dry weather runoff are below 1.2 mg/l in all watersheds, with the exception of watershed 1004 where substantially higher concentrations were measured. Comparison of the pre- and post-intervention median TP concentrations in all data (Table 15) reveals an increase in the median TP concentration during the post-intervention period for all watersheds except the intervention watershed 1001 and 1004. In contrast, when subsets of the data with similar seasons and sampling times are considered (Table 15), there is a decrease in the median TP concentration in all watersheds except 1005. This indicates that there are seasonal influences in the data, which presumably are related to rainfall. Unfortunately there are no data available to permit comparison of pre- and post-intervention concentrations for dry weather flows during the dry season.

Table 15: Mean and Median TP Concentration (mg/l) by Watershed

	1001		1002		1003		1004		1005	
	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post
All Data										
n	23	25	23	25	24	25	23	24	24	25
Mean	0.73	0.60	0.92	0.84	0.98	1.21	3.33	1.50	1.01	1.19
Median	0.60	0.51	0.77	0.82	0.62	0.67	2.54	1.05	0.73	0.85
Subsets[1]										
n	18	14	18	14	19	14	18	13	19	14
Mean	0.78	0.47	0.91	0.67	1.13	0.57	2.62	1.33	0.93	1.24
Median	0.61	0.41	0.73	0.56	0.75	0.58	1.82	1.07	0.75	0.83

1 – Data subsets with comparable sampling time and seasons. Evening samples were deleted from the pre-intervention data. The post-intervention data include only those data collected in months identical to the pre-intervention period.

TP flux estimates were calculated for watersheds 1001 and 1005 using the approach discussed in the nitrogen section above. Table 16 shows that median TP flux estimates decrease from the pre- to post-intervention periods in the intervention watershed (1001) but not in the education only watershed. Mean fluxes increase in both watersheds, but as discussed earlier, the mean values are strongly influenced by outliers and do not provide a good measure of central tendency for these data. Application of the Mann-Whitney (rank sum) test shows the reduction in median TP flux in 1001 is statistically significant. This suggests that the structural BMPs had a positive influence in reducing the TP fluxes, but because comparable data are not available for the control sites, it is not possible to ascertain the extent to which the ET controllers contributed to these reductions. Also, as discussed previously, reductions in flux could be influenced by several factors: reduction in concentration, reduction in flow, and/or seasonal variability.

Table 16: Mean and Median TP Flux (mg-P/acre/day) by Watershed (all data)

	1001		1005	
	Pre	Post	Pre	Post
All data				
n	14	22	10	21
Mean	265	370	473	1327
Median	164	109	219	219

Similar to the previous analyses of TN loads, the TP flux estimates in Table 16 can be used to speculate about the magnitude of the urban area contribution of TP loads to Newport Bay and the potential reduction in loads from structural BMPs. Based on the limited flux data, the annual TP load to Newport Bay in dry weather runoff from urban areas in the Newport Bay Watershed is estimated to range between about 5,000 to 11,000 lbs per year (see Table 17) based on a total urban area of 95.3 square miles obtained from Table 5 of the sediment TMDL (USEPA, 1998a). These estimated annual TP loads are greater than the urban allocation (for both dry and wet weather) and are less than the combined urban and construction allocations (Table 17). Note,

however, that these estimates are based on dry weather data only, and it is expected that a major portion of the TP loads will occur in runoff from winter storms. Therefore, actual annual TP loads would be expected to be greater. If it hypothesized that flux reductions observed in the intervention watershed 1001 could be realized over the entire watershed, then the potential reduction in annual dry weather TP loads from urban areas is estimated at 2700 lbs. As stated previously, these estimates are based on few data collected in a limited area, and should therefore be considered preliminary in nature.

Table 17: Estimated Annual TP Loads in Dry Weather Runoff from Urban Areas in the San Diego Creek Watershed

	TP flux (mg-P/acre/d)	Annual TP Load Rate to Newport Bay (lbs/acre/year)[1]	Annual TP Load to Newport Bay (lbs/year)
2007 Urban Area Allocatoion for Newport Bay		0.0485	2960
2007 Combined Urban and Construction Area Allocatoion for Newport Bay		0.251	15770
Pre-intervention conditions (median fluxes)	164 – 219	0.132 – 0.176	8049 – 10748
Post-intervention conditions (median fluxes)	109 – 219	0.088 – 0.176	5350 – 10748
Potential reduction			2700

1 - urban area is 95.3 square miles and the construction area is 3.0 square miles based on Table 5 in USEPA, 1998a

4.3. Metals

Metals TMDLs – The USEPA (June 2002) determined that TMDLs are required for dissolved copper, lead, and zinc in San Diego Creek, Upper Newport Bay, and Lower Newport Bay, and that TMDLs are required for cadmium in San Diego Creek and the Upper Newport Bay. The TMDLs for San Diego Creek are expressed as concentration limits, based on the CTR criteria at various hardness values that are associated with different flow regimes (Table 18). The flow regimes are based on 19 years of flow measurements in San Diego Creek at Campus Drive. The concentration-based TMDLs apply to all freshwater discharges to San Diego Creek, including discharges from agricultural, urban, and residential lands, and storm flow discharges. The

applicable flow regime at any location in the entire watershed is determined on the basis of discharge at Campus Drive.

Table 18: Summary of Dissolved Metal TMDLs for San Diego Creek

Dissolved Metal (mg/l)	Base flow (0–20 cfs) hardness @ 400 mg/L		Small flows (21-181 cfs) hardness @ 322 mg/L		Medium flows (182-814 cfs) hardness @ 236 mg/L		Large flows (>814 cfs) hardness @ 197 mg/L
	Acute	Chronic	Acute	Chronic	Acute	Chronic	Acute
Cadmium	19.1	6.2	15.1	5.3	10.8	4.2	8.9
Copper	50	29.3	40	24.3	30.2	18.7	25.5
Lead	281	10.9	224	8.8	162	6.3	134
Zinc	379	382	316	318	243	244	208

Metals Sources – The USEPA (June 2002) conducted a source analysis as part of the TMDL preparation. Surface runoff is the largest contributor of metals loads in the San Diego Creek Watershed, which includes natural and man made source (USEPA , June 2002). Much of the metals loads are from natural sources. The estimated anthropogenic contributions are metal specific and range from about 33% for zinc to 63% for cadmium (USEPA, June 2002). A primary anthropogenic source of heavy metals is runoff from urban roads, which contributes to sources of cadmium (tire wear), copper (brakes, tires), lead (brakes, tires, fuels and oils), and zinc (tires, brakes, galvanized metals). Use of copper sulfate by nurseries may also be a minor source of copper loads. Other copper and zinc uses in building materials (roofing and roof drains) may be another source.

The USEPA found that metal inputs were heavily influenced by rainfall and stream flow rates. Monitoring results were reported to be highly variable due to different rainfall amounts and flows during each water year. The EPA estimated that base flows account for 25% of the total metal loadings, with the remainder from low, medium and large flows caused by storms.

The EPA's preliminary analyses suggest that: 1) a primary source of metals in dry weather runoff in the study watershed is from roads (i.e. wash off of metals in driveways, parking lots, streets, gutters, etc.); 2) the runoff concentrations will be influenced by rainfall which result in wash off of accumulated metals; and 3) the concentrations can be variable depending on the amount of rainfall.

Study Data Comparison with Base Flow TMDLs – The metals TMDLs for base flow conditions are based on meeting the CTR criteria at a total hardness of 400 mg/l. The CTR criteria express maximum allowable concentrations in receiving waters for acute (short term) and chronic (4-day) exposure periods. The acute and chronic criteria are expressed as values that cannot be exceeded more that once in three years. Although the criteria are applicable in the

receiving waters and not in the urban runoff per se (i.e. the measured dry weather discharge), exceedance of the CTR in the urban discharge would suggest a potential for the discharge to contribute to an exceedance in the receiving waters.

Table 19 shows the mean and median heavy metal concentrations in the five study watersheds. (*Note to IRWD reviewer: we assumed that the analytical results are for dissolved metals based on guidance from IRWD, but this is not clearly indicated in the data base or draft report; it is likely the case as base flows are typically low in suspended sediments.*) With the exception of mean copper concentrations in some of the watersheds, all mean and median concentrations were below the chronic and acute CTR criteria. Copper, lead, and zinc concentrations occasionally exceeded the chronic CTR criteria, and copper and zinc concentrations occasionally exceeded the acute criteria. These exceedances suggest that the dry weather runoff can potentially contribute to an exceedance in the receiving waters. However, if intervention is determined to be effective in reducing runoff flows, then the BMPs would help to reduce impacts of these potential exceedances by allowing for greater dilution with the in-stream flows.

Table 19: Mean and Median Metal Concentrations (mg/l) by Watershed (all data)

	1001		1002		1003		1004		1005	
	Pre	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
Cadmium										
n	23	25	23	25	24	25	23	25	24	25
Mean	0.26	0.14	0.47	0.44	0.27	0.17	0.64	0.22	0.21	0.29
Median	0.27	0.10	0.24	0.10	0.10	0.10	0.36	0.10	0.10	0.10
n>6.2 µg/l	0	0	0	0	0	0	0	0	0	0
n>19.1 µg/l	0	0	0	0	0	0	0	0	0	0
Copper										
n	23	25	23	25	24	25	23	25	24	25
Mean	13.5	16.9	27.3	30.3	11.5	26.6	21.8	17.7	32.1	30.8
Median	11.5	11.4	10.9	14.0	11.1	14.3	12.7	11.4	12.3	20.4
n>29.3 µg/l	2	2	3	7	0	2	5	4	3	5
n>50 µg/l	0	1	3	3	0	2	2	3	3	2
Lead										
n	23	25	23	25	24	25	23	25	24	25
Mean	0.8	1.6	5.9	4.7	0.8	1.6	3.5	1.5	1.0	3.2
Median	0.6	0.6	0.9	1.2	0.6	0.8	0.7	0.7	0.7	1.3
n>10.9 µg/l	2	1	2	3	0	0	2	0	0	1
n>281 µg/l	0	0	0	0	0	0	0	0	0	0
Zinc										
n	23	25	23	25	24	25	23	25	24	25
Mean	58.7	37.2	115.2	86.3	56.3	56.8	83.6	40.9	74.0	75.0
Median	56.0	50.2	53.4	57.2	50.7	53.9	50.8	43.8	52.4	54.5
n>382 µg/l	0	0	1	2	0	0	1	0	0	0
n>379 µg/l	0	0	1	2	0	0	1	0	0	0

We were unable to locate dry weather metals monitoring information in the Central Irvine Channel, which is the immediate receiving water of the study watersheds (*IRWD please confirm*). OCPFRD dry weather monitoring data are available in San Diego Creek at Campus Drive, which is quite a ways downstream from the study watersheds. Data collected between 12/01 and 6/02 (Table 20) show that average dry weather concentrations at Campus Drive are well below mean and median concentrations measured in dry weather runoff from the study watersheds. Similar comparisons cannot be made for lead and cadmium because the method detection limits in the OCPFRD data are greater than those in the R3 data. None of the OCPFRD dry weather data exceed the chronic or acute criteria.

These comparisons suggest that metal loads in dry weather runoff from the study (urban) watersheds could be a contributing factor to dry weather copper and zinc loads measured at Campus Drive. These dry weather discharges do not result in non-compliance of the base flow metal TMDL at Campus (based on the reviewed data only). It is unknown if the elevated concentrations measured in the dry weather urban runoff result in exceedance of the CTR criteria in the immediate receiving waters. Note that if flow reductions observed in the intervention watershed are attributable to the ET controllers, then these controllers would help to reduce impacts from any potential exceedances of the TMDL because the discharges would be subject to greater dilution by the in-stream flows.

Table 20: Summary of OCPFRD Dry Weather Monitoring Data in San Diego Creek at Campus Drive (12/01 to 6/02)

	Cadmium	Copper	Lead	Zinc
Sample number	24	24	24	24
Range	All < 1 µg/l	<2 – 16 µg/l	<2-2.4 µg/l	<10-16
Mean		7.4 µg/l	most <2 µg/l	most <10
Median-		6.8 µg/l		

4.4. Pathogens

Pathogens are agents or organisms that can cause diseases or illnesses, such as bacteria and viruses. Fecal coliform bacteria are typically used as an indicator organism because direct monitoring of human pathogens is generally not practical. Fecal coliform are a group of bacteria that are present in large numbers in the feces and intestinal tracts of humans and animals, and can enter water bodies from human and animal waste. The presence of fecal coliform bacteria implies the water body is potentially contaminated with human and/or animal waste, suggesting the potential presence of associated pathogenic organisms.

Fecal Coliform TMDL – The RWQCB has adopted phased TMDL criteria for pathogens, with the initial focus on additional monitoring and assessment to address areas of uncertainty. The

goal of the Newport Bay TMDL is compliance with water contact recreational standards by 2014:

> Fecal coliform concentration of not less than five samples per 30 days shall have a geometric mean less than 200 most probable number (MPN)/100ml, and not more than 10 percent of the samples shall exceed 400 MPN/100ml for any 30-day period.

A second goal is to achieve the shellfish harvesting standards by 2020:

> The monthly median fecal coliform concentration shall be less than 14 MPN/100 mL, and not more than 10 percent of the samples shall exceed 43 MPN/100 mL.

The TMDLs are applicable for all flow regimes.

Study Data Comparison with Fecal Coliform TMDLs – Table 21 shows the mean and median fecal coliform concentrations measured in the five study watersheds. 70% to 100% percent of all fecal coliform measurements were greater than 400 MPN/ml in all study watersheds. This level of exceedance is substantially greater than the allowable 10%. The mean and median fecal coliform concentrations also exceed the 400 MPN/100ml criterion in all study watersheds. There was insufficient data to calculate the 30-day geometric mean (a minimum of 5 samples per 30 days needed), however, the TMDL criterion (30-day geometric < 200 MPN/100 ml) would likely be exceeded, assuming that any additional data would be of the same magnitude as those collected. Exceedance of the TMDL criteria in all study watersheds suggests that urban dry weather runoff is likely a contributing factor to any dry weather exceedance of the TMDL in the receiving waters.

Table 21: Mean and Median Fecal Coliform Concentration (MPN/100ml) by Watershed

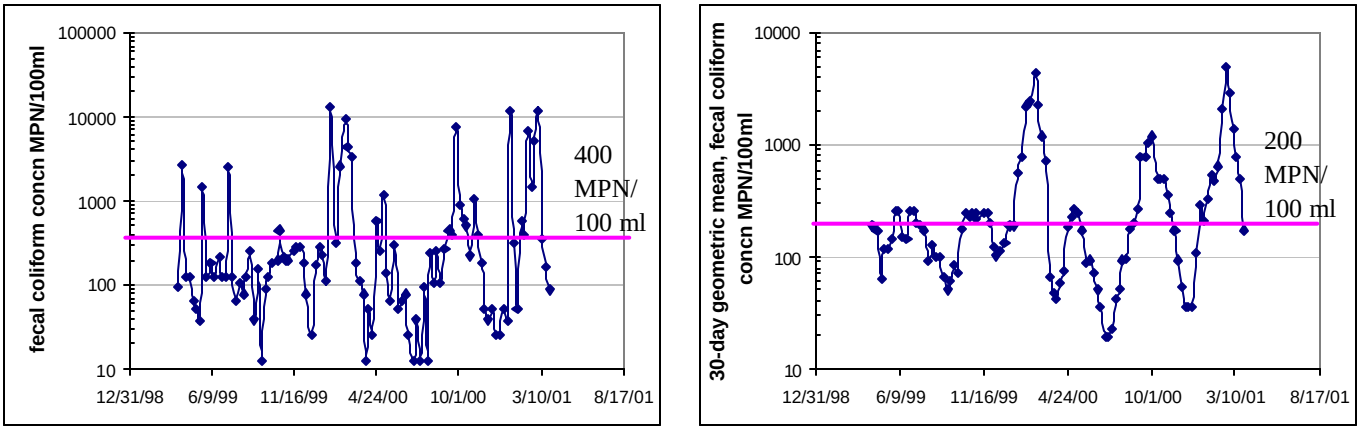
	1001		1002		1003		1004		1005	
	Pre	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
All Data										
n	22	24	21	24	23	24	21	24	23	24
Mean	4921	3003	5582	128193	34526	28980	28205	34185	17976	10326
Median	2300	1400	1700	3000	13000	4000	13000	13000	8000	8000
% > 400 MPN/100ml	82%	67%	86%	79%	100%	88%	95%	83%	92%	93%
Subsets [1]										
n	17	14	17	14	18	14	17	14	18	14
Mean	2545	3054	3090	5074	13783	37479	23312	20166	8524	6109
Median	2200	950	1400	1400	8000	2650	8000	6500	4000	2900
% > 400 MPN/100ml	100%	71%	82%	79%	100%	86%	94%	79%	100%	93%

1 – Data subsets with comparable sampling time and seasons. Evening samples were deleted from the pre-intervention data. The post-intervention data include only those data collected in months identical to the pre-intervention period.

We were unable to locate dry weather coliform monitoring information in the Central Irvine Channel, which is the immediate receiving water of the study watersheds (*IRWD please confirm*). Therefore it is unknown if elevated fecal coliform concentrations measured in the

study watershed contribute to an exceedance of the TMDL in the immediate receiving waters. The OCPFRD has collected dry and wet weather *E. coli* monitoring information in San Diego Creek at Campus Drive (OCPFRD, September 2001), which is considerably downstream from the study watersheds. A plot of the equivalent fecal coliform concentration (assuming an 80% *E. coli* content) shows exceedance of the TMDL occurs primarily during the wet season, although dry season exceedances are also evident (see Figure 9). This suggests that dry weather urban runoff is potentially a contributing factor to exceedance of the TMDL in dry weather flows at Campus Drive. The ET controllers would reduce the impacts from these potential exceedances if they were determined to be effective reducing the dry weather runoff volumes.

Figure 9: Time Series of Fecal Coliform Levels San Diego Creek at Campus Drive (converted from measured E. coli concentrations)



Median fecal coliform concentrations presented in Table 21 may be used to evaluate the influence of the structural and non-structural BMPs. When all monitoring dataset is considered, the median fecal coliform concentrations are equivalent or increase from pre- to post-intervention conditions in all watersheds except the 1001 (intervention watershed) and 1003 (a control watershed). Based on the Mann-Whitney (rank-sum) test, the reduction in median concentrations in 1001 and 1003 is significantly significant at the 95% confidence level. Thus the watershed with the irrigation controllers corresponded to a significant reduction in median fecal coliform concentrations, in comparison to 2 of the 3 control sites, while the education only watershed exhibited no discernable reduction in median concentrations.

When subsets of the data with similar seasons and sampling times are considered (Table 21), there is a decrease in the median fecal coliform concentration in all watersheds except 1002. However, because of the smaller sample sizes, the decrease is median concentration is statistically significant only in watershed 1003. This suggests that there could be seasonal influences in the monitoring data, but the data are not sufficient to determine if there are statistically significant differences in the median concentrations.

5. References

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OCPFRD, 2001. County of Orange Public Facilities and Resources Department, NPDE Annual Progress Report.

OCPFRD, September 2001. Newport Bay Fecal Coliform TMDL Annual Data Report.

RWQCB, 1995. Water Quality Control Plan, Santa Ana River Basin (8).

Schiff, K.C. and L.L.Tiefenthaler, June 2003. Contributions of organophosphorus pesticides from residential land uses during dry and wet weather. Technical Report 406, Southern California Coastal Water Research Project.

USEPA (Region 9), 1998a. *Total Maximum Daily Loads for Sediment and Monitoring and Implementation Recommendations; San Diego Creek and Newport Bay, California*

USEPA (Region 9), 1998b. *Total Maximum Daily Loads for Nutrients; San Diego Creek and Newport Bay, California*

USEPA, June 2002. Total Maximum Daily Loads for Toxic Pollutants – San Diego Creek and Newport Bay, California, June 14, 2002.

Tetra Tech, Inc., July 2000c. Newport Bay Watershed Urban Nutrient TMDL Compliance Evaluation.

Appendix A - Time-Series Plots

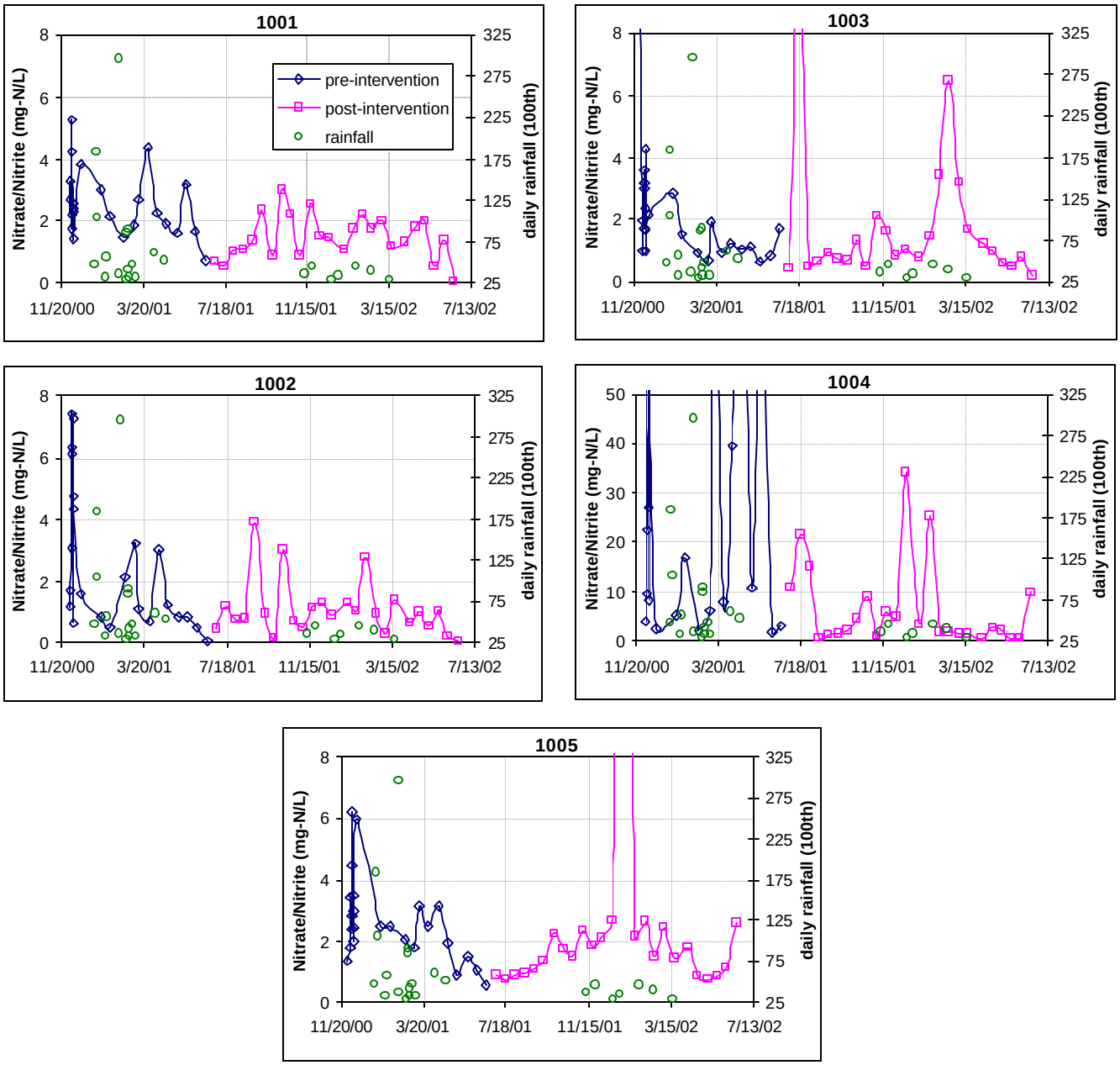


Figure A-1: Time Series of Nitrate/Nitrite in Dry Weather Samples (all data)

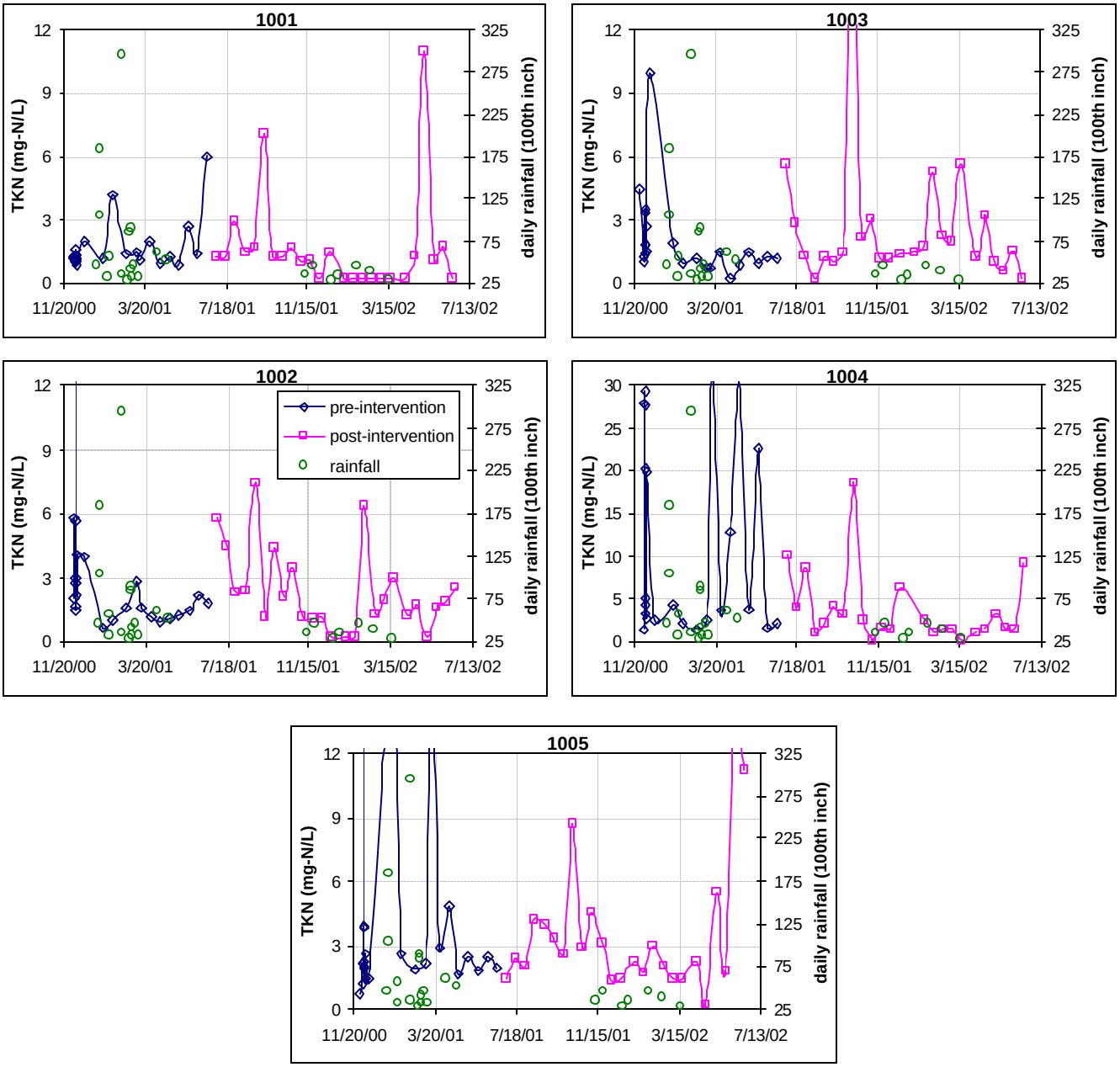


Figure A-2: Time Series of TKN in Dry Weather Samples (all data)

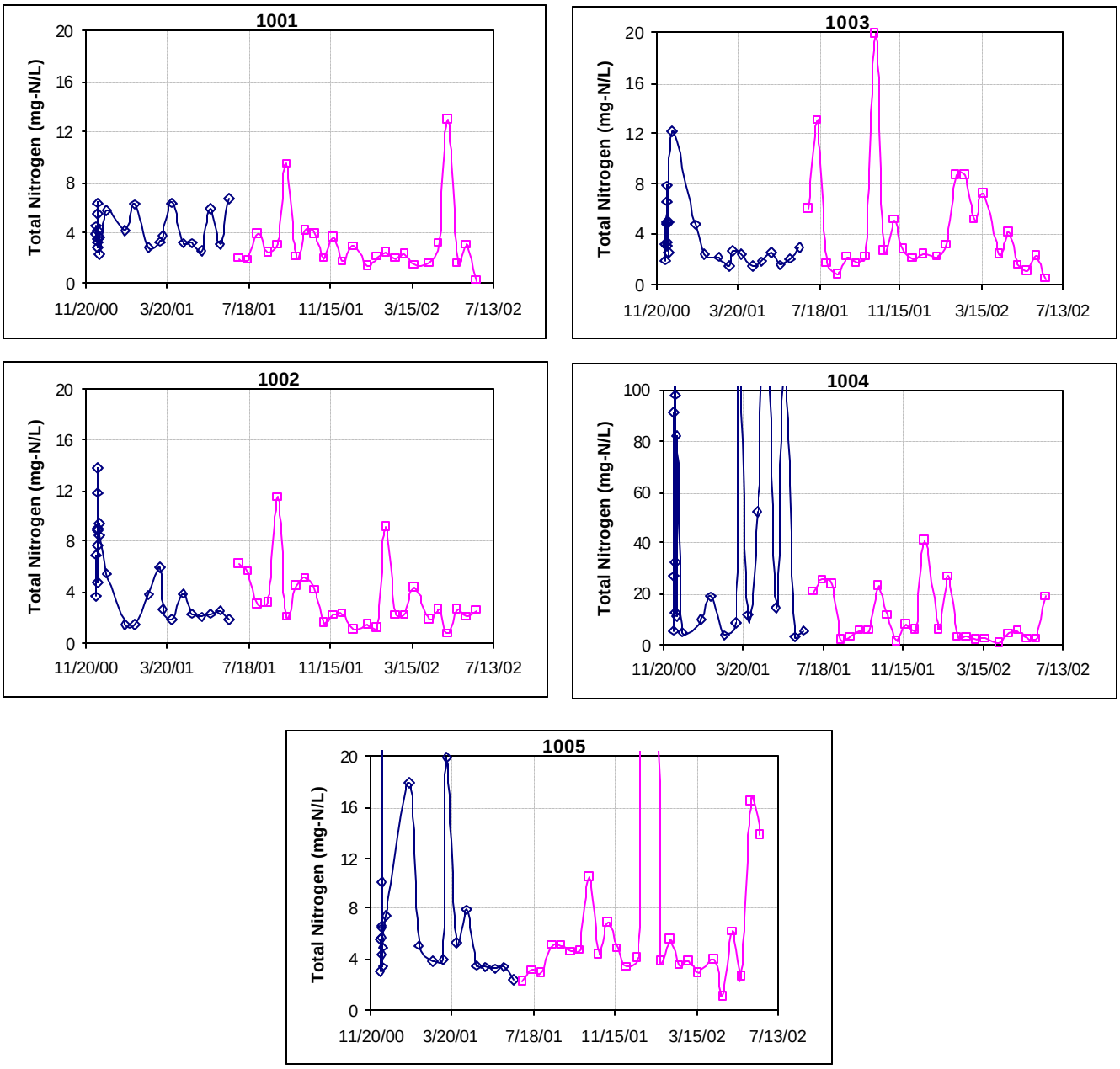


Figure A-3: Time Series of TN (Calculated) in Dry Weather Samples (all data)

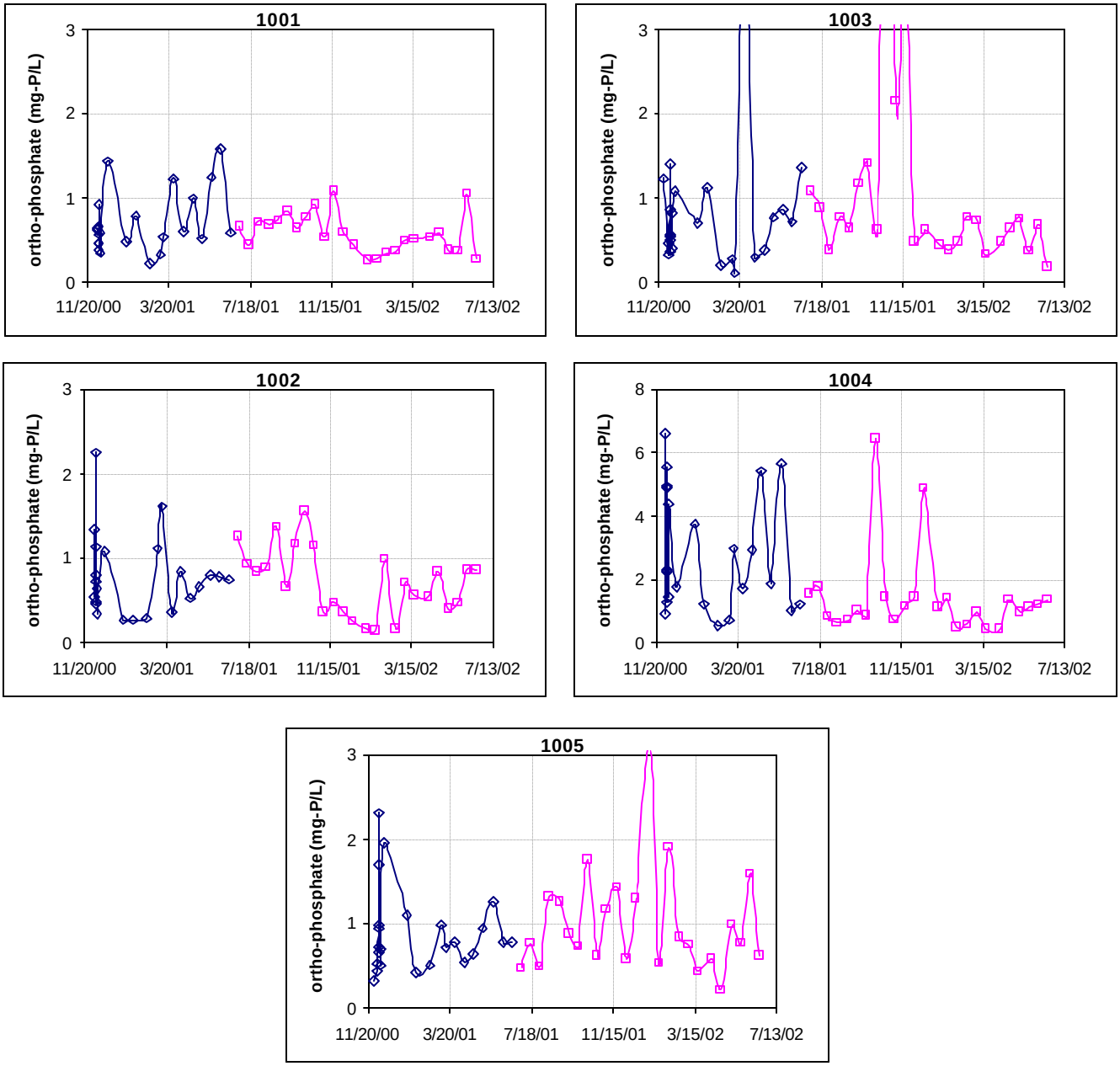


Figure A-4: Time Series of Ortho-Phosphate in Dry Weather Samples (all data)

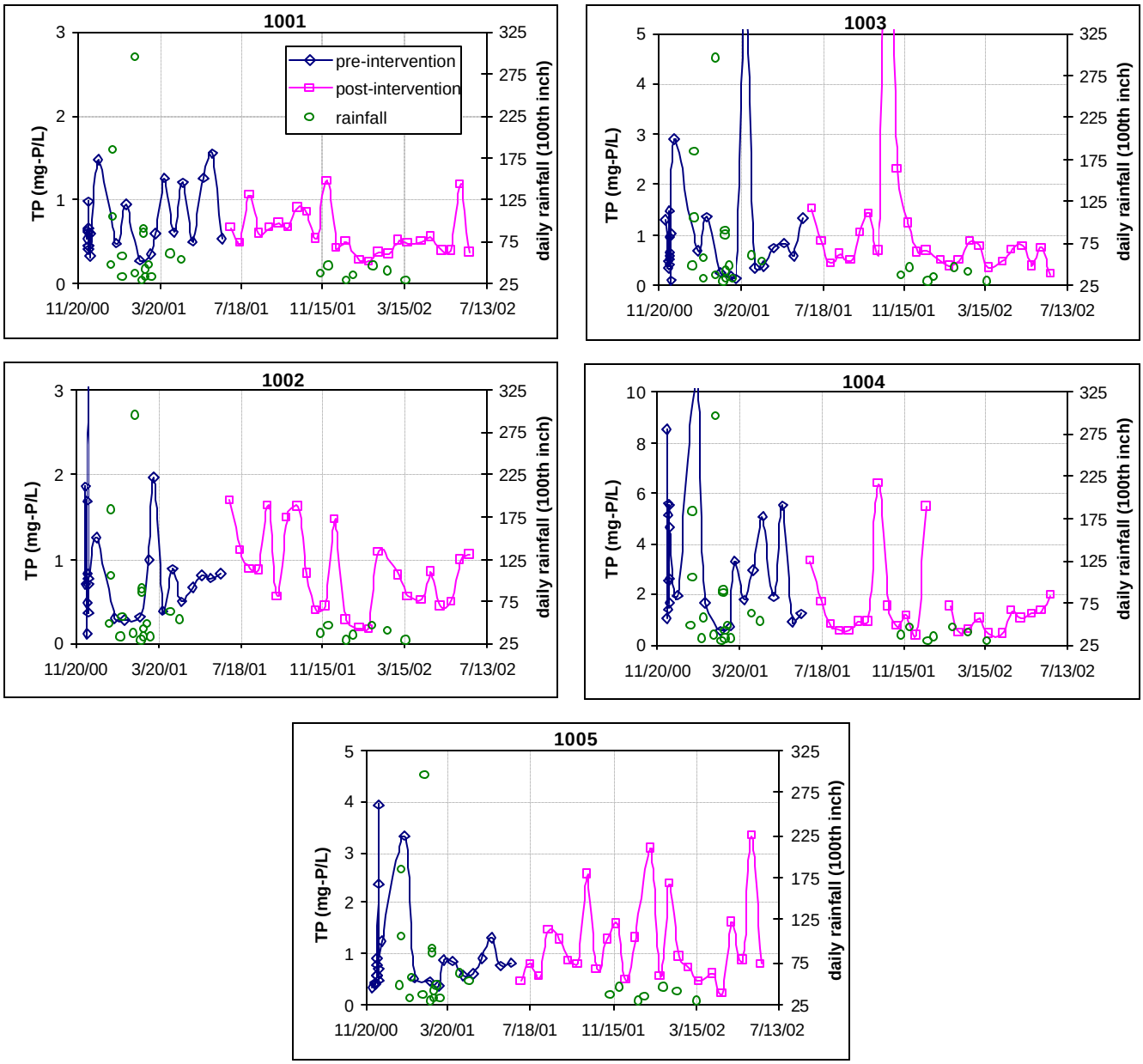


Figure A-5: Time Series of Total-Phosphorus in Dry Weather Samples (all data)

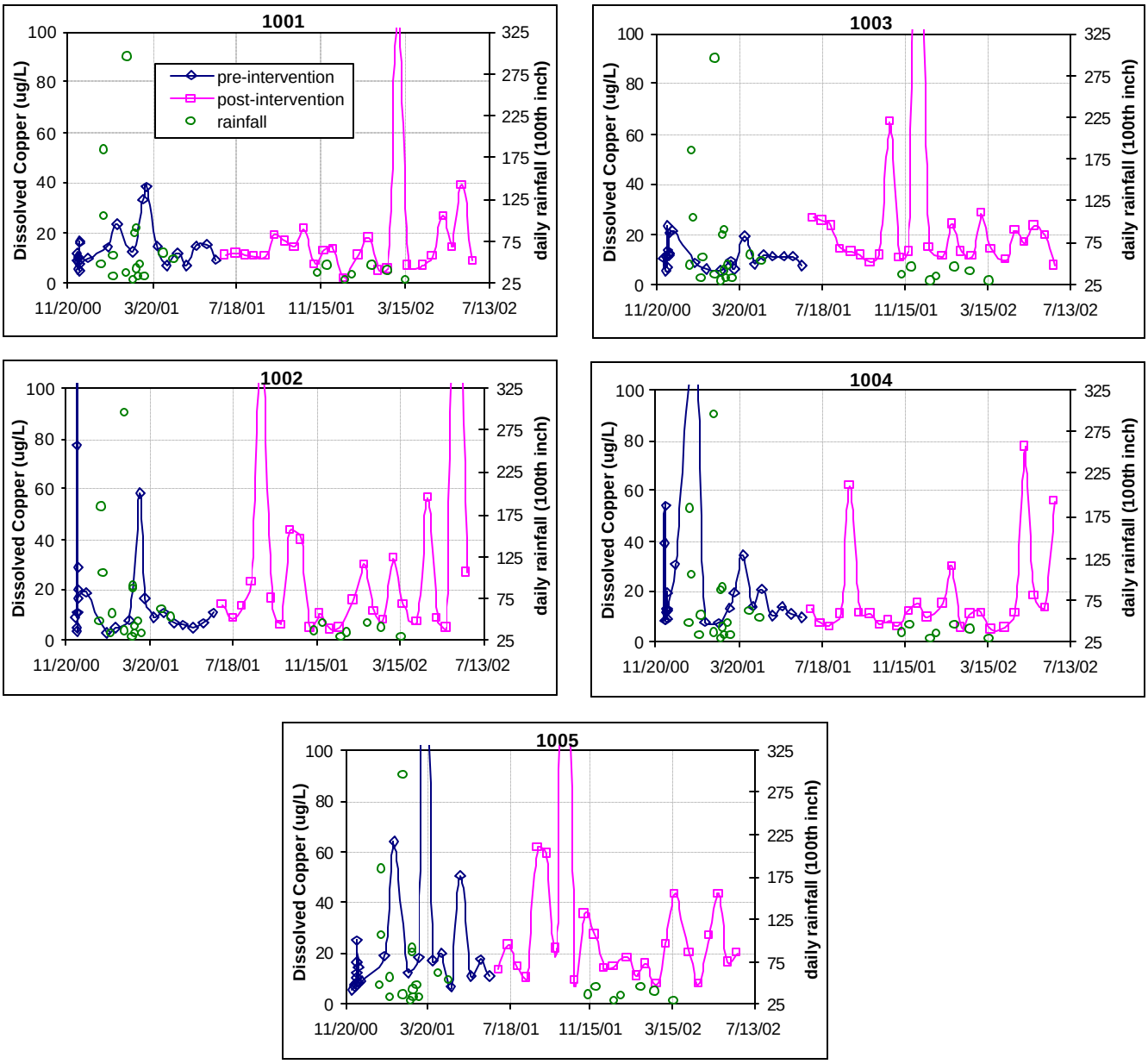


Figure A-6: Time Series of Dissolved Copper in Dry Weather Samples (all data)

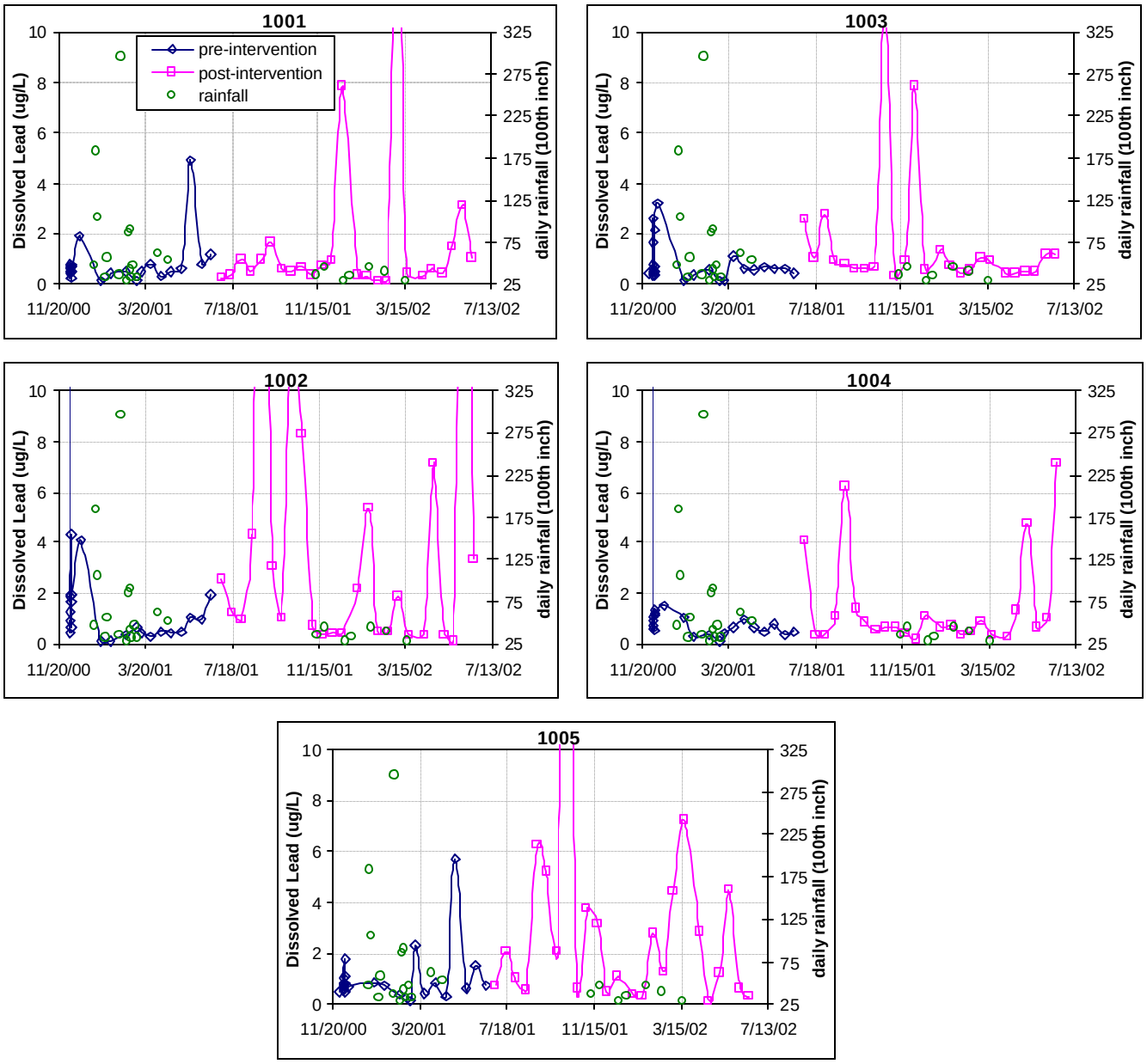


Figure A-7: Time Series of Dissolved Lead in Dry Weather Samples (all data)

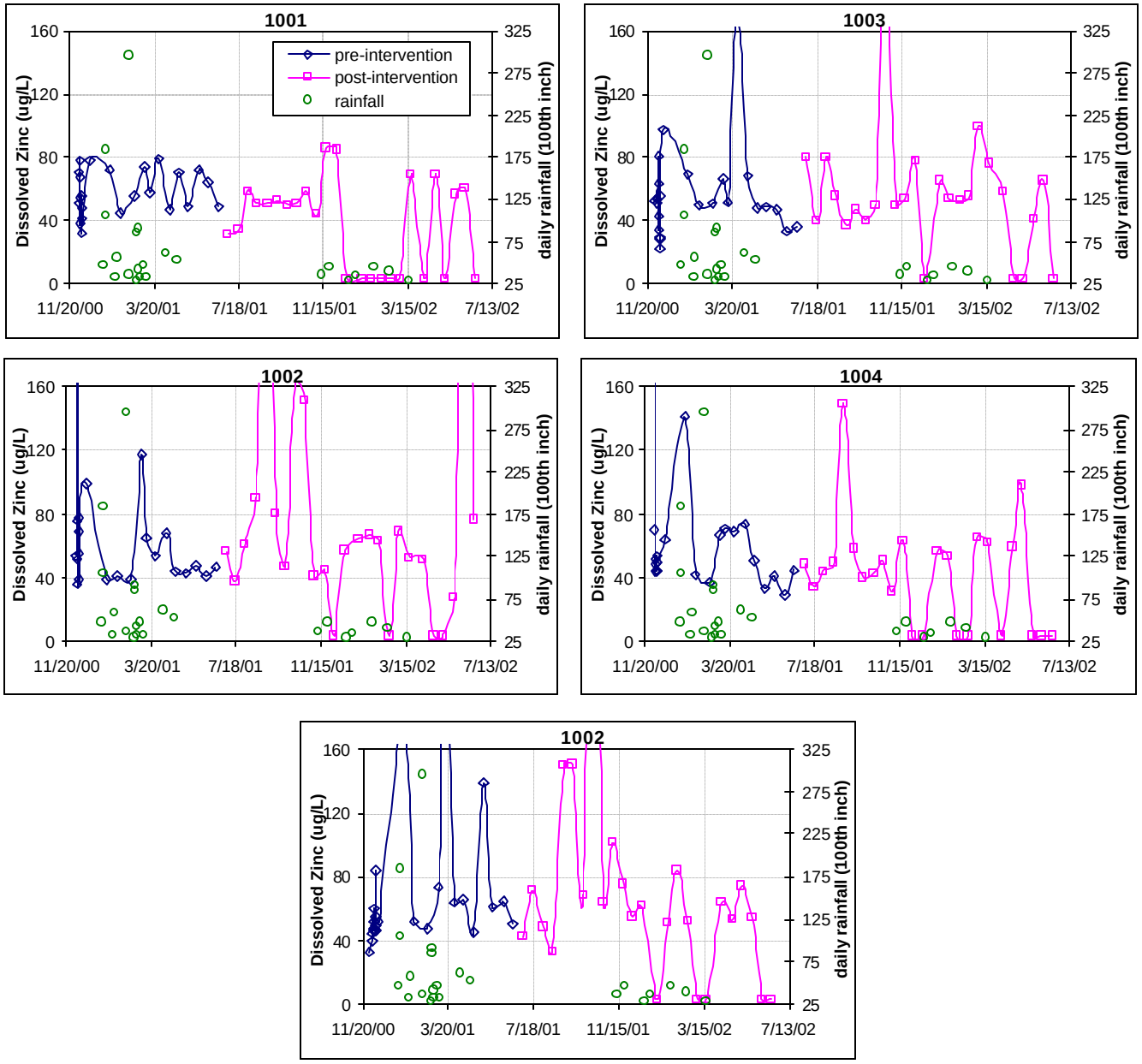


Figure A-8: Time Series of Dissolved Zinc in Dry Weather Samples (all data)

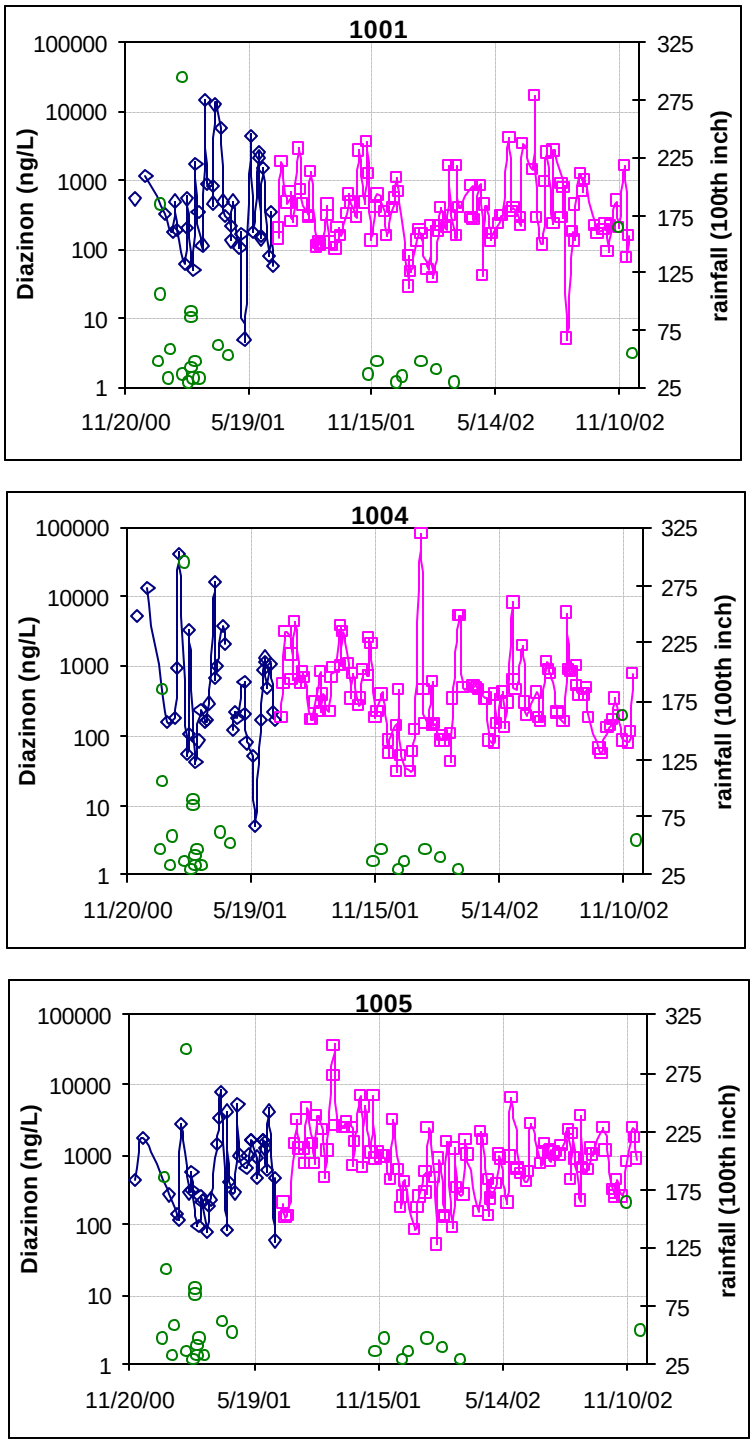


Figure A-9: Time Series of Diazinon in Dry Weather Samples (all data)

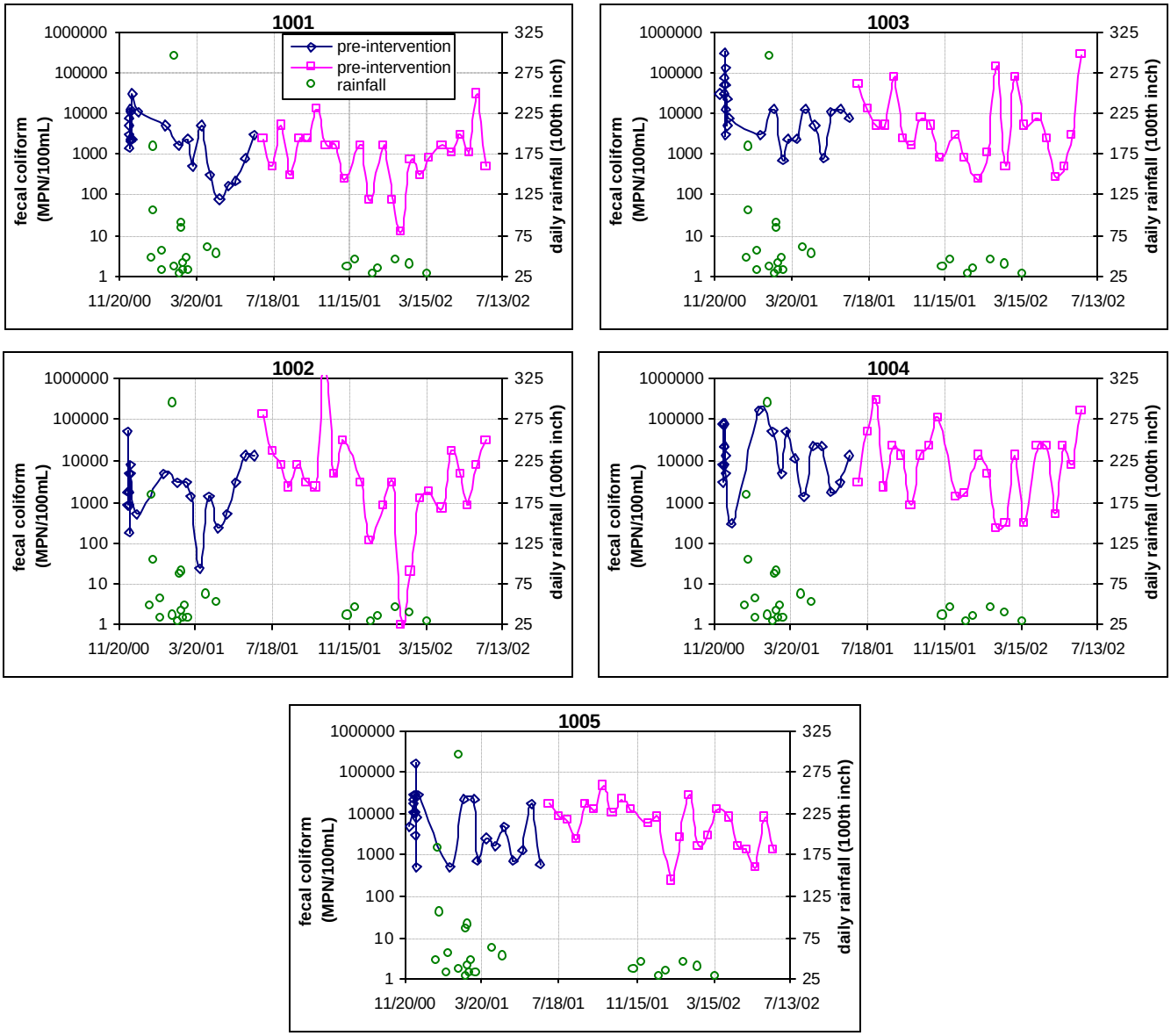


Figure A-10: Time Series of Fecal Coliform in Dry Weather Samples (all data)

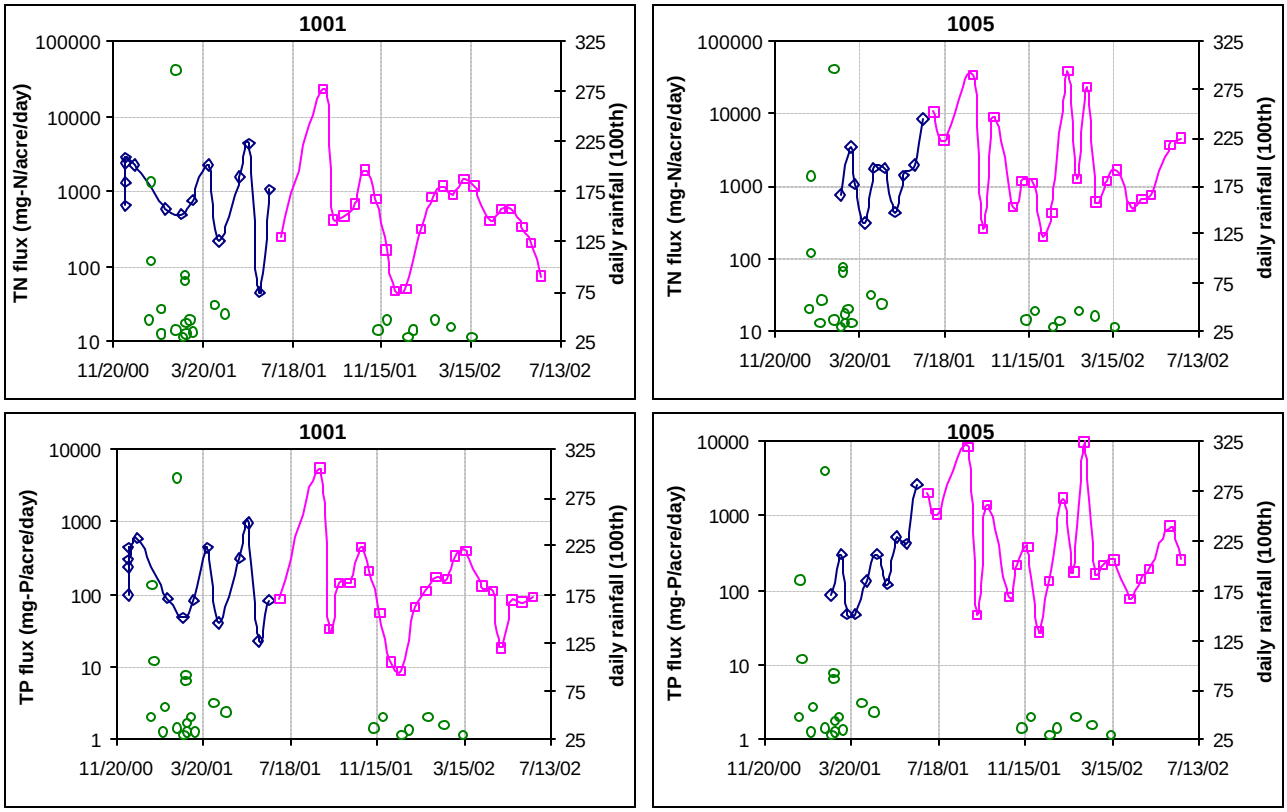


Figure A-11: Time Series of Nutrient Fluxes in Dry Weather Samples (all data)

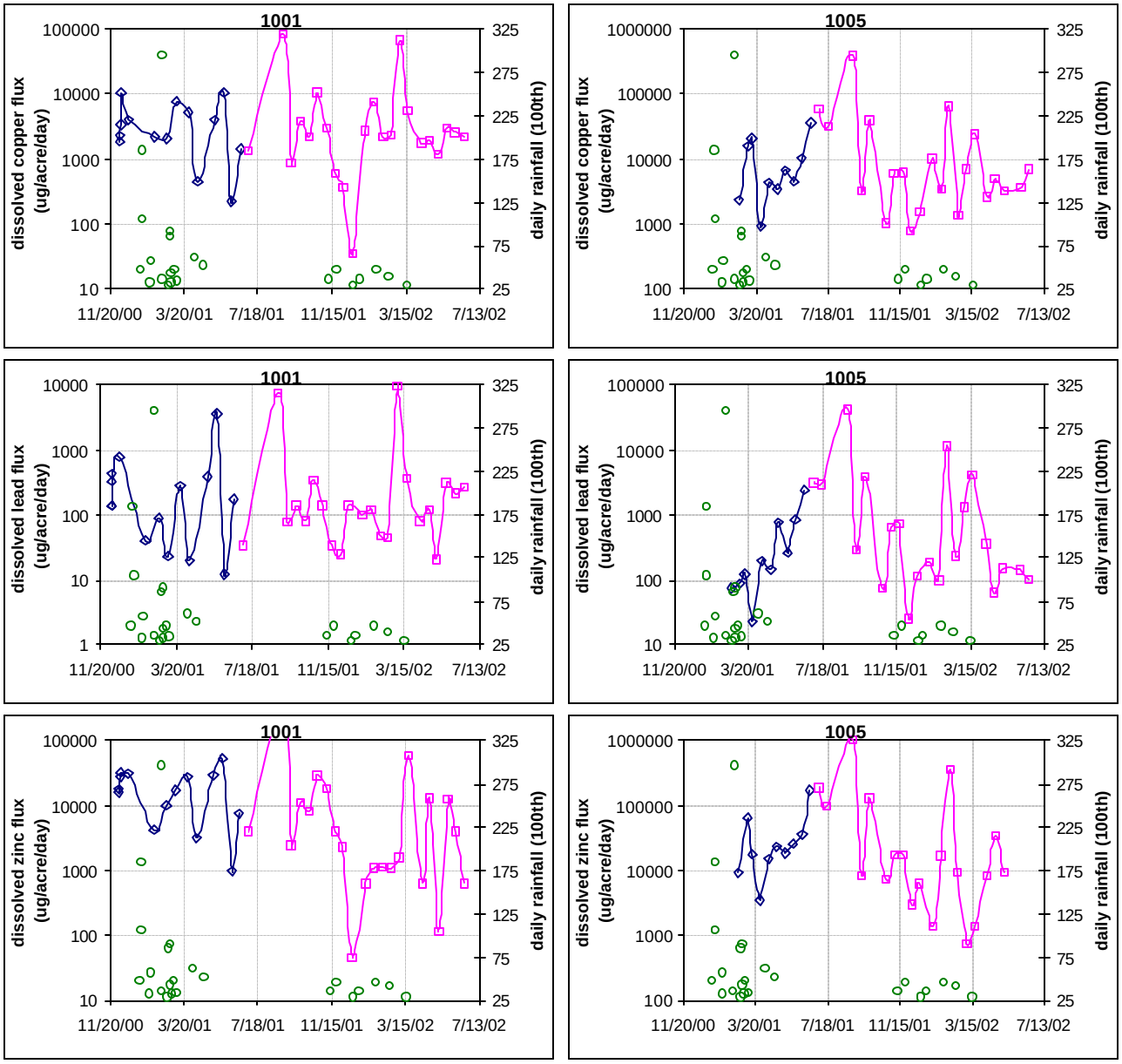


Figure A-12: Time Series of Dissolved Metal Fluxes in Dry Weather Samples (all data)

Appendix B – Summary Statistics

Table B-1: Descriptive Statistics

		1001		1002		1003		1004		1005	
Parameter	**Statistic**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
Nitrate/Nitrite as N (mg-N/L)	**n**	23	25	23	25	24	25	23	25	24	25
	% > MDL/RL	100%	96%	96%	96%	100%	100%	100%	100%	100%	100%
	Mean	2.56	1.47	2.57	1.07	2.13	1.71	36.50	6.61	2.61	4.13
	Median	2.32	1.38	1.56	0.93	1.68	0.94	16.88	2.29	2.45	1.48
	Trimmed mean	2.37	1.44	1.80	0.89	1.61	1.01	25.04	3.33	2.41	1.60
	min	0.74	0.05	0.05	0.05	0.65	0.20	1.70	0.60	0.54	0.73
	max	5.26	2.97	7.42	3.92	9.96	10.16	109.90	34.40	6.21	64.90
	25th percentile	1.81	1.05	0.82	0.53	0.98	0.64	5.62	1.43	1.79	0.96
	75th percentile	3.10	1.99	3.77	1.18	2.49	1.60	70.76	8.95	3.11	2.22
	St Dev	1.08	0.70	2.34	0.91	1.94	2.21	37.82	8.78	1.40	12.68
	IQR	1.29	0.94	2.95	0.65	1.51	0.96	65.14	7.52	1.32	1.26
	Skewness, gs	0.84	0.14	1.00	1.89	3.11	2.96	0.76	2.01	1.19	4.98
	gcr	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92
	symmetric?	Y	Y	N	N	N	N	Y	N	N	N
TKN (mg-N/L)	**n**	23	25	23	25	24	25	23	24	24	25
	% > MDL/RL	100%	64%	100%	84%	96%	92%	96%	92%	100%	96%
	Mean	1.68	1.63	2.74	2.37	1.97	2.71	11.50	3.72	4.08	3.61
	Median	1.27	1.21	1.78	1.90	1.38	1.46	4.26	1.91	2.23	2.39
	Trimmed mean	1.29	0.77	1.95	1.87	1.40	1.69	7.51	2.23	2.29	2.57
	min	0.88	0.25	0.68	0.25	0.25	0.25	1.44	0.25	0.76	0.25
	max	6.02	11.00	13.20	7.48	9.97	18.60	31.81	18.60	17.43	15.30
	25th percentile	1.13	0.25	1.33	1.13	1.01	1.20	2.55	1.41	1.88	1.71
	75th percentile	1.57	1.46	2.86	2.98	1.85	2.87	21.46	4.03	3.15	4.01
	St Dev	1.19	2.40	2.68	1.96	1.97	3.64	11.61	4.21	4.90	3.41
	IQR	0.44	1.21	1.53	1.85	0.84	1.67	18.90	2.62	1.26	2.30
	Skewness	2.84	3.16	3.00	1.23	3.24	3.77	0.75	2.31	2.29	2.34
	Gcr	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92
	symmetric?	N	N	N	N	N	N	Y	N	N	N
Ammonia as N	**n**	23	25	23	25	24	25	23	24	24	25

		1001		1002		1003		1004		1005	
Parameter	**Statistic**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
(mg-N/L)	**% > MDL/RL**	30%	20%	74%	64%	75%	52%	87%	71%	92%	96%
	Mean	0.13	0.08	0.25	0.42	0.26	0.29	7.05	0.25	0.85	0.42
	Median	0.05	0.05	0.18	0.20	0.17	0.10	0.71	0.14	0.43	0.22
	Trimmed mean	0.05	0.05	0.19	0.13	0.19	0.11	3.43	0.12	0.50	0.24
	min	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	max	1.12	0.36	0.90	5.45	1.06	2.29	26.34	2.03	6.92	2.41
	25th percentile	0.05	0.05	0.08	0.05	0.09	0.05	0.24	0.05	0.24	0.15
	75th percentile	0.12	0.05	0.30	0.28	0.29	0.36	13.69	0.28	0.94	0.42
	St Dev	0.23	0.07	0.22	1.06	0.26	0.48	9.14	0.40	1.39	0.50
	IQR	0.07	0.00	0.22	0.23	0.20	0.31	13.45	0.23	0.70	0.27
	Skewness	4.04	3.08	1.66	4.78	1.98	3.40	0.93	4.09	3.95	3.01
	gcr	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92
	symmetric?	N	N	N	N	N	N	Y	N	N	N
TN (calculated)	**n**	23	25	23	25	23	25	23	25	23	25
(mg-N/L)	**% > MDL/RL**	100%	80%	98%	90%	98%	96%	98%	96%	100%	98%
	Mean	4.24	3.09	5.31	3.44	3.66	4.42	48.00	10.18	6.89	7.74
	Median	3.84	2.27	3.95	2.55	2.66	2.50	19.01	5.57	5.06	4.36
	Trimmed mean	3.94	2.40	4.53	2.76	2.93	3.01	33.11	6.47	5.08	4.42
	min	2.30	0.30	1.50	0.78	1.46	0.45	3.28	0.74	2.48	1.07
	max	6.76	12.99	13.83	11.40	12.12	19.91	141.06	40.80	20.41	67.12
	25th percentile	3.20	1.79	2.27	2.10	2.11	2.04	9.05	2.71	3.52	3.47
	75th percentile	5.68	3.13	8.02	4.36	4.81	5.17	94.79	19.18	7.07	5.62
	St Dev	1.41	2.67	3.56	2.51	2.48	4.39	49.17	10.73	5.29	12.85
	IQR	2.48	1.34	5.75	2.26	2.70	3.13	85.74	16.47	3.55	2.15
	Skewness	0.55	2.82	0.84	1.87	2.13	2.27	0.74	1.37	1.88	4.46
	gcr	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92
	symmetric?	Y	N	Y	N	N	N	Y	N	N	N
ortho-phosphate	**n**	23	25	23	25	24	25	23	25	24	25
(mg-P/L)	**% > MDL/RL**	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Mean	0.71	0.58	0.79	0.72	0.81	1.26	2.84	1.40	0.89	1.00
	Median	0.58	0.53	0.73	0.72	0.64	0.64	2.23	1.10	0.76	0.77
	Trimmed mean	0.60	0.56	0.69	0.70	0.63	0.66	2.42	1.10	0.77	0.87
	min	0.23	0.26	0.28	0.15	0.11	0.19	0.52	0.43	0.33	0.22
	max	1.58	1.08	2.25	1.56	4.01	10.60	6.57	6.45	2.31	3.11
	25th percentile	0.47	0.38	0.48	0.41	0.38	0.47	1.25	0.75	0.55	0.59
	75th	0.86	0.72	0.96	0.93	0.92	0.89	4.63	1.42	0.98	1.29

		1001		1002		1003		1004		1005	
Parameter	**Statistic**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
	percentile										
	St Dev	0.37	0.23	0.47	0.39	0.77	2.11	1.89	1.35	0.49	0.62
	IQR	0.39	0.34	0.48	0.52	0.54	0.42	3.38	0.67	0.44	0.70
	Skewness	1.13	0.60	1.55	0.32	3.27	4.03	0.60	3.03	1.66	1.79
	gcr	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92
	symmetric?	N	Y	N	Y	N	N	Y	N	N	N
TP	**n**	23	25	23	25	24	25	23	24	24	25
(mg-P/L)	**% > MDL/RL**	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Mean	0.73	0.60	0.92	0.84	0.98	1.21	3.33	1.50	1.01	1.19
	Median	0.60	0.51	0.77	0.82	0.62	0.67	2.54	1.05	0.73	0.85
	Trimmed mean	0.61	0.53	0.72	0.77	0.65	0.68	2.73	1.06	0.72	0.95
	min	0.27	0.26	0.11	0.16	0.11	0.23	0.53	0.34	0.33	0.22
	max	1.55	1.22	3.65	1.69	6.18	11.70	10.37	6.38	3.92	3.32
	25th percentile	0.47	0.39	0.43	0.49	0.35	0.49	1.52	0.60	0.50	0.60
	75th percentile	0.97	0.67	0.94	1.08	1.08	0.87	5.11	1.55	0.91	1.46
	St Dev	0.38	0.27	0.77	0.47	1.26	2.23	2.58	1.51	0.92	0.83
	IQR	0.50	0.28	0.51	0.59	0.73	0.38	3.59	0.96	0.40	0.86
	Skewness	1.00	1.07	2.27	0.49	3.39	4.68	1.26	2.41	2.35	1.38
	gcr	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92
	symmetric?	N	N	N	Y	N	N	N	N	N	N
Cadmium	**n**	23	25	23	25	24	25	23	25	24	25
(ug/L)	**% > MDL/RL**	61%	12%	61%	36%	38%	16%	74%	36%	38%	44%
	Mean	0.26	0.14	0.47	0.44	0.27	0.17	0.64	0.22	0.21	0.29
	Median	0.27	0.10	0.24	0.10	0.10	0.10	0.36	0.10	0.10	0.10
	Trimmed mean	0.20	0.10	0.20	0.12	0.12	0.10	0.33	0.12	0.12	0.15
	min	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	max	0.56	0.79	3.40	3.50	1.77	0.92	4.54	1.22	0.92	1.89
	25th percentile	0.10	0.10	0.10	0.10	0.10	0.10	0.16	0.10	0.10	0.10
	75th percentile	0.39	0.10	0.40	0.26	0.26	0.10	0.42	0.23	0.25	0.45
	St Dev	0.15	0.15	0.78	0.79	0.37	0.20	1.15	0.25	0.20	0.37
	IQR	0.29	0.00	0.30	0.16	0.16	0.00	0.27	0.13	0.15	0.35
	Skewness	0.29	4.04	3.21	3.06	3.37	3.08	3.09	3.05	2.56	3.47
	gcr	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92
	symmetric?	Y	N	N	N	N	N	N	N	N	N
Copper	**n**	23	25	23	25	24	25	23	25	24	25
(ug/L)	**% > MDL/RL**	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Mean	13.5	16.9	27.3	30.3	11.5	26.6	21.8	17.7	32.1	30.8
	Median	11.5	11.4	10.9	14.0	11.1	14.3	12.7	11.4	12.3	20.4

		1001		1002		1003		1004		1005	
Parameter	**Statistic**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
	Trimmed mean	11.6	12.1	10.7	15.4	10.7	16.2	13.9	11.3	13.2	19.8
	min	5.2	1.9	3.2	4.6	5.6	7.2	7.3	5.1	5.4	7.9
	max	38.4	108.0	278.4	226.6	23.4	227.0	119.3	77.4	389.6	210.0
	25th percentile	8.4	8.8	6.2	8.0	8.0	11.6	10.0	7.5	8.7	14.2
	75th percentile	15.0	16.9	17.9	29.8	12.3	23.4	20.5	15.2	18.6	27.5
	St Dev	8.3	20.5	57.5	48.2	5.1	43.3	24.2	18.9	77.4	40.2
	IQR	6.7	8.1	11.8	21.8	4.2	11.8	10.5	7.7	9.9	13.3
	Skewness	1.9	4.0	4.1	3.3	1.1	4.5	3.3	2.3	4.7	4.0
	gcr	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92
	symmetric?	N	N	N	N	N	N	N	N	N	N
Lead	**n**	23	25	23	25	24	25	23	25	24	25
(ug/L)	**% > MDL/RL**	91%	92%	91%	96%	88%	100%	96%	100%	96%	96%
	Mean	0.79	1.59	5.93	4.72	0.82	1.59	3.47	1.47	1.01	3.24
	Median	0.60	0.60	0.89	1.20	0.59	0.81	0.72	0.69	0.74	1.30
	Trimmed mean	0.57	0.62	0.94	1.65	0.56	0.81	0.77	0.76	0.72	1.79
	min	0.10	0.10	0.10	0.10	0.10	0.28	0.10	0.21	0.10	0.10
	max	4.91	14.90	81.70	30.87	3.19	10.90	37.74	7.16	5.70	28.10
	25th percentile	0.46	0.38	0.41	0.40	0.42	0.53	0.48	0.44	0.52	0.62
	75th percentile	0.74	0.97	1.91	4.30	0.71	1.14	1.13	1.09	0.92	3.77
	St Dev	0.97	3.18	17.63	8.10	0.79	2.46	9.19	1.91	1.11	5.56
	IQR	0.28	0.59	1.50	3.90	0.29	0.61	0.65	0.65	0.40	3.15
	Skewness	3.81	3.63	4.06	2.58	1.95	3.16	3.32	2.14	3.62	4.02
	gcr	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92
	symmetric?	N	N	N	N	N	N	N	N	N	N
Zinc	**n**	23	25	23	25	24	25	23	25	24	25
(ug/L)	**% > MDL/RL**	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Mean	58.7	37.2	115.2	86.3	56.3	56.8	83.6	40.9	74.0	75.0
	Median	56.0	50.2	53.4	57.2	50.7	53.9	50.8	43.8	52.4	54.5
	Trimmed mean	58.6	26.4	54.2	57.6	51.2	53.1	53.2	27.7	54.5	58.3
	min	32.5	2.5	35.4	2.5	22.1	2.5	29.5	2.5	32.3	2.5
	max	79.2	86.2	1069.7	429.6	171.0	231.0	429.0	149.0	330.0	512.0
	25th percentile	48.1	2.5	41.7	40.4	40.9	40.2	43.3	2.5	46.9	42.8
	75th percentile	71.4	58.2	72.1	76.9	63.9	65.5	69.0	58.6	64.6	74.5
	St Dev	14.1	29.1	219.7	109.1	29.9	44.4	97.0	35.1	63.0	99.1
	IQR	23.2	55.7	30.4	36.5	23.0	25.3	25.7	56.1	17.7	31.7
	Skewness	-0.1	-0.1	4.1	2.6	2.6	2.4	3.0	1.1	3.4	3.8
	gcr	0.96	0.92	0.96	0.92	0.94	0.92	0.96	0.92	0.94	0.92

		1001		1002		1003		1004		1005	
Parameter	**Statistic**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**	**Pre**	**Post**
	symmetric?	Y	Y	N	N	N	N	N	N	N	N
Diazinon	**n**	37	104					36	104	39	104
(ng/L)	**% > MDL/RL**	97%	99%					97%	100%	100%	100%
	Mean	1457	748					2694	1556	1295	1711
	Median	345	291					231	346	614	884
	Trimmed mean	420	352					442	369	783	902
	min	5	5					5	29	60	53
	max	14465	16590					41402	80969	7910	34838
	25th percentile	156.8	166.6					157.6	150.2	262.8	415.8
	75th percentile	890.4	641.6					1119.2	791.3	1601.5	1609.8
	St Dev	3140.5	1753.2					7505.6	7977.2	1655.4	3741.7
	IQR	733.6	475.0					961.6	641.1	1338.7	1194.0
	Skewness	3.4	7.5					4.4	9.8	2.3	7.2
	gcr	0.77	0.47					0.78	0.47	0.75	0.47
	symmetric?	N	N					N	N	N	N
Chlorpyrifos	**n**	37	104								
(ng/L)	**% > MDL/RL**	57%	40%								
	Mean	38.3	456.4								
	Median	25.0	10.0								
	Trimmed mean	18.9	10.0								
	min	5.0	5.0								
	max	213.7	45094.0								
	25th percentile	10.0	5.0								
	75th percentile	42.2	28.7								
	St Dev	51.1	4419.7								
	IQR	32.2	23.7								
	Skewness	2.5	10.2								
	gcr	0.77	0.47								
	symmetric?	N	N								

Appendix C – Probability Plot Comparisons

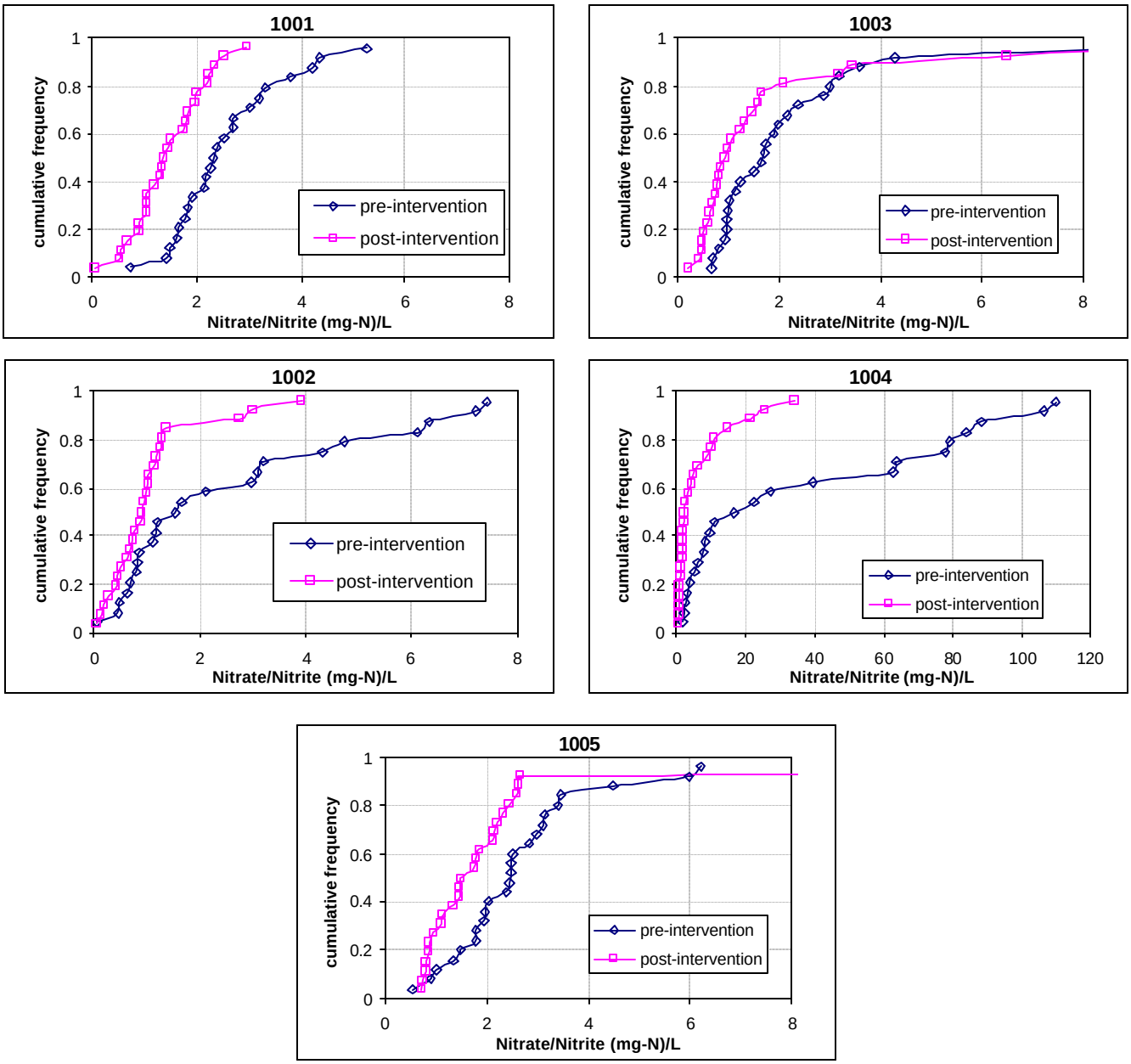


Figure C-1: Cumulative Frequency of Nitrate/Nitrite in Dry Weather Samples (all data)

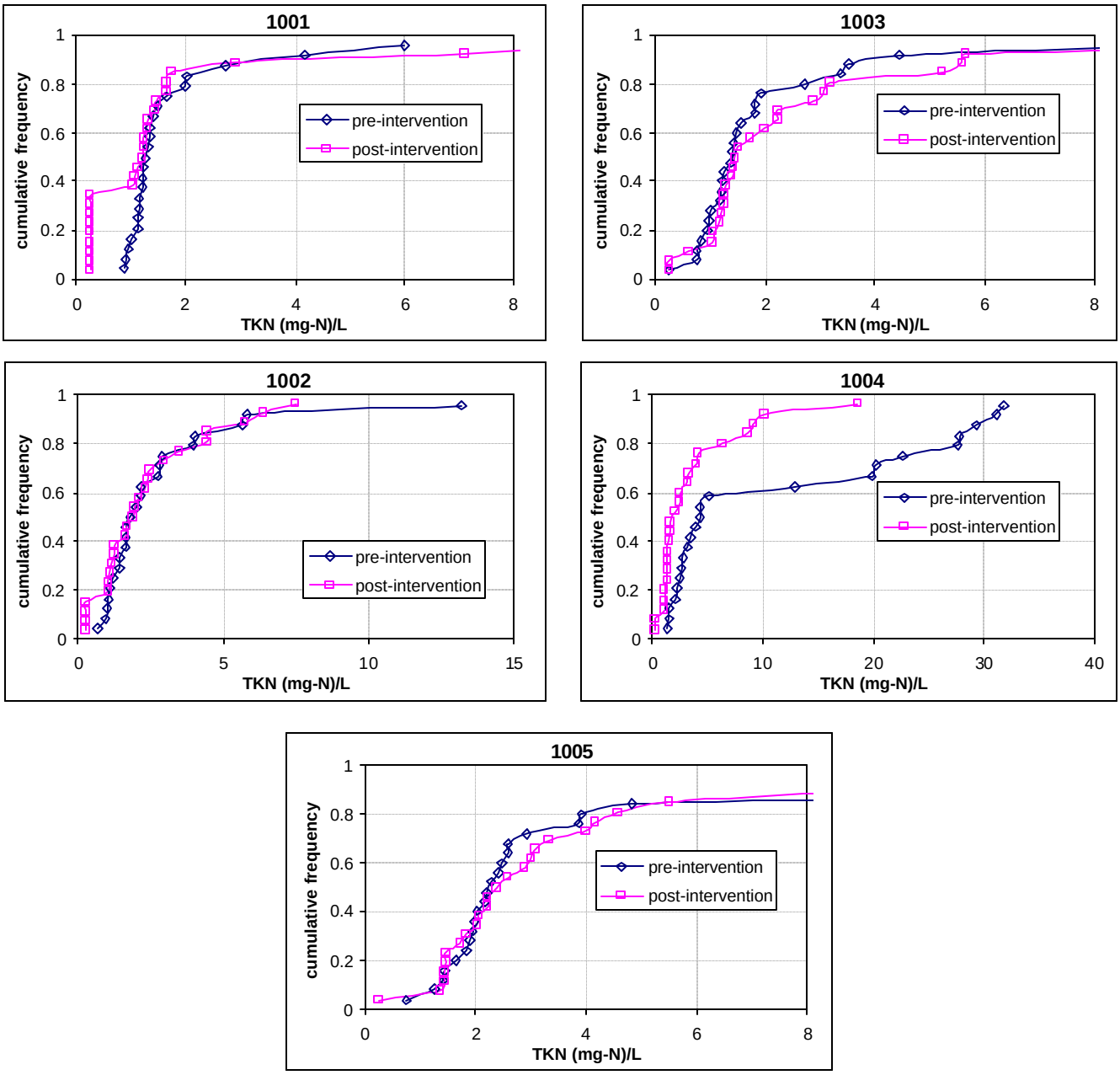


Figure C-2: Cumulative Distribution of TKN in Dry Weather Samples (all data)

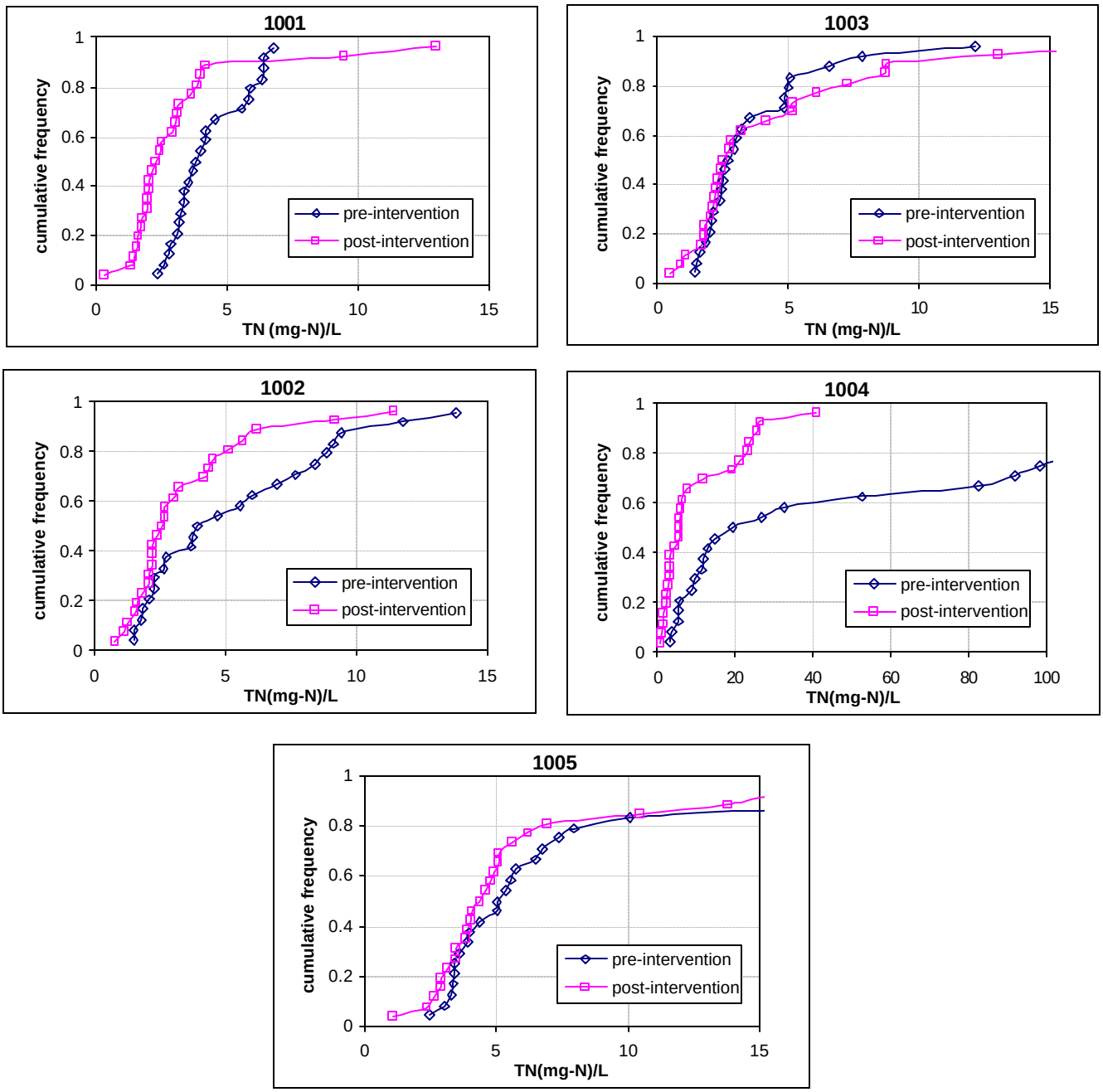


Figure C-3: Cumulative Distribution of TN (Calculated) in Dry Weather Samples (all data)

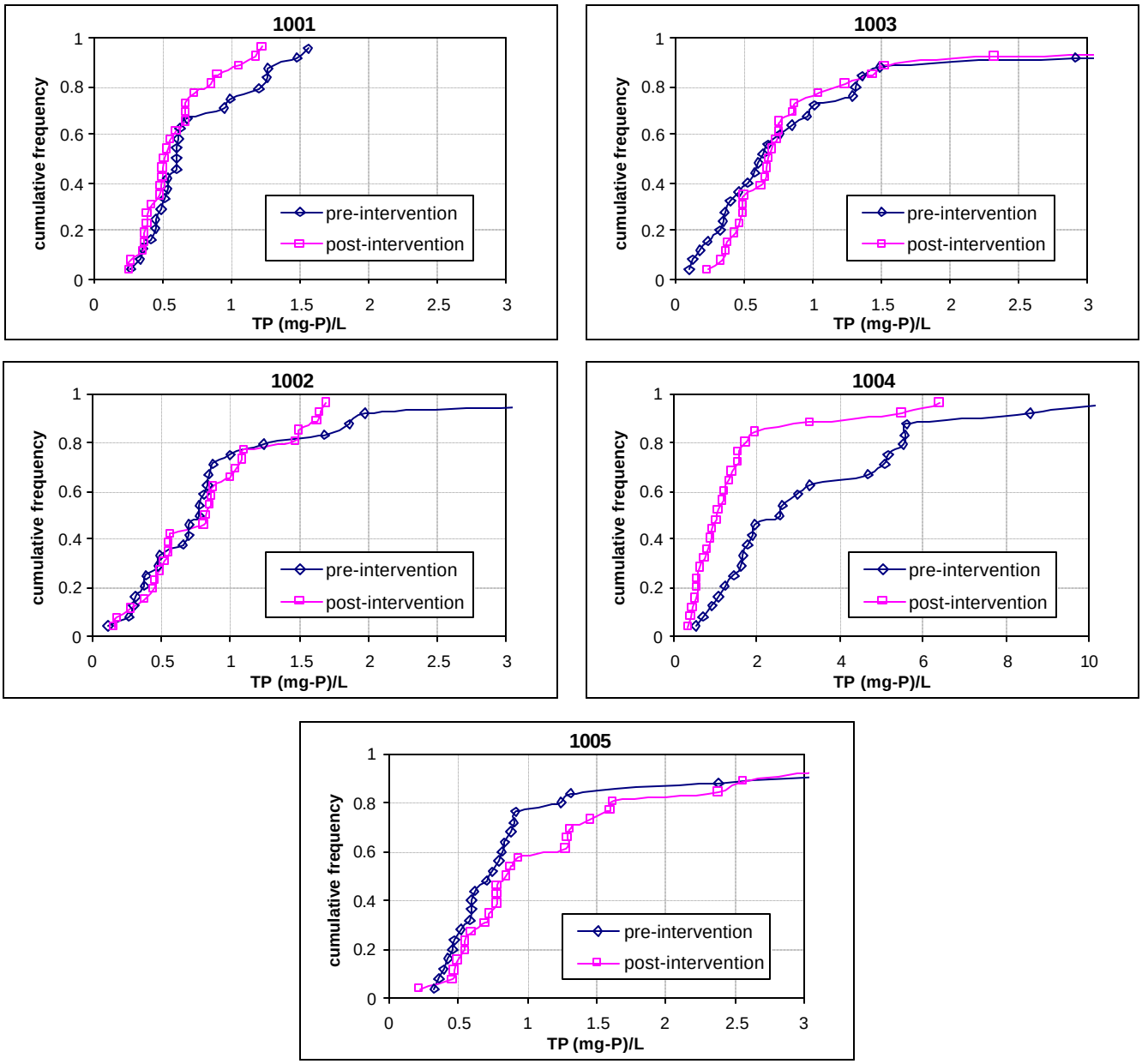


Figure C-4: Cumulative Distribution of TP in Dry Weather Samples (all data)

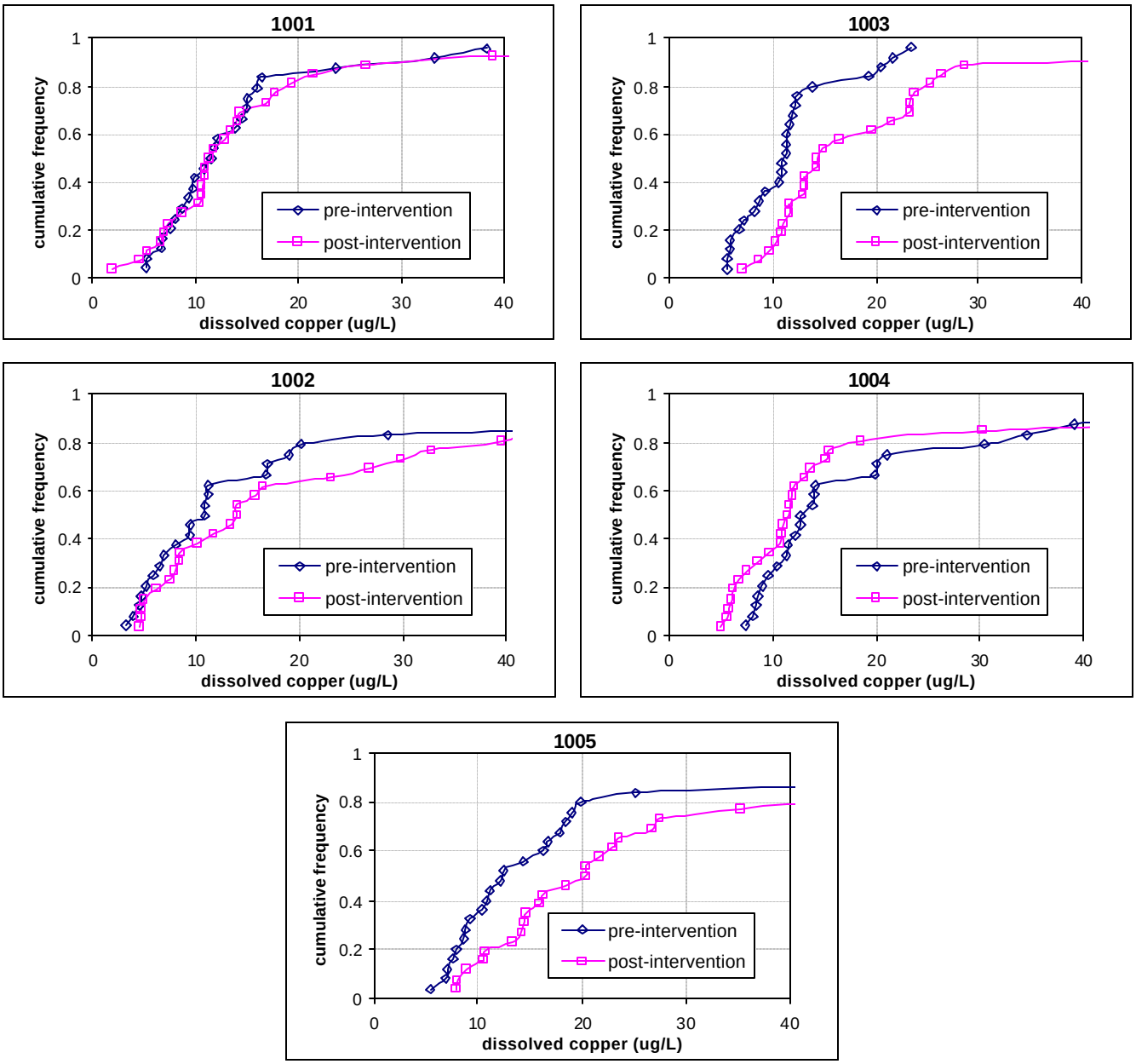


Figure C-5: Cumulative Distribution of Dissolved Copper in Dry Weather Samples (all data)

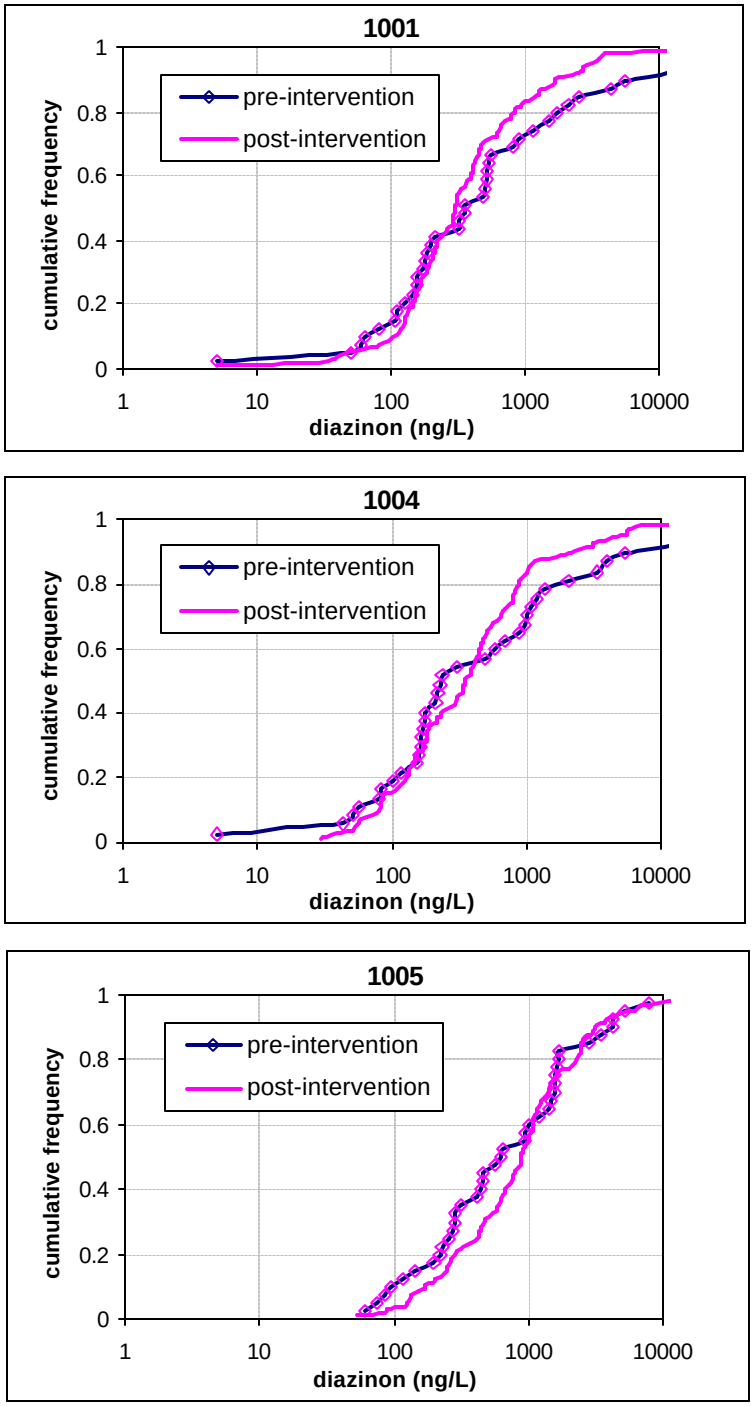


Figure C-6: Cumulative Distribution of Diazinon in Dry Weather Samples (all data)

Appendix F: Public Acceptance

The Residential Runoff Reduction Study

Appendix F: Public Acceptance

This appendix is divided into two parts. The first section describes the customer service program during the R3 Study time period and includes results of pre- and post-intervention surveys. The second part provides a representative sampling of public education materials distributed during the study. There were three groups of R3 study participants. The first group was the education group and the second group was the participants who had their home irrigation controllers replaced with an ET controller and lastly the control groups that received no treatment. The education group was self and randomly selected. Some of the education group participants voluntarily choose to participate in the study by replying to a letter. However, the majority of the education group was randomly selected through a door-to door campaign. The retrofit participants were selected through random "cold knocking" and through letter solicitations that explained the study.

Customer Interactions

ET Controller Installation Overview

ET Controllers were installed in two phases. The first phase was the installation of controllers at residences. The controllers were installed on the weekends between April and June 2001. The second phase of the installation process was the retrofit of City of Irvine and HOA sites. The retrofitted HOA sites watered the common areas of condominium and the City of Irvine sites watered the medians and streetscapes. Both of these two groups were all in the same watershed as the residential homes that were retrofitted. Initially, the time per installation was approximately one to one and one-half hours, depending on the number of valves. However, as

the IRWD staff became familiar with the process, which most had never done before, the time dropped to approximately one-half hour.

Residential post-installation concerns and problems

Home residents were advised that if they had any problems with the controller or if the controller required any adjustments, they should call the water district for assistance. IRWD's customer service department telephone number was left on the ET controller on a sticker. All calls related to the ET controller were logged in separately and routed to the appropriate staff member for assistance. Table 1 presents a summary of calls received from residential residents during the R3 study period. Generally, there were four common types of calls: 1) customer misunderstanding ("no problem" category), 2) installation-related issues, 3) system flaws, and 4) ET controller malfunctions.

Table 1: Telephone Log Summary

April 2001	1	August 2001	13	December 2001	1	April 2002	2
May 2001	12	September 2001	4	January 2002	4	May 2002	3
June 2001	7	October 2001	5	February 2002	9	June 2002	6
July 2001	13	November 2001	3	March 2002	4	July 2002	2

The first type were calls where the customer had a misunderstanding on the way the ET controllers were supposed to operate. In this type of call there was a "problem, where no problem actually existed". A common example was when a resident called to say that the sprinklers were not turning on every night. The staff member would then explain to the resident that with proper irrigation management it is normal if the irrigation sprinklers do not turn on every night.

The second types of calls received were either related to programming or installation-related mistakes. These usually occurred when the installation staff entered an incorrect value in the programming process. In other cases, a landscape contractor for the City of Irvine or HOA sites had incorrectly programmed the controller. Both groups were instructed at the beginning of the study to call IRWD to meet with a staff member who would adjust the ET controller for them.

The third category of calls included problems that were a result of a lack of irrigation system maintenance or a flaw in the design of the system. These problems were the responsibility of the homeowner to fix and were not related to the actual malfunctioning of the ET controller. For example, a customer called customer service and said that his lawn was turning brown because it was not being watered correctly. A site visit by staff would discover that the controller was set correctly, but the problem was that overgrown plant material was interfering with the normal spray pattern of the nozzle. It was this obstruction by plant material that caused the brown spot and not the settings on the ET controller.

The fourth category of calls was related to the ET controller malfunctioning. The calls from study participants were that the controller had stopped responding and the display was frozen, incorrect date or time display, or a signal dropout caused by a faulty program version. If resetting the unit or resending the ET signal could not correct the problem, the ET controllers were often changed out with a new controller with the latest version of the program. City of Irvine and HOA controllers with older versions of the controller were upgraded by uploading a new version of the program from a device provided by the manufacturer.

Tracking of Water Consumption of the City of Irvine and HOA Sites

In addition to responding to CSR calls, weekly meter reads were incorporated into the study as part of irrigation water management in order to monitor each site for excessive water usage. One ET controller installed for selected City of Irvine street landscapes was able to cover a larger area than the same controller installed in a residence. In addition, each of the City of Irvine retrofit sites had dedicated landscape irrigation water. Because of this, it was easier to track weekly water consumption of 18 meters instead of monitoring 112 residential meters. Weekly meter reads was a convenient way for staff to monitor water usage and to evaluate the performance of the ET controllers. Study staff periodically met with City of Irvine landscape staff to discuss the condition of the landscape and to discuss any other concerns. The landscape supervisor said that the appearance of the landscapes with the ET controllers were equal to similar city sites that did not have the ET controller.

One of the advantages of the ET controller is that it was able to receive a new ET signal if there was an unexpected change in weather conditions after a weekly signal had already been sent out. The controllers were grouped by water district zone, ET zone, and Zip code. Changes in weather conditions warranted staff to either increase the ETo or decrease the ET_o. During the rainy weeks, a signal would be sent to the all of the controllers that would pause the watering schedule for the appropriate number of days, this was referred to as a “rain pause signal”. Additionally, the controllers had a feature that allowed each valve to be micro-managed without having to adjust the entire watering schedule.

City of Irvine and Home Owner Associations

There are numerous benefits that can result from the installation of the ET controllers in a City environment as a water management tool. Costs that are associated with maintaining a city streetscape are labor hours and equipment. During the rainy season, city staff shuts off irrigation controllers for a given number of days that is determined by the amount of rainfall. This process is completed by manually having a city employee drive to each controller and turn the controllers off. This can be a very time intensive activity. In comparison the ET controllers are able to receive a rain pause signal and all the controllers in an area can be turned off within minutes. Hence, the ET controller can provide potential savings in labor and equipment required for programming each individual controller. It eliminates the guesswork as to whether or not to turn off the controllers. This savings in time and labor can be very substantial when the system needs to be shut down and then turned back on due to rain. With this system the city can allocate their resources more efficiently by focusing on landscape system maintenance instead of spending time on those tasks that can be performed with the ET controller technology. In addition, city staff will be able to cover a larger area. The water management features of the technology can maintain healthy landscapes and can help the city avoid penalty charges.

City and HOA controllers could be installed during regular business hours and no overtime was required for staff. These two groups were flexible about the installation times. In future programs or implementation of this technology it may be possible to train the local landscaper or contractor to install and monitor the controller. Monitoring the controller includes inspections of the irrigated area and meter reads. The local landscapers are probably the most familiar with irrigation controllers and could be cost effective to have them install the ET controller.

Customer Surveys

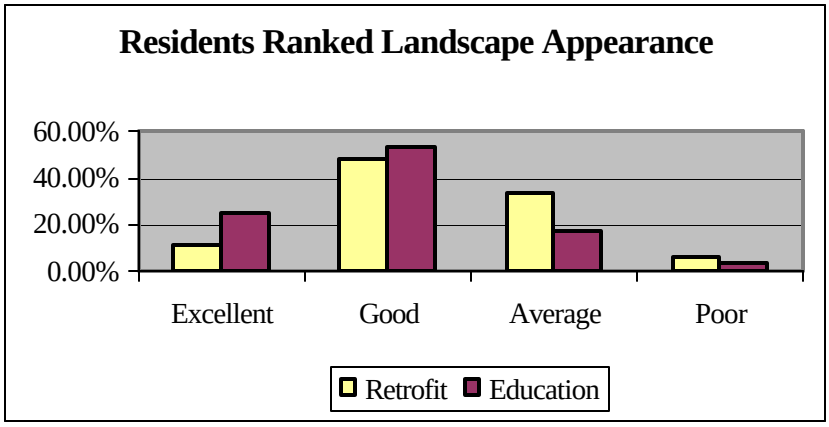
Pre-Survey Goal

The purpose of the pre-survey was to determine if the retrofit group and the education had similar irrigation practices and attitudes.

Survey Distribution

The pre-survey was distributed to the retrofit group while installation of the controller was taking place. Retrofit study participants were asked to fill-out the survey while staff was installing the controller. The education group received their survey as part of the initial educational packet that was randomly distributed to residents. Education group participants were provided a stamped addressed envelope to return their survey to the Irvine Ranch Water District. Ninety-seven (109/112) percent of those that received a survey from the retrofit group mailed the survey back. Twenty-four percent (53/225) of residents in the education group mailed back a survey.

Figure 1: Landscape Appearance

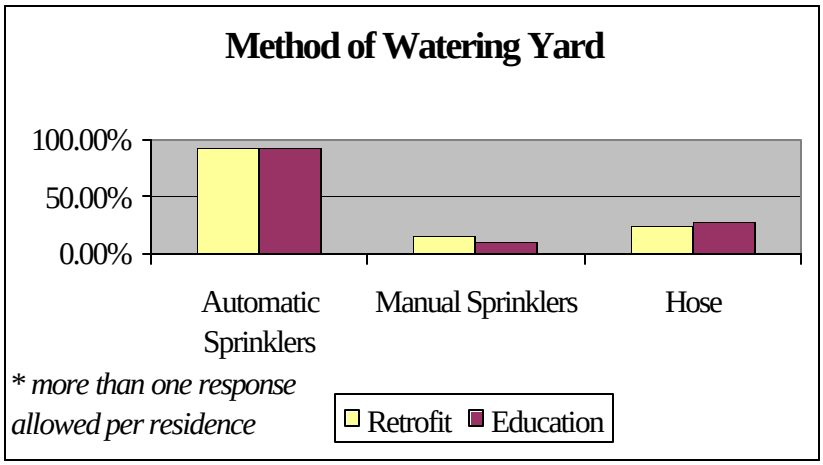


Selected Responses

A look at Figure 1 to the right shows the responses of both of the groups. Both groups gave similar responses. A majority of the residents in both groups believe that the appearance of the yard is average to good. Notice that the "excellent" response was selected by more of the education group that the retrofit group. One possible explanation for

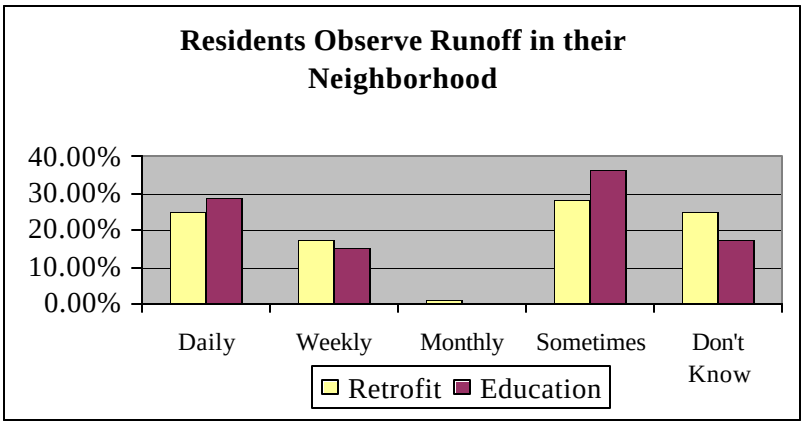
this response is that the staff was on-site while people were filling out their survey in the retrofit group.

Figure 2: Watering Methods



Residents were asked how they watered their lawn. Figure 2 shows responses across groups were very similar. The percentage of people in the retrofit and education group that use automatic sprinklers, manual sprinklers, or a hose are similar. The survey shows that the retrofit and education groups have similar watering behaviors. A majority of the participants used automatic sprinklers. This is important because the R3 study focuses on retrofitting the automatic irrigation controllers as a water management tool.

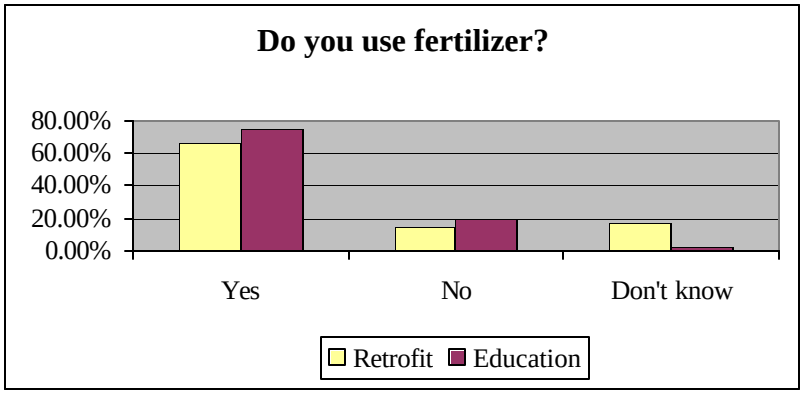
Figure 3: Runoff Observed



Residents were asked how often they observed runoff in their neighborhood. The data presented in Figure 3 shows that residents in both groups have similar attitudes and views of urban runoff.

Residents were asked if they used fertilizers in their landscape. As shown Figure 4 at right, fertilizer use in both groups is almost the same. Their behavior when it comes to applying fertilizers is also the same.

Figure 4: Use of Fertilizers



Residents were also asked if they used chemicals to control pests or weeds in their yard. Figure 5 shows their responses.

Figure 5: Use of Chemicals

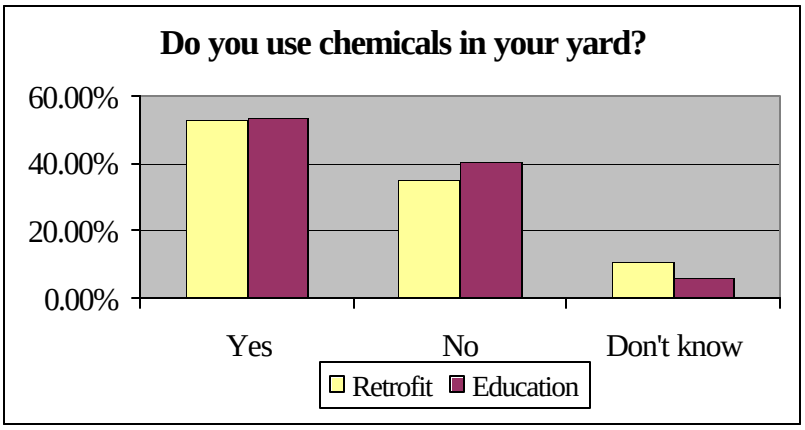


Table 2: Pre-Survey Responses

R3 Study Pre-Survey Results		
	Retro	Education
Who is responsible for yard maintenance at your home?		
Adult	68.81%	76.92%
Children	3.67%	3.85%
Yard Service	49.54%	40.38%
How is your yard watered?		
Automatic Sprinklers	92.66%	92.31%
Manual Sprinklers	14.68%	9.62%
Hose	23.85%	26.92%
How often is your yard watered?		
Summer- Days Per Week	RV	RV
Summer-Minutes Per Day	RV	RV
Summer-Don't Know	10.09%	5.77%
Winter - Days Per Week	RV	RV
Winter - Minutes Per Day	RV	RV
Winter-Don't Know	10.09%	9.62%
Controller Times Changed	RV	RV
How often do you see water runoff in your neighborhood?		
Runoff in Neighborhood-Daily	24.77%	28.85%
Runoff in Neighborhood-Weekly	17.43%	15.38%
Runoff in Neighborhood-Monthly	0.92%	0.00%
Runoff in Neighborhood-Sometimes	28.44%	36.54%
Runoff in Neighborhood-Don't Know	24.77%	17.31%
How often are patios, sidewalks, and driveways cleaned at your home?		
Driveways are cleaned-Daily	0.00%	1.92%
Driveways are cleaned-Weekly	39.45%	40.38%
Driveways are cleaned-Monthly	24.77%	21.15%
Driveways are cleaned-Sometimes	33.03%	34.62%
Driveways are cleaned-Other	RV	RV
How do you clean driveways	RV	RV
Who is responsible for pest and weed control in your yard?		
I am - Responsible for Weed/Pest Control	59.63%	67.31%
Yard Service- Responsible for Weed/Pest Control	30.28%	17.31%
Pest Control Service - Responsible for Weed/Pest Control	15.60%	25.00%
Dont Use Weed or Pest Control Service	6.42%	11.54%
Other - Responsible for Weed/Pest Control	0.00%	0.00%
Do you use chemicals to control pests or weeds in your yard?		
Chemicals are used to control pests/weeds	53.21%	53.85%
Chemicals are not used to control pests/weeds	34.86%	40.38%
Don't know if chemicals are used	11.01%	5.77%
Chemicals used are	RV	RV
Chemicals used, How often?	RV	RV

Do you use fertilizer in your yard?		
Fertilizer is used	66.06%	75.00%
Fertilizer is NOT used	14.68%	19.23%
Don't know if fertilizer is used	16.51%	1.92%
If Fertilizer used, which ones?	RV	RV
If Fertilizer used,how often?	RV	RV
Who is responsible for dispocal of unused landscape chemicals?		
I am - Responsible for disposal of unused chems	48.62%	63.46%
Pest Control - Responsible for disposal of unused chems	8.26%	5.77%
Yard Service - Responsible for disposal of unused chems	0.00%	0.00%
Don't know who - Responsible for disposal of unused chems	11.93%	7.69%
How are chems disposed of?	RV	RV
Rank the overall appearance of your yard?		
Appearance of yard-Excellent	11.93%	25.00%
Appearance of yard-Good	48.62%	53.85%
Appearance of yard-Average	33.94%	17.31%
Appearance of yard-Poor	6.42%	3.85%
Appearance of yard-Very Poor	0.00%	0.00%
How serious do you consider urban ruoff?		
Neighborhood Urban Runoff = Very Serious	6.42%	15.38%
Neighborhood Urban Runoff = Serious	16.51%	17.31%
Neighborhood Urban Runoff = Needs Improvement	46.79%	38.46%
Neighborhood Urban Runoff = No Problem	22.02%	23.08%
Irvine Urban Runoff = Very Serious	5.50%	15.38%
Irvine Urban Runoff = Serious	15.60%	11.54%
Irvine Urban Runoff = Needs Improvement	39.45%	42.31%
Irvine Urban Runoff = No Problem	18.35%	11.54%
Orange Co Urban Runoff = Very Serious	7.34%	15.38%
Orange Co Urban Runoff = Serious	21.10%	25.00%
Orange Co Urban Runoff = Needs Improvement	44.95%	34.62%
Orange Co Urban Runoff = No Problem	4.59%	1.92%
California Urban Runoff = Very Serious	13.76%	19.23%
California Urban Runoff = Serious	19.27%	21.15%
California Urban Runoff = Needs Improvement	40.37%	36.54%
California Urban Runoff = No Problem	3.67%	1.92%
Is there animal waste that gets left in you yard?		
Animal Waste is left in yard	35.78%	26.92%
Animal Wate is NOT left in yard	63.30%	69.23%
If Animal Waste is left in yard, then what type of animal	RV	RV
How many people live in your home?		
Household Adults	RV	RV
Household Children	RV	RV
*(RV) Responses Varied		

Post-Survey Goal

The purpose of the post-survey was to determine the attitudes of the study participants towards the ET controller and to determine if the education material had an impact on modifying behavior of the recipients. Specifically, determining whether or not there was an acceptance of the ET controller as a way of managing their landscape and was there a change in irrigation practices and behaviors because of the education material.

Survey Distribution

The post-survey was distributed to both of the groups through the mail. Twenty-three (52/225) percent of the education group participants responded to the survey and forty-five percent (50/112) of the retrofit group participants responded.

ET Controller

The majority of the retrofit households acknowledged their satisfaction with the ET controller's performance and agreed that they would recommend the ET controller to their friends. It appears that the residents liked the controller and did not mind having someone else manage their irrigation-watering schedule. Data shows that households accepted the controller as a method of saving water, reducing runoff, and watering their landscape. The survey shows that twice the number of retrofit households observed a decrease in their water bill than the education households did. A majority of the education households did not observe a change in their water bills. Data appears to show that the appearances of the retrofit landscapes were ranked equally with those landscapes that were part of the education group. It can therefore be concluded that the survey showed that the lower use of water did not create landscaped that were inferior to the

education group. The customer's perception of a lower bill is important for the success of any long-term conservation program.

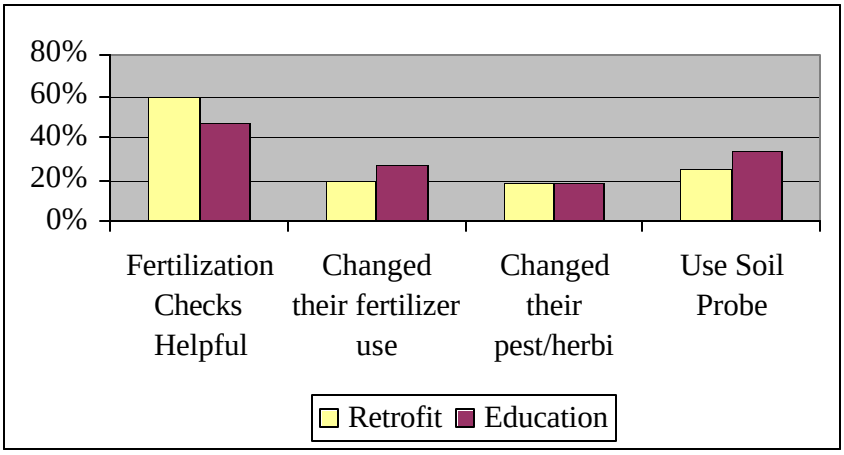
The retrofit and education group were asked if they were willing to pay for an ET controller signal. A majority of the households in both of the groups would not be willing to pay for an ET signal. The ET controller costs approximately $150.00 and the signal fee is $48 per year. The ET controller would be able to save less than 2 ccfs per month, which is a savings of about $14 per year. It appears that the savings in water use per year is not large enough for the water customer to pay for an ET signal.

ET Controller Selected Responses

- 72% of the retrofit households were satisfied with the ET Controller.
- 70% of the retrofit households would recommend the ET Controller to others.
- 44% of the retrofit households saw a decrease in their water bill,
- 38% saw their bill as unchanged.
- 23% of the education households saw a decrease in their water bill,
- 63% saw their water bills as unchanged.
- 69% of the education households ranked the appearance of their yard as good to excellent.
- 70% of the retrofit households ranked the appearance of their yard as good to excellent.
- 69% of the education households would not be willing to pay for an ET signal.
- 58% of the retrofit households would not be willing to pay for an ET signal.

Education Program

Figure 6: Impacts on Education Program



The results of the education program are summarized on Figure 6. More than half of the education households acknowledged that they sometimes or most of the time would change the settings on their controller according to ET via the monthly letter's suggested schedule. Monthly letters provided monthly landscape maintenance tips. Here, the majority of the households in both of the groups liked the tips on the irrigation checks, and fertilization sections. Although most people read these sections, a vast majority (80%) of households in both of the groups did not change their use of pesticides, herbicides, or fertilizers. In addition to the education materials, a soil probe was given to both groups at the beginning of the study. A soil probe is a tool that takes a soil sample and allows the user to see the depth and amount of moisture available to the plants. This allows the user of the soil probe to determine if the plants require more or less irrigation. More than half of the households in both groups only used the soil probe once or not at all. The majority of the people never used the soil probe at all. From a program point of view, people enjoy the education materials but they appear to have little effect on modifying behavior.

Education Material Selected Responses

- 54% of the education households changed their irrigation controller schedule (based on the recommendations included in the monthly tips) most of the time or sometimes.
- 58% of the education households and 42% of the retrofit households believed that the irrigation checks (part of the monthly tips) were helpful.
- 44% of the education households and 58% of the retrofit households believed that the fertilization checks (part of the monthly tips) were helpful.
- 81% of the education and 82% of the retrofit households have not changed their use of pesticides and herbicides.
- 73% of the education households and 80% of the retrofit households have not changed their use of fertilizer.
- 62% of the education households and 76% of retrofit households did not use the soil probe or they only used it once.

Table 3: Post-Survey Results

R3 Study Post-Survey Results

1. Rank the overall appearance of your yard.

	Excellent	Good	Average	Poor	Very Poor
Education	9.62%	59.62%	30.77%	1.92%	0.00%
Retrofit	16.00%	54.00%	24.00%	4.00%	2.00%

2. Have you seen any change in your water bill in the past 12 months?

	Increase	Decrease	Unchanged
Education	9.62%	23.08%	63.46%
Retrofit	14.00%	44.00%	38.00%

3. Which monthly monthly tips were helpful to you?

	Irrigation Checks	Watching for Runoff	Pest& Weed Control	Fertilization	None were Helpful	Dd Not Read
Education	57.69%	28.85%	23.08%	44.23%	1.92%	9.62%
Retrofit	42.00%	30.00%	46.00%	58.00%	2.00%	18.00%

4. How often did you use the soil probe?

	Once	2 to 6 times	More than 6 times	Only for the Rain	Did Not Use
Education	11.54%	30.77%	1.92%	3.85%	50.00%
Retrofit	12.00%	16.00%	6.00%	0.00%	64.00%

5. How often do you see water runoff in your neighborhood? (choose one)

	Daily	Weekly	Monthly	Sometimes	Don't Know
Education	25.00%	32.69%	5.77%	26.92%	11.54%
Retrofit	10.00%	36.00%	2.00%	40.00%	16.00%

6. How often are patios, sidewalks and driveways cleaned at your home? (choose

	Daily	Weekly	Monthly	Sometimes	Never
Education	0.00%	46.15%	21.15%	30.77%	3.85%
Retrofit	2.00%	48.00%	16.00%	32.00%	4.00%

7. How do you clean patios, sidewalks and driveways at your home?

	Hose	Broom	Blower	Other
Education	44.23%	63.46%	30.77%	RV
Retrofit	48.00%	58.00%	36.00%	RV

8. Have you changed your use of pesticides and herbicides in the yard in the past 12 months?

	Yes	No	How?
Education	15.38%	80.77%	RV
Retrofit	16.00%	82.00%	RV

9. Have you changed the use of fertilizer in your yard in the past 12 months?

	Yes	No	How?
Education	23.08%	73.08%	RV
Retrofit	18.00%	80.00%	RV

10. Is there animal waste that gets left in your yard?

	Yes	No	What type of animal
Education	21.15%	75.00%	RV
Retrofit	36.00%	64.00%	RV

11. How serious a problem do you consider urban runoff? (choose one)

	Very Serious	Serious	Needs Improvement	No Problem
Education	3.85%	38.46%	46.15%	9.62%
Retrofit	12.00%	28.00%	52.00%	10.00%

12. Were you satisfied with the test irrigation controller installed to manage the landscape water?

	YES	NO	Why
Retrofit	72.00%	24.00%	RV

13. Would you recommend this irrigation controller to others?

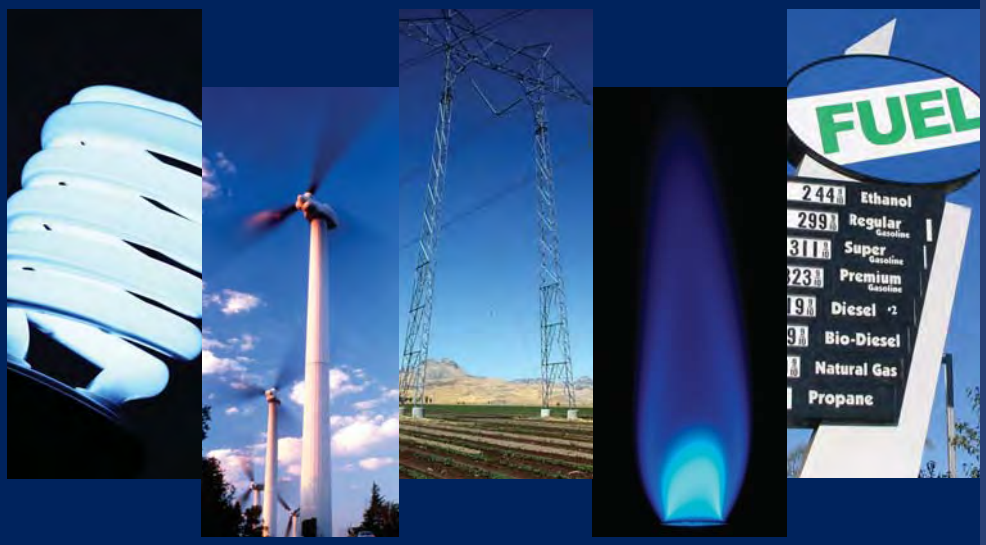
	YES	NO	Why
Retrofit	70.00%	24.00%	RV

14. Would you pay a monthly fee to have signal sent to the controller for landscape water management as tested in this study

	YES	NO	How Much?
Education	26.92%	69.23%	RV
Retrofit	38.00%	58.00%	RV

15. How often did you change your irrigation controller to the times provided in the monthly tips?

	Every Month	Most of the Time	Sometimes	Once or Twice	Never
Education	5.77%	28.85%	25.00%	23.08%	15.38%



2005

Integrated Energy Policy Report

November 2005

California Energy Commission

Arnold Schwarzenegger
Governor

CEC-100-2005-007CMF

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the Energy Commission's Editor

Elizabeth Parkhurst
July 8, 1953 – May 13, 2005

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Executive Summary

California is the sixth largest economy in the world. To meet the needs of its growing population, California's economy depends upon affordable, reliable, and environmentally sound supplies of electricity, natural gas, and transportation fuels. The challenge for California's policy makers is to manage an energy sector that is increasingly dependent on oil and natural gas and may face spiraling energy prices, potential supply shortages, and an inadequate and aging energy delivery infrastructure.

Energy prices in California are higher than ever before. Gasoline prices reached record levels in September, consuming valuable dollars that could otherwise have been spent on goods and services to help bolster the state's recovering economy. With world oil prices topping $70 per barrel, it is unlikely that gasoline consumers will see any meaningful relief in the near future. Electricity rates, although not as erratic as they were during the state's 2000-2001 energy crisis, are still among the highest in the nation, forcing businesses to struggle to maintain profit margins as the cost of doing business in the state rises. California depends upon natural gas to generate about half of its electricity, so natural gas prices that have more than doubled since 2000 are likely to keep electricity rates high.

Energy demand in all sectors will continue to rise with California's rapidly growing population and strengthening business sector. Weather-adjusted electricity consumption in California increased an average of 2 percent over each of the last two years and continues to rise. Meanwhile, state demand for transportation fuels has increased 48 percent over the last 20 years and continues to grow at an alarming rate despite record high gasoline and diesel prices. The state's dependence on natural gas to generate electricity is escalating along with the demand for natural gas in the residential and commercial sectors, with California's natural gas consumption second only to that of Texas.

Despite improvements in power plant licensing, enormously successful energy efficiency programs, and continued technological advances, development of new energy supplies is not keeping pace with the state's increasing demand. Construction of new power plants has lagged and the number of new plant permit applications has decreased. In addition, the development of new renewable resources has been slower than anticipated, due in part to the state's complex and cumbersome Renewable Portfolio Standard process. In the transportation sector, California's refineries cannot keep up with the mounting need for petroleum fuels and consequently depend upon increasing levels of imports to meet the state's needs. California also imports 87 percent of its natural gas supplies, which are increasingly threatened by declining production in most U.S. supply basins and growing demand in neighboring states.

California's energy infrastructure may be unable to meet the state's energy delivery needs in the near future. The most critical infrastructure issue is the state's electricity transmission system, which has become progressively stressed in recent years. The systematic under-investment in transmission infrastructure is reducing system reliability and increasing operational costs. Last year, transmission congestion and related reliability services cost California consumers over $1 billion. The state also experienced price spikes and several local outages over the past summer. California's petroleum import and refinery infrastructure also faces challenges including the inherent conflict between the need to expand import, refining, and storage facilities to meet transportation fuel demands and the environmental and social concerns of local communities affected by these needed expansions. In the natural gas sector, California has made infrastructure improvements that will increase the reliability and operational flexibility of the natural gas system, but must still address the need for additional pipeline capacity to meet peak demand.

In the *2003 Integrated Energy Policy Report* (*2003 Energy Report*) and the *2004 Integrated Energy Policy Report Update* (*2004 Energy Report Update*), the California Energy Commission (Energy Commission) recommended a broad range of strategies to reduce energy demand, secure additional energy supplies, move toward more sustainable technologies and fuel types, and build the necessary infrastructure to protect California from future supply disruptions and high prices. The *Energy Action Plan*, adopted earlier this year by the Energy Commission and the California Public Utilities Commission (CPUC), sets out a series of concrete actions for the state to undertake to meet these challenges. The state must reinforce

its commitment to these efforts and take immediate action to address problems in the energy sector to meet the state's policy goal of ensuring adequate, affordable, reliable, and environmentally sound energy services for its citizens.

Ensuring Adequate Electricity Supplies

As the state's demand for electricity increases, California could face severe shortages in the next few years. Of particular concern are the potential impacts of higher-than-average summer temperatures, which can drastically increase the state's electricity demand, as well as shortages resulting from decreased hydroelectric generation in lower-than-average precipitation years. Either of these situations could cause dangerously low reserve margins and potential supply disruptions, particularly in Southern California. Reserve margins could also be affected by the retirement of aging natural gas-fired power plants, which remain critical components of California's generation fleet despite strong policy directives to diversify the state's electricity supplies.

The *2005 Energy Report* assessment of electricity supply and demand concludes that maintaining adequate electricity reserves will be difficult over the next few years. The state has made some progress toward resource adequacy for investor-owned utilities by requiring them to maintain year-round 15-17 percent reserve margins. Jurisdictional authority over other load serving entities is less clear. Until recently there was no formal mechanism to ensure resource adequacy for publicly owned utilities, which provide up to 30 percent of the state's electricity. In September 2005 the Legislature passed and the Governor signed AB 380 (Nunez), Chapter 367, Statutes of 2005, which extends jurisdiction over independent load serving entities and requires publicly owned utilities to report their respective supply circumstances to the Energy Commission so that their resource adequacy progress can be accurately assessed in future *Energy Report* proceedings.

California must also address its long-term electricity needs by aggressively bringing new generation on line. The lack of long-term power contracts has stalled development and construction of more than 7,000 megawatts (MW) of permitted plants and sharply curtailed the number of new permit applications. Utilities need to invest now for the long term to avoid a repeat of the catastrophic mistakes made during the 2000-2001 energy crisis that Californians are still paying for today. California's dependence on natural gas to generate electricity is also increasing as utilities continue to purchase generation from the state's aging fleet of natural gas-fired power plants under short-term contracts. These issues are being addressed in the CPUC's 2006 long-term procurement proceeding. Through that proceeding investor-owned utilities should be encouraged to sign long-term contracts that will both cover the annual "net short" and allow for the orderly retirement or repowering of the aging power plants identified in the *2004 Energy Report Update.*

The utility procurement process needs to be more open and transparent for all parties. The state's investor-owned utilities continue to claim that much of the data used in their resource planning and procurement are confidential. The Energy Commission, however, concludes that important benefits come from rigorous public scrutiny and debate about the data and planning assumptions the CPUC ultimately uses to develop its resource procurement decisions. The Energy Commission will participate in the CPUC's rulemaking to revise regulations regarding disclosure of data and has initiated its own rulemaking to review data regulations for the next *Energy Report* cycle.

The Energy Commission strongly supports the following procurement recommendations:

- The CPUC should require investor-owned utilities to procure enough energy and capacity through long-term contracts to meet their net short positions. Procurement plans should provide for the orderly retirement or repowering of aging plants by 2012.

- The CPUC should develop a set of "coming and going" rules for departing load by the end of 2006.
- The Energy Commission and the CPUC should establish open and transparent resource planning and procurement processes for all-source and renewable resources and eliminate confidential procurement review groups.
- The CPUC and the Energy Commission should develop a more transparent and standardized method for addressing least-cost, best-fit criteria and consistently apply a renewable "rebuttable presumption" to all procurement.

An important alternative to building large new power plants is distributed generation, which is electricity produced on site or close to load centers that is also connected to a utility's distribution system. The most efficient and cost-effective form of distributed generation is cogeneration or combined heat and power. By recycling waste heat, these systems are much more efficient than systems that separately serve thermal and electric loads. They are also considerably more efficient than almost all conventional gas-fired power plants. California has more than 9,000 MW of combined heat and power systems throughout the state, representing approximately 17 percent of statewide generation. Most of these systems are larger than 5 MW, suggesting that the state should focus its efforts on large-scale projects that could provide more than 5,000 MW of additional generating capacity over the next 15 years.

Current state policy must change for California to tap into this potential generation source and retain the existing pool of combined heat and power facilities so critical to reliable operation of the state grid. Developers of new combined heat and power facilities are struggling to find customers to purchase their excess power at the wholesale level, and the state's suspension of direct access hampers their ability to sell their excess power at the retail level. For existing facilities, the unwillingness of utilities to renew existing qualifying facility contracts has led some operators to remove their combined heat and power systems entirely and rely instead on less efficient boilers to meet their heating needs. There will be serious adverse consequences for electric reliability, natural gas demand, and air quality if this trend is allowed to continue.

The Energy Commission strongly supports the following combined heat and power recommendations:

- The CPUC and the Energy Commission should establish annual utility procurement targets for combined heat and power facilities by the end of 2006.
- The CPUC should require investor-owned utilities to purchase electricity from combined heat and power facilities at prevailing wholesale prices.
- The CPUC should explore regulatory incentives that reward utilities for promoting customer and utility-owned combined heat and power projects.
- The CPUC should require that investor-owned utilities provide California Independent System Operator (CA ISO) scheduling services for these facilities and be compensated for doing so.

A significant percentage of California's electricity supply comes from the in-state Diablo Canyon and San Onofre nuclear power plants. Operators at these nuclear plants face many issues involving the transportation and disposal of spent fuel, upcoming extensions of their operating licenses, and major capital expenditures to replace aging steam generators. New nuclear power plant construction in California was suspended in 1976 pending determination by the Energy Commission that a high-level federal nuclear waste disposal repository has been approved and built. The Energy Commission reaffirms its 1978 finding that a high-level nuclear waste repository has been neither approved nor built. Californians have contributed well over $1 billion to the federal waste disposal development effort, which remains plagued with licensing delays, increasing costs, technical challenges, public opposition, and managerial problems.

The Energy Commission strongly supports the following nuclear recommendations:

- The federal government should return some portion of the funds paid by California ratepayers for a permanent national repository for nuclear waste in order to pay for interim storage of waste at California reactor sites.
- The Legislature should develop a suitable state framework to review the costs and benefits of nuclear power plant license extensions.

Reducing Energy Demand through Efficiency and Alternative Resources

Reducing the demand for energy is the most effective way to reduce energy costs and bolster California's economy. Reducing demand also reduces the likelihood of supply shortages that can cause costly price spikes and affect reliability. California will continue to depend upon petroleum fuels and natural gas to meet its energy needs for the foreseeable future. The state needs to act now to implement energy efficiency measures for petroleum fuels and increase its use of alternatives to reduce its reliance upon these increasingly volatile fuel supplies. Efficiency and renewable resources are top priorities in California's electricity loading order policy, and the state needs to extend these priorities to California's transportation sector by reducing demand for petroleum fuels through efficiency and alternative fuel use.

Electricity

California continues to be the national leader in efficiency. While energy use per person in the rest of the nation has increased by 45 percent over the last 30 years, California's per capita use has remained relatively flat as a result of the state's energy efficiency measures. In the *2003 Energy Report*, the Energy Commission concluded that California could save an additional 30,000 gigawatt hours (GWh) of energy from energy efficiency programs over the coming decade. In 2004, the CPUC established aggressive energy savings goals and authorized a significant increase in energy efficiency funding. Meeting these goals will reduce the utilities' need for additional electricity supplies between 2004 and 2013 by more than half. The recent passage of SB 1037 (Kehoe) Chapter 366, Statutes of 2005, further reinforces the state's energy efficiency policies by requiring all utilities to meet their unmet resource needs first with energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible.

The state's efficiency programs need to focus on peak savings as well as energy savings. Because California's electricity demand is driven by short summer peaks, reducing peak demand is essential for improving electricity reliability, reducing price volatility, and delaying the need for expensive power plants that operate only a few hours a year. The Energy Commission recommends renewed emphasis on energy efficiency programs that provide peak demand savings.

California's water infrastructure accounts for nearly 20 percent of the state's electricity consumption. If not coordinated and properly managed on a state-wide basis, water-related electricity demand could ultimately affect the reliability of the electric system during peak load periods when reserve margins are low. Water and wastewater agencies would similarly be unable to meet the needs of their customers without adequate electricity supplies. More efficient water usage, coupled with energy efficiency improvements in the water infrastructure itself, could reduce electricity demand in this sector. The Energy Commission, the Department of Water Resources, the CPUC, local water agencies, and other stakeholders should explore and pursue cost-effective water efficiency opportunities that would save energy and decrease the energy intensity in the water sector.

Demand response programs are the most promising and cost-effective options for reducing peak demand on California's electricity system. The CPUC is currently considering proposals from the investor-owned utilities to purchase and install advanced meters for all their customers. New metering technology is the primary platform for future voluntary and mandatory demand response policies. Although the CPUC adopted demand

reduction targets for investor-owned utilities in 2003, demand response programs have failed to deliver their savings targets for each of the last three years and appear unlikely to meet their targets for next year. Given the huge cost of serving California's peak loads, the state's policy makers must redouble their efforts to implement ambitious demand response programs, through tariffs and control technology, and install advanced meters for all customers as soon as practically possible.

The Energy Commission strongly supports the following energy efficiency and demand response recommendations:

- The CPUC and Energy Commission should closely monitor investor-owned utilities' energy efficiency programs to ensure that peak energy savings are captured in their respective efficiency portfolios.
- The CPUC, Department of Water Resources, the Energy Commission, local water agencies and other stakeholders should assess efficiency improvements in hot and cold water use in homes and businesses and include these improvements in 2006-2008 programs.
- The Energy Commission should establish, consistent with SB 1037, reporting requirements for publicly owned utilities to ensure that their energy efficiency goals are comparable to those required of investor-owned utilities.
- The CPUC and the Energy Commission must vigorously pursue actions to ensure that the state's demand response goals are met.

California is also a national leader in the development of renewable resources. Over the past 30 years, California has built one of the largest and most diverse renewable generation portfolios in the world. In 2002, California established its Renewable Portfolio Standard program, with the goal of increasing the percentage of renewable energy in the state's electricity mix to 20 percent by 2017. The *2003 Energy Report* recommended accelerating that goal to 2010, and the *2004 Energy Report Update* further recommended increasing the target to 33 percent by 2020. The *Energy Action Plan* supported this goal. The current process for procuring renewable resources is overly complex and cumbersome and, without improvement, could impede the state's ability to achieve its renewable goals.

The CPUC and the Energy Commission should work together to simplify, streamline, and expedite the state's Renewable Portfolio Standard process. The two agencies should also work together to establish simple rules for the Renewable Portfolio Standard program for both energy service providers and community choice aggregators. These rules should allow limited trading of renewable energy certificates, which would increase participation by these entities and help address the current transmission constraints that preclude access to promising renewable resource areas in the state. As the Western Renewable Energy Generation Information System begins operation, this compliance mechanism should be expanded to include the entire Western Electricity Coordinating Council.

There are several additional issues facing wind resource development in California. The state needs to focus on repowering aging wind facilities to increase the amount of renewable generation from these prime sites and reduce the number of bird deaths caused by wind turbines. The state also needs to conduct additional research and development at both the Energy Commission and the CA ISO to address current barriers to integrating intermittent wind resources into the state's transmission system.

California also has promising opportunities to increase energy production from renewable resources connected with the state's water system. In-conduit hydropower—turbines installed within conduits to generate electricity from flowing water in pipelines, canals, and aqueducts—is an attractive possibility because it is relatively easy to permit and has fewer environmental impacts than large hydroelectric power plants. Anaerobic digesters installed at or near wastewater treatment facilities, dairies, or food processing facilities can also produce biogas, which can be used to either power on-site generation or be sold to the grid. Biomass resources also offer possibilities that should be evaluated.

Many existing in-conduit facilities are facing the expiration of their standard offer power purchase contracts with the state's investor-owned utilities. Existing rules do not allow water or wastewater utilities to credit the electricity they generate to their energy bills. Therefore, if this electricity cannot be directly connected to an existing load, it must be sold into the wholesale bulk power market. The cost and complexity of selling into the wholesale bulk power and transmission markets are daunting, even for large generators, and can be prohibitive for very small generators. The Energy Commission recommends expediting and reducing the cost of utility interconnection, eliminating economic penalties including standby charges, removing size limitations for net metering, and allowing water and wastewater utilities to self generate and wheel power within their own systems.

The Energy Commission strongly supports the following renewable energy recommendations:

- The Energy Commission should ensure that publicly owned utilities meet the same Renewable Portfolio Standard targets for eligibility and compliance required of investor-owned utilities.
- The CPUC and the Energy Commission should establish a joint proceeding to develop a simpler and more transparent Renewable Portfolio Standard process by the end of 2006.
- The CPUC and the Energy Commission should closely monitor the 2005 renewable procurement cycle to determine the potential value of greater contract standardization.
- The CPUC should require investor-owned utilities to procure a prudent contract-risk margin, starting at 30 percent, to prevent under-procurement.
- The CPUC should quickly develop new standardized contracts for wind repowering projects to more efficiently harness wind resources and reduce bird deaths.

Transportation

The *2003 Energy Report* concluded that by far the most cost-effective strategy to reduce petroleum demand in the transportation sector is to increase vehicle fuel economy. The Energy Commission recommended that the state take steps to influence the federal government to double the combined fuel economy standards for cars and light trucks. Governor Schwarzenegger has called on the federal government to do exactly that. Unfortunately, efforts to spur the federal government to significantly increase the corporate average fuel economy standards for passenger cars and light trucks have not been successful. The federal government has proposed only a very minor increase in the light-truck standard and completely ignored potentially far-reaching savings in the passenger car market. California needs to intensify its efforts to forge a coalition with other states and stakeholders to persuade the federal government to double the corporate average fuel economy standards.

The state can pursue other strategies to increase transportation efficiency, including increasing the number of hybrid electric, plug-in hybrid electric, and light-duty diesel vehicles in California, more effective marketing of low-rolling resistance tires, implementing anti-idling regulations for trucks and truck stop electrification, and integrating transportation and land use planning.

Increased efficiency in new cars and light trucks alone cannot maintain the state's overall petroleum reduction goals. California must also vigorously support the rapid development and availability of alternative fuels so that their air quality and petroleum replacement benefits can be realized. The *2003 Energy Report* recommended a goal to increase the use of non-petroleum fuels to 20 percent of on-road demand by 2020 and to 30 percent by 2030. The Energy Commission continues to strongly support these goals, though meeting them will take considerable and concentrated effort given the current low penetration level of only 6 percent.

In his response to the Energy Commission's previous *Energy Reports*, the Governor made clear that the state needs to promote the efficient use of petroleum products and promote reductions in the demand for petroleum. As directed by the Governor, the Energy Commission has assumed the lead in developing a long-term transportation plan by March 31, 2006, that will reduce gasoline and diesel use and increase alternative fuel use. This effort will be a prelude to a larger alternative fuel plan for the state required by AB 1007 (Pavley), Chapter 371, Statutes of 2005, that is due by June 30, 2007. The Energy Commission envisions that the alternative transportation fuel plan must bridge the gap between today's technologies and the transition to hydrogen fuels and vehicles called for in the Governor's *Hydrogen Highway Network Blueprint Plan*. California must pursue a diverse portfolio of fuels and advanced transportation technologies that address both current supply and demand problems and build a sustainable foundation for the future.

The Energy Commission strongly supports the following transportation recommendations:

- The state should simultaneously reduce petroleum fuel use, increase fuel diversity and security, and reduce emissions of air pollution and greenhouse gases.
- The state should implement a public goods charge to establish a secure, long-term source of funding for a comprehensive transportation program including broad-based funding for infrastructure, technology and fuels research, analytical support, and incentive programs.
- The state should continue to work closely with other states to pressure the federal government to double vehicle fuel efficiency standards and enact fleet procurement requirements that include super-efficient gasoline and diesel vehicles.
- The state should establish a non-petroleum diesel fuel standard so that all diesel fuel sold in California contains a minimum of 5 percent non-petroleum content that would include biodiesel, ethanol, and/or gas-to-liquid components.
- The state should establish a state renewable gasoline fuel standard so that the pool of all gasoline sold in California contains, on average, a minimum of 10 percent renewable content.
- The state should investigate how investor-owned utilities can help develop the equipment and infrastructure to fuel electric and natural gas vehicles.
- The state should, for its fleet of vehicles, establish a minimum fuel economy standard and a procurement requirement for alternative fuels and vehicles, and examine the merits of using re-refined and synthetic oils.

Natural Gas

The *2003 Energy Report* recommended that the state reduce natural gas demand by increasing funding for natural gas efficiency programs. California has made progress in this area. In 2004, the CPUC increased 2005 funding for natural gas efficiency programs by $19.8 million and set aggressive goals intended to double annual gas savings by 2008 and triple them by 2013. The recently enacted SB 1037 also requires gas utilities to first meet their unmet resource needs with all available energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible. The Energy Commission and the CPUC should rigorously evaluate, measure, and monitor these gas efficiency programs to ensure that they produce their intended savings and that public funds are being well spent.

Another way to increase natural gas efficiency is to increase the role of combined heat and power facilities as a way to meet California's rising electricity supply needs.

Natural gas efficiency is a priority in the Energy Commission's natural gas research, development, and demonstration program. Approximately half of the $12 million in available 2005 funding has been allocated to efficiency research. The Energy Commission should continue its efforts to incorporate the results of this critical research into the state's natural gas efficiency programs.

Improving the Energy Infrastructure

Electricity Transmission Infrastructure

In both the *2003 Energy Report* and the *2004 Energy Report Update*, the Energy Commission identified existing problems with the state's transmission system and recommended improvements to the transmission planning and permitting processes that would speed up approvals of new transmission lines and upgrades to existing lines. However, the state still lacks a well-integrated transmission planning and permitting process that considers both generation and transmission needs, evaluates non-wires alternatives, plans for transmission corridors well in advance of need, and allows access to essential renewable resource areas in the state.

California policy makers must move aggressively to create a planning and permitting process that leverages the core responsibilities and strengths of the utilities, the Energy Commission, the CA ISO, and the CPUC. The Energy Commission reemphasizes its recommendation in the *2003 Energy Report* that the Legislature transfer the siting functions for transmission lines from the CPUC to the Energy Commission. In the absence of that authority, the Energy Commission will continue to work with other agencies to improve the transmission permitting process.

California still lacks a formal process to effectively plan for transmission corridors well in advance of their need. The Energy Commission recommends a corridor planning process that would identify the corridor needs of transmission owners; establish corridor priorities; identify major permitting, environmental, and land use issues; and ensure full participation of all affected local, state, and federal agencies and stakeholders. Further, the Legislature should authorize the Energy Commission to designate corridors so that utilities have a level of financial certainty that allows them to acquire land and easements, while also allowing the Energy Commission to proceed with the comprehensive environmental reviews that could significantly shorten overall planning and permitting lead times. The CPUC should also extend its current five-year limitation on investor-owned utility land banking for the cost of future transmission corridors within utility rate bases.

California must urgently encourage major investments in the new transmission infrastructure needed to access remotely located renewable resources in the Tehachapi and Imperial Valley areas. Without this investment it will be difficult for California to meet its statewide Renewable Portfolio Standard goals. In March 2005, Southern California Edison (SCE) proposed to the Federal Energy Regulatory Commission (FERC) a new category of transmission facility, called a "renewable-resource trunk line," that would allow the interconnection of large concentrations of renewable generation resources located within a reasonable distance of the existing grid under operational control of the CA ISO. However, in July 2005, FERC denied SCE's request, thereby eliminating a valuable regulatory instrument that could have overcome renewable transmission constraints. This denial clearly underscores the need to examine all regulatory options, including changes to the CA ISO tariff so that this new category of transmission project can be recognized by FERC. This recommendation was also made in the *2004 Energy Report Update*.

The Energy Commission strongly supports the following transmission recommendations:

- The Legislature should expeditiously transfer transmission permitting responsibilities from the CPUC to the Energy Commission, using the successful framework laid out in the Warren-Alquist Act for generation siting.
- The Energy Commission, the CPUC, and the CA ISO should collaborate to change the CA ISO tariff to encourage construction of transmission for renewable generation interconnections, as well as explore other regulatory mechanisms.
- The Legislature should assign the Energy Commission the statutory authority to establish a statewide corridor planning process and designate corridors for future use.

- The Energy Commission should actively participate in the federal corridor planning processes recently enacted as part of the federal Energy Act of 2005.

Petroleum Infrastructure

California urgently needs to expand its petroleum infrastructure. Despite recent and planned improvements, California still needs to expand its marine terminal capacity, marine storage, and the pipelines that connect marine facilities and refineries with main product pipelines. Most of the required expansion is needed in the Los Angeles Basin, which faces a number of barriers including scarcity of land, pressure to remove a portion of existing facilities in favor of container cargo facilities, and new standards for marine terminals. In Northern California, timely dredging of the Suisun Bay Channel, the Pinole Shoals, and other areas near refineries is critical to the efficient operation of petroleum infrastructure.

The *2003 Energy Report* identified the continuing need for modifying and expanding the state's petroleum infrastructure facilities to meet the state's rising demand for petroleum fuels. A major barrier is the inefficient and often overlapping responsibilities of permitting bureaucracies which frequently result in unacceptably lengthy lead times. There is a general consensus among stakeholders that the Energy Commission should work with representatives of the petroleum industry and permitting agencies to develop "best permitting practice" guidelines to streamline and coordinate the permitting process for new petroleum infrastructure. The Energy Commission believes these guidelines should include: the description of the agencies involved and their relationships in agency processes; critical path permitting timelines; information requirements; standardized permitting timelines; requirements for expedited permitting; mitigation requirements; concurrent and coordinated permit review; procedures for categorical exemptions and ministerial permits; and streamlined appeal processes.

The Energy Commission strongly supports the following petroleum infrastructure recommendation:

- The Energy Commission should develop petroleum infrastructure permitting guidelines based upon a "best practices" approach following this inter-agency evaluation.

Natural Gas Infrastructure

California imports 87 percent of its statewide natural gas supply, which is threatened by declining production in most U.S. supply basins. Though California has not experienced a widespread natural gas shortage in many years, colder-than-average weather, increased demand in other states, or natural disasters like Hurricane Katrina could quickly create demand spikes that would draw down stored gas supplies and adversely affect the state's ability to meet consumer natural gas demand. California needs to expand its analytical ability to determine the adequacy of its natural gas infrastructure and likelihood of potentially destructive peak demand spikes.

To prevent interruptions in the state's natural gas supplies, the *2003 Energy Report* recommended the state ensure that existing natural gas storage be used to provide adequate supplies and protect against price spikes. The state has made good progress in increasing its current storage inventory and also has plans to develop additional storage capacity in 2006. A margin of excess capacity will provide consumers a choice of supplies and is part of a critical foundation needed to support a competitive market and stabilize short-term pricing variations.

California has also improved its natural gas infrastructure by increasing intrastate pipeline capacity and in-state storage. Pipeline expansions completed over the last four years have also helped ensure that the state can access conventional natural gas supply basins outside of the state. The state must make certain that existing infrastructure is both maintained and retained. The state also needs to continue to evaluate the need for additional

pipeline capacity to meet customer demand on the coldest days in winter or when there are interstate pipeline disruptions.

An important addition to natural gas infrastructure in North America is the planned construction of liquefied natural gas import terminals. These facilities will increase natural gas imports to the U.S. over the next 10 years and also help meet California's growing natural gas needs. Currently, no liquefied natural gas terminals are located on the West Coast. The *2003 Energy Report* endorsed the need to develop these facilities and their associated infrastructure to better serve the natural gas needs of the western U.S.

The cost of delivering natural gas to the West Coast through a liquefied natural gas project is expected to be well below the market prices that California currently pays at its borders and could have a dramatic effect on gas market prices in the state. For example, if market prices dropped by 50 cents per million British thermal units, Californians would save more than $1 billion annually on their natural gas bills.

Several companies have recently proposed building liquefied natural gas import facilities in California and Mexico. In California, these include the Cabrillo Deepwater Port and the Clearwater Port, both of which are offshore projects, and the Long Beach LNG Import Project. In Mexico, there are three proposed facilities including the Terminal GNL Mar Adentrode Baja and the Moss Maritime LNG, both of which are off-shore projects, and the Sonora LNG facility. Construction has begun on a fourth project, Energia Costa Azul, expected to be on line in 2007.

Global Climate Change

California must continue to be highly aware of the environmental impacts of its energy policies. As the world's seventeenth largest emitter of greenhouse gases, California must incorporate its efforts to reduce greenhouse gases into its energy policies. In June 2005, Governor Schwarzenegger established greenhouse gas emission targets intended to reduce greenhouse gas emissions by 2010 to 2000 emission levels, by 2020 to 1990 levels, and by 2050 to 80 percent below 1990 levels. The Governor's Climate Action Team, led by the California Environmental Protection Agency, is charged with developing the program that will achieve the Governor's targets. The first report of the Climate Action Team is due to the Governor and Legislature in January 2006.

The state is exploring a number of strategies to reduce greenhouse gas emissions. The CPUC now requires that investor-owned utilities use a carbon dioxide adder of an initial $8 per ton in their long-term procurement plans, encouraging them to invest in lower-emitting resources. In addition, the CPUC unanimously adopted a resolution directing its staff to develop an investor-owned utility greenhouse gas performance standard "that is no higher than the greenhouse gas emission levels of a combined-cycle natural gas turbine" for all procurement contracts longer than three years. In the case of coal-fired generation, the capacity to capture and store carbon dioxide safely and inexpensively is essential for meeting these standards. The *Energy Action Plan* commits that the agencies will "… ensure that energy supplies serving California, from any source, are consistent with the Governor's climate change goals." The Energy Commission endorses the CPUC's setting a greenhouse gas performance standard for investor-owned utilities and agrees that an offset policy must await a formal greenhouse gas regulatory system and must include a reliable and enforceable system of tracking emission reductions. The Energy Commission looks forward to working with the CPUC to implement a greenhouse gas performance standard as part of the 2006 procurement proceeding.

While more specific recommendations must necessarily await the January 2006 report from Governor Schwarzenegger's Climate Action Team, the Energy Commission recommends the following:

- A greenhouse gas performance standard for utility procurement should be set no higher than emission levels from new combined-cycle natural gas turbines.
- Additional consideration is needed before determining what, if any, role greenhouse gas emission offsets could play in complying with such a standard.

Border Energy

The California-Baja California Norte border region extends about 60 miles north and south of the California-Mexico border. Rapid population, commercial, and industrial growth in the region is substantially increasing the demand for energy. The border region is becoming an "energy corridor" as states on both sides develop facilities not only to meet local needs, but also to export across state and international borders. This cross-border energy relationship is likely to become even more interdependent in the future with the growing need for new generation, transmission lines, and natural gas supply pipelines. The growing demand for energy in the border region also is adding to already significant air quality problems, and fundamental differences in the regulatory approaches on both sides of the border are hindering resolution of these environmental concerns.

The Energy Commission strongly supports the following border energy recommendation:

- The Energy Commission believes the state should work to establish a cross-border, binational policy to coordinate energy planning and development and address environmental concerns in the border region.

Conclusions

The health of California's economy depends upon reliable, affordable, adequate, and environmentally sound supplies of energy. The rising cost of energy hurts consumers who must spend a greater percentage of their income on energy and businesses who see their profits shrink as their energy costs rise. California's dependence on natural gas and petroleum fuels also continues to increase, making the state vulnerable to supply disruptions and painful price spikes.

Implementation of the recommendations in the *2005 Energy Report* will increase California's energy supplies, reduce energy demand, broaden the range of alternatives to conventional energy sources, and improve the state's energy delivery infrastructure. Many of these recommendations were made earlier in both the *2003 Energy Report* and the *2004 Energy Report Update*. While the state has made progress in implementing many of the recommendations from past *Energy Reports*, there is much more to be done. It is time for California to urgently address the many challenges facing the state's energy systems to safeguard its economy and its environment.

Chapter One: Introduction

This 2005 Integrated Energy Policy Report (Energy Report) was prepared in response to SB 1389 (Bowen), Chapter 568, Statutes of 2002, which requires that the California Energy Commission (Energy Commission) prepare a biennial integrated energy policy report. This report contains an integrated assessment of major energy trends and issues facing California's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety.

This report was developed under the direction of the Energy Commission's 2004-2005 *Integrated Energy Policy Report* Committee (Committee). There are two companion reports to the *2005 Energy Report*. The *2005 Strategic Transmission Plan* was developed in response to Public Resources Code requirements to prepare a strategic transmission investment plan to be included in the *Energy Report* adopted on November 1, 2005. The plan identifies recommended near-term transmission projects, including the criteria used to select those projects, as well as a description of the benefits they provide.

The *2005 CPUC Transmittal Report* identifies the likely range of statewide and utility-specific electricity need, issues relevant to this need, and responses to participant comments. The report also identifies the transmission projects necessary for investor-owned utilities to effectively conduct resource procurement and policy recommendations to the California Public Utilities Commission (CPUC) for addressing investor-owned utility transmission and resource needs.

SB 1389 also requires the Energy Commission to include in the *Energy Report* an assessment of the environmental performance of electric generation facilities in the state.

The *2005 Energy Report* contains recommendations to further the goals of the state's *Energy Action Plan*, developed in 2003 by the Energy Commission, the CPUC, and the California Consumer Power and Conservation Financing Authority. The *Energy Action Plan* contains joint goals for California's energy future and commits to achieving these goals through specific actions. The plan was intended to be a "living document" that would change with time, experience, and need, with the overarching goal of ensuring that California's energy supplies are adequate, affordable, technologically advanced, and environmentally sound.

The *2003 Energy Report* called on state government to reduce demand, secure additional energy supplies, give consumers more energy choices, and make needed infrastructure improvements to protect California from future supply disruptions and high prices. In 2004, the Energy Commission submitted an update to the Governor and the Legislature that reiterated the need for upgrading California's energy infrastructure. The update, the *2004 Integrated Energy Policy Report Update* (*2004 Energy Report Update*), provided additional analyses and recommendations on reliability, transmission planning, and renewable energy development, as well as a summary of the state's progress toward the 2003 recommendations.

The state has made some limited progress toward the goals in the *2003 Energy Report* and the *2004 Energy Report Update*, primarily in utility efficiency programs and natural gas infrastructure. Much remains to be done. The *2005 Energy Report* focuses on understanding the opportunities and obstacles faced in implementing strategies and accelerating progress along the path identified in the two previous years' reports.

Report Preparation Process

In late 2004, the Committee released its scoping order identifying key issues to be addressed in the *2005 Energy Report*. The scoping order was followed by 53 Committee workshops held from the fall of 2004 through the summer of 2005 to seek public input on the various key issues. A focus of these workshops was a series of staff white papers that discussed major energy issues in California and identified potential policy options to address those issues.

Throughout the workshops and development of the staff white papers, stakeholder participation was

extensive. The Energy Commission staff worked with key federal, state, and local agencies in preparing the white papers, involving more than 600 public and private stakeholders (see Appendix B). The white papers and stakeholder comments submitted for the record comprise more than 30,000 pages of material.

The Committee prepared its draft report and policy recommendations based on this extensive record. The draft report was the subject of five Committee hearings during September and October 2005 to receive public input. This final report incorporates information received at those hearings and in writing from participants and was adopted by the Energy Commission at its November 21, 2005, business meeting.

Chapter Two: Transportation Fuels

Roughly half of the energy Californians consume is for transportation. To meet that demand, the state relies almost exclusively on petroleum. This singular dependence on petroleum has set the stage for the extreme volatility in retail gasoline and diesel fuel prices that California is experiencing. It also has established the need for aggressive action by the state to safeguard consumers against more severe supply disruptions.

Sustaining California's economic vitality in the near term depends on ample supplies of gasoline and diesel fuels at reasonable prices. However, the state's refineries are no longer able to meet current and future petroleum demand in California and the region. California must increasingly rely on imports, for which there is limited storage capacity, and must also increase marine terminal capabilities at Southern California ports.

California's petroleum infrastructure operates at near capacity. Breakdowns and outages at in-state refinery and pipeline facilities quickly tighten gasoline and diesel fuel supplies and create price spikes. Since California is not directly connected by pipeline to other domestic refining centers, in-state refiners cannot readily procure gasoline, diesel, and other blending components when outages do occur. This contributes to higher and more prolonged price spikes.

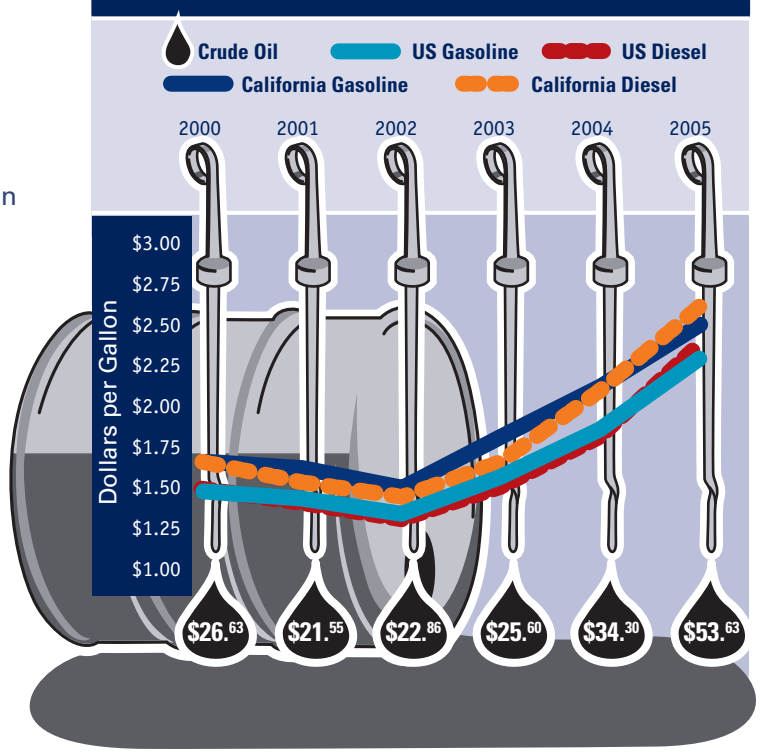
Difficulties with petroleum infrastructure in neighboring states also affect fuel supplies and prices in California. For example, the combination of unplanned refinery outages and pipeline maintenance in Washington in early 2005 tightened supplies of diesel fuel for both Washington and Oregon for more than 45 days, requiring additional deliveries of diesel from California and raising prices in this state.

World oil prices have nearly tripled in the last three years. Since crude oil is a global commodity, worldwide supply and demand dictate its price. Skyrocketing demand in China and other developing countries, coupled with political and social upheaval in key oil supply nations, is further taxing the international supply/demand equation.

Hurricanes Katrina and Rita caused the interruption of oil production and transport in the Gulf Coast and contributed to subsequent $70 per barrel oil prices, highlighting the dangerous reliance upon a single source of fuel.

Crude oil[1] is the single largest cost component in the production of transportation fuels, accounting for between 42 and 56 percent of the price of regular gasoline in the last year. In early September, the average retail price for regular grade gasoline and diesel fuel reached record highs of $3.05 and $3.39 per gallon, respectively.

Figure 1: **Gasoline, Diesel, and Crude Oil Prices**



Source: California Energy Commission.

1. California Energy Commission [http://www.energy.ca.gov/gasoline/margins/index.html], accessed August 18, 2005.

California's high gasoline prices are taking a toll on the state's economy. California consumers are spending more of their household income on gasoline than ever before. High fuel prices also reduce profit margins for the manufacturing and industrial sectors, which pass the higher cost of their goods and services to consumers. Californians are therefore not only paying higher prices for the gasoline they need, they are using the rest of their disposable incomes to pay higher prices for other products. Since September of 2004, the monthly average price of gasoline has increased by more than 35 cents per gallon, costing consumers an additional $6.1 billion for gasoline, a staggering blow for both consumers and California's rebounding economy.

In the meantime, demand for gasoline and diesel fuels is increasing despite record-high prices, and little has changed on the supply side since 2003. The industry is building some new storage facilities, and several smaller refineries are expanding their production capacities. These improvements, however, are not sufficient to address the problem of the rapidly widening gap between demand for petroleum and its supply.

Clearly, California needs a decisive policy to reduce its dependence on petroleum fuels and a broad collaborative framework to introduce more non-petroleum options into the market.

Building a Vision for the Future

In 2003, the Energy Commission and the California Air Resources Board (ARB) jointly adopted a strategy to reduce California's dependence on petroleum.[2] The two agencies demonstrated that it is feasible to reduce the on-road use of gasoline and diesel fuel to 15 percent below 2003 levels by 2020, based on technology and fuel options that are achievable and cost-beneficial. The two agencies recommended that the state pursue the strategy by influencing the federal government to double the fuel economy of new vehicles and increase the use of non-petroleum fuels to 20 percent of on-road fuel demand by 2020. The Energy Commission incorporated the findings of the joint report into the *2003 Energy Report* and recommended that the Governor and Legislature adopt the goals and strategy as state policy.

The Energy Commission and ARB showed that the combined corporate average fuel economy (CAFE) standards for new passenger cars and light trucks can be doubled in a cost-effective manner and without sacrificing safety or consumer choice. However, little has been done at the federal level, where responsibility for setting fuel economy standards rests. Congress chose to ignore this issue in the federal *Energy Act of 2005* (*Act*), and the Bush Administration's recent proposal to increase fuel economy standards for some light trucks will do little to blunt growing national petroleum demand.

Meanwhile, ARB adopted landmark regulations in 2004 limiting greenhouse gas emissions from new vehicles sold in California, beginning in model year 2009. New vehicles fully complying with this regulation will consume nearly 30 percent less fuel than vehicles built before 2009. Even this improvement, however, does not do enough to attain the level of fuel economy that the Energy Commission and ARB determined in 2003 is both "… achievable and cost-beneficial."

In his response to the *2003 Energy Report* and the *2004 Energy Report Update,* Governor Schwarzenegger called for California to continue its efforts to increase CAFE standards through a coalition of states and stakeholders. He also directed the Energy Commission to take the lead in crafting a workable long-term plan by March 31, 2006, to increase the use of alternative fuels.[3] Recent legislation also

2. *Reducing California's Petroleum Dependence*, California Energy Commission and California Air Resources Board, joint agency report, August 2003.

3. Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: *Review of Major Integrated Energy Policy Report Recommendations*, August 23, 2005.

requires the Energy Commission, in partnership with the ARB and in consultation with the State Water Resources Control Board, Department of Food and Agriculture, and other relevant agencies, to develop and adopt a state plan by June 30, 2007, that will increase the use of alternative transportation fuels.[4]

The Energy Commission clearly recognizes the continuing role that petroleum will play in meeting the state's transportation needs. The Energy Commission also recognizes that the industry will need to permit and construct a certain amount of new infrastructure to import, store, and distribute these fuels. To this end, the state should work with the industry and local governments to ensure these infrastructure improvements are implemented.

The Energy Commission believes strongly that California is at an important crossroads. First, the worldwide demand for petroleum is becoming a significant problem. Second, no matter how clean petroleum fuels are with respect to criteria pollutants, their use produces significant carbon dioxide emissions, the primary greenhouse gas. Petroleum fuels account for nearly half of all greenhouse gas emissions in California, and reducing their use is a cornerstone of the Governor's energy and climate change policies.

Both the Energy Commission and the petroleum industry recognize that non-petroleum fuels are becoming viable and necessary alternatives to gasoline and diesel fuels. The petroleum industry believes "that meeting the state's energy needs over the next several decades will require the balanced use of several elements. They include supporting a strong base of petroleum supply; growing the base of alternative and renewable fuels; and a prudent reduction in the rate of growth of energy demand through conservation and efficiency."[5]

On this last point, the Energy Commission is encouraged that the petroleum industry is not opposed to the Governor's recommendation to double the federal CAFE standards. Given the growing gap between in-state refining capacity and demand for transportation fuels and increasing concerns about global warming, the Energy Commission intends to accelerate the transition to an efficient, multi-fuel transportation market to serve the future needs of its citizens. It does not intend to arbitrarily restrict the petroleum industry's enterprise or to write off the state's leading source of transportation energy, which is petroleum. With its broad fuels expertise and extensive infrastructure, the petroleum industry is a critically important partner in this transition.

The Governor's *California Hydrogen Highway Network*, announced in April 2004, may eventually move the state to a hydrogen transportation fuel economy. The Energy Commission believes the alternative transportation fuel plan called for in AB 1007 must bridge the gap between today's technologies and the transition to hydrogen fuels and vehicles.

Consumption of non-petroleum fuels in California is currently stagnant at about 6 percent. The state must encourage the emerging non-petroleum fuel industry as suppliers of components for blended fuels and as developers of completely non-petroleum fuels and fueling systems. And, certainly, the state must establish a stronger relationship with the providers of the raw material needed for renewable fuels — California's agriculture, dairy, forest, and municipal sectors. This grand coalition is necessary to forge a new transportation sector that can make a significant contribution to meeting air quality, climate change, and energy security objectives.

Even more urgently than two years ago, California must pursue a diverse portfolio of fuels and advanced transportation technologies that address both current supply and demand problems and

4. AB 1007 (Pavley), Chapter 371, Statutes of 2005.

5. Testimony of Joseph Sparano, Western States Petroleum Association, transcript of the September 29, 2005 *Energy Report* hearing on *Transportation Fuels*, p. 39.

build a sustainable foundation for the future. The health of California's future economy depends upon it.

Recommendations

- The state should develop flexible overarching strategies that simultaneously reduce petroleum fuel use, increase fuel diversity and security, and reduce emissions of air pollution and greenhouse gases. The state's energy, environmental, and transportation agencies should integrate these strategies into their respective programs.
- The state should implement a public goods charge to establish a secure, long-term source of funding for a broad transportation program. Achieving the goals set out in this report and established by the Governor requires a comprehensive transportation program that provides funding for infrastructure investment, a broad range of technology and fuels research, analytical support, and incentive programs.

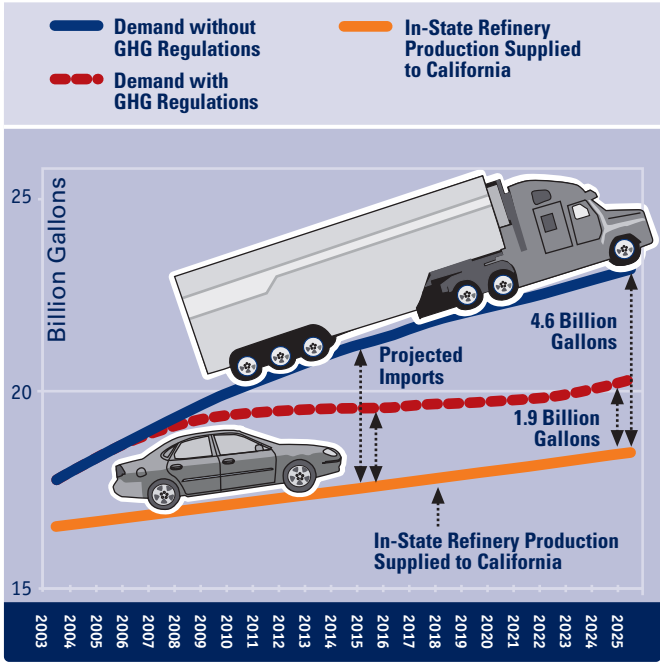
Demand for Gasoline and Diesel Fuel

In 2004, Californians consumed about 15.4 billion gallons of gasoline and 2.8 billion gallons of diesel fuel,[6] an increase of nearly 50 percent over the last 20 years. This demand continues, even in the face of record petroleum prices, for several reasons:

- Population growth and more on-road vehicles.
- Low per-mile cost of gasoline for the past two decades.
- Lack of alternatives to conventional gasoline and diesel fuels.
- Consumer preference for larger, less fuel-efficient vehicles.
- Land use planning that places jobs and housing farther apart without transportation integration.
- Lack of mass transit.

The Energy Commission projected on-road demand for gasoline and diesel fuels with and without the effects of ARB's greenhouse gas regulations. (See Figure 2.) If the state takes no further action to reduce petroleum use and current greenhouse gas regulations remain in place, demand for gasoline in California will increase to nearly 15.6 billion gallons per year by 2025. Without the regulations, demand is projected to grow to 18.2 billion gallons per year.

Figure 2: **Projected Gasoline and Diesel Demand**



Source: California Energy Commission.

6. *Forecasts of California Transportation Energy Demand 2005-2025*, CEC-600-2005-008, California Energy Commission staff report, April 2005.

Whether the greenhouse gas regulations remain in place or not will have little effect on the demand for diesel fuel, which is projected to grow to 4.9 billion gallons per year by 2025.[7] This forecast is lower than projected in the *2003 Energy Report* because of higher fuel prices and lower estimates of population growth, but it still represents a substantial increase over current levels.

The Energy Commission also forecasts demand for non-petroleum fuels, specifically electricity and natural gas. The results show that usage on a percentage basis will nearly triple by 2025, but the actual petroleum displacement will remain quite low. In the transportation sector, the annual demand for electricity, primarily for transit, is expected to grow from 590 to 1,800 million kilowatt-hours (kWh) between 2002 and 2025. During the same period, the staff projects demand for natural gas in vehicles will increase from 75 to 200 million therms per year. Still, the projected increases for 2025 are only about 1 percent of total future electricity and natural gas demand.

The Energy Commission's forecast covers only on-road, in-state demand and does not include non-road demand or demand for gasoline and diesel in neighboring states and Mexico. This is a critical shortcoming since California is the center of a regional petroleum market. California refineries provide Nevada with almost 100 percent of its transportation fuel needs, Arizona with over 60 percent of its needs, and Oregon with 35 percent of its needs. Baja California Norte also relies on California for a portion of its fuel needs, although no data is available as to the quantity.

Fuel demand in Arizona and Nevada is growing at an even higher rate than in California. This demand growth will more tightly squeeze California's refineries over the next several years. If growth in the Arizona and Nevada markets averages 3 percent per year over the next 10 years, pipeline exports of transportation fuels to these neighboring states could increase by nearly 1.8 billion gallons per year by 2015. Increased demand for transportation fuels in these out-of-state markets further taxes California's transportation fuel infrastructure.

Recommendation

- The Energy Commission must develop the capability to forecast non-road and out-of-state demand for transportation energy. These sectors may offer substantial petroleum and emission reduction opportunities and could materially affect the operation of California refineries and other petroleum infrastructure.

Diversifying California's Fuel Supply

In 2003, the Energy Commission concluded that increasing federal fuel economy standards would be the most effective measure to reduce gasoline consumption, but would also be the most difficult to achieve. Given inaction by both Congress and the Bush Administration to materially increase CAFE standards, the state must now redouble its efforts on actions it can take to directly affect petroleum consumption. The first step in this policy redirection is to increase emphasis on diversifying the transportation fuel market.

AB 1007 recognizes the important relationships among transportation fuel use, air quality, and the continuing need for research and development. The state plan called for in AB 1007 provides a comprehensive framework to examine broad transportation fuel issues and effectively integrate transportation energy and air quality policies. The bill requires that:

- The plan shall include an evaluation of alternative fuels on a full fuel-cycle assessment of emissions of criteria air pollutants, air toxics, greenhouse gases, water pollutants, and other substances that are known to damage human health, impacts on petroleum consumption, and other matters the state board deems necessary.

7. Ibid.

- The plan shall set goals for the years 2012, 2017, and 2022 for increased alternative fuel use in the state that accomplishes all of the following:
  - Optimizes the environmental and public health benefits of alternative fuels, including, but not limited to, reductions in criteria air pollutants, greenhouse gases, and water pollutants consistent with existing or future state board regulations in the most cost-effective manner possible.
  - Ensures that there is no net material increase in air pollution, water pollution, or any other substances that are known to damage human health.

Several workshop participants indicated during the *2005 Energy Report* workshops on transportation that while non-petroleum fuels can, in many cases, significantly reduce emissions for most criteria pollutants and toxic air contaminants, some do increase NOx emissions. The participants suggested that the state consider a health-risk approach that quantifies the total net emissions benefits of all criteria pollutants and toxic air contaminants to accelerate adoption of non-petroleum fuels without backsliding on air quality or public health, similar to concerns addressed in AB 1007.

Recently, the ARB approved emergency regulations to accelerate the onset of winter fuel specifications for California's refiners in an effort to increase the supply of gasoline in the wake of Hurricane Katrina. The ARB recognized this could potentially increase emissions of volatile organic compounds by 50 to 75 tons per day.[8] While supportive of this emergency action, the Energy Commission is also quite concerned that until the state takes concerted action to diverge from its growing reliance on petroleum-based fuels, California will face this prospect more frequently, and the ability to maintain California's particular set of gasoline and diesel requirements will erode. The Energy Commission also acknowledges that the state should proceed cautiously with a health-based assessment of non-petroleum fuels. But time is of the essence, and an examination of the merits of this approach should be part of the process of preparing the state alternative fuels plan.

In preparing the plan, the state should pursue all reasonable non-petroleum fuel and technology options. High priority should be given to fuel blends (for example, non-petroleum fuels blended with gasoline and diesel) that can be used in existing gasoline and diesel engines without modification (or with technology additions to existing engine systems which are achievable in the near-term) without voiding manufacturer warranties and that can be dispensed through the existing fueling infrastructure. Renewable fuel blends should be of particular importance given the potential to produce these fuels from in-state resources. Initially, renewable resources could likely come from outside California with value-added processes occurring in state to produce the fuels. Both scenarios would provide economic value to California.

Other fuel options, such as natural gas, require a separate fueling infrastructure and have been well suited to fleet or central fueling applications. Given the substantial greenhouse gas reduction and diversity benefits, the state should vigorously pursue these opportunities where they are cost effective. Still other options, such as E-diesel, require additional research and development or testing and verification. The state should provide all appropriate support for these pursuits.

The Energy Commission has examined a portfolio of non-petroleum fuel and technology options. None represent a panacea. Each has costs and performance characteristics that will define its most effective application in California's expansive

8. ARB, Hearing Officers Report, (Public Hearings to Consider an Emergency Regulatory Amendment Relaxing the Reid Vapor Pressure Standard for California Reformulated Gasoline in September and October 2005), September 8, 2005, p. 6 [http://www.arb.ca.gov/regact/rvp2005/hor.pdf].

transportation energy market. Each was examined from economic, environmental, and consumer perspectives. The results are presented in Table 1. The purpose of these results is not to define "winners" (with positive direct net benefit) and "losers" (with negative direct net benefit). Policy makers can and do use many criteria to determine which fuel and technology options to pursue. Table 1 evaluates some of the criteria, but not all. Further, the results of Table 1 are highly dependent on a number of assumptions that vary widely for a variety of reasons. Therefore, Table 1 is appropriately viewed as a policy guidance tool and not as a conclusion.

Ethanol

Ethanol is blended with gasoline to make transportation fuels. The two most common blends in California are E-5.7 (5.7 percent ethanol and 94.3 percent gasoline) and E-85 (85 percent ethanol and 15 percent gasoline).

Ethanol has been used in California primarily to comply with the now-rescinded federal requirement for minimum 2 percent oxygen content in gasoline.

Table 1: **Analysis Of Petroleum Reduction Options**

Alternative Fuel Option Scenario	Displacement in 2025, billion gallons gasoline equivalent	Percent Reduction from Base Case Demand[c], percent	Highest Cumulative Benefit or Change,[b] Present Value, 2005-2025, 5% Discount Rate, with Greenhouse Gas Standards, Billion $2005			
			A	C	D	A+C+D
			Direct Non-Environmental Net Benefit	Direct Environmental Net Benefit[f]	External Cost of Petroleum Dependency	Direct Net Benefit[g]
Electric Battery Technologies (NEV and CEV)	0.10	0.48	1.11	0.07	0.04	1.22
Grid-Connected Hybrid Electric Vehicles (HEV20)	0.53	2.56	0.62	0.32	0.19	1.13
Grid-Connected Hybrid Electric Vehicles (HEV60)	0.71	3.42	(1.29)	0.47	0.25	(0.58)
CNG for Light-Duty Vehicles (Honda Case)	0.02	0.10	(0.29)	0.01	0.01	(0.27)
CNG for Light-Duty Vehicles (Honda and GM Case)	0.08	0.40	(0.94)	0.02	0.05	(0.87)
Ethanol Blend (E10 reduced price case)	0.48	2.30	0.00	1.98	0.53	2.51
Ethanol Hi-Content Blend (E85)	1.61	7.73	0.00	0.20	0.42	0.62
LNG and CNG for Medium- and Heavy-Duty Vehicles (Standard Case)[d]	0.23	1.10	(0.74)	0.03	0.12	(0.59)
Gas-to-Liquid (GTL) and Coal-to-Liquid (CTL) Fuels	1.64	7.87	0.00	0.10	0.77	0.87
Renewable Diesel (20%, $1.00/gallon federal tax subsidy)	1.00	4.80	0.00	0.96	0.52	1.48
Renewable Diesel (20%, $0.30/gallon federal tax subsidy)	1.00	4.80	0.00	0.96	0.52	1.48
Heavy-Duty Hybrid Electric Vehicles (Aggressive Case)	0.05	0.24	(0.06)	0.03	0.01	(0.02)

a. This analysis is an update from the previous work (AB 2076 report) performed by the Energy Commission and ARB and adopted by the two agencies in 2003. b. Values in parentheses are negative. c. Base Case is combined on-road gasoline and diesel demand. d. This Aggressive Case employs a natural gas price from a long-term natural gas supply agreement (Clean Energy). e. Standard Case employs the Energy Commission natural gas price forecast. f. In scenarios where the net benefit value is negative, consumers experience greater costs than for the business-as-usual choice; thus, the assumed penetration rate and resultant displacement are not likely to occur unless an additional consumer benefit or motivation is provided to offset the negative value. g. This value is revenue neutral as it does not reflect the impact of the option on government revenue (program expenditures or fuel excise tax increases or decreases, for example).

State and federal regulations allow refiners to blend up to 10 percent ethanol for this purpose. However, most refiners have chosen to produce gasoline with ethanol content of 5.7 percent, the minimum needed to meet the federal 2 percent oxygen requirement. Blending gasoline with higher levels of ethanol produces emission increases that must be offset by other fuel property changes. Depending on the refinery and the market for ethanol and other blending components, these changes can add cost to producing gasoline. Also, gasolines with differing ethanol content cannot be co-mingled and must be stored and distributed separately under current regulations. As a result, nearly all gasoline sold in California has been blended with a standard ethanol content of 5.7 percent.[9]

Although the *Act* repealed the requirement for minimum oxygen content for gasoline, it has imposed a new renewable fuel requirement beginning in 2006. The new provision does not specify a renewable content for gasoline. Instead, it requires refiners nationwide to use increasing amounts of ethanol up to a maximum of 7.5 billion gallons by 2012, nearly double the amount used today. A rulemaking is underway at the U.S. Environmental Protection Agency (U.S. EPA) that will prescribe the market share of ethanol each refiner will be required to use. The *Act* also will allow refiners using more ethanol than their market share to accrue credits that they can sell to refiners using less than their market share. California refiners likely will continue to use significant amounts of ethanol in the near term, but will now have the flexibility to produce non-oxygenated gasoline as well.[10] Until the federal rulemaking is complete, the impact of the renewable fuel requirement on California will not be known.

Since state and federal regulations allow up to 10 percent ethanol in gasoline, the question that policy makers need to ask is whether refiners can cost-effectively blend greater amounts of ethanol in gasoline sold in California without backsliding on air quality. The answer is not straightforward and requires better understanding of several important issues.

ARB is in the process of updating its predictive model. The model is used to ensure that all gasoline sold in California has acceptable emission levels. ARB last updated the model in 1999. A major benefit of the current version is that it provides flexibility by allowing refiners to offset emission increases related to one gasoline specification with decreases in another. A shortcoming is that it does not accurately represent the vehicle fleet on the roads today because it relies on a limited sample of newer vehicles and does not adequately consider emissions from newer technologies or varied meteorological conditions. Recent studies show that newer vehicles are operating below respective certification levels for hydrocarbon, CO, and NOx.[11]

Equally important, the current predictive model does not consider the impact that ethanol has on permeation — evaporative emissions that result from the migration of liquid fuel components through the soft portion of motor vehicle fuel systems. Gasoline containing ethanol has been shown to increase permeation emissions relative to gasoline without ethanol. Due to the effectiveness

9. At least two refiners have produced gasoline with an ethanol content as high as 7.7 percent by volume and one as high as 10 percent. These refiners use proprietary storage and distribution systems to avoid co-mingling issues.

10. It is unlikely that refiners will produce and market non-ethanol gasoline because of minimum octane requirements; investments to date by refiners, terminal operators, independents, gasoline wholesalers, California's common carrier pipeline operator, and the railroads; long-term contracts for ethanol delivery by the railroads to refiners; and lack of segregated storage and pipeline facilities.

11. *A Summary of the Study of Extremely Low Emitting Vehicles Operating on the Road in California*, presentation by Joseph M. Norbeck, University of California, Riverside, transcript of the July 8, 2005 *Energy Report* workshop on *Air Quality and Opportunities to Expand Use of Alternative Transportation Fuels*, pp. 51-71.

of evaporative emission regulations in newer vehicles,[12] permeation impacts are greatest in pre-2000 vehicles and will diminish as these vehicles are retired. However, relying on fleet turnover is not an expeditious strategy. The merits of other forms of mitigation and offsets should be examined in the state plan.

ARB is updating the predictive model to reflect the vehicle fleet anticipated in 2010 and more recent NOx and permeation data. The ARB expects to approve the updated model in late 2005 or early 2006.

While gasoline blends up to E-10 are widely used in conventional automobiles, E-85 can be used only in specially designed vehicles known as fuel flexible vehicles (FFV). FFVs are designed to operate on any ethanol blend of gasoline up to 100 percent. FFVs also significantly reduce permeation emissions.

Automakers receive federal fuel economy credits for every vehicle sold, even in California where the E-85 fuel is largely unavailable. The federal *Act* extended the CAFE alternative fuel credit, which provides incentive for automakers to continue and even increase production of FFVs and provides incentives to install E-85 fueling stations. More than 250,000 FFVs operate in California, a number that is growing at a rate of 45,000 to 50,000 each year.[13] These vehicles represent a sizeable sales base for E-85. But with only three E-85 fueling stations in the entire state, FFVs in California operate almost exclusively on gasoline. The cost differential between producing an FFV and a conventional gasoline vehicle is minimal. In fact, many FFV owners are not even aware that they have a vehicle with fuel options.

ARB's clean fuels outlet's "trigger" offers a possible solution to this dilemma: major gasoline suppliers, as defined by the regulations, must equip an appropriate number of fueling stations to dispense clean fuels whenever automobile dealers expect to sell 20,000 clean alternative fuel vehicles in the state. The ARB executive officer has the discretion to identify the number of outlets that must be established. The regulation requires that the alternative fuel vehicles be cleaner than the comparable gasoline models with respect to criteria pollutant emissions. Consequently, with reformulated gasoline and cleaner vehicle technology, achieving the emissions differential required to "pull the trigger" has proven to be problematic.

Increasing the amount of ethanol in gasoline will result in a loss of fuel economy and require motorists to purchase more gasoline. For example, E-85 contains almost 30 percent less energy than gasoline, and retail prices should be set to reflect this disparity. In this way, retailers can offer E-85 at a gasoline equivalent value and build consumption volume in the early years of its introduction to better assure its sustainability over the long term.

About 90 percent of the ethanol used in gasoline arrives by train from the Midwest and is produced from corn. The remaining 10 percent comes by ship from Caribbean Basin Initiative countries and Brazil, where it is produced from sugar cane. California produces very little ethanol. Current production is approximately 40 million gallons per year. Several projects being permitted or under construction will boost the annual volume to over 120 million gallons within the next two years.

California has as-yet untapped potential to produce ethanol from cellulosic biomass material such as municipal, agricultural, and forestry wastes. Gasoline blended with ethanol produced from cellulosic

12. Testimony of Kevin Cullen, General Motors, transcript of the September 29, 2005 *Energy Report* hearing on *Transportation Fuels*, p. 109.

13. California Energy Commission's Joint Agency Department of Motor Vehicles Data Project, in cooperation with the Department of Motor Vehicles.

biomass material provides a three-fold decrease in greenhouse gas emissions compared with gasoline blended with corn-based ethanol. In-state production of ethanol from biomass would also be an economic boon for California. In the past, the technology has not been seen as economical and has not been demonstrated on a commercial scale. This may soon change. Iogen Corporation is operating what may be the world's first cellulosic ethanol demonstration plant near Ottawa, Canada. The demonstration plant produces 260,000 gallons of ethanol per year from straw. Iogen may soon announce plans for the first commercial-scale plant with a capacity to produce up to 50 million gallons per year.

In the Governor's response to the *2003 Energy Report* and *2004 Energy Report Update*, he specifically called on the Bio-Energy Interagency Working Group, led by the Energy Commission and composed of state agencies with important biomass responsibilities, to develop an integrated and comprehensive state policy on biomass. This policy should include electricity, natural gas, and petroleum substitution potential.

Biodiesel

In 2004, California fleets used about 4 million gallons of biodiesel.[14] Forty-two commercial plants in the U.S. produce biodiesel fuel from vegetable oil, animal fat, and used cooking oil. Biodiesel fuel can also be made from several different technologies collectively known as thermal conversion processes (TCP) that use a broad range of feedstock, including animal waste, animal carcasses, wood wastes, agricultural waste, plastics, tires, sewage sludge, and other waste containing hydrocarbons, fats, carbohydrates, or protein. Several TCP demonstration plants are operating in the U.S. and Europe.

Biodiesel blends as low B-2 (2 percent biodiesel and 98 percent conventional diesel) can play an important role in the introduction of cleaner conventional diesel fuels and advanced diesel engines. Ultra-low sulfur diesel fuel regulations become effective beginning in 2006, placing sulfur limits on all conventional diesel fuel sold in the United States at just 15 parts per million (ppm). Clean diesel engines entering the market between 2007 and 2010 will need ultra-low sulfur diesel fuel to meet their emissions targets. Ultra-low sulfur diesel has poor lubricity and requires additives. At concentrations of just 2 percent, biodiesel fuel can provide adequate lubricity for ultra-low sulfur diesel fuels. Today almost all vehicle and engine manufacturers accept using up to B-5 (5 percent biodiesel and 95 percent conventional diesel) with existing diesel engines, provided that the fuel complies with American Society for Testing and Materials (ASTM) specifications.

Biodiesel blends at higher concentrations are compatible with most diesel engines and fueling system components. B-20 (20 percent biodiesel and 80 percent conventional diesel) qualifies as an alternative fuel under requirements of the federal *Act*. However, only one vehicle or engine manufacturer currently recommends the use of biodiesel blends greater than B-5. Biodiesel blends up to B-20 can be legally sold in California as long as they meet ARB's aromatic and sulfur requirements and Department of Food and Agriculture specifications.

Currently, ARB does not have a fuel specification for biodiesel as an alternative fuel. Furthermore, a regulatory conflict has existed for certain fleets (including the military) in California that on the one hand must comply with ARB's diesel retrofit requirements, but on the other hand must use B-20 fuel to comply with federal fleet procurement requirements. Until recently, ARB has not allowed the use of biodiesel fuel in the diesel retrofit

14. Randall van Wedel, National Biodiesel Board, testimony at committee workshop on *Proposed Transportation Energy Efficiency and Alternative Fuels Analyses*, California Energy Commission, Sacramento, California, December 20, 2004.

program due to questions of compatibility with particulate traps. A new law,[15] however, states that:

Any federal, state, or local agency, or any regulated utility, or any owner or operator of a solid waste collection vehicle or collection vehicle (as defined in Section 2021 of Title 13 of the California Code of Regulations) may utilize a biodiesel blend fuel consisting of not more than 20 percent biodiesel in any retrofitted vehicular or off-road diesel engine certified by the state board, whether or not biodiesel is expressly identified as a fuel for use with the retrofit system.

Since this law sunsets in 2008, it offers only a temporary remedy. The state must still address the issue of compatibility on a permanent basis. In August 2005, ARB approved the use of B-20 with one manufacturer's particulate trap. However, no particulate matter or toxicity reduction credit is applied for the biodiesel portion used.

E-Diesel

Ethanol in diesel has been under active development with many demonstration and evaluation activities initiated in the late 1990s, and laboratory research before then. While both on-road and off-road applications have been explored, ethanol in diesel for general on-highway use in passenger cars and light-duty trucks appears unlikely for the foreseeable future. Automakers view this fuel as experimental and its use in passenger vehicles problematic due to fuel vapor flammability and related safety issues.

On the other hand, centrally fueled fleet applications are the logical place for this fuel, such as medium- and heavy-duty fleets and off-road equipment. In this environment fleet owners can undertake vehicle modifications, implementation of safety measures, training of personnel, and upgrading of supply tanks and associated equipment without the complexities (and costs) associated with dispersed use of the fuel in the larger petroleum infrastructure.

Since ethanol in diesel blends does not have an ASTM specification, it is not considered a commercial fuel by California's fuel quality regulating agency. Nevertheless, several fleets are operating under "developmental engine fuel" status, a designation provided by the Division of Measurements and Standards of the California Department of Food and Agriculture that permits use of the developmental fuel for a limited time in designated fleets.

Long Beach Container Terminal, Inc. is using E-diesel to operate 60 pieces of heavy equipment to move ship containers at the Port of Long Beach. Its annual consumption will be about 600,000 gallons. Other fleets using the same fuel are located in Tulare, Fresno, and the Los Angeles area and include refuse truck, transit, road maintenance, and construction activities.

Gas-to-Liquid

Gas-to-liquid (GTL) is a synthetic diesel-like fuel that can be used in both conventional diesel engines and fueling systems. GTL fuel is made with a process that converts hydrocarbon gas to a liquid fuel (generally referred to as the "Fischer-Tropsch reaction"). GTL fuel is currently produced from natural gas and coal feedstocks. Most new GTL plants planned and under construction will use natural gas. Other feedstocks, including petroleum coke and biomass, can also be used, but the technology has not been seen as commercially mature and is more costly. However, there is increasing interest in these technologies. For example, Rentech Inc. has announced that next year it will break ground on a

15. SB 975 (Ashburn), Chapter 365, Statutes of 2005.

plant in Wyoming that will produce 33,000 barrels per day of diesel fuel made from coal.

In neat form, GTL fuel is more expensive than conventional diesel fuel. But its superior fuel and emissions properties make GTL fuel ideal for blending with conventional diesel fuel. Tests in Europe show that GTL fuel blends between 30 and 50 percent substantially reduce emissions at comparable cost to conventional European diesel fuel. For California, the Energy Commission and ARB found that blending 33 percent GTL fuel with 67 percent conventional U.S. EPA diesel fuel produces a cost-competitive diesel fuel that can be used in existing engines and that complies with ARB's strict diesel fuel specifications.

California refineries have occasionally used GTL fuel as a blending component. Expanding its use as a diesel fuel option requires addressing the feasibility of importing large quantities into California. Natural gas feedstock costs are generally more favorable overseas, so few if any GTL production plants are planned in the United States, and significant expansions are underway overseas. As an imported product, GTL fuel would face the same import facility constraints at the ports of Long Beach and Los Angeles now faced by imported crude and refined products. Also, the federal government has approved GTL as an alternative fuel only if it is produced domestically.

Electricity

The use of electricity as a transportation fuel, as a replacement for gasoline or diesel, produces very large reductions in emissions due to California's clean and diverse mix of generation resources, as well as the inherent energy efficiency of electric drivetrains. For example, ARB has estimated that electric vehicles produce only about 6 percent of the air pollution of the cleanest new internal combustion cars available today, Advanced Technology PZEV hybrids.[16]

In 2002, approximately 300,000 units of electric transportation and goods movement equipment operated in California.[17] Industrial vehicles such as forklifts, industrial tugs, tow tractors, industrial sweepers and scrubbers, and burden and personnel carriers comprise most of this equipment. The category also includes neighborhood electric vehicles, electric-standby truck refrigeration units, and golf carts. All of this equipment has gasoline or diesel counterparts, so the choice of electric equipment displaces petroleum use and reduces emissions of criteria pollutants and greenhouse gases.

The number of electric transportation and goods movement technologies is expected to triple by 2020 to between 900,000 and 1 million units. This growth is due not only to natural market growth, but also to known regulatory requirements and financial incentive programs that encourage the use of electric technologies because of their inherent emissions benefits.

Recent legislation requires ARB to revise the Carl Moyer Memorial Air Quality Standards Attainment Program (Carl Moyer Program) to incorporate projects in which an applicant "scraps" internal combustion engine-driven non-road equipment and purchases new zero-emission non-road equipment.[18]

In 1990, ARB adopted low-emission vehicle standards requiring automobile manufacturers to offer a minimum percentage of zero-emission vehicles (ZEV). It was thought that battery-operated

16. 2000 ZEV Program Biennial Review, California Air Resources Board staff, August 7, 2000.

17. TIAX update to *2002 Arthur D. Little Electric Vehicle Market Assessment*, letter to the California Electric Transportation Coalition, TIAX, LLC, June 30, 2005.

18. SB 467(Lowenthal), Chapter 209, Statutes of 2005.

electric vehicles would satisfy ZEV requirements, but the ZEV market did not develop as expected. The main barrier has been the slow pace of battery technology development. Persistent problems include limited range, slow charging time, low energy density, and high replacement costs. Recent advancements in lithium-ion battery technology, however, could significantly improve the performance of both full-electric and hybrid electric vehicles. New generation lithium-ion batteries have a much longer life, can fully recharge in a few minutes, and provide greater power density.

Low-speed neighborhood electric vehicles (NEV) and city electric vehicles (CEV) are cost-effective alternatives to gasoline vehicles for short and stop-and-go trips. Whereas gasoline vehicle efficiency and performance drop significantly at slower speeds and produce high emissions under cold-start and stop-and-go conditions, NEVs and CEVs have demonstrated great success for several years for this purpose, and their strong performance has been virtually maintenance free. NEVs and CEVs are highly maneuverable in tight conditions and produce no tailpipe emissions. Over 30,000 NEVs have been sold in the United States and Europe.

Natural Gas

Natural gas is a completely non-petroleum transportation fuel option. Natural gas is used in the form of compressed natural gas (CNG) and liquefied natural gas (LNG). Vehicles using compressed natural gas include passenger cars and light trucks, medium-duty delivery trucks, and heavy-duty vehicles such as transit buses, school buses, and street sweepers. LNG is also used in heavy-duty vehicles such as refuse haulers, local delivery trucks, and transit buses. There are 365 CNG fueling stations and 29 LNG fueling stations in California, 40 percent of which are accessible by the public. None of these fueling stations are a joint venture facility with petroleum companies.

These stations have been established over a period of several years in order to comply with federal requirements for alternative fuel vehicle procurements. It is important that the availability of the alternative fuel vehicles be maintained so that state and private sector investments in this infrastructure not become stranded due to lack of use. These station investments are important building blocks for the state's displacement of petroleum fuels, and therefore must remain viable by fueling a consistent and reliable population of vehicles.

Natural gas vehicles have captured a small but significant share of the transportation market. Based on recent data from the California Department of Motor Vehicles, more than 30,000 natural gas vehicles are currently on state roadways (5,000 heavy-duty vehicles and 25,000 light-duty vehicles). These vehicles displace 70 million to 75 million gallons of petroleum fuel per year.[19] However, because Ford Motor Company and Chrysler have stopped production of their natural gas vehicles for the U.S. market (they still produce natural gas vehicles for the European market), it is unlikely that the number of light-duty natural gas vehicles in California will significantly increase. Today only General Motors and Honda include light-duty natural gas vehicles in the 2005 model year. In a bid to boost sales of its dedicated natural gas vehicles, Honda has introduced a home-fueling system, "Phill," that is now being offered to its CNG vehicle customers. Conversely, dozens of heavy-duty natural gas vehicles are available for order but are constrained by a limited number of engine models.

Heavy-duty CNG/LNG vehicles have been more expensive to purchase and operate than

19. Mike Eaves, California Natural Gas Vehicle Coalition, *Natural Gas Vehicle Role in Fuel Diversity for California*, presented at the Non-Petroleum Fuel Working Groups Conference, California Energy Commission, Sacramento, California, October 12, 2004.

conventional diesel vehicles. At least one study, however, suggests that on a life-cycle basis, heavy-duty CNG/LNG vehicles are competitive with conventional diesel.[20] On the other hand, another source suggests that, at $52,000 per ton of NOx reduction, CNG-fueled refuse hauling trucks are not a cost-effective strategy for reducing NOx emissions.[21]

Liquefied Petroleum Gas

While the number of liquefied petroleum gas (LPG) vehicles worldwide is 8 million and rising, the number of LPG vehicles in California is paradoxically decreasing. Today only one manufacturer has an engine certified for LPG operation, which is used mainly for shuttle buses and street sweepers. Outside California, several companies offer "upfit" packages for a broad range of engines and vehicle models. However, these companies find it difficult to meet California's emissions certification requirement. Therefore, they do not offer fuel system upfitter packages for vehicles in the California market. The cessation of certified automaker/ fuel system upfitter offerings for propane vehicles limits the availability of viable alternatives to gasoline and diesel fuels.

Liquefied petroleum gas, or propane, is a domestically produced fuel that is closer to gasoline than other alternative fuels.[22] LPG carries the benefits of reduced vehicle maintenance costs, emissions, and fuel costs when compared with conventional gasoline and diesel.[23] Most propane in California is produced from natural gas wells; lesser amounts are produced during the petroleum refining process. Since it is not used in most California motor vehicles, LPG would displace gasoline and diesel fuels. Of the 1,500 LPG service stations in California, 900 are "motor vehicle-friendly" and dispense LPG to motor vehicles. LPG is also an attractive option for non-road vehicles like forklifts. There are 32,000 LPG forklifts in California, though this market faces stiff competition from gasoline and electric forklift manufacturers.

Hydrogen

In April 2004, Governor Schwarzenegger signed an Executive Order intended to jump start the use and operation of hydrogen-fueled vehicles in California. The Governor's Order called for a hydrogen highway network, a public/private partnership that will "support and catalyze a rapid transition to a clean, hydrogen transportation economy in California, thereby reducing our dependence on foreign oil, and protecting our citizens from health harms related to vehicle emissions."[24]

The Governor's *Hydrogen Highway Blueprint Plan*, which was released in May 2005, calls for a dramatic increase in the use of hydrogen-fueled vehicles and a network of hydrogen fueling stations and other infrastructure in three phases. The first phase calls for 50 to 100 fueling stations and 2,000 vehicles by 2010. It also promotes increased renewable resource use with the goal to use 20 percent renewable resources for both the energy source and feedstock used in hydrogen production by 2010. The Governor's plan places great importance on the development of "bridging technologies," which assist the development of fuel cell technologies. Electric-drive technologies are bridging technologies,

20. *Comparative Costs of 2010 Heavy-Duty Diesel and Natural Gas Technologies*, final report, TIAX LLC, July 15 2005.

21. Presentation by Sean Edgar, transcript of the September 29, *2005 Energy Report* Committee hearing on *Transportation Fuels*, p. 124.

22. [http://www.consumerenergycenter.org/transportation/afv/propane.html].

23. *Propane as a Transportation Fuel*, fact sheet [http://www.energy.ca.gov/2005publications/CEC-600-2005-015-FS/CEC-600-2005-015-FS.PDF], accessed August 8, 2005.

24. Executive Order 5-7-04, April 20, 2004 and April 20, 2004 press release.

including hybrid, plug-in hybrid, and pure electric vehicles. Several non-petroleum fuels in use now and proposed for increased roles in California's transportation fuel mix are potential hydrogen carriers (that is, fuels that contain hydrogen and could be reformed to produce hydrogen for fuel cells in the future). Many state agencies are involved in implementing the Governor's plan.

Today, hydrogen is typically produced from natural gas, using steam for reforming. This feedstock is not easily produced from domestic sources in amounts that could support the volume of hydrogen needed for transportation use. Any reduction in petroleum imports would therefore very likely be offset by a corresponding increase in natural gas imports.

Both fuel cell vehicles and, with modifications, internal combustion engines can use hydrogen. Hydrogen and natural gas blends are in demonstration use now and could provide a logical transition to hydrogen-powered vehicles.

The most promising fuel cell under development for transportation fuel use is the proton exchange membrane (PEM) fuel cell. The PEM fuel cell has high power density, operates at low temperatures, permits adjustable power output, and allows quick start-ups. Seven PEM fuel cell vehicles, using gaseous or liquid hydrogen stored in tanks on the vehicles, are in active demonstration now in California.

Fuel cell vehicles can use either direct hydrogen or on-board reformers using ethanol, methanol, or gasoline. Most available data address direct hydrogen (compressed or liquefied) use. While this report focuses on direct hydrogen technology, it is possible that fuel cell vehicles using on-board fuel reformers will eventually be introduced. This would reap the benefits of both increased fuel economy and decreased emissions while still using existing gasoline or liquid fuel infrastructure. An additional benefit of fuel cell vehicle technology is the concept of a skateboard chassis with snap-on bodies. The possibility of an extremely compact all-electronic vehicle without mechanical parts could cut the cost of its production. The benefits of this fuel cell technology will be developed during its transition into the marketplace, expected between 2010 and 2020.

Recommendations

- The state should establish a non-petroleum diesel fuel standard so that all diesel fuel sold in California contains a minimum of 5 percent non-petroleum content that would include biodiesel, ethanol, and/or gas-to-liquid components.
- The Biodiesel Working Group should prepare and submit recommendations to the Energy Commission for inclusion in the AB 1007 state plan to expand the use of B-20 fuel by:
  - Conducting comprehensive tests to verify the net emissions characteristics of biodiesel fuels in existing engines and their effectiveness when combined with particulate traps.
  - Supporting research for development of after-treatment technology and fuel additives to improve the control of NOx emissions.
  - Investigating the feasibility of requiring B-20 fuel in all state-owned diesel vehicles, partnering with other public and private fleets to create a market for biodiesel.
  - Working with engine and component manufacturers to establish an acceptable biodiesel fuel standard that will preserve engine performance, durability, and warranties.
- The state should establish a California renewable gasoline fuel standard so that the pool of all gasoline sold in California contains, on average, a minimum of 10 percent renewable content.
- The Bio-Energy Interagency Working Group should prepare and submit recommendations to the Energy Commission for inclusion in the AB 1007 state plan to increase the use of E-85 fuel by:
  - Developing and certifying E-85-compatible fuel dispensing systems.
  - Implementing a process to expedite the permitting of E-85 stations.
  - Investigating the feasibility of requiring all or a portion of new cars sold in California to be FFVs.
  - Establishing a collaborative state/industry working group to identify fuel infrastructure

changes needed to increase production and distribution of E-85 gasoline and prepare a strategic plan to exploit opportunities to incorporate E-85 into the existing retail fueling system.
  - Sponsoring a consumer notification and education program promoting the availability of FFVs and E-85 fuel.
  - Evaluating various incentive options and programs in other states to determine their applicability and usefulness for creating an E-85 retail infrastructure in California.
  - Supporting research for the development of technologies to convert California's biomass resources to ethanol.
  - Examining the feasibility of establishing an ethanol pool, or reserve, to provide ethanol to E-85 fuel retailers at prices that are competitive with gasoline on a cents-per-mile basis.
- The state should consider amending the Carl Moyer Program to include criteria for reductions in petroleum use and greenhouse gas emissions.
- The state should open a dialog among the Energy Commission, the CPUC, ARB, local air quality management districts, utilities, and other stakeholders to investigate how investor-owned utilities can best develop the equipment and infrastructure to fuel electric and natural gas vehicles as required by Public Utilities Code Sections 740.3, 740.8, and 451.
- The Energy Commission should continue to help implement the *California Hydrogen Highway Blueprint Plan*, including: 1) prioritizing the use of renewable energy sources to produce hydrogen; 2) developing hydrogen fueling infrastructure and vehicular hydrogen technologies; and 3) using bridging technologies that can accelerate the technological development of fuel cell vehicles while providing near-term emission reductions of greenhouse gases and other pollutants.
- ARB should consider amending the clean fuels regulations to incorporate broader emission and/or petroleum reduction criteria in the clean fuels outlet "trigger" provision and examine its authority to require automakers to produce as many FFVs as possible for the California market.
- The state should engage the automakers and their selected fuel system "upfitters" to continue the production of the gaseous alternative fuel vehicles (natural gas and propane).

Increasing Vehicle Efficiency to Decrease Fuel Demand

Energy efficiency has always been the priority in California energy policy. The Energy Commission's efficiency standards and utility efficiency programs have been effective in moderating the growth in demand for electricity and natural gas. In the transportation sector, however, fuel economy standards for passenger cars and light trucks have been allowed to languish under the aegis of the federal government. Still despite the significant market penetration of light trucks and its dampening effect on overall fuel economy, as well as the substantial vehicle miles traveled each year, Californians are the ninth lowest consumers of gasoline on a miles-per-gallon basis in the United States. That fact indicates Californians' propensity for fuel efficient vehicles relative to other states.[25] The state must better understand and encourage this market preference for efficiency through a number of options that are becoming available in the marketplace.

Hybrid Electric Vehicles

The fuel economy of hybrid electric vehicles (HEV) is approximately double that of the average fuel economy of cars and light trucks in California today. HEVs have overall lower tailpipe emissions.[26] The few hybrid models for sale by automakers carry a price premium several thousand dollars above comparable gasoline models, although expected

25. Federal Highway Administration's Office of Highway Policy Information, based on data for 2000.

26. *California State Vehicle Fleet Fuel Efficiency Report*, Volume II, April 2004, CEC-600-03-004 [http://www.energy.ca.gov/reports/2003-05-12_600-03-004-VOL2.PDF], accessed August 8, 2005.

mass production will bring down their cost. Consumer awareness of HEVs is increasing, and automakers are responding, adding HEV models to current and future model lines. Only about 45,000 hybrid vehicles were on the road in 2004, out of a total state vehicle count of more than 26 million.[27] With average vehicle turnover at eight years for households and two and one-half years for business fleets,[28] influencing individual consumer preference may not be the most effective strategy to encourage their use. Providing incentives or requiring public and private fleet owners to buy HEVs could accelerate the rate of market penetration of hybrid vehicles. Public and private fleets in California currently have nearly 6,000 hybrid vehicles.[29]

Plug-In Hybrid Electric Vehicles

There is increasing attention to grid-connected, or "plug-in," hybrids as an on-road electric-drive technology option that can bridge the gap between today's hybrids and the zero-emission vehicles of the future. Plug-in hybrids are like today's hybrids, but with a larger battery pack and the capability to plug into grid-supplied electricity from a standard 110-volt outlet when available. Plug-in hybrids have the capability to provide 20 to 60 miles of all-electric battery-only (and zero-emission) range, before the internal combustion engine comes on to supply the remainder of the needed driving range. This is particularly important since 63 percent of consumer trips are fewer than 60 miles. In this way, plug-in hybrids address the limitations that all-electric vehicles have in terms of limited range and high battery cost. And because plug-in hybrids have substantial zero-emission range, they can produce significant reductions in petroleum, criteria pollutants, and greenhouse gas emissions — much more than the very efficient hybrid vehicles available today. Furthermore, optimizing the internal combustion engine of a plug-in hybrid to use a non-petroleum fuel, such as E-85, could result in a nearly petroleum-free vehicle. Several aftermarket companies are offering plug-in capabilities for hybrid electric vehicles on a very limited basis. Although, at present, no automaker has publicly announced plans to produce plug-in hybrid models, the City of Austin, Texas, has initiated a national Plug-In Partners campaign to create a market for the vehicles. The state should join the national Plug-In Partners campaign and work with other government and private fleet operators in California to communicate to auto manufacturers an interest in placing future procurement orders for plug-in hybrid vehicles.

Light-Duty Diesels

Light-duty diesel (LDD) vehicles are cars, mini- and full-sized vans, and small and full-sized pickup trucks that use diesel fuel as opposed to gasoline. Today's advanced LDDs offer turbo-charged high performance, high fuel economy, and low emissions compared to past gasoline and diesel engines. These new LDDs provide 45 percent better fuel economy compared to the equivalent gasoline powered car. Consumer reaction where these cars are available is positive. Prior to 1998, diesel car sales in Europe were typically 20 percent of the new automobile market. Since the introduction of LDDs in 1998, 48 percent of European new vehicle sales are LDDs. LDDs also offer higher torque (better response) and greater engine durability that make them more attractive in California's market.

Due to California's stringent NOx emission standards, limited LDDs were sold from 1998-2004, and no LDDs have been sold in California

27. California Energy Commission, Joint Agency Department of Motor Vehicle Data Project, based on Department of Motor Vehicle's October 1, 2004 vehicle registration database.

28. U.S. Department of Energy, *Transportation Energy Data Book*, Edition 24, Oak Ridge National Laboratory.

29. California Energy Commission, Joint Agency Department of Motor Vehicle Data Project, based on Department of Motor Vehicle's October 1, 2004 vehicle registration database.

since 2004. LDDs cannot meet existing emission standards with the present high sulfur diesel fuels. Vehicle manufacturers have made significant investments in advanced technologies and are demonstrating prototypes that will meet the adopted 2007 standards. With the availability of ultra-low sulfur diesel fuel beginning in 2006, in combination with the advanced diesel engine technology, LDDs may succeed in meeting California's stringent NOx standards. To be a viable, fuel-efficient option, consumers will have to overcome the higher initial purchase price, estimated at $1,000 to $3,000, and the petroleum industry will need to increase the number of diesel fueling stations.

Low-Rolling Resistance Tires

Tires that reduce road friction increase fuel economy. Most automobile manufacturers routinely use low-rolling resistance tires on new vehicles to help meet federal fuel economy standards. Consumers are not aware that tires affect vehicle fuel efficiency based on their rolling resistance characteristics and that the tires sold on new cars are usually more fuel efficient than normally purchased replacement tires. In a 2003 report, the Energy Commission concluded that fuel-efficient tires could provide substantial fuel savings. Sufficient data, however, is not yet available to draw conclusions regarding the performance and characteristics of fuel-efficient tires.[30]

Tire manufacturers assert that any improvement in tire efficiency will compromise tire life, performance, and safety and/or increase cost significantly. Nevertheless, tire manufacturers routinely use forms of rolling resistance measurement in the engineering and the design process for developing new tires. The manufacturers have not published useful information on rolling resistance or on tire performance as a function of rolling resistance. Without such information the Energy Commission cannot predict with any certainty the fuel consumption impact of low-rolling resistance tires.

Actual fuel economy performance of low-rolling resistance tires must be verified to ascertain possible tradeoffs and to avoid unacceptable penalties associated with improving tire efficiency beyond current practices. Legislation passed in 2003[31] requires tire manufacturers to report to the Energy Commission the rolling resistance and relative fuel economy of replacement tires sold in California. With this information composed in a reportable format, consumers will for the first time be able to select tires relative to their fuel economy in addition to the existing parameters of use, cost, and longevity. The Energy Commission will also be required to adopt (if feasible) minimum fuel efficiency standards for replacement tires resulting in a fuel economy equal to or better than tires on new vehicles.

The Energy Commission, in partnership with the California Integrated Waste Management Board (CIWMB), initiated a fuel efficient tire study in March 2005 to substantiate the potential of low-rolling resistance tires to save fuel in real world conditions. Results from this study should be available in 2006. The National Highway Transportation and Safety Administration also is conducting a study of the fuel consumption, safety, tread life, cost, and disposal issues regarding fuel efficient tires. These findings should be available in December 2005.

Truck Anti-Idling

Many truckers idle their engines in order to operate heaters and air conditioners while they sleep in their trucks at truck stops. ARB has adopted regulations limiting engine idling time for all heavy-duty trucks, except sleeper berth trucks, to five minutes. On October 20, 2005, ARB approved

30. California Energy Commission, *California State Fuel Efficient Tire Program: Volume 1 – Summary of Findings and Recommendations*, January 31, 2003, Publication # 600-03-001F-VOL1.

31. AB 844 (Nation), Chapter 645, Statutes of 2003.

amendments to the regulation that limit the idling of the sleeper berth trucks to five minutes beginning January 1, 2008.

One solution to idling truck engines is "electrification" of truck stops, which allows truckers to connect their trucks into heating, cooling, and other services for an hourly fee. Another is "shore power," which provides grid power for on-board electrical functions at truck stop parking places. A third option is an on-board auxiliary power unit, which typically is a small diesel-fueled generator mounted outside the cab that provides heat, air conditioning, and electricity. Each of these three options offers significant emissions reduction and fuel savings possibilities but also is limited by general knowledge within the industry and the required investments by the manufacturers, truck stop owners, or individual truckers.

In the spring of 2004, U.S. EPA convened the West Coast Collaborative as a multi-state effort to reduce emissions from diesel engines. Today the 700 collaborative partners include federal, state and local government agencies; non-profit organizations; public and private diesel users; clean technology producers; and diesel, biodiesel, and natural gas producers. The collaborative has been tasked with implementing the *West Coast Governors' Global Warming Initiative's* recommendations to establish a plan for the deployment of electrification technologies at truck stops in each west coast state on the I-5 corridor, on the outskirts of major urban areas, and on other major interstate routes. So far, the collaborative has helped establish grant and loan programs in all three states and is installing electrified parking spaces, advanced truck stop electrification, and auxiliary power units.

Recommendations

- The state should intensify its efforts with other states and stakeholders to influence the federal government to double CAFE standards and amend *Energy Policy Act* fleet procurement requirements to include hybrid and other super-efficient gasoline and diesel vehicles.
- The state should use the State of California's vehicle fleet as a model for efficiency and non-petroleum applications by:
  - Establishing a minimum fuel economy standard that is based on doubling current federal standards for passenger cars and light trucks by 2009 and directing the Department of General Services to develop and implement a vehicle procurement process that achieves this standard.
  - Implementing a procurement requirement for alternative fuels and vehicles.
  - Examining the merits of using re-refined and synthetic motor oils.
- The Energy Commission and Department of General Services should encourage local governments to adopt a minimum fuel economy standard and procurement process for both fuel efficient and alternative fuel vehicles. The Energy Commission should open a proceeding to investigate requiring that all public fleets adopt the minimum fuel economy standard and procurement process.
- The state should establish a combined state/industry working group to examine the markets for development and commercialization of plug-in hybrid electric vehicles. The state should develop partnerships with original equipment manufacturers to demonstrate plug-in hybrid electric vehicles, assess consumer demand for these options, and support early incentives to reduce initial consumer cost.
- The state should develop programs to:
  - Reduce diesel engine idling including truck parking space electrification (at privately owned facilities and those owned by the California Department of Transportation), marine port electrification, airport electrification, and electric standby for truck and container refrigeration units.
  - Reduce diesel and gasoline use in non-road vehicles including forklifts and other industrial vehicles. The state should closely coordinate these activities with other load management, energy efficiency, and greenhouse gas reduction programs.
- The state should establish a low-interest loan program, funded through the California Pollution Control Authority, the California Alternative

Energy and Advanced Transportation Financing Authority, or other sources, and administered by the Energy Commission to develop projects that reduce petroleum use and increase transportation fuel diversity.

- The state should continue current work to explore establishing energy efficiency criteria and, if appropriate, efficiency standards for replacement vehicle tires.
- The state should sponsor consumer outreach and education programs on transportation energy choices, including a consumer education campaign on vehicle maintenance practices that maintain vehicle efficiency. The state should create an information clearinghouse on efficient alternative fuel choices for consumers, along the lines of an Internet shopping guide.
- The state should sponsor transportation technology and fuels research, development, and demonstration to:
  - Expand the availability of engines and vehicles capable of using alternative fuels, new and retrofitted.
  - Reduce engine and vehicle consumption of all fuels.
  - Demonstrate alternative fuel engines and vehicles and improved efficiency technologies in on- and off-road applications.
  - Develop and demonstrate alternative fuel production technologies, emphasizing in-state resources.

Reducing Fuel Demand through Pricing Options

Mandating vehicle efficiency or substituting alternative fuels are not the only ways to reduce petroleum demand. Actions to increase travel cost can also reduce petroleum fuel demand.

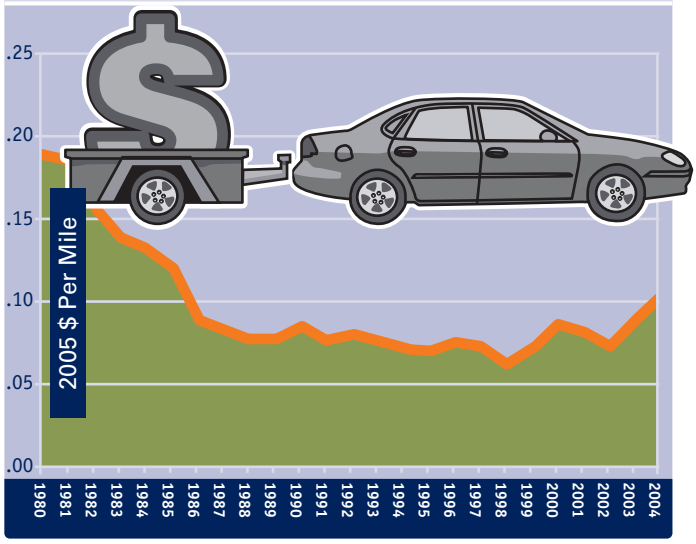
Gasoline has historically been a relatively inexpensive commodity in California. Since 1980, the real cost of gasoline has dropped by 40 percent while fleet-average fuel economy has nearly doubled. The average per-mile cost of gasoline in 2004 was nearly half what it was in 1980. This very likely has helped shape driving habits of California motorists and contributed to today's increasing demand. It also helps explain why pricing measures may be effective in reducing demand. Figure 3 shows the average per-mile cost of operating a gasoline-powered light-duty vehicle from 1980 to 2004.

The Energy Commission has studied the costs and benefits of four pricing options:

- "Feebate" for new light-duty vehicles: Applying a new vehicle variable fee or rebate pegged to the vehicle's fuel efficiency or carbon emissions would encourage consumers to buy vehicles with greater fuel efficiency. Feebates would be revenue neutral.
- Per-gallon fee for vehicle miles traveled: Replacing fuel excise taxes on a revenue neutral basis with a per-gallon fee would increase the per-mile cost of driving and encourage consumers to travel less. However, this option would not provide sufficient incentive for consumers to buy more fuel-efficient vehicles unless set at a high-level.
- Pay-as-you-drive automobile insurance: Offering to vary a portion of consumers' auto insurance premiums, depending upon miles traveled, instead of paying a fixed cost for auto insurance. When cost is directly tied to usage, consumers drive less and may choose to buy more fuel-efficient vehicles.
- Fuel tax increase: Increasing gasoline and diesel excise taxes by one dollar a gallon would almost certainly reduce travel and, over time, encourage consumers to buy more fuel-efficient vehicles. In order to be revenue neutral, the state would have to identify other taxes for reduction.

Figure 3: **Average On-Road Gasoline Cost Per Mile**

California, 1980-2004



Source: California Energy Commission.

Pricing options are usually vilified as hidden tax increases, and the Energy Commission recommends they be considered on a revenue neutral basis with compensating tax reductions to remove this onus. The focus should be on what activities government should tax, rather than crafting methods to increase government revenues.

At this point, policy makers should consider all demand reduction, fuel switching, and pricing options and pursue further study. Local, state, and federal policy makers must urgently make every effort to reduce fuel demand in today's climate of rising demand, highly volatile prices, and heightened international competition for petroleum supplies.

Recommendation

- The state should explore incentive programs to influence consumer choice for more efficient transportation options such as pay-as-you-drive insurance and direct purchase incentives for fuel-efficient vehicles.

Reducing Fuel Demand through Integrated Transportation and Land Use Planning

Changing land use patterns to reduce miles traveled, air pollution, and fuel demand has been a topic of debate for at least a decade. To resolve this thorny issue, state (Caltrans), regional, and city/county transportation and land use planning professionals must build an information and policy bridge among their departments. Transportation plans typically account for regional growth in city and county general plans. Metropolitan planning organizations are caught in a dilemma: they have the responsibility for transportation planning but lack the authority to authorize land use. Paradoxically, local governments do have land use authority but cannot directly affect fuel demand. The predictable result is today's urban sprawl. Policy makers must address this stubborn and politically charged disconnection, however difficult it may be.

The means to build this critical bridge exist: the Planning for Community Energy, Economic and Environmental Sustainability (PLACE3S) land use analysis methodology. This Energy Commission-supported methodology is the key analytical tool the Sacramento Area Council of Governments (SACOG) used for BLUEPRINT, an award-winning regional transportation and land use planning program designed to resolve complicated growth issues in regions with 1.5 million people or more. Implementation of this plan would reduce vehicle miles traveled by some 5.8 million per year while retaining almost $220 million a year in the regional economy (assuming a $2.45 per gallon petroleum price). If each metropolitan planning organization embraced both the BLUEPRINT program and the PLACE3S technology, metropolitan areas throughout the state could achieve similar savings. Because PLACE3S also addresses economic development, housing, infrastructure, open space, and many other issues, the state would realize additional benefits in other areas while providing local governments with highly valuable and sought-after technical help.

Recommendation

- The state should establish a strategic planning process with local governments and regional planning organizations to reduce transportation fuel consumption through improved public transportation and land use planning. It should create a center of excellence for regional planning based upon the PLACE3S planning tool and provide technical assistance and training.

Infrastructure for Transportation Fuels

Gasoline and diesel will continue to be California's primary transportation fuels for the foreseeable future. California cannot meet rising near-term fuel demand without a robust petroleum infrastructure including refineries, storage, pipelines, distribution terminals, and marine facilities. It is critical to California's economy that all reasonable measures be taken to ensure adequate supplies of gasoline and diesel as the state takes all the necessary steps to diversify the transportation fuel market. The Energy Commission noted constraints in parts of the state's petroleum infrastructure in the *2003 Energy Report*, particularly at marine facilities. These constraints will lead to supply problems and higher costs for both the industry and consumers and prevent deliveries of critical fuel supplies during refinery outages or other disruptions.

Increased Infrastructure Needs

The state's petroleum infrastructure has improved slightly since 2003. The industry has committed to expansion of some elements of its infrastructure. In spite of these needed improvements, California must expand marine terminal capacity, marine storage, and pipelines connecting marine facilities with refineries and other pipelines to meet rising fuel demand. The most urgently needed marine terminal expansion and storage is in the ports of Los Angeles and Long Beach. Building these needed facilities faces several hurdles, including scarcity of land and complex and overlapping permitting requirements. Social pressure and local port policies to remove portions of existing facilities in favor of container cargo facilities and open space could further threaten marine infrastructure.

Moreover, new State Lands Commission standards for marine terminals, known as the Marine Oil Terminal Engineering and Maintenance Standards (MOTEMS), may require substantial upgrades to a large percentage of the clean fuel receiving terminals, primarily in Southern California. These upgrades are likely to require substantial investments and could create operational disruptions. Some companies may choose to close terminals rather than rehabilitate them to the new standards.

The Los Angeles Basin will need at least an additional 2.8 million barrels of storage capacity and 46 million barrels of clean fuel marine terminal throughput capacity by 2025.[32] Crude oil import capacity appears sufficient for the next 20 years, assuming proposed crude oil and import terminal projects are approved and constructed within the next three to five years. In the San Francisco Bay Area, marine clean fuels storage also appears sufficient for the next 20 years, but the Bay Area needs a clean fuels marine terminal capacity expansion of at least 11 million barrels a year.[33] The Bay Area will also need additional crude oil marine terminal capacity equal to increased throughput of around 30 million barrels by 2015 and 56 million barrels by 2025.[34]

Expected storage and throughput needs will more than double if the courts overturn ARB's greenhouse gas regulations. The Los Angeles Basin

32. California Energy Commission, *An Assessment of Petroleum Infrastructure Needs*, staff report, April 2005, CEC-600-2005-009.

33. Ibid.

34. Ibid.

will require additional storage of 7.3 million barrels and 99 million barrels of additional throughput per year, assuming the construction of 2 million barrels of recently permitted additional storage capacity. The Bay Area will require additional storage capacity of at least 700,000 barrels by 2025 and clean fuels marine capacity of at least 25 million barrels of additional throughput per year, again assuming the construction of 1.7 million barrels of already permitted storage.[35] However, these projected infrastructure requirements make no assumptions about demand growth in out-of-state markets presently served by California refineries.

Fast-growing demand for transportation fuel in Nevada, Arizona, and Baja California Norte could also have a significant effect on California's petroleum infrastructure. California supplies the bulk of Nevada's and Arizona's transportation fuel, and demand in those rapidly growing regions is rising faster than it is in California. During 2004 alone, California delivered some 300,000 barrels of fuel per day to Nevada and Arizona.[36] If this demand grows just 3 percent per year over the next 10 years, the amount of fuel moving through California's petroleum marine terminals could easily double from today's level.

Recently announced pipeline expansion projects could relieve some of that pressure on California's infrastructure. Kinder Morgan Pipeline Company is expanding portions of its East Line, which is used to move petroleum from West Texas to Tucson and Phoenix. Completion of this expansion in the summer of 2006 will enable Texas-based refineries to send more fuel to Arizona.

Permitting Issues

The *2003 Energy Report* identified inadequate permitting coordination among a potpourri of local, state, and federal agencies as a major barrier to infrastructure expansion. The Energy Commission therefore recommended that the state establish a one-stop permitting shop for refineries, import and storage facilities, and pipelines. The overlapping and serial nature of federal, state, and local agency permitting and planning processes complicates the petroleum industry's ability to build new facilities needed to meet California's growing petroleum demand. The fact that activities proceed with little or no input from the Energy Commission is a further disconnect. The Energy Commission needs to work hand-in-hand with federal and state agencies, cities, counties, and port and air districts to make sure their processes are conducted in a timely fashion and take into account the state's rising fuel needs and the critical need for new petroleum infrastructure.

Participants in the Energy Commission workshops agreed that the Energy Commission should work with the permitting agencies and the industry to develop best practice guidelines for local and state agencies to streamline and coordinate petroleum infrastructure permitting processes. The federal *Energy Policy Act of 2005* grants U.S. EPA similar authority to coordinate federal agency review of refinery applications and speed the concurrent review of applications with state agencies.[37]

The Energy Commission should initiate an effort to identify and develop permitting guidelines for petroleum infrastructure projects, with no reduction in environmental standards, that focuses on the following elements:

- Descriptions of involved agencies and their interrelationships.
- Critical path permitting timelines.
- Information requirements.
- Standardized permitting timelines.

35. Ibid.

36. Presentation by Gordon Schremp and Chris Kavalec, California Energy Commission, transcript of the May 16, 2005, *Energy Report* workshop on *California's Petroleum Infrastructure Needs*, p. 4.

37. Title III, Oil and Gas, Subtitle H, Refinery Revitalization.

- Requirements for expedited permitting.
- Simplification of requirements.
- Concurrent and coordinated permit review.
- Procedures for categorical exemptions and ministerial permits.
- Streamlined appeal processes.

Air Quality Impacts

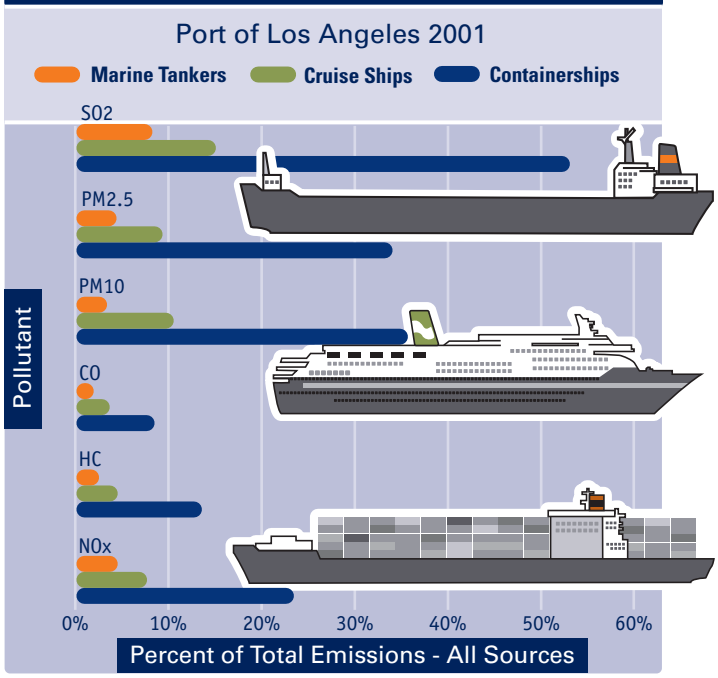
Emissions from the state's refineries have decreased over the last 25 years, partially due to major improvements in refinery emission controls.[38] However, in 2002, refineries still accounted for about 5 percent of California's total greenhouse gas emissions. Refinery emissions come from a variety of sources, including process boilers and flares and so-called "fugitive" emissions from small leaks in valves, pumps, tanks, pressure relief valves, and flanges.

Marine terminals generate high-levels of pollution from diesel port equipment, truck and rail traffic, and largely unregulated marine vessels. Loading and unloading crude oil and petroleum products create fugitive emissions and emissions from diesel engines operated in the process. Fugitive emissions are also a concern at bulk storage facilities located at refineries, marine terminals, and stand-alone facilities. Most emissions from bulk storage facilities are from leaks and evaporation. Increased demand for refined petroleum products will require increased bulk storage, regardless of whether products are refined within California or imported through marine terminals. California may therefore need to strengthen current fugitive emission regulations to better control air pollution at these facilities.

Petroleum marine tankers in the Port of Los Angeles generate much less air pollution than other ocean-going vessels. According to a 2004 study, marine tankers generated between 1.2 and 8.2 percent of total air pollution in the Port of Los Angeles in 2001. Figure 4 shows relative air pollution contributions from the three main types of ocean-going vessels.

Given California's rising thirst for petroleum, the state needs to frequently monitor emissions from its petroleum infrastructure. This is especially important since state and local agencies have little control over marine tanker emissions. More tanker traffic could exacerbate air pollution at California's ports, but the projected increases in container ship cargoes are likely to be a far bigger emissions problem. Higher numbers of smaller tankers, in use because of port depth restrictions, could also increase emissions. This makes the timely and effective dredging and maintenance of shipping channels even more critical.

Figure 4: Emissions from Selected Ocean-Going Vessels



Source: Starcrest Consulting Group, LLC, prepared for Port of Los Angeles, Final Draft Port-Wide Baseline Air Emission Inventory 2001, June 2004.

38. California Energy Commission, *Petroleum Infrastructure Environmental Performance Report*, June 2005, CEC-700-2005-012, p. 43.

Dredging is an essential component of the safe passage of petroleum tankers into San Francisco Bay since two-thirds of the bay is shallower than 18 feet. The U.S. Army Corps of Engineers, the U.S. Navy, and private terminal operators historically have dredged the bay. Through 2045, the Army Corps and the Navy are still projected to perform 80 percent of the dredging, but this task is dependent upon federal funding. Two critical dredging projects included in the *Energy Policy Act of 2005* include:

- Annual Army Corps dredging of the Suisun Bay Channel to 35 feet ($5.132 million). This passage allows transport of crude oil and other bulk materials through the San Francisco Bay and Carquinez Strait to the Sacramento-San Joaquin Delta.
- Dredging the San Pablo Bay/Pinole Shoals/Mare Island Strait, a major sea artery for bulk cargo and oil tankers through the San Francisco Bay Area ($1 million).

Regular dredging in the San Francisco Bay is ongoing, with some refinery terminals requiring dredging several times a year. The Army Corps, U.S. EPA, San Francisco Bay Conservation and Development Commission, San Francisco Bay Regional Water Quality Control Board, and the California Water Resources Control Board are the agencies that provide permits for dredging. These agencies established the Dredge Material Management Office to streamline multiple agency permitting of dredging and disposal of dredge materials using a single permit application reviewed concurrently by all agencies.

The Energy Commission should monitor the progress of dredging projects and either comment on or advocate for projects where needed to make sure that funding, permitting, and refinery access stay on track.

Environmental Justice Issues

Local communities close to oil refineries, port facilities, pipelines, and storage facilities believe that their communities bear an unfair share of the environmental, public health, and safety risks of those facilities. They express concern over respiratory and other health problems from prolonged exposure to toxic, carcinogenic, and hazardous chemicals in addition to noise, traffic congestion, truck and train accidents, and upsets and accidents at the facilities. Local communities believe there is inadequate agency monitoring and reporting of refinery emissions, agency enforcement of permits, and public notification of accidents and other disruptions.

The Coalition for a Safe Environment represents many of these local communities and has called for a moratorium on continued operation or expansion of petroleum infrastructure facilities. Such a policy would be on a direct collision course with California's critical need to maintain and expand petroleum infrastructure to meet fast-growing state demand. Resolving this difficult and sensitive social conflict is essential to the health, welfare, and economy of California. The Energy Commission will continue to advocate for and support environmental justice initiatives and respond to public concerns about this issue by supporting and working closely with the following projects and organizations:

- The South Coast Air Quality Management District's environmental justice work plan and community initiatives, including the Clean Air Congress, Clean School Bus Program, Asthma and Air Quality Consortium, Brain and Lung Tumor and Air Pollution Foundation, Neighborhood Environmental Justice councils (all of which address specific air quality issues in targeted communities), the Multiple Air Toxics Exposure Monitoring Program, and investments earmarked to reduce toxic air pollutant levels in targeted communities.
- The Bay Area Air Quality Management District's expansion of its database of environmental justice stakeholders and its incorporation of permit information on its website, as well as work with community members on air quality publications and in community meetings.
- ARB's Environmental Justice Policies and Actions, which establish a framework for incorporating environmental justice into its programs, research, and data collection projects to reduce cumulative emissions, exposure, and health risks in all communities, especially low-income and minority communities.

- The joint Energy Commission/ARB project, using existing data and modeling results to create neighborhood maps of the health-related air quality effects of local emission sources, including oil refineries.

Increasing Energy Efficiency at Petroleum Refineries

California refineries currently operate at 98 percent capacity and use large volumes of electricity and natural gas to produce transportation fuels. Petroleum refining is the number one consumer of energy in California's manufacturing sector. Making sure that the state's refineries have reliable electricity is critical to meeting California's growing transportation fuel demand.

The petroleum refining industry is one of the largest users of cogeneration in the U.S. California refineries have an installed cogeneration capacity of about 1,400 MW and have the potential to increase their use of cogeneration technologies. Cogeneration at refineries improves the efficiency of natural gas use and helps insulate the facilities from electric grid problems. In the event of a local electrical outage, refineries that can meet their own demand with on-site generation can also maintain production of vitally needed transportation fuels.

As a case in point, the mid-September electricity outage in Los Angeles caused the shutdown of the Conoco Phillips, Shell, and Valero refineries in Wilmington for several days. These three refineries represent a significant percentage of Southern California's gasoline and diesel production. None of these facilities has sufficient on-site generation that would protect them from local electricity grid outages and allow continued operation of essential refinery processes. This experience points out the need for the state to move more concertedly with the industry to identify and develop refinery-based cogeneration opportunities. However, despite the clear benefits of cogeneration in providing on-site electricity and using process waste products for fuel, utility procurement issues and regulations limiting the export of surplus electricity continue to hinder cogeneration expansion at California's refineries. The benefits to the grid itself would suggest the state ought to conduct electricity regulation in such a way that part of the utilities' obligation to serve is to facilitate this type of self-generation. A more detailed discussion of cogeneration issues can be found in Chapter 4 of this report.

Recommendations

- The state should establish a committee—led by the California Energy Commission with the participation of ARB, the State Lands Commission, Port Authorities for Long Beach and Los Angeles, Bay Conservation and Development Commission, Bay Area Air Quality Management District, and the South Coast Air Quality Management District—to prepare and submit recommendations to the Governor and the Legislature that balance the statewide need for reliable supplies of petroleum, blending components, and refined products with local needs to manage port operations and achieve financial, environmental, and land use objectives.
- The state should confirm federal support to maintain safe shipping passage in San Francisco Bay.
- The state should establish a uniform decision-making process coordinating multi-agency review of infrastructure proposals and employing best practices permitting to ensure that petroleum infrastructure permitting proceeds in a timely and environmentally sound manner.
- The state should work with the petroleum industry and other agencies to identify opportunities for additional cogeneration at refineries.

Chapter Three:
Electricity Needs and Procurement Policies

California's electric system, fueling the world's sixth largest economy, faces critical needs requiring swift and decisive action. State utilities and consumers alike face the specter of a precarious and fragile electric system where reserves are thin and unlikely to improve in the immediate future.

Following a period of flat to slow growth on the heels of the 2000-2001 energy crisis, California's demand is now growing, fueled by population growth and a rebounding economy. Coupled with increasing demand, the state's electric rates remain among the highest in the nation. While wholesale electricity prices have been relatively stable since the 2000-2001 energy crisis, those prices have gradually increased from an average of $20 per megawatt hour (MWh) in late 2001 to around $50 per MWh today.[39]

Although high rates remain a focus for the state, the challenge of ensuring adequate electricity supplies, especially during high-demand peak periods, has emerged as a critical issue over the past two years. The *2004 Energy Report Update* expressed serious concern over dangerously low reserve margins, particularly in Southern California for the years 2005-2008 and especially in light of the expected retirement of aging power plants.

Electricity supplies are not keeping up with demand. Construction of new power plants is not proceeding as planned, and the flow of new permit applications has noticeably decreased. Today California has more than 7,000 MW of permitted power plants that have not moved into construction. Adding to the problem, investor-owned utility (IOU) procurement focuses primarily upon near- and mid-term contracts, which perpetuates reliance upon the existing fleet of aging power plants.

California's electric transmission system is rapidly becoming a costly energy bottleneck for consumers. Transmission-related reliability and congestion costs were more than $1 billion in 2004, up from $627 million in 2003. Transmission lines are frequently running to their capacity limits, forcing system operators to back down less costly generation to keep from overloading the system. In addition, transmission line outages caused rolling blackouts of roughly one-half million customers in Southern California in August 2005.

Local reliability is another casualty of the state's inadequate electric transmission system. Of special concern are the greater San Francisco Bay Area and San Diego regions, along with growing apprehension over transmission capacity into the Los Angeles Basin. Without a modernized transmission grid, California's dependence upon aging, less efficient gas-fired plants to support local reliability and contribute to reserve margins will continue indefinitely.

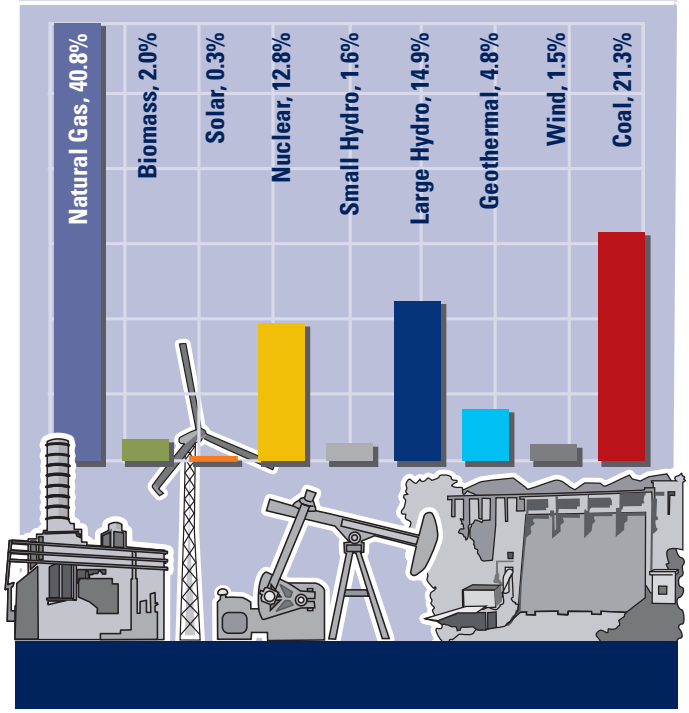
Despite policy pronouncements to diversify California's electric supply, very little progress has been made. Current rate regulation and utility accounting regimes are indifferent to growing natural gas dependence because fuel costs are treated as a straight pass-through in electric rates. As a result, the state's dependence on natural gas for power generation grows unabated, from 30 percent in 1999 to 36 percent in 2002 to 41 percent in 2004, as shown in Figure 5.[40] Governor Schwarzenegger recently declared that increased diversity will provide for a more secure power base and help address future electricity supply and price concerns, urging a balanced portfolio of clean and diverse resources.[41]

39. *Energy Market Report*, a publication of Economic Insight, Inc. The $20 to $50 per megawatt hour is an average of NP15, SP15, COB, and Palo Verde prices.

40. California Energy Commission, *Net System Power Report* for 1999, 2002, and 2004.

41. Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: *Review of Major Integrated Energy Policy Report Recommendations*, August 23, 2005.

Figure 5: **California's Electricity Supply, 2004**



Source: California Energy Commission.

In 2003, state policy makers identified an investment loading order as a transformational effort to curb demand and overcome the inertia that perpetuates the system's reliance on natural gas. The loading order calls for optimizing energy efficiency and demand response; meeting new generation needs first with renewable resources and distributed generation, then with clean fossil fuel generation; and improving the bulk transmission and distribution infrastructure.[42] Governor Schwarzenegger has embraced this loading order for California and supported the specific recommendations to achieve its goals in the *2003 Energy Report* and *2004 Energy Report Update*.[43]

The electricity and procurement policies recommended in this report are driven to a large extent by concerns about the need to diminish California's growing dependence on natural gas. Though the state's primary supply diversity strategy is the development of renewable resources, a lengthy and complex administrative and solicitation process hinders the state's ability to meet Renewable Portfolio Standard (RPS) targets. Untested thus far is the implementation of the CPUC's 2004 directive that renewables should be the "rebuttable presumption" for all IOU long-term procurement. Similarly, distributed generation sources, especially combined heat and power facilities, have not received the focused regulatory attention necessary for their expanded development.

The following chapter outlines the Energy Commission's assessment of electricity demand and supply trends, along with recommendations for IOU procurement. Chapter 4 outlines the steps the state must take to make sure that energy efficiency, demand response, and distributed generation goals are met. Renewable resource issues are examined in Chapter 6.

Electricity Demand

Electricity demand is measured in two ways: consumption and peak demand. Electricity consumption is the amount of electricity—measured in gigawatt hours (GWh)—that consumers in the state actually use. Consumption is primarily a money question for consumers and businesses: how much electricity am I being charged for and what will it cost me? In contrast, peak demand—

42. California Energy Commission, CPUC and CPA *Energy Action Plan*, Spring 2003, p.4.

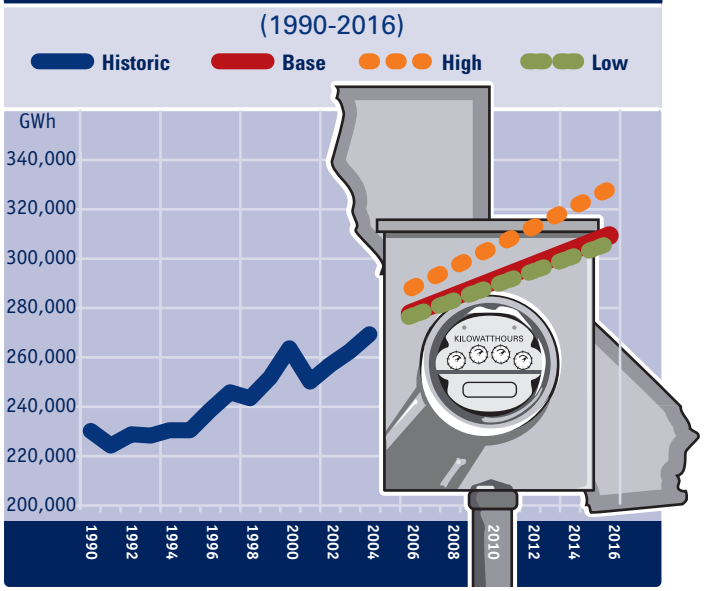
43. Letter from Governor Arnold Schwarzenegger to CPUC President Mike Peevey, April 28, 2004, and letter from Governor Arnold Schwarzenegger to the Legislature, attachment: *Review of Major Integrated Energy Policy Report Recommendations*, August 23, 2005.

measured in MW—is the amount of generation needed to keep electrons flowing in the system at any given moment of peak demand. Meeting peak demand is primarily an operational issue for system operators—how much will be needed to keep the lights on under worst case conditions?

Electricity consumption in California grew from 250,241 GWh in 2001 to 270,927 GWh in 2004. The state's annual electricity consumption increased almost 3 percent over those three years, higher than forecast in the *2003 Energy Report*.[44] Over the same period, consumption increased in all areas except the industrial sector, which remained relatively flat. Residential and commercial use increased an average of 3.3 percent. Primary reasons for the increased growth include a shorter and milder recession than projected in the 2003 forecast, along with diminished voluntary consumer conservation efforts compared to those achieved during the 2000-2001 energy crisis.

As shown in Figure 6, consumption is forecast to grow between 1.2 and 1.5 percent annually, from 270,927 GWh in 2004 to between 310,716 and 323,372 GWh by the end of the forecast period in 2016. Population is a key driver for residential consumption, commercial growth, demand for water pumping, and other services. The 2003 demand forecast assumed 1.4 percent population growth. The demand forecast for the *2005 Energy Report* projects consumption will be higher than in the 2003 forecast, but the annual demand growth rate will be lower due to lower population forecasts from the Department of Finance (DOF).[45] The DOF projects annual population growth at 1.2 percent and is based upon lower immigration and fertility assumptions than its 1998 forecast. The highest consumption growth is forecast for the Sacramento Municipal Utility District (SMUD) control area and Southern California portions of the CA ISO control area, reflecting strong population growth in those areas. Another key driver of California's energy demand is personal income.

Figure 6: **Statewide Electricity Consumption**



*Source: California Energy Commission, C*alifornia Energy Demand 2006-2016, Staff Energy Forecast, *revised September 2005, CEC-400-2005-034-SF-ED2.*

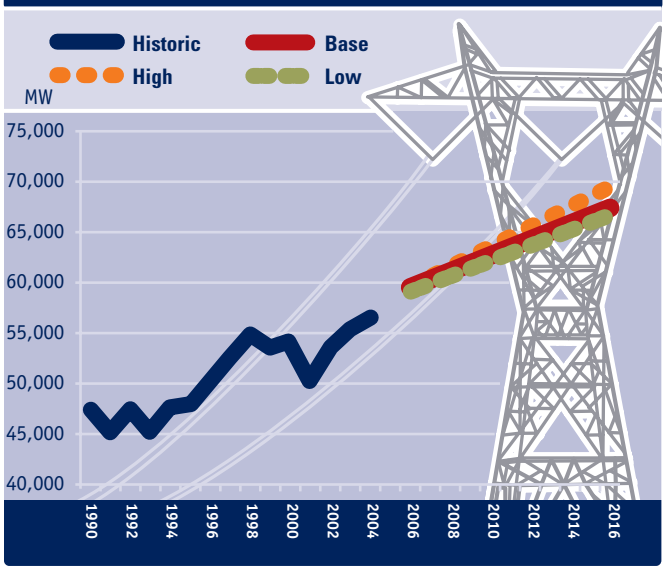
Statewide noncoincident peak demand reached 56,435 MW in 2004, up from 50,245 in 2001. Peak

44. *California Energy Demand 2006-2016*, staff energy forecast, revised September 2005, CEC-400-2005-034-SF-ED2, and *California Energy Demand 2003-2013 Forecast*, August 2003, CEC-100-03-002.

45. State of California, Department of Finance, *Population Projections by Race/Ethnicity for California and Its Counties 2000–2050*, Sacramento, California, May 2004. These population projections were prepared under the mandate of Government Code Sections 13073 and 13073.5. In addition, the State Administrative Manual, Section 1100 on state plans, sets the general policy of …" The use of the same population projections and demographic data that is provided by the State's Demographic Research Unit."

demand in California is forecast to grow between 1.4 and 1.75 percent, rising from 56,435 MW in 2004 to between 66,656 and 69,473 MW in 2016, as shown in Figure 7. On the peak demand side, the 2004 recorded peak was 3.3 percent higher than forecast, a difference of more than 2,000 MW, the approximate capacity of three of the state's largest fossil-fueled generators. The 2005 demand forecast uses this higher peak demand as its starting point.

Figure 7: **Statewide Peak Demand (1990-2016)**



Source: California Energy Commission, California Energy Demand *2006-2016,* Staff Energy Forecast, *revised September 2005, CEC-400-2005-034-SF-ED2.*

One of the difficulties in using long-term forecasts is that they are designed to project a growth rate in consumption and peak over a 10-year period. As shown in Figure 7, there is considerable variability in any given year. It can be quite misleading to simplistically apply a forecasted 10-year growth rate to predict demand in the early years of the forecast. The Energy Commission generally finds the staff's detailed end-use models more reliable in the long-term and the utilities econometric methodologies more useable in the near-term.

The Energy Commission's forecasts project consumption and peak demand assuming average weather conditions. Because weather is unpredictable, the actual consumption and peak will almost always vary from the forecasted projection. To account for this, the Energy Commission develops demand forecasts under hot-weather scenarios. In any given year, there is a 10 percent chance of temperatures that will increase statewide demand by 6 percent–about 3,600 MW in 2006.

Given that California covers a large geographical area, with many diverse climates, the demand forecast is adjusted for weather, based on average temperatures and the relationship between demand and temperature within each planning area. Northern California usually has its hottest temperatures in July and August while Southern California's occur in late August and September.[46] Total statewide peak will be different when the temperature in San Jose is 95 and Burbank is 75 than when those temperatures are reversed, even though the average temperature is the same. Depending on the temperature patterns across the state, the statewide or CA ISO coincident annual peak demand has been between 1 and 5 percent lower than the sum of the individual planning area peaks.

A cornerstone of the Energy Commission's demand forecast is the reporting of electricity sales by economic sector for each retail electricity seller in the state. Since restructuring of the state's electric industry, unclassified sales—sales not identified by economic sector—have become the fastest-growing consumption category. For forecasting purposes,

46. The timing of peak is based on historical data. This year, it appears that Los Angeles Department of Water and Power had its peak much earlier in the summer in July, demonstrating the difficulty of predicting weather with any precision.

these sales must be allocated to one of the various sectors, and improper allocation can cause forecasting errors. For example, because commercial and industrial customers have very different load shapes, assigning their usage to the wrong customer class could result in a forecast of system peak that is either too high or low, with a possible difference of over 1,000 MW. The Energy Commission, with the state's utilities, must continue its efforts to address these unclassified sales discrepancies.

At the demand forecast hearing, participants identified several key uncertainties driving the differences between staff and utility forecasts, including trends in commercial energy use and residential demographics and the currency of data. Staff forecasts decreasing commercial electricity use per square foot, reflecting the effects of building and appliance standards, which most participants thought unlikely when the standards were adopted. In the residential sector, utility forecasts generally assumed more growth in income and the number of households than the staff forecast, but smaller household size.

In response to these factors, the *Energy Report* Committee directed staff to vary these key assumptions to develop a reasonable range of possible outcomes. These forecast ranges also use more recent consumption data and new information on population and income. The resulting forecasts will be used in the *2005 Transmittal Report* to the CPUC.

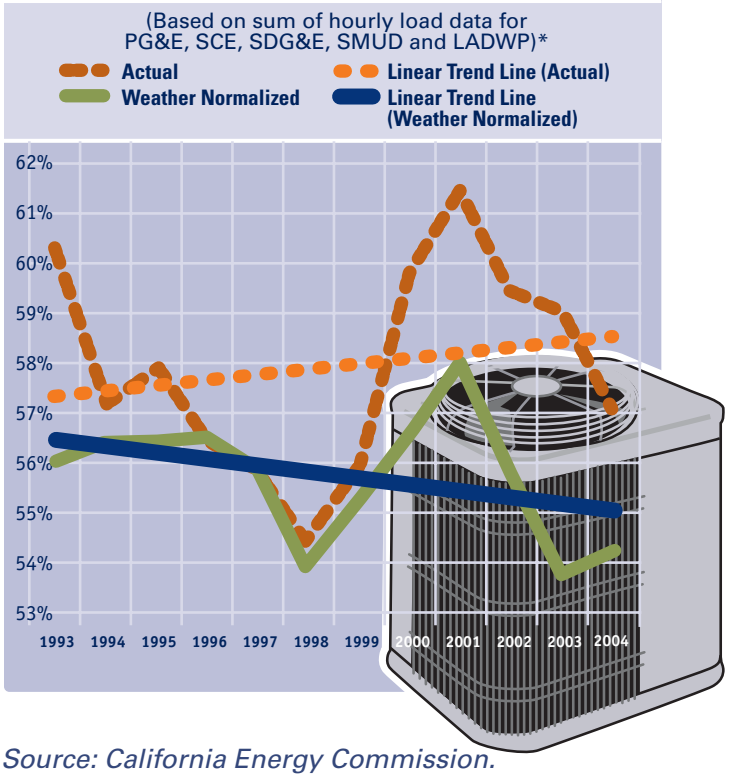
Another issue was the treatment of energy efficiency savings from IOU programs planned for later than 2008. The three IOUs included these impacts in their electricity demand forecasts. The revised staff forecasts do not include them because the significance of their impacts is dependent upon future CPUC decisions that could modify the energy efficiency targets before approving funding for post-2008 programs.

Growing "Peakiness" in Demand

Electricity demand in California increases most dramatically in the summer, driven by high air conditioning loads. The generation system must be able to accommodate these high summer peaks, in addition to the demand swings caused by weather variability and the economy. Though peak demand periods typically occur only between 50-100 hours a year, they impose huge burdens on the electric system.

One measure of the "peakiness" of the electric system is load factor, which measures the relationship between annual peak in MW and annual consumption in MWh. If peak demand grows faster than annual average consumption, the load factor decreases. As shown in Figure 8, weather-adjusted load factors in recent years have decreased as air conditioner loads have increased.

Figure 8: Statewide Annual Weather-Adjusted Load Factors



Source: California Energy Commission.
** Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, the Sacramento Municipal Utility District, and the Los Angeles Department of Water and Power.*

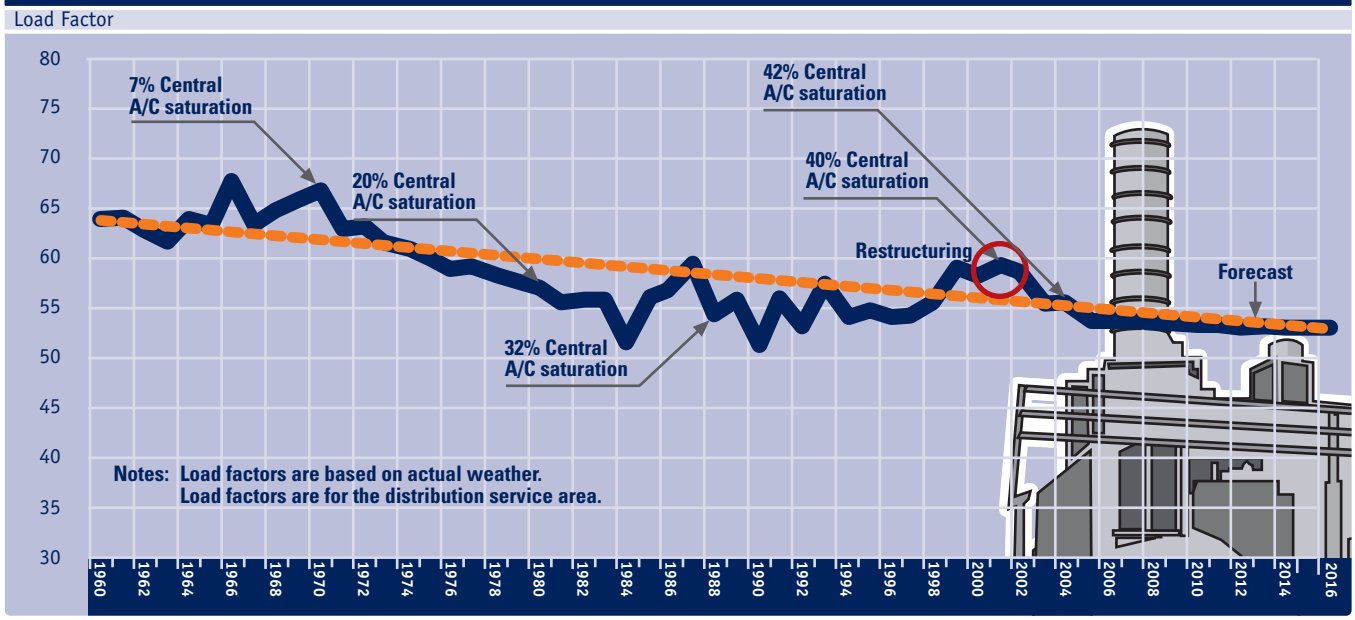
One problem with meeting peak demand is that most new gas-fired power plants are combined-cycle units designed to run at high load factors where they are most efficient and can generate enough revenue to recoup investments. Combined-cycle plants also have less capability to ramp up and down to meet peak demand than the older steam boiler units, which make up the majority of California's fleet of power plants. While some utilities have invested in simple-cycle peaking plants that run just a few hours each year, most of the state's new power plants are combined-cycle and are not well matched with swings in system demand. California must quickly and thoughtfully craft solutions for meeting this increasingly "peaky" demand.

Southern California Edison's (SCE) service area load factor has declined more rapidly than that of Pacific Gas and Electric (PG&E) over the past 34 years, as shown in Figure 9. SCE's current load factor is near 55, while PG&E's is just below 60. With increasing growth in residential and commercial construction in the Central Valley, it is possible that PG&E's future load factors may decline at a rate closer to SCE's.

Electricity Supply

Though the Energy Commission has certified and approved the construction of 22,386 MW of capacity since restructuring was implemented in 1998, only 13,805 MW have actually come on line.[47] Meanwhile, statewide electric loads have increased an average

Figure 9: **SCE Historic Load Factors 1960-2004**



Source: California Energy Commission.

47. California Energy Commission, *2005 Database of California Power Plants*.

2 percent per year over the last two years.[48] Since November 2003 alone, the Energy Commission has permitted 11 power plants totaling 5,750 MW of capacity, primarily natural gas-fired. However, California has 7,318 MW of approved power plant projects that have no current plans to begin construction because they lack the power purchase agreements needed to secure their financing.

Local agencies outside the Energy Commission's jurisdiction have also permitted 34 power plants totaling nearly 2,000 MW of capacity since November 2003. These plants are also primarily natural gas-fired, though renewable fuels make up about 30 percent. Twenty-two of these 34 permitted plants, totaling 1,200 MW, are operating, and the remainder are under construction. A total of 225 MW of wind capacity has also been added since 2003.

In addition, badly needed transmission upgrades have lagged and congestion has increased in certain areas of the CA ISO control area. In 2004, 850 MW of capacity was mothballed, meaning that these plants were shut down and prepared for long-term storage.

Table 2:
California's New Generation and Power Plant Applications

Year	New MW Online[a]	New Power Plant Applications (MW)	Number of Plants
1995	266.5	0	0
1996	240	0	0
1997	329	1,370	2
1998	0	3,151	5
1999	0	5,470	9 [c]
2000	0	5,740	17
2001	2,604	12,459	42 (15 peakers)
2002	3,276	1,137	4
2003	5,030	492	4
2004	61	401	3
2005	2,834[b]	2,060	5
2006	1,765[b]	No estimate	No estimate
2007	160[b]	No estimate	No estimate
2008	1,605[b]	No estimate	No estimate

a California Energy Commission, *2005 Database of Power Plants*.
b High probability.
c Application for Morro Bay repower project (530 MW submitted in 1999 and withdrawn the same year). A second application was resubmitted for 1,200 MW in October 2000.

48. *California Energy Demand 2006-2016, Staff Energy Forecast*, revised September 2005, CEC-400-2005-034-SF-ED2, and *California Energy Demand 2003-2013 Forecast*, August 2003, CEC-100-03-002.

The Energy Commission is concerned about local reliability in the San Francisco Bay Area and San Diego regions. In San Francisco, additional transmission capacity is urgently needed to reduce reliability must run costs and allow shut-down of the city's aging power plants. Several proposed transmission projects would allow San Francisco and the Northern Peninsula to reliably meet loads through 2011 while still allowing the shutdown of the Hunters Point and possibly the Potrero power plants. In San Diego, the majority of load is served by heavily congested transmission lines which cannot alone meet this region's reliability needs by 2010. New transmission is urgently needed to meet the increasing demand fueled by rapid population growth in the area. Two natural gas-fired combined-cycle power plants are under construction in the San Diego area and will help ease San Diego's need for electricity. The Palomar Escondido Energy Project and the Otay Mesa Power Plant Project will together add more than 1,000 MW of capacity.[49] These plants are scheduled to be on line in 2006 and 2008, respectively.

By June 1, 2006, the CPUC will require the state's IOUs to maintain 15-17 percent planning reserve margins. However, projections indicate that in a one-in-ten case, even 15-17 percent reserve margins might not be enough to maintain system reliability in Southern California due to transmission constraints.[50] Unanticipated events like sustained periods of extreme hot weather or unplanned power plant and transmission outages could cause reserve margins to dip perilously low.

While sufficient generation may be available in aggregate, transmission and local reliability constraints may mean that generation cannot be delivered to where it is needed. This issue of deliverability is currently being addressed in a CPUC proceeding. The CA ISO has released a three-part deliverability assessment, including:

- Deliverability of generation to aggregate load.
- Deliverability of imports.
- Deliverability to load (local area capacity).[51] (The CA ISO has determined that 25,044 MW of local generation is needed in local reliability areas for the CA ISO to reliably operate the grid.)

California's ability to maintain minimum reserve margins over the next five years will be largely determined by its ability to reduce demand, secure needed resources to meet increased load, and offset capacity losses from potential aging power plant retirements, especially in Southern California (Figure 10). A key element of this challenge is relieving transmission bottlenecks, which would create a more resilient electricity grid.

California will continue to rely heavily upon imported electricity from both the Southwest and the Pacific Northwest. Surplus electricity from the Southwest has been California's main source of imported power in recent years, but that region's explosive growth could reduce the availability of future surpluses. The Northwest will continue to have a large surplus of electric capacity available for export to both California and the Southwest in the summer, but a portion of this capacity will be stranded in the Northwest because of limited transmission access into California.

By 2016, California's utilities will need to procure approximately 24,000 MW of peak resources to replace expiring contracts and retiring power plants and meet peak demand growth.[52] This MW total

49. California Energy Commission, *2005 Database of California Power Plants*.

50. Presentation by David Ashuckian, Joint Agency Energy Action Plan Meeting, June 15, 2005 [http://www.energy.ca.gov/energy_action_plan/meetings/2005-06-15_meeting/2005-06-15_ASHUCKIAN.PDF], accessed September 12, 2005.

51. CA ISO presentations on deliverability, June 29, 2005 [http://www.caiso.com/docs/2005/06/28/2005062816522619093.pdf], accessed November 4, 2005.

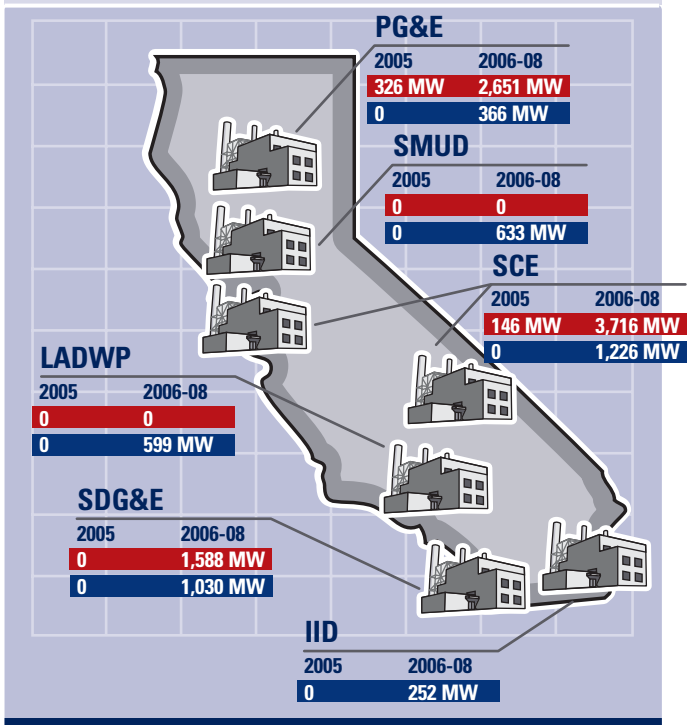
52. California Energy Commission, *Revised California and Western Electricity Outlook Report*, CEC-700-2005-019-ED2, July 2005, p. 73.

would serve retail loads, maintain a 15-17 percent reserve margin, and satisfy firm sales requirements.

Approximately 11,000 MW of Department of Water Resources (DWR) contracts will expire between 2009 and 2011, with another 9,000 MW of other contracts expected to expire by 2016. During this period, load is expected to grow by about 4,000 MW. The expiring contracts represent a range of old and new power plants, not all of which are unit specific. To the extent that utilities replace these contracts with long-term commitments to modern, clean, and efficient projects, including renewables, efficiency, and demand response, the next 10 years present a major opportunity for the state to modernize and transform its electric generation supply mix.

Figure 10: **Power Plant Additions & Retirements**

By Utility Service Area (2005-2008)



Source: Revised California and Western Electricity Supply Outlook, *July 2005, CEC-700-2005-019-ED2.*

Although some parties in the *Energy Report* proceeding have advocated that getting the market design right is an essential prerequisite for securing long-term investment in new power plants and transmission lines, the Energy Commission remains sharply focused on the adequacy of the state's infrastructure. While market design is unquestionably important, the Energy Commission remains convinced that a robust infrastructure can better support a less-than-perfect market design than the reverse. The Energy Commission believes that requiring the state's utilities to engage in long-term procurement now is the highest priority for California to ensure an affordable, reliable, safe, and environmentally sound electricity system.

Long-Term Statewide Need for Electricity Resources

The Energy Commission has estimated the need for the state's load serving entities (LSEs) to procure new resources, based on the staff's revised electricity forecast and resource plan information filed by load-serving entities in early 2005. The demand forecast includes a base forecast and high and low cases for both annual energy and peak demand. The supply information provided by LSEs includes data both on the energy and capacity of the physical resources they own or control and their existing contractual resources. The total statewide requirements shown in Figures 11 and 12 are based on the range of demand in the three cases of the revised staff forecast and the resource estimates provided by LSEs.

In Figure 11, the total energy demand includes LSE-reported "firm sales obligations," along with an incremental amount equal to the average generation for the years 2002 through 2006 from

the state's 66 aging power plants listed in Appendix A. The Energy Commission recommends retirement of these plants by 2012. This total demand is compared with the existing physical and contractual resources currently held by the LSEs. The figure also shows estimates of the amount of preferred resources defined in the state's loading order. These include renewable resources identified by PG&E, SCE, SDG&E and SMUD to meet their accelerated renewable generation targets, which will ultimately result in 33 percent or more renewables by 2020, and the uncommitted energy efficiency amounts needed to meet existing targets. The Energy Commission also recommends additional emphasis on distributed generation and combined heat and power resources though this amount is not included in this graph since no specific annual goals have been set.

Resource Adequacy Requirements

In 2005, the CPUC adopted a broad framework for resource adequacy requiring retail sellers, including IOUs and electric service providers, to meet year-round planning reserves.[53] Under this framework, every retail electricity seller must demonstrate that it has acquired sufficient resources to meet its expected peak load plus a 15-17 percent planning reserve.[54]

Figure 11: **Statewide Capacity Range of Procurement Need**

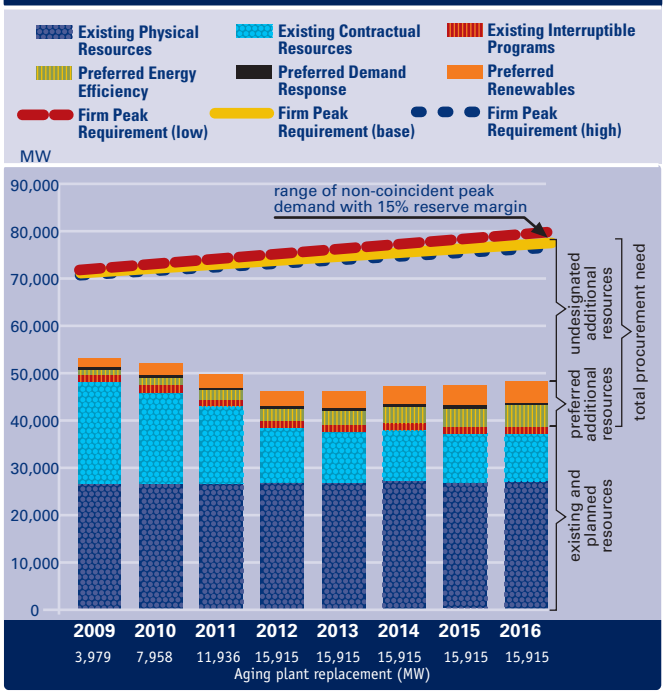
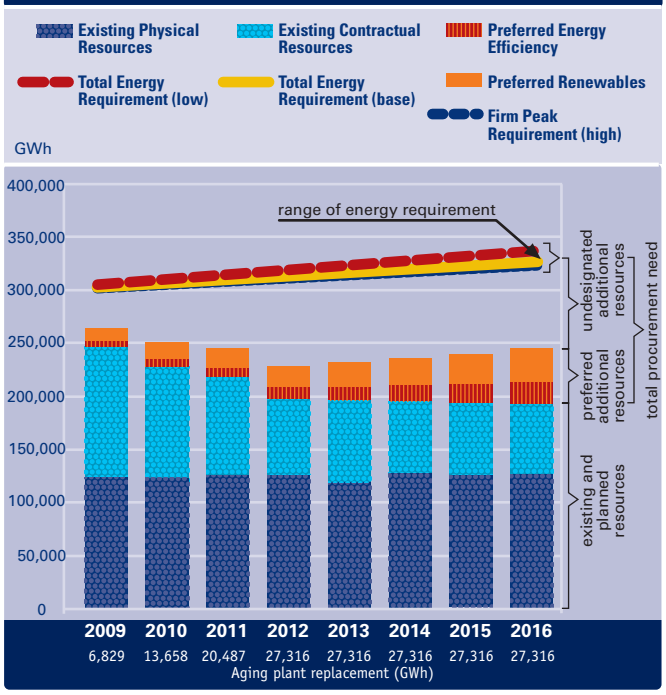


Figure 12: **Statewide Annual Range of Procurement Need**



53. The resource adequacy requirement will be phased in starting in 2006 with full compliance by 2008.

54. These load serving entities include the investor-owned utilities, electricity service providers registered by the CPUC, and community choice aggregators that may form pursuant to AB 117.

Commitments to meet 90 percent of load must be demonstrated one year in advance, while the remaining 10 percent must be demonstrated one month in advance. These resources must be available to the CA ISO to provide reserve support if they are not already scheduled. Consistent with policy direction from Governor Schwarzenegger, these requirements will take effect beginning in June 2006.

The comments received in the resource adequacy proceeding cover a wide range of perspectives and reveal the conflicting goals of different stakeholders trying to shape the details of permanent resource adequacy requirements. In general, generators seek long-term contracts that provide the necessary revenue to cover their going-forward fixed costs. Retail sellers prefer a future capacity market that allows customers to shop around, with minimal financial consequences to the retail seller when they leave. The CA ISO's primary concern is that local area reliability needs are met under a large range of contingencies. Not all of these objectives can be simultaneously satisfied in this first version of resource adequacy requirements. To meet the June 2006 schedule and address near-term reliability concerns, an interim version has been adopted and implemented, which will be modified through time to improve its performance.

The Energy Commission is working closely with the CPUC and the CA ISO to review annual compliance filings to make sure that retail sellers are accurately covering approved load forecasts. The Energy Commission is assisting the CPUC by reviewing retail sellers' load forecasts and making adjustments that account for the impacts of coincident peaks, energy efficiency, demand response, and distributed generation programs that affect all customers.

A critical element of resource procurement and resource adequacy is the juxtaposition of the deliverability requirements being developed by the CPUC with the CA ISO's new transmission planning process.

The CPUC and the Energy Commission are making good progress in establishing one-year obligations for resource adequacy. CPUC D.05-10-042, adopted on October 27, 2005, provides clarification of these requirements and the roles of the three regulatory agencies collectively charged with its oversight and compliance.[55] The capacity orientation and product language adopted in D.05-10-042 are foundational milestones on the road to creating a commercially tradeable capacity market that provides flexibility in meeting resource adequacy requirements consistent with previous *Energy Report* recommendations. As clearly shown in the numerous and diverse comments in the CPUC *Staff Capacity Markets* white paper, California is still a long way from creating a formalized capacity market. Although efforts so far are useful for assigning a value to existing capacity and separating capacity-oriented resources from energy-oriented resources, the current one-year forward time horizon is not likely to financially induce construction of much-needed new power plants. The Energy Commission is continuing to actively support efforts to create a capacity market in California.

In previous *Energy Reports*, the Energy Commission recommended that the Legislature establish comparable resource adequacy requirements for all retail sellers in the state, including publicly owned utilities. Publicly owned utilities are an integral part of the state's electricity grid and should therefore provide sufficient resources and reserves both to meet their own loads and contribute to statewide needs during system emergencies.[56] Governor Schwarzenegger's

55. CPUC, *Opinion on Resource Adequacy Requirements*, October 27, 2005, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/50731.htm], accessed November 6, 2005.

56. A review of publicly owned utilities with peak loads greater than 200 MW during this *Energy Report* proceeding discovered that some publicly owned utilities have insufficient resources to cover both their peak loads plus a 15-17 percent planning reserve margin.

recent response to the *2003 Energy Report* and *2004 Energy Report Update* endorsed the Energy Commission's recommendation to establish resource adequacy requirements for all retail sellers in California. In September 2005, the Legislature passed and the Governor signed AB 380, which directs publicly owned utilities to prudently plan for and procure adequate resources to meet their respective planning reserve margins. It also requires publicly owned utilities to provide information necessary for the Energy Commission to evaluate and report progress made by publicly owned utilities to ensure resource adequacy in future *Energy Reports*. AB 380 does not, however, legally require publicly owned utilities to make forward commitments or to make their resources available to the control area operator. The Energy Commission should evaluate publicly owned utility progress in the next *Energy Report* cycle and, if sufficient progress is not achieved, work with the Legislature to establish mandatory resource adequacy requirements.

Recommendations for Resource Adequacy

- The Energy Commission should continue to work with the CPUC and the CA ISO to flesh out details and accounting conventions for the CPUC's adopted resource adequacy framework.
- The Energy Commission should evaluate publicly owned utility progress in ensuring resource adequacy in the next *Energy Report* cycle and, if progress is insufficient, work with the Legislature to establish mandatory resource adequacy requirements.
- The CPUC should continue its efforts to develop a capacity market to provide flexibility in meeting resource adequacy requirements.

IOU Resource Procurement

In 2004 and 2005, the CPUC approved both IOU long-term procurement plans and a framework requiring LSEs to maintain year-round reserve margins of between 15 and 17 percent.[57]

Each of the utilities has completed agreements to either acquire power plants or purchase power from new facilities, including some that are outside the formal solicitation process. The following are publicly disclosed highlights of some of these agreements:

- SCE signed a power purchase agreement with an affiliate company for the 1,054-MW Mountain View Project in a one-on-one negotiated agreement approved by the CPUC.
- SDG&E acquired two turn-key projects, the 550-MW Palomar Project and the 45-MW Ramco Project, and signed a power purchase agreement with the 570-MW Otay Mesa Project under its 2003 grid reliability request for offers.
- PG&E acquired the rights to construct the partially completed 530-MW Contra Costa 8 Project as part of the Mirant settlement of claims from the 2000-2001 energy crisis.

In addition to the resources mentioned above, the state's three IOUs have signed about 80 contracts to date for power deliveries beginning in 2004 or later. Of these contracts, about 50 have terms of one-to-three years. Ten have terms of three to five years, and 20 are for five years or longer. The contracts' combined total capacity is about 9,000 MW for the one- to three-year contracts, about 1,500 MW for the three- to five-year contracts, and about 2,000 MW for the five-plus-year contracts.[58]

Over the last year, the Energy Commission and the CPUC have worked hard, through a number of rulings and orders, to better integrate the *2005 Energy Report* proceeding with the CPUC's upcoming 2006 IOU procurement proceeding. The two agencies have established the *Energy Report* process as the primary forum for determining load

57. The resource adequacy requirement will be phased in beginning in 2006, with full compliance by 2008.

58. These results include contracts from both requests for offers and bilateral agreements.

forecasting, resource assessment, and scenario issues connected with the CPUC's upcoming 2006 procurement proceeding. The rulings and orders require the Energy Commission to prepare a transmittal report, a companion to the *2005 Energy Report*, to identify a likely range of statewide and IOU-specific needs, issues relevant to these needs, and responses to participant comments.

To help evaluate electricity demand and supply, the Energy Commission in 2004 directed LSEs with peak demands over 200 MW to file retail price forecasts, demand forecasts, resource plans, and related materials. PG&E, SCE, and SDG&E were asked to file a number of resource plans identifying their respective forecasted electricity peak demand and energy requirements and provide detailed explanations of how they plan to meet those requirements under a variety of contingencies.

These resource plans included anticipated savings from energy efficiency and demand response programs and how utilities plan to meet the RPS goal of 20 percent renewable generation by 2010 and assumed a 15-17 percent planning reserve margin. While these resource plans generally reflect the state's loading order resource preferences and targets, they do not specifically reveal the resources IOUs will actually procure. This will depend upon which projects are bid into all-source solicitations and how well they meet IOU least-cost, best-fit selection criteria.

The *2005 Transmittal Report* to the CPUC provides a detailed basis of the Energy Commission's recommendations to the CPUC on the range of need and procurement policies that IOUs need to address in the CPUC's 2006 long-term procurement proceeding. The Energy Commission adopted the final *Transmittal Report* in November 2005.

Confidentiality in Resource Planning and Procurement

One of the most troubling aspects of IOU resource planning and procurement is the IOU claim that resource planning data are confidential. This confidentiality issue sparked much discussion and debate in the *2005 Energy Report* proceeding and resulted in a lawsuit by SCE seeking to prevent the Energy Commission from releasing bundled customer annual peak demand data,[59] followed by a second lawsuit by all three IOUs attempting to block public release of similar supply data.

For the last several years, the CPUC's resource planning process has been shrouded in a high degree of secrecy, with only a handful of individuals allowed to review and critique data submitted by IOUs. While some non-market participants in the CPUC's resource procurement proceeding are allowed to review the data through signed non-disclosure agreements and protective orders, most other parties do not have access to this important data. As a result, open public debate about the data, assumptions, and alternatives that form the foundation of IOU resource planning decisions has been severely truncated. The Energy Commission strongly believes that this environment of secrecy undermines public confidence in regulatory decisions.[60]

Energy Commission staff has been given access to CPUC confidential IOU data only after signing non-disclosure agreements and participating in procurement review groups. This practice is deeply troubling to Energy Commissioners since their staff is effectively precluded from discussing resource procurement specifics with them. When Energy

59. Bundled customers are customers for which a utility provides both electricity and electricity distribution services, as opposed to customers that use utility distribution service but buy their electricity from another retail seller.

60. Policy comments re: R.01-10-024: *ALJ's Ruling Regarding Confidentiality of Information and Effective Public Participation*, signed by William J. Keese, Chairman, California Energy Commission, April 16, 2003.

Commissioners are called upon to conduct the demand forecasting and resource planning that are critical to IOU resource procurement, they are not privy to the critical details of utility solicitation processes, the application of least-cost, best-fit criteria that led to the selection of some bids over others, or to the terms and conditions of those contracts.

In the case of RPS procurement, for example, Energy Commissioners will ultimately make decisions about the expenditure of supplemental energy payments—awards of public funds—to renewable project developers. Under current confidentiality constraints, Commissioners are unable to review or scrutinize detailed information about IOU RPS solicitations, the application of least-cost, best-fit criteria, the terms and conditions of the full range of bids considered, and the contracts ultimately forwarded to the CPUC for approval. In this secretive environment, it is difficult for Commissioners to effectively ensure that public funds actually contribute to the state's RPS goals or constitute an appropriate expenditure of the state's limited subsidy funds for renewable resource development.

For purposes of resource planning in the *2005 Energy Report* proceeding, reliance upon information that is not publicly available compromises the Energy Commission's accountability to the public, the Legislature, and the Governor. Being unable to openly discuss the information forming the basis of its resource planning decisions damages the Energy Commission's ability to be responsive to Californians who have the right to fully understand those decisions.

The Energy Commission investigated the information sharing practices of other western utilities as part of its regulatory process to ensure the release of, at minimum, aggregated summaries of this critical information.[61] All of the major western IOUs publicize much of the demand forecast and resource plan information that California IOUs seek to conceal from the public. Many of these utilities also publish these results at a much more disaggregated level.

California IOUs claim that unique conditions in California justify their need to withhold planning information from the public they serve. The Energy Commission investigated this claim and found it to be groundless. Using several measures—the percentage of bilateral contracts to total resources voluntarily entered into, the percentage of hydroelectric generation resources of total resources, and the possibility of load loss from competing suppliers—the Energy Commission found no meaningful correlation between these measures and the utility information disclosure policies of western utilities.[62]

The measures listed above illustrate the uncertainties that affect IOU exposure to the short-term and contract purchase markets. The first measure evaluates the dependence of IOUs upon intermediate-term market purchases. The second measure evaluates sudden changes that could potentially occur if hydroelectric generation is greater or less than average. The third measures the possibility that load could disappear and leave IOUs with excess resources that would then have to be sold into the market. Based on the Energy Commission's investigation, the notion that California IOUs are in some way different from those in other western utilities is unfounded.

The Energy Commission believes that public disclosure of demand forecasts and resource plans, in both energy and capacity terms, is critical to a sound, transparent planning process that is fundamentally responsive to the public it serves. Even greater disclosure is warranted for California IOUs because of their dominant size and the

61. California Energy Commission docket 04-IEP-1, direct testimony of Michael R. Jaske, July 8, 2005, pp. 4-6 and Table 2.

62. California Energy Commission docket 04-IEP-1, rebuttal testimony of California Energy Commission staff, August 12, 2005, Attachment C.

regulatory protection they enjoy as regulated monopolies. A more open environment is also consistent with the Public Records Act, which is designed to ensure the accountability of government to the public it serves. It is broadly worded in favor of open access, and its exceptions are very narrowly defined.

In its public comments, the League of Women Voters identified confidentiality as an issue that "may be the most critical one that our state needs to address if there is to be any rationality in a comprehensive integrated planning process."[63] The League further noted that IOU claims of confidentiality include all information associated with the application of least-cost, best-fit criteria in the selection of bids and on details of contracts. Without that available information, the League concluded that "the public cannot have confidence in the decision process."[64] The League expressed its respect for the confidentiality of proprietary information, but added that they do not support "failing to disclose information that is to be used in defining resource planning decisions, if that information is directly relevant to the public good."[65]

Some public interest groups do not recognize the impact the procurement review group process has had on resource planning transparency. For example, The Utility Reform Network (TURN) points out in its comments on the RPS that the "program takes many complicated decision processes and makes them transparent by subjecting the evaluation methodologies used by the IOUs to public review and CPUC approval.[66] "However, TURN's comments fail to note that only very general and opaque descriptions of least-cost, best-fit criteria and their application have been made public. No party, other than members of the procurement review groups, has any real understanding of how the principle of least-cost, best-fit is being used to shape the state's resource procurement. TURN does, however, identify what the Energy Commission believes is one of the primary downsides of inadequate public disclosure: "… that IOUs would simply invent their methodologies, their own contract terms, and their own preferred solicitation protocols. Leaving it to the utilities to unilaterally decide these elements could have perverse results and undermine the goal of ensuring fair, transparent, and open competition…"[67]

TURN's comments about all source procurement deepen the Energy Commission's apprehension about the procurement review group process. At a time when the CPUC has placed considerable emphasis on requiring that renewables be the "rebuttable presumption" for all IOU procurement, TURN, a primary participant in and defender of the procurement review groups, has come to a different conclusion: "Based on experience reviewing recent all source requests for offers, TURN believes that these solicitations are not likely to be effective vehicles for the selection of renewable resources. The metrics for comparing gas-fired resources with renewables are tricky, and the two sets of resources serve different purposes in IOU portfolios. Some of the benefits of fossil units (ramping, load following, ancillary services) are not available from renewables."[68]

63. Testimony of Jane Turnbull, League of Women Voters of California, transcript of the October 7, 2005, *Energy Report* Hearing on *Electricity Needs and Procurement Policies*, p. 111.

64. Ibid, p. 111.

65. Ibid, p. 112.

66. Comments of The Utility Reform Network on the draft committee report, docket 04-IEP-1, October 14, 2005, p.13.

67. Ibid.

68. Ibid.

Tricky or not, the Energy Commission believes these metrics deserve vigorous public debate and that the process would be better informed were it accessible to a full range of stakeholders, including the press, and not limited to IOUs and "non-market participants." These are fundamental aspects of public policy, better served by an open and transparent process rather than by a small elite, no matter how well-motivated.

The Energy Commission is committed to rigorous public scrutiny of data and planning assumptions and believes that responsible and effective resource planning cannot exclude the public. The *2005 Energy Report* has elected to rely exclusively upon publicly disclosed information for the basis of its assessments, findings, and policy recommendations. The Energy Commission believes that resource planning and procurement in California should be open and transparent to the public it serves.

The CPUC, through its rulemaking process, is reviewing its regulations governing the disclosure of records, and the Energy Commission will work closely and cooperatively with the CPUC to remove additional barriers to transparency, as called for in the *Energy Action Plan II*. The Energy Commission has also initiated a rulemaking to review its data regulations for the next *Energy Report* cycle to ensure more open and transparent resource planning. Environmental Defense, the Natural Resources Defense Council, and the Union of Concerned Scientists jointly submitted comments early in the *2005 Energy Report* process describing informational deficiencies in the 2004 IOU long-term procurement plans filed with the CPUC.[69] They recommended a robust assessment of alternative future supply portfolios for all load serving entities using scenario analysis. Such a review would focus on portfolio cost, risk, and emissions. Inadequate publicly available information, and the opaqueness of utility least-cost, best-fit methodology in particular, severely curtailed the quality of scenario analysis performed in the *2005 Energy Report* cycle.[70] The Energy Commission is committed to correcting this deficiency in the next *Energy Report* cycle and strongly believes that a rigorous portfolio analysis is a necessary cornerstone to integrated resource planning.

To ensure additional progress in creating an open and public review of resource planning and procurement, the Energy Commission makes the following recommendations:

- Beginning with the 2006 procurement proceeding, the CPUC should allow more public scrutiny and debate on utility resource solicitations, the application of least-cost, best-fit criteria for selecting resources, and utility choices for meeting long-term resource needs. In addition, the CPUC should discontinue its use of procurement review groups.
- The Energy Commission should ensure that portfolio analysis of future resource fuel types is a primary focus of the next *Energy Report* cycle and make the necessary changes in its Common Forecasting Methodology regulations to ensure appropriate information is collected from load serving entities. Details of the evaluation methodologies used, as well as the analytical results, should be the subjects of public workshops or hearings.

Resource Procurement Policies

The CPUC established general capacity amounts and types of contracts to guide IOU resource procurement in its December 2004 procurement decision.[71] The CPUC approved PG&E's strategy

69. Comments of Environmental Defense, Natural Resource Defense Council, and Union of Concerned Scientists, filed in docket 04-IEP-01-D, December 22, 2004.

70. Comments of the Natural Resources Defense Council on the *2005 Integrated Energy Policy Report* draft committee report, October 14, 2005, pp. 12-13, and the Union of Concerned Scientists, docket 04-IEP-1, October 14, 2005, pp. 5-6.

71. CPUC Decision 04-12-048, December 16, 2004, pp. 181-182.

to add 1,200 MW of capacity and new peaking generation in 2008 and an additional 1,000 MW of new peaking and dispatchable generation in 2010. The CPUC determined that SCE's primary need through 2011 is for peaking, dispatchable, and shaping resources and recommended that SCE rely mainly upon short-term and mid-term contacts, but also suggested it would be prudent to add some long-term contracts. The CPUC judged SDG&E to be essentially fully resourced through 2009, with the exception of needed investments in renewables to meet their RPS targets.

While the CPUC did not prohibit IOUs from entering into long-term contracts, utilities have shown little interest in doing so. The CPUC raised the possibility that utilities might need to either enter into new contracts or build new capacity to ensure adequate resources toward the end of this decade. The CPUC further noted that for these resources to come on line within this timeframe, construction needs to begin in the very near future.[72]

The Energy Commission believes the time has come when long-term procurement must aggressively move forward. California should not continue to rely primarily upon short- and mid-term contracts for the majority of its future electricity needs. While PG&E and SCE have each initiated requests for offers (RFO) on the street to procure 10-year contracts (SCE subsequently cancelled its solicitations), some parties claim that utilities have been unnecessarily restrictive in the kinds of resources they are specifying in their RFOs. The CPUC's directive that renewables are the "rebuttable presumption" in all long-term procurement raises the stakes for the solicitation process. California needs to move forward with a system of open, competitive procurement that allows all resources to compete with one another on a level playing field.

Uncertainty from Departing Loads

In the *2005 Energy Report* proceeding, California's IOUs identified departing load to electric service providers, community choice aggregators, and publicly owned utilities as their single greatest source of risk and uncertainty in planning for and procuring future resources. Utilities argued that until this issue is decided, they cannot engage in significant long-term procurement since they cannot accurately predict the amount of load they could lose. Their concern is that if they lose a significant portion of their load to a different supplier they could end up over-procuring resources and incurring stranded costs.

The CPUC acknowledged that while limiting procurement choices to short-term options could reduce the risk of stranded costs, it could also lead to rejection of longer-term contracts, especially in the renewables area that could then result in non-optimal resource portfolios and ultimately higher costs for all customers.[73] To address these concerns, the CPUC recommended a policy allowing IOUs to recover their stranded costs that included both exit fees and other non-bypassable surcharges.[74] The CPUC determined this would require departing load to assume its fair share of IOU costs, consistent with the CPUC policy to hold captive ratepayers harmless.

The Energy Commission agrees with the CPUC's conclusion that establishing exit fees for departing load is the most equitable approach for providing "the need for reasonable certainty for rate recovery" and ensuring that California meets its energy demand.[75] The Energy Commission believes that the CPUC policy of establishing exit fees is sufficient to eliminate the lion's share of IOU uncertainty about departing load and is troubled that IOUs are using these concerns over departing load to avoid securing the significant long-term procurement California needs to meet California's growing electricity demand.

72. Ibid, p. 185.

73. Ibid, p. 51.

74. Ibid, pp. 52 and 185.

75. Ibid.

During the *2005 Energy Report* workshops, several parties indicated that establishing the "coming and going rules" for future direct access is the best way to reduce remaining uncertainties about future IOU loads. The CPUC's Office of Ratepayer Advocates (ORA), SCE, PG&E, SDG&E, and TURN generally agreed that there is more uncertainty about reentry rights than there is about the departure of loads to other retail sellers.[76] Since utilities are the providers of last resort, the conditions under which departing load could return to IOU service were seen as the most critical element of these rules.

The ORA stated its preference for reentry is that once customers leave their utility, they should not be allowed to return. However, ORA did say it was open to solutions being explored in other parts of the country to develop capacity markets and ISO back-stop strategies.[77] SCE and PG&E both indicated that while at times their companies have considered the "once you're gone, you can't return" policy, they recognize that this is not what their customers want.[78] SDG&E called for reasonable switching rules to address departing load uncertainty.[79] TURN expressed concerns about the ability to enforce such a rule in a situation where the IOU is the only entity able to serve the load.[80]

Because the remaining uncertainty about departing load, especially return rights, is inhibiting investment in new generation, the Energy Commission makes the following recommendation:

- The CPUC should begin immediately to establish appropriate coming and going rules for departing load. The CPUC should establish a schedule that would provide a sound set of departing load rules by the end of 2006.

Need for Long-Term Contracts

Utilities have released some RFOs for long-term contracts, but they account for less than 20 percent of solicitations, totaling 2,000 MW of the approximately 12,500 MW under recent solicitations. Since California faces both increasing electricity demand growth and an urgent need to modernize its generation fleet, it is critical that there are enough long-term commitments to bring new generation on line and repower existing aging power plants. This is necessary both to meet future reliability needs and ensure moderate prices.

Arguing against long-term contracts, many parties point to the high cost of DWR contracts signed at the height of the 2000-2001 energy crisis. This concern is misplaced for several reasons. First, to the extent that the contracts were unit-specific (most were not), the DWR contracts were with older, less efficient plants and did not focus on inducing new construction or modernization. Second, the vast majority of the DWR contracts assigned the risk of fluctuation in natural gas prices to the purchaser — as would be the case today — making the lock-in of prices applicable only to non-fuel aspects of the contracts. All that was truly locked in was a reliance

76. Transcript from the *Energy Report* Committee workshops on June 29, 2005, on *Investor-Owned Utility Resource Plan Summary Assessment Report,* and July 7, 2005, on *Electricity Issues and Policy Options*.

77. Testimony of Scott Cauchois, Office of Ratepayer Advocates, transcript of the June 29, 2005, *Energy Report* Committee hearing on the *Investor-Owned Utility Resource Plan Summary Assessment Report*, pp. 116-128.

78. Testimony of Stuart Hemphill, Southern California Edison, transcript of the June 29, 2005, *Energy Report* Committee hearing on the *Investor-Owned Utility Resource Plan Summary Assessment Report*, pp. 20-30, and testimony of Harold LaFlash, Pacific Gas and Electric, pp. 11-20.

79. Testimony of Robert Anderson, San Diego Gas and Electric, transcript of the June 29, 2005, *Energy Report* Committee hearing on the *Investor-Owned Utility Resource Plan Summary Assessment Report*, pp. 31-37.

80. Testimony of Kevin Woodruff, The Utility Reform Network, transcript of the June 29, 2005, *Energy Report* Committee hearing on the *Investor-Owned Utility Resource Plan Summary Assessment Report*, pp. 89-104.

on outdated, inefficient generating technology and its chilling effect on new construction because of the unavailability of long-term contracts.

The *2003 Energy Report*, using gas price projections in the low-to-mid $3 range, estimated that fuel costs would make up 70 percent of the life cycle costs of a new combined-cycle power plant.[81] At a $6 gas price, fuel would represent about 80 percent of life cycle costs, and at $9, about 85 percent. Because the futures market cannot provide a price hedge for much longer than two years, the risk of gas price fluctuation is unavoidably absorbed by electricity ratepayers. Despite locking in only the 15 to 30 percent of life cycle costs that are not fuel related, the value of long-term contracts is the shift to newer and more efficient generating technologies that can produce material savings in the 70 to 85 percent of life cycle costs that are fuel driven. For example, at a gas price of $6, the fuel cost to produce one MWh from a plant with a heat rate of 11,000 British thermal units (Btu) per kilowatt hour (kWh) would be $66, compared with $42 from a plant with a heat rate of 7,000 Btu per kWh. At a $9 gas price, the comparison is $99 to $63.

Long-term contracts with renewable resources—which have no ongoing gas price exposure—turn the modernization concept into a true hedge against long-term natural gas prices. That is why the *2003 Energy Report* identified the Renewable Portfolio Standard as California's primary fuel diversification strategy and why the CPUC's 2004 procurement decision insisted that renewable resources be made the "rebuttable presumption" for all long-term procurement by IOUs.

Perversely, maintaining so many older plants on life support at low capacity factors has prevented construction of more efficient plants that would operate at higher capacities. Virtually all of the state's aging power plants operate at high heat rate capacities that would typically not be dispatched enough in the open market to cover their fixed costs and justify their continued operation. Heat rates for aging power plants in the state range from 8,720 to 12,150 Btu per kWh, with an average heat rate for the fleet of about 10,550 Btu per kWh in 2003.[82] This compares with a 7,000 Btu per kWh heat rate for a modern combined-cycle power plant operating at a high capacity factor.[83] The lower the heat rate, the less natural gas burned, ultimately resulting in lower-cost electricity.

For the *2004 Energy Report Update*, the Energy Commission identified a group of older power plants for study of the current and anticipated roles of aging plants and their impacts on the state's resources.[84] This study used criteria based on a combination of several attributes including age, size, capacity factor, efficiency, and environmental considerations to produce the list of aging power plants in Appendix A. This group of 66 aging gas-fired power plants represents large plants with relatively high heat rates (low efficiencies) and

81. California Energy Commission staff report, *Comparative Cost of California Central Station Generation Technologies*, August 2003, CEC-100-03-001. The natural gas price forecast provided in the appendix to this staff report shows prices in nominal dollars ranging from $3.94 in 2005 to $5.83 in 2013. The "low-to-mid $3 range" price forecast noted in the text is expressed here in year 2000 dollars, as it was reported in the *2003 Natural Gas Market Assessment* (August 2003, CEC-100-03-006).

82. *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirement*, California Energy Commission, draft staff white paper, August 13, 2004, CEC-100-04-005D, p. 31.

83. In 2003, new combined-cycle plants were operating at low capacity factors, around 21-22 percent, with lower than 7,000 Btu per kWh.

84. *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirement*, California Energy Commission, draft staff white paper, August 13, 2004, CEC-100-04-005D.

high operation (capacity factors).[85] The Energy Commission strongly recommends development of an IOU procurement policy that would cover IOU net short positions as well as the retirement or replacement cost of this group of aging power plants.

While it is undoubtedly true that operation of some of these aging plants is critical to meet local reliability, the state would be better off repowering the plants that are locationally critical to the state's electricity system. Currently, these plants have reliability must run (RMR) contracts, which are expensive mechanisms for ensuring system reliability. Utilities, the CPUC, and the Federal Energy Regulatory Commission (FERC) all agree that California should rapidly reduce its dependence upon these expensive contracts. The persistent dependence on RMR contracts more than seven years after implementation of the state's restructuring law is an unfortunate indictment of California's regulatory effectiveness.

Continuing short-term procurement for local area reliability prolongs reliance on aging units that could otherwise be repowered economically under the terms of longer-term contracts and thereby provide similar grid services at a more competitive price. Some of the RMR facilities could be eliminated altogether through transmission solutions, which require a more proactive approach to transmission planning, as discussed in Chapter 4.

From the IOU perspective, as long as their resource adequacy requirements are met with a combination of RMR contracts and short-term contracts with aging power plants, IOU near-term costs are characterized as "reasonable" in the regulatory sense. However, it is not clear that anyone is adequately considering the cumulative long-term economic impact on ratepayers; the reliability risk from continued dependence upon older, less reliable plants; or increasing natural gas price exposure from perennial short-term contracts.

Future gas prices are highly uncertain and pose significant risks for utility ratepayers. While short-term variability in gas prices can be readily mitigated with gas storage and natural gas hedging contracts, long-term fixed-price electricity contracts from gas-fired generators are not readily available given the difficulties in hedging the underlying fuel price risk.[86] When utilities are allowed to simply pass fuel costs through to ratepayers, as is the case today, they are likely to place less value on considering fuel price risk in their planning. This long-term risk exposure for ratepayers must be more effectively addressed in IOU long-term planning and procurement practices.

When aging power plants are secured under RMR or short-term bilateral contracts, they are not required to compete in an open, competitive market with new, more efficient power plants. As long as they are not required to face head-to-head competition with new, more efficient power plants, the benefits of replacement or repowering will not be realized. An open planning forum to assess the locational value of these plants and the advisability of replacing them with new generation or transmission upgrades is critical to the interests of the state. In addition, competitive bidding should be required for the selection of replacement assets. The CA ISO, in collaboration with the CPUC and the Energy Commission, should assess these needs in its new transmission planning process, which is discussed in greater detail in Chapter 4.

The Energy Commission recommends the following to ensure long-term contracts are signed that provide adequate electricity supplies for IOUs:

85. The study group included only natural gas-fired power plants of 10 MW or greater built before 1980. Peaking plants were excluded, as were plants known to be scheduled for retirement in the near term. Of the resulting 66 power plants, 16 are owned by publicly owned utilities.

86. *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans*, Mark Bolinger and Ryan Wiser, Ernest Orlando Lawrence Berkeley National Laboratory, August 2005, p. 44.

- The CPUC should require that IOUs procure enough capacity from long-term contracts to both meet their net short positions and allow for the orderly retirement or repowering of aging plants by 2012.

Portfolio Performance and Least-Cost, Best-Fit Criteria

In its December 2004 resource procurement decision,[87] the CPUC established its intended reliance upon a portfolio approach to balance adequate resources and procurement through "a mix of resources, fuel types, contract terms and types, with some baseload, peaking, shaping and intermediate capacity, with a healthy margin of built-in flexibility and sufficient resource adequacy."[88] The CPUC found that a mixed portfolio of varying contract terms and lengths could prevent utilities from over-subscribing to long-term contracts that could crowd out future opportunities.[89]

IOUs currently use least-cost, best-fit criteria to select bids from their solicitations. These appear to focus on ensuring that selected bids match the baseload, peaking, and other physical characteristics of system needs. Utilities have developed individual methods to calculate and weigh these criteria, including resource or market value, portfolio fit, credit, viability, transmission impact, debt equivalence, and non-price terms and conditions. Yet even descriptions provided by utilities on least-cost, best-fit criteria are not universally transparent and require a high degree of subjective interpretation and judgment. The application of these criteria in bid selection is known only to utilities and individuals participating in procurement review groups.[90]

For example, SCE provides the following description of how it applies least-cost, best-fit criteria to renewables:

Specifically, the [least-cost, best-fit] analysis will employ a production simulation model to calculate the total system production benefits and costs associated with a renewable generating facility. By incorporating Effective Load Carrying Capacity values, transmission costs, and integration cost and benefits, this analysis will produce a benefit/cost ratio for each Proposal. This ratio will then be used to compare the Proposals received.[91]

Production cost simulations and benefit/cost ratios are extremely complex and involve literally hundreds of assumptions that are speculative and require judgment. Many parties have legitimate differences of opinion about the most appropriate assumptions to use in these analyses. The Energy Commission's experience with production cost modeling indicates that, because critical assumptions in these models are highly speculative (such as future gas prices), the results from these models are far less precise than some claim.

87. CPUC Decision 04-12-048, December 16, 2004, p. 28.

88. Ibid, pp. 39 and 181.

89. Ibid, p. 180.

90. In its 2005 request for offers for renewables, Southern California Edison reserved the right to conduct the solicitation without procurement review group concurrence, subject to CPUC approval. Since all discussions with procurement review groups are confidential, no one outside the procurement review group could tell whether legitimate issues were raised by members and dismissed by the utility, or even the extent to which the details of the least-cost, best-fit criteria were disclosed within the group.

91. Southern California Edison, *2005 Request for Proposals from Eligible Renewable Energy Resource Suppliers for Electric Energy: Procurement Protocol.*

Developing a portfolio mix that economically meets baseload, intermediate, and peaking resource needs of utility load is the primary focus of the least-cost, best-fit criteria IOUs use for their resource procurement. The Energy Commission's review of this evaluation criteria indicated that there are significant limitations in market value and portfolio fit criteria currently being used by utilities.[92] The market valuation considers the present value of an asset compared with a market price assumption, while portfolio fit tries to compare an asset with its "short" or "long" positions. While these comparisons have value when evaluating a single asset, they are less valid when examining a larger portfolio since the portfolio then changes market price assumptions.

The state's energy objectives are broader than the IOU definition of least-cost, best-fit; they also include improving the security of a cost-effective supply under a range of uncertain but reasonably anticipated events, including:

- Major disruptions in supply or extreme volatility in the price of a single fuel, such as natural gas.
- Loss of access to or extended outage of a significant portion of a single technology type, such as nuclear.
- Adverse hydro and/or extreme temperature conditions.

The Energy Commission recommends the following to address concerns about portfolio fits and least-cost, best-fit criteria:

- The CPUC, in collaboration with the Energy Commission, should pursue the additional development of portfolio approaches and risk assessment to create a more transparent and standardized method for determining what constitutes least-cost, best-fit. This would allow policy makers to better ensure that IOU resource selections reflect the state's interests in addressing future electricity risk and uncertainty.

Before turning to key loading order policy issues, the Energy Commission believes that two other recommendations relating to supply management from the *2004 Energy Report Update* should be repeated and actively reconsidered:

- The Energy Commission should work with the utilities, the CPUC, and other agencies to identify cost-effective projects that would increase transfer capacity between the transmission system in the CA ISO control areas and the three other California control areas. This increased connectivity could provide both flexibility to control area operators when matching generators to load and reduce the number of power plants needed to meet systemwide demand. Operators would also have greater flexibility to import electricity from cooler regions with generation surpluses during peak load conditions.
- California should establish a joint planning effort to take full advantage of complementary utility systems in California and the Pacific Northwest. California energy agencies should identify regional policies to guide IOUs and others in developing exchange contracts with Pacific Northwest energy entities.

92. Presentation by Eric Toolson, Pinnacle Consulting, transcript of the July 28, 2005, *Energy Report* Committee hearing on *Strategic Transmission Planning Issues and Transmission Staff Report*, pp. 47-80, and California Energy Commission staff report: *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*, July 2005, 700-2005-018, attachment 3, *Risk, Portfolio Theory and Transmission Planning*.

Chapter Four:
Demand-Side Resources, Distributed Generation, and Other Electricity Supplies

In 2003, California's principal energy agencies established an energy resource loading order to guide the state's energy decision making. The loading order decreases electricity demand by increasing both energy efficiency and demand response. It also meets new generation needs first with renewable and distributed generation resources and second with clean fossil-fueled generation. The loading order was adopted in the 2003 Energy Action Plan *prepared by the energy agencies, and the Energy Commission's* 2003 Energy Report *used the loading order as its foundation for recommended energy policies and decisions.*

The state has outlined an aggressive strategy that combines energy efficiency and demand response programs to slow electricity demand growth. Governor Schwarzenegger recently affirmed his support for previous *Energy Report* recommendations "to ensure that efficiency maintains its preeminent place in preferred energy resource additions."[93] The Governor also recently signed legislation that requires investor-owned utility procurement plans to demonstrate that unmet resource needs will be met first with "all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[94] The legislation also adds a section to the Public Utilities Code placing a similar requirement on publicly owned utilities.

While California is on track to meet energy efficiency targets set two years ago, existing programs may not be taking full advantage of opportunities to further reduce peak electricity demand. Demand response programs, the most promising and cost-effective options for reducing peak demand on the state's electricity system, have unfortunately failed to deliver energy savings targets established by state policy makers for each of the last three years. It appears that they will also fall short of next year's targets. The Governor has committed to using advanced meters and dynamic tariffs to meet demand response goals. He has also directed the CPUC to proceed promptly with plans by PG&E and SDG&E to provide meters to residential and commercial customers and recommended that SCE accelerate its planned efforts.[95]

The state's primary strategy to diversify supplies is through development of renewable resources, yet the administrative complexity and lengthy solicitation process that has emerged under the Renewable Portfolio Standard (RPS) program is hampering the state's ability to meet its renewable targets. Additionally, neither distributed generation sources, including combined heat and power facilities, nor renewable technologies have received the regulatory attention and encouragement necessary to meet the desires of policy makers to increase reliance on these resources. Governor Schwarzenegger has emphasized that the state should encourage distributed generation and combined heat and power since "it can occur at load centers, reducing the need for further infrastructure additions."[96]

California policy makers must improve their efforts to reduce electricity demand growth and shave peak demand through energy efficiency and demand response programs. To bring enough new generation on line to meet future demand, the state must vigorously pursue preferred resources: renewables, distributed generation, and lastly, conventional generation. At the same time, California's bulk transmission system must be enhanced and fortified to ensure that electricity can be delivered when and where it is most needed, as discussed in Chapter 5.

The following sections outline measures the state must urgently take to ensure achieving energy efficiency, demand response, and distributed generation goals. Renewable resource issues are addressed in Chapter 6. Collectively, these measures will help protect Californians against blackouts, ensure reliable long-term supplies, decrease the state's growing dependence on natural gas, and reduce electricity costs for both residential and business customers.

93. Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: *Review of Major Integrated Energy Policy Report Recommendations*, August 23, 2005.

94. SB 1037 (Kehoe), Chapter 366, Statutes of 2005.

95. Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: *Review of Major Integrated Energy Policy Report Recommendations*, August 23, 2005.

96. Ibid.

Energy Efficiency

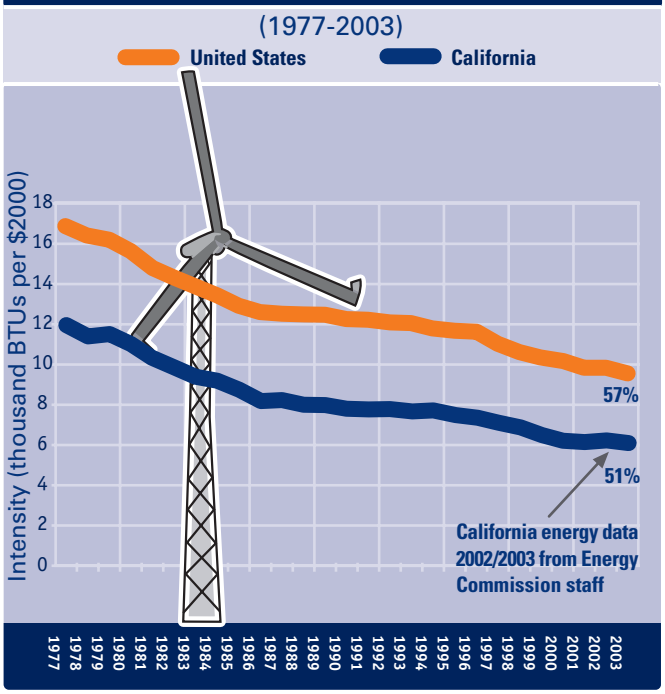
Energy efficiency is the first priority in California's loading order. Energy efficiency programs reduce the state's reliance on natural gas and the need for new power plants by reducing the amount of energy consumed. By decreasing peak demand, these programs also increase the reliability of the electricity system and reduce the environmental impact and cost of electricity.

California leads the nation in energy efficiency and conservation. As a result, electricity use per person in California has remained relatively flat over the past 30 years while the nation has seen a 45 percent increase. California's "energy intensity," the ratio of energy consumption to demand, is also well below that of the U.S. as a whole, as shown in Figure 13. Through 2003, California's energy efficiency programs have saved more than 40,000 gigawatt hours (GWh) of electricity and 12,000 MW of peak demand, equivalent to more than two dozen 500-MW power plants. These programs, mainly mandatory efficiency standards, will continue to save energy in the future.

The *2003 Energy Report* concluded that 30,000 additional GWh represent the maximum achievable electricity savings from energy efficiency programs over the coming decade. The CPUC adopted aggressive energy savings goals in 2004 to reach this potential. When these goals are met, energy savings will represent more than half of investor-owned utility (IOU) need for additional electricity between 2004 and 2013. To achieve these goals, the CPUC significantly increased IOU energy efficiency funding to $823 million for 2004-2005[97] and $1.98 billion for 2006-2008.[98]

California's building and appliance standards are the state's most cost-effective efficiency measures. Since the first round of standards was adopted in 1975, the state has saved 6,000 MW in peak demand and expects to save 10,000 MW by 2010. The Energy Commission also adopted new appliance efficiency standards in 2004 that will reduce consumer utility bills by $3.3 billion during the first 15 years they are in effect.[99] The Energy Commission will continue to evaluate energy-using technologies for incorporation into periodic updates to the state's building and appliance standards.

Figure 13: U.S. and California Energy Intensity



Source: Energy Information Agency and Bureau of Economic Analysis, except where otherwise noted.

97. CPUC, Decision 03-12-060, issued December 22, 2003, Energy Efficiency Rulemaking 01-08-028.

98. CPUC, Decision 05-09-043, issued September 27, 2005, Energy Efficiency Rulemaking 01-08-028.

99. California Energy Commission, July 2005, *Implementing California's Loading Order for Electricity Resources*, CEC-400-2005-043.

While the Title 24 Building Efficiency Standards ensure that new buildings and additions and alterations to existing buildings include energy efficiency in their design, there has been remarkably little regulatory attention to improving the energy efficiency of existing buildings. Although utility energy efficiency programs have generally promoted savings in existing buildings, there is still enormous potential for energy efficiency savings in existing buildings, which turn over very slowly and dominate energy consumption. The Energy Commission is developing a report to the Legislature in response to AB 549 (Longville), Chapter 905, Statutes of 2001, outlining options for upgrading existing buildings, including efficiency inspections when buildings are sold, and utility pilot programs like on-bill financing, building commissioning, and retro-commissioning. Close coordination with the benchmarking effort of the state's Green Buildings Initiative will improve the likelihood of upgrading existing buildings.

IOU planners need to be able to confidently account for energy efficiency savings in their procurement planning processes and decisions. Energy efficiency programs must be prudently managed and measured to ensure that projected savings actually materialize and are recognized in the planning process. The CPUC has changed the way efficiency programs will be administered in the future by establishing a new framework under which the CPUC and the Energy Commission cooperatively manage and contract for all efficiency monitoring and verification studies. This will establish a clear separation between program evaluators and administrators and program implementers to ensure that IOU intentions translate into real energy and peak demand savings. The Energy Commission and the CPUC should continue to work collaboratively to ensure the rigorous evaluation, measurement, and monitoring of energy efficiency programs. Doing so will give utility planners the accurate information they need for developing their procurement plans, while making certain that public funds are prudently spent. The recently enacted SB 1037 (Kehoe), Chapter 366, Statues of 2005, will add significant teeth to this process.

The CPUC has also changed how savings are quantified, evaluated, measured, and verified for post-2005 efficiency programs. The CPUC has returned program choice and the responsibility for energy efficiency portfolio management to IOUs and directed them to design and implement portfolios of utility and non-utility energy efficiency programs. Recognizing the key role of private energy service companies, local government agencies, nonprofit organizations, and other entities, at least 20 percent of IOU portfolios must be competitively bid to non-utility third parties. The reasoning for this change is that these entities will improve overall portfolio performance by developing proposals that will be both innovative and targeted to specific market needs and niches.

Energy efficiency program portfolios bid to non-utility third parties reflect a much-needed focus on programs that create peak demand energy savings. Energy efficiency programs must meet specific cost-effectiveness rules, which are typically measured by energy savings per dollar spent. This method can drive efficiency programs to focus on overall energy savings instead of on peak demand savings. Since California consistently experiences high peak summer demand, shaving those peaks is critical to reducing electricity price volatility, safeguarding reliability, and reducing the need for peaking power plants that operate only a few hours a year.

Residential space cooling contains the greatest potential for peak energy savings, followed by commercial space cooling and lighting.[100] The CPUC recognized that preliminary IOU efficiency

100. The Utility Reform Network comments at *2005 Energy Report* workshop on *Energy Efficiency Policies,* July 11, 2005.

portfolios were overly reliant upon high energy-using measures, like lighting, at the expense of critical peak impact end uses like air conditioning. In its April 2005 Decision 05-04-051, the CPUC stated that energy efficiency rules "should be modified to reflect the need to ensure reliability in the near term by encouraging aggressive programs that target measures with most of their energy savings during peak time periods."[101]

However, in its decision on 2006-2008 program funding, the CPUC rejected a proposal by The Utility Reform Network (TURN) that would have required utilities to rebalance their portfolios in favor of air conditioning savings. The CPUC reasoned that a large portion of the existing potential for these savings will be captured through efficiency increases in new residential air conditioners mandated by 2005 appliance standards and that utility programs have already increased funding for residential air conditioning programs compared with previous years. TURN expressed concern that IOU portfolios overemphasize savings from residential lighting at the expense of savings from space cooling.

The CPUC has made some progress toward establishing an appropriate balance between energy and peak savings in energy efficiency programs. For example, the CPUC requires program administrators to demonstrate how their proposed portfolios will aggressively lower peak demand. Existing programs must also meet the standard that demand reductions equal 0.217 times the energy savings goals, based upon the historic relationship between energy and peak savings.[102] However, the Energy Commission remains concerned that IOU energy efficiency portfolios should focus more on programs that realize peak energy savings to reach the state's overall peak savings goals. This is especially critical in the near term in Southern California, where reliability margins are significantly tighter than in Northern California.

This emphasis on peak savings, however, should be balanced with another key reason for establishing energy efficiency goals: their potential contribution to global climate change targets established by Governor Schwarzenegger. Generally, getting the greatest energy savings from the program portfolio could make the single biggest contribution to reducing climate change gases from electricity generation. While much of California's electricity needs are met by natural gas-fired power plants, saving energy at different times of the day and year also affects generation from power sources of different efficiencies and fuel types. The Energy Commission should analyze the impact of energy savings during different hours on climate change goals and tailor programs to reduce both climate change gases and peak demand.

IOU energy efficiency programs have traditionally been established on an annual basis, and individual programs frequently generate a market response that ends up depleting the program's funds before the end of the year. This has had two consequences. First, the state has not been able to capture the full amount of cost-effective peak demand and energy savings in that year, and utilities end up meeting their energy demand with resources lower in the loading order. Second, the businesses that provide energy efficiency services and equipment in California face the financial risk of annual boom and bust cycles. The CPUC should change this pattern by funding energy efficiency programs with enough budget flexibility to allow efficiency programs to meet market demand in a more timely fashion. In some cases, this may

101. CPUC, April 21, 2005, Interim Opinion: *Updated Policy Rules for Post-2005 Energy Efficiency and Threshold Issues Related to Evaluation, Measurement and Verification of Energy Efficiency Programs*, D. 05-04-051, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/45783.htm].

102. CPUC, September 27, 2005, Interim Opinion: *Energy Efficiency Portfolio Plans and Program Funding Levels for 2006-2008 – Phase 1 Issues* [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859-07.htm], accessed October 20, 2005.

simply provide the ability to transfer funds within the overall target budget from one program with low demand to another program with higher demand.

Overall utility efficiency budgets should be established with a balancing account structure that accommodates the full market demand for any given program. Generation procurement flexibility—with utilities purchasing what is necessary to meet their demand—should also apply to resources at the top of the loading order. Utilities should be expected to procure as much cost-effective energy efficiency as the market can provide, without annual budget constraints.

Because publicly owned utilities provide 25-30 percent of the electricity used in California, energy efficiency efforts by these entities are essential to the state's overall goal to reduce electricity demand. Although the state has adopted efficiency goals for IOUs, publicly owned utilities are not required to match this level of performance. The recently enacted SB 1037 may go a long way toward changing that. The Energy Commission should work with publicly owned utilities to establish goals similar to those required of IOUs by the end of 2006.

The Energy Commission needs better information about program plans and results to establish these goals. Without publicly available data, it is difficult to determine on a statewide basis how much publicly owned utilities spend on efficiency or how much energy they save. The Energy Commission should create a reporting requirement as part of its Common Forecasting Methodology regulations for publicly owned utilities to report the status and progress of their efficiency programs to allow transparent comparisons between IOU and publicly owned utility program designs, costs, and effectiveness. This requirement is consistent with SB 1037 requirements for publicly owned utilities to report annually to their customers and to the Energy Commission on their investments in energy efficiency and demand reduction programs, including descriptions of programs, expenditures, and expected and actual energy savings. This reporting requirement should not impose a cost burden on publicly owned utilities but should still provide enough needed information for useful comparisons.

Recommendations for Energy Efficiency

- The Energy Commission should continue to evaluate energy-using technologies for possible incorporation in periodic updates to the state's building and appliance standards.
- The Energy Commission should develop an aggressive implementation plan for improving the energy efficiency of existing buildings as a follow-up to its AB 549 report.
- The Energy Commission and the CPUC should continue to work together to ensure the rigorous evaluation, measurement, and monitoring of IOU energy efficiency programs.
- The Energy Commission should analyze the effect of energy savings on climate change goals, during different time periods, to reduce emissions of climate change gases.
- The CPUC should fund efficiency programs with enough budget flexibility to allow those programs to meet market demand in a timely way.
- Utilities should be required to procure as much cost-effective energy efficiency as the market can provide.
- The Energy Commission should create an efficiency reporting requirement for publicly owned utilities as part of its Common Forecasting Methodology regulations.

Demand Response

The *2004 Energy Report Update* highlighted the importance of demand response programs to CPUC and Energy Commission goals.[103] Demand response

103. The *Energy Action Plan*, adopted by the Energy Commission and CPUC in 2003, laid out goals for demand response programs that were further endorsed in the *2003 Energy Report*.

programs reduce peak demand in two ways. First, price-sensitive programs provide customers with the financial incentives and metering technology to reduce electric loads when prices and electricity demand are high. Second, reliability programs provide customers with a non-price signal that clearly shows when system resources are strained and demand reduction would be most beneficial. Reducing system load before it reaches capacity constraints increases the reliability of California's electricity grid. By reducing the need for additional system infrastructure or peaking generation, demand response also lowers consumer electricity costs over the long term.

Price-sensitive and reliability programs are both key components of demand response. The state has historically relied on reliability programs in times of constrained supply, most recently during the summer of 2005 in Southern California. Advances in metering and communications technologies allow significant improvements to price-responsive and signal-responsive programs. It is important to recognize that new metering technology will be the primary platform for the state's future demand response policies. Both types of programs are being designed to allow customer control—a key feature expected to increase participation by providing customers with greater choice over impacts on their homes and businesses.

Recent efforts in California to increase demand response programs have focused on price-sensitive programs like dynamic pricing and demand bidding. Dynamic or "real-time" pricing increases prices to reflect the actual high price of electricity during periods of high demand, sending price signals to customers that will require them to either reduce energy use or pay the full cost of such service. Large customers already have advanced meters designed to take advantage of dynamic pricing rates. The state needs to establish and implement default dynamic rates for these large customers. For dynamic pricing to be most effective, however, the state also needs to develop an advanced metering infrastructure for all customers, as recommended in the *2003 Energy Report* and the *2004 Energy Report Update*.

The CPUC set demand reduction targets for the state's IOUs in 2003. Although the utilities did not meet their targets for 2004, they did reduce demand by 556 MW, 63 percent of the statewide target. In 2004, the CPUC ordered utilities to file applications for a new default rate with critical peak features. The proposed new rate addressed both the lack of enrollment in voluntary demand response programs by large customers and the limited customer performance in other programs. After reviewing utility applications, however, the CPUC concluded that more time was needed to analyze the variety of critical peak pricing rate proposals. Instead of implementing these rates in time for summer 2005, the CPUC ordered new rate proposals for 2006 implementation.

In 2005, IOUs filed applications to implement default critical peak pricing tariffs for large customers, beginning in summer 2006. The CPUC expects to issue a decision on these tariffs in early 2006. IOUs will also develop customer education, assistance, and incentive plans to ease this rate transition for large customers. This effort could well bring IOUs closer to their demand response goals.

In addition to the advanced meters installed for large customers in the state, the CPUC has ordered IOUs to file business cases for applying advanced meters on a system-wide basis. These systems allow utilities to remotely read customer meters, support emergency reliability programs, and reduce the costs of billing, metering, and managing outages. Over the past year, IOUs completed an analysis of the costs and benefits of installing advanced metering networks. The CPUC and the Energy Commission reviewed these analyses and encouraged utilities to move forward with their applications.

PG&E and SDG&E filed plans aimed at quickly replacing their metering systems with advanced metering and communications systems capable

of supporting time-based rates for all customers. In contrast, SCE simply filed a plan directed at development of a new metering infrastructure, with the replacement of its metering systems lagging behind the other two IOUs. Governor Schwarzenegger recently urged the CPUC to require SCE to expedite its plans so that it will be on a par with the other utilities.[104]

Reliability programs should also be pursued with the advent of advanced metering infrastructure and communication technology. Many of the state's long-standing demand response programs, including interruptible rates and air conditioner cycling programs, simply curtail customers or appliances in response to a high-demand signal. Advanced communication technologies now permit less intrusive dispatchable demand reductions through two-way communication with customer thermostats and other equipment. Instead of completely shutting down groups of air conditioners, managers can adjust air conditioner levels to both shape demand and allow customers greater control and choice. These new programs should be further explored and promoted as the state increases its reliance upon demand response.

Publicly owned utilities are also exploring advanced metering infrastructures and demand response programs. Advanced metering and demand response efforts by publicly owned utilities will be essential for reaching the state's overall goal of reducing electricity demand and mitigating resource constraints and high prices. The Energy Commission should work with these publicly owned utilities to better understand their demand response efforts and develop goals by the end of 2006 similar to those adopted for IOUs.

As part of this effort to develop publicly owned utility goals, the Energy Commission again needs better information about these utilities' plans and results. The Energy Commission should include demand response information in the Common Forecasting Methodology reporting requirement recommended for energy efficiency programs without imposing an undue cost burden on these utilities, while still collecting the needed information to compare their performance with other demand response efforts in the state.

Advanced metering and dynamic pricing will likely be the foundation of California's future demand response programs. However, two pending efforts will affect the CPUC's ability to implement advanced metering and time-based electric rates. Under current approaches, customers who use high quantities of energy when wholesale prices are high are subsidized by customers who use low quantities of energy during the same time periods. Moving to a real-time pricing approach will eliminate that cross-subsidization, resulting in higher overall electricity costs for some customers and lower costs for others.

Although demand response remains in some ways controversial, California must grapple with the state's increasing number of peak load hours to improve system reliability and moderate electricity price volatility. The Energy Commission and the CPUC need to make major efforts over the next few years to determine the best mix of voluntary and mandatory demand response programs, as well as the right mix of price-sensitive and reliability programs.

Recommendations for Demand Response

- The CPUC needs to develop and implement dynamic rates for all customers with advanced metering.
- The state should develop an advanced metering infrastructure for all utility customers.

104. Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: *Review of Major Integrated Energy Policy Report Recommendations*, August 23, 2005.

- By the end of 2006, the Energy Commission should work closely with publicly owned utilities to better understand their demand response efforts and develop goals similar to those required of IOUs.
- The Energy Commission should include demand response information in the Common Forecasting Methodology.

Distributed Generation and Combined Heat and Power

An important alternative to new central station fossil-fueled generation is distributed generation (DG), which includes both cogeneration and self-generation. DG is broadly defined as electricity produced on-site or close to a load center that is also interconnected with a utility distribution system.[105] California has approximately 2,500 MW of small scale renewable and non-renewable DG and has added an average of 100 MW of new small scale DG capacity every year since 2001.

The benefits of DG go far beyond actual generation. DG reduces the need for new transmission and distribution infrastructure and improves the efficiency of the state's electricity system by reducing losses at peak delivery times. Customers can use DG technologies as either peaking resources or for energy independence and protection against supply outages and brownouts. DG is a key element of California's loading order strategy and will help meet the state's energy efficiency and renewable energy goals.

Cogeneration, or combined heat and power (CHP), is the most efficient and cost-effective form of DG, providing numerous benefits to California including reduced energy costs, more efficient fuel use, fewer environmental impacts, improved reliability and power quality, locations near load centers, and support of utility transmission and distribution systems. In this sense, CHP can be considered a viable end-use efficiency strategy for California businesses. There are more than 770 active CHP projects in California totaling 9,000 MW,[106] with nearly 90 percent of this capacity from systems greater than 20 MW. CHP has significant market potential, as high as 5,400 MW, despite high natural gas prices.

California should particularly encourage CHP at the state's petroleum refineries to make them less vulnerable to power outages. An electricity outage on September 12, 2005, in Southern California caused the shutdown of three refineries in Wilmington. These shutdowns resulted in pressure buildups that forced refinery operators to flare excess gases, affecting air quality in the area. The shutdown also impacted gasoline production and supply, causing shortages and price spikes. Increased CHP use at refineries is an important strategy that can help insulate refineries from these kinds of electric grid problems and maintain gasoline production and refinery safety.

The *2003 Energy Report* highlighted the importance of DG and CHP in meeting California's growing energy needs and providing an essential element of customer choice. The *2003 Energy Report* called for the creation of a transparent distribution system planning process addressing the utility benefits of DG and CHP. While some slight progress has been made, almost two years later there has been only a very small increase in the use of DG and CHP.

Despite policy preferences, DG and CHP in California still struggle with major barriers to market entry in the context of traditional utility cost-of-service grid management. In fact, many of the state's operating larger-scale CHP systems still run under the terms of generation contracts signed

105. This is a working definition for distributed generation used in various policy activities at the California Energy Commission and the CPUC.

106. *Assessment of California CHP Market and Policy Options for Increased Penetration*, California Energy Commission, CEC-2005-060-D, April 2005.

during the early 1980s following the national energy crisis of the late 1970s. These projects could shut down in the near future as their contracts expire. It is estimated that as much as 2,000 MW could shut down between now and 2010 because project owners have been unable to renew their utility contracts.[107,108]

The *2005 Energy Report* reaffirms its commitment to DG and CHP by separating the discussions of CHP and DG to provide more clarity for policy makers. As a first step, the Energy Commission funded the Assessment of California CHP Market and Policy Options for Increased Penetration, a study that identified a series of policy scenarios that could help focus policy direction on the effective deployment of future CHP.[109] The assessment produced a number of important findings.

California has more than 9,000 MW of CHP across the state. With statewide generation capacity at approximately 60,000 MW, CHP is a key component of generation delivered to the grid. CHP represents approximately 17 percent of the state's generation and is often key to preserving grid reliability. CHP systems smaller than 5 MW represent only about 3 percent of total CHP capacity in the state, though much of California's policy efforts over the past seven years have focused on these smaller DG systems, including small scale CHP. This finding suggests that the state should broaden its policy focus to include large scale CHP, which could produce several thousand MW of additional generation capacity over the next 15 years.

Current state policy must clearly change for California to take advantage of this valuable generation potential. It is equally important to retain the state's existing CHP that is so critical to the current reliable operation of the electric grid. CHP developers seeking to install new generation are presently discouraged from sizing their systems to satisfy their full thermal loads because they would have to generate more electricity than they could use on site. These developers frequently have trouble finding customers interested in buying their excess power at wholesale prices. Lack of a robust, functioning wholesale market in California worsens CHP concerns about this risk.[110] Even if wholesale markets were functioning well, CHP owners would still struggle with the complexity and cost of complying with the CA ISO's tariff requirements, including scheduling exports hour-by-hour, installing costly metering and reporting equipment, and other factors.

At the retail level, policy decisions (including suspension of direct access) have hampered CHP owners' ability to sell their excess power to customers. The lack of distribution wheeling tariffs and restrictions on "over the fence" transactions by Public Utilities Code Section 218 create additional barriers.[111] During the 2000-2001 energy crisis, Berry Petroleum needed additional steam for enhanced oil recovery and was willing to install additional CHP facilities to provide that steam. Berry was ultimately forced to install traditional boilers, however, because it could not secure a viable long-term contract for the excess electricity from the CHP facilities.[112] In another example, owners of

107. Public comments by Rod Aoki, representing Cogeneration Association of California and the Energy Producers and Users Coalition, *Energy Report* Loading Order workshop, July 25, 2005.

108. Comments by Cogeneration Association of California and the Energy Producers and Users Coalition, docket 04-IEP-1E, August 1, 2005.

109. *Assessment of California CHP Market and Policy Options for Increased Penetration*, California Energy Commission, CEC-2005-060-D, April 2005.

110. Comments by Cogeneration Association of California and The Energy Producers and Users Coalition, docket 04-IEP-01E, August 1, pp. 19-20.

111. Comments by Kevin Duggan representing California Clean DG Coalition, docket 04-IEP-1E, August 1, 2005, p. 2.

112. Panel discussion by Barry Lovell, Berry Petroleum Company, *Energy Report* workshop, *California's Market Potential for Combined Heat and Power (CHP) and Distributed Generation*, April 28, 2005, and comments filed, docket 04-IEP-1E, October 11, 2005, p. 2.

a 300-MW facility that has been reliably providing enough power to serve more than 400,000 SCE customers for two decades have been trying to negotiate a new contract for more than two years.[113] In yet another example, Valero Refining Company has been trying to secure a contract for over a year with PG&E to sell its excess power but has been unsuccessful because PG&E and the CA ISO are requiring Valero to execute a FERC jurisdictional interconnection agreement and pay the wholesale CA ISO tariff before selling power to the utility.[114] Equally troubling is the fact that Valero has received all necessary permits to install a second generating unit at its refinery but is reluctant to do so because of the "regulatory limbo" between the FERC and CPUC jurisdictions.[115]

Looking ahead to the future development of more workable CHP policies, California must recognize that CHP owners are not in the business of producing or selling electricity. CHP owners will choose to operate their businesses and simultaneously produce electricity only when the economics are favorable to them. CHP policy therefore must be different from the policies developed for traditional customer generators and merchant power plants. To illustrate this point, the CHP industry notes that "CHP resources are not and will never be fully dispatchable merchant facilities, designed solely for the purpose of producing power; CHP resources were built primarily to serve thermal energy load, or a combination of thermal and electric energy load."[116] This may not be especially problematic since neither all merchant plants nor all IOU power purchases serve a single purpose in an IOU's generation portfolio. IOUs structure their portfolios to include resources with different terms, load shapes, and operational characteristics.[117]

Based on analyses conducted over the course of the 2005 Energy Report and extensive input from the industry, utilities, the public, and others, the Energy Commission believes there are several key initiatives that California must pursue to encourage construction of additional cost-effective DG and CHP. CHP is of such unique value in meeting loading order efficiency and new generation objectives that CHP deserves its own place in the loading order. The Energy Commission and the CPUC should therefore separate CHP from DG in the next version of the Energy Action Plan so that CHP issues and strategies are not lost in broader DG issues and strategies.

The state also needs to improve access to wholesale energy markets and streamline the utilities' long-term contract processes so that CHP owners can easily and efficiently sell their excess electricity to their local utility. This would provide CHP owners with the certainty needed to guide their investment decisions to install or expand their CHP operations. By the end of 2006, the CA ISO should modify its CHP tariffs in recognition of the unique operational requirements of CHP and allow CHP owners to sell their power to the state's electric grid at reasonable prices. This is particularly important given the value CHP provides both IOUs and the CA ISO in reducing transmission

113. Comments by Cogeneration Association of California and The Energy Producers and Users Coalition, docket 04-IEP-01E, August 1, p. 7.

114. Ibid, p. 7.

115. Panel discussion by David Dyck, Valero Energy Corporation, *Energy Report* workshop, *California's Market Potential for Combined Heat and Power (CHP) and Distributed Generation,* April 28, 2005.

116. Comments by Cogeneration Association of California and The Energy Producers and Users Coalition, docket 04-IEP-01E, August 1, p. 14.

117. Ibid.

congestion and increasing local reliability. Additionally, utilities should be required to offer CA ISO scheduling services at cost to their CHP customers. Congestion and reliability issues will be compounded if California is derelict in addressing these barriers and ultimately loses these strategic generation resources. Natural gas resources and infrastructure would also feel the loss of this valuable generation, as would the environment, because of increases in boiler installations to meet thermal loads. If companies decide to leave California because of energy costs or reliability concerns, it would also mean the loss of well-paying industrial jobs.

Recent federal energy legislation suggests that the Public Utilities Regulatory Policies Act (PURPA), enacted in 1978, will likely remain in effect in California because of the lack of a robust and functioning wholesale market. By the end of 2006, the CPUC should require IOUs to buy, through standardized contracts, all electricity from CHP plants in their service territories at their avoided cost, as defined by the CPUC in R.04-04-025.[118] The Legislature should pass legislation requiring similar requirements for publicly owned utilities, irrigation districts, and other electricity service providers. These long-term contracts should be long enough for CHP owners to make well-informed investment decisions and provide assurances to the Energy Commission and the utilities of their long-term availability. The terms of these contracts should be at least 10 years; however, the Energy Commission and the CPUC should work together to evaluate whether these contracts should have terms with the same economic life as avoided resources.

IOUs also need an incentive to incorporate CHP into their systems and, more importantly, incorporate CHP into their system planning. The Energy Commission's recommendation is three-fold:

- As the *Assessment of California CHP Market and Policy Options for Increased Penetration* indicates, society as a whole benefits from CHP, though all CHP policy scenarios unfortunately produce utility revenue losses. For California to practically establish its societal preference for DG and CHP, IOUs should be compensated for their revenue shortfalls at least to the point of making them cost neutral. California should explore regulatory incentives to reward IOUs for promoting public– and utility-owned CHP and DG projects. Approaches like the Earned Rate Adjustment Mechanism, which have been successful in keeping IOUs revenue-neutral for energy efficiency programs, could also be implemented for both CHP and DG. California could additionally implement a regulatory approach similar to that of the United Kingdom, where utilities are provided incentives to interconnect DG and CHP projects. The United Kingdom provides even larger incentives to utilities for DG and CHP systems installed on constrained portions of their electricity systems. The CPUC should immediately develop a method to provide DG and CHP incentives to utilities and implement them by the end of 2006.
- The *Assessment of California CHP Market and Policy Options for Increased Penetration* determined the realistic goal of 5,400 MW of CHP by 2020, which will only be possible if the policies recommended here are actually implemented. By the end of 2006, the Energy Commission and CPUC should collaboratively translate this goal into annual IOU procurement targets. The Energy Commission and CPUC should establish mechanisms in this process to ensure that existing CHP systems retain their baseload positions in IOU portfolios. These mechanisms should rely upon cost/benefit methodologies being developed in CPUC Proceeding R.04-03-017 to make sure that California builds projects that provide the greatest societal benefit.

118. CPUC, April 28, 2004, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/36203.htm], accessed November 6, 2005.

- California must carefully consider how additional DG and CHP facilities could affect distribution system operations, reliability, and safety. California utilities are planning to invest billions of dollars in their distribution systems in coming years to keep up with their load growth. Now is the time to require the infrastructure investment that will enable utilities to include DG and CHP in their distribution systems. A careful review of Denmark's system, where CHP and DG make up more than 50 percent of the country's generation capacity, shows that distribution system operations can become expensive, complicated, and unpredictable if they are not designed to accommodate DG and CHP.[119] California should require utilities to design and construct distribution systems that are DG and CHP compatible. These designs must recognize the system benefits DG and CHP provide, including voltage support, system restoration and reliability, and intentional islanding.

Initial research from the Energy Commission's Public Interest Energy Research program shows that DG and CHP can provide quantifiable benefits to utility systems. The results of recently completed research on Silicon Valley Power's system show that a majority of Silicon Valley Power's customers could install DG, providing various degrees of utility benefits.[120] In this case study, the optimal portfolio was made up of smaller DG systems, averaging less than 160 kW. Some locations on the utility system are also better than others for utility voltage variability, losses, and other factors. The CPUC should require utilities to implement comparable planning models to determine where DG and CHP are most beneficial from system transmission and distribution perspectives.

CHP effectively reduces greenhouse gas emissions and both transmission and distribution congestion. CHP facilities are located in local load centers where system operators often struggle to maintain local reliability. CHP also provides significant resources during peak demand periods, which help mitigate operational problems involved with meeting peak demand. To maintain these environmental and transmission benefits, California should explore production credits for CO_2 reductions and, by the end of 2006, the CPUC should direct utilities to provide transmission and distribution capacity payments to CHP projects in the state.

Recommendations for Distributed Generation and Combined Heat and Power

- California should encourage the use of CHP at California refineries to make them less vulnerable to power outages.
- The state should require utilities to design and build distribution systems that are more DG- and CHP- compatible.
- The CPUC should require utilities to develop and implement planning models to determine where DG and CHP would be most beneficial, from transmission and distribution perspectives.
- California should explore establishing production credits for CO_2 reductions from CHP.
- By the end of 2006, the CPUC should direct utilities to make transmission and distribution capacity payments to CHP projects.

Other Electricity Supplies

Advanced Coal Technologies

California ratepayers enjoy the economic benefits of relatively low-priced electricity generated by coal plants in other western states. In 2004, 21 percent of all retail electricity sales in California came from this out-of-state coal-fired generation. Most of this was from purchases by the Los Angeles Department of Water and Power (LADWP) (51 percent of retail electricity sales from coal) and SCE (15 percent of electricity sales from coal). LADWP and several

119. Presentation on the operational impacts from large penetrations of CHP/DG, Paul-Frederick Bach, Eltra – Independent System Operator for Denmark, *Energy Report* workshop, *California's Market Potential for Combined Heat and Power (CHP) and Distributed Generation,* April 28, 2005.

120. Presentation by Peter Evans, New Power Technologies, *Energy Report* workshop, *California's Distribution Planning Process and the Role of Distributed Generation and Demand Response*, April 29, 2005.

other Southern California publicly owned utilities own almost all of the Intermountain pulverized coal project in Utah. LADWP, SCE, and other California publicly owned utilities own significant interests in the Mohave, Navajo, San Juan, and Four Corners pulverized coal projects in Arizona and New Mexico. The California Department of Water Resources (DWR) owns about one-third of the Reid Gardiner pulverized coal project in Nevada. These and other California ownership interests in out-of-state coal projects total 4,744 MW.

The CPUC's 2004 long-term procurement decision raised concerns about the financial risk of future greenhouse gas regulation and required California's IOUs to include an $8 per ton CO_2 adder when evaluating procurement contracts extending five years or longer. This has focused attention on California's interest in reducing ratepayer exposure to potential greenhouse gas retrofit (or offset) requirements, applied at some future date to coal-fired power plants, as well as on the role California utility procurement should play in influencing development of "clean" advanced coal combustion technologies.

The term "clean coal" gained widespread use in the 1980s by the U.S. Department of Energy (DOE) and others when referring to plants with very low SO_2, NOx, and particulate emissions, relative to conventional pulverized coal plants of that time. In the 1990s, researchers began to investigate processes for capturing 75-90 percent of the CO_2 at power plants from both combustion exhaust (flue gas) and processed fuel gas (synthesis gas). These technologies are very energy intensive, and their improvement is the goal of considerable research. This research now generally falls under the broad term "clean coal." Today, the term also implies low emissions of mercury and other air toxics.

Plant types considered "clean" include integrated gasification combined cycle (IGCC); pulverized coal with "ultra-supercritical" main steam conditions, like a thermodynamic state well above the pressure and temperature of the critical point of water (USC PC); and circulating fluidized-bed combustion plants with supercritical main steam conditions (SC CFBC). Each of these plant types may be designed with or without CO_2 capture. Numerous developmental technologies with integral CO_2 capture fall under the clean coal umbrella as well, including oxygen-fired pulverized coal plants with CO_2 recycle (Oxyfuel), a more complex variant known as chemical looping, and rocket engine-derived combustors.

IGCC technology has been the focus of many environmental advocates because of its perceived ease of extracting sulfur and other pollutants, as well as capturing CO_2, from the gas stream prior to combustion. Several demonstration plants are currently in operation, although not yet at full commercial scale. Experience with early demonstration projects suggests that electricity from the initial commercial scale plants will cost 15-20 percent more than electricity from pulverized coal plants with SO_2 and NOx emission controls, assuming that current reliability problems can be overcome. The economics of current IGCC technologies are best using the higher-rank bituminous coal typical of many commercially mined deposits east of the Mississippi River, and less favorable for lower-rank coals such as sub-bituminous or lignite that predominate in the West. This difference may be at least partially mitigated by blending lower-rank coal feed stocks with petroleum coke. Design changes or success with advanced, dry-feed compact gasification systems now under development by the DOE and industry partners may eventually make IGCC more economical for lower-rank fuels.

IGCC's relative competitiveness with pulverized coal plants improves if CO_2 removal is required, but such a requirement significantly reduces power output and increases the cost of both plant types. Studies by DOE, the Electric Power Research Institute (EPRI), and others have found that the incremental cost penalty for removing CO_2 from high-pressure IGCC syngas is about 25 percent on a levelized cost-of-electricity basis, while the cost penalty for removing it from the flue gas of a

conventional pulverized coal plant is about 70 percent. Additional costs for transporting and sequestering captured CO_2 are not included in the calculation but would be comparable for both plant types.

For regions like the West where lower-rank fuels predominate, USC PC and SC CFBC may be the most cost-effective advanced coal combustion options, but they lack the same opportunity for CO_2 capture offered by IGCC. Compared with the less than 38 percent efficiency of today's pulverized coal plants, new SC CFBC designs can achieve efficiencies of about 40 percent; future USC PC designs are projected to hit generating efficiencies above 45 percent and reduce CO_2 and other emissions by 15-22 percent.

Governor Schwarzenegger's response to the *2004 Energy Report Update* addressed the challenge of technology choice in the clean coal arena: "It is not possible to predict which technologies will advance to commercial maturity most rapidly, so a variety of technology paths must be encouraged. Furthermore, given the diversity of regional electricity markets and the wide variation in regional coal properties, effective deployment of advanced coal power systems may entail the adoption of many different technologies, such as … IGCC … and … SC CFBC …, as well as technologies yet to be developed."[121]

EPRI has developed a CoalFleet for Tomorrow initiative, a consortium of utilities and suppliers (including three to five companies that have pledged to build IGCC or other advanced coal plants) working with the DOE. Participants believe that collaborative research, development, and demonstration among industry stakeholders can both hasten the deployment of current state-of-the-art advanced coal plants and spur development of technical and operational improvements. Such advances are intended to boost availability, lower heat rate, and reduce emissions in the near term and lead to the commercial introduction of next-generation plant designs that will be approximately 20-25 percent lower in capital cost.

The CoalFleet for Tomorrow initiative strategy simultaneously addresses the research, development, and demonstration needs for three major time frames:

- Near-term refinements or evolutionary technologies for IGCC, USC PC, and SC CFBC plants coming online around 2010-2012: the early deployment projects.
- Mid-term research and development requiring demonstrations that will conclude after the earlier commercial projects are built; this work will produce technologies that can be readily incorporated in plants coming on line between 2012 and 2015.
- Longer-term research and development on advanced concepts for IGCC, USC PC, and SC CFBC plants—including integration of CO_2 capture systems—for plants coming on line after 2015-2020.

California's efforts should focus on this third category of research, which integrates the capture of CO_2 with development of advanced combustion technologies. In close coordination with the DOE, the Energy Commission is supporting a growing research program aimed at developing and validating options for sequestering CO_2 away from the atmosphere. The Energy Commission heads WESTCARB, one of seven regional carbon sequestration partnerships co-funded by DOE, which is a consortium of 70 public agencies, private companies, and nonprofit organizations. WESTCARB characterizes the leak-proof geologic formations throughout the region that are suitable for storing CO_2 safely for centuries or longer. In some instances, such storage can yield co-benefits such as enhanced oil and natural gas production.

121. Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: *Review of Major Integrated Energy Policy Report Recommendations*, August 23, 2005.

Findings to date suggest that the sandstone formations filled with saltwater deep beneath California's Central Valley could collectively store hundreds of years of CO_2 emissions at the current rate of emission by the state's power plants. Indeed, the Central Valley represents one of the largest potential onshore CO_2 "sinks" in the West. Suitable geologic reservoirs for CO_2 storage have also been identified in Arizona and other states to the east of California where new coal-fired power plants are proposed. WESTCARB is currently planning technology validation projects in California and Arizona to verify target reservoir properties, CO_2 injection and monitoring processes, and co-benefits where applicable. Such validation tests are essential to establish the viability of CO_2 capture from power plants (and other industrial point sources) as a greenhouse gas mitigation strategy.

As Governor Schwarzenegger stated in his response to the *2004 Energy Report Update*, "I support continued clean coal technology research and development towards zero emission operation so that we can economically achieve reduced emissions of pollutants such as SO_2, SO_X, NO_X, and mercury and develop methods for capturing and storing significant amounts of CO_2, either as an integral part of the energy conversion process or in pairing with external CO_2 sequestration."

In the interim, California's utility procurement policy will be critical to achieving its greenhouse gas reduction goals and could be a critical driver of clean coal technology development in the West. As discussed more fully in Chapter 9, because of severe projected in-state impacts, California has a special interest in avoiding the consequences of severe climate change and a compelling motivation to reduce greenhouse gas emissions.

On October 6, 2005, the CPUC unanimously adopted a resolution directing its staff to develop a greenhouse gas performance standard for IOUs "that is no higher than the GHG emission levels of a combined-cycle natural gas turbine" for all procurement contracts that exceed three years in length and for all new generation. In the case of coal-fired generation, the capacity to capture and store carbon dioxide safely and inexpensively is necessary to meet the standards. The CPUC resolution also directed its staff, working with the Energy Commission, to investigate "offset policies that are designed to ensure that the Governor's GHG goals are achieved," while noting that "any offset policy must include a reliable and enforceable system of tracking emissions reductions." Additionally, the CPUC resolution called on publicly owned utilities to "reduce emissions that contribute to global warming by adopting energy efficiency and renewables goals that are comparable to the standards that the IOUs are required to meet under state law and regulation, as well as adopting an equivalent GHG performance standard."[122]

In principle, the Energy Commission endorses the CPUC resolution with respect to non-PURPA baseload plants 50 MW and larger in size, and makes the following observations:

- There remains considerable uncertainty as to whether the $8 per ton CO_2 adder adopted in the CPUC's Decision 04-12-048 adequately captures the financial risk faced by California ratepayers from future greenhouse gas regulation. Idaho utilities are required to use a $12 per ton adder for planning purposes, and the CPUC's decision acknowledged a plausible range of $8 - $25 per ton to quantify this risk.

122. CPUC, *Policy Statement on Greenhouse Gas Performance Standards,* October 6, 2005 [http://www.cpuc.ca.gov/word_pdf/report/50432.doc].

- Sempra Global testified in the *Energy Report* hearings that its Granite Fox pulverized coal project planned for Nevada, when coupled with offsets to meet the proposed greenhouse gas procurement standard, could economically compete against a gas-fired combined-cycle plant assuming an $8 per ton adder, but was unlikely to be able to do so at a $25 per ton assumption. Sempra also expected that this financial risk would have to be contractually absorbed by the project developer rather than passed through to utility ratepayers.
- While the Energy Commission sees the cost-reducing benefits of an offsets approach to compliance, there are two fundamental prerequisites to such a policy being prudent. The first is establishing a greenhouse gas regulatory framework that provides complete assurance that such offsets will be recognized for compliance purposes and fully absorb the financial risk of future greenhouse gas regulation. The history of utility regulation, in California and elsewhere, suggests that inadequate vigilance on this point will ultimately result in a significant financial risk being borne by ratepayers.

  The second fundamental prerequisite to a prudent reliance on offsets is the creation of a credible, transparent accounting system that can readily verify the environmental integrity of allowable offsets. The Energy Commission believes that the performance/standards-based approach being developed by the California Climate Action Registry is a good foundation for such a system.

Recommendations

- Without burdening interstate commerce or discriminating against particular technologies or fuels, the state should specify a greenhouse gas performance standard and apply it to all utility procurement, both in-state and out-of-state, both coal and non-coal.
- While more specific recommendations must await the January 2006 report of Governor Schwarzenegger's Climate Action Team, the Energy Commission recommends that any greenhouse gas performance standard for utility procurement be set no looser than levels achieved by a new combined-cycle natural gas turbine. Additional consideration is needed before determining what, if any, role greenhouse gas emission offsets should play in complying with such a performance standard.
- The Energy Commission should work with the CPUC to develop a framework that is consistent with the record established at the Energy Commission.

Nuclear Resources

A significant portion (13 percent in 2004) of California's electricity supply comes from in-state nuclear power plants located at Diablo Canyon and San Onofre and from out-of-state plants at Palo Verde, Arizona. In addition to operating in-state nuclear facilities, California's utilities are responsible for decommissioning older retired reactors at Humboldt Bay, Rancho Seco, and San Onofre, and for the safe storage of spent nuclear fuel from operating and retired plants until the federal government builds a permanent national repository for highly radioactive material. Operators of the state's nuclear plants therefore face many issues including the transportation and disposal of spent fuel, potential extensions of operating licenses, and major capital additions, including the replacement of aging plant components like steam generators.

New nuclear power plant construction in California was suspended in 1976 pending assurances by the Energy Commission that the technology for the permanent disposal of high-level waste has been approved by the appropriate federal agency. In addition, for plants requiring reprocessing of spent fuel, the appropriate federal agency must approve a technology for reprocessing. In 1978, the Energy Commission determined that these conditions had not been met, so no new nuclear plants have been approved or built since that time.

Californians have contributed well over $1 billion to the federal waste disposal development effort. Although the U.S. Congress has selected the Yucca

Mountain Project to be a permanent deep geologic repository for the disposal of spent nuclear fuel, the federal waste disposal program remains plagued with licensing delays, increasing costs, technical challenges, and managerial problems. A recent Massachusetts Institute of Technology study, *The Future of Nuclear Power*, concluded that successful geologic disposal of high-level radioactive waste has yet to be demonstrated, although the authors did conclude that a high-level waste repository is likely to be commissioned in the U.S. within the next 10 to 20 years.[123]

The Energy Commission must therefore reaffirm the finding made in 1978 that a high-level waste disposal technology has been neither demonstrated nor approved. The Energy Commission also finds that reprocessing remains substantially more expensive than waste storage and disposal and has substantial adverse implications for the U. S. effort to halt the proliferation of nuclear weapons. In addition, the Energy Commission recommends that some portion of the funds contributed by California ratepayers toward federal disposal efforts be returned to the state to defray the ongoing costs of long-term on-site spent fuel storage made necessary by the lack of a permanent disposal solution.

Given the high-level of uncertainty surrounding the federal waste disposal program, California's utilities will likely be forced to indefinitely retain spent fuel in storage facilities at currently operating reactor sites. The state should evaluate the long-term implications of the continuing accumulation of spent fuel at California's operating plants, including a case-by-case evaluation of public safety and ratepayer costs of on-site interim storage versus transportation to off-site interim storage facilities.

Transporting spent fuel involves greater complexity, cost, and risk than leaving it in an on-site storage facility.[124] State of Nevada officials and the Alliance for Nuclear Responsibility raised concerns in the *2005 Energy Report* workshops about the potentially higher risks and radiation exposure associated with moving spent fuel shipments through heavily populated and congested urban areas in California. California officials have already expressed concern that DOE's rerouting has increased the number of nuclear waste shipments through California to avoid transport through Las Vegas and over Hoover Dam. In the future, an estimated 13-91 percent of truck shipments and 5-90 percent of rail shipments of spent fuel to the Yucca Mountain site could be routed through California.[125] The Energy Commission recommends that the state evaluate the implications of DOE's increasing use of California routes for shipments of nuclear waste to and from Nevada, and the precedent this could set for route selection of future shipments to Yucca Mountain.

A comparison of fees assessed by California on transporters of spent fuel with fees assessed by other states suggests that California's fees may be insufficient to cover state costs associated with spent fuel shipments for shipment inspections, tracking, and escorts. The state should reexamine the adequacy of California's nuclear transport permit fees and federal funding programs covering state activities associated with spent fuel shipments.

California also has an ongoing role in protecting public health and safety and assuring the economic cost-effectiveness of investing in electricity generation resources, including nuclear resources. The state must therefore consider the potential extensions of operating licenses, along with other resource

123. Massachusetts Institute of Technology, 2003, *The Future of Nuclear Power*, p. 86.

124. Bunn, Holdren et al, Harvard University/University of Tokyo, *Interim Storage of Spent Nuclear Fuel: A Safe, Flexible, and Cost-Effective Near-Term Approach to Spent Fuel Management*, June 2001, p. 18.

125. *Spent Nuclear Fuel Transportation to Yucca Mountain: Implication for California*, pp. 37-38, Bob Halstead, *Issues Concerning Nuclear Power* workshop, California Energy Commission, August 15, 2005.

options. IOUs are currently seeking approval to replace steam generators and other large plant components at the state's nuclear power plants, and additional large plant expenditures are likely to follow. Given the high cost of these projects—for example, $700 to $800 million for steam generator replacement costs alone—it is likely that IOU owners will seek to extend operating licenses at these units to recover those costs.

Communities located near reactor sites continue to be concerned about public health and safety, particularly with today's heightened awareness of terrorism. A recent report by the National Academies concluded that while successful attacks on spent fuel pools are difficult, they are a possibility and could lead to the release of large amounts of radioactive material.[126] Given these safety issues, as well as the long-term accumulation of spent fuel and adverse thermal impacts on the marine environment from once-through cooling at coastal nuclear plants, it is appropriate that the state undertake a careful and thorough review of the costs and benefits of license extensions. California's Legislature should develop a suitable framework for such a review, including the clear delineation of agency responsibilities, the scope of the evaluation, and the criteria for assessment.

Recommendations for Nuclear Resources

- The Energy Commission recommends that some portion of the funds paid by California ratepayers for a permanent national repository be returned to the state to help defray the cost of long-term on-site spent fuel storage.
- The state should evaluate the long-term implications of the continuing accumulation of spent nuclear fuel at California's nuclear plants.
- The state should evaluate DOE's increasing use of California routes to transport nuclear waste to and from Nevada.
- The state should reexamine the adequacy of California's nuclear transport fees and federal funding programs to cover the state's costs of spent fuel shipments.
- The Legislature should develop a suitable framework for reviewing the costs and benefits of nuclear plant license extensions and clearly delineate agency responsibilities, scope of evaluation, and the criteria for assessment.

126. Board on RadioActive Waste Management, National Academies. *Safety and Security of Commercial Spent Nuclear Fuel Storage*: Public Report, 2005 [http://bboks/nap.edu/catalog/11263.html], and *Safety and Security of Commercial Spent Nuclear Fuel Storage*, pp. 7-8, Kevin Crowley, *Issues Concerning Nuclear Power* workshop, California Energy Commission, August 15, 2005, [http://www.energy.ca.gov/2005_energypolicy/documents/2005-08015+16_workshop/presentations/panel-4].

Chapter Five: Transmission Challenges

California should waste no additional time in tackling its most vexing electricity infrastructure challenge: expanding and strengthening its electric transmission system. The state's more than 31,000 miles of transmission lines are as essential to energy delivery as the body's arteries are to the movement of blood. Without adequate transmission, electricity cannot move from its point of generation to the 37 million Californians who depend upon it. The consequences of transmission failure can be catastrophic, as the nation learned two years ago when an East Coast transmission failure blacked out New York City and large blocks of the East and Mid-Atlantic regions.

Though the Energy Commission strongly recommended improvements to transmission infrastructure in both the *2003 Energy Report* and the *2004 Energy Report Update*, little has been done. The situation has worsened since the Energy Commission concluded in the *2004 Energy Report Update* that California's systematic underinvestment in transmission has left the state's transmission lines congested, increasing the costs of electricity to consumers and reducing reliability. After this summer's transmission-related outages in Southern California, fixing this problem should be afforded the highest priority by state policymakers.

Governor Schwarzenegger recently agreed with the *2003 Energy Report* and *2004 Energy Report Update* recommendations on transmission, concluding that: "An effective transmission planning process should be at the bedrock of the state government's commitment to upgrading and expanding California's transmission infrastructure to promote competition, access low cost resources, increase reliability, meet renewable resource goals and assure resource adequacy."[127] The Governor agreed that generation and transmission planning should be linked and reinforced the need to examine generation, transmission, and non-wires alternatives, including energy efficiency, in developing an efficient, integrated, and dynamic electricity system. The Governor also agreed with the *Energy Report* recommendation to consolidate generation and transmission permitting within the Energy Commission. Finally, he agreed that the Energy Commission should have the authority to designate and preserve future transmission corridors so they will be available when needed.

California faces three urgent transmission issues:

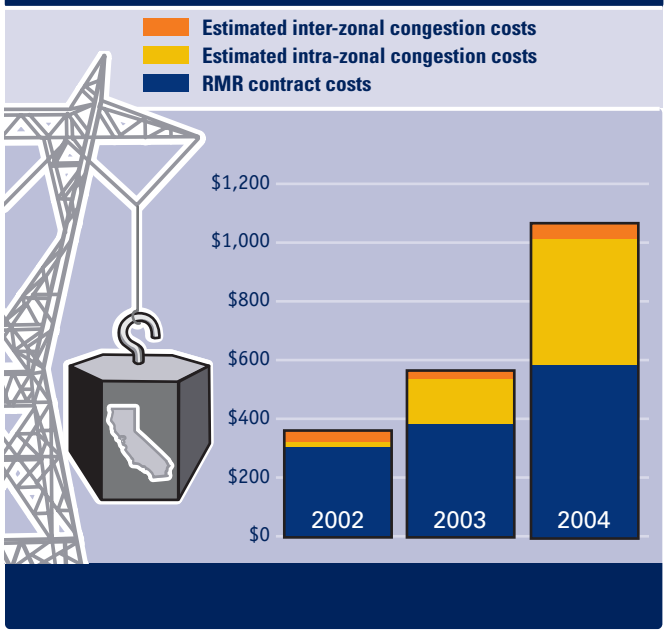
- The state lacks a well-integrated, proactive transmission planning and permitting process. Overlapping and often conflicting roles and responsibilities between state and federal agencies cripple California's ability to effectively secure the investment needed to address dramatic increases in congestion costs and serious threats to electric system reliability.
- California urgently needs a formal, collaborative transmission corridor planning process to identify critical transmission corridors well in advance of need so utilities can identify and retain lands and easements, and local governments can flag incompatible land uses.
- California needs major investments in new transmission infrastructure to interconnect with remote renewable resources in the Tehachapi and Imperial Valley areas, without which it will not be able to meet its Renewable Portfolio Standard (RPS) targets.

As the transmission system becomes increasingly stressed and power lines become more congested, costs increase because less expensive electricity must be curtailed and replaced with more expensive sources. When transmission lines are heavily loaded, small transmission outages can easily grow into larger transmission problems and more extensive outages. As shown in Figure 14, last year's total cost for transmission congestion and related reliability services in the CA ISO control area totaled over $1 billion, up from a total of $628 million in 2003.[128]

127. Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: *Review of Major Integrated Energy Policy Report Recommendations*, August 23, 2005.

128. California Energy Commission, staff report, *Upgrading California's Electricity System: Issues and Actions for 2005 and Beyond*, July 2005, CEC 700-2005-018, p. 2.

Figure 14: **U.S. & California Congestion & Reliability Costs**



Source: Adapted from CA ISO, April 2005, 2004 Annual Report on Market Issues and Performance.

California policy makers must quickly create an aggressive planning and permitting process to effectively leverage the core responsibilities and strengths of the utilities, the Energy Commission, the CA ISO, and the CPUC to collaboratively solve this critical problem. Since the 2000-2001 energy crisis, the roles of these agencies have changed with the evolving regulation of the state's transmission system. These roles and responsibilities must be clarified and duplication and conflicts resolved in a revamped transmission planning and permitting process. Progress will not be possible without interagency cooperation and collaboration. Despite substantial efforts made in the *2005 Energy Report* process, the Energy Commission and the CPUC have not been able to resolve differences in this area. The Legislature should take speedy action to realign the jurisdictional roles of these state agencies.

The state also lacks a workable transmission corridor planning process that addresses the long-term planning needs of utilities for future transmission. A state corridor planning process would streamline identification of future transmission paths. This is especially important in light of inevitable local land use controversies that arise as available land in California becomes increasingly scarce. A formal, more inclusive corridor planning process would allow California to work more effectively with federal and state agencies, local governments, and affected parties to plan future corridors. Emerging conflicts between the U.S. Forest Service and SCE over the first segment of the Tehachapi transmission line graphically illustrate the challenge of effectively coordinating interagency planning objectives.[129]

In addition, changes in federal law giving the Federal Energy Regulatory Commission (FERC) transmission siting authority and conferring eminent domain powers for transmission projects in federally designated corridors present a clear threat to California's ability to make land use and public health and safety decisions for transmission projects. Unless the state takes prompt action to establish an effective statewide corridor planning process and address permitting and planning problems, the federal government is prepared to take over where the state has failed to act. A thoughtful and well-designed statewide corridor planning process would also allow environmental assessments early in the planning process to preclude the long lead times that plague the current process.

129. September 15, 2005 letter from the forest supervisor, Angeles National Forest, U.S. Forest Service, to the supervisor for the California Environmental Quality Act, CPUC, on the SCE Antelope-Pardee Transmission Project.

Finally, without major transmission infrastructure investment, California will not be able to reap the benefits of some of the state's most promising areas for renewable generation: the Tehachapi and Imperial Valley areas. California needs to develop these resources to meet accelerated statewide renewable generation goals. Transmission interconnection issues for renewable resources located in developed areas are further complicated by the number of developers competing for transmission capacity and their limited ability to finance large transmission facilities. The *2004 Energy Report Update* recommended the formation of transmission study groups for the Tehachapi and Imperial Valley areas to prepare phased development plans, and these groups have made good progress. However, immediate actions are still needed to remove financing barriers and assure utility cost recovery for renewable transmission projects, including amendments to the CA ISO tariff that recognize the unique characteristics of these projects.

This chapter addresses the actions that California policy makers must take to adequately plan for, permit, and construct crucial transmission upgrades and expansions. It also lays out critical steps in establishing an effective corridor planning process and addressing renewable transmission needs for the state. Finally, the chapter identifies five major transmission projects that are needed in the near term to address California's transmission problems.

Background

In the *2003 Energy Report*, the Energy Commission concluded that the existing planning and permitting processes lacked essential mechanisms to plan, permit, and build critically needed transmission in California. At that time, the state did not have an official role in transmission planning. However, in 2004 the Legislature partially corrected that problem by establishing a strategic transmission planning element within the Energy Commission's *Energy Report* process.[130] The *2005 Strategic Transmission Plan*, a companion to the *Energy Report*, identifies actions to encourage needed investments to ensure reliability, relieve congestion, and meet future growth in both load and generation, including renewable resources.

The *2004 Energy Report Update* outlined a rational planning process that would identify needed transmission infrastructure investments, consider non-wires alternatives to transmission lines (such as generation and demand response measures), and approve those projects in a timely manner. Critical projects could then move directly to permitting so that the analysis required under California's Environmental Quality Act (CEQA) could more appropriately focus on alternative transmission routes, environmental impacts, and mitigation measures. The current hodgepodge system lacks some key components of this process while duplicating others.

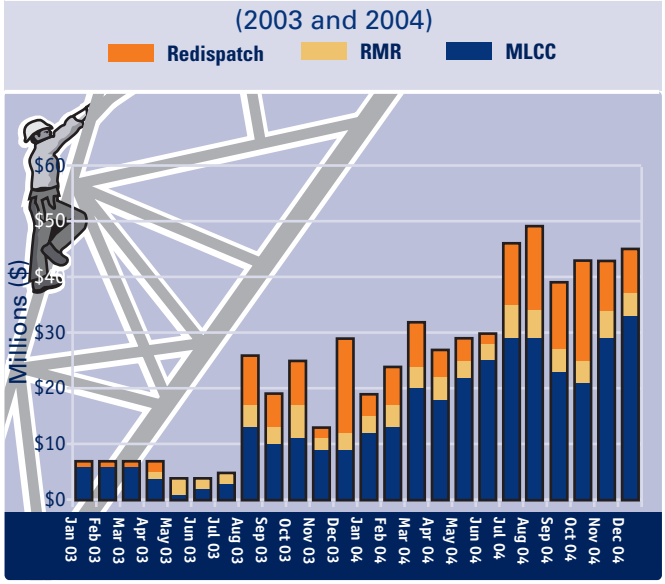
The *2004 Energy Report Update* recommended a collaborative process integrating transmission planning with electricity demand assessment, resource planning, and energy policy. The *Energy Report* stressed the importance of bringing all parties together to eliminate current overlap and duplication between the Energy Commission, the CPUC, the CA ISO, and the state's utilities.

In 2002 and 2003, the Legislature added new electricity resource and transmission planning responsibilities to the Energy Commission's *Energy Report* process. In 2002 the Legislature also assigned new responsibilities to the CPUC concerning investor-owned utility (IOU) procurement. The CA ISO has new management and, in recognition of the seriousness of the state's growing transmission problems, is proposing to revamp its transmission and grid planning processes. These agencies must

130. SB 1565 (Bowen), Chapter 692, Statutes of 2004, was signed into law on September 22, 2004.

work hand-in-hand with the Legislature to produce a proactive and forward-looking transmission planning and permitting process for California.

Figure 15: **CA ISO Monthly Total Intra-Zonal Congestion Costs**



Source: Adapted from CA ISO, April 2005, 2004 Annual Report on Market Issues and Performance, *p. ES-21, Table E.5 [http://www.caiso.com/docs/2005/04/28/2005042814580818934.pdf], September 1, 2005.*

Because electricity deliverability and system reliability are intertwined with electricity forecasting, assessment, and resource procurement, the *2005 Strategic Transmission Plan* provides the detailed assessment of transmission projects necessary for IOUs to effectively procure resources.[131]

Transmission Congestion and Reliability Concerns

In 2004, the cost of congestion and local reliability needs in the CA ISO system approximated $1.1 billion.[132] Figure 15 shows monthly intrazonal congestion costs for 2003 and 2004. As recently as this summer, California experienced numerous costly price spikes and several local outages during high peak load periods. This situation is expected to further deteriorate in coming years.

The San Diego region's transmission problems are acute and graphically illustrate the importance of adequate transmission. In 2001, SDG&E identified transmission constraints and increasing congestion on its Mission-Miguel line, a 230-kV line moving electricity from the southern part of its service territory to downtown San Diego. SDG&E at that time began the process of permitting and building upgrades to the line. By 2004, annual congestion costs totaled over $32 million, increasing to $48 million from July 2004 to July 2005.[133] Over the next year until the Mission-Miguel upgrade finally comes on line, congestion costs are expected to exceed $50 million. The Mission-Miguel No. 2 Line required only minimal regulatory approval since it was

131. CPUC Decision 04-12-048, December 16, 2004, p. 183 states: "To the extent an IOU believes that the range of need identified in the *2005 Energy Report* is sufficient to justify a transmission project then it may be identified as a specific proposal to satisfy need in the 2006 procurement proceeding filings."

132. California Energy Commission, *Strategic Transmission Investment Plan* Committee final report, November 2005, CEC-100-2005-006CTF.

133. Testimony of James Avery, San Diego Gas and Electric, transcript of the July 28, 2005, *Integrated Energy Policy Report Strategic Transmission Planning Issues and Transmission Staff Report* workshop, pp. 88-89.

located in an existing right-of-way. Still, even under a creatively developed construction plan, it took SDG&E three years to permit and another two years to build this critically needed upgrade.

SDG&E's transmission situation is very precarious. As its representative noted, "We have to weigh the question of do we take a line out to try to repair it. And if we do, we're sitting on one other line. And if we lose that line we can be in a blackout situation."[134] For example, while making repairs to damage on two towers supporting 138-kV lines feeding Southern Orange County, SDG&E temporarily took one of the lines out of service. On July 28, 2005, the second line went out, causing 35,000 customers in Laguna Niguel to lose power.

Local reliability issues have become even more complex and expensive as congestion has increased. Historically, local reliability on the CA ISO grid has been addressed either through transmission investment or reliability must run (RMR) contracts.[135] The CA ISO awards cost-based contracts to plants deemed critical to local reliability. Many power plants supporting this local reliability are old, inefficient, and slated for replacement or retirement. The challenge for policy makers, the CA ISO, and utilities is to identify the best balance of transmission and generation to create sustainable local reliability.

Both FERC and the CPUC have strongly encouraged utilities to pursue alternatives to the expensive, inflexible RMR contracts that were developed eight years ago as temporary local reliability measures. The continuing central role of these contracts in reliability planning brings the adequacy of the current grid expansion process into sharp question. Despite significant additions to the transmission system over the last several years, California is still experiencing congestion and must rely upon costly RMR contracts for the foreseeable future.

Integrating Transmission Planning and Permitting

Dysfunctional planning and permitting processes are exacerbating the state's worsening transmission problems. California needs a seamless process for quickly moving transmission projects through planning to permitting. Despite recent improvements in the CPUC's permitting application process, the illogical and cumbersome separation of generation and transmission planning and permitting still plagues the state. While the CPUC has not embraced the Energy Commission's *2003 Energy Report* and *2004 Energy Report Update* recommendations on consolidating transmission permitting authority at the Energy Commission, the CPUC's Office of Ratepayer Advocates has recently expressed its neutrality on the placement of permitting jurisdiction, noting its desire to have the same opportunity to participate and comment on transmission lines, with IOU reimbursement, wherever jurisdiction is ultimately placed.[136]

The challenge for state policy makers is to marry the pivotal role of FERC regulation, focused on the CA ISO, with the policy objectives and CEQA requirements valued so highly by California. A dependable foundation for permitting transmission facilities can only emerge from the successful hand-in-hand coordination of the legal duties of both federal and state jurisdictional entities.

134. Ibid.

135. The CA ISO conducts annual studies to identify power plants needed to meet reliability requirements and awards reliability must run contracts.

136. Testimony of Robert Kinosian, Office of Ratepayer Advocates, transcript of September 23, 2005, hearing on the *Energy Report 2005 Committee Draft Strategic Transmission Plan*, pp. 32-33.

California must also recognize the serious implications of changes at the federal level under the federal *Energy Policy Act of 2005* (*Act*) regarding transmission planning and permitting.[137] Prior to this new law, transmission line permitting was exclusively a state function. The state power of eminent domain, which is especially important for transmission rights-of-way, was historically reserved for franchised utilities.

New federal law requires the U.S. Department of Energy (DOE) to designate within the next year corridors of national significance. The FERC can now authorize construction of a transmission line if an application is submitted to construct a project in a DOE-designated transmission corridor and the state has failed to approve a transmission project for more than one year or has conditioned its approval in a way that makes construction economically unfeasible. In cases where FERC grants a transmission permit, it can authorize the permit holder to acquire the right-of-way needed to construct the project upon payment of "just compensation" as determined by a federal court. Creation of a federal power of eminent domain represents a significant loss of state sovereignty, and its application is likely to prove controversial with property rights advocates.

These changes in the federal landscape seriously threaten California's ability to make land use and public health decisions related to transmission projects. If California fails to immediately take the necessary actions to ensure adequate transmission infrastructure, the state will ultimately lose to the federal government its ability to determine how, where, and when to expand its bulk transmission grid, potentially thwarting the state's energy, environmental, and economic policy goals.

Transmission Planning Issues

The *2003 Energy Report* and the *2004 Energy Report Update* each made a number of recommendations to improve transmission planning following an extensive series of workshops with the CA ISO, the CPUC, utilities, and other concerned parties. In this *2005 Energy Report*, the Energy Commission also recommends changes to the transmission planning process designed to meet objectives outlined in the earlier reports and satisfy new statutory requirements to develop a strategic transmission plan.

The *2005 Strategic Transmission Plan* assesses statewide transmission reliability and economic need for projects, as well as projects necessary for achievement of statewide policy goals, including the RPS. Recommendations from this effort to approve projects are discussed in a later section of this chapter on near-term transmission projects. They are also examined in more detail in the *2005 Strategic Transmission Plan*.

Over the course of the *2005 Energy Report* workshops, a number of suggestions and opportunities emerged that the Energy Commission believes could significantly improve transmission planning in California. Several concerned parties reinforced the importance of avoiding duplication, effectively leveraging limited human resources, and more closely coordinating various forums concerned with transmission planning.

Recognizing that under a FERC-approved procedure the CA ISO has primary responsibility for planning the utility transmission systems residing within its grid, it is critical that this process play a central role in the state's planning efforts. Although the CPUC is attempting to address transmission planning within its procurement process, a number of inadequacies make transmission an uneasy fit within the procurement process. These are explained in the following excerpt from SCE:

Transmission investment decisions and retail procurement decisions generally serve two separate functions. Transmission investments are generally made to ensure a reliable and sufficient grid and

137. United States Code, 16 U.S.C. Section 824(e).

an enhanced wholesale market. Transmission investments are recovered through FERC rates and are placed into wires charges that apply to all customers who benefit from the investment. Retail procurement is performed on behalf of a specific group of customers who require a specific amount of power at a given time. Retail procurement costs are recovered through CPUC rates and are collected from those customers for whom procurement is being performed. Since these functions have distinctly different objectives, different customers, and different cost recovery mechanisms, transmission investment and retail procurement decisions should remain separate.[138]

One of the biggest problems with the existing approach to IOU transmission is its reactive nature and dependence upon IOU decisions and timing. The history of the Devers-Palo Verde No. 2 Transmission Line provides an example of the pitfalls of this reactivity, which is recounted in more detail in the *2005 Strategic Transmission Plan*.[139] For the past 20 years, progress on this critical infrastructure has been entirely dependent upon the shifting business priorities of SCE, while the economic consequences of inaction have been absorbed by its ratepayers and other grid users. This project has been studied for several decades, and a Certificate of Public Convenience and Necessity (CPCN) application is again pending before the CPUC. In 1985, SCE applied for a CPCN, receiving approval from the CPUC in 1988. SCE, however, decided to postpone construction at that time. In 1993, SCE requested abandonment of the project. SCE later decided to pursue the project again and filed a new CPCN application with the CPUC earlier this year. Some of the current reserve margin and reliability problems in Southern California could well have been avoided had SCE moved forward when its initial application was approved.

The CA ISO also acknowledges that the existing transmission planning process is overly reactive and insufficiently forward-looking. The current cumbersome and time-consuming process includes the following steps:

- Participating transmission owners submit annual transmission assessment and expansion plans for the coming five years, which are then reviewed by the CA ISO.
- The CA ISO's management approves projects that meet its criteria and cost less than $20 million; projects costing more than $20 million are submitted to the CA ISO's board of directors for approval.
- The CA ISO performs an assessment of the combined participating transmission owner plans to make sure that projects do not "fall through the cracks."
- Finally, the CA ISO conducts studies to determine RMR generation requirements.[140]

The CA ISO notes it is forced to be reactive in part because it only acts upon projects submitted by participating transmission owners. It further notes that the decision either to pay RMR costs or build facilities to avoid RMR costs has been largely left to the participating transmission owners. The CA ISO also points out that under this process, transmission expansion projects to ease congestion were completed only after significant congestion costs had already been incurred.

138. SCE filing in docket 04-IEP-1D *2005 Energy Report*: comments on *Electricity Issues and Policy Options* workshop, July 5, 2005, Appendix A, response to Question 2.

139. California Energy Commission, *Strategic Transmission Investment Plan* Committee final report, November 2005, CEC-100-2005-006CTF Appendix A: *Procedural History of PVD2*.

140. *New CA ISO Transmission Planning Process*, A.J. Perez, CA ISO, August 1, 2005.

The recent announcement that the CA ISO is proposing a new planning process, evolving from a reactive to a proactive role in transmission planning, offers a unique opportunity to better coordinate the activities of the three primary concerned state agencies: the CA ISO, the CPUC, and the Energy Commission.

Transmission Permitting Issues

In the *2003 Energy Report* and the *2004 Energy Report Update*, the Energy Commission recommended that the state consolidate permitting of new bulk transmission lines within the Energy Commission, using the Energy Commission's power plant siting process as a model.

In the *2004 Energy Report Update*, the Energy Commission noted longstanding, continuing, and widespread criticism of California's permitting process and strongly restated the *2003 Energy Report* recommendation that permitting jurisdiction be urgently addressed. The Energy Commission did note that the CPUC reached favorable decisions on several important transmission projects including Mission-Miguel and Jefferson-Martin.

Since adoption of the *2004 Energy Report Update*, the CPUC approved the Otay Mesa Power Plant Transmission Project and approved temporary modifications allowing the Mission-Miguel transmission upgrade to partially come on line a year ahead of schedule. Three additional critical transmission lines have pending CPCN applications, including two segments to enhance the Tehachapi and Devers-Palo Verde No. 2 transmission lines.[141]

While the CPUC has recently reduced extensive delays in some of its CPCN applications, one of the drivers for the proposed transfer of transmission permitting from the CPUC to the Energy Commission is the recognition that state and federal restructuring of the electricity industry greatly diminished the CPUC's oversight in financial regulation of IOU transmission investments. Before passage of California's electric industry restructuring law in 1996, the CPUC had primary responsibility for the regulation of all IOU investments, including transmission. The FERC is now responsible for financial regulation of IOU transmission investments, including cost recovery, which is shared by all customers under the CA ISO umbrella. The CPUC's role in financial regulation of IOU transmission investments is now limited to that of an intervener in FERC rate cases, on behalf of California IOU ratepayers, and allocating FERC-approved transmission costs to different classes of retail customers.

Earlier this year, the State of California Administration submitted a reorganization plan to the Little Hoover Commission and the Legislature that included implementing the *2003 Energy Report's* recommendation on transmission permitting.[142] The Attorney General pointed out during review of the proposal, however, that the transfer of authority to issue a CPCN using the Little Hoover reorganization process was constitutionally inappropriate because of the role of the CPCN in the CPUC's constitutionally conferred rate-making authority.[143] The Attorney General went on to note that the reorganization statute would permit transfers of authority that do not interfere with the CPUC's ratemaking function, citing as an example the *Warren-Alquist State Energy Resources*

141. California Energy Commission, *Upgrading California's Transmission System: Issues and Actions for 2005 and Beyond*, staff report, July 2005, CEC 700-2005-018, p. 17.

142. *A Vision for California's Energy Future*, Office of the Governor of the State of California, June 2005, p. 6 [http://www.lhc.ca.gov/lhcdir/reorg/EnergyGRP.pdf].

143. Letters from the Attorney General to the Little Hoover Commission regarding *Inquiry Regarding Governor's Energy Agency Reorganization Plan*, June 22 and 23, 2005.

Conservation and Development Act, where the Energy Commission has responsibility for the siting of thermal energy plants and their related transmission lines.[144] The Attorney General observed that the Energy Commission's power plant licensing responsibility does not extend to the rate-making functions included in siting and leaves the CPCN responsibility with the CPUC.

In light of this opinion, the Energy Commission recommends that the Legislature move this siting function from the CPUC to the Energy Commission, consistent with the *Warren-Alquist Act* framework. Under this proposal the siting of transmission lines would fall under the auspices of the Energy Commission through an Application for Certification, which must be obtained before an IOU can apply to the CPUC for a CPCN. This process has been highly successful for licensing new power plants since passage of the *Warren-Alquist Act* in 1974 and remains in place for utility-owned generation construction proposals today. It is critical to note that this process has not created duplicative requirements in both the Energy Commission's siting and CPUC's CPCN reviews, which could slow down construction of critically needed transmission facilities.

Recommendations to Improve Transmission Planning and Permitting

The Energy Commission recommends that a comprehensive planning process, including the CA ISO, the CPUC, other key state and federal agencies, local and regional planning agencies, IOUs and publicly owned utilities, generation owners and developers, and other interest groups, should:

- Assess statewide transmission needs for reliability and economic projects and RPS goals.
- Examine non-wires alternatives (generation and demand side measures) to transmission.
- Approve beneficial transmission infrastructure investment that smoothly moves into permitting including:
  - Addressing right-of-way needs.
  - Conducting designation and environmental review of needed corridors.
  - Identifying necessary land and easement acquisition.
  - Assessing costs and benefits that recognize the long useful life of transmission assets.
  - Incorporating quantitative and qualitative methods to assess strategic benefits.
  - Using an appropriate social discount rate.

To better align transmission with generation permitting and planning and ensure that needed transmission investments occur, the Energy Commission recommends that:

- The Legislature transfer transmission permitting responsibility from the CPUC to the Energy Commission using the framework laid out in the *Warren-Alquist Act* for generation siting that has worked successfully for the last 30 years.

Transmission Corridor Planning

California currently lacks a planning process that identifies transmission corridors before they are needed. Comprehensive long-term transmission planning should allow utilities to acquire needed lands and easements ahead of time. It should also make room for upfront environmental assessments that would streamline the current process and shorten lead times for bringing transmission on line. A formal corridor planning process would also more effectively deal with land use concerns by coordinating with local, state, and federal agencies, and other parties.

The *2004 Energy Report Update* recommended that the Legislature authorize the Energy Commission to designate needed transmission corridors and conduct appropriate environmental assessments as part of its new transmission planning responsibilities. It also recommended that the CPUC extend the time IOUs are allowed to keep their investments in future transmission corridors in their rate bases.

144. Public Resource Code Sections 25500, 25119, 25110, 25120, 25107.

Based on the extensive testimony and input of parties in the *2005 Energy Report* process, the Energy Commission identified three essential components of a successful corridor planning process for California:

- A corridor identification process.
- State corridor designation authority.
- Corridor land acquisition and banking.

The first element, a corridor identification process, would allow all stakeholders and the public to raise concerns and address issues early in the planning process. Under this proposed structure the Energy Commission would identify the corridor needs of transmission owners; establish corridor priorities; identify major permitting, environmental, and land use issues; and ensure participation of all affected local, state, and federal agencies and other concerned parties.

The second element, designation of corridors, would allow corridor recommendations (and land use requirements) to be set aside for future use through a corridor designation process. Corridor designation would require local planning agencies to avoid incompatible uses and also allow the Energy Commission to proceed with environmental reviews, significantly shortening the overall planning and permitting lead times for transmission. The designation process would be separate from the *Energy Report* process.

The third element, IOU land acquisition and banking for future corridors, would allow IOUs to retain investments in their rate bases for a longer period of time. The CPUC's current five-year limit on retaining IOU investment of lands in the rate base is insufficient for long-term corridor planning, and needs to be extended.

The federal *Energy Policy Act of 2005* directs the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior to designate under their respective authorities corridors on federal land in the 11 western states for energy corridors including transmission lines.[145] The agencies have determined that designating corridors as required by the *Act* constitutes a major federal action that may have a significant impact upon the environment within the context of the *National Environmental Policy Act of 1969*. For this reason, the agencies intend to prepare a programmatic environmental impact statement to address the environmental effects from the proposed action and the range of reasonable alternatives.[146] DOE and the Bureau of Land Management will lead this effort, with the U.S. Department of Agriculture's Forest Service participating as a cooperating agency. The Energy Commission plans to actively participate in this proceeding and other joint efforts involving federal land managers to ensure that future transmission corridors are adequately addressed by federal agencies.

Recommendations to Establish a Corridor Planning Process for California

The Energy Commission recommends the following actions to create a comprehensive corridor planning process that accommodates future needs for transmission:

- The Legislature should give the Energy Commission the statutory authority to establish a statewide corridor planning process and designate corridors

145. Section 368, Public Law 109-58 (H.R. 6), enacted August 8, 2005. The 11 western states include Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. Energy corridors include oil and gas and hydrogen pipelines, as well as electricity transmission and distribution facilities.

146. Programmatic environmental impact statement, *Designation of Energy Corridors on Federal Land in the 11 Western States*, DOE/EIS-0386.

for future use, enabling environmental reviews to begin earlier in the process and shortening the time frame of the transmission infrastructure planning and permitting processes.

- In establishing a statewide corridor planning process, the Energy Commission should work collaboratively with the CPUC, the CA ISO, other key state and federal agencies; local and regional planning agencies; IOUs and publicly owned utilities; generation owners and developers; the public; and other interested groups.
- The Energy Commission should actively participate in the recently initiated federal corridor planning efforts to evaluate issues associated with designation of energy corridors on federal lands in 11 western states, beginning with filing comments in the scoping of the programmatic environmental impact statement.

Transmission for Renewable Resources

The *2004 Energy Report Update* described the critical importance of transmission upgrades for interconnecting remote sources of renewable generation. Transmission upgrades in the Tehachapi wind and the Imperial Valley geothermal resource areas are needed to reap the benefits of some of California's most promising renewable resources. The Tehachapi Transmission and Imperial Valley Transmission groups that were convened following recommendations in the *2004 Energy Report Update* are making progress in developing plans for transmission upgrades. Yet despite their efforts and the efforts of utilities and the renewables industry, California remains stymied in its efforts to increase renewable transmission investment.

Possibly the single greatest blow to renewable transmission development is FERC's recent rejection of SCE's renewable trunk line proposal. SCE developed an innovative renewable resource "trunk line" concept that would interconnect a large concentration of potential renewable generation and be operated by the CA ISO. The trunk line proposal included several linked segments in the Tehachapi area and would have allowed SCE, PG&E, SDG&E, and other CA ISO grid users access to as much as 1,100 MW of renewable resources. Despite support by California's primary energy agencies, FERC did not approve the application. The FERC ruled that the third segment SCE identified as a "renewable resource trunk facility" was ineligible for rolled-in rates since the segment resembles more of a "generation tie" than a "network upgrade."[147]

Current FERC policy effectively bars the advanced planning and construction of transmission facilities necessary through the "chicken and egg" nature of renewable transmission development; renewable projects cannot secure contracts under RPS procurement procedures without knowing whether existing transmission will be able to accommodate them. At the same time, utilities are wary of investing in renewable transmission without assurances of cost recovery, which is premised on the renewable generation being built. This poses a major impediment to renewable resource development.[148]

Even when a renewable developer requests new transmission capacity, the present system assigns the bulk of the cost to the developer with the project that first pushes the transmission system beyond its existing capability. Transmission upgrades would be much more efficiently built through a phased-in development plan anticipating future renewable generation instead of additions of relatively small, individual projects. But phased-in development requires pre-building portions of transmission lines, currently not allowed under FERC regulation.

147. Southern California Edison, 112 FERC Section 61,014, 2005.

148. The FERC's abandoned plant policy means that Southern California Edison is exposed to the risk that it could be left with sizeable quantities of unused transmission and must assume liability for 50 percent of these "abandoned" costs. Southern California Edison Company, March 23, 2005, "Southern California Edison Company's Petition for Declaratory Order," United States of America, before the Federal Energy Regulatory Commission, docket EL05-80-000 [http://www.ferc.gov/docs-filing/elibrary.aso], accessed April 15, 2005, pp. 18-19.

Recommendations to Encourage Transmission for Renewables

Because of FERC's denial of the renewable trunk line concept, the Energy Commission strongly believes that its *2004 Energy Report* recommendation to implement changes to the CA ISO tariff is even more necessary today than it was a year ago for meeting California's renewable goals.[149] The Energy Commission, the CPUC, and the CA ISO should implement changes to the CA ISO tariff to encourage construction of transmission for renewables.

Near-Term Transmission Projects

The Energy Commission examined the need for transmission investment in detail in the *2005 Strategic Transmission Plan*. This transmission need was summarized in three broad categories:

- Projects needed for reliability.
- Projects needed to relieve transmission congestion.
- Projects needed to meet future load growth and generation, including renewable resources.

The *2005 Strategic Transmission Plan* focuses on near-term projects that would improve reliability, help mitigate congestion costs, access economic generation, assist in meeting RPS goals, and be on line by 2010. The Energy Commission has identified the five projects below as vital near-term transmission additions critical to meeting California's rapidly growing transmission needs. These projects are examined in greater detail in the *2005 Strategic Transmission Plan*.

San Diego 500-kV Sunrise Powerlink Project

The Sunrise Powerlink Project is proposed as a 500-kV transmission line connecting Imperial Valley to the San Diego service territory. The proposed 500-kV project would provide significant near-term system reliability benefits to California, reduce system congestion and its resulting congestion costs, and provide interconnection to renewable resources located in the Imperial Valley, as well as lower-cost out-of-state generation. Without the proposed project, it is unlikely that SDG&E will be able to meet the state's RPS goals, ensure system reliability, or reduce RMR and congestion costs. A potential northern interconnection to the proposed project could strengthen the CA ISO grid by providing a 500-kV interconnection between the SDG&E and SCE service territories. Therefore, the Energy Commission believes the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that the residents of San Diego and all of California can begin realizing these benefits by 2010.

Because San Diego faces significant land use constraints that will require resolution, the Energy Commission also recommends formation of a collaborative corridor study group to quickly address concerns of local, state, and federal agencies, landowners, and other interested parties.

Imperial Valley Transmission Upgrade Project

The Imperial Irrigation District and the Imperial Valley Study Group have developed transmission plans designed to deliver generation in the Imperial Valley to loads in California and the Western Electricity Coordinating Council (WECC). The Imperial Irrigation District plan, called the Green Path Initiative, is a phased transmission project that would connect generation in the Imperial Valley to SDG&E, SCE, the Western Area Power Authority, and Arizona. The Imperial Valley Study Group plan focuses on the delivery of power to California through SDG&E and SCE. The Imperial Valley Transmission Upgrade Project would increase transmission capacity by an additional 2,000 MW and provide access to valuable renewable resources needed to meet future load growth and RPS goals.

149. CA ISO Tariff Section 3.2.1.1 outlines the requirements for a need determination for economically driven projects, while Section 3.2.1.2 outlines the requirements for a need determination of reliability projects. Neither of the categories adequately accommodates the unique circumstances of renewable transmission projects.

The Imperial Valley is one of the state's most promising sources of renewable generation. Geothermal resources today produce around 450 MW in the Imperial Valley area, and developers estimate that an additional 1,350 to 1,950 MW could be developed over the next 15 years. In addition to providing a much-needed interconnection to these renewable resources to support California's RPS goals, the Imperial Valley Transmission Upgrade Project would also provide significant near-term system reliability. The Energy Commission therefore believes the proposed project offers significant benefits and recommends that it move forward expeditiously.

Since transmission development in the Imperial Valley region faces significant land use constraints requiring speedy resolution before completion of the project, the Energy Commission recommends that the Imperial Valley Study Group immediately coordinate with local, state, and federal agencies, landowners, and other interested parties.

Palo Verde – Devers No. 2 500-kV Transmission Project

The SCE-proposed Palo Verde-Devers No. 2 500-kV Transmission Project consists of a new 500-kV transmission line from the Palo Verde area of Arizona to Southern California. This project would occupy the same corridor as the existing Palo Verde-Devers 500-kV transmission line and significantly reduce congestion on transmission lines linking California to Arizona. It would also provide access to lower-cost out-of-state generation, even in the face of rapid growth in the Southwest.

The proposed project would provide strategic benefits to California ratepayers, including valuable insurance against abnormal system conditions and power outages. It would increase operating flexibility for California grid operators, reduce market power for generators, and reduce the need for additional infrastructure. The Energy Commission therefore believes that this proposed project offers significant benefits and recommends that it move forward expeditiously so that California can begin realizing these benefits by 2010.

The Energy Commission also recommends formation of a corridor study group to review current land uses along the existing Interstate 10 transmission corridor and coordinate with local, state, and federal agencies, landowners, and other interested parties.

Tehachapi Transmission and Expansion of Path 26

The Tehachapi area transmission projects proposed by SCE are critical for development of wind resources needed to meet RPS targets and would also reduce congestion on transmission lines serving Southern California. The project would ultimately allow interconnection with more than 4,000 MW of new wind generation and access a significant portion of the renewable generation that California utilities need to meet RPS goals by 2010. The Tehachapi Collaborative Study Group (TCSG) developed a conceptual transmission plan that would connect and deliver approximately 4,500 MW of Tehachapi wind generation to loads in California.

Another component of the conceptual plan is an interconnection to PG&E's system. An interconnection with PG&E would give PG&E access to Tehachapi renewable resources and potentially expand Path 26 transmission capacity into Southern California. The TCSG is examining this proposed interconnection.

The TCSG conceptual transmission plan includes facilities that would collect power from Tehachapi area wind projects and interconnect it with the state's transmission grid. Network upgrades would enable delivery to load centers. Transmission facilities would be built in four phases. Phases 1 and 2 would connect 1,600 MW of new wind resources to the Southern California grid. Phases 3 and 4 would allow interconnection of an additional 2,900 MW.

Because of its critical role in meeting RPS goals, the Energy Commission believes this proposed project offers significant benefits and recommends that all phases move forward expeditiously. CPCNs for Phases 1 and 2 are pending before the CPUC. The Energy Commission believes that the record developed on these projects in the *Energy Report* proceedings should be used to supplement the record developed at the CPUC to bolster additional support for this much-needed project.

Trans-Bay Cable Project

The Trans-Bay DC Cable Project, proposed by the City of Pittsburg and Trans Bay Cable LLC, a subsidiary of Babcock and Brown, would consist of an approximately 50-mile-long underwater DC cable connecting the Pittsburg Substation to the Potrero Substation in San Francisco.[150] The Trans-Bay DC Cable Project would provide 400 MW of new import capacity into downtown San Francisco, eliminating the need for RMR contracts at the Hunters Point and Potrero power plants, while ensuring electricity reliability beyond 2011. Along with other proposed strategies, the project has the potential to ensure the retirement of all older generation in San Francisco, resulting in significant environmental benefits. The proposed project would help ensure reliability, serve growing loads, and hasten retirement of aging generators in the San Francisco Peninsula area. Although the Trans-Bay DC Cable Project is not needed for reliability purposes until after 2011, the CA ISO has approved the project for early operation in 2009, consistent with Trans-Bay Cable LLC's plans.

The Energy Commission agrees with the CA ISO's assessment that the advanced in-service date provides insurance benefits that outweigh the net cost to CA ISO ratepayers. Therefore, the Energy Commission recommends that the Trans-Bay DC Cable Project be moved forward expeditiously in order for the San Francisco Peninsula and CA ISO control area to realize these reliability benefits.

Recommendations to Ensure Construction of Near-Term Transmission Projects

The Energy Commission recommends the following actions to ensure that new near-term transmission projects are on line by 2010 to improve reliability, help mitigate congestion costs, access economic generation, and assist in meeting RPS goals:

- All five near-term transmission projects should move forward expeditiously so that Californians can begin to realize their benefits by 2010.
- Collaborative corridor study groups should be formed for the San Diego 500-kV Project and the Palo Verde-Devers No. 2 500-kV Transmission Project to quickly address concerns of local, state, and federal agencies, landowners, and other interested parties.
- The Imperial Valley Study Group should immediately coordinate with local, state, and federal agencies, landowners, and other interested parties to confront the significant land use constraints that must be resolved before completion of the Imperial Valley Transmission Upgrade Project.

150. Pacific Gas and Electric, March 9, 2005, *San Francisco Phase II Study, Preliminary Cost Estimates and Discussion of Routes, Permitting and Schedules*, draft, p. 10.

Chapter Six:
Renewable Resources for Electricity Generation

California needs to increase its use of renewable resources to diversify the state's electricity system and reduce its growing dependence on natural gas. Over the past two decades, California has developed one of the largest and most diverse renewable generation mixes in the world. In 2004, 10.2 percent of the state's electricity came from renewable sources, excluding large hydroelectric power.[151] The Energy Commission estimates that the state has near-term economic potential for an additional 6,000 MW of renewables which, if developed, would nearly double California's renewable generating capacity.[152]

To meet its ambitious goals for increasing the percentage of electricity derived from renewable energy sources, California must address four major issues:

- The lack of progress in the Renewable Portfolio Standard (RPS) program.
- The need for new and/or upgraded transmission to access renewable resources in several areas of the state.
- The impact of integrating large amounts of intermittent renewable resources into the electricity grid.
- The need to repower aging wind facilities and reduce the number of bird deaths associated with the operation of wind turbines.

The RPS program is central to meeting California's renewable resource goals. Established in 2002, the RPS was designed to address the lack of long-term power purchase agreements that prevent developers from getting the financing they need to build their projects. After three years of implementation, however, the RPS is plagued by a lack of transparency, overly complex rules, and inconsistent application among retail sellers. As a result, only a small number of contracts have been signed for renewable projects, many of which will not even begin operation until the end of 2006.[153]

Even if sufficient contracts were signed to assure meeting the state's renewable resource goals, transmission upgrades are required to take advantage of resources in the Tehachapi wind and the Imperial Valley geothermal resource areas. Although the Tehachapi and Imperial Valley Transmission Groups have made progress in developing plans for transmission upgrades, FERC recently rejected SCE's renewable trunk line proposal, thereby removing the primary instrument the state could have used to address transmission constraints for renewables.

California has substantial wind resources likely to play an important role in meeting the state's RPS goals. However, significantly increasing the volume of wind resources in California's electricity mix could have negative impacts on the state's transmission system. California must also address barriers to repowering aging wind facilities, particularly in the Altamont Pass area. Replacing older turbines with larger, more efficient turbines will not only increase the volume of renewable energy available to meet RPS goals, but will also reduce bird deaths associated with wind turbine operation.

California also has significant biomass resources, with 1,000 MW of generating capacity accounting for more than 2 percent of the state's electricity mix. Biomass has value as a renewable resource that can help meet the state's RPS goals while also capturing social, economic, and environmental benefits and improving transmission reliability. In his response to

151. California Energy Commission, *California Electrical Energy Generation, 1995-2004*, [http://www.energy.ca.gov/electricity/electricity_generation.html], accessed November 7, 2005.

152. California Energy Commission, July 2005, *Implementing California's Loading Order for Electricity Resources*, CEC-400-2005-043, p. 26.

153. Southern California Edison, March 25, 2005, *Advice 1876-E-A to Public Utilities Commission of the State of California Energy Division, Supplement to Submission of Contracts for Procurement from Renewable Resources Pursuant to California Renewables Portfolio Standard Program*, and Pacific Gas and Electric, advice letter 2678-E to the CPUC, *Contract for Procurement of Renewable Energy Resources Resulting from PG&E 2004 Renewable Portfolio Standard Solicitation*, June 21, 2005.

the *2003 Energy Report*,[154] Governor Schwarzenegger called for an integrated and consistent state policy on biomass development.

While the *2003 Energy Report* and *2004 Energy Report Update* identified strategies to promote the development of renewable resources in California, additional work and legislative action are needed to overcome barriers facing these resources and to ensure that the state meets its RPS goals.

Background

When the RPS program was established in 2002, it required the state's investor-owned utilities (IOUs) to increase their use of eligible renewable resources by at least 1 percent of sales per year, with a target of 20 percent renewable resources by 2017. The *2003 Energy Report* recommended accelerating the goal to 2010 because of the perceived significant progress already made toward the 20 percent goal. The report also recommended developing more ambitious post-2010 goals to maintain the momentum for continued renewable energy development, expand investment and innovation in technology, and bring down costs.

The *2004 Energy Report Update* recommended an increased goal of 33 percent renewable by 2020, arguing that IOUs with the greatest renewable potential should have a higher RPS target. Because SCE has three-fourths of the state's renewable technical potential and had already reached 17.04 percent renewable by 2002,[155] the report recommended a new target for SCE of 35 percent by 2020.

The CPUC reinforced the importance of renewable energy as an integral part of the state's loading order policy by directing IOUs in their long-term procurement plans to consider renewable resources as "the rebuttable presumption."[156] IOUs must file long-term procurement plans every two years, starting in 2004, and justify any selection of fossil generation over renewable generation. Renewable generators must be responsive to IOU power needs for specific products and be cost-effective compared with fossil generators when a greenhouse gas adder is included.

The *2003 Energy Report* also recommended extending the RPS to all retail sellers of electricity, including publicly owned utilities. In the RPS statute, retail sellers include energy service providers (ESPs) and community choice aggregators. While ESPs and community choice aggregators have the same RPS obligations as IOUs, there are no rules in place for their participation or to ensure that RPS targets, eligibility requirements, and compliance dates are applied consistently among all participants. The absence of rules for ESPs and community choice aggregators is delaying the state from reaching its 20 percent renewable target by 2010.

Because publicly owned utilities provide 25-30 percent of the state's electricity, the *2004 Energy Report Update* argued that applying the accelerated and increased RPS targets to these entities was crucial for meeting the state's goals for renewable energy. However, attempts to pass legislation that would require publicly owned utilities to comply with RPS targets have been unsuccessful.

While California's renewable resources offer the potential to decrease the state's dependence on fossil fuels, significant transmission upgrades are needed to take advantage of resources in the

154. Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: *Review of Major Integrated Energy Policy Report Recommendations*, August 23, 2005.

155. California Energy Commission, July 2005, *Implementing California's Loading Order for Electricity Resources*, CEC-400-2005-043, Appendix A, Section 14.

156. CPUC, *Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company's Long-term Procurement Plans*, D.04-12-048, pp. 2 and 69, December 16, 2004.

Tehachapi wind and the Imperial Valley geothermal resource areas to move that energy from its source to customers. In addition, integrating large amounts of intermittent resources such as wind into the transmission system will require greater flexibility in system operations. In the near term, the state has determined that operational constraints posed by the intermittent nature of renewable resources are manageable and do not significantly increase costs. As the penetration of intermittent wind resources increases over time, however, additional measures will be needed to integrate these resources into the electricity system.

Taking advantage of California's substantial wind resources to meet RPS goals requires that two significant and related issues be addressed: repowering the state's aging wind facilities, particularly in the Altamont Pass area, and reducing the number of bird deaths associated with the operation of wind turbines. Repowered wind facilities with existing standard offer contracts cannot receive federal tax incentives unless they amend their contracts so that generation above historical production is paid at the utilities' current short-term avoided cost, which is much lower than current contract prices. Without the ability to recover additional costs through their contracts, wind facilities have little incentive to repower.

In the *2004 Energy Report Update*, the Energy Commission highlighted repowering as a primary option for reducing bird deaths associated with wind turbines, particularly in the Altamont Pass area. Preliminary research indicates that replacing a number of small turbines with fewer, larger turbines could likely reduce avian mortality. However, planning officials in the Altamont area have limited permits for both new and repowered wind facilities until they are confident that steps have been taken to reduce bird deaths.

Improving the Renewable Portfolio Standard Program to Meet Goals

Figure 16 on the next page shows California's progress toward RPS goals as well as the amount of renewable generation needed to reach those goals. Clearly, statewide renewable procurement is not proceeding as quickly as needed to reach RPS goals by 2010. Contracts from SCE's 2003 RPS solicitation were not approved until mid-2005, and the facilities are not expected to come on line until the end of 2006. The CPUC did not approve PG&E's first contracts from its 2004 RPS solicitation until July 2005, and SDG&E did not submit contracts from its 2004 solicitation for CPUC approval until September 2005. In July 2005, the CPUC approved the IOUs' long-term procurement plans and draft requests for offers for the 2005 RPS solicitation. PG&E released its 2005 RPS solicitation on August 4, 2005.

The primary problems with the RPS program are:

- The lack of transparency in the bidding, ranking, and contracting processes and the complexity in administering the program.
- The uneven application of RPS targets to all retail sellers in the state.

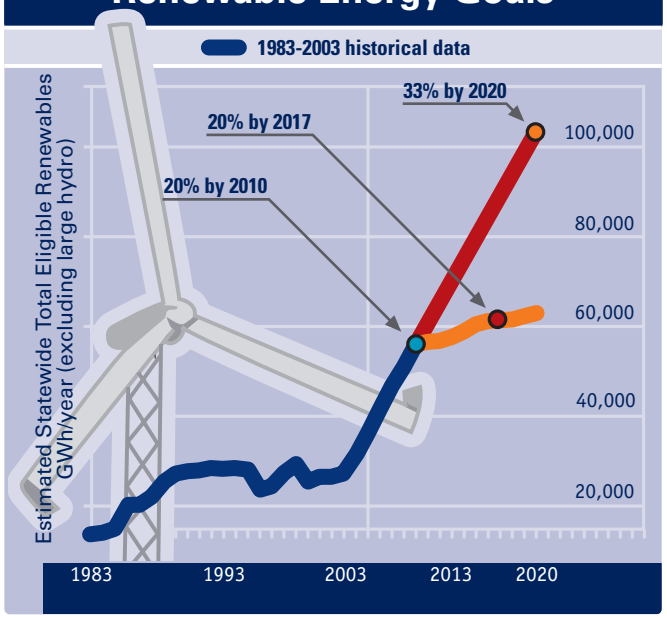
Too Little Transparency, Too Much Complexity

One of the main problems with the RPS program is the lack of transparency for program participants and the public. Transparency is necessary to ensure that all parties understand the allocation of the public funds that support the RPS program. The least-cost, best-fit method that IOUs use to rank RPS bidders is particularly unclear. The intent of the least-cost, best-fit process was to ensure that IOUs did not arbitrarily select projects without taking into consideration the full range of benefits provided by renewable generators. The CPUC defines "best fit" as "the renewable resources that best meet the utility's energy, capacity, ancillary service, and local reliability needs."[157] Each IOU has its own

157. CPUC, June 19, 2003, Decision 03-06-071, *Order Initiating Implementation of the SB 1078 Renewable Portfolio Standard Program*, p. 28, [http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/27360.pdf], accessed April 19, 2005.

distinct least-cost, best-fit methodology but those methodologies are only broadly described and use qualitative as well as quantitative components, making it impossible for policy makers to determine whether IOUs are selecting projects that are truly least-cost and best aligned with the state's policy to provide long-term benefits to the system.

Figure 16: **California's Renewable Energy Goals**



Source: California Energy Commission

Transparency is also necessary in the bid evaluation process for contracts. Currently, bid results are confidential except to a select group of parties within the procurement review group. As a result, decision makers at the Energy Commission are not privy to confidential information revealed to the procurement review group but must still approve allocation of supplemental energy payments to cover the above-market costs of contracts resulting from RPS solicitations. Without more clarity regarding the RPS bid evaluation process, the Energy Commission cannot be certain that supplemental energy payments will be used most efficiently to help meet the state's RPS goals.

The administrative complexity of the RPS program is another deterrent to reaching renewable goals by 2010. The RPS statute requires the CPUC to establish a benchmark price for energy to determine the need for public funds to cover the above-market costs of procuring renewable energy.[158] This "market price referent" is intended to be a proxy for the cost of developing conventional energy sources. The process for determining the market price referent, however, is convoluted and continues to increase in complexity. Reaching consensus among parties on the assumptions used to calculate the market price referent takes considerable time and resources. In addition, assumptions used to derive the market price referent may be significantly different from assumptions used in the CPUC's all-source procurement efforts, making the two procurement processes inconsistent. The potential use of multiple market price referents to reflect different products and contract terms also complicates administration of supplemental energy payments for above-market contracts.

The CPUC, in collaboration with the Energy Commission, should investigate options for developing an alternative RPS framework and propose legislation that would adopt a simpler and more transparent RPS process by next year.

Several options could increase transparency and simplify administration of the RPS program. One option is to make RPS procurement the same as all-source procurement, eliminating the market price referent and supplemental energy payment processes. To contain RPS program costs, the

158. SB 1078 (Sher), Chapter 516, Statutes of 2002, codified in pertinent part in Public Utilities Code Section 399.15, Subdivision (c).

CPUC could apply the same reasonableness review to renewable contracts as it applies to non-renewable procurement.

Another option is to follow the structure used in interim RPS procurement. In interim procurement, the CPUC publicly announced a single cut-off contract price below which contracts were judged reasonable, with costs recoverable in utility rates. This option would avoid much of the current complexity of multiple market price referents as well as the need for separate supplemental energy payments. Advantages of this option include proven success, simplicity, and transparency.

A third option is to award public funds for RPS contracts through auctions for production incentives, with awards conditioned on receiving contracts through the RPS solicitation process. The Energy Commission used the auction process to award funds to renewable energy developers when the public goods charge for renewable energy development was initially authorized in 1997.[159] All information submitted in the bids was publicly available, as were the criteria used in the bid selection process. The Energy Commission held three auctions for production incentives between 1998 and 2001, resulting in 400 MW of new renewable projects coming on line. Several stakeholders have recommended a return to the auction process, citing its simplicity and success.

In the meantime, the CPUC should allow for changes to the current program that can be accomplished under existing RPS law. In addition to changes to transmission cost adders, addressed later in this chapter, the CPUC should allow and encourage inter-utility trades under flexible compliance, the use of shaped products, and more flexible delivery requirements.

Encouraging shaped or firmed renewable products could provide the necessary flexibility for renewable generators to structure their RPS contracts to keep transmission costs low and better meet IOU energy profile needs. The CPUC should clarify that utilities can enter into RPS contracts for shaped products, such as the storage and shaping service offered by the Bonneville Power Administration that stores hourly wind energy generation in the federal Columbia River Hydroelectric System and delivers it to purchasing customers a week later.

To avoid under-procurement of renewable energy, the CPUC should require IOUs to procure a prudent contract-risk margin. There are many legitimate reasons for cancellation and delay of otherwise sound RPS contracts. These include unanticipated difficulties with getting required land easements; higher turbine and equipment prices than anticipated in contracts; uncertainty about the possibility of getting projects on line before incentives are fully subscribed; and difficulty in securing financing. In the state's experience with contracts for qualifying small power production facilities, one-third of the projects did not result in actual energy procurement. A 30 percent contract-risk reserve margin above the IOUs' annual procurement targets would be a prudent starting point to prevent under-procurement. In the longer term, as experience is gained with renewable solicitations, the margin should be revised to reflect actual versus contracted energy.

The CPUC, in collaboration with the Energy Commission, should also develop standardized power purchase contracts to speed up the contract negotiation process between IOUs and renewable bidders. Provisions relating to definitions, construction milestones, penalties, force majeure, operating reporting requirements, security, and other non-commercial terms should be standardized for three contract types (baseload, as-available, and peaking) while commercial terms such as term, delivery point, contract price, and contract quantity would remain subject to negotiation.

159. SB 90 (Sher), Chapter 905, Statutes of 1997, codified in pertinent part in former Public Utilities Code Section 383.5, Subdivision (c).

Recommendations to Reduce Complexity and Increase Transparency

- The RPS program is in need of a mid-course review and correction. After completion of the 2005 round of IOU solicitations, the CPUC and the Energy Commission should investigate whether a simpler and more transparent RPS process would better achieve the state's 2010 goals. A seminal question is the likely impact of the CPUC's "rebuttable presumption" for renewables directive for IOU all-source procurement. This review should be completed and transmitted to the Governor and Legislature by January 1, 2007.
- The CPUC should allow for changes to the current program that can be accomplished under existing RPS law, including inter-utility trades under flexible compliance, the use of shaped products, and more flexible delivery requirements, as well as changes to transmission cost adders, which are addressed later in this chapter.

Applying RPS Targets Consistently

Another major problem with the RPS is that RPS procurement targets are not being met uniformly among the various load serving entities (LSEs) in the state. Because publicly owned utilities are not subject to the same implementation rules as IOUs, their RPS programs include varying targets, timelines, and eligibility standards. An analysis prepared for the Energy Commission by Kema, Inc. indicates that publicly owned utility targets vary from 5 percent to 40 percent and dates vary from 2007 to 2017.[160] In addition, publicly owned utilities do not have the same enforcement mechanisms as IOUs, so their targets are simply goals. Also, though most publicly owned utilities include end targets, they do not include intermediate targets such as those faced by IOUs, ESPs, and community choice aggregators. Finally, even though hydroelectric projects larger than 30 MW are not considered eligible renewable resources under the RPS program for IOUs, most publicly owned utilities still count generation from these projects toward their renewable energy targets.

The Kema, Inc. analysis also indicates that some California publicly owned utilities are pursuing renewable goals that are reasonably consistent with the state's overall targets. However, other publicly owned utilities are not taking such aggressive action. A number of other states with RPS policies impose more significant requirements on publicly owned utilities than does California. Also, publicly owned utilities in California are not required by statute to conform to all the RPS requirements established for IOUs, including: definitions of eligible renewable resources and requirements for market price referents and supplemental energy payments; least-cost, best-fit criteria; standard contract terms and conditions; and other administrative details associated with procuring renewables.

Because of the difficulties associated with these complex administrative requirements for IOUs, they should not be applied to publicly owned utilities. However, the targets, timelines, and eligibility standards established for IOUs must be applied consistently to all publicly owned utilities since these entities are expected to contribute to statewide renewable goals. The *2004 Energy Report Update* recognized that smaller publicly owned utilities may have difficulties in complying with RPS goals because of contractual obligations, small load, slow growth rates, and the lack of locally available renewable resources. The state should therefore establish an exemption process to avoid overly burdensome requirements for these publicly owned utilities, consistent with the Energy Commission's earlier recommendations.

Applying consistent statewide RPS rules to publicly owned utilities will require legislative action. The need to bring publicly owned utilities into the RPS is underscored by data indicating that the volume of renewables in California's electricity mix has

160. Kema, Inc., *Publicly Owned Electric Utilities and the California RPS: A Summary of Data Collection Activities*, November 2005, CEC-300-2005-023.

actually dropped since 2002, from 11 percent to 10.2 percent statewide. Based on data submitted by IOUs on their progress toward RPS compliance, the shortfall appears to be from non-IOU retail sellers such as publicly owned utilities and ESPs. Although a number of publicly owned utilities already report more than 20 percent eligible renewables, in 2003 the state's largest publicly owned utilities, LADWP and SMUD, reported only 2 percent and 9 percent renewables, respectively, although the newly elected mayor of Los Angeles recently committed to reaching 20 percent by 2010.[161]

The lack of rules for RPS compliance is hampering the participation of ESPs and prospective community choice aggregators in the RPS program. RPS rules for IOUs, such as calling for electricity delivery, long-term contracts, and procurement oversight by the CPUC, do not fit typical ESP and community choice aggregator business models. Therefore, the state needs new regulatory structures for ESPs and community choice aggregators. Under the RPS statute, the CPUC must determine how these entities will participate in the RPS and be "subject to the same terms and conditions" as IOUs. The CPUC made some progress toward developing RPS procurement and compliance requirements for ESPs and community choice aggregators by issuing a draft decision in June 2005 setting forth basic parameters for RPS participation by ESPs, community choice aggregators, and small and multi-jurisdictional utilities.[162]

The CPUC draft decision proposes that ESPs and community choice aggregators not needing public goods charge funds to meet their RPS requirements be excused from some of the requirements imposed on the IOUs such as submitting renewable resource plans and using the least-cost, best-fit methodology to evaluate renewable bids. They would, however, still be required to meet annual procurement targets, the 20 percent target by 2010, and reporting and tracking requirements. If an ESP or community choice aggregator needs public goods charge funds, then it would be subject to all the same rules that apply to IOUs.

One way to facilitate the uniform participation of all LSEs in the RPS is to allow limited use of renewable energy certificates (RECs) for RPS compliance, with the associated electricity sold into the CA ISO real-time market or bilaterally to retail sellers. RECs allow the sale of the "greenness" of renewable electricity separate from the energy itself, called "unbundling." California's RPS program currently does not allow the use of unbundled RECs for RPS compliance. However, several stakeholders identified tradeable RECs as an important tool that IOUs, publicly owned utilities, ESPs and community choice aggregators could use to meet their RPS compliance obligations.

As outlined in the *2004 Energy Report Update*, unbundled RECs represent a potential advantage for California because they could reduce the need for new transmission lines, relieve transmission congestion, and help meet renewable energy goals. Though RECs can help utilities transfer renewable attributes between utilities, ESPs, community choice aggregators, and publicly owned utilities, RECs would not eliminate the need for transmission investments to interconnect and access renewable resources. Even with these potential transmission constraints, unbundled RECs may be a reasonable means for LSEs to increase the amount of renewable resources in the state, although some parties raise concerns that RECs could invite market manipulation or double counting.

161. "Villaraigosa Appoints New DWP Board," August 16, 2005, [http://www.latimes.com/news/local/la-me-dwp16aug16,1,3786019.story?coll=la-headlines-california], accessed August 16, 2005.

162. See CPUC Rulemaking R. 04-04-026, draft decision of ALJ Allen, *Opinion on Participation of Energy Service Providers, Community Choice Aggregators, and Small and Multi-Jurisdictional Utilities in the Renewables Portfolio Standards Program*, June 29, 2005 [http://www.cpuc.ca.gov/word_pdf/COMMENT_DECISION/ 47469.doc], accessed July 5, 2005.

By allowing limited use of RECs in the near term, California can gain experience and make necessary adjustments to ensure that RECs achieve their intended advantages. Until the Western Renewable Energy Generation Information System (WREGIS) is developed and in place to electronically track the transfer of RECs and help verify RPS compliance and prevent manipulation and double counting, the state should proceed with RECs on a limited basis. In the longer term, however, California should move toward full REC trading in the state and western region once WREGIS is operational and establish requirements including provisions to prevent double counting, assure energy is actually delivered, and prevent market manipulation.

The Energy Commission already has experience in tracking and verifying RECs on a limited basis. Though not used for RPS compliance purposes, the Energy Commission was among the first regulatory agencies in the U.S. to recognize RECs by allowing their use for verification in the Customer Credit Program. The Customer Credit Program provided incentives to customers who purchased renewable energy through direct access contracts with energy suppliers and marketers. To provide a high-level of flexibility in determining the best way to develop the renewables market, suppliers and marketers had the freedom to trade RECs on the wholesale level and procure RECs from registered generators or wholesalers. Because RECs alone did not qualify under the program, the RECs were then rebundled with energy deliveries. Over the four-year life of the program, the Energy Commission was able to successfully track and verify the use of RECs to substantiate qualifying sales of renewable energy.

Recommendations to Improve Consistency

- The Legislature should apply the same RPS targets, timelines, and eligibility standards to publicly owned utilities that it has established for IOUs. Consistent with the Energy Commission's 2004 recommendation, the state should establish an exemption process for small publicly owned utilities to avoid the overly burdensome requirements that compliance with RPS goals may present to them.
- The Legislature should authorize the CPUC to allow limited use of renewable energy certificates for RPS compliance to facilitate uniform participation of all load serving entities, with the associated electricity sold into the CA ISO real time market or bilaterally to retail sellers.
- The CPUC should move forward with a decision establishing rules that allow ESPs to proceed with RPS procurements. The decision should include a flexible compliance option allowing ESPs to enter into transfers or exchange arrangements with other LSEs that would function as an interim and limited use of renewable energy certificates.

Addressing Other Issues Associated with Developing Renewable Resources

California must also address a number of other issues affecting the development of renewable resources in the state, including:

- The need for new or upgraded transmission access for renewable resources.
- The impact of integrating large amounts of intermittent renewables into the transmission system.
- The need to repower the state's aging wind facilities.
- The need to reduce the number of bird deaths associated with the operation of wind turbines.

Transmission for Renewable Resources

Wind resources in the Tehachapi area and geothermal resources in the Imperial Valley are some of the state's most promising resources and could be vital components in meeting targets for renewable energy development in California. However, the state needs to resolve transmission constraints in those areas to access those resources.

In March 2005, SCE proposed a new category of transmission facility called a "renewable-resource trunk line." The trunk line would interconnect large concentrations of potential renewable generation resources located within a reasonable distance from the existing grid and be operated by the CA ISO. In July 2005, however, FERC denied

SCE's request.[163] This denial removed the primary instrument the state could have used to address transmission constraints for renewables. The FERC's denial of the renewable trunk line concept reinforces the need for the Energy Commission, the CPUC, and the CA ISO to investigate changes to the CA ISO tariff to recognize this new category of transmission project, as recommended in the *2004 Energy Report Update*. This recommendation is discussed in greater detail in Chapter 5 of this report.

California also needs a new approach for assessing transmission costs in RPS bid solicitations and in evaluating renewable bids under the least-cost, best-fit process. The CPUC's current approach does not account for network benefits, which some parties argue offset the transmission upgrade costs attributable to many renewable projects. Other parties believe that the cost of transmission upgrades should not automatically be assigned to RPS projects since those projects can compete for existing transmission capacity under the CA ISO's open access policies.

The current approach also allocates the entire cost of transmission upgrades needed to connect bidders in each solicitation to the projects bidding into that solicitation.[164] This approach fails to capitalize on the economies of scale that can be achieved by sizing transmission for multiple generators in rich pockets of potential renewable energy instead of pursuing a piecemeal approach with individual generators. Overly complex administrative burdens associated with developing transmission cost adders for use in IOU RPS procurement are erecting new barriers to renewable development.

Perhaps the most troubling aspect of transmission cost adders is the assertion by some parties in the CPUC proceeding that the current transmission cost adder approach actually penalizes renewable projects. Under the current structure, all existing users of transmission, primarily fossil-fueled generators, are essentially given priority for current transmission capacity while renewable generators are required to upgrade transmission to gain access to the grid. This perspective is difficult to reconcile with the state's preferred loading order.

The Energy Commission's *2005 Strategic Transmission Plan* addresses additional transmission issues associated with renewables in more detail.

Recommendations to Address Transmission Barriers

- The CPUC, the Energy Commission, and the CA ISO should investigate changes to the CA ISO tariff that would allow recognition of transmission needs not only for reliability and economic projects, but also for access to renewable projects to meet RPS goals.
- The CPUC, the Energy Commission, and the CA ISO should cooperate to revise the transmission cost adder process for RPS procurement to more accurately reflect transmission costs and reduce existing disincentives for renewables.

Integrating Renewable Resources into California's Electricity System

Given existing problems in California's transmission system, adding significant quantities of intermittent renewables envisioned in the RPS is likely to require greater flexibility in system operations, although the effects are likely to be local rather than statewide.[165] The CA ISO has made progress addressing this issue through the Participating Intermittent Renewables Program. As part of the program, the CA ISO uses wind forecasts to anticipate wind energy delivery and settles energy imbalance costs (charges for occasions when delivered energy differs from the

163. *Order on Petition for Declaratory Order re Southern California Edison Company*, docket EL05-80-000, 112FERC61,014, July 1, 2005.

164. If another bidder in the same area has also bid into that solicitation, transmission costs could be spread among the other bidders.

165. California Energy Commission, April 2005, *Assessment of Reliability and Operational Issues for Integration of Renewable Generation*, consultant draft report, prepared by Electric Power Group, LLC, and Consortium for Electric Reliability Technology

scheduled amount) with participating wind energy generators on a net monthly basis.[166] Wind generators pay a forecasting service fee of $0.10 per MWh to the CA ISO to participate in the program.[167]

However, more needs to be done to ensure that intermittent renewable resources are integrated into the state's system, while mitigating possible effects on reliability or system operations. The Consortium for Electric Reliability Technology Solutions (CERTS) issued a report in July 2005 identifying changes in CA ISO system operations needed to support the state's goal of 20 percent renewables by 2010.[168] The study identified a number of problems faced by control area operators. For example, control area operators may need to reduce generation output during high run-off and high-wind periods, especially during early morning hours when electricity loads are light. This could be mitigated by coordinating pumped storage hydroelectric generation to create load during these times.

The CERTS report also found that changing the mix of renewable resources can affect system stability. With significant wind energy in the mix, the need for controllable generation is larger. By increasing the amount of solar energy in the mix, however, load swings could be almost completely mitigated because of the high correlation between electricity production and load. SCE recently signed a 20-year power purchase agreement for development of a 500-MW solar project, representing the first major application of Stirling dish technology in the commercial electricity generation field.[169] SDG&E has also announced plans for a 300-MW solar project using the same technology.[170] Based on conclusions from the CERTS research, these solar projects could help address the impacts of integrating a large volume of wind into California's system while roughly tripling U.S. solar electric generating capacity.

The overriding message from the CERTS work is "We've done this before. We've been successful. But it requires planning, coordination, practices, procedures, and action."[171] CERTS points out that utilities have overcome larger operational challenges in the past, such as subsynchronous resonance problems with remote coal plants, minimum load issues with the introduction of large nuclear plants, and the absence of generation control when 10,000 MW of qualifying facilities came onto the grid.[172]

The state needs to increase its research and development efforts to better understand and address the impacts of integrating large amounts

166. See also Amendment 42 docket ER02-922-000 (*Intermittent Resources; CT 487; Intra-zonal Congestion; and Real Time Pricing*) [http://www.CA ISO.com/docs/2002/02/01/ 200202011116576547.html], accessed April 15, 2005, and *Participating Intermittent Resource Program (PIRP) - Background/Documentation*, [http://www.CAISO.com/docs/2003/01/29/ 2003012914271718285.html], accessed April 15, 2005.

167. See CA ISO Tariff Section 11.2.4.5.4 and Schedule 4 of Appendix F. [http://www.CA ISO.com/docs/2005/06/30/2005063008591817859.pdf], accessed July 7, 2005.

168. California Energy Commission, July 2005, *Assessment of Reliability and Operational Issues for Integration of Renewable Generation*, consultant report, prepared by Electric Power Group, LLC, and Consortium for Electric Reliability Technology Solutions, CEC-700-2005-009, [http://www.energy.ca.gov/ 2005_energypolicy/documents/index.html#051005].

169. "Major New Solar Energy Project Announced by Southern California Edison and Stirling Energy Systems, Inc.," August 9, 2005, [http://www.edison.com/pressroom/pr.asp?id=5885], accessed August 31, 2005.

170. "SDG&E to Buy Solar Electricity," September 8, 2005, *San Diego Union-Tribune* [http://www.signonsandiego.com/news/business/20050908-9999-1b8solar.html], accessed September 9, 2005.

171. Testimony of Jim Dyer, Consortium for Electric Reliability Technology Solutions, transcript of the February 3, 2005 *Energy Report* Committee workshop on *Transmission-Renewables and Integration Issues*, p. 9.

172. Ibid, pp. 5-12.

of intermittent renewable resources into California's system. Over the next year, the Energy Commission's Public Interest Energy Research (PIER) program will build on the CERTS work. In the meantime, policy makers should continue to work with utilities to identify options to improve the planning, monitoring, and operation of the CA ISO system in support of the state's accelerated RPS goals.

The Energy Commission, in collaboration with the Department of Energy, should also increase its research agenda for expanding the state's energy storage options. Given California's increasing commitment to intermittent sources of electricity, the state has a vested interest in aggressively exploring energy storage opportunities to increase the operational flexibility of the state's electricity grid and accommodate the impacts of growing volumes of intermittent resources.

Recommendations for Research and Development Efforts

- The CA ISO should undertake a research initiative addressing the attribute requirements of its system and focus on defining current and future control area attribute requirements.
- The CA ISO should undertake a research initiative to address minimum load issues, including forecasting future minimum load problems, the number of annual events, and the depth of the problem.
- The Energy Commission and the CA ISO should sponsor a joint initiative, with the participation of utility and industry stakeholders, to research and test alternative pricing schemes for operating attributes and integrate them into market design.
- The CA ISO should undertake a research initiative to address load as a provider of resource attributes, including the determination of: the resource attributes that could be provided by dispatchable load; pricing of those key attributes; infrastructure requirements to integrate load as a controllable device; and automatic load control requirements.
- The Energy Commission should explore options to enhance availability of hydroelectric generation for automatic load control.
- The Energy Commission should develop a research, evaluation, and deployment initiative to improve production forecasting, including investigating best practices and tools for wind energy forecasting, identifying errors in wind production forecasting, identifying wind monitoring requirements, and deploying needed monitoring equipment.

Repowering Wind Resources and Reducing Bird Deaths

California's nearly 1,000 MW of aging wind facilities were installed 20 years ago using smaller turbines that are less efficient and more costly to operate and maintain than the current generation of turbines. In its June 2003 decision on implementing the RPS, the CPUC supported repowering these facilities as "a common-sense approach to increasing procurement of renewable energy," and endorsed comments by The Utility Reform Network (TURN) that the CPUC should "require prompt negotiation to resolve what [TURN] characterizes as a stalemate around repower of existing wind facilities."[173] Despite this directive, however, very little has been accomplished toward repowering these facilities.

To date, California has made only limited progress toward repowering wind facilities, with only 120-135 MW of repowered wind contracts submitted to or approved by the CPUC as of October 2005.[174] Repowering efforts in the Altamont

173. CPUC, *Order Initiating Implementation of the SB 1078 Renewable Portfolio Standard Program*, Decision 03-06-071, June 19, 2003, pp. 57 and 60.

174. This total includes 37 MW of Southern California Edison contracts and 84-99 MW of Pacific Gas and Electric contracts. These numbers came from two sources: Energy Commission Renewable Portfolio Standard staff and Wiser, R., Porter, K., Bolinger, M., and Raitt, H., "Does It Have to Be This Hard? Implementing the Nation's Most Complex Renewables Portfolio Standard," *The Electricity Journal*, October 2005, Volume 18 Issue 8, pp. 55-67.

Pass Wind Resource Area have been hindered by a moratorium placed on wind development by Alameda County in 1998. The county will not approve additional permit applications to increase electricity production above the current cap of about 580 MW. Currently, neither Alameda County nor the wind industry proposes to repower the entire Altamont Pass; both are focused instead on renewing existing permits, with a proposed condition that repowering would only occur over 13 years.[175]

In addition, there are current limitations on federal tax incentives for wind projects. The federal production tax credit, recently extended to December 31, 2007, provides much-needed financial incentives for wind repowering. However, provisions in the U.S. Tax Code (Section 45) prevent repowered wind facilities with existing standard offer contracts from qualifying for the production tax credit unless the contract is amended so that any wind generation in excess of historical production levels is either sold to the utility at its current avoided cost or sold to a third party.[176] This provision discouraged wind operators from repowering because utility avoided costs are much lower than current contract prices.

As recommended in the *2004 Energy Report Update*, replacing older turbines can substantially increase wind production while decreasing the number of turbines and impacts on the environment. Repowering takes advantage of land already developed with access roads and transmission rights-of-way. New turbines are also quieter and reduce noise impacts typically associated with wind facilities.

Equally important, reducing the number of older wind turbines at particular locations in California can reduce deaths of raptors and other birds protected by domestic and international law, particularly in the Altamont area. California has an important opportunity to more carefully site new turbines based on knowledge of bird flight patterns, thereby reducing and avoiding bird deaths from wind turbines.[177]

The *2004 Energy Report Update* also recommended using findings from the Energy Commission's avian mortality studies to evaluate permits for new and repowered wind turbine facilities. Since publication of that report, an extremely polarized debate has emerged among the wind industry, the Energy Commission staff and consultants, and environmentalists who believe there have been inadequate efforts to reduce the number of birds killed by wind turbines in the Altamont Pass. A focal point of that debate has been the statistical reliability of the research cited in the *2004 Energy Report Update* and the subsequent use of that research by Energy Commission staff and consultants.

The Energy Commission believes that the earlier research, *Developing Methods to Reduce Bird Mortality in the Altamont Pass Wind Resource Area*, represents an important initial effort to craft a methodology to prescribe mitigation measures, but that it should not be misused to form the sole basis for such mitigation measures. Inadequate access to certain turbines, time lapses between surveys, length of survey period, and various extrapolation techniques deprive it of the evidentiary value that the Energy Commission would require as the basis for mitigation measures in a power plant siting

175. Alameda County is currently processing the reissuance of conditional use permits for the maintenance and operations of existing wind turbines in the Altamont Pass Wind Resource Area.

176. Standard offer contracts were instituted by the CPUC to establish prices, terms, and conditions for investor-owned utility purchases from independent generators, including renewable generators, in the early 1980s in response to the federal Public Utility Regulatory Policies Act of 1978.

177. California Energy Commission, December 2004, *Repowering the Altamont Pass Wind Resource Area (APWRA): Forecasting and Minimizing Avian Mortality Without Significant Loss of Power Generation* [http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2005-005.html#ExecutiveSummary], accessed April 21, 2005.

case. The scientific value of ongoing Energy Commission research into avian mortality prevention should not be jeopardized by misapplication of what are essentially experimental results.

Recommendations for Repowering and Reducing Bird Deaths

- Existing wind sites should be repowered to harness prime wind resources more efficiently and reduce or prevent bird deaths.
- The CPUC should quickly develop new standardized contracts to overcome impediments to repowering and take advantage of the federal production tax credit.
- Statewide protocols should be developed for studying avian mortality to address site-specific impacts in each individual wind resource area.

Recognizing the Value of Biomass Resources

California has approximately 1,000 MW of biomass-generated electricity, including some 600 MW from solid-fuel biomass (residues from forestry and agriculture) and about 400 MW from other sources such as landfill gas, biogas from wastewater treatment, direct burning of municipal solid waste, and anaerobic digestion of livestock manure. These feedstocks could support much greater use in electricity generation, fuels and chemicals, manufacturing, and the production of various co-products. The strategic value of using California's untapped biomass is the ability to solve two problems at once: waste disposal and mitigating environmental problems such as increased fire risk, air pollution, and climate change.[178]

The volume of energy provided by biomass generating facilities in California has declined in recent years due to facility closures in the solid-fuel biomass sector. Prior to 1980, only a handful of solid-fuel biomass power plants were operating at lumber or pump mills to supply power for on-site use. The advent of standard offer contracts in the early 1980s, however, led to the development of 33 new biomass generating facilities between 1985 and 1990, bringing total statewide biomass capacity to 770 MW by the end of 1990.[179]

Faced with proposals by the CPUC to restructure the state's regulated electric utility industry in 1994, IOUs began offering to buy out standard offer contracts for biomass generators in their service territories. Because of concerns about long-term liabilities for firm capacity within these contracts, many biomass generators were willing to accept the IOU offers. As a result, 17 biomass facilities totaling 215 MW shut down.[180]

After California's electricity market was deregulated in 1996, the state's solid-fuel biomass energy industry entered a period of relative stability for the remainder of the 1990s, with 27 facilities representing 540 MW of capacity remaining in operation. Many of the existing biomass facilities received financial incentives from state public goods charge programs that helped to offset the end of the fixed-price periods in generators' standard offer contracts. Then, during the 2000-2001 energy crisis, several idle biomass facilities were able to restart and resume operations. However, 14 biomass plants are still idle, including 5 that have closed since the 2000-2001 energy crisis.[181]

178. California Energy Commission, *Biomass Strategic Value Analysis*, CEC-500-2005-109-SD, June 2005.

179. *The Status of Biomass Power Generation in California*, July 31, 2003, G. Morris, Green Power Institute, under contract to National Renewable Energy Laboratory, publication number NREL/SR-510-35114.

180. Ibid.

181. Testimony of Julee Malinowski-Ball, California Biomass Energy Alliance, transcript of the October 6, *2005, Energy Report* hearing on *Demand Side Resources, Distributed Generation, Renewable Resources, and Other Electricity Resources*, pp. 63-68.

California today has 28 biomass plants totaling about 600 MW of capacity.[182] Many of these facilities are operating under older standard offer contracts with fixed energy prices through mid-2006. The long-term prospects for these projects will depend on their ability to negotiate new contracts.

Current high diesel prices are affecting the prices paid by the biomass industry for fuel gathering, processing, and transportation. Biomass fuel prices have risen approximately 8 percent since the beginning of 2005, in part because of increasing diesel fuel prices. To help offset these increased costs and prevent biomass curtailment, the Energy Commission is considering increasing the incentive level and cap for biomass technologies under the Renewable Energy Program. Because biomass operators will realize the benefits of changes in the federal production tax credit next year, the increased incentive level and cap are proposed to be in effect only through June of 2006.

Regarding future development of biomass resources in California, Governor Schwarzenegger, in his response to the *2003 Energy Report* and *2004 Energy Report Update*, expressed his support for the California Biomass Collaborative and charged the Interagency Working Group on Bioenergy with developing an integrated and consistent state policy on biomass. Developing the energy generation potential for biomass will require a concerted approach on the part of state and federal agencies and other stakeholders to address the technical, economic, environmental, and institutional challenges associated with its production and use.

Recommendations for Biomass Resources

To realize the potential economic, social and environmental benefits of sustained biomass development, the state should:[183]

- Develop a "road map" to guide future biomass management and development in California, including efforts to address technical, economic, environmental, and institutional challenges.
- Adopt clear and consistent policies for sustainable biomass development.
- Collaborate with federal agencies to leverage state and federal funding for biomass research, development, and demonstration projects.
- Establish state and local procurement and construction programs to increase biomass use.
- Coordinate state agency efforts on recommended actions for sustainable management and development.
- Encourage biomass-fueled electricity facilities to participate in competitive RPS requests for offers.

Taking Advantage of California's Solar Resources

California has abundant solar resources that can be used to help meet the state's growing need for electricity. Solar thermal facilities can provide dispatchable power during periods of peak demand as well as help mitigate the impacts of integrating large amounts of intermittent wind resources into the system. Recent utility contracts for 800 MW of solar thermal electric capacity represent a major shift from previous perceptions that solar technologies are always more expensive than conventional generating sources, particularly since the contracts will not require any public subsidies. These contracts also represent the first major commercial applications of Stirling dish technology. While having two large contracts with a single small company may raise concerns about project risk, the increased focus on large solar technologies is promising for the future development and deployment of these technologies in California and elsewhere.

182. Ibid.

183. California Energy Commission, *Biomass in California: Challenges, Opportunities and Potentials for Sustainable Management and Development,* Public Interest Energy Research California Biomass Collaborative Report, CEC-500-2005-160, June 2005.

California is also a leader in the installation of solar photovoltaic (PV) systems, with more than 130 MW of rooftop PV systems installed since 1981.[184] Since taking office in 2003, Governor Schwarzenegger has indicated strong support for solar energy development, initially by proposing to make half of all new homes built in the state solar-powered and then by proposing a goal of one million solar roofs in California by 2018.[185] In his response to the *2003 Energy Report* and *2004 Energy Report Update*,[186] the Governor reinforced the goal of a million solar roofs by outlining principles to be used to achieve that goal. As a further indication of his commitment to solar energy, the Governor recently signed a law that would promote the installation of PV generation in open spaces above and along 660 miles of open canals and pipelines on the State Water Project.[187]

Although state PV incentive programs such as the CPUC's Self Generation Incentive Program and the Energy Commission's Emerging Renewables Program have provided important support for the installation of PV systems, installed solar costs in California are still high, and the market is far from self-sustaining. The situation is exacerbated by the lack of a single, cohesive PV program in the state. Multiple and overlapping programs increase the risk of "double dipping" and the attendant monitoring and verification responsibilities of program administrators. Different programs with different funding sources are also inefficient because of the inability to move funding from a program that may be underutilized to one that is oversubscribed.

In recent years, the Self Generation Incentive Program has provided incentive levels that greatly exceeded rebate levels provided by the Emerging Renewables Program. Despite repeated recommendations by the Energy Commission and the solar industry, the CPUC has failed to lower incentive levels to align with those in the Emerging Renewables Program. As a result, the Self Generation Incentive Program is chronically oversubscribed, while the high incentive levels may be causing distortion in the Emerging Renewables Program.

The principles outlined in the *2004 Energy Report Update* for a successful and rational PV program still apply today. Achieving the scale proposed by the Governor requires a broad program that includes all residential and commercial buildings, whether existing or new. Also, because leveraging energy efficiency improvements should be a key consideration in deploying PV, new homes should be required to exceed current building efficiency standards, while existing buildings should be required to improve their efficiency by a fixed percentage. Similarly, PV installations should be linked to dynamic pricing tariffs and advanced metering to use solar systems to meet peak load, thereby lowering electric system costs and rates. Further, to provide the most benefit, solar installations should be targeted to climate zones with high peak demands for air conditioning.

A sound solar program should also include consistent, long-term declining incentives to

184. California Energy Commission, *Amount (MW) of Grid-Connected Solar Photovoltaics (PV) in California, 1981 to Present* [http://www.energy.ca.gov/renewables/emerging_renewables/GRID-CONNECTED_PV.XLS], forthcoming November 2005.

185. "Governor Announces Million Homes Solar Plan," press release, August 20, 2004 [http://www.governor.ca.gov/state/govsite/gov_htmldisplay.jsp?sCatTitle=Press%20Release&sFilePath=/govsite/spotlight/august20_update.html], accessed November 1, 2005.

186. Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: *Review of Major Integrated Energy Policy Report Recommendations*, August 23, 2005.

187. AB 515 (Richman), Chapter 368, Statutes of 2005.

provide the volume of sales and commitment needed to bring manufacturing and other costs down. The failure of the state's PV incentive programs to bring costs down and the severe oversubscription in those programs indicate that up-front rebates may not be the most efficient use of public funds to achieve the goal of a sustainable solar industry. Instead, as articulated in the *2004 Energy Report Update*, the state should transition to performance-based incentives to promote more cost-effective public funding in terms of long-term energy generation per dollar of incentive support. A truly sustainable solar program will pay for kWhs produced rather than for system installation with no measure of performance to ensure that systems are appropriately installed and functioning correctly.

A consolidated solar program should also include solar hot water technologies. While PV systems can shave peak electricity demand, solar thermal technologies can displace natural gas use and help reduce California's overwhelming dependence on natural gas. Importantly, in designing a scaled-up PV program, the state needs to better understand the failure of previous solar water heating programs in the 1980s in order to learn from past mistakes.

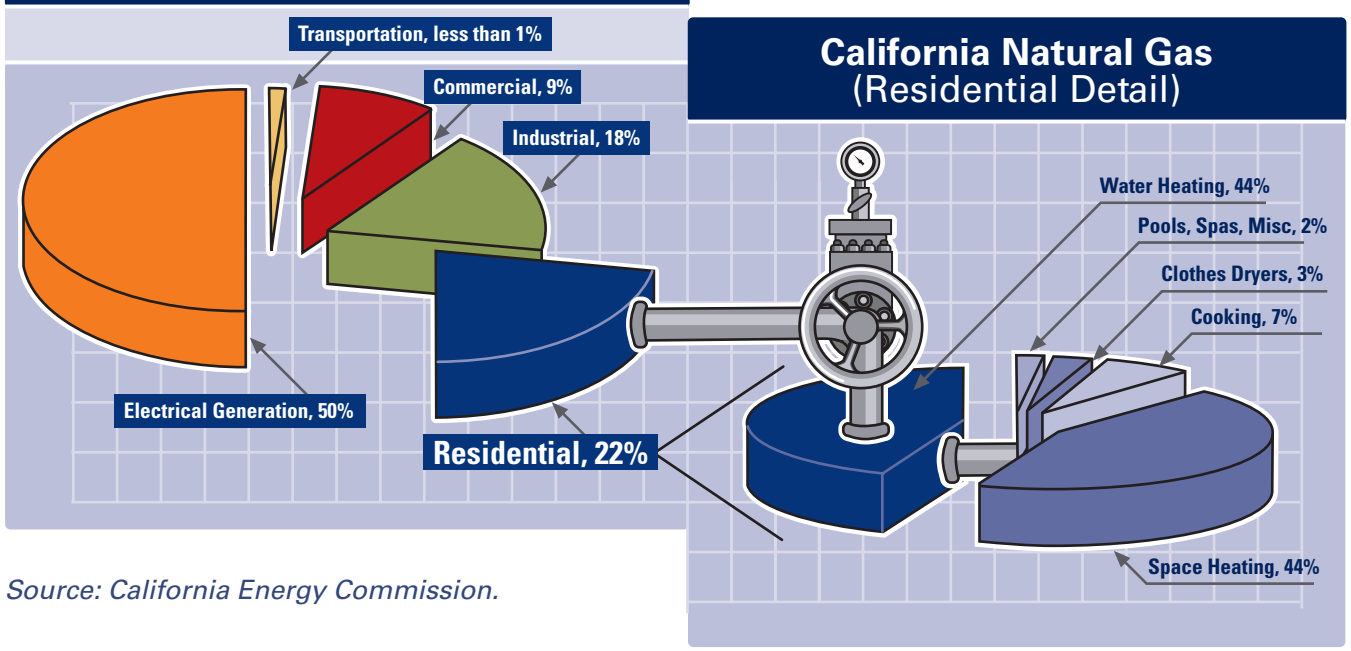
Massive deployment of PV systems on the scale envisioned by Governor Schwarzenegger requires a willing partnership with the operators of the distribution system because of the volume of interaction with the electric grid entailed by such deployment. Development of a unified solar program therefore requires careful exploration of a viable business role for utilities, as recommended in the *2004 Energy Report Update*.

The Energy Commission and the CPUC are working together to develop a unified PV program, with a proposed decision from the CPUC expected later in 2005. Such a program should have consistent funding levels and establish a performance-based incentive structure for both commercial and residential systems. In addition, the program should integrate energy efficiency and time-of-use rates to provide maximum benefits to PV purchasers and electricity consumers. The program must also be designed specifically to achieve the scale of PV penetration envisioned by the Governor. Most importantly, the overall aim of the program should be the efficient administration of funding to achieve the state's solar goals at the least possible cost.

Chapter Seven:
The Challenges and Possibilities of Natural Gas

California faces significant challenges in ensuring adequate natural gas supplies at reasonable prices to meet its growing natural gas demand. In the largely deregulated natural gas arena, California competes on a theoretically level playing field with the entire North American market. However, the state's geographic location—literally at the end of the interstate pipelines—poses significant challenges to securing adequate and reliable supplies of natural gas at reasonable prices.

Figure 17: **2004 Natural Gas Use In California**

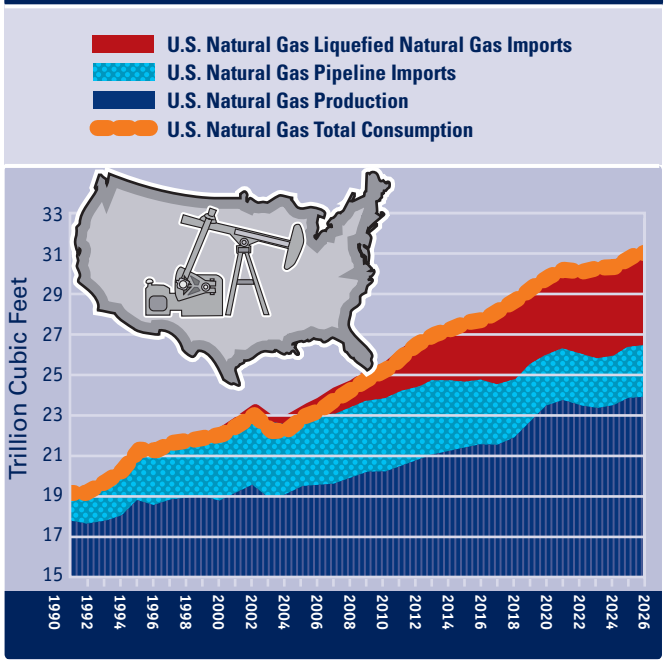


Source: California Energy Commission.

Natural gas plays a critical role in California's energy market. Electricity generation requires nearly half of the natural gas consumed in California. Consequently, any supply disruptions or price spikes directly affect the state's ability both to generate electricity and to do so at competitive prices.

California's natural gas demand growth is expected to be slower than the rest of the nation's due largely to the state's energy efficiency programs and the use of renewable energy for electricity generation. Nevertheless, the demand growth is increasing steadily. In-state natural gas production satisfies only about 13 percent of statewide demand. The resulting reliance on imports makes the state vulnerable to supply disruptions and price shocks that can negatively affect California's residents, businesses, and economy. New natural gas supplies are increasingly difficult to find and produce nationally, and the gap between U.S. demand and domestic supplies is widening each year, as shown in Figure 18.

Figure 18: **Projected U.S. Natural Gas Supply and Demand**



Source: U.S. Energy Information Administration.

Natural gas supplies to California are affected by demand in other states, as well as Canada and Mexico. As Canada and Mexico increasingly turn to natural gas to satisfy their own growing demand for electricity, traditional drilling and exploratory activities will be unable to keep up with the growing demand for natural gas, further intensifying competition for already scarce supplies.

Recent infrastructure improvements have reinforced California's interstate and intrastate pipeline and storage capacity and its ability to bring in, distribute, and store available supplies to meet average annual demand. However, hurricanes Katrina and Rita reduced production in the Gulf of Mexico, demonstrating that even currently available supplies might not be accessible at all times.

Competition for the limited supply of natural gas is driving prices higher, and California has little direct influence over market prices. Though wholesale natural gas prices in California are lower than those in most of the rest of the nation, they have more than doubled since 2000. Natural gas consumers spent more than $11 billion for natural gas in 2004 and are expected to spend even more this year.[188] Higher natural gas prices inevitably mean higher electricity prices.

The uncertainty of domestic supplies and increases in prices underscore the need for California to focus on actions within its control, specifically to find alternative sources of natural gas. Liquefied natural gas (LNG), in particular, offers significant potential. The possibility of importing natural gas across the water from virtually any source worldwide has the potential to provide large volumes of adequate and reliable supplies and consequently hold down prices. Importing LNG is not without its challenges, however, particularly in siting receiving terminals.

Natural Gas Demand

Natural gas use in the power generation sector accounts for the bulk of the state's increasing demand. Although Californians continue to use electricity more efficiently, total electricity demand is growing, requiring additional power plants to meet the state's needs. Since November 2003 alone, the state has permitted 11 power plants totaling 5,750 MW of capacity, primarily natural gas-fired.

Electricity demand in the short term can fluctuate dramatically depending on the weather. Hot

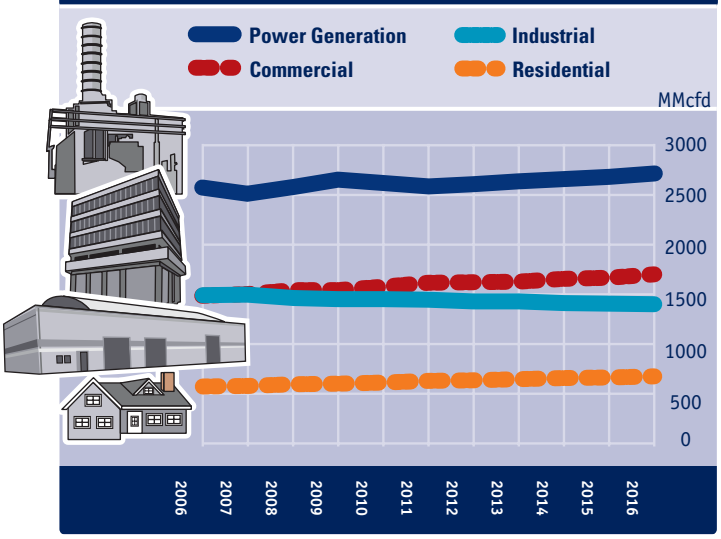
188. California Energy Commission, *Revised Reference Case in Support of the 2005 Natural Gas Market Assessment*, September 2005, CEC-600-2005-026-REV.

temperatures in the summer indirectly increase natural gas demand by increasing electricity demand for air conditioning; cold temperatures in the winter directly increase natural gas demand for heating. Variations in rainfall and snowpack in the mountains affect the availability of hydroelectric power, with additional natural gas-fired generation required when adequate hydroelectric supplies are not available.

As the population continues to increase over the next decade, natural gas demand for uses other than electricity generation is also expected to increase. As shown in Figure 19, the Energy Commission expects residential natural gas use to increase by 1.3 percent per year and commercial natural gas use to increase by 1.8 percent per year. Industrial natural gas demand, however, is expected to be flat or decline in nearly all of the western states because industrial customers are the most likely to respond to currently rising natural gas prices.[189]

California's ability to meet its natural gas needs will also be affected by rising demand in the rest of the U.S. and in neighboring countries. Natural gas demand throughout the U.S. (excluding Alaska and Hawaii) is expected to increase by 1.64 percent per year from 2006 to 2016. Similarly, in Canada and Mexico, natural gas consumption is expected to grow annually by 1.3 percent and 2.9 percent, respectively.[190] Three-quarters of total demand growth in North America stems from increased natural gas consumption for power generation.

Figure 19: **California Natural Gas Sector Demand Projection (by MMcfd)**



Source: California Energy Commission.

With the ongoing success of California's efficiency programs, natural gas demand growth in the state is expected to be lower than that in the rest of the nation over the next decade. California's energy efficiency programs over the last three decades have reduced natural gas use per household by more than half since 1975.[191] Total natural gas demand in California is projected to increase by 0.7 percent per year from 2006 to 2016, with strong growth in the residential and commercial sectors offset by declining industrial gas demand and slower growth in gas consumption by power generators than has been observed in recent years.

189. Ibid.

190. Ibid.

191. Ibid.

Past forecasts projected California's demand for natural gas for power generation to increase more quickly than demand in other sectors.[192] Now, however, the demand for gas in California's electricity sector is expected to grow at a relatively modest rate of 0.6 percent per year through 2016 as newly built power plants become operational and aggressive energy efficiency in electricity end uses and higher prices dampen demand. Without the addition of new, more efficient power plants to reduce the state's dependence on older, less efficient generation facilities that use more natural gas, California's dependence on natural gas for electricity generation would have grown much more rapidly. California's aggressive Renewable Portfolio Standard (RPS) will also reduce the electricity generating load from gas-fired facilities, particularly with the acceleration of the RPS goal of 20 percent renewable generation by the year 2010.

The overall increase in gas prices over the past several years has sparked a renewed interest in coal-fired electricity generation. New coal facilities are included in the resource plans for several western states, which could dampen projected natural gas demand growth for electricity generation in those states. Greater interest in renewable generation in other western states could also reduce their natural gas demand for power generation.

Because California's natural gas pipeline and storage capacities have increased faster than demand over the past five years, California's gas utilities are in better shape to avoid a widespread curtailment today than they were in 2000. Unfortunately, the conditions affecting natural gas supply adequacy are highly variable, including weather in the short-term and greater reliance in the western U.S. on gas-fired plants in the long-term.

Recommendation

- The Energy Commission currently evaluates natural gas adequacy under average conditions and normal peak conditions. However, there is a need to evaluate potential responses to extreme conditions to avoid costly natural gas curtailments. The Energy Commission should therefore devote resources to secure the necessary data and increase its analytical ability to ensure that the natural gas infrastructure will continue to be adequate in the future under all conditions.

Effect of Natural Gas Prices on Demand

The price of natural gas is of major concern to state energy policy makers. Futures prices currently traded in the markets exceed $9.85 per thousand cubic feet (Mcf).[193] Gas price volatility has become a regular feature of the natural gas market. Hurricane Katrina dramatically affected prices in both the short- and long-term: national natural gas spot prices rose to over $14/mmBtu at the national pricing point at Henry Hub and over $16/mmBtu for delivery to the New York area in both late September and again in late October. During this same time, the wholesale natural gas market prices at the Southern California border were in the $10-11/mmBtu range, a significant savings under most national prices. Although California's wholesale prices increased due to the hurricane, they did not increase as much as those in the rest of the nation. The discount to the national average for California consumers widened from $0.90 per Mcf to $2.60 per Mcf during this same time period.

At the customer level, higher natural gas prices can mean higher natural gas bills if consumption stays the same, especially for customers using natural gas to meet their heating needs. The U.S. Energy Information Agency forecasts that consumers'

192. California Energy Commission, *Natural Gas Market Assessment*, CEC-100-03-006, August 2003.

193. Expressed in 2004 dollars converted from $10 per million British thermal units expressed in 2005 dollars.

natural gas heating bills for this winter will be at least 50 to 70 percent higher than last winter, depending upon the region. At the wholesale level, higher natural gas prices also mean higher costs to generate electricity, which translate into higher costs for electricity ratepayers.

California has little influence over national natural gas market prices. Even when California's own demand is moderate, in-state prices can spike in response to extreme weather conditions in other parts of the country. In the past two years, natural gas prices have dramatically increased, and short-term natural gas market prices are now highly volatile. Although there could be a drop in natural gas prices over the next several years with the introduction of large new supplies into the market, such as LNG and major pipeline additions, Energy Commission staff models project a general increase in national natural gas wellhead prices over the next decade. The general increase reflects the growing difficulty of producing gas in the nation's conventional gas producing regions but does not account for market volatility and short-term price spikes.

Residential customers in California pay the highest natural gas prices in the state because of the cost involved in serving millions of dispersed customers in each utility service area. Over the next decade, the Energy Commission estimates that residential gas prices will fluctuate between $8.41 and $11.65 per Mcf.

Commercial customers can expect to pay between $7.57 and $9.72 per Mcf for natural gas over the same period, depending upon the service territory. Natural gas prices for industrial customers follow the same trends as those for other California customers, but at a much lower price level. There are fewer industrial customers, and most purchase their own natural gas, pipeline capacity, and storage services, making it less costly for utilities to provide service. Industrial customers can expect to pay between $5.13 and $9.72 per Mcf over the next 10 years.

Natural gas prices for electricity generators are expected to fluctuate between $4.24 and $7.00 per Mcf over the next 10 years and vary based on whether or not the generator is served by a natural gas utility or takes its fuel supplies directly from another source, such as an interstate pipeline or local gas producer, as well as where the generator is located and when the facility began operation.

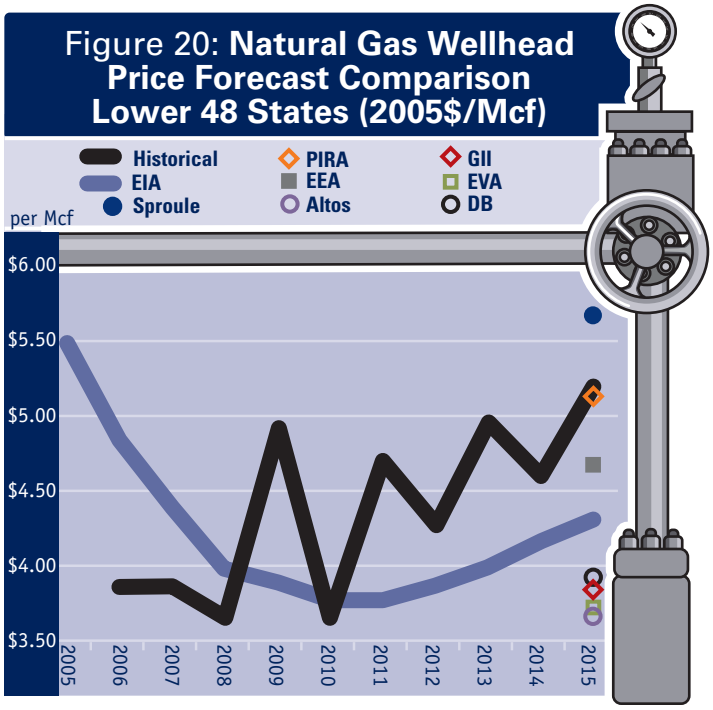
Since the energy crisis of 2001, natural gas prices that were anticipated to revert to the trends of the previous 10 to 15 years have instead consistently remained high. Global crude oil markets, a decreasing rate in finding new natural gas supplies, and events related to weather—most recently hurricanes Katrina and Rita—have continued to put pressure on natural gas prices across the nation. Generally, when hurricanes impact the industry, producers and pipelines recover and resume normal operations within one to three months. However, the repeated and harsh impacts of this season's two major hurricanes have dramatically increased natural gas prices, with price and supply effects possibly lasting for more than six months. These trends will likely continue to place upward pressure on natural gas prices. It is the industry's anticipation that the prices may not back down from the high-levels seen today for a significant period of time.

The Energy Commission staff forecast does not consider such unanticipated events in its price projections. The staff model is based on market fundamentals that normally drive the supply-demand balance in a well-functioning market; this model and other similar ones have a long history of providing reasonably accurate forecasts. Yet, clearly, today's market prices are substantially higher than the staff's forecasted prices.

In the past five years, numerous events have driven prices away from a fundamental forecast of future prices. In addition to the hurricanes, price manipulation documented in the Enron scandal and the misreporting of the natural gas price indices are examples of events that make comparing the staff

forecast—or any other forecast—with natural gas market prices increasingly problematic. Existing equilibrium model forecasts relied on by Energy Commission staff and others cannot adequately capture such events in advance with any accuracy, but such events do have a very real effect on market prices. The Energy Commission notes that a fundamental forecast may underrepresent future market prices.

Figure 20: **Natural Gas Wellhead Price Forecast Comparison Lower 48 States (2005$/Mcf)**



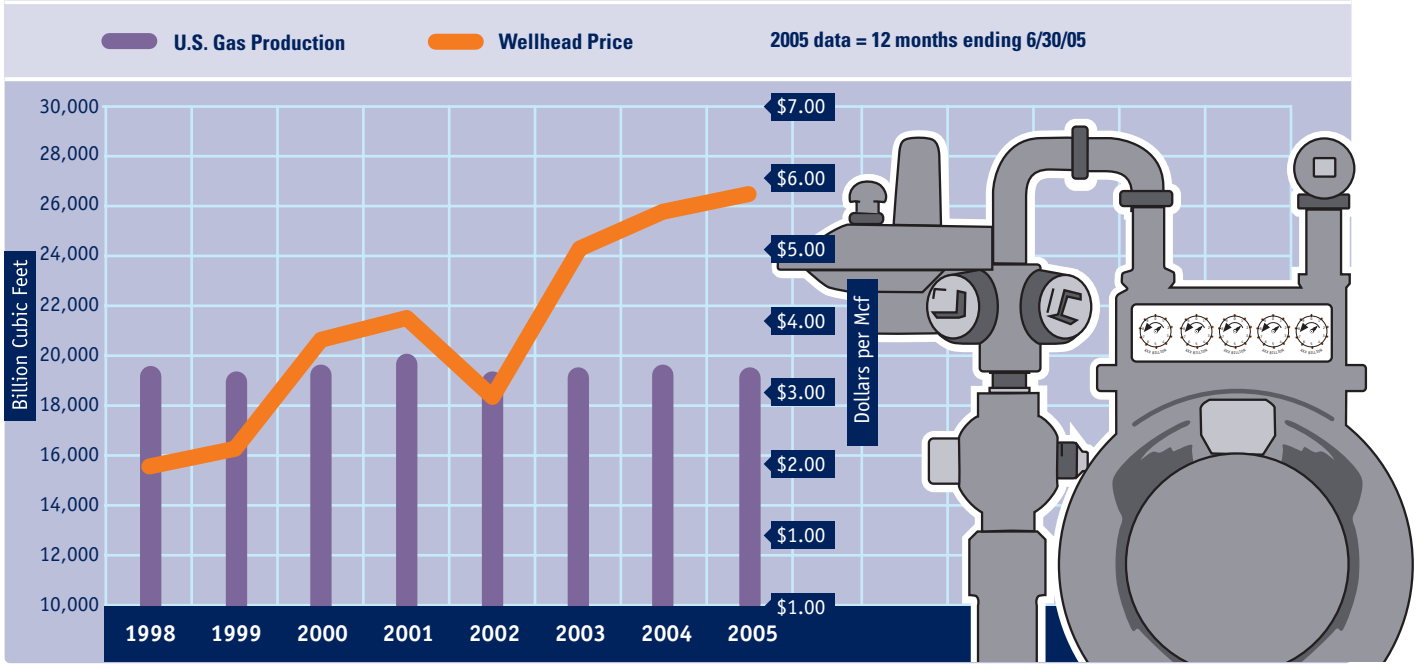
Source: California Energy Commission.

The Center for Energy Efficiency and Renewable Technologies (CEERT) noted in its comments that current natural gas prices reflect large scarcity rents above the marginal costs of production that consumers are paying. It further notes that equilibrium models like the Energy Commission staff North American Regional Gas model fail to capture this discrepancy.[194] While recognizing the difficulty in projecting what the scarcity price of natural gas will be in the future, CEERT points to this failure as a major shortcoming in staff's current approach to forecasting natural gas prices.

As shown in Figure 21, despite the high prices being paid for gas over the last few years, U.S. production has not increased, and not, as CEERT points out, because the gas industry has not tried. In fact, the number of wells drilled per year has followed producer prices fairly well. CEERT further notes that if U.S. production has not increased at today's high prices, it is unlikely to increase in the foreseeable future, especially if LNG supplies reduce current wellhead prices, as staff assumed in its assessment. The Energy Commission notes that CEERT made a similar critique of staff's forecast in the *2003 Energy Report* process. While the Energy Commission shares concerns about this dilemma, it also notes that some parties provided comments that the Energy Commission's price forecast is too low, while others criticized it as too high.

194. Presentation by Rich Ferguson, Center for Energy Efficiency and Renewable Technologies, transcript of the October 7, 2005 *Energy Report* Hearing on *Natural Gas Issues*, pp. 87-107.

Figure 21: **U.S. Natural Gas Production & Wellhead Prices**

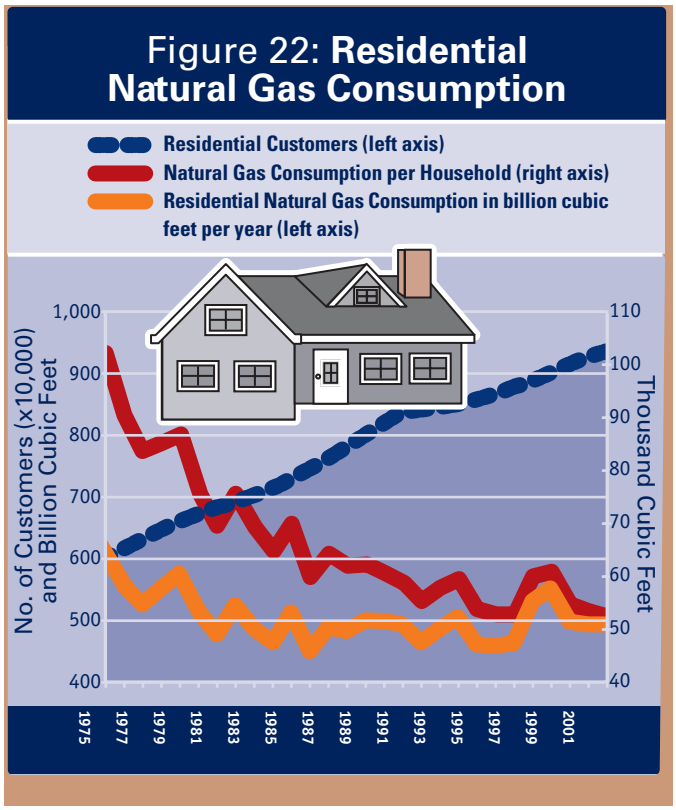


Source: Center for Energy Efficiency and Renewable Technologies, comments on the Draft Energy Report *Chapter 7: Natural Gas, October 14, 2005, based on EIA data.*

The Energy Commission will adopt the staff's forecast for the *2005 Energy Report* with the caveat that it should be augmented for its first two years by NYMEX prices. The Energy Commission should further investigate alternative forecasting methods in the *2007 Energy Report* cycle to better assess future natural gas prices.

Using Efficiency Measures to Reduce Demand

Increased efficiency in all of the state's energy sectors is the highest priority for meeting demand, consistent with the state's loading order policy. Historically, energy efficiency has been highly effective as a means to reduce demand. As an example, today's households use almost one-half the natural gas that households used in 1977, as seen in Figure 22. This fact is even more impressive when considering that today's average new home is considerably larger, and most new homes are being built in the harsher climates of the Central Valley, Inland Empire, and inland San Diego County.



Source: California Energy Commission

The 2003 Energy Report recommended that the state decrease natural gas use by increasing funding for natural gas efficiency programs. In addition, the recently enacted SB 1037 requires gas utilities to first meet any unmet resource needs with all available energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible.

California has made significant progress in this area. California's Building and Appliance Standards continue to help meet natural gas efficiency goals by reducing annual natural gas use. More importantly, in 2005, the CPUC authorized an additional $300 million in funding for natural gas efficiency programs for 2006-2008.[195] The CPUC has also set aggressive goals to double annual natural gas savings by 2008 and triple savings by 2013. When these goals are met, the cumulative savings will be equivalent to the amount of natural gas consumed by one million households.[196]

To increase natural gas efficiency in the future, combined heat and power facilities should play a much larger role in meeting California's electricity supply needs. By recycling waste heat, these systems are much more efficient than conventional fossil-fueled power plants. Additional savings may be available from the use of pressure drops in pipelines, flared gas, and "recycled energy," in which energy is recovered from industrial off-gases. To take full advantage of combined heat and power facilities and recycled energy, however, California needs to address a number of policy and institutional barriers, as identified in Chapter 4.

Although California's natural gas wholesale prices fluctuate more in response to national demand and supply than in-state demand and supply, more efficient use of natural gas within California will directly benefit consumers who reduce their consumption. Efficiency improvements in the electricity sector will also provide benefits to natural gas consumers since one-half of the state's natural gas demand is for power generation.

195. CPUC Decision 05-09-043, September 22, *2005, Interim Opinion: Energy Efficiency Portfolio Plans and Program Funding Levels for 2006-2008 – Phase 1 Issues*, http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859.htm], accessed October 24, 2005.

196. CPUC Decision 04-09-060, September 23, 2004, Interim Opinion: *Energy Savings Goals for Program Year 2006 and Beyond.*

Natural gas efficiency is also a priority in the Energy Commission's natural gas research, development, and demonstration program.[197] In 2005, the Energy Commission, with the concurrence of the CPUC, initiated a Public Interest Energy Research Program on Natural Gas (PIERNG). The 2005 budget for PIERNG was $12 million, which may increase by $3 million annually to a cap of $24 million. Approximately half of the 2005 funding has been allocated to energy efficiency projects. Depending on the priorities of the research agenda, additional dollars could be dedicated toward energy efficiency projects. Research results will be linked to state natural gas efficiency programs.

Recommendations

In light of the current high wholesale prices for natural gas, the CPUC's goals may not capture the maximum potential cost-effective savings. The Natural Resources Defense Council has indicated that the CPUC's natural gas savings targets represent only about 40 percent of the achievable potential.[198] The Energy Commission recommends:

- The CPUC should increase natural gas savings targets beyond their current level during its next goal revision.
- The CPUC and the Energy Commission should rigorously evaluate, measure, and monitor natural gas efficiency programs to ensure that they produce the intended savings, and that public funds are well spent.

Natural Gas Supplies

Gas producers across North America are struggling to keep pace with the growing demand for natural gas. Although the number of natural gas wells drilled in the U.S. and Canada is at an all-time high, conventional production from most of the mature supply basins in North America has declined or increased only modestly since 1990.[199] More importantly, the amount of gas produced per well is declining, and each well is being drained faster.

Production from newer supply basins in the Rocky Mountains, East Texas, and the deep water in the Gulf of Mexico has helped offset this decline. Supplies from some of these basins are produced from unconventional resources such as coal bed methane, tight sands gas, shale gas, or in very deep water, which all cost more to develop and produce and have raised the relative cost of natural gas across the continent.

Hurricane Katrina further affected natural gas supplies. For one week, from August 29 through September 6, natural gas production in the Gulf of Mexico was reduced by 83 percent of its usual volume—more than what California consumes in an average day. Releases from natural gas storage facilities and reductions in industrial demand due to flooded refineries and petrochemical complexes made up for the loss of production. Production resumed at half its normal pace, but full production is not expected to resume for many months.

Domestic natural gas production is expected to remain almost the same over the next decade and will not keep up with national growth in demand. This problem will be compounded by the decline in imports from Canada because of its own increased demand for natural gas. Though Arctic natural gas production could be available by 2013, it will require approving and building a new major pipeline to move remote supplies to markets in Canada and the lower 48 states.

197. CPUC R.02-10-001.

198. Testimony of Audrey Chang, Natural Resources Defense Council, transcript of the October 7, *2005 Energy Report Committee* hearing on Challenges and Possibilities of Natural Gas, pp. 57-58.

199. California Energy Commission, *Revised Reference Case in Support of the 2005 Natural Gas Market Assessment*, September 2005, CEC-600-2005-026-REV.

California's situation is exacerbated by the state's reliance on imports for 87 percent of its natural gas supplies. With the exception of the late 1990s when Occidental purchased the Elk Hills field from the federal government, in-state natural gas production has been steadily declining and will continue to do so by almost 1 percent per year despite efforts by government and industry to increase production.

Impact of Rising Demand in Neighboring States

Demand for natural gas in other states affects natural gas supplies to California. In Arizona, 43 new power plants totaling more than 8,000 MW have come on line since 2001. These are intermediate load and peaking power plants that often ramp up quickly to meet changing electricity demand. As a result, they may take more natural gas from the pipeline and do so faster than expected. Under normal conditions, this practice is not troublesome if the pipeline system can be balanced by taking gas out of storage. In the Phoenix area, however, the nearest storage facility is hundreds of miles away, and it is becoming increasingly common for pipeline pressure to drop during periods of high demand. If the gas pressure gets low enough, it could cause curtailments that could affect natural gas delivery into California. In addition, reducing gas deliveries to Arizona's power plants could cause a ripple effect through that portion of the electric grid that could ultimately reduce the reliability of electricity deliveries from out-of-state to Southern California.

Adding storage capacity in the Phoenix area could resolve this issue, but unfavorable cost recovery rules at FERC precluded development of a proposed private storage facility near Phoenix. To address the problem, FERC is exploring the option of granting market-based rates to new independent storage developers not affiliated with existing pipelines. A less direct solution would be the development of a storage facility inside California that is tied directly to one of the pipelines coming from Arizona. This solution, however, is less desirable than adding storage in the Phoenix area and raises complex regulatory and contractual issues.

The Potential of Liquefied Natural Gas to Increase Supplies

California clearly needs to increase the diversity of its natural gas supply portfolio. Being at the end of a long interstate pipeline network, California must also have access to a variety of sources. LNG is one such potentially cost-competitive and reliable source. Chilling and pressurizing natural gas reduces it to a liquid form and condenses its volume by 600 percent. This significant reduction in volume enables bulk shipping and storage before the liquid gas is revaporized into its gaseous state without any change to its chemical properties. Condensation allows importers to transport the liquefied gas over water, exponentially expanding the supply of natural gas.

Currently, the U.S. imports LNG into five receiving and regasification terminals in the lower 48 states to balance demand with total supply. LNG import facilities in North America that are under construction will increase natural gas supplies available to the U.S. over the next 10 years and will help meet California's additional natural gas needs by increasing total domestic supplies. In 2004, LNG imports made up 3.3 percent of total U.S. supply. By 2016, the Energy Commission staff expects that LNG will provide up to 22 percent of the total U.S. supply.

Of the five existing LNG facilities in the U.S., none are located on the West Coast. The *2003 Energy Report* highlighted the need for the development of LNG facilities and associated infrastructure to serve the natural gas needs of the western U.S. and suggested that California support the development of LNG facilities on the West Coast, consistent with environmental protection requirements. Several companies have recently proposed to build LNG import facilities in California and Mexico. In California, these include the Cabrillo Deepwater Port and the Clearwater Port, both of which are offshore projects, and the Long Beach LNG Import Project.

In Mexico, there are three proposed facilities including the Terminal GNL Mar Adentrode Baja and the Moss Maritime LNG, both of which are offshore projects, and the Sonora LNG facility. Construction has begun on a fourth project, Energia Costa Azul, expected to be on line in 2007. For California to access new LNG supplies, however, additional or modified pipeline infrastructure may be necessary.

The costs to deliver natural gas to the West Coast via an LNG project could be well below the market prices that California pays at its borders. This potential new supply source close to or in California could have a dramatic effect on the market prices in California. For example, if West Coast LNG supplies cause market prices to drop by $0.50 per mmBtu, then Californians would save over $1 billion annually on their natural gas bills. This magnitude of potential savings drives California's interest in LNG.

However, actual prices to consumers will depend upon the contracts signed between suppliers and consumers or their representatives. The CPUC will be examining very closely any potential contracts proposed by the regulated gas utilities to ensure potential benefits from LNG flow to consumers. Such contracts should incorporate measures to help lower overall prices and moderate price volatility, and address terms of access of suppliers to terminals, to maximize reliability of deliveries.

LNG simultaneously presents natural gas supply opportunities, additional infrastructure capacity into the West Coast, and coastal industrial development challenges. In considering LNG projects currently proposed for California, the state must address safety, environmental, and gas quality issues associated with these projects in an efficient and equitable manner. California has established the LNG Interagency Permitting Working Group, composed of 21 state, local, and federal agencies to ensure that all the reviewing agencies have the same information and are able to resolve administrative issues quickly.

An example of this working group's effectiveness was recently demonstrated. The federal *Energy Policy Act of 2005* allows for any coastal governor to designate an agency to consult with FERC on LNG import terminal safety issues and to also prepare a Safety Advisory Report on active terminal applications. Governor Schwarzenegger designated the Energy Commission to coordinate its review with the working group. With this group's active cooperation, the Energy Commission was able to produce a lengthy report on Sound Energy Solutions' proposed LNG import terminal at the Port of Long Beach within the 30 days allowed by law. In fact, California was the only state to have exercised this option. The FERC is still considering the more than 100 issues identified in the Safety Advisory Report.

The types of issues raised in the Safety Advisory Report included safety concerns for the import terminal and tanker operations. In a separate letter to the U.S. Coast Guard regarding its Waterway Suitability Assessment for the Port of Long Beach project, the Energy Commission detailed additional concerns and requested a response to three major areas:

- The potential impact on petroleum infrastructure in the San Pedro Harbor as a result of a catastrophic incident.
- The loss of operational transit time in the San Pedro Harbor due to the security zones that will be associated with movement and berthing of liquefied hazardous gas tank vessels.
- Elevated threat levels invoked by the Department of Homeland Security and the potential diminishment of movement by marine vessels in the San Pedro Harbor.

Although the letter to the Coast Guard deliberately focused narrowly on issues associated with petroleum infrastructure, both the Energy Commission and the LNG Interagency Permitting Working Group recognize the group's mission to ensure that any LNG development is consistent with the state's energy

policy of balancing environmental protection, public safety, and local community concerns to ensure protection of the state's population and coastal environment.

In addition, the LNG Interagency Permitting Working Group is involved with the review of the offshore LNG import terminal applications. The Cabrillo Port LNG Import Terminal proposed by BHP Billiton is currently in the middle of its application review process. Members of the working group are supporting both the U.S. Coast Guard and the California State Lands Commission, the lead federal and state permitting agencies. The working group has an added responsibility to provide information directly to the Governor for his ultimate decision to approve, approve with conditions, or deny this project, an action allowed by federal law for offshore projects but not onshore projects.

Potential Supplies from Alternative Sources of Natural Gas

To diversify California's natural gas supply sources, the state can examine the feasibility of increasing natural gas production from more innovative sources. For example, California is rich in biomass resources that are suitable as a feedstock for gasification technologies. Landfills in California currently produce natural gas, some of which is captured, cleaned, and used. Agricultural waste can be converted to synthetic natural gas. Underground gaseous reservoirs contain natural gas that does not meet pipeline specifications but that could still be converted to useful energy. Each of these potential alternatives presents technological and cost challenges to ensure that produced gas meets quality specifications and environmental protection requirements. Fortunately, these challenges are appropriate subjects of the state's natural gas research and development program.

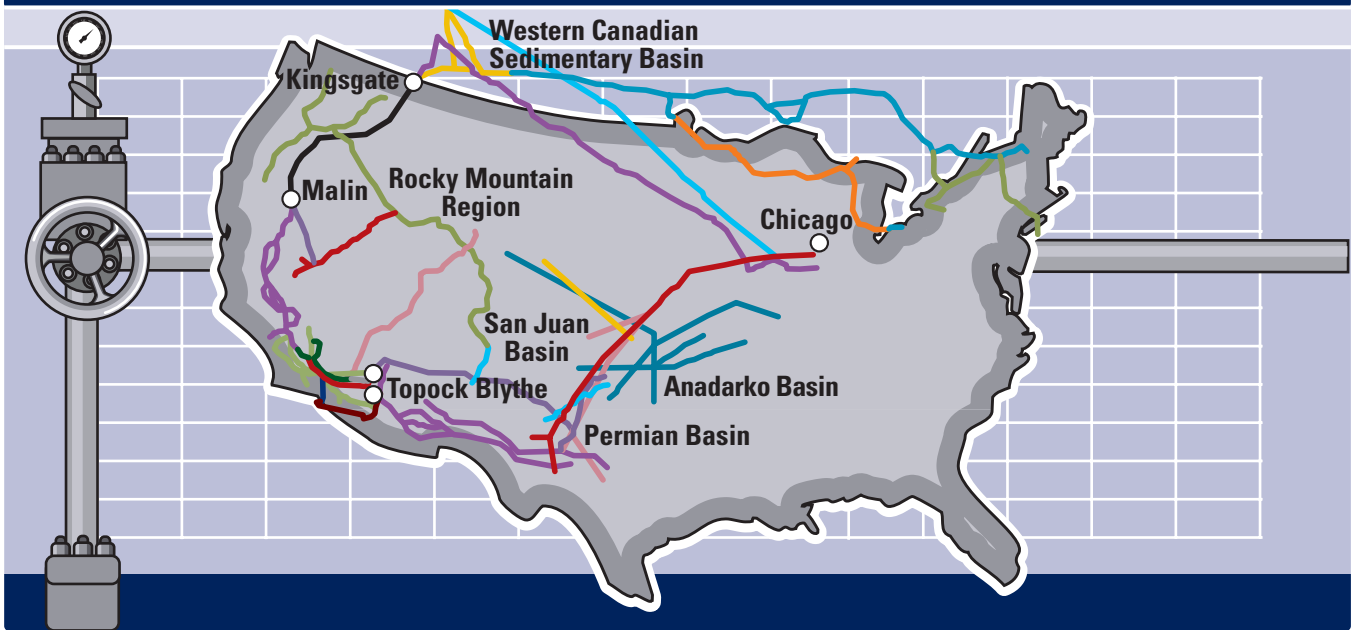
Using Infrastructure to Ensure Adequate Natural Gas Supplies

As California seeks adequate supplies of natural gas, it must also ensure that its infrastructure can both convey and store supplies. California has made great strides in addressing a variety of natural gas infrastructure shortfalls that plagued the state at the height of the 2000-2001 energy crisis. The state has increased intrastate pipeline capacity by approximately 0.906 billion cubic feet (bcf) per day since 2001 and added an additional 2.2 bcf per day of capacity to deliver supplies from Canada, the Rocky Mountains, and the Southwest.

To guard against interruptions in natural gas supplies, the *2003 Energy Report* recommended that the state ensure that existing natural gas storage capacity is used appropriately to provide adequate supplies and protect prices. California has added 38 bcf of storage capacity, which provides increased reliability to meet peak needs and adds operational flexibility across the state. During the past two years, users of those storage facilities have been placing natural gas into storage at record rates, and the state's inventory is at the high end of the five-year average. Plans exist to develop additional storage capacity next year.

California will benefit from expected modifications to the Transportadora de Gas Natural pipeline that links future natural gas supplies from proposed LNG facilities in Baja California Norte to San Diego. It will also benefit from a reversal of the Baja Norte pipeline, which currently transports natural gas from Arizona to the Baja California Norte market, if LNG projects are developed in Baja California Norte. A reversal of the pipeline would also allow natural gas from LNG facilities in Baja California Norte to serve markets in Northern and Southern California or Arizona. While these two infrastructure options provide pathways for new supply sources from Baja California Norte to reach California, modifying the Transportadora de Gas Natural pipeline would provide additional capacity into the state; reversing the Baja Norte pipeline does not increase capacity into the state. The CPUC is expected to ensure that ratepayers will only be charged for project costs that are commensurate with the benefits they actually receive.

Figure 23: **North American Natural Gas Pipelines Important to California**



Source: California Energy Commission, Natural Gas Assessment Update*, February 2005, p. 15. CEC-600-2005-003.*

With recent expansions, California has adequate in-state pipeline infrastructure over the next decade to move gas to load centers on an annual average basis. However, the state must make certain that existing infrastructure is maintained and retained. In addition, the state should continue to evaluate the need for additional pipeline capacity to meet the needs of all consumers, to meet peak summer and winter demand when there are interstate pipeline disruptions, or to resolve regional congestion. A margin of excess capacity will provide consumers a choice of suppliers and is the critical foundation needed to support a competitive market and stabilize short-term pricing volatility.

The state is considering other projects that will further strengthen the natural gas infrastructure in California. The CPUC is working with gas utilities to modify the portfolio of natural gas pipeline capacity contracts to better match current and future market conditions and achieve consumer savings, although several important issues remain unresolved.

Ensuring the Quality of Natural Gas Supplies

The *2003 Energy Report* recommended that the state initiate legislative hearings to examine the issue of gas quality and gas gathering as it relates to California gas production, and to determine whether additional legislative action is warranted to resolve the issues.

Expansion of gas field production in California will depend on improving the quality of natural gas delivered to the pipeline network. Total energy content, or heating value, is the component of gas quality that is of major concern. Most end-use appliances, from water heaters to power plants, will not operate properly outside a relatively narrow

heating value range. Gas supplies in different parts of the state and the western U.S. can have very different heating values, requiring blending and/or treatment before the gas can be used.

Gas quality is a concern not only for in-state production but also for imported supplies of LNG. The chemical composition of potential imported LNG may be significantly different from traditional supplies. The gas quality issue is potentially resolvable using known technologies, and by setting requirements for imported LNG supplies. However, because gas quality also affects air emissions, the state must carefully evaluate this issue to prevent unwanted impacts on air quality. The 2005 PIERNG program has funded more than $3 million in research devoted to understanding and resolving gas quality issues. The program plans further research efforts in 2006 to determine the effects of variable natural gas quality on large industrial end users.

The Energy Commission has been working cooperatively on this issue with the CPUC, the California Air Resources Board (ARB), and the Division of Oil, Gas, and Geothermal Resources. The agencies have held a number of hearings, workshops, and public meetings over the past year involving natural gas utilities, producers, pipeline and storage operators, consumers, and LNG project developers to accelerate resolution of natural gas quality issues in California. As a result, ARB has initiated a regulatory process to revise its natural gas specification affecting vehicles, which also indirectly affects pipeline supplies. The CPUC has also initiated a regulatory proceeding to examine requirements for pipeline natural gas quality. In addition, the Energy Commission has provided funding for research and development to address outstanding technical issues. Resolution of the issue of natural gas quality is expected by mid-2006. The Energy Commission will continue to monitor progress on the issue and may recommend legislative hearings in the future if a resolution is not accomplished as expected.

Chapter Eight:
Integrating Water and Energy Strategies

The link between energy and water use in the state is an important facet of California's energy system. While the most immediately recognizable aspect of this link is large-scale hydroelectric generation, the amount of energy used by the state's water infrastructure and water end-users is at least equally significant– and growing fast. The Energy Commission evaluated the relationship between water and energy systems to better understand this link and determine what, if any, mutually beneficial strategies can be developed to improve both the water and energy sectors. As a result of this initial work, the Energy Commission determined that much can be done to improve both systems.

California's water infrastructure uses a tremendous amount of energy to collect, move, and treat water; dispose of wastewater; and power the large pumps that move water throughout the state. California consumers also use energy to heat, cool, and pressurize the water they use in their homes and businesses. Together these water-related energy uses annually account for roughly 20 percent of the state's electricity consumption, one-third of non-power plant natural gas consumption, and about 88 million gallons of diesel fuel consumption.

The state's growing population is increasing the demand for water and the amount of energy needed to deliver and treat it. Water and energy demands are growing at roughly the same rate and are most critical in the state's urban areas. However, water-related electricity use is likely to grow at a faster rate because of: increasing and more energy-intensive water treatment requirements; conversion of diesel agricultural pumps to electric; increasing long-distance water transfers, which often have the impact of shifting water from agricultural to urban areas; and changes in crop patterns that require more energy-intensive irrigation methods.

If not coordinated and properly managed on a statewide basis, water-related electricity demand could affect reliability of the electric system during peak load periods when reserve margins are low. Conversely, without reliable and adequate supplies of electricity, water and wastewater agencies will not be able to meet the water needs of their customers. There are many opportunities to improve the performance of both systems by focusing on areas of mutual benefit. Particularly significant is the fact that Northern California receives two-thirds of the state's precipitation while two-thirds of the population lives in Southern California. Because of the distance and elevation involved in transporting water from Northern to Southern California, reducing water use in Southern California has more energy savings potential than reductions in other parts of the state.

Although opportunities for new hydroelectric generation projects are extremely limited in California, the state's existing hydroelectric system provides valuable peaking reserve capacity, spinning reserve capacity, load-following capacity, and transmission support—all at low energy costs. In addition, pumped storage facilities are generally considered to be the only current commercially viable method to store electricity on a large scale.

Power plants use a significant volume of water, primarily for cooling. This water demand by power plants can have a significant effect on local water supplies. The *2003 Energy Report* adopted a policy requiring new power plants to use degraded or recycled water or air-cooled systems to reduce the amount of fresh water used in power plant cooling systems. California has a number of power plants along its bays and coastline that use once-through cooling. The state has the opportunity to more comprehensively study the impacts of once-through cooling on the marine environment as part of the Governor's California Ocean Protection Council efforts, as well as the State and Regional Water Quality Control Boards' review of impacts under Section 316(b) of the federal *Clean Water Act*.

California can implement strategies now to increase water use efficiency, energy efficiency, peak operational flexibility, and renewable generation potential to serve the state's water and wastewater infrastructure.

Water Sources and Supplies

California receives its water from two sources: surface water and groundwater. Surface water includes natural lakes and streams as well as manmade reservoirs, canals, and aqueducts. Groundwater supplies about 30 percent of the state's average water demand but can supply as much as 60 percent during periods of extended drought. California's groundwater aquifers store

several hundred million acre-feet of water, compared with approximately 45 million acre-feet stored in the state's 1,200 reservoirs.[200] Pumping groundwater uses significant amounts of energy. Many of the state's groundwater aquifers are in decline as water is pumped out faster than it is replaced so that the water must be pumped from greater depths, requiring even more energy.

Water storage in the state relies upon surface impoundments, especially in major water projects, the Sierra snowpack, and groundwater. The Sierra snowpack is a key element in both the state's water supply and energy production. The annual snowpack essentially "stores" water that is later released slowly during the spring and summer into reservoirs, some of which also serve for flood control. Stored water is also used later in the summer to generate hydroelectric electricity.

California's growing population is putting great pressure on municipalities to secure enough water to meet that growth. Faced with limited fresh water, many agencies are using recycled water to meet their non-potable needs. The fastest-growing source of new water supplies is recycled wastewater from municipal and other systems. This water is treated to stringent health and quality standards before it is reused. Recycled water can substitute for fresh water in power plant cooling and other industrial processes, landscape irrigation, and to replenish groundwater aquifers.

Another option that many cities are considering to meet their future water demand is desalination, a process that removes salt from brackish water or seawater.[201] Because desalination is one of the very few options for increasing present water supplies, water agencies may build and operate many of these facilities in the future. Desalination facilities may make more economic sense in areas that have high energy and treatment costs for their current water supplies, like Southern California's urban areas.

California will face reduced water supplies in the future because of enforcement of the Colorado River Compact, which was signed in the early 1920s and apportions water from the Colorado River among several western states. California has historically used more than its allotted water because the other states were not using their full allotments. Since water demand in the Colorado River basin and Arizona is increasing dramatically, California can no longer use part of their water allotments. This will significantly impact water agencies in the southern part of the state.

Producing Energy from Water

Perhaps the most widely recognized aspect of the water-energy relationship is hydroelectric power generation in the state's hydroelectric power plants and pumped storage facilities. However, other opportunities exist to increase energy supplies from water and wastewater utilities. These include water storage for peak shifting, in-conduit hydroelectric generation, biogas cogeneration at wastewater treatment plants, and development of local renewable resources on water and wastewater utilities' extensive watersheds and rights-of-way.

However, existing tariffs and operating rules limit full development of self-generation by water and wastewater utilities. Interconnection constraints and prohibitive market rules discourage customer self-generation. Limitations on net metering and constraints on service account aggregation also prevent self-generation for geographically remote customer loads.

200. Association of California Water Agencies [http://www.acwa.com/mediazone/waterfacts/view.asp?ID=44]. An acre-foot is equal to about 325,850 gallons of water, or enough to cover an acre to a depth of one foot.

201. Fresh water aquifers containing salts, minerals, or other contaminants that require high-levels of treatment require only about one-third the energy to treat when compared to sea water desalination. Source: Inland Empire Utilities Agency and Metropolitan Water District 2005 water source energy intensity reports.

Hydroelectric Power

California is served by a vast network of reservoirs and dams, pumped storage, and run-of-river facilities. These facilities are operated by investor-owned utilities (IOUs), publicly owned utilities, state and federal agencies, irrigation districts and other entities, mostly for multiple purposes including power generation, water supply, recreation, and flood control. California's combined total hydroelectric capacity is more than 14,000 MW,[202] or about 25 percent of in-state generating capacity in an average precipitation year. In 2004, hydroelectric generation was about 29,000 GWh, or 13 percent of in-state generation.[203] California's hydroelectric system provides valuable peaking reserve capacity, spinning reserve capacity, load following capacity, and transmission support, all at low overall production cost since there is no associated fuel cost.[204]

Opportunities for construction of new hydroelectric plants and pumped storage projects are extremely limited in California. Most economically viable sites have already been developed, and development of remaining suitable sites faces restrictions due to lack of unallocated water rights, environmental issues, and political opposition. More than a third of California's hydroelectric capacity is expected to be relicensed by the FERC between 2000 and 2015. FERC normally issues licenses for a period of 30-50 years, after which facilities must apply for relicensing. The five-year public relicensing period offers an excellent opportunity to reduce or resolve the ecological impacts of these facilities. The *2003 Energy Report* recommended that the Energy Commission continue its efforts to help state and federal agencies more fully understand the effects of these facilities on regional and statewide electricity supply.

The most contentious relicensing issue for the state's hydroelectric projects is the competing allocation of water between the in-stream flows needed to sustain a healthy aquatic ecosystem and the amount of water diverted to hydroelectric generation. As understanding of freshwater aquatic ecosystems has improved, there has been increasing pressure for larger and more variable in-stream flows, which often means less available water for hydroelectric generation. The Energy Commission's Public Interest Energy Research (PIER) program has proposed research to improve the process of determining in-stream flows through the development and demonstration of new tools or the enhancement of existing tools. This research promises to ensure better environmental protection while reducing unnecessary curtailments of hydroelectric generation.

There are opportunities to enhance existing hydroelectric generation without causing further environmental damage through improved runoff forecasting and decision support models. Hydroelectric operators can benefit from a better understanding of climate and hydrologic conditions and from decision support models that allow operators to balance conflicting demands for water supplies. The PIER program is supporting research to develop probabilistic forecasts on an hourly-to-seasonal basis and decision support models for multi-purpose reservoirs.

202. California Energy Commission, *2003 Environmental Performance Report. Appendix D, California Hydropower System: Energy and Environment*, CEC-100-03-018, March 2003, p. D-6.

203. California Energy Commission, *Potential Changes in Hydropower Production from Global Climate Change in California and the Western U.S.*, June 2005, consultant report, prepared in support of the *2005 Energy Report*, CEC-700-2005-010.

204. California Energy Commission staff report, *California Hydropower System: Energy and Environment, Appendix D, 2003 Environmental Performance Report*; prepared in support of the *Electricity and Natural Gas Report* under the *Energy Report* proceeding (02-IEP-01), October 2003, CEC-100-03-018.

In-Conduit Hydropower

In-conduit hydropower uses turbines or other generating devices installed in conduits (pipelines, canals, and aqueducts) to generate electricity from water flowing in the state's water conveyance system. Most of the state's large water conveyance projects already take advantage of this technology, but additional opportunities remain to develop new or retrofitted generation in the state's water systems if costs and risks can be minimized. A recent PIER study estimated the statewide potential of hydropower capacity in manmade conduits at about 255 MW, with annual production of approximately 1,100 GWh.[205] The potential was split fairly evenly between municipal and irrigation district systems. This electricity production could be used to offset the energy demand of the conveyance system itself or sold into the grid.

In-conduit hydropower facilities are attractive because they are generally easier to license, tend to have fewer environmental impacts compared with other hydroelectric facilities and, because they are generally small, are more likely to meet requirements of the state's RPS program.[206] In most cases, in-conduit hydropower potential ranges from 1-2 kW to about 1 MW. However, many existing in-conduit facilities are facing the future challenge of the expiration of their standard offer power purchase contracts with the state's IOUs.

Existing rules do not credit power produced against a water or wastewater utility's total energy bills. Instead, wherever self-generated power cannot be directly connected to an existing load, it must be sold into the wholesale bulk power market. The costs and complexities of participating in the wholesale bulk power markets are daunting, even for large generators, and can be prohibitive for small generators. Many of the arguments made on behalf of combined heat and power in Chapter 4 apply equally well to water agency self-generation.

Existing energy efficiency programs can be tailored for special circumstances using customized incentives and standard performance contracting. In-conduit hydropower could be similarly treated and included as part of these tailored programs. Again, the issues of interconnection, sale, and the application of power to multiple accounts will need to be addressed.

Biogas Recovery

Some of the electricity needed to process wastewater can be used to produce digester biogas from anaerobic digesters installed at or near wastewater treatment facilities, which can then be used to self generate or be sold into the grid. Currently, about 50 percent of sewage sludge, 2 percent of dairy manure, and less than 1 percent of food processing wastes and wastewater generated in the state are used to produce biogas. California has 311 sewage wastewater treatment facilities, 2,300 dairy operations, and 3,000 food processing facilities. Converting these wastes into energy can help operating facilities offset the purchase of electricity and provide environmental benefits by reducing the discharge of air and groundwater pollutants.

Current rules discourage the full use of available biogas for either self generation or to serve offsite loads. Provisions under regulated tariffs enable dairy operations to produce electricity from biogas resources at one location and use it to offset electricity use at multiple locations, under multiple accounts for one customer. This same approach would significantly increase opportunities for biogas generation by wastewater agencies.

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205. California Energy Commission, *California Small Hydropower and Ocean Wave Energy Resources*, Mike Kane, Public Interest Energy Research Program, April 2005.

206. The Renewable Portfolio Standard limits eligibility of hydroelectric facilities to 30 MW or less.

Recommendation for Increasing Energy Production from Water

- The state, in collaboration with water utilities, wastewater districts and stakeholders, should assess and develop a comprehensive policy to promote self generation, including examining all cost-effective, environmentally preferred in-conduit, biogas, and other renewable options for water and wastewater systems.

  Attention should be given to the following:
  - Allowing water and wastewater utilities to self generate and use the produced electricity to offset power requirements at their other locations and for multiple accounts within their own systems.
  - Expediting and reducing the cost of interconnection, eliminating economic penalties such as standby charges, and removing size limitations for net metering.
  - Evaluating potential incentives to support the development and/or operation of in-conduit hydroelectric facilities.

Energy Use in California's Water Use Cycle

California uses about 14 trillion gallons of water in a normal year, with about 79 percent going to agriculture and the remainder to the urban sector.[207] Once water is collected or extracted from a source, it is transported to water treatment facilities and distributed to end users. Wastewater from urban end uses is collected and treated before it is discharged back into the environment, where it becomes a source for other uses. In general, wastewater from agricultural end uses is not treated (except for holding periods to degrade chemical contaminants before release to the environment) and is discharged directly to the environment as runoff into natural waterways or groundwater basins. As mentioned above, there is a growing trend to recycle some portion of the wastewater stream and redistribute it for non-potable end uses.

Because electric and gas meters do not measure water-related uses separately, it is difficult to determine the amount of water-related energy consumed by end users. Better information is available about

Table 3:
2001 Water-Related Energy Use In California

	Electricity (GWh)	Natural Gas (Mill. Therms)	Diesel (Mill. Gallons)
Water Supply and Treatment			
Urban	7,554	19	?
Agricultural	3,188		
End Uses			
Agricultural	7,372	18	88
Residential	27,887	4,220	?
Commercial			
Industrial			
Wastewater Treatment	2,012	27	?
TOTAL	**48,012**	**4,284**	**88**
2001 Consumption	250,494	13,571	?
Percent of Statewide Energy Use	19%	32%	?

Source: California Energy Commission, *California's Water-Energy Relationship*, final staff report, 2005

207. California Department of Water Resources, Bulletin 160-2005, provides the breakdown of urban and agricultural water use.

energy consumption by water and wastewater utilities.[208] As shown in Table 3, total water-related energy consumption is large, using roughly 19 percent of all electricity used in California, approximately 32 percent of all natural gas, and 88 million gallons of diesel fuel. These numbers are, however, preliminary, and are being refined through a PIER program research project, with results expected in early 2006. Question marks in the table indicate areas where additional information is needed.

Each element of the water use cycle has a unique "energy intensity," which is the amount of energy consumed per unit of water to perform water management-related actions such as desalting, pumped storage, groundwater extraction, conveyance, or treatment. The less energy required to perform such actions, the lower the energy intensity. Table 4 illustrates the considerable variability in the range of these intensities. A description of each segment of the water cycle follows.

Supply and Conveyance - Water must be transported long distances and over great elevations to reach the urban centers of the state, especially Southern California, which imports about 50 percent of its water supplies from the Colorado River and the State Water Project. Conveying water to Southern California communities can use 50 times as much energy as it takes to convey water to communities in Northern California, where the energy intensity of raw water supplies can be near zero for gravity-fed systems from the Sierra to urban areas in Northern California and agricultural districts in the Central Valley. Some portions of this energy can be recaptured through

Table 4: Energy Intensities in the Water Cycle[209]

Water Cycle Segments	Range of Energy Intensity (kilowatt hours/million gallons)	
	Low	High
Supply and Conveyance	0	4,000
Treatment	100	16,000
Distribution	700	1,200
Wastewater Collection and Treatment	1,100	4,600
Wastewater Discharge	0	400
Recycled Water Treatment and Distribution	400	1,200

Source: California Energy Commission, *California's Water-Energy Relationship*, final staff report, 2005.

208. Meters are typically installed to record the electricity or natural gas used by an entire household, building, or other type of facility.

209. The energy intensities in Table 4 are non-additive and reflect ranges of recorded energy use by water cycle function.

hydroelectric generation that uses the gravity of descending water to generate electricity.

Treatment - The volume of electricity required to treat water to drinkable standards varies tremendously within the state, ranging from water supplies that need little treatment to those that require treatment to remove contaminants, refined chemicals, and hazardous compounds. Proposed regulations[210] for more stringent water quality requirements could potentially increase electricity demand.

Distribution - Electricity use to distribute treated water to customers is primarily for pump motors and varies depending upon the topography of the area served and the total pipe length, water use, age, and size of the system.

Wastewater Collection, Treatment, and Discharge - Wastewater treatment consumes electricity in three stages: transport to the facility, treatment, and disposal/recycling, all primarily from the use of electric pumps and blowers. Wastewater pumps require more energy because they pump both liquids and solids. Recycled wastewater requires even more energy.

Recycled Water Treatment and Distribution - Most wastewater treatment facilities in the state treat their effluent to a secondary standard, making it possible to further treat the effluent to recycled water standards and expand available water supplies for non-potable uses.

Energy Consumption by Water End Users

Together, agricultural, residential, commercial, and industrial water-related end uses account for 58 percent of all water-related electricity and 99 percent of water-related natural gas use in California. The remaining 42 percent of water-related electricity is used to get the water to the end user at usable quality and to treat the discharged wastewater.

Agriculture

Each year California's agricultural sector consumes more than 10,000 GWh of electricity along with significant amounts of diesel fuel and natural gas to pump and move roughly 34 million acre-feet of water. Although most of that electricity use occurs during the summer, many agricultural operations are year-round. Shifts in agricultural crops and irrigation methods, such as drip irrigation that uses additional electricity to pressurize the system, may increase the amount of electricity used in the agricultural sector. Incentives to convert diesel-engine pumps to electric motors, an important air quality strategy, will also increase electricity use.

Residential, Commercial, and Industrial

Urban water use in California tends to be more energy intensive than in the agricultural sector because urban water systems use energy for pre-treatment as well as wastewater treatment, which is not generally required for agriculture, and because interbasin transfer systems are used primarily for urban water supplies.

The residential sector accounts for 48 percent of the electricity and natural gas consumption associated with urban water use. Residential energy uses include everything from water filtering and softening to heating and cooling to circulating water in a spa pump and, in some cases, pumping groundwater from private wells. In the residential sector, the major water-related electricity end uses are water heating and clothes drying. Water heating is also the major user of natural gas.

Commercial water-related energy use represents 30 percent of the electricity and 6 percent of the natural gas associated with urban water use. Industrial water-related energy use represents 22 percent of electricity and 45 percent of natural gas use. Commercial and industrial water uses include all those used in residences, plus hundreds more. Some of the more energy-intensive applications include high-rise supplemental pressurization to

210. To comply with the federal *Safe Drinking Water* and *Clean Water Acts*.

serve upper floors; steam ovens and tables; car and truck washes; process hot water and steam; process chilling; equipment cooling; and cooling towers.

Water is used by California's petroleum industry for refining and enhanced oil recovery operations. A typical refinery uses an average 65-90 gallons of water per barrel of crude oil processed and produces about 50-60 gallons of wastewater that generally must be treated prior to reuse or disposal; the difference is lost through evaporation.[211]

Recommendations for Energy Savings by End Users

- The Energy Commission, the California Department of Water Resources, the CPUC, water agencies, publicly owned utilities, and other stakeholders should explore and pursue cost-effective water efficiency opportunities that could result in significant energy savings to decrease the energy intensity of the water sector.
- These opportunities should include assessing efficiency improvements in hot and cold water use in homes and businesses, water saving appliances and fixtures, devices that use and move water, and other viable options to maximize energy and water savings. Near-term opportunities should be identified for inclusion in the 2006-2008 IOU energy efficiency portfolios.

Storing Electricity for Peak Generation and Peak Load Shifting

California has a number of pumped storage hydro facilities. In pumped storage facilities, water is pumped from a lower to a higher reservoir during off-peak times and is used to generate electricity when peaking power is needed. Pumped storage is generally considered the only commercially viable method for the large-scale storage of electricity. California has more than 4,000 MW of pumped hydro storage capacity, with about 2,700 MW in the CA ISO control area.[212] Two pumped storage projects that would add as much as 900 MW of generating capacity are in the FERC permitting stage but face opposition because of potential water resource, biological, visual, wilderness, and recreational impacts.

Pumped storage can minimize the system impact of integrating large volumes of intermittent wind resources into the state's power grid by absorbing electricity generation during high-wind periods that would otherwise cause operational problems for system operators.[213] Pumped storage can also be used in tandem with wind resources to shift delivery of wind energy from off-peak to on-peak periods during the day and smooth out production spikes.[214] One example is the Sacramento Municipal Utility District's proposed 400 MW pumped storage hydro facility in El Dorado County, which is intended

211. CH2M HILL, July 2003, *Water Use in Industries of the Future*, prepared under contract to the Center for Waste Reduction Technologies for United States Department of Energy, Office of Energy Efficiency and Renewable Energy, Industrial Technologies Program.

212. CA ISO, *Role of Energy Storage in California ISO Grid Operations*, presented by David Hawkins, Manager, Special Projects Engineering at California Energy Commission/Department of Energy Workshop on Energy Storage, February 24, 2005 [http://www.energy.ca.gov/pier/notices/2005-02-24_workshop/03%20Hawkins-CA-ISO%20presentation.pdf], accessed April 30, 2005.

213. California Energy Commission, *Assessment of Reliability and Operational Issues for Integration of Renewable Generation*, consultant final report, prepared by Electric Power Group, LLC, and Consortium for Electric Reliability Technology Solutions, August 2005 CEC-700-2005-009-F, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051005].

214. CA ISO, *Role of Energy Storage in California ISO Grid Operations*, presented by David Hawkins, Manager, Special Projects Engineering at California Energy Commission/Department of Energy Workshop on energy storage, February 24, 2005 [http://www.energy.ca.gov/pier/notices/2005-02-24_workshop/03%20Hawkins-CA-ISO%20presentation.pdf], accessed April 30, 2005.

to make the utility's wind energy projects more dispatchable.[215] Outside California, the Pacific Northwest's Bonneville Power Administration offers a storage and shaping service that integrates and stores hourly wind energy generation from the federal Columbia River hydroelectric system.

One possibility for developing new pumped storage projects is to connect two existing reservoirs or lakes with new pipelines for pumping and generating electricity. A U.S. Department of Energy (DOE) study has identified dozens of reservoir pairs in California that could yield as much as 1,800 MW of new pumped storage generation. This option avoids construction of new reservoirs but still faces the challenges of siting and building large pipelines in difficult terrain on protected lands.

Water storage can also reduce peak load. For example, the El Dorado Irrigation District reduced its on-peak electrical usage by more than 60 percent by allowing its tanks to drop to a lower minimum level and installing an additional 5 million gallon storage tank. Water agencies could save an estimated 250 MW of peak demand statewide with the creative use of water storage, including refilling water storage tanks during off-peak periods. Additional treated water storage in urban areas could also save 1,000 MW of peak demand. Together these savings would represent more than a third of the peak load from the water cycle.

Recommendation for Electricity Storage

- The Energy Commission's PIER program should evaluate and conduct research to examine opportunities to shift loads off peak and integrate intermittent renewable generation by maximizing use of storage in existing pumped hydro facilities and increasing use of water storage tanks and conveyance systems.

Water for Power Plant Cooling

California's 21 coastal power plants provide nearly 24,000 MW of generating capacity. These plants use "once-through cooling," which passes up to 17 billion gallons of seawater per day through a heat exchanger before returning it to the ocean. Recent studies indicate that this use of seawater for once-through cooling can contribute to the decline of fisheries and the degradation of estuaries and bay and coastal waters.[216] When ocean water is drawn through a power plant the process kills eggs, larvae, and adult fish, while adult fish and invertebrates are trapped and killed on water intake screens. Once-through cooling also affects the coastal environment because it returns seawater to the ocean at a higher temperature after passing through plant heat exchangers, affecting the early life stages of fish and shellfish.

In 2004, Governor Schwarzenegger established the Ocean Protection Council to implement the new *California Ocean Protection Act* and coordinate the work of state agencies related to the protection and conservation of coastal waters and ocean ecosystems. As part of its broader agenda, the Council is interested in understanding and addressing the impacts of once-through cooling on California's threatened coastal marine ecosystem. The Energy Commission has an opportunity through working with the Council to coordinate with other local, state and federal agencies, including the Santa Monica Bay Restoration Commission, the Coastal Commission, the State Water Resources Control Board, the Department of Fish and Game, and others to address once-through cooling issues in the broader context of protecting the state's fragile coastal marine ecosystem.

In September 2004, the U.S. Environmental Protection Agency (U.S. EPA) released a new federal

215. Sacramento Municipal Utility District, *Relicensing Hydro UARP FERC 2101: Proposed Iowa Hill Pumped Storage Development* [http://hydrorelicensing.smud.org/docs/docs_iowa.htm], accessed April 30, 2005.

216. California Energy Commission, June 2005, *Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants*. staff report, CEC-700-2005-013, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051005].

rule under Section 316(b) of the federal *Clean Water Act* to reduce the environmental impacts from existing power plants that use once-through cooling. Although the new 316(b) regulations recently issued by the U.S. EPA set forth performance standards affecting power plants using once-through cooling, there is no guidance that applies to California on appropriate sampling designs or impact analysis methods. There is a critical need for collaborative research to support the development of the most appropriate protocols and guidelines to assess the effects of once-through cooling on coastal and estuarine ecosystems.

Recommendations for Once-Through Cooling

- The Energy Commission's PIER program should continue to collaborate with the State Water Resources Control Board, the Regional Water Quality Control Boards, the Department of Fish and Game, and other stakeholders to develop sampling and other analytical protocols and guidelines that will provide clear, consistent approaches for assessing the ecological effects of once-through cooling.
- The Energy Commission should update its current memoranda-of-understanding agreement with the State Water Resources Control Board, the Regional Water Quality Control Boards, and the California Coastal Commission to develop a consistent regulatory approach for the use of once-through cooling in power plants, including the use of best-available retrofit technologies to minimize impacts on the marine environment. The Energy Commission should also actively participate in the 316(b) reviews of coastal power plant once-through cooling impacts.
- The Energy Commission should update current data adequacy regulations with respect to once-through cooling at the state's coastal power plants. Existing data adequacy regulations for power plant licensing applications do not provide sufficient guidance regarding the type and extent of data needed to complete an analysis of power plants proposing to use once-through cooling technologies.

The Impact of Water Efficiency on Energy Use

Agricultural Water Use Efficiency

Because of the large amount of energy consumed in California's water cycle, reducing water use also saves energy. Efficient irrigation techniques hold promise for substantially reducing the amount of water delivered. Agricultural water conservation can also increase on-farm energy demand, such as the energy required to pressurize drip and microspray irrigation systems, but this increase can be more than offset by greater on-farm irrigation system efficiency and operations and by energy reductions associated with delivering less water. Utilities and agencies are also addressing agricultural energy use with several targeted energy efficiency programs. The Agricultural Pumping Efficiency Program is funded by a public goods charge on utility bills and provides free pump efficiency evaluations for farmers and irrigation districts served by the state's three IOUs.

Large numbers of both PG&E and SCE agricultural customers have signed up for time-of-use (TOU) electric rate schedules. In the PG&E service area, 81 percent of agricultural revenues and 89 percent of agricultural kWh sales are on TOU rates, representing half of the utility's 80,000 agricultural accounts.[217] In the SCE service area, 71 percent of agricultural kWh sales are on TOU rates, generated by 18 percent of customer accounts.[218]

217. Communication between Ricardo Amon and Keith Coyne, Pacific Gas and Electric, August 4, 2005.

218. Communication between Ricardo Amon and Cyrus Sorooshian, Southern California Edison, August 11, 2005.

Although a large number of accounts use TOU rates, farmers cannot always meet TOU requirements to take advantage of the lower rates. When necessary, they use energy during peak period hours to provide water to crops when needed, in the proper amount, and using high distribution uniformity to maximize crop growth. Agricultural electricity end users would benefit from energy policies that allow customers to choose the demand response practices that best fit their businesses. The industry will be more inclined to invest in peak load reduction measures if given flexibility and strong, consistent price signals.

Energy Savings from Efficient Urban Water Use

In 2003, the Pacific Institute estimated the potential for cost-effective urban water conservation at about 651 billion gallons per year.[219] In early 2005, the California Urban Water Conservation Council posted the results from 32 percent of the agencies that signed their memorandum of understanding to institute best management practices (BMPs) in their water agencies. Taking only those BMPs for which water savings could be quantified, the reporting agencies saved more than 27.5 billion gallons of water in 2004 and more than 234 million kWh of electricity. Over the lifetime of each measure, the net present value of the avoided cost totals more than $200 million.[220] However, these energy savings were not recognized by either the CPUC or by the energy utilities as a fundable energy conservation measure.

Members of the Energy Commission's Water-Energy Working Group presented testimony on water use cycle energy savings and sought to establish the magnitude of potential energy savings associated with water savings. Table 5 compares energy efficiency programs in years 2004-2005, and those planned for 2006-2008, with water use efficiency programs savings and program implementation costs reported for the BMPs.

Significant untapped potential for energy savings exists in programs focused on water use efficiency. Energy savings from these programs could produce 95 percent of the savings expected from the 2006-2008 energy efficiency programs at 58 percent of the cost. Peak savings could account for 60 percent of planned-for reductions in demand.[221]

Increasing Water and Wastewater Treatment Efficiency

All water and wastewater treatment processes have opportunities to reduce energy use. Industry experts estimate that untapped energy efficiency opportunities in water and wastewater treatment range from 5 percent to 30 percent. In the mid-1990s, the Electric Power Research Institute and HDR, Inc. conducted an audit of the energy savings potential of water and wastewater facilities in California. At that time they estimated that more than 880 GWh could be saved by implementing a variety of measures including load shifting and installation of high-efficiency motors and pumps.

219. *Waste Not, Want Not: The Potential for Urban Water Conservation in California.* Pacific Institute, November 2004.

220. The saved energy was computed using the energy intensity of the water use cycle for urban water users of 4,000 kWh/MG in Northern California and 12,700 kWh/MG in Southern California. The computations were done separately for Northern and Southern California and then aggregated to arrive at the statewide totals. Resource values are produced using the E3 Avoided Cost Methodology adopted by the CPUC in the April 7, 2005 D.05-04-024, R.04-04-025.

221. The numbers for the energy programs come from CPUC documents: 2004-2005, CPUC R.01-08-028, D.03-12-060, 2005-2006, CPUC R.-01-08-0228, D.04-09-060. The numbers for the water use efficiency program are discussed in detail in Appendix D of the *California's Water-Energy Relationship*, final staff report. The energy savings have been apportioned to Northern and Southern California based on population. The cost for the water efficiency measures assumes an average of $384 per acre-foot, based on a range of $58-$710.

Table 5: **Comparison of Energy Efficiency Programs Resource Value to Water Use Efficiency**

	Energy Efficiency Programs 2004-2005	2006-2008	Water Use Efficiency (WUE)
GWh (annualized)	2,745	6,812	6,500
MW	690	1,417	850
Funding ($ million)	762	1,500	826
$/Annual kWh	0.28	0.22	0.13
WUE Relative Cost	46%	58%	

Source: California Energy Commission, *California's Water-Energy Relationship*, final staff report, 2005.

Time-of-Use Water Tariffs and Meters

The idea of TOU water tariffs and meters was raised several times during the *2005 Energy Report* proceedings as a way to encourage customers to reduce their water use by providing a more accurate assessment of the time value of water. Though water agencies are on standard TOU and demand rates, the incremental costs between on- and off-peak were not large enough to affect their decision making until the 2000-2001 energy crisis raised awareness about hourly energy costs in the highly volatile bulk power market.

At the retail level, it is important to recognize that many water customers in the state do not have water meters, though recently enacted legislation will change that. In addition, there are currently no time-of-use water meters. Water agencies are grappling with how to develop tariffs and rate schedules that properly reflect the value of water at different times during the day and the need to account for delays between energy consumption and the time of water use. The Energy Commission is funding a PIER research project to look at the feasibility of such meters and associated tariffs.

Investing in Water and Energy Efficiency

Despite some efforts targeted at improving the energy efficiency of heating water, the state's largest energy utilities have no authority to invest in programs that save cold water, regardless of whether the programs yield energy benefits. Because of the potential for reduced energy demand from these programs, the Energy Commission, the CPUC, utilities, and other stakeholders should more carefully examine investment in cold water savings.

Water utilities do, of course, invest in programs that save water. Water and wastewater utilities also participate in programs to increase the efficiency of their operations. Given the interconnectedness of water and energy resources in California, the fact that cost-effectiveness is determined from the perspective of a single utility and a single resource creates barriers to achieving greater energy savings from water efficiency programs. Water utilities only value the cost of treating and delivering water. Wastewater utilities only value the cost of collection, treatment, and disposal. Electric utilities only value saved electricity. Natural gas utilities only value saved natural gas. This single focus causes under-investment in programs that would increase the energy efficiency of the water use cycle, agricultural and urban water use efficiency, and generation from renewable resources by water and wastewater utilities.

Recommendation for Energy Savings in Water Use

- The Energy Commission's PIER program should evaluate and conduct research to better understand the interaction of water and energy within the state and identify new and innovative technologies and measures for achieving energy and water efficiency savings. Research should address potential savings throughout the water cycle, especially in Southern California where the energy intensity of water is greatest, and focus on identifying and implementing cost-effective retrofits in the water system that increase efficiency and provide both energy and peak savings. In addition, research should examine opportunities to increase savings through the development of TOU water tariffs and meters, along with increased flexibility in water deliveries.

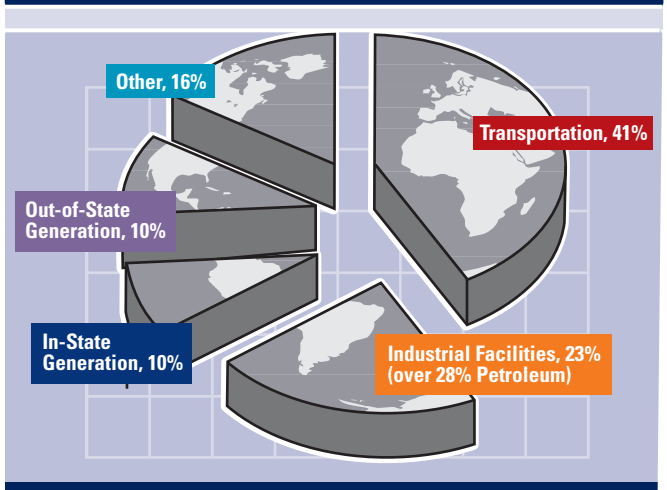
Chapter Nine:

Global Climate Change

Climate change is a worldwide phenomenon with significant implications for all sectors of the state's economy and natural resources. Most scientists now agree that climate change is occurring, is caused by human activities, and could severely affect natural ecosystems and the economy.

California is the seventeenth largest emitter of greenhouse gases in the world,[222] with more emissions than any state in the nation except Texas.[223] Greenhouse gas emissions in California are increasing mainly because of both population and economic growth. From 1990 to 2002, total greenhouse gas emissions rose nearly 12 percent; if current trends are permitted to continue, greenhouse gas emissions would increase by 24 percent from 1990 to 2020.

Figure 24:
Greenhouse Gas Emissions



Source: California Energy Commission

The primary source of greenhouse gas emissions is the burning of fossil fuels in motor vehicles, refineries, industrial facilities, and power plants.[224] In California, the transportation sector is the largest source of greenhouse gas emissions, as shown in Figure 24, producing 41 percent of the state's total emissions. Industrial facilities are the second largest source, producing nearly 23 percent of total emissions. Within this sector, petroleum refineries account for about 28 percent of total emissions. Electricity generation is the third largest greenhouse gas category, producing just under 20 percent of total emissions. While imported electricity is a relatively small share of California's electricity mix, out-of-state electricity generation sources contribute about half of the greenhouse gas emissions associated with electricity consumption in California.

In spite of its size, California ranks among the better states and countries when considering per capita emissions of greenhouse gases. This is the result of two primary factors: aggressive building and appliance standards put in place over the years by the Energy Commission that have limited power plant generation growth and the stringent air quality standards applied to power plants that have resulted in power plants burning cleaner natural gas rather than oil.

In its *2003 Energy Report*, the Energy Commission recommended the following actions to address climate change:

- Account for the cost of greenhouse gas emission reductions in utility resource procurement decisions.
- Require the reporting of greenhouse gas emissions as a condition of state licensing of new electricity generating facilities.

222. World Resources Institute [http://cait.wri.org/], accessed October 28, 2005.

223. California Energy Commission, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2002 Update*, CEC-600-2005-025, June 2005.

224. According to the Natural Resources Defense Council in its April 5, 2005, comments to the Energy Commission, California's CO_2 emissions in 1999 were 346 million metric tons of carbon dioxide ($MMTCO_2$) from in-state sources and 73 $MMTCO_2$ due to imported electricity.

- Use sustainable energy and environmental designs in all State of California buildings.
- Require all state agencies to incorporate climate change mitigation and adaptation strategies in planning and policy documents.[225]

Since 2003, state agencies have begun to take significant action in addressing these recommendations. Governor Schwarzenegger's recent Executive Order underscores the importance of addressing global climate change and provided specific targets.[226]

Resource Procurement

The CPUC, in a December 2004 decision, recognized the importance of reducing greenhouse gas emissions and directed the state's investor-owned utilities to account for climate change risk in their long-term resource procurement plans. Under this decision, the utilities are required to use a "greenhouse gas adder," with an initial value of $8 per ton to reflect the amount of carbon dioxide (CO_2) that would be emitted by an electricity generating unit under the terms of a contract. This adder represents an estimate of the likely future cost of purchasing CO_2 offsets to comply with future mitigation regulations. The adder also corresponds to the financial risk associated with likely future regulation of greenhouse gas emissions. This adder encourages utilities to invest more in lower-emitting resources, such as efficiency and renewable sources, and less in high-emitting resources such as conventional coal.

Power Plant Licensing

The Energy Commission is conducting a rulemaking to revise current regulations for power plant licensing and compliance to require power plant developers to report greenhouse gas emissions as an important first step in identifying mitigation opportunities.

State Buildings

Commercial buildings use about 36 percent of the electricity in California and, therefore, account for a significant portion of greenhouse gas emissions. The Governor's Executive Order 20-04 implemented the Green Building Initiative with an overall goal to reduce energy consumption in the commercial sector by 20 percent by the year 2015.

The Initiative involves the Energy Commission, state agencies under the direct authority of the Governor, the Department of General Services, and the Division of the State Architect. It also urges other entities such as the University of California, California State Colleges and Universities, Community Colleges, constitutional officers, legislative and judicial branches, the Public Employees Retirement System, and the CPUC to actively participate in helping to achieve the reduction goal.

State Planning Documents

In the State Water Plan, the Department of Water Resources (DWR) recognizes the long-term effects of changing climate on the quantity and timing of water availability and snowmelt. The plan encourages water planning agencies to monitor and model the hydrology effects of changing climate. The California Department of Transportation, in its most recent update of the State Transportation Plan, similarly encourages regional and local transportation plans to recognize the benefits and risks of climate change. The State Transportation Plan encourages state and local agencies to develop policies on transportation system efficiency, mode shifts, alternative fuels, and the fleet purchase of hybrid vehicles, which have important climate change co-benefits.

225. California Energy Commission, *2003 Energy Report*, CEC-100-03-019, December 2003, p. 42.

226. Executive Order S-3-05 by the Governor of the State of California, June 1, 2005 [http://www.climatechange.ca.gov].

The Governor's Greenhouse Gas Emission Reduction Targets

In June 2005, Governor Schwarzenegger signed Executive Order S-3-05,[227] establishing the following statewide greenhouse gas emissions targets:

- By 2010, reduce statewide greenhouse gas emissions to 2000 emission levels.
- By 2020, reduce statewide greenhouse gas emissions to 1990 emission levels.
- By 2050, reduce statewide greenhouse gas emissions to 80 percent below 1990 levels.

To meet the targets, the Governor directed the California Environmental Protection Agency to coordinate with the Business, Transportation and Housing Agency; the Department of Food and Agriculture; the Resources Agency; the ARB; the Energy Commission; and the CPUC. The Governor's Climate Action Team is made up of representatives from these agencies to implement global warming emission reduction strategies and report on the progress made toward meeting the statewide greenhouse gas targets established in the Executive Order. The first report is due to the Governor and the Legislature in January 2006 and bi-annually thereafter.

The Effects of Global Climate Change on Energy

Climate change could significantly affect energy supply in California. Today, California relies on hydroelectricity for 15 percent on average of the electricity used in the state. Depending on hydrological conditions, the temperature and precipitation effects from global climate change could alter future hydrologic conditions, which affect hydroelectric supply. With the expected warming trends, a decreased snow pack during the spring and summer months could deplete the "reservoir" of snow that provides water for hydropower.[228] Increased winter flows could increase flood protection requirements, which could reduce storage for summer use.

Earlier snowmelts could result in water being diverted from hydropower facilities to avoid damage as well as water releases from reservoirs to prevent flooding. With reservoir capacity well below most generating capacity needs, less runoff will be captured for summer peaking power demand.

Increased runoff in winter would also result in increased hydro generation at a time when demand related to space heating, particularly in the Pacific Northwest, would be less due to overall warming trends. Conversely, decreased runoff in the summer would decrease hydro generation at a time when peak power is most needed to meet air conditioning loads that will be higher, also due to increased warming.

Preliminary studies suggest that hydroelectric generation may increase under wetter scenarios, but generation will decrease from 10 to 30 percent if dry scenarios materialize. The degree of precipitation as a result of climate change is a key uncertainty that still needs to be addressed. Further study is needed on the changes in runoff and changes in hydropower output from climate change.

Climate change could also increase the energy demand in California by increasing the demand for cooling, but the degree of this increase depends on the actual level of warming. Californians currently spend about $30 billion for natural gas and electric heating and cooling each year. Climate change could increase state energy expenditures by about $2 billion in 2020.[229] This net increase results from higher summer cooling demand that cancels any decrease in winter warming demand from warmer temperatures.

227. Ibid.

228. California Energy Commission, staff presentation, *Climate Change Effects on Hydropower* in support of the *2005 Energy Report*, June 20, 2005.

229. Mendelsohn, R. *The Impact of Climate Change on Energy Expenditures in California* 2003-10-31 500-03-058CF A11, California Energy Commission, pp. 1-43.

Increased energy demand would also result from higher usage for residential units, commercial buildings, and water pumping for urban and agricultural use. Under a worst case scenario (a rise in 1.9 degrees Centigrade), the state's electricity requirements would increase by about 7,500 GWh of energy and by 2,000 MW of peak capacity in 2010.[230] Global climate change is also expected to reduce the amount of surface water available for irrigation.

Water agencies can be instrumental in mitigating the effects of climate change because of the close relationship between water use and energy consumption. Water agencies are the single largest electricity users in California, consuming 3,200 MW of peak electricity. Reducing this demand is possible by greater linkage between water conservation and energy efficiency programs, by adding more storage, and by encouraging water users to shift usage to off-peak periods. Over the longer term, changes in electricity rate design, financial incentives, and demand response programs are recommended.[231]

Climate Change Activities at the Energy Commission

The Energy Commission and the Center for Clean Air Policy (CCAP) have conducted and compiled "bottom-up" assessments of measures that can reduce greenhouse gas emissions in California. The goal of this effort was to identify and quantify a range of greenhouse gas emissions reduction and sequestration opportunities in the state, the potential costs of these reductions, and policy options that might be used to encourage implementation.

The cost-effectiveness and reduction potential for greenhouse gas mitigation options in the transportation and cement sectors were evaluated as well as options for sequestering CO_2 emissions in the forestry and agricultural sectors. This work was combined with a series of sector-specific greenhouse gas mitigation analyses conducted by ICF Consulting for the Energy Commission's Public Interest Energy Research (PIER) program that evaluated measures to reduce high global warming potential gases in the landfill, natural gas, semi-conductor, dairy, and other sectors.

In total, the measures analyzed have the potential to reduce greenhouse gas emissions by 44 million tons of CO_2 equivalent in 2010 and 117 million tons of CO_2 equivalent in 2020. These measures do not include the electric generation and oil refining sectors. These sectors contribute significantly to the state greenhouse gas inventory[232] and have the potential to contribute significant emissions reductions. Key findings and conclusions from this work are:

- Emission reductions are needed from multiple sectors of the California economy to achieve the Governor's targets.
- Cost-effective reductions are possible (less than $10 to $20 per ton) by 2010, but costlier options will be needed to achieve the 2020 target.
- Some options face technical or economic barriers or policy or political hurdles, which need to be overcome to fully realize the greenhouse gas reduction benefits.[233]

230. Baxter, L.W. and K. Calandri, "Global Warming and Electricity Demand: A Study of California" *Energy Policy* 1992: pp. 233–244.

231. Lon W. House, Ph.D., *There is No Electricity Crisis in California (That) The Water Agencies Can't Solve—Or Make Worse*, June 21, 2005.

232. According to the most recent state inventory, in-state power plants emitted about 44 $MMTCO_2e$ in 2002 and imported power accounted for about 52 $MMTCO_2e$ in 2002. A Center for Clean Air Policy analysis estimates that refineries emit 35 $MMTCO_2e$ in 2005.

233. Ned Helme, Center for Clean Air Policy, presentation in support of the *2005 Energy Report*, July 11, 2005.

In all, based on a very preliminary baseline emissions estimate developed by the Energy Commission,[234] there appear to be sufficient emissions reduction opportunities available in the state to contribute significantly to the greenhouse gas reduction targets established by the Governor in June 2005.

As directed by the Legislature in SB 1771 (Sher), Chapter 1018, Statutes of 2000, the Energy Commission established the Climate Change Advisory Committee to advise the Energy Commission on "the most equitable and efficient ways to implement national and international climate change requirements." The Advisory Committee's membership represents key sectors of the California economy that will be affected by climate change.

The Advisory Committee was charged with the task of reviewing the CCAP's sector analyses and providing recommendations to the Energy Commission for inclusion in the *2005 Energy Report*. The Advisory Committee established subcommittees for each sector. This body of work has been transmitted to the Secretary of the California Environmental Protection Agency for use by the Climate Action Team. The following summarizes the recommendations from the respective subcommittees.

Electricity Generation

The majority of the subcommittee concluded that:

- All California utilities, independent power producers, other load serving entities, and regulators need to take the financial risks of greenhouse gas regulation explicitly into account in long-term resource planning and procurement decisions.
- Each IOU, municipal utility, and load-serving entity should develop an action plan to meet the Governor's greenhouse gas reduction goals, implementation of which should be monitored by the Energy Commission and the California Environmental Protection Agency.
- California should pursue development of a program to determine and track greenhouse gas emissions throughout the Western Electricity Coordinating Council region, in cooperation with the Western Governors' Association and the Western Renewable Energy Generation Information System.
- Reductions under a mandatory greenhouse gas reduction program, should one be implemented, could be achieved faster, better, and cheaper through a well-designed, multi-sector cap and trade program, and electricity generated from in-state and out-of-state sources should be treated in a non-discriminatory fashion.
- California should seek credit for early actions in reducing greenhouse gas emissions in any future federal statutory or regulatory system and should take a leadership role in researching and developing low-carbon-emitting technologies.

A minority of the subcommittee took issue with several of the above positions and concluded that:

- Actions to address climate change will be most effective if implemented at the national and international level. Any mandatory state program should be done in concert with states in the Western Electricity Coordinating Council. Unilateral programs implemented by California will shift greenhouse gas emissions to generators in other states with which California is electrically linked, thus eliminating any overall reduction, and will result in higher prices and reduced reliability to California customers.

234. Preliminary projections for 2010 and 2020 are based on estimates by Gerry Bemis and Jennifer Allen published in *Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2002 Update*, CEC-600-2005-025, June 2005. The 2020 estimates were increased by Center for Clean Air Policy staff to reflect potential growth in other sectors beyond increases in gasoline, jet fuel, diesel, and natural gas demand. These projections should be considered placeholders until final state estimates are developed.

- The relative "carbon-efficiency" of California's electricity system compared to neighboring western states has been achieved by substantial investment by IOUs in energy efficiency and renewable energy. All load serving entities should be required to meet the same Renewable Portfolio Standard goal.
- Early dramatic reductions in greenhouse gas emissions will be expensive and unnecessary if the state transitions to a low- or zero-carbon energy system over a longer timeframe.
- Since California will continue to rely on coal for some portion of its electricity, the state should take a leadership role in developing technologies that capture and store CO_2.

Industry, Agriculture, and Forestry

A consensus of the subcommittee concluded that:

- All sectors take advantage of opportunities to reduce energy consumption through utility-sponsored programs, energy audits and cost-effective technologies such as benchmarking tools in the cement industry and occupancy sensors in commercial buildings larger than 100,000 square feet.
- New technologies are not being adopted because of bureaucratic barriers. For example, adoption of the ASTM C 150-04 standard for Portland cement and use of a carbon stock protocol for forestry, as well as small-scale biomass generators, could reduce greenhouse gas emissions.
- Performance-based incentives should be implemented for the adoption of new technologies that are not yet cost effective. Examples include concrete houses, curve sawing, and the use of net metering for methane digesters.
- A cap and trade program should be regional or national in design. A cap and trade program at the state level or focused on a single sector has inherent limitations.
- Include the crediting of forest-based greenhouse gas reductions in any multi-sector greenhouse gas cap and trade system that is established.
- Establish targets to protect and increase the state's overall forest carbon stocks and implement voluntary land-owner incentives to achieve such targets.
- Any conversion of forest land to non-forest use should require a California Environmental Quality Act-level analysis.
- The state should implement a public education campaign regarding the role of forests in climate change.
- The state should provide research funding to study the impacts of climate change on its forests, CO_2 emissions caused by forest land conversion, and climate mitigation opportunities.

Transportation Sector

A consensus of the subcommittee concluded that:

- Emission performance standards and fuel or carbon performance standards are the most direct approach to reducing greenhouse gas emissions from motor vehicles.
- Market-based incentives should complement standards to increase low- and no-emission strategies for the transportation sector.
- A coordinated approach to achieve climate change benefits is recommended, which is consistent with other state policy objectives, such as petroleum reduction, fuel diversity, air pollution reduction, and resource conservation.
- State policies should empower consumer choices of low- or no-emission fuels, vehicles, and transportation options.
- New opportunities for reducing greenhouse gas emissions exist in public fleets, freight, and air travel as well as for reducing vehicle miles traveled through smart growth and sustainable development approaches.
- The state should empower local governments to support low greenhouse gas strategies through partnership opportunities and by addressing environmental justice concerns.[235]

235. Transportation Subcommittee statement, Climate Change Advisory Committee to the Energy Commission, August 16, 2005.

Cross-Cutting Issues

A consensus of the subcommittee supports:

- A well designed, fair, and equitable cap and trade program if the state has accepted a mandatory greenhouse gas reduction requirement; the cap and trade program represents the best alternative to achieve cost-effective greenhouse gas reductions; and no other option will achieve more cost-effective and certain greenhouse gas reductions.
- California's efforts to independently pursue greenhouse gas reductions even while acknowledging that this approach is less than optimal. A broader regional, national, or international program would reduce "leakage" and expand the available set of cost-effective greenhouse gas control measures.
- A cap and trade program that can be readily adopted by neighboring states would enable linking with other trading programs in the U.S. and abroad, is multi-sector, and would potentially serve as a model for the development of a national policy.

Value of Greenhouse Gas Emissions Inventory and Registry

The Energy Commission conducts a variety of activities in the greenhouse gas emissions policy area. Two of these activities have a degree of similarity that some may see as a duplication of effort, but they actually complement one another. The greenhouse gas emissions inventory activity is important for identifying overall trends in emissions, while the registry activity is important for identifying emissions emanating from specific sources or companies and providing well-defined documentation of these emissions.

Greenhouse Gas Emissions Inventory

Greenhouse gas emissions inventories are used to determine overall greenhouse gas emissions associated with particular fuel use or economic sector activity. The data are translated into overall emissions using typical emissions factors that are generally accepted for the particular fuel or activity. Greenhouse gas emissions inventories are used to look at overall trends and are often used for setting overall policy goals. Their strength lies in the fact that there is a systematic, comprehensive process in place to collect usage data and to aggregate it to protect its confidentiality. In addition, greenhouse gas emissions inventories are relatively complete data sets and can be used to identify data gaps to direct data collection efforts for specific facilities or entities.

The weakness of the greenhouse gas emissions inventory lies in its aggregation. It is not possible to associate all emissions from a particular facility or company because the data are typically aggregated by fuel type or process. For example, a facility that uses several fuels would have a portion of its emissions summed under one fuel and the remainder under each of the other fuel uses. It would not be possible to obtain an assessment of total emissions from that facility.

California Climate Action Registry

A major benefit of a registry, such as the California Climate Action Registry, is that it provides a forum to develop a uniform and comprehensive database or inventory for a facility or company. The database would be able to include all process emissions and fuel uses at the facility or company. To evaluate reductions made at a specific facility or within a specific company, an emissions database or inventory needs to be comprehensive for the particular company or facility. In addition, a registry provides facilities and companies with a reliable source to obtain credit for their emissions reductions, since registry members must thoroughly document their emissions, including both direct and indirect emissions. The direct emissions can be aggregated on either a company or facility basis to protect proprietary information. Registry participants must allow an auditor to review their method of calculating their emissions. Once done, this registry-level inventory becomes the basis for obtaining credit for emissions reductions, including monetary valuation of emissions reductions.

Advancing the Science of Climate Change Assessment

State agencies historically have not considered the impacts of climate change in their strategic planning. In the energy sector, the trade-offs and value of building and appliance efficiency standards are not fully captured in analysis before the Energy Commission because their benefits to reduce greenhouse gas emissions are not taken into account. For example, options to reduce or eliminate hydrofluorocarbon emissions from air conditioning and refrigeration systems are not considered when establishing appliance standards.

Some state agencies are addressing these concerns in their long-term planning documents. This approach increases the need for coordination among agencies, common planning assumptions, and the integration of adaptation strategies across natural resources, a need that will only grow over time as more agencies anticipate climate change effects. Uncoordinated state planning efforts using disparate climate scenarios may result in the selection of contradictory policy options. Examples of this need for coordination include:

- The increased reliance on renewable energy as a greenhouse gas reduction strategy such as biomass-to-energy demands joint research with Department of Forestry to develop analytical tools to balance forest health with the removal of "fuel" for electricity generation. Although there are clear benefits to this removal, the methods and amounts must be consistent with the protection of sensitive species and habitat.
- The potential for impacts to the snow pack has serious implications for the availability of hydroelectricity. Thus, the Department of Water Resources is critical to the development of regional climate models designed to allow strategic planning for water availability and related planning for electricity supply.

The California Climate Change Center sponsored by the Energy Commission is developing probabilistic climate projections for California at an adequate level of geographical and temporal resolution for planning purposes. The Energy Commission, through the Climate Change Center, should continue to develop data and methodologies for assessing the regional implications of climate change to inform planning activities in the state. The resulting climate scenarios should be made widely available for the aforementioned strategic planning for all state agencies.

Recommendations

The Energy Commission should:

- Continue to provide technical and analytical support to the Governor's Climate Action Team.
- Consider the advisory recommendations of the Climate Change Advisory Committee in evaluating state-level strategies.
- Improve the "top-down" statewide inventory on greenhouse gas emissions and support steps to evaluate the need for a mandatory reporting system.
- Support efforts by the California Climate Action Registry to collect data on facility-level and entity-wide greenhouse gas emissions.
- Support efforts by the CPUC to fully internalize the benefits of reducing carbon generation through a carbon adder and greenhouse gas standard in utility resource procurement.

Chapter Ten:

California-Mexico Border Region Energy Issues

The California-Baja California Norte border region extends about 60 miles (100 kilometers) north and south of the California-Mexico border and links the two countries in a complex network of trade, cultural, social, and institutional relationships. The region includes the San Diego and Imperial counties of California and the Mexican cities of Tecate, Tijuana, Mexicali, Rosarito, and Ensenada.

The border region's population and businesses are growing rapidly. This growth is driving energy demand, which is in turn driving the need for new power plants, transmission lines, and natural gas facilities. Generation from new natural gas-fired power plants in the region will predominantly meet this growing demand for electricity, though attention is increasingly focused on developing renewable energy resources. At least one liquefied natural gas (LNG) facility is also being built in Baja California Norte to meet energy demand both locally and in California.

The border region is becoming an energy corridor as both sides of the border develop facilities to meet local needs and export energy across state and international borders. The energy relationship between California and Baja California Norte is expected to become even more interdependent in the future as new generation, transmission lines, LNG facilities, and natural gas pipelines are built to meet the region's increasing energy needs.

The growing demand for energy in the border region is adding to already significant air pollution problems. Yet fundamental differences persist in regulatory approaches on both sides of the border. A binational policy is urgently needed to coordinate energy and environmental issues in the border region. State and regional organizations including the Border Governors' Energy Worktable, Border Energy Issues Group, San Diego Association of Governments, and San Diego Regional Energy Office are working together to address many energy and environmental issues and improve both the economic vitality and quality of life in the border region.

Border Region Growth

The current population of the border region is close to 5 million and expected to grow to more than 7.5 million over the next 25 years. The greatest population densities are in San Diego, Tijuana, and Imperial Valley-Mexicali.

The driving economic force in the region continues to be the companies on the Mexican side of the border that manufacture or assemble a variety of products and equipment, known as the maquiladora industry. The North American Free Trade Agreement (NAFTA), passed in 1993, accelerated the growth of the maquiladora industry when U.S. companies subsequently located manufacturing plants in northern Mexico to reduce production costs and finish products for export either back to the U.S. or to other countries. NAFTA and other trade relationships with Mexico and Canada were also instrumental in San Diego's economic recovery from the recession of the first half of the 1990s. Over 700 maquiladora plants are now located in Baja California Norte.

Border Region Energy Demand

Electricity

Peak electricity demand in San Diego Gas and Electric's (SDG&E) service territory reached a record 4,065 MW in summer 2004. The Energy Commission estimates average annual growth rates of 2.1 percent for system peak load and 1.7 percent for electricity demand in SDG&E's service territory for 2004-2009. For the Imperial Irrigation District (IID), peak electricity demand is expected to increase from 840 MW in 2004 to about 1,000 MW by 2016.

The growth in electricity demand in Baja California Norte is expected to be the highest of any state in Mexico over the next 10 years. To meet this demand, Baja California Norte will need to almost double its electricity capacity.[236,237] In its official 2004-2013 electricity demand forecast, Mexico's Comisión Federal de Electricidad anticipates energy sales in Baja California Norte to increase an average of 7 percent and peak demand to continue to grow by 6.3 percent per year.

Natural Gas

Natural gas demand in SDG&E's service territory is forecast to grow 2.5 percent annually.[238] The primary driver for this gas demand in the near term is the natural gas needed to fuel new power plants. Demand for natural gas in Baja California Norte is driven mainly by power generation, a handful of industrial customers, and one local distribution company in Mexicali that serves about 25,000 customers.

Border Region Interdependencies

California and Baja California Norte share considerable natural gas and electricity infrastructure within the border region. Baja California Norte is geographically isolated from mainland Mexico, with no connections to Mexico's natural gas pipeline system and only limited connections to Mexico's national power grid.

Electricity

SDG&E consumes 3.5 times more power than Baja California Norte, cannot meet its customer demand solely with local generating capacity, and must import about 60 percent of its electricity from outside the region.[239] SDG&E's generating capacity is about 2,570 MW. Two new power plants are under construction in San Diego County, however, which will add more than 1,000 MW of capacity to SDG&E's system.

Electricity is imported through the Miguel Substation from the east and south and the San Onofre switchyard to the north. SDG&E can import electricity from out-of-state through the 500-kilovolt (kV) Southwest Power Link Transmission Line and from Mexico through two 230-kV transmission lines (Path 45).[240] The CPUC approved the Miguel-Mission No. 2 230-kV Transmission Line in 2004, which is expected to be operational by June 2006. This project will increase the system's ability to transfer electricity from the two power plants in Mexicali, Mexico, and from new generation in Arizona that is scheduled into the CA ISO control area at Palo Verde.[241]

Conversely, IID has historically been a net exporter of electricity. IID provides 468 MW of capacity within the border region and connects its transmission

236. *Energy Supply and Demand Assessment for the (California-Mexico) Border*, staff report, prepared in support of the *2005 Energy Report* proceeding, July 2005, CEC-600-2005-023.

237. *Energy Efficiency in the Border Region: A Market Approach*, The Western Governors' Association, Denver, CO, April 2004, pp. 6-10.

238. California Energy Commission, *Revised Reference Case in Support of the 2005 Natural Gas Market Asssessment*, September 2005, CEC-600-2005-026-REV.

239. *Energy Efficiency in the Border Region: A Market Approach*, The Western Governor's Association, Denver, CO, April 2004, p.6

240. San Diego Gas and Electric Company, July 9, 2004, *Long-Term Resource Plan of San Diego Gas and Electric Company (U 902 E)*, direct testimony of Linda P. Brown, California Public Utilities Commission, pp. 2-3.

241. CPUC, D. 04-07-026, *Application of San Diego Gas and Electric Company (U902 E) for a Certificate of Public Convenience and Necessity for the Miguel-Mission 230kV No. 2 Project, application.*

system with Southern California Edison (SCE) through the Valley and Devers substations, with SDG&E through the Miguel and Imperial Valley substations, and with the Palo Verde hub in Arizona. It also interconnects with Mexico through the Miguel Substation.

The Baja California Norte power system has 3,862 MW of generation capacity, with 2,652 MW dedicated to satisfy the Comisión Federal de Electricidad's public service load and 1,210 MW for export to California. Baja California Norte also satisfies a significant portion of its energy needs with 720 MW of renewable geothermal energy with the balance of its generation coming from natural gas-fired combined-cycle units (985 MW), oil-fired steam-cycle plants (620 MW), and oil-fired gas turbines (326.9 MW). The Comisión Federal de Electricidad plans to build an additional 1,282 MW of generating capacity in Baja California Norte between 2008 and 2013. Most of this planned generation is expected to be natural gas-fired.

Path 45 is the backbone of the transmission system in Baja California Norte, connecting it with San Diego and the Imperial Valley and allowing power transfers between northern Mexico and Southern California. One transmission line runs between SDG&E's Miguel Substation and the Comisión Federal de Electricidad's Tijuana Substation, and the other between SDG&E's Imperial Valley Substation and the Comisión Federal de Electricidad's La Rosita Substation. Additional study is needed to determine the upgrade potential of the east-west transmission line in Baja California between the Path 45 cross-border paths.

Natural Gas

Several high-capacity natural gas pipelines crisscross the border region. The Baja Norte Pipeline, completed in 2002, runs from Ehrenberg, Arizona, through Mexicali and interconnects with the Transportación de Gas Natural pipeline in Tijuana. Pacific Gas and Electric (PG&E) owns the U.S. segment (North Baja Pipeline), and Sempra Energy controls the segment in Mexico (Gasoducto Bajanorte). The Gasoducto Bajanorte segment serves the La Rosita and Termoeléctrica de Mexicali power plants in Mexicali and industrial customers in northern Baja California Norte and Southern California.

Sempra's pipeline runs from Otay Mesa near Tijuana to Playas de Rosarito, where it supplies natural gas to the Presidente Juarez Power Plant. Sempra also supplies natural gas through a separate pipeline to the local distribution company in Mexicali.

Baja California Norte must import its gas from the U.S. through the Transportación de Gas Natural and Baja Norte pipelines since the region has no local sources of natural gas. The development of one or more proposed liquefied natural gas (LNG) gasification and storage facilities will increase natural gas supply sources for the region and make Baja California Norte a net exporter of gas to the United States. Sempra's Energia Costa Azul Project is under construction and Chevron's Terminal GNL Mar has received initial permits. The Energia Costa Azul Project is expected to operate in 2007 and provide an average capacity of 1,000 million cubic feet per day (MMcfd) of natural gas. Chevron's plant will produce 700 MMcfd and is scheduled to go on line in 2007.

Sempra is planning to expand its Baja Norte and Transportación de Gas Natural pipelines to transport natural gas from the Energía Costa Azul LNG terminal. It is unclear, however, how SDG&E and Southern California Gas (SoCalGas) will plan and pay for future pipeline upgrades and coordinate cross-border delivery of gas into California. Other uncertainties include the amount and specific use (for example, power plants, commercial, residential) of the LNG supply dedicated for California, other parts of the U.S., and Baja California Norte.

In San Diego and Imperial counties, SDG&E distributes natural gas from SoCalGas and moves it south to load centers. The total capacity of the SDG&E natural gas transmission system is 620

MMcfd in winter and 600 MMcfd in summer.[242] Accepting LNG supplies from Mexico at Otay Mesa will require infrastructure improvements allowing the reversal of the flow of the gas in the SDG&E system. Other improvements may also be necessary to the SDG&E system, depending upon the amount of LNG delivered to Otay Mesa.[243]

Border Region Renewable Resources

SDG&E is required by state law to have a 20 percent renewable portfolio mix by 2017. The utility has committed to achieving this goal sooner, by 2010. A recent study identified significant solar energy, biomass, geothermal, and wind power opportunities in the California-Mexico border region.[244] This study is an important first step, though more detailed assessments are needed to ultimately stimulate additional renewable resource development in this area.

Obtaining renewable energy from Baja California Norte is more problematic because it would require costly upgrades to the existing transmission system to bring power across the border from the Cerro Prieto geothermal field and potential wind resources in La Rumorosa.

Facilities in Imperial County currently produce 635 MW of renewable energy, with an additional 270 MW of geothermal and 80 MW of biomass proposed for development. As a publicly owned utility, IID is not required to meet the specific targets and timelines of the state's Renewable Portfolio Standard (RPS). IID has, however, voluntarily adopted its own RPS. To reach its renewable goals, IID is negotiating to purchase approximately 200 MW of energy from Cal Energy's Salton Sea Unit 6, now under construction.[245]

Baja California Norte meets a large portion of its energy needs with renewable energy. The Cerro Prieto geothermal field provides 720 MW of geothermal generating capacity, and studies show additional potential both there and elsewhere in the region. The area also has promising potential for wind development, although further studies are needed to fully understand this resource potential. Mexico has set the national goal of bringing an additional 1,000 MW of renewable energy on line by 2006.

Transportation

The 150-mile border between California and Mexico contains six points of entry: San Ysidro, Otay Mesa and Tecate in San Diego County, and Calexico, Calexico East, and Andrade in Imperial County. In 2003 alone, 47 million people crossed the border northbound through San Ysidro, which is the busiest land crossing in the world.[246]

As noted earlier, cross-border trade between California and Mexico has increased substantially since the passage of NAFTA. In 2003, total trade activity totaled nearly $30 billion, with approximately

242. CPUC, November 2001, *California Natural Gas Infrastructure Outlook, 2002-2006*.

243. San Diego Gas and Electric Co., November 2003, *Responses to CPUC Data Requests, OIR to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California*, R.04-01-025.

244. *Potential for Renewable Energy in the San Diego Region*, San Diego Regional Renewable Energy Group, August 2005.

245. Imperial Irrigation District, press release: "IID Energy Honored for Geothermal Excellence", September 9, 2001. Found at: [www.iid.com/pressbox/press.read.php3?which=454].

246. California Department of Transportation, California/Mexico Border Briefing, p.ii [http://www.dot.ca.gov/dist/departments/planning/05_BorderBook.pdf].

98 percent of this trade transported by truck through Otay Mesa, Tecate, and Calexico East.[247] There were 2 million truck crossings at the border in 2003; this number is expected to increase to 5.6 million by 2030. Most of this truck transport across the California-Mexico border at the three main entry points originates at or is destined for locations outside San Diego and Imperial counties, including the ports of Long Beach and Los Angeles and the Los Angeles and Ontario airports.[248]

Idling cargo trucks emit harmful pollutants that affect air quality on both sides of the border. These trucks usually refuel in Mexico with fuel that can contain many times more sulfur than fuel sold in California.[249] Shifting some of this cargo and freight to railroads and switching to cleaner-burning diesel and non-petroleum fuels could reduce both congestion and diesel use, ultimately improving air quality. The establishment of clean cities programs in the San Diego-Tijuana and Calexico-Mexicali areas and the imposition of per-truck border crossing fees could raise funding for cross-border transportation projects.

Air Quality and Cross-Border Emissions Trading

The transportation sector is the major source of emissions in the border region. Because the region is subdivided into two binational air sheds that span the international border, neither government alone is able to address regional air pollution. Air pollution in the border region violates most ambient air quality standards in both the U.S. and Mexico for ozone and particulate matter. Carbon monoxide levels on the Mexican side of the border also exceed established standards. Increasing population in the border region and the associated increase in the number of automobiles and cargo trucks will only exacerbate this problem over time.

Cross-border emission trading has been effective in reducing air pollution in other parts of the world and could potentially reduce emissions in the border region. This concept faces challenges, however, including the legality of establishing international air basins, the enforceability of international credits, the lack of an existing emission credit program in Mexico, and the inconsistency of air quality monitoring data on both sides of the border. Emission trading could well require additional air quality monitoring programs. More investigation of this issue is clearly needed, though available information indicates the strong potential for environmental and economic benefits for both countries.

Border Region Efficiency

There is significant potential for reducing the rate of growth in electricity demand on both sides of the border through demand reduction and combined heat and power projects. A study conducted by the Western Governors' Association estimated that the potential energy efficiency savings for manufacturing facilities in Baja California Norte would be the highest in the region.[250] Average energy savings were estimated at 26 percent, and projected payback periods ranged from 1.3 to 6.0 years. The study also estimated that energy efficiency projects could reduce energy demand by as much as 10 percent in Baja California Norte.

While there is already awareness and active interest in both energy efficiency and load management in Baja California Norte, state and local energy

247. Ibid, p. V-3.

248. Ibid, p. 2-3.

249. Kazimi, C., Cuamea, F., Alvarez, J., Sweedler, A., and Fertig, M., *Emissions from Heavy-Duty Trucks at the San Diego-Tijuana Border Crossing*, San Diego State University and Universidad Autonoma de Baja California. San Diego, California and Tijuana, Baja California. San Diego State University Press. February 1997.

250. *Energy Efficiency in the Border Region: A Market Approach*, The Western Governors' Association, April 2004.

efficiency assistance programs lack the technical and financial resources to have a significant overall impact on the supply-demand balance in the region.

Recommendations

The state should establish a cross-border, binational policy to:

- Ensure that the planning, permitting, construction, and operation of electricity and natural gas infrastructure in the border region are coordinated and comply with the highest levels of environmental standards.
- Implement a common methodology to accurately forecast energy demand in the border region.
- Implement a loading order to encourage the development of the most efficient, clean, and cost-effective energy options.
- Develop programs to reduce demand and develop indigenous renewable resources.
- Develop and implement a cross-border emissions credit trading and offset program.
- Create opportunities to both improve the overall efficiency of transportation systems and expand the use of non-petroleum fuels.

Appendix A:
Aging Power Plant Study Group

California must also address its long term electricity needs by bringing new generation on line. The lack of available long-term power contracts has stalled the construction of more than 7,000 MW of plants already permitted and sharply curtailed the amount of capacity seeking new permits. If unforeseen events cause electricity demand to rise sharply in the next few years, utilities may find themselves forced once again to enter into high-priced contracts that result in higher electricity prices for consumers. The utilities need to invest now for the long term to continue to avoid the mistakes made during the 2000-2001 energy crisis that Californians are still paying for today.

As part of the *2004 Energy Report Update*, the Energy Commission identified a group of older power plants for use in studying the current and anticipated role of aging plants in the state's electricity system and their impacts on the state's resources,[251] using criteria based on a combination of several attributes including age, size, capacity factor, efficiency, and environmental considerations, to produce the following list of plants as a preliminary study group for the aging power plant study. This group of 66 aging gas-fired power plants represents larger plants with relatively high heat rates (low efficiencies) and relatively high operation (capacity factors).[252] In this *2005 Energy Report*, the Energy Commission recommends that the state's utilities undertake long-term planning and procurement that will allow for the orderly retirement or repowering of the aging power plants in this study group by 2012.

The study group list presented in the following pages is taken directly from last year's draft staff white paper. No attempt has been made to update the information, which reflects the status of reliability must run (RMR) contracts as of August 2004.

251. *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirement*, California Energy Commission, draft staff white paper, August 13, 2004, CEC-100-04-005D.

252. The study group included only natural gas-fired power plants of 10 MW or greater that were built before 1980. Peaking plants were excluded, as were any plants known to be scheduled for retirement in the near term. Of the resulting 66 power plants, 16 are owned by municipal utilities.

	Unit Identification		ER 94 ESPAR[1]		2002 Operating Data		
	Plant	Unit	In-Service Year	Capacity (MW)	Output (MWh)	Fuel Use (MMBtu)	NOx Emitted (pounds)
1	Contra Costa	6	1964	340	876,534	8,635,012	395,697
2	Contra Costa	7	1964	340	1,148,685	11,231,342	103,704
3	Humboldt Bay	1	1956	52	194,615	2,427,851	868,937
4	Humboldt Bay	2	1958	53	190,383	2,496,030	872,666
5	Hunters Point	4	1958	163	514,614	5,320,219	198,976[c]
6	Morro Bay	1	1956	163	30,826	343,384	20,521
7	Morro Bay	2	1955	163	80,218	852,057	51,193
8	Morro Bay	3	1962	338	503,361	4,776,954	159,684
9	Morro Bay	4	1963	338	1,000,637	9,545,492	336,051
10	Moss Landing	6	1967	739	2,276,079	20,879,237	182,344
11	Moss Landing	7	1968	739	1,730,249	16,032,235	281,251
12	Pittsburg	5	1960	325	547,082	5,652,989	132,775
13	Pittsburg	6	1961	325	703,877	7,523,108	88,369
14	Pittsburg	7	1972	720	2,760,981	27,536,340	1,113,654
15	Potrero	3	1965	207	570,643	5,927,227	325,825
16	Encina	1	1954	107	152,068	1,671,418	34,264
17	Encina	2	1956	104	191,628	2,142,231	43,916
18	Encina	3	1958	110	195,769	2,143,917	43,950
19	Encina	4	1973	293	933,529	10,730,897	219,983
20	Encina	5	1978	315	1,051,716	10,982,456	225,140
21	South Bay	1	1960	147	459,135	4,654,531	60,028
22	South Bay	2	1962	150	466,098	4,400,057	52,738
23	South Bay	3	1964	171	319,847	3,312,646	42,271
24	South Bay	4	1971	222	84,940	1,023,633	42,206
25	Alamitos	1	1956	175	142,973	1,809,301	56,448
26	Alamitos	2	1957	175	167,808	2,164,441	52,874
27	Alamitos	3	1961	320	1,043,989	11,092,851	206,735
28	Alamitos	4	1962	320	710,764	7,777,048	122,890
29	Alamitos	5	1969	480	1,433,863	14,778,258	92,473
30	Alamitos	6	1966	480	619,790	6,626,709	104,371

			Other Information						
NOx Rate (lb/MMBtu)	Heat Rate (Btu/ kWh)	Capacity Factor	RMR[2]	CA ISO or MUNI[3]	Air Basin[4]	Once-Through Cooled[5]	Redevelopment Plan[6]	SCR[7]	County
0.0458	9,851	0.294			SF	YES	NO	NO[a]	Contra Costa
0.0092	9,778	0.386	RMR		SF	YES	NO	YES	Contra Costa
0.3579	12,475	0.427	RMR		NC	YES	NO	NO[b]	Humboldt
0.3496	13,111	0.410	RMR		NC	YES	NO	NO[b]	Humboldt
0.0374[c]	10,338	0.360	RMR		SF	YES	YES	NO[c]	San Francisco
0.0598	11,140	0.022			SCC	YES	NO	NO[d]	San Luis Obispo
0.0601	10,622	0.056			SCC	YES	NO	NO[d]	San Luis Obispo
0.0334	9,490	0.170		ISO	SCC	YES	NO	NO[d]	San Luis Obispo
0.0352	9,539	0.338		ISO	SCC	YES	NO	NO[d]	San Luis Obispo
0.0087	9,173	0.352		ISO	NCC	YES	NO	YES	Monterey
0.0175	9,266	0.267		ISO	NCC	YES	NO	YES	Monterey
0.0235	10,333	0.192	RMR		SF	YES	NO	YES	Contra Costa
0.0117	10,688	0.247	RMR		SF	YES	NO	YES	Contra Costa
0.0404	9,973	0.438	RMR		SF	YES	NO	NO[a]	Contra Costa
0.0550	10,387	0.315	RMR		SF	YES	NO	NO[a]	San Francisco
0.0205	10,991	0.162	RMR		SD	YES	NO	YES	San Diego
0.0205	11,179	0.210	RMR		SD	YES	NO	YES	San Diego
0.0205	10,951	0.203	RMR		SD	YES	NO	YES	San Diego
0.0205	11,495	0.364	RMR		SD	YES	NO	YES	San Diego
0.0205	10,442	0.381	RMR		SD	YES	NO	YES	San Diego
0.0129	10,138	0.357	RMR		SD	YES	YES	YES	San Diego
0.0120	9,440	0.355	RMR		SD	YES	YES	YES	San Diego
0.0128	10,357	0.214	RMR		SD	YES	YES	YES	San Diego
0.0412	12,051	0.044	RMR		SD	YES	YES	YES	San Diego
0.0312	12,655	0.093			SC	YES	NO	YES	Los Angeles
0.0244	12,898	0.109			SC	YES	NO	YES	Los Angeles
0.0186	10,625	0.372	RMR		SC	YES	NO	YES	Los Angeles
0.0158	10,942	0.254			SC	YES	NO	YES	Los Angeles
0.0063	10,307	0.341			SC	YES	NO	YES	Los Angeles
0.0158	10,692	0.147			SC	YES	NO	YES	Los Angeles

	Unit Identification		ER 94 ESPAR[1]		2002 Operating Data		
	Plant	Unit	In-Service Year	Capacity (MW)	Output (MWh)	Fuel Use (MMBtu)	NOx Emitted (pounds)
31	Coolwater	1	1961	65	86,692	920,494	45,130
32	Coolwater	2	1964	81	108,811	1,122,952	100,371
33	Coolwater	3	1978	241	924,133	8,879,376	934,507
34	Coolwater	4	1978	241	781,626	7,657,460	819,318
35	El Segundo	3	1964	335	1,061,387	10,399,010	58,862
36	El Segundo	4	1965	335	1,340,186	13,301,719	99,620
37	Etiwanda Generating Station	3	1963	320	543,179	5,969,559	69,468
38	Etiwanda Generating Station	4	1963	320	258,695	3,019,710	50,263
39	Huntington Beach	1	1958	215	647,852	7,405,994	81,300
40	Huntington Beach	2	1958	215	699,436	7,633,953	87,194
41	Long Beach	8	1976	303	81,883	939,891	94,578[f]
42	Long Beach	9	1977	227	31,254	362,036	36,421[f]
43	Mandalay	1	1959	215	499,331	4,710,452	23,304
44	Mandalay	2	1959	215	564,964	5,144,509	31,252
45	Ormond Beach	1	1971	750	1,189,349	12,028,916	93,498
46	Ormond Beach	2	1973	750	1,210,342	12,059,181	93,552
47	Redondo Beach	5	1954	175	83,476	1,127,491	79,601
48	Redondo Beach	6	1957	175	47,302	670,001	24,897
49	Redondo Beach	7	1967	480	965,701	9,843,859	130,365
50	Redondo Beach	8	1967	480	984,254	9,695,744	92,965
51	Grayson	3	1953	19	[h]	[h]	[h]
52	Grayson	4	1959	44	63,853	864,829	14,693
53	Grayson	5	1969	42	70,442	950,925	21,418
54	Grayson	8	1977	95	8,385	134,416	16,066[i]
55	El Centro	3	1952	44	47,419	585,886	96,064
56	El Centro	4	1968	74	162,881	2,013,284	439,453
57	Haynes	1	1962	222	464,105	4,731,220	57,391
58	Haynes	2	1963	222	592,599	6,061,029	69,419

			Other Information						
NOx Rate (lb/MMBtu)	Heat Rate (Btu/ kWh)	Capacity Factor	RMR[2]	CA ISO or MUNI[3]	Air Basin[4]	Once-Through Cooled[5]	Redevelopment Plan[6]	SCR[7]	County
0.0490	10,618	0.152		ISO	SDT	NO	NO	NO[e]	San Bernardino
0.0894	10,320	0.153		ISO	SDT	NO	NO	NO[e]	San Bernardino
0.1052	9,608	0.438			SDT	NO	NO	NO[e]	San Bernardino
0.1070	9,797	0.370			SDT	NO	NO	NO[e]	San Bernardino
0.0057	9,798	0.362			SC	YES	NO	YES	Los Angeles
0.0075	9,925	0.457			SC	YES	NO	YES	Los Angeles
0.0116	10,990	0.194			SC	NO	NO	YES	San Bernardino
0.0166	11,673	0.092			SC	NO	NO	YES	San Bernardino
0.0110	11,432	0.344	RMR		SC	YES	NO	YES	Orange
0.0114	10,914	0.371	RMR		SC	YES	NO	YES	Orange
0.1006[f]	11,478	0.031		ISO	SC	YES	NO	NO[f]	Los Angeles
0.1006[f]	11,584	0.016		ISO	SC	YES	NO	NO[f]	Los Angeles
0.0049	9,434	0.265			SCC	YES	NO	YES	Ventura
0.0061	9,106	0.300			SCC	YES	NO	YES	Ventura
0.0078	10,114	0.181		ISO	SCC	YES	NO	YES	Ventura
0.0078	9,963	0.184			SCC	YES	NO	YES	Ventura
0.0706	13,507	0.054		ISO	SC	YES	YES	YES	Los Angeles
0.0372	14,164	0.031		ISO	SC	YES	YES	YES	Los Angeles
0.0132	10,193	0.230		ISO	SC	YES	YES	YES	Los Angeles
0.0096	9,851	0.234		ISO	SC	YES	YES	YES	Los Angeles
[h]	[h]	[h]		MUNI	SC	NO	NO	NO[h]	Los Angeles
0.0170	13,544	0.166		MUNI	SC	NO	NO	NO[h]	Los Angeles
0.0225	13,499	0.191		MUNI	SC	NO	NO	NO[h]	Los Angeles
0.1195[l]	16,031	0.010		MUNI	SC	NO	NO	YES	Los Angeles
0.1640	12,355	0.124		MUNI	SDT	YES	NO	NO[g]	Imperial
0.2183	12,360	0.252		MUNI	SDT	YES	NO	YES	Imperial
0.0121	10,194	0.239		MUNI	SC	YES	NO	YES	Los Angeles
0.0115	10,228	0.305		MUNI	SC	YES	NO	YES	Los Angeles

	Unit Identification		ER 94 ESPAR[1]		2002 Operating Data		
	Plant	Unit	In-Service Year	Capacity (MW)	Output (MWh)	Fuel Use (MMBtu)	NOx Emitted (pounds)
59	Haynes	5	1967	341	482,782	4,643,557	48,018
60	Haynes	6	1967	341	581,001	5,727,857	36,530
61	Scattergood	1	1958	179	449,830	4,508,090	26,317
62	Scattergood	2	1959	179	523,083	5,234,260	24,232
63	Scattergood	3	1974	445	259,997	2,568,005	15,980
64	Broadway	B3	1965	66	70,886	849,285	19,605
65	Olive	1	1959	46	19,535	244,391	22,738
66	Olive	2	1964	55	48,249	580,744	45,567
TOTAL				**17,126**	**36,993,000**	**377,117,000**	**10,186,000**

Notes

1 *1994 Electricity Report, Electricity Supply Assumptions Report* (ESPAR), Part III, *The Availability, Price and Emissions of Power from the Southwest and Pacific Northwest*.

2 RMR - 2004 Reliability Must Run unit.

3 CA ISO List or MUNI - on the CA ISO list of units with reliability concerns or owned by a municipal utility.

4 Air Basin
NC = North Coast
NCC = North Central Coast
SC = South Coast
SCC = South Central Coast
SD = San Diego
SDT = Southwest Desert
SF = SF Bay Area

5 Plants that use once-through cooling (OTC) and may be potential sites for desalination facilities.

6 The facility has a city- or county-formulated site reuse plan (SRP) which indicates local priorities for future use of the site.

7 SCR installed as of 2004. Emission factors in columns to the left are for 2002 and may not represent emissions levels with the use of SCR.

a Bay Area APCD Rule 9-11 has a staggered implementation schedule. Mirant, the owner of the Potrero, Contra Costa, and Pittsburg boiler units, has opted to comply via a "system cap," where all their boilers are held to an instantaneous cap. Currently, some units are cleaner than others and can be used to "balance" out the units that have not yet installed SCR. The final cap, in force 1/1/05, limits the boiler units to a combined 0.018 lbs NOx/mm Btu.

			Other Information						
NOx Rate (lb/MMBtu)	Heat Rate (Btu/ kWh)	Capacity Factor	RMR[2]	CA ISO or MUNI[3]	Air Basin[4]	Once-Through Cooled[5]	Redevelopment Plan[6]	SCR[7]	County
0.0103	9,618	0.162		MUNI	SC	YES	NO	YES	Los Angeles
0.0064	9,859	0.194		MUNI	SC	YES	NO	YES	Los Angeles
0.0058	10,022	0.287		MUNI	SC	YES	NO	YES	Los Angeles
0.0046	10,007	0.334		MUNI	SC	YES	NO	YES	Los Angeles
0.0062	9,877	0.067		MUNI	SC	YES	NO	YES	Los Angeles
0.0231	11,981	0.123		MUNI	SC	NO	NO	YES	Los Angeles
0.0930	12,511	0.048		MUNI	SC	NO	NO	YES	Los Angeles
0.0785	12,037	0.100		MUNI	SC	NO	NO	YES	Los Angeles

b SCR installation is not required by an air district BARCT rule or SIP.

c Bay Area APCD Rule 9-11 has a staggered implementation schedule. Pacific Gas and Electric Company, the owner of the Hunters Point boiler, opted to comply via a "system cap," where all the boiler units are held to an instantaneous cap. Currently, the only operating boiler unit at Hunters Points is Unit 4. The final cap, in force 1/1/05, limits the unit to 0.018 lbs NOx/mm Btu. Pacific Gas and Electric Company has purchased and surrendered to the district Interchangeable Emission Reduction Credits (IERCs) to comply with the system cap. The NOx emission factor shown is for 2000. The NOx emissions are calculated using the 2000 emission factor and 2002 fuel use.

d San Luis Obispo County APCD Rule 429 limits NOx emissions from all four boiler units to 2.5 tons per day, resulting in an effective emission factor of 0.0209 lbs/mmBtu. Emission controls (e.g., SCR) or operations limits or some combination of the two could be used to comply with the daily mass cap.

e Mojave Desert AQMD Rule 1158 requires that, after December 31, 2002, NOx emissions from all units at the Coolwater facility (boilers and CTCC) be capped at 1,319 tons per year. SCR is not currently required to comply.

f South Coast BARCT Rule 2009 only requires steam injection on the seven combustion turbines at the Long Beach combined-cycle facility. The 2002 NOx emissions are calculated using the 2002 fuel use and the average 2003 emissions factor.

g NOx emissions limited by Imperial District prohibitory Rule 400.

h Units 3, 4, and 5 burn landfill gas, which is incompatible with SCR. No data was available for Unit 3, but the Grayson facility is subject to District Rule 1135 and is limited to a system cap of 0.2 lbs NOx/MWHR or 390 lbs NOx/day.

i No NOx emission data available. NOx emissions calculated with 2002 fuel use and permit limit of 30 ppm.

Appendix B:
List of Participants in the *2005 Energy Report* Process

Government Entities

AC Transit
- Jamie Levin

Anaheim Public Utilities Department

Arvin-Edison Water Storage District
- Steven H. Lewis

Baja, California, Mexico State Government

Bay Area Air Quality Management District
- Steve Hill

Bonneville Power Administration
- Elliot Mainzer
- Steve Oliver

British Embassy, Washington, D.C.
- James Reilly

Bureau of Reclamation, United States Department of Interior

California Air Resources Board
- Analisa Bevan
- D. S. Garewal
- Robert Okammoto
- Gabriel M. Ruiz
- Mike Scheible
- Dean Simeroth
- Stella Ling-Taylor
- Michael Tollstrup
- Erik White
- Gary Yee

California Bay-Delta Authority

California Chamber of Commerce
- Bruce Magnani

California Coastal Commission
- Sarah Christe
- Peter Douglas
- Tom Luster

California Department of Fish and Game
- Banky E. Curtis
- Scott A. Flint
- Robert W. Floerke
- Sandra Morey
- Tim Stevens

California Department of Forestry
- Brian Barrera
- Doug Wickersen

California Department of Food and Agriculture
- Steve Shaffer

California Department of Justice
- Brian Hembacher

California Department of Water Resources
- Holly B. Cronin
- Bill Forsythe
- Charles Kearney
- Paul Massera

California Environmental Protection Agency
- Shannon F. Baxter
- Alan Lloyd
- Kevin Peetac
- Jeff Wong

California Government Affairs Navy Region Northwest
- Randal A. Friedman

California Hydropower Reform Coalition
- Laura W. Lorlander

California Institute for Energy and Environment
- Ed Vine

California Independent System Operator
- Gary DeShazo
- Jim Detmers
- Steve Greenleaf
- Dave Hawkins
- Mary McDonald
- Yuri Makarov
- Jeff Miller
- Lawrence Tobias

California Polytechnic State University, Irrigation Training and Research Center
- Dan Howes

California Public Utilities Commission
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- Michael Alcantar
- Billie Blanchard
- Theresa Cho
- Paul Clanon
- Maryam Ebke
- Tom Flynn
- Massis Galestan
- James Hendry

- Sepideh Khosrowjah
- Steve Larson
- Richard A. Myers
- Noel Obiora
- Wendy Maria Phelps
- Brian Schumacher
- Merideth Sterkel
- Stephen St. Marie

California Public Utilities Commission, Office of Ratepayer Advocates

- Scott Cauchois
- Robert Kinosian
- Mark R. Loy
- Don Schultz
- Don Smith

California Refuse Removal Council

- John McNamara
- Sean Robledo Edgar

California Regional Water Quality Control Board

- Arthur L. Coe

California State Assembly

- The Honorable Sam Blakeslee, 33rd Assembly District
- Mark Smith, Assemblymember Blakeslee's Legislative Aide

California State Automobile Association

- Lewison Lee Lem

California State Fire Marshal's Office

- Nancy Wolfe

California State Parks

- Richard Rayburn

California State University Fresno, Center for Irrigation Technology

- Peter Canessa
- James R. Tischer

California Water Resources Control Board

- Dominic Gregorio

Central Coast Regional Water Quality Control Board

- Michael Thomas

City of Berkeley

- Yolanda Wong

City of Del Mar

- Henry Abarbaneo

City of Imperial Beach

City of Redding Municipal Utility

- Russ Bennett
- Lowell Watros

City and County of San Francisco

- Jared Blumenfeld

City of San Diego

- Michael J. Aguirre
- Tom Blair
- Frederick M. Ortlieb

City of Santa Clara

- Mike Pretto

Comision Federal de Electricidad (CFE)

- Abelardo Borquez

County of Alameda

- Darryl Gray

County of Imperial

- Joe Maruca

Department of Transportation

- Bill Figge

East Bay Municipal Utility District

Energy Information Administration

- Robert Schnapp

Flex Your Power

- Wally McGuire

Governor Kenny Guinn, State of Nevada

Governor Jon Huntsman, Jr., State of Utah

Governor Dirk Kempthorne, State of Idaho

Harvard University

- William Rosenberg

Hopi Tribe of Arizona

- James Ham (Arnold & Porter, LLP)

Imperial County Air Pollution Control District

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- Stephen L. Birdsall
- Wally Leimgruber
- Brad Poiriez

Imperial Irrigation District
- Frank Barbera
- Orlando B. Foote (Horton, Knox, Carter & Foote)
- Juan Carlos Sandoval

Inland Empire Utilities Agency

Lawrence Berkeley National Laboratory
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- Larry Myer
- Lynn Price
- Alan Sanstad
- Ed Vine

Lawrence Livermore National Laboratory
- Robin Newmark

League of California Cities
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Legislative Analyst's Office
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Los Alamos National Lab

Los Angeles Department of Water and Power
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- Michael Cockagne
- Randy Howard

Maine Public Utilities Commission
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Metropolitan Water District of Southern California
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Mexico State Government – Baja, California
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Mid-Pacific Region, United States Bureau of Reclamation

Modesto Water District
- Rita Garcia
- Mike Kreamer
- Andy Sienkiewich

National Marine Fisheries Service
- Joe Dillon

National Renewable Energy Laboratory

Nevada State Agency for Nuclear Projects
- Fred Dilger

New York Public Service Commission
- Peter Bradford

Northern California Power Agency
- Kenneth C. Goeke

Nuclear Regulatory Commission
- Peter Bradford (Former Commissioner)
- Victor Gilinsky (Former Commissioner)
- William B. Jones

Oak Ridge National Laboratory
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Office of Emergency Services
- Bill Potter

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Redding Electric Utility
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Rice University
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Sacramento Area Council of Governments
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Sacramento Municipal Utility District
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- Steve Cohn
- David Hanson
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- Cliff Murley
- Todd Peterson
- Steve Redeke
- Ron Scott
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San Diego Air Pollution Control District
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San Diego Area Clean Cities Coordinator
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San Diego Association of Governments
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- Susan Freedman
- Edward Schafer
- Hector J. Vanegas

San Diego County Water Authority

San Diego Miramar College
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San Diego State University
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- Alan Sweedler
- Rich Van Schoik - SCERP

San Francisco Bay Conservation and Development Commission
- Leslie D. Lacko

Santa Clara Valley Water District
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Semitropic Water Storage District

South Coast Air Quality Management District
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- Dean Saito
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- Barry R. Wallerstein
- Denise R. Whitcher
- Paul Wuebben

South Western School District
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Stanford University
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State of Nevada
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- Bob Loux
- Joe Strolin

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University of California Energy Institute
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University of California Merced

University of California Santa Barbara
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University of Southern California
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United States Bureau of Land Management
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- Congresswoman Lois Capps, 23rd Congressional District

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Western Governors Association
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American Petroleum Institute
- Russell Jones

American Rivers
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American Wind Energy Association
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Americans for Solar Power
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Arizona Public Interest Research Group
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Association of California Water Agencies
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Audubon California
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Baker & O'Brien, Inc.
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Baker & McKenzie
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Biosphere Environmental Energy
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BKI
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Bluewater Network
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- Norman Johnson
- Warren Suter

Bradford Brook Associates
- Peter Bradford

Braun & Blaising, P.C.
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BRI Energy
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British Petroleum
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Brown Vence & Associates
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Caithness Energy, LLC
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California Climate Action Registry

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California Earth Corps
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California Natural Gas Vehicle Coalition
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California Onsite Generation
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California Portland Cement Company
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- Steve Coppinger

California Refuse Removal Council
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California State Association of Counties
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Calpine Corporation
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- Alz Amirli
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- Andrew Whittome

Cal Reports
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CALSTART
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Caltrans
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- Bill Figge
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Canadian Association of Farm Advisors
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Capitol Weekly
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Capstone Turbine Corporation
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Carnegie Mellon
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Carrington & Company
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Carrizo Gorge Railway
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- Rich Ferguson
- Sarah Myers
- Dave Olsen
- John Shears
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- Paul M. Seabey

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- J. Steve Welstand

Clean Fuel USA
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- Ann Hancock

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Coalition for a Safe Environment
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- Loren Kaye

Cogeneration Association of California
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- Nora Sheriff

Communities for a Better Environment
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- William Rostov

Consortium for Electric Reliability Technology Solutions
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Consortium Research Fellows Program
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Center for Resource Solutions
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- Jan Hamrin

Cummins Power Generation
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Cyrnel, LLC, Environmental Entrepreneurs
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Cyto Culture Environmental Biotechnology
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Delta Liquid Energy
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Diesel Technology Forum
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Diné CARE
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Distributed Utility Association
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Douglass & Liddell
- Gregory S. G. Klatt

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- Robert E. Reynolds

DTE Energy
- Richard Seguin

Duke Energy North America
- Andrew B. Brown
- Chris Ellison
- Melanie Gillette

Dynamic Design Engineering, Inc.
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Dynegy
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E3
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EBC Company
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Ecos Consulting

European Environment Agency
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Electramix
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Electric Power Research Institute
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- Brice Freeman
- Robert Goldstein
- Ellen Petrill

El Paso Western Pipeline

Ellison, Schneider & Harris, LLP
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- Jeff Harris

Energy and Environment Consultant
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Energy Circuit
- J. A. Savage

Energy Conversion Devices, Inc.
- Ben Ovshinsky

Energy Independence Now
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- Rick Margolin

Energy Producers and Users Coalition
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Energy Solutions

EnerNex Corporation
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Environ Strategy Consultants, Inc.

Environment California
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Environment Colorado
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Environmental Defense
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- Karen Douglas

Environmental Transportation Solutions
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EXAR
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Exxonmobil Gas & Power Marketing Company
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Far West Services, Ltd.
- Frank Schultz

Farber Energy Design
- Gary Farber

Fielder Law Firm
- Scott Fielder

Flynn RCI
- Barry Flynn

FPL Energy
- Diane Fellman
- Steve Ponder

Friends of Nevada Wilderness
- Sharon Netherton

Friends of the River
- Steven Evans

GE Energy
- DeLome Fair
- Jeff Ghilardi

General Electric
- Nick Miller

General Motors Corporation
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Geothermal Energy Association
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Geothermal Resources Council
- Ted Clutter

Geothermex
- Jim Lovekin

Global Business Networks
- Peter Schwartz

Golden Gate Audubon Society
- Elizabeth Murdock
- Miles McKey
- Daniel Richman
- Noreen Weeden

Grand Canyon Trust
- Roger Clark

Gravely and Associates

Gridwise Architecture Council
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- Eric Wong

Grupo de Ecologia y Conservacion de Islas, A.C.
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Harding Consulting
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Heal the Bay
- Craig Shuman

Hewlett Packard
- Robert Parkhurst

Heschong Mahone Group
- Doug Mahone

Horton, Knox, Carter & Foote
- Carrie Downey

HGP IWC
- Fred W. Giffels

Ibis Environmental Services
- Susan G. Orloff

ICLEI – Local Governments for Sustainability
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IEVA
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Imperial Valley Biorefining, Inc.
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Independent Energy Producers Association
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- Jan Smutney-Jones

Industrial Economics, Inc.
- Robert Unsworth

Infotility

Ingersoll-Rand
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Institute for Resource and Security Studies
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International Truck and Engine Corp.
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JBS Energy, Inc.
- Gary Kah
- Gayatri Schilberg

Jupiter Oxygen Corporation
- Thomas G. Weber

Kahl/Pownall Advocates
- Loren Kaye

Kearns & West

KEMA, Inc.
- Daniel Ruiz

Kern River Gas Transmission Company
- Laurie K. Brown
- Gregory T. Snow

Kyocera Solar, Inc.
- Cecelia Aguillon

LD Bond & Associates

League of California Cities
- Yvonne Hunter

League of Women Voters of California
- Jane Bergen
- Lynn Hicks
- Rita Norton
- Jane Turnbull

Legallycraig.com
- Craig J. Beauchamp

Lindh & Associates
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Local Power
- Robert Freehling

Los Angeles Audubon Society
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3M Corporation
- Andrew B. Brown
- Jeffery D. Harris

Mendocino Redwood Company
- John Nickerson

MidAmerican Energy Holdings Company
- Jonathan Weisgall
- Cathy S. Woollums

Mighty Power
- Tom Fulks

MIRANT
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Montana Environmental Info Center
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Mothers for Peace
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- Morgan Rafferty
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MRW & Associates
- Brian Holmes
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National Biodiesel Board
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National Center for Policy Analysis
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- Alex Leupp

National Ethanol Vehicle Coalition
- Gary Herwick

National Grid
- Johnny Johnston

National Hydropower Association

National Refinery Reform Campaign
- Denny Larson

Natural Resources Defense Council
- Devra Bachrach
- Sheryl Carter
- Ralph Cavanagh
- Audrey Chang
- Danny Cullenwarl
- David Hawkins
- Sarah Jaffe
- Nancy Ryan
- Luke Tonachel
- Devra Wang

Nature Trip

- Eddie Bartley

NERA Economic Consulting

New Car Technology
- Peter Evans

New Power Technologies
- Peter Evans

New United Motor Mfg. Inc.
- K. Kelley McKenzie

Nuclear Information and Resource Service
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North American Development Bank
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Northwest Power and Conservation Council
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NRG Energy Center San Diego, LLC
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Nuclear Information and Resources
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Nuclear Energy Institute
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- Paul H. Genoa
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02 Diesel, Inc.

James Peeples

Oak Creek Energy Systems, Inc.
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O'Connor Consulting Services, Inc.
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Office of Policy Analysis and Research
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Oiltanking
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Ontario-Montclair School District
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Ormat Nevada, Inc.
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Pacific Energy Policy Center
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Pacific Ethanol/California Renewable Fuels Partnership
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Pacific Gas and Electric Company
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- Joshua Bar-Lev
- Susan Buller
- John Carruthers
- Frank DeRosa
- James Filippi
- Les Guliasi
- Richard Hendrix
- Robert T. Howard
- Buck Jones
- Niels Kjellund
- Harold LaFlash
- Jeff Lewis
- Frank R. Lindh
- Bill Manheim
- Corey Mayers
- Steve McCarty
- Robert B. McLellan
- Mark J. Meldgin
- Thomas E. Miller
- David Oatley
- Roger Peters
- Dylan Savidge
- Chifong Thomas
- James A. Tramuto
- Kathy Treleven
- Chris Tufon
- Peter Turnbull
- Stacy W. Walter
- Christopher J. Warner
- Kim Whitsel
- Noel Wise

Pacific Institute
- Gary Wolff

Pacificorp
- Bill Edmonds
- Andy MacRitchie

Paul-Frederick Bach, Eltra

Pazza Verde Ventures

- Mauri Miller

Peru LNG S.R.L.
- Stephen Suellentrop

Pew Center on Global Climate Change
- Joshua Bushinsky

Phoenix BioIndustries
- Richard V. Eastman

Pilz and Company, LLC
- Patricia Pilz
- Carol Pilz Weisskopf

Pillsbury Winthrop, LLP
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Planning and Conservation League
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Power Generation Administration
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Powers Engineering
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Power Wheel Associates
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PPM Energy
- James Caldwell
- Christopher T. Ellison
- Andy Linehan

Primary Energy
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Primen
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Princeton Development Corporation
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Private Fuel Storage
- John Parkyn

Judd Putnam Engineering Services
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RCM Digesters, Inc.
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Redding Electric Utility
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RealEnergy
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Reflective Energies
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Regulatory and Cogeneration Services, Inc.
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Reliant Energy
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Rocky Mountain Institute
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Rocky Mountain Office of Environmental Defense
- Vickie Patton

Rosenblum Environmental Engineering
- John Rosenblum

Rossmann & Moore
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Integrated Energy Policy Report

November 2005

California Energy Commission

Arnold Schwarzenegger
Governor

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FINAL REPORT

NOVEMBER 12, 2008

SUBMITTED BY

THE MUNICIPAL WATER DISTRICT OF ORANGE COUNTY
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GRANT AGREEMENT NO. 06-211-559-0
FOR THE STATE WATER RESOURCES CONTROL BOARD
AND
THE METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA

Disclaimer

All water consumption, water quality, and flow measurement data for both the pre- and post-retrofit phases of this study contained within this Final SEEP Report, submitted on October 1, 2008, are considered finalized and serves as a supplemental report to the Final SEEP Report submitted on September 3, 2008.

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Acronyms

BMP	Best Management Practice
MWDOC	Municipal Water District of Orange County
NPDES	National Pollutant Discharge Elimination System
NOAA	National Oceanic and Atmospheric Administration
NON-SFR	Non-single-family residential; i.e. business, municipal or HOA
PAEP	Project Assessment and Evaluation Plan
QAPP	Quality Assurance Project Plan
SEEP	SmarTimer/Edgescape Evaluation Project
SFR	Single-Family Residential

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A. EXECUTIVE SUMMARY

The purpose of the SmarTimer Edgescape Evaluation Project (SEEP) was to retrofit specific groups of "structural" landscape Best Management Practices (BMPs) to improve water use efficiency of landscape irrigation across a set of residential and non-residential sub-watershed assessment areas in southern Orange County, California; and to evaluate the BMPs' effectiveness in reducing water consumption, dry weather runoff and pollutant loads for constituents of concern. "Structural" landscape BMPs, for the purpose of this project, include weather-based irrigation controllers (aka "SmarTimers"), "Edgescaping" where existing irrigated lawn area along the edge of a public sidewalk, street curb, driveway and/or private walkway is replaced with lower impact landscaping and permeable ground covering, and other irrigation enhancements & adjustments to further improve water efficiency and reduce runoff by eliminating overspray onto pavements and improve distribution uniformity. A by-product of the SEEP was the ability to determine the effectiveness of residential rebate outreach programs. Costs of implementation of selected BMPs in relation to benefits realized in the storm drain system were also analyzed.

The project evaluated the effectiveness of the BMPs by implementing them in diverse sub-watersheds that each drain entirely to a single storm drain monitoring site where flow and chemical parameters were easily measurable. Twenty-three (23) sub-watershed areas, located in ten cities within four different watersheds of the San Juan Hydrologic Unit in south Orange County, were selected as assessment areas for the project. All assessment areas had been fully developed for at least fifteen years prior to initiation of the SEEP. Residential (single- and multi-family) and non-residential land uses (private and public) were represented.

Three different BMP combinations were deployed at sixteen of the twenty-three assessment areas, with pre- and post-BMP conditions evaluated in comparison to seven un-retrofitted "control" assessment areas. The three BMP-retrofit combinations included:

- Group A - SmarTimer controllers only,
- Group AB - SmarTimers plus irrigation distribution system improvements, and
- Group ABC - SmarTimers plus irrigation distribution system improvements plus turfgrass replacement.

Pre- and post-retrofit assessments for water consumption, dry-weather runoff flow, fecal indicator bacteria, nutrient loads and surface flow/seepage ratios were made for each assessment area. Field data gathering took place over twelve (12) weeks starting in May 2007 and another twelve (12) weeks starting in May 2008. In the interim between sampling periods, the BMPs were implemented in the assessment areas.

Rebate-based marketing programs, implementation standards and technical support were developed to assist participants in accomplishing consistent BMP implementation to the extent feasible. In some cases, 'smart' irrigation controllers were found to be already in place and operational over a portion of the assessment areas prior to the initiation of the SEEP. In terms of BMP implementation, the SEEP resulted in 153 new SmarTimers being successfully deployed to control a total of 2,401,399 square feet of landscaped area at 16 assessment areas. For SFRs, irrigation distribution improvements were implemented over a total of 658,301 square feet at

seven (7) assessment areas, and turfgrass replacements were accomplished over 18,975 square feet at four (4) assessment areas. For NON-SFRs, irrigation distribution improvements were implemented over a total of 711,073 square feet at eight (8) assessment areas, and turfgrass replacements were accomplished over 49,963 square feet at four (4) assessment areas. The most variable implementation was at the six (6) predominately single-family residential assessment areas, where BMP-retrofit participation varied from 6.5% to 22% in terms of the number of single-family lots in the tract, representing 2.6% of their respective assessment area's overall irrigated acreage. New BMP coverage at the non-single-family assessment areas was 46.4% of overall irrigated acreage.

The PAEP for the SEEP established targets to reduce water consumption by an average of 7 to 21% at SFR sites and an average of 5 to 15% at Non-SFR sites. In order to detect changes in water consumption, water meter data for the 2002-2008 years (2002 through mid-2007 for pre-retrofit water consumption data and mid-2007 through mid-2008 for post-retrofit water consumption data) has been collected or requested to be examined for each assessment area. Not all participating water agencies were able to provide monthly consumption data. Implementation of SEEP BMPs commenced in September 2007 and was largely complete by May 2008. Thus the period of complete post-BMP installation data only occurs after May 2008. This report will present analysis of post-BMP water consumption for the brief period of post-installation available. Conclusions about the level of long term expected water savings based upon two months of post-installation history are speculative. It is highly desirable for additional follow-up analyses of water consumption once a longer history is available.

Examination of the results from the participants from the Santa Margarita Water District (SMWD) service area leads to some suggestive observations. First, the participating customers appear to have a somewhat higher level of pre-participation mean consumption than that of non-participating (control) customers. Second, mean consumption in both groups appears to fall from 2007 to 2008. Given that evapotranspiration was higher than normal in 2007 (about 7 percent higher at the California Irrigation Management Information Service (CIMIS) Irvine Station 75 in May-July 2007) and about normal in 2008, one would not be surprised to see a reduction in water consumption in 2008.

By examining SFR participants from the Moulton Niguel Water District (MNWD), these customers appear to have a somewhat lower level of pre-participation mean consumption as compared to non-participating (control) customers. And while July 2008 consumption is somewhat lower for most customers, the BMP-ABC type appears to have used more. This result should not be surprising as the new drought-tolerant plantings (contained in the "C" part of BMP-ABC) do require additional water to get established.

Dry weather flow measurements were taken continuously for twelve (12) weeks pre-retrofit from May to August 2007 and again post-retrofit in 2008 at flow gages installed at the storm drain monitoring sites for all twenty-three (23) assessment areas. Three (3) of the assessment areas produced no measurable dry weather flow, and four (4) areas had less than measurable dry weather flow under post-retrofit conditions.

Conductivity measurements were taken as twice-weekly grab samples for each of the twelve-week monitoring periods at the twenty-three assessment areas where flow was available to be measured. Conductivity was also measured continuously by sensors installed with the flow

gages from July-August in pre-retrofit 2007 and for the full twelve weeks in post-retrofit 2008. The purpose of the conductivity monitoring was, to the extent feasible, to ascertain the percentage of surface irrigation runoff in the dry weather flow. This evaluation was complicated by reclaimed water used at non-residential sites within 5 of the 9 single-family residential areas, and by highly variable conditions in the geologic substrate. Pre-retrofit conductivity patterns in the nineteen (19) assessment areas where flow was available to measure showed two sites with significantly elevated conductivity, suggesting geomorphic contributory factors.

To evaluate the effectiveness of the project with respect to water quality parameters, twice-weekly grab samples for nutrients, fecal bacteria, and dissolved organic carbon were taken at the twenty-three (23) assessment areas where flow was available to be sampled during laboratory operating hours. In the Final SEEP Report, pre- and post-retrofit concentration parameter differences will be statistically analyzed to determine the following: nutrient loading variations and patterns among the A, AB and ABC areas, the relationship of dissolved organic carbon to bacteria concentrations, nutrient concentration relationships to the other parameters, and the relationship of the water quality parameters to the flow rate.

B. INTRODUCTION

Currently in suburban south Orange County, 85% of single-family residences and virtually all non-residential developments have automatic sprinkler systems to keep landscaping lush in a semi-arid region where 94% of the potable water supply is imported. Most of these systems historically have utilized conventional timer-based landscape irrigation controllers that require an operator/owner to determine and adjust water frequency and duration for each valve zone. Because the operators are often either under-informed or inadequately vigilant, water waste and dry-season runoff occur due to over-watering compared to seasonal need of different plants; overly-rapid application of water relative to site permeability, which varies based on local soil type and cultural practices; improper irrigation system design and/or maintenance causing overspray or overflow; and extensive planting of water-needy turfgrass lawns.

In recent years, weather-based irrigation controllers (AKA SmarTimers) that automatically control the frequency and duration of watering based on actual need (typically calculated as a function of the current evapotranspiration rate, precipitation, humidity, wind, local soil and slope conditions, and/or plant types) have become available on the market. Other irrigation products that improve water distribution uniformity and efficiency, such as low-precipitation-rate 'rotating' sprinkler nozzles and drip irrigation, are also available. Local water agencies are making continuing efforts, with limited success so far, to promote these new SmarTimer and other high-efficiency irrigation products, as well as encouraging the use of California-friendly or native plants in lieu of water-thirsty lawn grasses to reduce consumption and regional dependence on imported water supplies. At the same time, local cities have been conducting public education under their National Pollutant Discharge Elimination System (NPDES) programs to encourage Best Management Practices (BMPs) such as optimizing landscape water and fertilizer application rates and keeping irrigation systems properly adjusted. For most cities, however, 'non-structural' landscape maintenance BMP compliance is difficult to enforce consistently; and requirements for 'structural' landscape design BMPs cannot typically be legally imposed on 'grandfathered' pre-existing developments.

Storm drain systems carry any wasted water as runoff, along with landscape-derived pollutants such as bacteria, nutrients and pesticides, to local creeks and the ocean and beaches. South Orange County's creeks are designated in the San Diego Region Basin Plan for beneficial use for REC-1 (contact) and REC-2 (non-contact) recreation, wildlife and warm water aquatic habitat, and industrial/agricultural use. South Orange County's coastal waters are designated with a wide range of beneficial uses, including: industrial water supply, navigation, contact and non-contact recreation, commercial and sport fishing, preservation of Areas of Special Biological Significance (ASBS), wildlife, rare and endangered species, mariculture, aquaculture, fish migration, fish spawning, and shellfish harvesting, per the 2005 California Ocean Plan.

Given the local Mediterranean climate, excessive perennial dry-season stream flows driven by irrigation runoff are an unnatural hydrologic pattern causing species shifts in local riparian communities and warm, unseasonal contaminated freshwater plumes in the near-shore marine environment. All the major watersheds in the SEEP study area drain to ocean beaches that are 303(d)-listed by the Environmental Protection Agency as impaired for recreational use due to elevated fecal indicator bacteria. A Total Maximum Daily Load (TMDL) for fecal bacteria has been approved locally for all the impaired waters; the Bacteria Load Reduction Planning process is expected to occur in 2008-2009. Additionally, two of the runoff-receiving creeks are

listed as impaired for nutrients and toxicity, which can be expected to impact their beneficial use for aquatic habitat.

The purpose of the SmarTimer/Edgescape Evaluation Project (SEEP) was to implement three (3) specific groups of BMPs to improve water use efficiency of landscape irrigation across a set of residential and non-residential sub-watershed assessment areas, and to evaluate the BMPs' effectiveness in reducing water usage, dry weather runoff and pollutant loads for constituents of concern.

The general goals of the SEEP were to:

1. Reduce the amount of water consumed for landscape irrigation;
2. Reduce irrigation runoff;
3. Contribute to achieving load reductions for bacteria and nutrients;
4. Improve understanding of the proportional sources of low flow in the MS4;
5. Improve understanding of bacteria population dynamics in the MS4; and
6. Improve understanding of factors affecting participation rates in the retrofit program.

The specific desired outcomes of the SEEP were:

1. Retrofit of SmarTimers, irrigation distribution system improvements, and turfgrass replacement BMPs at 10 to 30% of single-family residential (SFR) and at all targeted non-single family (non-SFR) sites within the selected sub-watershed assessment areas.
2. Documentation of the relative effectiveness of the BMP retrofits on reducing water consumption rates by conducting field measurements and evaluating pre- and post-retrofit water sales volume, MS4 low flow rates and laboratory analyses of bacteria and nutrient loads.
3. Assessment of the proportion of dry-weather irrigation-generated surface flows vs. subsurface seepage inputs to the MS4 through comparative analyses of shifts in electrical conductivity vs. flow rate;
4. Assessment of the possible causal relationship of fecal indicator bacteria concentrations to dissolved organic carbon concentrations in runoff; and
5 Assessment of the relative effectiveness of the proposed BMP implementation program in achieving high retrofit participation rates and other load reduction goals.

C. STUDY METHODOLOGY

The SEEP evaluated the effectiveness of BMPs by implementing them in a set of sub-watershed assessment areas that each entirely drains to a single storm pipe monitoring site where flow and chemical parameters could be easily measured. No previous studies had established baseline conditions for any of the sub-watershed assessment areas. Data on flow level, conductivity, fecal bacteria, nutrients and dissolved organic carbon were taken at the monitoring sites for twelve (12) weeks prior to BMP installation to set the baseline, and for another twelve (12) weeks after BMP installation to identify changes possibly attributable to BMP installation.

Evaluation periods occurred during the same twelve-week period in two (2) successive years to minimize seasonal data variation. Un-retrofitted 'Control' sites were monitored in the same way to establish year-to-year variability.

From a preliminary list of forty-two (42) areas, a final set of twenty-three (23) sub-watershed areas in ten cities across south Orange County were selected as assessment areas for the project based on drainage pattern, accessibility, land use variety, BMP implementation cost, and anticipated landowner cooperation. Sub-watershed assessment areas represented both residential and non-residential land uses. After final verification of accessibility for monitoring and landowner acceptance of proposed BMPs at non-residential areas, seven sub-watershed assessment areas were designated as "experimental controls" and the remainder was allocated to one of three BMP-retrofit groups:

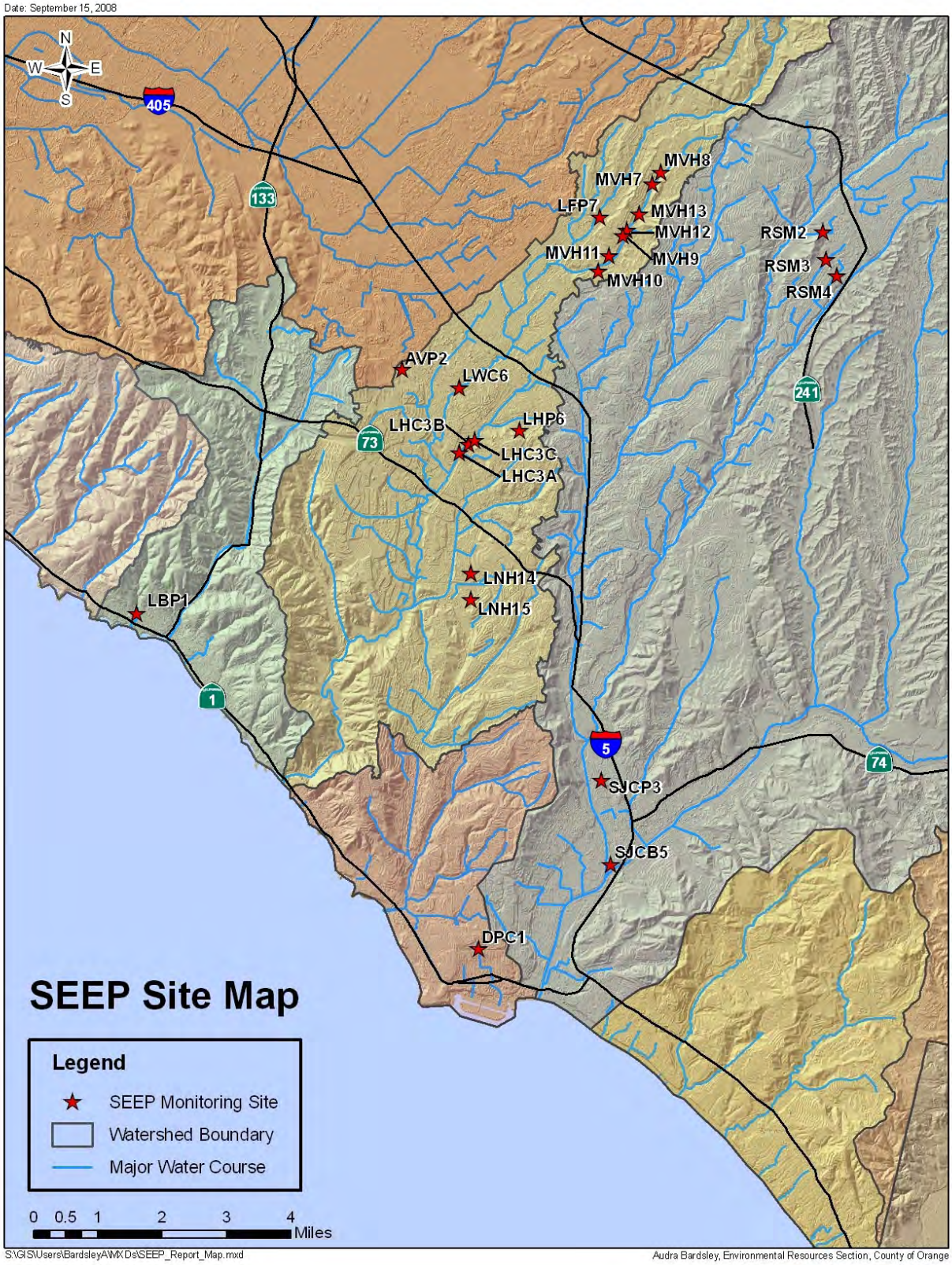
- Group A - SmarTimer controllers only;
- Group AB - SmarTimers plus irrigation distribution system improvements; or
- Group ABC - SmarTimers plus irrigation distribution system improvements plus turfgrass replacement with low-water-using landscape.

The final twenty-three (23) assessment areas, land uses and designated BMP groups are listed in Table B-1 and are located on Map B-2. Other descriptive characteristics for each area, including acreage, topography, percent impervious cover and aerial photos, are identified. The land uses are organized between single-family residential (SFR), where assessment areas are composed of a large number of individually-owned lots and many small irrigation systems and water meters; and non-single-family (NON), where assessment areas are mostly under control of a single owner and have one or a few large irrigation systems and water meters. For the non-single family areas, a more-specific land use descriptor is noted parenthetically in the table.

Table C-1 – Assessment Area Summary

Assessment Area ID	City	Assessment Area Name	Land Use Type	BMP Group	Latitude	Longitude	Address
RSMB2	Rancho Santa Margarita	Business Park 1	NON (bus)	Control	33.6361	-117.6097	29821 Avenita, Rancho Santa Margarita, CA
RSMB3	Rancho Santa Margarita	Business Park 2	NON (bus)	A	33.6299	-117.6088	29909 Banderas Rancho Santa Margarita, CA
LWC6	Laguna Woods	United Mutual	NON (bus)	A	33.59987	-117.7073	Avenida Sevilla & Medosa St. , Laguna Hills, CA
MVH8	Mission Viejo	Aguilar (J07P02)	SFR	A	33.64905	-117.6537	27356 Las Nieves, Mission Viejo, CA
MVH13	Mission Viejo	Vista del Lago	SFR	A	33.63969	-117.6593	Vista Del Lago & Duende, Mission Viejo, CA
RSMB4	Rancho Santa Margarita	Business Park 3	NON (bus)	AB			
AVP2	Aliso Viejo	Iglesia Park (Low Income Area)	NON (park)	AB	33.60465	-117.7233	2671 Via Iglesia, Aliso Viejo, CA
LFP7	Lake Forest	Pebble Creek Park	NON (park)	AB	33.63875	-117.67	Pebble Creek & Sunlight Creek, Lake Forest, CA
DPC1	Dana Point	Searidge	NON (park)	AB	33.47319	-117.6999	24662 Seacall Way, Dana Point, CA
LNH15	Laguna Niguel	Village Niguel	SFR	AB	33.552	-117.7036	29697 Moulton Pkwy, Laguna Niguel, CA
MVH12	Mission Viejo	Destello	SFR	AB	33.63589	-117.6625	Via Noveno, Mission Viejo, CA
LHC3C	Laguna Hills	Aliso Meadows 3 (L I A)	NON (mfr)	ABC	33.588013	-117.7027	25701 Via Lomas, Laguna Hills, CA
SJCB5	San Juan Capistrano	San Juan Capistrano City Hall	NON (gov)	ABC	33.49624	-117.6646	32400 Paseo Adelanto, San Juan Capistrano, CA
LHP6	Laguna Hills	El Conejo Park	NON (park)	ABC	33.59043	-117.6908	25612 Creek Dr., Laguna Hills, CA
LBP1	Laguna Beach	Riddle Park (ASBS)	NON (park)	ABC	33.54785	-117.7933	612 N Coast Hwy., Laguna Beach, CA
MVH9	Mission Viejo	Via Novena	SFR	ABC	33.6347	-117.6636	Via Noveno, Mission Viejo, CA
LNH14	Laguna Niguel	Yosemite/El Acampo	SFR	ABC	33.55201	-117.7023	Yosemite & El Acampo, Laguna Niguel, CA
LHC3A	Laguna Hills	Aliso Meadows1	NON (mfr)	Control	33.585233	-117.7069	25912 Via Lomas & Moulton Pkwy, Laguna Hills, CA
LHC3B	Laguna Hills	Aliso Meadows2	NON (mfr)	Control			
SJCP3	San Juan Capistrano	Long Park	NON (park)	Control	33.511975	-117.6674	31069 Camino Capistrano, San Juan Capistrano, CA
MVH11	Mission Viejo	Modesto	SFR	Control	33.63005	-117.6672	Corner of Modesto Dr. & Trabuco Rd. Mission Viejo, CA
MVH10	Mission Viejo	Via Gaviota	SFR	Control	33.62661	-117.6702	23070 Los Alisos Blvd. Mission Viejo, CA
MVH7	Mission Viejo	Del Lago School	SFR	Control	33.64652	-117.6559	27165 Entidad, Mission Viejo, CA

Figure C-1 – Assessment Area Locations Map



Prior landscape BMP effectiveness assessments in the Orange County region have addressed SmarTimer retrofits only. The Residential Runoff Reduction ("R3") Study conducted by the Municipal Water District of Orange County and the Irvine Ranch Water in 2001 to 2004 estimated that baseline urban runoff water savings from retrofitting of SmarTimers averaged 41 gallons per day per residential household and 545 gallons per day for larger non-residential sites with water meter accounts dedicated strictly to landscape irrigation. The observed reduction in runoff from the R3 retrofit test area was 50% when comparing pre-intervention and post-intervention periods and 71% in comparison to a non-retrofitted control area. However, runoff water quality was determined not to have been significantly affected in terms of pollutant concentrations. The R3's Irvine study area in central Orange County was limited and differs from the south Orange County SEEP study area in being flatter, more homogeneous, and generally having more highly-permeable soils, but similar patterns of effectiveness results were expected for the SEEP study area.

Baseline data had not previously been collected at any of the SEEP monitoring sites. The Quality Assurance Project Plan (QAPP) for the SEEP details the exact study area characteristics, sampling design, and standard operating procedures for every project sampling consultants. Study activities in the pre-retrofit phase of the SEEP included reconnaissance, grab-sampling and field gaging with continuous measurements during dry weather to establish the pre-retrofit baseline conditions at all assessment areas and their associated monitoring sites. Continuous flow monitoring equipment (Table C-2) was installed at the 23 monitoring sites for the full twelve-week pre-retrofit baseline monitoring period (May to August 2007). Installation of the continuous conductivity sensors was unexpectedly delayed until July 2007 at most sites. To supplement the continuous monitoring, the local cities collected grab samples twice weekly (from sites where flow was available to be sampled) within their respective jurisdictions and transported the samples to the designated consulting analytical laboratory for analysis. All work was conducted in accordance with the SEEP Quality Assurance Project Plan (QAPP) requirements and SWAMP Field Data Measurement Standard Operating Procedures (SOPs). Grab samples were analyzed by the laboratory for fecal indicator bacteria, nitrogen and phosphorus nutrients, conductivity, and dissolved organic carbon (Table C-3). Water usage data for all water meters within the sub-watershed assessment area boundaries was also collected from local water agency electronic records, for the 2007 pre-retrofit monitoring period as well as comparable periods for up to the prior 3 years, in order to account for the effect of year-to-year weather variability on water consumption.

Table C-2 – Continuous Flow and Conductivity Field Monitoring Equipment Summary

Parameter	Method / Range	Units	Detection Limit*
Flow depth	Pitot Hydrostatic Neutralizing	Inches	0.8 inches
Flow velocity	Ultrasonic Doppler	Feet/sec	0-14.7 ft/sec
Conductivity	Conductivity	µS/cm	0-20,000 µS/cm

Figure C-2 – Grab Sampling

Grab sampling at a site assessment location.

Figure C-3 Flow and Conductivity Equipment

Flow monitoring and conductivity equipment deployed into typical drain (AVP2).

Table C-3 – Laboratory Grab Sample Summary

Parameter	Method / Range	Units	Detection Limit*
Total coliform	SM 9222-B	CFU/100 mL	1
Fecal coliform	SM 9222-D	CFU/100 mL	1
Enterococcus	SM 9230-B	CFU/100 mL	1
Total N	SM 4500-N	mg/L	0.1
Total P	EPA 365.2 single reagent	mg/L	0.05
Dissolved Organic Carbon	EPA 415.1	mg/L	0.5
Ammonia-N	EPA 350.1	mg/L	0.1
Nitrate-N	EPA 353.3	mg/L	0.02
Orthophosphate (as P)	EPA 365.2	mg/L	0.05
Conductivity	SM 2510	µmhos/cm	1.0

Prior to initiation of the SEEP, all of the participating cities had non-structural BMP policies and public education programs in place in the project's assessment areas. Designated non-structural Landscape Maintenance BMPs include: optimizing water and fertilizer application and keeping irrigation systems in good repair and adjustment. However, compliance is difficult to rigidly enforce. Public Education programs, including direct mailing, water bill inserts and educational websites, assist business owners and residents with implementing water-wise irrigation practices. There are also rebate programs in place to financially assist property owners in voluntarily transitioning to water efficient irrigation system components as "structural" BMPs. However, no specific structural BMPs were previously required for any of the SEEP assessment areas, all of which were pre-existing developments exempt from NPDES requirements for structural BMPs at new developments. With the exception of SmarTimers previously installed within limited homeowner association (HOA) areas within some of the single-family residential areas, no significant structural BMPs were known to pre-exist the project in any of the SEEP assessment areas.

After completion of the pre-retrofit monitoring, landscape structural BMPs were retrofitted at the designated assessment areas in conformance with their Group A, Group AB, and Group ABC assignments between September 2007 and May 2008. BMP retrofits at the non-single-family private and publicly owned areas were carried out by the landowners in conformance with guidelines developed for each Group, and were then partially or fully reimbursed in a rebate format, depending on the terms negotiated to secure their participation in the SEEP. SmarTimers at the non-single-family sites were commercial units from 13 different manufacturers, of which the units controlled watering patterns based by real-time evapotranspiration data transmitted via satellite link or an on-site weather.

To solicit SEEP participation in the single family residential assessment areas, the areas were blanketed with targeted A, AB or ABC marketing materials including postcards, doorhangers, and mailings. Interested homeowners submitted applications with small cash deposit, which varied depending on which Group they were in. Once approved, the homeowners made appointments with one of three authorized BMP installers who were pre-trained in the SEEP eligibility, installation and procedural guidelines for each BMP Group. Participating homes in the Group A, AB and ABC assessment areas all had their conventional 'dumb' irrigation timers replaced with SmarTimers that directly connect to a local weather station via satellite or with a portable on-site sensor for evapotranspiration conditions. For homes in the Group AB and ABC assessment areas, the front-yard irrigation system was first audited to determine what distribution efficiency improvements were appropriate before the installers were engaged to implement the improvements. Emphasis was given to replacing high-precipitation nozzles with low-precipitation rotating nozzles, adjusting radius, spray pattern and riser height, reducing pavement overspray and otherwise improving uniformity of distribution. For homes in the Group ABC areas, the installers also assisted homeowners in selecting appropriate low-water-using "edgescaping" to replace turfgrass lawn areas in strips next to their front walks and driveways (thereby theoretically reducing both the need for water and dry- and wet-weather runoff potential). SEEP inspectors then verified that the residential Group A, AB or ABC BMPs were properly in place before payment of the rebate or payment, directly from the grant to the installers, was authorized. Data on the type and extent of BMP implementation and payment or rebate activity were tracked by location for each retrofitted sub-watershed assessment area for use in the project evaluation.

After the BMPs were in place within the assessment areas, the twelve-week post-retrofit phase of monitoring took place from May to August 2008, essentially replicating the pre-retrofit monitoring parameters, constituents and frequency. Data collected included continuous flow and conductivity monitoring, and twice-weekly grab sampling for laboratory analysis of fecal indicator bacteria (Total coliform, Fecal coliform and Enterococcus), nitrogen and phosphorus nutrients, and Dissolved Organic Carbon. Water usage data for all water meters within the assessment areas were obtained for the baseline pre-retrofit (minimum of 5 years). See Appendix B for the database of pre-retrofit water consumption information. Only three months of post-retrofit monitoring period data has been able to be collected for comparison to the pre-retrofit data due to the constraints of the project timeline as outlined in the Grant Agreement.

The SEEP project had three primary objectives for statistical analysis of collected data:

Water Consumption Savings – Based on metered water consumption data collected in this study, a robust statistical analysis has been used to determine the delta change in water

consumption for participating customers. Water consumption data from approximately five (5) years of water consumption data—four (4) years prior to the intervention and less than one (1) year of post-intervention data—has been analyzed to statistically estimate the delta change in water consumption of the different groups. These data has been used to form the basis for estimates of the net water savings attributable to the SmarTimers, irrigation distribution efficiency improvements, and turfgrass replacement with low-water landscaping. Statistical measures of the uncertainty surrounding these changes have also been developed to permit scientific inference. To control for confounding effects, a matched control group was developed and the change in water consumption of retrofitted areas and sites has been compared to that of non-retrofitted locations for this report.

Dry Weather Runoff Flow Volume Reduction– Based on real-time, 5-minute measurements of sub-watershed runoff, the differences in volumetric runoff between the twenty-three (23) assessment areas between the two dry-weather monitoring periods (May-August 2007 and 2008) has been analyzed. The change in runoff volume of retrofitted sites and assessment areas was compared to that of un-retrofitted sites and control areas. This analysis has been controlled for weather variations, land use, permeability and topographic characteristics to the extent feasible. Flow measurements have been converted into consistent hourly and daily data sets, tested for validity of measurement, and compared across the different sites to identify suspect data points. A m-regression method is also being used to develop an observation-specific data quality measure for use in subsequent modeling statistical analysis of the measured runoff volume. This analysis has also been controlled for weather variations and site characteristics in a regression modeling framework to measure both the mean change in volume and the uncertainty surrounding this mean change.

Runoff Water Quality Improvement – Based on grab sample measures of water quality indicators collected during the pre- and post-retrofit dry-weather monitoring periods (May-August 2007 and 2008), this study has statistically testing for any changes in concentration from baseline conditions and the estimates have been combined with predicted runoff volume to arrive at an inferred pollutant loading. Robust regression methods have been used to develop an observation specific data quality measure for use in subsequent modeling. Water quality parameter inter-relationships have also been extensively examined.

D. RESULTS

Participation Rates and Costs

Non-Single-Family Assessment Areas

For the non-single-family-residential assessment areas (NON-SFR), participation in group-specific BMP retrofitting activity was solicited in each city based on land use and ability to monitor prospective assessment areas, prior to the start of the SEEP. Three (3) suitable areas where BMP retrofitting was not arranged were identified as experimental Control sites. Ten of the eleven (10 of 11) non-single-family A, AB and ABC areas successfully completed BMP installations within the interim between the completion of the pre-installation monitoring in August 2007 and the start of the post-installation monitoring in May 2008. The eleventh area (SJCB5) did not complete its turf-replacement planting until July 2008, halfway through the

post-retrofit monitoring period. SJCB5 was also distinguished from the rest of the assessment areas by a reduction in total irrigated acreage because some its turf was replaced with non-irrigated permeable surfacing. Table D-1 summarizes the final non-single-family BMP implementation achieved.

Table D-1 – BMP Implementation Summary, Non-SFR Assessment Areas

Assessment Area ID	Final BMP Group	Total Assessment Area, acres	Total Irrigated Area, acres	SmarTimer coverage area pre-existing SEEP, acres	New SEEP "A" BMP coverage area, acres	New SEEP "B" BMP coverage area, acres	New SEEP "C" BMP coverage area, acres
RSMB2	*Control*	91.5	22.9	0	-	-	-
RSMB3	A	79.6	11.9	1.28	1.28	-	-
LWC6	A	34.5	5.2	0	5.2	-	-
RSMB4	AB	71.3	14.3	1.3	1.3	1.3	-
AVP2	AB	7.2	5.99	0	5.99	5.99	-
LFP7	AB	1.9	1.7	0	1.7	1.7	
DPC1	AB	8.0	6.25	0	5.16	5.16	-
LHC3C	ABC	3.48	1.2	0	0.66	1.2	0.11
SJCB5	ABC	3.04	0.6/0.537*	0	0.254	0.254	0.317*
LHP6	ABC	3.2	2.1	0	2.1	0.6	0.6
LBP1	ABC	3.37	1.7	0	0.75	0.12	0.12
LHC3A	*Control*	*4.1*	*1.5*	-	-	-	-
LHC3B	*Control*	*29*	*6.7*	-	-	-	-
SJCP3	*Control*	*4.01*	*3.4*	-	-	-	-
Totals		**307.09**	**73.78**	**2.58**	**24.39**	**16.32**	**1.15**

*Denotes pre/post-installation reduction in total irrigated area as a result of the project.

Costs for implementation of BMPs at non-SFR sites are summarized in Table D-2. The costs shown are installation costs only. Average installation costs ranged from $0.03 to $0.57 per square foot for Group A, from $0.08 to $4.47 per square foot for group AB, to $1.15 to $7.69 per square foot for Group ABC. As might be expected, Group ABC exhibited the widest cost range due to the wide variety of turfgrass removal and plant pallet replacement choices for each SEEP participant.

Table D-2 – BMP Installation Costs, Non-SFR Assessment Areas

Assessment Area ID	Final BMP Group	"A" SmarTimer, Total Cost	Cost per sq. ft for "A"	"B" Irrigation Distribution Improvement Total Cost	Cost per sq. ft. for "B"	"C" Turf Replacement Total Cost	Cost per sq. ft. for "C"
RSMB2	Control	-	-	-	-	-	-
RSMB3	A	$4,807	$0.09	-	-	-	-
LWC6	A	$129,851	$0.57	-	-	-	-
RSMB4	AB	$4,807	$0.08	$9,112	$0.16	-	-
AVP2	AB	$6,539	$0.03	$22,033	$0.08	-	-
LFP7	AB	$6,121	$0.08	$7,811	$0.11	-	-
DPC1	AB	$29,527	$0.13	$14,800	$0.07	-	-
LHC3C	ABC	$1,065	$0.04	$21,905	$0.42	$35,364	$7.69
SJCB5	ABC	$678	$0.06	$49,509	$4.47	$36,944	$3.34
LHP6	ABC	$2,866	$0.03	$5,650	$0.22	$30,079	$1.15
LBP1	ABC	$932	$0.03	$1,178	$0.23	$8,100	$1.55
LHC3A	Control	-	-	-	-	-	-
LHC3B	Control	-	-	-	-	-	-
SJCP3	Control	-	-	-	-	-	-
TOTALS		**$195,293.00**	**N/A**	**$131,998.00**	**N/A**	**$110,487.00**	**N/A**
AVERAGES		**$17,754**	**$0.12**	**$16,499.75**	**$0.72**	**$27,621.75**	**$3.43**

Single-Family Residential Assessment Areas

For the six (6) single-family-residential assessment areas that were retrofitted with BMPs, no solicitation of individual residents was made prior to the start of the project. The 10-to-30% participation rate goal established in the Project Assessment and Evaluation Plan (PAEP) was recognized as optimistic, because locally targeted SmarTimer rebate programs had previously achieved participation rates ranging from 3 to 10%. Participation was encouraged by implementing the following marketing strategies:

1) Postcards, door-hangers, and mass letter mailings including application forms and website links were delivered directly to homeowners within the assessment area boundaries.

2) A specific, priced "menu" of SEEP-eligible front-yard-only Groups A, AB and ABC improvements simplified the application, installation, inspection and payment processes. Pre-installation site reviews by trained SEEP inspectors were conducted to identify what irrigation improvements were actually needed.

3) BMP installation work was accomplished by one of two pre-selected and pre-trained landscape installation contractors. The contractors also helped applicants fill out the Group ABC application, which was the most complex.

4) No homeowner cost-share contribution was required for Group A (SmarTimer-only) participants. The cost of Group AB improvements up to a grant value of $1,785 per home was paid directly to the contractor, based on an owner cost-share of $175. Group ABC payments were made up to a per-home grant value of $3,235, with a $375 owner cost-share.

The SFR marketing effort began in June 2007, with the installation of BMPs commencing in September 2007, after the completion of the pre-retrofit water quality and flow monitoring

efforts. By December 2007, it was apparent that participation was lagging behind the project goals. In order to attain higher participation and greater BMP coverage, it was decided to 1) offer lower-cost options in two of the four assessment areas designated for Group AB and Group ABC improvements, and 2) offer irrigation and turf replacement improvements for City- or HOA-owned landscaped acreage within the single-family assessment areas. The secondary offerings in January 2008 resulted in four (4) SFR Group A participants in AB area LNH15, one (1) Group AB participant in Group ABC area LNH14, large Group AB projects on City-owned slopes within Group A areas MVH8 and MVH13, and small Group ABC projects on City-owned property within Group AB area MVH12 and Group ABC area MVH9. No HOA participation was accomplished, but it was determined that most HOA irrigation systems within the assessment areas were already controlled by SmarTimers. All of the Control areas remained un-retrofitted. Final participation results are summarized in Tables D-3 and D-4 below. Complete SFR BMP implementation details are available in Appendix A.

Table D-3 Single-Family Residential Participation Rates

Area ID No.	BMP Group	# of SFR in Area	# of SFR Participants	Final Participation Rate
MVH8	A	323	21	6.50%
MVH13	A	112	14	12.50%
MVH12	AB	68	9	13.24%
LNH15	AB	86	19	22.09%
MVH9	ABC	148	13	8.78%
LNH14	ABC	131	10	7.63%
Totals		**868**	**86**	**9.91%**

Table D-4 – BMP Implementation Summary, Single-Family Residential Areas

Area ID No.	Final BMP Group	Total Area within Drainage boundary, ac	Total Irrigated Area in drainage boundary, ac	SmarTimer coverage pre-existing SEEP, sq ft (non-SFR)	New SEEP "A" SmarTimer coverage area, sq ft*	New SEEP "B" improvement area, sq. ft.	New SEEP "C" improvement area, sq. ft.
MVH8 (SFR)	A	56.1	20.8	-	67,164	-	-
MVH8 City property	AB	-	-	-	60,984	60,984	-
MVH13 (SFR)	A	38	21.7	4.4 ac (HOA)	43,101	-	-
MVH13 City property	AB	-	-	-	265,716	265,716	-
MVH12 (SFR)	AB	13.8	5.6	1.4 ac (HOA)	24,668	13,561	-
MVH12 City property	ABC	-	-	-	6,400	6,400	6,400
LNH15	AB	13.05	2.9	0	38,295	9,965	0
MVH9 (SFR)	ABC	48.8	25.9	2.2 ac (HOA)	34,059	17,085	1,507
MVH9 City property	ABC	-	-	-	9,600	9,600	9,600
LNH14	ABC	30.54	13.7	6.5 ac (HOA)	20,952	9,274	1,468
MVH7	Control	29.5	11.2	0.81 (HOA)	-	-	-
MVH10	Control	16.7	4.3	0	-	-	-
MVH11	Control	32.8	23.0	1.6 (HOA)	-	-	-
Totals		**279.29**	**129.1**	**736,600**	**836,109**	**658,301**	**18,975**

*Back yard areas were not measured under the project. Where the SmarTimer controls front and back yards, the back yard area was assumed to be 120% of front yard area.

**Within the SEEP SFR areas, some HOA areas had pre-existing evapotranspiration-based "SmarTimers" that weren't part of the project but weren't "conventional" timer-based controllers.

The overall participation rate for the single-family-residential program, at 9.9%, consistent with locally targeted SmarTimer rebate programs that had previously achieved participation rates ranging from 3 to 10%. Specifically, the Group A participation rate in the Group A assessment areas was 8.1%, the Group AB participation in the two Group AB areas was 18.2%, and the total Group ABC participation in the two Group ABC areas was 8.2%.

Although the PAEP speculated that the higher-benefit Groups AB and ABC programs might attract more participants than the single-component Group A-only program, the actual outcome was that the Group AB program ultimately proved to be roughly twice as popular as either the Groups A or ABC program. This finding was somewhat surprising, considering the differential in cost. Homeowners were typically quite cost-sensitive; they resisted paying anything extra to extend the "B" irrigation improvements to the back yard, enlarge the "C" planting area, or add amenities such as mowstrips. It is conceivable that the "free offer" may have caused some recipients of the Group A mailers to have doubted its legitimacy or actual benefit. The lesser participation in the Group ABC program compared to the Group AB may have been driven by the larger homeowner's share of cost, by the more complex process, and/or by disinclination to make aesthetic changes to existing front yard landscaping. Greater participation in the AB may also have been encouraged by awareness of impending water shortages throughout the state.

When the no-cost Group A-only option was offered late in the implementation timeframe to one of the two Group AB areas, participation in that Group AB area increased, when the Groups A-only and AB options were offered in one of the two Group ABC areas, participation in that ABC area increased as well. The actual number of participants in the two areas offered the lower-cost options increased. This finding confirms that offering choices – and in particular, lower-cost choices – was effective in increasing participation. It should be noted that the flexibility in the process allowed only the City of Mission Viejo public property sites to garner increased benefits, and that the SFR participants were unaffected.

It should also be noted that the one extra mailing in January 2008, offering the lower-cost options but also reiterating the original Groups AB or ABC offers and extending the deadline, elicited additional applications for the original Groups AB or ABC offer compared to the original applications received in the two areas prior to the original December 31, 2007 deadline. The superior late-enrolling performance in the Group AB (as opposed to the Group ABC) area also tends to confirm that the Group AB program was well-received and that it may have built more credibility than the Group ABC. The seasonal timing – in early spring rather than late summer/fall – may also have encouraged the additional response. It seems likely that the visibility of the projects being installed was at least partly responsible for generating the additional interest. This consideration may support the idea of deliberately phasing future projects with temporary deadlines to create successive spurts of interest and urgency. This phased approach would also offer some potential to advertise the water consumption/water bill reductions achieved in participating neighbors' homes.

In looking at participation rates from all the assessment areas, it should also be noted that participation tended to be higher where assessment areas were smaller. This finding further suggests the leveraging value of word-of-mouth publicity. Limiting the neighborhood size as well as the duration of rebate offers to target areas may be useful as a strategy for future programs and could help keep administrative staffing needs to a minimum.

Average BMP installation costs for the single-family-residential program are summarized for each assessment area in Table D-5. Installation costs ranged from $0.11 per square foot for the Group A (SmarTimer) improvements to $7.68 per square foot for "C" component (edgescape) improvements of the Group ABC assessment areas. However, it should be noted that the pricing structure for the "C" component of the Group ABC improvements included necessary irrigation modifications (such as separation of valve zones) within the "C" component work area in addition to planting and mulching. The "C" component improvements also included the removal of a 2"-deep layer of soil and turf, which should promote enhanced infiltration of runoff coming from other parts of the yard during rainy weather. No wet-weather monitoring was conducted under the SEEP, so the cost/benefit of rain runoff attenuation was not specifically measured.

It should be noted that participants in the Group ABC program needed significantly more administrative and contractor attention, both routinely and for problem-solving purposes, compared to the Groups A or AB participants. This phenomenon would be problematic for future program expansion outside of the research context. Other less-personalized methods of promoting turf-replacement edgescaping (such as rebates, discount coupons, or contests) might generate fewer administrative demands and help control the associated extra costs, but might result in lower participation or slower penetration rates for future programs.

Table D-5 – BMP Implementation Costs, Single-Family Residential Areas

Assessment Area ID	Final BMP Group	"A" SmarTimer Total Cost for Area	Average Cost per sq. ft for "A"	"B" Irrigation Distribution Improvement Total Cost	Average Cost per sq. ft. for "B"	"C" Turf Replacement Total Cost	Average Cost per sq. ft. for "C"
MVH8 (SFR)	A	$7,330	$0.11	-	-	-	-
MVH8 (Non-SFR City)	AB	$3,464	$0.06	$9,692	$0.16	-	-
MVH13 (SFR)	A	$10,645	$0.25	-	-	-	-
MVH13 (Non-SFR City)	AB	$7,418	$0.03	$43,339	$0.16	-	-
MVH12 (SFR)	AB	$5,845	$0.24	$11,361	$0.84	-	-
MVH12 (Non-SFR City)	ABC	$1,582	$0.25	$7,494	$1.17	$10,775	$1.68
LNH15 (SFR)	AB	$10,055	$0.26	$17,095	$1.71	-	-
MVH9 (SFR)	ABC	$5,995	$0.18	$17,114	$1.00	$10,817	$7.17
MVH9 (Non-SFR City)	ABC	$2,373	$0.25	$11,241	$1.17	$16,163	$1.68
LNH14 (SFR)	ABC	$5,350	$0.26	$12,309	$1.33	$11,280	$7.68
Totals		**$60,057**	**$0.19**	**$129,645**	**$0.94**	**$49,035**	**$4.55**

Table D-6 lists the specific area of land affected by the SEEP project, broken down by SFR and NON-SFR participation rates.

Table D-6 Estimated Area of Study Sites (sq. ft.)

Single Family Residential Sites			
Assessment Area Site ID	**Area in sq ft**	**SEEP Improvement Area**	**Percent of Total Area Affected (%Participation)**
	(1)	**(2)**	**(3)=(2)/(1)**
MVH8	2,443,716	128,148	5.2%
MVH13	1,655,280	43,101	2.6%
MVH12	601,128	31,068	5.2%
LNH15	568,458	38,295	6.7%
MVH9	2,125,728	43,659	2.1%
LNH14	1,330,322	20,952	1.6%
MVH7	1,285,020	0	0.0%
MVH10	727,452	0	0.0%
MVH11	1,428,768	0	0.0%
SFR Subtotal	12,165,872	570,393	
Non-Single Family Residential Sites			
Assessment Area Site ID	**Area in sq ft**	**SEEP Improvement Area**	**Percent of Total Area Affected (%Participation)**
	(1)	**(2)**	**(3)=(2)/(1)**
RSMB2	3,985,740	0	0%
RSMB3	3,467,376	55,757	1.6%
LWC6	1,502,820	226,512	15.1%
RSMB4	3,105,828	56,628	1.8%
AVP2	313,632	260,924	83.2%
LFP7	82,764	74,052	89.5%
DPC1	348,480	224,770	64.5%
LHC3C	151,589	28,750	19.0%
SJCP5	132,422	11,064	8.4%
LHP6	139,392	91,476	65.6%
LBP1	146,797	32,670	22.3%
LHC3A	178,596	0	0%
LHC3B	1,263,240	0	0%
SJCP3	174,676	0	0%
Non-SFR Subtotal	**13,376,840**	**1,119,056**	

Water Consumption Results

In order to detect changes in water consumption, water meter data for the 2002-2008 years (2002 through mid-2007 for pre-retrofit water consumption data and mid-2007 through mid-2008 for post-retrofit water consumption data) has been collected and examined for all meters within each assessment area. The assemblage of comparable water consumption data sets was challenging due to the meter measurement cutoff dates and intervals (ranging from 30 days to 61 days) utilized by the seven different local water supply agencies that served the study area. A comprehensive review of the pre- and post-retrofit data has been completed to ensure proper comparability. All data collected as of August 30, 2008 is presented in Appendix B, and Table D-7 indicates which data have been collected.

Table D-7– Pre- and Post-Retrofit Water Consumption Data Collection Summary

Assessment Area ID	City	Assessment Area Name	Land Use Type	BMP Group	Water Agency	Time Period	Frequency
LWC6	Laguna Woods	United Mutual	NON (bus)	A	MNWD	1990-2008	Monthly
MVH13	Mission Viejo	Vista del Lago	SFR	A	MNWD/ SMWD	2002-2008	Monthly
MVH8	Mission Viejo	Aguilar (J07P02)	SFR	A	SMWD	2002-2008	Monthly
RSMB2	Rancho Santa Margarita	Business Park 1	NON (bus)	Control	SMWD	2002-2008	Monthly
RSMB3	Rancho Santa Margarita	Business Park 2	NON (bus)	A	SMWD	2002-2008	Monthly
AVP2	Aliso Viejo	Iglesia Park (Low Income Area)	NON (park)	AB	MNWD	1990-2008	Monthly
DPC1	Dana Point	Searidge	NON (park)	AB	SCWD	1990-2008	Monthly
LFP7	Lake Forest	Pebble Creek Park	NON (park)	AB	ETWD	2002-2008	Monthly
LNH15	Laguna Niguel	Village Niguel	SFR	AB	MNWD	1990-2008	Monthly
MVH12	Mission Viejo	Destello	SFR	AB	MNWD	2002-2008	Monthly
RSMB4	Rancho Santa Margarita	Business Park 3	NON (bus)	AB	SMWD	2002-2008	Monthly
LBP1	Laguna Beach	Riddle Park (ASBS)	NON (park)	ABC	LBCWD	1998-2008	Bimonthly
LHC3C	Laguna Hills	Aliso Meadows 3 (L I A)	NON (mfr)	ABC	MNWD	1990-2008	Monthly
LHP6	Laguna Hills	El Conejo Park	NON (park)	ABC	MNWD	1990-2008	Monthly
LNH14	Laguna Niguel	Yosemite/El Acampo	SFR	ABC	MNWD	1990-2008	Monthly
MVH9	Mission Viejo	Via Novena	SFR	ABC	MNWD	2002-2008	Monthly
SJCB5	San Juan Capistrano	San Juan Capistrano City Hall	NON (gov)	ABC	SJC	1999-2008	Monthly
LHC3A	Laguna Hills	Aliso Meadows1	NON (mfr)	Control	MNWD	1990-2008	Monthly
LHC3B	Laguna Hills	Aliso Meadows2	NON (mfr)	Control	MNWD	1990-2008	Monthly
MVH10	Mission Viejo	Via Gaviota	SFR	Control	MNWD	2002-2008	Monthly
MVH11	Mission Viejo	Modesto	SFR	Control	MNWD	2002-2008	Monthly
MVH7	Mission Viejo	Del Lago School	SFR	Control	SMWD	2002-2008	Monthly
SJCP3	San Juan Capistrano	Long Park	NON (park)	Control	SJC	1999-2008	Monthly

(mfr = multifamily residential bus = business gov = government facility)

Outdoor water consumption could be expected to change annually, at least in the early part of the dry season, as a result of residual soil moisture from seasonal rainfall. Evapotranspiration data was collected from the California Irrigation Management Information System for the 2007-2008 calendar years are presented in Table D-8.

Table D-8 Irvine Rainfall and Temperature Data

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Mean Evapotranspiration	2.18	2.49	3.67	4.71	5.18	5.87	6.29	6.17	4.57	3.66	2.59	2.25	49.63
	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
Mean Evapotranspiration	3	2.56	4.19	4.3	5.69	6.25	6.6	6.33	5.02	3.98	2.25	2.15	
Departure from Normal				-9%	10%	6%	5%	3%	10%				
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08						
Mean Evapotranspiration	2.21	2.48	3.67	5.03	4.81	6.4	6.27						
Departure from Normal				7%	-7%	9%	0%						

Rain Season (Sept-May)	Precipitation	Air Temperature, Average for following May to Aug (equivalent to SEEP monitoring period)
2003-2004	8.14	76.63
2004-2005	28.07	77.87
2005-2006	7.35	77.04
2006-2007	4.04	79.88
2007-2008	Not yet compiled	77.77

Outdoor water need and consumption would also be expected to vary depending on a number of other site characteristics in addition to land use and irrigated area. These factors include topography and soil type (which affect permeability and, if conditions are adverse, could cause more water wasted as runoff); and the type and age of the plant material (since new plantings require more watering than well-established ones). Table D-9 lists the various assessment area site characteristics observed in the SEEP.

Table D-9– Assessment Area Site Characteristics

Assessment Area ID	BMP Group	Land Use Type	Topography	Soil Type	Date of New Planting
RSMB2	Control	NON (bus)	Gentle slope	Loam/clay	-
RSMB3	A	NON (bus)	Gentle slope	Loam/clay	-
LWC6	A	NON (mfr)	Moderately sloping/terraced	clay	-
MVH8	A	SFR	Flat/gentle	clay	-
MVH13	A	SFR	Terraced hillside	clay	-
RSMB4	AB	NON (bus)	Gentle slope	Loam/clay	-
AVP2	AB	NON (park)	Steep hills around flat fields	Sand & clay	-
LFP7	AB	NON (park)	Flat/gentle	clay	-
DPC1	AB	NON (park)	Gentle & moderate slopes	Sandy loam	-
MVH8	AB	NON (City)	Gentle slope	clay	-
MVH13	AB	NON (City)	Moderate to steep slopes	clay	-
LNH15	AB	SFR	Gentle slope	clay	-
MVH12	AB	SFR	Terraced hillside	clay	-
LHC3C	ABC	NON (mfr)	Moderate slope	sandy	May 2008
SJCB5	ABC	NON (gov)	flat	clay	July 2008
LHP6	ABC	NON (park)	Moderate slope	clay	May 2008
LBP1	ABC	NON (park)	Steep hills around flat fields	Sand & rock	March 2008
MVH12	ABC	NON (City)	Gentle to moderate slope	clay	April 2008
MVH9	ABC	NON (City)	Moderate to steep slopes	clay	April 2008
MVH9	ABC	SFR	Terraced hillside	clay	Var. Oct 07- Apr 08
LNH14	ABC	SFR	Terraced hillside	clay	Var. Oct 07-Apr 08
LHC3A	Control	NON (mfr)	Gentle slopes	sandy	-
LHC3B	A	NON (mfr)	Gentle slope	Sand & rock	-
SJCP3	Control	NON (park)	flat	clay	-
MVH11	Control	SFR	Gentle slopes	clay	-
MVH10	Control	SFR	Gentle slopes	clay	-
MVH7	Control	SFR	Terraced hillside	clay	-

mfr = multifamily residential bus = business gov = government facility

Water consumption data have been separated according to meter types (indoor/outdoor potable meters; outdoor-only reclaimed-water meters; and outdoor-only potable meters) in order to facilitate understanding of irrigation and runoff changes. Raw water consumption data for each non-SFR meter (including those in SFR assessment areas) and each single-family-residential meter received up to August 30, 2008 from the Retail Water Agencies is included in Appendix B. Supplemental data and evaluation will be submitted prior to October 1, 2008.

The PAEP for the SEEP established targets to reduce water consumption by an average of 7 to 21% at SFR sites and an average of 5 to 15% at Non-SFR sites.

In order to detect changes in water consumption, water meter data for the 2002-2008 years (2002 through mid-2007 for pre-retrofit water consumption data and mid-2007 through mid-2008 for post-retrofit water consumption data) have been collected or requested to be examined for each assessment area. Not all participating water agencies were able to provide monthly consumption data. Implementation of SEEP BMPs commenced in September 2007 and were largely complete by May 2008. Thus the period of complete post-BMP installation data only occurs after May 2008. This report will present analysis of post-BMP water consumption for the brief period of post-installation available. Conclusions about the level of long term expected water savings based upon two months of post-installation history are speculative. It is highly desirable for additional follow-up analyses of water consumption once a longer history is available.

The monthly water consumption records from MNWD and SMWD were matched to participation records. Included participants fell into the following site assessment areas.

Table D-10 Participants by Water Agency

Number of Participants by Water Agency	
Site	**SFR Participants**
MVH8	18
MVH13	6
SMWD Subtotal	24
LNH14	10
LNH15	19
MVH9	11
MVH12	10
MVH13	6
MNWD Subtotal	56

The examination of water consumption will be divided into descriptive statistics that compare recent consumption of participants with all non-participants (i.e., the control group) and a more formal statistical modeling of the entire 2002 to 2008 period to permit scientific inference.

Descriptive Statistics of Water Consumption

The water consumption analysis begins by examining participants from Santa Margarita Water District (SMWD). Examination of the descriptive statistics of water consumption leads to some suggestive observations. First, the participating customers appear to have a somewhat higher level of pre-participation mean consumption than non-participating (control) customers. This may mean that SMWD residents with higher water bills were more likely to participate. (A statistical model will be used to formally test whether mean consumption between participants and controls is statistically and meaningfully different). Second, mean consumption in both groups appears to fall from 2007 to 2008. Given that evapotranspiration was higher than normal in 2007 (about 7 percent higher at the CIMIS Irvine Station 75 in May-July 2007) and about normal in 2008, one would not be surprised to see a reduction in water consumption in 2008. The significance of these differences can also be tested in a statistical model.

Table D-11 Comparison of SFR Water Consumption (SMWD)

Descriptive Statistics: Comparison of SFR Water Consumption, Control and Participants			
Santa Margarita Water District (SMWD)		**Non-Participant (Control) in ccf***	**Participant (ccf)**
Year			**SF-A**
2007	June-July Mean	21.9	24.1
	June-July Std. Dev.	10.19	9.15
	Resident Count	766	48
2008	June-July Mean	20.1	23.9
	June-July Std. Dev.	10.24	8.73
	Resident Count	764	48

*1 ccf = 748 gallons of water= 1 cubic feet of water

The table below suggests that participating Moulton Niguel Water District customers, if anything, appear to have a somewhat lower level of pre-participation mean consumption as compared to non-participating (control) customers. And while July 2008 consumption is somewhat lower for most customers, the BMP-ABC type appears to have used more. This result should not be surprising as the new drought-tolerant plantings (contained in the "C" part of BMP-ABC) do require additional water to get established.

Table D-12 Comparison of SFR Water Consumption (MNWD)

Descriptive Statistics: Comparison of SFR Water Consumption, Control and Participants					
Moulton Niguel Water District (MNWD)		Non-Participant (Control) in ccf	Participant (ccf)		
Year			SF-A	SF-AB	SF-ABC
2007	June-July Mean	21.7	18.3	20.5	20.1
	June-July Std. Dev.	11.81	7.60	10.88	6.56
	Resident Count	1,367	10	26	20
2008	June-July Mean	21.3	18.6	20.6	21.8
	June-July Std. Dev.	10.48	6.82	9.54	5.77
	Resident Count	1,276	10	26	20

Statistical Models of Water Consumption

Using the water consumption data, models were used to estimate mean consumption in pre- and post periods for participant and nonparticipant groups. A regression framework allows for (1) hypothesis testing within or across groups and (2) use of robust modeling techniques to identify and minimize the influence of spurious or outlying observations.

Form of the Model The form of the model is specified to have a single common pre-intervention mean (μ_{Common}) and to allow for tests of changes in this mean over time and across groups:

Equation 1

$$Consumption_{i,t} \equiv \mu_{Common} + I_{Part,\Pr e} \cdot \delta_{Part,\Pr e} + I_{Control,Post} \cdot \delta_{Control,Post} + I_{Part,Post} \cdot \delta_{Part,Post}$$

The indicator variable $I_{i,\ t}$ takes on the value one to indicate that an observation comes from group i and the time period t (pre/post). Thus, the indicator variable $I_{Part,Pre}$ takes on the value one for participants in the pre-period (2002-2007) and is zero otherwise.

The parameter $\delta_{Part,\Pr e}$ is the estimate of how consumption of participants in the pre-period differs from the common mean μ_{Common} in the pre-period. The common intercept will, by construction, pick up the estimate of control group pre-period mean consumption, since the parameter $\delta_{Part,\Pr e}$ absorbs any participant differences. The indicator variable $I_{,Control,Post}$ takes on the value one for control customers in the post-period (June 2008 -July 2008); its parameter is interpreted as the estimated change to the pre-period mean consumption.

Model Results

The results of the statistical models are presented below. SMWD participants do appear to have a statistically distinguishable and higher level of consumption in the pre-period—but less than 10 percent higher (≈1.95 ccf). Though MNWD participating customers are characterized by having lower consumption in the pre-period, this difference is not statistically distinguishable at a 95 percent confidence level.

Tests for changes in water consumption in the post-period (June –July 2008) are not statistically distinguishable at classical levels of significance. These results should be taken with a grain of salt given the very short post intervention period being analyzed. Once a longer post-installation consumption record is available, more sophisticated statistical modeling--that controls for weather and customer characteristics—would also provide more statistical power to distinguish small changes in consumption.

Table D-13 Statistics Modeling of SMWD SFR Participants

Statistical Model: Comparison of SFR Water Consumption, Control and SMWD Participants				
Monthly Consumption in ccf	**Coef.**	**Std. Err**	**t**	**P>|t|**
Participant – Pre Difference	1.9509	0.612591	3.18	0.001
Participant – Post Difference	1.5590	1.57228	0.99	0.321
Control– Post Difference	-0.3501	0.394006	-0.89	0.374
Common Intercept	20.4483	0.148712	137.5	0

Number of obs = 5699
F(3, 5695) = 5.71
Prob > F = 0.0007
R-squared = 0.003
Adj R-squared = 0.0025
Root MSE = 10.085

Table D-14 Statistics Modeling of MNWD SFR Participants

Statistical Model: Comparison of SFR Water Consumption, Control and MNWD Participants				
Monthly Consumption in ccf	**Coef.**	**Std. Err**	**t**	**P>|t|**
Participant – Pre Difference	-1.8276	1.438621	-1.27	0.204
Participant – Post Difference	0.6875	1.756636	0.39	0.696
Control– Post Difference	-0.5119	0.320522	-1.6	0.11
Common Intercept	21.8097	0.111581	195.46	0

Number of obs = 10697
F(3, 10693) = 1.72
Prob > F = 0.1607
R-squared = 0.0005
Adj R-squared = 0.0002
Root MSE = 10.733

Flow and Conductivity Monitoring Results

The PAEP for the SEEP established targets to reduce measured surface irrigation runoff by 10 to 25% at retrofitted SFR assessment areas and by 5 to 25% at retrofitted Non-SFR assessment areas. Because dry-weather flow may include subsurface seepage or groundwater in addition to surface irrigation flows, a related target to successfully estimate the proportion of surface versus subsurface seepage inputs at all the assessment areas was established.

In order to detect changes in surface irrigation runoff, pre-retrofit and post-retrofit dry-weather storm drain flows and conductivity were measured continuously during the monitoring periods at the monitoring sites for each assessment area. Collection of reliable flow and conductivity data during the pre-retrofit monitoring period was delayed at many sites by one or more problems including: incorrect or tardy deployment of sensors, debris clogs in weirs, flows too low to be measurable, vandalism, hypersensitivity, and 'noise' in sensor data. These issues were rapidly addressed, and a full twelve (12) weeks of continuous flow and conductivity data were collected during the pre-retrofit monitoring period. Fortunately, there was no unseasonal rainfall during the late-May to mid-August flow monitoring periods that would have further complicated the analysis. As a verification measure, conductivity was also measured in the laboratory from grab samples.

In the absence of mitigating BMPs, surface irrigation runoff has been shown in several earlier studies including the R3 study, to increase under hotter weather conditions when more irrigation tends to occur. Weather data collected from NOAA records indicates that the 2007 pre-retrofit wet season was drier and the warm season was hotter than the corresponding 2008 post-retrofit season, so slightly more runoff might naturally be expected for 2007. Based on the data from continuous flow sensors, graphs of the total flow in gallons per day and conductivity plotted over the course of the pre- and post-monitoring periods (May through August 2007 and 2008), for each assessment area, are included in Appendix C.

Prior studies in the region have shown that dry weather storm drain flows may contain a significant proportion of groundwater in addition to surface runoff. Conductivity has been utilized in several earlier studies as a useful marker in estimating the proportion of groundwater or seepage water in storm drains, in cases where the conductivity of the water used for irrigation is significantly different from that of the seepage water, and the proportion of one or the other in the storm drain is large. Groundwater or seepage water, which may have elevated conductivity due to soil or geologic conditions, can enter storm drains through pipe or culvert joints or cracks, perforated subdrain systems, or unlined channel banks. Conductivity may also be elevated in surface runoff compared to water supplies due to soil or intermittent pollutant conditions. The site conductivity measured in the grab samples at the monitoring sites will be compared to the conductivity found in local potable and reclaimed water supplies in the Final SEEP Report to determine to what extent, if any, groundwater seepage is occurring in the assessment areas of the SEEP.

Statistical Models of Inferred Runoff Rate per Day

Using the runoff flow and site area data, regression models were used to estimate mean runoff rate per day by site. A regression framework allows for (1) hypothesis testing within or across sites and (2) use of robust modeling techniques to identify and minimize the influence of spurious or outlying observations.

Form of the Model The form of the model is specified to have a single common pre-intervention mean (μ_{Common}) and to allow for tests of changes in this mean over time and across groups:

Equation 2

$$\frac{RunoffVolume_{i,t}}{SiteArea_i} \equiv \mu_{Common} + I_{i,\Pr e} \cdot \delta_{i,\Pr e} + \ldots + I_{Control,Post} \cdot \delta_{Control,Post} + I_{i,Post} \cdot \delta_{i,Post} + \ldots$$

The indicator variable $I_{i,\,t}$ takes on the value one to indicate that an observation comes from site i and the time period t (pre/post). Thus, the indicator variable $I_{,i,Pre}$ takes on the value one for site i in the pre-period (2007) and is zero otherwise. The parameter $\delta_{i,\Pr e}$ is the estimate of how runoff of participants in the pre-period differs from the common mean μ_{Common} in the pre-period. The common intercept will, by construction, pick up the estimate of control group pre-period mean runoff, since the parameter $\delta_{i,\Pr e}$ absorbs any differences in sites with customers participating in SEEP BMPs. The indicator variable $I_{,Control,Post}$ takes on the value one for control customers in the post-period (May 2008 - August 2008); its parameter is interpreted as the estimated change to the pre-period mean runoff.

Model Results: Comparison from the Pre-Period to the Post-Period

The results of the statistical models are presented below. The sites characterized as predominately single family residences (SFR) with participating residences appear to have statistically distinguishable levels of runoff rate per day in the pre-period—all had lower levels of runoff than the control sites, except MVH9 which was higher in the pre-period. The sites characterized as non-SFR with participating customers differ from the available control sites. One may confidently conclude that even after adjusting for differences in site area, the control sites are not good matches to the sites with participating sites. This, in turn, implies that cross-site comparisons in the post-period would be fraught with inferential risk.

Table D-15 Statistical Modeling of Runoff Flow for SFRs

SEEP Statistical Model of Runoff Flow Rate per Day Predominately Single Family Residential (SFR) Sites				
Dependent Variable: Dry Day Runoff Rate per Day (in inches per unit area) *(Runoff Rate per Day=Runoff Volume/Site Area)*				
Site__Period	**Coef.**	**Std. Err.**	**t**	**P>|t|**
Intercept (Mean for Control Sites in 2007)	0.11154	0.01054	10.58	0
LNH14_pre	-0.09454	0.02043	-4.63	0
LNH15_pre	-0.02989	0.02408	-1.24	0.215
MVH08_pre	-0.04851	0.01836	-2.64	0.008
MVH09_pre	0.53460	0.01880	28.43	0
MVH12_pre	0.15421	0.02381	6.48	0
MVH13_pre	0.94668	0.01970	48.06	0
LNH14_post	-0.04546	0.02037	-2.23	0.026
LNH15_post	-0.06972	0.02457	-2.84	0.005
MVH08_post	-0.08941	0.01872	-4.77	0
MVH09_post	-0.10489	0.01891	-5.55	0
MVH12_post	-0.09840	0.02397	-4.11	0
MVH13_post	-0.08682	0.01976	-4.39	0
SF_control_post	-0.06803	0.01495	-4.55	0
Number of obs 2226 F(13, 2212) = 347.47 Prob > F 0 Adj R-sqrd 0.6693 Root MSE 0.19773				

Table D-16 Statistical Modeling of Runoff Flow for NON-SFRs

SEEP Statistical Model of Runoff Flow Height NON-SFR Sites (Volume/Area, in inches)				
Dependent Variable: Dry Day Runoff Rate per Day (in inches per unit area) *(Runoff Rate per Day=Runoff Volume/Site Area)*				
Site__Period	**Coef.**	**Std. Err.**	**t**	**P>|t|**
Intercept (Mean for Control Sites in 2007)	0.08035	0.01126	7.13	0
DPC1_pre	-0.05046	0.02714	-1.86	0.063
LBP1_pre	-0.07538	0.03265	-2.31	0.021
LFP7_pre	-0.07335	0.03711	-1.98	0.048
LHC3C_pre	-0.07543	0.03301	-2.29	0.022
LHP6_pre	2.38977	0.03302	72.37	0
LWC6_pre	-0.07930	0.02050	-3.87	0
RSMB3_pre	-0.07543	0.01789	-4.22	0
RSMB4_pre	-0.06649	0.01819	-3.65	0
DPC1_post	-0.06935	0.02723	-2.55	0.011
LBP1_post	-0.05456	0.03265	-1.67	0.095
LFP7_post	-0.06194	0.03725	-1.66	0.096
LHC3C_post	-0.07457	0.03231	-2.31	0.021
LHP6_post	0.00020	0.03246	0.01	0.995
LWC6_post	-0.07224	0.01923	-3.76	0
RSMB3_post	-0.07775	0.01789	-4.35	0
RSMB4_post	-0.07998	0.01720	-4.65	0
NON_control_post	-0.06935	0.01596	-4.35	0
Number of obs	2794			
F(17, 2794)	362.07			
Prob > F	0			
Adj R-squared	0.6873			
Root MSE	0.2241			

Comparison of Runoff Rate per Day from the Pre-Period to the Post-Period

All sites show statistically distinguishable reductions in runoff rate per day. Control sites showed 0.068 and a 0.069 of an inch decline for SFR and Non-SFR respectively. All sites with participants showed at least this decline or more with a single exception each. Though no formal tests are constructed across control/SEEP-Participant sites—for the good reason of a lack of comparability in the pre-period--this outcome is consistent with a hypothesis of a SEEP effect

on runoff reduction. Clearly there are systematic forces that caused a decline in runoff from 2007 to 2008—namely a difference in summer evapotranspiration, higher than normal in 2007 (about 7 percent higher at the CIMIS Irvine Station 75 in May-July 2007) and about normal in 2008.

In general, the SEEP assessment areas represent only a small fraction of the watershed area for the major local creek systems into which the SEEP areas drain. As such, even a dramatic decrease in dry-weather runoff rates and volumes would not be expected to affect beneficial use of the creeks, except perhaps on a very localized basis in a riparian channel immediately downstream of an MS4 outfall where a retrofitted SEEP area represented a large percentage of the contributory subdrainage. Over time, consistently drier conditions along these localized riparian channels could cause a shift in the vegetative community composition and extent, or in the prevailing dry-weather water or groundwater depth and velocity, which could alter the aquatic and terrestrial wildlife and invertebrate populations.

Habitat conditions just downstream of the SEEP assessment-area MS4 outfalls were not monitored as part of this study. It is unlikely that measurable vegetative or fauna shifts would have occurred within the few months that were available for post-retrofit monitoring under the SEEP; and any such short-term shift would be difficult to distinguish from normal year-to-year weather-driven variability. In any case, shifts toward drier conditions should normally be considered as movement in the right direction – i.e, toward a more natural state of affairs for the local environment.

Water Quality Analyses Results

The PAEP for the SEEP established targets to reduce nitrogen nutrient loading by an average of 10 to 25% and phosphorus nutrient loading by an average of 5 to 12%. Changes in nutrient concentrations were not expected to be statistically significant.

In order to detect changes in nutrient loading, laboratory grab sampling and continuous flow monitoring data for the pre-retrofit (May through August 2007) and the post-retrofit (May through August 2008) dry-weather monitoring periods have been or will be collected and examined for all assessment areas. Appendix D contains all of the laboratory results for the grab samples collected through August 2008.

Analysis of Water Quality Indicators

The detailed site-specific analysis of water quality indicators can be found in Appendix D. To derive some general findings of this analysis, a set of pre/post comparisons of means is presented. Understanding that runoff volume was lower in 2008 than 2007, for both control and participant sites, is important.

Two quick observations can be made about the changes in water quality parameters summarized in Table D-16 below. First, is the large increase in Total and Fecal Coliform concentrations (not seen in Enterococcus.) Second is the decline in Total Nitrogen, Nitrate-N, and Ammonia concentrations, with most of this change appearing in participant (rather than Control) sites. It is hard to know the systemic causal forces for increases in bacteria counts (reduced flow, better breeding conditions, etc.).

Table D-17 Water Quality Results

SEEP Water Quality Analysis						
Water Quality Grab Sample Indicator	**2007 Mean**	**2008 Mean**	**Percent Change**	**Difference**	**Std Error**	**t-statistic**
Total Coliform (cfu/100 ml)	16092	137507	755%	121415	9122	13.31
Fecal Coliform (cfu/100ml)	6366	26701	319%	20334	3720	5.47
Enterococcus (cfu/100ml)	21307	20187	-5%	-1120	2471	-0.45
Orthophosphate-P (mg/l)	0.5595	0.6437	15%	0.0842	0.0336	2.50
Conductivity (µmhos/cm)	2264	2651	17%	387	144.7	2.68
Total Nitrogen-N (mg/l)	9.8143	4.5559	-54%	-5.2583	0.1868	-28.14
Total Phosphorus (mg/l)	0.5964	0.6801	14%	0.0836	0.0350	2.39
Dissolved Organic Carbon (mg/l)	19.9571	24.9237	25%	4.9666	1.8231	2.72
Ammonia-N (mg/l)	3.2592	1.8646	-43%	-1.3946	0.1320	-10.56
Nitrate-N (mg/l)	6.5508	2.6803	-59%	-3.8705	0.1038	-37.27

Figure D-1 shows the variation by site, by year in the total coliform concentrations. The majority of the SEEP areas showed an increase in total coliform concentrations increased during the 2008 monitoring period. LHC3B had the highest concentration during the 2008 monitoring season. The total coliform counts by site are plotted using a whisker-box plot with error bars that express a 95% confidence level (Cl notched skeletal boxplot).

Figure D-1 Total Coliform Counts by Site

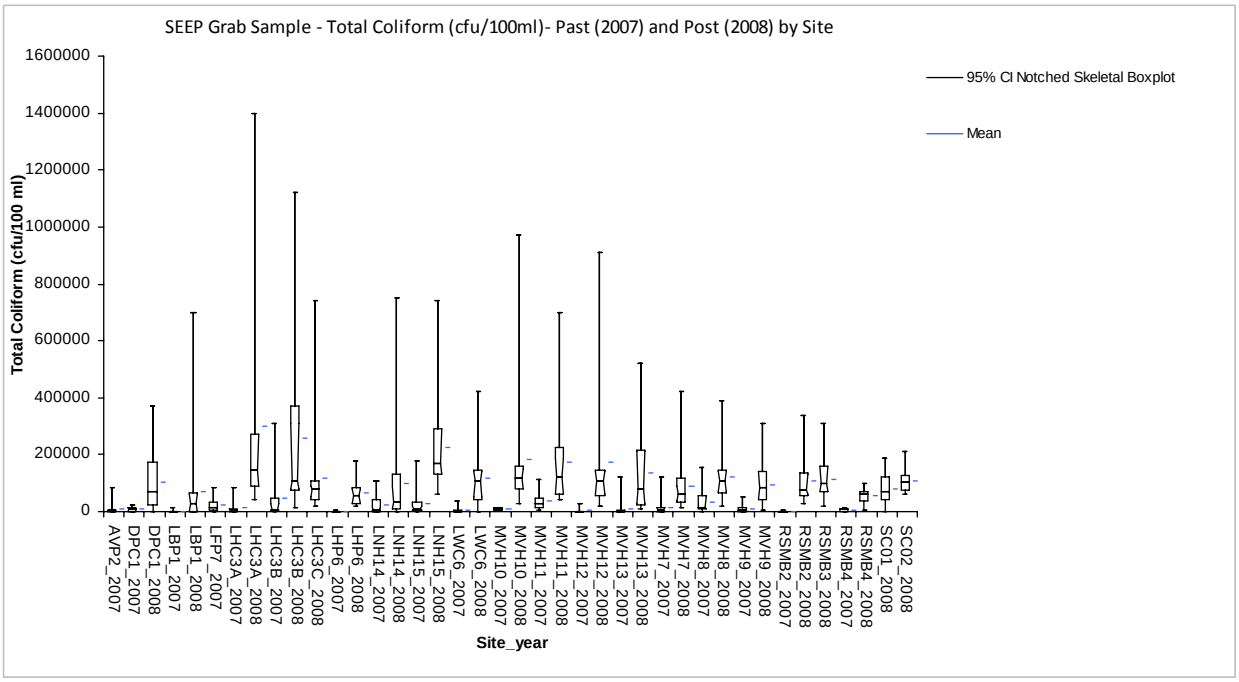


Figure D-2 shows the variation by site, by year in the total fecal coliform concentrations. The majority of the SEEP areas showed an increase in total coliform counts increased during the 2008 monitoring period. Again, the LHC3B area had the highest concentration seen for both monitoring periods.

Figure D-2 Total Fecal Coliform Counts by Site

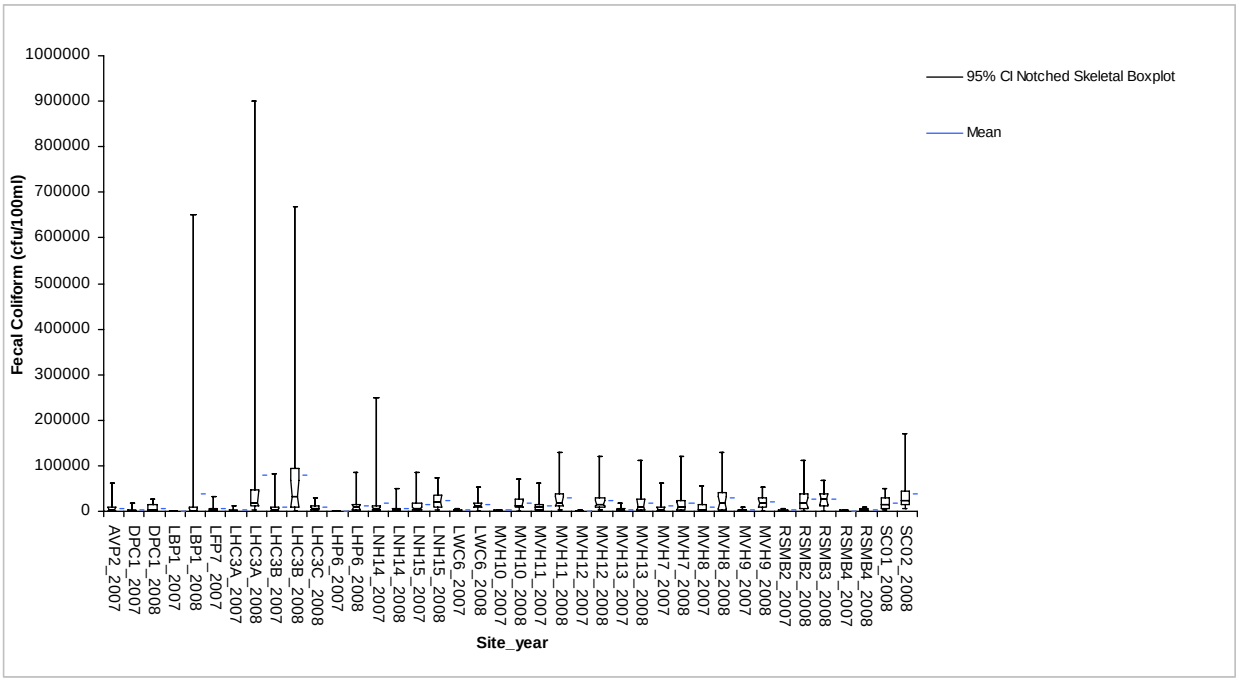


Figure D-3 shows the variation by site, by year in the total Enterococcus concentrations. There was a statistically significant decrease of approximately 5% in the total Enterococcus concentrations observed between the 2007 and 2008 monitoring periods.

Figure D-3 Total Enterococcus Counts by Site

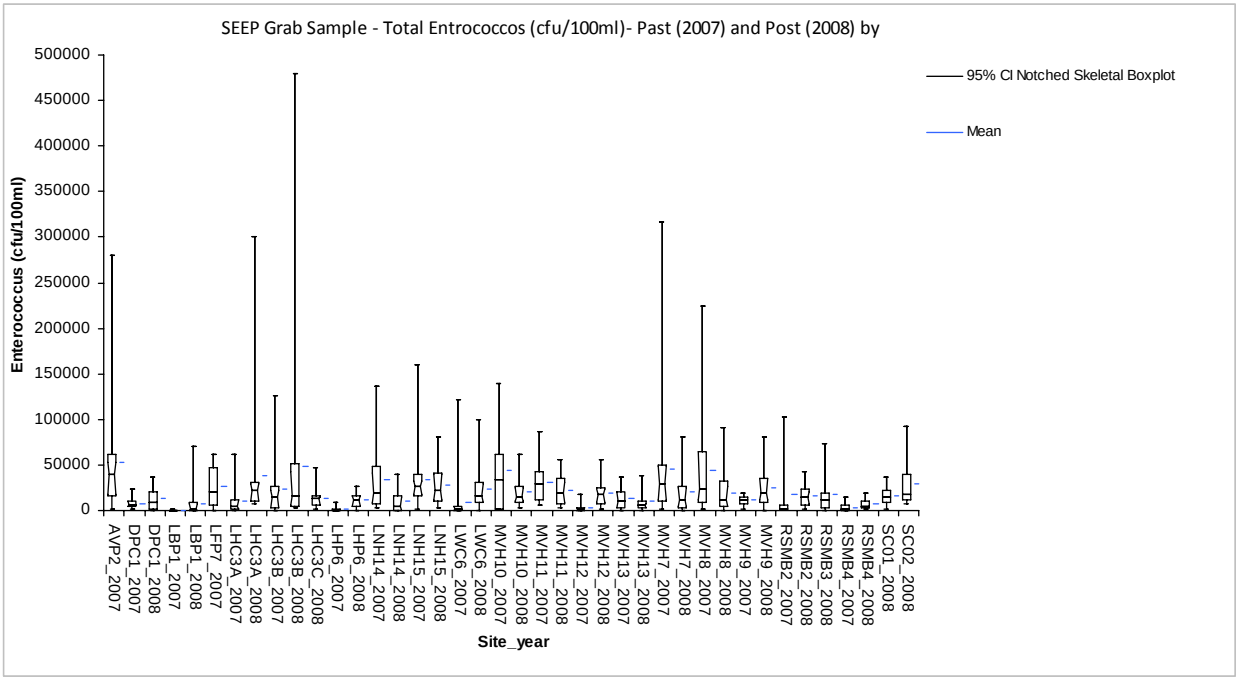
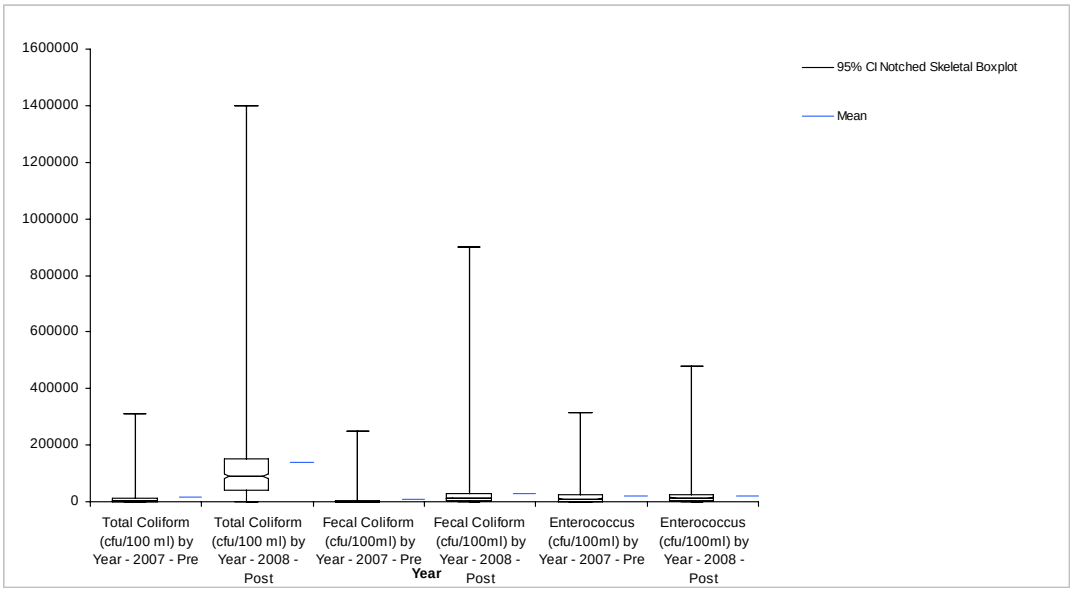


Figure D-4 Total Bacteria Counts by Site



Observed Dissolved Organic Carbon and Fecal Indicator Bacteria Relationship (FIB vs. DOC)

Figure D-5 Total Coliform Counts vs DOC by Site

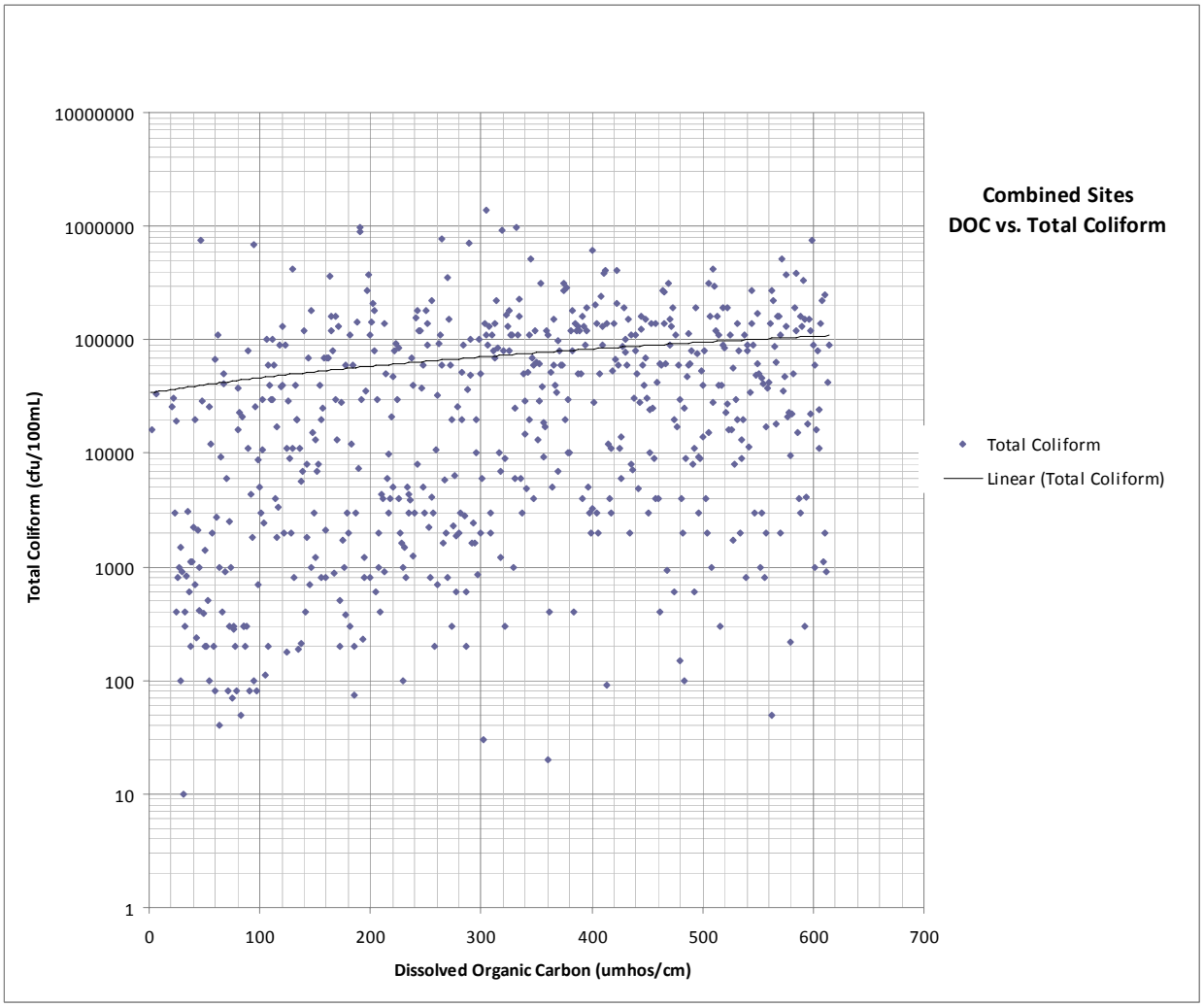


Figure D-6 Total Fecal Coliform Counts vs DOC by Site

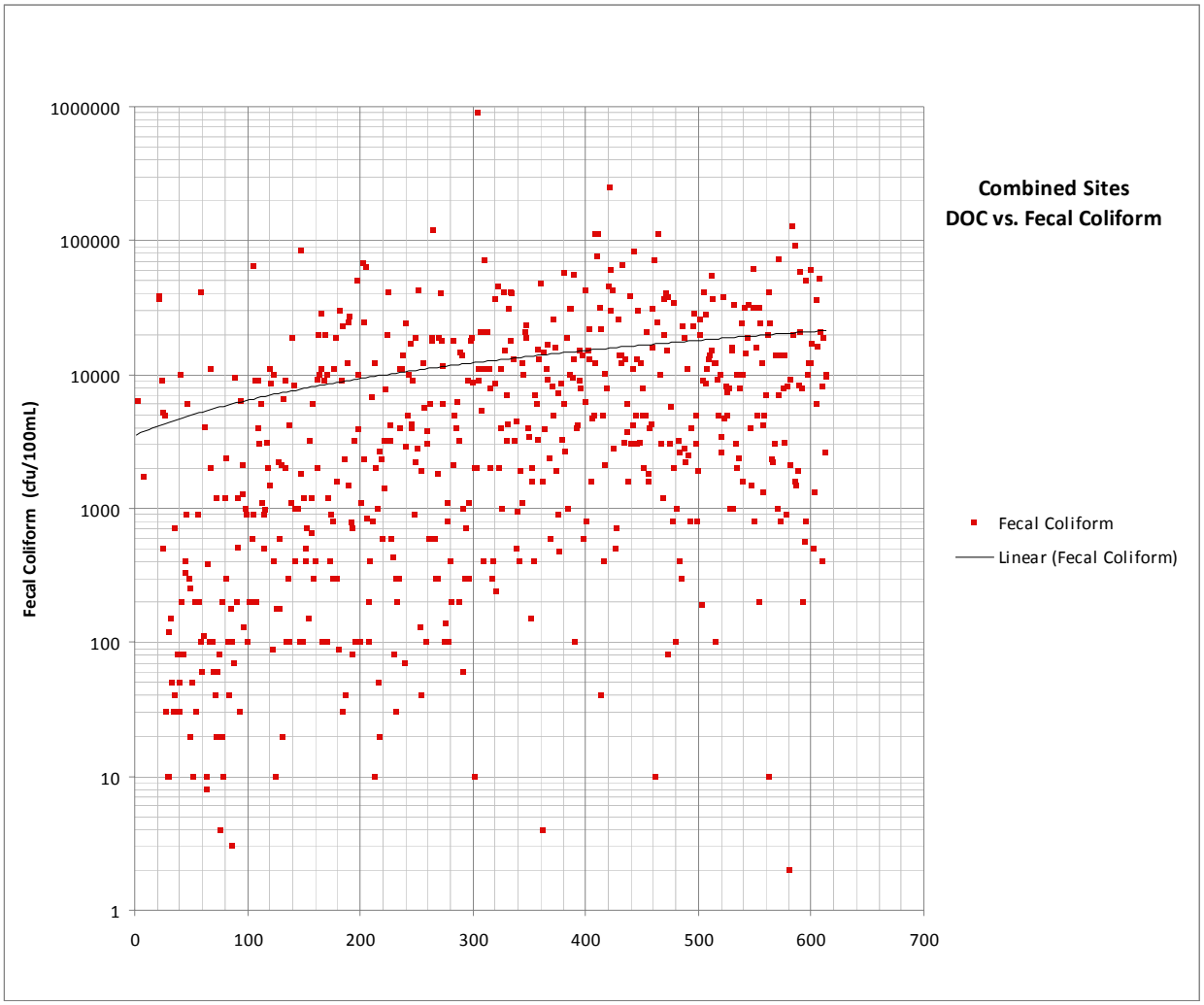
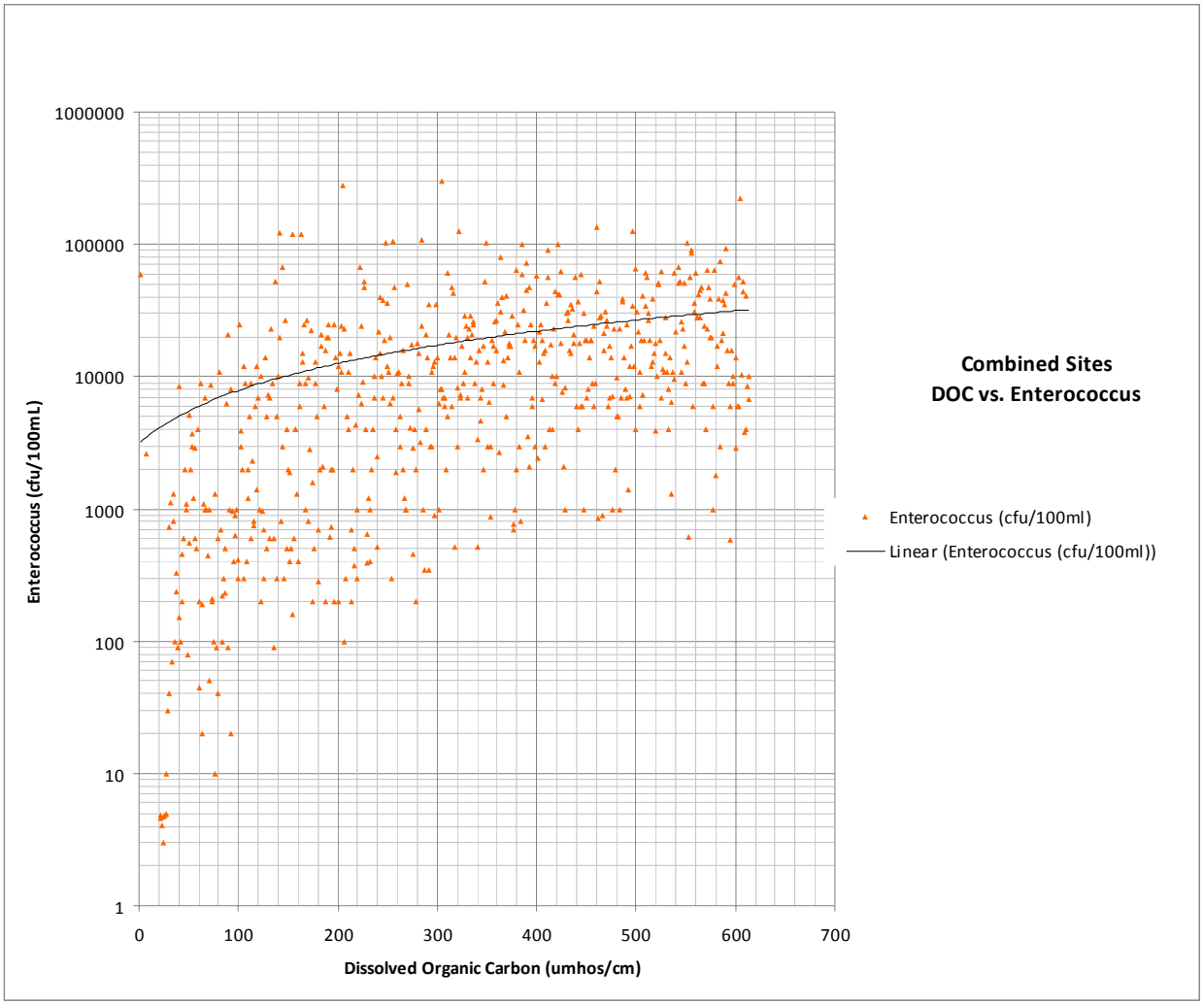


Figure D-7 Total Enterococcus Counts vs DOC by Site



Figures D-5 through D-7, above, show the observed relationships between dissolved organic carbon (DOC) and the Fecal Indicator Bacteria (FIB) samples that were collected in this study by site over both study periods. The PAEP for the SEEP posed the question of any relationship between DOC and FIB populations. In the SEEP data set overall, all three FIB indicators showed a generally positive relationship with DOC. This finding corresponds to the predicted result, since DOC is a food source for these indicator bacteria: A higher food supply would tend to support the growth of a larger bacteria population, unless there were other environmental factors that suppressed population growth. The noisiness of the SEEP dataset can be assumed to derive from the complex interplay of environmental factors that can affect bacteria populations, which may include water temperature, solar exposure, water chemistry, magnitude of the original contamination, competition/predation, and time lapsed since the conditions affecting a particular sample last shifted.

General FIB Observations

The PAEP for the SEEP established targets to reduce loading of fecal indicator bacteria (total coliform, fecal coliform, and Enterococcus) by an average of 10 to 25% at SFR areas and by an average of 5 to 25% at Non-SFR areas. The relationship of fecal indicator bacteria to dissolved

organic carbon concentration was also to be assessed, based on the idea that threshold DOC concentrations might drive increase or decrease in bacteria populations.

In order to detect changes in fecal indicator bacteria loading, laboratory grab sampling and continuous flow monitoring data for the pre-retrofit (May through August 2007) and the post-retrofit (May through August 2008) dry-weather monitoring periods have been collected and examined for all assessment areas. Appendix C summarizes the flow findings and Appendix D summarizes the laboratory results for the grab samples collected for this project.

FIB concentrations are characteristically highly variable in urban runoff - commonly by four to five orders of magnitude - and are typically highest in summer. FIB in surface runoff may be derived from birds, decomposing organic debris, manures, wildlife or pets. Previous studies have suggested that fecal indicator bacteria loading in storm drains may be effected by water temperature, sunlight exposure, nutrient content, and mobilization or settling of sediment. Filtration through a sufficient layer of soil is generally expected to reduce bacteria concentrations. Human health risks potentially associated with FIB are considered most worrisome if the FIB is associated with sewage, but there were no known sewage leaks or spills into any of the SEEP systems, either before or during the SEEP study.

All the inland receiving waters downstream of the SEEP assessment areas are designated in the Basin Plan for beneficial use for REC-2 non-contact recreation. The sites within the San Juan Creek watershed are also designated for contact recreation (REC-1), with the remaining sites considered to have "potential" for REC-1 use. The WQO for fecal coliform for inland surface receiving waters designated for REC-2 use states that "the average fecal coliform concentrations for any 30-day period shall not exceed 2,000/100 ml nor shall more than 10 percent of samples collected during any 30-day period exceed 4,000/100 ml." The objective for REC-1 use states that "the fecal coliform concentration, based on a minimum of not less than five samples for any 30-day period, shall not exceed a log mean of 200/100 milliliters(ml), nor shall more than 10 percent of total samples during any 30-day period exceed 400/100 ml."

WQOs for receiving waters are not directly applicable to water within storm drains, and bacteria concentrations at the local creeks were not measured as part of this study. Most of the SEEP areas contribute only a small proportion of the water discharging into the local creeks, but understanding their incremental contributions may be important for future TMDL modeling. For the 2007 pre-retrofit and the 2008 post-retrofit monitoring period, the measurements at only one SEEP monitoring site (LBP1) met the REC-1 objective. LBP1 is also the only one of the SEEP areas that historically discharged in close proximity to a heavily-used swimming beach. 7 SEEP areas met the REC-2 objective in 2007. None of the SEEP areas met the REC-2 objective in the 2008 monitoring period.

As context for these findings, it is important to recognize that WQOs for Fecal Indicator Bacteria (FIB) concentrations relative to recreational use historically were developed through epidemiological studies at receiving water sites where contamination with human sewage was known or suspected, where bacteria concentrations were shown to be statistically directly linked to human health risk. The measured bacteria are not normally pathogenic, but may indicate the presence of other viral or bacterial pathogens. None of the SEEP monitoring sites exhibited FIB concentrations in the 1,000,000+ range typically associated with sewage-contaminated discharges, or outside the range commonly seen at storm drain outfalls throughout the region. Except for downstream of LBP1, actual contact recreational use closely downstream of any of the SEEP areas is believed to be very rare.

Nutrient Analysis Results

Figure D-8 shows the variation by site, by year in the total nitrogen concentration. The majority of the SEEP areas showed a statistically significant decrease (approximately 50%) in total nitrogen concentration between the 2007 and 2008 monitoring periods.

Figure D-8 Total Nitrogen by Site

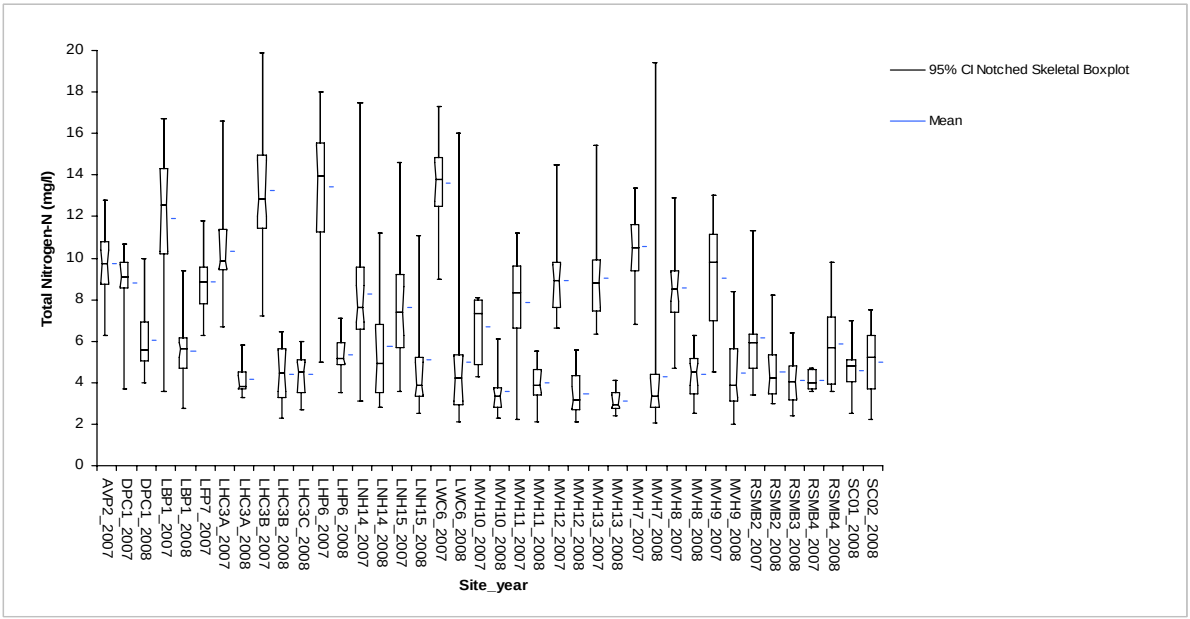


Figure D-9 shows the variation by site, by year in the total phosphorus concentrations. The overall mean total phosphorus concentration increased by approximately 14% between the 2007 and 2008 monitoring periods. Overall, the N:P ratio changed from 16.4:1 in 2007 to 6.7:1 in 2008. Figure D-9 shows the change in N:P ratio by site.

Figure D-9 Total Phosphorus by Site

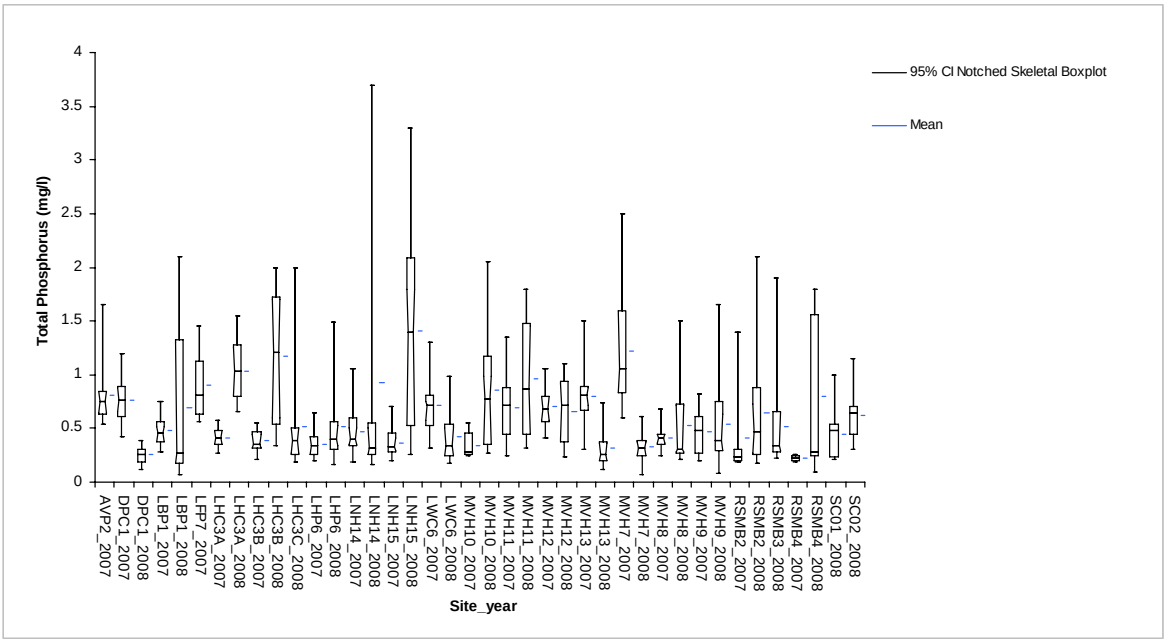


Figure D-10 Ammonia as Nitrogen by Site

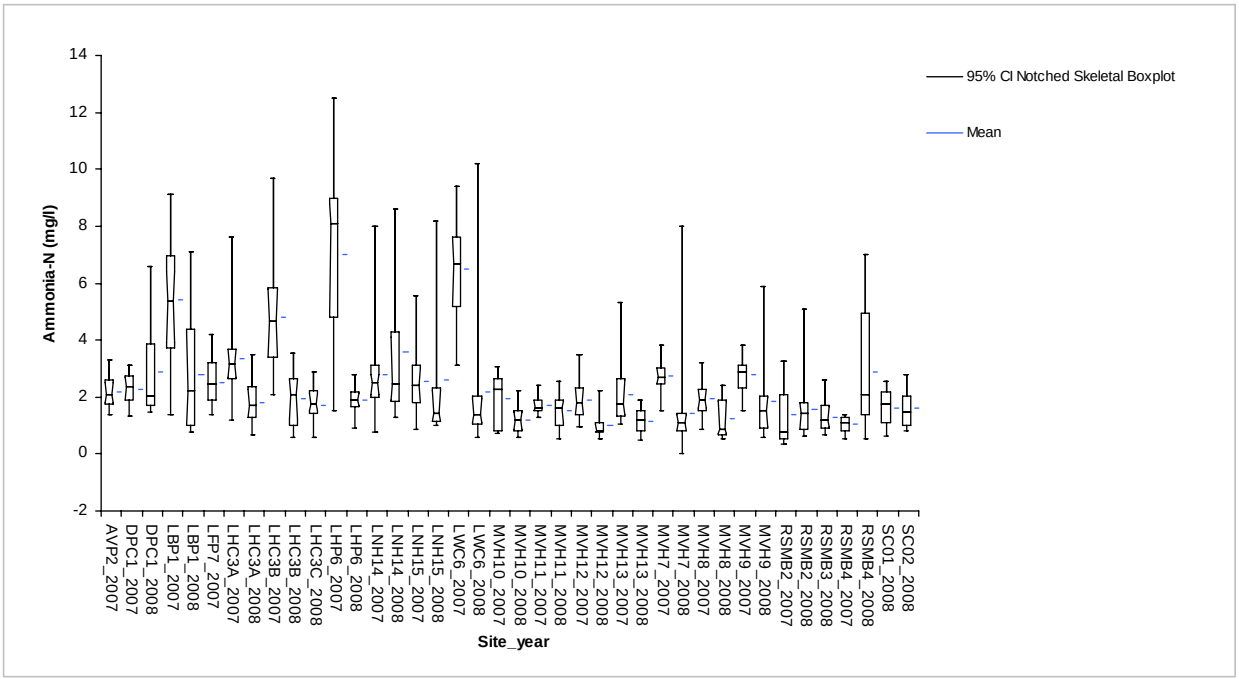


Figure D-11 shows the variation by site, by year in the conductivity values. It is important to remember what would be the expected year-to-year variability effect on groundwater-proportion and conductivity that might expected due to the difference in rainfall and ET between the pre and post years. In the drier pre-year, we can assume there would be less groundwater volume; there was more runoff volume in the pre-year; therefore one would expect that the pre-year would characteristically show a lower conductivity. As an overall mean, in fact the pre-year did show a 15% lower conductivity, but this varied from site to site.

Figure D-11 shows the variation by site, by year in the ammonia as nitrogen (Ammonia-N) values. Overall, the ammonia values were reduced after the BMP retrofits were implemented in study areas as did all other nitrogen species analyzed in the water quality grab samples.

Figure D-11 Conductivity by Site

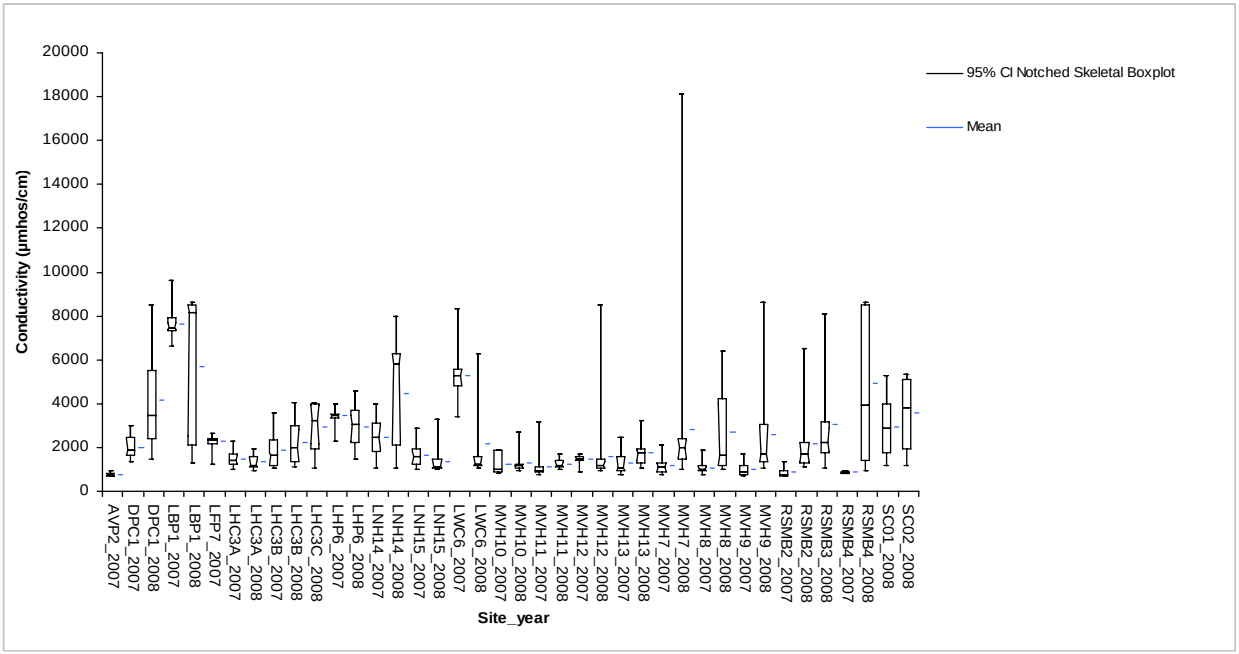
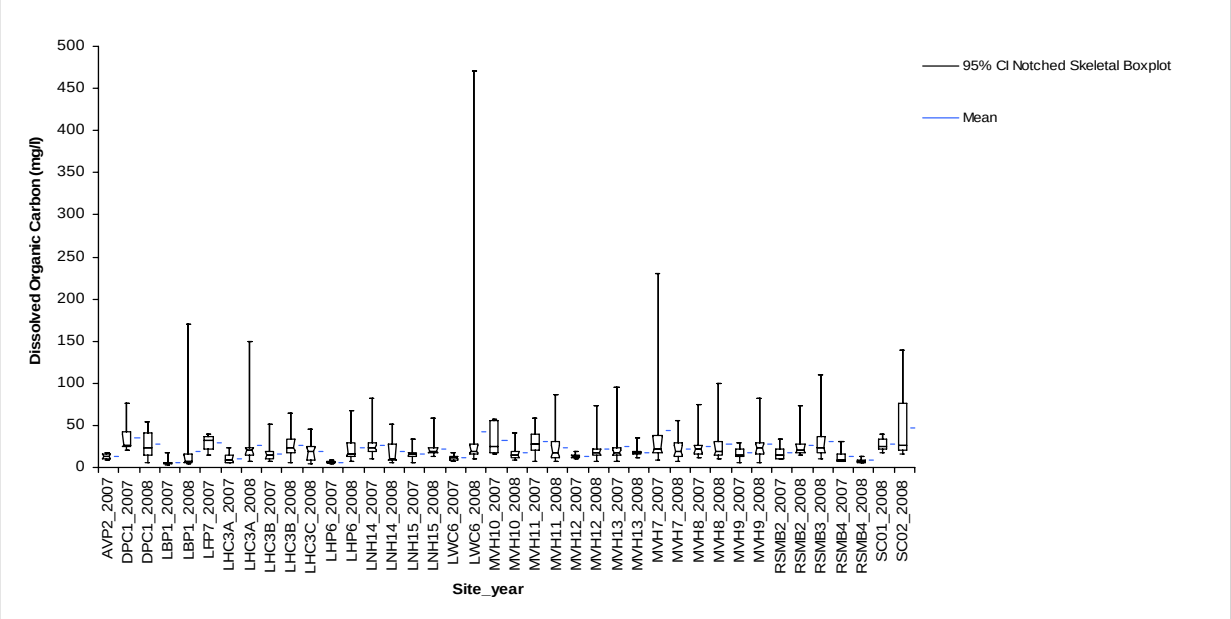


Figure D-12 shows the variation by site, by year in the dissolved organic carbon (DOC) values.

Figure D-12 Dissolved Organic Carbon (DOC) by Site



All the receiving waters into which the SEEP study areas drain are designated for beneficial use for aquatic habitat. Of the constituents measured under SEEP, nitrogen and phosphorus, as biostimulatory nutrients, are most closely linked to the aquatic habitat use. As noted above, the SEEP assessment areas represent only a small fraction of the watershed area for the major local creek systems into which the SEEP areas drain. Shifts in nutrient concentrations and loads from the SEEP areas would therefore be unlikely to significantly affect water quality conditions in the creeks, except perhaps on a very localized basis in a riparian channel immediately downstream

of an MS4 outfall where a retrofitted SEEP area represented a large percentage of the contributory subdrainage.

Receiving-water Water Quality Objectives (WQOs) are not directly applicable to water within storm drain pipes, and nutrient constituents were not measured at the creek outfalls below the SEEP monitoring sites. However, comparison of the SEEP monitoring site data to biostimulatory nutrient objectives may be instructive. The Basin Plan for the San Diego Region requires that "concentrations of nitrogen and phosphorus, by themselves or in combination with other nutrients, shall be maintained at levels below those which stimulate algae and emergent plant growth…..A desired goal in order to prevent plant nuisances in streams and other flowing waters appears to be 0.1 mg/L total P …natural ratios of nitrogen to phosphorus are to be determined by surveillance and monitoring and upheld. If data are lacking, a ratio of N:P = 10:1 shall be used." .

No individual Total P sample at any of the 23 SEEP monitoring sites met the 0.1 mg/L WQO goal during the 2007 pre-retrofit or the 2008 post-retrofit sampling period. Although these Total P values represent significant exceedances of the WQO's "desired goal", the context deserves to be explored: it should be noted that the "natural ratios" of nitrogen to phosphorus, as referenced in the Basin Plan WQO, have not been formally determined for south Orange County watersheds. As noted above, local geology may be suspected as a significant source of phosphorus and nitrogen in some locations. This perspective is supported by storm drain outfall dry-weather monitoring data in south Orange County extending back into 2003 (n>1,000).

E. CONCLUSIONS AND RECOMMENDATIONS

The general purpose of the SmarTimer/Edgescape Evaluation Project (SEEP) was to retrofit specific groups of "structural" landscape Best Management Practices (BMPs) to improve water use efficiency of landscape irrigation across a set of residential and non-residential sub-watershed assessment areas in southern Orange County, California. The general goals of the SEEP were as follows:

1. Reduce the amount of water consumed for landscape irrigation;
2. Reduce irrigation runoff;
3. Contribute to achieving load reductions for bacteria and nutrients;
4. Improve understanding of the proportional sources of low flow in the MS4;
5. Improve understanding of bacteria population dynamics in the MS4; and
6. Improve understanding of factors affecting participation rates in the retrofit program.

The specific desired outcomes of the SEEP were:

1. Retrofitting of SmarTimers, irrigation distribution system improvements, and turfgrass replacement BMPs at 10 to 30% of single-family residential (SFR) and at all targeted non-single family (non-SFR) sites within the selected sub-watershed assessment areas.
2. Documentation of the relative effectiveness of the BMP retrofits on reducing water consumption rates by conducting field measurements and evaluating pre-

and post-retrofit water sales volume, MS4 low flow rates and laboratory analyses of bacteria and nutrient loads.

3. Assessment of the proportion of dry-weather irrigation-generated surface flows vs. subsurface seepage inputs to the MS4 through comparative analyses of shifts in electrical conductivity vs. flow rate;
4. Assessment of the possible causal relationship of fecal indicator bacteria concentrations to dissolved organic carbon concentrations in runoff; and
5 Assessment of the relative effectiveness of the proposed BMP implementation program in achieving high retrofit participation rates and other load reduction goals.

In general, the SEEP was successful in gaining the desired amount of participants, reducing water consumption rates, decreasing urban runoff, and improving water quality. Continuous flow monitoring and water quality sample collection was largely successful over a vastly variable geographic area and garnered valuable data. Further, more robust results from analyses of more water consumption data will be presented in a supplemental report to be submitted in October of 2008. This report will present increased water consumption data and also present the finalized water quality and flow monitoring data.

SEEP Participation Rates

For the SEEP, there was a total participation rate of 9.91% for the targeted SFR and NON-SFR groups. This was just barely below the desired rate of the minimum 10% desired in the goals outlined above, but was on par with the previous BMP implementation studies that have been conducted in South Orange County, CA. Additionally, the impact of the SEEP was greater than in these previous studies since not only were SmarTimers installed, but irrigation system improvements were made and both plant palettes were changed and edgescaping was redone.

Water Consumption Analyses

Due to the severely limited timeframe for post-retrofit water consumption data collection (i.e. less than one full year of monthly water consumption data) for this study, only a snapshot of the effects that the retrofit process had on both the SFR and NON-SFR project areas can be elucidated.

Using the weather data—which show that the total mean evapotranspiration rate of 2007 was approximately 7% higher than that of the first part of 2008 (January—July)—along with the pre- and post-retrofit data that have been collected as of August 30, 2008, the following water savings have been presented:

- The SFR participants in the Group A Santa Margarita Water District participants showed a statistically significantly higher rate of consumption during the pre-retrofit period (approximately 1.95ccf).
- The SFR participants all groups (Groups A, AB, and ABC) of the Moulton Niguel Water District participants showed a slightly higher rate of consumption during the post-retrofit period, but these results are not statistically significant at the 95% confidence level. The Group ABC participants logically had the highest increase in post-retrofit water consumption as the new native or water-conserving plants that were recently planted required increased water consumption to become established before they help reduce landscaping water consumption.

Runoff Flow Analyses

Using the complete dataset from the 2007 pre- and 2008 post-retrofit dry weather monitoring periods, it was found that there was a statistically significant decrease in the levels of runoff in all of the SEEP areas. These results are on par with the previous BMP implementation studies that have been conducted in South Orange County, CA.

Water Quality Analyses

Comparing the pre- and post-retrofit monitoring period water quality data, the following conclusions can be made:

- The total coliform concentration overall increased by approximately 755% from the 2007 mean concentration to the 2008 mean concentration.
- The total fecal coliform concentration by site increased by approximately 319% from the 2007 mean concentration to the 2008 mean concentration.
- The Enterococcus concentration by site decreased by approximately 5% from the 2007 mean concentration to the 2008 mean concentration.
- The nitrogen species (total nitrogen, nitrate and ammonia) all decreased in the site areas that participated in the SEEP. The mean Total nitrogen concentration decreased by 54%, ammonia concentration decreased by 43%, and nitrate concentration decreased by 59% from the 2007 to the 2008 monitoring periods.
- The phosphorus species (total P and orthophosphate) increased overall—total phosphorus concentration increased by 14% and orthophosphate concentration increased by 15% from the 2007 to the 2008 monitoring periods.
- Dissolved organic carbon (DOC) concentration increased overall between the 2007 and the 2008 monitoring periods by 25%.

Recommendations

The most important recommendation for future projects like the SEEP would be to ensure proper time to collect all post-retrofit data prior to when final reporting is required to be completed. This allows for complete statistical analyses to be conducted and validated as well as enough time for the generation of robust discussions accompanying the data that is presented in the Final Report. The main constraint in this SEEP reporting process has been the lack of a complete post-retrofit water consumption database to allow for a month-by-month analyses. A complete year of post-retrofit data would allow for detailed identification of trends and patterns by site and by year.

Additionally, future studies allow for more data collection of the dry weather monitoring periods to get at least 3 years of water quality, flow, and water consumption data. The variability seen in this study and other studies between only two (2) years of data has been great and makes accurate analyses more difficult, and can lead to an incomplete picture of the overall effects of these implementation projects.

Another recommendation would be to limit the number of monitoring areas to increase the similarity between SFR and NON-SFR participant and control groups within a smaller geographic area. For example, the flow at the LBP1 was almost entirely comprised of seeping groundwater, while that of other areas such as RSMB2 and RSMB3 were almost entirely comprised of urban surface runoff. With a limited number of more homogenous sampling

locations, more complete data collection and analyses could be completed with less monetary and staffing resources, resulting in a more cost effective sampling and analyses program. However, it should be noted that the high variability of results between the assessment areas is, in itself, an important finding that speaks strongly to the difficulty and complexity of accurate watershed monitoring in a physiographically-complex environment with multiple land uses.

One important factor affecting water quality that was discovered in the course of this study was the implications of the conductivity findings for the probable proportion of surface runoff vs subsurface/groundwater & seepage inputs into the storm drains. Determining to what extent this would shift the perception of what reduction may have been achieved in just the surface irrigation runoff for each site. At most sites, there is no "groundwater/seepage" conductivity as a direct known measurement to support the analysis. In those cases, we could assume that the highest individual conductivity measurement for that site could represent groundwater, with the caveat that you would want to differentiate sites that probably don't have significant groundwater inputs. For example, for sites with reclaimed water inputs, you might assume groundwater input would be represented by measurements over about 2,300, since reclaimed is about 1800; sites without reclaimed water would indicate groundwater inputs where the highest measurement was over about 1,300. You could estimate the groundwater-percentage range for each site from the bottom to top quartile for each site. The individual site variability throughout the County is useful information when considering stormwater and surface water sampling projects and requirements.

LIST OF ITEMS SUBMITTED

ITEM	DESCRIPTION	SUBMITTED
1	PLANS AND COMPLIANCE REQUIREMENTS	
1.1	GPS Information	YES
1.2	PAEP	YES
1.3	MP	YES
1.3	Monitoring Report	YES
1.4	QAPP	YES
1.6	CEQA	YES
1.7	Permits	YES
2	WORK TO BE PERFORMED BY GRANTEE	
2.1.1	Participation Agreements	YES
2.2.3	Assessment Area Locations and BMP Group Assignments	YES
2.3.6	Sampling Station Locations; Sampling Station Photo Documentation; Baseline Flow, Water Quality, and Water Meter Data	YES
2.4.5	Performance Standards, Forms, Marketing and Training Materials	YES
2.5.8	BMP Photo Documentation and Program Participation Database	YES
2.6.5	Sampling Station Photo Documentation; Post-Installation Flow, Water Quality and Water Meter Data	YES
2.7.2	Copy of Presentation and Meeting Materials	YES

TECHNICAL TERMS

303(d) Listings – List of waterbodies that have been determined to be impaired. Section 303(d) of the Clean Water Act requires states to establish a listing of all impaired waterbodies and rank those waterbodies according to priority for TMDL development.

Areas of Special Biological Significance (ASBS) – A subset of state water quality protection areas that require special protection. Waste will be discharged at a sufficient distance from these designated areas to maintain natural water quality conditions.

Best Management Practices (BMPs) – Schedules of activities, prohibitions of practices, maintenance procedures, and other management practices to prevent or reduce the discharge of pollutants to waters of the United States. BMPs also include treatment requirements, operating procedures and practice to control plant site runoff, spillage or leaks, sludge or waste disposal, or drainage from raw material storage.

California Ocean Plan – A water quality control plan for ocean waters of California, created by the State Water Resources Control Board. The California Ocean Plan establishes water quality objectives for California's ocean waters and provides the basis for the regulation of wastes discharged into the State's coastal waters

Conductivity – A measure of the ability of water to pass an electrical current. Conductivity in water is affected by the presence of inorganic dissolved solids. The more of these solids present, the higher the conductivity of the water.

Constituents of Concern – High priority constituents

Dissolved Organic Carbon – A broad classification for organic molecules of varied origin and composition within an aquatic system. A high level of dissolved organic carbon can be an indicator of excess runoff.

Dry Weather Flow – Nuisance runoff from landscaping or other water waste during dry weather. Dry weather flows do not include water from a precipitation event.

Edgescaping – Replacement of a strip of turf around the edge of an area with drought tolerant vegetation to create a buffer zone between the lawn and concrete. The idea is to prevent water from spraying onto hard surfaces to prevent runoff.

Evapotranspiration – The quantity of water transpired (given off), retained in plant tissues, and evaporated from plant tissues and surrounding soil surface. Quantitatively, it is expressed in terms of depth of water per unit area during a specified period of time.

Fecal Bacteria – Used to assess the microbiological quality of water because, although not typically disease causing, they are currently used as indicators correlated with the presence of several waterborne disease-causing organisms.

Flux Rate – the amount that flows through a unit area *per unit time*

Grab sample – A sample which is taken from a stream of flow on a one-time basis without consideration of the flow rate of the stream and without consideration of time

Low Precipitation Rate – A low precipitation rate (amount of water applied to an irrigated area, usually expressed as inches per hour) can reduce runoff and erosion.

Municipal Separate Storm Sewer System (MS4) – A conveyance or system of conveyances (including roads with drainage systems, municipal streets, catch basins, curbs, gutters, ditches, man-made channels or storm drains):

1. Owned and operated by a state, city, town, borough, county, parish, district, association, or other public body (created by or pursuant to state law) having jurisdiction over disposal of sewage, industrial wastes, stormwater, or other wastes, including special districts under state law such as a sewer district, flood control district or drainage district, or similar entity, or an Indian tribe or an authorized Indian tribal organization, or a designated and approved management agency under section 208 of the Clean Water Act (CWA) that discharges to waters of the United States;
2. Designed or used for collecting or conveying stormwater;
3. Which is not a combined sewer; and
4. Which is not part of a publicly owned treatment works (POTW).

National Pollutant Discharge Elimination System (NPDES) – A national program under Section 402 of the Clean Water Act for regulation of discharges of pollutants from point sources to waters of the United States. Discharges are illegal unless authorized by an NPDES permit.

Nutrients – Elements like nitrogen and phosphorous that are essential to healthy plant life, but in excess are detrimental to water quality. This project tests for nitrogen, phosphorous, dissolved organic carbon, ammonia, nitrate and orthophosphate.

Rotating Sprinkler Nozzles – Rotating nozzles have multiple rotating streams that distribute water evenly and apply water slowly, allowing time for water to soak into the soil, reducing runoff and conserving water. These nozzles also help save water by increased wind resistance and less misting.

SmarTimer – A SmarTimer is an irrigation controller that uses information on weather, soil moisture, rain, wind, evaporation rates, plant transpiration rates and more to determine when and when not to water, rather than watering on an owner-programmed set schedule. SmarTimers are more efficient than regular timers and can reduce water usage by 30% or more.

Seepage– flow of a fluid through soil pores

Surface Water Ambient Monitoring Program (SWAMP) – SWAMP is a statewide monitoring effort designed to assess the conditions of surface waters throughout the state of California. The program is administered by the State Water Board. "Ambient" Monitoring refers to the collection of information about the status of the physical, chemical, and biological characteristics of the environment.

Total Maximum Daily Load (TMDL) – A calculation of the maximum amount of a pollutant that a waterbody can receive and still meet water quality standards, and an allocation of that amount to the pollutant's sources. Water quality standards are set by the State of California. They identify the uses for each waterbody, for example, drinking water supply, contact recreation (swimming), non-contact recreation (fishing, nature enjoyment) and aquatic life support, and the scientific criteria to support that use. A TMDL is the sum of the allowable

loads of a single pollutant from all contributing point and nonpoint sources. The calculation must include a margin of safety to ensure that the waterbody can be used for the purposes the State has designated. The calculation must also account for seasonal variation in water quality (from federal Clean Water Act).

Ultrasonic Doppler – relies on the Doppler Effect to relate the frequency shifts of acoustic waves to the flow velocity.

Wash-off coefficient – ratio between concentration in runoff and the total concentration in the catchment area

Watershed – The geographic area draining into a river system, ocean or other body of water through a single outlet and includes the receiving waters. Watersheds are usually bordered and separated from other watersheds by mountain ridges or other naturally elevated areas.

Audubon CALIFORNIA

Starr Ranch Sanctuary

Habitat Restoration

Goal

At Starr Ranch, Audubon California protects and restores the last remaining wild habitats of Orange County. Starr Ranch serves as a regional model for groundbreaking non-chemical methods of restoration enacted by both community volunteers and highly qualified field crews. Our goal is to actively restore 1,600 acres of degraded habitat, representing approximately 40% of Starr Ranch's total acreage, by 2020.

About Starr Ranch

Starr Ranch is a 4,000-acre Audubon Sanctuary in Southern California's highly suburbanized Orange County. All native habitats and wildlife are becoming rare in California, and the Ranch protects some especially endangered vegetation types such as coastal sage scrub, needlegrass grassland, and riparian woodland as well as species such as the federally threatened California Gnatcatcher (a songbird) and orange-throated whiptail (a lizard). The Southern Californian wild landscape has been subjected to development, repeated fire, and now faces the uncertain impacts of climate change. Additionally, invasive plants damage habitats across all of California's native landscapes. After invasive species control, restoration of native habitat is the second essential step towards bringing back the remarkable wild Mediterranean-climate landscapes of Southern California.

Starr Ranch protects some of the last pristine (i.e. undeveloped and unburned since 1980) wild landscapes in Orange County, and the management of these critical habitats begins with abating the threat of invasive species. At Starr Ranch, we take an innovative approach to invasive species control and rare habitat restoration that is both research-based and done completely without the use of toxic herbicides. Our goal is to serve as a model for the southern Californian region of a rigorous, sustainable approach to land management. Starr Ranch's restoration work has received state and national recognition and is praised as "unique and cutting edge" by the U.S. Fish and Wildlife Service. Our restoration work focuses on three rare California native habitats on Starr Ranch: coastal sage scrub, needlegrass grassland and creek-side habitat (known as riparian habitat.) As of 2011, a total of 485 acres are under active management.

Coastal Sage Scrub Project

Coastal sage scrub (CSS) restoration at Starr Ranch began in 2001 using unique methods that were developed onsite by Audubon staff and are now used by other preserves and parks throughout Southern California. Restoration sites follow a documented trajectory of invasive species control, native planting, and establishment with follow-up treatments until they reach a functional state close to a natural system. The field crew that works in the uplands uses physical methods to control targeted invasive plants in project sites. We use experiments to develop and refine restoration techniques. Currently 172 acres of coastal sage scrub are being restored of the 485 total upland invasive control acres the crew covers, and 15-30 acres will be added each year until the ultimate goal of 250 acres is reached.

Needlegrass Grassland Project

In 1999, Starr Ranch initiated a carefully designed, experiment-driven, non-chemical removal of a high priority invasive species, artichoke thistle, in 270 acres of our best needlegrass grasslands out of a total 700 acres of infested sites on the Ranch. After only one year of treatment, thistle

populations are reduced by 95%. Native grassland enhancement will eventually occur in 450 acres of the 700. As of 2011, the Starr Ranch field crew is controlling invasive species and testing methods of enhancing existing native grasses in 298 acres of needlegrass grassland. The last remaining native grasslands are slated for invasive control and enhancement during the 2013-14 season.

Riparian Project

Creek-side habitat – known as a riparian zone – is the vegetation along a stream or river. The Starr Ranch riparian restoration project has been ongoing since 2003. Two seasonal interns mapped invasive plants during the first years of the project and now recruit community volunteers for the Weed Warriors program. In 2007, the Ranch began a cooperative riparian invasive control project with the Orange County Conservation Corps (OCCC), who serve at risk young adults, to remove invasive plants along Bell Creek, a riparian corridor that is almost 5 miles long. As of 2011, interns and Weed Warrior volunteers worked in a total of 4.4 acres of an 11 acre intensive management area that outlines the extent of a high priority invasive species (periwinkle) along the main riparian corridor of Bell Creek. Riparian work acreages are relatively low since only two interns and volunteers do most of the work, using hand tools for safety. We add about 0.5 – 2.0 new invasive control acres per season, and monitor and restore in all work acreage. Interns walk the Bell Canyon riparian corridor (232 acres), each season to map and control rapidly spreading invasive plants. It is our expectation that we will eventually add Crow Canyon to this project, a second major riparian zone representing 129 acres for which we have completed the mapping of invasive plants. Projection for riparian project completion is less certain than in uplands since annual numbers of volunteers and OCCC crew funding are highly variable. Additionally, degraded (i.e. dominated by invasive species) stream banks are much less discrete and measurable than are the upland sites that occur in patchy mosaics. Generally, we hope to have most degraded stream banks with priority invasives under control by 2020.

Summary of Long-term Project Goals

In total, it is our goal to actively restore 1,600 acres, representing approximately 40% of Starr Ranch's total acreage. At our current rate, we can expect to reach this goal by 2020.

Needs

To achieve our restoration goals, Starr Ranch is dependent on the seven young temporary staff, recent college graduates, hired each season. Since the staff lives in historic Ranch buildings, salaries can be kept relatively low, totaling $82,000 per year (CSS restoration in southern California can cost $60,000-120,000 per acre). Annual costs over the next five years will remain stable since older restoration sites require less staff time. With additional support services charges, the current annual budget for restoration, including equipment and supplies, is $145,465. Restoration is an ongoing, long term process. The threat of new invasive species, repeated fire, and climate change require continual and persistent management and monitoring, in an approach advocated by the Ecological Society of America. To maintain rare habitat work at Starr Ranch in such a manner would require $727,325 over the next five years.

Summary of Long-term Project Goals

Riparian – 361 acres *
Needlegrass grassland – 450 acres
Coastal Sage Scrub – 250 acres

Total of 1,601 acres

* Note: these total acreages for riparian based on GIS estimates of creek area. Using a standardized definition of riparian (100 feet from creek center line onto both banks), Bell Creek was estimated at 125 acres and Crow Creek at 84 acres.

April 2010

Baker Water Treatment Plant
Preliminary Design Report

Prepared for:
Irvine Ranch Water District
PR 11218

Prepared by:
RBF CONSULTING
carollo

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EXECUTIVE SUMMARY

GENERAL

This report presents a summary description of the Baker Water Treatment Plant Project, including the raw water conveyance system, pre-treatment systems, membrane system, post-treatment systems, and product water delivery systems. The intent of this Preliminary Design Report (PDR) is to document the work that has been completed, including existing facilities investigations and testing, analysis of alternatives, economic analyses, and preliminary design, and to describe the project that is being recommended for final design, including project economics and implementation schedule.

INTRODUCTION AND BACKGROUND

The Baker Water Treatment Plant (Baker WTP) is a regional project that will treat up to 43.5 cfs (28 mgd) of raw water imported from the Metropolitan Water District (MWD) or supplied locally from Irvine Lake, to drinking water standards to supply water agencies in southern Orange County.

Irvine Ranch Water District (IRWD) is the lead agency for the Baker WTP project. The Project Stakeholders and their respective project capacity rights as currently defined are:

- El Toro Water District – 5.0 cfs
- Irvine Ranch Water District – 10.5 cfs
- Moulton Niguel Water District – 13.0 cfs
- Santa Margarita Water District – 13.0 cfs
- Trabuco Canyon Water District – 2.0 cfs
- Municipal Water District of Orange County – 0 cfs

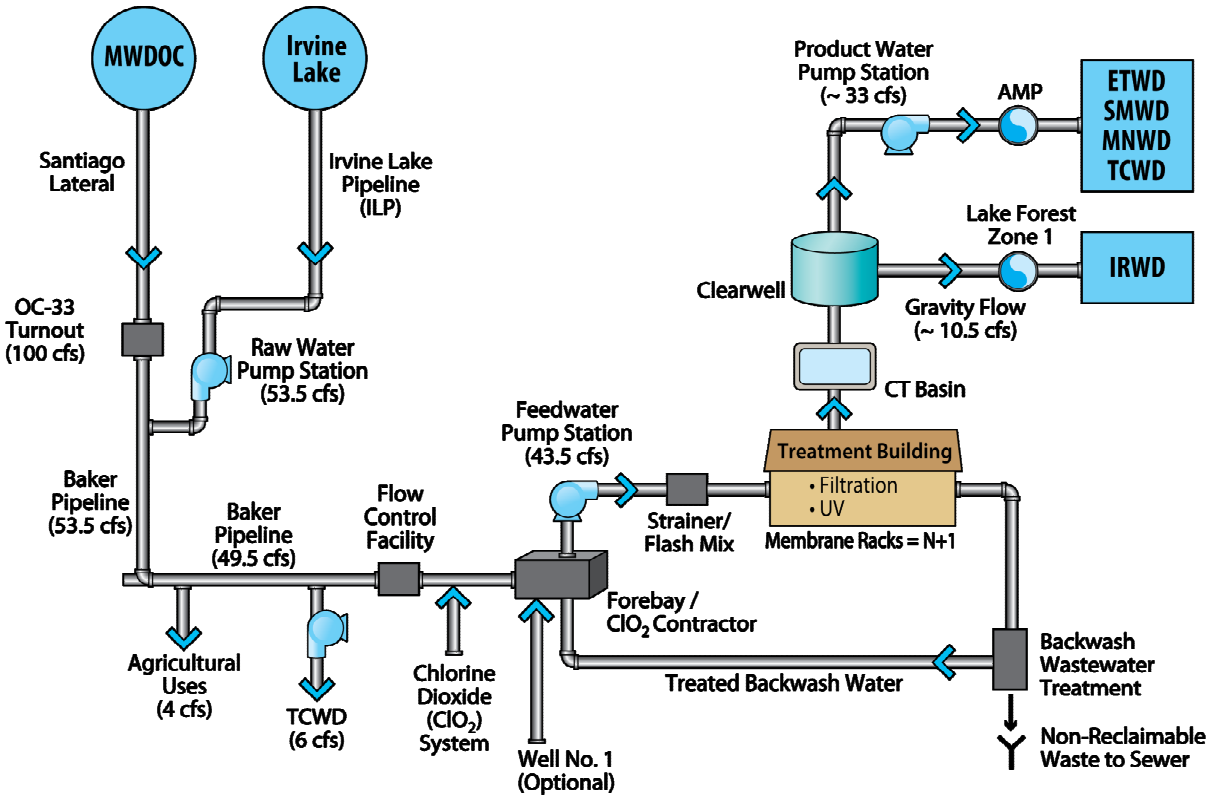
In December 1999, the Allen McColloch Pipeline (AMP) ruptured causing significant reduction in MWD supplies to south Orange County, and demonstrating south Orange County's dependence on AMP operation. The observed dependence on the AMP, led the Santiago Aqueduct Commission (SAC) to consider a new water treatment plant utilizing the Baker Pipeline for raw water transmission. In 2006, SAC and Project Stakeholders undertook a study to determine the feasibility of constructing a surface water treatment plant that could take advantage of already existing infrastructure, to develop a cost-effective local source of supply. This study concluded that such a project was feasible from both an engineering and cost perspective, and that existing infrastructure, primarily the SAC-owned Baker pipeline, Irvine Lake pipeline, and MWD owned AMP, could be used to convey raw water to the plant and deliver potable water to

local water agencies. The study also recommended that a new treatment plant using microfiltration membrane technology, pressure driven, be constructed at the former Los Alisos Water District (LAWD) Baker WTP site, located in the City of Lake Forest, near the terminus of the Baker pipeline and adjacent to the AMP. Subsequent engineering investigations have confirmed these recommendations, resulting in Project Stakeholders deciding to move forward with Project preliminary design.

PROJECT OVERVIEW

The Baker WTP Project has three primary components: raw water conveyance system, treatment system, and product water delivery system. Exhibit ES-1 schematically illustrates the proposed Baker WTP Project.

Exhibit ES-1 Baker WTP Project Illustration



The Baker WTP Project, starting at the OC-33 turnout, will use existing facilities or will construct new facilities that are located in the south Orange County cities of Orange, Irvine, and Lake Forest and unincorporated Orange County. The majority of new facilities, including all treatment processes, will be located at the former Los Alisos Water District Baker Plant site, located in the City of Lake Forest.

The following sub-sections briefly describe each of the Baker WTP Project primary components.

RAW WATER CONVEYANCE SYSTEM

The raw water delivery system is comprised primarily of existing facilities. New facilities include a raw water pump station, a pump station for TCWD, and flow control at the Baker WTP. Exhibit ES-2 shows an overview of the Baker WTP raw water delivery system.

For the majority of the year, the raw water source will be a blend of Colorado River Water (CRW) and State Project Water (SPW), delivered from MWD's Lower Feeder system to MWD's Santiago Lateral to SAC's Baker Pipeline, through the OC-33 turnout, and then to the Baker Plant.

During certain times of the year, and when MWD water is not available, the raw water source will be Irvine Lake, which stores a combination of MWD water (as described above) and surface runoff from the Irvine Lake watershed. Irvine Lake is jointly owned by IRWD and Serrano Water District. Irvine Lake water will be delivered to the plant via IRWD's Irvine Lake Pipeline (ILP), then to the Baker Pipeline and then to the Plant.

To deliver 43.5 cfs of Irvine Lake water to the Baker WTP at a required HGL of 690 ft, a raw water pump station is required. This raw water pump station is designed to pump water from the ILP into the Baker Pipeline. The raw water pump station is sized to deliver up to 43.5 cfs of Irvine Lake water to the Baker WTP, 6 cfs to TCWD, and 4 cfs for existing agricultural use, for a total capacity of 53.5 cfs. The proposed raw water pump station is located at the Peters Canyon site in the City of Orange. The pump station will be housed within a building.

Flow from the Baker pipeline will terminate at the Baker WTP at a new forebay. Flow control is required just upstream of the forebay to achieve an HGL sufficient to supply the forebay with the plant's raw water demand.

If IRWD's Well No. 1 (LAWD) is re-commissioned, it may provide a small additional source of raw water, and may be designed to deliver groundwater to the forebay. Therefore, it is assumed that water from Well No. 1 will undergo the same treatment process as the water delivered from the Baker Pipeline.

TREATMENT SYSTEM

Exhibit ES-3 illustrates the recommended treatment system. Selection of the treatment process for the Baker WTP was based on many factors, including raw water quality,

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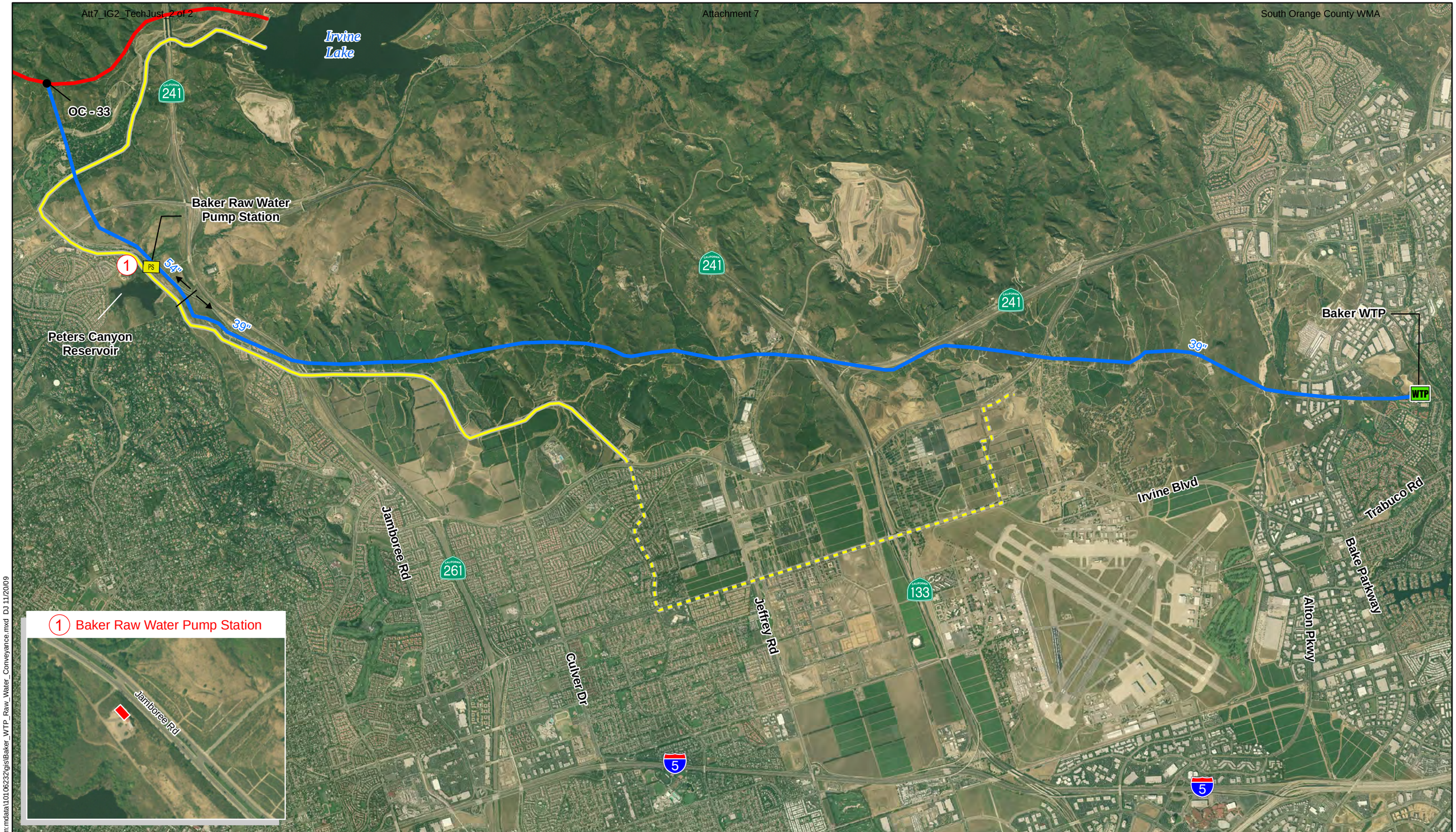

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RBF CONSULTING GIS

carollo Engineers...Working Wonders With Water™

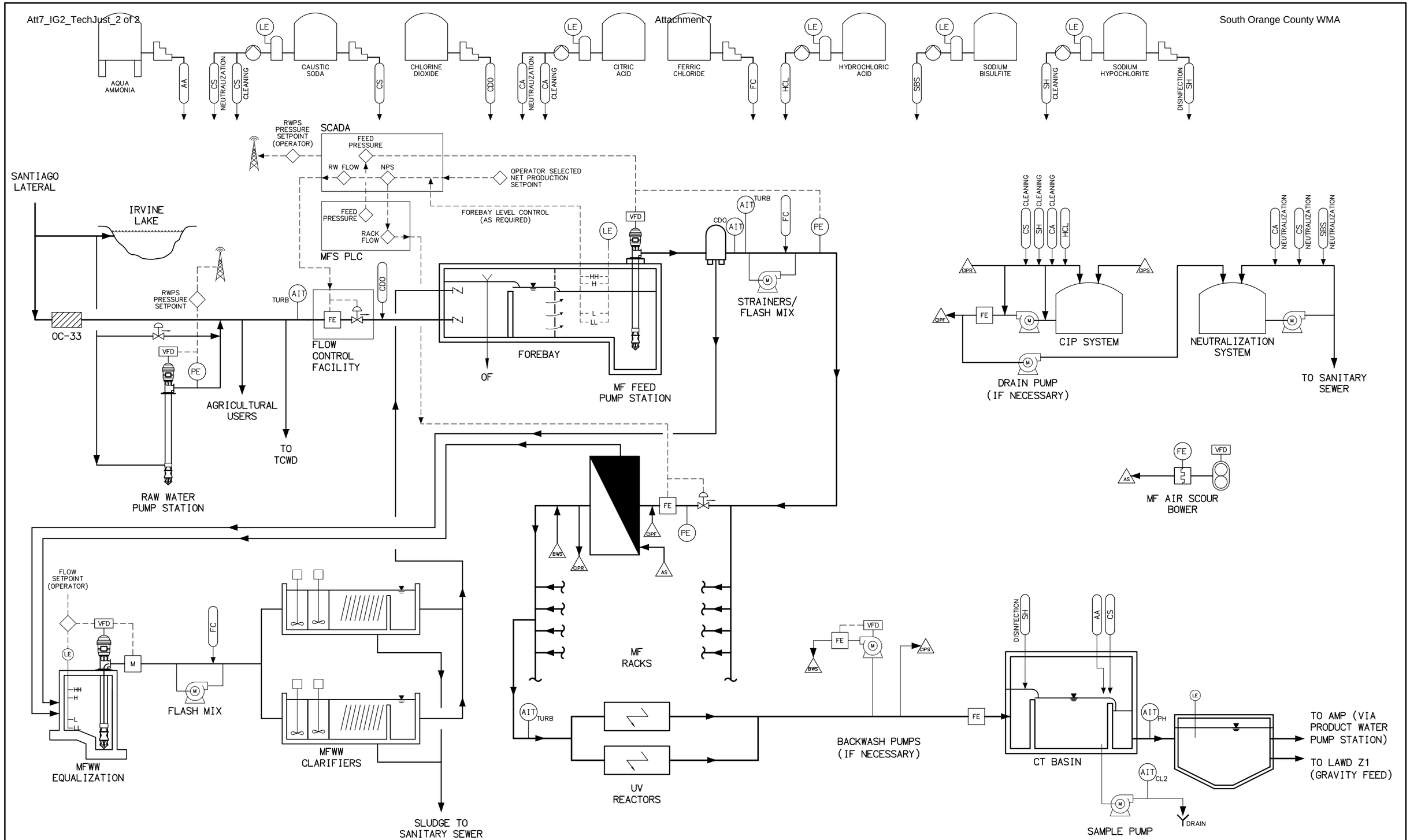
0 1 2 Miles

Baker Pipeline
Santiago Lateral
ILP (Future Recycled Water)
Irvine Lake Pipeline
Pump Station
Reservoir

Baker Water Treatment Plant

Raw Water System Overview

Exhibit ES-2



RBF CONSULTING	carollo	*IRVINE RANCH WATER DISTRICT* *BAKER WATER TREATMENT PLANT* PROCESS FLOW DIAGRAM	EXHIBIT ES-3

drinking water quality regulations (current and future), ease of operation, and life-cycle cost. Considerable focus was placed on ensuring that overall project costs, variable raw water quality, taste and odor flexibility, ease and cost of operation and maintenance, and plant footprint size were all acceptable. With all alternatives and factors presented and considered, IRWD and the Project Stakeholders confirmed the selection of pressurized membrane filtration for Baker WTP.

The main components of the treatment system are all located at the Baker WTP site and are briefly described below:

CHLORINE DIOXIDE PRE-TREATMENT

Chlorine dioxide will be used for pretreatment of iron and manganese when Irvine Lake water is being supplied to the plant. Through bench testing, it was determined that chlorine dioxide is the most effective pretreatment oxidant for Irvine Lake water, and is essential for prevention of membrane fouling. Effective removal of iron and manganese also will mitigate potential aesthetic issues of the product water and will ensure compliance with USEPA secondary MCLs.

Chlorine dioxide will be dosed upstream of the forebay, downstream of the flow control valve.

Chlorine dioxide will be generated at the plant, due to its inability to be compressed or stored commercially as a gas because of its explosive properties. It was decided that a three chemical combination, using sodium chlorite, sodium hypochlorite, and hydrochloric acid, would be used to generate the chlorine dioxide to avoid the need for chlorine gas storage and use at the plant.

Chemicals will be stored in a fully enclosed chemical building located on site.

FOREBAY AND FEED WATER PUMP STATION

The forebay will control or enhance hydraulic operations and treatment processes and will provide four primary functions:

- storage needed to equalize flow from the Baker Pipeline to the membrane filtration system (MFS),
- protection of the MFS from pressure surges in the Baker Pipeline,

- contact time for the chlorine dioxide pre-treatment system required when Irvine Lake water is supplied to the plant,
- serves as a forebay for the membrane feed water pump station.

The forebay is sized at 785,000 gallons and will be a cast-in-place, partially buried structure, with a roof system that will accommodate a fully enclosed Feed Water Pump Station.

The Feed Water Pump Station will transfer water from the forebay through the membrane system. Flow to the membranes will continually vary based upon a number of factors, including cycle times for backwash, chemically enhanced backwash, clean-in-place operations, and membrane integrity testing. Water levels in the forebay will vary due to the variation in flow between the Baker Pipeline supply and the variable feed water rates. Anticipated maximum feed pressures to the membrane system are in the range of 25 psi to 40 psi. The feed water pump station will be equipped with VFD-driven vertical turbine pumps and will be housed in a fully enclosed structure located on top of the forebay roof.

STRAINER / FLASH MIX SYSTEM

Wedge wire type feed water strainers (250 μm) will be used to remove debris and large particles from the flow stream that can damage and/or plug membrane hollow fibers and pores.

Coagulant will be fed upstream of the MFS to reduce the rate of membrane fouling and reduce the formation of disinfection by products. Coagulant must be thoroughly mixed for effective coagulation. A pump diffusion flash mix system will be used for this purpose. The final decision on coagulant is pending jar testing of Irvine Lake water to determine effectiveness to reduce TTHM formation potential. Jar testing will be performed by Carollo at the start of final design. The two coagulants under consideration are Polyaluminum chlorides (PACl)/aluminum chlorohydrates (ACH) and ferric chloride.

PRESSURIZED MEMBRANE FILTRATION (PMF)

Pressurized Membrane Filtration (PMF) is the core filtration process selected for the Baker WTP. PMF will be used at the Baker WTP to meet California Department of Public Health (CDPH) treatment requirements for turbidity removal and to partially satisfy the disinfection requirement.

The membrane filtration system will be designed to net 28 mgd. Additional water will be produced by the system for cleaning sequences (chemical cleaning and backwash). Feed water recovery has been specified to be a minimum of 92%.

The membrane system will be PVdF (Polyvinylidene fluoride) hollow fiber based systems, filtering water from outside to inside. Individual modules with capacities of 15 to 20 gpm are assembled on individual racks with common piping with capacities of 2 mgd to 3 mgd, depending upon the system manufacturer. A total of not more than 14 racks is anticipated, which includes one fully redundant rack.

The PMF equipment will be housed within a fully enclosed treatment building. The treatment building will contain the membrane filtration system (racks, cleaning, backwash and air subsystems, and controls), UV system, electrical equipment, control room, laboratory (wet room), and HVAC equipment.

From September to December 2007 (Phase I), and then from February to April 2008 (Phase II), pressure membrane system pilot tests were performed on Irvine Lake water and SPW. Two manufacturers were selected for the pilot testing: Pall and Siemens. Each of these manufacturers has been requested to prepare a bid for supplying the Baker WTP membrane system [Pall Microza – Module designation USV 6203 (MF); Siemens CP-Module designation L2OV (UF)]. The bids will be competitive, evaluated bids, with the basis of selection being a present worth analysis of chemical, energy, and membrane replacement costs, plus bid price. Bids are expected to be received April 2010.

BACKWASH WASTE WATER SYSTEM

Treatment and recycling of the combined waste washwater (CWW) minimizes plant waste discharges and maximizes plant feed water recovery. The Baker WTP will collect and treat waste water produced within the plant, and recycle this treated waste water to the head of the plant. The total or CWW for the Baker WTP comes from two sources: the membrane feed water strainers waste washwater (SWW) and the membrane filtration system waste washwater (MFWW), excluding chemical cleaning solutions. The estimated flowrate for the CWW depends upon the membrane system selected and performance, but is estimated to range between 0.5 and 3.0 mgd.

Seven alternative backwash waste water systems were investigated and from this screening process two alternatives, second stage membranes and plate settlers, were advanced for further evaluation. The final screening analysis resulted in conventional treatment utilizing plate settlers being recommended due to their adequate performance for the intended application, lower capital cost, and lower annual operating costs.

Discharges to the sanitary sewer will be greatly reduced due to the backwash waste water system. Residual discharges to the sanitary sewer are estimated to be about 130,000 to 200,000 gpd (primarily dependent upon the type of membrane system selected), and the instantaneous maximum flow is anticipated at 0.5 cfs (or 220 gpm).

With the backwash waste water system, the overall feed water recovery for the plant is estimated to be 99.5%, based on an average raw water flow rate of 28.1 mgd.

UV DISINFECTION

UV disinfection will be provided at the Baker WTP following membrane treatment to meet regulatory disinfection requirements. CDPH establishes total treatment requirements with respect to *Giardia*, virus, and *Cryptosporidium* reduction, based upon federal requirements in the Interim Enhanced Surface Water Treatment Rule (IESWTR) and the Long Term 2 Enhanced Surface Water Treatment Rule (LT2ESWTR).

With membrane filtration credits provided by the CDPH considered, the disinfection process requirements for the Baker WTP are 0.5-log *Giardia* inactivation and 4-log virus removal (see Table 2.3).

The primary goal of the UV disinfection is to achieve the 0.5-log *Giardia* inactivation. The virus removal requirement will be achieved by chemical disinfection.

The UV system can also be used for destruction of trace organic compounds through the use of higher UV doses alone and/or in combination with hydrogen peroxide as an advanced oxidation process (AOP). Use of UV for destruction of trace organics (including taste and odor causing compounds) assumes that granular activated carbon (GAC) contactors are installed downstream for removal of hydrogen peroxide and byproducts generated by this process. Treatment for taste and odor causing compounds at the Baker WTP is limited to space planning for a future GAC system, and expandability of the UV system for AOP.

The UV system design also considered CDPH notification level for N-nitrosodimethylamine, more commonly referred to as NDMA, to account for future expandability needed in the UV system to achieve high UV doses for photolysis of NDMA.

A low pressure high output (LPHO) UV system was selected for the Baker WTP, after evaluation with medium pressure systems. The evaluation primarily centered around capital cost, life cycle cost, space requirements, and operations and maintenance requirements.

CONTACT (CT) BASIN

Following UV disinfection, the treated water will flow into a partially-buried concrete contact (CT) basin to provide disinfection contact time per CDPH regulations. The basin will be sized to provide adequate contact time for free chlorine to meet the 4-log virus inactivation requirement. This criteria assumes that the membrane filtration system is provided zero credit for virus inactivation.

Alternate sodium hypochlorite injection points will be provided in the basin to allow for manual adjustment of dosing points, in order to minimize TTHM formation during periods of low plant flow or when contact time in the CT basin is increased.

Post-treatment chemicals to be injected at the CT basin include: sodium hypochlorite for disinfection, aqua ammonia for chloramine formation, and caustic soda for pH control. Metering pumps for post-treatment chemicals will be paced on a flow meter located immediately upstream of the CT basin and adjusted based on a chlorine residual analyzer.

From the contact basin, the treated water flows to IRWD's existing 16 MG clearwell.

PRODUCT WATER DELIVERY SYSTEM

The product water delivery system includes an existing 16 MG clearwell, a new product water pump station, and the existing Allen McColloch Pipeline (AMP). All product water from the plant will initially be stored in existing Zone 1 (LAWD) reservoir, which will be converted to the Baker WTP clearwell. For design purposes, the HGL variation in the reservoir was set to fluctuate between 600 and 621 feet amsl.

A Product Water Pump Station (PWPS) will be constructed at a capacity of 33 cfs, which is based upon the total plant production of 43.5 cfs, minus IRWD's capacity allocation of 10.5 cfs. IRWD's capacity allocation will be delivered directly to their Zone 1 (LAWD) system through an existing 24-inch diameter pipeline.

The discharge hydraulic conditions of the PWPS are based upon the hydraulic grade line of the AMP. The AMP HGL varies greatly between summer (high demand) and winter (low demand) conditions. The absolute minimum and maximum HGL in the AMP are understood to be a low of 630 ft and a high of 806 ft per MWD's drawing B-416427 (AMP Hydraulic Plan and Profile). MWDOC has analyzed the AMP pipeline under peak day (maximum day demands) up to the year 2035. Based on this analysis, the lowest (non-surge) stable HGL was determined for 2035 to be approximately 703 ft at OC-88 (South County Pump Station), and 701 ft at OC-74 (IRWD connection point on the Baker site), which are within the range provided by Flow Science.

Hydraulic analysis verified the HGL fluctuation in the AMP require variable speed drives to maintain discharge flow under variable conditions. Speed reduction down to 70-percent was considered in selecting the type and number of pumps. It is recommended that for low discharge head conditions (below 690 feet), the flow into the AMP should be managed by pressure reduction with a throttling valve.

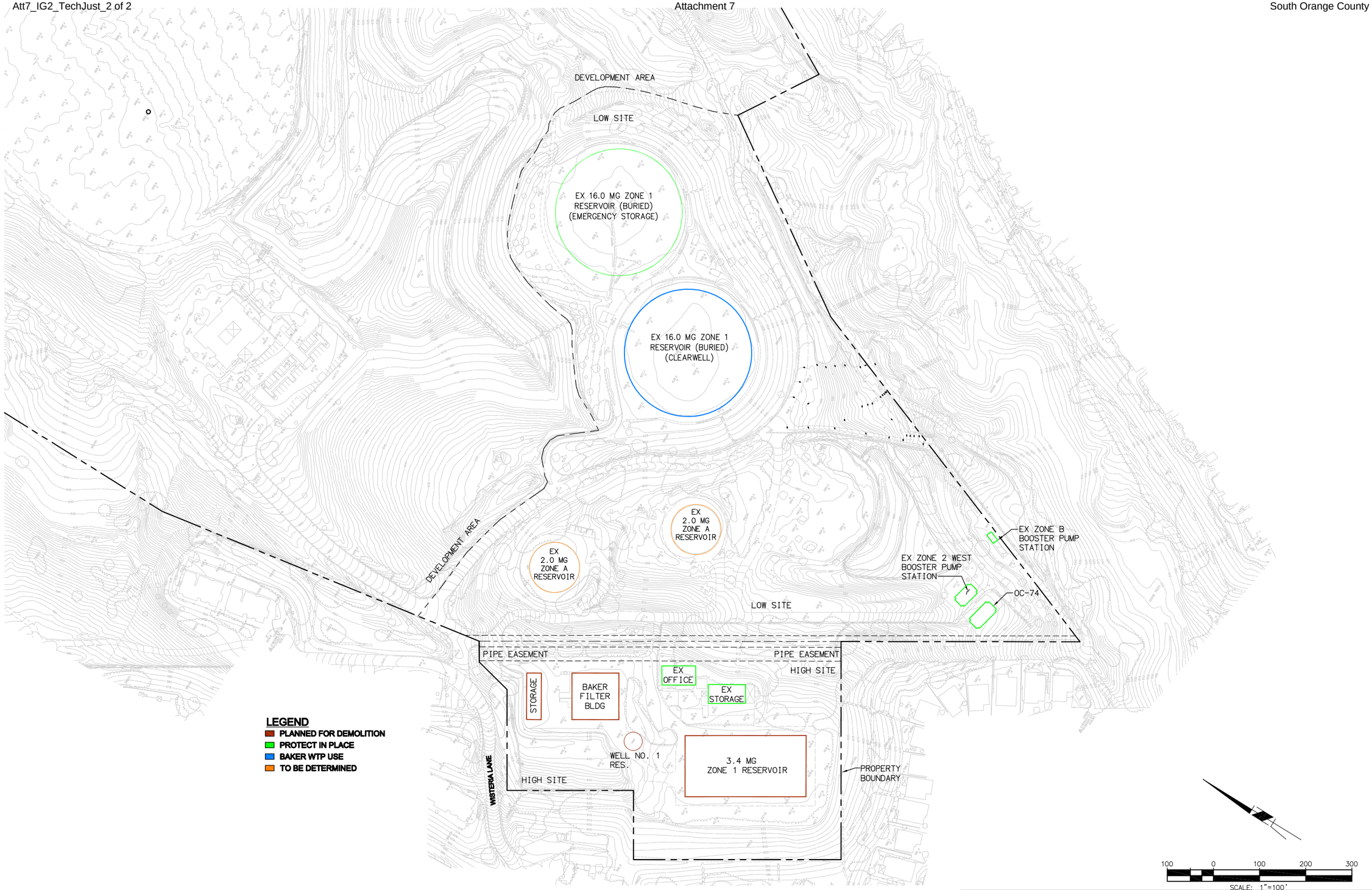
The design of the PWPS includes four (4) vertical turbine type duty pumps + one (1) stand-by pump configuration. The pump station will housed in a building, and will include an air conditioned electrical room with five variable frequency drive controllers. Equipment exterior to the building will include a surge tank, SCE transformer, switchboard, and power generator.

BAKER SITE

The Baker WTP will be located at the former Los Alisos Water District (LAWD) Baker Water Treatment Plant (WTP) site. Currently, there is existing operation of on-site facilities to provide supplemental water from the Baker Pipeline to the Zone A (LAWD) recycled water system, to supply demands to a nearby equestrian center and, at times provide make up water from local man made lakes. The original Baker Filter building will be demolished as part of this project, along with several other facilities, namely: storage building, 3.4 million gallon cast-in-place reservoir, Well No. 1 onsite storage and piping system. Prior to demolition IRWD will need to make provisions for an alternative supply of water to serve these demands.

The new Baker WTP will primarily be constructed at the “high” elevation area of the site. Several buildings will be protected-in-place in this area, namely the administration office and adjacent storage building. Exhibit ES-4 shows existing onsite facilities that will require demolition and those required to be protected-in-place.

The layout of the new Baker WTP is shown on Exhibit ES-5. The decision to construct the Baker WTP at the high elevation area was a result of cooperation between IRWD’s development group, which is planning to improve the Baker site’s low elevation area to include a future park and natural treatment system (NTS) basin, and IRWD’s engineering staff and consultant. There are several facilities that will be constructed at the low elevation site area. These facilities include a pipeline required to deliver water from the Baker WTP to the 16 MG clearwell, electrical service conduit, Trabuco Canyon Water District (TCWD) pump station, flow control facility, product water pump station and associated piping. These facilities have been sited to minimize potential for interference with proposed development plans.



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RBF CONSULTING

carollo

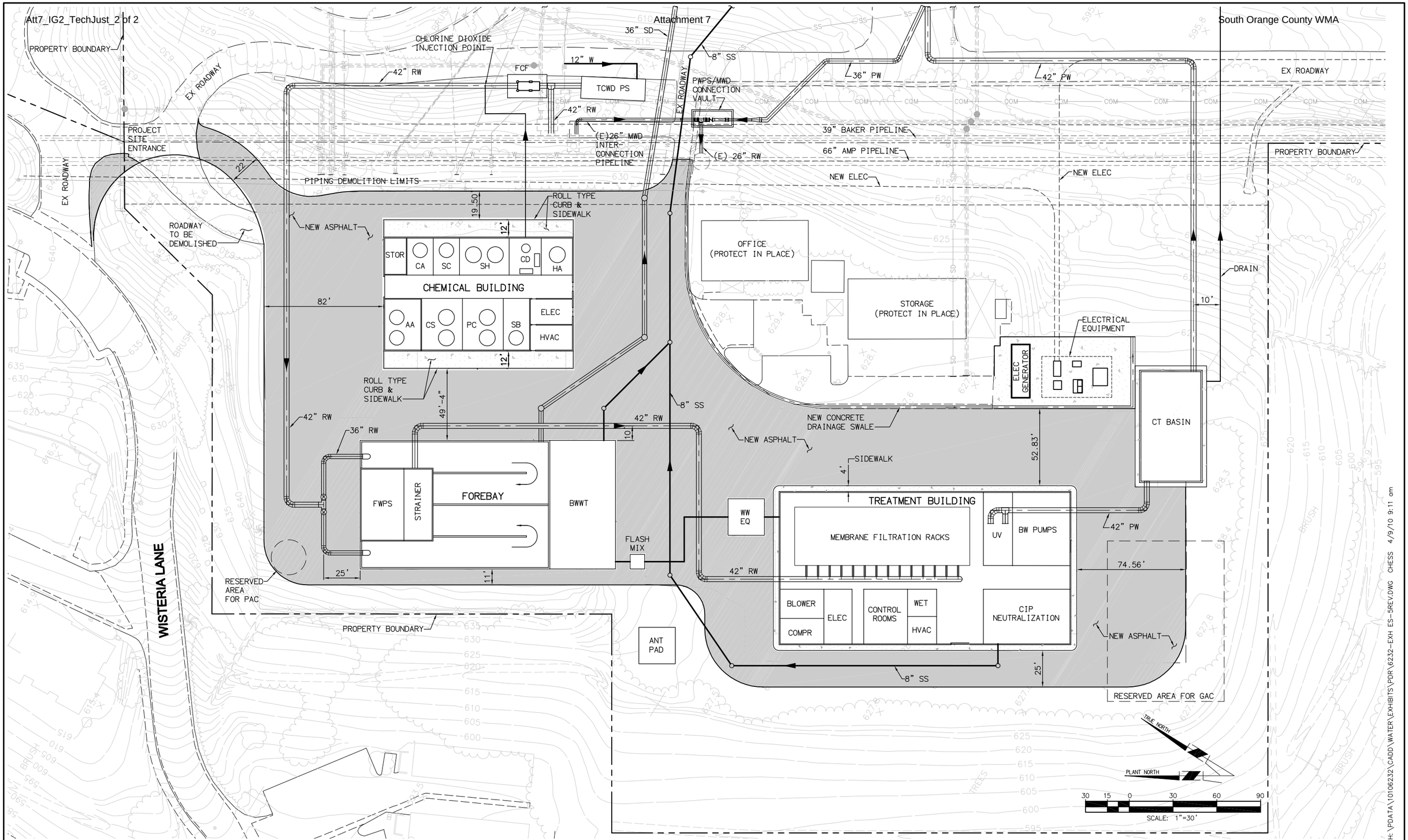
IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

BAKER SITE
EXISTING FACILITIES

EXHIBIT

ES-4



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RBF CONSULTING

carollo

IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

PROPOSED SITE LAYOUT

EXHIBIT

ES-5

ECONOMIC EVALUATION

For the Baker WTP Project, an economic evaluation was conducted. All costs are presented in April 2010 dollars (ENR Index = 8676). The capital costs approximate Class 3 budget estimates as defined by the Association for the Advancement of Cost Engineering (AACE). Estimates provided herein have an associated accuracy of -10 percent to +30 percent. Class 3 level estimates are intended for budget, authorization, or control.

CAPITAL COST

An updated estimate of construction cost has been prepared for the Baker WTP Project. Construction costs were converted to capital cost by including contingencies and non-construction project related costs to the estimate. A summary of these estimates are provided in Table ES-1. Cost estimates are included in Section 23 and Appendix Q of this report.

OPERATION AND MAINTENANCE COST

Operation and maintenance (O&M) costs have been developed from several data sources and engineering calculations. Table ES-2 contains a summary of the estimated annual O&M cost. A breakdown of the O&M costs is given in Section 23.

ANNUALIZED COST ESTIMATES

Annualized capital cost (with repayment over 30 years @ 4.5 percent) and annual O&M costs, were converted to $/acre-foot of water unit cost based on anticipated water volume production. The plant is assumed to have a 90 percent utilization throughout the year. Future projections, in $/acre-foot of water, to the year 2028 were developed based on inflation assumptions and anticipated escalation of fees as described in Section 23.

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Table ES-1 - Baker WTP Project - Summary of Estimated Capital Costs [1]

Baker Water Treatment Plant	Cost
Equipment and Buildings	
WTP Equipment, Sitework and Buildings	$31,869,000
Mobilization / Insurance / Management [2]	$2,550,000
Subtotal (Equipment and Buildings)	***$34,419,000***
Integration Facilities	
OC-33 Expansion	$240,000
Raw Water Pump Station	$2,908,000
Flow Control Facility, Forebay Reservoir, TCWD PS and Feed Water PS	$4,300,000
Product Water Pump Station	$3,504,000
Backup Power	$1,250,000
Mobilization / Insurance / Management [2]	$976,000
Subtotal (Integration Facilities)	***$13,178,000***
SUBTOTAL (Equip. and Bldgs + Int. Facs.)	***$47,597,000***
District Costs [3]	**$2,200,000**
Baker Site Land Use Cost [4]	**$440,000**
Environmental [5], Engineering[6]	**$4,607,000**
Contingency / Legal [7]	**$6,611,000**
TOTAL ESTIMATED CAPITAL COST	**$61,455,000**

[1] Capital cost are Class 3 Estimates as defined by AACEI with estimated -10% to +30% range of accuracy

[2] Mobilization / Insurance / Management Cost calculated at 8-percent of capital cost

[3] Cost provided by IRWD - includes project management, field support, construction administrative services, inspection and G&A.

[4] Cost for land use at Baker Site per Baker WTP Agreement Section 3.1. Area = 4 acres. Unit Cost = $110,000 /acre

[5] Environmental Documentation cost is based on EIR preparation cost provided to IRWD of $170,000.

[6] Based on approved design fee for Baker WTP plus authorized flow test budget, and design fee for forebay and feed water pump station.

[7] Contingency / Legal is based on 15-percent of Subtotal (Equipment and Buildings + Integration Facilities excluding cost for Moblization, Insurance and Management).

Table ES-2 Estimated Annual O & M Cost Summary

Baker Water Treatment Plant [1]	Value
1 Chemical Mixing	$3,800
2 MF System	$716,300
3 UV System	$21,200
4 Process Chemicals	$1,212,100
5 Energy Costs from Pumping	$1,516,300
6 Washwater Pumping	$15,900
7 Labor [2]	$379,600
8 Other System O&M Costs [3]	$75,000
Cost per Year ($) [4]	**$3,940,000**

[1] Energy, Chemical, and Consumables (Replacement) costs are escalated at an annual rate of 5-percent.
[2] Labor costs are based on weekly operator staffing of T5 (40 hrs) and T4 (30 hrs), with escalation of 3-percent annually.
[3] Other O&M costs are escalated at a annual rate of 3-percent.
[4] Based on 90% treatment plant utilization (evaluated at 330 days per year). Rounded to nearest $1,000.

ECONOMIC EVALUATION RESULTS

The estimated capital cost of the project (in April 2010 dollars), including construction, engineering, environmental, construction management and administration, is $61,455,000.

The estimated annual operation and maintenance costs (in 2010 dollars), including energy, chemical and replacement costs, labor, and other ongoing costs is $3,940,200.

The cost of Baker WTP water is estimated as $766 per acre-foot, assuming capital cost amortized over 30 years at 4.5-percent interest, and excluding the cost of wheeling water still be finalized with MWD. Based upon rate projections provided by MWD, it is anticipated that treated water from the Baker WTP will cost the same as imported water by the year 2017, approximately 5 years after project startup, and at lower cost thereafter.

SCHEDULE

Table ES-3 summarizes the proposed project schedule.

Table ES-3 Baker WTP Schedule Summary

Construction Contract/ Milestone	Start Date	Finish Date
Raw Water Pump Station / OC-33 Modf.		
Design	April 2010	March 2011
Bidding & Award	March 2011	May 2011
Construction	June 2011	June 2012
Baker Water Treatment Plant		
Design	April 2010	March 2011
Bidding & Award	March 2011	May 2011
Construction	June 2011	November 2012

SECTION 1 INTRODUCTION

1.1 PROJECT OBJECTIVES

The Baker Water Treatment Plant (Baker WTP or Project) is a regional project, intended to:

- Increase potable water supply to south Orange County,
- Improve water reliability to areas of south Orange County by providing a local treatment plant, capable of treating water from MWD as well as local Irvine Lake water.
- Deliver a local potable water supply that can be relied upon in the event of emergency conditions or scheduled maintenance of the Metropolitan Water District's delivery system
- Produce potable water at a competitive cost to MWDOC treated water rates.

1.2 PROJECT BACKGROUND

The Baker WTP project will augment potable water supplies to parts of south Orange County, California by locally treating and delivering Colorado River Water, State Project Water, and Irvine Lake Water. South Orange County currently receives the majority of its potable water from Municipal Water District of Orange County (MWDOC) via Metropolitan Water District's (MWD's) Diemer Filtration Plant and Allen McCulloch pipeline, and is lacking large-scale alternative local supplies. This Project will provide a reliable local supply to south Orange County and is a result of years of coordination by south Orange County water agencies.

Several years ago, the Santiago Aqueduct Commission (SAC) undertook a study to determine the feasibility of constructing a surface water treatment plant that could take advantage of already existing infrastructure, to develop a cost-effective local source of supply. This study concluded that such a project was feasible from both an engineering and cost perspective. Part of this cost effectiveness is due to the use of existing infrastructure, primarily the SAC-owned Baker pipeline and Irvine Lake pipeline, which could convey raw water to the plant and MWD owned Allen McCulloch pipeline (AMP), which could be used to deliver potable water to local water agencies. The study also concluded that the treatment plant location was best suited at the former Los Alisos Water District (LAWD) Baker WTP site, located in the City of Lake Forest, near the terminus of the Baker pipeline and adjacent to the AMP.

Following completion of the SAC study, participating water agencies, identified in this report as Project Stakeholders, solicited proposals from Consultants, and selected the RBF/Carollo team to execute preliminary and final design tasks necessary to solicit competitive bids for construction, and to provide engineering support through construction and commissioning.

1.3 PROJECT STAKEHOLDERS

The Baker WTP Project is being implemented by Project Stakeholders. The Stakeholders include five (5) south Orange County water retail agencies, and the area's MWD member. These agencies are:

- El Toro Water District (ETWD)
- Irvine Ranch Water District (IRWD)
- Moulton Niguel Water District (MNWD)
- Santa Margarita Water District (SMWD)
- Trabuco Canyon Water District (TCWD)
- Municipal Water District of Orange County (MWDOC) - MWD member

The retail agencies are jointly financing the project. Each agency's financial participation will be proportionate to their capacity rights' shares in the project. MWDOC's participation in the Project is to facilitate coordination between the retail agencies and MWD and assisting in the water billing function. IRWD is the lead agency for the Baker WTP project, responsible for managing design, overseeing construction, and will also be responsible for operating and maintaining the plant.

All five water retail agencies are expected to receive water from the Baker WTP, and are expected to hold capacity rights to the plant.

1.4 BAKER WTP CAPACITY ALLOCATIONS / EXISTING FACILITIES CAPACITY RIGHTS

Capacity allocations in the Baker WTP are defined in the *Agreement for Construction, Operation and Maintenance of Baker Water Treatment Plant,* which was revised in December 2009 to reflect the Baker WTP capacity as 43.5 cfs. The capacity allocation among the Stakeholders in the Baker WTP is anticipated to be according to Table 1.1.

Each of the Stakeholders has unique water rights in the Baker Pipeline (managed by the Santiago Aqueduct Commission) and Allen McColloch Pipeline

(managed by Metropolitan Water District of Orange County). See Table 1.1 for a summary of capacity in both pipelines and the Baker WTP.

Table 1.1 – Stakeholder Summary

Agency	Baker WTP Capacity (cfs)	Existing Water Rights in Baker Pipeline	Existing Water Rights in AMP (through MWDOC)
Irvine Ranch Water District (IRWD)	10.5	Y	Y
El Toro Water District (ETWD)	5	N	Y
Moulton Niguel Water District (MNWD)	13	N	Y
Santa Margarita Water District (SMWD)	13	Y	Y
Trabuco Canyon Water District (TCWD)	2	Y	N
Total	**43.5**	-	-

Exhibit 1.1 depicts a portion of the Santiago lateral, the Baker Pipeline, the Irvine Lake Pipeline, and the Baker site.

1.5 PROJECT CONCEPT DEVELOPMENT

The development of the Baker WTP project concept as described in this PDR has evolved through a number of steps, including:

1.5.1 Feasibility Study

In August 2006, the Santiago Aqueduct Commission commissioned a feasibility study to investigate the concept of a treatment plant serving supplemental treated water to agencies of Southern Orange County. With water supply reliability as a focal point of the study, water supply to the Baker Pipeline was considered from Metropolitan Water District (MWD) and Irvine Lake. MWD receives supplies of Colorado River Water (CRW) and State Project Water (SPW). Thus, three primary water source types exist for the Project.

The feasibility study was completed January 2007, and amended in June 2007 to include further financial analysis. Analysis covered operational capacities of 33 and 40 cfs. Potential treatment processes were analyzed based on cost, treatment plant layout, and the capability of each process to effectively treat each water source type. The study concluded with the recommendations for the Baker WTP to be:

1) located at the Baker Site in Lake Forest, and
2) a pressure membrane filtration plant with disinfection by UV / chlorination.

1.5.2 Pilot Testing

Following the feasibility study, pilot testing with two pressure membrane filtration systems (Pall and Memcor CP/Siemens) was performed on Irvine Lake and State Project water. The final bench test report was completed in June 2007. The pilot test report was completed in August 2008. The pilot report verified adequate treatment by both manufacturer system, and established maximum flux rates for each of:

- Pall = 50 gfd
- Memcor = 45 gfd

1.5.3 Technical Memorandum

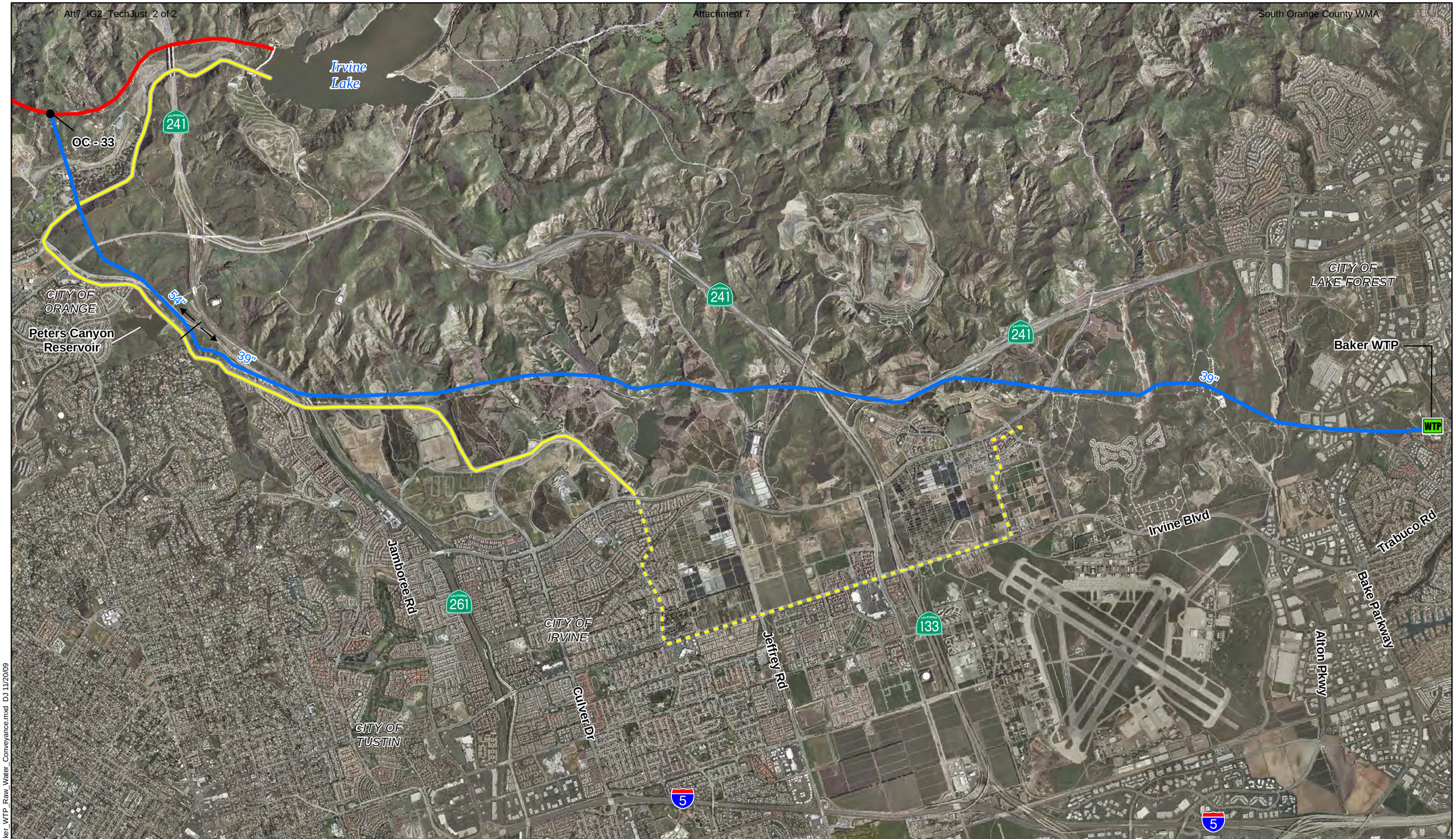
Following the award for design of Baker WTP, the RBF/Carollo engineering team completed a technical memorandum entitled *The Baker Regional Water Treatment Plant – Design Concept and Cost Update* in November 2008. The memorandum updated the preliminary design concept for Baker WTP at capacities of 40 and 60 cubic feet per second (cfs) in advance of a Baker Pipeline flow test, and estimated capital, operations and maintenance and product water costs, and compared these costs to the June 2007 financial analysis. Conclusions were that costs were generally comparable, assuming the same design configuration is implemented.

1.5.4 Baker Pipeline Flow Test

On April 21, 2009 a flow test of the Baker Pipeline was completed. The purpose of the flow test was to determine the current pipeline capacity based on the minimum hydraulic grade necessary to operate pressure membranes without pumping. Following the flow test, RBF Consulting prepared a preliminary design memorandum that summarized the results, and estimated the maximum capacity of the Baker Pipeline to be 40 cfs (based on a minimum required HGL of 720 ft at the Baker WTP site for pressurize membrane filtration at the high site elevation

1.5.5 Preliminary Design Memoranda

In May 2009, RBF/Carollo began submitting preliminary design memoranda (PDMs) to IRWD for the major project components. The purpose of the PDMs was to summarize the Project in greater detail, identify design-related issues associated with each major project component, identify alternatives, present evaluation of alternatives, make



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Baker Pipeline
Santiago Lateral
ILP (Future Recycled Water)
Irvine Lake Pipeline (ILP)

Baker Water Treatment Plant
Project Overview
Exhibit 1.1

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recommendations, identify design criteria, and receive client feedback on major issues and decisions, as required. Each PDM was delivered to IRWD and distributed to the Project Stakeholders. Collectively, fifteen PDMs were prepared, as listed.

1. Baker Pipeline Hydraulics
2. Iron and Manganese Management
3. Product Water Pump Station
4. Membrane Filtration
5. Raw Water Conveyance Facilities / Raw Water Pump Station
6. Baker Plant Site – Facility Layouts / Plant Hydraulics
7. Pre-Treatment
8. Backwash Wastewater Treatment and Recovery
9. Chemical Storage
10. Disinfection
11. Electrical – Site Infrastructures
12. Instrumentation and Controls
13. Pump Station – Surge Analysis
14. Cost Estimate
15. Back-up Power Generation

Internal meetings were held with IRWD to review client comments. All review comments received from the PDMs are incorporated in this Preliminary Design Report.

1.5.6 Historical Overview

The Baker WTP project entails construction of a new membrane filtration plant at the Baker site. The Baker site was owned by the Los Alisos Water District, and utilized as the agency's headquarters and location of the Baker Filter Plant. The Baker Filter Plant was constructed in 1970 and had a rated capacity of 15 cfs. As water quality regulations became more stringent it was not cost effective to upgrade the Baker Filter Plant, so the plant was decommissioned.

When residential development increased in Southern Orange County in the mid-1970s, the need for a larger transmission pipeline became evident. In 1977, the design of the Diemer Intertie or Allen McColloch Pipeline (AMP) began. The AMP was constructed to deliver treated

imported water to southern Orange County from the Diemer Plant located in the City of Yorba Linda. Demand increased in the AMP, leading to the need for a parallel pipeline. During construction of the AMP Parallel a reach of the 54-inch section of the Baker Pipeline was utilized. To replace the reach for the Baker Pipeline a new reach of 39-inch pipeline was constructed.

As residential development increased, reliance on raw water through the Baker Pipeline diminished. Eventually, Baker Pipeline operation was reduced to delivery of water for remaining agriculture use (approximately 4 cfs) and Trabuco Canyon Water District's Dimension Plant (maximum flow rate of 6 cfs).

In December 1999, the Allen McColloch Pipeline ruptured causing significant reduction in MWD supplies to southern Orange County, and demonstrating the dependence of this region on AMP operation. The observed dependence on the AMP, led the Santiago Aqueduct Commission to consider a new water treatment plant utilizing the Baker Pipeline for raw water transmission, and to begin seeking Project participants (Stakeholders).

1.6 SUMMARY OF PROJECT

The Baker WTP project consists of existing and proposed facilities for raw water conveyance, water treatment and product water delivery. A schematic diagram summarizing the Baker WTP project and ownership of facilities is provided as Exhibit 1.2.

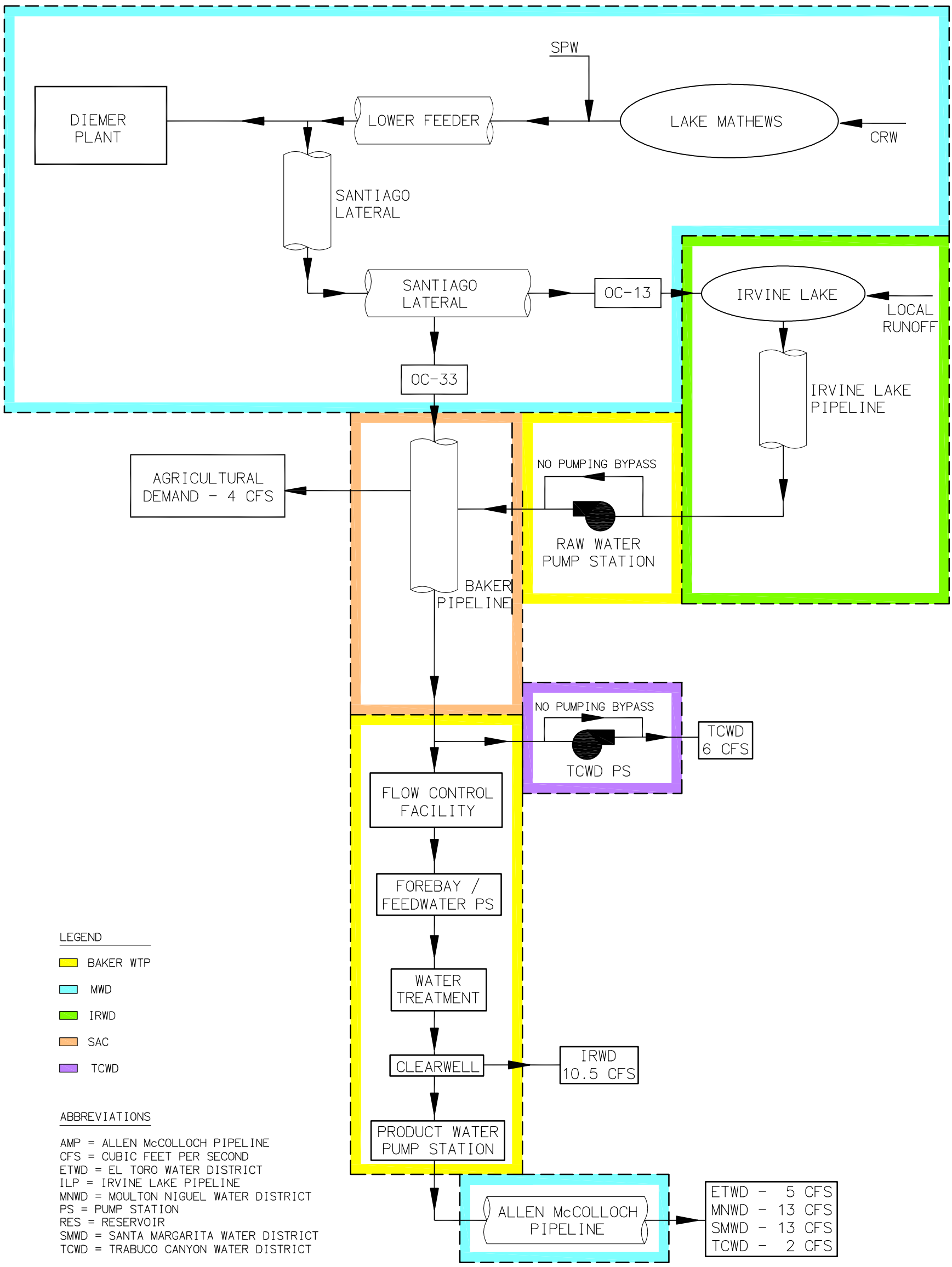
The following descriptions provide a brief summary of the overall project. Further details regarding each aspect of the overall Project are provided in the later sections of the Preliminary Design Report.

1.6.1 Raw Water

The sources, facilities and operation to ensure raw water supply include:

1.6.1.1 Sources

Raw water conveyed to the Baker WTP will be imported water from the Metropolitan Water District (MWD) system, or Irvine Lake water. The MWD system will supply Colorado River Water, State Project Water or a combination of both. Irvine Lake water will be used under two conditions:



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carollo

IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT
PROJECT SUMMARY SCHEMATIC

EXHIBIT 1.2

1) outage of Santiago Lateral or Diemer Filtration Plant (emergency conditions or scheduled maintenance)

2) as determined annually - based on rainfall conditions and Irvine Lake water level, not exceeding a three month period.

Small additional flow may be delivered to the Baker WTP from IRWD's Well No. 1, which is approximately 1 mile west of the Baker WTP.

1.6.1.2 Conveyance System

Primary operation of Baker Pipeline will consist of raw water supplied by gravity from the Santiago Lateral to the Baker WTP. Secondary operation will convey Irvine Lake water to the Baker WTP by pumping (Raw Water Pump Station) from the Irvine Lake Pipeline to the Baker Pipeline. Primary and secondary operation will supply up to 43.5 cfs (28 mgd) for treatment.

A forebay will be constructed at Baker WTP to manage variable treatment process flow rates and isolate the Baker WTP from the hydraulics of the Baker Pipeline. Flow and head conditions into the forebay will be controlled by a flow control facility, consisting of a motor operated sleeve valve. A pump station (Feedwater Pump Station) will be constructed to boost water from the forebay to pressure membrane filters. The pump station will boost raw water from the forebay to the hydraulic grade required for filtration through the membrane media.

1.6.2 Operation

Raw water delivery will be scheduled with Metropolitan Water District. All flows scheduled but not delivered through the OC-33 turnout will result in discharge to Irvine Lake. However, flow rejection should only occur during plant shutdown or transfer from Santiago Lateral to Irvine Lake supply.

Raw Water Conveyance System operation will require communication and analysis of flow rates at OC-33, Baker Raw Water Pump Station, the Flow Control Facility and

Feedwater Pump Station; hydraulic grades at the Baker Raw Water Pump Station and Feedwater Pump Station; and water surface level at Irvine Lake and the forebay for proper operation.

1.6.3 Treatment Process

Baker WTP will utilize pressure membrane filtration for treatment, and include pre-treatment and backwash waste water treatment / recovery for optimum plant production.

1.6.3.1 Pre-Treatment

Raw water pre-treatment will include the use of strainers and dosing of coagulant, upstream of the membrane filters. In addition, Irvine Lake water will introduce higher levels of iron and manganese in the raw water supply. As a result, chlorine dioxide will be dosed into Irvine Lake water upstream of forebay ensuring oxidation for removal by filtration.

1.6.3.2 Membrane Filtration

Pressure membrane filters will be installed in the treatment building for Baker WTP. The treatment process will be designed for a maximum raw water delivery of 43.5 cfs (28 mgd), and backwash waste water recovery.

1.6.3.3 UV Disinfection

UV disinfection will be located downstream of the pressure membrane filters to provide additional disinfecting primarily for Giardia inactivation, with all equipment contained within the treatment building.

1.6.3.4 Chloramination Disinfection

Secondary disinfection will be in the form of chloramination, with a CT Basin constructed adjacent to the treatment building.

1.6.3.5 Backwash Waste Water Treatment / Recovery

Backwash waste water will be collected from the feedwater strainer system and membrane filtration system for treatment and recovery. The recommended backwash treatment system is sedimentation with plate settlers constructed at an elevation

enabling water recovered from the sedimentation basin to flow to the raw water forebay by gravity.

1.6.4 Product Water Delivery

Treated or 'product' water from Baker WTP will flow by gravity from the CT basin to an existing on-site reservoir to serve as the clearwell. From the clearwell product water will be distributed by gravity or pumping. The clearwell and product water distribution system are describe further:

1.6.4.1 Clearwell

An existing 16 MG reservoir formerly operated by Los Alisos Water District as Zone 1 emergency storage will be modified for use as the Baker WTP clearwell.

1.6.4.2 Gravity Delivery

IRWD will be the only agency receiving product water by gravity. IRWD's capacity of up to 10.5 cfs (approximately 4,700 gpm) will be conveyed through the existing 24-inch outlet pipeline from the clearwell to the IRWD's Los Alisos Zone 1 system.

1.6.4.3 Product Water Pump Station

To deliver product water to all other Project stakeholders, a new pump station will be constructed to boost water from the clearwell to the Allen McColloch Pipeline. The pump station will have a design capacity of 33 cfs (approximately 14,800 gpm). The proposed capacity by agency is as follows:

- El Toro Water District – 5 cfs
- Moulton Niguel Water District – 13 cfs
- Santa Margarita Water District – 13 cfs
- Trabuco Canyon Water District – 2 cfs

1.6.4.4 Allen McColloch Pipeline

The Allen McColloch Pipeline (AMP) crosses the Baker site in parallel to the Baker Pipeline and immediately east of the new WTP. The pipeline will convey pumped flow from the clearwell to the Project Stakeholders.

Connection to the AMP will be made at the vault on the Baker site which was constructed during the Baker Pipeline / Allen McColloch Pipeline temporary inter-connection, when the AMP was being repaired.

1.7 PRELIMINARY DESIGN REPORT OBJECTIVES

The objectives of the Baker WTP Preliminary Design Report are:

- Definition of the overall Baker WTP concept
- Presentation of Preliminary Design analysis
- Economic evaluation, including capital and operation / maintenance costs, and product water cost comparison with imported water.

SECTION 2 SOURCE WATER, REGULATIONS AND TREATMENT OBJECTIVES

2.1 OVERVIEW

This section identifies the water sources for the Baker Water Treatment Plant Project, summarizes the quality of those sources, discusses the impact of existing and anticipated regulatory requirements, and details the product water quality goals.

2.2 RAW WATER SOURCES

Raw water sources for the Baker WTP include existing supplies and possible future sources. Existing sources of supply include imported water from Metropolitan Water District (MWD), Irvine Lake, and a possible future supplemental supply from IRWD's Lake Forest Well No. 1. Exhibit 2.1 shows the raw water sources.

2.2.1 Metropolitan Water District (Santiago Lateral)

MWD water will be the primary supply source for the Baker WTP. Imported water from MWD will be delivered through the Santiago Lateral to the Baker Pipeline at MWD's OC-33 turn-out. Imported water supply from MWD for Baker WTP will consist of a blend of Colorado River Water (CRW) and State Project Water (SPW).

The ratio of this blend has varied significantly in recent years, and can be anticipated to vary in the future. The composition of the blend from MWD depends upon the delivery of State Project Water, which can be limited based on drought conditions and environmental constraints. Each year the California Department of Water Resources sets a 'Table A Allotment' which determines the distribution of water through the State Project system. As a result of the recent drought and environmental constraints limiting SWP flow through the Bay Delta, the percentage of SPW was significantly reduced within the Lower Feeder and Santiago Lateral in 2008 and 2009. The reduction altered the percentage of SPW to CRW from, approximately 50% CRW:50% SPW in 2007, to 93% CRW:7% SPW in 2008.

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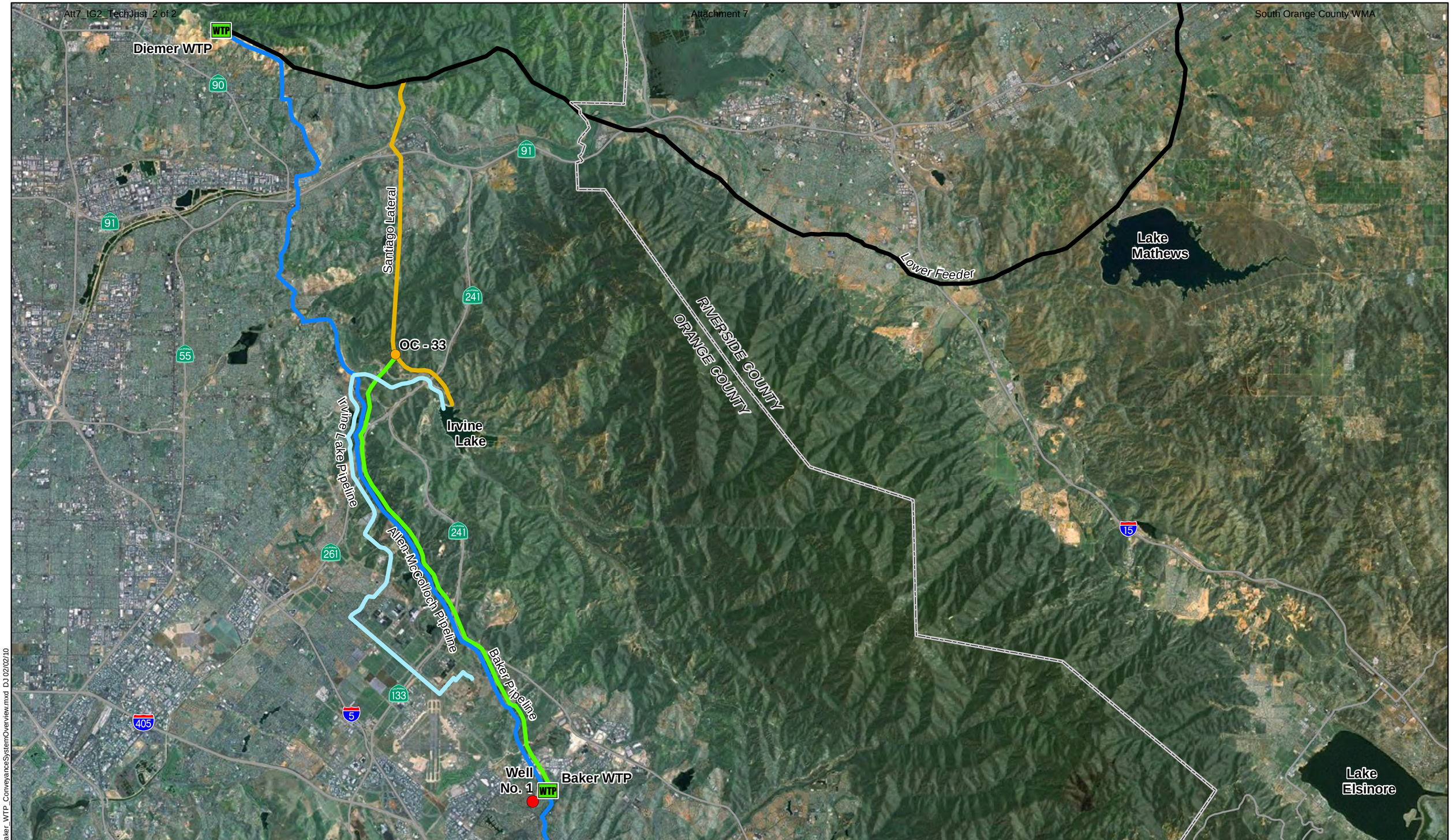

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Well No. 1
Allen-McColloch Pipeline
Baker Pipeline
Irvine Lake Pipeline
Lower Feeder
Santiago Lateral

Baker Water Treatment Plant Project

Raw Water Sources

Exhibit 2.1

In terms of treatment approach, SPW supply is a driver for a number of processes selected for the plant. Organic material in SPW is prone to chlorinated disinfection byproduct formation, specifically trihalomethanes (THM). Raw SPW and low CRW to SPW blends represent a worst case for meeting disinfection goals without exceeding applicable MCLs for THM, therefore for design purposes it is anticipated that imported water supply from MWD will be in the form of:

- 100% SPW, or
- 50% / 50% blend of CRW and SPW

2.2.2 Irvine Lake Water (ILW)

Water to Irvine Lake water is derived from two sources: MWD imported water via the Santiago Lateral, described above, and local run-off water captured from the Irvine Lake watershed.

Irvine Lake stores up to 28,000 AF and currently varies in depth from (EL.) 710 to 790 ft. Like any lake, Irvine Lake is subject to seasonal limnological phenomena. The phenomena include algae blooms which may produce additional fresh biologically derived organic carbon, and may increase coagulant demand while reducing filtration rates.

Algae blooms may also produce compounds that have a noxious taste and odor. These compounds may also be toxic and can be difficult to remove during conventional filtration and disinfection.

2.2.3 Lake Forest Well No. 1

Lake Forest Well No. 1 (owned and operated by IRWD) is a potential supplemental supply source for the Baker WTP. In the past, the well has been operated to supply to the Baker Filter Plant, local irrigation and make-up water for nearby community lakes. The current capacity of the well is estimated to be approximately 200 gpm (Boyle 2002).

A benefit/impact study was prepared by Carollo Engineers. The study recommended that, should water from Well No. 1 be used at the Baker WTP, it be added to the MF waste washwater equalization basin to allow for clarification and recirculation to the head of the plant. This approach also eliminates the need for constructing a well to waste system and utilizes the already planned facilities to handle solids with the sludge removal system. The study is provided as Appendix A.

Subsequent to this study, with the addition of the forebay, the recommendation has been revised to deliver Well No. 1 flows to the forebay. Accommodations will also be provided to deliver the flow to the CT basin, if accepted by California Department of Public Health.

2.3 ANTICIPATED RAW WATER QUALITY

An estimated range of raw water quality was prepared based on an understanding of the current and possible future raw water sources described above. The raw water quality estimate focused on parameters that will be critical to meet the anticipated product water quality.

The key raw water quality parameters for plant design and operation are:

- Total Dissolved Solids (TDS) - TDS levels in CRW can be as high as 700 mg/L, exceeding the secondary (recommended) maximum contaminant level (SMCL) of 500 mg/L. Though MWD had set a goal of 325 mg/L of TDS for delivery, there has not been adequate SPW available in recent years to blend CRW water below the SMCL of 500 mg/L. Product water TDS will be solely dependent on the blend provided by MWD.

- Total Organic Carbon (TOC) - TOC in SPW is known to have a strong tendency to form disinfection by-products (DBPs) when chlorine is used. The TOC level in ILW is comparable to the TOC level in SPW. To minimize DBPs, chloramines will be used as the residual disinfectant in the distribution system. Additional processes recommended to minimize DBP formation are in-line coagulation and UV disinfection.

- Temperature - Membrane system capacity decreases at low water temperatures due to higher water viscosity. The minimum water temperature used for design is 10° Celsius for the membrane system, since excursions below 10°C are uncommon. Historic low temperatures (4°C) will impact CT requirements for virus inactivation and have been taken into account in the CT basin design.

- Alkalinity – Alkalinity, including carbonate alkalinity, measures the highest in Irvine Lake Water.

- Hardness - The blending strategy to be implemented by MWD will dictate finished water hardness, since hardness removal is not a treatment goal for the Baker WTP. While hardness removal is not a treatment goal for the main

plant process, a softened carrier water system will be provided to avoid scaling caustic soda, sodium hypochlorite, and aqua ammonia diffusers.

- Turbidity - Raw water turbidity in CRW, SPW and ILW are low enough to accommodate direct filtration by membrane.

- Bromide - Bromide is primary to the formation of bromate and organohalide disinfection by-products. Chloramination will serve as the control strategy for bromate formation.

- Iron and Manganese - Neither is known to have detrimental health effects. However, they can be associated with unpleasant taste and odor, and staining of laundry and fixtures. Iron and manganese have a secondary MCL of 0.3 mg/L and 0.05 mg/L, respectively. Most significant to Baker WTP is the potential for dissolved forms to adversely impact membrane filtration (See Section 8 – Iron and Manganese Management). Chlorine dioxide will serve as the control strategy for iron and manganese oxidation.

A summary of raw water quality anticipated from the three primary source types is provided in Table 2.1.

Table 2.1 – Water Quality by Source[1]

Parameter	Unit	50% Colorado River Water (CRW) - 50% State Water Project (SPW)		100% State Water Project (SPW)		100% Irvine Lake (ILW)	
		Avg	Max	Avg	Max	Avg	Max
TDS	mg/L	470	565	248	430	575	640
TOC	mg/L	2.8	3.3	2.8	4.7	3.2	4.6
Temperature	°C	8 (min)	25	4 (min)	25	13 (min)	27
Hardness	mg/L as CaCO3	195	270	99	158	330[2]	--
Alkalinity	mg/L as CaCO3	100	115	72	98	160[2]	--
Turbidity	NTU	2.5	21	3.5	41	6	35
Bromide	mg/L	0.10	0.20	0.20	0.48	0.082	0.14
Total Iron	µg/L	ND[3]		ND		189	>300
Total Manganese	µg/L	ND		ND		35	>50

Notes:
1. Assumes the Baker WTP could receive 100% SPW to a blend of 50% SPW – 50% CRW or 100% ILW.
2. Two analyses only.
3. Non Detectable, typ.

2.4 CURRENT AND ANTICIPATED REGULATORY REQUIREMENTS

Baker WTP will provide water in adherence with current and pending rules and regulations regarding surface water treatment and disinfection by-products dictated by state and federal regulations.

2.4.1 California Department of Public Health (CDPH)

Current regulatory requirements for product water at the Baker WTP will be dictated by the CDPH, Division of Drinking Water and Environmental Management. The regulatory requirements are set forth in the California Code of Regulations, Title 22.

The CDPH drinking water standards are equivalent to or more stringent than national primary drinking water standards as established by the Environmental Protection Agency (EPA). Baker WTP will meet these standards as listed in Title 22 of the California Code of Regulations, and adhere to standards and best practices related to:

- Product water primary maximum contaminant levels (MCL)
- Product water secondary maximum contaminant level (SMCL)
- Public health goals (PHG)
- Water quality reporting
- Use of best available treatment technology

Title 22, Chapter 17 contains nine Articles pertaining directly to surface water treatment. Table 2.2 summarizes the pertinent Articles.

Table 2.2 – Title 22 Surface Water Treatment Articles

Article	Synopsis
1-General Requirements and Defintions	Establishes treatment techniques in lieu of maximum contaminant levels for turbidity and certain microbial contaminants. Provides definition of terms.
2-Treatment Requirements, Watershed Protection Requirements and Performance Standards	Provides multibarrier treatment requirements. Provides requirements for avoiding filtration. Provides requirements when filtration is necessary. Provides requirements for recycled flow. Provides disinfection requirements.
3-Monitoring Requirements	Provides monitoring requirements.
3.5-Enhanced Filtration and Disinfection	Provides enhanced requirements for systems serving at least 10,000 people.
4-Design Standards	Provides minimum design standards for surface water treatment processes.
5-Operation	Provides operator requirements.
6-Reporting	Provides reporting requirements to the SWRCB.
7-Watershed Sanitary Surveys	Provides requirements for sanitary surveys of the watershed, which must be completed every five years.
8-Public Notification	Provides requirements for notification of customers.

2.4.2 Long Term 2 Surface Water Treatment Rule

Baker WTP will treat surface water originating from MWD's lower feeder, a blend of CRW and SPW, or Irvine Lake. As a result, the Project will be subject to the Long Term 2 Enhanced Surface Water Treatment Rule (LT2ESWTR), a federal water treatment regulation established to define requirements for, and assess Crytosporidium removal.

In the case that source water is susceptible to Crytosporidium contamination, membrane filtration must meet three criteria for construction and operation.

1. The process must comply with the definition of membrane filtration as stipulated by the LT2ESWTR, and thus be a separation process with a maximum particulate size, physical barrier and demonstrated efficiency to the Environmental Protection Agency (EPA).

2. The removal efficiency of the membrane filtration process must be established through a product-specific challenge test and direct integrity testing. *Note: In California, third party challenge testing*

results need not be conducted at every site. Previous third party testing for the membrane filters under consideration for the Baker WTP will be used to meet this requirement.

3. The membrane filtration system must undergo periodic direct integrity testing and continuous indirect integrity monitoring during operation.

The total disinfection requirements for Giardia, virus, and Cryptosporidium are presented in Table 2.3. Dedicated disinfection processes must meet the balance of the disinfection requirements not met by membrane filtration (equivalent to 0.5-log Giardia inactivation and 4-log virus inactivation).

Table 2.3 – Summary of Regulatory Disinfection Requirements

	Required Log Reduction		
	Giardia	**Virus**	***Cryptosporidium***
Treatment Requirements			
Federal Treatment Requirements[1]	3.0	4.0	2.0[2]
Additional Requirements for Membrane Facilities[3]	1.0	0	2.0
Additional Disinfection Requirements[4]	0.5	0	0
Total Treatment Requirements	4.5	4.0	4.0
Membrane Filtration Credit	4.0	0.5-2.0[5]	4.0[6]
Disinfection Process Requirement	0.5	4.0[7]	0.0

Notes
1. Based on federal requirements in the Surface Water Treatment Rule, IESWTR and LT2ESWTR.
2. Based on results of *Cryptosporidium* source water monitoring program by the Serrano Water District on ILW (Bin 1).
3. Membrane facilities in California are currently required to be operated and maintained to achieve 4-log *Cryptosporidium* and *Giardia* removal.
4. California requires additional disinfection downstream of filters of 0.5 log *Giardia* or 4-log virus.
5. 0.5 for MF pressurized systems, 2.0 for UF ZW500d submerged system.
6. Based on full compliance with the IESWTR and LT2ESWTR.
7. Current membrane integrity testing methods cannot verify virus removal as required by the USEPA Membrane Filtration Guidance Manual. It is recommended that the District achieve virus inactivation though free chlorine disinfection.

2.4.3 Disinfection By-Products

Compliance with Stage 1 and 2 Disinfectants / Disinfection Byproducts Rule (D/DBPR), which establishes the maximum residual disinfectant goals for chlorine, chloramines, and chlorine dioxide, maximum contaminant level goals four trihalomenthanes (THM), two haloacetic

acids (HAA), bromate and chlorite according to the National Primary Drinking Water Regulations, and regulations for the State of California.

2.4.4 Potential (Future) Treatment Goals

The CDPH has established a notification level for three nitrosamines including N-nitrosodimethylamine (NDMA) at 0.01-µg/L. Other potential contaminants of concern including atrazine and 1,4 dioxane. These standards are not enforceable, and there is no data to suggest that these are specifically applicable to the sources water for the Baker WTP. Space has been reserved on site for construction of an advanced oxidation process (AOP) using medium pressure UV reactors and granular activated carbon. Section 15 provides a discussion of UV reactor selection and recommends low pressure high output system for this project.

2.4.5 Other Dedicated Treatment Requirements

In addition to the water quality and monitoring standards, CDPH Title 22, Chapter 17 mandates the treatment plant design and construction includes the following:

- Alarm devices to provide warnings of process failures
- Standby replacement equipment available to assure continuous operation and control of unit processes
- Continuous turbidity monitoring
- Multiple filter units which provide redundant capacity when filters are out of service for backwash or maintenance.

2.5 TREATMENT OBJECTIVES

The following requirements hold for treatment of surface water for Baker WTP:

- Daily effluent turbidity of <0.3 NTU in 95-percent of samples
- 4.5-log Giardia inactivation/removal
- 4.0-log Crytosporidium inactivation/removal
- 4.0-log virus inactivation/removal
- Iron and manganese removal

2.6 PRODUCT WATER QUALITY GOALS

Baker WTP will be designed with established minimum product water quality goals, based upon State of California Department of Public Health (DPH) standards, and additional project specific goals as described below.

2.6.1 Turbidity

Turbidity standards require that 95% of turbidity standards taken each month be less than 0.3 NTU, with a maximum of 1 NTU. Because membrane filtration will be used, performance requirements in the membrane procurement specification require filtered water turbidity to be less than 0.1 NTU 95% of the time with a maximum of 0.15 NTU.

2.6.2 Iron and Manganese

The three primary objectives of iron and manganese management are:

- Finished water with iron and manganese concentrations below their respective SMCL.
- Prevention of membrane fouling. Review of literature and troubleshooting of membrane plants suggests that an iron concentration as low as 0.05 mg/L and a manganese concentration as low as 0.02 mg/L is an appropriate target for these constituents in the membrane filtrate.
- Reasonable effort to minimize customer aesthetic complaints. Review of literature suggests that iron level as low as 0.1 mg/L and manganese level as low as 0.02 mg/L in the finished water could generate complaints.

Based on the above considerations, the following treatment goals were established

- Manganese level in MF feed water: 0.02 mg/L
- Iron level in MF feed water: 0.05 mg/L

2.6.3 Chlorine Dioxide

Chlorine dioxide used for iron and manganese control (see Section 8) must comply with the Maximum Residual Disinfectant Level (MRDL) of 0.8 mg/L in the finished water. However, a project specific limit of 0.2 mg/L will be met to prevent potting of the Pall membrane module.

2.6.4 Chlorite

Typically, the reaction of chlorine dioxide produces approximately 50 to 70 percent conversion of chlorine dioxide to chlorite (weight to weight basis). The MRDL for chlorite leaving the Baker WTP is 1.0 mg/L, resulting in the need to limit the chlorine dioxide dose to a maximum of 1.4 mg/L.

2.6.5 Disinfection Byproducts

Virus disinfection with free chlorine in source waters for the Baker WTP is anticipated to result in formation of Total Trihalomethane (TTHM) and Haloacetic Acids (HAA). In order to comply with related standards, goals of 64 μg/L for TTHM after free chlorine disinfection (80% of the MCL of 80 μg/L), and 48 μg/L of HHA (80% of the MCL of 60 μg/L) have been selected for the Baker WTP. This allows for additional formation of 10% to 15% in the distribution system following chloramination.

2.6.6 Total Chlorine

Chloramine concentration in the distribution system must be compatible with MWDSC's level, since the two sources will be blended in the AMP and could be blended in IRWD's system. Therefore, the minimum free chlorine residual at the end of the chlorine contact basin should be 2 mg/L.

Table 2.4 provides a summary of the project Product Water Quality Goals.

Table 2.4 – Product Water Quality Goals Summary

Constituent	Units	Goal
Turbidity	NTU	<0.3 NTU 95% of the time
Manganese	mg/L	<0.02 mg/L
Iron	mg/L	<0.05 mg/L
Chlorine Dioxide	mg/L	<0.2
Chlorite	mg/L	<1.0
TTHMs	μg/L	<64
HAA	μg/L	<48
Corrosivity		Non-corrosive
Total Chlorine	mg/L	2 mg/L

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SECTION 3 RAW AND PRODUCT WATER CONVEYANCE HYDRAULICS

3.1 OVERVIEW

This section describes the hydraulic conditions for the facilities that feed the Baker WTP and deliver product water to customers. The facilities that were subjected to hydraulic analyses include both existing and proposed systems:

Raw (Untreated) Water Facilities

- MWD facilities, including the Santiago Lateral and OC-33 turnout,
- Existing raw water facilities, including the Baker pipeline, Irvine Lake, and Irvine Lake Pipeline, and
- Proposed raw water facilities, including the Raw Water Pump Station, flow control facility, forebay, and Feed Water Pump Station.

Baker Water Treatment Plant

Product (Finished) Water Systems

- Clearwell,
- Product Water Pump Station, and
- The Allen McColloch pipeline.

Included are descriptions of existing and proposed facilities, system operation, and overall project hydraulics.

3.2 MWD SYSTEM

MWD delivers State Project and Colorado River Water through the Lower Feeder to the Santiago Lateral. The Santiago Lateral supplies the Baker Pipeline through the OC-33 turn-out located north of Irvine Regional Park. Exhibit 3.1 provides an overview of the pipelines that will influence hydraulics to the Baker WTP Project.

3.2.1 Santiago Lateral

The Santiago Lateral is a pipeline of approximately 8.7 miles in length, ranging in diameter from 72-inch at its upstream end, to 48-inch at its terminus in Irvine Lake. The pipeline receives State Project and Colorado River Waters from MWD's Lower Feeder. The Santiago Lateral was

constructed, by MWD, in 1956, to deliver raw water to the City of Anaheim and several water districts. Currently, the active service connections on the lateral are:

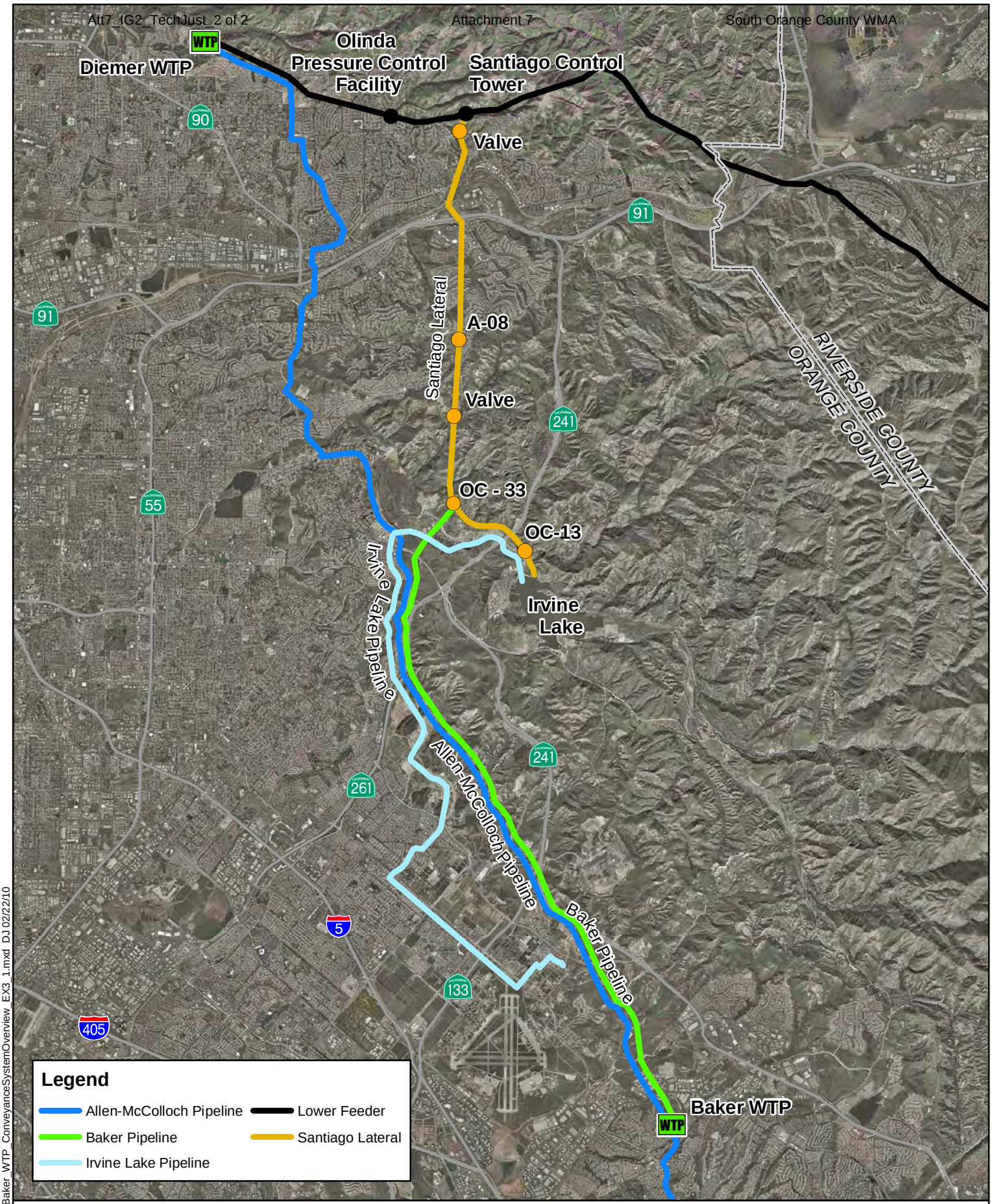
- A-08 serves 23 cfs to the City of Anaheim's Walnut Canyon Reservoir and Water Treatment Plant.
- OC-33 supplies a current capacity of 40 cfs to the Baker Pipeline.
- OC-13 is an in-line meter on the Santiago Lateral that conveys up to 100 cfs to Irvine Lake

The design capacity of the pipeline, at its headworks (Santiago Control Tower) on the Lower Feeder, is 150 cfs. The capacity is reduced to 100 cfs about halfway along its length, and continues at this capacity to Irvine Lake. In 2002, MWD performed a flow test for the Santiago Lateral and concluded that the flow through OC-13 should be limited to 100 cfs. During the test, flows at A-08 and OC-33 were 20 cfs and 19 cfs, respectively.

Releases into the Santiago Lateral originate at the Santiago Control Tower. The Santiago Control Tower communicates with the Olinda Pressure Control Facility located downstream of the control tower on the Lower Feeder. When the water surface level, in the control tower, moves outside of the preset range (962 feet to 966 feet) the Olinda facility either reduces or increases the flow in the Lower Feeder, as necessary, in order to maintain the preset range (HGL) in the tower.

There are two sectionalizing valves on the Santiago Lateral – one just downstream of the Venturi meter, near the tower, and another at the upstream end of the Santiago Tunnel. The former valve is not used to regulate flow, whereas the valve at the tunnel is sometimes throttled to control flow to OC-33 (described below) and OC-13 (turn-out to Irvine Lake). Downstream of the tunnel, flow in the pipeline is unregulated, and cascading flow occurs at several locations when the flow to the lake is insufficient to raise the HGL, in the lateral, above the pipeline's summits.

Exhibit 3.2 shows the pipe and hydraulic profiles of the Santiago Lateral.



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Baker Water Treatment Plant Project

Conveyance System Overview

Exhibit 3.1

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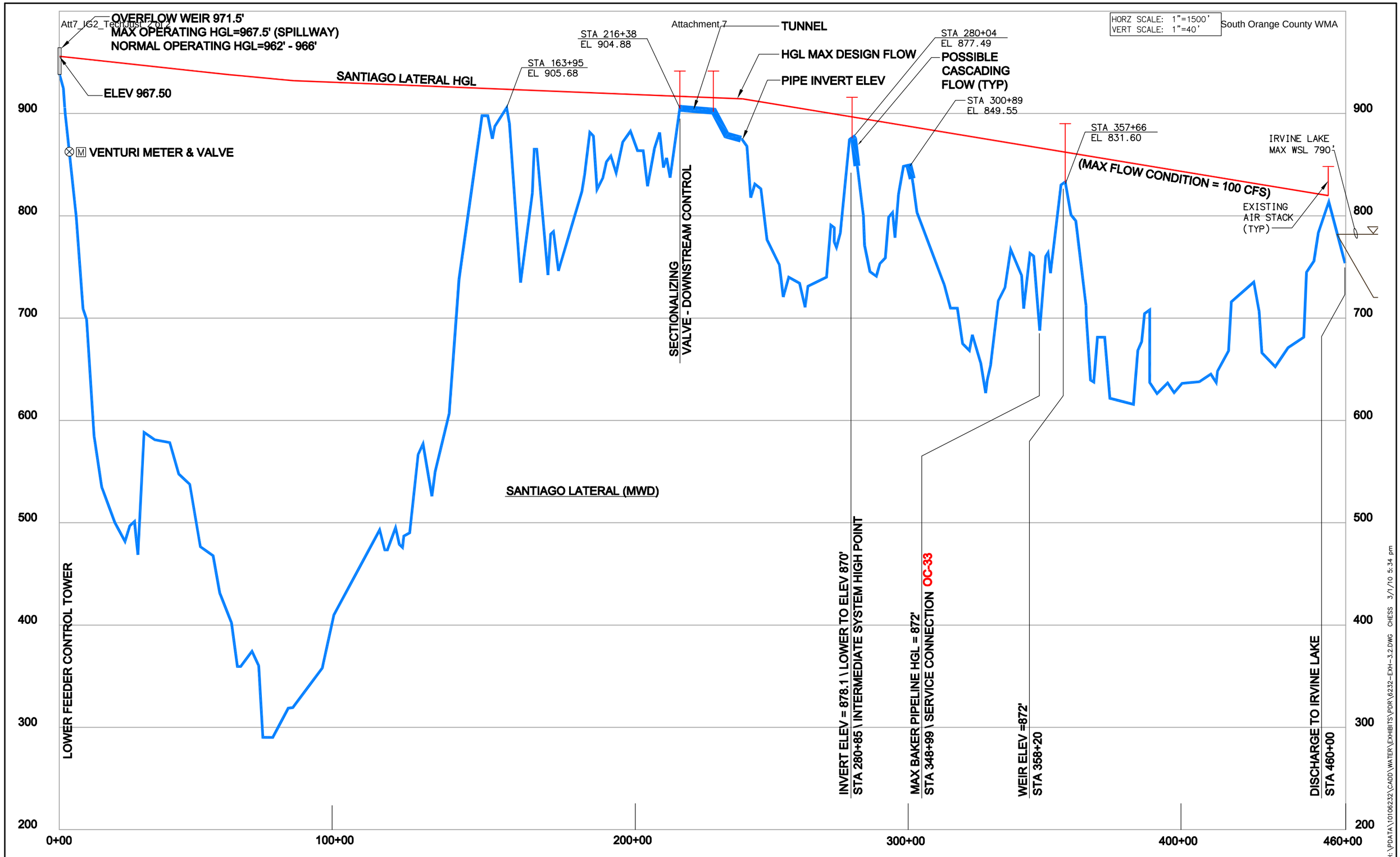

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IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

SANTIAGO LATERAL PROFILE

EXHIBIT 3.2

3.2.2 OC-33

OC-33 is the turn-out from the Santiago Lateral to the Baker Pipeline. The turn-out currently has a flow meter rated up to 40 cfs. OC-33 was once equipped with a flow meter capable of measurement up to 100 cfs. When flow rates declined in the Baker Pipeline, the Santiago Aqueduct Commission elected to replace the meter with a smaller one to achieve increased accuracy. Increased flows through the turn-out, as a result of Baker WTP, may require modifications to the turn-out, as discussed in Section 4.

3.3 EXISTING RAW WATER CONVEYANCE FACILITIES

Existing raw water facilities downstream of the Santiago Lateral are illustrated on Exhibit 3.1 and include:

- Baker Pipeline
- Irvine Lake
- Irvine Lake Pipeline

3.3.1 Baker Pipeline

The Baker Pipeline, originally named the Santiago Aqueduct, was constructed in 1962 by the Santiago Aqueduct Commission to provide untreated Colorado River water to several water districts and agricultural interests in central Orange County. In recent years, MWD has delivered a blend of Colorado River Water and State Water Project Water to the Baker Pipeline.

3.3.1.1 Hydraulics

The Baker Pipeline was designed to operate with downstream control, and, structurally, to withstand a maximum HGL of 872 feet. An HGL of 872 feet can only be realized when the discharge to Irvine Lake, through the Santiago Lateral, is 100 cfs. The HGL in the Santiago Lateral at OC-33 is fixed at its maximum by the elevation of a high point in the Santiago Lateral immediately downstream of OC-33. It is impossible to develop a higher HGL (i.e., > 832 feet) at this point without discharging to Irvine Lake; thereby limiting the Baker Pipeline to a flow rate below its potential. The maximum HGL achievable at this point (i.e. 872 ft) occurs with maximum flow in the lateral (i.e., 100 cfs). When there is less flow, the HGL

diminishes until it reaches approximately 832 feet, at which point there is no discharge to Irvine Lake. A profile of Baker Pipeline and hydraulic profile is provided in Exhibit 3.3.

3.3.1.2 Flow Test

Irvine Ranch Water District and RBF Consulting completed a flow test of the Baker Pipeline on April 21, 2009 to evaluate its hydraulic performance. Flow in the Baker Pipeline was controlled during the test at the Baker site by a temporarily installed butterfly valve on the 20- / 24-inch pipeline that served the former Baker Filter Plant. At 15-minute intervals during the 4-hour test, flow readings were taken at OC-33 and the Baker site, and pressure readings were taken at the Irvine Lake Pipeline / Baker Pipeline turnout, Baker site, and selected high points (air valve locations) along the Baker Pipeline.

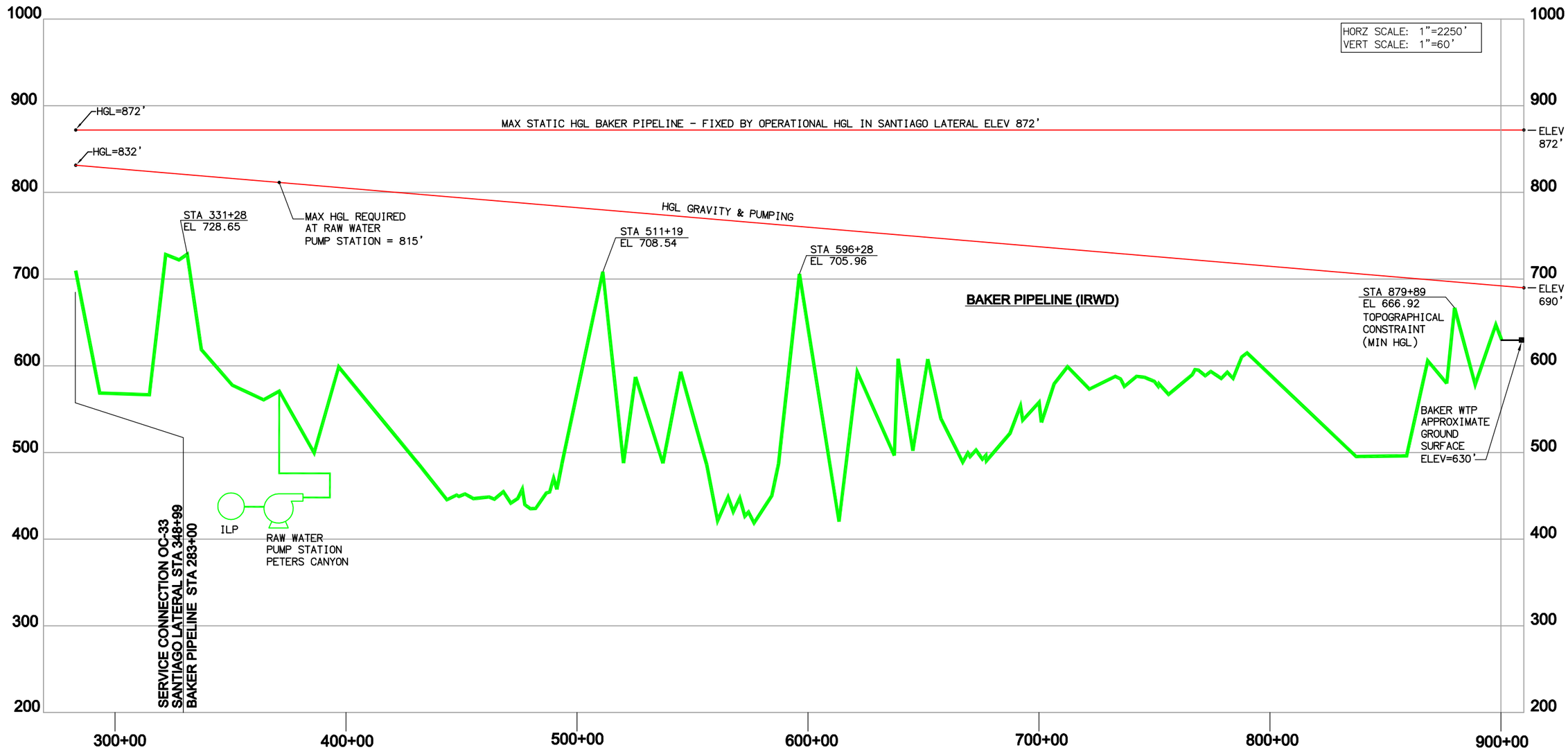
3.3.1.3 Flow Test Analysis

The flow test results were used to determine a representative Hazen Williams C Factor for the Baker Pipeline. It was observed that valve modulation (both opening and closing the 24-inch butterfly valve) significantly impacted pressure and flow values at the beginning and end of the flow test. As a result, focus in the calculations was placed on flow test results from 9:55 am to 10:55 am, as shown on Exhibit B1 of Appendix B.

Based on the flow test results, a Hazen Williams factor of 140 was selected to predict friction losses in the Baker Pipeline. Exhibit B2 in Appendix B depicts the results of the flow test against various values of the Hazen Williams factor.

3.3.1.4 Capacity Rights

The Baker Pipeline capacity is physically dependent on hydraulics, and institutionally limited by capacity rights allocated by agreement. In October 2009, Irvine Ranch Water District and RBF / Carollo completed efforts to determine the proposed reallocation of water rights through the Baker Pipeline. The efforts focused on pipeline hydraulics to



OPERATING CONDITION MAX DESIGN FLOW
BAKER WTP - 43.5 CFS TRABUCO WTP - 6 CFS AGRICULTURAL - 4 CFS

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IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

BAKER WATER TREATMENT PLANT
BAKER PIPELINE PROFILE

EXHIBIT 3.3

maximize plant flow and minimize the transfer of capacity rights in Reaches 1 through 5. Two alternative capacities of raw water supply to Baker WTP were recommended:

- 37 cfs – considering the use of available head for pressure membrane filtration, requiring an HGL of 720 feet at the Baker WTP
- 43.5 cfs – considering the use of a forebay reservoir and pump station, requiring an HGL of 690 feet

Cost analysis of each alternative was presented at the Project Stakeholder's meeting held on October 29, 2009. With Project Go-No-Go Decision 1 the Stakeholders selected the higher (43.5 cfs) flow alternative as the basis for treatment plant design.

3.3.2 Irvine Lake

Irvine Lake (also referred to as the Santiago Reservoir) was built in 1931 to serve nearby agricultural demands. The lake is currently supplied by State Project and Colorado River waters delivered by Metropolitan Water District through the Santiago Lateral and OC-13. The lake has a maximum capacity of approximately 28,000 acre-feet. From the 2007 Feasibility Study it is understood that the lake captures an average of approximately 7,000 acre-feet of local runoff per year. A summary of the water storage (capacity) and surface area is provided as Exhibit 3.4. Throughout the upper WSLs (750 – 790 ft) of Irvine Lake, approximately 5,000 AF is contained within each 10 ft band. This is the approximate quantity of water that is expected to be withdrawn from the lake over a 6 to 8 week period on an annual basis.

Delivery of Irvine Lake water to the Baker WTP will provide reliability, in the event of an emergency or maintenance caused outage along the Santiago Lateral or the Lower Feeder. In the event that it should become necessary to curtail or limit service to OC-33, Irvine Lake can be used as a raw water source for the Baker WTP, either replacing or supplementing the MWD supply.

Water is transferred from Irvine Lake into the Irvine Lake Pipeline through the Irvine Lake Outlet Tower. The tower is 8 ft in diameter and is controlled by using the upper gates (24-inch gates) at elevations of 720,

730, 740 and 750 ft. All lower gates (30-inch gates) are buried under lake sediments. To maintain long-term operation of the tower and improve water quality in the Irvine Lake Pipeline, an extension to the 720 gate was installed to raise the inlet elevation to 735 ft. Irvine Ranch Water District has also considered an extension to the 710 gate. However, the extension has been put on hold pending seismic evaluation of the tower as required by the Division of Safety of Dams.

Each of the gates is equipped with a Johnson screen with the following characteristics:

- "T" shape configuration
- 30-inch diameter
- 96-inch length
- Slot opening = 0.50"
- 79.6% open area
- Collapse strength = 10' of water
- Material – 304 SS

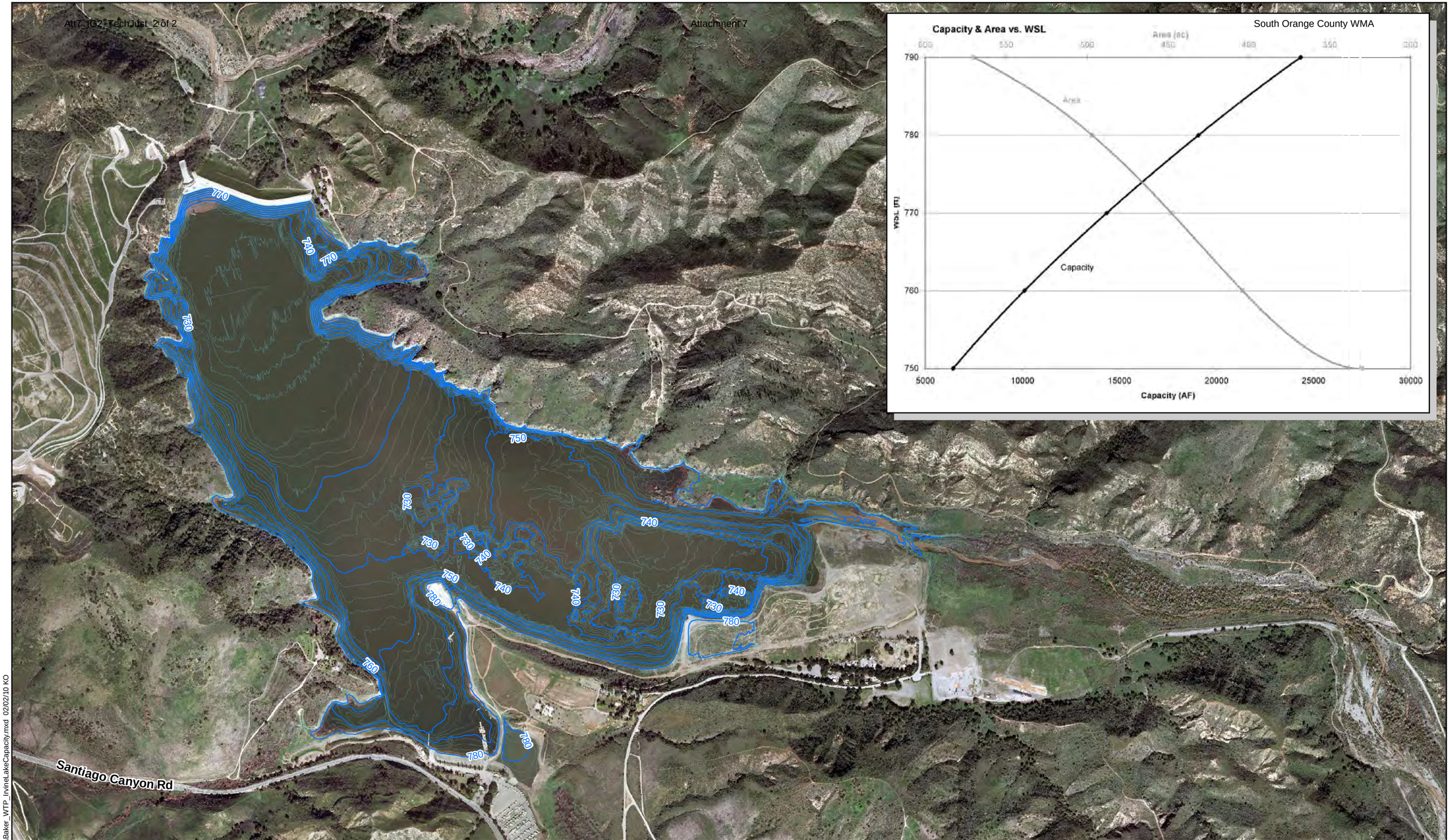
Johnson recommends that the maximum through-slot velocity of the screens be 0.5 fps which will produce a per-screen capacity of 11.25 cfs. However flows up to 22.5 cfs per screen can be achieved with a through-slot velocity of 1.0 fps although increased fouling will result. Therefore, at the lower flow rate, the outlet tower could release 45.0 cfs, and at the higher flow rate – a maximum of 90.0 cfs (if screens fully clean).

3.3.3 Irvine Lake Pipeline

The Irvine Lake Pipeline (ILP) originates at Irvine Lake and conveys water from the lake's outlet works through a pipeline of varying diameters over a total length of about 65,000 feet to its terminus near Lambert Reservoir north of the former El Toro Marine Corps Air Station. The pipeline was constructed to serve agriculture demands, through three reaches:

- The Irvine Lake Reach extends from Irvine Lake to Peters Canyon Reservoir.
- The Rattlesnake Reach extends through the Cities of Orange, Tustin and Irvine before terminating near the Rattlesnake Reservoir in the North Irvine area.

South Orange County WMA



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Baker Water Treatment Plant

Irvine Lake and Capacity

Exhibit 3.4

- The Lambert Reach is under evaluation to determine the date at which it will be separated and utilized as part of the Zone C recycled water system.

The capacity to be delivered through the Irvine Lake Pipeline during Baker WTP operation is under analysis by IRWD and RBF Consulting with consideration of:

- Outlet Tower capacity – when the screens are mostly clear of debris IRWD has measure flows between 60 and 70 cfs in the upper reach of the ILP,
- Current and future agriculture demands on the Irvine Lake Pipeline and Baker Pipeline,
- Supply to Serrano Water District and Trabuco Canyon Water District.

The above listed factors may cumulatively limit the raw water flow to the Baker WTP when supplied from Irvine Lake to less than 43.5 cfs. However, for the PDR the capacity of the Raw Water Pump Station is maintained as 53.5 cfs (43.5 cfs for Baker WTP, 4 cfs for Baker Pipeline served agriculture, 6 cfs for TCWD), as a conservative basis for Project costs. Additional evaluation is required to quantify these impacts.

3.4 PROPOSED RAW WATER CONVEYANCE FACILITIES

The proposed raw water conveyance facilities include all facilities to be constructed to enable delivery of untreated water from Santiago Lateral or Irvine Lake Pipeline to the Baker WTP.

3.4.1 Alternative Facilities Considered

The approach to delivering raw water to the treatment plant has been studied by weighing factors such as:

- Capital Cost
- Lowest Energy Use
- Surge Protection
    - Baker Pipeline
    - Treatment Plant
- Ease of Operation

- Land Acquisition

Several alternative facilities were considered in developing the proposed concept for the raw water conveyance system. Appendix C describes the facilities previously considered, including a hydraulic control structure, regulating reservoir and constant head tank.

3.4.2 Proposed Facilities

The facilities to be constructed to enable raw water delivery to the Baker WTP include:

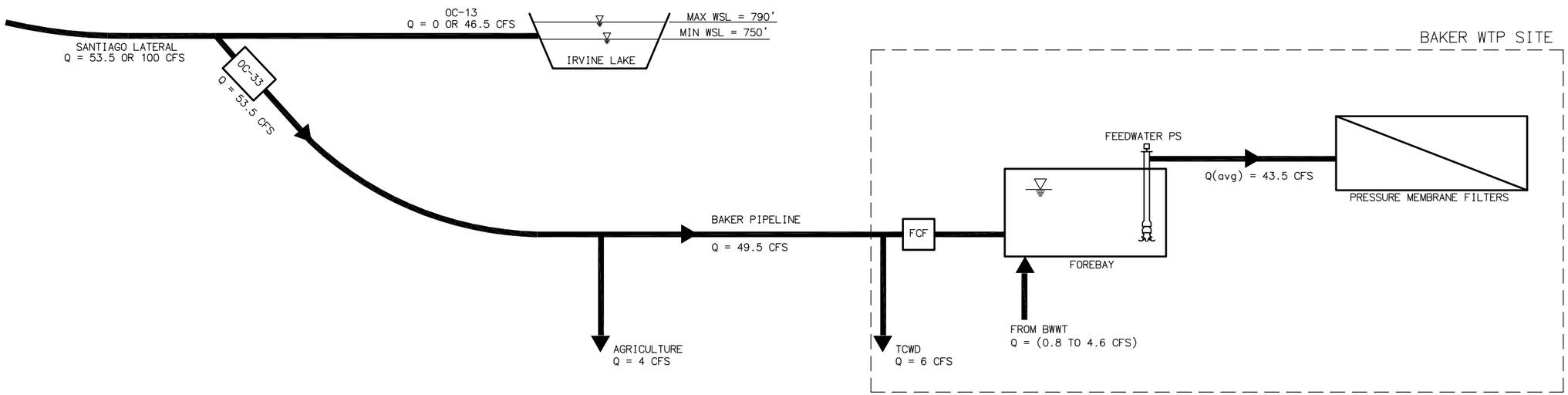
- Raw Water Pump Station - a pump station constructed to boost water from the Irvine Lake Pipeline to the Baker Pipeline, with a maximum design flow rate of 53.5 cfs (24,000 gpm).
- Flow Control Facility – at the terminus of the raw water pipeline, the flow control facility consists of a motor operated sleeve valve to control the flow into the forebay. A redundant sleeve valve is included in the cost estimate.
- Forebay - a 0.785 MG partially buried, cast-in-place concrete reservoir to isolate the hydraulics / surge of the Baker Pipeline and treatment plant systems, and to provide flow equalization between the constant flow rate of raw water delivery in the Baker Pipeline, and variable flow rate of the treatment plant due to operation (backwashing and integrity testing).
- Feedwater Pump Station - vertical turbine pumps to boost water from the forebay through the pressure membranes. Pumps will have variable speed drives to manage variable flow rates through the treatment process, and maximum and minimum discharge pressure based on the acceptable range of pressure upstream of the membrane filters.

3.5 RAW WATER SYSTEM OPERATION

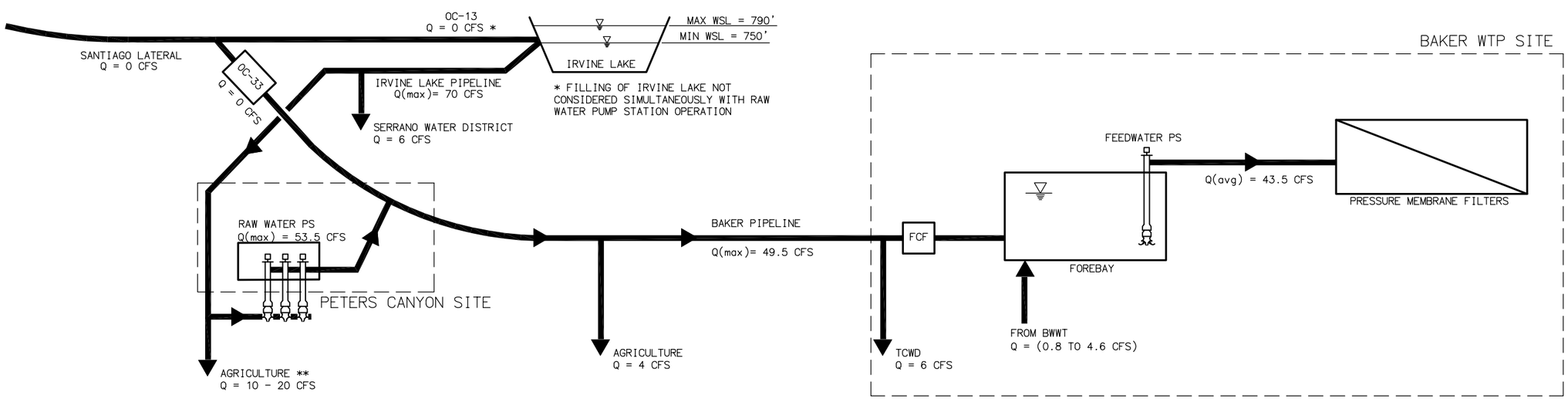
There are two methods (gravity and pumping) for the conveyance of raw water to the Baker WTP. These methods comprise a total of six operational schemes, which are summarized in Table 3.1. Exhibits 3.5 shows the overall system under gravity and pumping conditions. Exhibits 3.6 (gravity operation) and 3.7 (pumping operation) depict all methods of water conveyance as described and defined in Sections 3.5.1 and 3.5.2.

TABLE 3.1
BAKER WATER TREATMENT PLANT
RAW WATER CONVEYANCE OPERATIONAL SCHEMES

CONVEYANCE METHOD	OPERATIONAL SCHEME	Water Source	Santiago Lateral		Baker P/L Flow	ILP Flow	Comments
			Flow	Flow to Lake			
GRAVITY	Gravity - Normal Operation	Santiago Lateral	Yes	Possible - but not required	OC-33 to WTP	No	Flow to Irvine Lake may increase HGL at OC-33 to Max = 872'
	Gravity - Combined Baker P/L and ILP	Santiago Lateral & Irvine Lake	Yes	Possible - but not required	OC-33 to WTP	From Irvine Lake to RWPS and downstream	Requires high WSL in Irvine Lake & reduced flow through OC-33. Blending at RWPS.
	Gravity Transfer - Baker P/L to ILP	Santiago Lateral	Yes	May be required	OC-33 to RWPS to ILP	Downstream of RWPS	Flow to lake may be required in order to develop high HGL in Santiago Latral and full flow to WTP
	Gravity Transfer - ILP to Baker P/L	Irvine Lake	No	Unlikely	RWPS to WTP	From Irvine Lake to RWPS and downstream	No flow through OC-33
PUMPING	Pumping - Normal Operation	Irvine Lake	Unlikely		RWPS to WTP	From Irvine Lake to RWPS and downstream	No flow through OC-33. WSL in Irvine Lake greater than 740'
	Pumping - Combined Baker P/L (gravity) and ILP (RWPS feed)	Santiago Lateral & Irvine Lake	Yes	Unlikely	Gravity from OC-33 blending with ILP water pumped by RWPS to Baker P/L	Yes	Blended Irvine Lake and Santiago Lateral waters. WSL in Irvine Lake greater than 740'



GRAVITY- SANTIAGO LATERAL SUPPLY TO BAKER WTP



PUMPING - IRVINE LAKE WATER SUPPLY TO BAKER WTP

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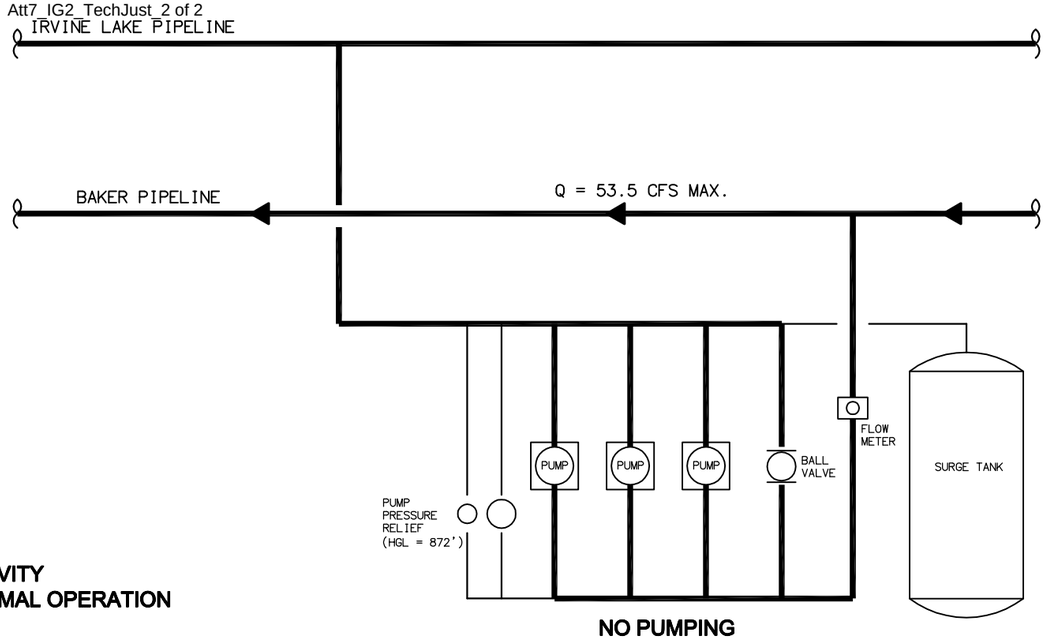
IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

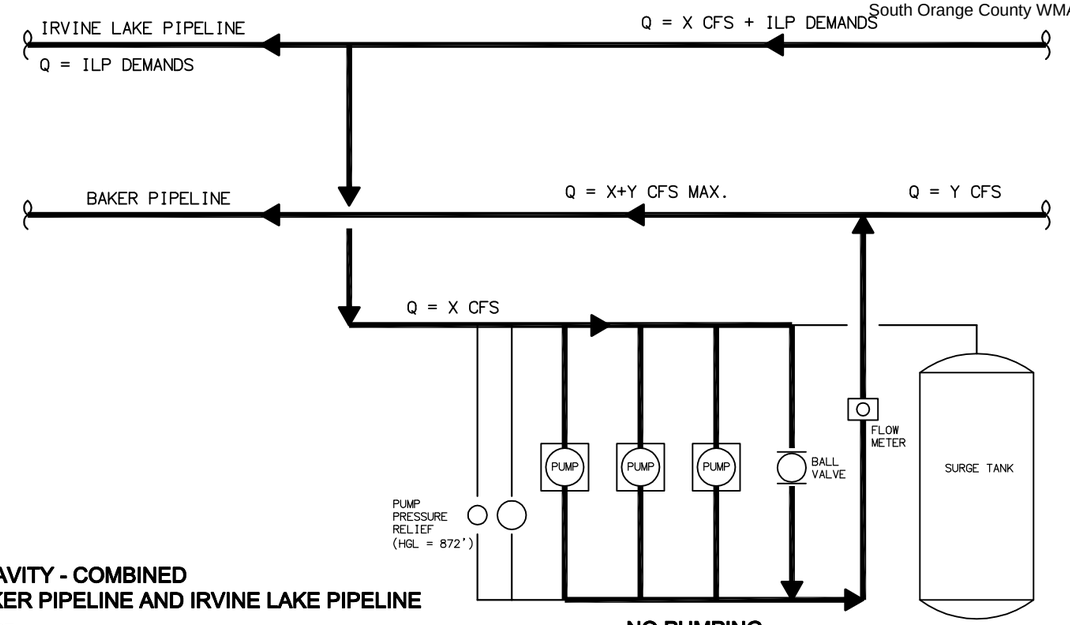
RAW WATER CONVEYANCE SYSTEM OPERATION SUMMARY

EXHIBIT 3.5



GRAVITY
NORMAL OPERATION

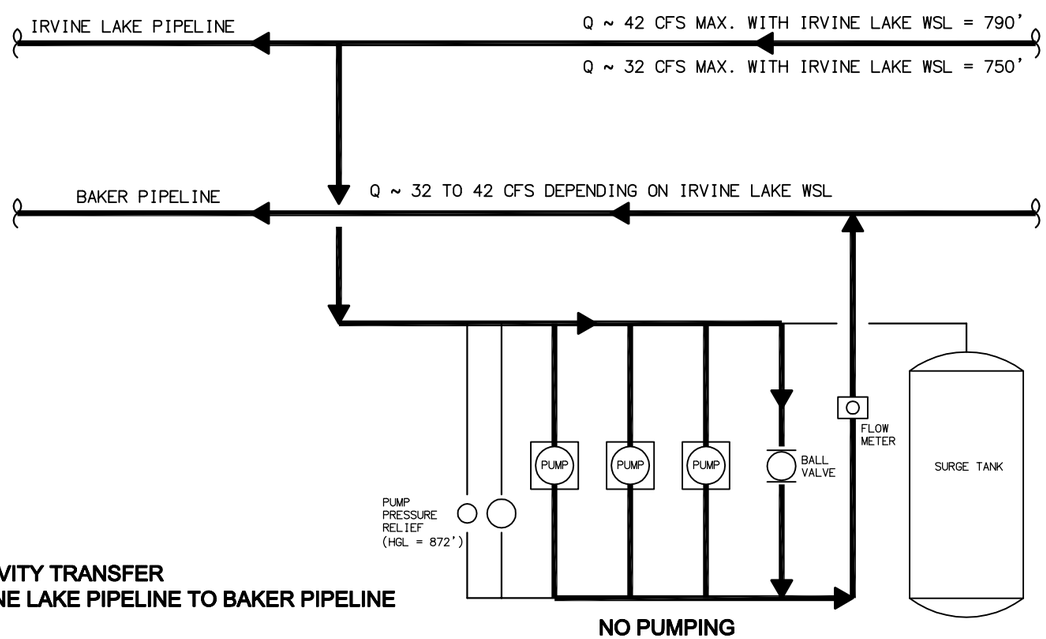
NO PUMPING



GRAVITY - COMBINED
BAKER PIPELINE AND IRVINE LAKE PIPELINE

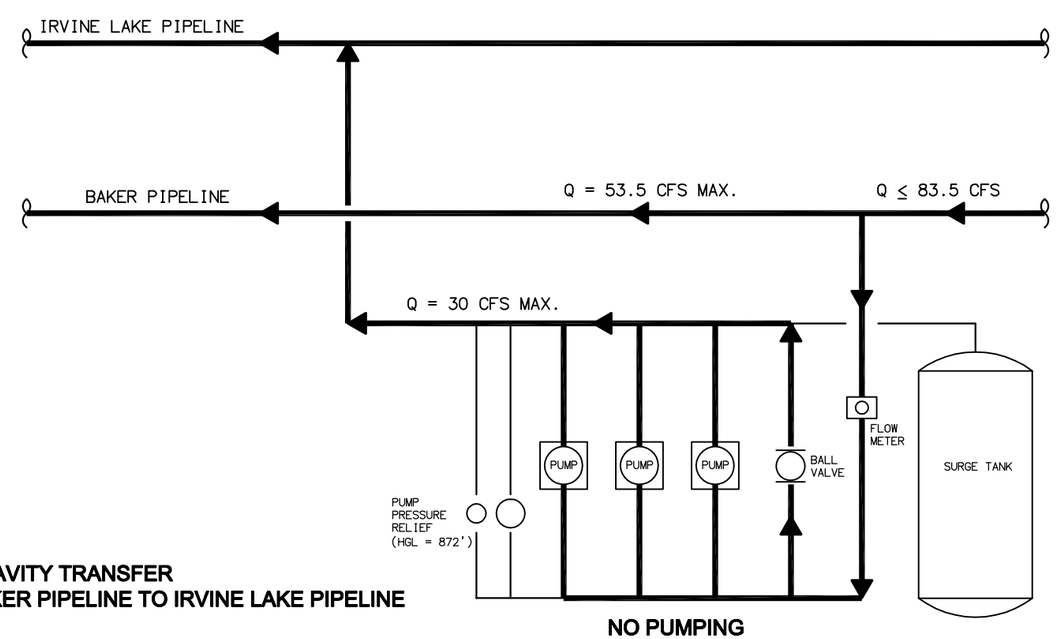
NO PUMPING

WHERE:
X CANNOT EXCEED 42.5 CFS
Y CANNOT EXCEED 53.5 CFS
X+Y CANNOT EXCEED 53.5 CFS



GRAVITY TRANSFER
IRVINE LAKE PIPELINE TO BAKER PIPELINE

NO PUMPING



GRAVITY TRANSFER
BAKER PIPELINE TO IRVINE LAKE PIPELINE

NO PUMPING

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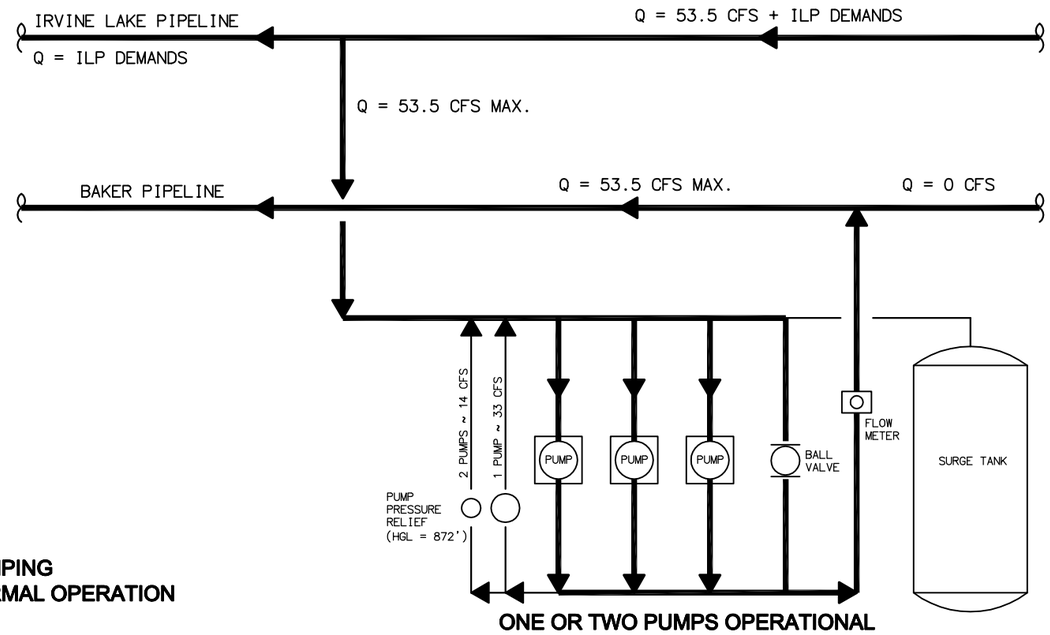
IRVINE RANCH WATER DISTRICT

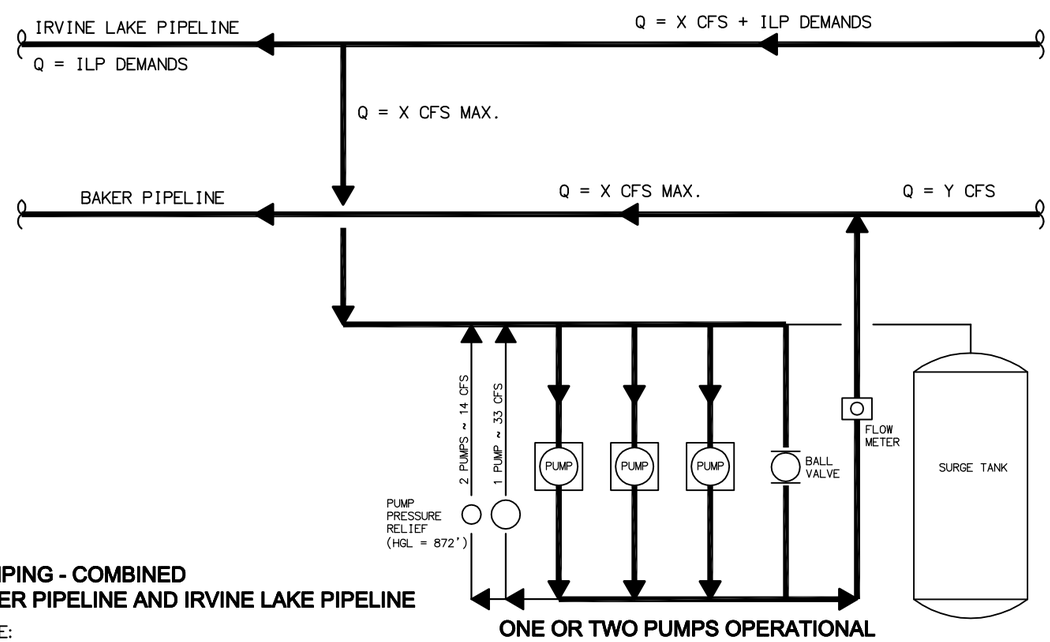
BAKER WATER TREATMENT PLANT

RAW WATER PUMP STATION
GRAVITY OPERATION SCHEMATIC

EXHIBIT
3.6



PUMPING
NORMAL OPERATION



PUMPING - COMBINED
BAKER PIPELINE AND IRVINE LAKE PIPELINE

WHERE:
X CANNOT EXCEED 42.5 CFS
Y CANNOT EXCEED 53.5 CFS
X+Y CANNOT EXCEED 53.5 CFS

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IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

RAW WATER PUMP STATION PUMPING OPERATION SCHEMATIC

EXHIBIT **3.7**

3.5.1 Gravity Conveyance

The majority of the time (i.e. ten to eleven months annually) raw water will be conveyed to the Baker WTP, directly from the MWD system, by gravity, through the Baker Pipeline. No intermediate storage facility will be involved, between the MWD system and the forebay at the Baker WTP. Gravity conveyance includes four possible operational schemes as described below.

Gravity - Normal Operation

This will consist entirely of Santiago Lateral gravity supply, through OC-33, to the Baker WTP, agricultural users and TCWD, through the Baker Pipeline. No pumping.

The flow through OC-33 and the Baker Pipeline (Gravity-Normal Operation – See Table 3.1) will be controlled by:

- MWD releasing Lower Feeder water, into the Santiago Lateral, on a daily basis, at the flow rates requested by IRWD through MWDOC.
- Instantaneous control through operation of the 18-inch sleeve valve upstream of the Baker WTP forebay.

Under conditions when the plant's output is being maintained at a constant daily rate, any flow swings will be absorbed by the forebay, and there should be no discharge of water to the lake or overflows to the stormwater system, at the plant.

Since the water released by MWD is generally not variable, variation of Baker Pipeline flow and plant demand, ranging from daily to instantaneous, will be absorbed by one or a combination of the following:

- Flows, in Baker Pipeline, in excess of plant demand, will occur daily as a result of variable flow through the pressurized membranes due to backwashing or maintenance. Such flow variations are accounted for in the design capacity of the forebay,
- As a less desired alternative, excess water that cannot be handled in this manner will first result in modification of flow rate from the feedwater pump station, and if still unresolved thereafter, will lead to the reduction of flow to the plant by closing the sleeve valve at the flow control facility to divert excess raw water flow to Irvine Lake. See

Section 7 and 10 for further on the flow control facility and feedwater pump station, respectively.

- If flow cannot be controlled within the normal operating range of the forebay or operation of the flow control facility, thereby causing the high WSL in the forebay to be exceeded, then excess flow from the Baker Pipeline will overflow into the local drainage system of the Baker WTP, discussed in Section 17.

Gravity – Combined Baker Pipeline and Irvine Lake Pipeline

Under certain conditions it may be desirable to receive water from both OC-33 and Irvine Lake, by gravity alone. This mode of operation presents no difficulties since the water from Irvine Lake would be operated at a variable rate while the MWD supplied water would be the base flow. That is, minor variations in the Baker Pipeline demand would be made up from Irvine Lake. However, the aggregate flow rate that is possible is limited, because the water surface level in Irvine Lake is significantly lower than that possible at OC-33. As a result, the flow rate from OC-33 must be reduced in order to prevent back-flow to the lake.

Gravity Transfer – Baker Pipeline to Irvine Lake Pipeline

Water from the Santiago Lateral can be transferred directly to the Irvine Lake Pipeline from the Baker Pipeline under conditions when it is not desirable to convey lake water in the Lake Reach of the ILP. In such a case, Santiago Lateral water, through OC-33 and Reach 1 of the Baker Pipeline, can be passed around the Lake Reach of the ILP by opening the 18-inch ball valve, in the RWPS, and back-flowing through the pump station. The valving has been sized to accommodate a flow of 30 cfs. However, the operation of the ball valve will require a minimum downstream backpressure in order to keep the valve from cavitation. This downstream backpressure should be achievable since the minimum values of the downstream HGLs are less than the normal operating range of WSLs in Irvine Lake (750' to 790'). The following Table 3.2 shows the minimum HGLs in the ILP needed, at the Raw Water Pump Station, to preclude cavitation. These values are below the expected HGLs in the ILP which will be controlled by the WSL in Irvine Lake as well as downstream takeouts.

Table 3.2 Operational Scheme – Baker to Irvine Lake Pipeline

Operating Condition	HGL	
	Baker P/L	Minimum Req'd in ILP
Max HGL in Santiago Lateral (Filling Irvine Lake at Flow Rate = 100 cfs)	872	749
Normal Maximum Operating HGL in Baker (No Flow to Irvine Lake)	832	725
Normal Operating HGL in Baker (Max Flow in Baker - No Flow to Irvine Lake)	815	714

Gravity Transfer – Irvine Lake Pipeline to Baker Pipeline

Under conditions when the Baker WTP plant requires raw water deliveries from Irvine Lake, that are on the order of 39 cfs, or less, flow to the plant can be achieved without pumping. That is, when the lake is at its minimum operational WSL of 750', about 16 cfs can be delivered by opening the 18-inch ball valve in the pump station and allowing flow to bypass the pumps. Also at the high WSL of 790' in the lake, about 39 cfs can be delivered to the plant without pumping. The above flow rates are based upon the assumption that there are no agricultural or TCWD demands.

When raw water is released from Irvine Lake into the ILP, flow can be delivered to the Baker WTP via the Baker Pipeline either by gravity or by pumping. (See Exhibit 3.8). Pumping will be necessary whenever the Baker WTP is supplied near normal operating capacities (i.e. in the range of 40 cfs). The conditions associated with these schemes are laid out in Table 3.1. Additional constraints associated with the Gravity Transfer – ILP to Baker P/L are as follows:

- Total flow through the Irvine Lake Pipeline equal to or less than 39 cfs, and the Irvine Lake WSL is 790'. Flow to Baker WTP in this scheme will depend on the simultaneous agriculture demands, and supplies to Serrano Water District and Trabuco Canyon Water District,

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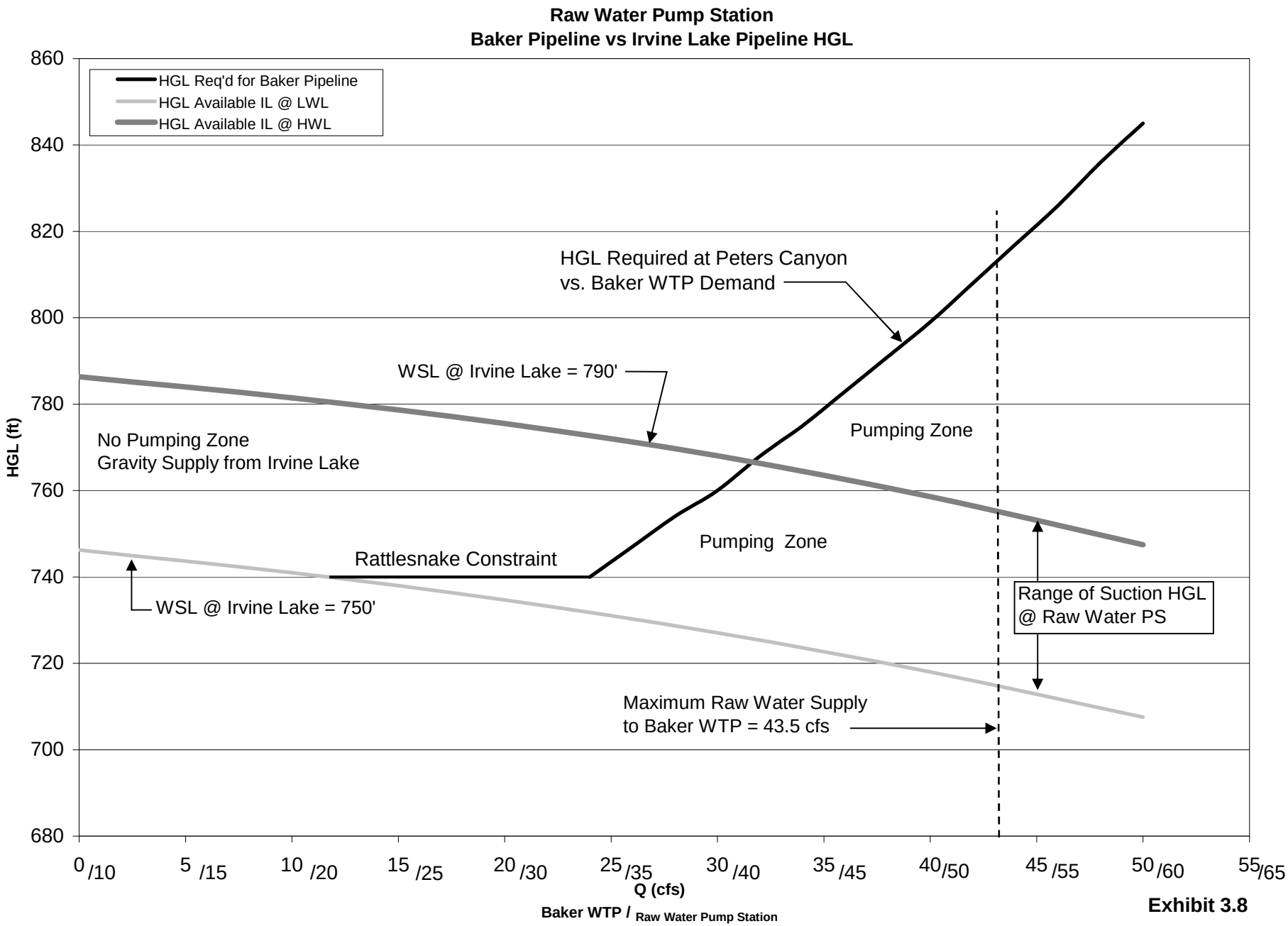

Raw Water Pump Station
Baker Pipeline vs Irvine Lake Pipeline HGL
HGL Req'd for Baker Pipeline
HGL Available IL @ LWL
HGL Available IL @ HWL
HGL (ft)
860
840
820
800
780
760
740
720
700
680
HGL Required at Peters Canyon
vs. Baker WTP Demand
WSL @ Irvine Lake = 790'
No Pumping Zone
Gravity Supply from Irvine Lake
Pumping Zone
Pumping Zone
Rattlesnake Constraint
WSL @ Irvine Lake = 750'
Range of Suction HGL
@ Raw Water PS
Maximum Raw Water Supply
to Baker WTP = 43.5 cfs
0 /10
5 /15
10 /20
15 /25
20 /30
25 /35
30 /40
35 /45
40 /50
45 /55
50 /60
55 /65
Q (cfs)
Baker WTP / Raw Water Pump Station

Exhibit 3.8

- Total flow through the Irvine Lake Pipeline between 33 cfs and 39 cfs, when the Irvine Lake WSL is between 750' and 790'. Again, flow to Baker WTP will be subject to the simultaneous demands of agriculture and other agencies.

- The Rattlesnake hill which is about one-third of the distance between the RWPS and the WTP will require a minimum HGL at the RWPS of 740 feet. This is referenced in Section 5 as the 'Rattlesnake Constraint'.

3.5.2 Pumping Conveyance

The Baker Raw Water Pump Station will pump Irvine Lake water, delivered to it through the ILP, through the Baker Pipeline to the Baker WTP, within the limits of the following constraints: Also, see Table 3.1.

- The Santiago Lateral is not being operated to fill Irvine Lake.
- WSL in the lake is greater than 740'.

The first constraint arises because the filling of Irvine Lake typically occurs at high flow rates. This results in an elevated HGL at OC-33 as well as an increase in the required discharge pressure at the Raw Water Pump Station, in the event that filling the lake and pumping from it should occur simultaneously. This is not a design condition for the RWPS since it will stretch the pumps beyond recommended operating limits.

The second constraint is based on the capacity limitations of the Irvine Lake Tower below the elevation of 740 ft, and because the release of Irvine Lake water with substantially heightened concentrations of manganese and iron occurring below this WSL, would be avoided.

<u>General Baker P/L Operation</u>

Since, under normal operating conditions, there are no institutional complications associated with withdrawals from Irvine Lake, the flow in the Baker Pipeline can be maintained or instantaneously modified as long as it is kept below the pipeline's maximum capacity. However, since the plant's instantaneous flow requirement may exceed the pipeline's capacity, the WSL in the forebay must be held within the band that defines its operational volume. In order to accomplish this, the flow control valve may be modulated based upon an assessment of the

forebay's high and low WSLs, and the flow measurement at the flow control facility.

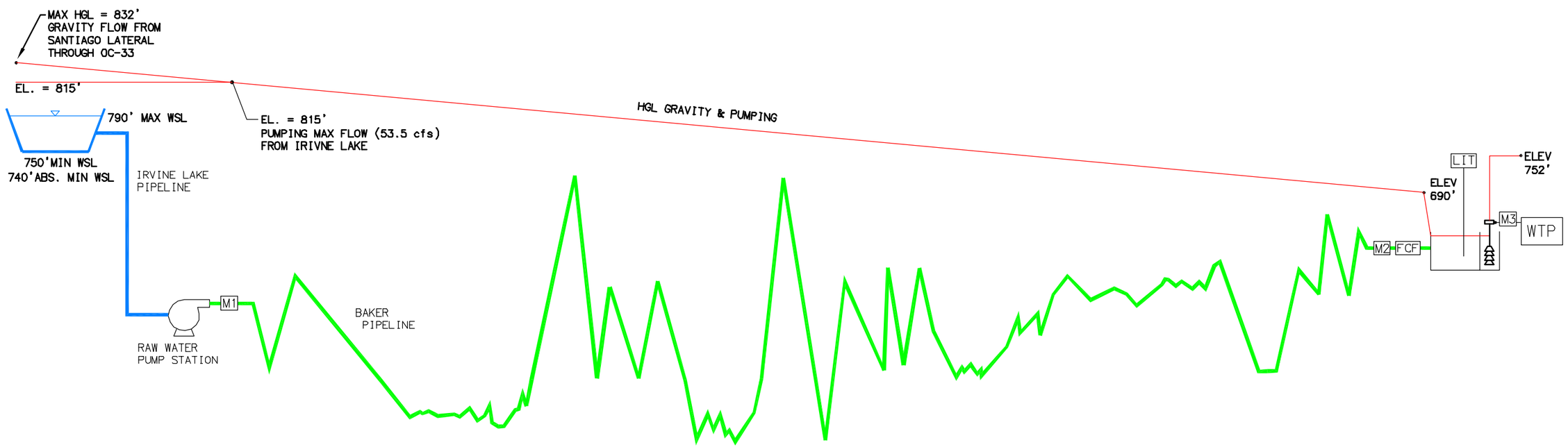
There are two operational schemes for the pumping of Irvine Lake water, which are described summarized in Table 3.1 and described below:

- Pumping - Normal Operation
- Pumping – Combined Baker P/L (gravity) and ILP (RWPS feed)

Pumping – Normal Operation

When pumping and delivering, only Irvine Lake water to the WTP, the Baker Raw Water Pump Station, will target a discharge HGL that will be a function of the system curve for the Baker P/L. Demands in the Baker P/L, downstream of the RWPS, for agriculture, Trabuco Canyon Water District and the WTP, will define the pump station's discharge. It is not envisioned that the pump station will be operated simultaneously with the filling of Irvine Lake, through Santiago Lateral and OC-13; this would raise the discharge HGL of the RWPS above the normal operational design point.

Calculation of the headloss through Irvine Lake Pipeline to the Raw Water Pump Station is provided in Table E1 of Appendix E.



SCHEMATIC OF RAW WATER CONVEYANCE SYSTEM

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RBF CONSULTING	carollo	*IRVINE RANCH WATER DISTRICT* *BAKER WATER TREATMENT PLANT* RAW WATER CONVEYANCE SYSTEM OPERATION SCHEMATIC	EXHIBIT 3.9

Pumping – Combined Baker P/L (gravity) and ILP (RWPS feed)

It will be possible to combine flows from the Santiago Lateral, through OC-33 to the Baker Pipeline, with water from Irvine Lake. Under this operational scheme:

- there will be no flow to the lake (i.e. HGL at OC-33 </= 832')
- the flow from OC-33 will be constant
- variations in downstream demand will be met from Irvine Lake via the ILP and the RWPS

3.6 TREATMENT

Water will be conveyed through the treatment system by a combination of gravity flow and pumping. Exhibit 3.10 shows the hydraulic profile of the treatment plant.

3.7 PRODUCT WATER SYSTEM

The Product Water System includes the clearwell to store product water from Baker WTP, and the Product Water Pump Station to boost water into the Allen McColloch Pipeline.

3.7.1 Clearwell

The clearwell for the Baker WTP will be an existing 16 MG buried concrete reservoir, previously used as emergency storage for Zone 1 of the Los Alisos Water District system. A 42-inch pipeline will be constructed to deliver product water from the CT basin to the clearwell by gravity. The reservoir low and high water level elevations are 595 ft and 621 ft, respectively.

3.7.2 Product Water Pump Station

The Product Water Pump Station will be designed to pump a flow of 33 cfs from the clear well through a new 36-inch diameter pipeline to the Allen McColloch Pipeline.

3.7.3 Allen McColloch Pipeline

Product water delivery to El Toro Water District, Moulton Niguel Water District and Santa Margarita Water District will be through the AMP Pipeline. Trabuco Canyon Water District's plant capacity will be conveyed into the AMP. As TCWD does not currently own capacity in the AMP, a transfer of water with one of the other Project Stakeholders

will be established to provide TCWD its capacity. Product water will be delivered to the AMP at the connection constructed during the Baker Pipeline/AMP interconnect. Hydraulic grade in the AMP varies significantly by season, with a maximum HGL of 806 ft during periods low demand (wet season) to an absolute minimum HGL of 630 ft during periods of high demand (dry season).

3.8 PRODUCT WATER SYSTEM OPERATION

The product water system will deliver water by gravity or pumping as summarized:

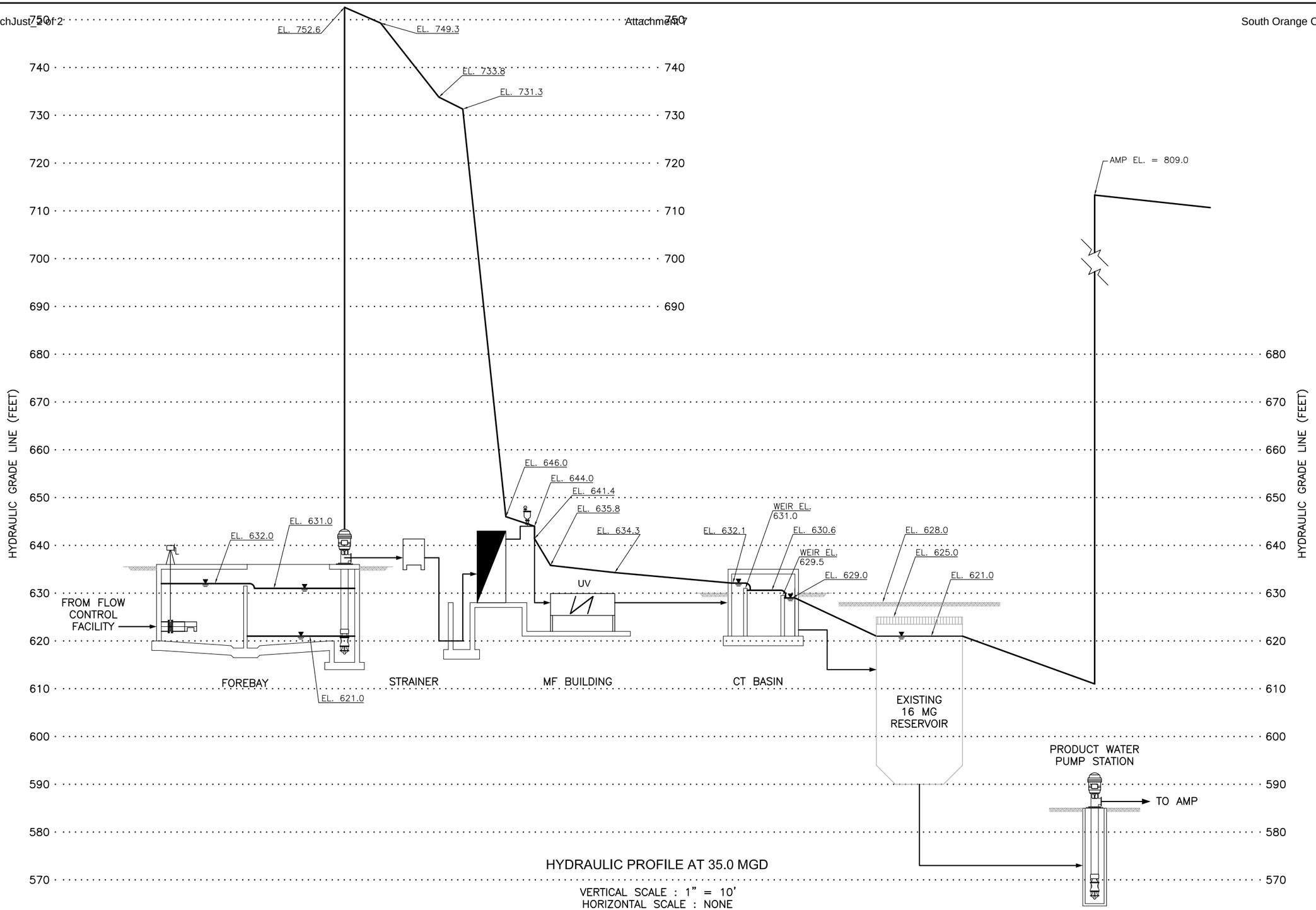
- Gravity Flow – from the clearwell to IRWD through the existing Zone 1 outlet pipeline to the reservoir.
- Pumped Flow – the pump station will be designed to pump from the clearwell to the AMP, accounting for the variable levels in the clearwell and HGL in the AMP.

3.9 HYDRAULICS

The overall Baker WTP project hydraulics are illustrated on Exhibit 3.11, noting the following:

Raw Water System

1. OC-33 turnout – HGL can range from 832 to 872 ft dependent on the flow in Santiago Lateral to Irvine Lake.
2. Raw Water Pump Station – discharge HGL of 815 ft, and design not based on pumping during the filling of Irvine Lake.
3. Topographic Constraint – the HGL in Baker Pipeline should be a minimum of 15 feet above the centerline elevation of the pipeline, and will be greater when Irvine Lake is being filled from the Santiago Lateral.
4. Flow Control Facility – this facility will control flow and break head of gravity flow from Baker Pipeline to the forebay. The estimated range of HGL on the upstream side of the facility is 690 to 730 ft. Downstream of the facility the HGL will be within a few feet of the water surface level in the forebay.
5. Feedwater Pump Station – this facility will boost water to an HGL determined by the membrane system manufacturer, currently estimated at 752 feet.



HYDRAULIC PROFILE AT 35.0 MGD

VERTICAL SCALE : 1" = 10'
HORIZONTAL SCALE : NONE

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IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

HYDRAULIC PROFILE MAIN PROCESS

EXHIBIT 3.10

6. Strainer – a strainer for protection of the membrane system will be located downstream of the feed water pump station, and will generate additional headloss anticipated to range from 0 to 16 ft, depending on feed water pump station discharge flow.

Treatment Plant

7. Membrane Filtration and UV – a total of 64 feet of headloss is accounted for across the filters and UV system.

8. CT Basin – this open basin was located such that adequate head is provided for gravity flow of product water to the clearwell.

Product Water System

9. Clearwell – the existing 16 MG reservoir operating range is considered to be 600 to 621 ft.

10. Product Water Pump Station – this pump station will boost water from the clearwell to the Allen McCulloch Pipeline, and account for headloss in the 36-inch diameter pipeline to the point of connection and valve / metering vault near the connection.

11. Allen McColloch Pipeline Connection – the HGL of the AMP is understood to vary from a minimum HGL of 630 ft, to a maximum of 806 ft.

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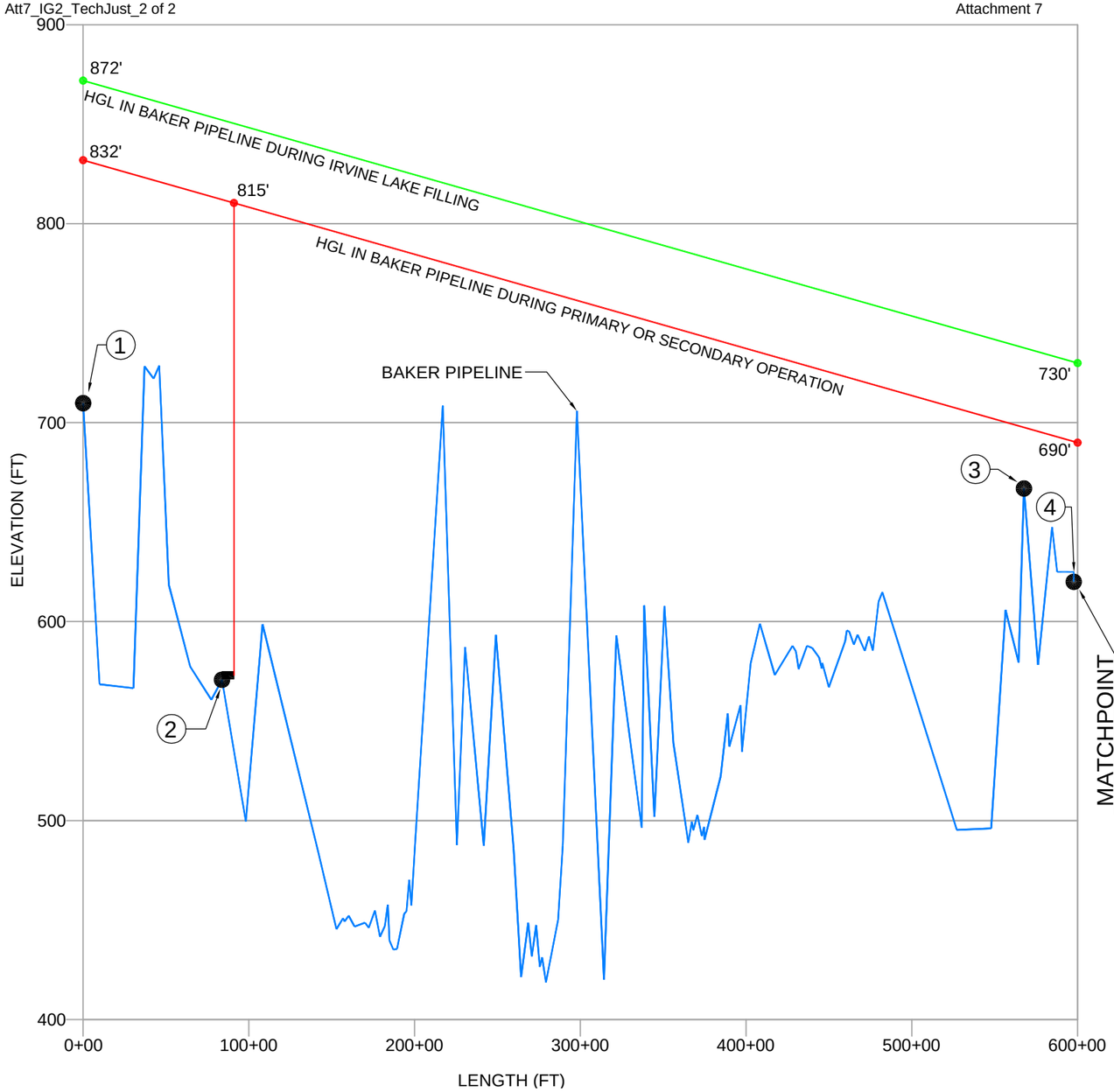

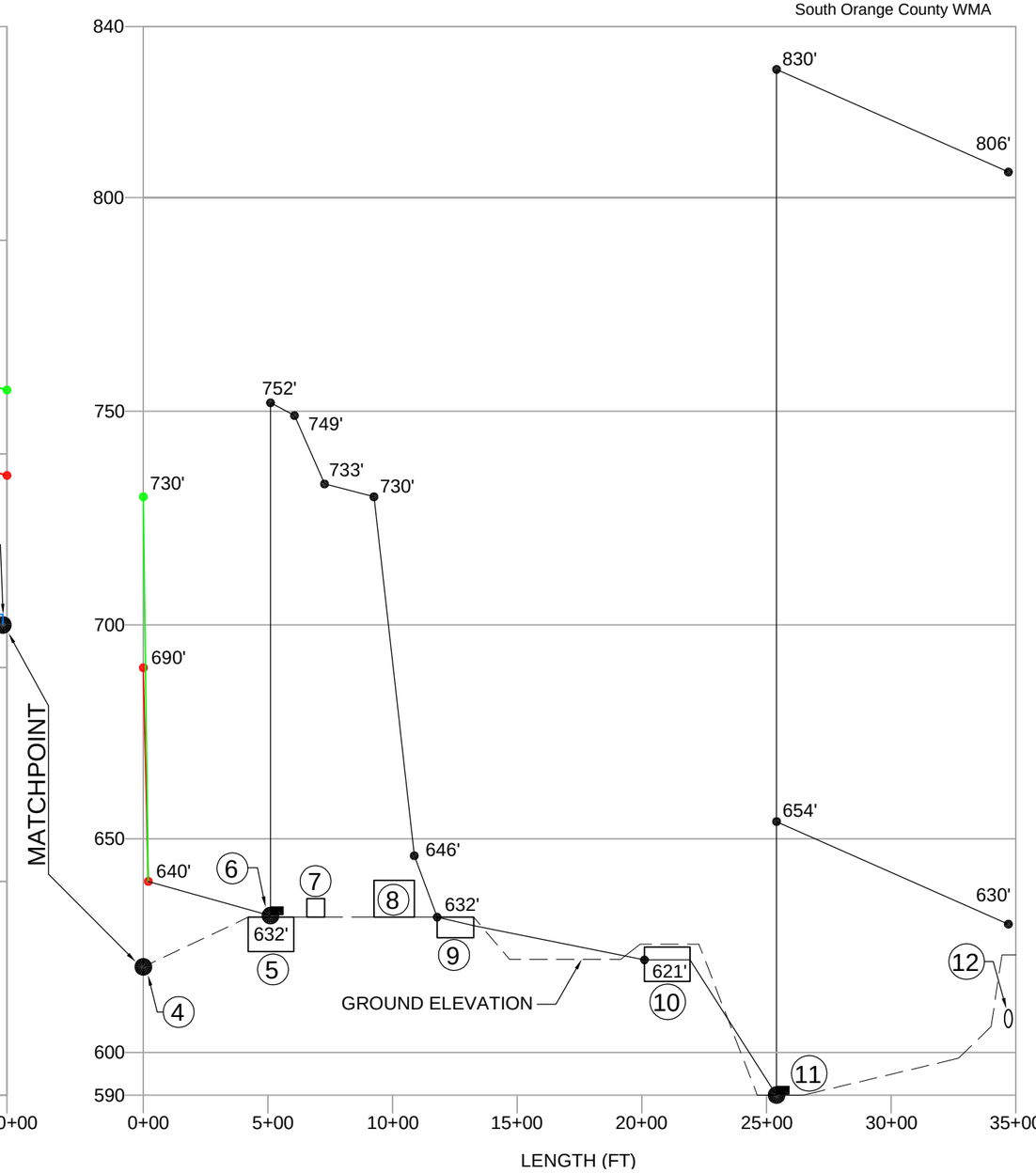

NO.	FACILITY	MAX. HGL (ft)	MIN. HGL (ft)	HGL GOVERNED BY
1	OC-33 TURN-OUT	872	832	SANTIAGO LATERAL TOWER
2	RAW WATER PUMP STA.	832	815	FLOW THRU OC-33
3	TOPO CONSTRAINT	737	697	BAKER P/L HGL
4	FLOW CONTROL FAC.	690 - 730	640	BAKER P/L HGL
5	FOREBAY	632	621	PLANT OPERATION
6	FEEDWATER PUMP STA.	752	-	HGL GOVERNED BY
7	STRAINER	749	733	FWPS HGL
8	MF / UV	731	646	PMF MANUF. DESIGN

NO.	FACILITY	MAX. HGL (ft)	MIN. HGL (ft)	HGL GOVERNED BY
9	CT BASIN	632	631	FIXED
10	CLEARWELL	621	600	PLANT OPERATION
11	PRODUCT WATER PS	830-654	-	AMP HGL
12	AMP CONNECTION	806	630	AMP DEMANDS

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RBF CONSULTING

carollo

IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

BAKER PROJECT
HYDRAULIC PROFILE

EXHIBIT

3.11

SECTION 4 OC-33 Turnout

4.1 OVERVIEW

The OC-33 turnout is an existing in-line metering facility off of the Santiago Lateral. Its function is to measure flows that pass from the Santiago Lateral to the Baker Pipeline. Capacity of the turn-out is limited by the maximum flow measurement of the installed meter. This section addresses flow capacity and required modification of the OC-33 turn-out, prior to and after the start up of the Baker WTP.

4.2 CAPACITY

The OC-33 turn-out capacity under prior, current and future conditions is explained as:

4.2.1 Prior Capacity

The OC-33 turn-out was constructed with a flow meter (Venturi type) capable of measurement up to 100 cfs (for construction plans, refer to Appendix D). A combination of agricultural demand and supply to water treatment plants in southern Orange County dictated the range of flow measurement necessary.

4.2.2 Current Capacity

Raw water supply to Los Alisos Water District and El Toro Water District, through the Baker Pipeline, declined in the late 1970s and 1980s due to residential development and the decommissioning of the Baker Filter Plant. Eventually, the flow rate through OC-33 dropped to approximately 15-percent of maximum flow. In 1989, the flow meter was replaced with a new meter (Venturi type) capable of more accurately measuring lower flows and limited to 40 cfs.

4.2.3 Future Capacity

Operation of the Baker WTP will increase the normal flow through the OC-33 turn-out to Baker Pipeline. The allocated water rights per the current Baker Pipeline Agreement (held between Santiago Aqueduct Commission and each agency) total to 104.9 cfs in Reach 1.

The Project Stakeholders plan to reallocate the water rights in the Baker Pipeline with the Baker WTP Project. The water rights will be revised (per Table 4.1) to 99 cfs in Reach 1, and include capacity for:

- Baker Water Treatment Plant - held by IRWD, MNWD, SMWD, ETWD, TCWD.
- Agriculture Use - capacity for agriculture users in the area of Orchard Hills and North Irvine area.
- Trabuco Canyon Water District –Six (6) cfs capacity in Baker Pipeline for supply to the Dimension Plant.
- Irvine Ranch Water District –Thirty two (32) cfs capacity for transfer of water through Reach 1 of the Baker Pipeline to the Irvine Lake Pipeline when the Irvine Lake Reach (of the ILP) requires maintenance.
- Other Baker Pipeline Water Rights Holders – agencies or entities with water rights to Baker Pipeline that are not participating in the Baker WTP project (including the County of Orange, East Orange County Water District and The Irvine Company).

Table 4.1 Maximum OC-33 Flow Rate

Capacity Rights of	Flow (cfs)
Baker Water Treatment Plant	43.5
Agriculture Use	4.0
Trabuco Canyon Water District	6.0
Irvine Ranch Water District	32.0
Other Baker Pipeline Water Rights Holders	13.5
Total	99.0

4.3 MODIFICATION

The existing flow meter is limited to measurement of 40 cfs. Therefore, the existing meter will be removed and replaced with a Venturi or Mag type flow meter (at MWD's direction) capable of measuring up to 100 cfs. Coordination with MWD has been initiated, and regularly scheduled meetings are planned to continue discussion between MWD and IRWD through final design. Further discussion of MWD coordination is provided in Section 24.

SECTION 5 RAW WATER PUMP STATION

5.1 OVERVIEW

The Baker Raw Water Pump Station (RWPS) will enable supply of raw water from Irvine Lake to the Baker Water Treatment Plant. This section describes the basis for design and operation of the pump station, covering the following topics:

- Capacity – basis for the design capacity of the pump station
- Hydraulics – pump station specific hydraulic calculations and analysis
- Site Development – location of the pump station, site access, demolition, earthwork, drainage, easements and geotechnical conditions
- Design Criteria – summary of design parameters
    - Pump
    - Surge
    - Mechanical
    - Structural
    - Geotechnical
    - Operation

5.2 Capacity

The capacity of the pump station includes delivery of raw water for the Baker WTP, the Trabuco Canyon Water District filtration plant, and agriculture demands. These flows are shown in Table 5.1.

Table 5.1 RWPS Capacity

Demand Point	Flow (cfs)
Baker WTP	43.5
Trabuco Canyon Water District – Dimension WTP	6.0
Agricultural Use	4.0
TOTAL	**53.5**

Three agencies (East Orange County Water District, The Irvine Company and the County of Orange), which are not Baker WTP stakeholders, have capacity rights totaling 13.5 cfs in Reach 1 of the Baker Pipeline. It is assumed these agencies will continue with their allocated rights in the Baker Pipeline and may receive water from Reach 1, during operation of the Baker WTP. These flows are considered to be separate from water supplied to the Baker Pipeline through the Baker Raw Water Pump Station, and therefore are not included in the pump station capacity.

5.3 Hydraulics

Hydraulic calculations to estimate the range of suction and discharge pressures for the RWPS are provided in Table E1 of Appendix E. The range of suction pressures accounts for minor and frictional losses through the Irvine Lake Pipeline. The range of discharge pressures is based on the minimum discharge HGL necessary to maintain a minimum head of 15 feet over the high points in the Baker Pipeline.

A summary of the primary calculation values is provided as Table 5.2.

Table 5.2 RWPS Hydraulics

Description	Parameter
Hydraulics (Suction)	
Water Level in Irvine Lake	750 - 790 ft
Maximum Flow	70 cfs
Headloss thru IL outlet tower and Irvine Lake Pipeline	0 - 57 ft
Minimum HGL at Raw Water Pump Station	708 ft
Hydraulics (Discharge)	
Discharge HGL in Baker Pipeline	815 ft
Maximum Flow	53.5 cfs

The 100% and 70% speed curves, for a representative pump (Johnston 27 CC) and for lake levels of 750 ft and 790 ft, are shown in Exhibit 5.1. The curves represent two-pumps operating with one standby. The condition with one pump operating is not shown since the HGL at which water is delivered to the RWPS is generally above the system curve for lower flows, and gravity flow is possible.

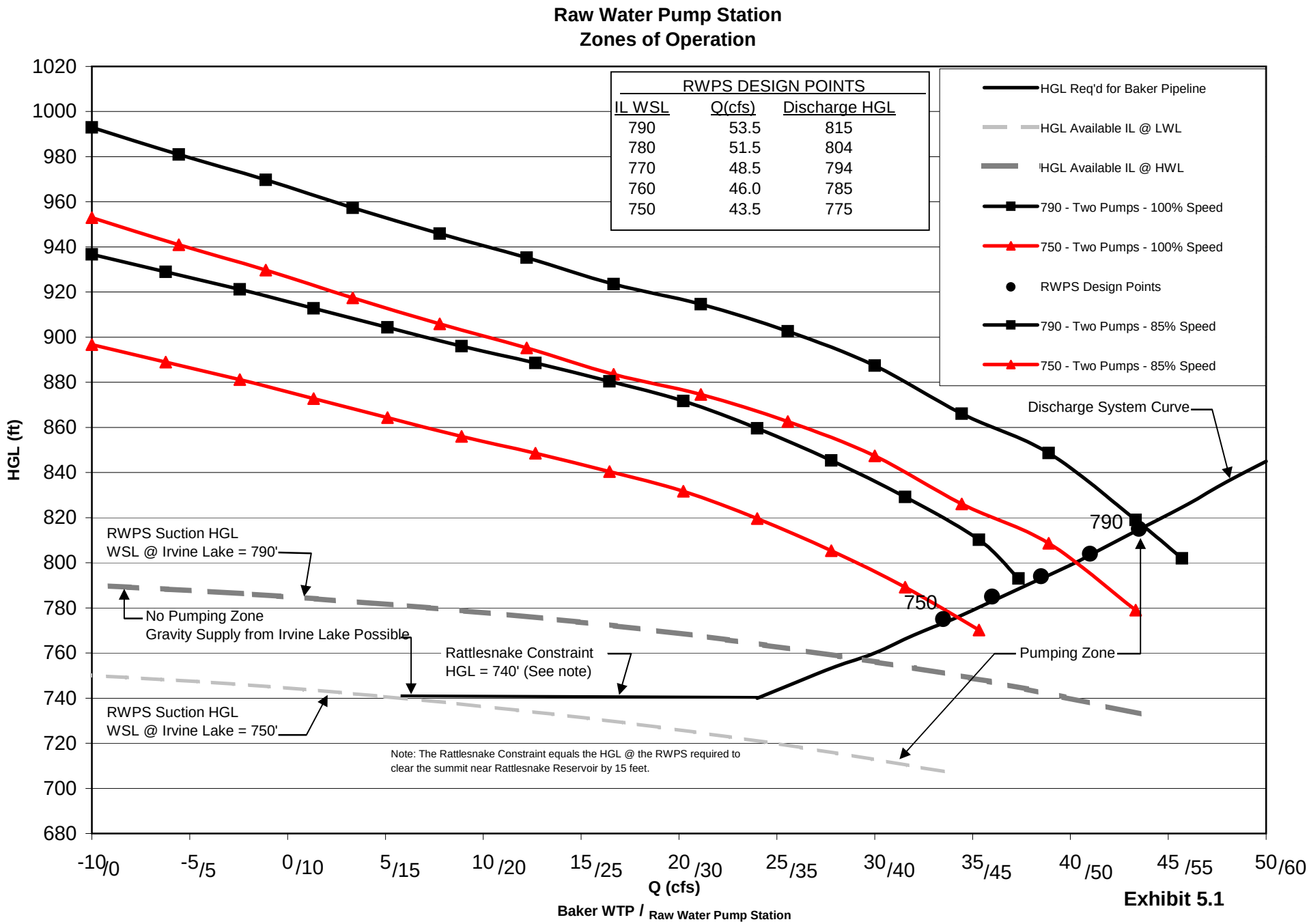
Raw Water Pump Station
Zones of Operation
RWPS DESIGN POINTS
IL WSL Q(cfs) Discharge HGL
790 53.5 815
780 51.5 804
770 48.5 794
760 46.0 785
750 43.5 775
HGL Req'd for Baker Pipeline
HGL Available IL @ LWL
HGL Available IL @ HWL
790 - Two Pumps - 100% Speed
750 - Two Pumps - 100% Speed
RWPS Design Points
790 - Two Pumps - 85% Speed
750 - Two Pumps - 85% Speed
Discharge System Curve
790
750
RWPS Suction HGL
WSL @ Irvine Lake = 790'
No Pumping Zone
Gravity Supply from Irvine Lake Possible
Rattlesnake Constraint
HGL = 740' (See note)
Pumping Zone
RWPS Suction HGL
WSL @ Irvine Lake = 750'
Note: The Rattlesnake Constraint equals the HGL @ the RWPS required to clear the summit near Rattlesnake Reservoir by 15 feet.
HGL (ft)
1020 1000 980 960 940 920 900 880 860 840 820 800 780 760 740 720 700 680
-10/0 -5/5 0/10 5/15 10/20 15/25 20/30 25/35 30/40 35/45 40/50 45/55 50/60
Q (cfs)
Baker WTP / Raw Water Pump Station

Exhibit 5.1

Separate design points were calculated for each ten feet of lake level from 790 ft to 750 ft. The development of these values is shown in Table E1 of Appendix E. They reflect a reduction in flow through the ILP and the Baker Pipeline as a function of declining water surface level in Irvine Lake. The reduction of flow was made in order to achieve pumping conditions, over the 40-foot range in Irvine Lake WSLs, which would parallel the system curve and thereby fix the power requirements required for the maximum outlet tower flow rate (70 cfs) at the highest lake level (790'). The horsepower required to pump from this lake level at 53.5 cfs is approximately the same as that required to pump from a WSL of 750 ft at 43.5 cfs. In order to maintain the same discharge rate over the entire range of declining lake levels the pump station horsepower would have to increase from 750 to 1,000 HP.

This approach to sizing the RWPS was taken since the possible range of flow through the ILP and the Baker Pipeline has not been finalized to the extent that discrete design points are available. Although it is believed that the demands underlying the pumping rates are reasonable, this is a matter that must be addressed further in final design, including coordination amongst the Project Stakeholders.

5.4 SITE DEVELOPMENT

The Baker Raw Water Pump Station will be constructed at the "Peters Canyon" site which is owned by the Santiago Aqueduct Commission (SAC). The site is located in the City of Orange, between the Peters Canyon Reservoir and Jamboree Road. The pump station will be constructed within the SAC parcel, but will require construction easements with the County of Orange and Metropolitan Water District (see **Drawing C3**). Currently, two buildings exist at the site:

- Irvine Lake Pipeline / Baker Pipeline Flow Control Facility – operated by IRWD
- Municipal Water District of Orange County and East Orange County Water District Flow Control Facility – operated by MWD

Crossing the site are the Irvine Lake Pipeline, Baker Pipeline and Allen McColloch Pipeline. The IRWD flow control facility is used for routine transfer of water from the Baker Pipeline to the Irvine Lake Pipeline.

5.4.1 Site Access

Site access consists of a unpaved roadway off of Jamboree Road. A swing gate is located along the roadway allowing access of authorized vehicles only. Asphalt pavement exists along a portion of the site access road closer to the buildings and in the area designated for parking.

5.4.2 Demolition

The Irvine Lake Pipeline / Baker Pipeline Flow Control Facility will be demolished in order to accommodate construction of the Baker Raw Water Pump Station.

5.4.2.1 Description

The pump station construction will occur on SAC, MWD and County of Orange owned land, requiring the demolition of the existing flow control facility and earthwork to prepare a level pad for the building. Site demolition will consist of demolition and removal of:

- ILP / Baker Flow Control Building
- Asphalt Pavement
- Electrical Meter / Switchboard
- Chainlink Fence
- Portions of pipeline connected to the Irvine Lake Pipeline and Baker Pipeline.

Exhibit 5.2 (Drawing D2) depicts the existing building, pipelines and area of demolition and land ownership at the site. The function of transferring water from the Baker Pipeline to the ILP will be temporarily discontinued with the demolition of the facility. Concurrent with the demolition work, two buried butterfly valves, at the connections to the Baker Pipeline and the ILP, will be refurbished, or removed and replaced.

5.4.2.2 Hazardous Materials

The possibility of hazardous materials (e.g. lead paint, asbestos) having been incorporated into the original construction will be investigated. If present, these materials will be removed by a specialty contractor prior to the general demolition.

5.4.3 Earthwork

The new pump station site may also need space reserved for a surge tank connected to the Irvine Lake Pipeline. The surge tank would be adjacent to the pump station building. Retaining walls would be constructed to extend the construction pad while minimizing the necessary earthwork prior to construction.

5.4.4 Drainage

Few changes to the existing drainage patterns will be required. The overall site is small in terms of stormwater development, thus there will be no major drainage control facilities incorporated into the construction.

Exhibit 5.3 (Drawing C3) shows the proposed site improvements associated with the construction of the Raw Water Pump Station.

5.5 Design Criteria

5.5.1 Pump

The pump design parameters are summarized in Table 5.3. The system curve and pump curves are depicted on Exhibit 5.1. Design is based on 70-percent speed as the lowest pump speed.

Table 5.3 RWPS - Pump Criteria

	Units	Value
Pump Station Design Capacity	CFS	53.5
Pumps Type: Vertical Turbine	-	-
No. of Pumps	NO.	3
No. of Redundant Pumps	NO.	1
Design Flow per Pump	GPM	12,000
TDH	FT of Water	105
Power	HP	450

5.5.2 Surge

Flow Science, Inc. prepared a surge analysis for the RWPS. The analysis considered surge conditions on the suction and discharge sides of the pump station.

No potentially damaging surge events, which would require the installation of a surge tank to protect the Baker Pipeline, are predicted for the discharge side of the pump station. However, the report recommends:

- the installation of vacuum relief valves at local high points Stations, 328+13, 164+85, 597+81, and 881+62 on the Baker Pipeline and,

- the construction of a constant-head-tank upstream of the WTP, in order to protect the plant from low pressures that could be produced as a result of a power failure at the RWPS (Note that the currently planned forebay will function as a constant-head-tank, with respect to the protection of the membranes).

The protection of the ILP, from transients caused by a power failure at the RWPS, will require one of the following:

- the construction of a 3,200 cu. ft. surge tank on the suction side of the Raw Water Pump Station or,

- the installation of an eight-inch diameter surge relief valve at ILP station 328+20.

During a complete power interruption, without one of these facilities, there would be an incursion into the ILP's safety margin for transient events. The surge tank would be more expensive to construct than the relief valve, although the latter would require the construction of approximately 1,500 feet of 8-inch diameter pipe. Alternatively the relief valve could be installed at Sta 214+00 where it would be able to discharge into an existing detention basin and require approximately 200 feet of 8-inch pipeline.

Analysis is on-going and will be continued into and through design to finalize the facilities necessary and in support of coordination with MWD. The conclusions provided herein are based on the Draft Report (November 2009), which has been provided to MWD for initial review.

5.5.3 Mechanical

The mechanical layout of the RWPS, illustrated on Exhibit 5.4 (Drawings M17 - Plan, M18 and M19 - Sections), encompasses the configuration of the pumps, valves, meter and surge tank associated with the design. The mechanical criteria associated with valving, meters and surge are summarized in Table 5.4.

Table 5.4 RWPS - Mechanical Criteria

Equipment	Count	Size	Description
Check Valves	3	30-inch	Silent Check
Butterfly Valves	3	30-inch	Manual – Gear Operator - Direct Burial
Butterfly Valves	3	30-inch	Manual – Gear Operator
Butterfly Valves	2	20-inch	Manual – Gear Operator
Butterfly Valves	2	12-inch	Manual – Gear Operator
Globe Valve	1	16-inch	Pressure Relief
Globe Valve	1	10-inch	Pressure Relief
Ball Valve	1	18-inch	Flow Control - MOV
Air Valves	3	6-inch	Combination Air Vac / Release
Air Valve	1	4-inch	Air Release
Air Valve	1	2-inch	Air Release
Meter	1	30-inch	Magnetic
Surge Tank	1	3500 cu. ft.	Hydropneumatic

5.5.4 Structural

The Raw Water Pump Station will be constructed as a masonry block building measuring approximately 30 ft by 60 ft. The new building will be constructed with slope retainment to the south to reduce the extent of grading into the existing slope. In addition, the planned area for the surge tank requires a retaining wall, as shown in Exhibit 5.3 (**Drawing C3**).

5.5.5 Geotechnical

A geotechnical investigation, including borings and soil data logging, will be completed with the design of the Raw Water Pump Station.

5.5.6 Operation

The RWPS will be operated to convey Irvine Lake water to the Baker WTP in the event of an interruption in supply from the Santiago Lateral. When flow is reduced or stopped through OC-33, Irvine Lake can be used as a raw water source for the Baker WTP, either replacing or supplementing the MWD supply.

The modifications made at the Peters Canyon site will not affect the ability of the Baker Pipeline to be utilized as bypass pipeline in the event of future maintenance of the Allen McColloch Pipeline.

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SECTION 6 TRABUCO CANYON WATER DISTRICT PUMP STATION

6.1 BACKGROUND

Trabuco Canyon Water District receives raw water through the Baker Pipeline, which it treats at its Dimension Plant. Raw water is currently delivered to TCWD from the Baker Pipeline by way of a 12- / 16-inch pipeline. IRWD and TCWD operate the connection based on a minimum HGL of 720 ft, to provide a flow of up to 6 cfs at the minimum required pressure for the Dimension Plant.

Under the proposed project, the Baker Pipeline will be operated to deliver raw water flow of 43.5 cfs to the Baker WTP. In the event that all water rights are conveyed through Reach 1 of the Baker Pipeline, the HGL at the Baker WTP is estimated to be 690 feet. As a result, a pump station will be required to continue raw water delivery to the TCWD Dimension Plant.

This section describes the preliminary design concept and criteria for the TCWD Pump Station.

6.2 PUMP STATION

The TCWD Pump Station will be constructed to receive water from the Baker Pipeline and boost water to a minimum HGL of 720 ft for supply to TCWD's Dimension Plant. As currently considered the pump station will draw water from the main raw water pipeline to the Baker WTP Project, upstream of the flow control facility. A bypass pipeline will be provided to transfer water by gravity, similar to current conditions, when sufficient head exists. The pump station will be constructed along the access road situated between the Baker Pipeline valve vaults and Zone A Reservoirs. Design of the pump station will consist of three (3) pumps, with two as duty pumps, and one stand-by. All pumps will be constructed above ground and inside a block wall enclosure with a chainlink cage over the top for security.

6.3 CAPACITY

The pump station capacity of 6 cfs (2,700 gpm) equals the water rights currently held by TCWD in the Baker Pipeline. It is understood that TCWD operation of the Dimension Plant includes periods of backwash where rapid decreases of flow to the plant ranging from 1 to 3 cfs can occur.

6.4 HYDRAULICS / OPERATION

The HGL upstream of the TCWD Pump Station will vary with the hydraulic conditions in the Baker Pipeline. During normal operation of the Baker WTP, the HGL is estimated to drop below 720 ft, due to the existing water rights for agricultural demands in the upstream reaches of Baker Pipeline. When Irvine Lake is being filled from the Santiago Lateral the HGL into the Baker Pipeline will rise by approximately 40 ft. In this case, the HGL in Baker Pipeline will rise above 720 ft, allowing for flow to bypass the TCWD Pump Station directly to the Dimension Plant.

The TCWD Pump Station design must also account for the rapid variation of flow during backwashing of the media filters at the Dimension Plant. Two potential solutions are under consideration:

1. Relief Valve – a valve to release flow during the short periods of reduced flow through the Dimension Plant media filters.

2. Flow Equalization – an equalization basin between the TCWD Pump Station and Dimension Plant.

6.5 DESIGN CRITERIA

The hydraulic design criteria for the TCWD Pump Station are summarized in Table 6.1.

Table 6.1 TCWD Pump Station Design Criteria

Type:	Unit	Value
Type of Pump: Horizontal Split Case or Vertical Pumps	-	-
No. of Pumps (Duty and Redundant)	NO.	3
No. of Redundant Pumps	NO.	1
Capacity per Pump	GPM	1,350
TDH (Maximum)	FT of Water	60
Size	HP	25
Mechanical	-	-
Upstream Pipeline Diameter	IN	12
Inlet Pipeline	IN	12
Discharge Pipeline	IN	12
Isolation Valves	IN	12
Downstream Pipeline Diameter	IN	16

SECTION 7 FLOW CONTROL FACILITY

7.1 OVERVIEW

The flow control facility at the Baker Water Treatment Plant will control flows originating either from the Santiago Lateral through OC-33 or from Irvine Lake via the Baker Raw Water Pump Station. In each case, the facility will handle flows up to the maximum capacity of the Baker Pipeline, less takeouts for agricultural interests and TCWD. These takeouts represent about twenty percent of the total pipeline capacity, but are withdrawn from the pipeline upstream of the facility.

7.2 HYDRAULICS AND OPERATION

The Baker Water Treatment Plant has been sized to treat a raw water flow of about 43.5 cfs (28 mgd). Exhibit 7.1 shows the upstream HGL at the facility, as a function of the flow rate delivered through the Baker Pipeline to the facility. The downstream HGL required to deliver the flow to the forebay is represented by the lower curve. The HGL at the entrance to the facility will be reduced, by the flow control valve, to an HGL sufficient to supply the forebay, with the WTP's raw water demand.

Both ball valves and sleeve valves were analyzed in order to determine their suitability as flow control valves. Butterfly and gate valves were summarily eliminated because of their inability to operate, without cavitating, where there is little outlet pressure. In this case, the only available pressure downstream of the flow control facility is that required to convey the raw water to the forebay, a vertical distance of less than 20 feet. Two ball valve configurations were considered:

- Parallel trains: 12-inch ball valves and static sleeve valves (Table 7.1)
- Single train:18-inch ball valve—16-inch static sleeve valve (Table 7.2)

Neither of these configurations proved to be workable over a sufficient range of flow conditions, tending to cavitate at low flows, while at higher flows the valves approached full-open and could not be expected to effectively modulate flows.

An 18-inch angle-pattern sleeve valves will be capable of operating over the full range of flows without cavitating (see Table 7.3). Exhibit 7.2 (see **Drawing M1**) depicts the proposed flow control facility with two sleeve valves for redundancy. Dependent on the potential for quagga mussel in the Irvine Lake Pipeline and Baker Pipeline, strainers upstream of the flow control facility may be necessary.

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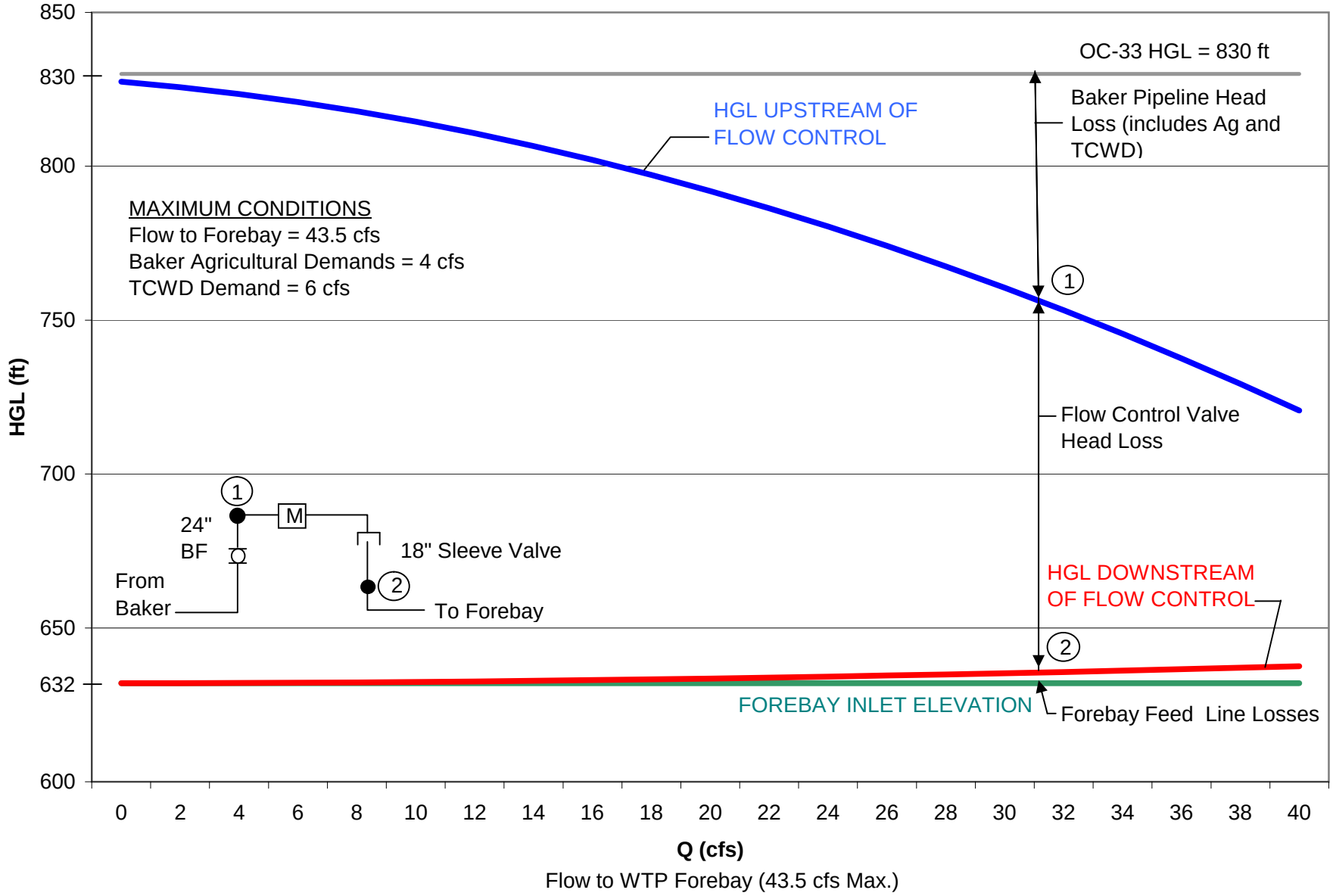
Exhibit 7.1
Flow Control Valve



Flow to WTP Forebay (43.5 cfs Max.)

TABLE 7.1
BAKER WATER TREATMENT PLANT
FLOW CONTROL FACILITY - CAVITATION ANALYSIS
Two Parallel 12-inch Ball Valves and Static Sleeve Valves

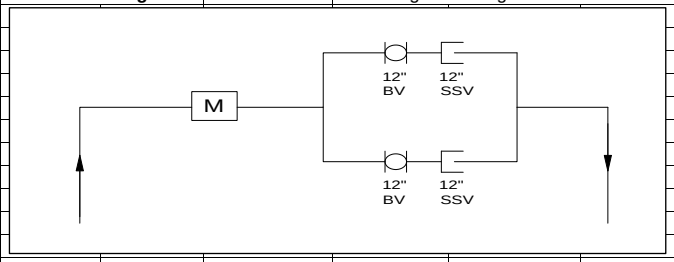
Raw Water Flow to WTP (CFS)	Flow Through Each Parallel Valve (CFS)	Valve Elevation (Feet)	HGL (Feet) --12-INCH BALL VALVE		HGL (Feet) --12-INCH STATIC SLEEVE VALVE		BALL VALVE									
							Head (Feet)			Ball Valve						
			Upstream	Downstream	Upstream	Downstream	Upstream	Downstream	Difference Across Valve	Cavitation Parameter	Valve Diameter (Inches)	Velocity (FPS)	C_v gpm/√psi	C_v cfs/√ft	% of Full Open C_v	Valve Angle (Degrees)
0	0.0	618	830	632	632	632	212	14	198	0.24	12	0.0	0	0.0	0.0	0
5	2.5	618	822	633	633	632	204	15	189	0.25	12	3.2	247	0.4	1.2	13
10	5.0	618	814	635	635	632	196	17	179	0.28	12	6.4	508	0.7	2.4	25
15	7.5	618	804	639	639	633	186	21	166	0.32	12	9.6	793	1.2	3.8	35
20	10.0	618	792	644	644	634	174	26	148	0.40	12	12.7	1119	1.6	5.3	42
25	12.5	618	777	651	651	634	159	33	126	0.52	12	15.9	1512	2.2	7.2	50
30	15.0	618	761	659	659	636	143	41	101	0.73	12	19.1	2027	3.0	9.7	57
35	17.5	618	742	669	669	637	124	51	73	1.16	12	22.3	2794	4.1	13.3	63
40	20.0	618	721	680	680	638	103	62	40	2.36	12	25.5	4284	6.3	20.4	72
45	22.5	618	698	693	693	640	80	75	5	23.88	12	28.7	14388	21.1	68.5	84

Valve Angle (Degrees)	% of Full Open C_v	Ball Valve Diameter (Inches)	C_v gpm/√psi	C_v cfs/√ft
5	0.2			
10	0.9	12	21003	30.8
15	1.4			
20	1.8			
25	2.4			
30	3.1			
35	3.7			
40	4.7			
45	5.9			
50	7.2			
55	9.0			
60	11.2			
65	14.1			
70	18.0			
75	24.5			
80	41.5			
85	73.0			
90	100.0			

Acceptable Design Limits

Cavitation Parameter > 1.50
Velocity - Ball Valve < 30 fps
Velocity - Butterfly Valve < 16 fps
Velocity - Pipe/CML < 20 fps
Velocity - Pipe/Fusion Bonded Epoxy Lining < 30 fps
Valve Angle - 15 degrees minimum
Valve Angle - 75 degrees maximum

Schematic Diagram



VALVE ANGLE VS. PERCENT OF FULL OPEN FLOW COEFFICIENT (Cv)

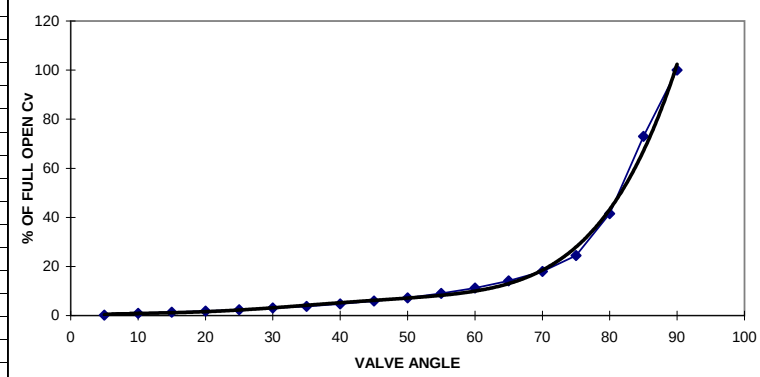
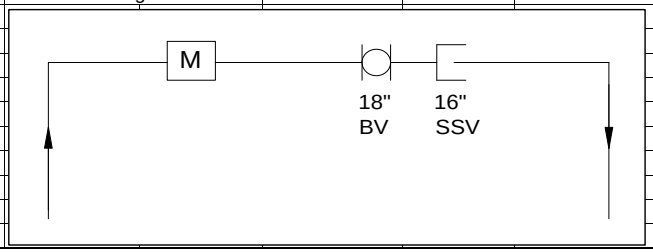


TABLE 7.2
BAKER WATER TREATMENT PLANT
FLOW CONTROL FACILITY - CAVITATION ANALYSIS
18-inch Ball Valve and 16-inch Static Sleeve Valve

Raw Water Flow to WTP (CFS)	Valve Elevation (Feet)	HGL (Feet) --18-INCH BALL VALVE		HGL (Feet) --16-INCH STATIC SLEEVE VALVE		BALL VALVE									
						Head (Feet)			Ball Valve						
		Upstream	Downstream	Upstream	Downstream	Upstream	Downstream	Difference Across Valve	Cavitation Parameter	Valve Diameter (Inches)	Velocity (FPS)	C_v gpm/√psi	C_v cfs/√ft	% of Full Open C_v	Valve Angle (Degrees)
0	618	830	632	632	632	212	14	198	0.24	18	0.0	0	0	0.0	0
5	618	822	633	633	632	204	15	190	0.25	18	2.8	247	0	0.5	7
10	618	814	635	635	632	196	17	180	0.28	18	5.7	507	1	1.1	12
15	618	804	638	638	633	186	20	166	0.32	18	8.5	791	1	1.7	19
20	618	792	643	643	634	174	25	149	0.39	18	11.3	1115	2	2.4	25
25	618	777	649	649	634	159	31	128	0.50	18	14.2	1502	2	3.2	31
30	618	761	657	657	636	143	39	104	0.69	18	17.0	2002	3	4.2	38
35	618	742	665	665	637	124	47	76	1.06	18	19.8	2728	4	5.8	45
40	618	721	676	676	638	103	58	45	2.02	18	22.6	4058	6	8.6	54
45	618	698	687	687	640	80	69	10	9.89	18	25.5	9517	14	20.1	72

Valve Angle (Degrees)	% of Full Open C_v	% of Full Open C_v	Valve Diameter (Inches)	C_v gpm/√psi	C_v cfs/√ft
5	0.2	0.2			
10	0.9	0.9	18	47256	69.3
15	1.4	1.4			
20	1.8	1.8	**Acceptable Design Limits**		
25	2.4	2.4	Cavitation Parameter > 1.50		
30	3.1	3.1	Velocity - Ball Valve < 30 fps		
35	3.7	3.7	Velocity - Butterfly Valve < 16 fps		
40	4.7	4.7	Velocity - Pipe/CML < 20 fps		
45	5.9	5.9	Velocity - Pipe/Fusion Bonded Epoxy Lining < 30 fps		
50	7.2	7.2	Valve Angle - 15 degrees minimum		
55	9.0	9.0	Valve Angle - 75 degrees maximum		
60	11.2	11.2			
65	14.1	14.1	Schematic Diagram		
70	18.0	18.0			
75	24.5	24.5			
80	41.5	41.5			
85	73.0	73.0			
90	100.0	100.0			



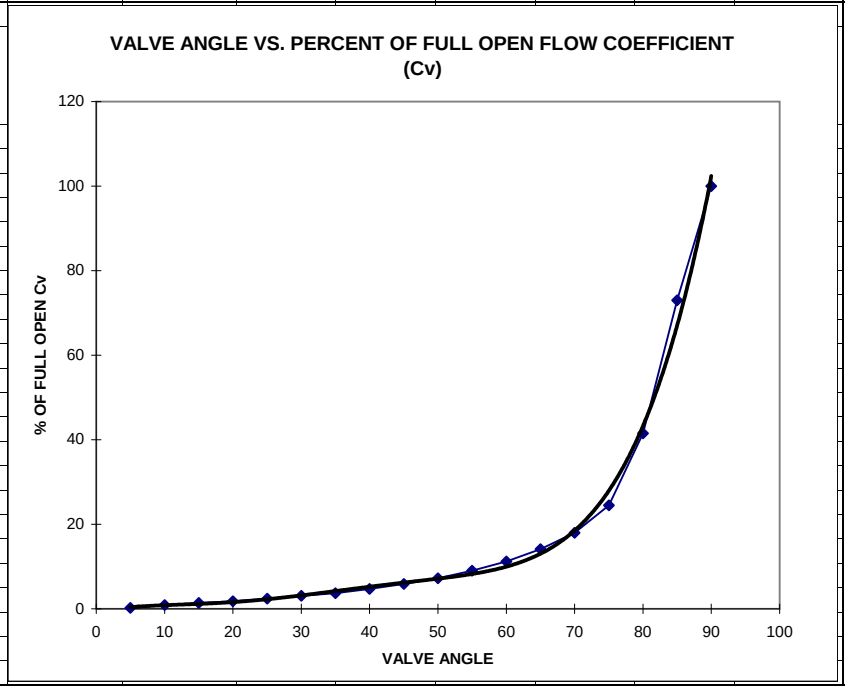


TABLE 7.3
BAKER WATER TREATMENT PLANT
FLOW CONTROL FACILITY - CAVITATION ANALYSIS
18-inch Angle Pattern Sleeve Valve

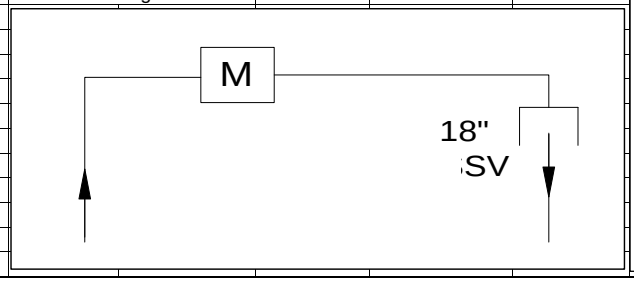
Raw Water Flow to WTP (CFS)	Valve Elevation (Feet)	HGL (Feet) --18-INCH SLEEVE VALVE		SLEEVE VALVE									
				Head (Feet)			Sleeve Valve						
		Upstream	Downstream	Upstream	Downstream	Difference Across Valve	Cavitation Parameter	Valve Diameter (Inches)	Velocity (FPS)	C_v gpm/√psi	C_v cfs/√ft	% of Full Open C_v	Stroke %
0	618	830	632	212	14	198	0.24	18	0.0	0	0.0	0.0	0
5	618	822	632	204	14	190	0.25	18	2.8	247	0.4	3.7	2
10	618	814	632	196	14	182	0.26	18	5.7	504	0.7	7.5	4
15	618	804	633	186	15	171	0.28	18	8.5	779	1.1	11.7	6
20	618	792	634	174	16	158	0.31	18	11.3	1081	1.6	16.2	8
25	618	777	634	159	16	143	0.35	18	14.2	1423	2.1	21.3	11
30	618	761	636	143	18	125	0.41	18	17.0	1826	2.7	27.3	15
35	618	742	637	124	19	105	0.50	18	19.8	2327	3.4	34.8	20
40	618	721	638	103	20	82	0.65	18	22.6	3000	4.4	44.9	27
45	618	698	640	80	22	58	0.96	18	25.5	4035	5.9	60.3	41

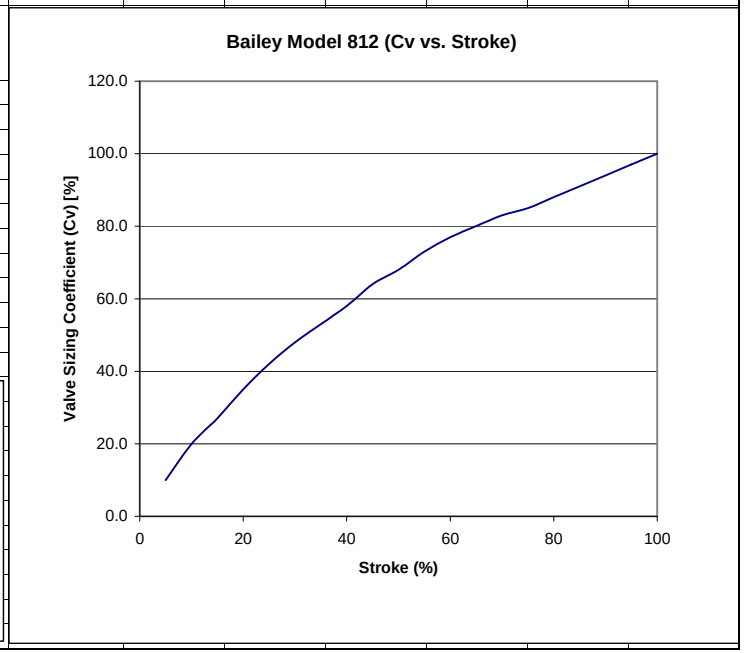
Stroke %	% of Full Open C_v	Valve Diameter (Inches)	C_v Bailey Model 812 gpm/√psi	C_v Bailey Model 812 cfs/√ft
5	10.0	18	6689	9.8
10	20.0			
15	27.0			
20	35.0			
25	42.0			
30	48.0			
35	53.0			
40	58.0			
45	64.0			
50	68.0			
55	73.0			
60	77.0			
65	80.0			
70	83.0			
75	85.0			
80	88.0			
85	91.0			
90	94.0			
95	97.0			
100	100.0			

Acceptable Design Limits

Cavitation Parameter - No minimum
Velocity - Sleeve Valve < 30 fps
Velocity - Butterfly Valve < 16 fps
Velocity - Pipe/CML < 20 fps
Velocity - Pipe/Fusion Bonded Epoxy Lining < 30 fps
Stroke - No Min - No Max

Schematic Diagram





7.3 SITE IMPROVEMENTS

Several factors influenced the location of the flow control facility.

- Lower elevation of the flow control valve allows greater back pressure on the valve and the less potential for cavitation.
- The lower elevation eliminates the need for a vault of about 15 feet of depth.
- An additional advantage of the location is that it provides for a longer raw water pipeline, which equates to greater chlorine dioxide contact time.

The flow control facility will be located along the access road to the Baker site, and northeast of the existing connection to the Baker Pipeline as shown on Exhibit 7.3. The flow control facility will be constructed into the existing slope, requiring a wall for retainment of 5 +/- feet on the back side of the facility. Along the access road, the facility will include extension of the wall or bollards to protect all mechanical equipment. An enclosure will be considered for sound attenuation.

Exhibit 7.3 Flow Control Facility Site

7.4 ACCEPTABLE DESIGN LIMITS

Acceptable design limits (per Table 7.4) were used for the design of the flow control facility:

Table 7.4 Acceptable Design Limits

Component	Maximum Velocity (cfs)	Minimum Cavitation Parameter	Valve Angle or Stroke	
			Minimum	Maximum
Pipe Lining				
Cement Mortar	20	NA	NA	NA
Fusion Bonded Epoxy	30	NA	NA	NA
Valves				
Butterfly	16	-	-	-
Ball	30	1.5	15 degrees	75 degrees
Sleeve	30	0.15	5-percent	None

The cavitation parameter is calculated by dividing the downstream absolute pressure by the pressure drop across the valve. The lower the number, the greater the cavitation potential. Therefore, for the same downstream conditions, a sleeve valve can break ten times the head that a ball valve can without cavitating.

7.5 DESIGN CRITERIA

The design criteria for the flow control facility are summarized in Table 7.5.

Table 7.5 Flow Control Facility Design Criteria

Description	Units	Value
Location: Parallel to the access road east of the valve vault.	-	-
Mechanical	-	-
Upstream (Raw Water) Pipeline Diameter	IN	24
Reduced Pipe Diameter	IN	18
Flow Control Valve Type: Motor Operated Sleeve Valve	-	-
Sleeve Valve Diameter	IN	18
Downstream (Raw Water) Pipeline Diameter	IN	48

SECTION 8 IRON AND MANGANESE MANAGEMENT

8.1 OVERVIEW

The Baker WTP will require pretreatment for the management of iron and manganese in the ILW raw water supply. Pretreatment is essential for prevention of membrane fouling. Pretreatment, in conjunction with membrane treatment, will mitigate potential aesthetic issues and ensure compliance with Secondary MCLs.

Membrane filtration requires periodic cleaning such as conventional backwash and chemically enhanced backwash (CEB). Membranes may also be cleaned in place (CIP) to maintain production.

Filtered water and sodium hypochlorite are typically used to prepare the cleaning solutions. Pilot test data indicate that chlorine concentration in the cleaning solutions for Baker WTP could vary from 400 mg/L for CEB to 1,000 mg/L for CIP solution. With such chlorine concentrations, dissolved iron and manganese present in the filtered water will be oxidized in the cleaning solutions and precipitate on the membranes. Every backwash will push the oxidized iron and manganese into the membrane pores instead of removing them creating a fouling condition that is difficult to reverse.

Iron and manganese concentrations reported in this work are below historical levels and existed primarily in oxidized (filterable) solids form before pre-treatment. However, there is a significant potential for manganese to be present in its dissolved form in ILW. This could result in rapid membrane fouling and elevated manganese concentrations in finished water if manganese is not adequately oxidized upstream of the membrane filtration process.

Iron and manganese may also generate aesthetic issues such as staining of laundry and fixtures. Iron and manganese could also be detrimental to various industrial processes. As a consequence, the USEPA has set the SMCL at 0.3 mg/L for iron and 0.05 mg/L for manganese.

Bench testing conducted for the Baker WTP showed that treating ILW with a chlorine dioxide preoxidation ahead of the membrane filtration process will minimize membrane fouling, while meeting finished water iron and manganese goals.

8.2 OBJECTIVES

The three primary objectives of iron and manganese management are:

- Production of finished water with iron concentration and manganese concentration below their respective SMCL
- Prevention of membrane fouling-Review of literature and troubleshooting of membrane plants suggests that an iron concentration as low as 0.05 mg/L and a manganese concentration as low as 0.02 mg/L is an appropriate target.
- Minimization of customer aesthetic complaints-Review of literature suggests that iron levels as low as 0.1 mg/L and manganese levels as low as 0.02 mg/L in the finished water could generate complaints.

The following treatment goals were established to achieve the objectives:

- Manganese level in MF feed water: 0.02 mg/L
- Iron level in MF feed water: 0.05 mg/L
- Monitor and control concentrations and dosing rates of oxidant chemicals for minimizing residual disinfectant level and ensure compliance with the Maximum Residual Disinfectant Level (MRDL).

8.3 OXIDATION

Oxidation is recommended for the pretreatment process. Oxidation of dissolved manganese requires either higher oxidant dosage or longer contact time than oxidation of dissolved iron. Therefore, selection of the oxidant chemical must be based on manganese oxidation. Oxidant chemicals considered for use at the Baker WTP, include:

- Potassium Permanganate
- Ozone
- Sodium Hypochlorite
- Chlorine Dioxide

Potassium permanganate was disregarded because of its operational challenges and the risk of pink water events in case of overdosing. Ozone was disregarded because of the risk of fatal damage to the membranes with any residual. It was

determined that bench testing must be conducted to distinguish between sodium hypochlorite and chlorine dioxide.

8.4 BENCH TESTING

A supplemental bench-testing program was conducted to support design criteria for oxidant selection, dose, and required contact time upstream of the membrane filtration system. Irvine Lake water samples were taken at a sampling station on the Irvine Lake Pipeline just upstream of the existing Irvine Lake Pipeline Disinfection Facility in Irvine Regional Park.

The bench-testing included analysis of sodium hypochlorite and chlorine dioxide for further evaluation of required dose and contact time. Sodium hypochlorite was abandoned because it could not achieve the required level of manganese oxidation in 20 minutes, which would have required a contact basin too large to fit on the plant site. Based upon the results of the bench-test program, the Baker WTP design should:

- Incorporate injection of chlorine dioxide downstream of the flow control facility based on the measure flow rate of raw water to the forebay.
- Achieve a minimum contact time of 5 minutes upstream of the membranes in order to oxidize dissolved manganese and achieve the treatment objectives defined in Section 8.2. The bench-test program confirmed that dissolved iron was undetectable after oxidation by chlorine dioxide.

8.5 OXIDANT GENERATION

Chlorine dioxide cannot be compressed or stored commercially as a gas because it is explosive under pressure. Therefore, it is manufactured on site and never shipped. In addition, strong aqueous solutions of chlorine dioxide will release gaseous chlorine dioxide into a closed atmosphere above the solution at levels that may exceed critical concentrations. For drinking water applications, chlorine dioxide aqueous solutions between 0.1 and 0.5 percent (e.g., 1,000 mg/L and 5,000 mg/L) are typically produced at the point of use from two alternative generation methods:

1. Two chemicals: sodium chlorite, and chlorine gas
2. Three chemicals: sodium chlorite, sodium hypochlorite, and hydrochloric acid

Comparison of chlorine dioxide generation methods is provided in Table 8.1.

Table 8.1 Pros and Cons of Chlorine Dioxide Generation Methods

Generation Method	Pros	Cons
Sodium Chlorite Chlorine Gas	- Most efficient production method (95% yield) - Lower O&M cost ($4.60 per pound of chlorine dioxide)	- Hazards associated with on-site storage and handling of chlorine gas (150 lb cylinders)
Sodium Chlorite Sodium Hypochlorite[1] Hydrochloric Acid	- Use of sodium hypochlorite is less hazardous than chlorine gas - Sodium hypochlorite already used for cleaning membranes	- Less efficient production method (90% yield) - Degradation of sodium hypochlorite solution - Potential low pH - Higher O&M cost ($5.45 per pound of chlorine dioxide)[2]

Notes
1. 12.5 percent solution is used. The use of 0.8 percent solution to produce chlorine dioxide is unproven. The same 12.5 percent solution will be used for membrane CEB and CIP
2. Cost for 28 mgd and a chlorine dioxide dose of 1 mg/L is estimated to be at $12.70 per acre-foot for the two chemical generation method and $15.00 per acre-foot for the three chemical generation method.

Despite the technical benefits and the lower O&M costs of the two-chemical generation method, IRWD selected the three-chemical generation method for operator safety and neighborhood acceptance.

8.6 OXIDANT PACING METHOD

Two pacing methods are available for each of the two generation methods described in the previous paragraph.

For the **automatic or direct method**, the concentration of the chlorine dioxide solution delivered by the generator is continuously adjusted to the WTP flow set point and the chlorine dioxide demand. Concentration of the chlorine dioxide solution is measured by means of an optical analyzer. When sodium hypochlorite is used in lieu of chlorine gas, a pH loop may be added, as the liquid phase reaction is best achieved at low pH. Automatic control valves and flow meters are used to ensure the correct ratio of chemicals is continuously combined together. The water flow rate through the generator is constant. The chlorine dioxide solution is directly injected into the process piping by the generator.

For the **batch method**, the concentration of the chlorine dioxide solution produced by the generator is set at a fixed rate. Water flow rate through the generator is also constant. A high concentration chlorine dioxide solution is stored in a batch tank. Storage time is limited to avoid significant degradation. Metering pumps are flow paced to achieve the required dosing turndown ratio.

Comparison of chlorine dioxide pacing methods is provided in Table 8.2.

Table 8.2 Pros and Cons of Chlorine Dioxide Pacing Methods

Pacing Method	Pros	Cons
Direct	Less equipment No chlorine dioxide solution tank No need for scrubber	Turndown ratio limited by the hydraulic requirements of the Venturi and the optimum reaction conditions Backpressure limited to 30 psi Generator continuous operation More maintenance Risk of forming chlorate at plant low flow
Batch	Infinite turndown ration with metering pump and mass flow meter Dosing concept similar to other chemicals with metering pump Generator operates at a constant set point. Turns on/off on batch tank level Less maintenance Inventory of chlorine dioxide solution allows for response time for routine maintenance Better consistency of the chlorine dioxide dose	Chlorine dioxide solution tank Floating cover or vapor eductor More expensive equipment Larger footprint

The batch pacing method is selected in order to provide a more robust and more reliable chlorine dioxide generation system.

8.7 OXIDANT RESIDUAL CONTROL

The use of chlorine dioxide for the Baker WTP Project beckons consideration of residual control in the product water.

Chlorine Dioxide

The MRDL for chlorine dioxide leaving the Baker WTP is 0.8 mg/L. Also, the maximum continuous level of chlorine dioxide acceptable to the potting of the Pall membrane module is 0.2 mg/L.

Chlorine dioxide in water does not hydrolyze to any appreciable extent but remains in solution as a dissolved gas. Therefore, chlorine dioxide dosage shall be adjusted based on iron and manganese levels in ILW. The adjustment will be indirectly achieved through the operation of an on-line chlorine dioxide analyzer on the MF feed water pipeline.

Chlorine dioxide residual can be destroyed by sunlight or other sources of ultraviolet (UV) light. Continuous operation of UV reactors for disinfection purpose should eliminate any traces of chlorine dioxide in the finished water at the Baker WTP.

Chlorite

Typically, the reaction of chlorine dioxide produces approximately 50 to 70 percent conversion of chlorine dioxide to chlorite (weight to weight basis). The bench-scale testing study confirmed the 50 percent conversion for initial chlorine dioxide doses of 1.0 mg/L and 1.5 mg/L. The MCL for chlorite leaving the Baker WTP is 1.0 mg/L. Therefore, a maximum dosage limit of 1.4 mg/L for chlorine dioxide should prevent the need for reducing chlorite level in the finished water.

The Office of Environmental Health Hazard Assessment has finalized a Public Health Goal (PHG) of 0.050 mg/L for chlorite. The PHG is set at a level at which no known or anticipated adverse effects on health occur with an adequate margin of safety. The PHG is not based on a risk/benefit analysis; it is not an MRDL, and compliance is not required. However, when a PHG is exceeded, it is commonly mentioned in the annual water quality report issued to the customers.

Two methods of compliance (if required in the future) are presented in the following paragraphs. The methods are the use of ferrous iron as an additional pretreatment step and the use of GAC contactors downstream of the membrane system.

- Ferrous iron has been proven to reduce both chlorine dioxide and chlorite to chloride without forming additional chlorate. However, ferrous iron could resolubilize manganese dioxide because manganese dioxide can act as an electron acceptor in a reducing environment. To minimize the risk of resolubilization of manganese dioxide, ferrous chloride or ferrous sulfate should be added 5 minutes after the addition of the coagulant. The practical implementation of the approach would require a clarification process upstream of the membrane feed pumps as the 5-minute lag time cannot be achieved in-line between the flash-mix system and the MF system. Footprint will be reserved on the proposed site layout.

- Granular Activated Carbon (GAC) contactors can remove chlorite by adsorption and chemical reduction. As the contactors are operated with no chlorine, the formation of chlorate is minimized. Further bench-testing would be required to assess the chlorite removal achieved with GAC.

Other Residuals

Generation of chlorine dioxide may also generate chlorate and chloride.

Chlorate is unregulated for now. However, California Department of Public Health requires that a notification be issued for levels of chlorate in the finished water at or above 0.8 mg/L. The bench-scale testing study indicated that less than 0.25 mg/L of chlorate should be produced when dosing chlorine dioxide at 1.4 mg/L. Also, the additional chlorate that could be formed by reaction of the residual chlorite with sodium hypochlorite should not lead to a chlorate concentration above the notification level. No known treatment exists for removing chlorate when formed. The practical approach for minimizing chlorate at the Baker WTP is to:

- Install a batch generator that will always produce high concentrations of chlorine dioxide and therefore promote low initial formation of chlorate
- Monitor and control the pH of the reaction that produce chlorine dioxide to prevent the generator from operating at high pH
- Monitor and control the chlorine dioxide residual at the treatment building

Chloride has a SMCL of 250 mg/L. The magnitude of chloride ions formed during the generation of chlorine dioxide and the dosing of chlorine dioxide at 1.4 mg/L will not measurably increase the chloride ion concentration in the raw water.

8.8 OXIDANT MONITORING

Analytical equipment will be required to monitor the performance of the chlorine dioxide generator and ensure compliance with the chlorine dioxide MRDL and the chlorite MCL. The analytical chemistry of chlorine dioxide is complicated by the chemical's volatility and sensitivity to light. Some analytical methods may be labor-intensive and require a high level of technical skill. The preliminary monitoring program includes:

- Quarterly checking of the generator performance
- Daily sampling for chlorine dioxide at the entrance to the distribution system
- Daily sampling for chlorite at the entrance to the distribution system

- Monthly three-sample set in the distribution system for chlorite
- Daily sampling for chlorate at the entrance to the distribution system

Amperometric titration methods will be used for compliance monitoring of the chlorine dioxide residual and chlorite concentrations in the distribution system as well as for determining the purity of the chlorine dioxide delivered by the generator. The amperometric titrator will be installed at the Baker WTP in the treatment building.

8.9 DESIGN CRITERIA

The design criteria for the iron and manganese management facilities are summarized in Table 8.3.

Table 8.3 Iron and Manganese Management Design Criteria

Description	Units	Value
Maximum Dissolved Manganese Concentration in MF Feed Water	MG/L	0.02
Maximum Dissolved Iron Concentration in MF Feed Water	MG/L	0.05
Generator Type: Batch; 3-chemicals	-	-
Generator Number: 1 (with space for future standby generator)	-	-
Maximum Chlorine Dioxide Dose	MG/L	1.4
Minimum Generator Capacity	Pound per day	350
Required Minimum Contact Time in the Forebay	MIN	5
Total Hydraulic Residence Time in the Forebay (per design)	MIN	10
Additional Contact Time in the Upstream Piping	MIN	7
Note: sodium chlorite, sodium hypochlorite, and hydrochloric acid storage facilities, as well as chlorine dioxide feed system are described in Section 13		

SECTION 9 FOREBAY

9.1 INTRODUCTION

A forebay will be constructed at the Baker WTP:

1. To provide an equalization volume upstream of the membrane filtration system (MFS). The equalization volume allows the Baker WTP to be fed at a constant flow and the MFS to be operated at a typical variable flow; therefore reducing the size of the MFS.

2. To provide a surge control volume large enough to close the plant raw water flow control valve in a time long enough to minimize pressure surges and protect the integrity of the pipeline upstream of the Baker WTP.

3. To provide a contact volume corresponding to the minimum contact time of 5 minutes identified in Section 8 for chlorine dioxide to oxidize dissolved manganese before filtration by the MFS.

4. To support the installation of the membrane feed water pump station. The six membrane feed pumps are each installed in a separate bay at the end of the equalization basin. The pump station and its operation are described in Section 10.

The Baker WTP is a base loaded plant. Therefore, the forebay must be designed to minimize the downtime associated with maintenance activities. As such, the design of the forebay accounts for two 50-percent capacity cells within the forebay. Each cell includes a 50-percent capacity contact basin, followed by a 50-percent capacity equalization basin. Each cell within the forebay is designed with a dedicated 48-inch diameter overflow.

9.1.1 Capacity

The total capacity of the forebay will be 785,000 gallons, made up of:

- The *equalization volume* of the forebay is 500,000 gallons, as agreed with the MFS suppliers and as specified in the Membrane Procurement Package. The volume is equally split between the two cells of the forebay. Appendix F includes a depiction of the variation in level in the forebay as a result of maintenance (backwash, CIP) and integrity testing of the membrane filtration system.

- The *total contact volume* of the forebay is 210,000 gallons. It corresponds to a hydraulic residence time of 10 minutes at plant full

capacity with a T_{10} (time that 10 percent of the water leaving the basin has a residence time equal to or less than) to T ratio of 0.5. Therefore, the contact volume achieves the minimum chlorine dioxide contact time of 5 minutes discussed in Section 8. The volume for contact is equally split between the two cells of the forebay.

- The *surge control volume* is 75,000 gallons based on a minimum flow control valve closure time of three minutes, as discussed in Section 7. The surge volume is added as freeboard on top of the equalization basins and contact basins.

Appendix F includes the calculation of total forebay capacity.

9.1.2 Hydraulics

Raw water will enter the two contact basins in parallel through 36-inch pipeline and 36-inch butterfly valves. Both contact basins will be operated at a constant water level (EL. 632.0) set by an outlet weir. The contact basins will be hydraulically connected through the raw water pipeline. Raw water will be forced below an under baffle wall before flowing over/through an above baffle/diffusion wall. This design will improve the efficiency of the contact basin (e.g., increase T_{10}/T as required) for the chlorine dioxide that does not hydrolyze and remains as a dissolved gas in water.

Beyond the contact basin raw water will flow into each of the two equalization basins. The equalization basins are operated at variable level, with a maximum operational water level of EL. 631.0. From the equalization basins, the water is pumped by the feedwater pump station to the MFS. The equalization basins are hydraulically connected through a normally open 48-inch by 48-inch flushed bottom slide gate. During maintenance of one half (or one cell) of the forebay, the slide gate will be closed to isolate each half.

9.2 FOREBAY CONSTRUCTION

The forebay will be constructed within the existing slope area behind the former Baker Filter Building. Exhibit 9.1 (Drawing M15) shows the forebay planned to have dimensions of 88 feet by 130 ft and depth varying from 16 feet to 23 feet. A pump-bay will be constructed to provide adequate suction head and flow distribution for the vertical turbine pumps planned for the Feedwater Pump Station. A section of the forebay is provided as Exhibit 9.2 (Drawing M16).

9.2.1 Covers

Top concrete slabs will be constructed over the contact basins to prevent destruction of the chlorine dioxide residual by sunlight. Additionally, because chlorine dioxide does not hydrolyze (remains as a dissolved gas in water), a slight negative pressure (e.g., 2-inch of water) will be maintained below the top slab of the contact basins by use of fans, to minimize leakage of chlorine dioxide above the water surface.

Strainers to protect the membrane hollow fibers will be installed downstream of the Feedwater Pump Station. As a result, the equalization basins were considered with an open top. However, algae may grow in the basins of the forebay if no roof is constructed. Algae growth would most substantially impact the Project by creating taste and odor events, and impairing the operation of the strainers. Therefore, structurally supported retractable fabric covers from Geomembrane Technology Inc. (GTI), or alternative covers preferred by the District will be specified over the top of the equalization basins.

9.2.2 Access

Access to each contact and equalization basin will be provided by two 36-inch by 36-inch hatches or removable covers, with a ladder at each and access safety equipment (Safe-T-Climb system or equivalent). A total of eight hatches for access will be provided.

9.2.3 Earthwork

The location of the forebay impacts the extent of grading and shoring necessary for construction. The proposed ground elevation at the forebay is (EL.) 635 ft +/-, and the top of bottom slab is anticipated to be (EL.) 613 ft +/-. Slopes exist to the north and west of the forebay. The slope to the north should be protected with the use of shoring. The inlet pipelines into the reservoir will penetrate the forebay in the upper third of the wall, which will minimize excavation out to the property line to the north. The manufactured slope to the west will also require shoring during construction.

9.2.4 Drainage

The forebay will be drained by opening the normally closed 24-inch by 24-inch flushed bottom slide gates and turning on one of the membrane feed pumps at low speed. The floor of the forebay slopes toward the drains.

When the low-low level alarm that protects the membrane feed pump is activated, the remaining water will be removed by a drain or sump pump. If a drain pipeline is not utilized, then hydraulic and electrical connections will be available at low point in the membrane feed pump wet wells for connection of a temporary sump pump.

The forebay will be constructed with an exterior drainage system to convey any water trapped in the soil surrounding the tank to drain. This will allow the forebay to be designed for a drained condition (i.e. no hydraulic lateral surcharge). The system will consist of perforated PVC pipeline installed around the perimeter of the structure.

9.3 MAINTENANCE

One-millimeter backwashable strainers will be installed upstream of the flow control facility in order to prevent blockage of the sleeve valve. These strainers will also minimize the accumulation of solids in the forebay. Nevertheless, solids will accumulate in the forebay over time. In order to facilitate solids removal, the bottom slabs are designed with a 2.5 percent slope directed towards the membrane feed pump wet wells. Accumulated solids can be hosed down to the wet wells for removal by the temporary sump pump.

9.4 DESIGN CRITERIA

The design criteria for the forebay are summarized in Table 9.1.

Table 9.1 Forebay Design Criteria

Description	Units	Value
Structural		
Type: unlined reinforced cast-in-place concrete	-	-
T_{10} / T = 0.5	-	-
Contact Volume (2 x 105,000 gallons)	GAL	210,000
Equalization Volume (2 x 250,000 gallons)	GAL	500,000
Surge Volume	GAL	75,000
Total Volume	**GAL**	**785,000**
Mechanical		
Piping Material: cement mortar lined steel	-	-
Slide Gate, Hatch, and Ladder Material: 316 stainless steel	-	-
Structurally Supported Retractable Cover: GTI or equal	-	-

SECTION 10 FEED WATER PUMP STATION

10.1 INTRODUCTION

The membrane filtration system (MFS) will be fed by the feed water pump station (FWPS) located in the forebay. The pumping requirements are MFS-specific, and detailed pump criteria will be developed once a MFS is selected. For purpose of estimating costs and developing a forebay layout (see Section 9), pumping requirements are presented in this section based on similar project experience and projections based on preliminary operating conditions provided by Pall and Siemens.

10.1.1 Capacity

Maximum FWPS capacity has been estimated at 35 mgd, based on an "instantaneous factor" (IF) of 1.25 and a net production of 28 mgd. The IF is defined as the ratio of the maximum instantaneous flow rate to the net production rate. This value has been selected based on preliminary information provided by Pall and Siemens. The IF is based on system and project specific factors that will be determined after a MFS supplier is selected.

The IF is derived by the membrane supplier to determine the flow rate each rack needs to produce while in filtration mode to make up for membrane cleaning down time and excess filtrate production needed for backwash and chemical cleaning cycles.

The MFS feed flow will be less than the 35 mgd when the following cleaning events occur:

- Backwash - Up to 2 racks out of service simultaneously for 2-4 minutes. An estimated 1000 individual backwashes occur per day at minimum anticipated backwash intervals (20 minutes).
- Chemically cleaning (enhanced backwash or clean-in-place) - One rack at a time for 1 hour to 7 hours. A maximum of 14 chemical cleaning events per day (one per rack) has been specified in the procurement documents.
- Direct Integrity testing – One rack at a time for approximately 30 minutes, not to coincide with a chemical cleaning. One integrity

test per day is required by regulation (a maximum of 14 racks is specified in the procurement documents).

The cycling of racks into and out of service results in rapid changes in FWPS flow. Exhibit 10.1 presents modeled feed flow rate variations for a membrane system operating at an IF of 1.25. Abrupt decreases in flow indicate a rack taken off line; abrupt increases in flow indicate a rack brought back on line.

10.1.2 Hydraulics

The hydraulic profile presented in Section 3 is based on a maximum instantaneous flow of 35 mgd and a maximum headloss through the membrane rack of 37 psi. These values are subject to change based on specific supplier requirements after membrane system selection.

Table 10.1 Feed Water Pump Station Hydraulics

Description	Parameter
Hydraulics (Suction)	
Water Level in Forebay[1]	621 - 631 ft
Maximum Flow[2]	54 cfs
Maximum static lift between forebay and membrane system	10 ft
Hydraulics (Discharge)	
Minor losses between feed pump discharge and membrane rack[2]	6 ft
Losses through strainer, associated isolation valves and manifolds[2]	16 ft
Losses through membrane system[3]	87 ft
HGL at filtrate manifold[4]	644 ft
HGL at Raw Water Pump Station[2,3]	753 ft

Notes:
1. Water level in forebay to vary under normal operation to cycling of membrane racks through cleaning cycles and integrity testing.
2. Loss estimated based on estimated maximum flow between the FWPS and the membrane racks. Actual value to be determined based on selected membrane system and supplier guaranteed maximum for the project.
3. Losses estimated based on previous project experience. Actual value to be determined based on selected membrane system and supplier guaranteed maximum for the project.
4. Filtrate manifold elevation to be fixed in order to keep membrane racks under the HGL.

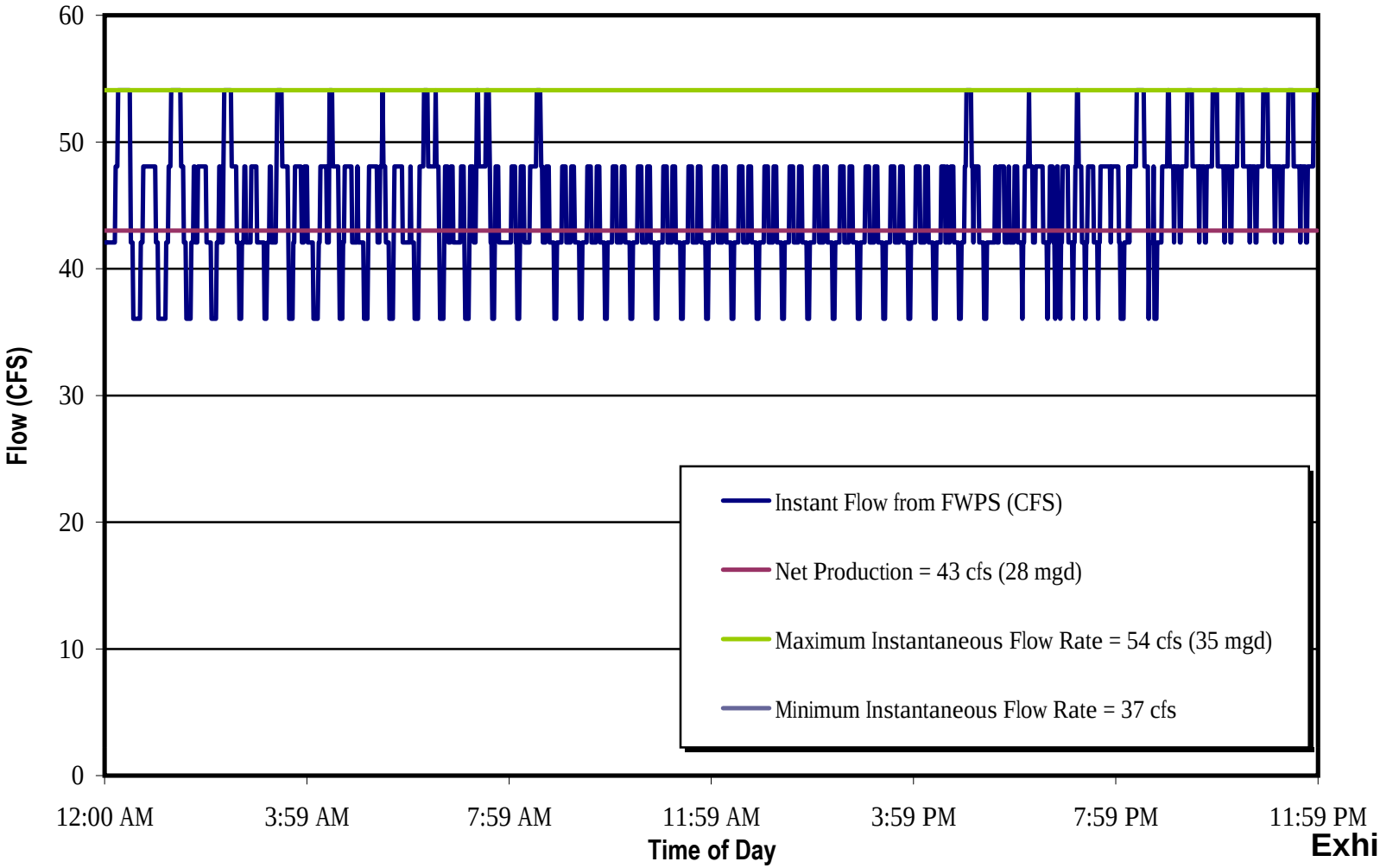

60
50
40
30
20
10
0
Flow (CFS)
12:00 AM
3:59 AM
7:59 AM
11:59 AM
3:59 PM
7:59 PM
11:59 PM
Time of Day
Instant Flow from FWPS (CFS)
Net Production = 43 cfs (28 mgd)
Maximum Instantaneous Flow Rate = 54 cfs (35 mgd)
Minimum Instantaneous Flow Rate = 37 cfs

Exhibit 10.1

Upstream hydraulics

- The forebay level will be allowed to vary between high and low levels according to instantaneous membrane flow demands.

Downstream hydraulics

- Control pressure is governed by the membrane rack feed water control valve.
- Position of (and headloss through) the control valve is governed by the pressure setpoint and the transmembrane pressure of the rack.
- Control pressure setpoint will be determined by the MFS PLC based on control valve position of the most fouled (highest TMP) membrane rack.

10.1.3 Operation

A preliminary control description is presented below.

Primary Pump Control

- Pumps will operate on pressure control from PIT XXX-XX, located in the treatment building.
- Pressure will be determined primarily within the MF system PLC, and sent to SCADA, which will control the pumps.
- One of the 6 feed pumps will serve as an installed redundant pump.
    - Redundant pump to be used to provide additional flow as required in Forebay Level Control (FLC) mode.
- A hardwired LOW-LOW level switch will shut down MF feed pumps
- LIT XXX-XX will initiate Forebay Level Control (FLC) mode as necessary to maintain the forebay between High and Low levels.

Secondary Pump Control

- FLC Mode will be accomplished through an automatic override of the operator selected production set point (up or down depending on the forebay level).
- The new setpoint is then signaled to the MPLC, which in turn adjusts the flow through the membrane racks.
-
- At LOW level, the SCADA will decrease the operator selected production

setpoint by 25%.

- Hold value for 10 minutes, recheck level. If level is above the LOW level, hold setpoint.
- If level is still below LOW level, readjust flow setpoint by the following formula:
- Flow in MGD = OPERATOR SETPOINT *
  - (Max Adjustment at LOW LOW LEVEL (%)+((Max Adjustment at LOW LOW LEVEL (%)-Initial Adjustment at LOW LEVEL(%)/(LOW LEVEL (FT)-LOW LOW LEVEL(FT)))*Measured Level (ft))
- Recheck level in 10 minute increments. LOW-LOW level shut off by level switch.
- Forebay level control mode will be maintained until the forebay level is 5 feet.

- At HIGH LEVEL, the SCADA will increase the operator selected production setpoint by 10%.
  - Hold value for 10 minutes, recheck level. If level is BELOW than HIGH LEVEL, hold setpoint.
  - If level is still ABOVE HIGH LEVEL, readjust flow setpoint by the following formula:
    - =1+((Max Adjustment at HIGH HIGH LEVEL(%)-Initial Adjustment at HIGH LEVEL(%))/(HIGH HIGH LEVEL(ft)-HIGH LEVEL(ft)))*(Measure Forebay Level (ft)-HIGH LEVEL (ft))+Initial Adjustment at HIGH LEVEL(%))
  - The maximum production rate will be capped at 10% greater than rated MF plant capacity.
  - SCADA will signal the flow control valve to begin closing if the water level in the forebay exceeds HIGH HIGH LEVEL.
  - Forebay level control mode will be maintained until the forebay level is 5 feet.

10.2 DESIGN CRITERIA

Vertical turbine pumps are recommended for the FWPS. Minimum footprint requirements and ability to pump from a buried forebay are the primary criteria for this recommendation.

10.2.1 Structural

- Pumps will be mounted on the top slab of the forebay.
- A concrete masonry block building will be constructed on top of the forebay, around the FWPS, strainer, and flash mix equipment. Building footprint will be 64' x 72'.

10.2.2 Pump

Table 10.2 Feed Water Pump Design Criteria

Feedwater Pump Station	Units	Values
Location: Above Forebay	-	-
Pump Station Design Capacity (Range)	CFS	27 to 54
Pump Type: Vertical Turbine with VFD	-	-
No. of Pumps	NO.	6
No. of Redundant Pumps	NO.	1
Design Flow Range per Pump	GPM	4,861
Mechanical	-	-
Discharge Pipeline Diameter	IN	18
Isolation Valve Size	IN	18
Flow Meter Size	IN	30
Discharge Header Pipeline Diameter	IN	42

10.2.3 Mechanical

A preliminary mechanical equipment layout sketch is provided in Exhibit 10.2.

10.2.3.1 Piping

Piping in the pump discharge manifold through the strainer will be mortar lined steel. Piping material between the strainer and the membrane filtration system will be selected to minimize risk of membrane damage due to corrosion byproducts from the pipe. Piping material must be coordinated with membrane system supplier in order to maintain membrane warranty. Candidate materials are 316 stainless steel and mortar lined steel.

10.2.3.2 Mechanical Design Criteria

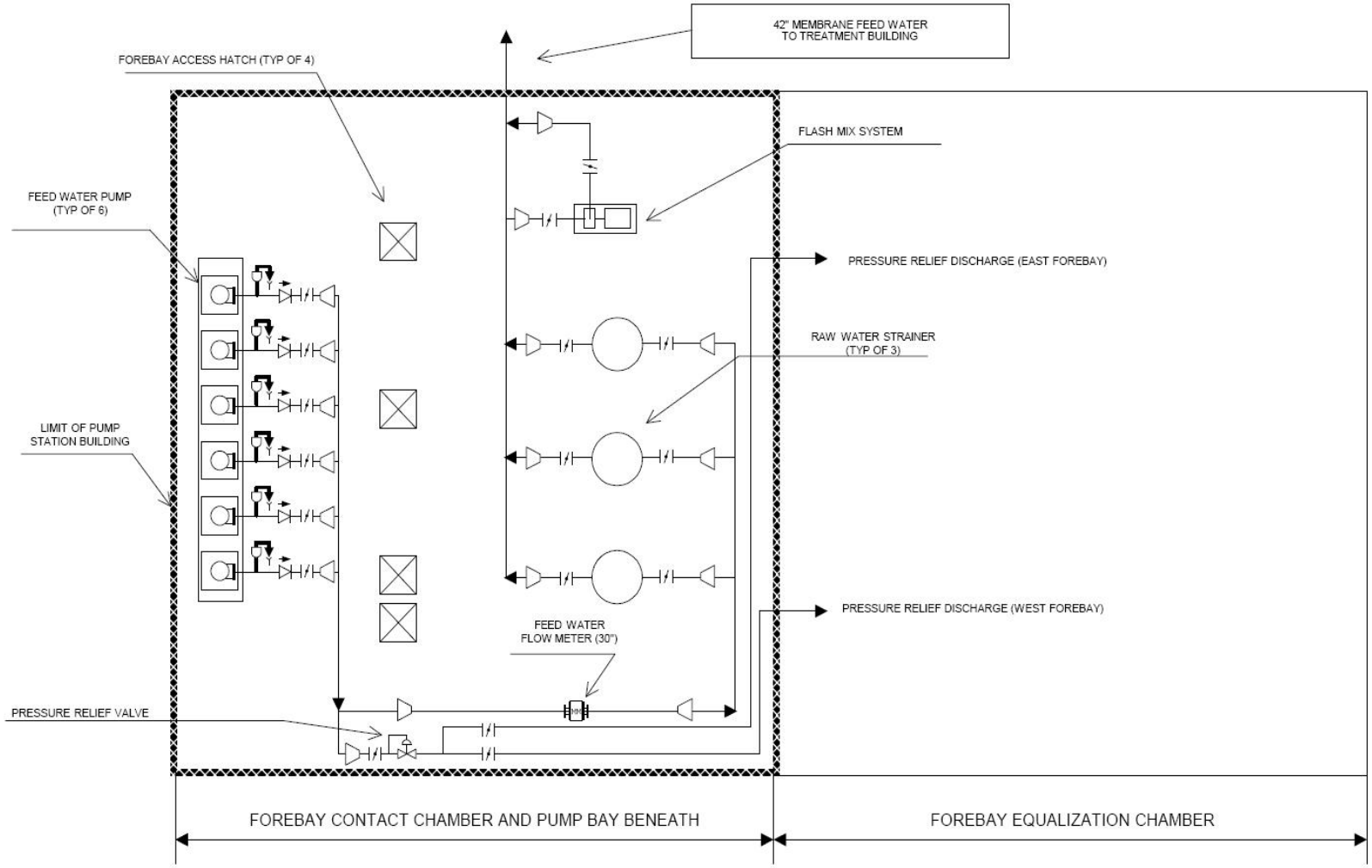
Valves used in the FWPS are shown schematically in Exhibit 10.2, and listed in Table 10.

Table 10.3 FWPS Mechanical Criteria

Equipment	Count	Size	Description
Check Valves	6	16-inch	Silent Check
Butterfly Valves	6	16-inch	Manual – Gear Operator (FW Pumps)
Butterfly Valves	3	16-inch	Manual – Gear Operator (Pressure Relief)
Butterfly Valves	6	24-inch	Manual – Gear Operator (Strainers)
Butterfly Valves	2	12-inch	Manual – Gear Operator (Flash Mix Pump)
Globe Valve	1	16-inch	Pressure Relief
Air Valves	6	4-inch	Combination Air Vac / Release (FW Pumps)
Air Valve	1	2-inch	Air Release
Meter	1	30-inch	Magnetic
Surge Tank	TBD	-	Hydropneumatic

10.2.3.3 Metering

Flow from the FWPS will be metered on the common discharge manifold by a 30” magnetic flow meter.



PLAN
NOT TO SCALE

Feedwater Pump Station Layout
Exhibit 10.2

SECTION 11 Strainer/Flash Mix System

11.1 OVERVIEW

Pretreatment will be required upstream of the microfiltration (MF) membrane system at Baker WTP to achieve:

- Large solids removal to assist in protecting membrane fibers from damage and irreversible fouling.
- Total organic carbon (TOC) removal to assist with disinfection byproducts (DBP) control.
- Iron and manganese removal (see Section 8).

11.2 FEEDWATER STRAINERS

Membrane feed water strainers are used to remove debris and large particles from feed water that can damage and/or plug membrane hollow fibers and pores. Damaged membrane fibers can result in non-compliance with required log removals, requiring downtime for fiber repair and loss of plant capacity. As such, MF system suppliers require straining as part of their membrane module warranty.

Self-cleaning strainers are the most common type of screen for membrane filtration pretreatment. Other types of equipment such as basket screens and cartridge filters are not practical in surface water applications due to frequency of screen change outs and manual cleaning.

Potential manufacturers of the feed water strainers with relevant membrane experience include: Amiad, Boll, and Fluid Engineering. Hellan Strainers may be considered pending additional evaluation.

The strainer size recommended for Baker WTP is 250 μm, considering:

- Membrane suppliers under consideration for the Baker WTP have recommended a range between 250 μm to 400 μm.
- Screen sizes less than 250 μm would require additional straining units
- Screen sizes less than 250 μm would generate higher volumes of waste washwater

A wedge wire type strainer is recommended over mesh strainers on the basis of:

- Greater mechanical strength.
- Lower headloss.
- Reduced potential for clogging by algae.

11.3 IN-LINE COAGULATION

A coagulant feed point upstream of the MF system is recommended to meet the following objectives:

- Reduce the rate of membrane fouling.
- Reduce the formation of disinfection by products.

Addition of coagulant to the feed water will reduce or, at some feed water doses, eliminate the need for a secondary feed at the waste washwater treatment clarifier. Lower membrane fouling rates also reduce cleaning frequency and associated downtime and chemical costs. Note that a separate coagulant feed point will be used for removal of suspended solids from the membrane filtration system backwash stream prior to recycling, as discussed in Section 14.

11.3.1 Coagulation Selection

There are several commonly used inorganic coagulants that could be considered for settling clarified solids and minimizing TTHM formation. However, not all of the commonly used coagulants are suitable for in line addition to membrane feed water. Candidate inorganic coagulants are listed below in order of preference for in-line coagulation applications:

- Polyaluminum chlorides (PACl)/aluminum chlorohydrates (ACH) are generally preferred from a membrane process perspective. They require the least amount of time to form filterable floc and reaction times are relatively unaffected by water temperature.
- Ferric chloride has been used successfully in in-line coagulation membrane applications. At the Hemet WFP the addition of low coagulant doses (2 mg/L - 5 mg/L) reduced the cleaning frequency from monthly to quarterly.

- Iron and aluminum sulfates (alum) have been shown to increase the rate of MF fouling in some applications and are generally not preferred by the MF system suppliers.

IRWD's membrane pilot study (MPI, 2008) demonstrated that the addition of ferric chloride to the membrane feed water resulted in lower rates of transmembrane pressure rise (fouling) compared to periods without coagulant addition.

Disinfection By-Product (DBP) Control

Coagulant selection will also consider effectiveness to reduce the formation of total trihalomethanes (TTHM).. Jar testing on coagulated ILW and SPW is recommended to generate data to assist in coagulant selection to meet applicable TTHM standards.

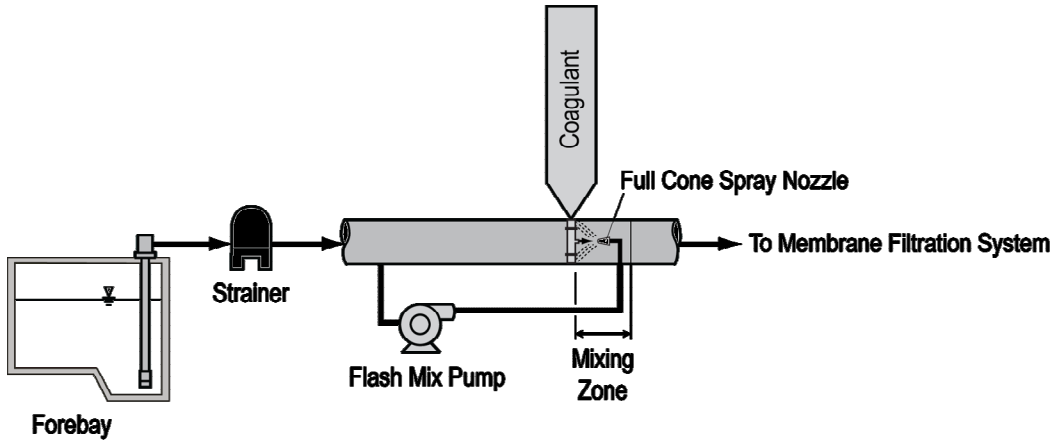
Testing will simulate coagulation, filtration, and chlorine disinfection processes at the Baker WTP, focusing on coagulants preferred for in-line coagulation/MF (ferric chloride and polyaluminum coagulants). Coagulant selection and dose will be based on a maximum TTHM concentration of 64 μg/L after free chlorine disinfection (80% of the limit of 80 μg/L), to account for additional TTHM formation of 10% to 15% in the distribution system following chloramination.

11.3.2 Flash Mixing

High intensity mixing is required for effective coagulation. Pump diffusion flash mix (see schematic on Exhibit 11.1) is recommended for the following reasons:

- Works at both high and low flow rate (high turndown) compared to static mixers.
- High (and adjustable) mixing energy delivered.
- Can be accomplished between the forebay and the membrane system without breaking head.

Exhibit 11.1 Flash Mix Schematic



11.4 DESIGN CRITERIA

11.4.1 Feedwater Strainer

Preliminary design criteria and equipment characteristics for three strainer manufacturers is provided in Table 11.1.

Table 11.1 Strainer Design Criteria

Manufacturer	Amiad	Boll	Fluid Engineering
Screen Size	250 µm	250 µm	250 µm
Proposed Configuration	3 x 50%	3 x 50%	3 x 50%
Screen Type	Wedge Wire	Wedge Wire	Wedge Wire
No. of Straining Elements	1	52	1
Strainer Body Diameter (in)	67	53	56
Inlet/Outlet Size (in)	24	24	24
Filtration while Backwashing?	Y	Y	Y
Backwash Mechanism	Brush/Radial Liquid Backwash	Radial and axial flow liquid backwash	Radial liquid backwash through suction scanner
Backwash Pressure Source	System pressure	System pressure	System pressure
Backwash Rate (gpm)	310	538	400-500
Backwash Volume (gallons)	155	225	1000
Backwash Duration (seconds)	30	25	120
Percent of Raw Water Wasted (Typical)	0.05	0.03	0.07
Strainer pad footprint (ft^2)	625	540	540

Note:
1. Includes costs for strainer supplier scope of supply only (strainer bodies, elements, and controls).

11.4.2 Flash Mix System

The key components of the pumped diffusion flash mix system are the booster pump and titanium mixing nozzle (required for corrosion characteristics). Table 11.2 summarizes the design criteria for the pumped diffusion flash mix systems in the feed water and waste washwater treatment systems.

Table 11.2 Flash Mix Design Criteria

Description	Units	MF Feed Water Criteria	BWWT Criteria
Flash Mix Type: Pumped Diffusion Flash Mix			
Pump type: End Suction Centrifugal			
No. of Pump	NO	1	1
Pump Motor	HP	15	5
Mixing Intensity (G)	S^{-1}	750	750
Mixing Energy (GxT)	-	1600	1600
Notes: 1. A standby perforated pipe diffuser will be provided at each coagulant injection point for redundancy.			

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SECTION 12 TREATMENT PROCESS

12.1 OVERVIEW

Treatment process selection for the Baker WTP Project is documented in the report entitled "Design Concept and Cost Update" (RBF and Carollo Engineers, November 2008), Appendix G includes schematics of the process alternatives considered. Exhibit 12.1 shows the comparison matrix. This section covers:

- a summary of the findings of the process selection study.
- additional information documenting refinements made to the process recommendation since that report was issued.

12.2 TREATMENT PROCESS ALTERNATIVES

As part of the preliminary design effort for the Baker WTP Project, Irvine Ranch Water District, Carollo Engineers, and RBF Consulting reviewed potential treatment process alternatives. A process selection matrix, provided as Exhibit 12.1, was developed by Carollo Engineers to compare seven possible alternatives. From the seven process alternatives, the focus was narrowed to one process (Baseline) for comparison to previous studies, and two primary alternatives as follows.

- Baseline - preoxidation with chlorine dioxide, pressurized membrane filtration, UV disinfection, virus inactivation with free chlorine and residual disinfection with chloramines.
- Alternative 1A - preoxidation with chlorine dioxide, pressurized membrane filtration, UV disinfection, granular activated carbon, virus inactivation with free chlorine and residual disinfection with chloramines.
- Alternative 1B - preoxidation with chlorine dioxide, powdered activated carbon, submerged membrane filtration, UV disinfection, virus inactivation with free chlorine and residual disinfection with chloramines.

12.3 PROCESS SELECTION

Selection of the treatment process for the Baker WTP Project was based on many factors, including raw water quality, drinking water quality regulations (current and future), ease of operation, and life-cycle cost. Considerable focus was placed on ensuring that overall project costs, variable raw water quality, taste and odor flexibility, ease and cost of operation and maintenance, and plant foot

print size were all acceptable. With all alternatives and factors presented and considered, IRWD and the Project Stakeholders confirmed the selection of the Baseline alternative (pressurized membrane filtration) for the Baker WTP Project.

12.4 PROCESS REFINEMENTS

12.4.1 Forebay

Two alternatives for providing feed pressure were presented for final selection of the pressurized membrane process configuration:

- Use of pressure in Baker Pipeline from MWD and Raw Water Pump Station for driving membrane filtration
- Break head at the Baker WTP and construct a forebay and Feed Water Pump Station

A forebay was selected for the following reasons:

- Chlorine Dioxide Contact Time: Potential remote locations for the chlorine dioxide system were determined to be undesirable, and the chlorine dioxide contact time requirement could therefore not be met in the pipeline. The forebay includes a dedicated contact time compartment to allow for oxidation of manganese when Irvine Lake is the water source.
- Hydraulic control for membrane system operation: Direct use of pressure in the Baker Pipeline would require active flow control on raw water from both MWD and the Raw Water Pump Station. The alternative was to design the membrane system to accept constant flow from the Baker Pipeline by adding additional membrane racks. Additional membrane racks would have increased the equipment and treatment building costs (see Section 23).

12.4.2 Taste and Odor Control

Granular activated carbon contactors have been removed from the project due to cost constraints. The site has been planned to allow for addition of GAC at a later date should GAC be determined to be necessary. There is space on the site for addition of powdered activated carbon at later date as a lower cost alternative for taste and odor control. See Exhibit 17.1 for the areas reserved at the Baker WTP site in case GAC and PAC systems are added in the future.

Exhibit 12.1 – Treatment Process Comparison Matrix

	Baseline ClO_2-PMF-UV-Cl_2	**Alt 1A** ClO_2-PMF-GAC-UV-Cl_2	**Alt 1B** ClO_2-SMF-PAC-UV-Cl_2	**Alt 2** O_3-BAF-SMF	**Alt 3** O_3-SED-GMF	**Alt 4** ClO_2-SED-GAC-UV-Cl_2
Layout Flexibility (Land Development)	1	2	2	3	$\boxed{4}$	$\boxed{4}$
Consistency with Diemer Aesthetics	$\boxed{4}$	2	3	1	1	2
Operational Effectiveness						
Filtration	1	1	1	1	2	2
T&O Events	$\boxed{4}$	2	2	1	1	2
DBPs	1	1	1	2	2	1
Capacity	1	1	2	1	1	1
Total	**12**	**9**	**11**	**9**	**11**	**12**

LEGEND:

1. Good *2: Moderate* *3: Poor* *4: Not Addressed*

12.5 PROCESS FLOW DIAGRAM

The Process Flow Diagram (PFD) developed for the project is presented as Exhibit 12.2 (also **Drawing G7** of the Preliminary Submittal). The PFD depicts major treatment processes, pump stations, chemical feed points, piping, control loops, ancillary equipment, and instrumentation.

12.5.1 Primary Treatment Process Flow

Key elements of the primary treatment process and their roles in meeting treatment objectives are summarized in Table 12.1 below.

Table 12.1 Key Processes and Their Roles in Meeting Treatment Objectives

Treatment Objective	Treatment Goal	Associated Processes and Structures
Manganese Removal[1]	<0.02 mg/L	Chlorine Dioxide/Membrane filtration
DBP Control[2]	<64 µg/L TTHM[3] <48 µg/L HAA5[3]	Coagulation/Flash Mix (Main Process) Chloramine as residual disinfectant through ammonia addition at CT Basin
Turbidity Removal	<0.1 NTU 95% of the time	Membrane Filtration Forebay
Disinfection - Cryptosporidium	4-log removal/inactivation[4]	Membrane Filtration
Disinfection - Giardia	4.5-log removal/inactivation[4]	Membrane Filtration – 4 log UV Disinfection – 0.5 log
Disinfection - Virus	4.0-log removal/inactivation[4]	Free chlorine addition at CT Bain
Corrosion Control	Non-corrosive finished water	Caustic soda feed at CT basin.

Notes:
1. Manganese removal required only when Irvine Lake used at supply for Baker WTP. SMCL for manganese is 0.05 mg/L. Lower goal established to minimize membrane fouling from manganese, and to prevent aesthetic issues in the distribution system.
2. DBP control strategy is to minimize free chlorine contact time in CT Basin. Coagulant addition removes Membranes and UV to provide Giardia disinfection upstream of the CT Basin. This reduces treatment requirement in CT Basin to virus only. Residual disinfection with chloramines minimized additional DBP formation in the distribution system.
3. DBP goals set to 80% of MCL to allow for additional formation of 10% to 15% in the distribution system.
4. Section 15 provides a discussion of disinfection goals established for the project.

12.5.2 Waste Washwater Recovery

The individual membrane racks that make up the membrane system (up to 14) backwash in discrete events. The backwash water or membrane filtration waste washwater (MFWW) is equalized in the MFWW equalization basin and pumped at a constant rate to the clarification process to avoid overloads and upsets.

The clarification process selected for the Baker WTP is lamella plate setters. This process can be hydraulically loaded 3 to 4 times higher than a conventional clarification process. As a result, the MFWW clarifiers can be sized for common wall construction with the forebay, reducing construction costs. Other high rate clarification processes are available, however they rely on polymer addition and may result in irreversible membrane fouling.

12.6 TREATMENT PROCESS

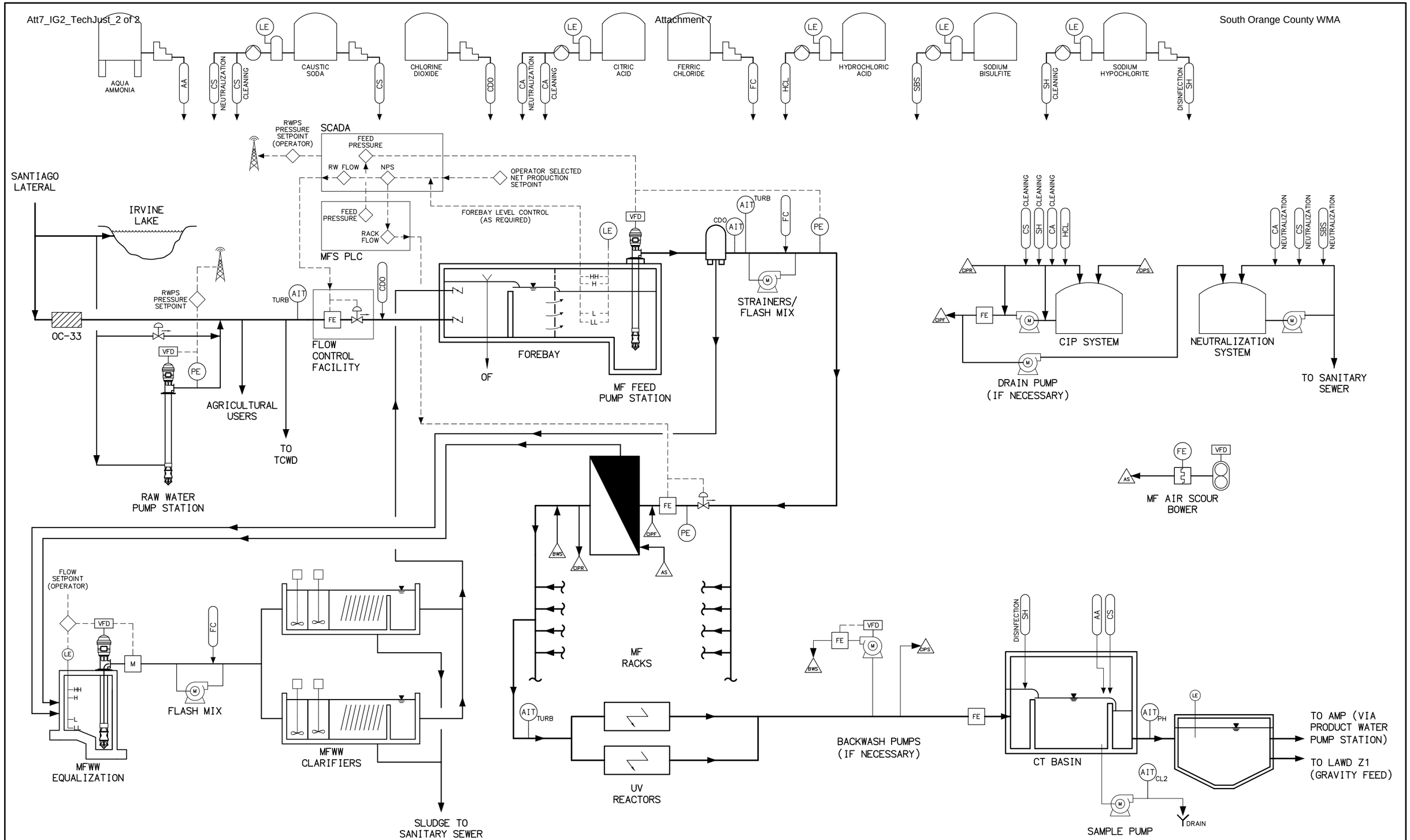
Pressurized membrane filtration (PMF) is the core filtration and disinfection process selected for the Baker WTP. Membrane filtration is a physical particle removal and disinfection process. Several manufacturers can supply systems approved by the California Department of Public Health for removal of turbidity, Giardia, cryptosporidium, and viruses.

12.6.1 Description

PMF will be used in the Baker WTP to meet treatment requirements for turbidity removal and to partially satisfy disinfection requirement. Complimentary processes will be utilized to meet additional treatment requirements. Membrane system design characteristics are discussed below.

- Membrane systems under consideration are PVdF (Polyvinylidene fluoride) hollow fiber based systems, filtering water from outside to inside. Individual modules with capacities of 15 to 20 gpm are assembled on individual racks with common piping with capacities of 2 mgd to 3 mgd. A maximum of 14 racks is specified in the procurement documents, including one fully redundant rack not required to meet nominal 28 mgd capacity.

- Automation – Membrane systems are highly automated and sophisticated processes that require PLC based controllers.



RBF CONSULTING

carollo

IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

PROCESS FLOW DIAGRAM

EXHIBIT 12.2

- Feed water pumping – Only pressure driven membrane systems are under consideration for this project. Feed pressure at the membrane racks will vary by supplier. Anticipated maximum feed pressures are in the range of 25 psi to 40 psi.

- Membrane System Capacity: The membrane filtration system will be designed to net 28 mgd. Additional water will be produced by the system for cleaning sequences (chemical cleaning and backwash). Feed water recovery has been specified in the procurement documents to be a minimum of 92%.

- Residuals Handling: With the exception of chemical cleaning residuals, washwater will be equalized, clarified and recycled to the forebay for reuse. Neutralized cleaning solutions will be discharged to the sewer. See Section 14.

- Cleaning Operations: Three primary cleaning operations are used in membrane filtration systems used to maintain capacity and minimize transmembrane pressure and energy use:

  - Backwash – In this process, a dedicated pump station pumps filtered water from the inside-out removing particles accumulated on the membrane surface. Backwash sequences also use air delivered concurrently with water through a compressed air (compressors or blowers, depending on the manufacturer). Backwashes occur every 15 to 30 minutes on each rack. Backwashes are initiated and function fully automatically, though additional backwashes can be manually initiated.

  - Chemically Enhanced Backwash (CEB) – CEB use commodity cleaning chemicals (sodium hypochlorite, caustic soda and citric acid and/or mineral acids) to remove materials from the membrane surface not removed by backwashing. Inorganic scale, coagulants, biological growth, and organic materials sorbed to the membrane surface are typically responsible for membrane fouling and are targeted by these chemicals. The CEB system uses chemical cleaning equipment consisting of pumps, tanks, recirculation loops and water heaters. CEB may occur up to once per day per rack, and take approximately one hour to complete.

CEB are fully automated and are typically initiated automatically though they can be manually initiated.

- Clean in Place (CIP) – This process uses the same subsystems as CEB, but uses higher doses of cleaning solutions with longer soak durations (up to 7 hours per rack). CIPs have been specified to occur no longer than once per month per rack. CIPs are manually initiated. Most sequences occur automatically, but operator input is required at steps required verification of chemical doses.

- Integrity Testing: The membrane systems have been specified to include two mean of integrity checks, direct (pressure decay testing) and indirect (turbidity monitoring).

  - Pressure decay testing (PDT) – In this test pressurized air is introduced into the membrane modules and displaces water. The rate of pressure loss is indicative of integrity breaches (fiber or module damage), and is used to calculate a log removal value (disinfection performance). PDT occurs automatically once per day are required by federal regulation. Failed tests will shut a rack down for retesting and/or membrane repair.

  - Indirect integrity testing – Laser turbidimeters have been specified for monitoring turbidity on each rack as an indicator of membrane integrity. Increases in turbidity may signal fiber damage and raw water bypass through the membrane fibers. Sustained turbidities over 0.1 NTU will cause a rack to shut down.

- Cleaning Solution Neutralization – Spent cleaning solutions will be neutralized and discharged to the sanitary sewer. Chlorinated solutions will be neutralized with sodium bisulfite and caustic soda, acidic cleaning solutions with caustic soda. Criteria for discharge is a chlorine residual of less than 1 mg/L of free chlorine, and pH between 6.5 and 8.5.

- Ancillary Equipment – Membrane systems utilize ancillary equipment to support cleaning procedures. Major ancillary equipment includes CIP, neutralization, and backwash pumps, air compressors (for valve operation and integrity testing), and backwash air blowers.

12.6.2 Manufacturers

Two manufacturers are listed in the procurement specification based on the District's previous pilot testing effort on Irvine Lake Water and State Project Water.

- Pall Microza - Module designation USV 6203 (MF)
- Siemens CP – Module designation L20V (UF)

Practical differentiation between MF and UF membranes in drinking water applications is ability of UF to remove virus to a greater degree than MF membranes. CDPH approved third-party testing of these two systems resulted in approval for Siemens for 1.5 log virus removal credits versus Pall's approval for 0.5 log virus removal credits. However, no distinction is made in the plant disinfection strategy between the two system for two reasons;

- Integrity testing procedures are not capable of verification of virus rejection due to high-pressure requirements for such testing.
- The minimal cost difference for disinfectant contact time required to meet overall virus disinfection goal of 4-log.

12.6.3 Procurement

Procurement will be completed through a competitive evaluated bid. The basis is present worth of chemical, energy, and membrane replacement costs plus bid price. Key elements of the membrane suppliers' scope of supply include:

- Membrane modules and racks
- Membrane system controls, PLC, programming, and instrumentation
- Chemical cleaning, neutralization, and backwash pumps
- Chemical cleaning and neutralization tanks
- Integrity monitoring systems
- Blowers and compressors
- Installation, start up, and testing services.

- 48 month 100% module replacement warranty plus a minimum of 6 additional years pro-rated module replacement warranty.
- 48-month labor and equipment fiber repair services
- 24 month process warranty and equipment

Key membrane system related equipment not provided by the membrane suppliers:

- Feed water pumps
- Feed water strainers
- Installation of racks and modules
- Interconnecting piping
- Cleaning chemical storage and feed systems
- Anchor bolts

12.7 MEMBRANE FILTRATION SYSTEM DESIGN CRITERIA

Design criteria for the membrane filtration system are provided in Table 12.2.

Table 12.2 Membrane Filtration System Design Criteria

Pressurized Membrane System		
Type: Polymeric Hollow Fiber Microfiltration Or Ultrafiltration		
Number Of Membrane Racks (Max)	NO.	14
Number Of Redundant Membrane Racks	NO.	1
Minimum Recovery	PERCENT	92
Backwash Interval (Min) Per Rack	MINUTES	TBD
Backwash Supply Flow Rate (Water)	GPM	TBD
Backwash Supply Flow Rate (Air)	SCFM	TBD
Chemical Backwash Interval (Min) Per Rack	DAYS	1
Clean-In-Place Interval (Min) Per Rack	DAYS	30

12.8 TREATMENT BUILDING

The Treatment Building will house the membrane filtration system (racks, cleaning, backwash and air subsystems, as well as dedicated membrane system controls) and the UV system. The building has been sized to allow space for the treatment building electrical equipment, control room, laboratory (wet room), and HVAC equipment.

The south end of the building will be located six feet below the membrane rack and control room level. This allows the CT basin inlet weir to be used as a means of keeping the UV reactors fully submerged (below the hydraulic grade line), and provides secondary containment for chemical cleaning and neutralization tanks.

Primary process lines (membrane feed and filtrate) will be located in the center of the building, located in a trench or concrete encased beneath the floor slab. All valves and instrumentation associated with these lines will be kept above grade for ease of access and maintenance.

A plan view of the treatment building is provided in Exhibit 12.3 (Drawing R1). In addition, renderings of the treatment building are provided as Drawings R2 to R9.

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SECTION 13 Chemical Storage and Feed Systems

13.1 OVERVIEW

The Baker WTP will require the use of various chemicals throughout the treatment processes. Some chemicals are necessary for meeting finished water quality goals, while others are utilized as part of the membrane cleaning process. The equipment and procedures for storing and delivering chemicals to treatment processes are described in this section.

Objectives include:

- Size the chemical systems at the Baker WTP.
- Define design criteria for each chemical system.
- Define the major components of each chemical system-Prepare schematics.
- Establish preliminary layout for the Chemical Building.
- Estimate requirements for chemical deliveries.

13.2 CHEMICAL REQUIREMENTS

There are nine chemicals planned for use at the Baker WTP:

Chlorine Dioxide – Used for oxidation of iron and manganese in raw water from Irvine Lake.

Primary Coagulant – Used to inhibit membrane fouling. Used to assist with disinfection by product (DBP) control.

Sodium Hypochlorite – Used for virus disinfection, membrane cleaning and on site generation of chlorine dioxide.

Aqua Ammonia – Will be combined with free chlorine to form chloramines, the residual disinfectant in the distribution system.

Sodium Hydroxide – Used for pH adjustment of finished water, membrane cleaning and neutralization of membrane cleaning wastewater.

Citric Acid – Used for membrane cleaning.

Hydrochloric Acid – Used for pH adjustment of membrane cleaning solution, neutralization of membrane cleaning wastewater and on site generation of chlorine dioxide

Sodium Bisulfite – Used for dechlorination of membrane cleaning wastewater.

Sodium Chlorite – Used for on site generation of chlorine dioxide.

13.3 CHEMICAL SYSTEM DESIGN CRITERIA

13.3.1 Chemical System Sizing Criteria

Each of the chemical systems is sized based on the following criteria

- Each chemical storage system shall be designed for a minimum of one full truck load of the chemical with 50% of that required volume in reserve.
- Chemical storage system shall have a minimum of two tanks for chemicals with continuous usage to allow for one tank to be taken off-line for maintenance and cleaning without affecting plant operations.
- One tank is acceptable for chemicals with intermittent usage.
- Each chemical storage system shall be designed for a minimum of 15 days of storage under average chemical dose applied to the full plant design capacity of 28 MGD.
- When optional chemicals are available such as for primary coagulant, the most corrosive alternate is assumed for material selection.
- For each chemical metering system, the type of metering pump is based on the following criteria:
    - Pump shall be suited for the chemical application intended.
    - For each established flow and discharge pressure, pump to be the reasonably largest one so it could be easily retrofited with another type in the future

  Based on these criteria, the design is developed around Milton Roy double diaphragm hydraulically actuated Milroyal G. Pulseafeeder will be listed as an alternative supplier.
- For each chemical transfer application an air-operated double-diaphragm air pump is specified. Supplier is Wilden or equal.
- Each chemical is conveyed neat – not diluted - to the point of use.
- Should dilution water be required to design and operate the diffuser, dilution water will be conveyed to the point of use.
- Softened water will be used as dilution water for sodium hypochlorite, aqua ammonia, and sodium hydroxide.
- A screw type air compressor system is provided to feed the air-operated pumps and the air-actuated valves.

13.3.2 Piping and Tank Materials

Table 13.1 lists the pipe and storage tank materials recommended for each chemical. Material selection for the chemical tanks and chemical piping is based on a meeting held with IRWD on May 20, 2009 as well as

Table 13.1 Pipe and Storage Tank Materials Summary

	In Containment Area (Chemical Building)						Outside Containment Area			
Chemical	**Tank Material**	**Tank Vent Material (5)**	**Tank OF Material**	**Tubing Material**	**Fittings Material**	**Valve Material Type**	Tubing Material	Carrier Pipe Material	Valve Material	Comment
Bulk Chemical										
Sodium Hypochlorite 12.5%	FRP	PVC SCH80	PVC SCH80	PVC SCH80	PVC SCH80	PVC 3-Piece True Union Ball Valve (1)	Teflon	PVC SCH80	PVC ChemFlare End (1)	
Aqua Ammonia 29%	Lined Steel	PVC SCH80	PVC SCH80	316	316 Swagelock-type	SS 3-Piece 60 Series Ball Valve	Teflon	PVC SCH80	PVC ChemFlare End	Pressurized tank (top and bottom dome + legs)
Caustic Soda 25%	Steel (2)	PVC SCH80	PVC SCH80	Black steel (3)	Black steel	Carbon Steel Flanged Lubricated Plug Valve	Teflon	PVC SCH80	PVC ChemFlare End	Flat bottom
Ferric Chloride 39%	FRP	PVC SCH80	PVC SCH80	PVC SCH80	PVC SCH80	PVC 3-Piece True Union Ball Valve	Teflon	PVC SCH80	PVC ChemFlare End	
Citric Acid 50%	FRP	PVC SCH80	PVC SCH80	316	316 Swagelock-type	SS 3-Piece 60 Series Ball Valve	Teflon	PVC SCH80	PVC ChemFlare End	
Sodium Bisulfite 38%	FRP	PVC SCH80	PVC SCH80	PVC SCH80	PVC SCH80	PVC 3-Piece True Union Ball Valve	Teflon	PVC SCH80	PVC ChemFlare End	
Chlorine Dioxide On Site Generation										
ClO2 Solution (2,500 mg/L) Batch Tank	FRP	PVC SCH80	PVC SCH80	PVC SCH80	PVC SCH80	PVC 3-Piece True Union Ball Valve	Teflon	PVC SCH80	PVC ChemFlare End	Black FRP tank
Sodium Chlorite 25% - 31%	FRP	PVC SCH80	PVC SCH80	PVC SCH80	PVC SCH80	PVC 3-Piece True Union Ball Valve	Teflon	PVC SCH80	PVC ChemFlare End	
Hydrochloric Acid 15%	FRP (Epoxy Vinyl Ester Only) (4)	PVC SCH80	PVC SCH80	PVC SCH80	PVC SCH80	PVC 3-Piece True Union Ball Valve	Teflon	PVC SCH80	PVC ChemFlare End	

NOTES
(1)Sodium Hypochlorite Application: Vented ball to relieve pressure build-up inside valve
(2) Caustic Soda Application: Unlined steel tank is appropriate. However, rust will be visible inside the tank
(3) Caustic Soda Application: No trace heat tracing because of use of 25% Caustic soda and indoor installation
(4) Hydrochloric Acid Application: Vinyl ester lined steel tank would be a good alternative. However, nozzles below 4" would be in titanium
(5) Material to transition to CPVC SCH80 before penetrating through the roof

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coordination with design-build team for the Wells 21/22 Project.

13.4 DESIGN CRITERIA BY CHEMICAL

13.4.1 Primary Coagulant

The primary coagulant will be added at the primary process flash mix system and/or at the secondary flash mix system prior to the MF waste water clarifiers. Table 13.2 summarizes the design criteria for the primary coagulant system.

Table 13.2 Primary Coagulant Design Criteria

Description	Units	Criteria
Type: Ferric Chloride, 39% Solution (4.6 lb/gal)		
Feed Points: Flash Mix, Membrane Backwash		
Dosage:		
Flash Mix (equivalent raw water; Min-Ave-Max)	mg/L	2-10-20
Metering Pumps		
Type: Double diaphragm hydraulically actuated with gauge leak detection		
Number		
Duty	No.	2
Standby	No.	1
Design Capacity (Each)	gph	45
Model	Milton Roy	Milroyal G
Storage Tanks		
Type: Vertical FRP		
Number	No.	2
Volume		
Each	Gal.	8,000
Total	Gal.	16,000
Days of Storage (Average Dosage)	Days	29
Delivery Interval (Average Dose)	Days	7

Notes
1. Chemical system can accommodate ferric chloride, ferric sulfate, alum, and polyaluminum chloride
2. Dosage is based on doses actually used at the Serrano Water District WTP, the Eastern Municipal Water District Hemet Water Filtration Plant, and jar testing data for particulate removal at the Palmdale Water District WTP

13.4.2 Sodium Hydroxide

Sodium hydroxide (or caustic soda) is used to raise the pH of the solution or process flow that it is added to. At the Baker WTP, sodium hydroxide will be added to the effluent of the CT basin in order to raise the pH to an appropriate level prior to the water being sent to the distribution system. It will also be added to the membrane cleaning solution used to clean the membranes on a monthly basis and to the cleaning waste water after membrane cleaning has taken place in order to adjust the pH prior to disposal to the sanitary sewer. Table 13.3 summarizes the design criteria for the sodium hydroxide system.

Table 13.3 Sodium Hydroxide Design Criteria

Description	Units	Criteria
Type: Liquid, 25% solution (2.67 lb/gal as 25%)		
Feed Points: CT Basin Effluent, CIP Tank, CIP Neutralization Tank		
Dosage at CT Basin (Min-Ave-Max):	mg/L	1-4-7
Dosage at CIP & Neutralization Tanks	mg/L	10,000 & 16,400
Metering Pumps		
Type: Double diaphragm hydraulically actuated with gauge leak detection		
Number (CT Basin)		
Duty	No.	1
Standby	No.	1
Design Capacity (Each)	gph	30
Model	Milton Roy	Milroyal G
Transfer Pumps		
Type: Air-operated double diaphragm		
Number (CIP Tank, CIP Neutralization. Tank)		
Duty	No.	1
Standby	No.	1
Capacity (Each)	gpm	TBD
Model	Wilden	TBD
Storage Tanks		
Type: Vertical Welded, Bare Steel		
Number	No.	2
Volume		

Description	Units	Criteria
Each	Gal.	8,500
Total	Gal.	17,000
Days of Storage (Average Dosage)	Days	25
Delivery Interval (Average Dose)	Days	7

Sodium hydroxide is typically used in concentrations of 25% and 50% by weight. The 25% solution is typically used during the winter to avoid crystallization of the chemical during the colder months, while the 50% solution is typically used during the summer since it is less expensive per equivalent weight of sodium hydroxide. During the winter months, 25% solution may be purchased direct from the local suppliers or 50% solution may be purchased and diluted onsite. The freezing point for 25% sodium hydroxide is 5 degrees F, while the freezing point for 50% sodium hydroxide is 53 degrees F.

13.4.3 Citric Acid

Citric acid is used during monthly chemical cleaning of the membrane system and will be pumped to the membrane CIP tank at a dosage of 20,000 mg/L. Table 13.4 summarizes the design criteria for the citric acid system.

Table 13.4 Citric Acid Design Criteria

Description	Units	Criteria
Type: Liquid, 50% solution (5.2 lb/gal)		
Feed Points: CIP Tank		
Maximum Dosage:	mg/L	20,000
Transfer Pumps		
Type: Air-operated double diaphragm		
Duty	No.	1
Standby	No.	1
Design Capacity (Each)	gpm	TBD
Model	Wilden	TBD
Storage Tanks		
Type: Vertical FRP		
Number	No.	1

Description	Units	Criteria
Volume	Gal.	6,900
Days of Storage (Average Dose)	Days	46
Delivery Interval (Avearge Dose)	Days	31

13.4.4 Sodium Bisulfite

Sodium bisulfite will be applied to the chemical cleaning solution in the neutralization tank after chemical cleaning of the membrane units has taken place in order to remove chlorine from the sodium hypochlorite CIP solution.Table 13.5 summarizes the design criteria for the sodium bisulfite system.

Table 13.5 Sodium Bisulfite Design Criteria

Description	Units	Criteria
Type: Liquid, 38% solution (4.1 lb/gal)		
Feed Points: Neutralization Tank		
Dosage (CEB – CIP):	mg/L	410-1,030
Transfer Pumps		
Type: Air-operated double diaphragm		
Duty	No.	1
Standby	No.	1
Design Capacity	gpm	TBD
Model	LMI (Milton Roy)	Series B/C
Storage Tanks		
Type: Vertical FRP		
Number	No.	1
Volume	Gal.	6,300
Days of Storage (Average Dose)	Days	102
Delivery Interval (Average Dose)	Days	68

13.4.5 Sodium Hypochlorite

Sodium hypochlorite will be added to the inlet of the CT basin in order to provide the primary virus disinfection for the plant. It will also be added to the membrane CIP tank for chemical cleaning of the membrane units on a monthly basis and on a daily basis through the chemically enhanced backwashes. The chemical cleaning of the membranes is designed for the use of 400 mg/L of sodium hypochlorite for the CEB's and 1,000 mg/L for the monthly CIP's. Sodium hypochlorite will also be used to generate chlorine dioxide.

Table 13.6 summarizes the design criteria for the sodium hypochlorite system based upon the use of bulk sodium hypochlorite delivered at 12.5%. The concentration of sodium hypochlorite degrades over time and a final solution concentration of 10.5% was assumed for application to the processes for storage and feed calculation purposes.

Table 13.6 Sodium Hypochlorite Design Criteria

Description	Units	Criteria
Type: Liquid, 10.5% solution (1.0 lb/gal as hypochlorite or 0.95 lb/gal as chlorine)		
Feed Points: CT Basin Influent, CIP Tank		
Dosage at CT Basin Influent (Min-Ave-Max)	mg/L	2.5-3.0-4.0
Dosage at CIP Tank (CEB-CIP)	mg/L	400-1,000
Demand at Chlorine Dioxide Generator (Min-Ave-Max)	ppd	34-136-191
Metering Pumps		
Type: Double diaphragm hydraulically actuated with gauge leak detection		
Number (CT Basin Inlet)		
Duty	No.	1
Standby	No.	1
Design Capacity (Each)	gph	40
Model	Pulsafeeder	Pulsar Hypo
Transfer Pumps (CIP Tank)		
Number		
Duty	No.	1
Standby	No.	1

Description	Units	Criteria
Capacity	gpm	TBD
Model	Wilden	TBD
Storage Tanks		
Type: Vertical FRP		
Number	No.	2
Volume		
Each	Gal.	8,500
Total	Gal.	17,000
Days of Storage (Average Dosage)	Days	16
Delivery Interval (Average Dose)	Days	5

Two options are available for valves on the sodium hypochlorite storage and feed system, which are ball valves with drilled balls and diaphragm valves. Due to the fact that sodium hypochlorite produces a gas as it degrades over time, pressure can build up in locations where this gas can be trapped such as in the ball of a ball valve. If the ball does not have a way to release the pressure, it can explode and cause injury. Therefore, it is required that all ball valves used for sodium hypochlorite have a hole drilled in one side of the ball. While diaphragm valves do not trap liquid the way ball valves can, they are more expensive and operators at other sites have expressed a preference for ball valves. This preference is based on how quarter turn ball valves can be operated quicker, which is important when performing pump calibrations. Based upon this information, ball valves with drilled balls are the basis for design.

Delivery of 12.5 percent sodium hypochlorite solution is selected for consistency between District's different operations sites.

13.4.6 Aqua Ammonia

Aqua ammonia is added to the finished water to combine with the free chlorine provided by the sodium hypochlorite and form chloramines. Chloramines react minimally with organic carbon in the water and therefore minimize the formation of disinfection by-products. Table 13.8 summarizes the design criteria for the aqua ammonia system.

Table 13.7 Aqua Ammonia Design Criteria

Description	Units	Criteria
Type: Liquid, 29% solution (2.2 lb/gal)		
Feed Points: CT Basin Effluent		
Dosage (Min-Ave-Max)	mg/L	0.6-0.8-1.0
Metering Pumps		
Type: Double diaphragm hydraulically actuated with gauge leak detection		
Number		
Duty	No.	1
Standby	No.	1
Design Capacity (Each)	gph	5
Model	Pulsafeeder	Pulsar Hypo
Storage Tanks		
Type: Vertical, Pressurized, Lined Steel		
Number	No.	2
Volume		
Each	Gal.	5,000
Total	Gal.	10,000
Days of Storage (Average Dosage)	Days	92
Delivery Interval (Average Dose)	Days	59

13.4.7 Chlorine Dioxide

Chlorine dioxide will be added to the raw water received from Irvine Lake, at the plant site, in order to oxidize iron and manganese as described in Section 8. Table 13.9 summarizes the design criteria for the chlorine dioxide generation system. A detailed discussion regarding the different means for on-site generation of chlorine dioxide is provided in Section 8.

Table 13.8 Chlorine Dioxide Design Criteria

Description		Units	Criteria
Type: On-site Generation, Three-chemicals, Batch Tank			
Feed Point: At Baker WTP, upstream of forebay			
Dosage (Min-Ave-Max)		mg/L	0.5-1.0-1.4
Metering Pumps			
Type: Double diaphragm hydraulically actuated with gauge leak detection			
Number			
	Duty	No.	1
	Standby	No.	1
	Design Capacity (Each)	gph	660
	Model	Milton Roy	Milroyal C
Sodium Chlorite			
Type: Liquid, 25% solution, 2.6 Lbs/gal			
	Demand at ClO2 Generator (Min-Ave-Max)	ppd	83-331-463
	Storage Tank		
	Type: Vertical FRP		
	Number	No.	1
	Volume	Gal.	6,900
	Days of Storage (Average Dose)	Days	53
	Delivery Interval (Average Dose)	Days	36
Hydrochloric Acid			
Type: Liquid, 15% solution, 1.3 Lbs/gal			
	Demand at ClO2 Generator (Min-Ave-Max)	ppd	33-133-187
	Storage Tank		
	Type: Vertical FRP		
	Number	No.	1
	Volume	Gal.	8,000
	Days of Storage (Average Dose)	Days	80
	Delivery Interval (Average Dose)	Days	53
Sodium Hypochlorite	Gravity Fed. Type, Number, Volume. Refer to Table 13.6		

Supplemental calculations for the chemical storage and feed systems are provided in Appendix H

13.5 CHEMICAL STORAGE BUILDING

A preliminary layout for the chemical facility is provided in Exhibit 13.1 (Drawing M2). Highlights of the layout include the following:

- The chemical building is air-conditioned. The air handling unit is located in the HVAC room.
- The chemical building is equipped with a fire detection system and a fire protection system.
- Each chemical is stored in its dedicated containment area. Aqua ammonia is stored in a separate room. Chlorine dioxide is also stored in a separate room.
- Each containment area:
    - is constructed with above grade containment walls. Based on available space, access to the containment area will be through stairs or ladders.
    - has a volume based on the volume of the larger tank, plus 10 minutes of sprinkler system operation, plus freeboard.
    - is equipped with its own chemical delivery lock box to be designed per the requirements of the Orange County Fire Department.
    - includes a sump. Hydraulic connections and electrical connection are provided at each sump for installation of a temporary sump pump.
- Chemical storage tanks are installed on elevated concrete pads to ensure that metering and transfer pumps are provided with a flooded suction
- Metering pumps are accessible from outside of the containment area. Instrumentation displays can be read from outside of the containment area.
- The chemical building includes a storage room for storage of spare parts. The softening equipment is located in this room. The air compressor system is also located in the storage room.

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SECTION 14 BACKWASH WASTE WATER SYSTEM

14.1 OVERVIEW

The total or combined waste washwater (CWW) flow for the Baker WTP will be comprised of:

- Membrane feed water strainers waste washwater (SWW).
- Membrane filtration system waste washwater (MFWW), excluding chemical cleaning solutions.

Estimated range of CWW flows at the Baker WTP are 0.5 mgd to 3.0 mgd (primarily dependent on membrane system selection and performance). In most cases, this waste washwater is amenable to treatment and recycling back to the head of the plant. Treatment and recycling facilities minimize plant waste discharges and maximize plant feed water recovery.

14.1.1 Water Quality

Sources of waste washwater from the Baker WTP are depicted in Exhibit 14.1. A summary of CWW quantity and quality is presented in Table 14.1.

Exhibit 14.1 Sources of Waste Washwater

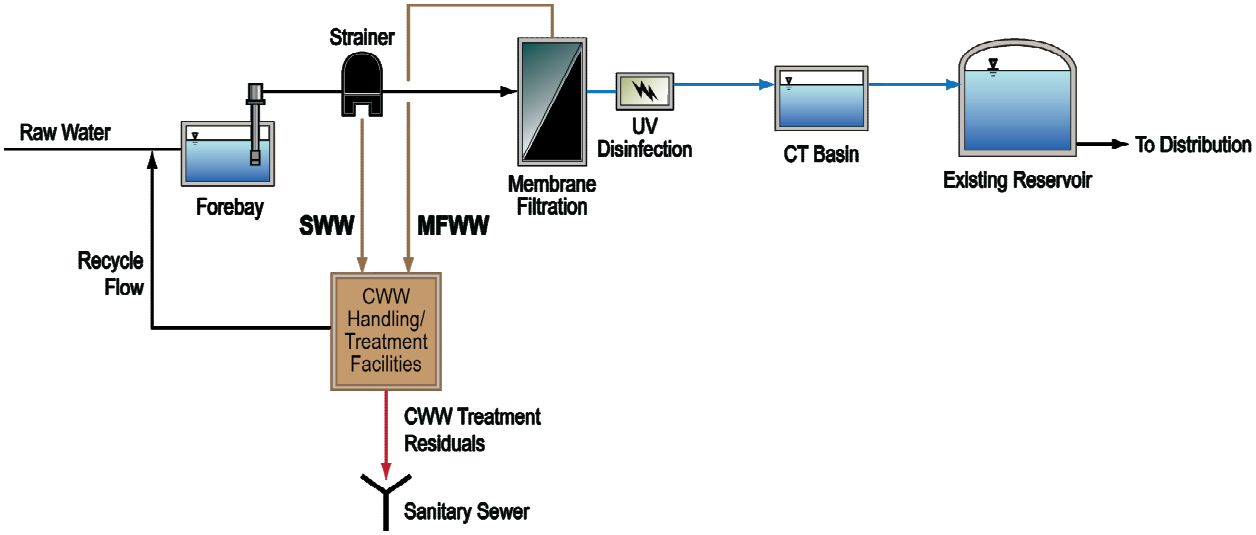

Table 14.1 Summary of Combined Waste Washwater Characteristics

	Units	CWW Flow Condition		
		Average	Minimum	Maximum
Assumed Operation and Raw Water Quality Data				
MF System Recovery	%	92	98	90
Raw Water Coagulant Dose[1]	mg/L	10	10	10
Raw Water Turbidity[2]	NTU	6	6	6
Raw Water Total Manganese[3]	mg/L	0.075	0.075	0.075
Estimated CWW Quantity and Quality				
Daily CWW Generation[4]	Million Gallons	2.2	0.5	3.0
CWW Turbidity	NTU	74	288	58
CWW TSS[1,3]	mg/L	194	751	151
CWW Total Manganese[3,6]	mg/L	1.7	7.4	1.4

Notes
1. Ferric sulfate is the assumed coagulant. A TSS to dose ratio of 0.79 is assumed.
2. Average Irvine Lake Water assumed for calculations in this table.
3. Manganese concentrations based on data presented in Malcolm Pirnie, 2008.
4. Based on total membrane system feed flow (raw water and recycle flows) at indicated recovery. Includes SWW flows.
5. A ratio of 1:1.3 (NTU:TSS) has been assumed for TSS calculations.
6. Assumes 50% removal in washwater treatment process, 80% removal in the primary MF process, and raw water manganese concentration of 0.075mg/L.

14.1.2 Treatment Alternatives

The following treatment alternatives screening is based on meeting key treatment goals for the CWW stream.

- Turbidity – An operational goal for turbidity in the recycle stream of less than 2 NTU, but no greater than average feed water turbidity.

Treatment processes used for treating combined washwater (CWW) flows at membrane facilities have a common treatment objective of liquid/solid clarification. These processes are varied in their suitability for specific applications. For the purpose of preliminary screening, candidate liquid/solid clarification processes used for treating CWW are grouped into broad categories in Table 14.2.

Appendix I includes supplemental calculations in support of the backwash wastewater treatment system preliminary design.

Table 14.2 Preliminary Screening of CWW Treatment Alternatives

	Fatal Flaw(s)	Other Considerations
Clarification		
Plate settlers	None	Proven solids removal technology
Lagoons	Required footprint; visual impact to planned future development	Eliminated
Actiflo®	Polymer carry over could permanently foul membranes	Eliminated
Dissolved Air Floatation (DAF)	Similar application of DAF to water using in-line coagulation have required the use of excess polymer to develop float.	Eliminated
Filtration		
Second stage membranes	None	Recycling permeate to head of plant required
Pressurized Media filtration	None	Provides reliable Mn removal Requires upstream clarification Waste washwater requires equalization and discharge to sewer
Disposal		
Discharge of all CWW flows to sanitary sewer	Wastes up to 3.0 million gallons per day of CWW	Minimal equipment requirements Largest volume of sanitary sewer discharge Requires additional sanitary sewer pipeline capacity to be constructed

From this preliminary screening two alternatives (CWW1 and CWW2) were carried forward for further consideration.

Alternative CWW1 - Second Stage Membranes

In this alternative, a dedicated membrane system would be installed to filter CWW flows prior to recycling to the head of the plant. No pretreatment (clarification) is required upstream. Equalization of CWW flows is required for proper membrane system operation. Phase 2 pilot testing (MPI, 2008) included verification of this approach on State Project supply at 80% recovery, providing the basis for the total waste flow estimates and Mn removal estimates.

Alternative CWW2 - Plate Settlers

This alternative consists of plate settlers for CWW clarification with space provided for future addition of pressurized media filters for enhanced Mn removal. Pressure filters would require an additional pump station. It is

recommended that pressure filters be used only as needed in the future for the following reasons:

- ILW, the source of manganese at the Baker WTP, will be used for a limited duration each year, limiting the possibility of manganese accumulation in the plant.
- Settled water will be returned to the forebay and where it will be contacted with water containing chlorine dioxide at the forebay inlet prior to transfer to the membrane system.
- The Baker WTP will be designed for blending ILW with MWDSC supplies to lower manganese concentrations. This strategy can be implemented should manganese levels exceed project goals.

14.1.3 Treatment Process Selection

A summary of final screening of alternatives CWW1 and CWW2 are presented in Table 14.3.

Table 14.3 Summary of Final Screening of Alternatives CWW1 and CWW2

Screening Criteria	Alternative	
	CWW1 Second Stage Membranes	CWW2 Plate Settlers
Direct Capital Cost ($)	3,510,000	1,640,000
Annual Operating Costs ($/year)	557,000[1,2] to be adjusted for new raw water costs.	317,000[1]
Average Plant Discharge to Sanitary Sewer at 28 mgd Production (mgd)	0.5	0.12
Projected Range of Finished Water Mn Concentrations, ILW Supply (mg/L)[3,4,5]	0.012 – 0.021	0.012 – 0.049
Projected Range of Finished Water Mn Concentrations, MWDSC Supply (mg/L)[6]	ND	ND

Note
1. Includes amortized capital costs at 4.5 percent over 30 years, purchase cost of raw water discharged to sewer, electrical, and chemical costs.
2. Includes cost components in Note 1 plus membrane replacement costs.
3. Based on operation with Irvine Lake Water at raw water Mn concentration of 0.075 mg/L. Low end of project based on residual manganese concentration measured in bench testing presented in Section 8, and 100% removal of oxidized manganese solids in the membrane system.
4. High range of estimates based on 50% removal of manganese solids in CWW clarifier (based on literature review) and 80% removal of manganese in across the membrane filtration system (based on pilot study results).
5. Irvine Lake supply to be used no more than 3 months per year; Alternative supplies (State Project Water and Colorado River) contain non-detectable concentrations of Mn.
6. MWDSC supplies have non-detectable levels of manganese.

14.1.4 Recovery

For alternative CWW2, estimated residual discharges to the sanitary sewer include:

- Neutralized chemical cleaning residuals – 10,000 gallons per day
- Sludge from the CEE clarifier – 120,000 gallons per day

The overall feed water recovery for the plant is estimated to be 99.5%, based on an average raw water flow of 28.1 mgd.

14.1.5 Sludge Disposal

It is assumed that sludge (as well as neutralized chemical cleaning residuals) will be disposed of in the sanitary sewer.

14.2 BACKWASH WATER DESIGN CRITERIA

14.2.1 Process

Criteria for key components of the CWW treatment system are included in Table 14.4, below.

14.2.2 Mechanical

14.2.2.1 Piping

Process piping for the MFWW equalization basin will be 14-inch mortar lined steel. Piping will be routed to allow for use of either one or both CWW clarifiers. Clarifier outlet piping will allow for return of settled water to either half of the forebay by gravity, and either the chlorine dioxide contact compartment or pumping equalization compartment.

14.2.2.2 Valves

Valving will include:

- Isolation valves (14-inch cast iron coated butterfly valves) for MFWW transfer pumps
- Check valves and combination air valves (cast iron bodies) for MFWW transfer pumps.
- MFWW inlet piping and each connection to the forebay will be equipped with isolation valves.

14.2.2.3 Metering

CWW will be metered at the discharge of the MFWW transfer pumps.

14.2.2.4 Coagulant / Chemical Mixing

As with the main process flash mix system, coagulant will be dosed to the CWW at the transfer pump discharge as needed to meet settled water quality goals. Dose in the CWW will depend on the dose delivered in the membrane feed water as required to maintain membrane performance and meet DBP goals. A metering pump sized for a maximum dose of 20 mg/L at 28 mgd in the main process flow will be dedicated to the CWW system. Coagulant mixing will be accomplished with a pumped diffusion flash mix system (constant speed end suction centrifugal). Estimated driver horsepower is 5 HP.

14.2.3 Structural and Layout

CWW clarifier has been sized to allow for common wall construction with the forebay.

The CWW Treatment/Handling facilities layout is further described in Exhibit 14.2 (Drawing M13 – Plan View) and Exhibit 14.3 (Drawing M14 – Section).

SECTION 15 ULTRAVIOLET DISINFECTION

15.1 OVERVIEW

The total disinfection requirements for Giardia, virus, and Cryptosporidium are established in Table 2.3 of Section 2, along with CDPH approved disinfection credits for membrane filtration, which will serve as the core of the treatment process at Baker WTP. Dedicated disinfection processes must meet the balance of the disinfection requirements not met by membrane filtration (i.e., 0.5-log Giardia inactivation and 4-log virus inactivation).

To achieve the required additional disinfection requirements, the recommendation made in the Baker Pipeline Regional Treatment Facility Feasibility Study (Malcolm Pirnie, Inc., 2007) consists of a combined ultraviolet (UV) for Giardia inactivation and free chlorine for virus inactivation.

This section discusses the use of UV, which will provide Baker WTP with a multi-barrier approach to disinfection as well as a strategy for complying with current and future regulatory requirements.

15.2 DISINFECTION GOALS

The primary goal of UV disinfection at Baker WTP is to achieve 0.5-log *Giardia* inactivation.

15.2.1 UV for Giardia Disinfection

UV systems can inactivate *Giardia* and *Cryptosporidium* at low UV doses. Therefore, UV disinfection system sizing is based on an assumption of worst-case additional *Cryptosporidium* inactivation requirement per LT2ESWTR for a compliant membrane filtration plant, i.e. 1.5-log (based on a maximum *Cryptosporidium* removal/inactivation requirement of 5.5 log and 4-log removal in the membrane system). This requirement would be triggered in the unlikely event that future *Cryptosporidium* sampling requires additional *Cryptosporidium* inactivation. The UV system will be sized to meet a UV dose of 3.9 mJ/cm^2 for 1.5-log Cryptosporidium inactiviation, and initially operated to meet a UV dose of 1.5 mJ/cm^2 for 0.5-log Giardia inactivation.

15.2.2 UV for Advanced Oxidation Processes (AOP)

UV can also be used for destruction of trace organic compounds through the use of higher UV doses alone and/or in combination with hydrogen peroxide as an advanced oxidation process (AOP). Use of UV for

destruction of trace organics (including taste and odor causing compounds) assumes that granular activated carbon (GAC) contactors are installed downstream for removal of hydrogen peroxide and byproducts generated by this process.

Given the 0.01-µg/L CDPH notification level for three nitrosamines including N-nitrosodimethylamine (NDMA), an analysis was conducted to develop a cost effective approach to account for future expandability of the Baker WTP UV system to high UV doses for photolysis of NDMA. The dose requirement for a 90% destruction of NDMA by photolysis is 700 mj/cm^2. The use of hydrogen peroxide in an AOP process would provide flexibility for partial destruction of other potential contaminants of concern including atrazine and 1,4 dioxane.

15.3 Equipment

15.3.1 Medium Pressure versus Low Pressure High Output UV Systems

UV systems for potable water applications fall into two basic categories:

- Systems with medium pressure (MP) lamps, and
- Systems with low-pressure high output (LPHO) lamps.

The LPHO lamps consume 100 to 500 watts of electricity per lamp and emit germicidal UV light at a single wavelength of 253.7 nm with electrical conversion efficiency between 30 and 40 percent. The MP lamps, on the other hand, consume 1 to 20 kW of electricity per lamp and emit germicidal UV light over a wide range of wavelengths from 200 to 300 nm with an electrical conversion efficiency of 10 to 15 percent.

The unique qualities and differences between LPHO and MP lamps have various impacts on UV system design and costs (capital and O&M) associated with the UV process. Table 15.2 summarizes the general comparison between LPHO and MP UV systems.

The decision to design around MP or LPHO is made on a case-by-case basis. The primary issues typically evaluated are capital cost, life cycle cost, space requirements, and operations and maintenance requirements. Since power cost is a major component of overall UV life cycle costs, this is frequently a key criterion for equipment selection.

Table 15.1 Generalized Comparison of MP and LPHO UV Systems

Parameter	MP System	LPHO System
Capital Cost	Lower	Higher
Space Required	Lower	Higher
Maintenance Requirements	Lower	Higher
Power Costs	Higher	Lower
Lamp Life	Lower	Higher
Fouling Rates	Higher	Lower
Headloss	Lower	Higher
Cleaning	Automatic Wipers	Offline acid rinse
Mercury Release Containment	More difficult	Less difficult
Expandability to high doses for oxidation and photolysis	More Feasible	Less Feasible

At this time, MP UV reactors are best suited for use in UV/AOP applications. Of the major conventional disinfection UV system manufacturers, two have AOP systems currently in use for destruction of organic chemicals at treatment plants utilizing H_2O_2; Trojan Technologies (London, Ontario) and Calgon Corporation (Pittsburgh, Pennsylvania). Each of these manufacturers can scale their reactors from disinfection to AOP doses by the addition of lamps and electrical equipment.

15.3.2 MP versus LPHO for Phasing in AOP at the Baker WTP

Two alternatives were evaluated for phasing in UV/AOP to meet future regulations for trace organic compounds and/or controlling taste and odor causing compounds.

- Alternative 1: Initial installation of a LPHO system for disinfection only. Replacement with a MP system for UV/AOP at year 10 (earliest anticipated timing for trace organics regulation).
- Alternative 2: Initial installation of a MP system for disinfection only. Upgrade of MP system for use as UV/AOP reactor at year 10.

15.3.3 Results Summary

Present worth including amortized capital cost and annual operations and maintenance costs for Alternative 1 are 38% less over the first 10 years than Alternative 2 when both are used for Giardia disinfection only. ($958,600 for LPHO versus $1,536,800 for MP).

Costs for years 11 through 30 were estimated as follows:

- Year 11 - Alternative 1: Remove LPHO (no salvage value), install MP UV/AOP reactors and upgrade electrical system.
- Year 11 - Alternative 2: Add additional MP lamps to existing reactors and upgrade electrical system.
- Years 11-30 - Operate both as UV/AOP reactors for 3 months of the year, and as disinfection only for 9 months of the year.

Total life cycle costs are estimated at $7.3M for Alternative 1 versus $7.1M for Alternative 2.

Alternative 1 (LPHO for initial installation and addition of MP if needed in the future) is recommended based on lower present worth of UV equipment when used for disinfection only. The detailed analysis is included in Appendix J.

15.4 DESIGN CRITERIA

Key preliminary design criteria for sizing the Baker WTP UV system are summarized in Table 15.3 below.

Table 15.2 UV System Design Criteria

Description	Units	LPHO System Criteria
Design Flow	mgd	28
Maximum Headloss[1]	inches	18
Design UVT[2]	%	80
Train Redundancy	No.	1
Treatment Requirement	Log	1.5-log *Cryptosporidum*
UV Dose	mJ/cm^2	3.9
Process Location	-	Post-MF, upstream of future GAC and CT basin
Dose Monitoring Strategy	-	UVDGM compliant MS2 or T1 phage calculated dose algorithm
Manufacturer	-	Wedeco (No other LPHO manufacturer in the USA)

Notes
1. Headloss through UV system (reactor + associated piping and components) at design flow and redundancy.

SECTION 16 CONTACT (CT) BASIN DISINFECTION

16.1 OVERVIEW

A CT Basin will be constructed to provide disinfection contact time, in accordance with regulations outlined in:

- California Surface Water Treatment Rule
- California Regulations Related to Drinking Water

The CT Basin will be a partially-buried concrete reservoir sized to provide adequate disinfection contact time for free chlorine to meet 4-log virus inactivation requirements. Sizing Calculations for the CT basin are provided in Appendix K.

16.2 DISINFECTION GOALS

The total disinfection requirements for Giardia, virus, and Cryptosporidium are established in Table 2.2 of Section 2, along with CDPH approved disinfection credits for membrane filtration, which will serve as the core of the treatment process at Baker WTP. Dedicated disinfection processes must meet the balance of the disinfection requirements not met by membrane filtration (i.e., 0.5-log Giardia inactivation and 4-log virus inactivation). Ultraviolet disinfection will be used to meet the 0.5-log giardia inactivation requirement, as discussed in Section 15. The CT Basin will be sized to meet the 4-log virus inactivation requirements.

Some of the candidate membrane filtration systems have been granted virus log removal credit by CDPH. However, it should be recognized that none of the integrity tests utilized by these systems are sensitive enough to detect a breach of the size of a virus (e.g., less than 0.5 µm). Therefore, post-membrane disinfection facilities should be designed for total virus inactivation or 4-log.

16.3 DISINFECTION BY-PRODUCTS

Provisions will be made to minimize formation of total trihalomethanes within the basin, particularly during periods of low plant flow when contact time in the CT basin is increased. In order to minimize potential for TTHM formation:

- an alternate chlorine injection point and fixed weir will be provided at an intermediate distance between the inlet and outlet of the basin.
- at low flows, the chlorine injection point can be manually changed by valving.

16.4 POST TREATMENT CHEMICAL INJECTION

Post-treatment chemicals to be injected at the CT basin include:

- Sodium hypochlorite for disinfection.
- Aqua ammonia for chloramine formation.
- Caustic soda for pH control.

Metering pumps for post treatment chemicals will be paced on a flow meter located immediately upstream of the CT basin.

16.4.1 Sodium Hypochlorite

Sodium hypochlorite will be dosed via a perforated pipe diffuser located underneath the nape of the inlet and intermediate fixed weirs. This will minimize off-gassing. Metering pump will be controlled based on the measured flow and an operator input dose setpoint. The target chlorine residual will be met by trimming the sodium hypochlorite flow to measured residual chlorine immediately upstream of the CT basin outlet weir.

16.4.2 Aqua Ammonia

Aqua ammonia for chloramine formation will be dosed via a perforated pipe diffuser located underneath the nape of the fixed outlet weir. This will minimize off-gassing. Metering pump will be based on a set ratio with the sodium hypochlorite pumps, with ammonia to chlorine ratio of between 4 and 5 to 1.

16.4.3 Corrosion Inhibitor

Corrosion inhibitor (if necessary) will be dosed at the outlet weir.

16.4.4 Caustic Soda

Caustic soda will be dosed via a perforated pipe diffuser located at the outlet weir. Metering pump will be controlled based on measure CT basin inlet flow and an operator selected dose setpoint. The metering pump flow will be trimmed based on a target pH.

16.5 DESIGN CRITERIA SUMMARY

Design criteria for the CT Basin are summarized in Table 16.1.

Table 16.1 Basin Design Criteria

Disinfection (CT) Basin		
Type: Partially Buried Concrete, Serpentine Channels	-	-
Virus Inactivation (pH=6-9, Min. Temperature = 4° C)	**LOG**	**4.0**
Concentration x Time (CT) Requirement	MG.MIN/L	12.4
Number of Trains	NO.	2
Disinfection Capacity, Total	MGD	35
T_{10} / T	PERCENT	60
L/W Ratio	-	34
Water Depth	FT	10.5
Total Volume	GAL	200,000
Overall Basin Dimensions (L x W)	FT x FT	44 x 80
Free Chlorine Average Dose	mg/L	3.0
Free Chlorine Average Residual	mg/L	2.0
Ammonia Average Dose	mg/L	0.5

Exhibit 16.1 (**Drawing M11** – Plan) and Exhibit 16.2 (**Drawing M12** – Section) summarize the preliminary design of the CT basin.

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SECTION 17 TREATMENT PLANT SITE

17.1 OVERVIEW

The treatment plant of the Baker WTP project will be constructed at the Baker site, comprising the following (see Exhibit 17.1).

- Treatment Plant (or High) site – primary area of new construction,
- Pipeline Easements – for the Baker and Allen McColloch Pipelines,
- Low site – located to the east of the pipeline easement,
- Development Area – area to the northeast of the treatment plant, planned for development.

This section describes the existing and future facilities for Baker WTP at the Baker site and covers the following topics:

- Existing Facilities – description of current and future conditions,
- New Facilities – description of the size and height of each,
- Site Access – means of access for the site, with focus on chemical delivery,
- Plant Layout – a summary of layout of the plant with supporting rationale,
- Civil Site Design – preliminary grading and drainage, and
- Utilities – describing utility abandonments, replacements, new installations and pipeline materials.

17.2 EXISTING FACILITIES

Existing facilities at the Baker site include reservoirs, filter plant, pump stations and storage/office buildings. Exhibit 17.1 delineates the four areas of the Baker site, shows the location of each of the existing facilities, and categorizes each as:

a) planned for demolition,

b) protected in-place or,

c) future use under analysis by IRWD.

17.2.1 Baker WTP Use

- 16 MG Pre-Stressed Concrete Reservoir (nearest to Baker WTP) – the fully buried reservoir was used for emergency storage by Los Alisos Water District. With Baker WTP the reservoir will be converted to the clearwell for storage of product water prior to distribution.

17.2.2 Future Use Under Analysis

- 16 MG Buried Pre-Stressed Concrete (furthest from Baker WTP) – used for emergency storage by LAWD, diameter of approximately 300 ft and depth of 30 ft. The second reservoir is being analyzed as part of the Lake Forest Sub Area Master Plan. The analysis will determine whether the reservoir will continue to provide emergency storage for the LAWD Zone 1 system, or be used as recycled water storage tank long-term.

- Zone A Reservoirs - two 2.0 MG recycled water reservoirs exist on the Baker site. The reservoirs were constructed as above ground steel tanks, and currently serve the LAWD Zone A system.

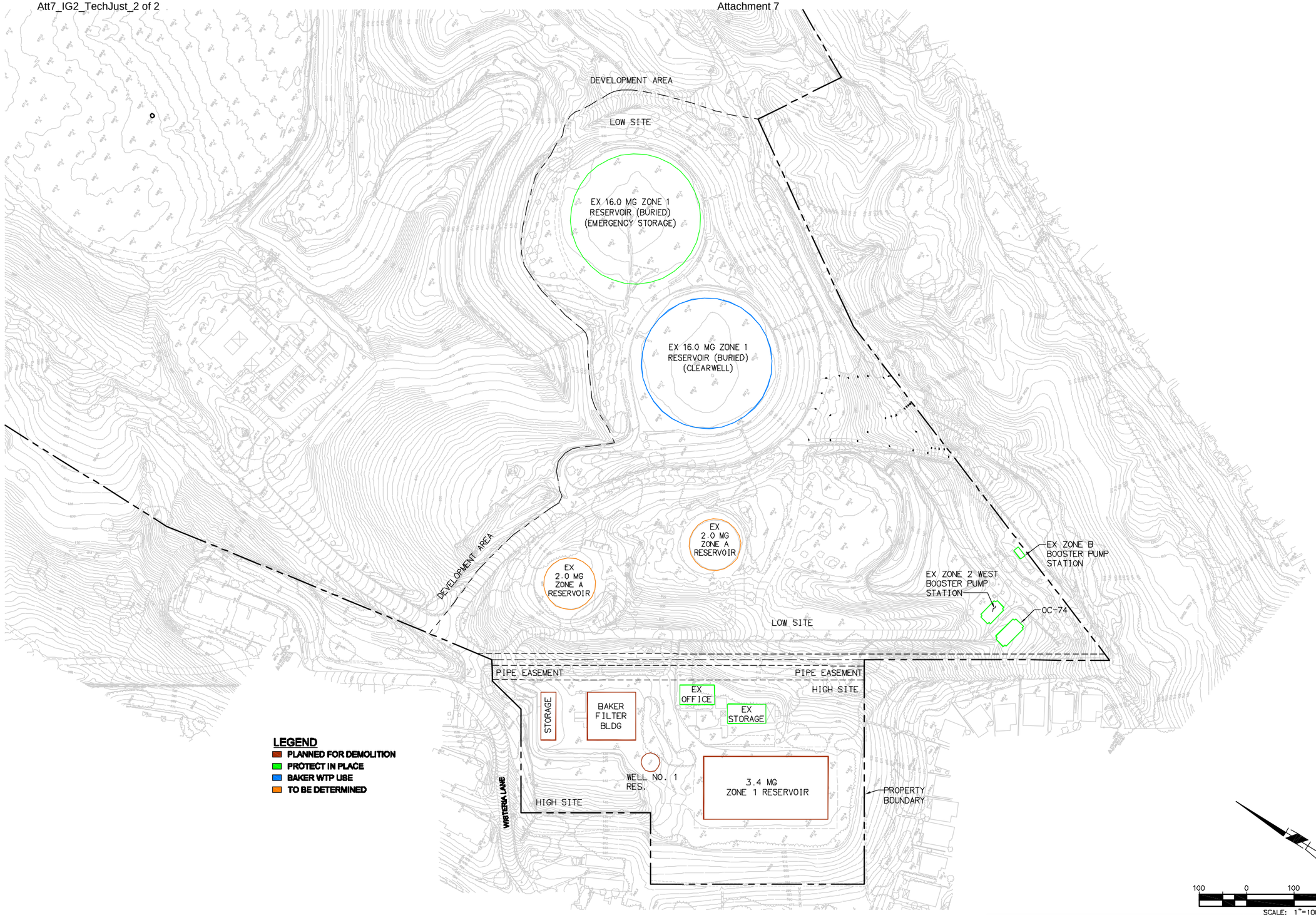
17.2.3 Planned for Demolition

- Filter Building - the filter building of the former Baker Filter Plant is a metal building measuring approximately 100 ft x 100 ft - not large enough to house the membrane filters for Baker WTP. The building will be inspected for hazardous materials prior to demolition.

- Storage Building (north of existing Baker Filter Building) – this storage building is too small to be used for chemical storage. The building will be inspected for hazardous materials prior to demolition.

- Zone 1 3.4 MG Reservoir – formerly used as the clearwell for Baker Filter Plant, this buried concrete reservoir is no longer in service and will be demolished.

- Well No. 1 System - constructed to supply water to the LAWD Zone 1 domestic water system. Constructed with a design capacity of approximately 1,000 gpm, which declined to an approximate maximum of 200 gpm. The well is no longer in operation. Prior to being taken out of service the well had provided water for:



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IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

BAKER SITE
EXISTING FACILITIES

EXHIBIT

17.1

- o supplemental water to the filter in the basins of the former Baker Filter Plant before its addition to the Zone A non-potable system in the LAWD system
- o distribution for small areas of irrigation, and
- o make-up water for manmade lakes within residential communities of Lake Forest, west of the Baker WTP site.

Now, these demands are met by water from the Baker Pipeline. IRWD is in the process of developing a plan for converted service to each of the users of the former Well No. 1 system, including recycled water or continued Baker Pipeline supply. The new system will be installed prior to site demolition and construction at Baker WTP. Thereafter, any on-site pipeline to the system will need to be protected in place, and the existing above ground steel tank can be demolished.

17.2.4 Protect In Place

- Zone 2 West Pump Station – located in the southern corner of the Baker site, supplying water from Zone 1 to 2 of the LAWD system.
- OC-74 Turn-out Building – located beside the Zone 2 West Pump Station, enabling supply of treated water from the AMP to the LAWD Zone 1 system, as necessary.
- Zone B Pump Station - near Serrano Creek, boosting water from the Zone A system (two reservoirs at the Baker site).
- Office and Storage Building (south of the existing Baker Filter Building) – both buildings will be protected in-place. Access to each facility will be impacted during construction.

17.3 NEW FACILITIES

Construction at the treatment plant will include the new facilities for:

- Raw Water – to collect, control and convey raw water for treatment
- Treatment – all facilities associated with the main treatment process
- Chemicals – to store and deliver
- Backwash Wastewater – for treatment and recovery

- Disinfection – bringing product water to drinking water standards
- Product Water – to deliver product water
- Non-reclaimable wastewater disposal

The new facilities for Baker WTP are summarized in Table 17.1.

Table 17.1 New Facilities Summary

Facility	Size	Construction
Raw Water System		
Flow Control Facility	T.B.D.	Slab on grade with surrounding wall.
TCWD Pump Station	T.B.D.	Slab on grade with surrounding wall.
Forebay	785,000 gal (71' x 135')	Cast-in-place concrete reservoir.
Feedwater Building - Pump Station - Strainer	64' x 72'	Building housing pump and flah mix / strainer.
Treatment System Treatment Building - Office / Control Center - UV Disinfection System	105' x 200'	Single story building (slab on grade).
Chemical System Chemical Building	80' x 132'	Single story building (slab on grade).
Backwash Waste Water System MFWW Equalization and Pumps	30,000 gal (20' x 25')	Buried pre-cast concrete tank w/ submersible pumps.
Sedimentation Basin	44' x 71'	Concrete basin with top just above grade.
Disinfection System Contact Basin	200,000 gal 44' x 80'	Concrete basin with top just above grade.

17.4 TREATMENT PLANT ACCESS

The future treatment plant site can be accessed from:

1. Wisteria Lane – access originating at Trabuco Road, and passing through the residential communities along Peachwood Drive, Palmwood Drive, and Wisteria Lane. Wisteria Lane has limited turning radius off of Palmwood Dr. and into the Baker site, and will require parking restriction enforcement on the south side of the street if chemical deliveries are made through this access.

2. Commercentre Drive – access is also possible from Commercentre Drive to the existing Baker site via Biscayne Bay or Indian Ocean Drive and dirt roads across the future development area. Access provided from Commercentre Drive will require the future development to accommodate turning radius requirements of the chemical delivery trucks to the Baker WTP, both during and after construction.

As site access must account for increased delivery frequency and larger chemical delivery trucks it is recommended that access via Commercentre Drive be pursued. Dependent on the final development planning, access from Indian Ocean Drive may provide the least extent of improvements, while also reducing the impact to existing or future residential communities.

If site access cannot be made through the future development, then:

- the access gate to the plant from Wisteria will need to be expanded, including some re-grading of the joint homeowner / Baker site slope, west of the existing gate,
- the City of Lake Forest will need to change to and enforce parking restriction on the southside of the Wisteria Lane,

17.5 TREATMENT PLANT LAYOUT

Alternative layouts of the treatment plant site were developed. Each alternative was based on consideration of:

- On-Site Access – based on a turning radius of 55 ft (chemical delivery truck), maintaining chemical delivery to both the east and west side of the chemical building, and providing maintenance access to all other facilities (treatment building, SCE switchboard and transfer, CT basin, forebay, feedwater pump station and backwash wastewater treatment.
- Visual and Noise Impacts – the nearby residential community to the Baker site was considered in layout alternatives. New above ground facilities were set back from the property boundary and facilities known to create noise during normal operation (i.e. Feedwater Pump Station and strainer) are planned in buildings.
- Yard Piping – the length of pipeline and number of utility crossings was considered in each alternative.

- Adjacent Facilities – the location of facilities at times was dictated by certain advantages in siting of facilities near each other.

Three alternatives were presented to the IRWD in workshop form, and to the Project Stakeholders in report form.

Alternative 1 – with the treatment building where the Zone 1 reservoir currently exists, and the chemical building where the filter building exists.

Alternative 2 – with the treatment building where the Zone 1 reservoir currently exists , and the chemical building in the center of the site.

Alternative 3 – with the treatment building where the filter building exists, and the chemical building where the Zone 1 reservoir exists.

Alternative 1, shown as Exhibit 17.2 (Drawing C1 and Exhibit ES-4), was selected for the Baker WTP based on its major advantages in addressing the considerations previously listed, and as summarized in Table 17.2.

Table 17.2 Layout Advantages

Consideration	Advantage
On-Site Access	- Ease of access to both sides of the chemical building for deliveries.
Visual and Noise Impacts	- Minimal impact with the feedwater pump station and strainers in a building, and the chemical and treatment buildings located where facilities currently exist.
Yard Piping / Adjacent Facilities	- Siting of the CT basin near the chemical building reduces pipe construction. - Siting the backwash wastewater treatment and forebay next to each other eliminates the construction water pipeline in recirculating treated backwash water.

17.6 CIVIL SITE DESIGN

Preliminary design of the grading and drainage for the plant layout is provided as Exhibit 17.3 (Drawing C2). The grading and drainage concept was based on:

- Maintaining a similar approach to site drainage as existing, including areas of sheet flow, on-site storm drains and v-gutters.

- Grading down the existing slope behind the filter building for construction of the forebay, feedwater pump station and backwash wastewater treatment facilities.

17.7 Utilities

The major utilities and construction related to utilities are covered in this section.

17.7.1 Baker Pipeline Connection

Raw water will be delivered to the Baker WTP through the Baker Pipeline. The existing connection and valve vault off of the Baker Pipeline will be used. There are currently three connections to Baker Pipeline through the vault.

- 20-inch former feedwater pipeline to the Baker Filter Plant with an existing ball valve
- 12-inch former by-pass pipeline to the Baker Filter Plant with an existing gate valve
- 12-inch pipeline to Trabuco Canyon Water District with an existing gate valve.

The 12- and 20-inch pipelines to the former filter plant combine beyond the vault into the 24-inch main feedwater pipeline. Trabuco Canyon Water District's pipeline increases to a 16-inch pipeline beyond the vault.

For Baker WTP each of the existing connections to the Baker Pipeline will be utilized as follows:

- IRWD connection (12-inch and 20-inch pipeline and valves) – the existing 12- and 20-inch connections to the Baker Pipeline will be maintained. Each of the existing isolation valves will be replaced with new ball valves. After each valve pipeline diameter increasers will be added to upsize the 20-inch pipeline to 24-inch and 12-inch to 16-inch. The new 16- and 24-inch pipelines will join beyond the valve vault into a single 36-inch.
- TCWD connection (12-inch valve and 16-inch pipeline) - will be maintained and continue to serve the Dimension Plant. The existing pipeline will serve as the majority of the suction and discharge pipe to the TCWD Pump Station.

17.7.2 Flow Control Facility and Solids

The flow control facility will be constructed with a sleeve valve having openings of approximately 3/8" to 1/2" size. Small solids may pass

through the sleeve valve and into the forebay. As a result, the construction of raw water strainers upstream of the flow control facility has recently been considered. If added to the Project, the flow control facility would be moved to the north along the access road to provide room for the strainers to be immediately downstream of the connection to the Baker Pipeline.

17.7.3 Raw Water Pipelines

Raw water pipeline will be constructed to deliver water from the Baker Pipeline to the forebay. All raw water pipelines will be cement mortar and lined steel pipe. As shown on Exhibit 17.2, reaches of 36-inch and 42-inch pipeline will be constructed between the flow control facility and forebay. Thereafter, 42-inch pipeline will be constructed from the feed water pump station to the treatment building.

17.7.4 Product Water Pipelines

Product water pipelines for Baker WTP are summarized in Table 17.3.

Table 17.3 Product Water Pipelines

From	To	(E)xisting or (N)ew	Size (in)
Treatment Building	CT Basin	N	42
CT Basin	Clearwell	N	42
Clearwell	IRWD Zone 1	E	24
Clearwell	Product Water Pump Station	N	36
Product Water PS	AMP	N	36

New 42-inch pipeline will be constructed from the treatment building to the CT basin, and the CT basin to the clearwell. At the clearwell a new connection will be required. The connection will include a valve vault adjacent to the existing reservoir, and wall (toward the top of the tank) or roof penetration and include inlet piping within the reservoir so that water discharge within the tank occurs 4 to 6 feet from the tank invert. Product water will be conveyed from the clearwell through an existing 24-inch Lake Forest Zone 1 pipeline to IRWD, and in a new 36-inch pipeline to the Product Water Pump Station and Allen McColloch Pipeline.

17.7.5 Chemical Distribution

Chemical distribution pipelines are summarized in Table 17.4, and also discussed in Section 13.

Table 17.4 Chemical Distribution Pipelines

Type	From	To	Tube Material / Carrier Pipe
Aqua Ammonia	Chemical Building	CT Basin	Teflon / 316 SS
Chlorine Dioxide	Chemical Building	Raw Water Pipeline	Teflon / PVC Sch 80
Citric Acid	Chemical Building	Treatment Building	Teflon / 316 SS
Ferric Chloride	Chemical Building	Treatment Building	Teflon / PVC Sch 80
Hydrochloric Acid	Chemical Building	Chemical Building	Teflon / PVC Sch 80
Sodium Bisulfite	Chemical Building	Treatment Building	Teflon / PVC Sch 80
Sodium Hydroxide	Chemical Building	Treatment Building	Teflon / Black Steel
Sodium Hypochlorite	Chemical Building	CT Basin	Teflon / PVC Sch 80

17.7.6 Drainage

Ultimate drainage design for the Baker WTP will need to incorporate emergency overflow conditions, as well flow from the 100 year storm. One option still to be investigated is using the proposed detention basin planned as part of the adjacent development. This detention basin is planed to be located at the low area of the Baker site. It is understood that the detention basin may be located where the two 2.0 MG Zone A reservoirs are located. If so, worst-case storm drain/overflow conditions could be handled by transferring flow from the high site to the low site by either sheet flow, construction of a new drainage pipeline, or a combination of both.

17.7.7 Water Discharge

The Baker WTP may need to convey raw or treated water for discharge to Serrano Creek in case of emergency operating conditions. Conditions upon which discharge may be required include:

- Overflow of the Forebay (raw water) – occurring only if the level in the forebay cannot be maintained and the flow control valve does not modulate appropriately to reduce or shut-off flow.

- Overflow or Discharge from the Contact Basin (treated water) – occurring only if the flow to the contact basin exceeds discharge, and the water cannot be delivered to the clearwell or the forebay.

If flow to Serrano Creek is required, there are two likely discharge points. These are:

- East of the 16 MG Reservoirs – the overflow pipeline for the two 16 MG reservoirs consists of 18-, 36- and 48-inch pipeline. The discharge point is on the Baker site, east of the reservoirs and north just north of the property boundary / off-site trail. At the discharge point is existing rip-rap and a 72-inch pipeline to carry the flow under the existing trail to Serrano Creek. The existing pipeline was constructed as storm drain line 'B' of the Zone 1 emergency storage reservoirs.

- East of the Zone 2 West Pump Station – a storm drain was also constructed near the Zone 2 West Pump Station with the Zone 1 emergency reservoirs. The line is referenced as storm drain line 'D'. The discharge of this pipeline does not appear to have rip rap, and would be anticipated to have greater impact to Serrano Creek if utilized.

Further evaluation of water discharge options and locations will be provided during final design.

17.7.8 Sewer

Concurrently with the design of Baker WTP, the Lake Forest Sub Area Master Plan is being prepared by Dudek. The report includes an evaluation of the sewerage of the Baker Site (Baker WTP and future development). Therefore, a definitive plan for the disposal of the plant's non-reclaimable wastewater (NRW) will be developed as the master plan progresses. At present, two possible approaches to the disposal of wastes have been considered, both of which require a crossing of Serrano Creek with new pipeline:

- Construction of a gravity sewer from the sedimentation basin, that will be constructed as part of this Project to the southern corner of the project site, where a sewer siphon would be constructed to cross Serrano Creek and connect with the 15-inch VCP pipeline on the other side or,

- Construction a pump station and forcemain along the same alignment, and to the same terminus.

IRWD and RBF have also begun consideration of the following:

- Construction of a shallow gravity sewer along the foot path that parallels Serrano Creek on its north side. The discharge location would be about 600 feet north of Trabuco Road to an existing 15-inch VCP sewer.

Each of these options appear feasible. However, the shallow sewer option may be preferred because it does not require a crossing of Serrano Creek. However, the final recommendation depends on the results of the master planning efforts. Further evaluation of the sewer

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SECTION 18 PRODUCT WATER PUMP STATION

18.1 INTRODUCTION

A Product Water Pump Station (PWPS) will be constructed to pump product water from the clearwell to the Allen McColloch Pipeline for delivery to each Project Stakeholder, except Irvine Ranch Water District. Irvine Ranch Water District will receive water from the clearwell by gravity, into the Lake Forest Zone 1 system.

This section covers the preliminary design of the Product Water Pump Station, addressing:

- Capacity
- Hydraulics
- Site Development
- Design Criteria
- Surge System

18.1.1 Capacity

The capacity for the Product Water Pump Station will be 33 cfs, based on the total capacity for Baker WTP, minus IRWD's capacity. Table 18.1 summarizes capacity in the pump station by agency.

Table 18.1 Product Water Pump Station Capacity

Agency	Capacity (cfs)
El Toro Water District (ETWD)	5
Moulton Niguel Water District (MNWD)	13
Santa Margarita Water District (SMWD)	13
Trabuco Canyon Water District (TCWD)	2
TOTAL	**33**

18.1.2 Hydraulics

Hydraulic calculations were completed for the suction and discharge of the Product Water Pump Station. A summary of each is provided.

Suction side hydraulics - were based on the low and high water operating levels of the Baker WTP clearwell. The proposed clearwell for the Baker WTP is the southern most 16.0 MG reservoir at the Baker Site. The tank was constructed with a low water level of 595 ft and high water level of 621 ft above mean sea level (amsl). For the basis of preliminary design of the PWPS the design minimum HGL at the pumps was evaluated as 585 ft amsl calculated to be 10 feet of headloss from the clearwell to the pump station.

Discharge side hydraulics - were based on the hydraulic grade line of the Allen McColloch Pipeline. The hydraulic grade line of the Allen McColloch Pipeline varies significantly between summer (high demand) and winter (lower demand) conditions. The absolute minimum and maximum HGL in the AMP are understood to be a low of 630 ft, and high HGL of 806 ft per coordination with Flow Science. Metropolitan Water District has performed analysis of the AMP pipeline under peak day (maximum day demands) up to the year 2035. Based on that analysis, the lowest (non-surge) stable HGL was determined for 2035 to be approximately, 703 ft at OC-88 (South County Pump Station), and 701 ft at OC-74 (IRWD connect on the Baker site).

Table 18.2 PWPS Capacity and HGL Requirements

Description	Parameter
Hydraulics (Suction)	
Water Level in Clearwell	595 - 621 ft
Maximum Flow w/ one standby pump (4 pumps)	33 cfs
Maximum Flow w/ no standby pump (all 5 pumps)	40 cfs
Headloss thru Suction Piping (Maximum)	24 ft
Minimum HGL at Product Water Pump Station (per headloss calculation)	585 ft
Hydraulics (Discharge)	
Discharge HGL in Allen McColloch Pipeline	630 – 806 ft
Maximum Flow	33 cfs

A summary of delivery capacity and HGL requirement is provided as Table 18.3.

Table 18.3 PWPS Capacity and HGL Requirements

Agency	Capacity (cfs)	Distributed By	HGL Required (ft)
Irvine Ranch Water District	10.5	IRWD System	595 – 621 ft
El Toro Water District	5	AMP	630 ft (min) to 806 ft (max)
Moulton Niguel Water District	13		
Santa Margarita Water District	13		
Trabuco Canyon Water District	2		

Hydraulics calculations for the Product Water Pump Station were completed to determine the total dynamic head, type and number of pumps, develop system curves and plot preliminary pump curves utilizing variable speed drives to address the fluctuations in discharge head. Table 18.3 summarizes the capacity and HGL requirements. Table L1 of Appendix L also depicts the HGL conditions from the clearwell to the AMP.

Hydraulic analysis verified the HGL fluctuation in the AMP require variable speed drives to maintain discharge flow. Speed reduction down to 70-percent was considered in selecting the type and number of pumps.

The design of the pump station includes four (4) duty pumps + one (1) stand-by pump configuration. It was determined through coordination with pump manufacturers and hydraulic calculations that the infrequent low HGL range below 690 ft should be separated from the pump design operating band, and managed by pressure reduction with a throttling valve. If a baseload for the Product Water Pump Station is established, it may be possible to change the pump station design to include single speed pumps. This issue will be further investigated in final design.

Exhibit 18.1 depicts the operating range of the pump station, and depicts the operation conditions where pressure reduction will be needed to provide flow during low head conditions in the Allen McColloch Pipeline.

See Table L2 of Appendix L for the design criteria of the pumps.

18.1.3 Operation

The Product Water Pump Station will be operated to deliver up to 33 cfs of flow to the Allen McColloch Pipeline. Pressure information will be received from the AMP to determine the correct operating range of the pumps and the throttling valve.

18.2 SITE DEVELOPMENT

The Product Water Pump Station site layout is shown in Exhibit 18.2 (Drawing C4).

To the south of the pump station is a 24-inch pipeline that was used to fill the existing 16 MG reservoirs with treated water through the OC-74 turn-out off of the Allen McColloch Pipeline.

The extent of grading, and reserved space for a surge tank, SCE transformer, switchboard, and power generator. An access road around the pump station will be constructed for ease of access for maintenance / equipment trucks. The proposed pump station building will require 2 – 3 ft of soil retainment along the north wall which will have to be accounted for in the structural design. However, this minimizes the grading implications and prevents disturbance of soil over the top of the northern most 24-inch IRWD / LAWD Zone 1 pipeline.

18.3 MECHANICAL

The mechanical layout of the PWPS is based on four vertical turbine type pumps, with a fifth pump as stand-by, a high-to-low pressure bypass, and a throttling valve. Suction and discharge header pipelines will be 36-inch based on the full design capacity of the pump station (33 cfs or 14,800 gpm). Pipelines to and from each pump will be 20-inch (8.25 cfs or 3,700 gpm). All isolation valves shall be butterfly type. In addition, a throttling valve, motor operated ball valve type will be installed to reduce head when the AMP has a low HGL. The ball valve will be located within the PWPS pump room and above the finished floor with a minimum of 3 ft height to centerline. The mechanical design for the pump station will include HVAC for air conditioning the electrical room planned to have five variable frequency drive controllers.

Exhibit 18.3 (Drawings M20 and M21) shows the mechanical layout of the Product Water Pump Station.

Pump Curve
4 Pump Configuration - Product Water Pump Station

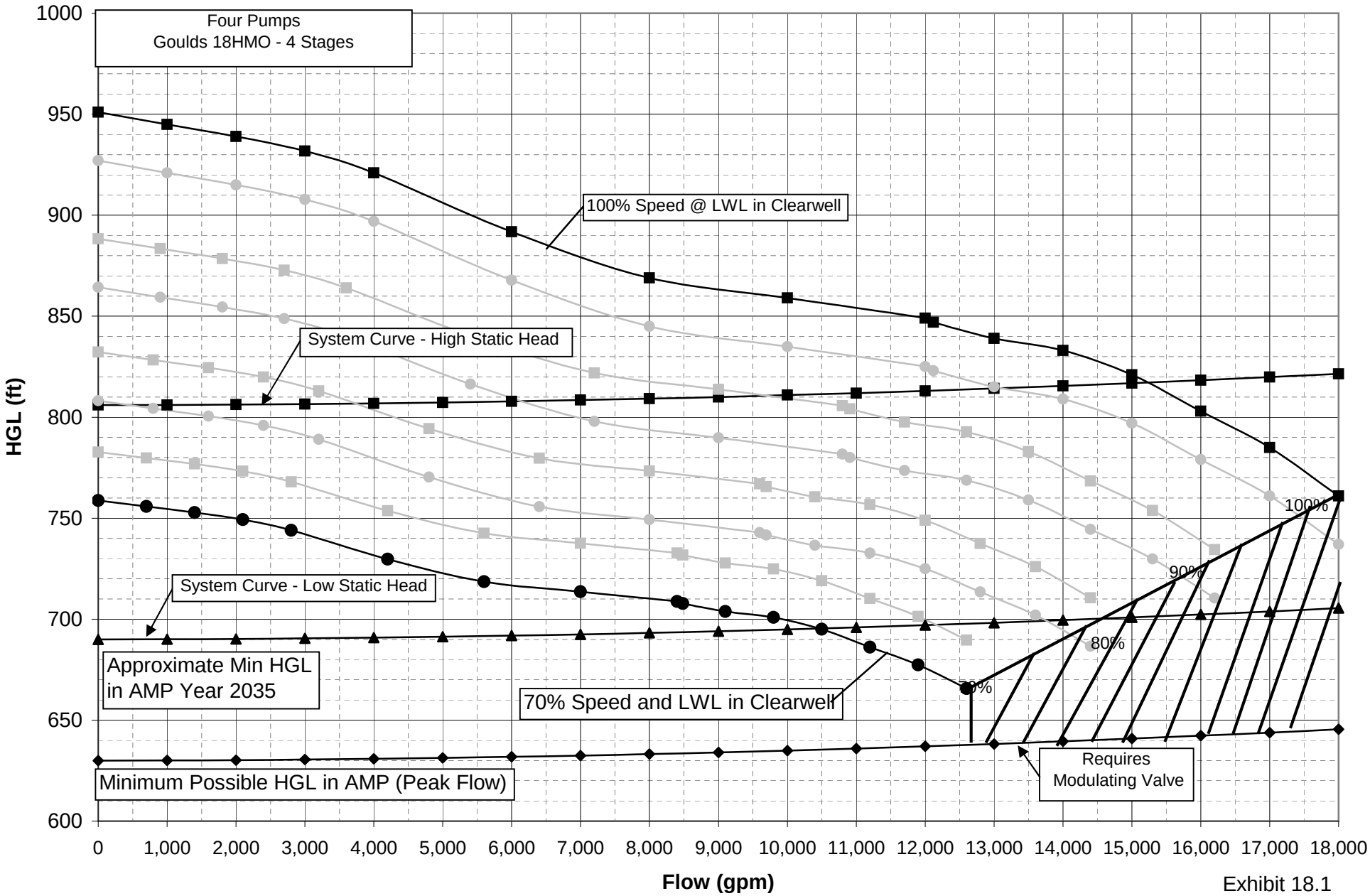


Exhibit 18.1

The discharge pipeline from the PWPS will be 36-inch diameter. The pipeline will connect to the AMP at design Station 353+35 (Record 353+37.20). This is the current location of an air-valve as well as the emergency inter-connection vault for the AMP to the Baker Pipeline. It is anticipated that the connection facility will involve the following:

- Utilization of the existing air-valve structure at Station 353+37.20 as the connection point.
- Construction of one or two new vaults for the installation of a magnetic meter, check valve, new isolation valve for the existing AMP/Baker cross-connection, and a removable spool to render the cross-connection inoperable when flow from the AMP to the Baker is not required.

The new vault(s) will be reinforced concrete, approximately ten feet deep and will be situated adjacent to the existing access road. The length and width of the vaults cannot be determined until the design criteria are established by MWD.

Exhibit 18.1 (Drawing M22) shows the proposed metering vault for the pump-in connection to the Allen McColloch Pipeline. The drawing has been provided to MWD for review.

18.4 DESIGN CRITERIA

The design criteria for the Product Water Pump Station are provided as Table 18.4.

Table 18.4 Product Water Pump Station Design Criteria

Description	Units	Value
Type: Vertical Turbine	-	-
No. of Pumps	NO.	5
No. of Redundant Pumps	NO.	1
Capacity per Pump	GPM	3,700
TDH (Maximum)	FT of Water	235
Size	HP	300
Mechanical	-	-
Upstream Pipeline Diameter	IN	36
Inlet Pipeline	IN	20
Discharge Pipeline	IN	20
Isolation Valves	IN	20
Throttling Valve	IN	24
Downstream Pipeline Diameter	IN	36

18.4.1 SURGE

Preliminary surge analysis for the Product Water Pump Station has been completed. The analysis analyzed power failure to the Product Water Pump Station under three steady state flow conditions.

1. Full AMP winter demands without OC-88 and OC-88a pump stations or surge protection at the pump stations.

2. Full AMP summer demands with OC-88 pump station and its associated surge protection in operation.

3. Full AMP winter demands with OC-88a pump station and its associated surge protection in operation.

The results of the surge analysis show that loss of power to the Product Water Pump Station will cause a pressure drop wave in the AMP. When reflected the wave would cause an upsurge wave along the AMP exceeding the 830 ft HGL level. In order to prevent the excessive HGL (greater than 830 ft) it is recommended that a pressurized surge tank of 1,810 cu. ft. be installed downstream of the flow control ball valve. Additionally, it was found that a surge relief valve downstream of the flow control ball valve will be necessary. The combination of the surge tank and pressure relief valve will serve to prevent the HGL in the AMP from exceeding 830 ft under all three operating conditions.

Analysis is on-going and will be continued into and through design to finalize the facilities necessary and in support of coordination with MWD. The conclusions provided herein are based on the Draft Report, which has yet to be reviewed by MWD.

18.4.2 GEOTECHNICAL

A geotechnical investigation, including borings and soil data logging will be completed during the design of the Product Water Pump Station.

SECTION 19 ELECTRICAL SITE INFRASTRUCTURE

19.1 OVERVIEW

This section describes the electrical distribution systems for the Raw Water Pump Station, Baker Water Treatment Plant and Product Water Pump Station.

19.2 RAW WATER PUMP STATION

SCE will provide a 480 volt, 3 phase, electrical service to accommodate the loads of the Raw Water Pump Station. The single line diagram for the pump station is included in Exhibit 19.1 (Drawing E11).

The new metered switchboard is located on the pump station site as shown on Exhibit 19.2 (Drawing E10). The service to the pump station will be provided from an upsized SCE transformer also shown on Exhibit 19.2. The existing transformer serves three facilities; 1) EOCWD flow control facility, 2) MWDOC-Gerald price facility and 3) IRWD Santiago aqueduct flow control facility. The IRWD flow control facility will be demolished. The new SCE transformer will be sized to serve the EOCWD facility, MWDOC facility and the new pump station. The pump station contractor will install a new concrete pad with slab box for the upgraded transformer and conduits from the transformer to the switchboard. SCE will install the new transformer, wiring from the transformer to the switchboard and set the meter in the switchboard. Electrical service to the existing facilities will be unavailable during the transformer replacement. IRWD will advise EOCWD and MWDOC of the planned upgrades to the electrical service and required outages.

The motor control center, VFDs and control panel are located as shown on Exhibit 19.2 (Drawing E10). The motor control center includes feeder circuit breakers for the VFDs, circuit breaker feeder for air conditioning, a 480 -120/208 Volt stepdown transformer and 120/208 Volt distribution panel to accommodate auxiliary loads such as lighting and receptacles. The control panel houses the PLC, radio, UPS and associated control components. Radio communication will be used between the pump station and the treatment facility. The antenna will be mounted on the roof of the pump station building at a height specified by IRWD. The radio communication and system integration is further described in Section 20.

19.3 GENERAL POWER SERVICE AND DISTRIBUTION – BAKER WATER TREATMENT PLANT SITE

19.3.1 Existing Conditions

Four electrical metered services are currently installed at the Baker site. These metered services are listed below and shown on Exhibit 19.3:

Treatment Building - 480 Volt, 3 phase

Treatment Building - 208 Volt, 3 phase

Zone B Booster Pump Station - 480 Volt, 3 phase

Zone 2 West Booster Pump Station – 480 Volt, 3 Phase

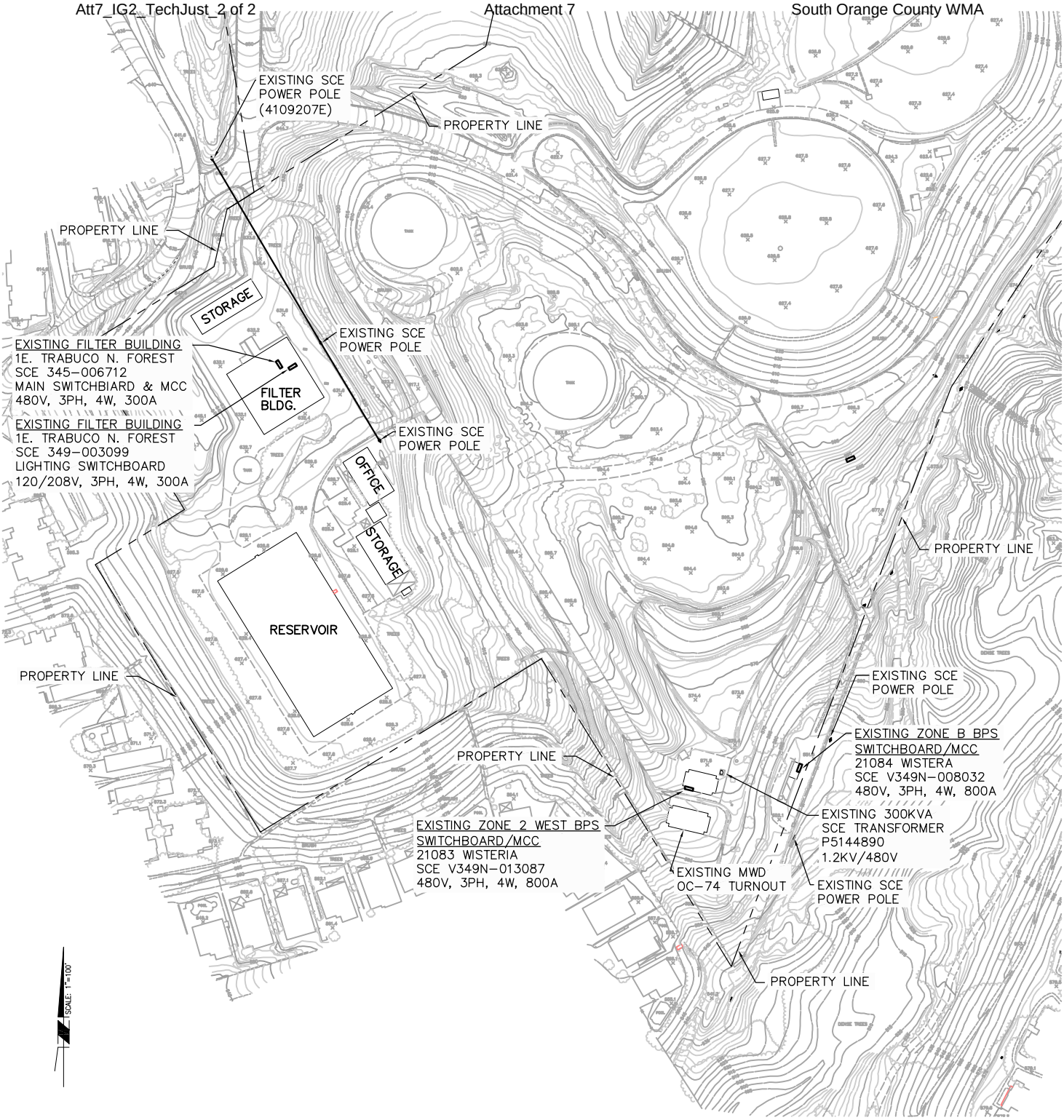
The proposed water treatment plant requires a 480 Volt, 3 phase electrical service to accommodate the approximate connected load of 3,776 Amperes. The existing Treatment Building 480 Volt and 208 Volt services (noted as Items 1 and 2 above) will be demolished. The proposed product water pump station requires a 480 Volt, 3 phase electrical service to accommodate the approximate load of 1,913 Amperes. The existing Zone B Booster Pump Station and Zone 2 West Booster Pump Stations are currently served at 480 Volts, 3 phase, and have connected loads of 751 and 700 Amperes, respectively.

SCE requires that the existing metered services and all new services required at the site be combined and served from one SCE point of connection. The services for the proposed water treatment plant and product water pump station will be provided from the overhead distribution line located adjacent to the existing water treatment facility. The new service plan also incorporates the existing Zone B Booster Pump Station and Zone 2 West Booster Pump Station.

Exhibit 19.4 depicts the proposed single line diagram and includes a summary of the loads for the existing facilities. Exhibit 19.5 (Drawing E2) depicts the proposed locations for the new electrical components.

19.3.2 Overall Site Electrical Distribution

The new electrical service for the water treatment plant site will be metered at 12.5 kV. SCE will install and maintain the 12.5 kV metering structure, medium voltage wiring, transformers and low voltage wiring



EXISTING SCE ELECTRICAL SERVICES

1"=100'-0"

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IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

EXISTING ELECTRICAL SERVICES

EXHIBIT 19.3

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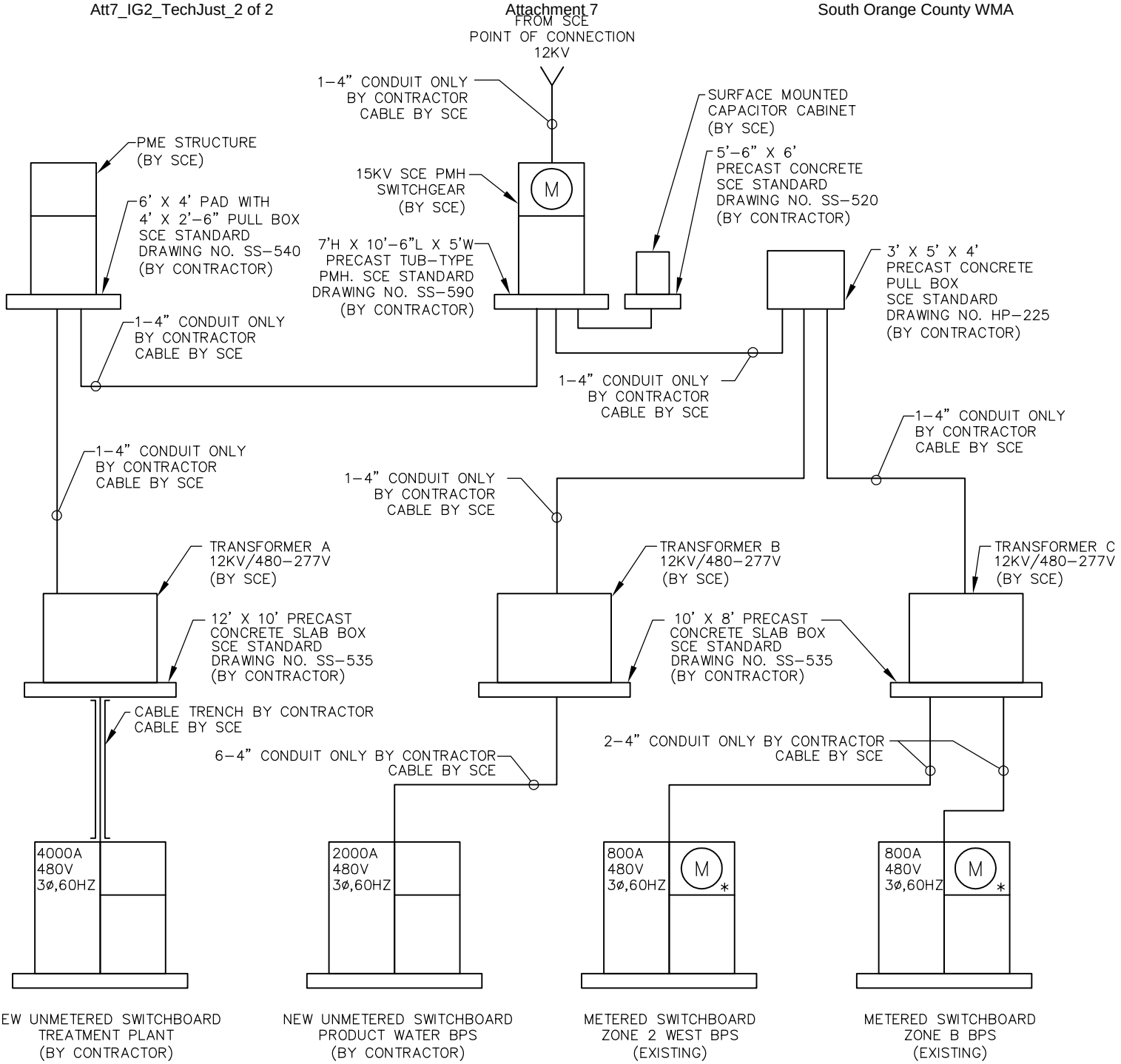

* SCE TO REMOVE EXISTING METER

ZONE 2 WEST BPS

LOAD SCHEDULE		
EQUIPMENT	HP	AMPS
PUMP 1	50	65
PUMP 2	100	124
PUMP 3	200	240
PUMP 4	200	240
15KVA XFMR	–	31
TOTAL		700

ZONE B BPS

LOAD SCHEDULE		
EQUIPMENT	HP	AMPS
PUMP 1	200	240
PUMP 2	200	240
PUMP 3	200	240
15KVA XFMR	–	31
TOTAL		751

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IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT

OVERALL POWER SERVICE BLOCK DIAGRAM

EXHIBIT 19.4

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from the transformers to the unmetered switchboards. The electrical contractor will install the conduit systems, concrete slab boxes for the transformers and other structures as required by the approved SCE service plan. SCE requires these facilities be inspected and approved by SCE field inspectors prior to SCE installing the wiring in conduits or setting transformers on the concrete pads. The Electrical Contractor will coordinate these inspections with the SCE field inspector. These requirements will be included in the project specifications prepared for the project.

The existing metered switchboards for the Zone B Booster Pump Station and Zone 2 West Booster Pump Stations will remain. SCE will provide the electrical service from the new SCE transformer "C" to each switchboard and will remove the existing meters at each switchboard.

New unmetered switchboards will be installed by the electrical contractor for the proposed product water pump station and the water treatment facility. SCE will install the wiring from the new SCE transformers to the unmetered switchboards. If the electrical usage at the proposed booster pump station is required to be individually metered for rate purposes, a power meter will be included in the electrical design for the proposed pump station. This power meter will be owned and maintained by IRWD.

19.3.3 Location of Electrical Facilities

The 12.5 kV metering and transformers for the water treatment plant will be located near the water treatment plant. SCE will serve these facilities from the existing SCE pole located at the entrance to the facility. Serving the facility from this pole allows the removal of the existing SCE poles adjacent to the water treatment facility. The existing SCE pole is located outside the IRWD property line requiring an easement from the adjacent property owner for the new underground service installation. SCE requires an easement with a width of six (6) feet extending from the existing SCE pole to the IRWD property line as depicted on Exhibit 19.5 (Drawing E2). SCE will obtain required easements from adjacent property owners. However, SCE will not pay a property owner for an easement and any charges for the easement would be paid by IRWD.

SCE transformer "A" to feed the proposed water treatment facility will be located near the new 12.5 kV metering structure. SCE transformer "B" will serve the new product water pump station and will be located near the

new product water pump station. SCE transformer "C" will serve the existing pump stations and will be located in the vicinity of the existing pump stations.

19.3.4 Construction Requirements

The electrical contractor for the water treatment facility will install the infrastructure for the SCE facilities including the concrete pads, pullboxes and conduit systems. SCE requires that clearances be maintained around SCE electrical equipment as depicted on Exhibit 19.6. The SCE facilities must be installed on non-sloped areas with appropriate access for SCE service vehicles.

SCE requires an easement from IRWD for the capacitor bank and PMH structure for the 12.5 kV primary metering equipment located as shown on Exhibit 19.6.

19.3.5 SCE Contractual Requirements

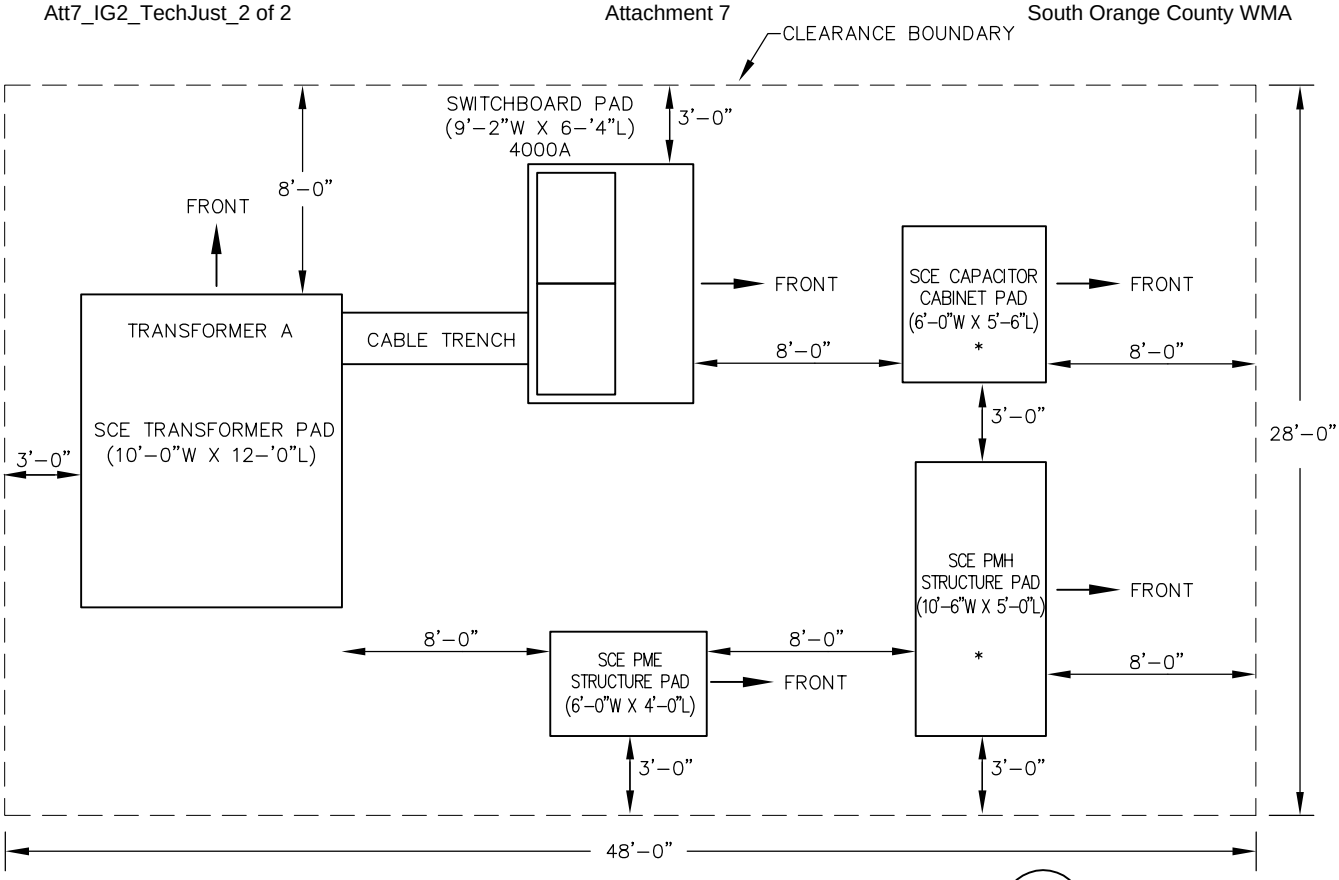
SCE will bill on a monthly basis for the installation and maintenance of the installed SCE facilities. Energy usage and demand charges will also be included on the monthly bill from SCE. The monthly charges will be determined by SCE after loads for the facility are finalized. These charges will be determined in a similar manner to those established at the Los Alisos Water Reclamation Plant where SCE owns and maintains the 12.5 kV system and the service is metered at 12.5 kV under Time of Use rate schedule TOU-8.

19.3.6 Treatment Plant

The 480 Volt, three phase electrical service is provided to the Treatment Plant per Section 19.3 and as shown on Exhibit 19.5 (Drawing E2).

The single line diagrams for the facilities at the treatment plant are included as Exhibit 19.7A to 19.7F (Drawings E3, E5 to E9). Power to each of four motor control centers will be provided from Switchboard MSB-2. Four motor control centers provide power distribution for the loads of the treatment plant area as follows:

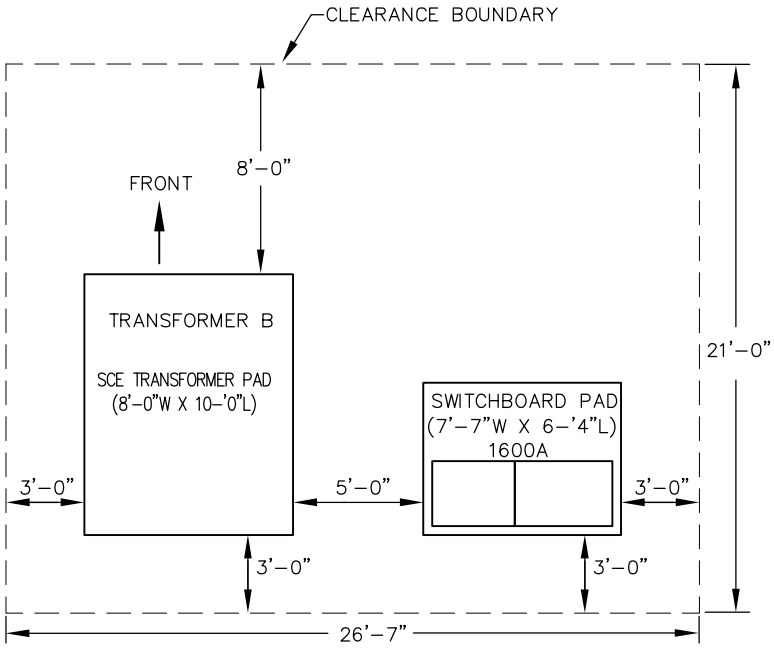
1. MCC – WTP feeds RO Treatment Plant loads
2. MCC – FWPS feeds Feedwater Pump Station Loads
3. MCC – CHEM feeds chemical system loads



WATER TREATMENT PLANT ELECTRICAL SERVICE EQUIPMENT CLEARANCE (A / 19.8)

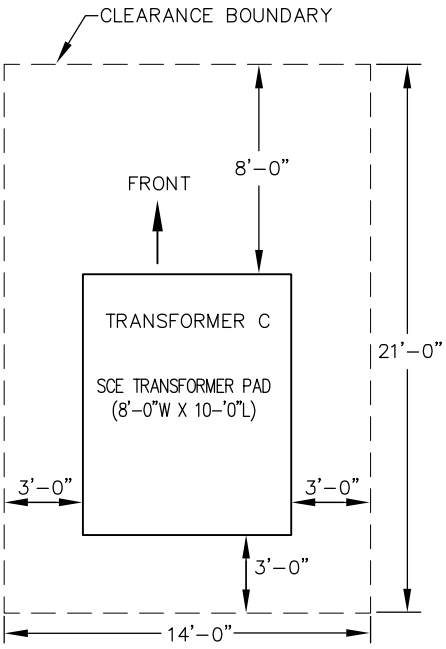
NTS

* SCE REQUIRES EASEMENT FROM IRWD
FOR CAPACITOR & PMH STRUCTURE PADS



PRODUCT WATER BPS ELECTRICAL SERVICE EQUIPMENT CLEARANCE (B / 19.10)

NTS



TRANSFORMER C CLEARANCE (C / 19.5)

NTS

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IRVINE RANCH WATER DISTRICT

BAKER WATER TREATMENT PLANT
ELECTRICAL SERVICE EQUIPMENT CLEARANCE

EXHIBIT 19.6

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4. MCC – TCWD feeds Trabuco Canyon Water District pump station loads

The SCE transformer and unmetered switchboard to serve the treatment plant are located as shown on Exhibit 19.8 (Drawing E4). The Motor Control Centers will be located in dedicated rooms within the treatment plant, feedwater pump station and chemical buildings. The MCC for the Trabuco Canyon Pump Station will be located adjacent to the pump station in a weatherproof NEMA 3R airconditioned enclosure.

19.3.7 Product Water Pump Station

The 480 Volt, three phase electrical service is provided to the Product Water Pump Station as described in Section 19.3. The single line diagram for the pump station is included in Exhibit 19.9 (Drawing E13).

The SCE transformer and unmetered switchboard are located on the pump station site as shown on Exhibit 19.10 (Drawing E12). The automatic transfer switch and motor control center are located in the pump station electrical room. The motor control center includes five 300 horsepower variable frequency drives, feeder circuit breaker for air conditioning, a 480 -120/208 Volt stepdown transformer and 120/208 Volt distribution panel to accommodate auxiliary loads such as lighting and receptacles. The control panel is also located in the electrical room and houses the PLC and associated control components. The control panel and control functionality is further described in Section 20.

19.4 Backup Power

19.4.1 Baker Site Generators

A description of backup power is provided for the treatment plant and product water pump station.

19.4.1.1 Treatment Plant

A 2,000 kW diesel emergency generator will provide 480 Volt, 3 phase, power to the Water Treatment Plant in the event that SCE power is unavailable. Under emergency conditions, the loads selected to run on emergency power will be selected by

PLC programming. The generator is sized to accommodate selected loads of the plant as summarized in Table 19.1.

Table 19.1 Water Treatment Plant Generator Sizing Criteria

Load	kW
Membrane Process	230
Chemical	165
Flash Mix Strainer	6
BWWWT	135
Feedwater Pump Station	1125
Trabuco Canyon Water District Pump	40
Total	**1701**

The emergency generator is equipped with an integral fuel tank sized to operate the generator at full load for 24 hours. The location for the emergency generator is shown on Exhibit 19.8 (Drawing E4).

19.4.1.2 Product Water Pump Station

A 1,100 kW diesel emergency generator will provide 480 Volt, 3 phase, power to the Product Water Pump Station in the event that SCE power is unavailable. The generator is rated to accommodate selected loads at the pump station as indicated in Table 19.2.

Table 19.2 Product Water Pump Station Generator Sizing Criteria

Load	HP/kW	Backup Generation Required
Pump 1	300 HP	Yes
Pump 2	300 HP	Yes
Pump 3	300 HP	Yes
Pump 4	300 HP	Yes
Pump 5 (Standby)	300 HP	No
Air Conditioning	60 kW	Yes
Lighting/Receptacles	10 kW	Yes

The emergency generator is equipped with an integral fuel tank sized to operate the generator at full load for 24 hours. The pump station generator is located as shown on Exhibit 19.10 (Drawing E12).

19.4.1.3 Raw Water Pump Station

An emergency generator or a connection for a portable emergency generator is not required for the Raw Water Pump Station. This decision is based upon the following:

1. The SCE power supply in the area of the pump station is reliable.
2. SCE generally restores power in a short time following an outage.
3. Alternatives exist for Baker WTP operation without the Baker Raw Water Pump Station:
4. Changing back to supply from Santiago Lateral
5. Irvine Lake water supplied by gravity at a reduced capacity
6. The period of usage of Irvine Lake Water is expected to be limited to about six to eight weeks annually. This short period of time minimizes the probability of a power failure during the annual window of operation of the pump station. The ability to deliver water from the lake by gravity, at about fifty percent of maximum, will mitigate the effect of a power loss by allowing the WTP to continue operating, albeit at a production rate less than maximum.

19.5 ELECTRICAL DESIGN CRITERIA

The major electrical equipment will be specified as indicated Table 19.3:

Table 19.3 Electrical Equipment Summary

Equipment	Manufacturer/Model Number	Sole Source (Yes/No)
Motor Control Center	Allen-Bradley, no equal	Yes
Motor Management Relays	Multilin 369, Model HIRMOE, no equal	Yes
Switchboards	GE, Square D, or equal	No
Power Monitor	Multilin PQM-T20-C-A, no equal	Yes
Transformer, Dry Type	Square D electromagnetically shielded type, or equal	No
Automatic Transfer Switch	ASCO 7000 Series, GE Zenith ZTS, no equal.	No
Generator	Onan, Caterpillar	No
Variable Frequency Drive	Allen Bradley Power Flex 18-pulse, no equal	Yes

SECTION 20 INSTRUMENTATION AND CONTROL

20.1 OVERVIEW

This section summarizes the proposed approach for the following components of instrumentation and control system design:

- Equipment/instrument tagging
- Modes of equipment control
- Control system network
- IRWD preferred control system equipment manufacturers
- SCADA and PLC programming

20.2 EQUIPMENT / INSTRUMENT TAGGING

Equipment and instruments will be tagged in accordance with the IRWD Process Equipment & Instrument Tag Guideline, which is included as Appendix M.

20.3 MODES OF EQUIPMENT CONTROL

With the exception of equipment provided as part of the Membrane System, including blowers, compressors, backwash pumps, and pumps related to the membrane cleaning system, there will be two primary modes of control for every piece of equipment in the facility: Local and Remote. In the Local mode, the equipment will be controlled via control devices (pushbuttons and/or selector switches) located in the field either directly adjacent to the equipment or in a field control panel located near the equipment. In the Remote mode, the equipment will be controlled remotely either by a PLC or by control functions invoked through the facility SCADA system.

20.3.1 Local Control – Gates and Valves

Each gate and valve will be equipped with a LOCAL-OFF-REMOTE (LOR) selector switch and OPEN/CLOSE pushbuttons.

- LOCAL position - the OPEN/CLOSE pushbuttons will be enabled, thus allowing the equipment to be controlled locally.
- OFF position - the local OPEN/CLOSE pushbuttons will be disabled and all modes of control will be inhibited. The gate/valve will remain in the position that it was in when the LOR switch was placed in OFF.

- REMOTE position - the local OPEN/CLOSE pushbuttons will be disabled, and the equipment will be controlled remotely.

In addition to the position status of the gate/valve, the position of the LOR switch will be monitored via discrete inputs to the PLC that controls/monitors the equipment, and will be displayed in SCADA.

20.3.2 Local Control – Process Equipment (pumps, fans, etc.)

Each piece of process equipment will be equipped with a HAND-OFF-AUTO (HOA) selector switch.

- HAND position - the equipment will start.
- OFF position - the equipment will stop and all modes of control will be inhibited.
- AUTO position - the equipment will be controlled remotely.

In addition to the status of the equipment (running, failed, etc.), the position of the HOA switch will be monitored via discrete inputs to the PLC that controls/monitors the equipment, and will be displayed in SCADA.

20.3.3 Remote Control – Gates and Valves

Each gate and valve will have a software AUTO/MANUAL (A/M) selector switch in SCADA, which will be enabled when the LOR switch in the field is placed in the REMOTE position. In addition to the A/M switch, each gate and valve will have software OPEN/CLOSE pushbuttons in SCADA.

- MANUAL position - the gate/valve will be controlled with the software OPEN/CLOSE pushbuttons in SCADA.
- AUTO position - the gate/valve will be controlled by the PLC.

In general, the facility will be designed such that gates and valves operate in the AUTO mode of control under normal conditions.

20.3.4 Remote Control - Process Equipment (pumps, fans, etc.)

Each piece of process equipment will have a software AUTO/MANUAL (A/M) selector switch in SCADA, which will be enabled when the HOA switch in the field is placed in the AUTO position. In addition to the A/M

switch, each piece of equipment will have software START/STOP pushbuttons in SCADA.

- MANUAL position - the equipment will be controlled with the software START/STOP pushbuttons in SCADA.
- AUTO position - the equipment will be controlled by the PLC.

In general, the facility will be designed such that process equipment operates in the AUTO mode of control under normal conditions.

20.4 CONTROL SYSTEM NETWORK

A preliminary SCADA Block Diagram showing the major control system network components is provided as Exhibit 20.1 (Drawing I011).

As shown on the SCADA Block Diagram, the facility control system will be comprised of a network of distributed PLC's and a SCADA network. The quantity and location of PLC's will be established primarily by geography where the PLC closest to the unit process will be the point of connection for that unit process to the control system. The following is a summary of the PLC locations and the major unit processes that will be connected to each.

PLC Location	Major Unit Processes
Raw Water Pump Station	Raw Water Pump Station
Forebay	Feed Water Pump Station Raw Water Strainer & Flash Mix Backwash Water Treatment
Treatment Building	Membrane System Ultraviolet Disinfection Membrane Filtration Waste Washwater CT Basin
Chemical Building	All chemical storage and feed systems Flow Control Facility
Product Water Pump Station	Product Water Pump Station

In addition to a PLC, each control panel will include the following major components: fiber patch panel, managed network switch, and an operator interface terminal (HMI) comprised of a PC, keyboard, and a touch screen monitor mounted on the control panel door.

With the exception of the Raw Water Pump Station, the facility control system network will be comprised of a self-healing, fiber ring employing rapid spanning-tree network protocol via connections to the managed network switches installed in the individual control panels. The self-healing, fiber ring will be used to implement PLC-to-PLC, PLC-to-SCADA, and SCADA-to-PLC monitoring and control functions by linking all of the control system components (PLC's, HMI's, Servers, etc.). The Raw Water Pump Station control panel will communicate with the facility control system via wireless radio link.

Operator access to the SCADA system for process control and monitoring will be provided at each process control panel, as well as at workstations located in the Control Room. In addition to the SCADA workstations in the Control Room, the design will also include one computer to be used as a development station. The SCADA Block Diagram shows various other network devices, such as servers and network attached storage devices, however the necessity and selection of these devices will be coordinated and finalized with the District during final design.

To enhance reliability of the control system network, redundant fiber optic cables comprising the fiber ring will be specified. Wherever possible, the redundant fiber optic cables will be installed in separate conduits to decrease the likelihood of a simultaneous failure of both cables. Furthermore, where the fiber optic ring connects to the control room network equipment, the two sides of the fiber optic ring will be installed separate conduits, decreasing the likelihood of isolating the control room network equipment from the unit process control panels. Given the self-healing nature of the network architecture, if one side of the fiber ring is broken, the communication paths will be automatically re-routed thus allowing the control system to remain functional.

20.5 CONTROL SYSTEM EQUIPMENT MANUFACTURERS

In conversations with District Staff, and through the process of reviewing the District's standard specifications, the following preferred control system equipment manufacturers have been identified:

Equipment	District-Preferred Manufacturer
Programmable Logic Controllers	Modicon Quantum with Unit Processors
PLC Programming Software	Modicon Unity
SCADA Software	Wonderware Archestra
HMI Monitors	Allen-Bradley 17" Industrial Touch Screen
SCADA Servers	Dell
Managed Ethernet Switches	Hirschmann
Ethernet Radios	MDS
Uninterruptible Power Supplies (UPS)	Powerware
Control Panel Enclosures	Hoffman

20.6 SCADA AND PLC PROGRAMMING

Services for SCADA and PLC programming will be procured under a stand-alone contract that will be assigned to the General Contractor selected for construction of the Baker WTP. Carollo/RBF will develop the Request for Proposals (RFP) for the SCADA and PLC programming services based on the District's standard programming agreement, and the specific software requirements for the Baker WTP control system design.

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SECTION 21 ARCHITECTURAL

21.1 OVERVIEW

The architectural theme of the District's new Baker Water Treatment Plant (Baker WTP) is critical to the overall success of the project. The 5.25-acre site is located on top of a hill south-east of Wisteria Lane in Lake Forest, CA. The site is surrounded by residential neighborhoods and a future 3-acre public park. This section presents the summary of the effort by the PDR team to develop the appropriate architectural theme.

21.2 ARCHITECTURAL CRITERIA

The initial step in developing the architectural theme was to identify criteria determined to be important to all the stakeholders. Three categories of criteria were considered: neighborhood and developer concerns; District and stakeholders issues; and process criteria. Detailed issues are outlined below.

21.3 NEIGHBORHOOD AND DEVELOPER CONCERNS

- Provide space/landscaping to mitigate view from properties on the west side.
- Minimize structure height so not to obstruct neighbor's view
- Buildings should have a community building appearance, and the site should not resemble an industrial park with outdoor machinery and chemical storage tanks visible from the east side future park, residential development, and surrounding residents
- Mechanical equipment sound level should be attenuated in building

21.4 DISTRICT AND STAKEHOLDER ISSUES

- Buildings and facilities positioned on site "campus style"
- Build-out capacity achieved as part of the project to be 28 mgd
- Facilitate access for chemical delivery trucks
- No administration building
- Small lab or wet room included in the treatment building
- Reserve footprint for potential future GAC contactors and PAC dosing system

21.5 PROCESS DESIGN CRITERIA

- Plant building useful life to be 50 years
- Corrosive chemicals to be stored in chemical building, and to be used in the forebay (chlorine dioxide), treatment building (membrane cleanings), CT basin (disinfection) and backwash treatment facilities (coagulation).

21.6 ARCHITECTURAL THEME

Based on the above criteria listed in paragraph 21.2, the architectural theme was developed around:

- Walls: concrete masonry unit (CMU) blocks
- Roof: steel deck
- Doors (office part of treatment building): aluminum frame
- Doors (other locations): hollow metal framed doors
- Windows: aluminum frame

The following paragraphs illustrate the architectural concept for different buildings and treatment processes to be built at the Baker WTP.

21.7 MEMBRANE FEED WATER PUMP STATION

21.8 TREATMENT BUILDING

21.9 CHEMICAL BUILDING

21.10 CT BASIN

21.11 PRODUCT WATER PUMP STATION

SECTION 22 SITE SECURITY

22.1 OVERVIEW

This section discusses the security measures envisioned at each of the facilities of the Baker Water Treatment Plant Project.

22.2 RAW WATER PUMP STATION

The Raw Water Pump Station will be located at the Peters Canyon site, which already has security measures consisting of an access gate and chainlink fence. Both measures will be maintained at the site. Portions of the chainlink fence will be removed and replaced during construction.

22.3 TREATMENT PLANT

A chainlink fence will be constructed along the access road east of the Baker Pipeline easement for security of the Baker WTP site. The existing access gate from Wisteria Lane will be maintained. A new access gate will be constructed for vehicle access from the low site area. Surveillance cameras will be installed at the treatment plant as part of site security. The number and locations of cameras will be determined during design. The manufacturer and model is shown in Table 22.1.

Table 22.1 Security Camera Manufacturer Data

Manufacturer	Model Number
Industrial Video and Control	PTZ-3330-01

22.4 FLOW CONTROL FACILITY AND TCWD PUMP STATION

The flow control facility and TCWD Pump Station will be constructed within a block wall enclosure with chainlink roof.

22.5 PRODUCT WATER PUMP STATION

A chainlink fence will be constructed around the Product Water Pump Station. The site is already bounded to the south by an existing fence separating the Baker site from Serrano Creek. The new fence will run along each access road, along the top of slope to the north of the pump station and tie into the existing fence.

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SECTION 23 ECONOMIC EVALUATION

23.1 OVERVIEW

The purpose of this section is to discuss capital and O&M cost factors and assumptions used to develop the Baker WTP Project cost estimates. Opinion of costs for both capital and O&M are also included, and were based upon the project components and features general described in Sections 4 to 22 of this report. All costs presented herein are described in February 2010 dollars (ENR index = 8660).

The capital cost estimates herein approximate Class 3 budget estimates as defined by the Association for the Advancement of Cost Engineering (AACE), with associated accuracy of -10 to +30 percent. Class 3 level estimates are intended for budget, authorization of contract purposes. These estimates are based on the Engineer's perception of current conditions in the project area and are subject to change as variances in cost of labor, materials, equipment, services provided by others, or economic conditions occur.

Estimates previously prepared for the project include:

- The Baker Pipeline Regional Treatment Facility Feasibility Study, prepared by Malcolm Pirnie in January 2007, which included an addendum in June 2007 to estimate the cost of treated water from Baker WTP Project for comparison with the projected cost of treated water from Metropolitan Water District.

- The Baker Regional Water Treatment Plant – Design Concept and Cost Update with concept level costs, prepared following the award for design by RBF Consulting and Corollo Engineers in November 2008.

- Updated project cost estimate in June 2009, by RBF / Carollo, to take into consideration (i) preliminary design concepts (including the potential of pumping raw water supplied from the Santiago Lateral through the Baker Pipeline) and (ii) alternative treatment plant capacities.

- Preliminary Design Memorandum No. 14 – Cost Estimate, dated November 2009, issued to the Project Stakeholders including costs under three Project alternatives, and comparison of Baker WTP Project treated water cost with water purchased through Municipal Water District of Orange County.

23.2 OBJECTIVES

The objectives of the economic evaluation of the Baker WTP Project are to:

- Identify the basis of the probable capital costs
- Provide a detailed breakdown of probable construction costs
- Estimate capital costs
- Determine the amortized value over a 30-year period
- Estimate O&M costs
- Escalate O&M costs based on expected rates
- Estimate the cost of water produced by Baker WTP Project and compare it to the projected cost of treated imported water.

23.3 BACKGROUND

Preliminary Design Memorandum No. 14 presented the cost for the BAKER WTP PROJECT under three alternative Project definitions. The three alternatives are summarized in Table 23.1.

Table 23.1 BAKER WTP PROJECT Alternatives Summary

Baker Water Treatment Plant		Alternative 1	Alternative 2	Alternative 3
1	Raw Water Delivered	37 cfs 23.9 MGD	37 cfs 23.9 MGD	43.5 cfs 28.1 MGD
2	Product Water Produced	36.5 cfs 23.6 MGD 23,782 AFY[2]	36.5 cfs 23.6 MGD 23,782 AFY[2]	43.0 cfs 27.8 MGD 28,018 AFY[2]
3	Membrane Filtration Capacity [1]	25.7 MG	35.1 MG	30.2 MG
4	Membrane Rack Configuration	N+1	N+4	N+1
5	Number of Membrane Racks	10	13	12
6	OC-33 Modification	60 cfs	60 cfs	60 cfs
7	Regulating Reservoir	1.0 MG	n/a	n/a
8	Constant Head / Balancing Tank	0.5 MG	0.3 MG	n/a
9	Forebay	n/a	n/a	1.0 MG
10	Raw Water Pump Station (Design Capacity)	47 cfs	47 cfs	53.5 cfs
11	Product Water Pump Station (Design Capacity [3])	29 cfs	29 cfs	33 cfs

[1] MF Capacity is based on flow rates for Raw Water and Membrane Filtration Washwater, and defined as volumetric (MG).
[2] Annual Production in AFY is based on a 90-percent utilization rate.
[3] Product Water Pump Station (Design Capacity) is rounded to the nearest cubic foot per second.

Each alternative was fully analyzed to generate cost values for capital and operation and maintenance, and quantify the overall product water cost. Table 23.2 summarizes the product water cost by alternative as presented in Preliminary Design Memorandum No. 14.

Table 23.2 Cost Summary by Alternative

Alt	Description	Raw Water (cfs)	Product Water (cfs)	Product Water Cost ($/AF)
1	Regulating Reservoir, Constant Head Tank, N+1 Membrane Configuration	37 cfs	36.5 cfs	$765
2	Constant Head Tank, N+4 Membrane Configuration	37 cfs	36.5 cfs	$771
3	Forebay Reservoir and Feedwater Pump Station, N+1 Membrane Configuration	43.5 cfs	43.0 cfs	$766

At the Project Stakeholder meeting held in November 2009, Alternative 3 was selected. The primary factors influencing the decision included:

- Land Acquistion – not required for Alternative 3.
- Schedule Impact – without land acquisition, no impact to schedule.
- Comparable cost – product water cost for each alternative was within $5 per acre-foot (< 1% cost variation between alternatives).

23.4 ECONOMIC EVALUATION

The remainder of this section provides an updated economic evaluation consistent with the current design concept for the Project as described in Sections 4 to 22. While the current definition of the Project stems from the selection of Alternative 3 there have been some modifications to the Project since the issuance of PDM No. 14, including:

- OC-33 Modification = 100 cfs
- Forebay – Capacity = 0.785 MG

- Number of Membrane Racks (dependent on manufacturer) = 14 (max)

Table 23.3 summarizes the Project as currently defined.

Table 23.3 Project Summary

	Baker Water Treatment Plant	Value
1	Raw Water Delivered	43.5 cfs 28.1 MGD
2	Product Water Produced	43.0 cfs 27.8 MGD 28,018 [2] AFY
3	Membrane Filtration Capacity [1]	30.2 MG
4	Membrane Rack Configuration	N+1
5	Number of Membrane Racks (Max.)	14
6	OC-33 Modification	100 cfs
7	Forebay	0.785 MG
8	Raw Water Pump Station (Design Capacity)	53.5 cfs
9	Product Water Pump Station (Design Capacity)	33 cfs

[1] MF Capacity is based on flow rates for Raw Water and Membrane Filtration Washwater, and defined as volumetric (MG).

[2] Annual Production in AFY is based on a 90-percent utilization rate (evaluated at 330 days per year).

23.5 Capital Costs

The estimates of capital costs in this section provide: 1) a more detailed break down of the Baker WTP Project and associated "integration facilities", and 2) refined unit costs for general, sitework, mechanical, and electrical components of the Project. Unit costs were derived from recent RBF/ Carollo projects.

23.5.1 Construction

Construction costs are estimated based on the following:

- Capital cost are Class 3 Estimates as defined by AACEI with a -10% to +30% range of accuracy.
- Mobilization and demobilization, insurance and management are based on 8-percent of total construction costs.
- Pressurized Membrane Filtration (PMF) Equipment costs are based on an average cost developed from the budget estimates provided by Pall and Siemens on October 23, 2009.

- Electrical capital costs are assumed at 12.5-percent of total corresponding facility cost.

The total capital cost estimate is summarized in Table 23.4, and shown in further detail in Table Q1 of the Appendix Q.

23.5.2 Other Capital Costs

Engineering

The cost of engineering (design) of the Baker WTP Project is based on the authorized budget, plus an the cost for the design of the forebay and feedwater pump station.

Environmental

The cost of preparing the environmental documentation for Baker WTP Project is based on the preparation of an Environmental Impact Report (EIR). IRWD has received a fee estimate of $170,000 from their environmental consultant for the preparation of the report.

Construction Management / District Costs

IRWD will perform construction management and inspection activities during the construction of the proposed project. These costs are allocated under “District Costs”. IRWD staff has provided an estimate of District Costs to the Project stakeholders. The estimate covered costs for project management, field support, construction administration services and inspections, and totaled to $2,200,000.

Baker Site Land Use Cost

The Baker Water Treatment Plant Agreement (Agreement) defines cost to the project for the use of land at the Baker Site in Lake Forest, California. A cost of $110,000 / acre was defined in the Agreement based on an appraisal of land value. The high site of the Baker Site is the reserved area for construction of Baker WTP Project. The high site has an approximate area of 4.0 acre. Thus, land use cost is shown as a one-time cost of $440,000.

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Table 23.4 - Baker WTP Project - Summary of Estimated Capital Costs [1]

Baker Water Treatment Plant	Cost
Equipment and Buildings	
WTP Equipment, Sitework and Buildings	$31,869,000
Mobilization / Insurance / Management [2]	$2,550,000
Subtotal (Equipment and Buildings)	***$34,419,000***
Integration Facilities	
OC-33 Expansion	$240,000
Raw Water Pump Station	$2,908,000
Flow Control Facility, Forebay Reservoir, TCWD PS and Feedwater PS	$4,300,000
Product Water Pump Station	$3,504,000
Backup Power	$1,250,000
Mobilization / Insurance / Management [2]	$976,000
Subtotal (Integration Facilities)	***$13,178,000***
SUBTOTAL (Equip. and Bldgs + Int. Facs.)	***$47,597,000***
District Costs [3]	**$2,200,000**
Baker Site Land Use Cost [4]	**$440,000**
Environmental [5], Engineering[6]	**$4,607,000**
Contingency / Legal [7]	**$6,611,000**
TOTAL ESTIMATED CAPITAL COST	**$61,455,000**

[1] Capital cost are Class 3 Estimates as defined by AACEI with estimated -10% to +30% range of accuracy

[2] Mobilization / Insurance / Management Cost calculated at 8-percent of capital cost

[3] Cost provided by IRWD - includes project management, field support, construction administrative services, inspection and GandA.

[4] Cost for land use at Baker Site per Baker WTP Agreement Section 3.1. Area = 4 acres. Unit Cost = $110,000 /acre

[5] Environmental Documentation cost is based on EIR preparation cost provided to IRWD.

[6] Based on approved design fee for Baker WTP plus authorized flow test budget, and design fee for forebay and feed water pump station.

[7] Contingency / Legal is based on 15-percent of Subtotal (Equipment and Buildings + Integration Facilities excluding cost for Moblization, Insurance and Management).

23.6 Operation and Maintenance Costs

O&M costs have been developed based on previous projects and engineering calculations. A summary of total O&M costs is provided in Table 23.5. All costs are discussed below and further information is provided in Appendix Q.

23.6.1 Energy Costs

Energy costs are estimated based on a unit cost of $0.13 per kilowatt-hour (KWh). Tables Q2 through Q8 in Appendix Q estimate the annual energy costs, in February 2010 dollars. An escalation rate of 5-percent was used to estimate future energy costs.

23.6.2 Chemical and Replacement Costs

A breakdown of the chemical costs for the treatment facility is provided in Tables Q9 and Q10 in Appendix Q. Membrane replacement costs are summarized in Table Q11 in Appendix Q. An escalation rate of 5-percent is used to estimate future chemical and replacement costs.

Table 23.5 Estimated Annual O&M Cost Summary

Baker Water Treatment Plant [1]		Value
1	Chemical Mixing	$3,800
2	MF System	$716,300
3	UV System	$21,200
4	Process Chemicals	$1,212,100
5	Energy Costs from Pumping	$1,516,300
6	Washwater Pumping	$15,900
7	Labor [2]	$379,600
8	Other System O&M Costs [3]	$75,000
Cost per Year ($) [4]		**$3,940,000**

[1] Energy, Chemical, and Consumables (Replacement) costs are esclated at a annual rate of 5-percent.

[2] Labor costs are esclated at a annual rate of 3-percent.

[3] Other O&M costs are esclated at a annual rate of 3-percent.

[4] Based on 90% treatment plant utilization (evaluated at 330 days per year). Rounded to nearest $1,000.

23.6.3 Labor Costs

The labor costs are estimated for the Project in Table Q12 in Appendix Q. The labor cost includes time for two full time operators at the treatment plant. This value may change depending on the final classification of Baker WTP Project by the California Department of Public Health. An escalation rate of 3-percent is used to estimate future labor costs.

23.6.4 Other O&M Costs

This evaluation takes into consideration additional O&M costs associated with the overall Project system, including the integration facilities. This cost is assumed at 2-percent of the amortized cost annual capital costs, and are escalated at an annual rate of 3-percent to estimate future costs.

23.7 Baker WTP Water Cost

Based upon the capital and O&M costs developed herein, an economic evaluation was performed for the Project calculating the cost of water available via the Baker WTP Project project, and comparing this cost with projected MWDOC treated water costs. Cost of Baker WTP Project water is estimated in Table 23.6based on the following estimates and assumptions:

- Costs defined in February 2010 Dollars for direct comparison with prior analysis (ENR index = 8660).
- A capital cost amortized over 30 years at 4.5-percent interest (per Feasibility Study).
- Energy, chemicals, and replacement costs assumed to escalate at a rate of 5-percent annually.
- Labor costs assumed to escalate at a rate of 3-percent annually.
- Other O&M costs assumed to escalate at a rate of 3-percent annually.
- Untreated Tier 1 and Tier 2 water costs from MWDOC assumed to escalate at a rate of 21.5-percent and 14.3-percent, respectively, in year 2011, and a rate of 5-percent thereafter .

23.8 Water Cost Comparison

When comparing the cost of water for Baker WTP Project with cost of treated water imported by MWDOC, it is anticipated that treated water from the Baker WTP Project will cost the same as imported water by the year 2017,

Table 23.6 - Summary of Annual Treated Water Cost (2010 Dollars)

Baker Water Treatment Plant	COST
Total Capital Cost	$61,455,000
Capital Cost	**$61,455,000**
1. Annual Capital Cost [2]	$3,749,000
2. Annual Project O & M Costs [3]	
2.1 Energy, Chemicals, and Consumables	$3,485,600
2.2 Labor	$379,600
2.3 Other O & M Costs [4]	$75,000
Subtotal Annual Capital/O&M Cost	**$7,689,200**
($/AF)	**$274**
3. Cost of Untreated Water from MWDOC [5] ($/AF)	**$492**
Water Production[6] = 28,018 AFY	
Baker WTP Treated Water Unit Cost ($/AF)	**$766**

Abbreviations: AFY = Acre-Feet per Year, FWPS = Feedwater Pump Station, PW = Product Water, Reg = Regulating, Res = Reservoir RW = Raw Water

[1] Unit Cost of Water is for 2009 cost assumptions

[2] Based on 30 year period at 4.5%

[3] See Table 14.3 for Estimated Annual O&M Cost by alternative.

[4] Based on 2% of annual capital cost

[5] Based on estimates shown in Table Q14 of Appendix Q (per 9/1/2009 MWD rate change). This cost represents an increase of $68 / AF to Tier 1 and 2 melded untreated water rate since last estimate prepared June 2009.

[6] Based on 90% treatment plant utilization (evaluated at 330 days per year).

Annual Payment Calculation

Annual Capital Costs	
Interest (Annual) =	4.5%
Rate (Monthy) =	0.00375
Years =	30
Months =	360
Loan Amount =	$61,455,000
Monthly Payment =	$312,417
Annual Payment [7] =	**$3,749,000**

[7] Based on CRF value of 0.061

approximately 5 years after project startup. Thereafter, the Baker WTP Project is anticipated to produce water at lower cost than as purchased through MWDOC. This is based on the following methodology:

- A meld of Tier 1 and Tier 2 rates has been developed for this evaluation (90% of Tier 1 rate, and 10% of Tier 2 rate). The cost of the Tier 1 and 2 melded rate per the water rates 'Effective 1/1/2009' was $424 per acre-ft.

- On September 1, 2009 the Metropolitan Water District of Southern California adjusted the cost of treated and untreated water. The cost of the untreated water melded water rates 'Effective 9/1/2009' was recalculated to be $492 / AF.

- The melded cost for treated and untreated water, based on water rate projections provided by Municipal Water District of Orange County and Irvine Ranch Water District, are provided in Table Q13 in Appendix Q.

- Annual capital recovery and O&M costs were converted to $/acre-foot ($/AF/yr) values using the anticipated production volume of 28,018 AFY. As indicated in the cost summary tables shown above, projected costs are determined based on a plant utilization rate of 90-percent.

- A detailed breakdown of estimated future water costs is provided in Table Q14 in Appendix Q. Table Q15 in Appendix Q provides a summary of the estimated water costs over the next 20 years based upon projections of untreated water costs from MWDOC and water treatment costs for Baker WTP Project.

- Exhibit 23.1 presents a graphical representation of the escalated costs for Baker WTP Project and MWD treated water over the next 20 years. Table Q16 in Appendix Q summarizes the cost difference by year for treated water from Baker WTP Project and MWD.

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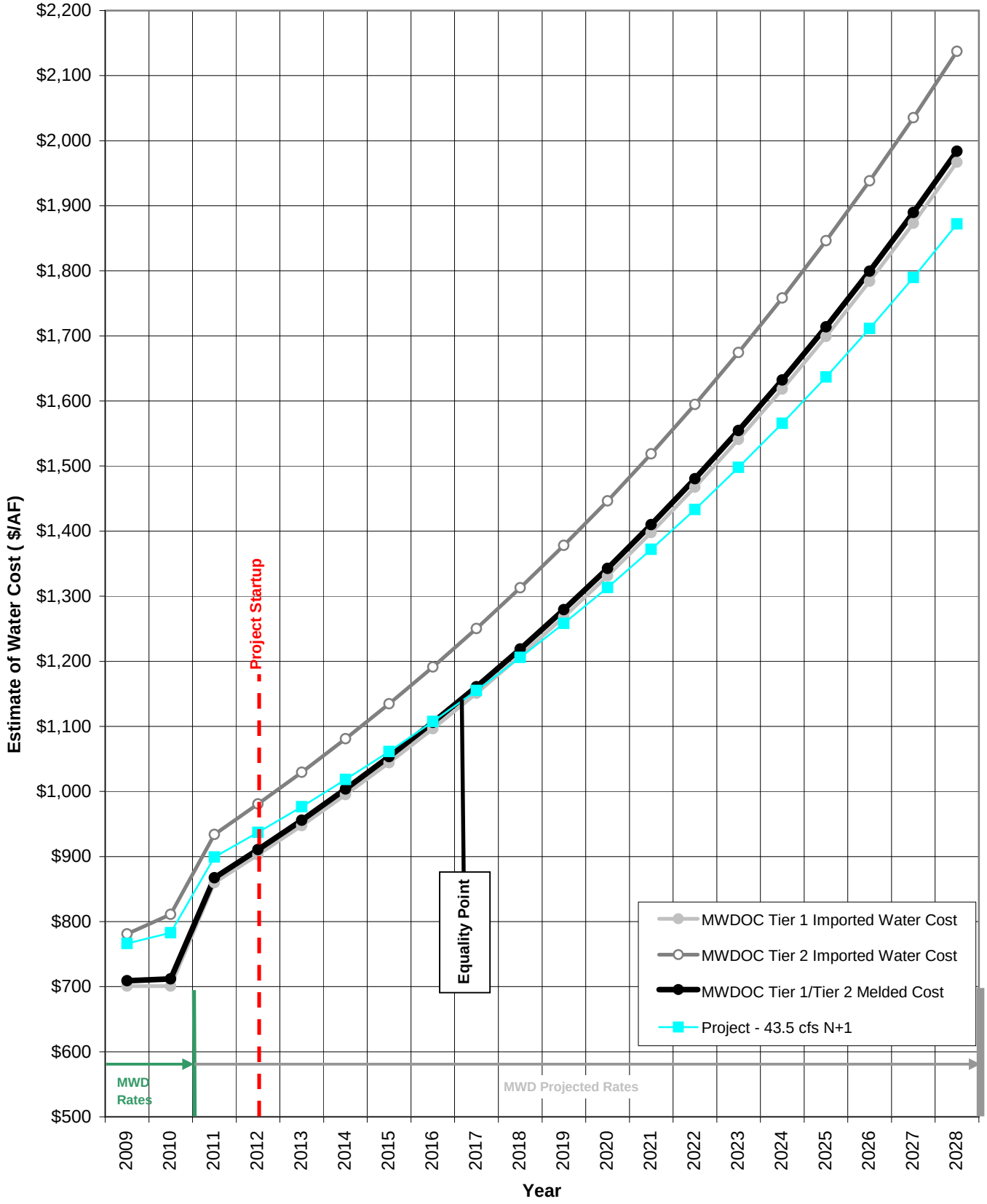
Exhibit 23.1 - Cost of Water Comparison
Imported Water (MWDOC)
vs.
Baker WTP



SECTION 24 INSTITUTIONAL FACTORS

24.1 BACKGROUND

Institutional factors that must be considered in the design, and prior to construction of the Baker WTP, include:

- MWD Coordination.
- Regional Water Quality Control Board Coordination.
- Other Permitting and Coordination.

24.2 MWD COORDINATION

Several issues remain to be resolved with MWD prior to the final design of the Baker Water Treatment Plant project. These include:

- Capacity of OC-33
- Flow through OC-33
- MWD acceptance of Baker surge analysis recommendations
- Product Water Pump Station discharge location and connection design
- MWD acceptance of AMP surge analysis recommendations
- Raw water delivery protocol
- Encroachment permits into AMP pipeline easement

24.2.1 Capacity of OC-33

Since the original construction of the Baker Pipeline, the capacity of OC-33 has been changed on at least two occasions: from an initial capacity of 40 cfs, up to 100 cfs, and then back to its current capacity of 40 cfs. With the construction of the Baker WTP Project, a turnout metering capacity of 100 cfs is recommended (see Section 4). As a result, the existing meter may have to be replaced or the nameplate capacity revised.

24.2.2 Flow through OC-33

When raw water is being directly supplied to Baker WTP through the Santiago Lateral, occasional discharges past OC-33 will occur when there is a temporary rejection of the Baker Pipeline flow by the flow control facility at Baker WTP. Generally, these flows can be expected to be

lower than 10 cfs, which is less than ten percent of the proposed meter capacity of 100 cfs. (The MWD Administrative Code provides that flows through a turnout that are less than ten percent of the rated meter capacity will be billed at the full 10 percent of the meter's capacity.) Unless some arrangement or variance is worked out with MWD, the project could be paying for more water than it receives.

Additionally, when water is supplied from Irvine Lake to the Raw Water Pump Station, there may be occasions when a reverse flow occurs through OC-33, which would be picked up by OC-13.

24.2.3 Baker Surge Analysis

The Baker Pipeline surge analysis completed for this project, predicts slight transient increases in the operating HGL of the Santiago Lateral, following a power failure at the Baker Raw Water Pump Station. These increases are minor (5 feet max) but are in excess of the design HGL for the Santiago Lateral. Coordination with MWD has been initiated and will continue through final design.

24.2.4 Product Water Pump Station Discharge to AMP

The connection point of the Product Water Pump Station discharge line to the AMP, has been tentatively placed at a location just downstream of the existing Baker/AMP emergency connection. Neither the location of the connection point nor the design details of the connection have been reviewed with MWD. MWD's Administrative Code (paragraphs 4700 and 4800) covers the design elements required for a connection that receives water from its system, but not that introduces water into its system. Coordination with MWD has been initiated and will continue through final design.

24.2.5 AMP Surge Analysis

A surge analysis of the AMP will be required to analyze the impacts of the Baker WTP. When complete, the recommendations of the AMP study will be reviewed and accepted by MWD.

24.2.6 Raw Water Delivery Protocol

Raw water deliveries through the MWD system are critical to the operation of the Baker WTP. The MWD Administrative Code defines and limits the advance notice requirements for variations in the deliveries through its service connections.

The MWD Administrative Code requires that the receiving agency stipulate a continuous demand rate. The Baker WTP system will be unable to comply this with this requirement under certain conditions. These conditions will be mitigated, to some extent, by allowing discharges to Irvine Lake and by absorbing small flow variations in the plant's forebay.

This matter must be coordinated with MWD to ensure a mutual understanding of the technical capabilities, as well as the institutional constraints, of the Baker WTP are fully understood.

24.3 REGIONAL WATER QUALITY CONTROL BOARD

The membrane filtration system will be operated to isolate any racks requiring maintenance, allowing water produced during maintenance / testing to be re-circulated to the forebay for treatment.

However, as discussed in Section 17, Baker WTP will be constructed to discharge water to Serrano Creek in the event of the following failed operation / emergency conditions of:

- Overflow of the forebay (which is only possible if the flow control valve fails open) - Water discharged from the forebay would be a combination of raw water and recirculated treated backwash water.
- Product Water to Waste (if off-specification water from the contact basin could not be returned to the forebay) - Water discharge from the contact basin would be water treated through the membrane filtration that cannot be brought to specification due to a failure of the finished water chemical system. Such water would require dechlorination if discharged to Serrano Creek.

Coordination with the Santa Ana Regional Water Quality Control Board will be necessary to gain approval for discharges to Serrano Creek. Coordination may lead to the requirement of the filing of a *Limited Threat Discharge to Surface Water – Notice of Intent* to be processed with the Santa Ana RWQCB.

24.4 SANTIAGO AQUEDUCT COMMISSION COORDINATION

The Santiago Aqueduct Commission has the governing authority over the Baker Pipeline and owns the property where the Raw Water Pump Station is planned for construction. With the Baker WTP Project each Stakeholder will hold capacity rights in the Baker Pipeline equivalent to their water rights in the Baker WTP.

The only agencies holding capacity rights in the Baker Pipeline initially were Santa Margarita Water District, Trabuco Canyon Water District and Irvine Ranch Water District. As a result, IRWD and RBF Consulting evaluated the total capacity rights in the Baker Pipeline, and developed an approach to reallocating the water rights per the Baker Pipeline Agreement, allowing for each agency to retain or obtain rights equivalent to capacity in the WTP. The reallocation accounted for present worth and maintained overall total value by modifying the capacity to all entities owning capacity rights in the pipeline.

All five (5) reaches of the Baker Pipeline were modified. The revised capacity per reach is:

- Reach 1 = 99.00 cfs
- Reach 2 = 54.78 cfs
- Reach 3 = 50.68 cfs
- Reach 4 = 50.68 cfs
- Reach 5 = 49.50 cfs

IRWD presented the revision to water rights to the Santiago Aqueduct Commission. The Baker Pipeline Agreement is being modified accordingly, including the compensation (for buying or selling capacity) between each of the agencies.

24.5 PERMITTING AND COORDINATION

Table 24.1 provides a summary of permitting and coordination anticipated for the Baker WTP.

Baker WTP
Permit Compliance Plan

Table 24.1

Agency	Permit / Submittal / Request	Processing Time	Prerequisite Data	Items to be Sent	Responsible Party	Critical Project Component
California State Water Resources Control Board (SWRCB)	• Notice of Intent (NOI) - NPDES General Permit for Construction Activity • Spill Prevention Control and Countermeasure (SPCC)	Submit 30 days prior to start of construction	Site Specific Storm Water Pollution Prevention Plan (SWPPP)	• Notice of Intent • Site Map	RBF / Carollo	Site Construction Chemical Storage
California Dept. of Industrial Relations Division of Occupational Health and Safety (CAL-OSHA)	• Excavation Permit • Pressure Vessel Permit	Over the counter.	Contractor ready to begin work.	• Permit Application Form • Copy of updated safety program • Application Fee • Competent Person Letter	Contractor	Construction Safety: Pipeline Trench Confined Space(s)
City of Lake Forest	• Plan Submittal for City review (building permit no required) and transfer to OCFA	2 to 4 weeks	90% Design Plans + Chemical Data	• Required drawings and information for OCFA	RBF / Carollo	OCFA Requirements
East Orange County Water District (EOCWD)	• Encroachment Permit for Raw Water Pump Station	2 to 4 weeks	90% Raw Water Pump Station Design Plans	• Required drawings	RBF / Carollo	Raw Water Pump Station Construction
Irvine Ranch Water District (IRWD)	• Connection Permit	1 month	Location of connection to Serrano Creek sewer pipeline.	• Location of pipeline connection	RBF / Carollo	Backwash waste water system design.
	• Discharge Permit	6 months	Flow rate and water quality data for non-reclaimable waste water.	• Annual flow, BOD, and suspended solids	RBF / Carollo	Non-reclaimable waste water disposal.
Metropolitan Water District (MWD)	• Approval of plans for connection to AMP and Product Water PS surge design. • Encroachment Permit for Raw Water Pump Station	3 months	60% Design Plans for Raw Water and Product Water Pump Station	• Required drawings	Agency	Raw and Product Water Pump Station Construction
Orange County Fire Authority (OCFA)	• Approval of plans by OCFA regarding fire safety provisions	1 month	60% Design Plans + Chemical Data	• Plans must identify fire sprinkler information • Fire Master Plan • Chemical Classifications • Hazardous Materials Plan	RBF / Carollo	Fire Protection Systems: Fire Sprinkler Systems Fire Hydrant Chemical Storage
South Coast Air Quality Management District (SCAQMD)	• Permit to Construct / Operate Form 400-A • Form 400-CEQA • Other Forms (as needed)	3 months	60% +/- Design Plans	• Application • Design Drawings • Emission Control Equipment List • Drawings / Schematics of Equipment • Process Description with rate, emission sources, manuf data, VOCs, equipment location	RBF / Carollo	Grading
State of California Department of Public Health (CDPH)	• Amended Waterworks Permit	6 months	60% +/- Design Plans	• Treated water quality • Treatment Plant operation description • Other information as requested	Agency	WTP Process and Water Quality
Utility Coordination	• Contact for utility information to avoid conflicts.	60 to 90 days	60% +/- Design Plans	• Required drawings showing utilities (horizontal and vertical).	RBF / Carollo	Underground Construction
Utility Owners (Others)	• Encroachment Permits (as applicable).	1 to 2 months	60% +/- Design Plans	• Required drawings showing utilities (horizontal and vertical).	RBF / Carollo	Underground Construction

SECTION 25 SCHEDULE

25.1 OVERVIEW

Construction of the Baker Water Treatment project will be divided into two construction contracts, with a bid package for each.

- Construction Bid Package No. 1 – Raw Water Pump Station and OC-33 Modification
- Construction Bid Package No. 2 – Baker Water Treatment Plant covering all facilities at the Baker site:
    - Flow Control Facility
    - TCWD Pump Station
    - Forebay and Feedwater Pump Station
    - Treatment Building, UV and CT Basin
    - Backwash Wastewater Treatment
    - Yard Piping (w/ connections to Baker Pipeline, 16 MG Res. and AMP)
    - Product Water Pump Station

Table 25.1 provides a summary of the anticipated start and completion dates for the design, bidding, and construction milestones to both construction contracts.

Table 25.1 Baker WTP Project Schedule Summary

Construction Contract/ Milestone	Start Date	Finish Date
Raw Water Pump Station / OC-33 Modf.		
Design	April 2010	March 2011
Bidding & Award	March 2011	May 2011
Construction	June 2011	June 2012
Baker Water Treatment Plant		
Design	April 2010	March 2011
Bidding & Award	March 2011	May 2011
Construction	June 2011	November 2012

25.2 SCHEDULE

The detailed design and construction schedule for Baker WTP is provided as Exhibit 25.1, and construction schedule for the Raw Water Pump Station as Exhibit 25.2.

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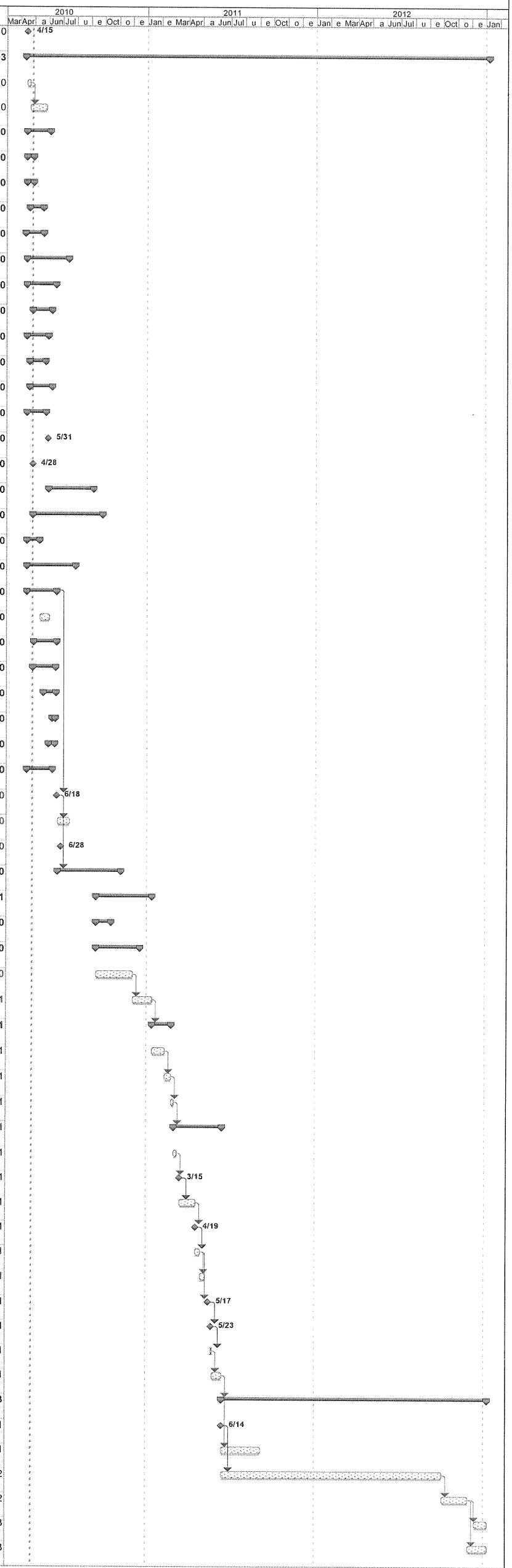
BAKER WATER TREATMENT PLANT PROJECT
FINAL DESIGN, BIDDING, AND CONSTRUCTION SCHEDULE
ONSITE BAKER WATER TREATMENT PLANT FACILITIES

Updated April 14, 2010

ID	Task Name	Duration	Start	Finish
1	BAKER FINAL DESIGN KICKOFF	0 days	Thu 4/15/10	Thu 4/15/10
2	Onsite Facilities (Baker WTP and Product Water PS)	717 days	Mon 4/12/10	Tue 1/8/13
3	Prepare Draft Detailed Equipment Lists	5 days	Thu 4/15/10	Wed 4/21/10
4	Review / Finalize Lists with IRWD (Anticipated 3 - 4 Coordination Mtgs)	5 wks	Thu 4/22/10	Wed 5/26/10
5	Geotechnical Investigation	37 days	Thu 4/15/10	Fri 6/4/10
10	Determine NRW Point of Discharge	11 days	Thu 4/15/10	Fri 4/30/10
18	Determine Method for Surface Discharge Disposal	11 days	Thu 4/15/10	Fri 4/30/10
23	Determine Use of Existing Admin Building	22 days	Wed 4/21/10	Thu 5/20/10
30	Site Access	30 days	Mon 4/12/10	Fri 5/21/10
36	Building Architecture	65 days	Thu 4/15/10	Wed 7/14/10
44	Membrane Building Layout (i.e. Space Planning)	46 days	Thu 4/15/10	Thu 6/17/10
51	Chemical Building Layout	30 days	Wed 4/28/10	Tue 6/8/10
57	Flow Control Valve(s) / TCWD Pump Station / Upstream Strainers Design	33 days	Thu 4/15/10	Mon 5/31/10
63	Forebay / ClO2 Contact Basin	25 days	Wed 4/21/10	Tue 5/25/10
69	16 MG Clearwell Modifications	35 days	Wed 4/21/10	Tue 6/8/10
75	Product Water Pump Station	30 days	Thu 4/15/10	Wed 5/26/10
81	MWD Milestones that Impact Onsite Facilities	0 days	Mon 5/31/10	Mon 5/31/10
84	Site Development	0 days	Wed 4/28/10	Wed 4/28/10
87	MF System Design	70 days	Tue 6/1/10	Tue 9/7/10
92	System Integrator Selection	108 days	Wed 4/28/10	Mon 9/27/10
106	Demolition	20 days	Thu 4/15/10	Wed 5/12/10
108	SCE Coordination	76 days	Thu 4/15/10	Fri 7/30/10
111	Interim Drawing Submittal Preparation	47 days	Thu 4/15/10	Fri 6/18/10
112	Demolition Plan	3 wks	Thu 5/13/10	Wed 6/2/10
113	Site Civil	36 days	Fri 4/30/10	Fri 6/18/10
120	Mechanical Plans and Sections	36 days	Wed 4/28/10	Wed 6/16/10
129	Architectural Plans	20 days	Fri 5/21/10	Thu 6/17/10
135	Structural Plans	5 days	Wed 6/9/10	Tue 6/15/10
137	Electrical	10 days	Tue 6/1/10	Mon 6/14/10
140	Instrumentation	40 days	Thu 4/15/10	Wed 6/9/10
142	Interim Drawings Submittal	0 days	Fri 6/18/10	Fri 6/18/10
143	IRWD Review	20 days	Mon 6/21/10	Fri 7/16/10
144	Workshop for RBF/Carollo to Present Design to IRWD and Stakeholders	0 days	Mon 6/28/10	Mon 6/28/10
145	60% Design	100 days	Mon 6/21/10	Fri 11/5/10
229	90% Design	88 days	Mon 9/13/10	Wed 1/12/11
230	Landscape Design	25 days	Mon 9/13/10	Fri 10/15/10
233	Permit Packages Preparation / Assistance	70 days	Mon 9/13/10	Fri 12/17/10
240	90% PS&E Preparation	11.6 wks	Mon 9/13/10	Wed 12/1/10
241	IRWD Review	30 days	Thu 12/2/10	Wed 1/12/11
242	100% Design (Incorporate IRWD Comments)	30 days	Thu 1/13/11	Wed 2/23/11
243	100% PS&E Preparation	20 days	Thu 1/13/11	Wed 2/9/11
244	Final Review (Back-Check) by IRWD	10 days	Thu 2/10/11	Wed 2/23/11
245	Final Design Submittal	4 days	Thu 2/24/11	Tue 3/1/11
246	Bid Phase	75 days	Wed 3/2/11	Tue 6/14/11
247	Bid Packages Assembled and Distribution to Bidders	1 wk	Wed 3/2/11	Tue 3/8/11
248	Pre-Bid Meeting	0 days	Tue 3/15/11	Tue 3/15/11
249	Bid Preparation	5 wks	Tue 3/15/11	Mon 4/18/11
250	Bid Opening	0 days	Tue 4/19/11	Tue 4/19/11
251	Bid Evaluation / Recommendation for Award	8 days	Tue 4/19/11	Thu 4/28/11
252	Stakeholders' GO / NO GO DECISION	7 days	Fri 4/29/11	Mon 5/9/11
253	E&O Committee Meeting	0 days	Tue 5/17/11	Tue 5/17/11
254	Board Meeting	0 days	Mon 5/23/11	Mon 5/23/11
255	IRWD Issues Notice of Award	2 days	Mon 5/23/11	Tue 5/24/11
256	IRWD Issues Notice to Proceed	3 wks	Wed 5/25/11	Tue 6/14/11
257	Construction Phase	410 days	Tue 6/14/11	Tue 1/8/13
258	Pre-Construction Meeting	0 days	Tue 6/14/11	Tue 6/14/11
259	Submittals	60 days	Wed 6/15/11	Tue 9/6/11
260	Construction	17 mons	Wed 6/15/11	Tue 10/2/12
261	Start-up and Testing	2 mons	Wed 10/3/12	Tue 11/27/12
262	Record Drawings	1 mon	Wed 12/12/12	Tue 1/8/13
263	Project Closeout	6 wks	Wed 11/28/12	Tue 1/8/13



Project: Baker Final Design Schedule_
Date: Mon 4/26/10

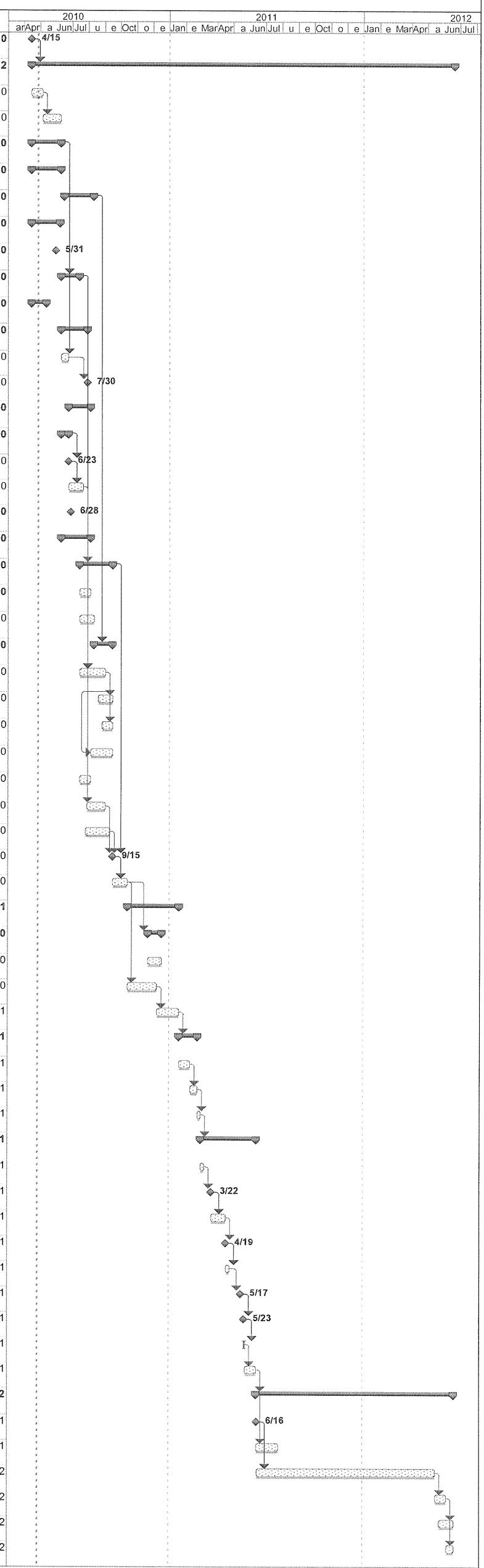
Task | Split | Progress | Milestone | Summary | Project Summary | External Tasks | External MileTask | Split

EXHIBIT 25.1

BAKER WATER TREATMENT PLANT PROJECT
FINAL DESIGN, BIDDING, AND CONSTRUCTION SCHEDULE
RAW WATER DELIVERY SYSTEM (OC-33 AND RAW WATER PUMP STATION)

Updated April 14, 2010

ID	Task Name	Duration	Start	Finish
1	**BAKER FINAL DESIGN KICKOFF**	**0 days**	**Thu 4/15/10**	**Thu 4/15/10**
2	**Raw Water Delivery System (OC-33, Raw Water Pump Station)**	**570 days**	**Thu 4/15/10**	**Wed 6/20/12**
3	Prepare Draft Detailed Equipment Lists	15 days	Thu 4/15/10	Wed 5/5/10
4	Review / Finalize Lists with IRWD (Anticipated 2 Coordination Mtgs)	5 wks	Thu 5/6/10	Wed 6/9/10
5	**Verify Raw Water Pump Station Capacity at 53.5 cfs**	**40 days**	**Thu 4/15/10**	**Wed 6/9/10**
6	**Determine Available Capacity in Irvine Lake Pipeline (ILP)**	**40 days**	**Thu 4/15/10**	**Wed 6/9/10**
17	**Coordinate with County of Orange and MWD for Easement Requirements**	**40 days**	**Wed 6/16/10**	**Tue 8/10/10**
21	**Geotechnical Investigation**	**38 days**	**Thu 4/15/10**	**Mon 6/7/10**
26	**MWD Coordination**	**0 days**	**Mon 5/31/10**	**Mon 5/31/10**
28	**Surge Analysis**	**25 days**	**Thu 6/10/10**	**Wed 7/14/10**
30	**Demolition**	**20 days**	**Thu 4/15/10**	**Wed 5/12/10**
32	**SCE Coordination**	**36 days**	**Thu 6/10/10**	**Fri 7/30/10**
33	Finalize Electrical Loads / Provide to SCE	2 wks	Thu 6/10/10	Wed 6/23/10
34	SCE Provides Design Criteria	0 days	Fri 7/30/10	Fri 7/30/10
35	**Pump Station Building Architecture**	**30 days**	**Thu 6/24/10**	**Wed 8/4/10**
41	**Interim Drawing Submittal Preparation**	**10 days**	**Thu 6/10/10**	**Wed 6/23/10**
52	Interim Drawings Submittal	0 days	Wed 6/23/10	Wed 6/23/10
53	IRWD Review	20 days	Thu 6/24/10	Wed 7/21/10
54	**Workshop for RBF/Carollo to Present Design to IRWD and Stakeholders**	**0 days**	**Mon 6/28/10**	**Mon 6/28/10**
55	**Develop Technical Specification Sections and Project Manual**	**40 days**	**Thu 6/10/10**	**Wed 8/4/10**
61	**Plans Preparation - 60% Submittal**	**45 days**	**Thu 7/15/10**	**Wed 9/15/10**
62	**General Sheets**	**3 wks**	**Thu 7/15/10**	**Wed 8/4/10**
63	**Typical Details**	4 wks	Thu 7/15/10	Wed 8/11/10
64	**Civil**	**25 days**	**Wed 8/11/10**	**Tue 9/14/10**
71	**Mechanical Plans, Sections, and Details**	7 wks	Thu 7/15/10	Wed 9/1/10
72	**Architectural Floor Plan, Elevations, Roof Plan, Details and Schedules**	4 wks	Thu 8/19/10	Wed 9/15/10
73	**Structural Details**	3 wks	Thu 8/26/10	Wed 9/15/10
74	**Electrical**	6 wks	Thu 8/5/10	Wed 9/15/10
75	**Instrumentation**	3 wks	Thu 7/15/10	Wed 8/4/10
76	IRWD Project Manual Preparation	5 wks	Thu 7/29/10	Wed 9/1/10
77	Construction Cost Estimate Update	7 wks	Mon 7/26/10	Fri 9/10/10
78	60% Submittal	0 days	Wed 9/15/10	Wed 9/15/10
79	IRWD Review	20 days	Thu 9/16/10	Wed 10/13/10
80	**90% Design**	**70 days**	**Thu 10/14/10**	**Wed 1/19/11**
81	**Permit Packages Preparation / Assistance**	**20 days**	**Mon 11/22/10**	**Fri 12/17/10**
82	OCFA	1 mon	Mon 11/22/10	Fri 12/17/10
83	90% PS&E Preparation	8 wks	Thu 10/14/10	Wed 12/8/10
84	IRWD Review	30 days	Thu 12/9/10	Wed 1/19/11
85	**100% Design (Incorporate IRWD Comments)**	**25 days**	**Thu 1/20/11**	**Wed 2/23/11**
86	100% PS&E Preparation	15 days	Thu 1/20/11	Wed 2/9/11
87	Final Review (Back-Check) by IRWD	10 days	Thu 2/10/11	Wed 2/23/11
88	Final Design Submittal	4 days	Thu 2/24/11	Tue 3/1/11
89	**Bid Phase**	**75 days**	**Wed 3/2/11**	**Tue 6/14/11**
90	Bid Packages Assembled and Distribution to Bidders	1 wk	Wed 3/2/11	Tue 3/8/11
91	Pre-Bid Meeting	0 days	Tue 3/22/11	Tue 3/22/11
92	Bid Preparation	4 wks	Tue 3/22/11	Mon 4/18/11
93	Bid Opening	0 days	Tue 4/19/11	Tue 4/19/11
94	Bid Evaluation / Recommendation for Award	5 days	Tue 4/19/11	Mon 4/25/11
95	E&O Committee Meeting	0 days	Tue 5/17/11	Tue 5/17/11
96	Board Meeting	0 days	Mon 5/23/11	Mon 5/23/11
97	IRWD Issues Notice of Award	2 days	Mon 5/23/11	Tue 5/24/11
98	IRWD Issues Notice to Proceed	3 wks	Wed 5/25/11	Tue 6/14/11
99	**Construction Phase**	**266 days**	**Wed 6/15/11**	**Wed 6/20/12**
100	Pre-Construction Meeting	0 days	Thu 6/16/11	Thu 6/16/11
101	Submittals	6 wks	Wed 6/15/11	Tue 7/26/11
102	Construction	12 mons	Thu 6/16/11	Wed 5/16/12
103	Start-up and Testing	3 wks	Thu 5/17/12	Wed 6/6/12
104	Record Drawings	1 mon	Thu 5/24/12	Wed 6/20/12
105	Project Closeout	2 wks	Thu 6/7/12	Wed 6/20/12



Project: Exhibit 25.2.mpp
Date: Mon 4/26/10

Task | Split | Progress | Milestone | Summary | Project Summary | External Tasks | External MileTask | Split

EXHIBIT 25.2

APPENDIX A

Well No. 1 Memorandum

Project Coordination

To: Irvine Ranch Water District - Engineering **JN:** 10-106232

From: Cindy Miller - RBF; Jim Meyerhofer, Vincent Roquebert, Dan Hugaboom - Carollo

Date: September 3, 2009

Re: Baker Water Treatment Plant – Well No. 1

PURPOSE

The purpose of this memorandum is to provide the IRWD alternatives and a recommendation for utilizing water produced from Well No. 1 in the proposed water process for the Baker WTP. Well No. 1 is located adjacent to the Baker WTP and is currently piped to discharge into a well tank located on the Baker WTP site.

REFERENCES

Information for this memorandum was obtained from the following sources:

- Groundwater Supply Evaluation for the Los Alisos System (Boyle Engineering Corporation, December 2002)
- Baker WTP Preliminary Design Memorandums (RBF/Carollo, 2009)

BACKGROUND

IRWD owns a well adjacent to the Baker WTP site. Based on the available information this well is operated at approximately 200 gallons per minute (gpm) or 322 acre.ft/year. If included in the treatment process this well would increase plant output by 1.1%.

The Boyle report indicates that a pump pedestal and waste line need to be added to Well No. 1 in order to comply with criteria for a potable water well. Assuming the appropriate upgrades are made to make the well suitable for potable water use, the primary issue with its use at the Baker WTP is water quality. Well water quality most relevant to the purpose of this memorandum is summarized in Table 1 below.

Well No.1 exceeds potable water standards (at times) for iron, manganese, arsenic, TDS, and turbidity. Alternatives for managing these constituents involve blending with process flows at the Baker WTP. At minimum plant flows (assumed to be 10 mgd of raw water), Well No. 1 is diluted at a ratio of 35:1. At peak plant flows dilution is increased to 87:1. Dilution eliminates water quality concerns for all of these constituents without additional treatment, with the exception of turbidity. Treatment requirements would be limited to virus disinfection, which can be accomplished in the CT basin proposed for the main treatment process.

The Boyle report indicates that rehabilitation activities were performed on Well No. 1 to eliminate silting. It is unclear from the report if and by how much well water turbidity has decreased. However, it is assumed in this memorandum that well water turbidity has been reduced to a more typical value 0.5 NTU.

Table 1 Well No. 1 Water Quality[1]

Constituent	Potable Water Standard	Range (mg/L)	Average (mg/L)
Total Hardness	None	189 - 500	390
Total Alkalinity	None	225 - 268	240
pH	SMCL = 6.5 to 8.5	6.7 - 7.6	7.3
Total Dissolved Solids (TDS)	SMCL = 500 mg/L	600 - 950	710
Turbidity	<0.3 NTU 95% of the time	1.1 - 7.5	4.6
Arsenic	MCL = 0.010 mg/L	ND - 0.012	0.007
Iron	SMCL = 0.3 mg/L	ND - 2.96	0.6
Manganese[2]	SMCL = 0.050 mg/L	ND - 0.07	0.044

Note:
1. Based on annual water quality data presented in Boyle (December 2002) from 1989 to 2001.

ALTERNATIVES FOR INCLUSION OF WELL NO. 1

The following treatment alternatives have been developed to manage turbidity from Well No. 1. Other constituents of interest in Well No.1 will be managed through dilution into the main process stream. Alternatives are summarized in Table 2.

Blending into the Membrane Waste Washwater (MFWW) Equalization Basin

In this alternative, well water is pumped into the membrane waste washwater (MFWW) equalization basin, transferred to the clarification process, and ultimately introduced into the raw water pipeline. This eliminates any concerns about silt (turbidity) in Well No. 1 impacting finished water quality or membrane performance. In addition, turbidity peaks associated with well cycling could be handled in the clarification process, eliminating the need for a dedicated well to waste system. Blending in this manner will not impact the treatment process selection, equipment, or pipeline sizing for the Baker WTP. Finished water quality is not impacted.

This alternative would require construction of a pipeline from nearby the existing well tank on the Baker WTP site to the MFWW equalization basin, associated valving and controls. These improvements are depicted in Figure 1.

Blending with Finished Water at the CT Basin

In this alternative, well water is pumped into the CT basin and blended with membrane permeate from the Baker WTP prior to disinfection. This would allow the water to be disinfected in the CT basin proposed for the main process stream. In order to for this alternative to be viable, it must be confirmed that Well No. 1

rehabilitation activities have lowered turbidity to more typical well turbidity levels (less than 0.5 NTU). Assuming a well water turbidity of 0.5 NTU, finished water turbidity would be expected to increase by 33% to 100% (up to 0.020 NTU to 0.030 NTU) depending on the Baker WTP flow rates. This alternative eliminates any risk of MF system fouling from well water manganese or iron.

This alternative would include construction of a pipeline from nearby the existing well tank on the Baker WTP to the CT basin, a well to waste pipeline to the proposed MFWW equalization basin, associated valving and controls. The well to waste pipeline would be used to mitigate any turbidity peaks associated with pump start up. These improvements are depicted in Figure 2.

Table 2 Alternatives for Using Well No. 1 Water at the Baker WTP

Alternative	Pros	Cons
Blend into MFWW Equalization Basin	• No measurable impact to finished water quality • No impact to process selection/sizing • Turbidity removal with minimal additional capital cost (pipeline only) • No new residuals stream • No well to waste line required	• Risk (minimal) of impacting MF performance from additional iron and manganese load.
Blend Directly into CT Basin Inlet	• Eliminates possible impacts to membrane system performance • No new residuals stream	• Increases finished water turbidity from 0.015 NTU to 0.020 NTU to 0.030 NTU at low Baker WTP flows

CONCLUSIONS

- Well No. 1 is suitable for blending into the CT basin at the Baker WTP without violating any primary or secondary MCLs.
- At assumed well turbidity of 0.5 NTU and minimum Baker WTP flows, direct blending of Well No. 1 into the CT basin is expected to increase finished water turbidity from 0.015 NTU to 0.020 NTU. At minimum plant flows, blended turbidity could reach 0.03 NTU. This approach would require construction of both a blend line and a well to waste line.
- Well No. 1 could be blended into the MFWW equalization basin to utilize clarification and filtration facilities proposed for the Baker WTP to manage turbidity from Well No 1. This approach eliminates impacts to plant finished water quality from Well No. 1 and requires only one pipeline to be constructed.

RECOMMENDATIONS

It is recommended that Well No. 1 be blended into the MFWW equalization basin if it is to be used as a supply source for the Baker WTP.

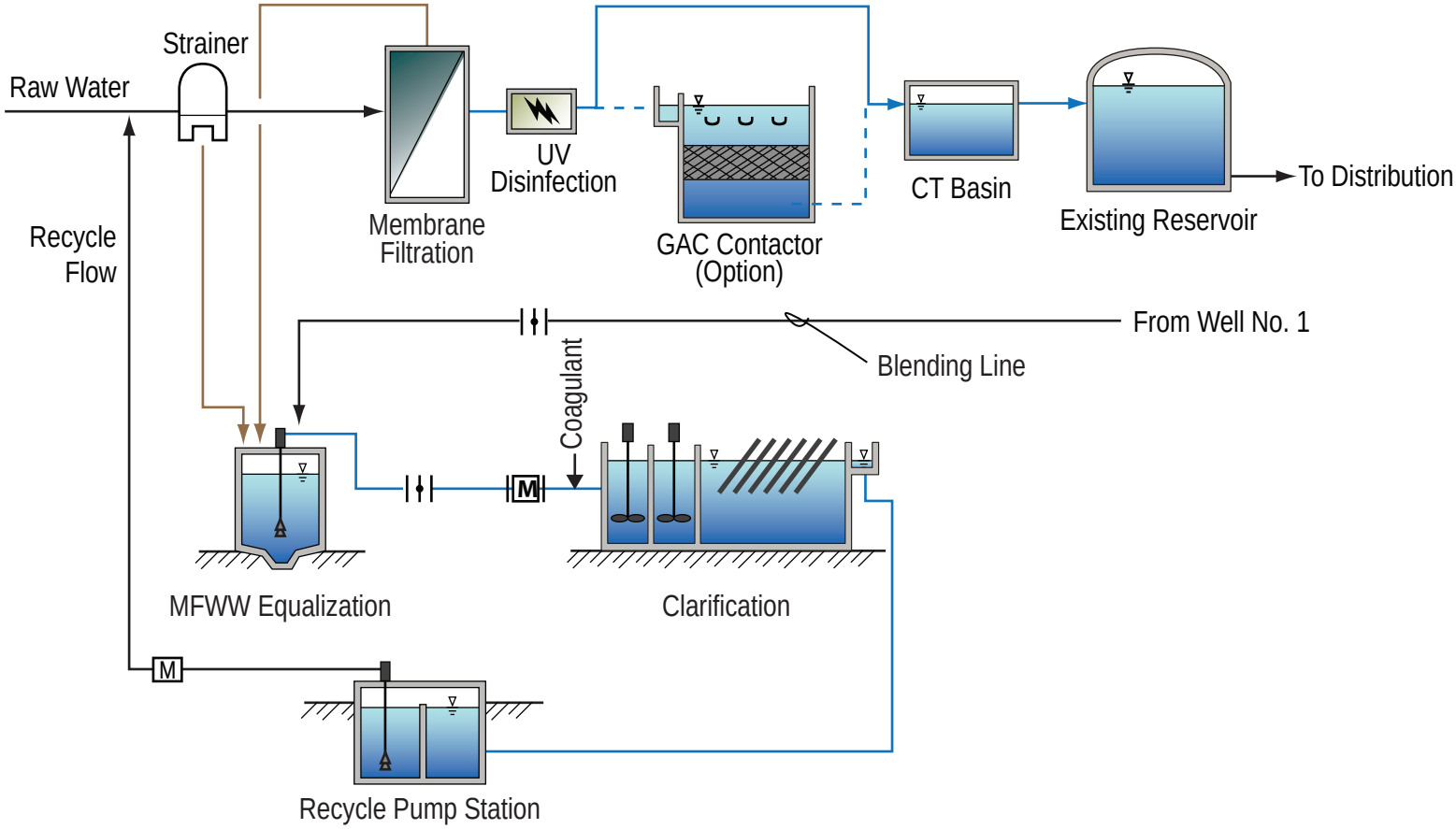


Figure 1
Well No. 1 MFWW Equalization Basin Blending Alternative
IRWD

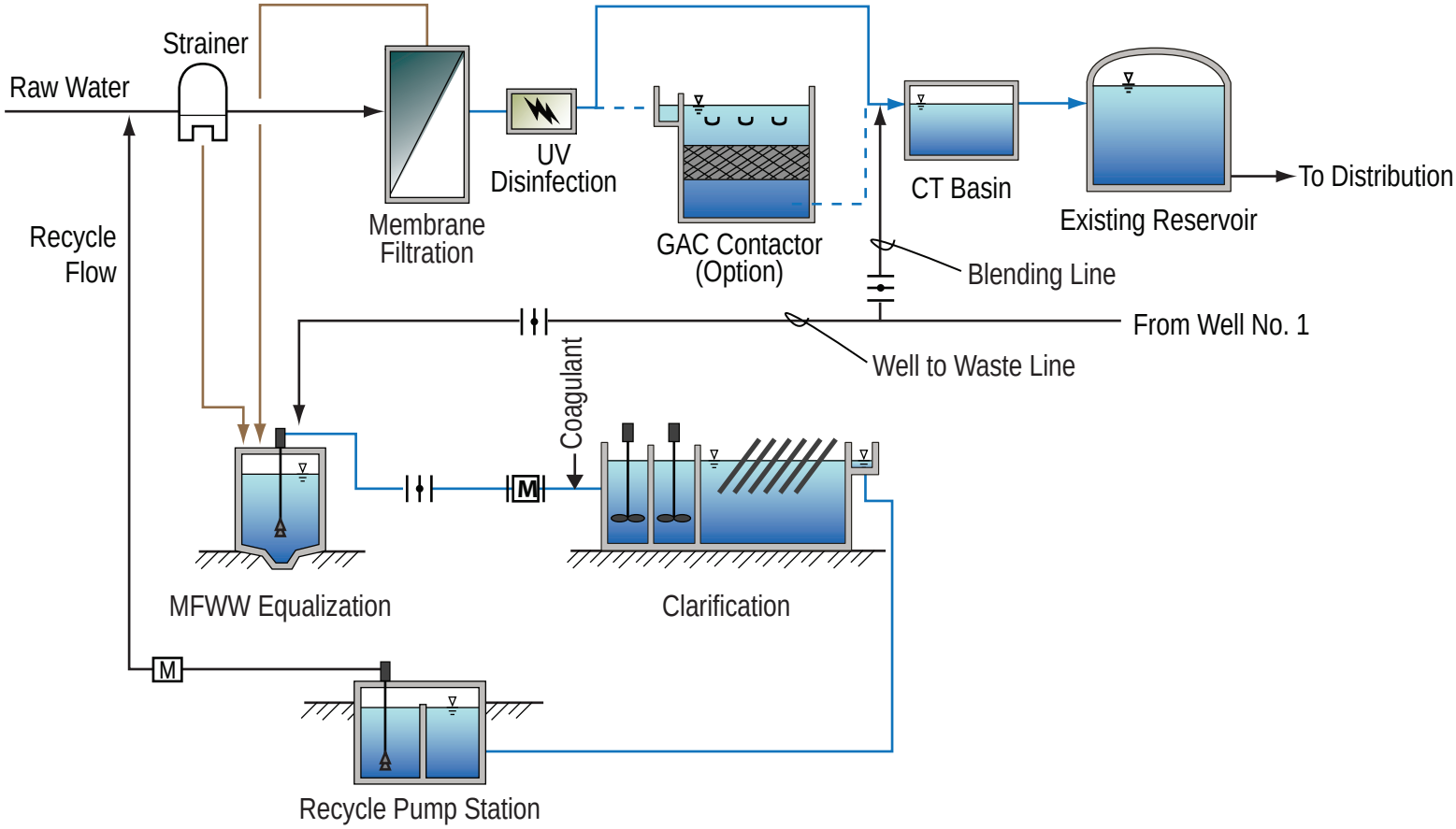


Figure 2
Well No. 1 CT Basin Blending Alternative
IRWD

APPENDIX B

Baker Pipeline Flow Test – Results / Calculations

TABLE B1
BAKER PIPELINE FLOW TEST
FLOW TEST SUMMARY

DATA LOGGING LOCATION	Parameter	STEP																																	
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
		TIME OF TEST (Minutes)																																	
		0	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	90	95	100	105	110	115	120	125	130	135	140	145 [1]	150	155	160
		9:00 AM	9:05 AM	9:10 AM	9:15 AM	9:20 AM	9:25 AM	9:30 AM	9:35 AM	9:40 AM	9:45 AM	9:50 AM	9:55 AM	10:00 AM	10:05 AM	10:10 AM	10:15 AM	10:20 AM	10:25 AM	10:30 AM	10:35 AM	10:40 AM	10:45 AM	10:50 AM	10:55 AM	11:00 AM	11:05 AM	11:10 AM	11:15 AM	11:20 AM	11:25 AM	11:30 AM	11:35 AM	11:40 AM
SANTIAGO LATERAL																																			
OC-33 IRWD Flow Reading	**Flow (cfs)**	4.29	3.75	4.08	4.56	4.02	9.62	9.28	15.94	16.01	24.6	23.8	23.8	29.66	35.28	37.42	37.61	39.23	39.4	39.83	39.83	39.83	39.83	39.82	39.82	39.82	39.82	30.29	17.81	14.16	*10*	7.63	3.94	
OC-33 MWD Flow Reading	**Flow (cfs)**	3.17	4.06	-	3.96	-	9.50	9.40	15.42	15.72	-	30.13	-	30.71	35.20	37.42	-	39.46	39.26	40.00	40.00	40.00	40.00	40.00	40.00	40.00	38.10	28.87	15.05	11.25	6.09	5.21	4.06	
B01 Pressure Reading	**Pressure (psi)**	48	48	51	51	51	50	50	50	49.5	49.5	49	49	48.5	48	48	48	48	48	48	47.5	47.5	47.5	47.5	47.5	47.5	48	49	50	50	*51*	51	51	
Centerline Elev = 717'	**HGL (ft)**	830.9	830.9	837.8	837.8	837.8	835.5	835.5	835.5	834.3	834.3	833.2	833.2	832.0	830.9	830.9	830.9	830.9	830.9	830.9	829.7	829.7	829.7	829.7	829.7	829.7	830.9	833.2	835.5	835.5	*837.8*	837.8	837.8	
BAKER PIPELINE																																			
EOCWD FCF @ Sta 370+00	**Pressure (psi)**	104	104	105	105	105	103	100	102	102	101	100	100	100	100	99	99	99	99	99	99	99	99	99	99	99	99	100	100	101	102	103		
Gage Elev = 600'	**HGL (ft)**	840.2	840.2	842.6	842.6	842.6	837.9	831.0	835.6	835.6	833.3	831.0	831.0	831.0	831.0	828.7	828.7	828.7	828.7	828.7	828.7	828.7	828.7	828.7	828.7	828.7	828.7	831.0	831.0	833.3	835.6	837.9		
B47 4"AVAR @ Sta 597+81	**Pressure (psi)**	50	52	52	51	52	50	50	48	48	45	45	42	41	38	38	37	37	36	34	34	34	33	32	32	32	36	41	47	50	50	52	52	
Gage Elev = 715'	**HGL (ft)**	830.5	835.1	835.1	832.8	835.1	830.5	830.5	825.9	825.9	819.0	819.0	812.0	809.7	802.8	802.8	800.5	800.5	798.2	793.5	793.5	793.5	791.2	788.9	788.9	788.9	798.2	809.7	823.6	830.5	830.5	835.1	835.1	
B90 3" AV @ Sta 900+62	**Pressure (psi)**	83	83	83	83	80	80	77	77	70	70	64	64	57	57	54	54	52	52	50	50	47	47	46	46	50	58	63	76	78	78	78	78	83
Gage Elev = 655'	**HGL (ft)**	846.7	846.7	846.7	846.7	839.8	839.8	832.9	832.9	816.7	816.7	802.8	802.8	786.7	786.7	779.7	779.7	775.1	775.1	770.5	770.5	763.6	763.6	761.3	761.3	770.5	789.0	800.5	830.6	835.2	835.2	835.2	835.2	846.7
TCWD - Pressure Readings	**Pressure (psi)**					74		72	67			62		57				47		46			42	40		39								
Gage Elev = 665.5'	**HGL (ft)**					836.4		831.8	820.3			808.7		797.2				774.1		771.8			762.5	757.9		755.6								
Baker WTP (Exist Contr Panel)	**Pressure (psi)**	90.93	88.58	89.3	89.16	89.06	85.3	85.8	79.3	81.4	72.9	72.6	62.5	62.61	52.71	52.62	48.5	48.4	44.78	45.17	41.84	42.04	38.9	39	36.25	36.25	46.05	65.84	62.31	86.62	89.95	89.36		
Gage Elev = 636'	**HGL (ft)**	846.0	840.6	842.3	842.0	841.7	833.0	834.2	819.2	824.0	804.4	803.7	780.4	780.6	757.8	757.6	748.0	747.8	739.4	740.3	732.7	733.1	725.9	726.1	719.7	719.7	742.4	788.1	779.9	836.1	843.8	842.4		
24-inch Lateral @ 18-inch conn.	**Pressure (psi)**	107	107	107	106	98	103	103	98	98	90	78	78	68	68	64	64	58	58	56	56	52	52	50	50	58	58	62	78	94	102	108		
Gage Elev = 597'	**HGL (ft)**	844.2	844.2	844.2	841.9	823.4	834.9	834.9	823.4	823.4	804.9	777.2	777.2	754.1	754.1	744.8	744.8	731.0	731.0	726.4	726.4	717.1	717.1	712.5	712.5	731.0	731.0	740.2	777.2	814.1	832.6	846.5		
18-inch Line to 2.0 MG Clearwell	**Flow (cfs)**	0	0	0	0	4.5	5.8	6.6	10.7	15.2	17.9	22.2	23.5	27.3	28.8	30	31.5	32.2	33.4	34.0	34.9	35.6	36.0	36.9	35.0	33.3	25.5	24.3	8.8	6.2	2.3	0.0		
2.0 MG Reservoir (East)	**Pressure (psi)**	0	0	0	0	0	0	0	1	1	3	7	8	8	13	15	15	17	17	18	18	20	20	22	22	22	14	14	6	5	5	4		
Gage Elev = 599'	**HGL (ft)**	602.2	602.4	602.6	602.8	602.9	603.5	603.8	604.4	605.8	606.8	608.2	609.0	609.4	609.2	608.7	611.9	611.5	614.2	611.2	612.0	612.2	614.8	619.1	622.0	624.8	629.1	629.9	630.5	629.9	629.4	627.9	627.0	624.9
	WSL(ft)	1.39	1.47	1.56	1.63	1.68	1.95	2.07	2.33	2.95	3.39	3.97	4.35	4.49	4.4	4.18	5.58	5.41	6.58	5.26	5.64	5.7	6.82	8.69	9.97	11.19	13.04	13.38	13.62	13.38	13.17	12.49	12.13	11.2
2.0 MG Reservoir (West)	**HGL (ft)**	603.6	603.6	603.6	603.7	603.6	603.7	603.7	603.8	603.9	604.0	604.2	604.2	604.4	604.5	604.8	605.0	605.3	605.5	605.6	606.0	606.4	607.1	607.6	608.0	608.4	609.7	610.1	610.6	611.6	612.1	613.9	613.5	614.6
	WSL(ft)	2.01	2.01	2.01	2.03	2.01	2.05	2.05	2.06	2.12	2.17	2.23	2.25	2.32	2.39	2.49	2.59	2.73	2.8	2.85	3.04	3.19	3.51	3.74	3.89	4.06	4.64	4.79	5.02	5.46	5.68	6.43	6.28	6.77

[1] OC-33 flow reading was not available. Interpolation was used to determine flow and pressure for use in subsequent figures and analysis.

Exhibit B1
Baker Flow Test (HGL per Time)

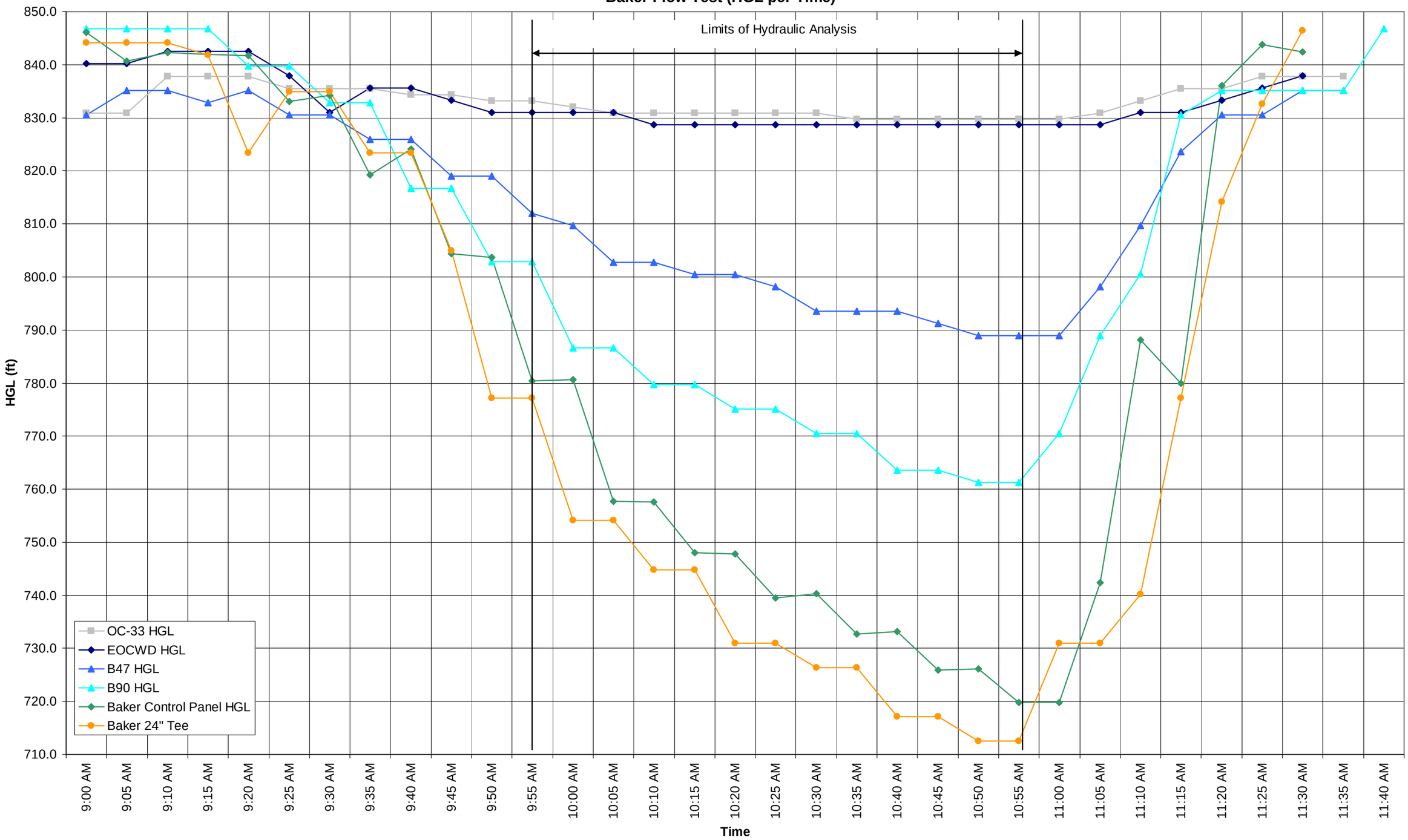
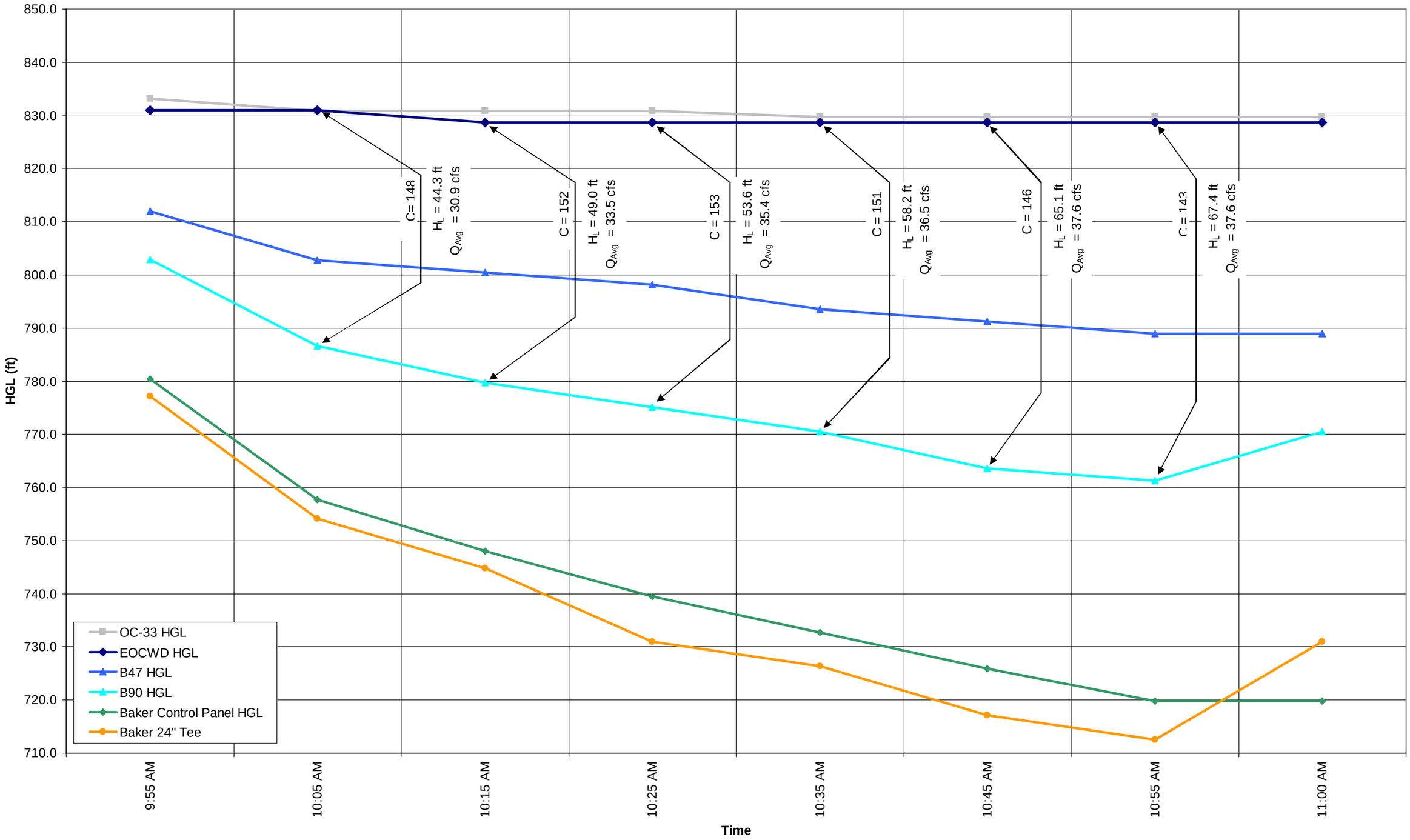


Exhibit B2
Hazen Williams 'C' Value Determination from Results



APPENDIX C

Raw Water Conveyance Facilities Previously Considered

FACILITIES CONSIDERED PREVIOUSLY

Hydraulic Control Structure

The Santiago Lateral and the Baker Pipeline have a combined length of approximately nineteen miles, beginning at the Lower Feeder and terminating at the Baker Water Treatment Plant. The Baker Pipeline, itself, traverses twelve miles of undulating terrain from its connection to the Santiago Lateral to the Baker WTP. These existing facilities provide the system backbone that make the steady-state delivery of water to the WTP possible. However, it is the long lengths of these facilities, particularly the Baker Pipeline, that could make the control of flow to the plant a challenge.

Slight variations in demand, at the treatment plant, will produce swings in the hydraulic grade line along the length of the Baker pipeline. These variations in demand will then become translated into rejection, to Irvine Lake, of a portion of the water delivered by MWD, through the Santiago Lateral, to OC-33. Any instantaneous reduction in demand at the plant raises the HGL at OC-33 and when the HGL exceeds 832' water is spilled to Irvine Lake. This condition arises because of the profile of the Santiago Lateral. Immediately downstream of OC-33 is a high point in the pipeline that limits the HGL at OC-33 to about 832', except when water is discharged to the lake, a maximum HGL elevation of 872' can be realized at OC-33. In order to counter this effect, as well as to provide for a greater HGL at OC-33 that would allow the development of greater capacity, in the pipeline and the WTP, IRWD proposed to MWD, the construction of a hydraulic control structure, at the high point in the Santiago Lateral downstream of OC-33.

This facility would:

- reduce variations in the HGL at OC-33
- dampen variations of flow in the Baker Pipeline
- eliminate unintended flows to Irvine Lake

To date, MWD staff has held an opposed stance toward the proposal.

Regulating Reservoir

Without free-water-surface storage, at the head of the Baker pipeline, alternative means of regulating the flow and mitigating operational spikes in the HGL, at OC-33, in the Santiago Lateral, as well as along the Baker Pipeline, have been considered. Unfortunately, a regulating tank on the Baker pipeline near OC-33 is impossible to site, because of topographical constraints (no locations with sufficient elevation) in the vicinity of the turnout. However, between OC-33 and the plant, there are two locations that have been considered for a regulating tank:

- near Peters Canyon reservoir in the vicinity of the raw water pump station
- near Orchard Hills development

At both of the locations the regulating tanks would have to intercept the HGL approximately at their mid-height. The approximate ranges in the HGL at these locations are:

- Peters Canyon – 872' to 818' +/-
- Orchard Hills – 872' to 750+/-

In order to be effective over the possible ranges in the water surface levels, in the tanks, their heights would be about 54' and 112', respectively. As a practical matter, the tanks would be sized to operate over a band width of water surface levels of about 30', thereby allowing equal volumes of storage above (15') and below (15') the most likely HGL at normal operating downstream demand. The capacity of the tank, at either location, would be on the order of two million gallons. When pumping, from Irvine Lake, this volume would provide about one hour of storage, for plant operation, during a power failure at the pump station. During gravity flow condition, from the Santiago Lateral, this volume would allow about one hour of continued delivery of water through OC-33, in the event of a treatment plant shutdown, without discharging to Irvine Lake.

Balancing and Constant-Head Tanks

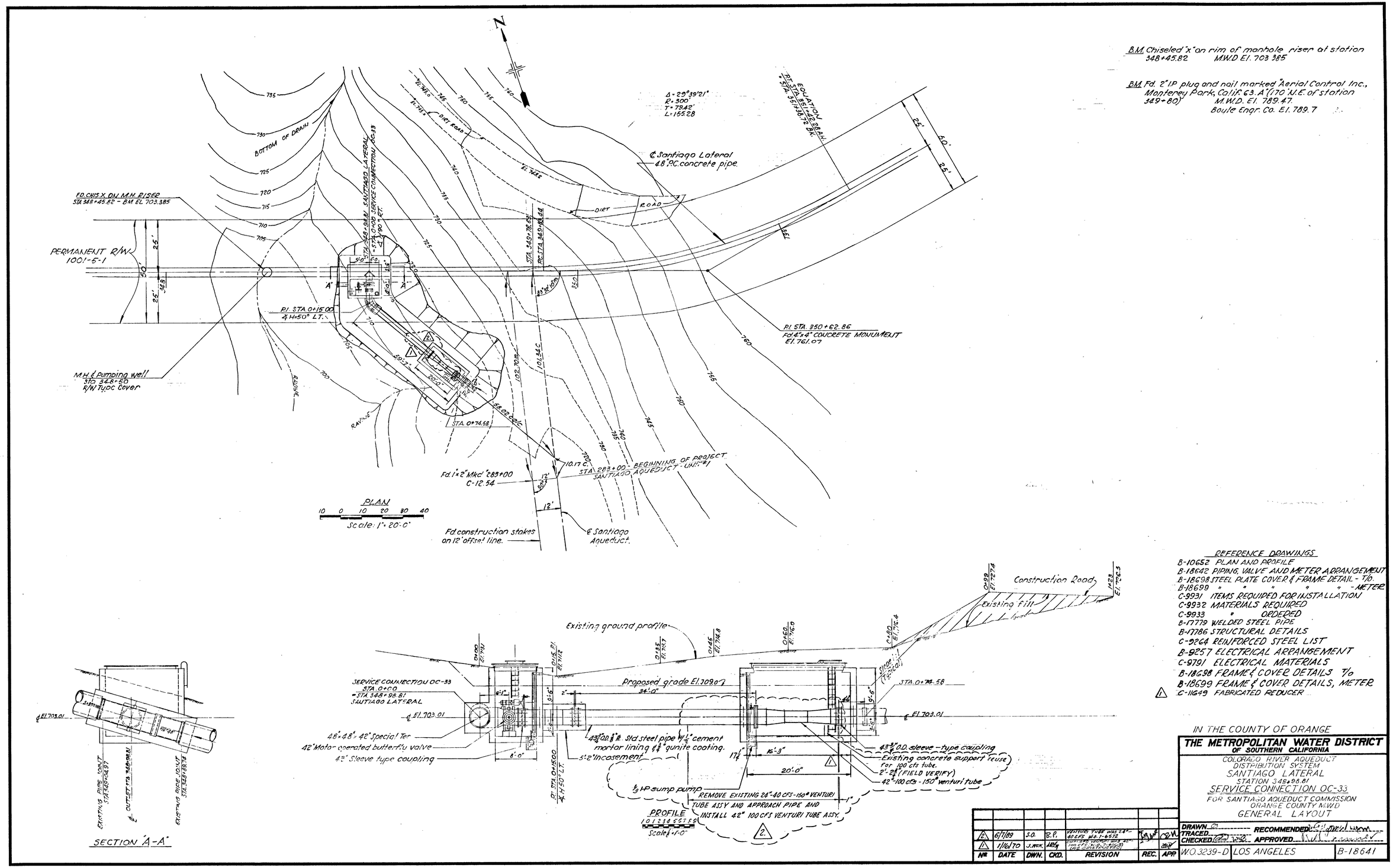
For the purposes of this report, these terms are defined as follows:

- Constant Head Tank – Storage that includes no volume for plant flow variation
- Balancing Tank – Storage that has sufficient volume to accommodate all variations in plant flow

In addition to dealing with major flow adjustments, due to the unforeseen shutdown of either the pump station or the water treatment plant, instantaneous flow variations of short duration can be part of the normal plant operation. Depending on the number of filter racks, and the frequency of backwash and cleanings, these variations in flow may run from 25 to 45 cfs, for a few minutes at a time, several times per day, as well as fluctuations, of lesser magnitude, several times per hour. Since the capacity of the pipeline is below the possible upper flow demand of the plant, operational storage, near the plant, is required in order to provide a mechanism for supplying supplemental water, during peaking, and for storing water during low plant demand.

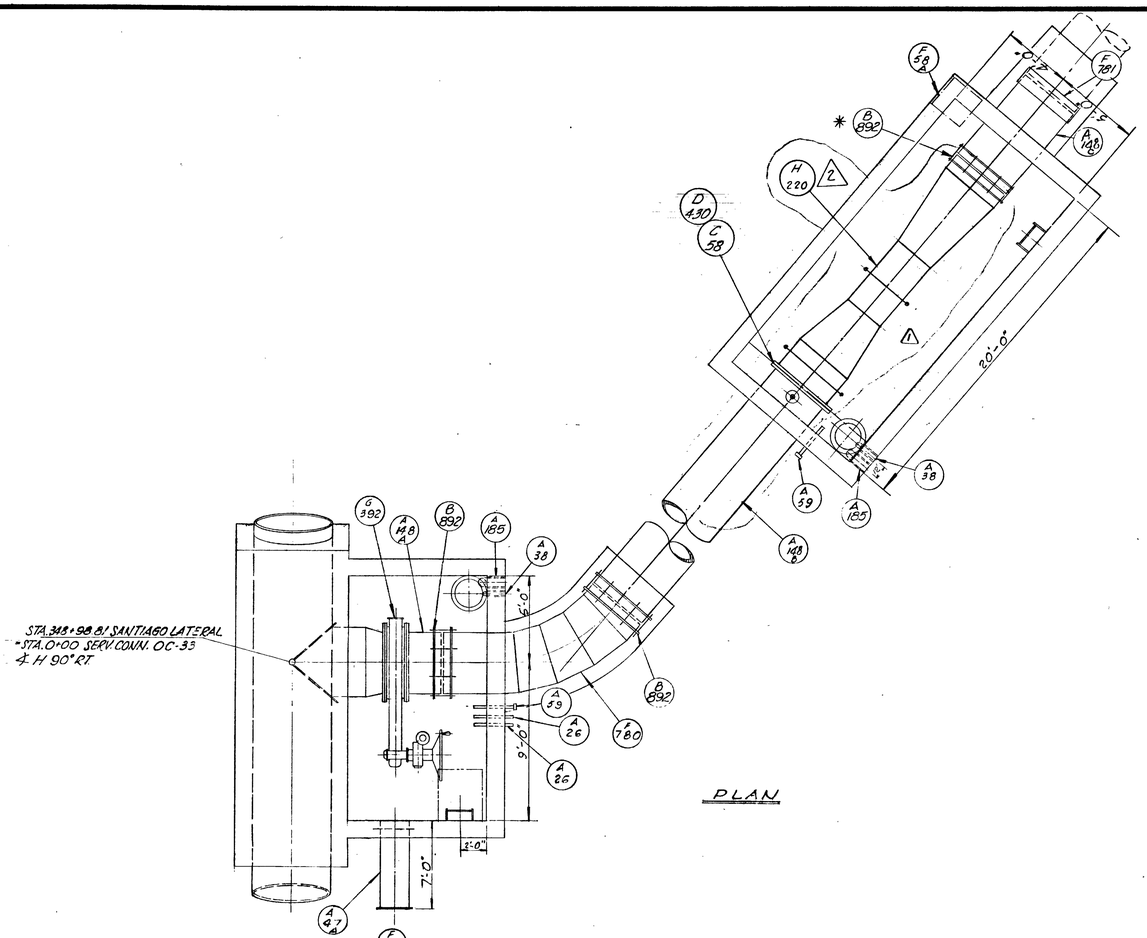
APPENDIX D

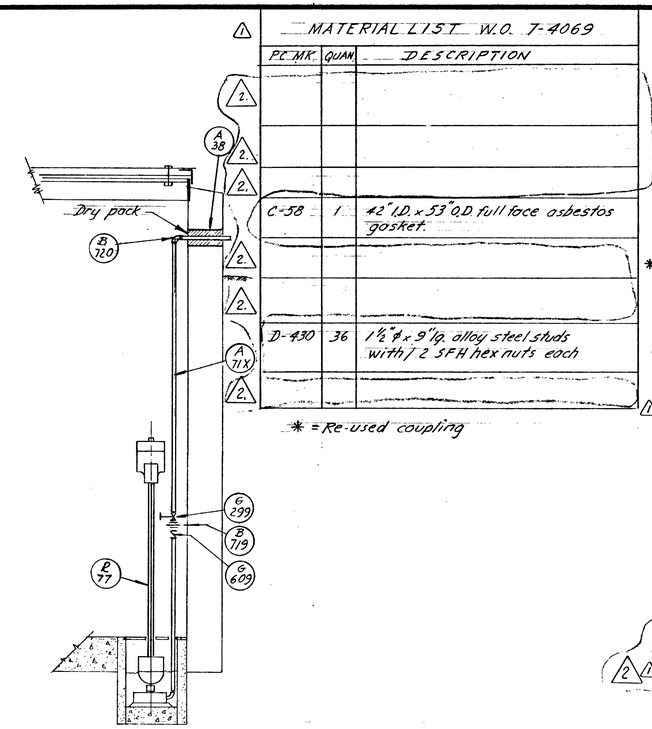
OC-33 Construction Plans


B.M. Chiseled "x" on rim of manhole riser at station 348+45.82 M.W.D El. 703.385
B.M. Fd. 2" IP plug and nail marked "Aerial Control Inc., Monterey Park, Calif. 63. A" (170' N.E. of station 349+80) M.W.D. El. 789.47. Boyle Engr. Co. El. 789.7
PLAN
Scale: 1" = 20'-0"
PERMANENT R/W 100'-5-1
FD. CH15 X ON M.H. RISER STA 348+45.82 = BM EL 703.385
M.H. & Pumping Well STA 348+50 R/W Type C Cover
P.I. STA 0+15.00 Δ H=50° LT.
STA 348+98.81 SANTIAGO LATERAL = STA 0+00 SERVICE CONNECTION OC-33
STA 340+78.09
PC. STA 340+98.24
STA 0+74.58
Δ = 29°39'21" R = 300' T = 79.42 L = 155.28
P.I. STA 351+42.28 = STA 351+38.72 BK.
EQUATION
℄ Santiago Lateral 48" P.C. concrete pipe
DIRT ROAD
BOTTOM OF DRAIN
RAVINE
P.I. STA 350+62.86 Fd 4"x4" CONCRETE MONUMENT El. 761.07
Fd 1"x2" Mkd "283+00" C-12.54
STA 283+00 - BEGINNING OF PROJECT SANTIAGO AQUEDUCT - UNIT #1
Fd. construction stakes on 12' offset line.
℄ Santiago Aqueduct.
Construction Road
Existing Fill
Existing ground profile
Proposed grade El. 709.07
SERVICE CONNECTION OC-33 STA. 0+00 = STA 348+98.81 SANTIAGO LATERAL
℄ El. 703.01
48"x48"x42" Special Tee
42" Motor operated butterfly valve
42" Sleeve type coupling
42 3/8" O.D. 3/8" W.T. Std steel pipe w/ 1/4" cement mortar lining & 3/8" gunite coating.
5'-2" Incasement
1/2 HP sump pump
REMOVE EXISTING 24"-40 CFS-150# VENTURI TUBE ASSY AND APPROACH PIPE AND INSTALL 42" 100 CFS VENTURI TUBE ASSY.
42 3/8" O.D. sleeve-type coupling
Existing concrete support reuse for 100 cfs tube.
2'-2 3/8" (FIELD VERIFY)
42"-100 cfs-150" venturi tube
STA. 0+74.58
PROFILE
Scale: 1" = 10'
SECTION "A-A"
EXISTING PIPE 10" OUT STA 348+04.97
OUTLET STA 348+98.81
EXISTING PIPE 10" OUT STA 348+98.74
REFERENCE DRAWINGS
B-10652 PLAN AND PROFILE
B-18698 PIPING, VALVE AND METER ARRANGEMENT
B-18698 STEEL PLATE COVER & FRAME DETAIL - T/O.
B-18699 " " " " " -METER
C-9931 ITEMS REQUIRED FOR INSTALLATION
C-9932 MATERIALS REQUIRED
C-9933 " ORDERED
B-17779 WELDED STEEL PIPE
B-17786 STRUCTURAL DETAILS
C-9264 REINFORCED STEEL LIST
B-9257 ELECTRICAL ARRANGEMENT
C-9791 ELECTRICAL MATERIALS
B-18698 FRAME & COVER DETAILS T/O
B-18699 FRAME & COVER DETAILS, METER
C-11649 FABRICATED REDUCER
IN THE COUNTY OF ORANGE
THE METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA
COLORADO RIVER AQUEDUCT DISTRIBUTION SYSTEM
SANTIAGO LATERAL
STATION 348+98.81
SERVICE CONNECTION OC-33
FOR SANTIAGO AQUEDUCT COMMISSION
ORANGE COUNTY M.W.D
GENERAL LAYOUT
DRAWN
TRACED
CHECKED
RECOMMENDED
APPROVED
6/7/89 S.O. B.P. VENTURI TUBE WAS 24"-40 CFS W.O. 7-6572
1/16/70 J.MCK. KDG
NO. DATE DWN. CKD. REVISION REC. APP
W.O. 3239-D LOS ANGELES B-18641

FORM NO. 39-1 1M 11-60 P.O. 92276

SPECIFICATIONS No. SHEET No. 1M-12





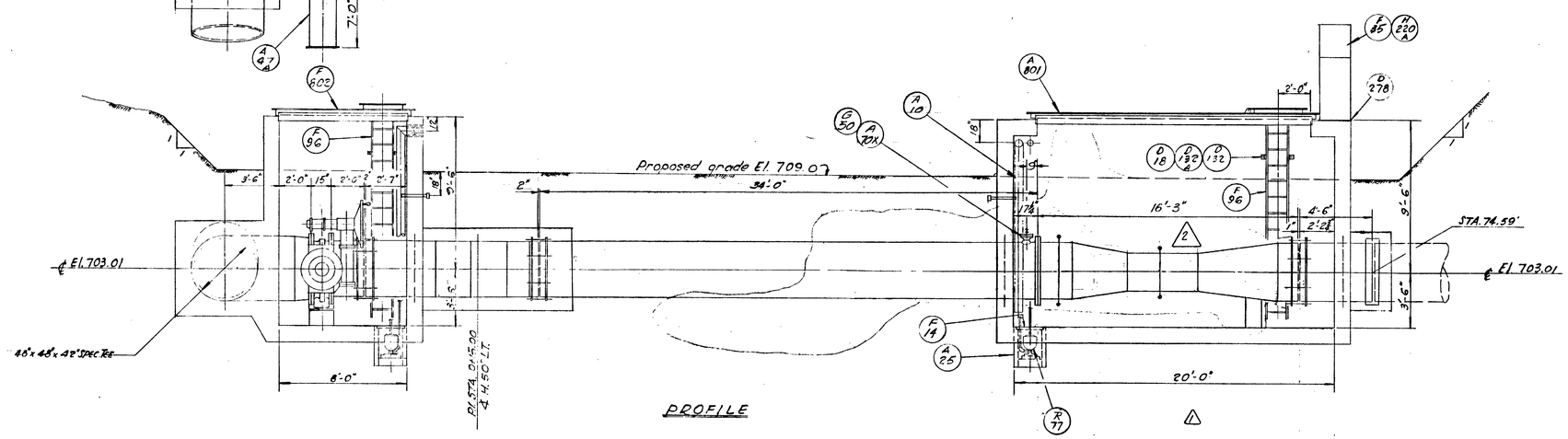
MATERIAL LIST W.O. T-4069		
PC. MK.	QUAN.	DESCRIPTION
C-58	1	42" I.D. x 53" O.D. full face asbestos gasket.
D-430	36	1½" ø x 9" lg. alloy steel studs with/ 2 SFH hex nuts each

* = Re-used coupling

	Pc Mk.	Quan.	Description
	A-10	40	LF. 6" O.D. STD STEEL CASING
	A-25	2	18" I.D. PCP 2'-6" SUMP
	A-185	2	4" I.D. STD. PIPE SLEEVE 14" LG
	A-40	2	6" I.D. STD. PIPE SLEEVE 14" LG.
	A-71X	40	LF. 1½" EX. HVY. RED. BRASS PIPE T&C.
	A-70X	1	1" x 2" LG. EX. HVY. RED. BRASS NIPPLE
	A-148A	1	42" I.D. PIPE NIPPLE FOR SPEC. M-2343
	A-148B	1	42" I.D. METER APPROACH PIPE FOR SPEC. M-2343
	A-148C	1	42" I.D. PIPE SPOOL P.E. SPEC. M-2343
	A-47A	1	20" VALVE SHAFT EXTERIOR HOUSING
	A-26	1	½" COUP. NIPPLE 18" LG.
	A-59	2	¾" " " 18" LG.
	A-60	1	1" " " 18" LG.
*	B-892	3	43⅜" SLEEVE TYPE COUPLING SPEC. 2343
	B-1342	2	1⅛" x .125# BRASS COUPLINGS
	C-58	3	42" I.D. x 53" O.D. x ⅛" THK. FF ASBESTOS GASKETS W/36-1⅝" DIA. HOLES ON 49¾" BC.
	B-720	4	1⅛"-90°-125# BRASS ELBOW
	B-719	2	1⅛"-125# BRASS SCREWED GROUND JOINT UNIONS
	D-18	20	¾" x 3½" LG HEX. HD. MACH. BOLT W/1 S.F. HVY. HEX. NUTS EA.
△1	D-89	72	1½" x 8¾" LG. ALLOY STEEL STUDS W/2 SFH HEX NUTS EA.
	D-132	20	¾" 2 UNIT TYPE 1A, PLAN CLICH ANCHOR
	D-132A	20	EXTRA LEADS
	D-278	4	⅝" x 1¾" HEX. HD CAP SCREWS.
	F-780	1	42" I.D. 50° MITERED ELBOW, P.E. M-2343
	F-781	1	2 PIECE BUTT STRAP FOR 43¾" O.D. PIPE.
	F-14	2	18" METAL SUMP COVERS
	F-35	1	BUILDERS TYPE "M" INSTRUMENT HOUSING
	F-58A	1	BUILDERS TYPE "M" INSTRUMENT MOUNTING BASE
	F-96	2	STD. STEEL LADDERS W/ A & 2 B BRACKETS
	F-801	1	STEEL PLATE COVER ASSEMBLY
	F-802	1	" " " "
	G-299	2	1½"-125# BRZ. GATE VALVE - CRANE #440
	G-50	1	1"-250# BRONZ COCK VALVE
	G-392	1	42" MOTOR OPERATED BUTTERFLY VALVE
	G-609	2	1½" 125# BRZ. VERT. LIFT CHECK VALVE CRANE #29
△2	H-220	1	42"-100 CFS VENTURI TUBE ASSEMBLY
△2	H-220A	1	100 cfs BUILDERS TYPE M FLOW METER W/CTM TRANSMITTER & CRA-TYP REMOTE INSTRUMT.
	R-77	2	⅓ HP. SUMP PUMP (PENBERTHY)
		1	51" O.D. x 51" O.D. x 43" I.D. x ⅜" THK. ⅊ FAB. D WELD STEEL CROTCH-PLATE REINF-TEE WITH ONE END BELLED FOR STANDARD LOCK JOINT ONE END PLAIN AND SIDE OUTLET FLANGED. SPEC. M-2342.
		1	51" O.D. x ⅜" THK. ⅊ FAB STL. SPOOL WITH ONE END PLAIN & ONE SPIGOT RING FOR STD. LOCK JOINT M-2342
		1	51" I.D. x 14" WIDE x ⅜" THK. ⅊ FAB STL. COMPLETE BUTT STRAP TO BE FURNISHED IN TWO IDENTICAL PIECES TOGETHER WITH ONE PIECE 1" x ¼" STL. BAR 15" LG. & 8" STL. PIPE PLUGS. SPEC. M-2342.
		2	RUBBER GASKETS FOR 51" DESIGN DIAM. LOCK JOINT BY 3⅝" CROSS SECTION SPEC M-2342

REFERENCE DRAWINGS

B-10652 PLAN AND PROFILE
B-18641 GENERAL LAYOUT
B-18698 STEEL PLATE COVER & FRAME DETAIL - T/O
B-18699 " " " " " METER
C-9931 ITEMS REQUIRED FOR INSTALLATION
C-9932 MATERIALS REQUIRED
C-9933 " ORDERED
B-17779 WELDED STEEL PIPE
B-17786 STRUCTURAL DETAILS
C-9264 REINFORCED STEEL LIST
B-9257 ELECTRICAL ARRANGEMENT
B-9791 ELECTRICAL MATERIALS
B-18698 FRAME & COVER DETAILS T/O
B-18699 FRAME & COVER DETAILS, METER



THE METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA

COLORADO RIVER AQUEDUCT
DISTRIBUTION SYSTEM
SANTIAGO LATERAL
STATION 348+98.81
SERVICE CONNECTION OC-33
FOR SANTIAGO AQUEDUCT COMMISSION

PIPING, VALVE AND METER ARRANGEMENT

DRAWN C.G. RECOMMENDED
TRACED
CHECKED L.G.W. APPROVED

No	DATE	DWN.	CKD.	REVISION	REC.	APP.
△2	6-8-89	S.O.	B.P.	VENTURI TUBE WAS 54" AB EFG. METER WAS C-4148 MAT'LS		
△1	1/16/70	L.W.		CHANGED VENTURI TUBE WAS 7-4069 (NOT CONSTRUCTED)		

W.O. 3239-D LOS ANGELES B-18642

MICROFILMED
AUG 24 1966
SEP 22 1966
FEB 5 1978
MAR 27 1980
OCT 1 1995
OCT 14 1997
DIETERICH-POST PAPER CLOTH 1085

APPENDIX E

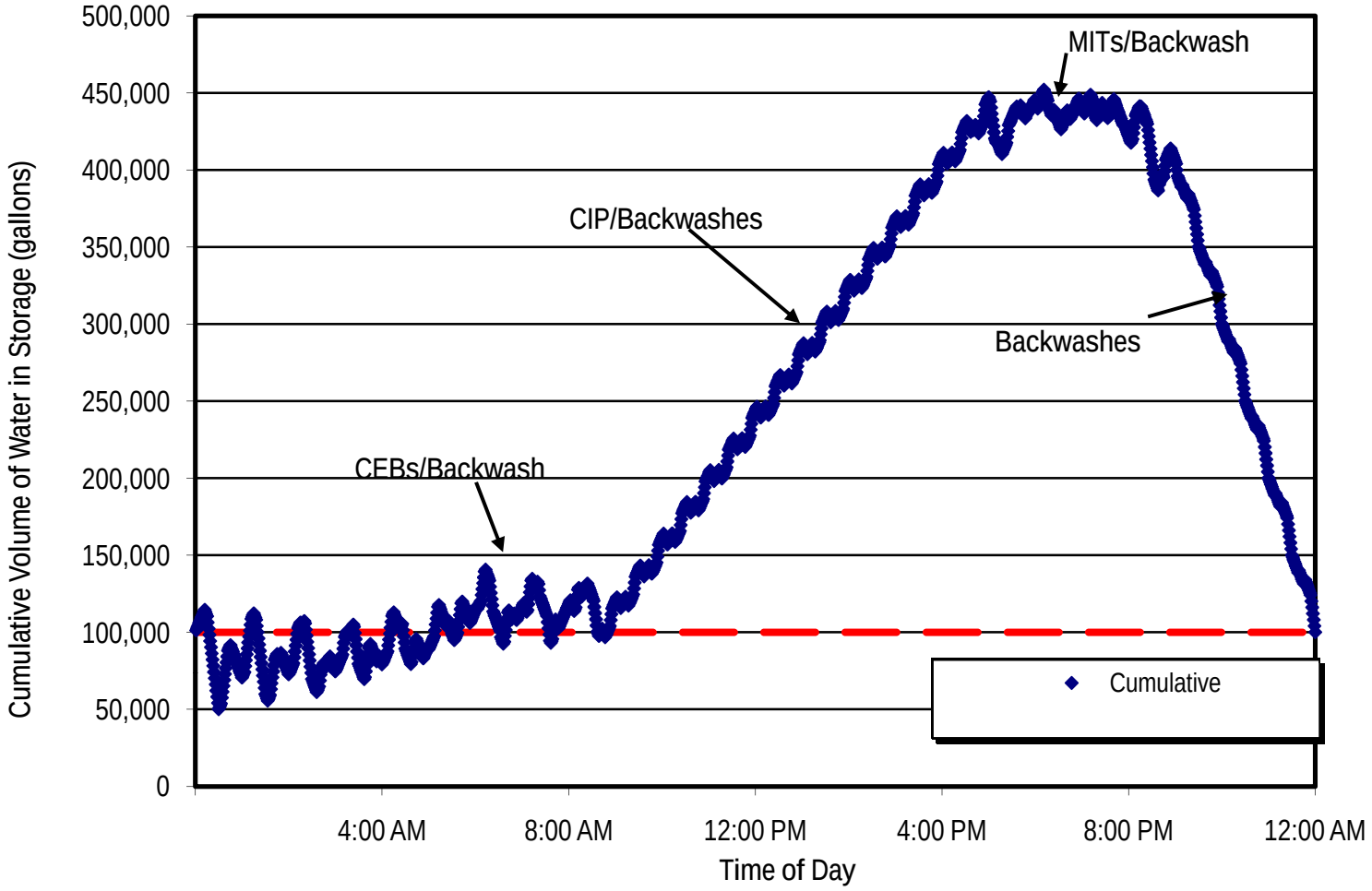
Raw Water Pump Station Calculations

TABLE E1
BAKER WATER TREATMENT PLANT PROJECT
RAW WATER CONVEYANCE FACILITIES
IRVINE LAKE PIPELINE / BAKER HYDRAULICS FOR RAW WATER PUMP STATION

Irvine Lake WSL (ft)	Maximum Design Q at Outlet Tower (cfs)	Maximum Gravity Flow in ILP (cfs)	Q (cfs)	Tower Intake Loss (ft)	Tower Outlet Loss (ft) (30-inch)	Pipeline Length (ft) and Diameter (in)	Pipeline Loss to Serrano T/O (ft)	Q Serrano T/O to RWPS (cfs)	Pipeline Loss Serrano T/O to RWPS (ft)	Total Pipeline Loss (ft)	Suction HGL at Peters Canyon (ft)	Suction Head	Discharge Static Lift to 815'	System HGL	Discharge Static Lift to System Curve'	RWPS Discharge (cfs)	TDH to 815'	TDH to System Curve	HP Lift to 815'	HP Lift to System Curve
790	70	42.5	70.0	10.0	2.3	11,000' - 39" 2,800' - 33" and 42" parallel 5,000' - 54"	39.7	64.0	4.9	44.6	733	143	82	815	82	53.5	92	92	744	744
			60.0	7.3	1.7		29.9	54.9	3.7	33.5	747	157	68	784	37	45.9	75	44	520	304
			50.0	6.9	1.2		21.3	39.2	2.0	23.3	759	169	56	757	0	38.2	62	0	356	0
			40.0	6.4	0.7		14.1	22.4	0.7	14.8	768	178	47	734	0	30.6	50	0	232	0
			30.0	5.6	0.4		8.3	9.6	0.1	8.4	776	186	39	716	0	22.9	41	0	143	0
			20.0	4.4	0.2		3.9	2.7	0.0	3.9	781	191	34	702	0	15.3	34	0	79	0
			10.0	2.5	0.0		1.1	0.4	0.0	1.1	786	196	29	693	0	7.6	29	0	33	0
			0.0	0.0	0.0		0.0	0.0	0.0	0	790	200	25	690	0	0.0	25	0	0	0
780	67.5	40	67.5	9.3	2.1		37.2	61.5	4.5	41.7	727	137	88	804	77	51.0	97	87	750	668
			60.0	7.3	1.7		29.9	54.7	3.6	33.5	737	147	78	782	45	45.3	85	52	581	355
			50.0	5.5	1.2		21.3	45.6	2.6	23.9	749	159	66	756	6	37.8	71	11	403	64
			40.0	4.4	0.7		14.1	36.4	1.7	15.8	759	169	56	733	0	30.2	59	0	271	0
			30.0	3.6	0.4		8.3	27.3	1.0	9.3	767	177	48	716	0	22.7	50	0	172	0
			20.0	2.5	0.2		3.9	18.2	0.5	4.4	773	183	42	702	0	15.1	43	0	98	0
			10.0	1.1	0.0		1.1	9.1	0.1	1.2	778	188	37	693	0	7.6	38	0	43	0
			0.0	0.0	0.0		0.0	0.0	0.0	0	780	190	35	690	0	0.0	35	0	0	0
770	65	37.5	65.0	8.6	2.0		34.6	59.0	4.2	38.8	721	131	94	794	74	48.5	103	82	753	601
			60.0	7.3	1.7		29.9	54.5	3.6	33.5	727	137	88	780	52	44.8	95	59	640	402
			50.0	6.9	1.2		21.3	45.4	2.6	23.9	738	148	77	754	16	37.3	82	21	462	119
			40.0	6.4	0.7		14.1	36.3	1.7	15.8	747	157	68	732	0	29.8	71	0	321	0
			30.0	5.6	0.4		8.3	27.2	1.0	9.3	755	165	60	715	0	22.4	62	0	210	0
			20.0	4.4	0.2		3.9	18.2	0.5	4.4	761	171	54	702	0	14.9	55	0	124	0
			10.0	2.5	0.0		1.1	9.1	0.1	1.2	766	176	49	693	0	7.5	49	0	55	0
			0.0	0.0	0.0		0.0	0.0	0.0	0	770	180	45	690	0	0.0	45	0	0	0
760	62.5	35	62.5	8.0	1.8		32.2	56.5	3.9	36.1	714	124	101	785	70	46.0	108	78	754	541
			60.0	7.3	1.7		29.9	54.2	3.6	33.5	718	128	97	761	44	39.4	103	49	614	292
			50.0	6.4	1.2		21.3	45.2	2.6	23.9	729	139	86	741	12	32.9	90	16	448	79
			40.0	4.4	0.7		14.1	36.2	1.7	15.8	739	149	76	724	0	26.3	78	0	312	0
			30.0	3.6	0.4		8.3	27.1	1.0	9.3	747	157	68	710	0	19.7	70	0	208	0
			20.0	2.5	0.2		3.9	18.1	0.5	4.4	753	163	62	699	0	13.1	63	0	125	0
			10.0	1.1	0.0		1.1	9.0	0.1	1.2	758	168	57	693	0	6.6	58	0	57	0
			0.0	0.0	0.0		0.0	0.0	0.0	0	760	170	55	690	0	0.0	55	0	0	0
750	60	32.5	60.0	7.3	1.7		29.9	54.0	3.6	33.4	708	118	107	775	68	43.5	114	74	751	489
			50.0	6.9	1.2		21.3	45.0	2.5	23.9	718	128	97	751	33	36.3	102	37	557	205
			40.0	6.4	0.7		14.1	36.0	1.7	15.8	727	137	88	730	3	29.0	91	0	399	0
			30.0	5.6	0.4		8.3	27.0	1.0	9.3	735	145	80	714	0	21.8	82	0	270	0
			20.0	4.4	0.2		3.9	18.0	0.5	4.4	741	151	74	701	0	14.5	75	0	164	0
			10.0	2.5	0.0		1.1	9.0	0.1	1.2	746	156	69	693	0	7.3	69	0	76	0
			0.0	0.0	0.0		0.0	0.0	0.0	0	750	160	65	690	0	0.0	65	0	0	0

APPENDIX F

Forebay Calculations


500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Cumulative Volume of Water in Storage (gallons)
MITs/Backwash
CIP/Backwashes
Backwashes
CEBs/Backwash
Cumulative
4:00 AM
8:00 AM
12:00 PM
4:00 PM
8:00 PM
12:00 AM
Time of Day

Forebay Sizing Calculations
Baker WTP
IRWD

CHLORINE DIOXIDE CONTACT CHAMBER

Raw Water Flow=	43.5	cfs	
Maximum Return Water Flows=	3.81	cfs	(2.46 mgd see MFWW Calcs)
Contact Chamber Max Flow=	47.3	cfs	
Contact Time for Mn Oxidation=	10	min	
	600	seconds	
Required Contact Chamber Volume=	28386	ft^3	
Average Chamber Depth=	13.5		
First 20 feet	19	ft	
Next 44 feet	11	ft min	
Chamber Width =	16.5	ft	
Chamber Length=	64	ft	
Calculated East Chamber Volume=	14256	ft^3	
Calculated West Chamber Volume=	14256	ft^3	
Total Volume (exclude between slab and low water level)=	28512	ft^3	
	213,270	gallons	
Time Provided=	603	seconds	
	10.0	minutes	

EQUALIZATION CHAMBER

Volume Required for MF Equalization=	500,000	gallons	
	66,845	ft^3	
Maximum depth=	10.5	feet between LL and HH (El 620.5 and EL 631)	
Channel Width=	16.5	feet	
Required Channel Length=	386	feet	
East Channel Length=	64	feet from outlweir to south end	
	128	feet from south end to end of pump bay	
West Channel=	same as East channel		
Total Length=	384	feet	
Actual Volume Provided=	497,629	gallons	
Additional Volume for Surge Equalization =	75,000	gallons	
	10,027	ft^3	
Provided Surge Volume Above High Equlization level			
Equalization Area =	12732	ft^2	
	7937	gallons per inch	
Inches above equlization elevation to provide surge equalization=	9.45	inches	

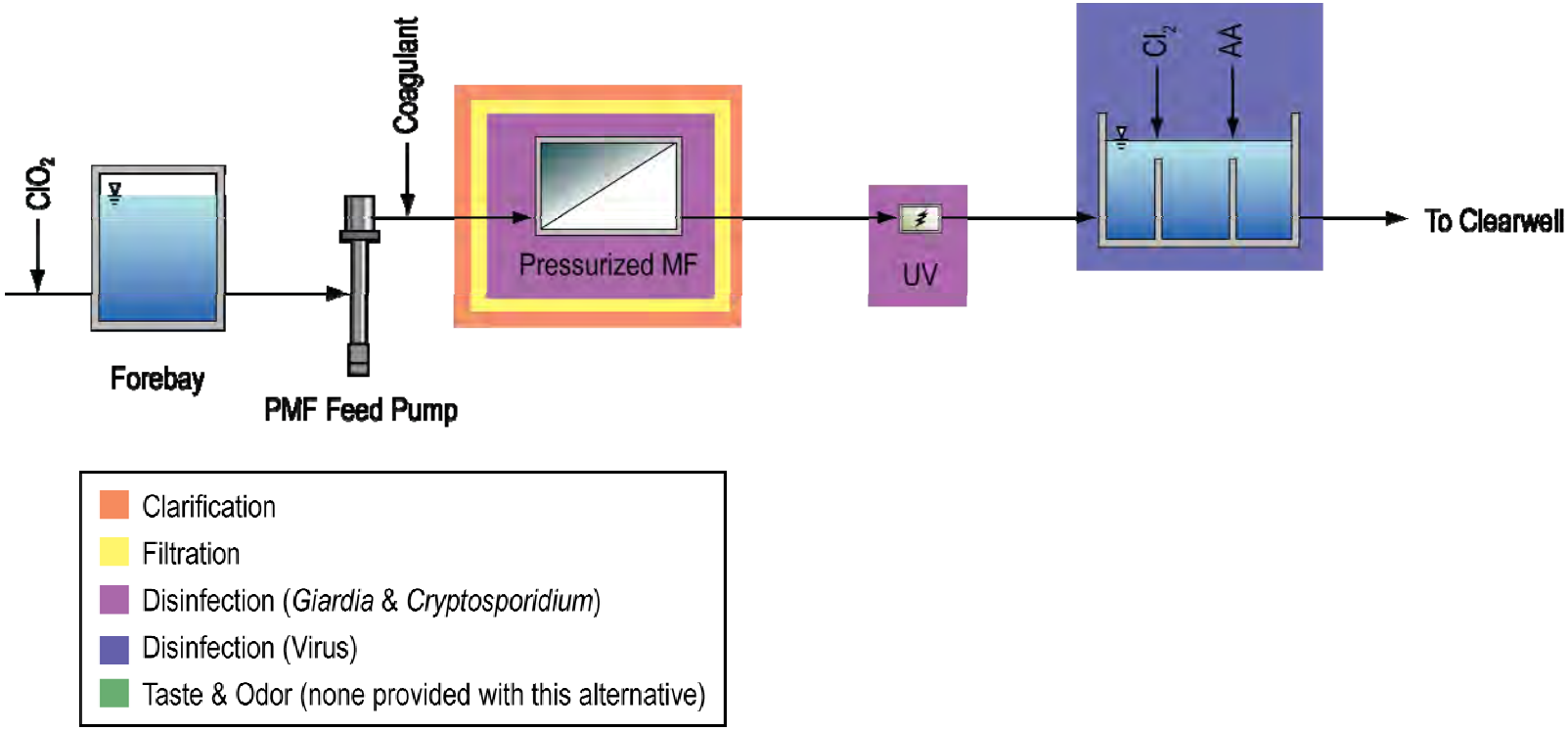
-Therefore, Oulet weir submerged
Overflow to be minimum elevation of 10" above contact zone levation of 632 or minimum 632.83'

TOTAL EQUALIZATION VOLUME	**785,899**	**gallons**
Chlorine Dioxide Contact Chamber	213,270	gallons
Equalization Chamber	497,629	gallons
Surge Volume	75,000	gallons

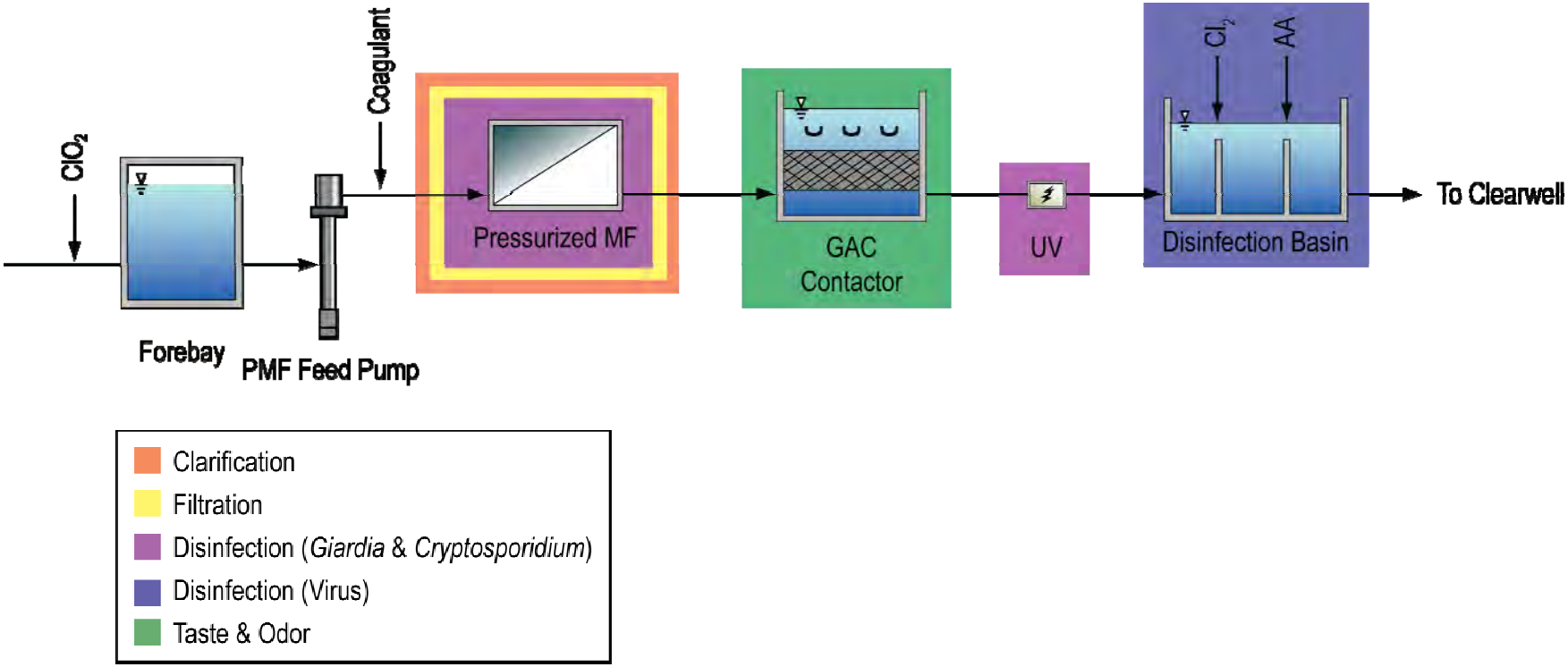
APPENDIX G

Process Schematics

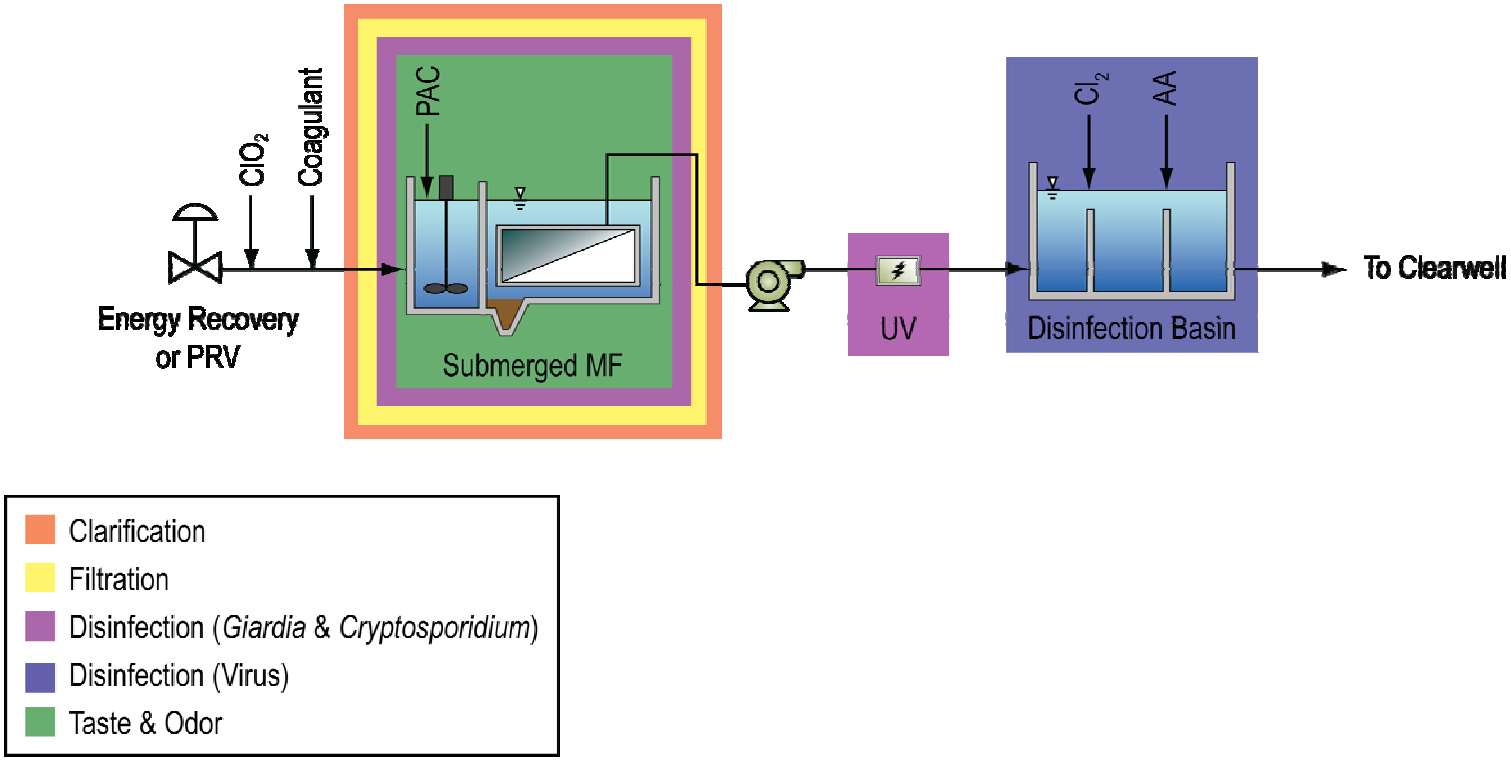
Preoxidation/Membrane Filtration/ UV+Chlorine Disinfection/Chloramination



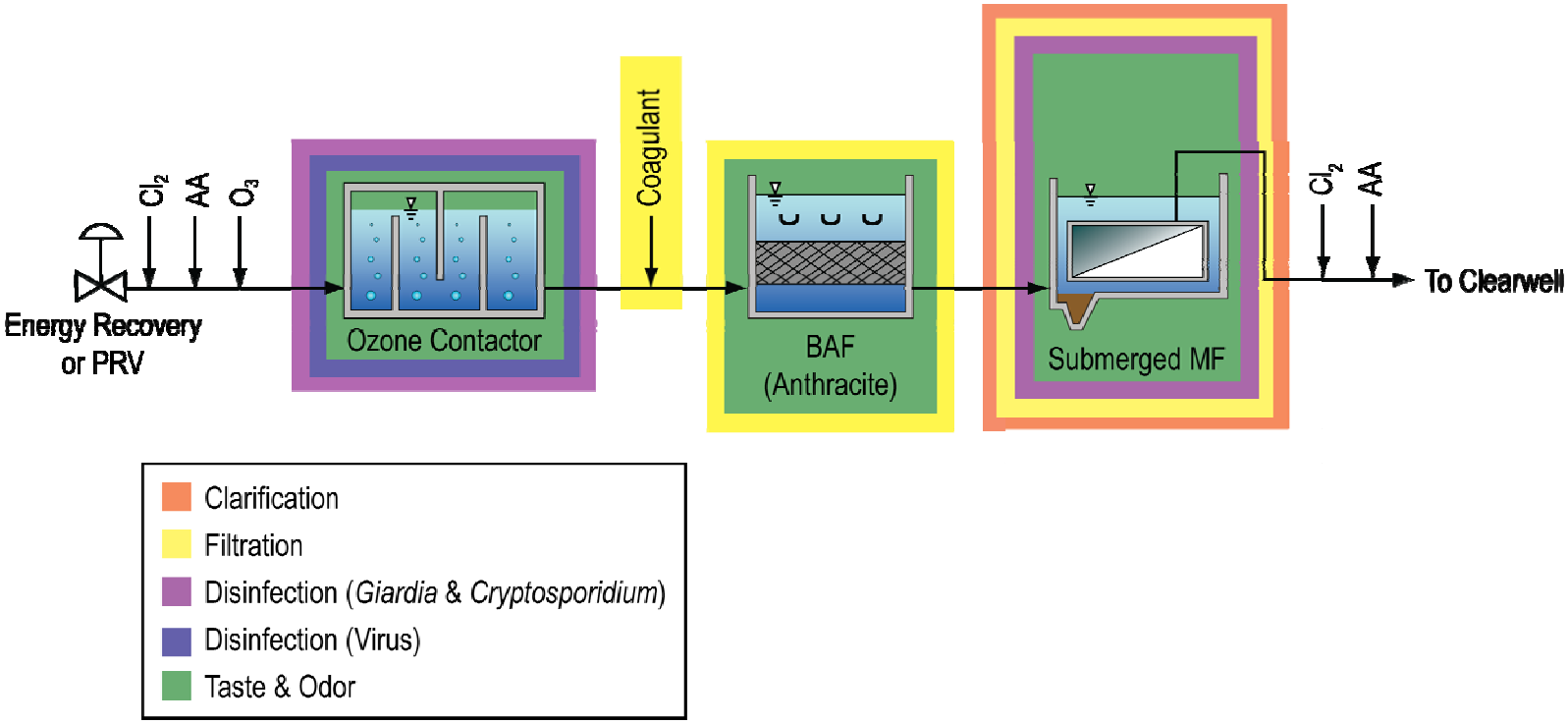
Preoxidation/Membrane Filtration/GAC Contactors/UV/Chlorine Disinfection/Chloramination



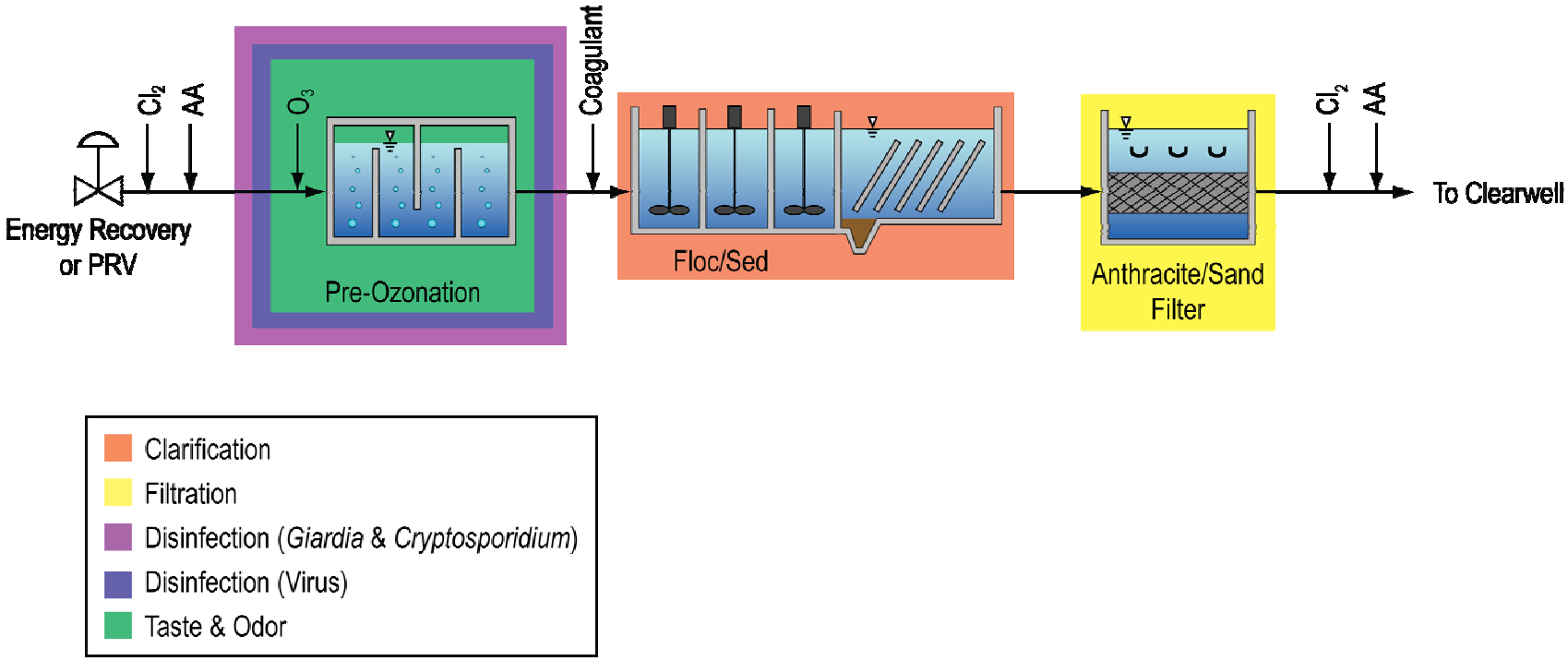
Preoxidation/PAC/Membrane Filtration/ UV/Chlorine Disinfection/Chloramination



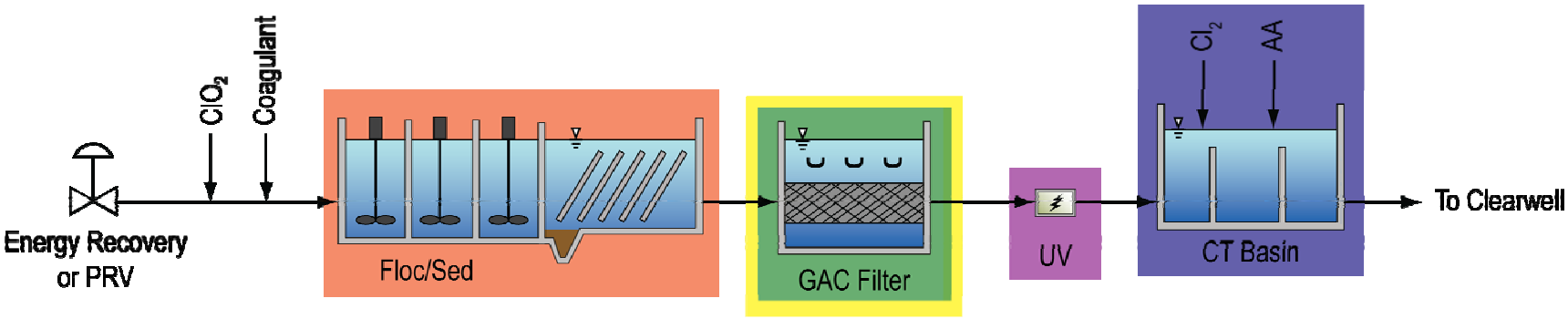
Ozone/BAF/Membrane Filtration/Chloramination



Ozone/Media Filtration/ Chloramination



Preoxidation/GAC Media Filtration/ Chlorine Disinfection/Chloramination



- Clarification
- Filtration
- Disinfection (*Giardia* & *Cryptosporidium*)
- Disinfection (Virus)
- Taste & Odor

APPENDIX H

Chemical System Calculations

Primary Coagulant (PC) SYSTEM CRITERIA
Baker WTP
Irvine Ranch Water District

Description		Units	Min	Avg	Max
Ferric Chloride PROPERTIES					
Concentration	39 %				
Specific Gravity	1.42				
Solution Strength	4.6 lb/gal				
DESIGN CRITERIA					
Process Flow Rate		mgd	14.1	28.1	28.1
Chemical Dosage		mg/l	2.0	10.0	20.0
Chemical Usage		ppd	234	2344	4687
Chemical Feed Rate		gph	2.1	21.2	42.4
Chemical Feed Rate		gpm	0.04	0.35	0.71
Chemical Feed Rate (Pre-Membrane)		gpd	51	508	1017
BULK STORAGE TANKS					
Bulk Storage Tanks		No.		2	
Storage Capacity (each tank)		gal		8,000	
Storage Capacity (total)		gal		16,000	
Storage Time (total)		days	268	31	20
Delivery Truck Full Load		gal		4,000	
Time Between Delivery (average)		days	67	7	5
No. of Truck Deliveries in Storage		#		4	
METERING PUMPS					
Pump Type				Hydraulic Diaphragm	
Pump Model Number, or equal				TBD	
Connection Size		mm		TBD	
Motor Speed Turndown Ratio		ratio		TBD	
Stroke Turndown Ratio		ratio		TBD	
Required Pump Capacity (maximum)		gph		42	
Required Pump Capacity (minimum)		gph		2.1	
Required Minimum Turndown		ratio		20:1	
Process Flow Rate		mgd	14.1	28.1	28.1
Number of Metering Pumps in Service		No.	1	1	1
Chemical Feed Rate (Total)		gph	2	21	42
Metering Pump Capacity (Per Pump)		gph	TBD	TBD	TBD
Pump Speed		%	TBD	TBD	TBD

Notes:
1. Motor speed under PLC control to maintain pH set point. Stroke length manually adjusted, as required, to modify metering pump range.

Primary Coagulant (PC) SYSTEM CRITERIA
Baker WTP
Irvine Ranch Water District

Description		Units	Min	Avg	Max
Ferric Chloride PROPERTIES					
Concentration	39 %				
Specific Gravity	1.42				
Solution Strength	4.6 lb/gal				
DESIGN CRITERIA					
Process Flow Rate		mgd	14.1	28.1	28.1
Chemical Dosage		mg/l	2.0	10.0	20.0
Chemical Usage		ppd	234	2344	4687
Chemical Feed Rate		gph	2.1	21.2	42.4
Chemical Feed Rate		gpm	0.04	0.35	0.71
Chemical Feed Rate (Pre-Membrane)		gpd	51	508	1017
BULK STORAGE TANKS					
Bulk Storage Tanks		No.		2	
Storage Capacity (each tank)		gal		8,000	
Storage Capacity (total)		gal		16,000	
Storage Time (total)		days	268	31	20
Delivery Truck Full Load		gal		4,000	
Time Between Delivery (average)		days	67	7	5
No. of Truck Deliveries in Storage		#		4	
METERING PUMPS					
Pump Type				Hydraulic Diaphragm	
Pump Model Number, or equal				TBD	
Connection Size		mm		TBD	
Motor Speed Turndown Ratio		ratio		TBD	
Stroke Turndown Ratio		ratio		TBD	
Required Pump Capacity (maximum)		gph		42	
Required Pump Capacity (minimum)		gph		2.1	
Required Minimum Turndown		ratio		20:1	
Process Flow Rate		mgd	14.1	28.1	28.1
Number of Metering Pumps in Service		No.	1	1	1
Chemical Feed Rate (Total)		gph	2	21	42
Metering Pump Capacity (Per Pump)		gph	TBD	TBD	TBD
Pump Speed		%	TBD	TBD	TBD

Notes:
1. Motor speed under PLC control to maintain pH set point. Stroke length manually adjusted, as required, to modify metering pump range.

CAUSTIC SODA (CS) SYSTEM CRITERIA FOR
CLEANING SOLUTION MAKEUP AND NEUTRALIZATION
Baker WTP (BASIS - Pall MF)
Irvine Ranch Water District

Description		
CAUSTIC SODA PROPERTIES		
Concentration	25 %	
Specific Gravity	1.27	
Solution Strength	2.6 lb/gal	
For citric neutralization	0.82 lbs NaOH/lb citric acid	
DESIGN CRITERIA (CS/SH CIP AND CEB SOLUTIONS)		
Volume Solution per CEB/CIP	gallons	5000
Chemical Dosage CIP	mg/l	12000
Chemical Dosage CEB	mg/l	0
USAGE FOR CIP CLEANING SOLUTIONS		
Pounds/CIP	lbs.	501
Volume Chemical per CIP	gallons	189
Time for Chem Transfer	minutes	TBD
Required Minimum Transfer Pump Flowrate	gpm	TBD
USAGE FOR CEB CLEANING SOLUTIONS		
Pounds/CEB	lbs.	0
Volume Chemical per CEB	gallons	0
Time for Chem Transfer	minutes	TBD
Required Minimum Transfer Pump Flowrate	gpm	TBD
TOTAL USAGE PER RACK		
CIP Frequency	per month	1
CEB Frequency	per month	30
Monthly Usage per Rack	gallons	189
NO. OF RACKS	**ea**	10
TOTAL MONTHLY USAGE FOR MEMBRANE CLEANING	**gallons**	1894
DESIGN CRITERIA (NEUTRALIZATION OF ACID CIP AND CEB SOLUTIONS)		
Volume Solution per CEB/CIP	gallons	5000
Chemical Dosage TO NEUTRALIZE ACID CIP	mg/l	16400
Chemical Dosage TO NEUTRALIZE ACID CEB	mg/l	16400
USAGE FOR NEUTRALIZING CIP ACID CLEANING SOLUTIONS		
Pounds/CIP	lbs.	684
Volume Chemical per CIP	gallons	259
Time for Chem Transfer	minutes	TBD
Required Minimum Transfer Pump Flowrate	gpm	TBD
USAGE FOR NEUTRALIZING CEB ACID CLEANING SOLUTIONS		
Pounds/CEB	lbs.	684
Volume Chemical per CEB	gallons	259
Time for Chem Transfer	minutes	TBD
Required Minimum Transfer Pump Flowrate	gpm	TBD
TOTAL USAGE PER RACK		
CIP Frequency	per month	1.00
CEB Frequency	per month	1.00
Monthly Usage per Rack	gallons	518
NO. OF RACKS	**ea**	10
TOTAL MONTHLY USAGE FOR MEMBRANE CLEANING	**gallons**	5177
BULK STORAGE TANKS	SEE "CAUSTIC SODA FOR CORROSION CONTROL"	
TRANSFER PUMPS FOR CIP SOLUTION MAKEUP		
Pump Type		AIR ACTUATED DIAPHRAGM
Pump Model Number, or equal		TBD
Connection Size	inches	TBD
Speed Turndown Ratio	ratio	TBD
Total Turndown Ratio (w/ changing hose)	ratio	TBD
Required Pump Capacity (maximum)	gpm	TBD
Required Pump Capacity (minimum)	gpm	TBD
Total Turndown	ratio	TBD
Number of Transfer Pumps in Service	No.	1
Chemical Feed Rate (Total)	gpm	TBD
Chemical Feed Rate (Per Pump)	gpm	TBD
Pump Speed	%	TBD
TRANSFER PUMPS		
Pump Type		AIR ACTUATED DIAPHRAGM
Pump Model Number, or equal		TBD
Connection Size	inches	TBD
Speed Turndown Ratio	ratio	TBD
Total Turndown Ratio (w/ changing hose)	ratio	TBD
Required Pump Capacity (maximum)	gpm	TBD
Required Pump Capacity (minimum)	gpm	TBD
Total Turndown	ratio	TBD
Number of Transfer Pumps in Service	No.	1
Chemical Feed Rate (Total)	gpm	TBD
Transfer Pump Capacity (Per Pump)	gpm	TBD
Pump Speed	%	TBD

Notes:
1. Transfer pumps will be calibrated on site to deliver required flow and operated at constant speed.

Caustic Soda (CS) SYSTEM CRITERIA for Corrosion Control
Baker WTP
Irvine Ranch Water District

Description		Units	Min	Avg	Max
CAUSTIC SODA PROPERTIES					
Concentration	25 %				
Specific Gravity	1.27				
Solution Strength	2.6 lb/gal				
DESIGN CRITERIA					
Process Flow Rate		mgd	14.1	28.1	28.1
Chemical Dosage		mg/l	1	4	7
Chemical Usage		ppd	117	937	1640
Chemical Feed Rate		gph	1.8	14.8	25.9
Chemical Feed Rate		gpm	0.03	0.25	0.43
Chemical Feed Rate		gpd	44	355	621
Monthly Usage for Corrosion Control		gallons	1330	10638	18617
Membrane Cleaning Monthly Usage		gallons	7071	7071	7071
BULK STORAGE TANKS					
Bulk Storage Tanks		No.		2	
Storage Capacity (each tank)		gal		8,500	
Storage Capacity (total)		gal		17,000	
Storage Time (total incl. membrane cleaning)		days	61	29	20
Delivery Truck Full Load		gal		4,500	
Time Between Delivery (average)		days	16	8	5
				4	
METERING PUMPS (for Corrosion Control)					
Pump Type				Hydraulic Diaphragm	
Pump Model Number, or equal				TBD	
Connection Size		mm		TBD	
Motor Speed Turndown Ratio		ratio		TBD	
Stroke Turndown Ratio		ratio		TBD	
Required Pump Capacity (maximum)		gph		26	
Required Pump Capacity (minimum)		gph		1.8	
Required Minimum Turndown		ratio		14:1	
Process Flow Rate		mgd	14.1	28.1	28.1
Number of Metering Pumps in Service		No.	1	1	1
Chemical Feed Rate (Total)		gph	2	15	26
Metering Pump Capacity (Per Pump)		gph	TBD	TBD	TBD
Pump Speed		%	TBD	TBD	TBD

Notes:
1. Motor speed under PLC control to maintain pH set point. Stroke length manually adjusted, as required, to modify metering pump range.

HYDROCHLORIC ACID (HCL) SYSTEM CRITERIA
Baker WTP (BASIS - Siemens MF)
Irvine Ranch Water District

Description		Units	Avg
CITRIC ACID PROPERTIES			
Concentration	15.0 %		
Specific Gravity	1.07		
Solution Strength	1.34 lb/gal		
DESIGN CRITERIA (Acid CIP)			
Volume Solution per CEB/CIP		gallons	5000
Chemical Dosage for CIP		mg/l	400
Chemical Dosage for CEB		mg/l	400
USAGE FOR CIP			
Pounds/CIP		lbs.	17
Volume Chemical per CIP		gallons	12
Time for Chem Transfer		minutes	TBD
Required Minimum Transfer Pump Flowrate		gpm	TBD
USAGE FOR CEB			
Pounds/CEB		lbs.	17
Volume Chemical per CEB		gallons	12
Time for Chem Transfer		minutes	TBD
Required Minimum Transfer Pump Flowrate		gpm	TBD
TOTAL USAGE PER RACK			
CIP Frequency		per month	1
CEB Frequency		per month	1
Monthly Usage per Rack		gallons	25
NO. OF RACKS		**ea**	10
TOTAL MONTHLY USAGE FOR MEMBRANE CLEANING		**gallons**	100
BULK STORAGE TANKS	SEE "CHLORINE DIOXIDE (CDO) THREE CHEMICAL SYSTEM CRITERIA"		
TRANSFER PUMPS			
Pump Type			AIR ACTUATED DIAPHRAGM
Pump Model Number, or equal			TBD
Connection Size		inches	TBD
Speed Turndown Ratio		ratio	TBD
Total Turndown Ratio (w/ changing hose)		ratio	TBD
Pump Capacity (maximum)		gpm	TBD
Pump Capacity (minimum)		gpm	TBD
Total Turndown		ratio	TBD
Number of Metering Pumps in Service		No.	1
Chemical Feed Rate (Total)		gpm	TBD
Chemical Feed Rate (Per Pump)		gpm	TBD
Pump Speed		%	TBD

Notes:
1. Transfer pumps will be calibrated on site to deliver required flow and operated at constant speed.

SODIUM BISULFITE (SBS) SYSTEM CRITERIA
Baker WTP (BASIS - Pall MF)
Irvine Ranch Water District

Description		Units	Plant Capacity 28 mgd
SODIUM BISULFITE PROPERTIES			
Concentration	38 %		
Specific Gravity	1.34		
Solution Strength	4.2 lb/gal		
For SH neutralization	1.47 lbs SBS/lb CL2		
DESIGN CRITERIA (Sodium Hypochlorite CEB/CIP)			
DESIGN CRITERIA (NEUTRALIZATION OF SH EFM/CIP)			
SEE "SODIUM HYPOCHLORITE (SH) MEMBRANE CLEANING SYSTEM CRITERIA" FOR SH CLEANING DOSES			
Volume Solution per CEB/CIP		gallons	5000
Chemical Dosage CIP		mg/l	1470
Chemical Dosage CEB		mg/l	588
USAGE FOR CIP			
Pounds/CIP		lbs.	61.3
Volume Chemical per CIP		gallons	14
Time for Chem Transfer		minutes	TBD
Required Minimum Transfer Pump Flowrate		gpm	TBD
USAGE FOR CEB			
Pounds/CEB		lbs.	25
Volume Chemical per CEB		gallons	5.8
Time for Chem Transfer		minutes	TBD
Required Minimum Transfer Pump Flowrate		gpm	TBD
TOTAL USAGE PER RACK			
CIP Frequency		per month	1
CEB Frequency		per month	30
Monthly Usage per Rack		gallons	188
NO. OF RACKS		**ea**	10
TOTAL MONTHLY USAGE FOR MEMBRANE CLEANING		**gallons**	**1881**
BULK STORAGE TANKS			
Storage Tanks		No.	1
Selected Volume per Tank		gal	6,300
Storage Capacity (total)		gal	6,300
Storage Time (total)		days	100
Delivery Truck Full Load		gal	4,200
Time Between Delivery (average)		days	67
No. of Truck Deliveries in Storage		#	1.5
TRANSFER PUMPS			
Pump Type			AIR ACTUATED DIAPHRAGM
Pump Model Number, or equal			TBD
Connection Size		inches	TBD
Speed Turndown Ratio		ratio	TBD
Total Turndown Ratio (w/ changing hose)		ratio	TBD
Required Pump Capacity (maximum)		gpm	TBD
Required Pump Capacity (minimum)		gpm	TBD
Total Turndown		ratio	TBD
Number of Transfer Pumps in Service		No.	1
Chemical Feed Rate (Total)		gpm	TBD
Transfer Pump Capacity (Per Pump)		gpm	TBD
Pump Speed		%	TBD

Notes:
1. Transfer pumps will be calibrated on site to deliver required flow and operated at constant speed.

SODIUM HYPOCHLORITE (SH) MEMBRANE CLEANING SYSTEM CRITERIA
Baker WTP (BASIS - Pall MF)
Irvine Ranch Water District

Description			Units	Avg
SODIUM HYPOCHLORITE PROPERTIES				
Concentration	10.80 %	as NaOCl		
Specific Gravity	1.17			
Solution Strength	1.050 lb SH/gal			
Solution Strength	1.000 lb Cl/gal			
DESIGN CRITERIA (SH EFM/CIP)				
Volume Solution per EFM/CIP			gallons	5000
Chemical Dosage CIP			mg/l	1000
Chemical Dosage CEB			mg/l	400
USAGE FOR CIP				
Pounds/CIP			lbs.	41.7
Volume Chemical per CIP			gallons	42
Time for Chem Transfer			minutes	TBD
Required Minimum Transfer Pump Flowrate			gpm	TBD
USAGE FOR CIP				
Pounds/CEB			lbs.	16.69
Volume Chemical per CEB			gallons	16.7
Time for Chem Transfer			minutes	TBD
Required Minimum Transfer Pump Flowrate			gpm	TBD
TOTAL USAGE PER RACK				
CIP Frequency			per month	1
CEB Frequency			per month	30
Monthly Usage per Rack			gallons	542
NO. OF RACKS			**ea**	**10**
TOTAL MONTHLY USAGE FOR MEMBRANE CLEANING			**gallons**	**5423**
BULK STORAGE TANKS	SEE "SODIUM HYPOCHLORITE (SH) SYSTEM CRITERIA"			
TRANSFER PUMPS				
Pump Type				AIR ACTUATED DIAPHRAGM
Pump Model Number, or equal				TBD
Connection Size			inches	TBD
Speed Turndown Ratio			ratio	TBD
Total Turndown Ratio (w/ changing hose)			ratio	TBD
Required Pump Capacity (maximum)			gpm	TBD
Required Pump Capacity (minimum)			gpm	TBD
Total Turndown			ratio	TBD
Number of Transfer Pumps in Service			No.	1
Chemical Feed Rate (Total)			gpm	TBD
Transfer Pump Capacity (Per Pump)			gpm	TBD
Pump Speed			%	TBD

Notes:
1. Transfer pumps will be calibrated on site to deliver required flow and operated at constant speed.

SODIUM HYPOCHLORITE (SH) DISINFECTION SYSTEM CRITERIA
Baker WTP
Irvine Ranch Water District

Description		Units	Min	Avg	Max
SODIUM HYPOCHLORITE PROPERTIES					
Concentration	10.8 %	as NaOCl			
Specific Gravity	1.17				
Solution Strength	1.050 lb SH/gal				
Solution Strength	1.000 lb Cl/gal				
DESIGN CRITERIA					
Process Flow Rate		mgd	14.1	28.1	28.1
Chemical Dosage for Disinfection (mg/L of Chlorine)		mg/l	2.5	3	4
Chemical Feed Rate		gph	12.2	29.3	39.0
Chemical Feed Rate		gpm	0.20	0.49	0.65
Chemical Feed Rate		ml/min	770	1,847	2,463
Daily Usage		ppd	293	703	937
Monthly Usage for Disinfection		gallons	8,786	21,086	28,115
Monthly Usage for MF Cleaning		gallons	5,423	5,423	5,423
Monthly Usage for ClO2 Generation		gallons	1,024	4,098	5,737
Total Monthly Usage at 28 mgd		**gallons**	**15,233**	**30,607**	**39,275**
BULK STORAGE TANKS					
Bulk Storage Tanks		No.		2	
Storage Capacity (each tank)		gal		8,500	
Storage Capacity (total)		gal		17,000	
Storage Time (total)		days	33	17	13
Delivery Truck Full Load		gal		4,900	
Time Between Delivery (average)		days	10	5	4
No. of Fuill trucks i					
DISINFECTION SYSTEM METERING PUMPS					
Pump Type				Hydraulic Diaphragm	
Pump Model Number, or equal				TBD	
Connection Size		mm		TBD	
Speed Turndown Ratio		ratio		TBD	
Total Turndown Ratio		ratio		TBD	
Required Pump Capacity (maximum)		gph		40	
Required Pump Capacity (minimum)		gph		10	
Required Minimum Turndown		ratio		4:1	
Process Flow Rate		mgd	14.1	28.1	28.1
Number of Metering Pumps in Service		No.	1	1	1
Chemical Feed Rate (Total)		gph	12	29	39
Metering Pump Capacity (Per Pump)		gph	TBD	TBD	TBD
Pump Speed		%	TBD	TBD	TBD

Notes:
1. Motor speed under PLC control to maintain chlorine residual set point. Stroke length manually adjusted, as required, to modify metering pump range.

APPENDIX I

Backwash Wastewater Calculations

Meurer Research, Inc.
6270 Joyce Dr. Golden, CO 80403
Phone 303-279-8373 Fax 303-279-8429

Plate Settler Design Sheet

Project Name: Irvine Ranch Water District

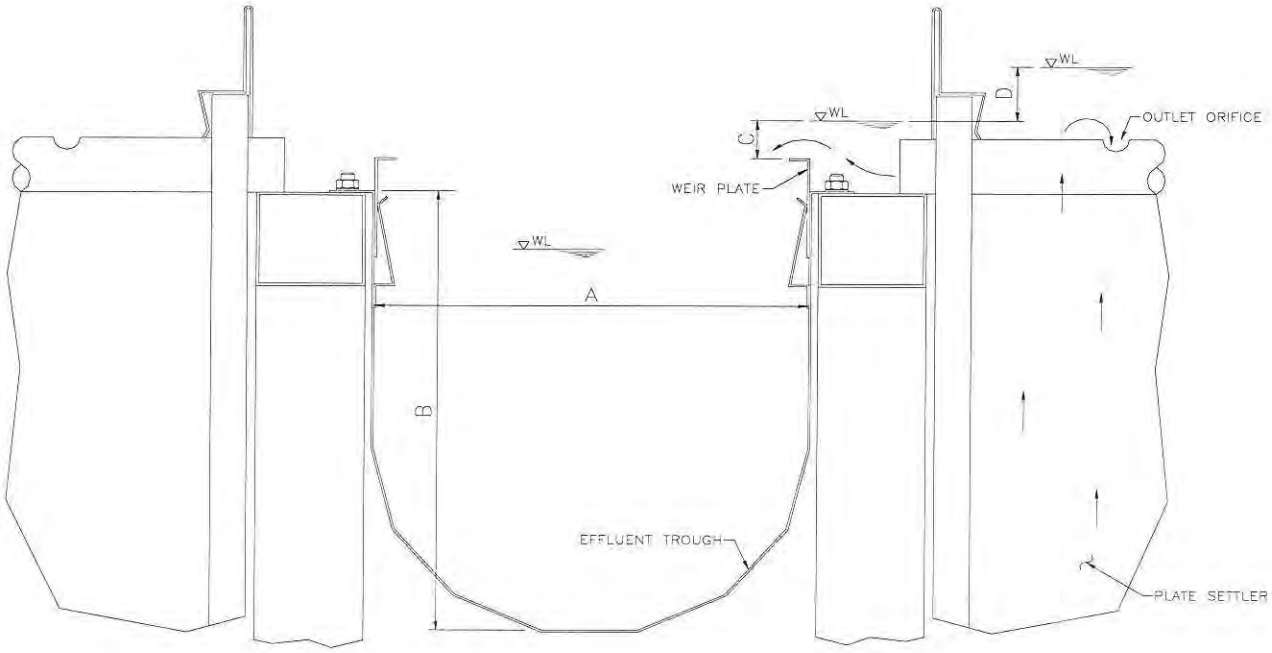
Date: 4/23/2009

Total Design Flow:	3.00 mgd	2084 gpm	Number of Basins:	1
Design Flow per Basin:	3.00 mgd	2084 gpm	Length of Basin:	40 ft
Hydraulic Flow per Basin (max.):	3.00 mgd	2084 gpm	Width of Basin:	20 ft
			Depth of Basin (SWD):	16 ft

Design Loading Rate:	0.4 gpm/ft^2	Effective Settling Area:	5209 ft^2
Efficiency Factor:	90 %	Projected Settling Area:	5788 ft^2
Angle of Plate Inclination:	55 degrees	Actual Settling Area:	10090 ft^2

Width of plate:	4.5	Plate Settler Area:	45.0 ft^2
Length of plate:	10	Total Plates per Basin:	224
No. of Rows per Basin:	3	No. of Plate Cartridges per Row:	1
Flow per Plate:	9.29 gpm	No. of Plate Settlers per Cartridge:	75
Outlet Orifices per Plate:	4	Weight of Cartridge:	4498 lbs
Diameter of Orifices:	3/4 inches	Length of Plate Settler Equipment:	20.0 ft
Head loss through orifices (D):	1.38 inches	Width of Plate Settler Equipment:	18.3 ft

Number of Troughs:	3 (2 + 2 half troughs)	Width of Trough (A):	12 inches
Flow per Trough:	695 gpm	Depth of Trough (B):	12 inches
Trough Capacity:	717 gpm	Head loss over weir (C):	0.77 inches



Floc/Sed

Assumption: Coagulant used in the primary process stream; coagulation here is supplemental

		MAX	AVG	MIN	
Flow	mgd	3.0	1.4	0.3	
Flash mix type:			Pump Diffusion		
Coagulant:		PACl	PACl	PACl	
Dose:	mg/L	20	10	5	
Flocculator Type:		Vertical	Vertical	Vertical	
Flocculation time	min	25	25	25	per Susumu pg. 376
Total Flocculation basin volume	gallons	52080	52080	52080	
No. of Stages	ea	2	2	2	
Flocculation volume each stage	gallons	26040	26040	26040	
	ft3	3481	3481	3481	
L,W,H	ft	15	15	15	
G					
Stage 1		60	60	60	
Stage 2		30	30	30	
Power Stage 1	Hp	0.8	0.8	0.8	
Power Stage 2	Hp	0.2	0.2	0.2	
Total Power	Hp	1.0	1.0	1.0	

APPENDIX J

Ultraviolet Light Disinfection Calculations

Baker Water Treatment Plant
Irvine Ranch Water District

UV System Design Approach

09/03/2009

DESCRIPTION		UV FOR DISINFECTION ONLY		REFERENCE
		LPHO LAMP ALTERNATIVE	MP LAMP ALTERNATIVE	
Approach				
Year 1		Install UV reactors for disinfection only (LPHO lamps, 50 KVA)	Install UV reactors for disinfection only (MP lamps, 230 KVA)	
Unit Costs				
UV Disinfection Equipment		$487,000	$437,000	Vendor Quote
Equipment Installation	33%	$162,333	$145,667	Tracy, CA
Mobilization/Insurance/Management	10%	$64,933	$58,267	
Annual O&M Cost		$15,000	$55,000	UVCAT
Present Worth Analysis (i=4.5%)				
P		$714,267	$640,933	
P/A (30 years)	16.2889	$244,333	$895,889	
TOTAL		$958,600	$1,536,822	

Notes:
1) UV reactor is sized to minimize headloss and maximize head available to the membrane system. Therefore, buiding size and process mechanical are the same for LPHO reactors and MP reactors
2) Annual O&M cost for base loaded WTP at 25 MGD. Water UV transmittance at 85%. 1.5-log Crypto/Giardia inactivation. Power at $0.13/kWhr. Replacement lamps included
3) UVCAT is Carollo Engineers proprietary simulation software

Baker Water Treatment Plant
Irvine Ranch Water District

UV System Design Approach

09/03/2009

DESCRIPTION		UV FOR DISINFECTION INITIALLY. UV/AOP AFTER 10 YEARS		REFERENCE
		LPHO/MP ALTERNATIVE	MP ALTERNATIVE	
Approach				
Year 1		Install UV reactors for disinfection only (LPHO lamps, 50 KVA)	Install UV reactors for UV/AOP. Install UV MP lamps for disinfection only. Install electrical for disinfection only (230 KVA)	
Year 1		Size plant switchboard, treatment building switchboard or MCC, and conductors in between to accommodate future installation and power UV/AOP (900 KVA).		
Year 11		Remove LPHO UV disinfection reactors. Install UV/AOP reactors. Upgrade electrical switchboards	Add MP lamps to UV reactors for UV/AOP. Upgrade electrical switchboards	
Unit Costs				
UV Disinfection Equipment		$487,000	$437,000	Vendor Quote
Installation	33%	$162,333	$145,667	Tracy, CA
Mobilization/Insurance/Management	10%	$64,933	$58,267	
Annual O&M Cost (Years 1 to 10)		$15,000	$55,000	UVCAT
Salvage Value (Year 11)		$0	N.A.	
UV/AOP Equipment (Year 11)		$1,036,000	$599,000	Vendor Quote
Installation (Year 11)	33%	$341,880	$197,670	Tracy, CA
Mobilization/Insurance/Management (Y 11)	10%	$137,788	$79,667	
Annual O&M Cost (Years 11 to 30)		$425,000	$425,000	UVCAT
Present Worth Analysis (i=4.5%)				
P		$714,267	$640,933	
P/A (10 years)	7.9127	$118,691	$435,199	
P/F (11 years)	0.6162	$933,953	$539,998	
P/A (years 11 to 30)	13.0079	$5,528,373	$5,528,373	
TOTAL		$7,295,283	$7,144,504	

Notes:
1) UV reactor is sized to minimize headloss and maximize head available to the membrane system. Therefore, buiding size and process mechanical are the same for LPHO reactors and MP reactors
2) Annual O&M cost for base loaded WTP at 25 MGD. Water UV transmittance at 85%. 1.5-log Crypto/Giardia inactivation (disinfection). 1-log MIB removal (AOP). AOP used 3 months per year. Power at $0.13/kWhr. Replacement lamps included
3) UVCAT is Carollo Engineers proprietary simulation software

APPENDIX K

Contact Basin Disinfection Calculations

BAKER REGIONAL WATER TREATMENT PLANT
4-LOG VIRUS INACTIVATION WITH FREE CHLORINE

	Max	Min.	CT (mg/L*min)					Ratio
	Flow[a]	Temp	Required	Actual				of
Month	(mgd)	(^{o} C)		Pipe 1	Pipe 2	CT	Total	CT_a/CT_r
Jan	35.0	4	9.2	0.0	0.0	9.9	9.9	1.08
Feb	35.0	10	5.9	0.0	0.0	9.9	9.9	1.7
Mar	35.0	10	5.9	0.0	0.0	9.9	9.9	1.7
Apr	35.0	11	5.4	0.0	0.0	9.9	9.9	1.8
May	35.0	11	5.4	0.0	0.0	9.9	9.9	1.8
Jun	35.0	15	3.9	0.0	0.0	9.9	9.9	2.5
Jul	35.0	27	2.2	0.0	0.0	9.9	9.9	4.5
Aug	35.0	25	2.2	0.0	0.0	9.9	9.9	4.6
Sep	35.0	15	3.9	0.0	0.0	9.9	9.9	2.5
Oct	35.0	12	5.0	0.0	0.0	9.9	9.9	2.0
Nov	35.0	10	5.9	0.0	0.0	9.9	9.9	1.7
Dec	35.0	10	5.9	0.0	0.0	9.9	9.9	1.7

Water Quality

pH = 6 - 9
Chlorine Residual (mg/L) = 2.00

CT Volume

Filtrate Pipe from Filtration Building to Basin [Pipe 1]

Dia =	42	inches
Length =	0	feet
Volume =	0	gallons
T_{10}/T =	80%	

FW Pipe from Basin to 16 MGD Reservoir [Pipe 2]

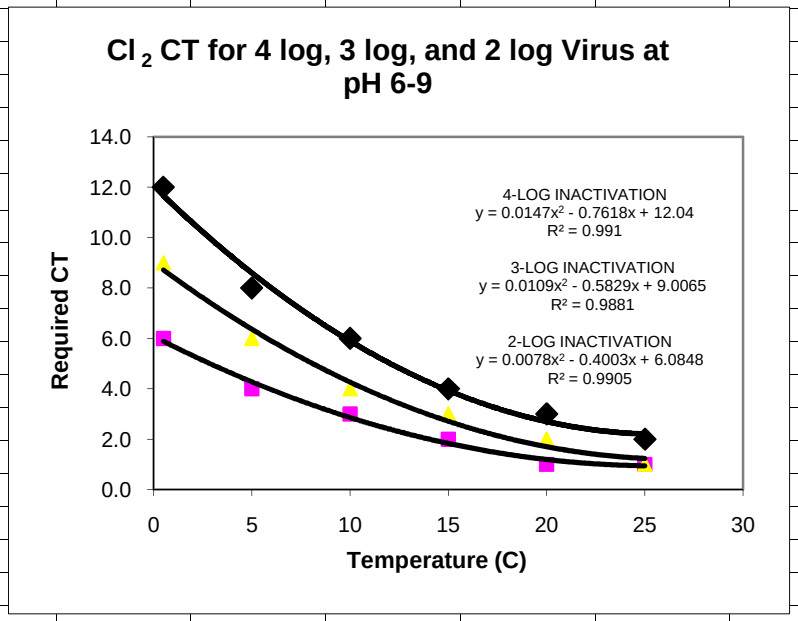
Dia =	42	inches
Length =	0	feet
Volume =	0	gallons
T_{10}/T =	80%	

CT Basin

Channel Width	6.2	ft
Channel Length	208	ft
L/W	34	
Area =	2,559	sq ft
Minimum Depth =	**10.5**	ft
Total Volume =	201,024	gallons
AWWARF T_{10}/T =	**60%**	
Design T_{10}/T =	60%	
Safety Factor =	1.0	

Ref. AWWARF Improving Clearwell Design for CT Compliance; Figure 7.7

CL2 LOG Virus Formula



Source: EPA SWTR Guidance Manual
Table E-7

x	y	y	y
Temp	Required	Required	Required
(^{o} C)	4 -LOG CT	3 -LOG CT	2 -LOG CT
[t]	**[CT]**	**[CT]**	**[CT]**
0.5	12.0	9.0	6.0
5	8.0	6.0	4.0
10	6.0	4.0	3.0
15	4.0	3.0	2.0
20	3.0	2.0	1.0
25	2.0	1.0	1.0

APPENDIX L

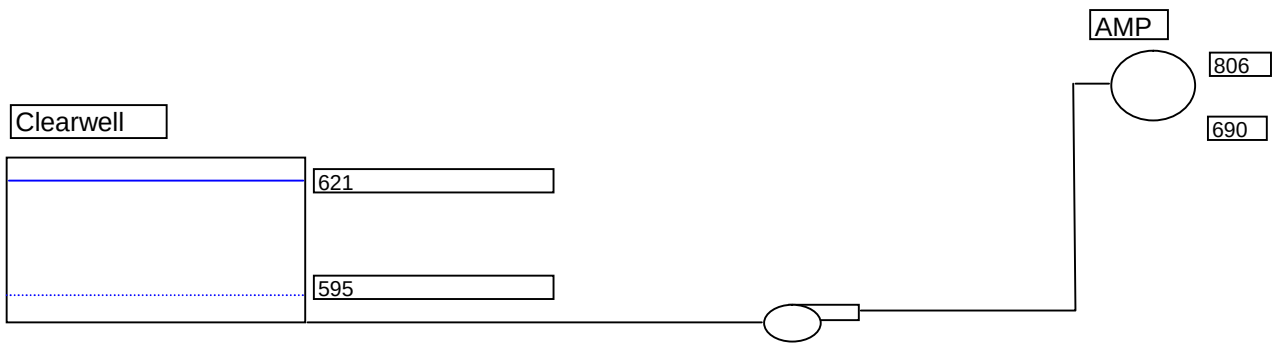
Product Water Pump Station Calculations

Baker WTP
Product Water Pump Station
Hydraulic Calculations
TABLE L1 - Static Head Calculation

Static Head Condition				Comment
Clearwell Reservoir Minimum	595	(ft)	(Elev.)	Conservative, Min = 2 ft
Clearwell Reservoir Maximum	621	(ft)	(Elev.)	HWL
Maximum HGL of AMP =	806	(ft)	(Elev.)	
Minimum (Design) HGL of AMP =	690	(ft)	(Elev.)	

Static Head, **Low Head** Condition:	**69**	**(ft)**
Static Head, **High Head** Condition:	**211**	**(ft)**

AMP = Low HGL 690 to 630 ft handled by pressure reduction.



Baker WTP
Product Water Pump Station
Hydraulic Calculations
TABLE L2 - Pump Design Summary

Pump Requirements	Q =	14,800	gpm	=	33.0	cfs
Static Head	Low Static Head =	69	ft			
	High Static Head =	211	ft			
Suction Piping	Suction Losses =	10	ft @ Design Flow			
Discharge Piping	Friction Losses =	5	ft @ Design Flow			
	Minor Losses =	8	ft @ Design Flow			
Total Dynamic Head	TDH =	235	ft @ Design Flow (High Head Condition)			
Pump Efficiency	Efficiency =	82	% (Up to 86% depending on operation point)			
Pump Horsepower	hp =	300	per pump (4 duty - 1 back-up)			
Net Positive Suction Head	NPSHA =	39.5	ft			
	NPSHR [1] =	18.0	ft			

[1] Based on ITT Industries / Goulds Pump Model No. 18HMO.

APPENDIX M

IRWD – Process Equipment & Instrument Tag Guidelines

SEPTEMBER 2009
South Orange County WMA

IRWD

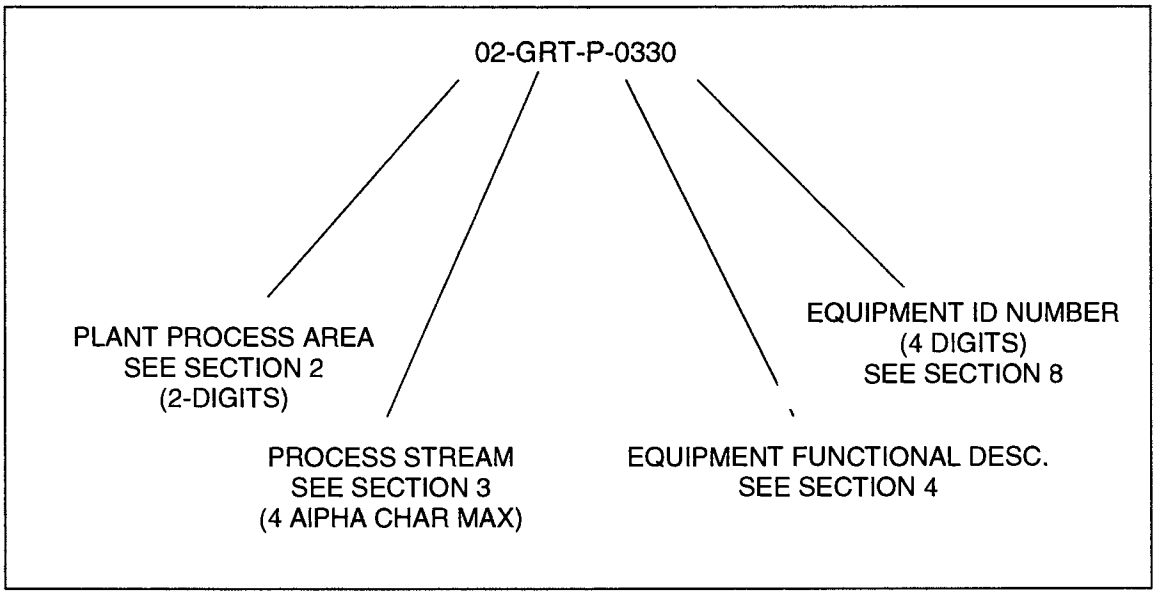
PROCESS EQUIPMENT & INSTRUMENT TAG GUIDELINE

TABLE OF CONTENTS

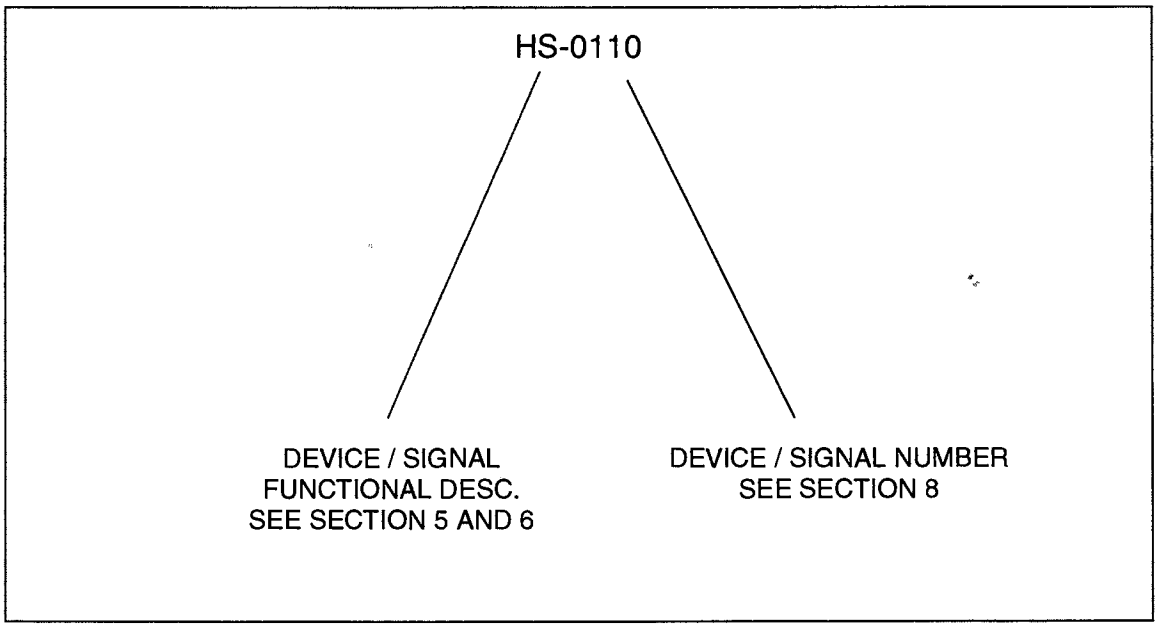
Section Title

1. EQUIPMENT AND INSTRUMENT TAG FORMAT

EQUIPMENT



INSTRUMENTATION DEVICE AND SIGNALS



2. PLANT PROCESS AREAS

(The Plant Process Area does not denote a physical area, it identifies an entire plant process)

AREA NUM	EQUIPMENT DESCRIPTION
00	INFLUENT/RAW/PRETREATMENT
01	
02	
03	
04	
05	
06	
07	
08	
09	
10	
11	
12	
13	
14	
15	ELECTRICAL AND COMMUNICTATIONS
16	OFF-SITE (RTU) COMMUNICATIONS SIGNALS
17	MISCELLANEOUS AREAS
18	
19	

- 1 PROCESS AREA FOR CHEM

3. PLANT PROCESS STREAMS

ABBREVIATION	EQUIPMENT DESCRIPTION
AA	AQUA AMMONIA
BWS	BACKWASH SUPPLY
CA	COMPRESSED AIR
CF	RO CLEANING FEED
CLW	RO CLEANING WASTE
CR	RO CLEANING RETURN
CW	CLARIFIED WATER
D	DRAIN
FPW	FINAL PRODUCT WATER
FW	FILTERED WATER
OF	OVERFLOW
NRW	NON RECLAIMABLE WASTE
PCR	PERMEATE CLEANING RETURN
REC	RO CIP RECIRC
ROC	RO CONCENTRATE
ROF	RO FEED
ROP	RO PERMEATE
RW	RAW WATER
S	SEWER
SA	SULFURIC ACID
SD	STORM DRAIN
SH	SODIUM HYDOXIDE
SHC	SODIUM HYPOCHLORITE
SPD	SUMP PUMPED DRAIN
TI	THRESHOLD INHIBITOR
WT	POTABLE WATER
WBW	WASTE BACKWASH

4. EQUIPMENT FUNCTIONAL DESCRIPTIONS

ABBREVIATION	EQUIPMENT DESCRIPTION
AC	AIR CONDITIONING PACKAGE UNIT
AHU	AIR HANDLER
ATS	AUTOMATIC TRANSFER SWITCH
AV	AIR VAC
BAT	BATTERY BANK
BCH	BATTERY CHARGER
BCP	BRANCH CIRCUIT PANEL
BFV	BUTTERFLY VALVE
BKR	BREAKER (POWER)
BLV	BALANCING VALVE
BOL	BOILER
BPV	BACK PRESSURE VALVE
BSR	BARSCREEN, RAKE
BV	BALL VALVE
BWR	BLOWER
CEN	CENTRIFUGE
CF	CARTRIDGE FILTER
CHL	CHLORINATOR
CHR	CHILLER
CLF	CLARIFIER
CLR	COLLECTOR, SLUDGE OR SCUM
CMP	COMPRESSOR
CND	CONDENSOR
CON	CONTROLLER, MOTOR, ELECTRONIC
CRN	CRANE
CT	CURRENT TRANSFORMER
CTW	COOLING TOWER
CUB	CUBICLE
CV	CHECK VALVE
CVY	CONVEYOR
DG	DEGASSIFIER
DLN	DRIVE LINE
DP	DISTRIBUTION PANEL 480V OR 240V
DPR	RELAY, MACHINE DIFFERENTIAL
DRY	DRYER
EF	EXHAUST FAN
ELV	ELEVATOR
ENG	ENGINE
EVP	EVAPORATOR
EW	EYE WASH (SAFETY SHOWER)

ABBREVIATION	EQUIPMENT DESCRIPTION
EXR	EXCHANGER
F	FAN
FBK	FEEDER BREAKER
FIX	FIXTURE, LIGHTING
FLA	FLAME ARRESTOR
FLR	FLARE
FLT	FILTER
FLV	FLAPPER VALVE
FP	FEED PUMP
FRM	FRAME
FRQ	RELAY, FREQUENCY
FRX	FIRE EXTINGUISHER
GAT	GATE
GBK	GENERATOR BREAKER
GBX	GEARBOX
GDR	GRINDER
GEN	GENERATOR
GEX	GENERATOR EXCITER
GLV	GLOBE VALVE
GOP	GATE OPERATOR
GV	GATE VALVE
HTR	HEATER
IOC	RELAY, INSTANTANEOUS OVERCURRENT
IRC	IRRIGATION CONTROLLER
ITC	RELAY, INST/TIME OVERCURRENT
LER	RELAY, LOSS OF EXCITATION
LP	LIGHTING PANEL/LOW VOLTAGE PANEL
M	MECHANICAL EQUIPMENT
MBK	MAIN BREAKER
MCC	MOTOR CONTROL CENTER
MDRV	MAGNETIC DRIVE
MOV	MOTORIZED VALVE OPERATOR
MP	METERING PUMP
MS	MOTOR STARTER
MSB	MAIN SWITCH BOARD
MTG	METERING SECTION
MTR	MOTOR
MXR	MIXER
NSO	RELAY, NEGATIVE SEQUENCE OVERCURRENT
NV	NEEDLE VALVE
OPS	OPERATOR
CP	PANEL (CONTROL, FIELD)
P	PUMP
PD	PULSATION DAMPENER

ABBREVIATION	EQUIPMENT DESCRIPTION
PIPE	PIPING
PIV	PINCH VALVE
PM	POWER MONITOR
PRD	PRESSURE REDUCING VALVE
PRG	PRESSURE REGULATING VALVE
PRV	PRESSURE RELIEF VALVE
PRVB	PRESSURE RELIEF/VACUUM BREAKER
PTEQ	PORTABLE EQUIPMENT
PTS	POTENTIAL TRANSFORMER
PUR	PURIFIER
PV	PLUG VALVE
PVD	RELAY, DIFFERENTIAL VOLTAGE
PWR	RELAY, PILOT WIRE DIFFERENTIAL
PWS	RELAY, PILOT WIRE SENDING
REF	REFRIGERATOR, STORAGE
REG	REGULATOR
RLY	RELAY
RPD	REDUCED PRINCIPLE DEVICE
RPR	RELAY, POWER DIFFERENTIAL
SBD	RELAY, STATIC DIFFERENTIAL
SBK	STANDBY POWER BREAKER
SBR	SCRUBBER
SCPR	SERVICE CONNECTION PRESSURE REGULATOR
SF	SUPPLY FAN
SFR	RELAY, STATIC FREQUENCY
SOF	SOFTENER
SPR	SEPARATOR
STR	STRAINER
STRC	STRUCTURE
SV	SOLENOID VALVE
SWBD	SWITCHBOARD
SWGR	SWITCHGEAR
SWI	SWITCH
SWP	SWEEP ARM ASSEMBLY
SYN	RELAY, SYNC CHECK
TBC	TURBOCHARGER
TBK	TIE BREAKER
TCV	TROTTLE CONTROL VALVE
TK	TANK
TOC	RELAY, TIME OVERCURRENT
TOU	RELAY, TIME OVER/UNDER VOLTAGE
TRP	TRAP
TSV	TELESCOPING VALVE
TUR	TURBINE
TUV	RELAY, TIME VOLTAGE

ABBREVIATION	EQUIPMENT DESCRIPTION
TWR	TOWER (SURGE)
UPS	UNINTERRUPTABLE POWER SUPPLY
UVS	RELAY, UNDER VOLTAGE AND PHASE SEQUENCE
VB	VACUUM BREAKER (WATER)
VBR	RELAY, VOLTAGE BALANCE
VDC	DOUBLE CHECK VALVE (FIRE SYSTEM)
VEHL	VEHICLE
VFD	VARIABLE FREQUENCY DRIVE
VKG	KNIFE GATE VALVE
VNTV	VENT VALVE
VRD	RELAY, RESTRAINED DIRECTIONAL OVERCURRENT
XFMR	TRANSFORMER

5. DEVICE / SIGNAL FUNCTIONAL DESCRIPTION

Following is a table of abbreviations for signal functional identification. The table is a comprehensive list of many types of signals and devices.

Following the comprehensive table section in Section 6 is a list of commonly used abbreviations. These are shown in the sample P & IDs that are also provided in this document.

	Controllers				Readout Devices		Switches and Alarm Devices										Transmitter								
Initiating or Measured Variable	Recording	Indicating	Blind	Self Actuated Control Valves	Recording	Indicating	Alarm High	Alarm High/High	Switch High	Switch High/High	Alarm Low	Alarm Low/Low	Switch Low	Switch Low/Low	Alarm Comb	Switch Comb	Recording	Indicating	Blind	Solenoids, Relays,	Primary Elements	Test Point	Well or Probe	Viewing Device or Glass	Safety Device
Analysis	ARC	AIC	AC		AR	AI	AAH	AAHH	ASH	ASHH	AAL	AALL	ASL	ASLL	AAHL	ASHL	ART	AIT	AT	AY	AE	AP	AW		
Burner/ Combustion	BRC	BIC	BC		BR	BI	BAH	BAHH	BSH	BSHH	BAL	BALL	BSL	BSLL	BAHL	BSHL	BRT	BIT	BT	BY	BE		BW	BG	
Density	DRC	DIC	DC	DCV	DR	DI	DAH	DAHH	DSH	DSHH	DAL	DALL	DSL	DSLL	DAHL	DSHL	DRT	DIT	DT	DY	DE	DP			
Voltage	ERC	EIC	EC		ER	EI	EAH	EAHH	ESH	ESHH	EAL	EALL	ESL	ESLL	EAHL	ESHL	ERT	EIT	ET	EY	EE				
Flow Rate	FRC	FIC	FC	FCV, FICV	FR	FI	FAH	FAHH	FSH	FSHH	FAL	FALL	FSL	FSLL	FAHL	FSHL	FRT	FIT	FT	FY	FE	FP		FG	
Flow Quantity	FQRC	FQIC			FQR	FQI	FQAH	FQAH	FQSH	FQSH	FQAL	FQAL	FQSL	FQSL	FQHL			FQIT	FQT	FQY	FQE				
Flow Ratio	FFRC	FFIC	FFC		FFR	FFI	FFAH	FFAH	FFSH	FFSH	FFAL	FFAL	FFSL	FFSL	FFHL										
Hand		HIC	HC						HSH	HSH			HSL	HSLL											
Current	IRC	IIC			IR	II	IAH	IAHH	ISH	ISHH	IAL	IALL	ISL	ISLL	IAHL	ISHL	IRT	IIT	IT	IY	IE				
Power	JRC	JIC			JR	JI	JAH	JAHH	JSH	JSHH	JAL	JALL	JSL	JSLL	JAHL	JSHL	JRT	JIT	JT	JY	JE				
Time	KRC	KIC	KC	KCV	KR	KI	KAH	KAHH	KSH	KSHH	KAL	KALL	KSL	KSLL	KAHL	KSHL	KRT	KIT	KT	KY	KE				
Level	LRC	LIC	LC	LCV	LR	LI	LAH	LAHH	LSH	LSHH	LAL	LAL	LSL	LSL	LAHL	LSHL	LRT	LIT	LT	LY	LE		LW	LG	
Moisture	MRC	MIC	MC		MR	MI	MAH	MAHH	MSH	MSHH	MAL	MALL	MSL	MSLL	MAHL	MSHL	MRT	MIT	MT	MY	ME	MP	MW		
Pressure	PRC	PIC	PC	PCV	PR	PI	PAH	PAHH	PSH	PSHH	PAL	PALL	PSL	PSLL	PAHL	PSHL	PRT	PIT	PT	PY	PE	PP			PSV, PSE
Pressure Differential	PDRC	PDIC	PDC	PDCV	PDR	PDI	PDAH	PDAH	PDSH	PDSH	PDAL	PDAL	PDSL	PDSL			PDRT	PDIT	PDT	PDY	PE	PP			
Quantity	QRC	QIC			QR	QI	QAH	QAHH	QSH	QSHH	QAL	QALL	QSL	QSLL	QAHL	QSHL	QRT	QIT	QT	QY	QE				
Radiation	RRC	RIC	RC		RR	RI	RAH	RAHH	RSH	RSHH	RAL	RALL	RSL	RSLL	RAHL	RSHL	RRT	RIT	RT	RY	RE		RW		
Speed	SRC	SIC	SC	SCV	SR	SI	SAH	SAHH	SSH	SSHH	SAL	SALL	SSL	SSLL	SAHL	SSHL	SRT	SIT	ST	SY	SE				
Temperature	TRC	TIC	TC	TCV	TR	TI	TAH	TAHH	TSH	TSHH	TAL	TALL	TSL	TSLL	TAHL	TSHL	TRT	TIT	TT	TY	TE	TP	TW		TSE

	Controllers				Readout Devices		Switches and Alarm Devices										Transmitter								
Initiating or Measured Variable	Recording	Indicating	Blind	Self Actuated Control Valves	Recording	Indicating	Alarm High	Alarm High/High	Switch High	Switch High/High	Alarm Low	Alarm Low/Low	Switch Low	Switch Low/Low	Alarm Comb	Switch Comb	Recording	Indicating	Blind	Solenoids, Relays,	Primary Elements	Test Point	Well or Probe	Viewing Device or Glass	Safety Device
Temperature Differential	TDRC	TDIC	TDC	TDCV	TDR	TDI	TDAH	TDAH	TDSH	TDSH	TDAL	TDAL	TDSL	TDSL			TDRT	TDIT	TDT	TDY	TE	TP	TW		
PLC/MMI																				UY					
Vibration/Machinery Analysis	VRC	VIC	VC		VR	VI	VAH	VAHH	VSH	VSHH	VAL	VALL	VSL	VSLL	VAHL	VSHL	VRT	VIT	VT	VY	VE				
Weight/Force	WRC	WIC	WC		WR	WI	WAH	WAHH	WSH	WSHH	WAL	WALL	WSL	WSLL	WAHL	WSHL	WRT	WIT	WT	WY	WE				
Weight/Force Differential	WDRC	WDIC	WDC		WDR	WDI	WDAH	WDAH	WDSH	WDSH	WDAL	WDAL	WDSL	WDSL			WDRT	WDIT	WDT	WDY	WE				
Event/State/ Presence	YRC	YIC	YC		YR	YI	YAH	YAHH	YSH	YSHH	YAL	YAL	YSL	YSL	YAHL	YSHL			YT	YY	YE				
Posistion/Dimension	ZRC	ZIC	ZC	ZCV	ZR	ZI	ZAH	ZAHH	ZSH	ZSHH	ZAL	ZAL	ZSL	ZSL	ZAHL	ZSHL	ZRT	ZIT	ZT	ZY	ZE				
Gauging/Deviation	ZDRC	ZDIC	ZDC	ZDCV	ZDR	ZDI	ZDAH	ZDAH	ZDSH	ZDSH	ZDAL	ZDAL	ZDSL	ZDSL			ZDRT	ZDIT	ZDT	ZDY	ZDE				

6. COMMONLY USED DEVICE AND SIGNAL FUNCTIONAL IDENTIFICATION

Following is a table of abbreviations for signal functional identification. The table is a comprehensive list of many types of signals and devices.

Following the comprehensive table section in Section 6 is a list of commonly used abbreviations. These are shown in the sample P & IDs that are also provided in this document.

TAG	DESCRIPTION
	DISCRETE DEVICES:
HI	SELECTOR SWITCH STATUS (REMOTE-LOACL)
HK	OUTPUT TO EQUIPMENT (e.g. PUMP CALL, VALVE OPEN/CLOSE COMMAND)
HS	HAND SWITCH – FIELD DEVICE
YI	STATUS INDICATION (MOTOR RUN STATUS)
YN	DATA LINK (MODBUS, MODBUS PLUS)
ZI	POSITION FEEDBACK SIGNAL
ASH	ANALYZER VALUE - HIGH
ASL	ANALYZER VALUE - LOW
FSH	FLOW HIGH SWITCH
FSL	FLOW LOW SWITCH
HKC	OUTPUT TO A VALVE TO CLOSE
HKO	OUTPUT TO A VALVE TO OPEN
LSH	LEVEL SWITCH HIGH
LSL	LEVEL SWITCH LOW
ZSC	CLOSED POSITION SWITCH
ZSO	OPEN POSITION SWITCH
UA	DEVICE FAIL (MOTOR OVERLOAD, COMMON FAIL OR ALARM)
YI	RUNNING STATUS (MOTOR)
	ALARMS:
LA	LEVEL ALARM
PA	PRESSURE ALARM
TA	TEMPERATURE ALARM
EA	POWER FAIL ALARM
UA	EQUIPMENT FAIL OR ALARM
LAH	LEVEL ALARM HIGH
LAL	LEVEL ALARM LOW

TAG	DESCRIPTION
	CONTROL SIGNALS:
SC	SPEED CONTRL (ANALOG SIGNAL TO VFD)
FC	FLOW CONTROL (ANALOG SIGNAL TO FCV)
ZC	POSITION CONTROL (ANALOG SIGNAL TO VALVE)
FSP	FLOW SETPOINT
RSP	REMOTE SETPOINT
	INSTRUMENTATION:
FI	FLOW RATE INDICATING TRANSMITTER (ANALOG SIGNAL)
PI	PRESSURE (ANALOG SIGNAL)
SI	SPEED (ANALOG SIGNAL)
ZI	POSITION (ANALOG SIGNAL)
AE	ANALYTICAL INSTRUMENTATION DEVICE
	SOFTWARE CALCULATED VALUES:
FQI	FLOW TOTAL
KQI	MOTOR RUN TIME TOTAL
KQR	MOTOR NUMBER OF STARTS
	DATA NETWORK CONNECTIONS:
YN	DATA LINK (MODBUS, MODBUS PLUS, ETHERNET, SERIAL DATA)
	SWITCH DEVICES
HA	HAND-AUTO
HOA	HAND-OFF-AUTO
HSC	HAND SWITCH COMPUTER
LOR	LOCAL-OFF-REMOTE
OAC	OPEN-AUTO-CLOSE
OO	ON-OFF
OOA	ON-OFF-AUTO
OOR	ON-OFF-REMOTE
OSC	OPEN-STOP-CLOSE
OSCA	OPEN-STOP-CLOSE-AUTO
	OTHER DEVICES/EQUIPMENT
PLC	PROGRAMMABLE LOGIC CONTROLLER
RTU	REMOTE TERMINAL UNIT
SCS	SUPERVISORY CONTROL STATION
TSP	TWISTED SHIELDED PAIR
TTR	TONE TELEMETRY RECEIVER
TTT	TONE TELEMETRY TRANSMITTER

7. STANDARD DEVICE AND SIGNAL PLC I/O IDENTIFICATION

Following is a table of abbreviations for typical signal identification for the PLC I/O for typical equipment.

The I/O shown in the table matches the typical equipment schematics and PLC programming templates for the equipment.

PUMP (CONSTANT SPEED)			
	HI-001	DI	Station Pump 1 In Remote
	YI-001	DI	Station Pump 1 Run Status
	UA-001	DI	Station Pump 1 Fail
	HI-001A	DI	Station Pump 1 TOU Key Switch Status
	YI-001A	DI	Station Pump 1 TOU Relay Status
	PAHL-001	DI	Station Pump 1 Hi/Lo Disch. Pressure Alarm
	PAL-001	DI	Station Pump 1 Low Suction Pressure Alarm
	UA-001A	DI	Station Pump 1 Alarm
	HK-001	DO	Station Pump 1 Run Command
	HK-001A	DO	Station Pump 1 TOU Lockout Command
PUMP (VARIABLE SPEED)			
	HI-001	DI	Station Pump 1 In Remote
	YI-001	DI	Station Pump 1 Run Status
	UA-001	DI	Station Pump 1 Fail
	HI-001A	DI	Station Pump 1 TOU Key Switch Status
	YI-001A	DI	Station Pump 1 TOU Relay Status
	PAHL-001	DI	Station Pump 1 Hi/Lo Disch. Pressure Alarm
	PAL-001	DI	Station Pump 1 Low Suction Pressure Alarm
	UA-001A	DI	Station Pump 1 Alarm
	HK-001	DO	Station Pump 1 Run Command
	HK-001A	DO	Station Pump 1 TOU Lockout Command
	SI-001	AI	Station Pump 1 Speed
	SC-001	AO	Station Pump 1 Speed Command
VALVE (OPEN/CLOSED)			
	HI-001	DI	Valve In Remote
	ZSO-110	DI	Valve Open Position
	ZSC-110	DI	Valve Closed Position
	HKO-110	DO	Valve Open Command
	HKC-110	DO	Valve Closed Command

VALVE (MODULATING)			
	HI-110	DI	Valve In Remote
	ZI-110	AI	Valve Position
	FC-110	AO	Valve Position Command (flow control)
other control	LC-110	AO	Valve Position Command (level control)
commands:	PC-110	AO	Valve Position Command (pressure control)
	ZC-110	AO	Valve Position Command (position control)
PRESSURE REDUCING VALVE VAULT			
	ZSC-10	DI	Zone x-y PRV Large Valve Closed Position
	ZSC-20	DI	Zone x-y PRV Small Valve Closed Position
	PT-20	AI	Zone x-y PRV Upstream Pressure
	PT-10	AI	Zone x-y PRV Downstream Pressure
SURGE TANK			
	LSHH-209	DI	Suction Surge Tank Level High Alarm
	LSLL-209	DI	Suction Surge Tank Level Low Alarm
	UA-209	DI	Suction Surge Tank Control Panel Alarm
AIR COMPRESSOR			
	YI-303	DI	Air Compressor Run Status
	PSLL-301	DI	Compressed Air Low Pressure
UNINTERRUPTIBLE POWER SUPPLY			
LOOP - 08	EA-725	DI	UPS System Fail
	YI-725	DI	UPS System On Batteries
STATION POWER			
LOOP - 09	EA-731	DI	Station Power Phase Loss
MCC POWER LOSS			
LOOP - 09	EA-731	DI	Station Power Phase Loss
INTRUSION DETECTION			
LOOP - 10	ZSC-712	DI	Station Intrusion Door Status -
	HI-713	DI	Station Intrusion Override Switch -

8. PANEL IDENTIFICATION

TAG	DESCRIPTION
CP	CONTROL PANEL
LCP	LOCAL CONTROL PANEL
FOP	FIBER OPTIC PANEL
MCP	MASTER CONTROL PANEL (MWRP)
TDB	TUBE DISTRIBUTION BOX

Use numbering for panels which correspond to the general plant process area location of the equipment.

Example:

9. MCC IDENTIFICATION

Use numbering for MCC which correspond to the general plant process area location of the equipment.

Example:

10. MANHOLE AND PULL BOX IDENTIFICATION

TAG	DESCRIPTION
MH	MANHOLE
PB	PULL BOX
JB	JUNCTION BOX

Use numbering for manholes and boxes which correspond to the to the general plant process area location of the equipment.

Example:

11. EQUIPMENT, DEVICE & INSTRUMENT NUMBER

1 Process Plants:

Typically use 4 digits for process plant:

- MWRP
- LAWRP
- DATS
- PTP
- Baker Plant

Refer to P & ID sheets attached for examples of process plant equipment numbering sequences.

2 Water Distribution and Collections Facilities:

Typically use 3 digits for water distribution, collections, and similar facilities:

A. Booster Pump Station:

001-004	Typically used for pumps in the station (pump 1, 2, 3, 4 – not 101, 102 or 100, 200, etc.)
100-199	Low pressure (suction/downstream) side of the station
200-299	High pressure (discharge/upstream) side of the station
300-399	Process equipment not directly in the main process (air compressor for example)
700-799	Facility equipment (power, doors, lighting, UPS)

B. Reservoir:

10	Inlet valve equipment
20	Outlet valve equipment
100-199	Reservoir process (level transmitter, level floats, overflow float, etc.)

700-799 Facility equipment (hatches, power, etc.)

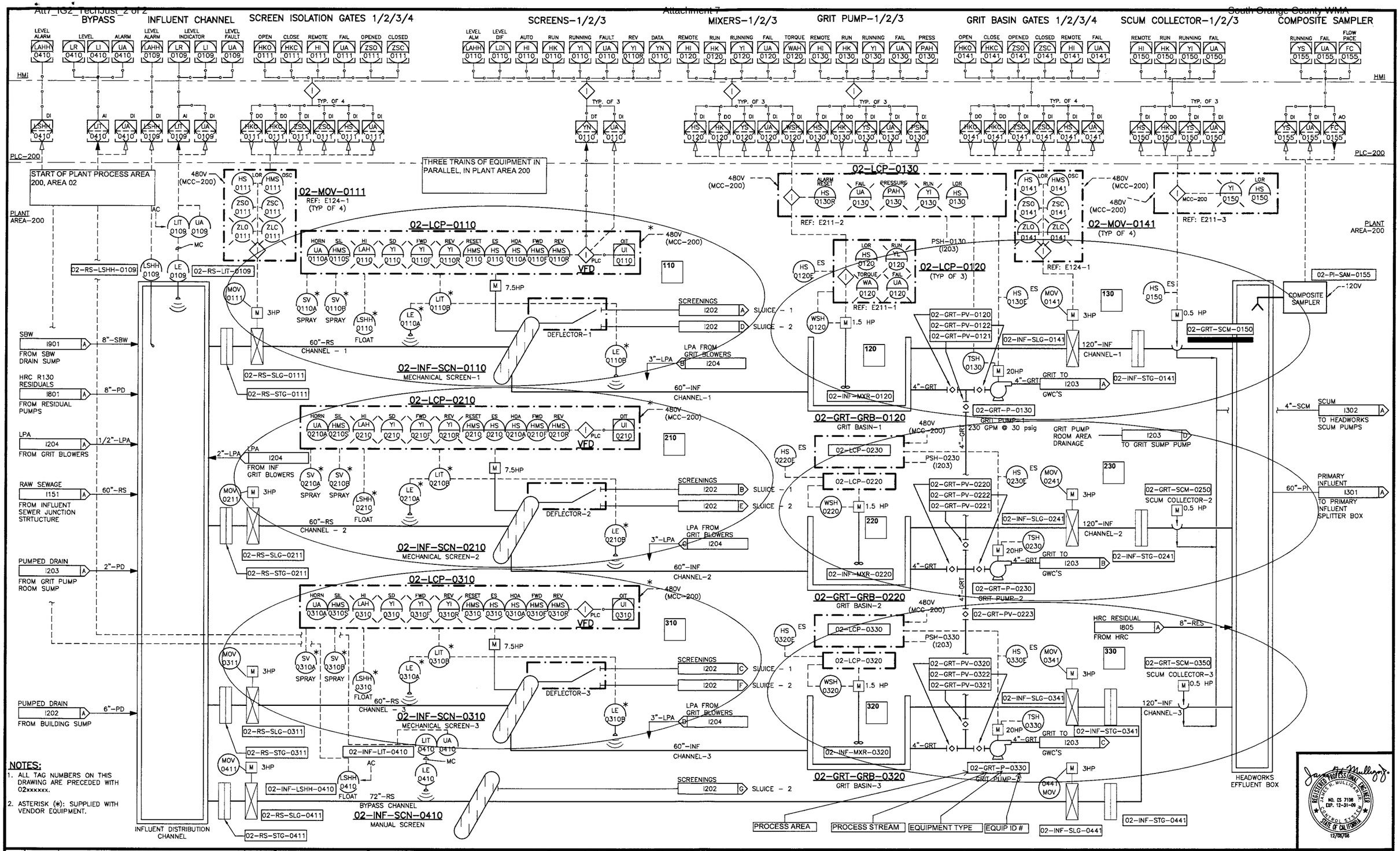
C. PRV:

10-19 Small Valve or downstream process

20-29 Large Valve equipment of upstream process

3 P & ID PROCESS AND EQUIPMENT NUMBERING EXAMPLES

(SEE ATTACHED P&ID SHEETS)



NOTES:

1. ALL TAG NUMBERS ON THIS DRAWING ARE PRECEDED WITH 02xxxxxx.
2. ASTERISK (*): SUPPLIED WITH VENDOR EQUIPMENT.

No.	DATE	REVISIONS	APP'D
–	–	–	

DESIGNED: G. BARELA
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BRUCE R. WILLEY — HDR PROJECT ENGINEER RCE 33687 — DATE 12/08/08
STEVEN L. MALLOY — IRWD PRINCIPAL ENGINEER RCE 31926 — DATE 12/17/08

IRVINE RANCH WATER DISTRICT

IRVINE RANCH WATER DISTRICT
MWRP PHASE 2 EXPANSION
PROJECT NUMBERS 20214 & 30214

VERIFY SCALE
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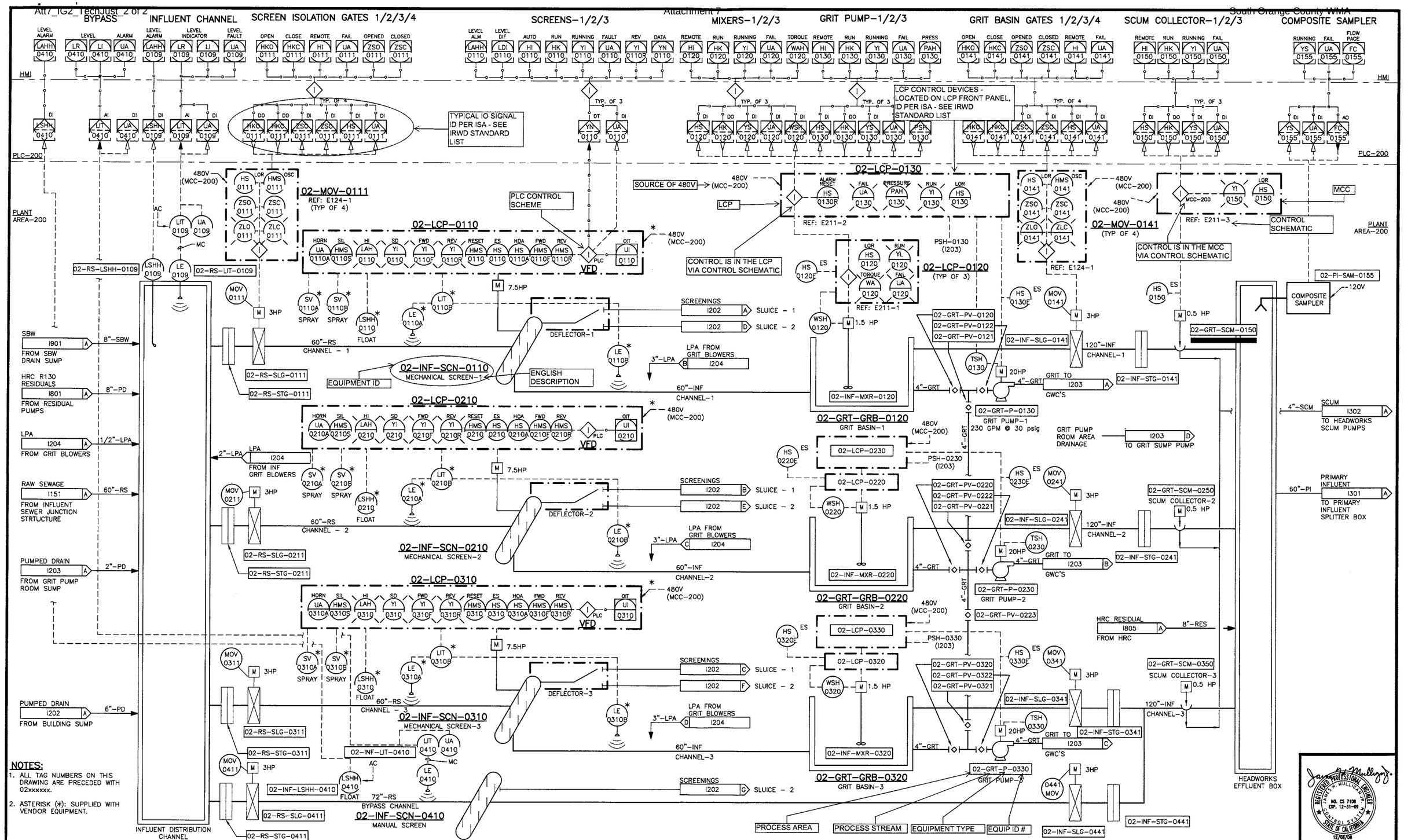
P&ID HEADWORKS SCREENS AND GRIT BASINS

DRAWING 1201
SHEET 569 OF 628

REGISTERED PROFESSIONAL ENGINEER
JAMES R. MULLIGAN, JR.
NO. C5 7108
EXP. 12-31-09
CONTROL SYSTEMS
STATE OF CALIFORNIA
12/08/08

CONFORMED DOCUMENT



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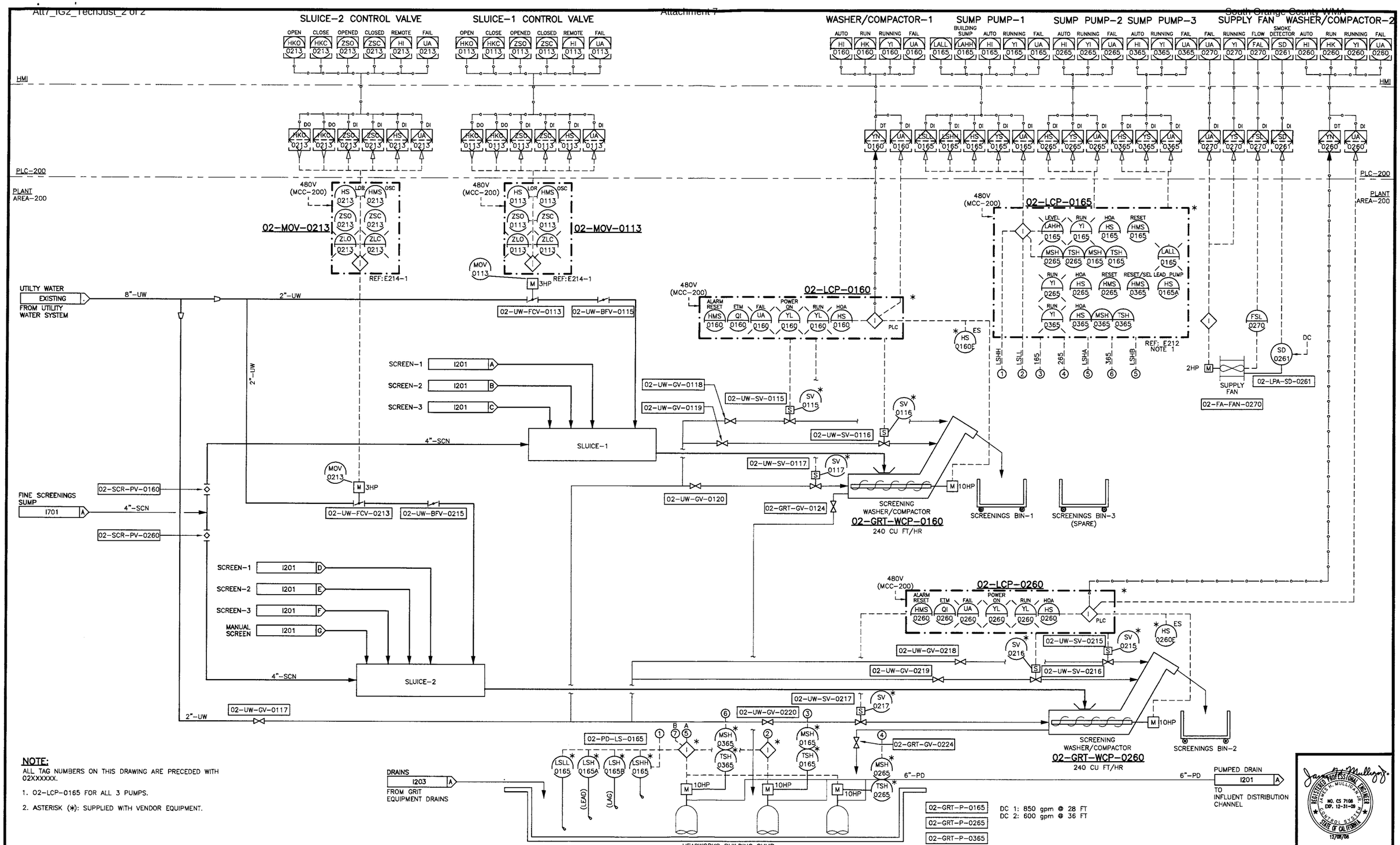
P&ID HEADWORKS
SCREENS AND GRIT BASINS

DRAWING 1201
SHEET 569 OF 628

REGISTERED PROFESSIONAL ENGINEER JAMES A. MULLIGAN JR. NO. CS 7108 EXP. 12-31-09 CONTROL SYSTEMS STATE OF CALIFORNIA 12/08/08

CONFORMED DOCUMENT

CONFORMED DOCUMENT



NOTE:

ALL TAG NUMBERS ON THIS DRAWING ARE PRECEDED WITH 02XXXXXX.

1. 02-LCP-0165 FOR ALL 3 PUMPS.
2. ASTERISK (*): SUPPLIED WITH VENDOR EQUIPMENT.

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MWRP PHASE 2 EXPANSION
PROJECT NUMBERS 20214 & 30214

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P&ID HEADWORKS SCREENINGS PROCESSING

DRAWING 1202
SHEET 570 OF 628

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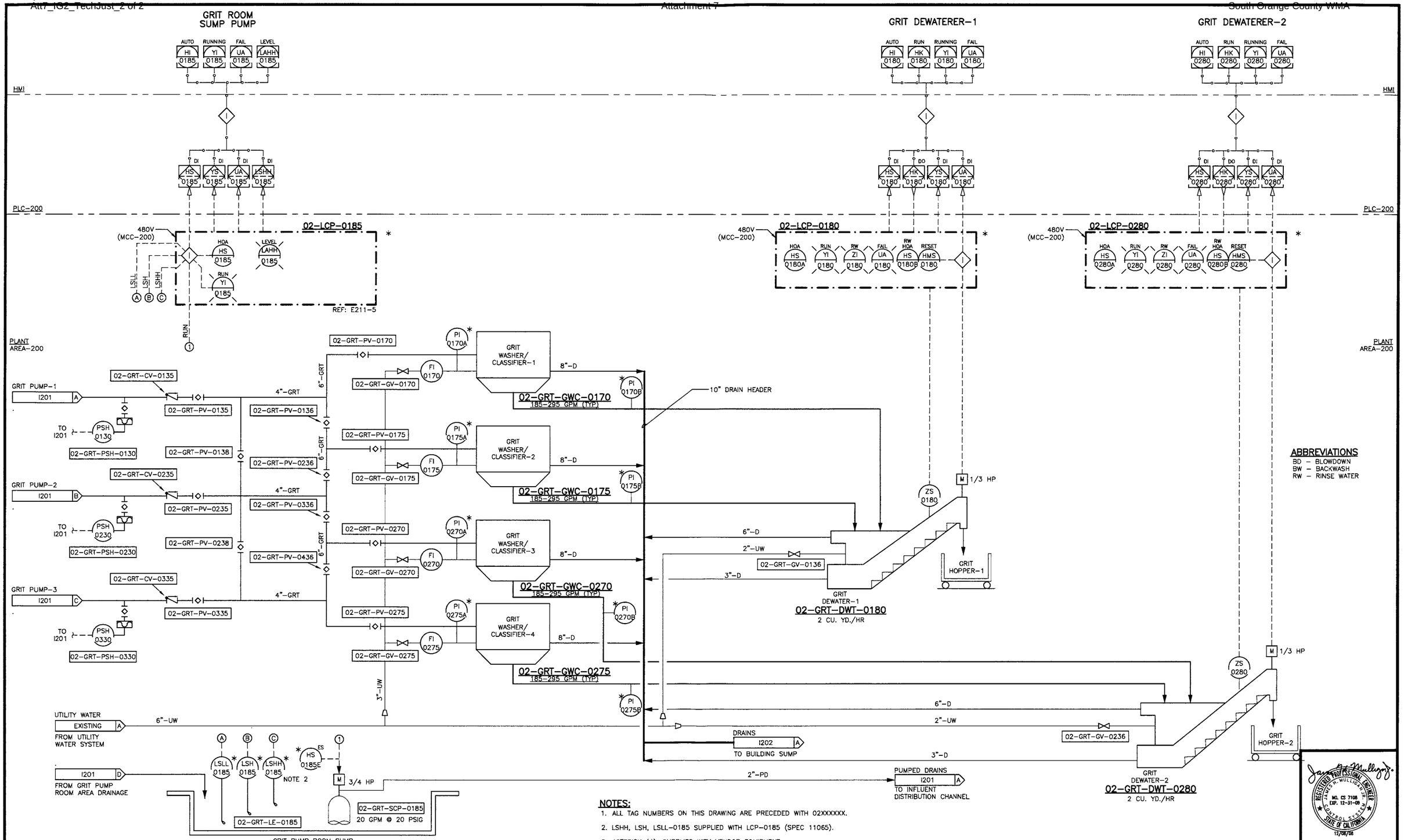
CONFORMED DOCUMENT



NOTES:

1. ALL TAG NUMBERS ON THIS DRAWING ARE PRECEDED WITH 02XXXXXX.
2. LSHH, LSH, LSLL-0185 SUPPLIED WITH LCP-0185 (SPEC 11065).
3. ASTERISK (*): SUPPLIED WITH VENDOR EQUIPMENT.

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MWRP PHASE 2 EXPANSION
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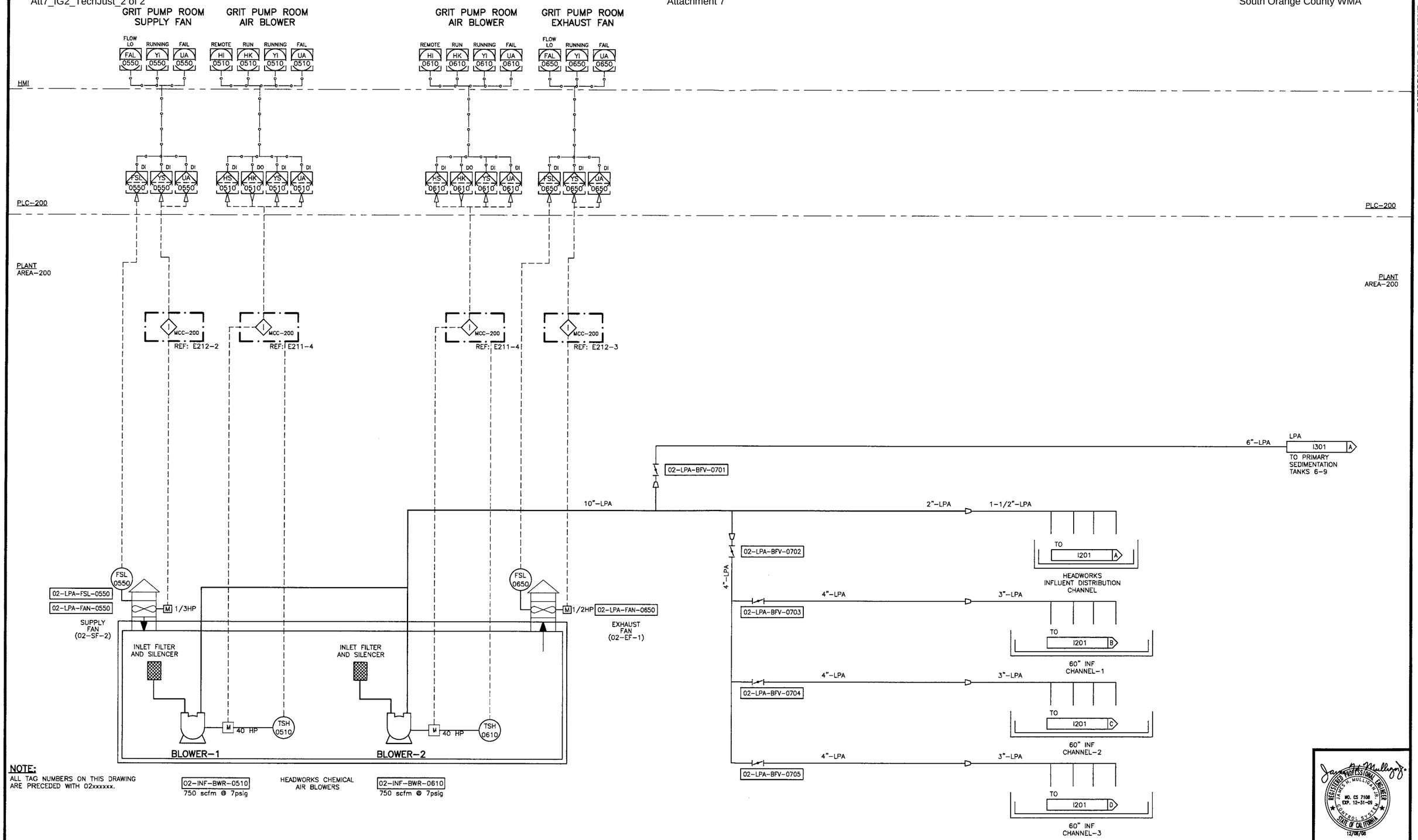
P&ID HEADWORKS
GRIT PROCESSING

DRAWING 1203
SHEET 571 OF 628

CONFORMED DOCUMENT



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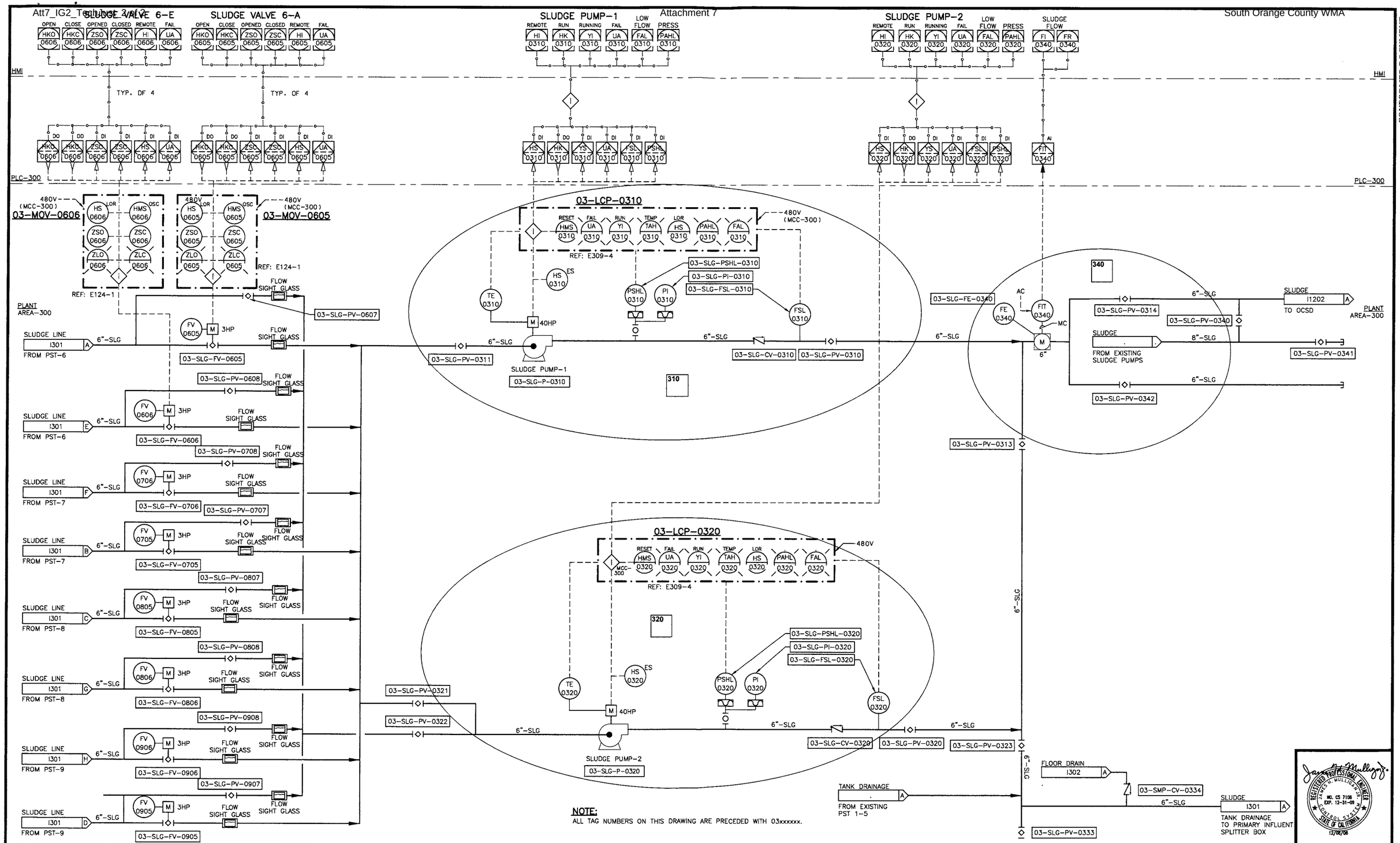
P&ID HEADWORKS
SCREENS AND GRITS
LOW PRESSURE AIR SYSTEM

DRAWING 1204
SHEET 572 OF 628



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IRVINE RANCH WATER DISTRICT
MWRP PHASE 2 EXPANSION
PROJECT NUMBERS 20214 & 30214

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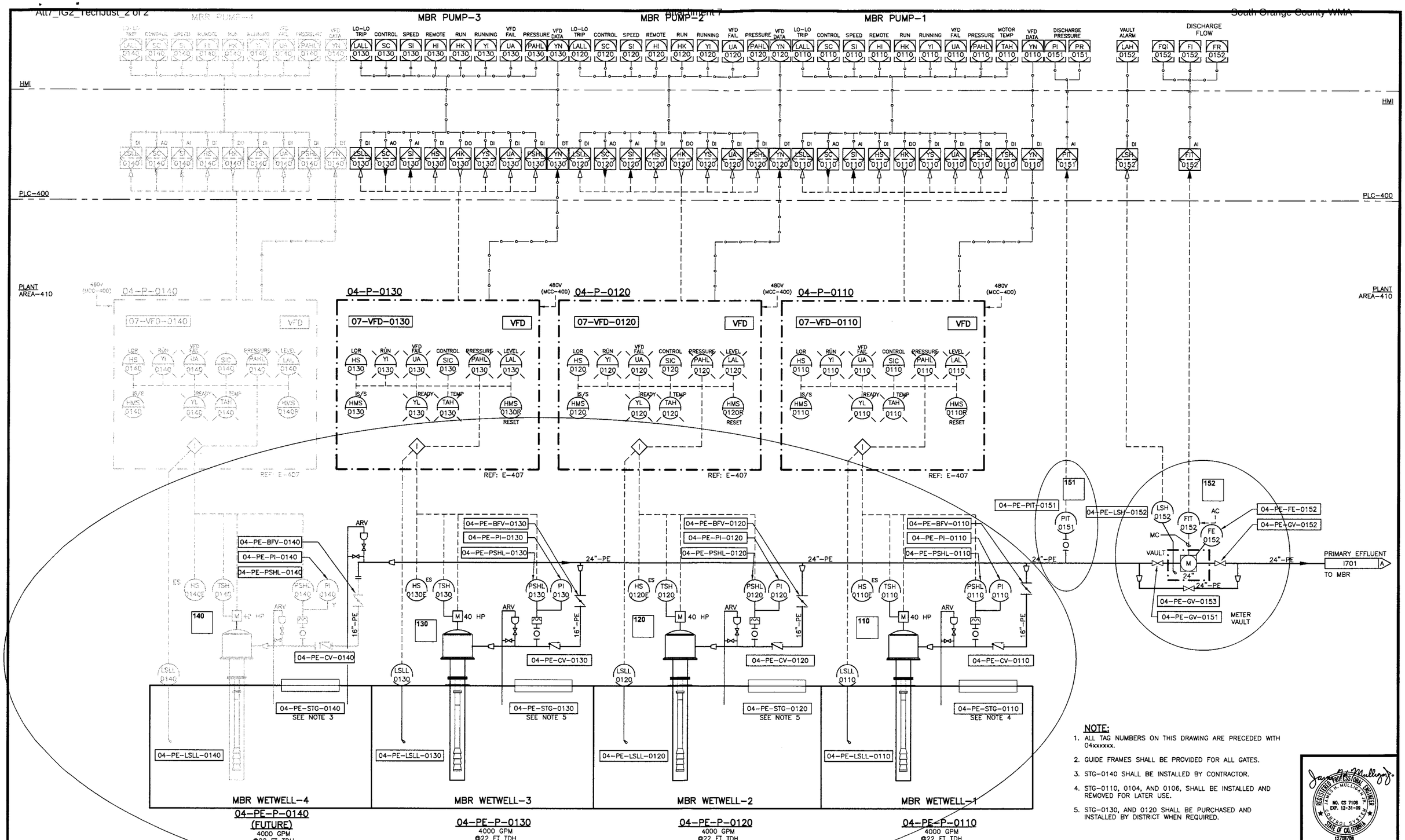
P&ID PRIMARY SEDIMENTATION TANKS
PRIMARY SLUDGE PUMPS

DRAWING 1303
SHEET 575 OF 628

REGISTERED PROFESSIONAL ENGINEER JAMES H. MULLIGAN JR. NO. CS 7108 EXP. 12-31-08 CONTROL SYSTEMS STATE OF CALIFORNIA 12/08/08

CONFORMED DOCUMENT



NOTE:

1. ALL TAG NUMBERS ON THIS DRAWING ARE PRECEDED WITH 04xxxxxx.
2. GUIDE FRAMES SHALL BE PROVIDED FOR ALL GATES.
3. STG-0140 SHALL BE INSTALLED BY CONTRACTOR.
4. STG-0110, 0104, AND 0106, SHALL BE INSTALLED AND REMOVED FOR LATER USE.
5. STG-0130, AND 0120 SHALL BE PURCHASED AND INSTALLED BY DISTRICT WHEN REQUIRED.

REGISTERED PROFESSIONAL ENGINEER — JAMES R. MULLIGAN, JR. — NO. CS 7108 — EXP. 12-31-08 — CONTROL SYSTEMS — STATE OF CALIFORNIA — 12/08/08

No.	DATE	REVISIONS	APP'D
–	–	–	

DESIGNED: G. BARELA
DRAWN: B. PARKS
CHECKED: J. MULLIGAN

HDR
HDR Engineering, Inc.
3230 El Camino Real
Suite 200
Irvine, California 92602-1377

BRUCE R. WILLEY — HDR PROJECT ENGINEER — RCE 33687 — DATE 12/08/08
STEVEN L. MALLOY — IRWD PRINCIPAL ENGINEER — RCE 31926 — DATE 12/17/08

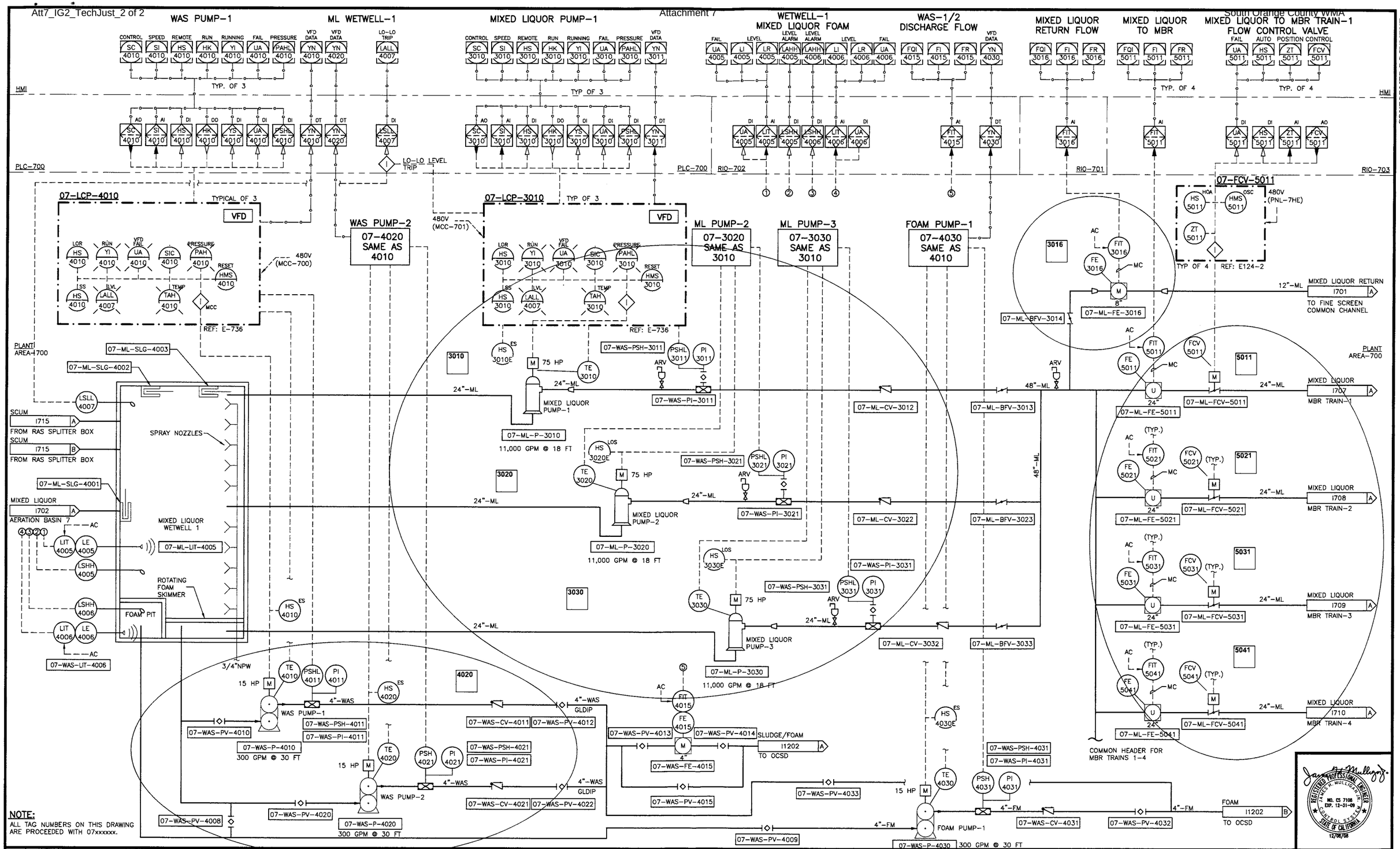
IRVINE RANCH WATER DISTRICT

IRVINE RANCH WATER DISTRICT
MWRP PHASE 2 EXPANSION
PROJECT NUMBERS 20214 & 30214

VERIFY SCALE
BAR IS ONE INCH ON ORIGINAL DRAWING
0 1"
IF NOT ONE INCH ON THIS SHEET, ADJUST SCALE ACCORDINGLY.

P&ID PEPS-1
MEMBRANE BIOREACTOR FEED

DRAWING 1402
SHEET 577 OF 628



CONFORMED DOCUMENT

No.	DATE	REVISIONS	APP'D
2	–	CONFORMED DOCUMENT	–

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IRVINE RANCH WATER DISTRICT

IRVINE RANCH WATER DISTRICT
MWRP PHASE 2 EXPANSION
PROJECT NUMBERS 20214 & 30214

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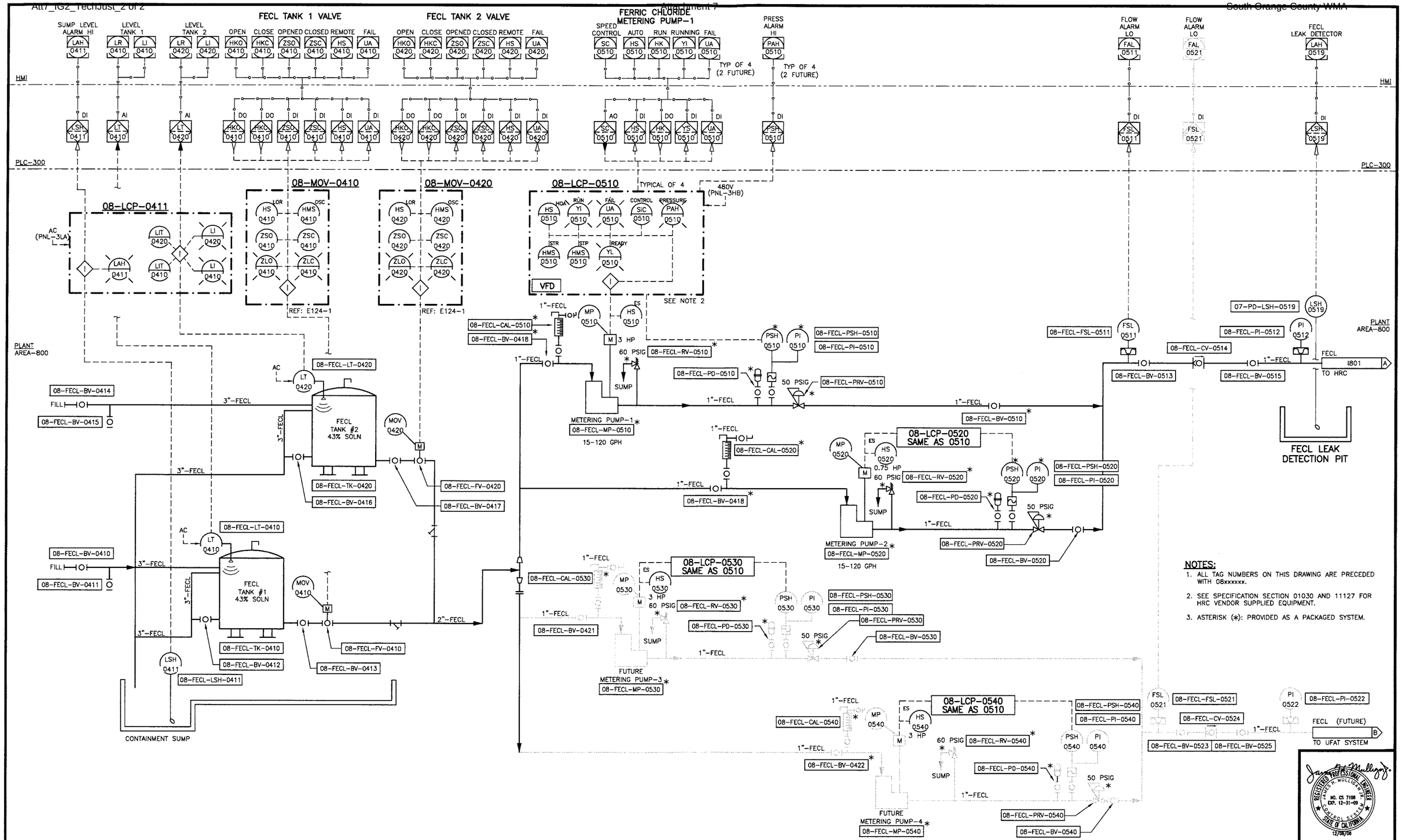
P&ID MEMBRANE BIOREACTOR
MIXED LIQUOR PUMPS 1-3

DRAWING 1704
SHEET 584 OF 628

REGISTERED PROFESSIONAL ENGINEER — JAMES K. MULLIGAN — NO. CS 7106 — EXP. 12-31-09 — CONTROL SYSTEMS — STATE OF CALIFORNIA — 12/08/08

CONFORMED DOCUMENT



NOTES:

1. ALL TAG NUMBERS ON THIS DRAWING ARE PRECEDED WITH 08xxxxxx.
2. SEE SPECIFICATION SECTION 01030 AND 11127 FOR HRC VENDOR SUPPLIED EQUIPMENT.
3. ASTERISK (*): PROVIDED AS A PACKAGED SYSTEM.

REGISTERED PROFESSIONAL ENGINEER JAMES R. MULLIGAN NO. CS 7108 EXP. 12-31-09 CONTROL SYSTEMS STATE OF CALIFORNIA 12/08/08

No.	DATE	REVISIONS	APP'D
–	–	–	

DESIGNED: G. BARELA
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Irvine, California 92602-1377

BRUCE R. WILLEY — HDR PROJECT ENGINEER RCE 33687 — DATE 12/08/08
STEVEN L. MALLOY — IRWD PRINCIPAL ENGINEER RCE 31926 — DATE 12/17/08

IRVINE RANCH WATER DISTRICT

IRVINE RANCH WATER DISTRICT
MWRP PHASE 2 EXPANSION
PROJECT NUMBERS 20214 & 30214

VERIFY SCALE
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0 1"
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P&ID HIGH RATE CLARIFIER
FECL SYSTEM

DRAWING 1804
SHEET 611 OF 628

APPENDIX Q

Economic Evaluation Calculations

TABLE Q1
BAKER WATER TREATMENT PLANT
DRAFT PRELIMINARY DESIGN REPORT
ESTIMATE OF CAPITAL COSTS

Item No.	Item Description	Quantity	Unit	Unit Price[1]	Total Price [1]
	Baker Water Treatment Plant Equipment and Buildings				
1	***Membrane Filtration/ UV System***				***$15,527,000***
1.1	Pressurized Membrane Building	21,000	SF	$160	$3,360,000
1.2	PMF Equipment [10]	30,161,000	GAL	$0.34	$10,255,000
1.3	UV System	27,791,000	GAL	$0.04	$1,112,000
1.4	Process Mechanical	1	LS	$800,000	$800,000
2	***Washwater Equalization and Treatment***				***$1,960,000***
2.1	Membrane Filtration Washwater Equalization	55,000	GAL	$3	$165,000
2.2	Membrane Filtration Washwater Transfer Pumps	60	HP	$3,000	$180,000
2.3	Washwater Treatment	5,000,000	GAL	$0.20	$1,000,000
2.4	Recycle Pump Station	55,000	GAL	$3	$165,000
2.5	Recycle Pumps	150	HP	$3,000	$450,000
3	***Chemical Building / Chlorine Dioxide System***				***$4,724,000***
3.1	Mechanical / Building / Site Work	27,791,000	GAL	$0.14	$3,891,000
3.2	Chlorine Dioxide Chemical / Mechanical Equipment	1	LS	$750,000	$750,000
3.3	Flash Mix Equipment	1	LS	$82,500	$82,500
4	***Contact Basin***				***$860,000***
4.1	Contact Basin	215,000	GAL	$4	$860,000
5	***Electrical and Instrumentation***				***$3,721,000***
5.1	*Water Treatment Plant Site*	1	LS	$551,000	$551,000
5.2	Electrical (Membrane Filtration / UV System) [3]	1	LS	$2,215,000	$2,215,000
5.3	Electrical (Washwater Equalization and Treatment) [3]	1	LS	$280,000	$280,000
5.4	Electrical (Chemical Building) [3]	1	LS	$675,000	$675,000
6	***HVAC***				***$1,550,000***
6.1	HVAC	1	LS	$1,550,000	$1,550,000
7	***Site Work and Piping***				***$3,527,000***
7.1	Sitework	1	LS	$850,500	$850,500
7.2	Site Mechanical	1	LS	$2,676,000	$2,676,000
8	***Mobilization / Insurance / Management***				***$2,550,000***
8.1	Mobilization / Insurance / Management	1	LS	$2,550,000	$2,550,000
				Subtotal - Equipment and Buildings	**$34,419,000**
	Integration Facilities				
9	***OC-33 Expansion***				***$240,000***
9.1	OC-33 Expansion Mechanical / Site Work	1	LS	$240,000	$240,000
10	***Raw Water Pump Station***				***$2,908,000***
10.1	Site Work	1	LS	$181,000	$181,000
10.2	Yard Piping	1	LS	$246,000	$246,000
10.3	Mechanical	1	LS	$1,019,000	$1,019,000
10.4	Building	1	LS	$254,000	$254,000
10.5	Electrical & Instrumentation	1	LS	$808,000	$808,000
10.6	Surge Design / Facilities	1	LS	$400,000	$400,000
11	***Forebay System (Reservoir /Feedwater Pump Station / TCWD PS)***				***$4,300,000***
11.1	Forebay Reservoir (0.8 MG)	1	LS	$1,300,000	$1,300,000
11.2	Forebay Earthwork (Cut / Fill)	1	LS	$80,000	$80,000
11.3	Flow Control Facility Mechanical (w/ enclosure)	1	LS	$250,000	$250,000
11.4	Feedwater Pump Station (w/ building)	1	LS	$1,700,000	$1,700,000
11.5	TCWD Pump Station (w/ building)	1	LS	$370,000	$370,000
11.6	Electrical & Instrumentation	1	LS	$600,000	$600,000

TABLE Q1
BAKER WATER TREATMENT PLANT
DRAFT PRELIMINARY DESIGN REPORT
ESTIMATE OF CAPITAL COSTS

Item No.	Item Description	Quantity	Unit	Unit Price[1]	Total Price [1]
12	***Product Water Pump Station / AMP Connection***				***$3,504,000***
12.1	Site Work	1	LS	$52,000	$52,000
12.2	Yard Piping	1	LS	$391,000	$391,000
12.3	Mechanical	1	LS	$1,228,000	$1,228,000
12.4	Building	1	LS	$273,000	$273,000
12.5	Electrical & Instrumentation	1	LS	$938,000	$938,000
12.6	Surge Design / Facilities	1	LS	$300,000	$300,000
12.7	AMP Metering Vault / Connection	1	LS	$322,250	$322,250
13	***Backup Power***				***$1,250,000***
13.1	Backup Power at Treatment Plant Site	1	LS	$740,000	$740,000
13.2	Backup Power for Product Water Pump Station Site	1	LS	$510,000	$510,000
14	***Mobilization / Insurance / Management***				***$976,000***
14.1	Mobilization / Insurance / Management [4]	1	LS	$976,000	$976,000
				Subtotal - Integration Facilities	**$13,178,000**
				SUBTOTAL (Equipment and Buildings + Integration Facilities)	**$47,597,000**
				District Costs [5]	**$2,200,000**
				Baker Site Land Use Cost [6]	**$440,000**
				Environmental Documentation [7]	$170,000
				Engineering [8]	$4,437,000
				Contingency / Legal [9]	$6,611,000
				Contingency / Engineering / Environmental / Legal / Administration	**$11,218,000**
				TOTAL ESTIMATE OF CAPITAL COST	**$61,455,000**

Notes:

[1] Capital cost are Class 4 Estimates as defined by AACEI with estimated -15% to +30 range of accuracy

[2] Final cost to be determined by Southern California Edison.

[3] Electrical calcualted 12.5% of total corresponding facility cost.

[4] Mobilization / Insurance / Management Cost calculated at 8-percent of capital cost.

[5] Estimate provided by IRWD - includes cost for project management, field support, construction administrative services and inspection.

[6] Cost for land use at Baker Site per Baker WTP Agreement Section 3.1. Area = 4 acres. Unit Cost = $110,000 /acre.

[7] Environmental Documentation cost is based on EIR preparation cost provided to IRWD.

[8] Based on approved design fee for BWTPP, plus authorized flow test budget, and forebay / feedwater pump station design.

[9] Contingency / Legal is based on 15-percent of Subtotal (Equip. and Buildings + Int. Facilities excluding cost for Moblization, Insurance and Management).

[10] Based on calculation using average of budget estimates provided by Pall and Siemens on 10/23/09.

Table Q2: Flash Mix Energy Costs

Item	Unit	Values
Power	hp	5
Days/ year [1]	-	329
Energy	kWh/year	29,395
Unit Cost	$/kWh	$0.13
Total	**$/Year**	**$3,821**

[1] Based on 90-percent plant utilization

Table Q3: Membrane Filtration Energy Costs

Item	Unit	Values [3]
Upstream Elevation	feet	70
Downstream Elevation	feet	0
Product Water	MGD	27.5
Minimum Recovery	%	92%
Gross Production (including recycle flows)	MGD	29.4
Maximum Instantaneous Flux	gfd	45
On-Line Factor	%	86%
Net Flux	gfd	36
Membrane Area per Module	s.f.	538
Min. Number of Modules	No.	1537
No. of Duty Units	No.	11
No. of Rotating (Standby) Units	No.	0
No. of Units Out of Service	No.	1
Total Number of Units	No.	12
No.of Modules per Unit	No.	140
Total Number of Modules	No.	1676
Backwash Flow per Module	gpm	8
Maximum Backwash Flow	gpm	1117
Average BW Interval	min	30
% Time Backwash Pump is in Operation	%	73%
Power	hp	28
Days/ year [1]	-	329
Energy	kWh/year	121,853
Unit Cost	$/kWh	$0.13
MF Backwash Pumping Energy Cost	$/Year	$15,841
Air Compressors	$/Year	$12,150
EFM/ CIP Pumps	$/Year	$1,200
Total	**$/Year**	**$29,191**

[1] Based on 90-percent plant utilization

[2] Pall MF system was selected for cost estimates as O&M costs are anticipated to be higher than those for Siemens.

[3] Forebay Pump Station pumping costs are presented in Table 14.13. Annual cost is estimated at $511,979.

Table Q4: UV System Energy Costs

Item	Unit	Values
Energy Use	kWh/day	365
Days/ year [1]	-	329
Energy	kWh/year	120,034
Unit Cost	$/kWh	$0.13
Total	**$/Year**	**$15,604**

[1] Based on 90-percent plant utilization

Table Q5: Raw Water Pump Station Energy Costs

Item	Unit	Values
Power	hp	1200
Days/ year [1]	-	55
Energy	kWh/year	1,175,820
Unit Cost	$/kWh	$0.13
Total	$/Year	$152,857

[1] Based on 15-percent utilization rate for the RWPS

Table Q6: Product Water Pump Station Energy Costs

Item	Unit	Values
Upstream Elevation	feet	615
Downstream Elevation	feet	820
Capacity - Flow	cfs	32.5
	gpm	14,587
	mgd	21.0
Power	hp	1080
Days/ year [1]	-	329
Energy	kWh/year	6,349,408
Unit Cost	$/kWh	$0.13
Total	$/Year	$825,423

[1] Based on 90-percent plant utilization

Table Q7: MFWW Transfer Pumping Energy Costs

Item	Unit	Values
Flow	gpm	1,646
TDH	ft	35
Power	hp	21
Days/ year [1]	-	329
Energy	kWh/year	122,324
Unit Cost	$/kWh	$0.13
Total	$/Year	$15,902

[1] Based on 90-percent plant utilization

Table Q8: Feedwater Pump Station / TCWD Pump Station Energy Cost

Item	Unit	Feedwater Pump Station	TCWD PS
Upstream Elevation	feet	630	690
Downstream Elevation	feet	725	725
Capacity - Flow	cfs	43.5	6
	gpm	19,524	2,693
	mgd	28.1	3.9
Power	hp	670	34
Days/ year [1]	-	329	329
Energy	kWh/year	3,938,301	200,131
Unit Cost	$/kWh	$0.13	$0.13
Total	$/Year	$511,979	$26,017

[1] Based on 90-percent plant utilization

Table Q9: Cost of Cleaning Chemicals for Membrane System

Baker Water Treatment Plant	Project Total ($/year)
MF CIP Chemicals	
Citric Acid 50% (Cleaning)	$180,079
Citric Acid 50%(Neutralization)	$0
NaOCl 12.5%	$5,823
NaSHSO3 38%	$4,200
NaOH 25% (Cleaning)	$36,616
NaOH 25% (Neutralization)	$60,050
MF EFM Chemicals	**$286,769**
NaOCl 12.5%	$64,048
NaSHSO3 38%	$46,202
Total	**$397,019**

[1] Based on 90-percent plant utilization

Table Q10: Cost of Process Chemicals

Baker Water Treatment Plant	Project (43.5 cfs) Total ($/year)
Ferric Chloride, 42%	$577,124
NaOCl	$208,163
NaOH 25%	$108,527
AA 29%	$106,764
Chlorine Doxide	$211,535
Total	**$1,212,113**

[1] Based on 90-percent plant utilization

Table Q11: Cost of Replacing Consumables

Baker Water Treatment Plant	365 days	90% Plant Utilization [1]
	Project [2] (43.5 cfs)	Project (43.5 cfs)
Spare Parts [3]	$102,549	$102,549
Module Replacment	$187,540	$187,540
UV Lamp Replacement	$6,018	$5,567
Total	**$296,108**	**$295,656**

[1] Module and Spare Parts Costs are not impacted by plant utilization rate.

[2] Module Replacement determined by the number of modules required.

[3] Spare Parts cost is based on 1-percent of membrane cost. Cost fully incurred after second year (post warranty).

Table Q12: Labor Costs

Baker Water Treatment Plant	Unit	Values
No. of Operators	No.	2
Weeks per Year	week	52
Hours per Week (T4)	hr	40
Unit Cost (T4) [1]	$/h	$100
Subtotal (T4) Labor Cost	$/Year	$208,000
Hours per Week (T5)	hr	30
Unit Cost (T5) [1]	$/h	$110
Subtotal (T5) Labor Cost	$/Year	$171,600
Total	**$/Year**	**$379,600**

[1] Includes G and per the Baker Agreement of 78.6-percent

Table Q13: Estimation of Untreated Water Cost from MWDOC

Baker Water Treatment Plant	MWDOC Rates for Treated Water [1]					Assumed MWDSC Rates for Untreated Water[2][3]				MWDOC Surcharge Rate		Assumed MWDOC Rates for Untreated Water [4]		
	Tier 1		Tier 2		Mix [5]	Tier 1		Tier 2		Tier 1	Tier 2	Tier 1 [6]	Tier 2 [6]	Mix [5]
	Rate	% Increase	Rate	% Increase	Rate	Rate	% Increase	Rate	% Increase	Rate	Rate	Rate	Rate	Rate
2009	$701		$781		$709	$484		$564		n/a	n/a	$484	$564	$492
2010	$701	-	$811	-	$712	$484	0.0%	$594	-	$6.5	$6.5	$491	$601	$502
2011	$860	22.6%	$934	15.2%	$867	$594	22.6%	$684	15.2%	$8.0	$8.0	$602	$692	$611
2012	$903	5.0%	$981	5.0%	$911	$623	5.0%	$718	5.0%	$8.5	$8.5	$632	$727	$641
2013	$948	5.0%	$1,029	5.0%	$956	$654	5.0%	$754	5.0%	$8.5	$8.5	$663	$762	$673
2014	$995	5.0%	$1,081	5.0%	$1,004	$687	5.0%	$792	5.0%	$9.0	$9.0	$696	$801	$706
2015	$1,044	5.0%	$1,135	5.0%	$1,053	$721	5.0%	$831	5.0%	$9.0	$9.0	$730	$840	$741
2016	$1,097	5.0%	$1,191	5.0%	$1,106	$757	5.0%	$873	5.0%	$9.5	$9.5	$767	$882	$778
2017	$1,151	5.0%	$1,250	5.0%	$1,161	$795	5.0%	$916	5.0%	$9.5	$9.5	$804	$925	$816
2018	$1,208	5.0%	$1,313	5.0%	$1,219	$834	5.0%	$962	5.0%	$10.0	$10.0	$844	$972	$857
2019	$1,268	5.0%	$1,378	5.0%	$1,279	$876	5.0%	$1,009	5.0%	$10.0	$10.0	$886	$1,019	$899
2020	$1,331	5.0%	$1,447	5.0%	$1,343	$919	5.0%	$1,059	5.0%	$10.0	$10.0	$929	$1,069	$943
2021	$1,398	5.0%	$1,519	5.0%	$1,410	$965	5.0%	$1,112	5.0%	n/a	n/a	$976	$1,123	$990
2022	$1,468	5.0%	$1,595	5.0%	$1,480	$1,013	5.0%	$1,168	5.0%	n/a	n/a	$1,024	$1,179	$1,040
2023	$1,541	5.0%	$1,675	5.0%	$1,554	$1,064	5.0%	$1,226	5.0%	n/a	n/a	$1,076	$1,238	$1,092
2024	$1,618	5.0%	$1,758	5.0%	$1,632	$1,117	5.0%	$1,288	5.0%	n/a	n/a	$1,129	$1,300	$1,146
2025	$1,699	5.0%	$1,846	5.0%	$1,714	$1,173	5.0%	$1,352	5.0%	n/a	n/a	$1,186	$1,365	$1,204
2026	$1,784	5.0%	$1,938	5.0%	$1,799	$1,232	5.0%	$1,420	5.0%	n/a	n/a	$1,245	$1,433	$1,264
2027	$1,873	5.0%	$2,035	5.0%	$1,889	$1,293	5.0%	$1,491	5.0%	n/a	n/a	$1,307	$1,505	$1,327
2028	$1,967	5.0%	$2,137	5.0%	$1,984	$1,358	5.0%	$1,565	5.0%	n/a	n/a	$1,373	$1,580	$1,394

[1] Based on June 2009 water rate projections provided to IRWD by MWDOC, and updated after 9/1/2009 to account for MWDSC water rate change.

[2] 2009 and 2010 rates for full service untreated and treated MWDSC water is based on estimates posted on MWDSC's website November 2009.

[3] Future cost of untreated MWDSC water is estimated based on escalation rates similar to the treated water costs

[4] The sum of MWDSC untreated water cost and MWDOC surcharge rates

[5] Assumes 90-percent of Tier 1 and 10-percent of Tier 2

[6] Assume rates to annualy escalate at a rate of 5-percent beyond year 2020

Table Q14: Projected Cost of Water for Baker WTP

Baker Water Treatment Plant - 43.5 cfs Forebay, Feedwater PS, N+1

Year	Energy, Chemical, & Consumables Costs (5% Escalation)	Labor Costs (3% Escalation)	Non-Reclaimable Water Treatment (3% Escalation)	Other O&M System Costs (3% Escalation)	Total Escalated O&M Costs ($/AF/yr)	Annual Capital Cost ($/AF/yr)	Cost of Untreated Water from MWDOC ($/AF/yr)	Total Project Costs Alternative 1 ($/AF/yr)
2009	$3,485,600	$379,600	$0	$75,000	$141	$134	$492	$766
2010	$3,659,900	$391,000	$2,300	$77,300	$147	$134	$502	$783
2011	$3,842,900	$402,700	$4,600	$79,600	$155	$134	$611	$899
2012	$4,035,000	$414,800	$7,000	$82,000	$162	$134	$641	$937
2013	$4,236,700	$427,200	$9,400	$84,400	$170	$134	$673	$976
2014	$4,448,600	$440,100	$11,900	$86,900	$178	$134	$706	$1,018
2015	$4,671,000	$453,300	$14,600	$89,600	$187	$134	$741	$1,061
2016	$4,904,600	$466,900	$17,200	$92,200	$196	$134	$778	$1,108
2017	$5,149,800	$480,900	$20,000	$95,000	$205	$134	$816	$1,155
2018	$5,407,300	$495,300	$22,900	$97,900	$215	$134	$857	$1,206
2019	$5,677,600	$510,200	$25,800	$100,800	$225	$134	$899	$1,258
2020	$5,961,500	$525,500	$28,800	$103,800	$236	$134	$943	$1,313
2021	$6,259,600	$541,200	$31,900	$106,900	$248	$134	$990	$1,372
2022	$6,572,600	$557,500	$35,100	$110,100	$260	$134	$1,040	$1,433
2023	$6,901,200	$574,200	$38,400	$113,400	$272	$134	$1,092	$1,498
2024	$7,246,300	$591,400	$41,800	$116,800	$285	$134	$1,146	$1,566
2025	$7,608,600	$609,100	$45,400	$120,400	$299	$134	$1,204	$1,637
2026	$7,989,000	$627,400	$49,000	$124,000	$314	$134	$1,264	$1,712
2027	$8,388,500	$646,200	$52,700	$127,700	$329	$134	$1,327	$1,790
2028	$8,807,900	$665,600	$56,500	$131,500	$345	$134	$1,394	$1,872

Annualized Capital Cost = $3,749,000

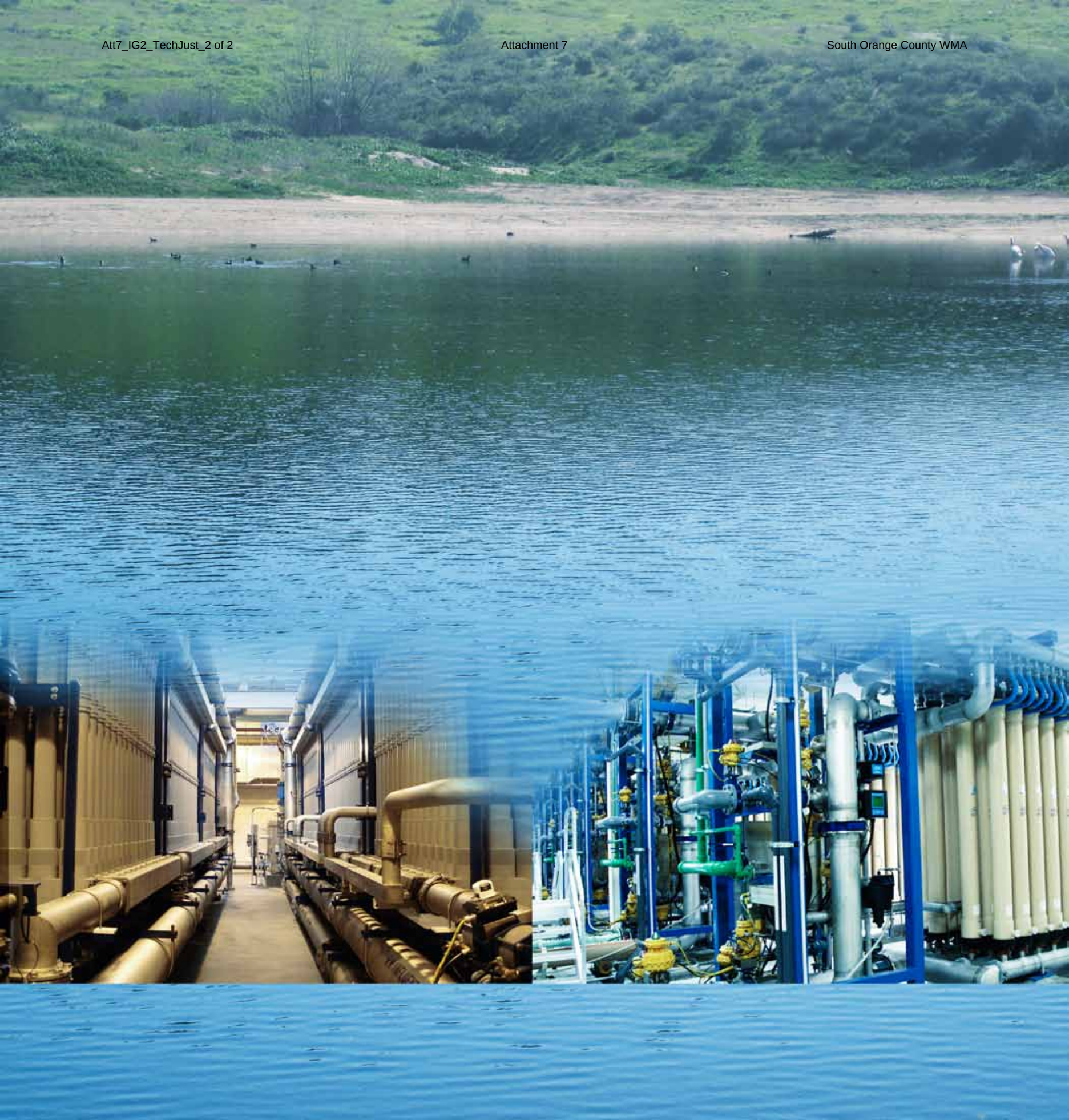
Annual Production (AF)= 28,018

Annualized Capital Cost Per AF= $134

Table Q15: Projected Cost of Baker WTP Product Water

Baker Water Treatment Plant	Cost ($)
2009	$766
2010	$783
2011	$899
2012	$937
2013	$976
2014	$1,018
2015	$1,061
2016	$1,108
2017	$1,155
2018	$1,206
2019	$1,258
2020	$1,313
2021	$1,372
2022	$1,433
2023	$1,498
2024	$1,566
2025	$1,637
2026	$1,712
2027	$1,790
2028	$1,872

Table Q16: Baker WTP Water Costs vs. MWDOC Import Water Cost

Baker Water Treatment Plant	$/AFY Cost Difference (Baker WTP Water Cost minus MWDOC Tier 1/Tier 2 Meld) [1] ($)
Present - 2009	$57
Project Startup - 2012	$27
2014 (year 2 of operation)	$15
2015 (year 3 of operation)	$8
2016 (year 4 of operation)	$2
2017 (year 5 of operation)	($6)
2018 (year 6 of operation)	($13)
2020 (year 8 of operation)	($30)
2024 (year 12 of operation)	($67)
2028 (year 16 of operation)	($112)

[1] Melded rate at ratio of 90-percent Tier 1 and 10-percent Tier 2.