Energy Research and Development Division
FINAL PROJECT REPORT

EL DORADO COUNTY WATER SYSTEMS ENERGY GENERATION, STORAGE, EFFICIENCY, DEMAND MANAGEMENT & GRID SUPPORT

Appendix A

Prepared for: California Energy Commission
Prepared by: El Dorado Irrigation District with Domenichelli and Associates, Inc.

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APPENDIX A:
El Dorado County Water Systems

El Dorado County Water Systems

Assess Existing and Future Water and Energy Demand and Use Patterns

TM#2 – Task 2.2. Existing Systems Water and Energy Demands Technical Memorandum

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1.0 Introduction

The purpose of this study is to summarize and quantify the existing water and energy demands within the El Dorado Irrigation District (EID) and Georgetown Divide Public Utility District (GDPUD) systems.

With nearly 39,000 water accounts, EID is one of the largest energy users in El Dorado County. Similar to other water systems in California, El Dorado County water systems have limited water storage and operate on an on-demand basis. Doing so requires EID to operate during peak energy periods that result in higher energy costs. In an effort to improve efficiency and reduce energy costs, EID has implemented the use of demand management at Sportsman Pump Station, load shedding at El Dorado Hills Water Treatment Plant (EDHWTP), and solar energy at El Dorado Hills Wastewater Treatment Plant (EDHWWTP) which is further discussed in Technical Memorandum #7.

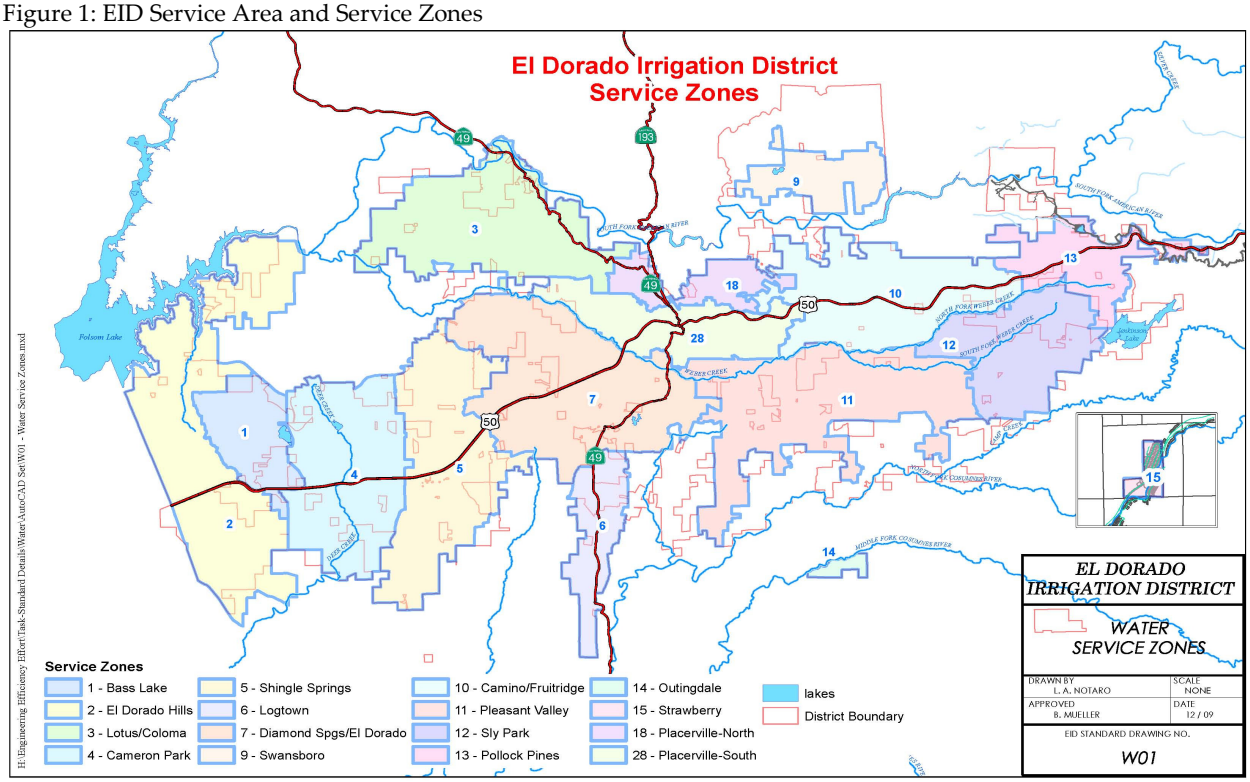
As another El Dorado County water purveyor, GDPUD has been equally involved in attempting to identify and implement solutions for balancing water delivery and energy use. This study will serve as a basis for existing conditions by describing and quantifying system capacity, energy usage and operational deficiencies.

2.0 El Dorado Irrigation District

2.1. Overview of Existing Water Supply and Demand

EID's delivery infrastructure for water include approximately 1,200 miles of pipeline, 27 miles of ditches, 5 treatment plants, 36 storage reservoirs and 37 pumping stations. The following figure (Figure 1) identifies EID's service area and defined service zones.

Figure 1: EID Service Area and Service Zones



EID's water system has a safe yield of approximately 63,550 acre-feet/year (19.7 billion gallons) that supplies nearly 39,000 water accounts. There are two service areas that are distinguished by their supply source. The Western/Eastern area receives water from EID's eastern sources (Project 184 and Jenkinson Lake) and the El Dorado Hills area receives water from Folsom Reservoir with yearly supplementation from EID's eastern sources by means of the Gold Hill Intertie (GHI). Supplementation is primarily used when annual maintenance is performed at the EDHWTP. The Western/Eastern area is comprised of Bass Lake, Cameron Park, Shingle Springs, Logtown, Swansboro, El Dorado, Diamond Springs, Pleasant Valley, Sly Park, Pollock Pines, Camino, Placerville, and Lotus/Coloma. The following table (Table 1) summarizes the availability and demand of water for each service area for 2009.

Table 1: 2009 Water Availability and Demand

El Dorado Hills Service Area	Western/Eastern Service Area
Water supply = 15,163 AF	Water Supply = 39,001 AF
Total Potential Demand = 12,070 AF	Total Potential Demand = 35,225 AF

Source: El Dorado Irrigation District, *2009 Water Resources and Service Reliability Report*, July 2009

Table 1 shows that the El Dorado Hills area accounts for nearly twenty-five percent of the water demand within EID's system. In addition, this area is one of EID's larger energy users. Since EID's water system covers such a large amount of area it would be difficult to analyze the entire

system in detail, therefore, the analysis for this report will concentrate on the El Dorado Hills service area.

The El Dorado Hills service area boundary is defined by Folsom Reservoir and the South Fork American River to the north, Cameron Park to the east, Deer Creek to the south, and Sacramento County line to the west. As shown in Figure 2, water is taken from Folsom Lake via the Folsom Lake Intake and Pump Station (FLIPS) and sent to the EDHWTP for treatment. Once treated, water is sent to the 820 and 960 pressure zones. The 820 pressure zone consists of three water tanks; Promontory, Salmon Falls, and Monte Vista. Since Monte Vista Tank is at a higher elevation an additional smaller in-line pump station is used to fill this tank. The 960 pressure zone consists of five water tanks; Highland View, Oak Ridge (2 tanks), Ridgeview, and Lower Valley View. Since Highland View and Ridgeview Water Tanks are at a higher elevation an additional smaller in-line pump station and Oakridge Pump Station (Oak Ridge PS) are used to fill these tanks, respectively. Also, a portion of the El Dorado Hills service area, specifically the upper Serrano development, is served by the Bass Lake Tanks by means of the GHI. The GHI is also able to supply the entire El Dorado Hills service area, but only during low demand periods due to pipeline capacity in the GHI.

Figure 2: El Dorado Hills Schematic for Existing System

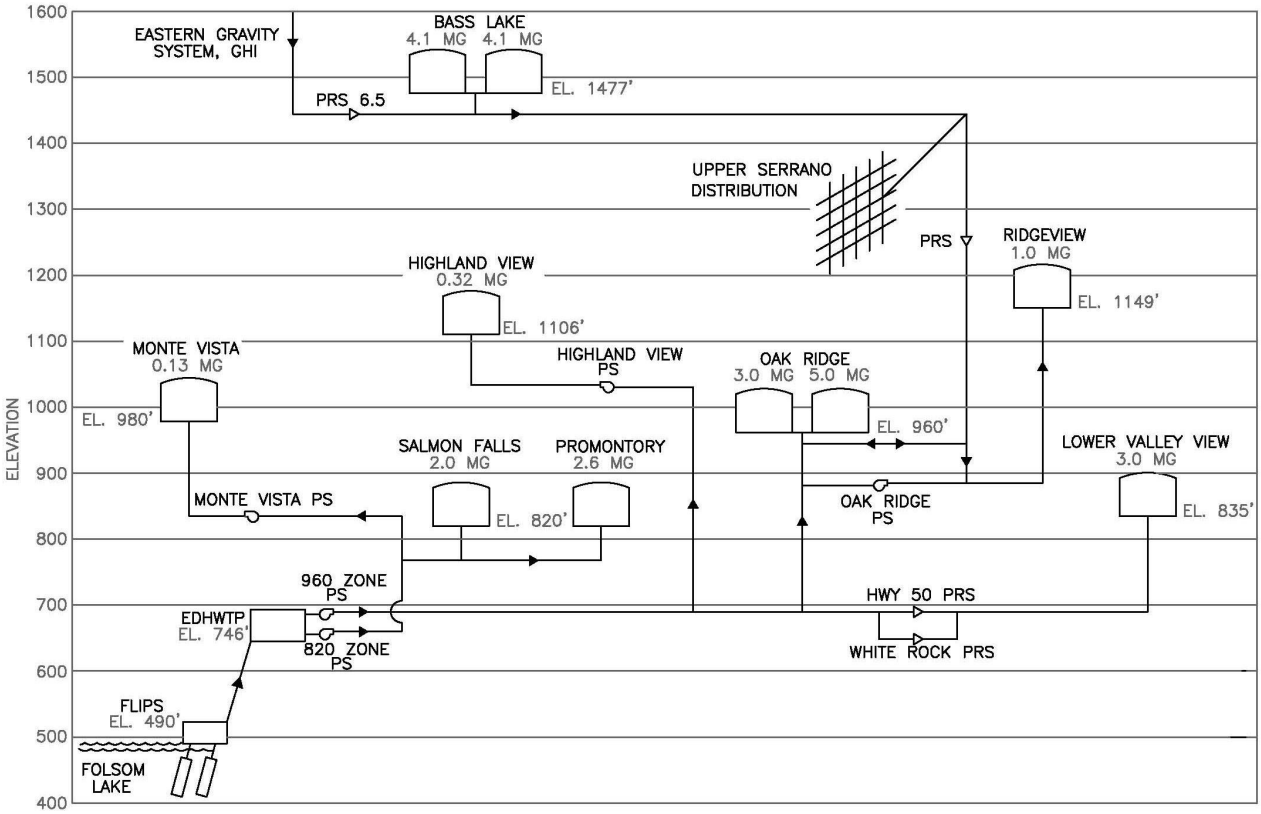


Figure 2 illustrates the range of topography in this area. The numerous elevation changes necessitate the use of pumping systems throughout the service area. Gravity water supply from EID's eastern sources would be ideal since it would dramatically reduce energy costs, however

the increasing amount of water supply needed for this area, restriction of conveyance capacity, and restrictions in upstream water diversions make it unfeasible.

Since pumping is required, the amount of energy needed and associated costs to produce and deliver potable water can be high for the following reasons: 1) Amount of energy required to operate the water system; 2) Time of day in which energy is consumed; and 3) Mode of operation. As a Pacific Gas & Electric (PG&E) customer, EID's energy rates vary based upon the time of year and day. For instance, rates during a peak period are higher than during a part peak or off peak period. The following tables (Table 2 & Table 2A) describe in detail PG&E's rate structure and associated energy charges based on time of year and day.

Table 2: PG&E Rate Structure

Summer (May through October)			Winter (November through April)		
Peak	Mon – Fri*	12:00 PM – 6:00 PM	Peak	NA	NA
Part Peak	Mon – Fri*	8:30 PM – 12 PM 6:00 PM – 9:30 PM	Part Peak	Mon – Fri	8:30 AM - 9:30 PM
Off Peak	Mon – Fri*	9:30 PM – 8:30 AM	Off Peak	Mon – Fri	9:30 PM – 8:30 AM
	Sat – Sun	12:00 AM - 12:00 AM		Sat – Sun	12:00 AM - 12:00 AM

* Except holidays

Table 2A: PG&E Energy Charges ($/kWh)*

Summer (May through October)					Winter (November through April)				
	FLIPS		EDHWTP	Oak Ridge PS		FLIPS		EDHWTP	Oak Ridge PS
Meter Type	E20S	E19S	E20S	A6	Meter Type	E20S	E19S	E20S	A6
Peak	$0.15	$0.15	$0.15	$0.45	Peak	NA	NA	NA	NA
Part Peak	$0.10	$0.11	$0.10	$0.20	Part Peak	$0.09	$0.09	$0.09	$0.17
Off Peak	$0.08	$0.09	$0.08	$0.12	Off Peak	$0.08	$0.08	$0.08	$0.12

* Rounded to the nearest hundredth decimal place

By identifying the amount of energy consumed, time of day usage and mode of operation, changes can be made to keep energy costs at a minimum by utilizing lower rates during part peak and off peak periods and ensure the system is operated at its maximum efficiency.

The ten tanks shown in Figure 2 serve specific areas within the system and are divided by pressure reducing stations and valves. In the future, two additional tanks will be added to the system to assist with growing demand. The Upper Valley View Tank, which will serve the Blackstone development (also known as West Valley), is currently undergoing construction modifications and the Carson Creek Tank, which will serve the Carson Creek development, is still in the planning stage. All tanks and their capacities are shown in Table 3.

Table 3: El Dorado Hills Service Area Tanks and Capacities

Tank	Current Capacity	
	AF	Gal
Monte Vista	.40	130,000
Salmon Falls	6.14	2,000,000
Promontory	7.98	2,600,000
Highland View	1.00	325,000
Lower Valley View	9.21	3,000,000
Upper Valley View - not in service	2.15	700,000
Oak Ridge - 2 tanks	24.55	8,000,000
Ridgeview	3.07	1,000,000
Carson Creek - not constructed	10.74	3,500,000
Bass Lake - 2 tanks	25.16	8,200,000

At this time, the available water supply for the area is restricted by infrastructure, storage capacity and other conveyance facilities. EID's Storage Evaluation for Potable Water System Report states there are two tanks in this service area that are deficient in capacity. Monte Vista and Ridgeview Water Tanks require additional capacity to handle existing water demands. Recent actions to improve supply conditions include the expansion of EDWTP from a capacity of 19.5 million gallons per day (MGD) to 26 MGD, improvements to FLIPS, and the construction of Promontory and Upper Valley View Water Tanks.

In 2009, water demand for the El Dorado Hills service area was published as 3.9 billion gallons. With the anticipated completion of the Blackstone and Carson Creek developments within the next 5 to 8 years, an additional amount of demand will be added. Also in March 2010, EID announced that 700 additional equivalent dwelling units (EDU) were available for purchase which also increases the future annual supply availability. The summation of these anticipated demands is shown in Table 4.

Table 4: Anticipated Future Demands

Source of Additional Demand	Demand	
	AF	MG
Existing Demand	.012	3,933
Blackstone Development	.001	367
Carson Creek Development	.001	468
700 additional EDUs	.001	196
Total Demand	**.015**	**4,964**

2.2. Folsom Lake Intake and Pump Station

FLIPS is located within El Dorado Hills, CA adjacent to Folsom Lake. This facility has two pump stations because of the large elevation difference between the lake and EDHWTP. The intake removes water from the lake at various depths that are dependent upon the lake water level. The intake has a total of nine submersible pumps. The original intake consisted of five pumps, and with recent improvements, four additional pumps were added. To date, there are two 100 horsepower (HP), three 200 HP, and four 140 HP pumps. The two 100 HP pumps are labeled A-Side and serve as an emergency backup. The remaining pumps are labeled B-Side and serve as primary for the system. Water through the intake is sent to the secondary pump station to boost the water to EDHWTP. The secondary pump station has a total of six pumps; two 200 HP pump that receives water from the A-Side intake pumps and four 500 HP pumps that receive water from the B-Side intake pumps. The four 500 HP pumps have variable frequency drive motors (VFD) to reduce power surges by reducing the number of pump starts and stops and ensure a more even use of power. Since the pumps can deliver a range of flows, VFDs enable the pumps to run at reduced speeds depending on the amount of water needed at the EDHWTP. The VFD control set points are based on the raw water tank and clearwell levels that are located at EDHWTP.

In October 2004, EID's Demand Response Engineering Analysis of El Dorado Irrigation District's El Dorado Hills Sub-System Report recommended that EID modify its operation to increase the amount of energy cost savings. The idea was to adjust operation so that the least amount of energy usage would occur during the peak period of the day. Within the last couple of years EID has been able to fine tune its FLIPS operation and achieve that additional amount of savings. Figure 3 shows energy usage for a typical summer day and how FLIPS's modified operation has reduced energy during peak hours.

Figure 3: FLIPS Time of Day Energy Usage

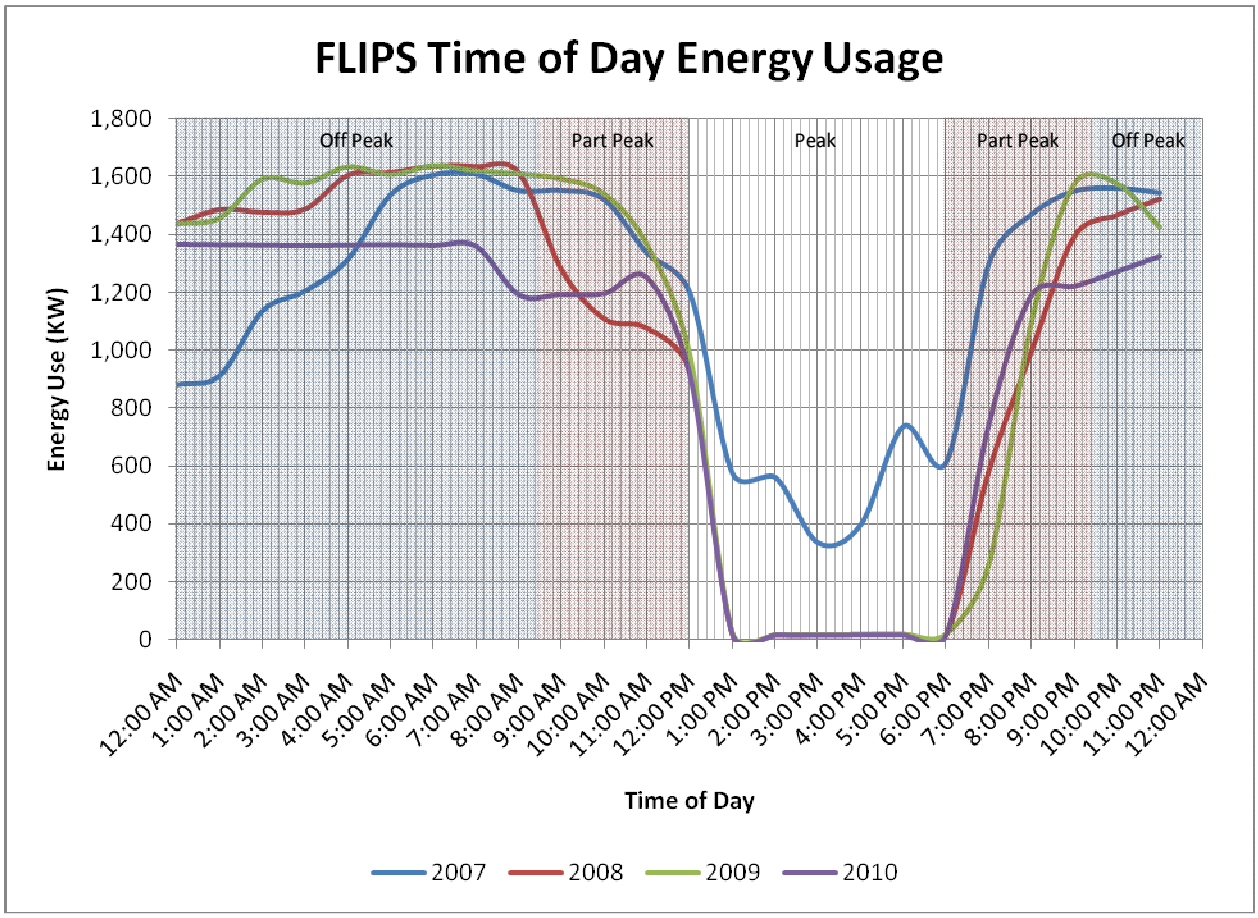
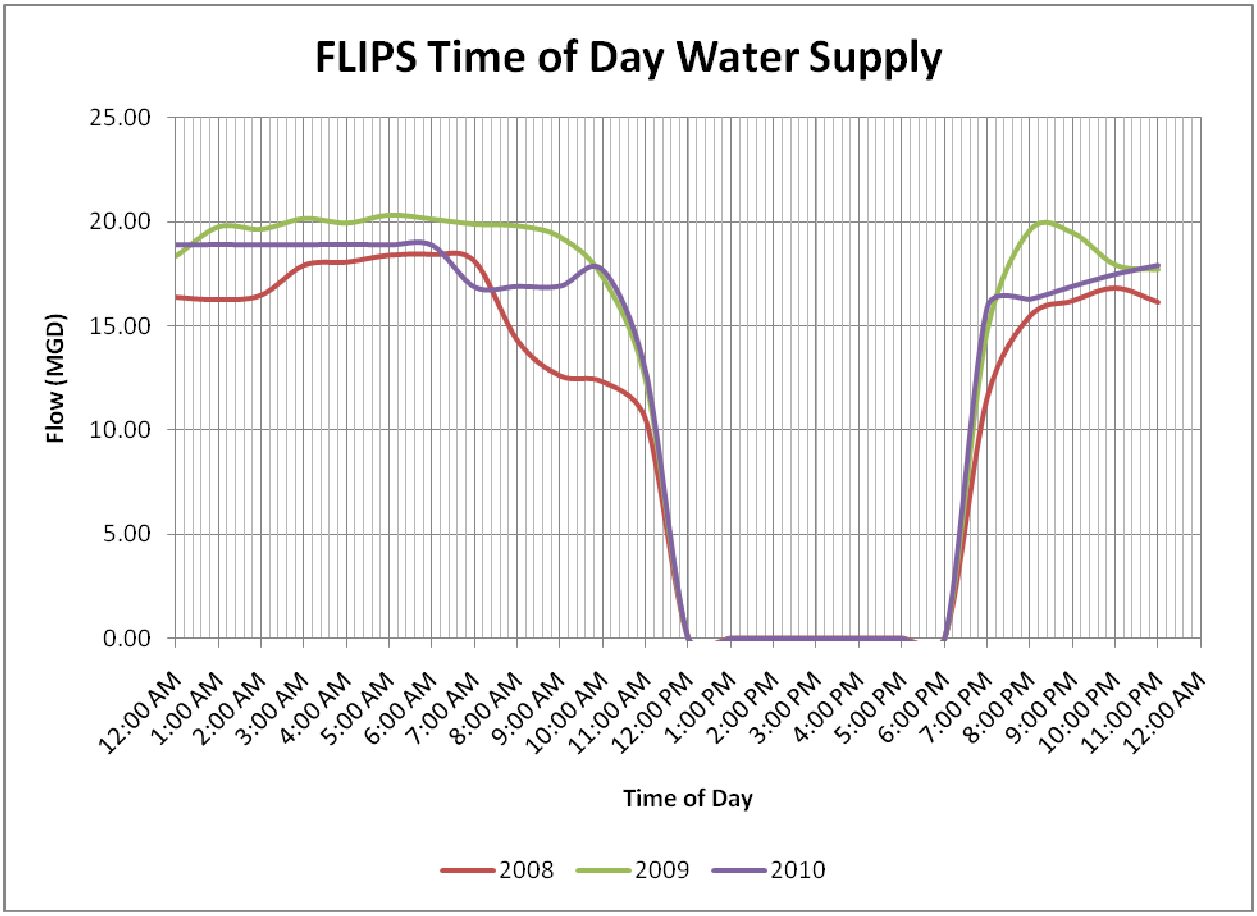


Figure 3 illustrates the continuous improvement to FLIPS with each year being better than the last in terms of reduced energy usage. The curve for year 2010 represents EID's new mode of operation. Previously, FLIPS would modulate flow in order to allow EDHWTP to maintain a steady treatment process. However, doing so caused power surges during pump startup, excessive ramping up and down of the pumps, and increased energy costs. The rise and falls during the off-peak and part-peak periods in the energy curves for 2007, 2008, and 2009 show how much more energy was used while trying to maintain a steady process flow for EDHWTP. The frequent starts and stops of the pumps also created the requirement for additional maintenance to the station. In realizing this, the new mode of operation set flow control points for FLIPS and made changes to EDHWTP's operation (further discussed in Section 2.3. El Dorado Hills Water Treatment Plant). The pumps now ramp up to a steady state and maintain its best efficiency point that provides a smoother energy curve.

In the figure (Figure 4) below, observe the close correlation between energy usage (Figure 3) and water flow through FLIPS. As stated earlier, daily operations are suspended during the energy peak period (12:00 PM – 6:00 PM) to reduce energy costs. During this time period, the system utilizes storage facilities throughout the system to provide continuous water service to customers. Figure 4 is also another good illustration of the new operational changes made in

2010. Note the flat curve for 2010 in comparison to the other years, which shows the pumps operating at a steady rate of approximately 19.5 MGD for the majority of the operating period.

Figure 4: FLIPS Time of Day Water Supply



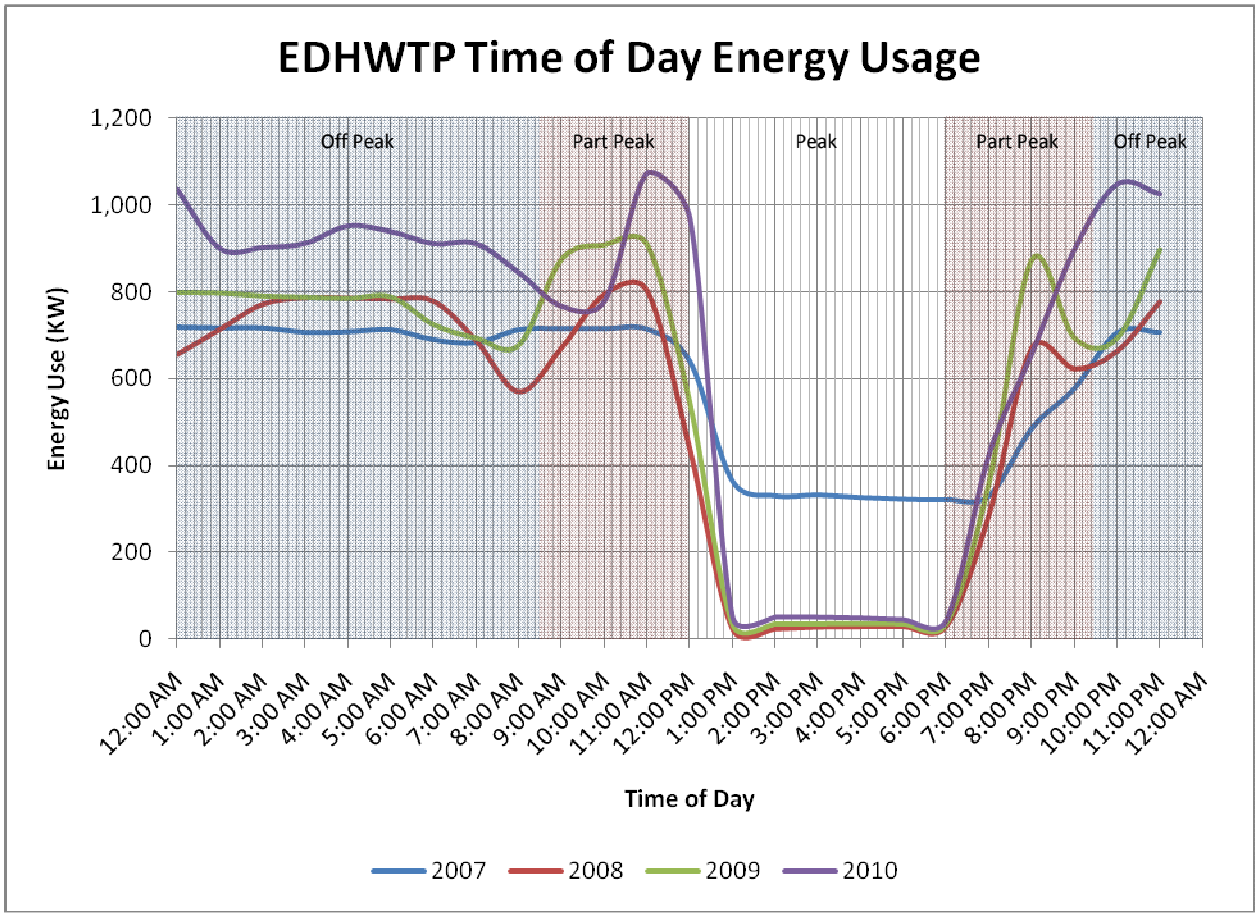
2.3. El Dorado Hills Water Treatment Plant

EDHWTP is located within El Dorado Hills, CA on Francisco Drive and provides water treatment for the El Dorado Hills service area. Raw water is delivered from Folsom Lake via FLIPS and is treated to drinking water standards. Once treated, the potable water is sent into the distribution system for consumption. EDHWTP feeds two different pressure zones; the 820 and 960 pressure zones. The 820 pressure zone is feed by three 125 HP pumps and the 960 pressure zone is feed by six pumps; 4 - 300 HP, 1 - 200 HP, and 1 - 150 HP. One pump for each zone has a VFD to reduce the number of pump starts and stops and adjust the pump speed depending on system demand.

Since FLIPS and EDHWTP are in series and respond to each other's operational changes, it is expected that they would have similar energy curves. Recommendations from EID's Response Engineering Analysis of El Dorado Irrigation District's El Dorado Hills Sub-System Report were also implemented at EDHWTP to help increase energy cost savings. Similar to FLIPS, operation for a typical summer day runs on an 18 hour schedule from 6PM to 12 PM, as shown in Figure

5. Doing so allows EDHWTP to avoid the peak period and associated rate, thus, reducing energy costs.

Figure 5: EDHWTP Time of Day Energy Usage



As mentioned in Section 2.2. Folsom Lake Intake and Pump Station, a new mode of operation was implemented in year 2010. Previously, FLIPS would modulate flow and EDHWTP was set to maintain a steady treatment process flow. Doing so caused several issues for FLIPS with little benefit to the EDHWTP. Now, FLIPS is kept at a steady flow rate and allows EDHWTP to adjust the process speed based on system demand by adjusting the filtration process and changing the clearwell level set points. As a result, EDHWTP has increased its operational flexibility by utilizing its existing process controls and can now make small adjustments without significantly affecting FLIPS. The energy curves for year 2010 in Figures 3 and 5 demonstrate a smoother, more consistent process in terms of energy usage. In addition to the daily shutdown schedule from 12 PM to 6 PM, EDHWTP also participates in PG&E's Peak Day Pricing (PDP) program. PDP is a pricing plan in response to a statewide initiative led by the California Public Utilities Commission (CPUC) for the reduction of peak energy demand. The goal for the program is to help stabilize PG&E's power grid to avoid power interruptions and reduce power plant load capacity during high demand periods. The program offers financial incentives to encourage customers to conserve and/or shift energy use to off peak periods when

the grid is at or near capacity. By participating in this program additional energy cost savings are enjoyed because of the financial incentives that are offered.

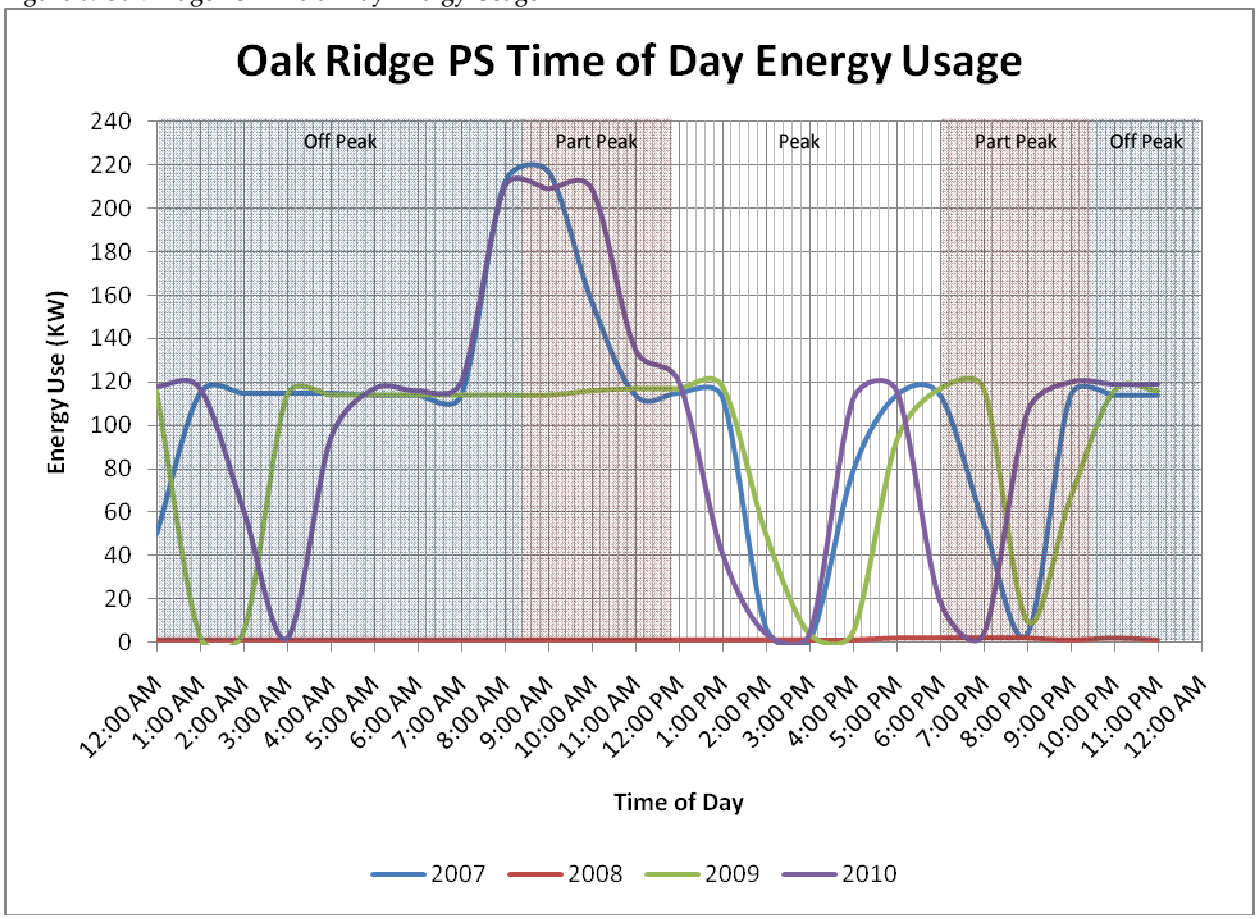
Given that FLIPS and EDHWTP implement the same operational process, it is assumed that a time of day water supply graph would resemble the FLIPS graph (Figure 4) shown above. It is also important to note that due to EDHWTP's fluctuation of filtration process speed and adjustments to the clearwell set points, a graph would not provide an accurate snapshot of how much water is delivered to the system. For instance, if the clearwell set points were raised to allow more storage of treated water, EDHWTP's production of water would be higher than the actual amount of water being delivered to the system. According to EID staff, from May through October, EDHWTP operates on an 18-hour daily schedule and produces water up to a maximum rate of 19.5 MGD; and from November to April, EDHWTP operates on a 24-hour daily schedule and produces water at an average rate of 4 MGD.

2.4. Oak Ridge Pump Station

Oakridge PS is located within El Dorado Hills, CA off of Cabrito Road. Water is received from EDHWTP via the 960 pressure zone pumps and then boosted to the Ridgeview service area for distribution. The pump station consists of three pumps; 1 - 75 HP, 1 – 100 HP, and 1 – 125 HP.

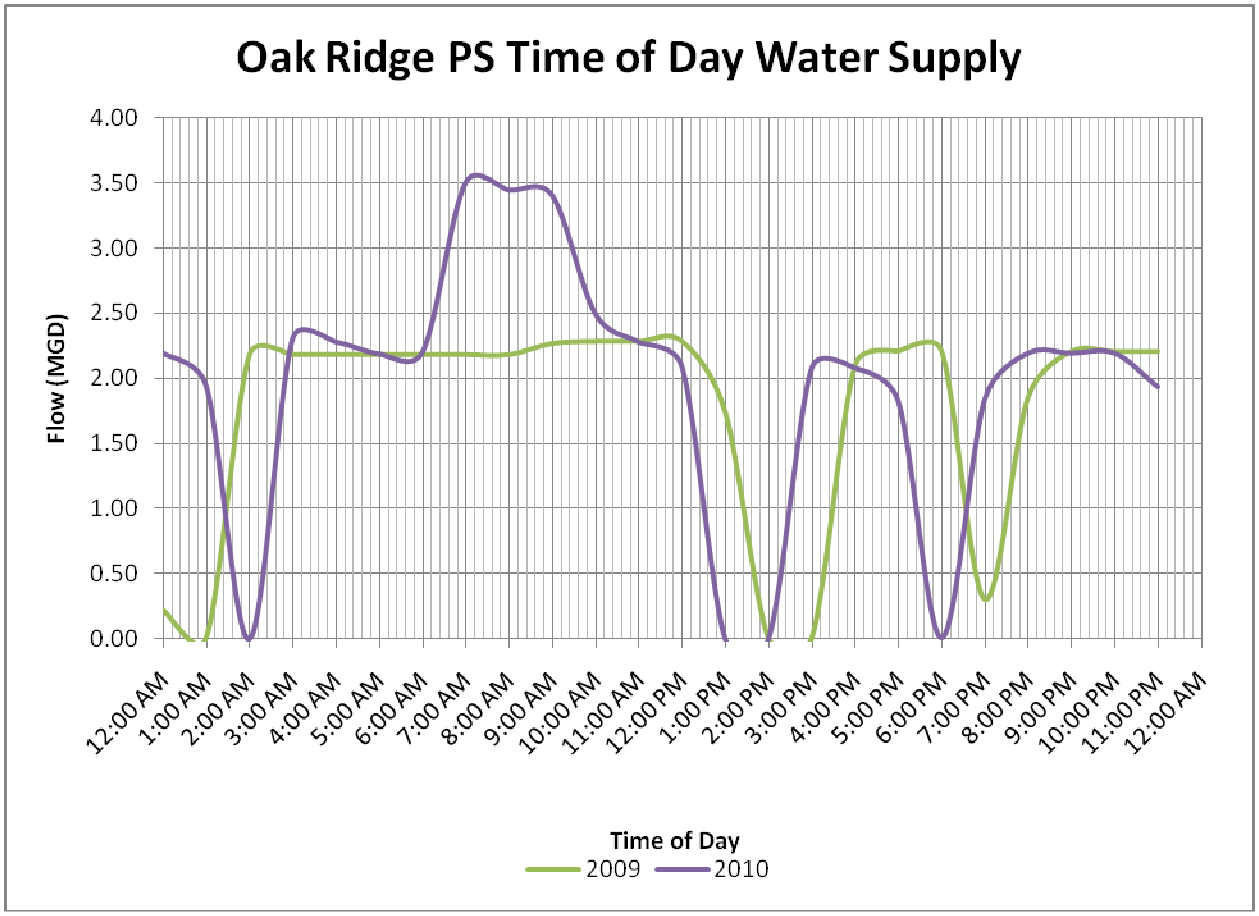
With the exception of 2008, Oak Ridge PS is normally operated daily and on an on-demand basis, as a result, energy usage and costs can be quite high during high demand periods. In late 2008, dry weather conditions required EID to implement water conservation measures that were continued into 2009. By doing so, the reduction in water availability allowed EID to utilize its eastern water supply source via the GHI to feed the Ridgeview service area and keep the operation of Oak Ridge PS to a minimum. Figure 6 shows daily energy usage during a typical summer day and the result of implementing water conservation measures during 2008 and briefly during 2009. Investigation of several days throughout the year concluded that Figure 6 is a typical representation of how Oak Ridge PS operates daily. The highest demand period occurs mostly during the part peak period of the day with cyclic activity the rest of the day. Limited capacity in Ridgeview Tank causes Oak Ridge PS to run extended amounts of time and in doing so, increases energy costs, especially during peak and part peak periods.

Figure 6: Oak Ridge PS Time of Day Energy Usage



EID's Storage Evaluation for Potable Water System Report states that Ridgeview Tank is currently undersized by approximately 2 million gallons. Evidence of this can be seen in Figure 7. The numerous rise and falls throughout the course of a typical summer day indicate that Ridgeview Tank storage volume is insufficient for its service area water demand. EID staff has also confirmed that during the summer months Ridgeview Tank can have multiple "turnovers" per day. As a result of Ridgeview Tank's restricted capacity, Oak Ridge PS is forced to operate during peak and part peak periods which result in higher energy costs. The construction of an additional Ridgeview water storage tank would give Oak Ridge PS the operational flexibility to shift its time of use from the peak period of the day as well as mediate the additional concerns previously mentioned.

Figure 7: Oak Ridge PS Time of Day Water Supply

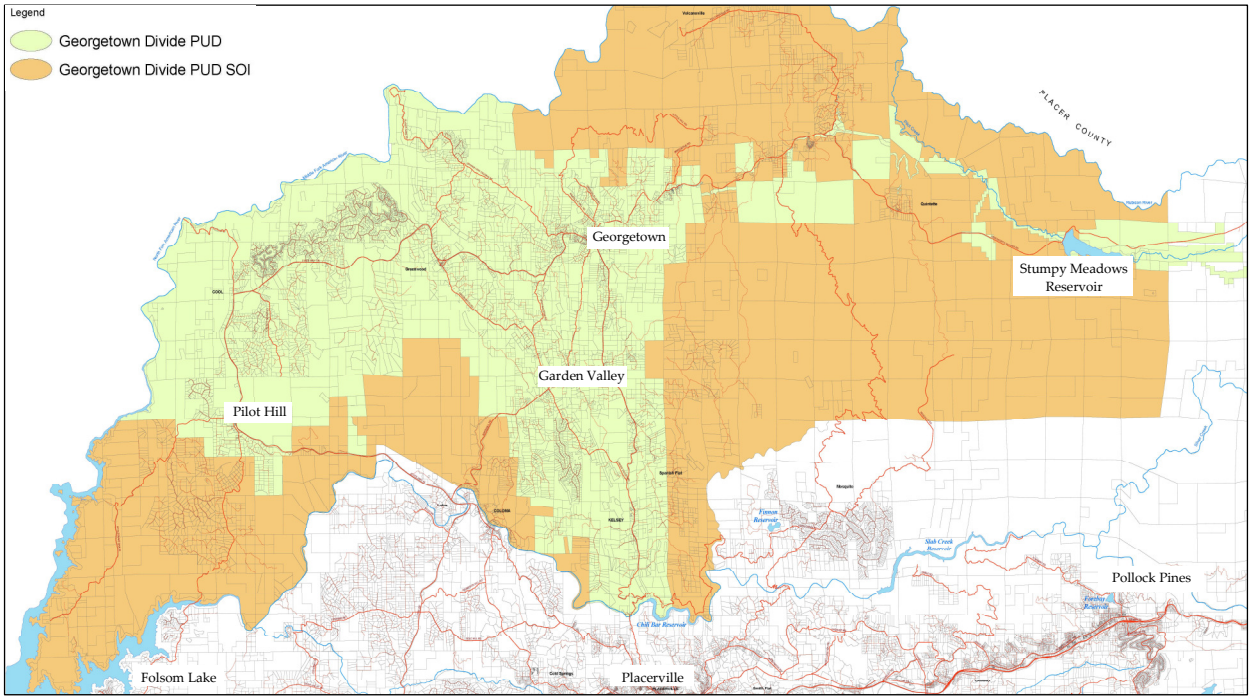


3.0 Georgetown Divide Public Utility District

3.1. Overview of Existing Water and Energy Demands

GDPUD provides water in the Georgetown Divide area of El Dorado County including the surrounding areas of Cool, Pilot Hill, Greenwood, Georgetown, Garden Valley, and Kelsey. Figure 8 below identifies GDPUD service area.

Figure 8: GDPUD Service Area



The primary source of water supply for GDPUD is the Stumpy Meadows Project. It is owned and operated by GDUPD and consists of Stumpy Meadows Dam and Reservoir which is located on Pilot Creek. The reservoir has a storage capacity of approximately 20,000 acre-feet. Water is released from Stumpy Meadows Reservoir and travels through nearly 75 miles of ditch and pipeline to provide water for agricultural and potable use.

GDPUD's existing reservoir and water conveyance system is currently optimized to provide maximum water supply yield and reliability for GDPUD water demands. A previous study examined potential increases in water storage to reduce energy usage and concluded that Walton Lake and Auburn Lake Trails Water Treatment Plants could potentially utilize the existing clear wells at each of their respective facilities for regulating storage. The clear wells are currently used to store filtered water and act as reserve to allow continuous operation of the water treatment plant (WTP), as well as supply water during backwash procedures. The existing clear well capacities were designed for its current operation and consequently do not allow for operational flexibility. As a result, modifications to the operation process are not considered feasible and a further discussion of energy demands is not warranted.

As GDPUD's demand for water supply increases, additional storage facilities or an increase to existing storage and conveyance facilities will allow for operational flexibility; as a result, it would increase the potential to reduce energy costs by utilizing additional storage during daily peak periods.

4.0 REFERENCES

The following references were reviewed in carrying out the investigation described in this report. Information from these references is incorporated throughout the report.

California Water Consulting, Inc., *Georgetown Divide Public Utility District Reoperation Project Memorandum*, May 2010.

California Water Consulting, Inc., *Options to Increase Water Supply*, April 2009.

El Dorado Irrigation District, *2009 Water Resources and Service Reliability Report*, July 2009.

El Dorado Irrigation District, *First Amendment to the 2009 Water Resources and Service Reliability Report,* March 2010.

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Pacific Gas & Electric Company, *Electric Rates*, Retrieved from http://www.pge.com/nots/rates/tariffs/electric.shtml, June 2010.

El Dorado County Water Systems

Assess Existing and Future Water and Energy Demand and Use Patterns

TM#3 – Task 2.2. Future Water Demands Technical Memorandum

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1.0 Introduction

The purpose of this study is to summarize and quantify the El Dorado Hills service area future water demands within the El Dorado Irrigation District (EID) system. The following information provides details on anticipated demands within the next eight (8) years. HDR, Inc. is currently preparing an updated Water Supply Master Plan which will contain a more in-depth analysis regarding long term water demand within the EID system. This TM references the current Administrative Draft Water Supply Master Plan, dated 2001. However, the master plan is outdated and does not reflect recent changes due to the economy and slow growth of the area. Many expected projects were either delayed or canceled along with a sharp decline in additional water demand.

2.0 El Dorado Irrigation District

2.1. Overview of Existing Water Demand

EID's facilities and delivery infrastructure for water include approximately 1,200 miles of pipeline, 27 miles of ditches, 5 treatment plants, 36 storage reservoirs and 37 pumping stations. EID's water system has a firm yield of approximately 19.7 billion gallons per year (63,550 acre-feet) that supplies nearly 39,000 water accounts. There are two service areas that are distinguished by their supply source. The Western/Eastern area receives water from EID's eastern sources (Project 184 and Jenkinson Lake) and the El Dorado Hills area receives water from Folsom Reservoir with yearly supplementation from EID's eastern sources by means of the Gold Hill Intertie (GHI). Supplementation is primarily used when annual maintenance is performed on El Dorado Hills Water Treatment Plant (EDHWTP).

The Western/Eastern area is comprised of Bass Lake, Cameron Park, Shingle Springs, Logtown, Swansboro, El Dorado, Diamond Springs, Pleasant Valley, Sly Park, Pollock Pines, Camino,

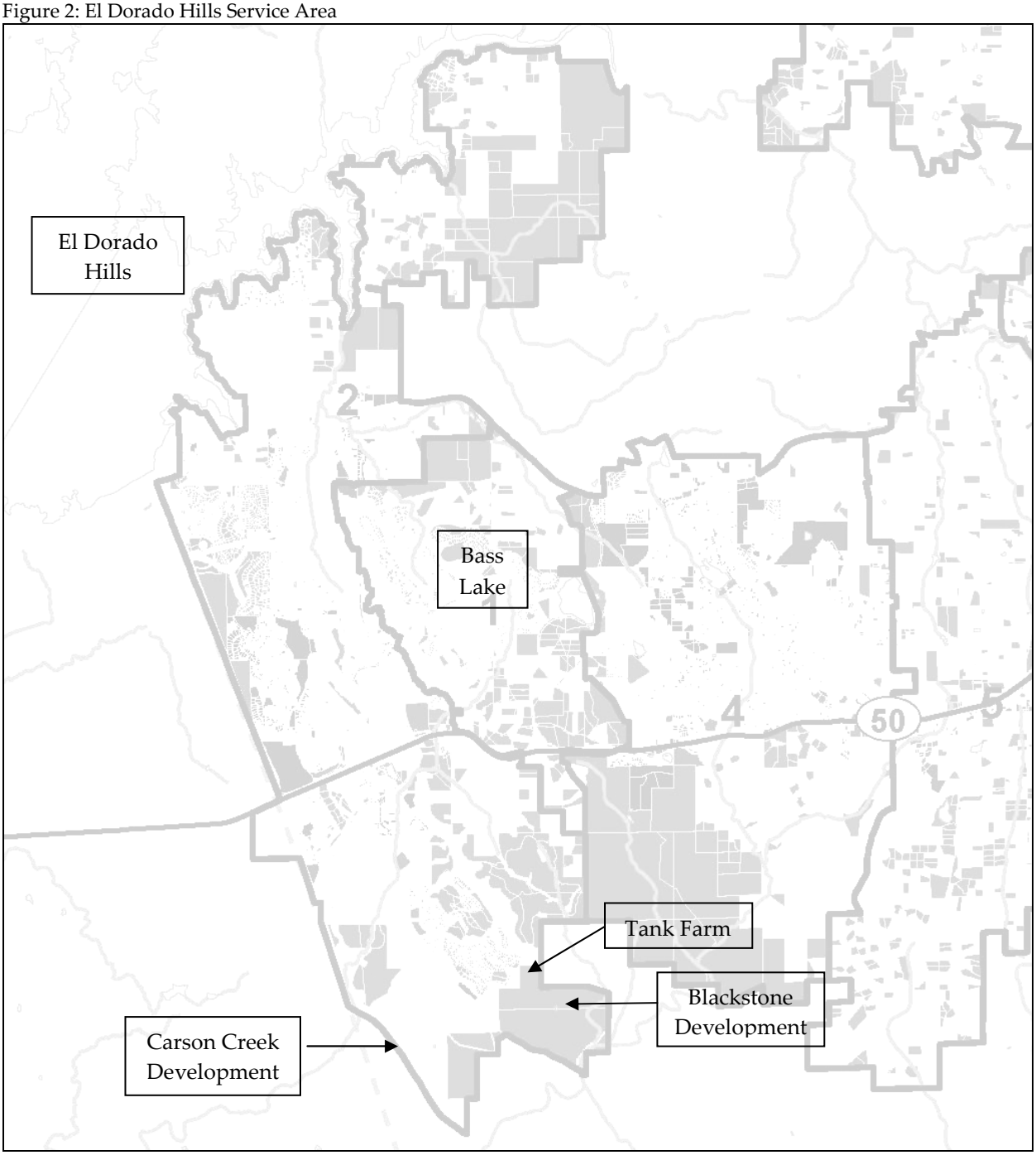
Placerville, and Lotus/Coloma. The Strawberry and Outingdale service zones are satellite systems because they are not contiguous to the rest of the service area. They also receive their water directly from the Middle Fork Cosumnes River and South Fork American River, respectively.

Although encompassing a relatively small area geographically in the county, the El Dorado Hills area accounts for nearly twenty-five percent of the water demand within EID's system. Since EID's water system covers such a large amount of area it would be difficult to analyze the entire system in detail, therefore, the analysis for this report will concentrate on the El Dorado Hills service area.

2.2. Overview of Future Water Demand for El Dorado Hills

In 2009, water demand for the El Dorado Hills service area was published as 12,070 Acre-Feet (AF). With the anticipated completion of the Blackstone (also known as West Valley) and Carson Creek developments within the next 5 to 8 years, additional demand is anticipated. Figure 2 shows the location of the new developments that will be added to the service area.

Figure 2: El Dorado Hills Service Area



Under Assessment District No. 3, the Blackstone development is entitled to 663 equivalent dwelling units (EDU). Also, the Facility Plan Report (FPR) states that an extra 80 EDUs will be transferred from the adjacent East Ridge parcel to cover Blackstone developments additional need, thus, bringing the EDU total to 743. The FPR further explains that since both properties are under the same ownership the transfer of additional EDUs is possible and is currently in progress. An additional tank (Upper Valley View) was recently constructed to serve this area.

The tank has a capacity of 700,000 gallons and is located in the "tank farm" on the northern boundary of the development.

Under the Agreement for provision of services and advance partial purchase of facility capacity charges (Carson Creek), the Carson Creek development is entitled to 784 EDUs. Since construction for this development is still in the planning stage, the Carson Creek tank has not been built. The tank will have an estimated capacity of 3,500,000 gallons and will be located in the "tank farm" on the northern boundary of the Blackstone development.

In March 2010, EID announced that 700 additional EDUs are available for purchase which will further increase the yearly demand. The summation of all anticipated demands for the El Dorado Hills service area is shown in Table 2.

Table 2: Anticipated Future Demands

Source of Additional Demand	Demand (gallons)
Existing Demand	3,933,000,000
Blackstone Development	367,000,000
Carson Creek Development	468,000,000
700 additional EDUs	196,000,000
Total Demand	**4,964,000,000**

Recent actions to improve supply conditions include the expansion of El Dorado Hills Water Treatment Plant (EDHWTP) from a capacity of 19.5 million gallons per day (MGD) to 26 MGD. By doing so will ensure these new developments and additional available EDUs will be supplied by EID's allocation of Folsom Lake water.

3.0 REFERENCES

The following references were reviewed in carrying out the investigation described in this report. Information from these references is incorporated throughout the report.

El Dorado Irrigation District, *2009 Water Resources and Service Reliability Report*, July 2009.

El Dorado Irrigation District, *First Amendment to the 2009 Water Resources and Service Reliability Report,* March 2010.

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El Dorado County Water Systems

Demand Management Options

TM#4 – Task 2.3. Identify Options for Demand Management during Utility Peak Periods

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1.0 Introduction

Large amounts of energy consumption are common among water purveyors due to the necessity of pumping water to and from storage facilities and throughout distribution systems. As a result, associated energy costs can be high. It is also important to note that energy rates vary depending on the time of year and time of day usage. PG&E's daily rates are divided into the following three periods: peak period, partial peak, and off peak. Storage tanks and reservoirs assist in demand management during peak and partial peak periods by gravity feeding the system and reducing the amount of energy consumed. While some pumping may still be required, the overall amount of energy used and associated cost is much less. If possible, a gravity fed system is the optimal choice for water transfer since it requires minimal energy usage during any period of the day. El Dorado Irrigation District (EID) staff has identified a service area that has the potential to reduce energy usage and cost by increasing the use of its existing gravity water system.

2.0 El Dorado Hills Water Service Area

2.1. Overview of Service Area

The El Dorado Hills water service area has the ability to receive water from two sources: water pumped from Folsom Lake or gravity fed from EID's eastern sources. Typically, water is removed from Folsom Lake via the Folsom Lake Intake Pump Station (FLIPS) and sent to El Dorado Hills Water Treatment Plant (EDHWTP) for treatment and delivery to the system. Additional information with regards to this pumping system has been detailed in Technical Memorandum 2 (Existing System Water and Energy Demands). When gravity water is fed into the system it is received via the Gold Hill Intertie (GHI) which is a large diameter gravity pipeline (varies from 24" to 18") that travels from EID's eastern service area and enters through

Pressure Regulating Station 6.5 and stored in the Bass Lake Tanks. Due to pipeline capacity in the GHI, it is only able to supply the El Dorado Hills service area during low demand periods, typically from November through the end of April. Figure 1 (below) shows the pumped and gravity water sources and main pipelines for the El Dorado Hills service area.

Figure 1: El Dorado Hills Water Supply Sources and Main Pipelines

2.2. Potential Savings

The El Dorado Hills service area has the potential to further reduce its energy consumption and associated energy costs by increasing the duration of operation of its gravity fed system during the low demand period of the year (November – April) which would reduce pumping hours at EDHWTP and FLIPS. During this time of the year EDHWTP and FLIPS are taken offline for a period of time necessary for maintenance activities and the GHI is utilized to supply the system. Once maintenance has been performed EDHWTP and FLIPS are brought back online for service. Recent changes to the shutdown schedule have been aimed at further utilizing the low demand period by extending the length of the shutdown. Examination of typical water flows is required to determine the feasibility of an extended shutdown schedule and quantify the amount of potential savings in energy usage and associated cost. Table 1 (below) summarizes the monthly totals of water supplied from the pumped system in million gallons (MG) during the low demand period with no supplementation from the gravity system.

Table 1: EDHWTP and FLIPS Flow Data - No Gravity System Supplementation

PRS 6.5 Offline	Nov 08	Dec 08	Jan 08	Feb (Avg.)	Mar 09	Apr 09
Days	30	31	31	28	31	30
EDHWTP Flow (MG)	186	150	39	67	94	146
FLIPS* Flow (MG)	127	106	63	65	67	109

*FLIPS flow data is the actual amount of water delivered to the system

It is important to note that flows from the FLIPS flow meter were used for this analysis. EID staff confirmed that the higher flows of the EDHWTP flow meter are due to additional water in the system that does not enter the distribution system. For example, water that is used for backwash processes and then returned to the headworks of the treatment plant. Also, notice that in order to compile data for months that PRS 6.5 was not in service, months from different years were used to estimate expected flows during the low demand period. This was done because in the past the operating procedure included water supplementation into the service area from the gravity system. The reported values for the month of February were taken as an average of January 2008 and March 2009 flows because there has not been an instance in recent history when the service area did not receive supplemented water from the gravity system during the month of February.

Flow data was also complied for PRS 6.5 when EDHWTP and FLIPS were offline to estimate capacity and compare to the pumped-only flow values. Due to recent construction activities at EDHWTP, more recent chronological data was available for use. Table 2 (below) summarizes the monthly total of water supplied from the gravity system in MG during the low demand period with no supplementation from the pumped system (EDHWTP and FLIPS). This data

provides additional information on typical low demand period flows as well as GHI's ability to transfer water supply from the east and feed the El Dorado Hills service area with no supplementation.

Table 2: PRS 6.5 Flow Data - No Pumped System Supplementation

EDHWTP Offline	Nov 09	Dec 09	Jan 10	Feb 10	Mar 10	Apr 10
Days	30	31	31	28	31	30
PRS 6.5 Flow (MG)	167	127	113	97	136	104

The preliminary data provided in Tables 1 and 2 indicate that it may be feasible to extend the length of the shutdown period and maximize the use of GHI to reduce energy consumption. Table 2 shows that GHI supplied larger flows during the low demand period when compared with what the pumped system supplied. Additional data is needed to determine if GHI could supply water demands through the end of April. Typically, during the month of April the water demand begins to rise along the GHI and as a result reducing the amount of flow available for the El Dorado Hills service area. Accurate demand information would assist in determining if there is sufficient water available to continue supply through the end of April. Based on these results and obligation to provide reliable drinking water it is estimated that the pumped system would have to be brought back online during April to support the additional demand.

Table 3 (below) provides a monthly comparison of flows during the low demand period with each system (pumped vs. gravity) acting independently to supply the service area. Table 3 indicates that the gravity system was recently able to handle increased flows when compared to what the pumped system typically experienced in the past. Again, recent construction activities to EDHWTP and FLIPS (expansion project) provided valuable data (Table 2) showing the capabilities of GHI during the low demand period.

Table 3: Comparison of Historical Flows Between Pumped and Gravity System

	Nov	Dec	Jan	Feb	Mar	Apr
FLIPS Flow (MG)	127	106	63	65	67	109
PRS 6.5 Flow (MG)	167	127	113	97	136	104

The opportunity to exclusively use the gravity system for five of the six months of the low demand period with the possibility on continuing it through the sixth month can provide a

significant savings in energy usage and cost. The amount of savings would include the total amount of energy used by both EDHWTP and FLIPS. Table 4 and 5 (below) quantifies the total monthly energy usage and cost for the pumped system to operate during the low demand period.

Table 4: Potential Energy Savings Due to Extended Shutdown of Pumped System

PRS 6.5 Offline	FLIPS		EDHWTP	
	Part Peak kWh	Off Peak kWh	Part Peak kWh	Off Peak kWh
Nov 08	72,815	208,414	44,629	123,032
Dec 08	64,157	139,631	47,743	96,593
Jan 08	42,497	94,574	24,980	59,841
Feb (Avg.)	46,187	81,033	31,872	60,003
Mar 09	49,876	67,492	38,764	60,165
Apr 09	64,634	118.102	50,834	91,743
Subtotal	**1,049,412**		**730,199**	
Total	**1,779,611 kWh**			

Table 5: Potential Cost Savings Due to Extended Shutdown of Pump System

PRS 6.5 Offline	FLIPS	EDHWTP
Nov 08	$31,415	$17,518
Dec 08	$22,051	$15,032
Jan 08	$17,830	$9,727
Feb (Avg.)	$16,943	$10,933
Mar 09	$16,057	$12,139
Apr 09	$22,443	$16,076
Total	**$208,165**	

Similar to Table 1, months when there was no supplementation from the gravity system were used to estimate a maximum savings in energy usage and cost. It is also important to note that if the pumped system was solely operating during the time period (Nov 09 – Apr 10) when GHI supplied higher flows (Table 3), the amount of potential savings would have increased by an additional 38% resulting in an even more substantial savings.

2.3. Conclusion

Based on the available information the feasibility of extending the pumped system's shutdown schedule is favorable. Extending the shutdown to six months could save **1,779,611 kWh** of energy which would result in a cost savings of **$208,165**. It is recommended that additional GHI data is gathered and examined to more accurately determine the maximum estimated flows per month during the low demand period to ensure it could provide the required supply. Accurate demand information for the El Dorado Hills service area could then be compared to conclude whether GHI could supply the demand the entire six month period.

El Dorado County Water Systems

Inventory and Replacement List

TM#5 – Task 2.4 Inventory Existing Equipment for Improved Energy Efficiency Technical Memorandum

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1.0 Introduction

The purpose of this study is to identify opportunities to improve pumping efficiencies within several existing pump stations located in the El Dorado Irrigation District (EID) service area. Pumping systems are a vital component to supplying safe and reliable drinking water in El Dorado County due to the wide range of elevations. As a result, pump station energy use has the potential to represent a sizeable portion of EID's operating costs. Significant cost factors include:

1. The consumption of large amounts of energy based on the efficiency and size of the pumps required.
2. The use of pumps during daily peak (high cost) energy use periods to deliver water on-demand.

These energy use factors are based on system demand and available supply conditions that are difficult and costly to alter. Therefore, it is important to utilize pumps with high efficiency ratings and to use them as efficiently as possible to keep energy costs to a minimum. This study focuses on summarizing each pump station's energy use, efficiency and making recommendations for potential energy savings.

2.0 El Dorado Irrigation District

2.1. Overview

EID has identified ten pump stations (Figure 1) to be evaluated for possible energy efficiency improvements. A pump station evaluation form was completed for each location by EID staff which included approximated operating points where available. These ten pump stations

utilize pumps ranging from 5 horsepower (HP) to 200 HP. The following assumptions have been made in order to conduct the evaluation:

1) All pumps still operate on their published performance curve. This assumption is necessary due to the minimal amount of data (flows with a corresponding head values) available to produce an updated performance curve.

2) All Pumps operate at a constant set point (one flow and corresponding head value), thus maintaining the same pump efficiency throughout the entire pump cycle.

3) New pumps for replacement are estimated to have a minimum efficiency rating of 70%.

4) 2010 energy usage information was provided by EID for economic analysis and it is assumed that energy usage per pump station has not changed substantially (See Attachment B).

5) Based on conversations with local pump suppliers, in general, as pumps approach the end of its service life, typically 15 to 20 years, efficiency gradually reduces by 10% to 20%.

6) Pump replacement costs do not include labor, electrical or controls changes and are approximate. It is assumed that replacement work would be done as maintenance and be included within EID's Operations and Maintenance (O&M) budget.

7) Payback periods are approximated based on recent energy usage data and assumes no finance costs for replacement (Payback equals cost of new pump divided by yearly savings).

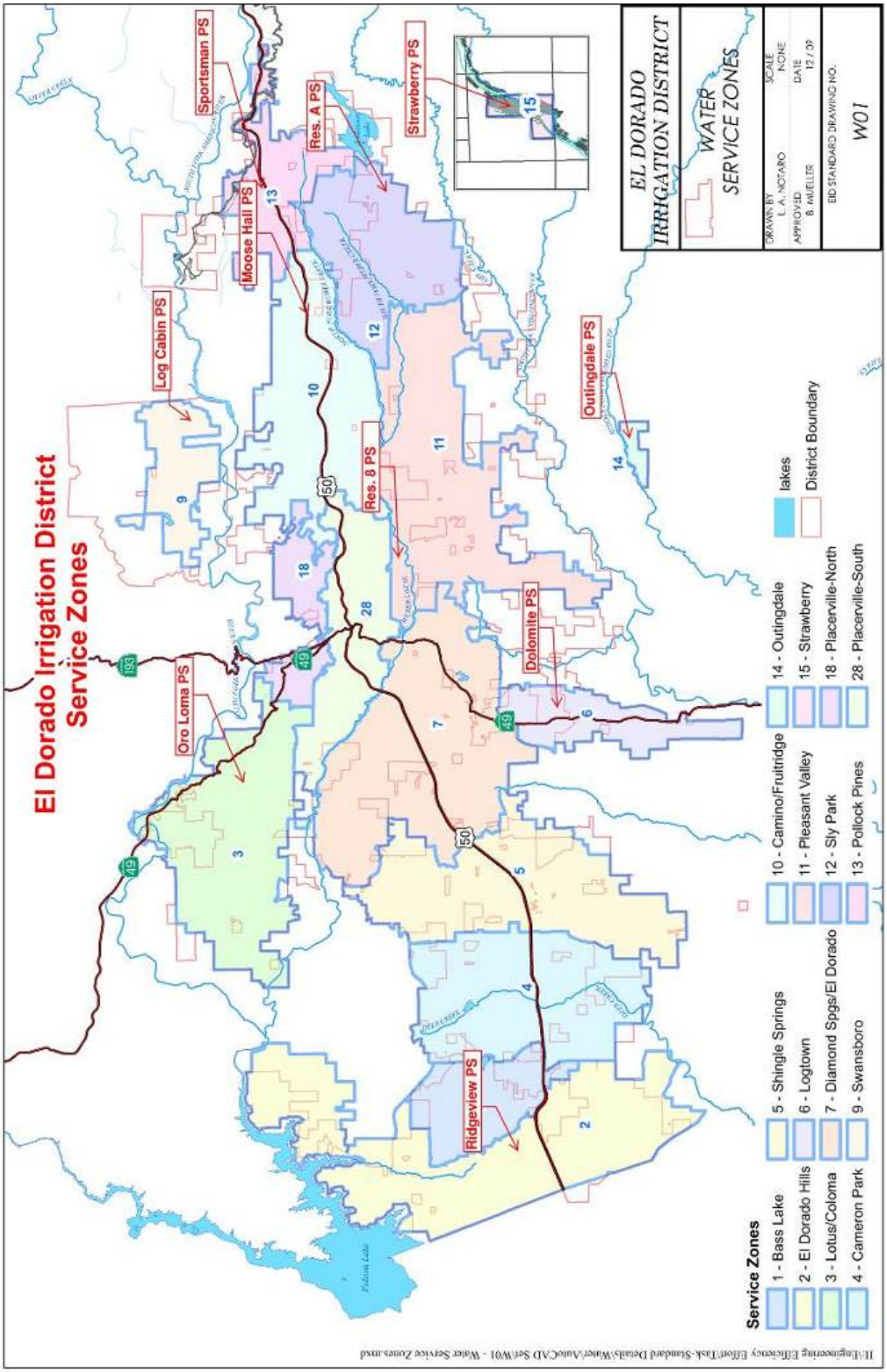


Figure 1. Location of Pump Stations Selected by EID for Evaluation

2.2. Dolomite Pump Station

Dolomite Pump Station is a small pump station that receives water from an adjacent covered reservoir and serves a small community of local residences. This station has a two pump configuration with the lead pump running the majority of the time. The stand-by pump does not alternate with the lead pump and only turns on if the pressure in the system cannot be maintained.

Recent improvements to this station include the replacement of the lead pump along with the addition of two bladder tanks to reduce pump cycling. Run-time information for the stand-by pump was unavailable and considered unnecessary due to the limited amount of run time, typically only during summer peak periods. EID staff has also noted that this pump is too big for the system.

Table 1 (below) provides a summary of the two pumps within this station. Gould's pump performance curve states that the lead pump has the ability to operate with a maximum efficiency rating of 73% when operating at its Best Efficiency Point (BEP). Recent flow and pressure testing indicated that on average the station is required to produce 125 feet of head at 35 gallons per minute (GPM), which results in the pump operating at an approximate efficiency rating of 51%. A replacement pump was researched and a Goulds 15SV9 pump should run at its maximum efficiency of 68.4% under the flow and pressure condtions above. As a result, the pump should run with a 2 HP motor at 1800 rpm. This is in contrast to a 5 HP or a 7.5 HP motor running at 3500 rpm which is the current configuration.

In order to minimize maintenance and wear on a single pump, the operating strategy should be changed from one pump always being the lead pump to an alternating strategy. This will better utilize the available equipment and extend the life of the pumps.

Table 1: Dolomite Pump Station

Dolomite		
	Lead Pump	**Standby Pump**
Manufacturer	Goulds	Paco
Model	3656/3756 S-Group	12709
Type	Centrifugal	Centrifugal
HP	5	7.5
RPM	3500	3500
Flow (gpm)	49	Stand-by
TDH (ft)	125	Stand-by
Impeller Size (in)	5-15/16	7.1
Efficiency (%)	51	40
Max Efficiency (%)	73	72
Age (years)	1	15+

Figure 2: Dolomite Pumps

Economic Analysis:
Replacement of the Paco 12709 stand-by pump (7.5 HP) would result in an efficiency increase of 19% (difference between existing lead pump and new pump). The new pump would operate as the lead pump and result in an approximate monthly savings of $109. The approximate cost for a new 5 HP pump is $1,572 which equates to a payback period of approximately 1.2 years.

Recommendations:
Even though the Goulds pump operates at a non-optimal efficiency rating it is not recommended at this time to replace the pump since it was recently purchased and installed. However, if the District can use this pump elsewhere in the system, both pumps could be replaced and maximum efficiency can be achieved.

If the District does not want to remove the recently installed Goulds pump, The lag pump (Paco), is estimated to be more than 15 years old and is reaching the end of its service life. It is recommended that when it reaches the end of its service life, a higher efficiency pump which better fits the duty points of the system be purchased and installed. Once installed it would serve as the lead pump and operate at a higher efficiency than the existing lead (Goulds) pump. Doing so results an optimal use of energy in the pump station while keeping capital costs to a minimum.

2.3. Moosehall Pump Station

Moosehall Pump Station is operated during the winter months when the Main Ditch, which is the normal gravity water supply, is out of service. The normal gravity feed to the station has a

head of approximately 380 feet (165 psi) due to elevation change. The high head from the gravity feed is reduced at the station by the use of a pair 12 inch Bailey sleeve valves.

Compared to other pump stations in the system, it is relatively large in capacity (1000 gpm) and is used as an in-line booster station to transfer water from EID's southern water sources (Reservoir A WTP) to the north (Reservoir 1 WTP) to replace the Main Ditch source when it is out of service. In order to accomplish this transfer, the pumps must pump back through the sleeve valves whose purpose it is to reduce pressure. The District is concerned that, used in this way, the pumps are running inefficiently and would like to investigate a possible bypass around the valves for the pumping operation.

This station has a two turbine pump configuration (1 duty and 1 standby) and utilizes 200 HP, 7 stage vertical turbine pumps. These turbine pumps have a maximum efficiency rating of 83.5% which is in the typical range for multi-stage turbine pumps. Existing flow and pressure conditions allow the pumps to operate close to that value (82%). Table 2 (below) summarizes the turbine pump information for this station.

Table 2: Moosehall Pump Station

Moosehall		
	Pump	**Pump**
Manufacturer	American Turbine	American Turbine
Model	12-H-150 (B)	12-H-150 (B)
Type	Vertical Turbine	Vertical Turbine
HP	200	200
RPM	1760	1760
Flow (gpm)	1000	1000
TDH (ft)	64	64
Impeller Size	NA	NA
Efficiency	82	82
Max Efficiency	83.5	83.5
Age (years)	20+	20+

Figure 3: Moosehall Pumps

After obtaining the pump curves and sleeve valve curves from their respective manufacturers, a comparative analysis was performed. The curve for the sleeve valves defines the relationship between the variable C_v and the percent stroke of the valve. The manufacturer states the value for C_v for reverse flow through the valve can be estimated as 80% of the given value for normal flow. Essentially this means, at an equivalent pressure, the valves will pass 80% of the forward flow in reverse. Per the given curves, valve no. 2 has a higher flow rate than valve no. 1. Valve no. 1 will be used to calculate flows knowing that slightly higher flows are possible with valve no. 2.

C_v defines the relationship between pressure and discharge volume for a particular valve. Using this relationship, a flow of 47.5 cfs is obtained. This is the flow that could be expected to run through a fully open valve at a 165 psi pressure. The expected value for reverse flow is then 80% of this, or 38 cfs.

Assuming the pump creates a pressure of at least 165 psi and the flow from the pump in the reverse direction is at capacity or 1,000 gallons per minute (2.2 cfs). This is less than 6% of the full open reverse flow valve capacity. Therefore it is reasonable to conclude that if when the pumps are running at least one of the valves is fully open, there should be little to no head loss pumping backwards through the sleeve valve. When the calculations are performed, a head loss of approximately 0.5 psi is obtained.

Using a horsepower to kilowatt conversion of 1 HP = 0.735 kW and estimating that the pumps will be running 24 hours per day for the months they operate, an estimate of monthly savings can be obtained. Assuming a new pump system is 10% more efficient yields a savings of approximately $3,800 per month. A 20% more efficient system yields approximately $7,000 per month in savings.

Recommendations:

Given the calculations, assumptions and reasoning above, it would be in the best interest of the District to replace the pumps rather than consider a bypass construction project. The District will then need to consider if larger pumps for anticipated greater future demands are prudent or whether the station is adequate at its current size.

The existing vertical turbine pumps appear to be operating at an acceptable efficiency point which is near the maximum efficiency possible for these pumps. However, EID staff has noted that these pumps have been in service for more than 20 years. It is important to note that though the turbine pumps are functional, as they continue to approach the end of their service life, reliability becomes a concern. As a turbine pump ages, efficiency can reduce by as much as 20%.

Due to the relatively long service history of these turbine pumps, they are considered ready for replacement. New pumps would restore the efficiency and reliability of the station. This will aid in lessening energy and maintenance costs during their seasonal operation.

2.4. Oro Loma Pump Station

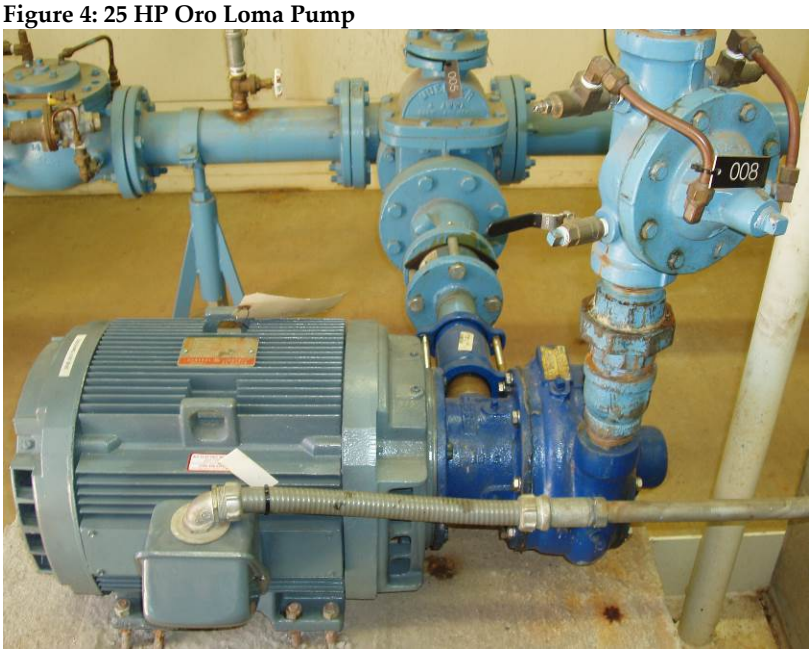
Oro Loma Pump Station is categorized as a mid-size station. The station uses four pumps of varying sizes to accommodate a range of flows. Operating data was not available for the Paco pump (7.5 HP), but was assumed to operate at its maximum efficiency of 54% for the economic analysis. Table 3 (below) shows the efficiency ratings for each pump within the station. The 50 HP pump does not need to be considered for replacement as it has an acceptable efficiency rating and operates as a fire flow pump for a limited run time. The remaining two pumps are both 25 HP and have a maximum efficiency of 62%.

Table 3: Oro Loma Pump Station

Oro Loma				
	Pump	**Pump**	**Pump**	**Pump**
Manufacturer	Paco	Paco	Paco	Paco
Model	1570-1	1570-1	3095-5	1070-5
Type	Centrifugal	Centrifugal	Centrifugal	Centrifugal
HP	25	25	50	7.5
RPM	3500	3500	3550	3500
Flow (gpm)	100	100	500	NA
TDH (ft)	376	376	257	NA
Impeller Size	6-3/4	6-3/4	8-4/10	6
Efficiency	56	56	78	54*
Max Efficiency	62	62	81	54
Age (years)	NA	NA	NA	NA

***Estimated efficiency value**

Figure 4: 25 HP Oro Loma Pump



Economic Analysis:
The following assumptions were used for the economic analysis:

1) Only the 7.5 HP pump operates during Off-Peak periods

2) The 7.5 HP and 25 HP (2) pumps operate 50% and 25% of the Partial-Peak period, respectively

3) The 25 HP (2) pumps each operate 50% of the Peak-Period

4) The 50 HP pump is a standby pump for extreme flow events such as fire suppression

Replacement of the 7.5 HP and two 25 HP pumps would result in an efficiency increase of 16% and 14%, respectively and approximate total monthly savings of $86. The approximate cost for a new 7.5 HP and two 25 HP pumps is $2,301 and $6,281 ($3,141 each), respectively, which equates to a payback period of 8.3 years.

Recommendations:
During the Site visit it was noted that the 25 HP pumps were cycling frequently. The pumps standby period was approximately 5 minutes and the runtime was approximately 2 to 3 minutes. The 7.5 HP pump ran constantly. This was at about 9:30AM when water usage should be tapering off. This suggests that the 7.5 HP pump cannot meet demands at any time other than lowest demand period.

The frequent start/stop operation of the 25 HP pumps means the motor startup current is being drawn from the electrical supply many times per day. Startup current is usually 2 to 3 times the running current for a particular motor. Each time the motor starts, it causes a brief spike in energy usage. If it were only starting a few times per day, this would not be an issue, however per EID staff this occurs for a large part of the day.

If the 7.5 HP pump were taken out of service and a slightly larger, VFD controlled pump were used in its place, the start/stop frequency would be lessened greatly. It may even be possible to place one of the 25 HP pumps on VFD control and eliminate the fourth pump altogether.

The incoming pressure to this station is around 60psi. It was noted there were pressure reducing valves (PRV) on both the small feed line to pump No. 4 and the larger line feeding pumps nos. 1 to 3. EID staff stated these PRVs were installed subsequent to the initial construction of the station, but were not certain why they were installed. It is likely they were installed to adjust the incoming pressure to better fit the requirements of the pumps and adjust where the pumps were running on their curves. If this is the case, energy (pressure) is being expended through the valves needlessly when what is really required are pumps that better fit the system.

It is recommended that three new pumps are installed to replace the existing pumps (7.5 HP & 2 25 HP). The new pumps would have higher efficiency ratings at the operating conditions to allow for the most efficient use of energy.

2.5. Outingdale Recycled Water Pump Station

Outingdale Recycled Water Pump Station is a small station that consists of three 10 HP pumps. Existing conditions allow the pumps to run near their maximum efficiency ratings, however, these pumps only have a maximum efficiency rating of 54%. These ratings are low and are not suitable for their current operation. It was also noted by EID staff that these pump's Net Positive Suction Head (NPSH) requirements are too high for the existing operating conditions. Table 4 (below) summarizes pumps within the Outingdale Recycled Water Pump Station.

Table 4: Outingdale Recycled Water Pump Station

Outingdale RW			
	Pump	**Pump**	**Pump**
Manufacturer	Berkeley	Berkeley	Berkeley
Model	B1-1/2ZPL	B1-1/2ZPL	B1-1/2ZPL
Type	Centrifugal	Centrifugal	Centrifugal
HP	10	10	10
RPM	3550	3550	3550
Flow (gpm)	100	100	100
TDH (ft)	220	220	220
Impeller Size	7-7/8	7-7/8	7-7/8
Efficiency	53	53	53
Max Efficiency	54	54	54
Age (years)	NA	NA	NA

Figure 5: Outingdale Pumps

Economic Analysis:

The economic analysis assumes that only one pump is operating at any given time. The peak hour flow condition was neglected due to the short amount of time the lag pump would operate to provide assistance. The replacement of each pump would increase efficiency by 17% (each pump) resulting in an approximate total monthly savings of $103. The approximate cost for three new 10 HP pumps is $7,583 ($2,528 each) which equates to a payback period of 6.1 years.

Recommendations:

It is recommended that the three existing pumps (10 HP) are replaced with new pumps to address the low efficiency as well as the low NSPH. Existing operating conditions should be assessed first to ensure the correct pumps are purchased.

2.6. Reservoir 8 Pump Station

Reservoir 8 Pump Station is a small size station that receives water from a nearby tank (Reservoir 7) and delivers it to the surrounding community. The station has a three pump configuration with two duty pumps that supply domestic use and a larger standby pump that serves as a fire pump for fire flow conditions. Operating data for the 10 HP pump (fire pump) was unavailable, but since this pump is only used for fire flow conditions an evaluation of its efficiency was not deemed necessary. The two 5 HP pumps have a maximum efficiency rating of 68%, but operate around 60%. These pumps have been estimated to be 15+ years old indicating they are approaching the end of their service lives.

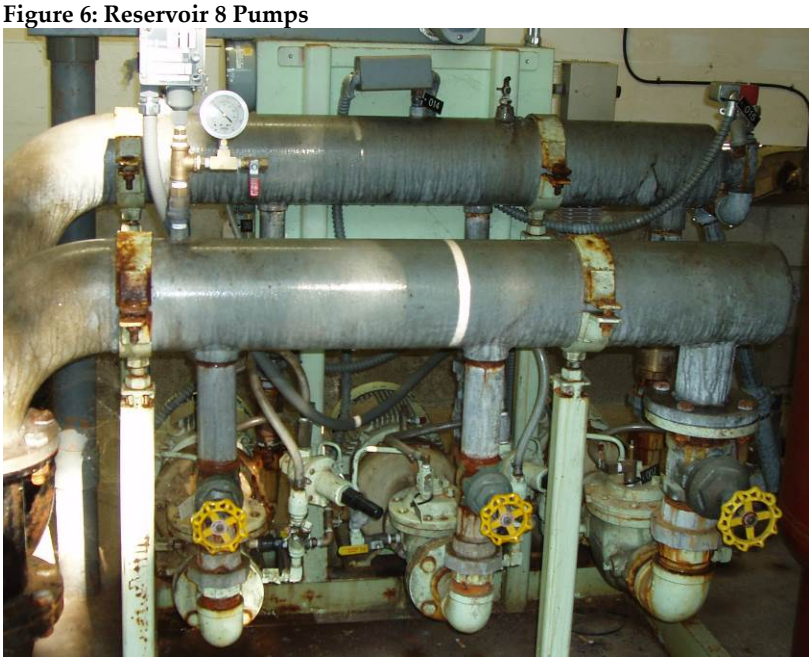
The operating conditions for these pumps are not ideal. Water is supplied to the station at 52 psi, it is then pressurized to 150 psi and regulated down to 60 psi by a PRV for distribution. The result being the water goes through a 90 psi change in pressure that is wasted. An 8 psi boot is required and a 90 psi boost is provided. A Goulds 3910 vertical pump could be used here with similar benefits as those listed for the Dolomite PS. These pumps would be approximately 1 HP

as opposed to the 5 HP models currently in use. The maximum efficiency for the 3910 is 53%, which is actually less than the current model, but the actual energy used will be much less.

Table 5: Reservoir 8 Pump Station

Reservoir 8			
	Pump	**Pump**	**Pump**
Manufacturer	Paco	Paco	Paco
Model	1270-5	1270-5	2070-5
Type	Centrifugal	Centrifugal	Centrifugal
HP	5	5	10
RPM	3500	3500	3500
Flow (gpm)	80	80	Fire Pump
TDH (ft)	115	115	Fire Pump
Impeller Size	5-8/10	5-8/10	6.2
Efficiency	60	60	Fire Pump
Max Efficiency	68	68	Fire Pump
Age (years)	15+	15+	15+

Figure 6: Reservoir 8 Pumps



Recommendations:
It is recommended that the two existing 5 HP pumps are replaced with two new lower horsepower pumps. It is important to note that as they continue to approach the end of their service life, the reliability of the pumps becomes a greater concern. These pumps can be expected to have lost at least 10% of their efficiency due to their age reducing their current operating efficiency to 50%.

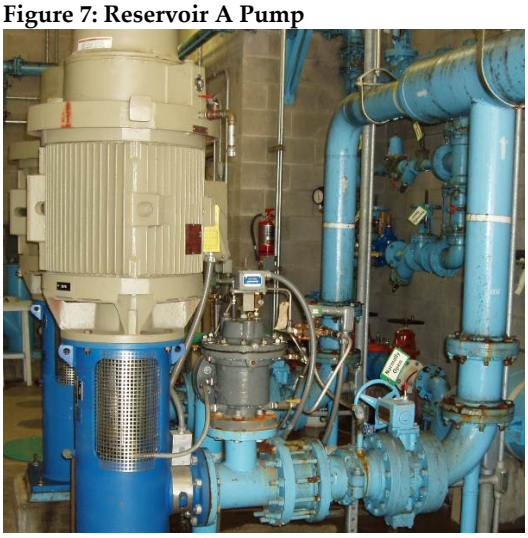
2.7. Reservoir A Pump Station

Reservoir A Pump Station is a large size pump station that serves as a booster station to transfer water from Reservoir A to the Sly Park Water Tanks. EID staff has also noted that these pumps run on a limited basis. This station contains two 100 HP vertical turbine pumps that are estimated to operate at an efficiency of 82% as shown in Table 6 (below). These turbine pumps were installed in 2002 and are still within their service life.

Table 6: Reservoir A Pump Station

Reservoir A		
	Pump	**Pump**
Manufacturer	Floway	Floway
Model	10JKH	10JKH
Type	Vertical Turbine	Vertical Turbine
HP	100	100
RPM	1790	1790
Flow (gpm)	750	750
TDH (ft)	380	380
Impeller Size	NA	NA
Efficiency	82	82
Max Efficiency	84	84
Age (years)	8	8

Figure 7: Reservoir A Pump



Recommendations:

There are no recommendations to increase efficiencies for this pump station. The installed equipment suits it purpose.

2.8. Strawberry Recycled Water Pump Station

Strawberry Recycled Water Pump Station is a small station that consists of three 5 HP pumps. Table 7 (below) summarizes the pump information for this station. EID staff has noted that these pumps are 20+ years old and have maintenance issues. Issues include the requirement to remain on all the time because these pumps are not self–priming, impellers break off the shafts, excessive vibrations, cavitations, pumping prime is often lost, and the pumps cannot deliver enough flow to the plant. These pumps have a maximum efficiency of 48%, but operate around 34%, which is well below the optimal efficiency range.

Table 7: Strawberry Pump Station

Strawberry RW			
	Pump	**Pump**	**Pump**
Manufacturer	Crown	Crown	Crown
Model	PO3LB	PO3LB	PO3LB
Type	Centrifugal	Centrifugal	Centrifugal
HP	5	5	5
RPM	1750	1750	1750
Flow (gpm)	115	115	115
TDH (ft)	41	41	41
Impeller Size	7B	7B	7B
Efficiency	34	34	34
Max Efficiency	48	48	48
Age (years)	20+	20+	20+

Figure 8: Strawberry Pump

Economic Analysis:

Replacement of these pumps would increase efficiency by approximately 56% resulting in a monthly savings of $1,249. The approximate cost for three new 5 HP pumps is $4,716 ($1,572 each) which equates to a payback period of 3.8 years. It is important to also note these pumps share power lines with the adjacent treatment plant (plant), but the plant's energy usage was considered negligible based on conversations with EID. New pumps selected for service here may need to be larger than existing as the existing pumps are unable to handle the existing demand.

Recommendations:

These pumps have poor efficiency ratings and have numerous maintenance issues. It is recommended that these pumps be replaced with higher efficiency pumps that can operate under the existing operating conditions. Also, since the pumps have passed the 20 year service mark, efficiency may have been reduced by as much as 20%, thus potentially the current pumps could be operating with as low as 14% efficiency.

2.9. Log Cabin Pump Station

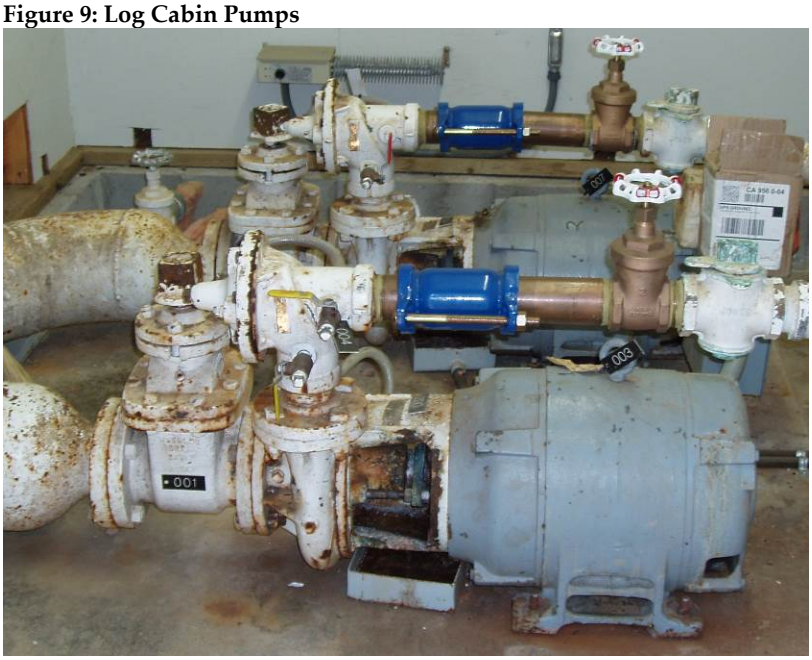
Log Cabin Pump Station is categorized as a mid-size pump station. This station receives water from an adjacent tank and serves the surrounding community. It has a two pump configuration that use equally sized pumps. The station also includes a hydro-pneumatic tank with a capacity of 3,500 gallons to reduce the number of pump cycles. Existing operating conditions were not available to determine each pump's operating efficiency rating. Known information has been summarized in Table 8 below.

Table 8: Log Cabin Pump Station

Log Cabin		
	Pump	**Pump**
Manufacturer	Griswold	Griswold
Model	R2GH	R2GH

Type	Centrifugal	Centrifugal
HP	20	20
RPM	3450	3450
Flow (gpm)	NA	NA
TDH (ft)	NA	NA
Impeller Size	7-31/32	7-31/32
Efficiency	NA	NA
Max Efficiency	77	77
Age (years)	15+	15+

Figure 9: Log Cabin Pumps



Economic Analysis:

The pumps have been estimated to be between 15 and 20 years old, thus affecting their reliability and potentially reducing their efficiency. If the pumps were assumed to operate at their maximum efficiency (77%) minus the reduction due to age (20%), replacement of these pumps would result in an approximate monthly savings of $67. The approximate cost for two new 20 HP pumps is $5,872 ($2,936 each) which equates to a payback period of 7.3 years.

Recommendations:

Recommendations for improving efficiency cannot be made due to the lack of flow and head values. It is recommended that the pumps be replace based on age. A pump test could be performed to determine operating conditions including efficiency.

2.10. Ridgeview Pump Station

Ridgeview Pump Station is a mid-size station that receives water from an adjacent tank and delivers it to the surrounding community. The station has a three pump configuration that consists of two 25 HP pumps and a 7.5 HP pump. Information for the 7.5 HP pump was not available for evaluation, but EID staff has noted that this pump is in poor condition and needs replacement. Table 9 (below) summarizes the station's pump information. The maximum efficiency rating for the two 25 HP pumps is 68% and they operate around 65%.

Table 9: Ridgeview Pump Station

Ridgeview			
	Pump	**Pump**	**Pump**
Manufacturer	Goulds	Weinmain	Weinmain
Model	5BF85	3L5	3L5
Type	Centrifugal	Centrifugal	Centrifugal
HP	7.5	25	25
RPM	3450	1750	1750
Flow (gpm)	NA	300	300
TDH (ft)	NA	155	155
Impeller Size	NA	13	13
Efficiency	NA	65	65
Max Efficiency	NA	68	68
Age (years)	NA	NA	NA

Figure 10: Ridgeview Pumps

The two 25 HP pumps are operating near their peak efficiency. As such they appear to be appropriately sized. Replacing them prior to their end of service life period would be

premature. They should be monitored and replaced when the efficiency drops below acceptable levels.

Per EID staff comments, the 7.5 HP pump is old, is at the end of its serviceable life and should be replaced. Additional information would be required to determine the 7.5 HP pump's operating conditions and potential savings with replacement. Operating conditions also need to be verified to ensure the proper and efficient operation of a new pump.

Recommendations:
It is recommended that as these pumps reach the end of their service lives they are replaced with higher efficiency pumps. The 7.5 HP pump is a higher priority since it is the only pump that can handle the daily off peak periods (low flow), has extended run times, and is noted to be in poor condition. If this pump were to fail, the 25 HP pumps would be required (depending on pump control settings) to deliver the low flow. One of the 25 HP pumps is controlled by VFDs and would be more able to pump the low flows than the fixed speed pump. Doing so would likely cause the pump to cycle excessively, causing premature wear.

2.11. Sportsman Pump Station

Sportsman Pump Station is a large size station that delivers water into the surrounding distribution system. The station has a three turbine pump configuration that consists of two 200 HP turbine pumps and one 100 HP turbine pump. A performance curve for the 100 HP turbine pump was unavailable during the evaluation. Table 10 (below) summarizes the three turbine pumps for this station. The maximum efficiency for the 200 HP turbine pumps is 80% and operates around 78%. The turbine pumps operate at an acceptable efficiency rating but are estimated to be 20+ years old.

Table 10: Sportsman Pump Station

Sportsman			
	Pump	**Pump**	**Pump**
Manufacturer	Johnston	Johnston	Johnston
Model	RX53285	TY53127	TY53127
Type	Vertical Turbine	Vertical Turbine	Vertical Turbine
HP	100	200	200
RPM	1775	1775	1775
Flow (gpm)	250	550	550
TDH (ft)	NA	850	850
Impeller Size	10	11	11
Efficiency	NA	78	78
Max Efficiency	NA	80	80
Age (years)	20+	20+	20+

Figure 11: Sportsman Pumps

Economic Analysis:
The following assumptions were used based on conversations with EID staff:

1) During the Off-Peak period the 200 HP turbine pumps operate 50% of the total period and the 100 HP turbine pump operates the remaining time. This high flow fills up the Pollock Pines Reservoir during off peak periods.

2) The Partial-Peak period operation is the same as the Off-peak period

3) During the Peak-Period only the 200 HP turbine pump operate

The replacement of these two turbine pumps (200 HP) would increase pump efficiency by 12% and result in an approximate monthly savings of $1,102. The approximate cost for two new 200 HP turbine pumps is $30,000 ($15,000 each) which equates to a payback period of 2.3 years. The 100 HP turbine pump is estimated to also operate at a reduced efficiency due to its age, so it is recommended that a pump test be performed to determine its existing conditions and potential savings with replacement.

Recommendations:
EID staff has noted that these turbine pumps have been in service for 20+ years, thus potentially reducing the efficiency to 58% (200 HP turbine pumps). It is recommended that EID perform testing as described above and plan for the replacement of these turbine pumps based upon the results of those tests.

3.0 Conclusion

Preliminary evaluation of each pump station has determined that 8 of the 10 pump station require additional analysis or action. The following table (Table 11) provides a ranking of each pump station based on EID staff comments and estimated payback period. EID staff concerns took precedence because of the operational issues associated with each pump station. Based on results, it is recommended that Moosehall PS be upgraded as a priority as these pumps are the only source of water for the northern section of the service area during the winter months and reliability is a concern. The Reservoir 8, Dolomite and Outingdale pump stations should be upgraded next as these seem to have the most to gain in efficiency.

Table 11: Summary Table

Summary of Recommendations and Approximate Paybacks and Costs					
Rank	**Site**	**Recommendation**	**Pay Back (yr)**	**Cost**	**Comments**
1	Moosehall	Plan for replacement	NA	NA	Pumps 20+ years old
2	Reservoir 8	Replace 2 of 3 pumps	2.5	$3,144	None
3	Dolomite	Replace 1 or 2 pumps	1.2	$1,572	None
4	Outingdale RW	Replace 3 of 3 pumps	6.1	$7,583	Staff Concerns
5	Strawberry RW	Replace 3 of 3 pumps	3.8	$4,716	Staff Concerns
6	Oro Loma	Replace 3 of 3 pumps	8.3	$8,582	None
7	Log Cabin	Perform pump test	7.3	$5,872	Pump test needed
8	Sportsman	Replace 2 of 3 pumps	2.3	$30,000	None
9	Ridgeview	Replace 3 of 3 pumps	5.6	$6,281	Staff Concerns
10	Reservoir A	None	None	None	None

APPENDIX A –

Meeting Minutes from Pump Station Evaluation Site Visit

Meeting Minutes

El Dorado Irrigation District – Pier Grant #2

Subject: **EID Facility Evaluation**
Prepared For: Attendees
Prepared By: Tom Dugan
Reviewed By: Daryl Heigher
Date/Time: July 25, 2013 7:30 AM – 12:30 PM
Location: El Dorado County
Project Number: EID-033 - PEIR Grant

Attendees:
See Below

1. Purpose of Meeting

Attend a site visit of El Dorado Irrigation District's (EID) pumping plant facilities with the intent of evaluating and identifying potential opportunities for improved pumping efficiency based on age, pipe configuration and energy usage.

2. Attendees

Name	Agency	Phone	Email
Bob Rice	EID	530-642-4079	brice@eid.org
Ken	EID		
Daryl Heigher	D&A	916-933-1997	darylh@daengineering.net
Courtney Thomas	D&A (Intern)	916-933-1997	
Tom Dugan	D&A	916-933-1997	tomd@daengineering.net

3. Discussion Summary

Six EID pump station facilities were visited on Thursday July 25, 2013 with the site visit lead by Bob Rice and Ken (EID O&M). The following summarize the information learned from the visit and data needed to further identify potential opportunities for improved pumping efficiency.

1. Ridgeview

a. The Oak Ridge facility can be used to fill the Ridgeview storage tank

b. The system currently operates with three pumps in parallel (2 duty, 1 fire). The pumps are feed from an on-site storage tank though a 6-inch buried manifold.

c. A hydro-pneumatic tank is used to maintain a constant pressure (approximately 65 psi) at the supply to the distribution system.

d. The long-term intent is to relocate the facility on adjacent EID property. The purpose is to minimize noise to adjacent residents and increase facility security by placing all pumps and equipment in a masonry building.

e. EID indicated they were not convinced the pump control settings were properly adjusted to optimize the system. Need to look at pressure drops within the system and evaluate the on/off pressure set points.

f. Need to evaluate existing valve placement and recommended piping modifications.

Data Request:

- Definition/clarification of how EID rates their pump conditions
- As-built drawings of the pump station supply and distribution systems
- Pump run history and stage setting data
- System schematic (e.g. water sources, distribution pressure zone demands, system elevations)
- Pump flows v. pressure (Q in and Q out); pump curves (original design); pump characteristics (e.g. hp and impeller diameters, amps draw)

2. Oro Loma

a. The system is supplied by another pump station upstream and supplies water across two ridges. The system is comprised of four pumps (3 duty, 1 fire). Two of the three duty pumps are of equal size (Pumps #1 and #2); the third is smaller (pump #4) and was found to be constantly running.

b. Pump #4 draws water from an influent pipe, with a pressure of approximately 60 psi, through a Pressure Reducing Valve (PRV). Pumps #1 and #2 cycle on and off alternately to offset pressure drops within the system.

c. Pumps #1, #2 and #3 draw water through a separate, larger PRV.

d. The pump startup amp draw to cycle pump #1 and #2 is likely to be high and costly as the pumps were starting every few minutes and running only for a minute or so.

e. EID indicated that pump #4 is able to hold pressure fairly consistently during non-peak hours. ***(Post Meeting Note**: Initial thought would be to switch roles of pump #1 and #2 with pump #4 and consider installing a VFD to better regulate pumps #1 and #2 to meet the systems demands. Pump #4 would cycle on only if the duty pumps (either pump #1 or pump #2) capacity was being exceeded.*

f. All pumps have check valves on their discharge pipes, as required for proper operation. The type of check valve needs to be evaluated to verify its effect on efficiency.

g. EID indicated that the system does experience pressure drops within the system possibly as a result of the pump not keeping up with demand or system hydraulics (e.g. piping friction losses).

Data Request:

- System schematic (e.g. water sources, distribution pressure zone demands, system elevations)
- Pump flows v. pressure (Q in and Q out); pump curves (original design); pump characteristics (e.g. hp and impeller diameters, amps draw)

3. Dolomite

a. The pump station serves a local high point within the system. The PS has a covered reservoir that is fed from Sly Park Reservoir. Pump station is comprised of two small centrifugal pumps that pump to two hydro-pneumatic tanks.

b. On the day of the site visit, pump #2 was found to have lost its prime and was not pumping. This caused pressure drops to be reported and air to become entrapped within the system. The other pump could not keep up with system demand. The trapped air was being expelled from the system through the air vent in the vault outside the pump house.

c. This is a very small station which supplies a low number of customers. Changes to the station will need to be very cost conscious to have a positive effect on the bottom line.

Data Request:

- System schematic (e.g. water sources, distribution pressure zone demands, system elevations)
- Pump flows v. pressure (Q in and Q out); pump curves (original design); pump characteristics (e.g. hp and impeller diameters, amps draw)
- Copies of the small vertical pump cut-sheets that Bob referenced as a possible solution

4. Crest View

a. This station consists of a small, single centrifugal pump with a 4" diameter supply line. It currently resides in a buried metal vault that is equipped with a 2 gallon compressor with pressure regulator settings. Adjacent to the buried pump box is a subgrade air vent that is located on the supply line.

b. Approximately 25-feet north of the vault is a buried hydro-pneumatic tank of unknown size, material, and condition.

c. The PS serves approximately eight local residents and is supplied from the Diamond Springs Main (DSM). EID staff expressed that this pump station had not given maintenance crews any trouble that they could remember. However, as there is only one pump, there is no redundancy. A failure would mean loss of pressure to local residents.

d. EID needs to know more about the hydro-pneumatic tank's condition and size. It could be a possible safety hazard as it is being charged to approximately 100 psi.

e. EID expressed interest in re-building the facility in the future, above ground adjacent to the existing site and containing the pumps and equipment in an above ground building eliminating the confined space entry requirements of the current vault.

Data Request:

- Design pump curves, flow v. pressure records, system hydraulics schematic and elevations
- Any other as-built information for the existing facility

5. Reservoir 8

a. The existing system is comprised of three centrifugal pumps in parallel. They are supplied from an above ground 6-inch manifold. The pumps pump feed a hydro-pneumatic tank and an above ground 6-inch manifold.

b. The supply pipe pressure gauge was reading a pressure of 52 psi. The system appeared to be raising the pressure to 108 psi only to reduce the pressure through a PRV on the

discharge side to 60 psi. This results in a net gain of 8 psi by expending the energy to raise the pressure by 56 psi. The efficiency of this system would seem to be very low. Piping and pump changes are in order here.

c. At the time of our visit only pump #2 was running. The supply pressure gauge read 108 psi and the discharge pressure also read 108 psi. This would indicate

d. EID staff mentioned they had considered replacing the existing facility with a new skid mounted pump setup.

Data Request:

- As-built drawings of the pump station supply and distribution systems
- Pump run history and stage setting data
- System schematic (e.g. water sources, distribution pressure zone demands, system elevations)
- Pump flows v. pressure records – need to install flow meters
- Pump on/off settings

6. Moose Hall

a. The system is supplied from a higher reservoir (approximately 350 feet of head) that discharges to a covered on-site reservoir. The supply water pressure is dissipated through two sleeve valves that are located in a sub-grade vault.

b. January through September, EID serves its customers by gravity reservoir discharges. October through December, EID utilizes twin vertical turbine pumps to pump water back into the system. Currently during the pumping operation, the water is pumped back through the sleeve valves. This creates a greater head to pump against thereby using more energy than is actually required to meet the water supply requirements.

c. The energy savings for this pump station will likely come from re-piping the pump discharge such that it bypasses the sleeve valves.

d. This site should also be evaluated for a small hydro-electric project that would utilize the available head pressure to create energy.

Data Request:

- Need Moose Hall system pipe schematic
- Need operating conditions for vertical pumps
- Need source of water during pumping operations

APPENDIX B – Pump Station Evaluation Forms

PUMP STATION EVALUATION

General Info

Date if site Visit: 7/27/10
Facility Code:
Title: Oxidizing ditch RWPS
Location:
Year Constructed:
As-built Drawings: Yes No ?
Conditions: Poor Fair Good Excellent
Comments: Pump have too much NPSH

Building

Material Type: Wood Concrete Block Other
Size square feet: 8 x 8
Power/Controls Enclosed: Yes No
Site Condition: Poor Fair Good Excellent
Comments:

Pump Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
No.				
RPM				
Capacity (GPM/FT)				
Type	7.87'	7 7/8	7 7/8	
Size In. (inlet/Outlet)				
Manufacturer	Berkeley	Berkeley	Berkeley	
Model No. ~~B1½~~	~~[illegible]~~	B1½ ZPLS	B1½ ZPLS	
Serial No.				
Impeller Type				
Pump Curve No.				
Frame No.	213JM	215JM	213JM	
Part No.				

pic

Condition Poor Fair Good Excellent
Control Valves Yes No
Comments:

Motor Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
HP	10	10	10	
RPM	3510	3500	3505	
Safety Factor	1.15	1.15	1.15	
Voltage	230/460	230/460	230/460	
Nameplate Amps	25/12	22/11	25/12	
Code	H	L	G	
Type	D4 DP	TERC	D4	
Manufacturer	US Motors	Baldor	US motors	
Serial No.		F070423390	Z01Y339R112M	
Spec No.				

pic

Condition Poor Fair Good Excellent
Comments:

Piping System	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
Pipe Size	1.5			
Valve Size (discharge)	1.5			
Valve Type (discharge)	BF			
Check Valve Type	Flap			
Check Valve Size	1.5			

Hydropneumatic Tank Yes (No)
Hydropneumatic Tank Size (gallons) ____
Comments ____

Miscellaneous

Flow Meter	? (Yes)	No	Range ____
Suction Gauge	(Yes)	No	Range 30 to 100
Discharge Gauge	(Yes)	No	Range 0-160
Chart Recorder	Yes	(No)	
Hour Meters	(Yes)	No	
Log Book	(Yes)	No	

Generator

Manufacturer: No
Output (kW) ____
Motor Size (HP) ____
Type (Gas/Diesel) ____
Transfer/Auto ____
Fuel Storage Size ____
Fuel Storage: Above Below

Control System

Type: AB (Tesco) Other: Simple relays
Model No. ____
Control Condition: Poor Fair (Good) Excellent

Power Supply

Meter PGE No. ____ pic
Voltage ____
Phase ____
Main Breaker (A) ____
Condition: Poor Fair (Good) Excellent
Comments ____

Alarms

Alarm Type ____
Alarm Condition 1: Thermal cut out
Alarm Condition 2: High pressure
Alarm Condition 3 ____
Alarm Condition 4 ____
Central Alarming ____
Communications ____

Safety Condition

_____

_____

_____

_____

General Conditions

Repair Frequency _____

Suspected Cause of Problems _____

_____

_____

_____

_____

Action Items

Layout – Piping and pumps

PUMP STATION EVALUATION

General Info

Date if site Visit: 7/27/10
Facility Code:
Title: Res A
Location: Pollock
Year Constructed:
As-built Drawings: (Yes) No
Conditions: Poor Fair (Good) Excellent
Comments:

Building

Material Type: Wood Concrete (Block) Other
Size square feet: 50 x 20
Power/Controls Enclosed: (Yes) No
Site Condition: Poor Fair (Good) Excellent
Comments:

Pump Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
No.				
RPM	1770	1770		
Capacity (GPM/FT)	728/392	728/392		
Type	VTP	VTP		
Size In. (inlet/Outlet)	10 5KH	10 5KH		
Manufacturer				
Model No.				
Serial No.	47798-1-1	50033-1-1		
Impeller Type				
Pump Curve No.				
Frame No.	L404TP16			
Part No.				
Condition	Poor Fair	(Good) Excellent		
Control Valves	(Yes) No			

pics

Comments:

Motor Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
HP	100	100		
RPM	1790	1790		
Safety Factor	1.15	1.15		
Voltage	460	460		
Nameplate Amps	113	113		
Code	G	G		
Type	KS	KS		
Manufacturer	G.E.	G.E.		
Serial No.				
Spec No.				
Condition	Poor Fair	(Good) Excellent		

Comments:

ST630591 YT63687A

Piping System	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
Pipe Size	6	6		
Valve Size (discharge)	6	6		
Valve Type (discharge)	Gate	Gate		
Check Valve Type	Disk	Disk		
Check Valve Size	6	6		

Hydropneumatic Tank Yes (No)
Hydropneumatic Tank Size (gallons) —
Comments

Miscellaneous

Flow Meter	(Yes)	No	Range
Suction Gauge	Yes	(No)	Range
Discharge Gauge	(Yes)	No	Range 0 - 300
Chart Recorder Scada	(Yes)	No	
Hour Meters Scada	(Yes)	No	
Log Book	(Yes)	No	

Generator

Manufacturer None - Site Has generator but not connected to PS power.
Output (kW)
Motor Size (HP)
Type (Gas/Diesel)
Transfer/Auto
Fuel Storage Size
Fuel Storage Above Below

Control System

Type (AB) Tesco Other
Model No.
Control Condition Poor Fair Good (Excellent)

Power Supply

Meter PGE No.
Voltage
Phase
Main Breaker (A) 800
Condition Poor Fair (Good) Excellent
Comments

p) 2

Alarms

Alarm Type
Alarm Condition 1
Alarm Condition 2
Alarm Condition 3
Alarm Condition 4
Central Alarming
Communications

Safety Condition

_____

_____

_____

_____

General Conditions

Repair Frequency _____

Suspected Cause of Problems _____

_____

_____

_____

_____

Action Items

Layout – Piping and pumps

PUMP STATION EVALUATION

General Info

Date if site Visit: 7/27/10
Facility Code:
Title: ~~[illegible]~~ Sportsman
Location:
Year Constructed:
As-built Drawings: Yes No
Conditions: Poor Fair (Good) Excellent
Comments: ~~75 x 155~~

Building

Material Type: (Wood) Concrete Block Other
Size square feet: 75 x 55
Power/Controls Enclosed: (Yes) No
Site Condition: Poor Fair Good (Excellent)
Comments:

Pump Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
No.				
RPM				
Capacity (GPM/FT)	2054		750/750	
Type			11 EWC	
Size In. (inlet/Outlet)				
Manufacturer				
Model No.		11 EHC		
Serial No.	Rx53285	TY53127	95JB1897	
Impeller Type				
Pump Curve No.				
Frame No.				
Part No.				
Condition	Poor Fair (Good) Excellent			
Control Valves	(Yes) No			

pics

Comments:

Motor Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
HP	100	200	200	
RPM	1775	1785	1785	
Safety Factor	1.15	1.15	1.15	
Voltage	460	460	460	
Nameplate Amps	118	215	216	
Code	B	B	G	
Type			KS	
Manufacturer	Newman	Newman	G.E.	
Serial No.				
Spec No.			5K5445D T6465	
Condition	Poor Fair (Good) Excellent			

Comments:

404TP/003722PB

404TP/003722PB

Piping System	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
Pipe Size	12	12	12	
Valve Size (discharge)	6	8	8	
Valve Type (discharge)	BF	BF	BF	
Check Valve Type	clay	clay	clay	
Check Valve Size	8	8	8	

Hydropneumatic Tank Yes (No)
Hydropneumatic Tank Size (gallons) —
Comments

Miscellaneous

Flow Meter	x2	(Yes)	No	Range
Suction Gauge		(Yes)	No	Range 0-100
Discharge Gauge		(Yes)	No	Range 0-600
Chart Recorder	Scada	(Yes)	No	
Hour Meters		(Yes)	No	
Log Book		(Yes)	No	

Generator

Manufacturer None
Output (kW)
Motor Size (HP)
Type (Gas/Diesel)
Transfer/Auto
Fuel Storage Size
Fuel Storage Above Below

Control System

Type AB (Tesco) Other Sig IV
Model No.
Control Condition Poor Fair (Good) Excellent

Power Supply

Meter PGE No.
Voltage
Phase
Main Breaker (A)
Condition Poor Fair (Good) Excellent
Comments

pic

Alarms

Alarm Type
Alarm Condition 1
Alarm Condition 2
Alarm Condition 3
Alarm Condition 4
Central Alarming
Communications

pic

Safety Condition

_____

_____

_____

_____

General Conditions

Repair Frequency _____

Suspected Cause of Problems _____

_____

_____

_____

_____

Action Items

Layout – Piping and pumps

PUMP STATION EVALUATION

Orig 1988
Owens

General Info

Date if site Visit: 7/27/10
Facility Code:
Title: Moose Hall
Location:
Year Constructed: Pumps ~1980
As-built Drawings: Yes No
Conditions: Poor Fair (Good) Excellent
Comments:

Building

Material Type: (Wood) Concrete Block Other
Size square feet: 30 x 15
Power/Controls Enclosed: (Yes) No
Site Condition: Poor Fair (Good) Excellent
Comments: Bldg is also a wet well for Res

Pump Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
No.				
RPM				
Capacity (GPM/FT)				
Type				
Size In. (inlet/Outlet)				
Manufacturer				
Model No.				
Serial No.				
Impeller Type				
Pump Curve No.				
Frame No.	44STP			
Part No.				
Condition	Poor Fair (Good) Excellent			
Control Valves	Yes No			

Pics

Comments: Pump Data - See attached info from RF McDonald

Motor Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
HP	200	200		
RPM	1775	1775		
Safety Factor	1.15	1.15		
Voltage	460/~~[illegible]~~	460		
Nameplate Amps	236	236		
Code	G	G		
Type	RU	RU		
Manufacturer	US Motors	US motor		
Serial No.				
Spec No.				
Condition	Poor Fair (Good) Excellent			

Pics

Comments:

6349/V07V162R110B-4

6349/V11V280R148R-2

Piping System	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
Pipe Size	8	8		
Valve Size (discharge)	10	10		
Valve Type (discharge)	Clay	Clay		
Check Valve Type	/	/		
Check Valve Size	/	/		

Hydropneumatic Tank Yes (No)
Hydropneumatic Tank Size (gallons) None
Comments

Miscellaneous

Flow Meter	Yes	No	Range
Suction Gauge	Yes	(No)	Range
Discharge Gauge	(Yes)	No	Range 0-300
Chart Recorder Liq IV	(Yes)	No	
Hour Meters	(Yes)	No	
Log Book	(Yes)	No	

Generator

Manufacturer None
Output (kW)
Motor Size (HP)
Type (Gas/Diesel)
Transfer/Auto
Fuel Storage Size
Fuel Storage Above Below

Control System

Type AB (Tesco) Other Liq IV
Model No.
Control Condition Poor (Fair) (Good) Excellent To be replaced w/ AB

Power Supply

Meter PGE No.
Voltage 480 3φ pic
Phase
Main Breaker (A) 1000 service
Condition Poor Fair (Good) Excellent
Comments

Alarms

Alarm Type See pic
Alarm Condition 1
Alarm Condition 2
Alarm Condition 3
Alarm Condition 4
Central Alarming
Communications

Safety Condition

_____

_____

_____

_____

General Conditions

Repair Frequency _____

Suspected Cause of Problems _____

_____

_____

_____

_____

Action Items

Layout – Piping and pumps

R.F. MacDonald Co.
your boiler & pump solutions team
~ since 1956

Mooschall pumps
Replaced in early 2010

Date : January 4, 2010 Quote No.: KP010410-1

Provided For:	El Dorado Irrigation District 2890 Mosquito Road Placerville, CA 95667	Requested By:	Dave Constancio Phone: (916) 933-6101 Fax: (916) 933-6274 Email: dconstancio@eid.org

Your Reference	Quotation Prepared By	Payment Terms	Terms
Verbal	Kevin Peters Quotation valid for 30 days for the issue date.	Net 30 days upon Credit Department approval. All equipment is invoiced on the date of shipment. A finance charge of 1-1/2 % per month may be added to past due balances.	Standard Terms & Conditions and Warranty apply. Availability is subject to change. Prices quoted are F.O.B. Origin and do NOT include any freight, handling or taxes. Orders entered and subsequently canceled are subject to the remedies provided by the Uniform Commercial Code.

Qty.	Description of Product	Shipment	Net Each Price	Total Item Price
1	Budget estimate for rebuild of **American Turbine**		$16,357.00	$16,357.00
	model 12H150 – 7 stage vertical turbine pump			
	to include:			
	Pick-up and delivery of pump			
	Disassemble and sand blast parts to inspect			
	Work up repair scope and report "as found"			
	Meet with customer prior to doing the work			
	Replace bowl bearings anf stuffing box bushing			
	Replace bowl wear rings. Skim cut impellers.			
	Dynamically balance impellers			
	Coat OD of bowl and suction bell			
	Coat ID and OD of short column section			
	Straighten pump shaft as needed.			
	Shop labor to reassemble.			
We appreciate your business !				$16,357.00

PUMP STATION EVALUATION

General Info

Date if site Visit: 7/27/10
Facility Code:
Title: Res B
Location: Diamond Springs
Year Constructed:
As-built Drawings: (Yes) No
Conditions: Poor (Fair) Good Excellent
Comments:

Building

Material Type: (Wood) Concrete Block Other
Size square feet: 16 x 10
Power/Controls Enclosed: (Yes) No
Site Condition: Poor Fair (Good) Excellent
Comments:

Pump Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
	x	x	Large	
No.				
RPM	3510	3510	3_5	
Capacity (GPM/FT)	–	–	–	
Type	–	–	–	
Size In. (inlet/Outlet)	1.5	1.5	2	
Manufacturer	PACO	PACO	PACO	
Model No.	03-12705-73001	"	03-20705-73001	
Serial No.	BX75797	BX75792	MW74908	
Impeller Type	–	–	6.2"	
Pump Curve No.	–	–		
Frame No.	182JM	182JM	84_CB	
Part No.	PIP 162A	PIP162A	PIP130B	
Condition	Poor (Fair) Good Excellent			
Control Valves	(Yes) No			

Pictures

Comments:

Motor Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
			Large	
HP	5	5	10	
RPM	3510	3510	3_5	
Safety Factor	1.15	1.15	1.15	
Voltage	230/460	230/460	230/460	
Nameplate Amps	14/7	14/7	7.6/13	
Code	B	J	J	
Type	K	G	K	
Manufacturer	G.E.	G.E	G.E	
Serial No.				
Spec No.	5K182DL5148G	5K182DL5146G	5K184DL5200	
Condition	Poor (Fair) Good Excellent			

Pictures

Comments:

Piping System	Pump #1	Pump #2	Pump #3 (Large)	Pump #4
Pipe Size	1.5	1.5	2	
Valve Size (discharge)	1.5	1.5	2	
Valve Type (discharge)	~~check~~ Gate	~~check~~ Gate	~~check~~ Gate	
Check Valve Type	BS			
Check Valve Size	1.5	1.5	2	

Hydropneumatic Tank (Yes) No

Hydropneumatic Tank Size (gallons) 449

Comments

Miscellaneous

Flow Meter	Yes	(No)	Range
Suction Gauge	(Yes)	No	Range 0-160
Discharge Gauge	(Yes)	No	Range 0-160
Chart Recorder SC 400	(Yes)	No	
Hour Meters	(Yes)	No	
Log Book	(Yes)	No	

Generator

Manufacturer No

Output (kW)

Motor Size (HP)

Type (Gas/Diesel)

Transfer/Auto

Fuel Storage Size

Fuel Storage Above Below

Control System

Type (AB) Tesco Other

Model No. SLC 5/05

Control Condition Poor Fair Good (Excellent)

Power Supply

Meter PGE No. pic

Voltage

Phase

Main Breaker (A) 200

Condition Poor Fair (Good) Excellent

Comments

Alarms

Alarm Type

Alarm Condition 1 Low pressure

Alarm Condition 2

Alarm Condition 3

Alarm Condition 4

Central Alarming

Communications

check w/phil

Safety Condition

upgrade was planned

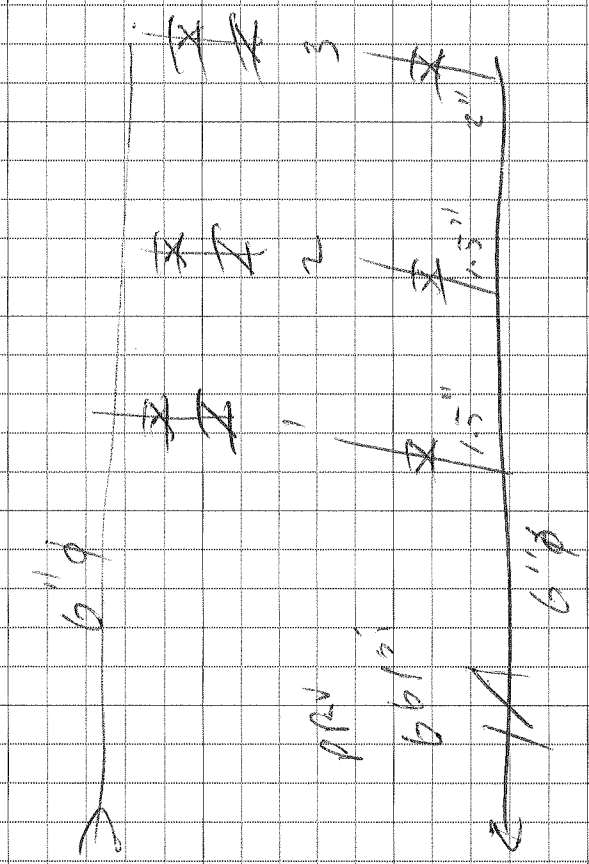
General Conditions

Repair Frequency

Suspected Cause of Problems

Action Items

Layout – Piping and pumps



PUMP STATION EVALUATION

General Info

Date if site Visit: 7/27/10
Facility Code:
Title: Log Cabin
Location:
Year Constructed:
As-built Drawings: Yes No
Conditions: Poor Fair Good Excellent
Comments:

Building

Material Type: Wood Concrete Block Other
Size square feet:
Power/Controls Enclosed: Yes No
Site Condition: Poor Fair Good Excellent
Comments:

Pump Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
No.	—	—		
RPM	—	—		
Capacity (GPM/FT)	—	—		
Type	—	—		
Size In. (inlet/Outlet)	3	3		
Manufacturer	Jacuzzi	"		
Model No.	206H2TB	"		
Serial No.	—	—		
Impeller Type	—	—		
Pump Curve No.	—	—		
Frame No.	254TCZ	"		
Part No.	—	—		

Condition Poor Fair Good Excellent
Control Valves Yes No
Comments:

pic

Motor Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
HP	20	"		
RPM	3500	"		
Safety Factor	1.15	"		
Voltage	230/460	"		
Nameplate Amps	46/23	"		
Code	B	"		
Type				
Manufacturer	Century pump	"		
Serial No.	6-321219-01	6-321219-01		
Spec No.				

Condition Poor Fair Good Excellent
Comments:

pic

Piping System	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
Pipe Size	2	3		
Valve Size (discharge)	2	2		
Valve Type (discharge)	Gate	Gate		
Check Valve Type	clay	clay		
Check Valve Size	2	2		

Hydropneumatic Tank (Yes) No

Hydropneumatic Tank Size (gallons) 18' x 5 diameter ~ 3500 - 3200

Comments 1964

Miscellaneous

Flow Meter	Yes	(No)	Range
Suction Gauge	(Yes)	No	Range 0-35'
Discharge Gauge	(Yes)	No	Range 0-300
Chart Recorder	Yes	(No) - scada	
Hour Meters	(Yes)	No	
Log Book	(Yes)	No	

Generator

Manufacturer Caterpillar

Output (kW) 150

Motor Size (HP) ?

Type (Gas/Diesel) Diesel

Transfer/Auto yes

Fuel Storage Size –

Fuel Storage (Above) Below

Pic

Control System

Type (AB) Tesco Other Micrologix 1500

Model No.

Control Condition Poor Fair Good (Excellent)

Power Supply

Meter PGE No.

Voltage 240

Phase 3φ

Main Breaker (A) 100

Condition Poor Fair (Good) Excellent

Comments

Alarms

Alarm Type

Alarm Condition 1 Power

Alarm Condition 2 pressure - Low/high

Alarm Condition 3 pump fail

Alarm Condition 4

Central Alarming

Communications phone/Radio

Action Items

Layout – Piping and pumps

PUMP STATION EVALUATION

General Info

Date if site Visit: 7/7/10
Facility Code:
Title: Strawberry RWPS
Location: Strawberry
Year Constructed:
As-built Drawings: Yes No
Conditions: Poor (Fair) Good Excellent
Comments: Pumps older than station

Building

Material Type: Wood Concrete (Block) Other
Size square feet: 10' x 8
Power/Controls Enclosed: (Yes) No
Site Condition: Poor Fair (Good) Excellent
Comments:

Pump Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
No.				
RPM				
Capacity (GPM/FT)				
Type				
Size In. (inlet/Outlet)				
Manufacturer	Crowns			
Model No.	PO3USVBRH			
Serial No.	485930-2494			
Impeller Type	?			
Pump Curve No.				
Frame No.	184T			
Condition	(Poor Fair) Good Excellent			
Control Valves	Yes No			

Comments: Pump #1 (3C03F-9*07B-200)

Motor Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
HP	5			
RPM	1750			
Safety Factor	1.15			
Voltage	230/460			
Nameplate Amps	13/6.5			
Code	EM3615T			
Type	TEFC			
Manufacturer	Baldor			
Serial No.				
Condition	Poor (Fair) Good Excellent			

Comments:
Spec #1 3662 71T031

Piping System	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
Pipe Size	3"	3"	3"	
Valve Size (discharge)	3"	3"	3"	
Valve Type (discharge)	BF	BF	BF	— clow
Check Valve Type	Nibco	Crispin	GA iron	
Check Valve Size	3"	3"	3"	

Hydropneumatic Tank Yes (No)
Hydropneumatic Tank Size (gallons) —
Comments Pumps on all the time for prime

Miscellaneous

Flow Meter	(Yes)	No	Range 0-200
Suction Gauge	Yes	(No)	Range 0-15 psi
Discharge Gauge	(Yes)	No	Range
Chart Recorder	(Yes)	No	
Hour Meters	(Yes)	No	
Log Book	(Yes)	No	

Generator

	Model	Serial	arrangement #
Manufacturer	Ca 3304	* 9HK00154 *	1004416

Output (kW) 3φ 480/170, 240/340, 208/330, 1φ 120/70
Motor Size (HP)
Type (Gas/Diesel) Frame 443 1800 RPM
Transfer/Auto
Fuel Storage Size 200 gal.
Fuel Storage Above (Below)
inst

Control System

Type (AB) Tesco Other
Model No. SLC 5/05
Control Condition Poor Fair Good (Excellent) new

Power Supply

Meter PGE No. Series 011 0 2448, 906 R52
Voltage 480
Phase 3φ
Main Breaker (A) 200
Condition Poor Fair (Good) Excellent
Comments

Alarms

Alarm Type T1 line SCADA
Alarm Condition 1 Low Flow
Alarm Condition 2 High "
Alarm Condition 3 Pump Temp High
Alarm Condition 4 Pump Fail
Central Alarming yes Galaxy
Communications T1.

#5 power failure

Safety Condition

NO issues

General Conditions

Repair Frequency Big problem.

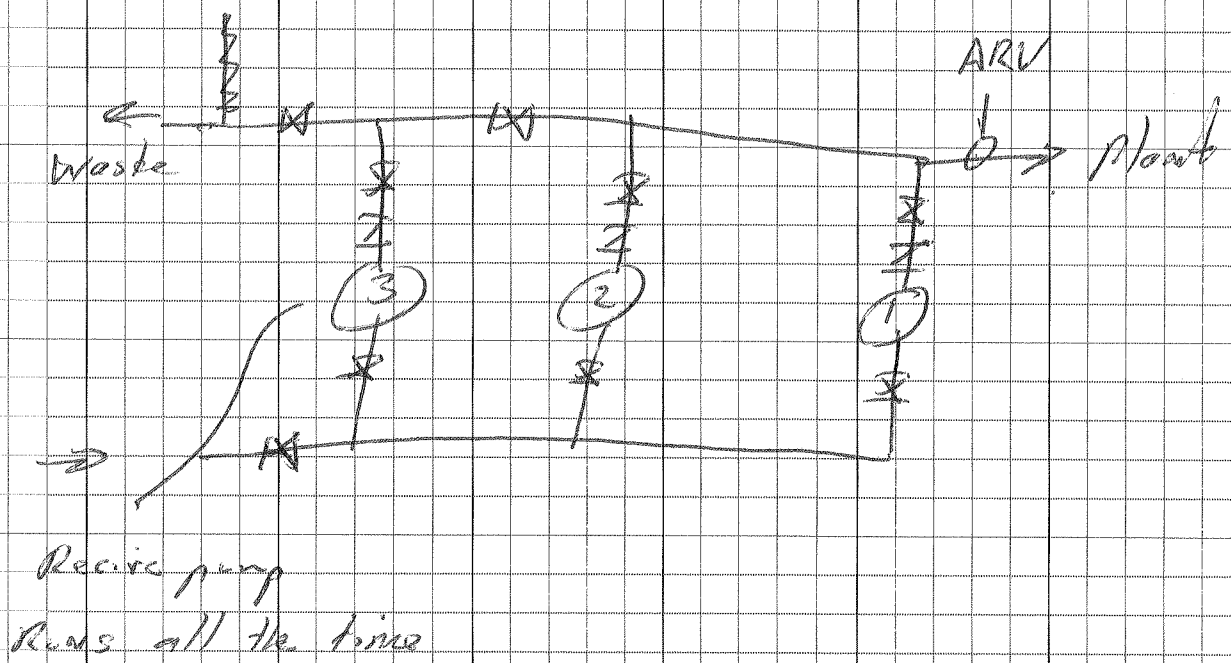
Suspected Cause of Problems

Impellers break off shafts, vibration and cavitation problems, prime is lost often due to above ground pump too high, Not self priming. pump rated to flow at 120 gpm, plant needs 200 gpm.

Action Items

- Vibration & Cavitation issues w/ pumps
- Pumps lose prime, run continuously to maintain prime, w/ waste gate
- Pump too small, need 200 gpm to plant
- 15' suction head from River

Layout – Piping and pumps



PUMP STATION EVALUATION

General Info

Date if site Visit: Dolomite 7/23/10
Facility Code:
Title:
Location: 49/Dolomite
Year Constructed: ~1980
As-built Drawings: (Yes) No
Conditions: Poor Fair Good Excellent
Comments:

Building

Material Type: (Wood) Concrete Block Other
Size square feet:
Power/Controls Enclosed: (Yes) No
Site Condition: Poor Fair (Good) Excellent
Comments:

Pump Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
No.				
RPM				
Capacity (GPM/FT)				
Type	7.1"	5 15/16		
Size In. (inlet/Outlet)	1.5"	2"		
Manufacturer	PACO	Gould		
Model No.	03-12-07-73000/2741			
Serial No.	GY-656819	E06-1304-7		
Impeller Type				
Pump Curve No.				
Frame No.	184SM	184SM		
Part No.		3656		
Condition	Poor Fair Good Excellent			
Control Valves	Yes No	Size 1 1/2 x 2-6		

Comments:

Motor Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
HP	7.5 Hp	5		
RPM	3465	3450		
Safety Factor	4.0	1.5		
Voltage	240/460	208/230/460		
Nameplate Amps	19/9.6	13.2/12/6		
Code	H	K		
Type	UT-4TE	Class F TEFC		
Manufacturer	PACO	Baldor		
Serial No.				
Spec No.	F-572-03-818	5273R024		
Condition	Poor Fair Good Excellent			

Comments:

Ser # F05122232819

Cat # JMM3613T

Spec # 36H17X100

Piping System	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
Pipe Size	1.25	1.25		
Valve Size (discharge)	1.25	1.25		
Valve Type (discharge)	Gate	Gate		
Check Valve Type	Swing	Swing		
Check Valve Size	1.25	1.25		

Hydropneumatic Tank (Yes) No

Hydropneumatic Tank Size (gallons) 2 x 119 gallons

Comments

Miscellaneous

Flow Meter	Yes	(No)	Range
Suction Gauge	(Yes)	No	Range 0-15
Discharge Gauge	(Yes)	No	Range 0-150
Chart Recorder	Yes	(No)	
Hour Meters	(Yes)	No	
Log Book	(Yes)	No	

Generator

Manufacturer None

Output (kW)

Motor Size (HP)

Type (Gas/Diesel)

Transfer/Auto

Fuel Storage Size

Fuel Storage Above Below

Control System

Type AB (Tesco) Other

Model No. LIQ 3 RTU 8

Control Condition Poor Fair (Good) Excellent

Power Supply

Meter PGE No. 1004386804 / TEG1004386804090 8

Voltage 120-480V

Phase

Main Breaker (A) 100

Condition Poor (Fair) Good Excellent

Comments

Alarms

Alarm Type None

Alarm Condition 1

Alarm Condition 2

Alarm Condition 3

Alarm Condition 4

Central Alarming

Communications

Safety Condition

_____

_____

_____

_____

General Conditions

Repair Frequency _____

Suspected Cause of Problems _____

_____

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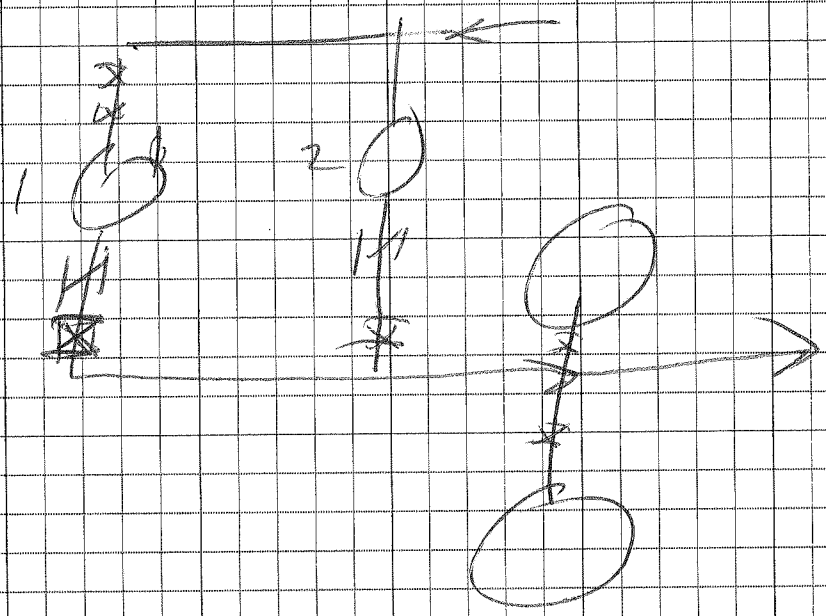
_____

Action Items

Layout – Piping and pumps



PUMP STATION EVALUATION

Tim: Send new prints to ops for the p.s.

General Info

Date if site Visit: Oro loma 7/23/10
Facility Code: 82015 Project No. Dwg# 4423
Title:
Location:
Year Constructed: ? 82-83
As-built Drawings: (Yes) No
Conditions: Poor Fair (Good) Excellent
Comments:

Building

Material Type: (Wood) Concrete Block Other on concrete
Size square feet: 18' x 12' Asphalt Shingle Roof
Power/Controls Enclosed: (Yes) No
Site Condition: Poor Fair (Good) Excellent
Comments:

3 150 BIC 4105 JT YB (No on Valve

Pump Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
No.			Aqua energ.	
RPM				
Capacity (GPM/FT)	100/376	100/376		
Type	6.75"			6.0"
Size In. (inlet/Outlet)				
Manufacturer	PACO	PACO		PACO
Model No.				
Serial No.	CW571417 01	AW571417		34482
Impeller Type		6.75"		
Pump Curve No.				
Frame No.	256TCZ	256TCZ	324TS	184TCZ
Part No.	691590173000 1A02-1	371590173000 1A02-1		10-10707-730001-1741
Condition	Poor Fair (Good) Excellent			
Control Valves	Yes No			
Comments:				Run continuous

Motor Data	**Pump #1**	**Pump #2**	**Pump #3**	**Pump #4**
HP	25	25	Lincoln 50 hp	7.5
RPM	3550	3550	3490	3450
Safety Factor	e=86.5 1.0	e=88.5/81.0	1.15	1.15 e=84% P.F. 93%
Voltage	3Ø 230/460	230/460	230/460	208/230/460 3Ø
Nameplate Amps	62.6/31.3	62.6/31.3	120/60A	19/18/9
Code	G		E	J
Type	B-DP K	TEFC		F
Manufacturer	GE	GE	Lincoln	Baldor
Serial No.			2656775	OPSB
Spec No.	5K256JZ1278	5K256JZ1278		WCM3219T(Cat) Sep 36H454Y80
Condition	Poor Fair (Good) Excellent			F0309301477
Comments:				

Max KVAR 7.1

Piping System	Pump #1	Pump #2	Pump #3	Pump #4
Pipe Size	2"	2"	3"	
Valve Size (discharge)	4"	4"	3"	
Valve Type (discharge)	Gate	Gate	~~Check Motor~~ Disk	
Check Valve Type	~~Disk~~	Disk	4"	
Check Valve Size	2"		4"	

Hydropneumatic Tank (Yes) No

Hydropneumatic Tank Size (gallons) 470 Max pres 135 @ 450°F Shell 281A455

Comments Roy E Hanson LA, CA

Miscellaneous

Flow Meter	(Yes)	No	Range _____
Suction Gauge	(Yes)	No	Range _____
Discharge Gauge	(Yes)	No	Range _____
Chart Recorder	Yes	(No)	
Hour Meters	(Yes)	No	
Log Book	(Yes)	No	

Generator

Manufacturer None

Output (kW)

Motor Size (HP)

Type (Gas/Diesel)

Transfer/Auto

Fuel Storage Size

Fuel Storage Above Below

Control System

Type AB Tesco Other None

Model No.

Control Condition Poor Fair Good Excellent

Power Supply

Meter PGE No. 15 192 286, 89821R, TE6000 89821R01298

Voltage 120-480, 4

Phase 1Ø + 3Ø

Main Breaker (A) 100A

Condition Poor Fair (Good) Excellent

Comments See plans

Alarms

Alarm Type None

Alarm Condition 1

Alarm Condition 2

Alarm Condition 3

Alarm Condition 4

Central Alarming

Communications

Safety Condition

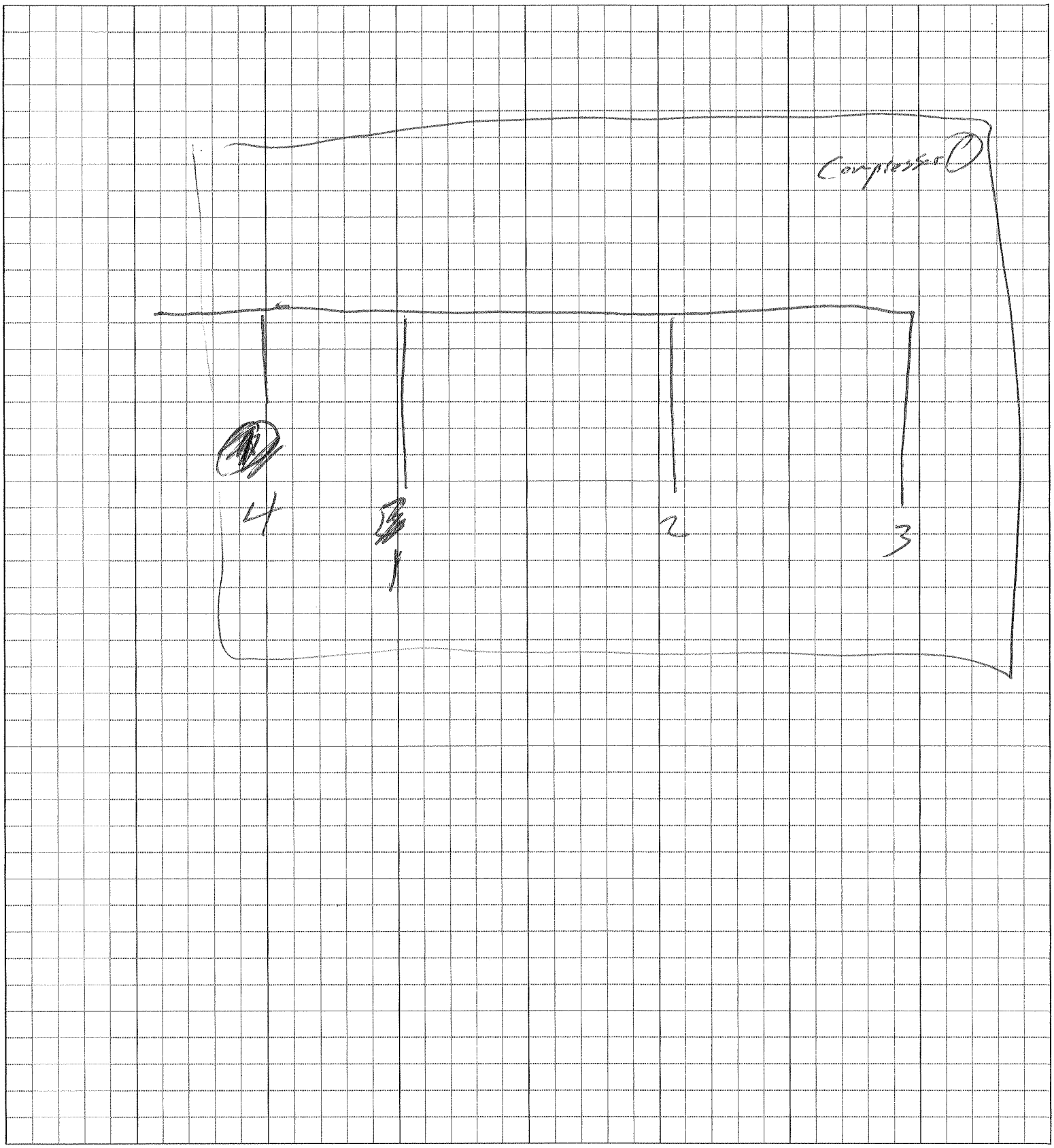
General Conditions

Repair Frequency Joel Beall

Suspected Cause of Problems

Action Items

Layout – Piping and pumps



PUMP STATION EVALUATION

General Info

Date if site Visit: 7/23/10
Facility Code:
Title: Ridge View
Location: El Dorado Hills
Year Constructed:
As-built Drawings: Yes No
Conditions: Poor Fair Good Excellent
Comments: Could use paint on piping systems

Building

Material Type: Wood Concrete Block Other ~~None~~
Size square feet: 10 x 10
Power/Controls Enclosed: Yes ~~No~~
Site Condition: Poor ~~Fair~~ Good Excellent
Comments: paint needed

Pump Data	**Pump #~~1~~ 2**	**Pump #~~2~~ 1**	**Pump #3**	**Pump #4**
No.				
RPM		–	–	
Capacity (GPM/FT)		400/130'	400/~~[illegible]~~ 130	
Type		13" ~~[illegible]~~ imp	13" D	
Size In. (inlet/Outlet)		4"/3"	4"/3"	
Manufacturer	Gould	Weinman	Weinman	
Model No.		5321-11V	325-2	
Serial No.	5BF85	T753545		
Impeller Type	1½x2-8	–		
Pump Curve No.		–		
Frame No.		289T	289T	
Part No.		325-250P246		Part # 325-2
Condition	Poor Fair	Good Excellent	T628726 Serial	
Control Valves	Yes No			
Comments:				

Motor Data	**Pump #~~1~~ 2**	**Pump #~~2~~ 1**	**Pump #3**	**Pump #4**
HP	7.5	25	25	
RPM	3450	1770	1765	
Safety Factor 89%	1.15 e-93.6	1.15	1.15	
Voltage	208/230/460	230/460	230/460	
Nameplate Amps	21/18.8/9.4	60/30	64/32	
Code		G	~~D~~ F	
Type	3656		P	
Manufacturer	Baldor	Baldor	Reliance	
Serial No.	F495			
Spec No.	Jmm3709T	C0405210156	P28~~5~~00418-61-BW	
Condition	Poor 2 Fair 3	Good 1 Excellent		
Comments:				

Spec 37M31X75

RAM 213JM

Piping System	**Pump #1**	**Pump #~~2~~ 3**	**Pump #~~3~~ 2**	**Pump #4**
Pipe Size	4	4	2"	
Valve Size (discharge)	4"	4	2"	
Valve Type (discharge)	Gate	Gate	Gate	
Check Valve Type	Clay	Clay	Plate	
Check Valve Size	4"	4"	2"	

Hydropneumatic Tank (Yes) No

Hydropneumatic Tank Size (gallons) ?

Comments

Miscellaneous

Flow Meter	Yes	No	Range
Suction Gauge	Yes	(No)	Range
Discharge Gauge	(Yes)	~~No~~	Range 0-30
Chart Recorder	~~Yes~~	~~No~~ NO	
Hour Meters	(Yes)	No	
Log Book	(Yes)	No	

Generator

Manufacturer Howe

Output (kW)

Motor Size (HP)

Type (Gas/Diesel)

Transfer/Auto

Fuel Storage Size

Fuel Storage Above Below

Control System

Type (AB) Tesco Other

Model No. Powerwin 100 Logix 5555

Control Condition Poor Fair Good (Excellent)

ATEJV104492R700995

Power Supply

Meter PGE No. 01272927PGE 4492 R 7

Voltage 480

Phase 3P

Main Breaker (A)

Condition Poor (Fair) Good Excellent

Comments Little Rust

Alarms

Alarm Type

Alarm Condition 1 High level

Alarm Condition 2 power fail

Alarm Condition 3 Low level

Alarm Condition 4 Intrusion

Central Alarming yes - Galaxy

Communications Radio - T1

Safety Condition

_____

_____

_____

_____

General Conditions

Repair Frequency _____

Suspected Cause of Problems _____

_____

_____

_____

_____

Action Items

Layout – Piping and pumps

El Dorado County Water Systems

Analyze Hydro Options Study Recommendations for Integration into Existing Water Systems for Grid Support

TM#6 – Task 2.5. Hydroelectric Opportunities Technical Memorandum

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1.0 Introduction

The purpose of this study is to evaluate hydroelectric power generation opportunities within the El Dorado Irrigation District (EID) and Georgetown Divide Public Utility District (GDPUD) systems. EID and GDPUD are interested in determining opportunities for renewable energy throughout their system where it may be economically feasible. Additionally, this report will make recommendations to the California Energy Commission for the need for future programs to make hydroelectric generation more feasible.

In July of 2009 EID along with the El Dorado County Water Agency (EDCWA) published the El Dorado County Hydroelectric Development Options Study. The project looked at over 100 hydroelectric development opportunities throughout the County. Of the 100 options evaluated, detailed economic and financial analyses were performed on the "top 10" hydro options. The study determined that the top recommended projects included the Pleasant Oak Main (POM) Tank 7 In-conduit hydro project and the El Dorado Main (EDM) Tank 3 In-conduit hydro project.

EID entered into an agreement with PG&E for the Tank 7 In-conduit hydro project under the Feed-In-Tariff (FIT) program. The Tank 3 project was determined to ultimately not be feasible because portions of the project being on US Forest Service land, thus not allowing the project to be exempt from FERC licensing.

The purpose of this report is to look at possible reoperation of the POM system to optimize the energy production at the Tank 7 in-conduit project and explore potential reoperation opportunities for the Oak Ridge Tanks to Bass Lake Tanks pumped storage project that was identified as a potentially higher ranking project with some reoperation.

Additionally, for GDPUD this report will consider reoperation opportunities to increase generation revenue at the existing Buckeye and Tunnel Hill hydroelectric projects and potential new hydroelectric projects at Stumpy Meadows Dam and Sand Trap Siphon.

Figure ES1 shows the location of the top hydroelectric projects identified in the previous study.

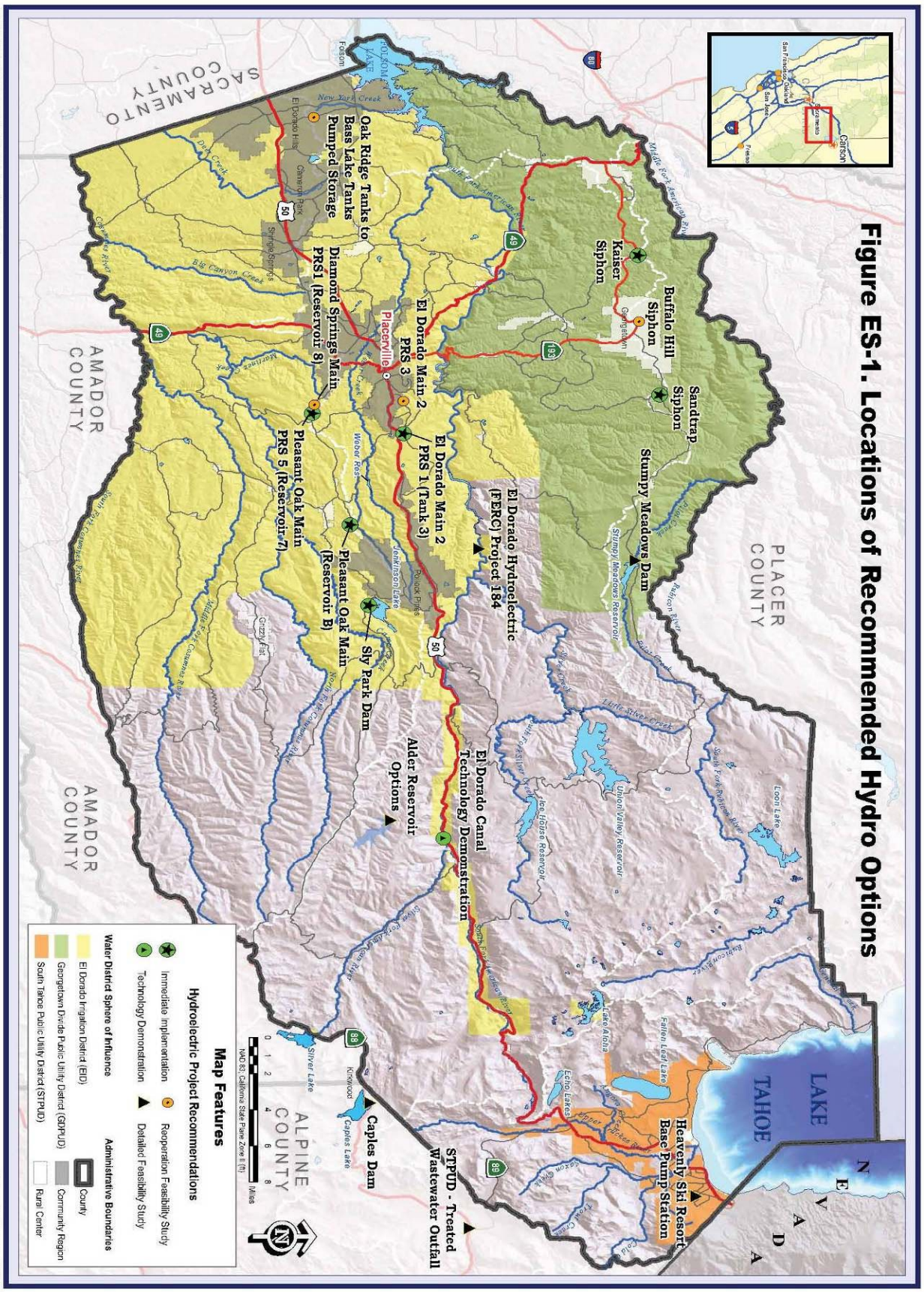
Figure ES-1. Locations of Recommended Hydro Options
Kaiser Siphon
Buffalo Hill Siphon
Sandtrap Siphon
Stumpy Meadows Dam
El Dorado Main 2 PRS 3
El Dorado Main 2 PRS 1 (Tank 3)
El Dorado Hydroelectric (FERC) Project 184
Oak Ridge Tanks to Bass Lake Tanks Pumped Storage
Diamond Springs Main PRS1 (Reservoir 8)
Pleasant Oak Main PRS 5 (Reservoir 7)
Pleasant Oak Main (Reservoir B)
Sly Park Dam
El Dorado Canal Technology Demonstration
Alder Reservoir Options
Heavenly Ski Resort Base Pump Station
STPUD - Treated Wastewater Outfall
Caples Dam
PLACER COUNTY
SACRAMENTO COUNTY
AMADOR COUNTY
ALPINE COUNTY
LAKE TAHOE
NEVADA
Map Features
Hydroelectric Project Recommendations
Immediate Implementation
Reoperation Feasibility Study
Technology Demonstration
Detailed Feasibility Study
Water District Sphere of Influence
El Dorado Irrigation District (EID)
Georgetown Divide Public Utility District (GDPUD)
South Tahoe Public Utility District (STPUD)
Administrative Boundaries
County
Community Region
Rural Center
Miles
NAD 83, California State Plane Zone II (ft)
Map Prepared by: Ethan Kessler 07/13/09
C:\GIS Data\Projects\2009\El Dorado Hydro\Final\Project overview 07 13 09.mxd

2.0 In-conduit Hydro potential at Tank 7

2.1. Project Background

The Pleasant Oak Main (POM) at the Tank 7 hydroelectric station would be within the El Dorado Irrigation District (EID) potable water system, located off of Pleasant Valley Road between Placerville and Pleasant Valley, CA (see Figure 1). The system is fed from the Reservoir A Water Treatment Plant. The daily flow rate in the system is operator determined based on demand in the system from the previous day. Pressure reducing stations are located at each of the reservoir/tanks located along the system.

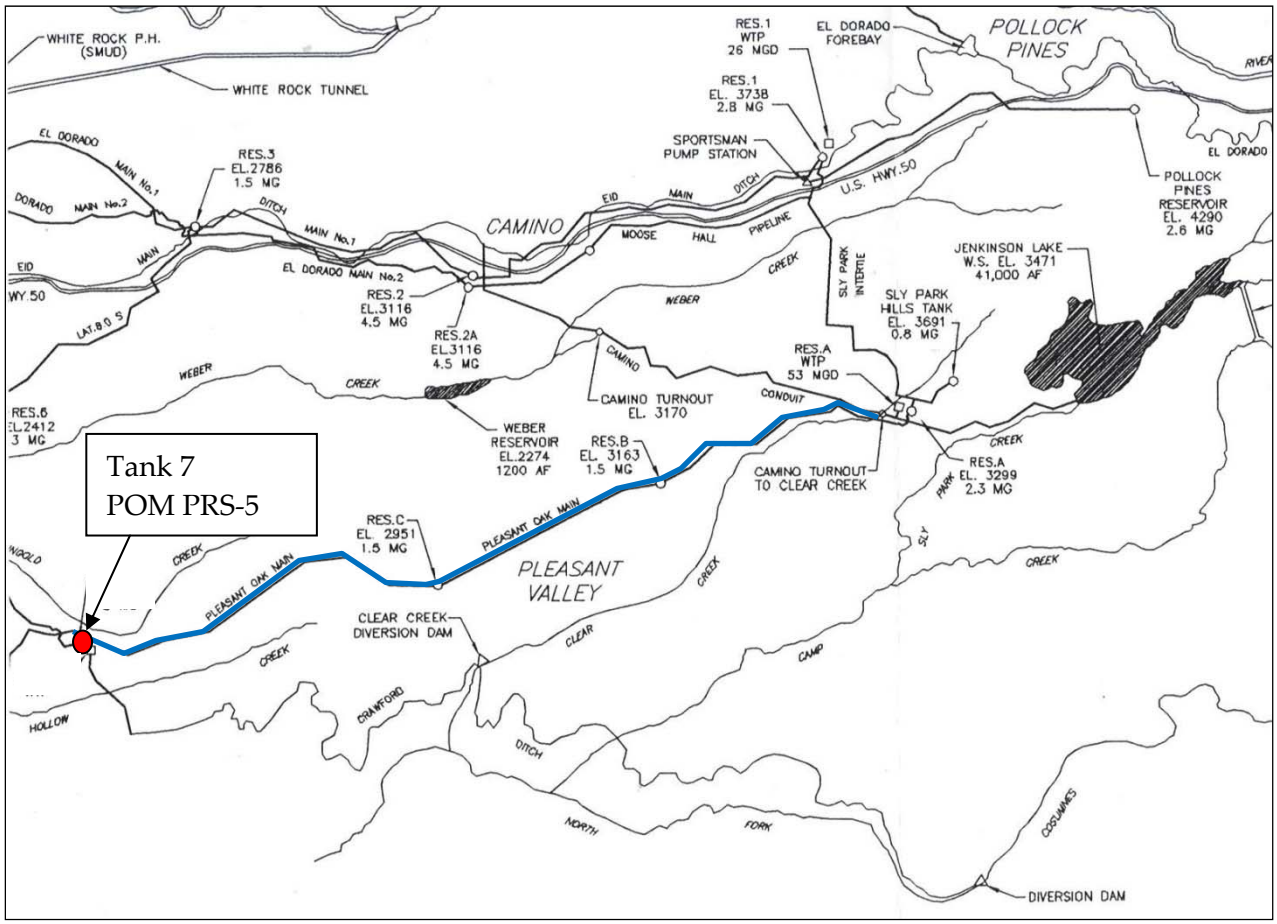

Figure 1. Location of Tank 7 (Reservoir 7) in relation to EID's potable water system.

Preliminary feasibility analysis of potentially adding in-conduit hydroelectric facilities at each of the PR stations (Reservoir B, C and Tank 7) showed that a facility at Tank 7 was the preferred of the three, yielding the greatest power generation and would provide the most feasible location for the plant, based on existing data.

2.2. Existing Facilities and General Description

The existing pressure reducing station (PRS-5) is located on the northeast side of the Tank 7 site (Figure 2) on the existing pipeline (varying size) conveying flow from Reservoir C to Tank 7. Pressure upstream of the PRS-5 varies from 110 psi to 166 psi. The PRS discharges essentially to the tanks at Reservoir 7 with approximately 30ft of head (13psi). Flow in the pipeline varies from 3cfs to 32cfs throughout the year.

Figure 2. Location of existing POM-PRS5 at Reservoir 7

The following schematic (Figure 3) shows the piping layout and flow through the existing system. The pipeline from Reservoir C also feeds the Oak Hill Lateral before discharging into Tank 7. Up to 10cfs is diverted into the Oak Hill Lateral. Other flow off of the main pipeline includes a small flow feeding the existing site facilities (drinking water, bathrooms, etc.). A back-up chlorination system exists on site that was used during the conversion of the reservoir to tanks; however it is not currently being used.

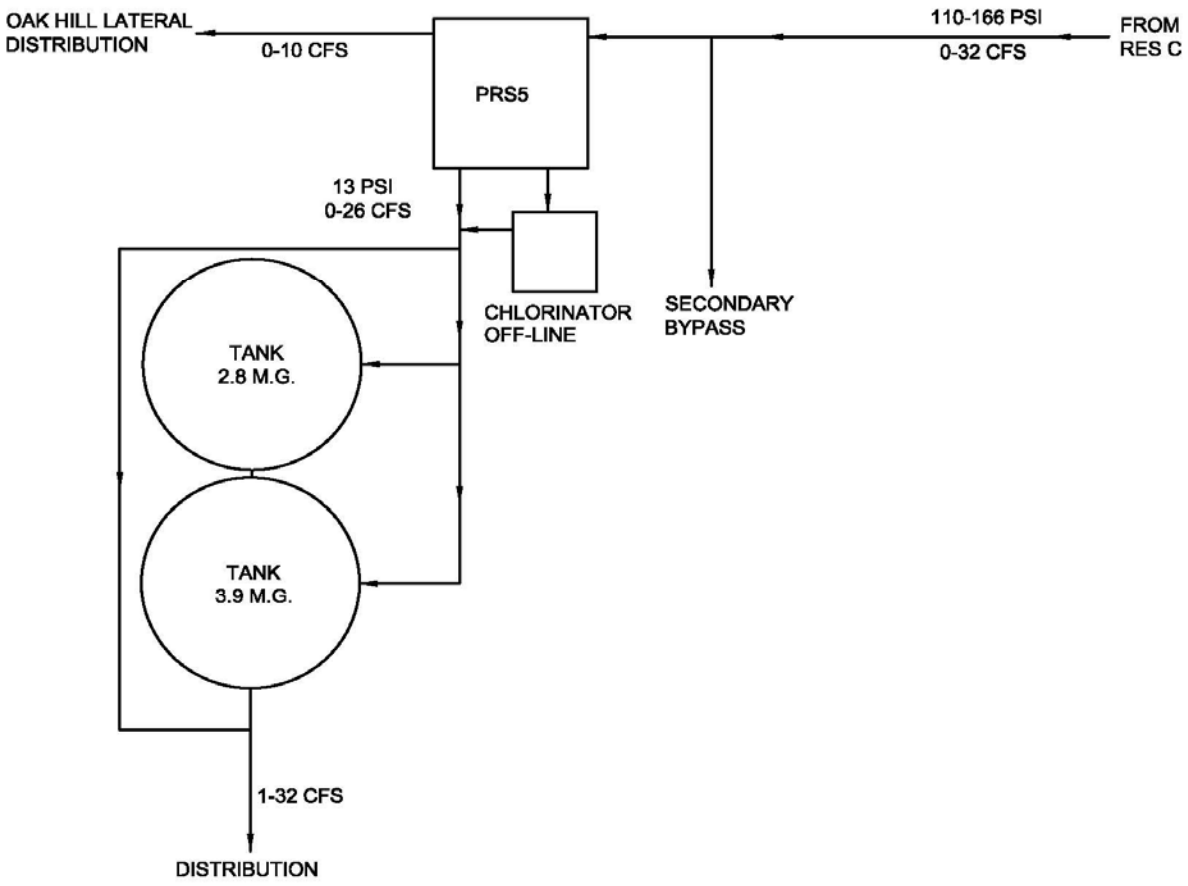

Figure 3. Schematic Layout of Piping at Tank 7.

The site has limited area available for the hydroelectric station which would be located in the north-east corner of the property near the entrance to the facility (Figure 4 and 5). Three-phase electrical service is adjacent to the site for project interconnection.

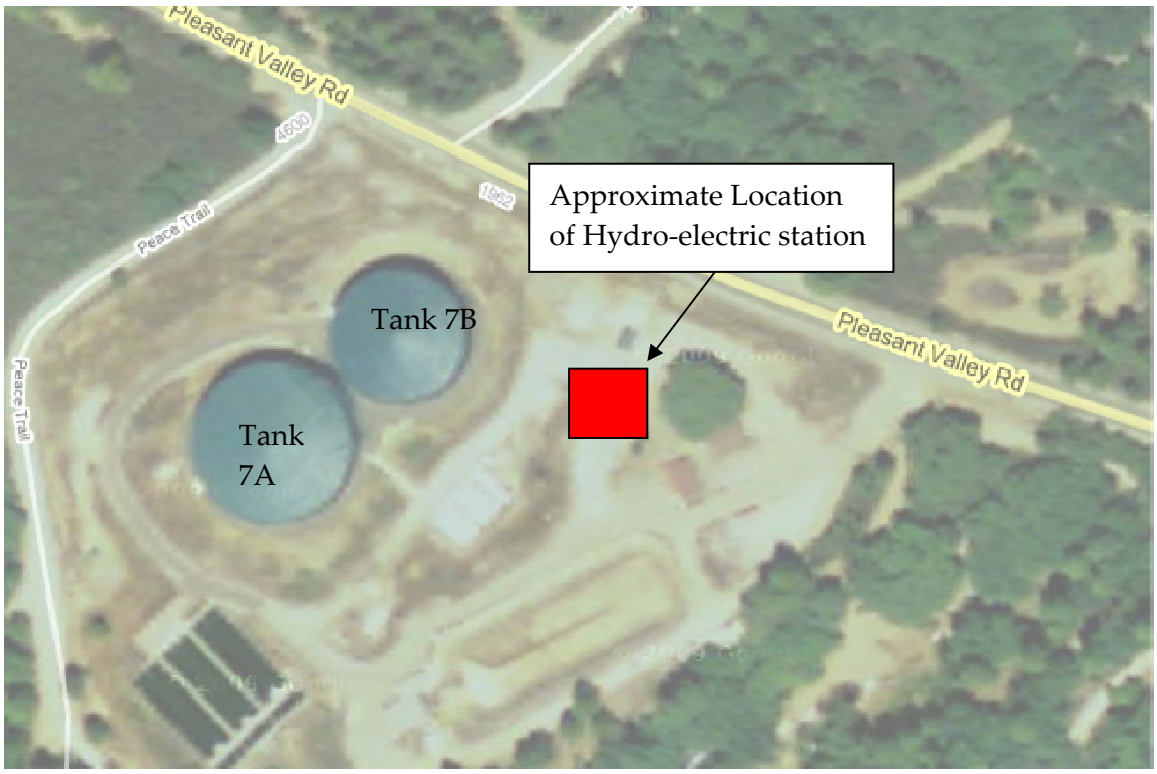

Figure 4. Approximate location of new hydroelectric station

Figure 5. View of proposed hydroelectric station location (looking from existing PRS-5)

2.3. Design Parameters

2.3.1. Project Facilities and Operation

The hydroelectric station would be located on the existing 24-inch pipeline upstream of the existing PRS-5. The hydro station would consist of pumps as turbines (PATs) potentially operating at variable speed with regenerative power converters. The facilities would be housed in a masonry building approximately 1100 square feet in area. Associated fencing and security features would be included in the design.

A schematic of the new hydroelectric station in relation to the existing piping system is shown below (Figure 6). Flow off of the main line would be diverted through the hydroelectric station. Flows that are too low or high for the station would continue through the existing PRS-5. Additionally, flow to the Oak Hill lateral and minor flows used at the facility would continue through the existing mainline.

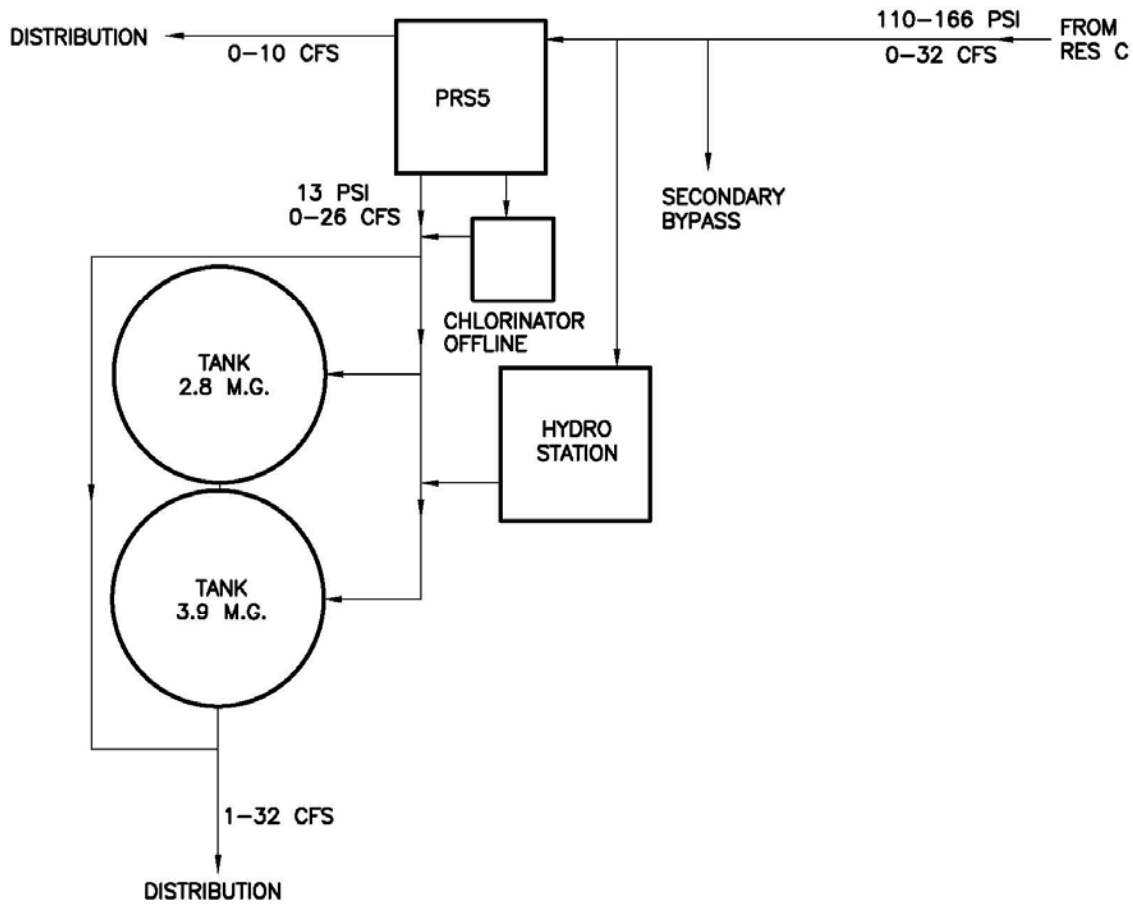

Figure 6. Schematic layout of piping for new hydro-electric station.

The hydroelectric station would include flow control in addition to the turbine units to regulate the plant operation. The existing PRS-5 system would operate as a bypass to allow continuous flow in the EID system during an emergency and while the hydro station is off line. The station

would rely on a programmable control system for regulating flows to the hydro station (as described later in this report). The controller would split flow to the individual turbine units based on pressure and flow readings from the system.

Three-phase Pacific Gas & Electric (PG&E) transmission lines are located along Pleasant Valley Road less than 50 feet from the site. Power generated from the project would be transmitted to the grid at this location and sold to PG&E

2.3.2. Turbine Selection, Control and Operational Scenarios

EID obtained proposals from equipment suppliers and considered two different types of technologies. The more conventional fixed speed PATs can provide sufficient generation to allow for an estimated payback period of 18-20+ years however there are several operational considerations. The turbines have an optimal flow range of operation that does not completely overlap with each other. Consequently, not every desired flow setpoint can be obtained through the turbine or combination of turbines. Under this operating scenario a portion of flow will be bypassed (approximately 10% of the total flow).

The second option being considered would apply regenerative drives to allow for variable speed operation to turbines. The addition of Regen VFDs to the system would further reduce the fluctuations by increasing the operational range of the turbines. Less flow would need to be bypassed and more power could be captured. Wear and tear on the valves and other components at the hydro station would be reduced by minimizing cycling. The station would be simpler to operate with wider flow ranges and have an estimated payback period 19-20+ years. Due to the immaturity of this technology and commercially operated facilities, EID determined it would not pursue this technology at this time.

2.3.3. Pressure Concerns/Issues

There are several pressure issues to consider during the design of the facility. The Oak Hill lateral and on-site facilities must have sufficient pressure to deliver water to the system. Additionally it was determined that filling the tanks requires a minimum 30ft of pressure downstream of the hydroelectric and PRS-5 stations. For these reasons it was determined that the facility should bypass flow off of the mainline rather than allowing all flow through the station and providing a separate bypass and pressure reducing valve. Additional control and operational considerations are described below.

2.4. Power Failure Contingency

If utility power is lost, the station must disconnect from the grid per PG&E rules. Flow through the hydro generators will increase due to the lack of utility connection (resistance) until the upstream valves can close. The valves would close over an approximate one minute period and the existing bypass PRV station would open. The existing Reservoir 7 station has a 50kw backup generator that could be used to power the lighting and controls at the new hydro station during an outage. Once utility power is restored and the transfer switch returns to normal position, the Hydro station would be allowed to restart.

2.5. Estimated Energy Production

Based on the conventional fixed speed turbine generator without cycling the turbines, the project will generate approximately 1,641 MWh per year. The following Table 1 provides project design and energy production data.

Table 1. Facility design criteria

Design Criteria	Value
Design Head	340ft at 5cfs 220ft at 25cfs
Design Flow	25cfs max 5cfs min
Nameplate Capacity	350 (kW)
Estimated Annual Generation (see below)	1,585 (MWh)

2.6. Estimated Generation with current operation

Flow records were examined to determine typical flow that would be available for hydropower generation at the Pleasant Oak Main PRS 5 at Tank 7. Average power generation at the powerhouse is estimated based on available water, head, efficiency, loss estimates and typical operation. The average monthly and annual powerhouse generation expected to be available are shown below in Table 2.

Table 2. Pleasant Oak Main PRS 5 (Tank 7) Powerhouse Generation

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Projected Average Power Generation of Pleasant Oak Main PRS 5 @ Tank 7													
MWh	162	96	59	58	52	64	115	122	180	226	224	227	1,585

2.7. Potential Re-operation of POM for Tank 7 In-conduit Hydro

2.7.1 Short Term (Current) POM System Options

In order to evaluate the options for potential re-operation of the system, an H2ONet model of the existing system was developed using profile and flow data supplied by EID. Using the model and varying the flow to the hydro project, several scenarios were analyzed to relate generation potential to time of day, and rate of flows to deliver the same demands from the Tank 7 site to downstream users.

The current operation at Tank 7 is to measure a demand for a given day and to reproduce the same amount the following day. The tanks would adjust (fill and empty) for the diurnal

changes. Due to the large amount of storage (6.5MG) at the two (Tank 7) tanks, the amount of storage used (especially during the low use months) is relatively low.

Re-operation through holding back flow during off peak and delivering higher flow during peak demand hours would generate more energy during the high energy use periods and also deliver more flow during the peak water use hours. With the current storage at the Tank 7 tanks, this mode of operation could significantly increase the peak hour energy output of the proposed hydro plant.

The issues with the above re-operation scheme are:

1. the upstream storage available to hold back the flows
2. the desire to treat water at the Reservoir A treatment plant at a relatively continuous and constant rate for as long as possible.

The POM has three upstream storage facilities at Res A, Res B, and Res C. These storage facilities are in-line covered reservoirs each with considerably less volume than at the Tank 7 location. Table 3 shows the relative existing storage for each facility. These upstream reservoirs would have to be controlled to deliver the re-operated diurnal flows to Tank 7. The lack of storage at these facilities, in particular at Res C (next reservoir upstream of Tank 7), limits the amount of flow to be held back during the off peak hours.

Table 3. Existing Pleasant Oak Main (POM) Storage Facilities

Location	Existing Storage (million gallons)
Reservoir A (at the treatment plant)	2.28
Reservoir B	1.5
Reservoir C	1.5
Tank 7 (at the proposed hydro plant)	6.5

Reservoir C with 1.5 MG of storage has at most approximately 500,000 gallons of storage available to hold back flow to Tank 7. This would be less than one hour of storage during the summer average day flows and only 3 hours during the lowest winter months. Reducing instead of stopping flow during off-peak and increasing flow during peak periods could be optimized with the available storage, but this would create significantly increased complexity to the operation of each of the reservoirs with only minimal benefit. Using the H2Onet model and varying (optimizing) flow in a minimum 6-hour interval generated only 5% increase in power generation. This was not considered a viable approach relative to the difficulties in operation and the wear on the equipment due to multiple on-off sequencing of the turbines.

Due to the limitations on storage in the POM upstream of Tank 7, re-operation other than adding the new hydro plant will not be recommended at this time. Minor operational changes may be attempted by operations staff during early implementation of the project.

2.7.2 Long Term (Current) POM System Options

The long term plan for the POM system includes adding storage at Res B and Res C per a recent master plan of storage for EID. The plan also includes replacing the covered reservoirs with above ground storage tanks. Enough storage can be added to accommodate smoother operation of the entire POM system as well as the proposed hydro plant at Tank 7. The current size and capacity of the Tank 7 hydro plant will not change, but the added upstream storage could accommodate the hydro plant energy peaking. Based on the anticipated storage increases at the POM sites, the hydro plant could see up to 30% more generation by adding 1 million gallons of storage above what is needed per the masterplan for local demands at each location. Table 4 below shows proposed future storage based on the *2002 Storage Evaluation for Potable Water System by Owen Engineering*.

Table 4. Proposed Pleasant Oak Main (POM) Storage Facilities

Location	Future Storage (million gallons)
Reservoir A (at the treatment plant)	2.28 (no change)
Reservoir B	4.0
Reservoir C	2.2
Tank 7 (at the proposed hydro plant)	6.5 (no change)

Added storage at the reservoir locations will accommodate peak energy production as well as provide smoother operation of the system. Increased generation during peak hours is 1.2 (winter peak) to 2 (summer peak) times the value of generation during non-peak hours under PG&E's Feed-In-Tariff contract. The reduced fluctuations in flow will reduce the need to change (switch over) the turbines that are on line at any given time.

Another benefit of adding storage within the POM system will be the potential to add at least two more hydro plants on the POM; one at Res C and another at Res B. Each Reservoir has a pressure reducing station just upstream similar to Tank 7. These stations have flows similar to Tank 7 but each has a lower head available. Another factor that made this less desirable than the Tank 7 site was that a three phase tie-in will require nearly ½ of a mile of transmission lines at each location. With the addition of storage and related re-operation to achieve peak production, these two marginal projects may become economically feasible in the future.

2.8. Estimated Generation with revised operation and additional storage alternatives

Based on the available storage and potential for reoperation Table 4 below shows the affects of the proposed reoperation.

Table 4. Pleasant Oak Main PRS 5 (Tank 7) Powerhouse Generation with reoperation

Reoperation Scenario	Estimated Generation (MWh)
None (existing operation)	1,585
Short Term Reoperation	1,755
Long Term Reoperation	2,060

2.9. Conclusions

Based on the generation estimates provided above, the potential increase in generation anticipated during short term operation does not appear to be significant enough to warrant the changes in operation necessary. Operations staff was consulted during the process of developing reoperation scenarios. The difficulties associated with short term reoperation include potential problems with the existing floating covers on Res B and C as more fluctuation in water level occurs and additional operation staff time to balance the system. Therefore, short term reoperation is not recommended.

In the future, the covered reservoirs will be replaced with tanks that can be better utilized to re-operate the system. It is recommended to increase the storage at Res B and C above what is currently planned by approximately 500,000 to 1,000,000 gallons each at the time of installation to increase flexibility in the system. The added cost of the additional storage would be much less significant if done at the same time proposed improvements are made. Potential increases in power generation would be used to pay for the increased storage. It is recommended that EID consider increasing proposed storage to allow for additional flexibility in operation to maximize energy generation.

3.0 Oak Ridge Tanks to Bass Lake Tanks Pumped Storage

3.1. Background

This project is at a pumping station currently under design at the Oak Ridge storage facilities in the community of El Dorado Hills. The current project will pump flow from the Oak Ridge Tanks which serve the El Dorado Hills area, up to the Bass Lake Tanks to serve the Cameron Park area. The reoperation project would convert the design to a pumped storage project, pumping flow from the Oak Ridge storage tanks to Bass Lake storage tanks during off-peak hours then generating power at the Oak Ridge tanks site during peak energy demand periods. The hydro station will consist of one PAT or could simply be one of the pumps at the station running in reverse. The facilities will be housed in the pump station masonry building or in a separate building approximately 200 square feet in area. Access and distance to power grid are good. Whether or not the existing storage is sufficient for feasible operations is an important component to the future implementation of this hydro option.

The Gold Hill Intertie conveys flow to the Bass Lake tanks (8.2MG). The pipeline also connects the Bass Lake tanks to the Oak Ridge tanks (8 MG), which supply the El Dorado Hills area. The Oak Ridge tanks are also connected to and fed from the El Dorado Hills Water Treatment Plant (EDHWTP). The Bass Lake tanks serve the Cameron Park and El Dorado Hills area and have been sized for build out conditions. To augment the flow to the Bass Lake tanks for future needs in the Cameron Park area, the pump station upgrade is currently under design that would send flow from the Oak Ridge tanks to the Bass Lake tanks.

3.2. Project Facilities and Operation

This hydro option would be a pumped storage project, pumping flow from the Oak Ridge storage tanks to Bass Lake storage tanks during off-peak hours, then generating power back at the Oak Ridge site during peak energy demand periods. The concept of pumped storage can be achieved while there is excess storage available at the Bass Lake tanks. As the Cameron Park/El Dorado Hills area water usage increases over time, the volume of storage available for hydro generation will decrease.

Under current conditions, the Cameron Park area is not built out and there is excess storage available to store and deliver flows through the proposed hydro turbine. However, much of the El Dorado Hills area served by the Oak Ridge tanks is built out and during the higher water use (corresponding to the peak energy use) periods, there is limited excess volume at the Oak Ridge tanks. Allowing the Oak Ridge Tanks to empty during the filling of the Bass Lake tanks is not recommended. If sufficient water can be pumped to and through the Oak Ridge tank station to Bass Lake during off peak hours, a large portion of the return demands in El Dorado Hills during peak hours can be supplied from the Bass Lake tanks and through the hydro turbine. Estimates of current demands and excess storage available at the Bass Lake and Oak Ridge tanks are shown in Table 5.

Table 5 Bass Lake and Oak Ridge Tanks Monthly Demands and Available Storage

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Bass Lake Demand (MGD)	4.3	4.7	4.1	4.5	4.5	4.5	5.2	4.2	5.3	6.6	6.4	6.1
Available Storage	3.9	3.5	4.1	3.7	3.7	3.7	3.0	4.0	2.9	1.6	1.8	2.1
Oak Ridge Demand (MGD)	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Available Storage	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4

Based on EID staff input, the Bass Lake service area demand was estimated to be equal to the flow that passes through Pressure Regulating Station No. 6.5 (PRS 6.5). PRS 6.5 is located near Bass Lake Tanks and provides water via the Gold Hill Intertie. Data for the past two and a half

years was collected to determine an average daily demand for each month. The values for Bass Lake Demand in Table 5 also include additional water required for emergency storage, equalization storage, and fire suppression. Similar data for Oak Ridge Tanks was not available due to system's piping configuration. The pipeline that delivers water from EDHWTP to Oak Ridge Tanks has several laterals that use water for other service areas in the system. Therefore, it was difficult to estimate actual demand for the Oak Ridge service area and the number of parcels within the service area was used to calculate an average daily demand. Just as before, this value was added to the additional storage requirements to determine the excess amount of storage available.

Excess storage in the Bass Lake tanks can be used to supply the Oak Ridge service area or to keep the Oak Ridge tanks full by passing flow through the proposed turbine. Assuming the current excess storage values above, Table 6 provides the potential energy production in MW for the proposed turbine. The turbine head is approximately 465 feet based on the elevation difference and losses through the 20,000 feet of pipe. The average flow rate would be approximately 8.65 CFS for 6 hours each day during the summer months. The turbine would be a 250 KW unit. An alternative would be using a variable speed unit that would add flexibility in duration and flow rates through the turbine. However this type of unit will add cost to the installation and would be considered in the preliminary design efforts.

Table 6 Estimated Daily Energy Production, Daily Pump Energy, and Monthly Income for Oak Ridge

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Generation (kW/day)	1,520	-	-	-	-	-	-	1,520	1,520	1,520	1,520	1,520	9,120
Revenue ($/day)	358							358	358	358	358	358	358
Pump Energy (kW/day)	2,990							2,990	2,990	2,990	2,990	2,990	1,794
Pump Cost ($/day)	239							239	239	239	239	239	239
Net Income ($/month)	2,495	-	-	-	-	-	-	2,376	2,495	2,614	2,614	2,495	15,089

Assumptions: no generation on weekends and holidays, pumping cost = .08 $/kW, revenue = .2357 $/kW

Energy production during the winter months is unfeasible due to PG&E current rate schedule. The price for energy production is less than the cost of energy use to pump the water uphill to Bass Lake Tanks. Therefore, attempting to use the turbine during the winter months will produce a negative net income for those months. The income values in Table 6 take into consideration the cost to pump water uphill during the off-peak period. With conservative estimations for capital and maintenance costs, the payback period exceeds 20 years.

3.3. Future Opportunities for the Oak Ridge Tanks to Bass Lake Tanks Pumped Storage

With increased water demands anticipated in the Cameron Park area, the existing excess storage available for generation at the Oak Ridge site will diminish. In order to continue to use the system as a pump storage facility, storage would have to be added in the Cameron Park zone to serve the added demands in that area or to augment for future demands in El Dorado Hills area. Because the Bass Lake and Oak Ridge tanks have been sized for build out conditions, it is unlikely that more storage would be added if the only benefit would be for energy production at a relatively small hydro-electric facility.

Installation of a pumped storage facility at the Oak Ridge Tanks pump station would provide only a temporary benefit for the enhancement of renewable energy production by the District, therefore, this project should not be pursued further unless projected water demands and planned means of supply are altered in the future. For example, the District may decide to increase future supplies to the El Dorado Hills area from the Gold Hill Intertie system, which would increase the net generation at the Oak Ridge Tanks pump station.

4.0 Georgetown Divide Public Utility District

The Georgetown Divide Public Utility District (District) Reoperation Project is intended to investigate water conveyance system reoperation options for the District. This work effort was designed to investigate and document options that might be available to reoperate the District's raw and treated water conveyance systems to reduce energy costs and/or increase revenue at existing and potentially new hydroelectric power plants.

The District provides water in the Georgetown Divide area of El Dorado County including the areas of Cool, Pilot Hill, Greenwood, Georgetown, Garden Valley, and Kelsey. The Stumpy Meadows Project, owned and operated by the District, is the District's primary water supply source. The main feature of the Stumpy Meadows Project is Stumpy Meadows Dam and Reservoir located on Pilot Creek. The reservoir has a total storage capacity of about 20,000 acre-feet. Water from Stumpy Meadows Reservoir is released to Pilot Creek and rediverted and conveyed through the El Dorado Conduit and Georgetown Divide Ditch to meet the water supply demands of the District's service area.

4.1. Analysis

The investigation relied on available information and discussions with District personnel. Previous studies performed by the District and the El Dorado County Water Agency were reviewed as a source for pertinent data and information describing the Districts water system. Available information describing the District's raw water conveyance system was compiled and reviewed to understand the function and flexibility of the existing system and consider how operation could be optimized to provide for the following benefits.

- Increase revenue at the existing Buckeye and Tunnel Hill hydroelectric projects and potential new hydroelectric projects at Stumpy Meadows Dam and Sand Trap Siphon.

In addition to evaluating options to optimize operation of the existing raw water system to reduce costs and/or increase hydroelectric generation, expanded system reoperation was also considered which would include the ability to add new water storage features or expand existing storage facilities to increase the performance of the District's raw water system to increase hydro generation revenue. The new or expanded storage features considered could include one or more of the following.

- Walton Lake,
- Greenwood Lake,
- Auburn Lake Trails, and
- New Georgetown Reservoir (abandoned site near District office).

A meeting with Steve Gau (District Operations Manager) and Kelly Shively (District Assistant Operations Manager) was held at the District office clarifying existing raw water operation strategies, available operational flexibility and summary findings of this investigation.

No reoperation of the District's existing or an expanded raw water conveyance system was considered that could potentially reduce the reliability or availability of water supply to meet District demands.

4.2. Existing System Reoperation Options

The Districts existing reservoir and raw water conveyance system operation is currently optimized to maximize water supply yield and reliability to meet District water supply demands. An investigation was undertaken to consider if alternative operations could be employed to provide additional benefits while continuing to maintain water supply yield and reliability. Reoperation to allow the following additional benefits were considered.

- Increase generation revenue at the existing Buckeye and Tunnel Hill hydroelectric projects and potential new hydroelectric projects at Stumpy Meadows Dam and Sand Trap Siphon.

4.3. Increase Buckeye and Tunnel Hill Hydroelectric Project Revenue

The Buckeye Hydroelectric Project is located on the El Dorado Conduit which is approximately 10 miles long consisting of pipe and ditch and conveys waters released from Stumpy Meadows Reservoir and rediverted or diverted directly from Pilot Creek to a release point in the Georgetown Divide Ditch just west of Tunnel Hill. Most of the water is diverted through the Tunnel Hill Hydroelectric Project (600 kw) and returns to the Georgetown Divide Ditch. Water then flows to the Buckeye Hydroelectric Project (390 kw).

Currently, the volume of water being used for hydrogeneration at the Buckeye and Tunnel Hill Projects is determined primarily by the Districts water supply demands, tributary water that might naturally drain to the conveyance system, and spill water that periodically occurs from

Stumpy Meadows Reservoir. Water is not released from storage at Stumpy Meadows Reservoir to increase hydrogeneration as this operation could risk water supply yield available to meet District demands.

Pacific Gas & Electric (PG&E) purchases energy generated from both of the existing hydrogeneration projects under Feed-in-Tariff contracts. These contracts include time-of-delivery factors that make energy produced during the peak period of the day significantly more valuable than during the off-peak time of day. As an example, during the period from June through September, the value of energy is about 280% greater during the Super-Peak period (Monday - Friday, 12:00 noon - 8:00 pm) of the day than compared to the Night period (10:00 pm - 6:00 am) of the day. Therefore, there is a significant hydrogeneration revenue advantage to operate to generate as much energy as possible during the peak periods of the day.

During the irrigation season, typically stretching from May through September, portions of the conveyance system currently operate at near flow capacity. Therefore, because of this constraint a time-of-delivery type of operation is not possible during the irrigation season. However, during the off-irrigation season, typically stretching from October through April, this time-of-delivery operation is possible and could provide significant hydrogeneration revenue enhancement. In fact, a time-of-delivery operation is already incorporated into the current system operation.

Currently, Walton Lake is operated to take advantage of the time-of-delivery value of energy. This operation is conducted to maximize the benefit to the hydroelectric generation projects while not impeding on water supply availability or reliability. The most flexibility for this type of operation exists between the time Stumpy Meadows Reservoir spills to the beginning of irrigation season, as during this time, water is abundant and water supply demands are relatively low leaving capacity available in the system. There is no additional opportunity to operate the system to take additional advantage of the time-of-delivery value of energy that isn't already underway.

4.4. Releases from Stumpy Meadows Reservoir in Anticipation of Spill

Under current operation, no water is released from storage at Stumpy Meadows Reservoir solely to increase hydrogeneration at the existing Buckeye and Tunnel Hill Hydroelectric projects because this could risk water supply yield available to meet District demands. However, under spill conditions a portion of the water spilled from Stumpy Meadows Reservoir is diverted from Pilot Creek to increase generation opportunity at the existing hydroelectric projects. This same water could also be utilized at any new hydroelectric projects on the system including potential hydroelectric projects at Stumpy Meadows Dam and Sand Trap Siphon.

This investigation considered if it would be possible to release water from storage at Stumpy Meadows Reservoir in anticipation of spill in order to provide additional water for

hydrogeneration. Once it becomes known that Stumpy Meadows will spill through investigation of water in storage and information describing snowpack accumulation in the watershed tributary to the reservoir, water could be released from storage prior to when the reservoir would naturally spill. This could potentially extend the period of time when spill water could be rediverted at the Pilot Creek Diversion and used to generate at hydroelectric projects. However, because of the following conditions, this operation would likely produce little or no significant increases in hydrogeneration.

- Stumpy Meadows Reservoir does not spill every year,
- the time period from when it is known that Stumpy Meadows will spill until it actually spills is relativity short (probably less than one month),
- under conditions when this operation would be possible, water available for hydrogeneration from sources other than Stumpy Meadows Reservoir is significant, and
- anytime a release from storage is made other than to meet water supply demands, there is an inherent risk to water supply yield.

The possibility of releasing additional water stored in Stumpy Meadows Reservoir to increase the flow available to the hydroelectric projects, while possible during spill years is not thought to be useful in providing a significant increase in hydrogeneration revenue.

4.5. Expanded System Reoperation Options

This section considers an expanded system reoperation which would include the ability to add new water storage features or expand existing storage facilities to increase the performance of the District's raw water system to increase hydrogeneration revenue at existing and potentially new hydroelectric power plants.

As discussed in *Section 3.2* of this memorandum, the District currently operates in a limited way to provide time-of-delivery operation at certain times of the year to optimize hydrogeneration at the existing projects. This operation is limited primarily because the capacity, both conveyance and storage, is utilized to provide for water supply delivery and not available to further maximize hydrogeneration.

The following expanded or new storage facilities were considered in this investigation and could increase hydroelectric revenue by allowing a time-of-delivery operation.

Walton Lake

Expanded storage at Walton Lake could provide for added water supply reliability as well as act as a forebay for the existing Buckeye and Tunnel Hill Hydroelectric Projects.

Greenwood Lake and Auburn Lake Trails

Expanded storage at Greenwood Lake and/or Auburn Lake Trails could provide for added water supply reliability as well as act as an afterbay for the existing Buckeye and Tunnel Hill Hydroelectric Projects and a potential new project at Sand Trap Siphon.

New Georgetown Reservoir (abandoned site near District office)

Storage made available at a new Georgetown Reservoir could provide for added water supply reliability as well as act as an afterbay for Buckeye, Tunnel Hill, and Sand Trap Hydroelectric Projects.

Investigating the potential size, field constraints, specific operation, costs and benefits of the addition of new storage facilities is beyond the scope of this investigation. However, a sensitively analysis looking at the potential increase in hydroelectric generation revenue at the existing Buckeye and Tunnel Hill Hydroelectric Projects was conducted to get a sense of the magnitude of benefit that might be possible with the addition of storage and a more robust time-of-delivery operation. The results are shown in Table 4.1 below.

Table 4.1

Representative Increase in Hydroelectric Revenue at

Buckeye and Tunnel Hill Hydroelectric Projects Combined

Month	Representative Energy Generation[1] (mWh)	Representative Revenue, ($)		Revenue Increase ($)
		Existing[2]	With Additional System Storage[3]	
Jan	170	16,000	18,400	2,400
Feb	150	14,000	16,100	2,100
Mar	170	16,000	20,000	4,000
Apr	160	15,000	18,800	3,800
May	580	54,000	54,000	0[4]
Jun	560	52,000	52,000	0[4]
Jul	580	54,000	54,000	0[4]
Aug	580	54,000	54,000	0[4]
Sep	560	52,000	52,000	0[4]
Oct	170	16,000	18,400	2,400
Nov	160	15,000	17,300	2,300

Dec	170	16,000	18,400	2,400
TOTAL	**4,000 mWh**	**$374,000**	**$393,000**	**$19,000**

[1] The representative energy generation does not purport to be actual values, but simply a representative energy generation operation of the combined Buckeye and Tunnel Hill Hydroelectric Projects.

[2] The representative revenue does not purport to be actual values, but simply a representative revenue expected assuming the corresponding energy generation.

[3] This value represents the potential additional revenue that might be available if additional storage were available in the raw water system to allow a time-of-delivery operation.

[4] The raw water system is at near capacity during the irrigation season and therefore, no time-of-delivery operation is possible.

Values in *Table 4.1* suggest that the magnitude of additional revenue that might be possible with an increased time-of-delivery operation could be relatively small at about $19,000 per year. This value is quite low because the time when the time-of-delivery operation is possible (October - April) there is relatively little water available for operation and the price differential between peak and off-peak is relatively small. Similarly, when large quantities of water are available for generation during the irrigation season (May - September) and the energy price differential is at its largest, the capacity of the raw water conveyance system does not allow for a time-of-delivery operation.

The expected additional energy revenue generation that might be possible through new storage facilities and a time-of-delivery operation seems quite small compared to the costs associated with the construction, operation and maintenance of additional or enlarged storage facilities. Therefore, it does not appear that increase hydroelectric revenue at the existing Buckeye and Tunnel Hill Hydroelectric Project would support such an action. However, if additional hydroelectric projects were incorporated in the system, those projects would also enjoy the revenue benefits of additional storage in the system.

4.6. Summary Of Investigation

The ability to re-operate the existing GDPUD's raw water system to reduce operating costs or to increase hydropower generation at the existing Buckeye and Tunnel Hill Hydroelectric Projects is rather limited. GDPUD operates its water supply system to maximize water supply availability and reliability. There is little flexibility available to increase hydroelectric generation revenue or reduce energy costs.

While adding new storage facilities or increasing the size of existing storage facilities could provide for an increase in hydroelectric revenue for both existing hydroelectric projects and potential new projects by altering the timing of flow to take advantage of “on-peak” power values, it seems that this benefit would not be sufficient to support the construction, operation and maintenance cost of these new facilities.

In the future, if additional raw water or clearwell storage or conveyance capacity is required to meet water supply demands, incremental "up-sizing" of these potential new facilities should be considered to provide for increased hydrogeneration revenue and/or a reduction in energy costs at WTP's. The incremental cost to up-size potentially new facilities may be offset by hydrogeneration revenue enhancement and/or energy cost savings attained with the new facilities.

5.0 Energy Policies Supporting Hydroelectric Generation

California and national energy policies and regulations have changed significantly over the past two to three years, and are expected to change even more dramatically over the next several years. The changes stem from growing scientific community consensus on global climate change, public official policies addressing the increasing public health costs of fossil fuel effects on air quality, ongoing petroleum shortages and volatile fossil fuel prices, geopolitical and national security issues related to foreign energy dependence, and political support for California leading the nation toward a "clean energy economy". These trends have enhanced, and may further enhance, the economics of hydroelectric development in El Dorado County.

Appendix A presents a summary of energy policies and programs affecting the feasibility of renewable energy in general and hydroelectric energy in the water sector specifically as of mid-2009. Appendix A includes excerpts taken from the Hydroelectric Development Options Study, which were not updated for this study but reflect the trends and direction of energy policy related to hydroelectric generation.

Since the 2009 Hydroelectric Development Options Study was prepared, new state legislation and policies have been proposed (and some implemented) that further pertain to renewable energy. Most of the state legislation and policies focus on integration of renewable resources with the existing electric utility grid operations. Similar to previous legislation and policies, the new measures support opportunities and increase incentives for renewable energy including small hydroelectric, and many de-emphasize and reduce opportunities for conventional central station, fossil-fuel generating projects.

On a national level, the hydropower industry associations have been very active recently in lobbying to streamline Federal Energy Regulatory Commission rules related to hydroelectric exemptions and licensing. However, no federal legislation is known to be under development that would relieve the existing rigorous approval processes. Congressional action is particularly needed where proponents seek exemptions from FERC licensing to add small hydro facilities to existing dams and pipelines on federal lands and facilities.

5.1. Current Energy Policy Direction

Legislative and regulatory initiatives are focusing on reducing dependence on fossil fuels. The regulatory focus has been on all major carbon-generating sectors of the economy, differing somewhat between the national and state policies, but overall the emphasis has been on the following themes:

- Reduce greenhouse gas emissions to reduce the effects of manmade contributions to global climate change ("Global Warming")
- Reduce reliance on fossil fuels and imported fuels for energy production to reduce the negative economic consequences associated with international disruptions in petroleum production ("Energy Independence")
- Increase limitations on pollutants from energy generation to improve ambient air quality and reduce adverse public health effects and costs ("Public Health Costs")
- Shift energy policies from near-term, economic-driven decisions to long-term environmental and sustainability-driven decisions ("Clean-Energy Economy")
- Stimulate the national and California economies with investments, incentives, and jobs in infrastructure to support new (e.g., fuel cell) and emerging (e.g., electric car) industries, including a focus on efficiency in the water industry that is heavily dependent on energy ("Renewables Industry" and "Energy Efficiency")

The recent and ongoing state legislation of most importance to small hydro include the following:

- **AB 2037 (Perez) Air Pollution Standards for Electric Generation,** which prohibits public and private electric utilities from financing or constructing new electrical generation facilities in an air basin that does not meet specified air pollution criteria. This legislation was signed into law by the Governor on September 28, 2010.
- **AB 2514 (Skinner) Energy Storage Targets,** which requires public and private electric utilities to adopt and then achieve by certain years through 2020 viable and cost-effective energy storage systems to help the electric utility grid manage imbalances in the timing and sources of renewable energy generation and customer peak period demands. This legislation was signed into law by the Governor on September 29, 2010.
- **SB 32 (Negrete-McLeod) – Small Renewables Feed-in-Tariff Program Expansion**, which increases the maximum eligible system size for the Small Renewable Feed-in Tariff program from 1.5 MW to 3 MW. This bill also requires the CPUC to adjust the price of this tariff based on environmental attributes and also increases the statewide program cap from 500 MW to 750 MW. A January 27, 2011 Administrative Law Judge's ruling set the schedule for briefs on the implementation of SB 32 and requires that briefs be filed no later than March 22, 2011. The ruling requested the parties' views on

multiple topics, including expedited interconnection procedures and Commission consideration of locational benefits.

The concept of energy storage (AB 2514) represents an increasingly attractive option for water systems in foothill and mountain communities, particularly in high fire risk regions such as El Dorado County. Basically, the projected increase in off-peak non-firm wind energy, which in California is greatest in the nighttime hours, needs to be stored somehow for use during customer peak demand periods, which is generally noon to 8pm. For water systems in areas with considerable topographic variation, small-scale pumped storage hydroelectric systems could be added to existing water systems at an incremental cost. This type of storage would convert non-firm, renewable energy (i.e., wind) into storage representing distributed firm energy that could be dispatched based on daily grid demands.

This type of storage would benefit the existing water system by increasing supply reliability, and would have the significant additional benefit of increasing storage in high fire-risk regions of the state. If planned in cooperation with fire prevention and suppression agencies, the new storage added to the water systems could be strategically placed to help ensure gravity flow water supplies are available for firefighting even during catastrophic events where power for system pumping is lost to a region. Such a system would also complement the State's programs that are targeting greater distributed energy generation, and represent an economic stimulus for rural and suburban regions of California that have disproportionately high levels of unemployment.

5.2. Renewable Portfolio Standards, Feed-in Tariffs, and the Renewable Auction Mechanism

The CPUC and CEC are jointly responsible for implementing a program [Senate Bill (SB) 107] that targets the State's Investor Owned Utilities (IOUs) and others to reduce greenhouse gas emissions by mandating electric utility acquisition of required levels of renewable energy. A key element of this program is the Renewable Portfolio Standards (RPS) Program. Through a variety of utility, non-utility, and other measures, the IOUs are required to achieve certain amounts of qualified renewable energy by certain dates, with progress to be measured and reported annually to the State Legislature. The current goals are 20% by 2012 and 33% by 2020. California's three largest IOUs collectively served 15% of their 2009 retail electricity sales with renewable power. Preliminary data on the 2010 RPS percentages will be available when the March 2011 RPS Compliance reports are filed.

As part of the RPS Program, the CPUC mandated that each major IOU develop a Feed-In Tariff (FIT) Program for non-utility generators that offers above-market (i.e., Market Price Referent) energy payments based on a formula approved by the CPUC, and a Renewable Auction Mechanism (RAM) that allows generators to submit bids, which the IOUs will select on the basis of price, least expensive first. Additionally, the CPUC authorized the use of tradable Renewable Energy Credits (RECs) by IOUs as an additional compliance tool for the RPS Program. Presented below is more detailed information regarding the FIT Program and RAM.

FIT Program

The CPUC established a Feed-In Tariff (FIT) Program for renewable energy generation projects in February 2008. Under the program, investor-owned utilities including PG&E "must take" qualifying renewable electricity at predetermined purchase prices. The program uses a standard form purchase agreement with optional 10-, 15- and 20-year terms with prices guaranteed for the entire term of the agreement.

PG&E energy purchase rates under the FIT Program are changed annually based on the CPUC-approved Market Price Referent (MPR). The MPR is based on a formula that includes the price of natural gas and other factors. FIT agreement rates for a specific project are based on the MPR for the year in which the FIT agreement is signed, and the actual year of project commercial operation. PG&E can change the FIT rates for a project according to CPUC rules if the project does not come online within 18 months of FIT agreement execution.

FIT contract rates increased from 2008 to 2009, but then decreased roughly 15 percent from 2009 to 2010. Under the 2008 MPR, PG&E's FIT was $0.11730/kWh for a 20-year option agreement for a project coming on line in 2011. The FIT for the same project under the 2009 MPR (currently in effect) is $0.09674/kWh for a 20-year agreement. According to the CPUC, the MPR will be updated again in the first quarter of 2011.

The FIT Program has greatly increased interest and in some cases (e.g, GDPUD) development of small hydroelectric projects for water systems by guaranteeing payments for qualified generation through contracts up to 20 years long. Projects identified in the 2009 Hydroelectric Options Study could become financially feasible if variable speed technology matures and there is a significant increase in energy pricing.

Another feature of the FIT Program is that the FIT rate is adjusted by a time-of-delivery (TOD) factor that is approved by the CPUC and that varies between investor-owned utilities. TOD factors, or multipliers, are also modified and approved annually by the CPUC. For PG&E, and depending on season and time-of-day, the TOD multiplier for the 2009 MPR varies from 0.66 to 2.04, with the highest multiplier applying to PG&E's peak demand period on summer days.

The remaining unallocated capacity of the IOUs' FIT Programs indicates that either some modifications or additional incentives need to be offered to increase interest in the FIT Programs. In PG&E's service area, the capacity available under the FIT Program is 105 MW for water and wastewater facilities (E-PWF) and an additional 105 MW for non-water and wastewater facilities (E-SRG). However, the full 105 MW remains unallocated under the E-PWF category and 72 MW remains unallocated under the E-SRG category. Clearly, some action is warranted by PG&E, the CPUC, and/or the Energy Commission to increase attention to small hydro and other renewable energy projects under the FIT programs.

RAM

RAM is a simplified and market-based procurement mechanism for renewable distributed generation projects up to 20 MW on the system side of the meter. The CPUC adopted RAM as

the primary procurement tool for system-side renewable distributed generation because it will promote competition, elicit the lowest costs for ratepayers, encourage the development of resources that can utilize existing transmission and distribution infrastructure, and contribute to RPS goals in the near term.

To begin the program, the CPUC authorized the utilities to procure 1,000 MW through RAM. Going forward, the capacity authorization will reflect each utility's need for system-side distributed generation under 20 MW.

According to the CPUC, RAM is a unique program because it streamlines the procurement process for developers, utilities, and regulators. It allows bidders to set their own price, provides a simple standard contract for each utility, and allows all projects to be submitted to the CPUC through an expedited regulatory review process.

Under the RAM, projects submit price bids and IOUs select projects in order of least-costly first. Each IOU must enter into a standard contract with each winning bidder up to the capacity limits in each solicitation and total program capacity limits. There will be two auctions per year, held concurrently by all three IOUs, and a project may bid into all three auctions.

The CPUC issued its decision adopting the RAM on December 16, 2010. However, PG&E and Southern California Edison both filed applications requesting rehearing of the decision. It is uncertain how long it will take the Administrative Law Judge to consider the briefs or when a final decision will be reached.

The FIT Program and RAM both appear to be beneficial for EID, GDPUD, and other County water purveyors. Table 1 displays key aspects of these programs.

Table 1: Comparison of FIT and RAM

	FIT	RAM
What It Is/How It Works	• FITs present a simple mechanism for small renewable generators to sell power to the utility at predefined terms and conditions, without contract negotiations. • The power that is sold to the utilities under the FIT will contribute to each utility's ability to meet its RPS goals. • Renewable Energy Credits (RECs) transfer to utilities per FIT contract terms (RECs transfer to the utilities only for the energy sold to the utilities. If some energy is used onsite under the Net Sales approach, the applicable RECs stay with the system owner).	• Projects submit price bids • IOUs select projects in order of least-costly first • Each IOU must enter into a standard contract with each winning bidder up to the capacity limits in each solicitation and total program capacity limits. • There will be two auctions per year, held concurrently by all three IOUs; a project may bid into all three IOU's auctions.

Eligibility	• Open to all renewable resources • These tariffs are not available for facilities that have participated in the California Solar Initiative (CSI), Self-Generation Incentive Program (SGIP), Renewables Portfolio Standard (RPS) program or other ratepayer funded generation incentive program, including net metering tariffs.	• Seller need not be a retail customer and the facility need not be located on property owned or under the control of a retail customer.
Capacity Limits	• **Program cap:** 500 MW • **System size:** facilities up to 3 MW	• **Program Limit:** 1,000 MW • **Project/Transaction Limit**: 20 MW max for signing standard contract for full buy/sell or excess sales transaction.
Price	• Current price: 2009 Market Price Referent (MPR) (2010 MPR expected Q1 2011)	• Varies by bid, but least-cost projects selected first
Time-of-Day (TOD) Multiplier	The MPR will be multiplied by a TOD factor to reflect that electricity produced during peak times is most valuable. See http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/Feedin_Tariffs_FAQs.pdf	
Timeline	• Program start date: February 14, 2008 • SB 32 amended PU Code and increased the eligible project size to 3 MW. SB 32 became effective on January 1, 2010.	• CPUC Adopted RAM on 12/16/10 • IOUs shall file Tier 3 advice letters within 60 days of December 16, 2010 Decision. Implementation advice letters shall include: Procurement protocols; RAM standard contract; program details; timing of RAM auctions; specific amounts of capacity and type of resources in each auction over the next two years.

5.3. Renewable Energy Credits

"Renewable Energy Credit" (REC) is defined in Public Utilities Code Section 399.12 and includes all renewable and environmental attributes associated with the production of electricity from an eligible renewable energy resource. One REC is generated for each MWh of renewable energy from a qualified facility, which is certified by the Commission as meeting the CPUC's Renewable Portfolio Standard program.

Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002) directed the Commission to "design and implement a tracking system to ensure that renewable energy output is counted only once … for verifying…" REC "… claims in California or other states." The Commission, together with the Western Governors' Association (WGA) and the Western Electric Coordinating Council, developed the Western Renewable Energy Generation Information System (WREGIS) to meet this legislative mandate and address California's REC tracking needs.

The Commission worked with the CPUC on a series of draft and final reports on the definition and certification of RECs. A Final Report was adopted by the CPUC on November 21, 2008, and by the Commission on December 3, 2008. The analyses and conclusions of the Final Report demonstrate that WREGIS satisfies the three statutory requirements of Public Utilities Code Section 399.13 subdivision (c).

Depending on the type of power purchase agreement that EID or GDPUD may elect, RECs may or may not be assigned to the purchasing utility. FIT agreements, for example, dedicate all RECs to the purchasing utility. Under the NEM program, RECs may or may not be retained by EID or GDPUD.

On March 11, 2010, the CPUC authorized the use of tradable RECs by investor-owned utilities as an additional compliance tool for the RPS program. RPS-obligated retail sellers can buy, sell and trade RECs separately from their underlying energy and use those tradable RECs for compliance with the RPS.

Tradable REC transactions, by definition, do not require the procuring utility to also purchase the associated energy. Therefore, in order to protect consumers from potentially excessive payments for tradable RECs in the early stages of the REC market, the framework includes an interim price cap of $50 on RECs used for RPS compliance by investor-owned utilities (tradable RECs for which an IOU pays more than $50 per REC may not be used for RPS compliance). The price cap will terminate December 31, 2013.

5.4. Small Hydro as a Distributed Generation Resource

PG&E has released a map showing regions within its service territory where distributed generation is desirable for grid loading. Figure 7, which was adapted from PG&E's 2011 Solar PV Program Map, shows the locations with the greatest likelihood for successful generator interconnection, including hydroelectric interconnection. El Dorado County is identified as an area that has excess (unused) capacity on the grid and is therefore targeted to increase distributed generation. Therefore, PG&E is expected to help facilitate small hydro, solar, and other renewable energy projects that the County's water purveyors, other public agencies, residents, and private developers may pursue.

EID's and GDPUD's proximity to the Sacramento Municipal Utility District (SMUD), along with SMUD's Upper American River Project transmission system in El Dorado County, represent another opportunity for small hydroelectric development within the existing water systems. Like the investor-owned utilities, SMUD has adopted RPS and other renewable energy goals, some of which are more aggressive than the investor-owned utilities. While options for small

hydroelectric power sales to PG&E focus on either its FIT Program, upcoming RAM program, or its annual RPS solicitation process, SMUD also seeks unsolicited proposals that could help it meet its 2020 33% RPS goal. Given that most of the water systems are in PG&E's service territory, and because of the proximity to SMUD's transmission lines crossing El Dorado County from the Upper American River project, EID and GDPUD may want to consider developing and submitting a programmatic-scale small hydro plan to both utilities that would be economically feasible to develop. Such a proposal would not have to be limited to the constraints or timing of either PG&E's or SMUD's RPS or FIT (or future RAM) Programs, but could be attractive to one or both utilities with a large number of projects, opportunities for energy storage, and cumulative capacities approaching 30 MW.

Figure 7. Preferred Locations for Distributed Generation Interconnection (Map adapted from PG&E's 2011 Solar PV Program Map)

5.5. Energy Policy Effects on the Water Sector

Historically, California water policies and regulations focused on water supply, water conservation, and water quality, and have been largely independent of energy policies and regulations. However, because the water industry (including conveyance, treatment, and distribution) uses approximately one-fifth (19 percent) of electricity and 30 percent of non-power plant natural gas in the State (CARB 2008), the water sector is being targeted for regulation from a different angle – namely, energy as it relates to water use efficiency, water recycling, water system energy efficiency, and energy recovery/renewable energy production. As an example, the State Water Plan goal of 20 percent urban water conservation by 2020 targets both water and energy conservation.

The changing energy policies require new thinking about water supply, conveyance, treatment, distribution, and hydroelectric generation in El Dorado County. How much and what type of energy is used, when energy is used to treat and deliver water, efficiency of conveyance and treatment of current water sources, energy requirements to convey and treat additional water sources, and energy recovery are becoming increasingly emphasized.

6.0 Current Impediments to Hydroelectric Projects

Completing the FERC exemption process on the Tank 7 Hydro-electric project has helped develop a basis of understanding of the required steps for other projects that may be considered for implementation in the future. However, all of these projects including Tank 7 have significant challenges to overcome before moving forward. Impediments to construct hydro-electric projects include:

- Regulatory requirements such as precluding the use of a FERC exemption when the facility is located on Federal land.
- Variability of flow and pressure for in-conduit projects, making designed operations more complex.
- Fluctuating rates offset by the utilities making feasibility uncertain.
- Limited funding options, especially in the current economy. More attractive financing options for public agencies are needed.
- Most of the hydro-electric projects are secondary to other uses such as providing a reliable source of water to customers. Any changes to the current delivery system or schedule are often viewed as detrimental to the primary objective.
- FIT rates need to increase measurably above the 2009 Market Price Referent levels before EID and the District consider many of the projects to be economically feasible. Variable-rate bonds are currently available that have very low interest rates. However, the 15- to 20-year financing of the small hydro projects cannot be justified with variable rate bonds given the future uncertainties of the national economy, even with a 20-year guaranteed FIT. Financing with currently available 6% fixed-rate bonds yields a marginal payoff period of close to 20 years for many of these projects.

7.0 Overall Conclusions

Based on the analyses shown above the potential for reoperation in the water system exists to increase hydroelectric power generation. However, as the water purveyors main goal is to provide reliable water service, changes in operation do not appear feasible at this time. It should be noted however that future planning of the system, including increases in storage facilities, has the potential to take power generation into consideration. Increasing the proposed storage by approximately 20-30% could provide increased flexibility in the system from an operational point of view and also allow operation to maximize hydroelectric generation. This technical memorandum also points to the need for somewhat higher FIT energy payment rates and expanding the definition of qualified renewable energy resources to incentivize EID, GDPUD and other water purveyors to add small hydroelectric generation with their water system operations. For the top six small hydro projects identified by the 2009 Hydroelectric Development Options Study, either FIT rates need to increase by about 25%, or low-interest, fixed rate bond financing in the range of 2% to 3% will be needed before EID and GDPUD can proceed with the top few projects. Even with these options for financing, a few of the projects (e.g., EDM Res 3 and Stumpy Meadows Dam) will still face regulatory hurdles of added federal agency consultations, permits and substantial costs because of their location on federal lands or at existing dams. This and the need for increased energy storage on the grid as discussed above should be factored into regulatory and qualifying renewable resource rule changes if the State's policymakers wish to encourage water purveyors to broaden the mission of their operations and contribute substantially to the Governor's Renewable Portfolio Standard (RPS) goal of 33% by 2020.

8.0 REFERENCES

The following references were reviewed in carrying out the investigation described in this report. Information from these references is incorporated throughout the report.

EN2 Resources, Inc., *Final El Dorado County Hydroelectric Development Options Study*, July 24, 2009

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El Dorado County Water Systems

Energy Generation, Storage, Efficiency, Demand Management & Grid Support

TM#7 – Task 2.6. Solar Opportunities Technical Memorandum

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1.0 Introduction

The purpose of this study is to evaluate solar power generation opportunities within the El Dorado Irrigation District (EID) and Georgetown Divide Public Utility District (GDPUD) systems. EID and GDPUD are interested in determining opportunities for green energy throughout their system where it may be economically feasible. Additionally, this report will make recommendations to the California Energy Commission for the need for future programs to make solar more feasible.

EID is familiar with the solar process and has an existing solar system in operation at their El Dorado Hills Waste Water Treatment Plant (EDHWWTP). The system is a 1MW ground mounted system that is located adjacent to the existing plant. The system currently offsets the energy usage at the older portion of the plant saving EID nearly $300,000 annually. Figure 1 shows a view of the existing solar plant at EDHWWTP.

A study was previously conducted by Black & Vetch (BV) in 2007, which evaluated solar possibilities at multiple sites which found few opportunities. However, due to changes in technology, EID has continued their interest in solar power and to update the BV study for four (4) prospective sites. The four (4) sites being evaluated are Bass Lake Facility, Deer Creek Wastewater Treatment Plant (DCWWTP), EDHWWTP, and EID Headquarters. Figure 2 shows the approximate location of each site.

Figure 1. View of existing solar plant located at the EDHWWTP

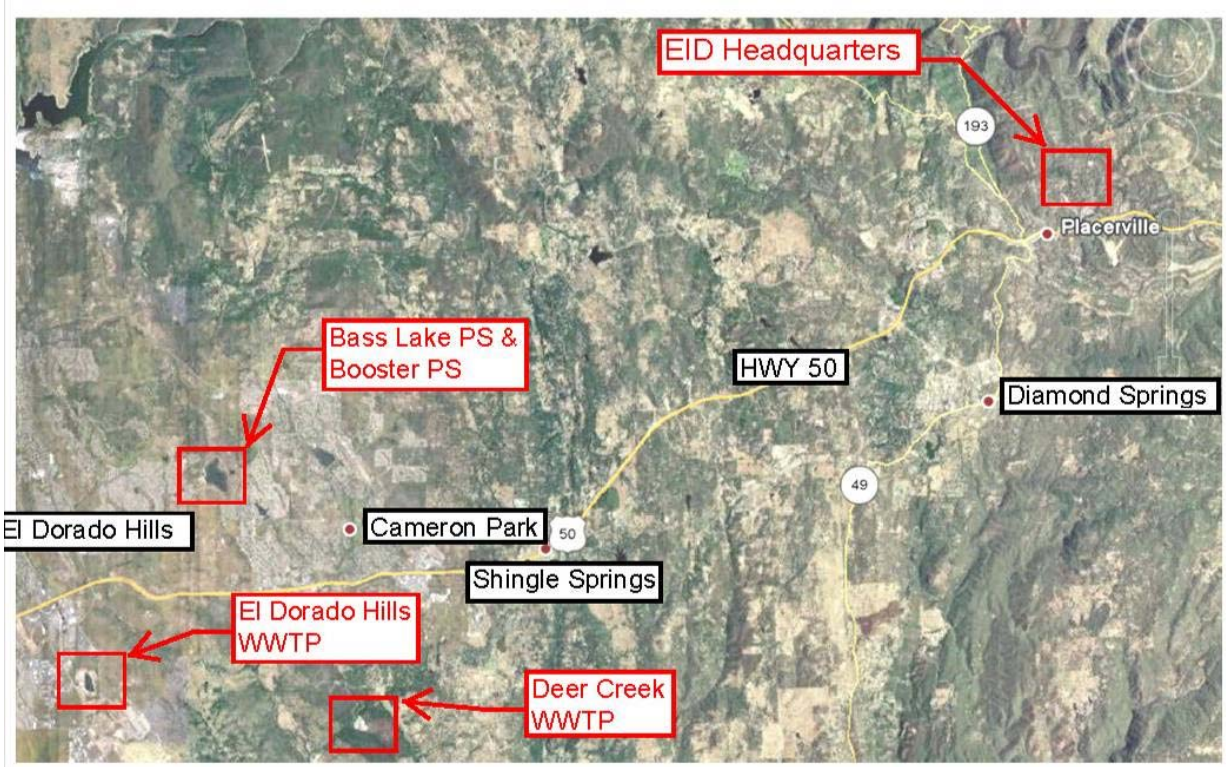


Figure 2. Site vicinity map

Bass Lake Facility

The Bass Lake and Recycled Water Booster Pump Stations are located outside of Cameron Park to the west of Bass Lake and to the north of the intersection of Bass Lake Road and Serrano Parkway. The booster station has three (3) PG&E utility meters. Two (2) meters are located near buildings on the north side of the property and the third meter is located at the Recycled Water Booster Pump Station along Bass Lake Road. There are three (3) areas being evaluated at this site for potential solar installation.

Deer Creek WWTP

The DCWWTP is located southeast of Cameron Park. Deer Creek Road is the main access road to the treatment plant. Deer Creek is located to the southeast of the treatment plant. The treatment plant has two (2) PG&E utility meters. One meter serves the older portion of the plant and the other feeds the newer portion of the plant. There are three (3) areas being evaluated at this site for potential solar installation with one area being a far better option than the other.

El Dorado Hills WWTP

The EDHWWTP is located within El Dorado Hills on the south side of Highway 50. The main access to the treatment plant is off of Latrobe Road. The treatment plant has four (4) PG&E utility meters. One meter serves the older portion of the plant and the other two (2) meters will serve the newer portions of the plant that are currently being constructed. There are two (2) areas being evaluated at this site for potential solar installation. The existing solar plant located on the EDHWWTP property feeds the meter serving the older portion of the plant.

EID Headquarters

The EID Headquarters is located within the City of Placerville on the north side of Highway 50 off of Mosquito Road. The headquarters has two (2) PG&E utility meters. One meter is located at the main office and the other meter is located at the adjacent maintenance yard. There are three (3) areas being evaluated at this site for potential solar installation.

In order to design an optimal system at each site, the project team performed a detailed and structured analysis. Each site was assessed based on 1) power consumption, infrastructure, and rate schedules 2) energy production goals and feasibility, 3) available area and layout, and 4) environmental impacts. Recommendations are provided for each site based on the findings of this analysis. Section 5.0 provides details of each site analysis.

2.0 Solar Energy Production Systems

Solar radiation can be captured in multiple ways. The two (2) main groups of technology are solar thermal and solar photovoltaic (PV). Solar thermal systems produce electric power by converting the sun's energy into high temperature heat. Solar PV systems use cells that are arranged and connected into a module/panel that collects and absorbs the radiant sun's energy in a form of direct current electricity. PV systems can be scaled to almost any size, have minimal maintenance requirements, and can be easily integrated into existing municipal facility. These attributes make solar PV suitable for use throughout EID's system. For this reason our analysis focuses on solar PV systems.

A typical solar PV system is equipped with three (3) main components: solar panels, inverter, and meter. The solar panel is constructed of an arrangement of solar cells. The cells are made of a semiconductor material and when the sun strikes these metals one side becomes positively charged and the other side becomes negatively charged. This produces a direct electric current. The direct current electricity collected from each solar panel is transferred to the inverter through a system of module strings. The inverter converts the direct current into alternating current that is synchronous with the utility grid. The inverter sends the alternating current electricity to the main circuit breaker panel. From there, the electricity is metered and can offset the current demand or spin the meter backwards and feed back into the grid effectively selling power back to the utility.

2.1. Types of Solar PV Systems

2.1.1. Fixed vs. Tracking

In a fixed system the solar panels are installed at a fixed inclination and direction. A fixed system is a robust mounting system. This type of system typically has less maintenance due to the minimal amount of moving parts. A typical fixed system is mounted to the ground with a support system that has an integrated rack and solar panel attached to it. The solar panels are typically fixed at 0°, 5°, or 10° and can be engineered with an adjustable tilt rack. A positioning pin is incorporated in the rack that typically allows 0°, 10°, 20°, 30°, and 40° module tilt for simple and easy seasonal adjustments.

A tracking system is a unique system that has the ability to follow the earth's orbit and track the sun to capture the greatest amount of solar energy possible. The solar panels are mobilized by a timed motor that turns the panels in the east-west direction to follow the angle of the sun instead of being in a fixed position. This type of system requires more structural elements due to higher load demands and therefore has higher installation costs. Also, this type of system typically requires more maintenance. However, this type of system also tends to be more efficient than a fixed system because the panels are constantly moving to be oriented perpendicular to the sun's rays and therefore has higher power generation potential.

Figure 3. Example of a Tracking System

For the purposes of this analysis fixed systems are being considered at all locations. Tracking systems may be considered at the locations where there are not significant hillsides that may inhibit a tracking system. However, to simplify the analysis, fixed systems are assumed at all locations.

2.1.2. Mounting Options

Ground Mounted Arrays

Ground mounted systems are solar panels mounted directly to the ground. This type of system can be installed relatively easily, can be easily maintained, and is typically the most cost effective system. Main performance factors to consider when installing a ground mount solar system are the terrain conditions (flat, sloped, or irregular ground surface), type of soil, orientation and inclination angle, and obstructions. Typically, the best location for ground mounted solar panels is on a south facing slope that has a uniform ground surface that is not rocky. It is important to consider any obstructions in the area that might cause shading of the panels.

Ground mounted arrays are being considered at EDHWWTP (similar to the existing system on site), DCWWTP and Bass Lake.

Roof Mounted Arrays

Roof mounted systems are solar panels that are mounted on top of a roof. Typically the best location for solar panels is on a south facing roof with a pitch of approximately 35° that does not

contain any obstructions that might cause shading of the panels. However, roofs that face east or west with a different pitch may be acceptable. Solar panels can also be mounted on flat roofs facing up or mounted to a frame that tilts toward the south at an optimal angle. Solar panels can be mounted to an existing roof or incorporated into the design of a new roof. If solar panels are being installed on an existing roof, the roof will need to be inspected by a structural engineer to determine if it can withstand an additional weight load of the solar system. The condition and age of the roof will also be taken into consideration. The roof may need to be retrofitted to accommodate a solar PV system.

Roof mounted systems are being considered at EID Headquarters and DCWWTP.

Figure 4. Example of roof mounted arrays tilted for the optimal angle.

Parking Structure Arrays

Parking structure solar systems basically consist of a frame structure that has an integrated solar panel roof racking system. The frame and roof racking system can be designed and engineered in a variety of configurations with a wide range of roof geometries and can be designed and installed to accommodate existing parking lots or any open area. These types of systems can be relatively expensive due to the level of engineering that is involved for the structural elements of the system. However, they can be popular due to the shaded area and available parking and/or storage that is created below the structure.

Parking structure arrays are being considered at EID Headquarters. Other locations do not have sufficient parking areas to make this a viable option.

Figure 5. Example of Parking Structure Arrays.

Floating Arrays

Floating array systems consist of solar panels that are mounted on a unique buoyant platform for installation on bodies of water. The solar panels are mounted on pontoons and have integrated walkways that allow for routine system inspections and maintenance.

Floating solar arrays have some beneficial side effects other than producing electricity. The system provides an opportunity for dual land usage with a design footprint that does not encroach upon valuable land by occupying unusable space while producing clean energy. The system can improve water quality by inhibiting algae growth and can reduce the amount of water loss due to evaporation by blocking sunlight and protection from the wind. Limited site preparation decreases installation time and associated costs. However, this type of system typically encounters technical complexities, regulatory hurdles, and higher installation and maintenance costs. Floating systems tend to get expensive due to the number of structural elements and level of engineering required for the design. Also, this type of system may require more maintenance and monitoring than other systems.

According to recent contacts with the manufacturers of floating array systems, the technology has advanced significantly to reduce the overall costs to become more competitive with the ground mounted systems. Additionally, the newer technologies have enabled the system to work with greater variations in water level. The systems can be designed and constructed to work at all water levels (from a full reservoir to an empty reservoir) as long as the body of water has a flat bottom with no obstructions that may potentially damage the floats. The footprint of the system will be designed to float over the flat bottom of the body of water and not over a portion of the sloped embankments. Recent innovations have made floating array systems more feasible than in previous studies.

Figure 6. Example of a Floating Array system.

3.0 Solar Energy Purchase Programs and Economic Incentives

California Energy Commission (Commission), California Public Utilities Commission (CPUC), and Pacific Gas and Electric Company (PG&E) websites and reports were reviewed to identify economic programs and incentives that may be applicable to EID, GDPUD and other El Dorado County water purveyor solar projects. Opportunities including incentive rates for solar energy have changed substantially over the past decade. CPUC regulatory proceedings, 2009/2010 legislation, and California Air Resources Board (CARB) regulatory proceedings indicate additional changes in the near future.

Governor Arnold Schwarzenegger recently signed into law several pieces of legislation that affect the solar industry and which took effect on January 1, 2010. The CPUC issued Decision 10-04-052 on PG&E's Solar Photovoltaic (PV) Program (PG&E Application 09-02-019) on April 22, 2010. CARB is developing a Renewable Electricity Standard (RES) that, when implemented, will extend a 33 percent Renewable Portfolio Standard (RPS) requirement to publicly-owned utilities, similar to existing requirements for investor-owned electric utilities, and also possibly expand the scope for qualified renewable energy sources. Regulatory proceedings are also underway on Renewable Energy Credits (REC) and Tradable RECs.

The recently passed legislation most relevant to water purveyor solar projects is:

- AB 920 (Huffman) – Net Energy Metering (NEM) - payment for net excess generation. Allows Net Energy Metered customers to sell any net excess electricity (kWh) generated over the course of 12 months to their electric utility at a rate to be determined by the CPUC. This legislation was signed into law by the Governor on October 11, 2009.
- SB 32 (Negrete-McLeod) – Small Renewables Feed-in-Tariff - program expansion. Increases the maximum eligible system size for the Small Renewable Feed-in Tariff program from 1.5 MW to 3 MW. This bill also requires the CPUC to adjust the price of this tariff based on environmental attributes and also increases the statewide program cap from 500 MW to 750 MW. A January 27, 2011 Administrative Law Judge's ruling set the schedule for briefs on the implementation of SB 32 and requires that briefs be filed no later than March 22, 2011. The ruling requested the parties' views on multiple topics, including expedited interconnection procedures and Commission consideration of locational benefits.

The effects of the above legislation are uncertain for existing solar programs, rates, and incentives. The effects of the ongoing regulatory proceedings are similarly uncertain. With the failure of Proposition 23 in November 2010, which would have halted implementation of AB 32, additional legislative and regulatory initiatives are anticipated as California policymakers seek to accelerate California electric utility renewable energy programs.

The remainder of this section focuses on existing solar program incentives that are applicable to the four solar project opportunities:

- California Solar Initiative
- PG&E's Net Energy Metering
- PG&E's Feed-In Tariff Program
- Renewable Auction Mechanism
- PG&E's Solar PV Program
- Federal Tax Incentives for Private Investors
- Renewable Energy Credits

EID and other County water purveyors are encouraged to monitor the rapidly evolving renewable energy regulations and financial incentive programs as California electric utilities work toward the 33 percent renewable energy goal by 2020.

3.1. California Solar Initiative Program

The California Solar Initiative (CSI) is part of the Go Solar California campaign, an unprecedented $3.3 billion ratepayer-funded effort that aims to install 3,000 MW of new grid-connected solar over the next decade and to transform the market for solar energy. The CSI Program is overseen by the CPUC for the participating State investor-owned utilities (i.e., PG&E, Southern California Edison Company, and San Diego Gas and Electric Company).

The CSI Program provides incentive payments either in one lump sum for smaller systems, or via elevated energy payments over the course of five years for larger systems. Smaller systems typically receive an upfront, capacity-based incentive, called the Expected Performance-Based Buydown (EPBB). Larger systems receive incentives based on their actual performance over the course of five years, called the Performance Based Incentive (PBI).

The capacity of EID's solar projects (i.e., over 50 kW) indicate that the PBI would apply. The CSI Program requires that the solar projects be sized to the facility load (or less) (PG&E Webinar – PG&E and Solar November 2009).

CSI PBI rates are based on a reservation that is determined by PG&E at the time the reservation request application is approved. The actual PBI rate may be lower than the current incentive rate shown for the current CSI Program rate step depending on the timing of the reservation approval.

CSI PBI rates are issued on a first-come, first serve basis, with 10 descending rate steps as capacity is added through the program. PG&E is currently in the eighth CSI Program rate step, with a commercial PBI rate of $0.05/kWh and a government/non-profit PBI rate of $0.15/kWh. PG&E has issued a total of 52.6 MW of CSI solar project conditional reservation letters for the eighth step, with 61.15 MW unreserved, and 8.99 MW under review. Due to budgetary constraints, all un-confirmed CSI megawatts are not guaranteed a CSI incentive at this time.

However, the Program Administrator is still accepting reservation request applications. The megawatt amount remaining will be incentivized as funding becomes available or as projects drop out. A waiting list for megawatts that become available can be found on the Program Administrator's website. In accordance with the CSI Program Handbook, no projects or applications are reserved under a given PBI rate step until all required information has been submitted and approved in writing by the program administrator, which for west slope El Dorado County purveyors is PG&E.

3.2. Net Energy Metering (NEM) Program

NEM would allow EID and GDPUD to offset the cost of electric usage at a site (e.g., wastewater treatment plant or EID headquarters) with energy that the solar project exports to the electric grid. A PG&E "net meter" would be installed to measure the difference between electricity purchased and electricity exported. The solar projects would need to be 1 MW or less in capacity, and the project would need to be reviewed and approved by PG&E.

NEM is only available to customers that have an existing electrical account with PG&E and agree to install PG&E's "net meter" at the project site. Electrical design and equipment requirements would apply as specified in an "Interconnection Agreement" so that the project operates "in parallel" with PG&E's electrical system. In addition to the Interconnection Agreement and other items, PG&E requires a completed Application Form 79-974, a Single Line Drawing technical diagram, and signed-off building permit.

Under the NEM program, electricity purchases and credits are accounted monthly at the applicable customer rate. Credits can be carried over month-to-month, and accounts are 'trued-up' annually.

As described above, AB 920 (Huffman) was signed into law in 2009. This legislation allows Net Energy Metered customers to sell any net excess electricity generated over the course of 12 months to their electric utility at a rate to be determined by the CPUC. According to PG&E, NEM accounts work with a second rate schedule, which is referred to as an otherwise-applicable-rate schedule (OAS). The customer must request an OAS in the Interconnection Agreement. The OAS determines the rates and charges for setting up the NEM meter and the calculation of NEM bills. The OAS may be any metered rate schedule for which the account would be eligible if the customer did not have a generating facility, and does not have to be the rate schedule established prior to becoming a NEM customer.

3.3. Feed-In Tariff Program

The CPUC established a Feed-In Tariff (FIT) Program for renewable energy generation projects in February 2008. Under the program, investor-owned utilities including PG&E "must take" qualifying renewable electricity at predetermined purchase prices. The program uses a standard form purchase agreement with optional 10-, 15- and 20-year terms with prices guaranteed for the entire term of the agreement.

PG&E solar energy purchase rates under the FIT Program are changed annually based on the CPUC-approved Market Price Referent (MPR). The MPR is based on a formula that includes the price of natural gas and other factors. FIT agreement rates for a specific project are based on the MPR for the year in which the FIT agreement is signed, and the actual year of project commercial operation. PG&E can change the FIT rates for a project according to CPUC rules if the project does not come online within 18 months of FIT agreement execution.

PG&E's FIT under the 2008 MPR was $0.11730/kWh for a 20-year option agreement for a project coming on line in 2011. The FIT for the same project under the 2009 MPR (currently in effect) is $0.09674/kWh for a 20-year agreement. According to the CPUC, the MPR will be updated again in the first quarter of 2011.

Another feature of the FIT Program is that the FIT rate is adjusted by a time-of-delivery (TOD) factor that is approved by the CPUC and that varies between investor-owned utilities. TOD factors, or multipliers, are also modified and approved annually by the CPUC. For PG&E, and depending on season and time-of-day, the TOD multiplier for the 2009 MPR varies from 0.66 to 2.04, with the highest multiplier applying to PG&E's peak demand period on summer days.

As described above, SB 32 (Negrete-McLeod) was signed into law in 2009. This legislation increases the size of FIT-qualified renewable energy projects from 1.5 MW to 3 MW. The legislation also requires the CPUC to develop pricing considerations for environmental benefits, which may include market-based pricing. The new guidelines for the increase in qualified project capacity and the pricing considerations for environmental attributes are subject to CPUC rulemaking and are still under review.

3.4. Renewable Auction Mechanism

The Renewable Auction Mechanism (RAM) is a simplified and market-based procurement mechanism for renewable distributed generation projects up to 20 MW on the system side of the meter. The CPUC adopted RAM as the primary procurement tool for system-side renewable distributed generation because it will promote competition, elicit the lowest costs for ratepayers, encourage the development of resources that can utilize existing transmission and distribution infrastructure, and contribute to RPS goals in the near term.

To begin the program, the CPUC authorized the utilities to procure 1,000 MW through RAM. Going forward, the capacity authorization will reflect each utility's need for system-side distributed generation under 20 MW.

According to the CPUC, RAM is a unique program because it streamlines the procurement process for developers, utilities, and regulators. It allows bidders to set their own price, provides a simple standard contract for each utility, and allows all projects to be submitted to the CPUC through an expedited regulatory review process.

Under the RAM, projects submit price bids and IOUs select projects in order of least-costly first. Each IOU must enter into a standard contract with each winning bidder up to the capacity

limits in each solicitation and total program capacity limits. There will be two auctions per year, held concurrently by all three IOUs, and a project may bid into all three auctions.

The CPUC issued its decision adopting the RAM on December 16, 2010. However, PG&E and Southern California Edison both filed applications requesting rehearing of the decision. It is uncertain how long it will take the Administrative Law Judge to consider the briefs or when a final decision will be reached.

3.5. Solar PV Program

PG&E developed its Solar PV Program Power Purchase Agreement (PPA) to procure, over a five-year period, 250 MW of PV Products as authorized by CPUC Decision 10-04-052 (adopted April 22, 2010). This program targets mid-sized projects, typically 1 to 20 MW, mounted on the ground or rooftops, within its service area. Projects developed by independent parties would be offered a standard contract and pricing derived from the utility's own costs to streamline review of their applications.

On February 2, 2011, PG&E issued the 2011 Solar PV Program PPA Request for Offers (RFO). The goal of the first round of the RFO is to procure 50 MW, and PG&E is seeking to execute agreements with a 20-year term from PV facilities that are 1 to 20 MW in size. The facilities must be new PV facilities located in PG&E's service territory and interconnected to PG&E's electric system.

A mandatory bidders' conference was held on February 8, 2011, and PG&E anticipates that the final PPAs will be executed on June 17, 2011. PG&E will issue future RFOs for the remaining 200 MW of PV Products that it intends to procure under this program over the next five years.

3.6. Federal Tax Incentives for Private Investments in Solar Opportunities

Investment, production, and other federal tax incentives would be available to private investors that develop the solar projects on behalf of EID or other public water purveyors. An example of such an arrangement is EID's existing solar array at the EDHWWTP that Shell Energy of North America developed on EID land.

The American Recovery and Reinvestment Act of 2009 (ARRA) extended and modified previous investment, production and other federal tax incentives to encourage private funding and development of renewable energy resources. Solar project tax credits generally were extended through December 31, 2016.

Presented below are highlights of ARRA extensions and revisions that may be applicable to private investments in EID's solar projects.

Production Tax Credit (PTC): Solar as well as other qualified renewable energy projects are eligible for the PTC that provides a 2.1-cent per kWh benefit for the first ten years of a renewable energy facility's operation.

Investment Tax Credit (ITC): Businesses that place in service solar facilities after December 31, 2008 are eligible for the ITC (in lieu of the PTC), which generally provides a 30 percent tax credit of net system costs with no cap. Private business-owned systems may also be eligible under the ARRA for a Modified Accelerated Cost Recovery System (MACRS) 5-year accelerated depreciation program. In addition, for tax years beginning after October 3, 2008, the credit can offset the alternative minimum tax.

Treasury Grant in Lieu of Tax Credits: A third incentive established by the ARRA is a grant system administered by the Treasury Department. In lieu of the PTC or ITC, private investors developing solar projects can receive a grant of up to 30 percent of the basis of the property's value. The grant is similar to the investment tax credit. The Treasury Department will issue a grant in an amount equal to 30% of the cost of the renewable energy facility within 60 days of the facility being placed in service or, if later, within 60 days of receiving an application for such grant.

3.7. Renewable Energy Credits

"Renewable Energy Credit" (REC) is defined in Public Utilities Code Section 399.12 and includes all renewable and environmental attributes associated with the production of electricity from an eligible renewable energy resource. One REC is generated for each MWh of renewable energy from a qualified facility, which is certified by the Commission as meeting the CPUC's Renewable Portfolio Standard program.

Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002) directed the Commission to "design and implement a tracking system to ensure that renewable energy output is counted only once … for verifying…" REC "… claims in California or other states." The Commission, together with the Western Governors' Association (WGA) and the Western Electric Coordinating Council, developed the Western Renewable Energy Generation Information System (WREGIS) to meet this legislative mandate and address California's REC tracking needs.

The Commission worked with the CPUC on a series of draft and final reports on the definition and certification of RECs. A Final Report was adopted by the California Public Utilities Commission on November 21, 2008, and by the Commission on December 3, 2008. The analyses and conclusions of the Final Report demonstrate that WREGIS satisfies the three statutory requirements of Public Utilities Code Section 399.13 subdivision (c).

Depending on the type of power purchase agreement that EID or GDPUD may elect for a solar project, RECs may or may not be assigned to the purchasing utility. FIT agreements, for example, dedicate all RECs to the purchasing utility. Under the NEM program, RECs may or may not be retained by EID or GDPUD.

On March 11, 2010, the CPUC authorized the use of tradable RECs by investor-owned utilities as an additional compliance tool for the RPS Program. RPS-obligated retail sellers can buy, sell and trade RECs separately from their underlying energy and use those tradable RECs for compliance with the RPS.

Tradable REC transactions, by definition, do not require the procuring utility to also purchase the associated energy. Therefore, in order to protect consumers from potentially excessive payments for tradable RECs in the early stages of the REC market, the framework includes an interim price cap of $50 on RECs used for RPS compliance by investor-owned utilities (tradable RECs for which an IOU pays more than $50 per REC may not be used for RPS compliance). The price cap will terminate December 31, 2013.

3.8. Loan Programs

One of the greatest drawbacks to solar energy projects are the relatively high capital costs. Often the costs to build and finance a project are too large to make the project feasible. There are several programs through PG&E and the CPUC that would reduce the financing costs. The programs include the Qualified Energy Conservation Bond (QECBs) and the Clean Renewable Energy Bonds (CREBs). These loan programs provide lower interest (2-3%) financing for the projects that is then paid off over about a 15-year period. These loan rates lower the annual costs of the project significantly over the current 6% interest market rate a Water District typically can get. The programs go through cycles and if their goals are not met during one cycle they will repeat at another date. GDPUD secured about $1.5 million in CREBs for small hydro in 2009, which will expire if unused within 3 years. GDPUD could apply for reallocation of the CREBs for qualifying solar. If EID determines that it would like to pursue this type of financing, CREBs and other loan programs should be explored. These programs will be essential for making the EID projects feasible from an economic perspective.

3.9. Findings

Based on the information presented above, it appears that EID and GDPUD may qualify for the following programs for projects that they own and operate:

- California Solar Initiative (CSI)
- PG&E's Net Energy Metering (NEM)
- PG&E's Feed-In Tariff Program (FIT)
- PG&E's Renewable Auction Mechanism (RAM)
- PG&E's Solar PV Program
- Renewable Energy Credits (RECs)

Of the above programs, the FIT Program, RAM, and Solar PV Program appear to be the most beneficial for EID, GDPUD, and other El Dorado County water purveyors. Table 1 displays key aspects of these three programs.

Considering the high capital costs of a solar energy system, a grant program such as the CSI will be essential to EID and GDPUD to make solar projects feasible. They cannot take advantage of tax incentives, and like other municipalities, would need to depend on grants to reduce the initial capital costs of installing and operating a solar energy system.

Federal tax incentives for private investors may be pursued under an agreement with a private investor at some of the sites. The benefits of such an agreement would include: no upfront costs; limited risks and liability, with the majority of both borne by the private developer; and, long-term energy payments or net metering once the developer recaptures its costs, earns a profit, and withdraws from the project.

Table 1: Comparison of FIT, RAM and Solar PV Program

	Feed-In Tariff (FIT)	Renewable Auction Mechanism (RAM)	PG&E Solar Photovoltaic Program
What It Is/How It Works	• FITs present a simple mechanism for small renewable generators to sell power to the utility at predefined terms and conditions, without contract negotiations. • The power that is sold to the utilities under the FIT will contribute to each utility's ability to meet its RPS goals. • Renewable Energy Credits (RECs) transfer to utilities per FIT contract terms (RECs transfer to the utilities only for the energy sold to the utilities. If some energy is used onsite under the Net Sales approach, the applicable RECs stay with the system owner).	• Projects submit price bids • IOUs select projects in order of least-costly first • Each IOU must enter into a standard contract with each winning bidder up to the capacity limits in each solicitation and total program capacity limits. • There will be two auctions per year, held concurrently by all three IOUs; a project may bid into all three auctions.	• PG&E's goal with the PV Program Power Purchase Agreement (PPA) is to procure, over a 5-year period, 250 MW of PV Products • PG&E intends to issue the 2011 Solar PV Program PPA Request for Offers (RFO) on February 2, 2011, subject to CPUC approval of a compliance filing required by Resolution E-4368 which implements PG&E's PV Program PPA RFO. • PG&E is seeking to execute agreements with a 20 year term from PV facilities that are 1 to 20 MW in size.
Eligibility	• Open to all renewable resources • These tariffs are not available for facilities that have participated in the California Solar Initiative (CSI), Self-Generation Incentive Program (SGIP), Renewables Portfolio Standard (RPS) program or other ratepayer funded generation incentive program, including net metering tariffs.	• Seller need not be a retail customer and the facility need not be located on property owned or under the control of a retail customer.	• The generating facility producing the Product must be a new PV facility located in PG&E's service area and interconnected to its system. • PG&E developed an interactive **map** (http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/) of its service territory. Areas with a higher likelihood for successful interconnection are identified.
Capacity	• **Program cap:** 500 MW	• **Program Limit:** 1,000 MW	• **PG&E 5-Year Total Procurement:** 250 MW

Limits	• **System size:** facilities up to 3 MW	• **Project/Transaction Limit**: 20 MW max for signing standard contract for full buy/sell or excess sales transaction.	• **Goal for 1st Round of PG&E PPAs:** 50 MW • **PV Facility Size:** 1-20 MW (Participants may offer different size options to enhance resource selection opportunity within the 50 MW target)
Price	• Current price: 2009 Market Price Referent (MPR) (2010 MPR expected Q1 2011)	• Varies by bid, but least-cost projects selected first	• No greater than $246/MWh (prior to adjustment for time of delivery)
Time-of-Day (TOD) Multiplier	The MPR will be multiplied by a TOD factor to reflect that electricity produced during peak times is most valuable. See http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/Feedin_Tariffs_FAQs.pdf		
Timeline	• Program start date: February 14, 2008 • SB 32 amended PU Code and increased the eligible project size to 3 MW. SB 32 became effective on January 1, 2010.	• CPUC Adopted RAM on 12/16/10 • IOUs shall file Tier 3 advice letters within 60 days of December 16, 2010 Decision. Implementation advice letters shall include: Procurement protocols; RAM standard contract; program details; timing of RAM auctions; specific amounts of capacity and type of resources in each auction over the next two years.	**Below is the expected schedule for the 2011 Solar PV PPA RFO:** PG&E Issues RFO — February 2, 2011 Bidders' Conference Registration Deadline — February 2, 2011 by 5:00 P.M. Bidders' Conference — February 8, 2011 Deadline for Participants to submit Offers — March 2, 2011 at 1:00 P.M. Proof of completed Inter-connection Application — March 22, 2011

			PG&E notifies Participants of Selected Offers	April 15, 2011
			Participants Provide Proof of Interconnection Screens	June 3, 2011
			Execute final PPAs	June 17, 2011
			Target Advice Letter Filing for Executed PPAs	July 15, 2011
Contact	Feed-inTariffs@pge.com		Interconnection applications must be directed to PG&E's Generation Interconnection Services at gen@pge.com. Interested parties may contact the Generation Interconnection Project Manager, William Chung, 415-973-1350 or MWCb@pge.com.	

4.0 Potential Generation and Capital Cost Estimates

In order to estimate the potential energy generation at each site previous generation studies were evaluated. Of particular interest was the Black & Veatch 2007 Study evaluating the actual production of the existing 1MW solar plant at the EDHWWTP. According to the evaluation study, the actual savings being seen by EID are less then what was predicted by the original Solar World forecast. The overall difference between what was forecast and the actual production was approximately 3-4% (with the difference being higher during summer months). Based on the system performance to date and the similarities between this existing system and the proposed systems it was determined to use the performance of the solar plant at EDHWWTP as a benchmark.

4.1. Background of Existing System

The EID solar array is 1,008 kW DC with four 225kW inverters. The solar panels are fixed at a 20 degree tilt (roughly latitude minus 15 degrees, which is optimal for summer production. The panels face 15 degrees west of south, again for maximum production in the peak afternoon.

4.2. Generation Estimates

EID has records of actual production from the time the plant came on line in 2006. The following table summarizes the actual array production to date.

Table 2. Estimated production for a 1MW array system.

Month	Array Production (kWh), (2006)	Array Production (kWh), (2007)	Array Production (kWh), (2008)	Array Production (kWh), (2009)
January	N/A	109,041	13,887	85,041
February	N/A	80,938	104,738	78,266
March	N/A	149,783	143,600	139,963
April	N/A	157,116	169,812	161,937
May	N/A	174,627	177,619	160,344
June	167,780	171,280	177,380	166,198
July	167,068	168,151	170,375	184,081
August	143,796	178,561	170,373	174,851
September	130,635	102,872	157,042	150,907
October	132,688	null	132,515	126,899
November	78,669	null	84,221	101,083
December	69,901	null	69,838	66,695
Total Annual Production =	**916,893**	**1,292,369**	**1,571,397**	**1,596,264**

In order to determine the average generation the two years that have complete data were averaged (2008 and 2009) for an average generation of 1,583,830. For this analysis an average annual production of approximately 1, 580,000 kWh will be used to estimate production for a 1MW system. All other system generation will be approximated as a percentage of this amount. Additionally, the Black & Veatch study determined that approximately 40% of the production was during PG&E peak hours. This will be used to determine the rate of return based on PG&E peak rates (as discussed in the previous economics section).

4.3. Basis for Capital Cost Estimates

Capital costs were estimated on a per kW basis. In order to estimate the standard costs of a system, multiple solar manufacturers were contacted and the latest cost information was gathered. Additionally, costs for EID's existing system and previous feasibility reports from Black & Veatch were utilized.

As a basis for costs a standard ground mounted system on a fairly flat area that requires minimal grading, minor site improvements and can be easily connected to the grid has an estimated cost of $6,500/kW. Other improvements required at the site will increase the per kW costs. The costs do include an estimated cost for connecting the system to PG&E's grid. Additionally, other types of systems will also increase costs. The following table summarizes the costs per kW used for various conditions and system types:

Table 3. Estimated Capital Costs used for different system requirements.

Type of System and site conditions	Estimated Capital Cost ($/kW)
Basic Ground Mounted on flat area (minimal improvements) <2MW	$6,500
Basic Ground Mounted on flat area (requiring additional site improvements) <2MW	$7,000
Basic Ground Mounted on sloped area (grading and additional improvements required) <2MW	$8,000
Larger Ground Mounted system (> 2MW)	$6,000
Floating Arrays	$8,000
Roof Mounted System	$9,000

The following section describes the conditions at each site and the capital costs and generation estimates for each.

5.0 Site Evaluations

5.1. Bass Lake

5.1.1. Electrical Load Present

Bass Lake has three (3) utility meters. Two of which, are small services for the buildings on the north side of the property. One meter is a single phase 120/240 vac meter that has a 200A main breaker. The second meter is 3 phase 120/240 vac that has a 200A main breaker.

The third meter services the Recycled Water Booster Pump Station and the Bass Lake Pump Station. This meter is 3 phase, 480 vac and 2000A. Consequently, this service supports the largest load on the property and is typically used in the summer months when recycled water demands are the highest. It is unknown how much this service will be used in the future, which may affect the feasibility.

5.1.2. Available Area

It should be noted that EID has future plans for a water treatment plant at the Bass Lake site. As sites are pursued for solar opportunities they should be coordinated with other EID departments in order to not interfere with future plans.

Three (3) areas on the property were considered. The first site in located near the sports field and is a flat area approximately 20,000 square feet in size. It is hidden from the main roadway; however it is within 100 feet of the sports field, which leaves the solar project susceptible to vandalism or accidental damage.

Figure 7. View of open area near the sports field.

The second site is located on the water surface or on the north side of the lake. The panels could be ground mounted and have the lake water rise and fall below the panels. The land area is

quite large measuring approximately 250,000 square feet but is located somewhat remote to the yard and would require extension of the PG&E service. Another option would be to float the panels on the water.

Figure 8. View of Bass Lake.

The third area is located near the Recycled Water Booster Pump Station building and is located between Bass Lake Road and the Pump Station. This area is level and flat and does not contain any trees. The site measures approximately 70,000 square feet.

Figure 9. View of open area near the Recycled Water Booster Pump Station.

See Figure 10 for an aerial showing the potential solar locations at the site.

5.1.3. Layout

The layout of the PV system would be similar to EDHWWTP for ground mounted solar panels. Optionally, automated tracker style panels should be considered for increased production. Additionally, floating arrays are being considered for installation on the lake.

5.1.4. Optimal Size of System

The optimal size of the system will depend on the metered service selected and the type of panels installed. Static inclined panels will be sized differently from automated tracker panels.

Small PV installations similar to residential size (10~20kw) could be installed behind either of the two smaller meters with the 3 phase service being the first choice of the two.

If panels were to be installed on the lake or on the north side of the lake, a fairly large system (>2MW) could be installed with the main limitation being the installation cost.

However, the service for the Recycled Water Booster Pump Station is large enough to support a 750kw system without any significant utility modifications. The system would be connected below the existing utility meter but above the existing main breaker. This would enable the connection to offset meter usage from the largest energy user on the property.

5.1.5. Capital Cost and Generation Estimates

The feasibility of each of the possibilities is good with the site next to the Recycled Water Booster Pump Station standing out as the simplest installation. The only concern with that site is the close proximity to Bass Lake Road and the visual impacts this may cause (see environmental section of this report).

Cost for ground based installation can be approximated by using an average cost of $6,500/kW. This estimate includes additional site grading and preparation costs. The ground that would be utilized is flat and level in the vicinity of the Recycled Water Pump Station which already has a sizeable utility connection. This area is a candidate for the lowest possible installation cost.

If the floating based installation option is chosen, its cost can be approximated by using an average cost of $8,000/kW given that additional structure or floating rafts would be needed for each panel.

A summary of the estimated capital costs for each project option can be found in Table 4 below.

Table 4. Capital Cost and Estimated power generation for potential projects

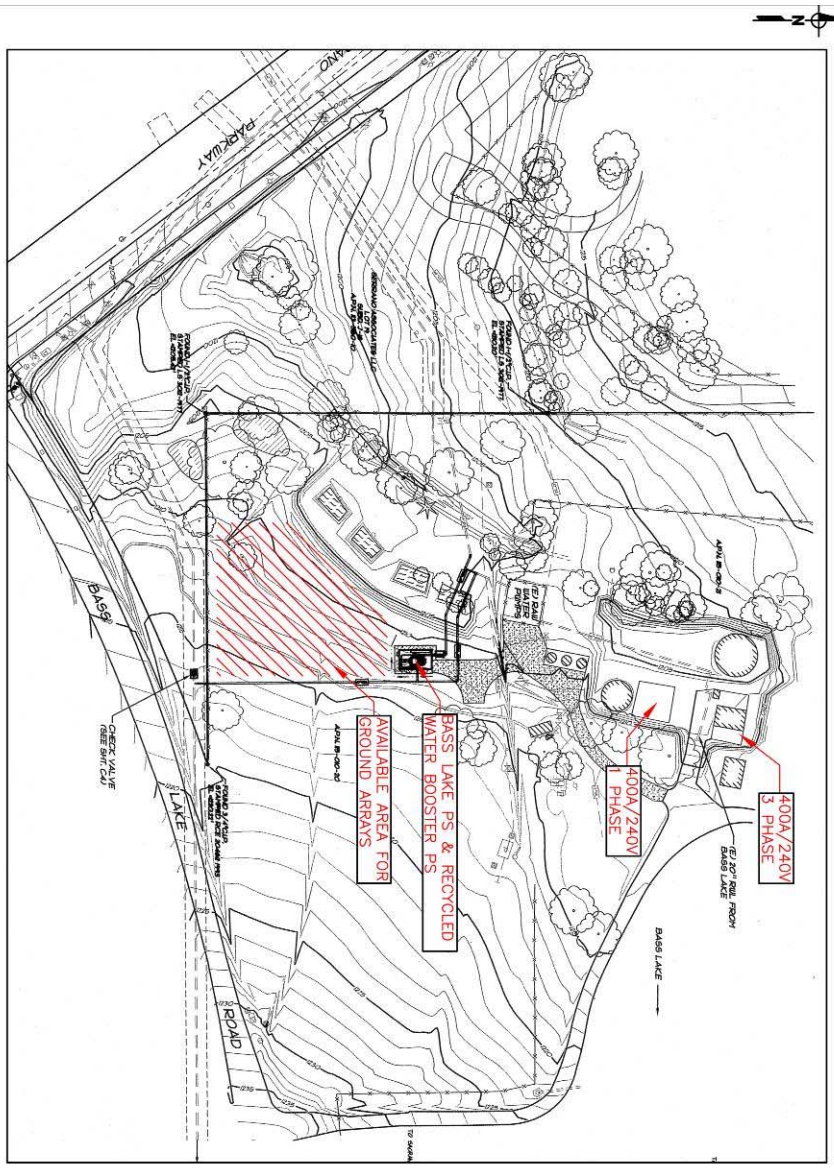
Type of System	Potential System Size	Average Cost ($/kW)	Total Estimated Capital Cost (1)	Potential Power Generation (2)
Ground Mounted (near Recycled Water PS)	750 kW	$6,500	$4.875 Million	1,185,000 kW

Ground Mounted on north side of Lake	>2MW	$6,000	$12 Million	3,160,000 kW
Floating Arrays	1-2MW	$8,000	$8-16 Million	1,580,000 kW – 3,160,000 kW

Note: (1) Capital Costs assume that the site work will be completed by an outside contractor as part of the overall project

(2) Potential power generation is based on a 1MW system producing approximately 1.580 MWh annually

FIGURE 10
BASS LAKE PUMP STATION SITE
SCALE: 1" = 100'



BASS LAKE SITE
SCALE: 1" = 1000'

5.2. Deer Creek Wastewater Treatment Plant (DCWWTP)

5.2.1. Electrical Load Present

The DCWWTP has two (2) utility services. One feeds the older portion of the plant (aeration basins, etc) and is rated 3000A at 480vac. The actual load varies daily but based on the utility information, the peak usage is approximately 500kW.

The meter that feeds the newer portion of the plant (UV disinfection, etc.) has a main service size of 2000A at 480vac. The actual load varies daily and by season, but based on the utility information, the peak usage is approximately 500kW during the summer months.

5.2.2. Available Area

The slope to the North East of the plant faces South West and could work well for fixed mounted solar. The slope incline is approximately 30% and measures approximately 600,000 square feet. As can be seen in the figure below the slope is heavily vegetated. This area would require significant clearing and grading to terrace the slope prior to installation of the ground mounted arrays. The additional work required at this site is reflected in the capital costs estimated.

Figure 10. View of sloped area that could be used for solar.

See Figure 12 for an aerial showing the potential solar locations at the site.

5.2.3. Layout

The layout of the PV system would be similar to the EDHWWTP for ground mounted solar panels. Optionally, automated tracker style panels could be considered. Additionally, roof mounted arrays were originally considered for this site. However, due to the limited area available for this use and the potential costs this option was eliminated from further review.

5.2.4. Optimal Size of System

The optimal size of the system will depend on the metered service selected and the type of panels installed. Static inclined panels will be sized differently from automated tracker panels.

While it is possible to feed solar power behind each utility meter and offset usage, it may be more prudent to combine the services and feed behind a single utility meter that is large enough to handle the entire solar installation.

If the size of the system exceeds the capacity of one or the combined total of the existing services, the only way to offset usage and to exceed present capacity is to combine the services together into a single 12kv service and obtain a metered service at that voltage.

If the entire slope is utilized, a 6MW system could be installed. That size would far exceed the plants total peak usage of 1MW and would require a 12 kv service. If only a smaller portion of the slope is used, and the existing services were to remain, each service could support about a 1.25MW system each. PG&E would need to be contacted to confirm the transformer sizing at each existing meter.

5.2.5. Capital Cost and Generation Estimates

The feasibility of utilizing the northeast slope is good. A small system of 1MW or less would be connected to the old existing meter service only. A medium system of up to 2MW would be connected to both existing meters. A large system, greater than 2MW, would require a new 12kv meter installation and would be the least cost per watt to install.

The ground that would be utilized is sloped and would require clearing and terracing prior to use increasing the costs for site improvements. Cost for ground based installation can be approximated by using an average cost of $8,000/kW. This rate should be sufficient for the installation to 1MW. If the size of the project is larger, the cost per watt may be lower (~$6,000/kW) due to economy of scale.

A summary of the estimated capital costs for each project option can be found in Table 5 below.

Table 5. Capital Cost and Estimated power generation for potential projects

Type of System	Potential System Size	Average Cost ($/kW)	Total Estimated Capital Cost (1)	Potential Power Generation (2)
Ground Mounted (on sloped area up to 1 MW)	1 MW	$8,000	$8 Million	1,580,000 kW
Ground Mounted (on sloped area up to 6 MW)	6 MW	$6,000	$36 Million	9,480,000 kW

Note: (1) Capital Costs assume that the site work will be completed by an outside contractor as part of the overall project

(2) Potential power generation is based on a 1MW system producing approximately 1.580 MWh annually

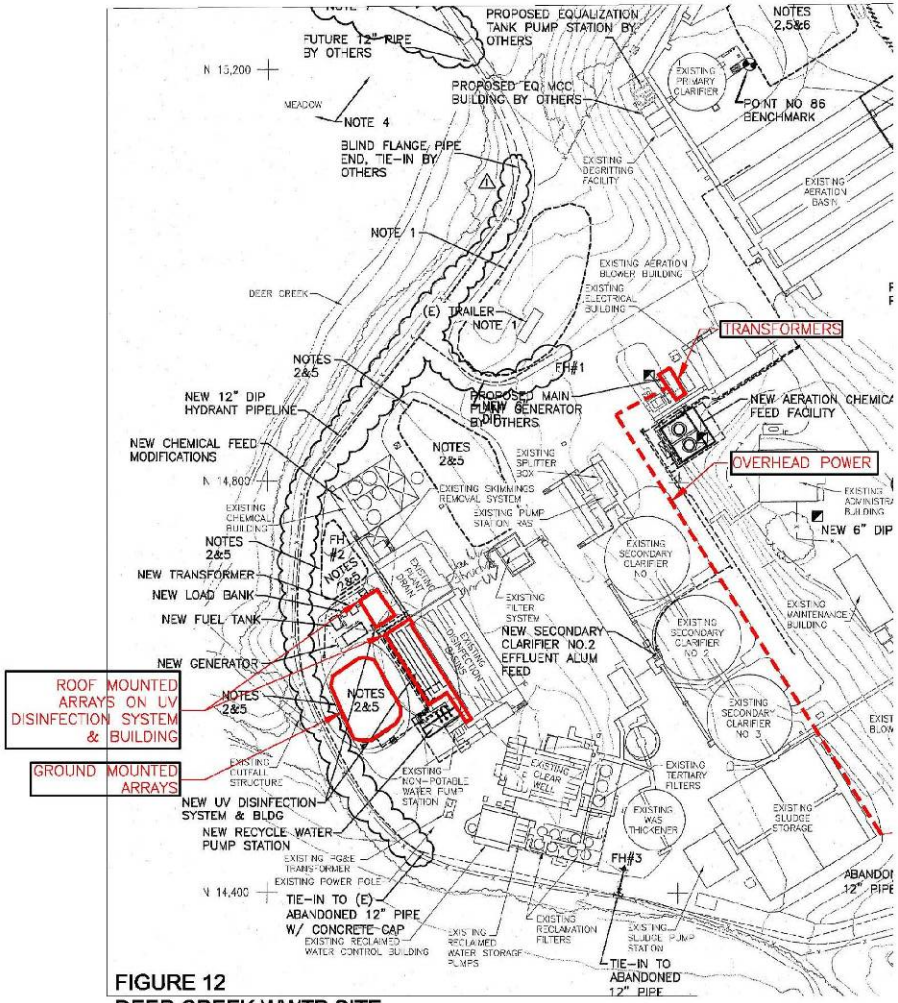
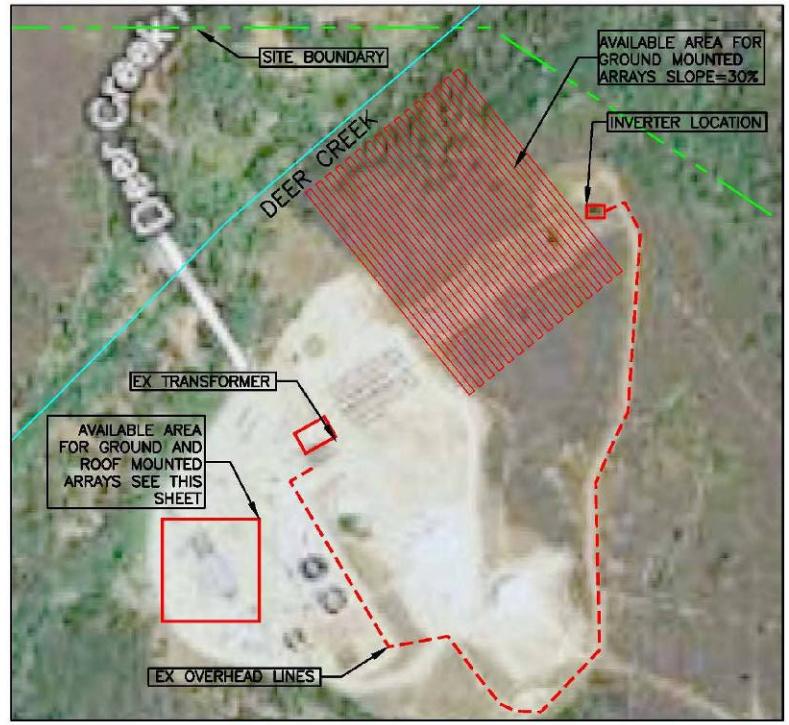


FIGURE 12
DEER CREEK WWTP SITE
SCALE: 1" = 100'



DEER CREEK SITE
SCALE: 1" 250'

5.3. El Dorado Hills Wastewater Treatment Plant (EDHWWTP)

5.3.1. Electrical Load Present

The EDHWWTP has three (3) utility services. One feeds the older portion and two (2) feed the newer portion of the plant that is currently under construction.

The service that feeds the older portion of the plant and is rated 4000A at 480vac. It is presently connected to the existing 1MW solar system.

The meter that feeds the remaining newer portion of the plant (Headworks Equalization, etc.) has a main service size of 2000A at 480vac. The system is in construction and usage information is not available yet.

The meter that feeds the newer portion of the plant (UV disinfection, etc.) has a main service size of 2000A at 480vac. The system is in construction and usage information is not available yet. It is assumed that these new portions of the plant could handle a load similar to the existing 1MW solar system.

5.3.2. Available Area

The existing storage reservoir on site was considered for potential floating arrays. As previously mentioned the manufacturers will design the floating arrays to allow the reservoir to be completely emptied therefore the size of usable area will be equivalent to the bottom area of the reservoir (approximately 200,000 square-feet).

Figure 11. View of pond at EDHWWTP (evaluated for solar potential)

Two other areas are available on site, one is to the north of the existing PV panel area and the second is south of the existing PV panel area. The area to the north measures approximately 250,000 square feet. The area to the south measures approximately 230,000 square feet.

Figure 12. View of area adjacent to the existing solar arrays at the EDH WWTP

These areas are fairly flat and would require minimal grading. The site would require some improvements to the existing drainage in order to accommodate the new system. Currently a drainage swale runs to the south of the existing solar array system (see overhead image figures). This drainage swale would need to be improved or potentially piped. These improvements will add to the overall cost of the system.

See Figure 15 and 16 for a plan of the site showing the potential solar locations.

5.3.3. Layout

The layout of the PV system would be similar to the existing panels at the EDHWWTP for ground mounted solar panels. Optionally, automated tracker style panels could be considered.

5.3.4. Optimal Size of System

The optimal size of the system will depend on the metered service selected and the type of panels installed. Static inclined panels will be sized differently from automated tracker panels.

If the north area is utilized, another 1MW system could be installed similar to the existing system. If the south area is utilized it could also receive approximately 1MW of PV panels. The north system could feed to the headworks service and the south system could feed to the UV service.

If the floating arrays were used this could also support a 1MW system.

5.3.5. Capital Cost and Generation Estimates

The feasibility of these systems is good since they would be similar to the existing system and connected in similar fashion to the existing PV panels.

The ground that would be utilized is flat and level East of the recycled water storage reservoir and would require some improvements to the existing drainage swale. This area is candidate for one of the lowest possible installation cost. Cost for ground based installation can be approximated by using an average cost of $7,000/kW.

If the floating based installation option is chosen, its cost can be approximated by using an average cost of $8,000/kW given that additional structure or floating rafts would be needed for each panel.

Table 6. Capital Cost and Estimated power generation for potential projects

Type of System	Potential System Size	Average Cost ($/kW)	Total Estimated Capital Cost (1)	Potential Power Generation (2)
Ground Mounted	1-2 MW	$7,000	$7-14 Million	1,580,000 kW – 3,160,000
Floating Arrays	1 MW	$8,000	$8 Million	1,580,000 kW

Note: (1) Capital Costs assume that the site work will be completed by an outside contractor as part of the overall project

(2) Potential power generation is based on a 1MW system producing approximately 1.580 MWh annually

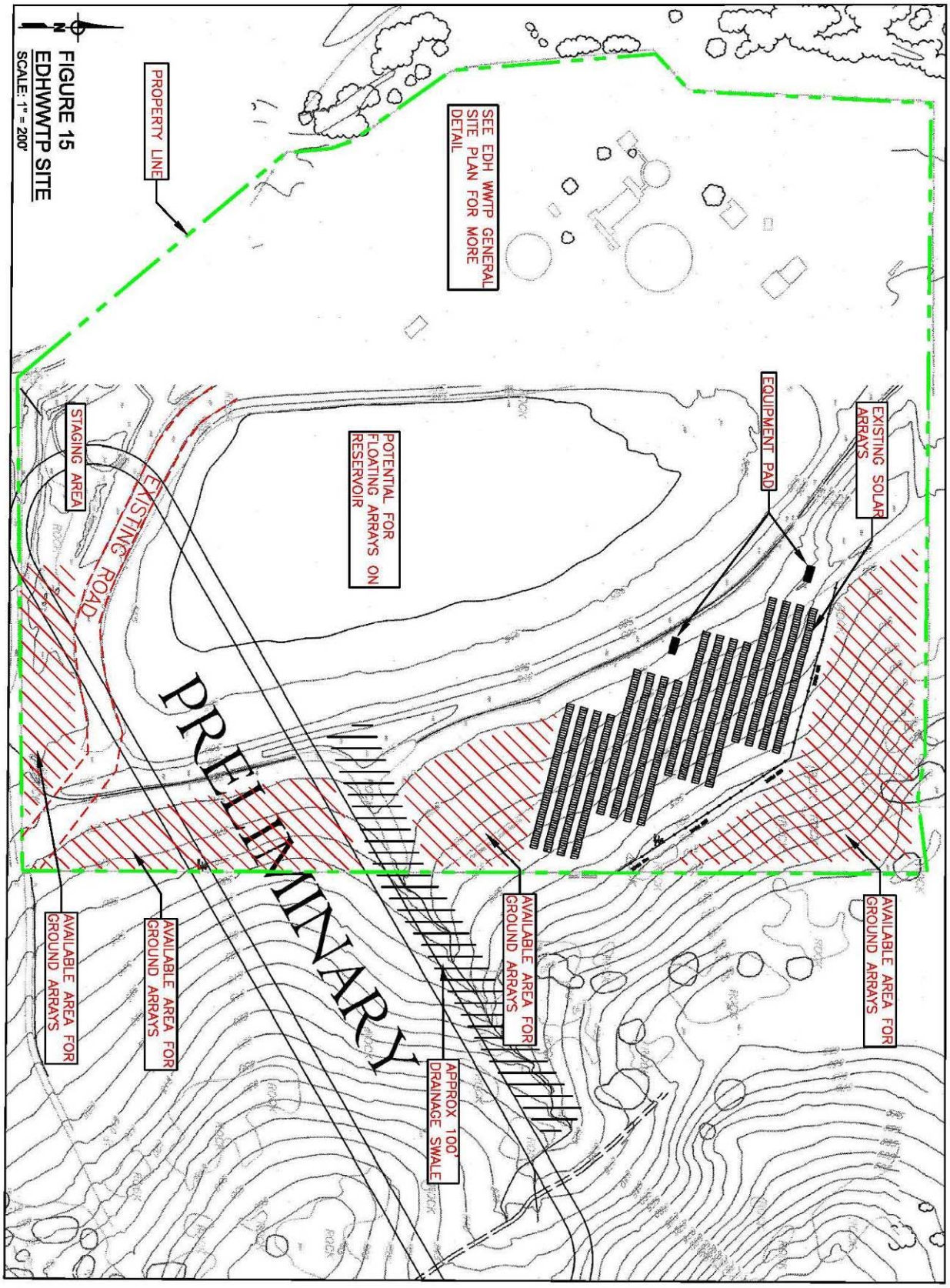


FIGURE 15
EDHWWTP SITE
SCALE: 1" = 200'

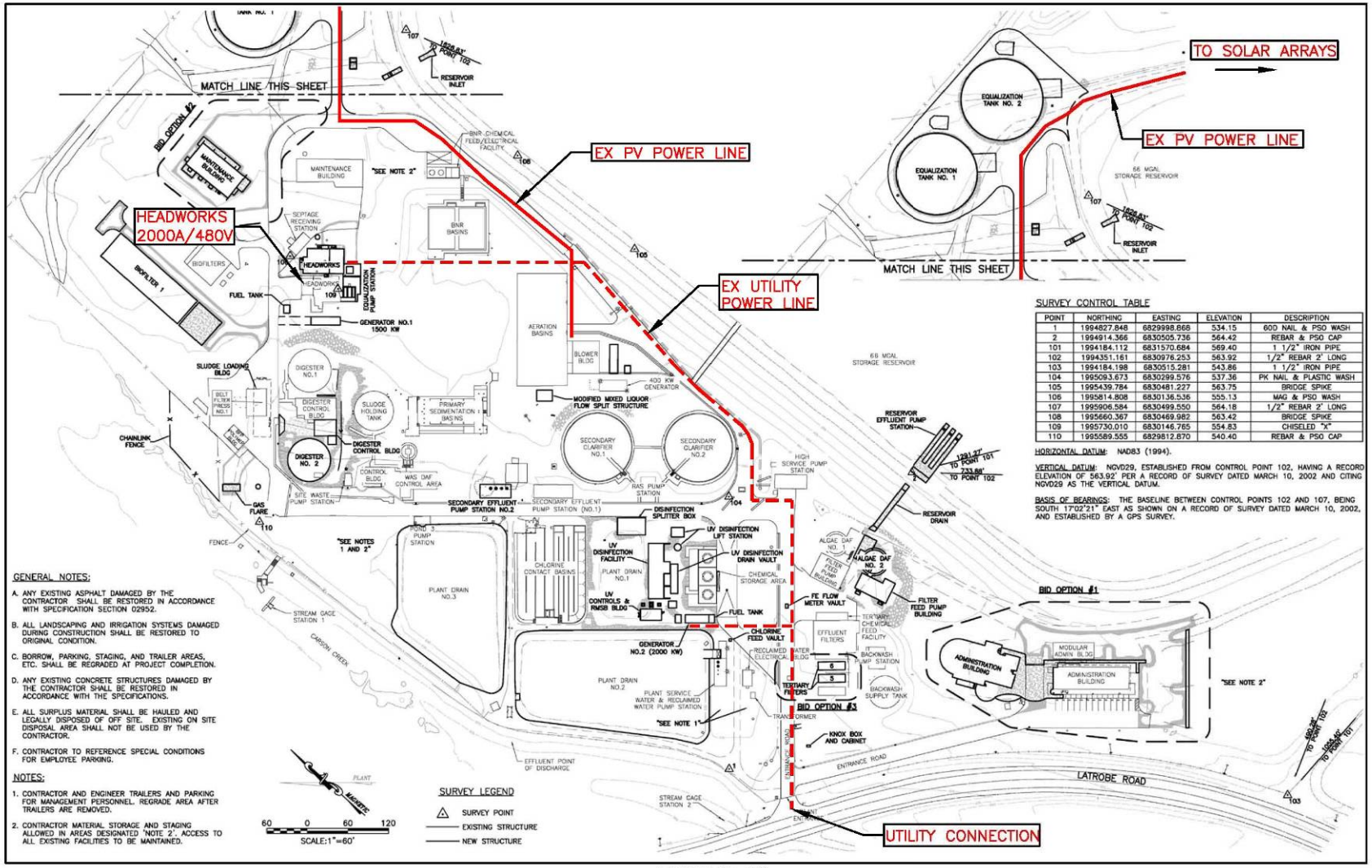


FIGURE 16
EDHWWTP PLAN
SCALE: 1" = 150'

5.4. El Dorado Irrigation District Headquarters

5.4.1. Electrical Load Present

Two (2) utility meters and services presently exist at the EID headquarters and at the adjacent maintenance yard. The meter for the Headquarters building is dedicated to the building and is 3 phase, 1600A, 480vac service.

The maintenance yard service is 3 phase, 1200A, 480vac.

5.4.2. Available Area

The building roof of the main office and the adjacent parking lot are two possible areas. The roof areas measure approximately 22,000 square feet. Some of the roof space is used for air handling equipment and will either reduce the total solar area or will force the solar panels to be built above them. The parking lot serving the main office has about 17,000 square feet of elevated space available.

Figure 13. View of EID Headquarters (potential for roof and parking lot solar)

Figure 14. View of EID Headquarters parking lot evaluated for solar

Additionally, EID currently has an open space available near the front of their parking lot area that has been reserved for display of historical artifacts related to EID or for potential demonstration displays. This area has been discussed for used as a solar demonstration. EID is consistently looking for opportunities to educate the public on solar and other types of green energy.

Another possible area is the upper parking area near the maintenance yard. This is a large parking lot that serves the main office. Approximately 40,000 square feet of elevated space could be made available above the parking lot.

See Figure 19 for a plan of the site showing the potential solar locations.

5.4.3. Layout

Either roof mounted or elevated structure mounted panels would be required for this site.

5.4.4. Optimal Size of System

The optimal size of the system would offset the headquarters building power. Based on the utility meter readings, a system up to 250kw could be used to fully offset the meter.

5.4.5. Capital Cost and Generation Estimates

The roof of the headquarters building and annex are the most feasible as compared to the parking lot where new structures would be required. The structures over the parking lot would add significantly to the cost of the system.

Cost for roof based installation can be approximated by using an average cost of $9,000/kW. The roof area that would be utilized may require some improvements to the structure to support the panels.

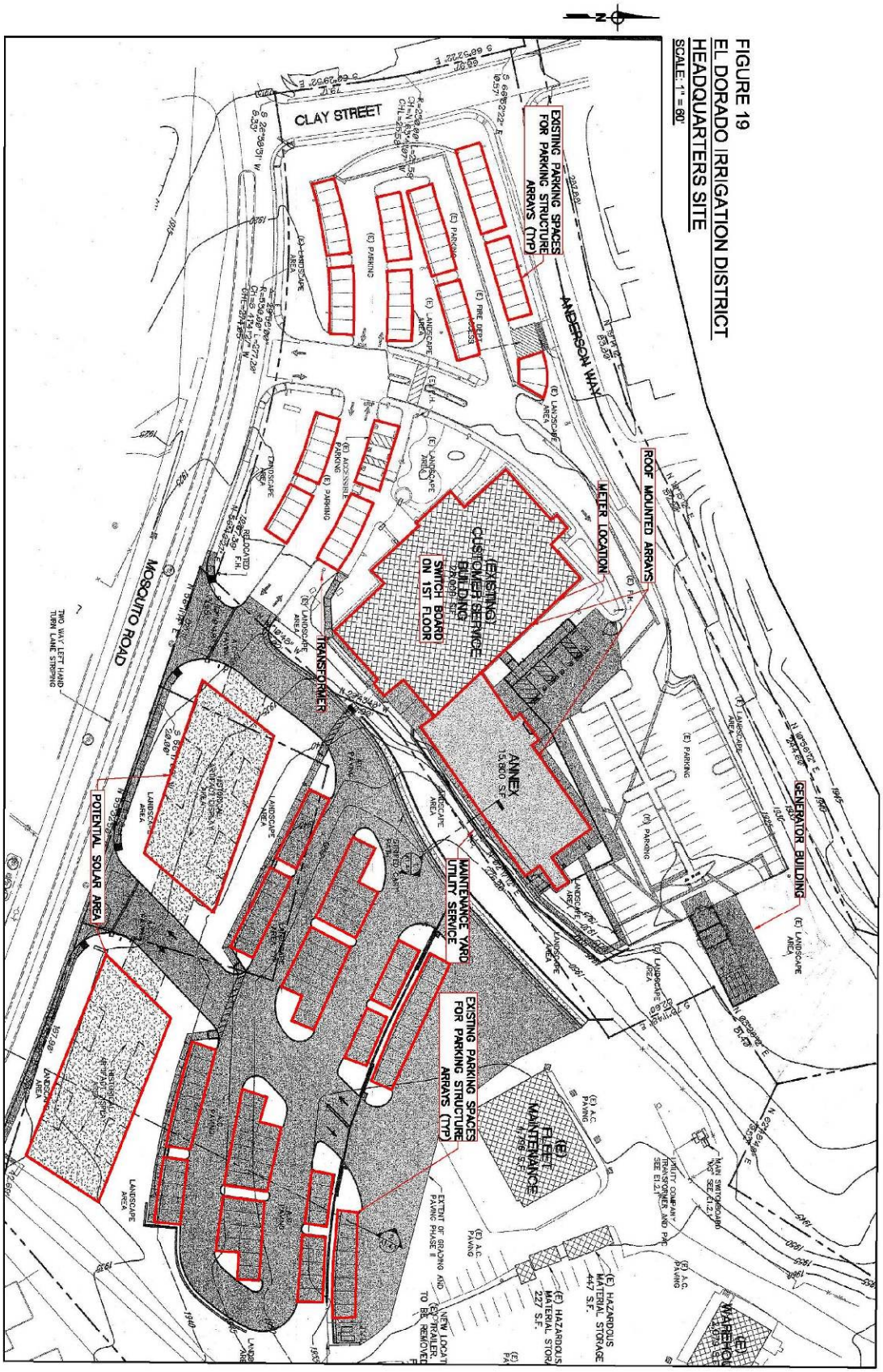
Table 7. Capital Cost and Estimated power generation for potential projects

Type of System	Potential System Size	Average Cost ($/kW)	Total Estimated Capital Cost (1)	Potential Power Generation (2)
Roof Mounted/Parking Structure Units	250kW	$9,000	$2.25 Million	395,000 kW

Note: (1) Capital Costs assume that the site work will be completed by an outside contractor as part of the overall project

(2) Potential power generation is based on a 1MW system producing approximately 1.580 MWh annually

FIGURE 19
EL DORADO IRRIGATION DISTRICT
HEADQUARTERS SITE
SCALE: 1" = 60'



6.0 PRELIMINARY ENVIRONMENTAL CONSTRAINTS ANALYSIS

6.1. Introduction

An initial environmental constraints analysis was performed for four (4) site locations under consideration for installation of solar panels. The four (4) site locations are owned and operated by EID and include Bass Lake Pump Station and Serrano Reclaim Booster Pump Station, Deer Creek Wastewater Treatment Plant, El Dorado Hills Wastewater Treatment Plant, and the EID Headquarters Building. The results of this environmental analysis will assist with the following tasks:

1. Preparation of preliminary engineering and cost estimates for each alternative.
2. Analysis of each alternative relative to economic considerations.
3. Identification of public/private financing and power purchase options.
4. Summary of findings and identification of preferred alternatives for implementation.

This analysis is preliminary and is intended for the above tasks. This analysis was not required for California Environmental Quality Act (CEQA) compliance; however, the organization and content of the following section is based on CEQA guidelines and it addresses the environmental considerations included in the District's review worksheet for CEQA Categorical Exemptions.

The following sections and Appendix A analyze the potential environmental issues and constraints beginning with the Bass Lake area and followed by Deer Creek Wastewater Treatment Plant, El Dorado Hills Wastewater Treatment Plant and EID Headquarters Building.

6.2. Bass Lake

6.2.1. Environmental Setting

This site is situated on the western slope of the Sierra Nevada at an elevation of approxiamtely 1,250 feet. The site is located immediately north of Bass Lake Road and adjacent to and west of the Bass Lake Reservoir. Bass Lake Road provides the primary access to the project area. Surrounding land uses include recreation facilities, proposed commercial development and residential areas.

The site is surrounded by gently rolling hills with slopes between 3 and 15 percent. The primary habitat at this site is Blue Oak Woodland which is characterized by an overstory of various densities dominated by blue oak (*Quercus douglasii*) and interior live oak (*Q. wislizenii*). The shrub layer is minimal and the herbaceous vegetation is dominated by annual grasses and forbes. At the south side of the site the habitat transitions from woodland to annual grassland, which extends south across Bass Lake Road.

A small ephemeral drainage fed from the overflow of the lake extends from the western edge of the lake and flows westward toward a baseball field where it turns south, skirting the west side

of the proposed project area. The lake itself is a well developed lacustrine habitat surrounded by riparian vegetation. The lake supports waterfowl, wading birds, and other wildlife.

6.2.2. Previous Environmental Documentation

More investigation is needed to identify the previous environemntal documentation and analyses completed for the Bass Lake Area. No recent documents were identified by District staff that would support this analysis. A thorough review of the Project record would be needed should this site location be selected.

6.2.3. Environmental Checklist and Analysis

Appendix A outlines and describes the environmental issues considered as part of this analysis. The Appendix begins with an analysis of areas of critical concern, followed by a discussion of significant effects due to unusual circumstances and other environmental issues. The websites and documents reviewed as part of the analysis are cited for reader's reference.

6.2.4. Summary Results

Based on the environmental review provided above and Appendix A checklist, more information is needed to determine the extent of environmental constraints associated with the installation of solar panels at the Bass Lake Reservoir. The panels would likely be proposed in a previously undeveloped area and/or on the reservoir. Based on this analysis, the environmental impacts could vary substantially based on the final location of the panels.

There are several biological resource concerns, including impacts to aquatic habitat and bald eagle foraging habitat associated with installing solar panels on the lake. In addition, mitigation for impacts to oak woodland habitat would be required if oaks are removed to install solar panels. An aesthetic impact associated with installing panels on the lake is also a major concern. Installing panels on the lake could require preparing an EIR. If the Project only involves land-mounted solar panels, it may quality for a mitigated negative declaration.

Figure 15. View northwest from Bass Lake Dam toward proposed solar panel installation area

Figure 16. View southwest with overview of proposed solar panel installation area. Bass Lake Road at right near oak trees

Figure 17. View to southeast of Bass Lake from the dam; proposed site for floating solar panels

6.3. Deer Creek Wastewater Treatment Plant (DCWWTP)

6.3.1. Environmental Setting

The DCWWTP complex is located on the western slope of the Sierra Nevada at an elevation of approximately 850 feet. The complex is situated in a small valley near the confluence of Deer Creek and a small tributary of Deer Creek. The Deer Creek flows on the north side of the treatment plant and tributary skirts the southwestern edge of the plant. The nearby land uses include residential areas north of the site and along the access road.

The site is surrounded by rolling hills with some moderately steep slopes. Several habitats are located near the project including Valley-foothill riparian habitat which surrounds Deer Creek and the nearby tributary to the southeast. A variety of riparian trees dominate the vegetation in this area such as valley oak, Fremont's cottonwood and several species of willow. The northern and eastern edge of the project area is characterized by dense chapparal composed of chamise, whiteleaf manzanita, and toyon. The soils in this area are derived from serpentine rocks and may support rare, endemic plant populations. Blue oak woodland abuts the riparian and chaparral areas to the north and west.

6.3.2. Previous Environmental Documentation

In February 2008, an Initial Study/Mitigated Negative Declaration (IS/MND) was completed for the Deer Creek Road Paving, Water Line, and Crossing Project. Although this IS/MND does address areas in the vicinity of Deer Creek Wastewater Treatment Plant, it does not address all of these areas under consideration for the installation of solar panels. A thorough review of the Project record would be needed should this site location be selected.

6.3.3. Environmental Checklist and Analysis

Appendix A outlines and describes the environmental issues considered as part of this analysis. The Appendix begins with an analysis of areas of critical concern, followed by a discussion of significant effects due to unusual circumstances and other environmental issues. The websites and documents reviewed as part of the analysis are cited for reader's reference.

6.3.4. Summary Results

Based on the environmental review checklist in Appendix A, more information is needed to determine the extent of environmental constraints associated with the installation of solar panels at the Deer Creek Wastewater Treatment Plant. The panels may be proposed in a previously developed area and they may be installed in a previously undeveloped area. Based on this analysis, the environmental impacts associated with this location would depend on the final location of the panels.

There are several biological resource concerns, including special-status species and sensitive habitats associated with clearing native vegetation for the installation of solar panels. In addition, mitigation for exposure to naturally occurring asbestos would be required at this site. We recommend preparing a CEQA initial study. With appropriate mitigation, this project would likely meet CEQA requirements with a mitigated negative declaration.

Figure 18. View east across parking area toward hillside proposed for potential solar panel installation

Figure 19. View west with overview of Deer Creek Wastewater Treatment Facility complex

6.4. El Dorado Hills Wastewater Treatment Plant (EDHWWTP)

6.4.1. Environmental Setting

The EDHWWTP complex is situated within the unincorporated area administered by El Dorado County and within the El Dorado Hills Community Services District. The complex is located approximately one mile south of Highway 50. The area consists of an approximately 24-acre reservoir with an office structure, maintenance yard and associated parking areas. The solar panels are proposed in an area with existing solar panels on the east side of the reservoir and within the reservoir itself.

The El Dorado Hills Wastewater Treatment Plant is surrounded by open space to the south and residential to the east and commercial development to the north. Latrobe Road provides the primary access adjacent to and west of the facility.

The site is located along the western edge of the foothills of the Sierra Nevada at an elevation of approximately 550 feet. The site is gently sloping at the foot of rolling hills to the east. The primary habitat surrounding the site is annual grassland and oak savanah. There are very few trees on site. The herbacous vegetation is composed primarily of introduced grasses with some native forbes. Carson Creek, a perennial stream, is located along the western edge of the parcel, outside of the Project area. Off-site to the west, as the terrain gets flatter, the annual grassland conatins vernal pool complexes and other seasonal wetlands.

The reservoir on-site is a mangaged facility with little habitat value due to frequent vegetation maintenance. There is very little vegetation around the reservoir and little aquatic vegetation in the reservoir. There were a few waterfowl using the reservoir, but these are likely transient, moving off to better habitat nearby.

The attached photograph of the existing solar panels provides a representative example of the type of panels under consideration at EDHWWTP.

6.4.2. Previous Environmental Documentation

In January 2005, an IS/MND was completed for the El Dorado Hills Wastewater Treatment Plant, Solar Photovoltaic System Project. The project consisted of installation of approximately 35,200 square feet of solar photovoltaic system panels at the EID El Dorado Hills Wastewater Treatment Plant. The panels were installed within the existing fenced property of the treatment plant. On the basis of the whole record, the IS/MND found no substaintial evidence the project would have a significant effect on the environment.

6.4.3. Environmental Checklist and Analysis

Appendix A outlines and describes the environmental issues considered as part of this analysis. The Appendix begins with an analysis of areas of critical concern, followed by a discussion of significant effects due to unusual circumstances and other environmental issues. The websites and documents reviewed as part of the analysis are cited for reader's reference.

6.4.4. Summary Results

Based on the environmental review checklist in Appendix A and based on a review of the IS/MND completed for EDHWWTP, Solar Photovoltaic System Project, there are no major environmental constraints associated with the installation of solar panels at the EDHWWTP. The panels would be located in a previously developed area and would essentially expand an area with existing panels. The installation of the panels would not result in a significant change to the character and setting of the area. We recommend further investigation into some of the checklist items checked as "maybe". Based on this analysis, the environmental constraints associated with this alternative location may meet the requirements for CEQA Categorical Exemption 15301(2)(b), Class 1 – Existing Facility (Minor Alteration).

Figure 20. View to the northeast of existing solar panels at the EDHWWTP; new panels would be installed in foreground

Figure 21. View to the southwest of the storage reservoir at the EDHWWTP

6.5. EID Headquarters

6.5.1. Environmental Setting

The EID Headquarters Building is situated within the incorporated area administered by the City of Placerville, approximately one-quarter mile north of Highway 50. The Headquarters Building area consists of a 2-story office building with parking areas to the north, south, and east of the building. The solar panels proposed in the employee parking areas would be situated immediately adjacent to and west of the main building.

The EID Headquarters Building is surrounded by single-family residential areas to the north, east and west and a recently developed bus station immediately south. The primary access is Mosquito Road.

The area is highly developed with little to no natural habitiat where ground disturbing activities are proposed. The elevation of the site is approximately 1,920 feet and the site is surrounded by urban development, including commerical and residential land uses. The nearest natural habitat is offsite, along Randolph Canyon Creek near the El Dorado Trail, approximately 80-100 feet from the southeast corner of the project. A narrow band of riparian vegetation is present along the creek.

The attached photograph of solar panels in Cameron Park provides a representative example of the type of panels under consideration at the EID Headquarters Building parking area.

6.5.2. Previous Environmental Documentation

In September 2000, a Draft Environmental Impact Report (EIR) was prepared for the EID Headquarters Master Plan Project and a Final EIR was prepared in Decmebr 2000. The EIR addressed environemntal impacts associated with the development of the Headquarters

Building. Subsequent to the preparation of the Final EIR, two addenda were issued to address changes to the original project description. It is possible that the installation of solar panels in the parking areas at the Headquarters Building could be prepared as an addendum to the Master Plan EIR.

6.5.3. Environmental Checklist and Analysis

Appendix A outlines and describes the environmental issues considered as part of this analysis. The Appendix begins with an analysis of areas of critical concern, followed by a discussion of significant effects due to unusual circumstances and other environmental issues. The websites and documents reviewed as part of the analysis are cited for reader's reference.

6.5.4. Summary Results

Based on the environmental review checklist in Appendix A, there are no known environmental constraints associated with the installation of solar panels at the employee parking areas adjacent to the EID Headquarters Building. The panels would be located in a previously developed parking lot in an area that is behind the building and not readily visible from the nearby access road (Mosquito Road). The installation of the panels would not result in a significant change to the character and setting of the area. Based on this analysis and a discussion with EID Environmental Review Specialist, Chris Word, the environmental constraints associated with this alternative location may meet the requirements for an Addendum to the EID Headquarters Master Plan Final EIR (2000) or a CEQA categorical exemption Class 1 15301(2)(b) – Existing Facility (Minor Alteration). An addendum would not require public circulation.

Figure 22. EID Headquarters Building and parking area

Figure 23. Example of solar panels above parking area near Marshall Medical in Cameron Park

7.0 Economic Feasibility Analysis

7.1. Introduction

In order to determine the feasibility of solar opportunities at each site the different economic programs were considered for each site opportunity along with environmental impacts and capital costs. An evaluation and recommendation for each site is presented below.

The following is based on EID owning and operating a solar project independently to either offset their existing electrical uses or to sell back to PG&E. Additionally, an agreement with private investors could be pursued by EID in the future to reduce initial costs, reduce risks and take advantage of tax incentive programs that EID is not eligible for. The details of such an agreement would need to be worked out between EID and the investor. This analysis does not speculate on the terms of such an agreement.

7.1.1. Operation and Maintenance costs

PV systems are extremely durable; having no moving parts and tend to degrade slowly over their 30-year lifespan. Maintenance consists of cleaning the modules at least once a year to prevent dirt, dust, and salt buildup. Inverters necessary to convert the direct current produced by the panels to alternating-current used by the plant require more maintenance that the panels themselves and need to be replaced every 10-15 years although larger inverters (> 50 kW) may be "rebuilt". It is estimated that the annual maintenance costs for systems up to 1MW will be approximately $20,000 and systems 1-2MW will be $30,000 and over 2MW will be $50,000. This estimate includes cleaning, preventative maintenance, unscheduled maintenance, insurance, and rebuilding/replacing the inverter once in the 30-year life.

7.2. Criteria for Evaluation

In order to evaluate the feasibility of each potential project the criteria for evaluation must be established. Based on criteria used previously by EID projects are evaluated and ranked on the following criteria:

- Net Present Value (NPV) of the project
- Payback period for the project (must be less than 20-years)

Potential projects at each site were evaluated using the criteria and then ranked. In order to provide equal comparison each project was evaluated using a 30-year loan period with a 6% interest rate. The following sections describe the programs used to determine the potential annual return for each project which will be used to determine the NPV and payback periods in a separate section.

The projects will be ranked by this criteria and then the most feasible projects will be identified.

7.3. Site Evaluation Data

7.3.1. Bass Lake

The programs that could be applied at the Bass Lake Facilities include:

- California Solar Initiative (CSI)
- PG&E's Net Metering Program (NMP)
- PG&E's Feed-In Tariff (FIT)

If the 750kW system is selected to offset the usage of the Recycled Water Pump Station EID could utilize the CSI and NMP Programs. The capital cost of the system would be significantly reduced by the CSI Program. As mentioned previously the CSI program will pay $0.26/kWh for the first five years. For the 750kW system that equals approximately $308,100/year and $1,540,500 over five years.

To determine the annual return of offset costs for the system it is assumed that EID would utilize the A6 rate schedule of:

Total Energy Rates ($ per kWh)	
Peak Summer	$0.45853
Part-Peak Summer	$0.20294
Off-Peak Summer	$0.11828
Part-Peak Winter	$0.16767
Off-Peak Winter	$0.12231

For ease of calculation a rate of $0.45853/kWh was used for the peak production (assumed to be 40% of the total potential production) and $0.12/kWh was used for the remainder of the production (60% of the total potential production. This yields an annual potential cost savings of approximately $302,663.

To determine the feasibility the annual payment for a 30-year loan at 6% interest was determined. For the 750kW project the annual payment would be $359,476/year.

The other ground mounting and floating arrays would utilize the FIT program to feed electricity back into the system. The FIT program rates are $0.09674/kWh for off-peak times and $0.19735/kWh for peak times (other TOD factors were neglected for this analysis). For a 1MW system this yields an annual return of $216,435 (assuming 40% production during peak times and 60% during off-peak). This yields a payback period of well over 30years for these projects (see table below).

Unfortunately, these systems do not meet the requirements of the CSI program and the large capital costs cannot be offset which makes these projects less feasible.

Table 8. Capital Cost and Estimated power generation for potential projects

Type of System	Total Estimated Capital Cost (1)	Potential Power Generation (2)	App. Programs	Potential Annual Return	Annual Debt Service (based on 6% interest)	O&M Costs
Ground Mounted (near Recycled Water PS)	$4.875 Million	1,031,250 kW	CSI NMP	$263,400 with an additional $268,125/yr for	$359,476	$20,000

750kW				the first 5 years		
Ground Mounted on north side of Lake (>2MW)	$12 Million	2,750,000 kW	FIT	$432,869	$884,864	$50,000
Floating Arrays (1-2MW)	$8-16 Million	1,375,000 kW - 2,750,000 kW	FIT	$216,435 - $432,869	$589,909 - $1,179,818	$50,000

Note: (1) Capital Costs assume that the site work will be completed by an outside contractor as part of the overall project

(2) Potential power generation is based on a 1MW system producing approximately 1.580 MWh annually

7.3.2. Deer Creek Wastewater Treatment Plant (DCWWTP)

The programs that could be applied at the DCWWTP Facilities include:

- PG&E's Feed-In Tariff (FIT)

The ground mounting systems would utilize the FIT program to feed electricity back into the system. The FIT program rates are $0.09674/kWh for off-peak times and $0.19735/kWh for peak times (other TOD factors were neglected for this analysis). For a 1MW system this yields an annual return of $216,435 (assuming 40% production during peak times and 60% during off-peak). This yields a payback period of well over 30 years for these projects.

Unfortunately, these systems do not meet the requirements of the CSI program and the large capital costs cannot be offset which makes these projects less feasible.

Table 9. Capital Cost and Estimated power generation for potential projects

Type of System	Total Estimated Capital Cost (1)	Potential Power Generation (2)	Applicable Programs	Potential Annual Return	Annual Debt Service (based on 6% interest)	O&M Costs
Ground Mounted (on sloped area up to 1 MW)	$8 Million	1,185,000 kW	FIT	$216,435	$589,909	$50,000
Ground Mounted (on sloped area up to 6 MW)	$36 Million	9,480,000 kW	FIT	$1,298,610	$2,654,591	$50,000

Note: (1) Capital Costs assume that the site work will be completed by an outside contractor as part of the overall project

(2) Potential power generation is based on a 1MW system producing approximately 1.580 MWh annually

7.3.3. El Dorado Hills Wastewater Treatment Plant (EDHWWTP)

The programs that could be applied at the EDHWWTP include:

- California Solar Initiative (CSI)
- PG&E's Net Metering Program (NMP)

It is recommended to utilize the energy created on site for the added load anticipated for the treatment plant expansion and utilize the CSI and NMP Programs. The capital cost of the system would be significantly reduced by the CSI Program. As mentioned previously the CSI program will pay $0.26/kWh for the first five years. For the 1MW system that equals approximately $410,800/year and $2,054,000 over five years.

To determine the annual return of offset costs for the system it is assumed that EID would utilize the A6 rate schedule of:

Total Energy Rates ($ per kWh)	
Peak Summer	$0.45853
Part-Peak Summer	$0.20294
Off-Peak Summer	$0.11828
Part-Peak Winter	$0.16767
Off-Peak Winter	$0.12231

For ease of calculation a rate of $0.45853/kWh was used for the peak production (assumed to be 40% of the total potential production) and $0.12/kWh was used for the remainder of the production (60% of the total potential production. This yields an annual potential cost savings of approximately $403,550.

To determine the feasibility the annual payment for a 30-year loan at 6% interest was determined. For the 1MW ($7million) project the annual payment would be $516,171/year.

Table 10. Capital Cost and Estimated power generation for potential projects

Type of System	Total Estimated Capital Cost (1)	Potential Power Generation (2)	Applicable Programs	Potential Annual Return	Annual Debt Service (based on 6% interest)	O&M Costs
Ground Mounted (1-2MW)	$7-14 Million	1,580,000 kW – 3,160,000 kW	CSI NMP	$403,550 with an additional $357,500/yr for the first 5 years for a 1MW system. If the new load is determined to be greater a larger system could be utilized	$516,171 - $1,032,342	$30,000
Floating Arrays (1MW)	$8 Million	1,580,000 kW	CSI NMP	Same as above	$589,909	$30,000

Note: (1) Capital Costs assume that the site work will be completed by an outside contractor as part of the overall project

(2) Potential power generation is based on a 1MW system producing approximately 1.580 MWh annually

7.3.4. EID Headquarters

The programs that could be applied at the Bass Lake Facilities include:

- California Solar Initiative (CSI)
- PG&E's Net Metering Program (NMP)

It is recommended to utilize the energy created on site to offset the usage at the EID Headquarters and utilize the CSI and NMP Programs. The capital cost of the system would be significantly reduced by the CSI Program. As mentioned previously the CSI program will pay $0.26/kWh for the first five years. For the 0.25MW system that equals approximately $102,700/year and $513,500 over five years.

To determine the annual return of offset costs for the system it is assumed that EID would utilize the A6 rate schedule of:

Total Energy Rates ($ per kWh)	
Peak Summer	$0.45853
Part-Peak Summer	$0.20294
Off-Peak Summer	$0.11828
Part-Peak Winter	$0.16767
Off-Peak Winter	$0.12231

For ease of calculation a rate of $0.45853/kWh was used for the peak production (assumed to be 40% of the total potential production) and $0.12/kWh was used for the remainder of the production (60% of the total potential production. This yields an annual potential cost savings of approximately $100,888.

To determine the feasibility the annual payment for a 30-year loan at 6% interest was determined. For the 0.25MW project the annual payment would be $165,912/year.

Table 11. Capital Cost and Estimated power generation for potential projects

Type of System	Total Estimated Capital Cost (1)	Potential Power Generation (2)	Applicable Programs	Potential Annual Return	Annual Debt Service (based on 6% interest)	O&M Costs
Roof Mounted/Parking Structure Units (250kW)	$2.25 Million	395,000 kW	CSI NMP	$100,888 with an additional $102,700/yr for the first 5 years	$165,912	$5,000

Note: (1) Capital Costs assume that the site work will be completed by an outside contractor as part of the overall project

(2) Potential power generation is based on a 1MW system producing approximately 1.580 MWh annually

7.4. Project Ranking and Recommendations

In order to rank the projects the NPV was determined using the data summarized in the sections above. All NPVs were determined to be negative based on the annual debt service exceeding the potential annual return from the projects. Additionally, it was determined that the payback period for each project exceeds the project feasibility criteria of 20-years (all are well over 30-years) and therefore this criterion was not used in the project rankings.

Table 12 below shows the proposed rankings of the projects based on their NPVs.

Table 12. Proposed Ranking of Projects based on NPV

Ranking	Project	NPV
1	EDHWWTP Ground 1MW	-$352,227
2	Bass lake Ground 750 kw	-$395,200
3	EID Headquarters 250kw	-$497,508
4	EDHWWTP Float 1MW	-$1,352,227
5	EDHWWTP Ground 2MW	-$3,303,350
6	Bass lake Float 1MW	-$5,709,050
7	DCWWTP 1MW	-$5,709,101
8	Bass lake Ground 2MW	-$6,729,873
9	Bass lake Float 2MW	-$10,729,873
10	DCWWTP 6MW	-$18,813,094

7.4.1. Bass Lake Recommendations

For the Bass Lake site it is recommended to pursue the 750kW solar system to offset the usage at the Recycled Water Pump Station. The other systems are less feasible and would require additional environmental analysis. The 750kW system could qualify for a Mitigated Negative Declaration (MND). The larger projects are cost prohibitive and would require EID to find a grant program or perform some of the work in house to reduce the capital costs of the project. While the cost of a floating array system has been reduced significantly due to new technologies the rate of return and the environmental issues make this a less feasible alternative. As previously mentioned the District would need to pursue a low interest loan program or offset the capital costs with a grant in order to make the project feasible.

7.4.2. DCWWTP Recommendations

It is not recommended to pursue any potential projects at the DCWWTP due to the poor economics of the project and the additional environmental studies that would need to be performed.

7.4.3. EDWWTP Recommendations

It is recommended that EID pursue additional solar power generation at the EDHWWTP site to offset future demands anticipated due to the expansion of the system. Having an existing system on site will make it easier to expand under the environmental process. Because both the ground mounted and floating array systems have similar payback periods either one could be pursued. As previously mentioned the District would need to pursue a low interest loan program or offset the capital costs with a grant in order to make the project feasible.

7.4.4. EID Headquarters Recommendations

It is recommended that EID pursue solar power generation at the EID Headquarters to offset existing demands. The environmental impact of the roof mounted and parking structure arrays is minimal. This would also be an opportunity for an educational information display on-site to help promote renewable energies in El Dorado County. As previously mentioned the District would need to pursue a low interest loan program or offset the capital costs with a grant in order to make the project feasible.

7.4.5. Other Benefits

It is also important to note that there are benefits to construction of a solar project other then economical. These include:

- Solar energy is renewable
- Solar energy is environmental friendly
- Increase in power self-sufficiency

While the projects may not be economically feasible these additional benefits and EID's commitment to renewable energies make them worth pursuing.

8.0 Findings and Conclusions

From the analysis performed above it can be seen that none of the projects identified and evaluated for this project are economically feasible based on typical financing available to water agencies. Two major factors were identified that make solar projects, developed and financed through water agencies, similar to these not feasible. These factors are; 1) high initial capital costs and 2) high financing costs. While the capital costs of solar technologies have been reduced in recent years the capital costs are still high (especially when the costs must be financed) and exceed the potential return on the investment causing the NPVs of the projects to be negative.

In order to identify potential programs and assistance that could help make the solar projects more feasible the following cost reduction factors were quantified for the three top ranked projects:

1. The capital cost reduction necessary (through grants or other incentives) for a payback period of 20-years at a 6% interest rate.

2. The interest rate necessary for a payback period of 20-years if the capital costs were not reduced.

Table 13 below summarizes the results.

Table 13. Cost reduction or interest rate requirements for a 20-year payback period

Ranking	Project	Capital Cost	Reduced Cost Required (at 6% interest rate)	% Cost Reduction Required	Interest Rate Required (with no cost reduction)
1	EDHWWTP Ground 1MW	$7,000,000	$5,790,509	17%	3%
2	Bass lake Ground 750KW	$4,875,000	$3,921,219	20%	3%
3	EID Headquarters 250KW	$2,250,000	$1,532,438	32%	1%

8.1.1. Conclusions

Based on the above it can be seen that in order to make these project feasible either a large reduction in capital costs (20-50%) or a reduction in financing interest rate to 1-3% are necessary. This would require additional grant funding programs or low interest rate financing programs.

As previously stated in this report the existing solar array facility located and operated by EID at their EDHWWTP was financed using a grant program from PG&E that offset the initial capital costs by 50%.

It is the conclusion and recommendation of project team that the California Energy Commission (CEC) and other government agencies interested in promoting solar energy consider the following:

1. Implement additional grant programs to offset capital costs
2. Implement a low interest loan program to offset financing costs

A low interest loan program could be modeled after the State Revolving Fund (SRF) program used by the California Department of Public Health (CDPH) to fund water and wastewater projects. This program has successfully been run through the State of California. Grant programs could be modeled after programs currently run by PG&E.

El Dorado County Water Systems

TM#8 – Task 2.8 Identify Near, Mid-Term and Long-Term Energy Efficiency and Generation Opportunities

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1.0 Introduction

The purpose of this technical memorandum is to identify opportunities throughout El Dorado County and adjacent areas for near, mid-term and long-term energy efficiency and generation opportunities. Each of the following El Dorado County water purveyors was contacted to determine the opportunities within their District:

- El Dorado Irrigation District (EID)
- Grizzly Flats Community Services District (GFCSD)
- South Tahoe Public Utility District (STPUD)
- Georgetown Divide Public Utility District (GDPUD)
- Tahoe City Public Utility District (TCPUD)
- City of Placerville (provides water and sewer distribution service)
- Heavenly Ski Resort

A survey form was sent to each of the agencies. The form provided a format for describing potential energy generation and efficiency projects. Each District was asked to provide as much information as available on potential projects. Additionally, survey forms were distributed to other water purveyors outside of El Dorado County that have systems and challenges similar to El Dorado County. These included:

- City of Folsom
- Amador Water Agency
- Tuolumne Utilities District

Although responses were not received from the majority of agencies contacted, phone and email contact did yield limited results. The following describes the energy generation opportunities that were identified from this effort. Facilities were visited when possible.

Additionally, other reports, studies and quotes provided to the agencies were utilized to identify potential opportunities.

2.0 El Dorado County Overview

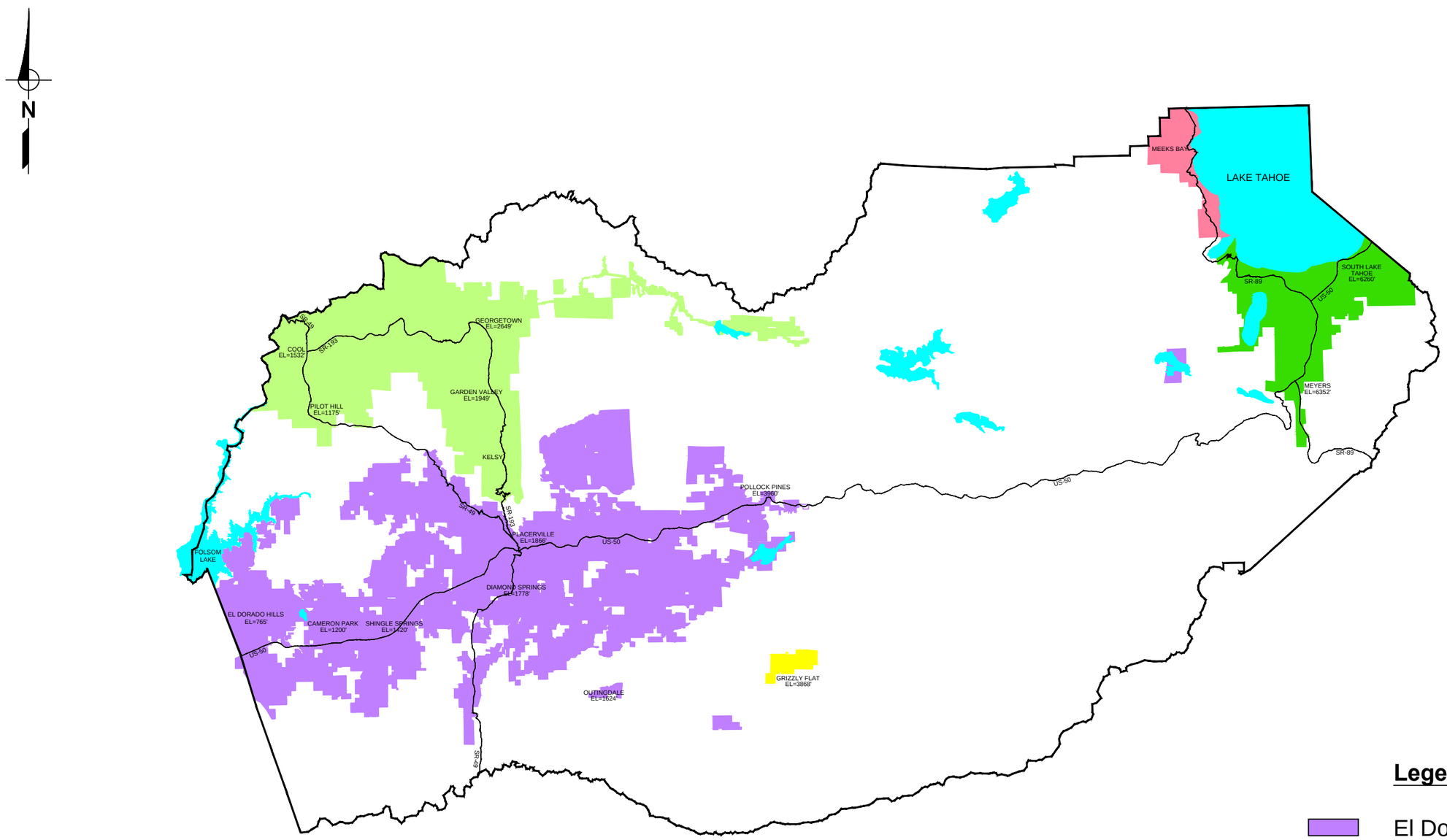
El Dorado County is located in east-central California and encompasses approximately 1,805 square miles of rolling hills and mountainous terrain. The County's western boundary contains part of Folsom Lake, and the eastern boundary is also the California-Nevada State line. The County is topographically divided into two zones. The northeast corner of the County is in the Lake Tahoe basin, while the remainder of the County is in the "western slope," the area west of Echo Summit.

El Dorado County has twelve water purveyors which include a number of smaller water systems in the Tahoe basin and the City of the Placerville which distributes water provided by EID. The smaller systems in the Tahoe basin were not contacted for renewable opportunities. The focus of this TM is on the five largest water purveyors in El Dorado County which include:

1. El Dorado Irrigation District (EID)
2. Grizzly Flats Community Services District (GFCSD)
3. South Tahoe Public Utility District (STPUD)
4. Georgetown Divide Public Utility District (GDPUD)
5. Tahoe City Public Utility District (TCPUD)

Figure xx shows the service areas of each of these Districts. The water supply for the western slope areas mainly consists of surface water from the watersheds of the Sierra Nevada mountain range. The Tahoe Basin purveyors obtain most of their supplies from groundwater. The Sierra Nevada snowpack serves as natural storage for much of the region's annual precipitation. The surface water is stored in a system of reservoirs that are utilized for both water storage and recreational use. The water distribution system consists of water storage tanks (treated water), pipelines, and pump stations. A majority of the area is served by gravity with the use of multiple pressure reducing stations in order to mitigate for the large variation in elevation throughout the region.

The large variations in elevation provide significant opportunities for hydroelectric generation throughout the County. The western slope area is mainly served by Pacific Gas and Electric (PG&E), which also operates several of the existing hydroelectric projects in the area along with the Sacramento Municipal Utility District (SMUD). The Tahoe Basin electric service provider is Liberty Utilities.



EL DORADO COUNTY WATER AGENCIES
FIGURE 1

0 3 6
SCALE: 1" = 6 MILES

Legend

- El Dorado Irrigation District
- Georgetown Divide PUD
- Grizzly Flats CSD
- South Tahoe PUD
- Tahoe City PUD

3.0 Types of Renewable Energy Generation Considered

There are multiple types of energy generation which may be applicable in the El Dorado County Region. They include:

- Hydroelectric
- Solar
- Wind
- Biomass
- Biogas

3.1. Hydroelectric

Out of all of the renewable energy sources utilized in the United States, hydroelectric power plays the most vital role. Roughly 96 percent of the renewable energy used in the United States is created through hydroelectric facilities. Hydroelectric power is a renewable resource because it is does not pollute the environment and the water that is used to generate energy is not consumed by the process. Hydroelectric power is created when water driven by gravity passes through a propeller-like turbine, which turns a shaft in a generator to create electricity. The process essentially converts the kinetic energy in the water into mechanical energy, and then converts the mechanical energy into electricity.

Hydroelectric facilities come in many forms, can be located on rivers, streams and canals, and can be closed-loop or open-loop. Closed-loop systems are made of two reservoirs that are separate from free flowing sources of water. Open-loop systems use a free flowing source of water to operate. Open-loop systems are the most commonly used type of facility throughout the United States, and typically appear in the form of dams. In addition to providing electricity, dams provide other benefits including flood control, water storage, and recreation opportunities. However, dams can disrupt stream flows, reservoir surface area, amount of groundwater recharge, and water quality. Dams can impact the natural habitat by displacing terrestrial organisms and altering fish migration patterns. Dams may also increase the potential for landslides and erosion.

Modular pumped storage facilities are an example of a closed-loop system. Pumped storage facilities can be filled with different types of water, from groundwater to municipal wastewater. They reuse the same water by pumping the water back up through the turbines after it has flowed through, which prepares it to be released again. Though more energy is used to pump the water back up to the higher elevation than is generated when the water flows through by gravity, the system can still be economically efficient by using energy during off-hours and generating energy during peak hours. In addition, pumped storage facilities are stable because they do not rely on varying rainfall. They are also feasible because the artificially created systems can be placed outside of environmentally sensitive areas, alleviating permitting issues.

Hydro-electric opportunities in El Dorado County consist of small hydroelectric, in-conduit hydroelectric, and pumped storage. A brief description of each type of hydroelectric is provided below.

3.1.1. Small and Large Hydroelectric

Due to the large variations in elevation throughout the County hydroelectric generation, both small and large, continue to provide the greatest potential for renewable energy generation in the area. Small hydroelectric projects are considered those that produce less than 30MW of power. The majority of the potential projects identified are considered small hydroelectric facilities, however there are a number of larger projects that should be considered long term. While larger projects have a greater return on investment for power they also have greater costs and permitting issues that must be considered.

3.1.2. In-Conduit Hydroelectric

The water distribution system in the County operates mainly by gravity. The large variations in elevation result in significant pressure which must be mitigated by the use of pressure reducing stations. This results in a loss of energy that could otherwise be utilized. In-Conduit Hydroelectric projects are in concert with the pressure reducing valve with a turbine that converts the pressure loss into power. The power can be utilized at a nearby site or sent back to the grid depending on the area.

3.1.3. Pumped Storage

Pumped storage utilizes excess storage capacity to deliver water via gravity through a turbine to generate power during peak energy demand periods and then pumping water back up for storage during off-peak hours when energy demand is lower. Pumped storage requires significant storage facilities that can meet water demands during peak hours when energy demand is also at its peak.

3.2. Biomass Energy Production

Biomass electrical energy generated in California is considered renewable energy. Biomass is generated from a variety of sources including Forest maintenance operations, municipal waste and agricultural waste. The greatest potential for biomass energy production in El Dorado County consists of Forest maintenance waste and municipal waste. However, biomass energy facilities are not currently located within El Dorado County. They are located in the nearby cities of Lincoln, Rocklin and Woodland. These biomass energy production facilities are located at distances that make utilization of biomass from forested areas economically infeasible. Opportunities do exist for investment in biomass transportation infrastructure and research and development for small-scale biomass utilization facilities which are currently not feasible. Biomass facilities can have a significant environmental effect and the process to approve and construct a new facility is expensive and time consuming. While no facilities are planned in the County a 2MW biomass facility is planned and in active development in Placer County (Cabin Creek). Once this facility is completed it will be within 60 miles of El Dorado County facilities

which may make the use of biomass energy more feasible. The County should continue to consider this energy source in the future.

3.3. Solar

Solar radiation can be captured in multiple ways. The two (2) main groups of technology are solar thermal and solar photovoltaic (PV). Solar thermal systems produce electric power by converting the sun's energy into high temperature heat. Solar PV systems use cells that are arranged and connected into a module/panel that collects and absorbs the radiant sun's energy in a form of direct current electricity. PV systems can be scaled to almost any size, have minimal maintenance requirements, and can be integrated into an existing municipal facility.

Multiple types of PV mounting systems were considered in the evaluation including ground mounted, roof mounted, parking structure arrays and floating arrays.

3.4. Biogas

When waste is naturally decomposed, it releases gases, termed "biogas," that can be used as a clean, renewable source of energy. Biogas results from a biological process called anaerobic fermentation, in which organic matter is decomposed without the use of oxygen. The biogas that is produced is mainly comprised of two gases: methane (CH_4) and carbon dioxide (CO_2). Both of these constituents are considered greenhouse gases due to the negative impacts they have on the environment when released into the atmosphere. However, if the biogas is captured and then burned in a controlled way to produce electricity, it is in fact an effective source of clean energy. The reason that burning greenhouse gases can have a positive effect on the environment is that instead of allowing the gases to be released into the atmosphere, they are used up to produce energy.

Biogas is considered to be a renewable source of energy because it is continually available from human and animal waste and it does not require oxygen to be produced, thereby conserving resources. The three main types of facilities typically having excess biogas are waste landfills, concentrated animal feeding operations (CAFO's), and sewage treatment plants. Generally, the most cost-effective site to harness biogas is at large dairy or swine plants.

The main advantages of biogas fuel are that it is a clean, renewable source of energy and it reduces waste and converts it into a useful product. On the other hand, there are a number of disadvantages of biogas fuel that have limited its growth. Utilizing biogas can be a dangerous process because it is unstable and prone to explosions if it comes in contact with oxygen. It also contains impurities, even after it has been refined, which can be corrosive to metal parts in engines. The main drawback of biogas production is its economic limitations. It is not widely used throughout the United States because technology has not advanced enough to make biogas production an efficient and profitable system. Also, the process works better in warmer climates, such as tropical regions.

El Dorado County does have some use of biogas at the Union Mine Disposal site to power their wastewater treatment plant and some limited use at the El Dorado Hills Wastewater Treatment

Plant to power some minor equipment. However, the use of bio-gas on a larger scale is not feasible. The use should be considered at wastewater treatment facilities where it can offset the operation costs of equipment.

3.5. Wind

Wind is the natural result of the sun's uneven heating of the earth, the irregularities of the earth's surface, and the earth's rotation. As these processes occur, it is possible to harness the wind by use of a turbine to produce electricity. The turbine operates by using the wind's kinetic energy to generate mechanical power through a rotating shaft, then converting the mechanical power into electricity through a generator. The two types of wind turbines used today are vertical-axis design, which can have two or three blades, and horizontal-axis, which has three blades.

Wind is a clean and renewable source of energy because it does not require the use of fossil fuels or other valuable resources to produce it and there is no resulting pollution because it does not generate any pollutant emissions or harmful greenhouse gases. Once the wind turbines have been put into operation, the process requires little operation and maintenance.

Despite the growing popularity of wind energy, there are a few drawbacks. There has been some resistance from residents living near potential wind farms due to concerns of noise and appearance. Also, wind turbines can pose a threat to wildlife by killing birds and bats that may fly into the rotating propellers. Another issue is that the electricity is produced intermittently, as the wind patterns cannot be controlled or adjusted.

Not every location is suitable for a wind turbine system. In order to effectively produce energy, the turbines should have a wind speed of about 10 miles per hour or more. The most suitable areas for wind energy in the United States are in the nation's central region and along the coastline. In El Dorado County, the average wind speed is between 6 and 8 miles per hour which is considered low for this application. Also, the best terrain for a wind energy system would be an elevated flat site. The elevations in El Dorado County are highly varied, so a flat site might not be available, even if the elevation was high enough. Wind has been considered as an option for South Tahoe Public Utility District, which owns and operates a ranch in Alpine County that more closely meets these criteria. Otherwise no opportunities were identified within El Dorado County.

4.0 Renewable Opportunities by Water Purveyor

The following provides an overview of each water purveyor contacted as part of the survey process and renewable energy opportunities identified. The opportunities identified are for near-term, mid-term and long-term. If a response was not received by an agency an overview is provided along with recommendations for future study. It should be noted that the following provides estimates based on limited data available. These estimates are expected to change based on final site locations, permitting requirements and equipment selection.

4.1. El Dorado Irrigation District

4.1.1. Overview

El Dorado Irrigation District (EID) is the largest water purveyor in El Dorado County. EID serves more than 100,000 customers, and its service area encompasses approximately 220 square miles on the western slope of the Sierra Nevada mountains. Elevations in the service area range from 500 to more than 4,000 feet. EID's delivery infrastructure for water include approximately 1,200 miles of pipeline, 27 miles of ditches, 5 treatment plants, 36 storage reservoirs and 37 pumping stations.

EID's main potential for renewable energy systems include hydroelectric and solar. Other energy savings opportunities explored for EID include demand management and reoperation of pump stations for improved efficiency. These opportunities have been analyzed in more detail in TMs 6 and 7. EID is currently in the process of final design and permitting for the Pleasant oak Main PRS 5 (Tank 7) project. The project is expected to go to construction in late 2014.

Project Name	Type of Renewable	Term (Near, mid or long)	Capacity	Potential Generation
Sly Park Dam	RPS-Qualified Hydro	Near	400kW	1,833 MWh/year
Sly Park Dam Fish Release	RPS-Qualified Hydro	Near	44kW	343 MWh/year
Sly Park Narrows Dam (add'l reservoir storage not estimated)	RPS-Qualified Hydro	Long	576kW	4,037 MWh/year
Weber Dam Re-Op	RPS-Qualified Hydro	Long	204kW	581 MWh/year
Weber Dam Re-Op w/ Flashboards	RPS-Qualified Hydro	Long	216kW	615 MWh/year
Caples Lake - Kirkwood Meadows PUD	RPS-Qualified Hydro	Long	280kW	1,000 MWh/year
Silver Lake Dam	RPS-Qualified Hydro	Long	29kW	76 MWh/year
Echo Lake Dam	RPS-Qualified Hydro	Long	144kW	505 MWh/year
El Dorado Main 1-PRS 12 (at airport)	RPS-Qualified Hydro	Mid	25kW	220 MWh/year

El Dorado Main 1-PRS 13 at Reservoir 6 (Tank 6 inlet)	RPS-Qualified Hydro	Mid	110kW	590 MWh/year
El Dorado Main 2 PRS 1 (Tank 3)	RPS-Qualified Hydro	Near	360kW	1,739 MWh/year
El Dorado Main 2 - PRS 4 (Whispering Pines)	RPS-Qualified Hydro	Near	90kW	472 MWh/year
El Dorado Main PRS 3	RPS-Qualified Hydro	Mid	195kW	892 MWh/year
Diamond Springs Main PRS I (Res 8)	RPS-Qualified Hydro	Mid	140kW	690 MWh/year
Pleasant Oak Main at Res B (2 stations)	RPS-Qualified Hydro	Mid	450kW	2,657 MWh/year
Pleasant Oak Main PRS 2 at Res C	RPS-Qualified Hydro	Near	174kW	914 MWh/year
Pleasant Oak Main PRS 3	RPS-Qualified Hydro	Mid	140kW	620 MWh/year
Pleasant Oak Main PRS 4	RPS-Qualified Hydro	Long	91kW	477 MWh/year
Pleasant Oak Main PRS 5 (Tank 7)	RPS-Qualified Hydro	Mid	420kW	1,765 MWh/year
Deer Creek WWTP Outflow	RPS-Qualified Hydro	Long	3kW	26 MWh/year
Oak Ridge Tanks to Bass Lake Tanks Pumped Storage	RPS-Qualified Hydro	Mid	280kW	874 MWh/year
PRS into Bass Lake Tanks Sta. 6.5 (1477')	RPS-Qualified Hydro	Mid	72kW	567 MWh/year
EDHWWTP Ground	Solar	Mid	1MW	1,580 MWh/year
Bass Lake Ground	Solar	Mid	750kW	1,185 MWh/year
EID Headquarters	Solar	Mid	250kW	395 MWh/year

EDHWWTP Float	Solar	Mid	1MW	1,580 MWh/year
EDHWWTP Ground	Solar	Mid	2MW	3,160 MWh/year
Bass Lake Float	Solar	Long	1MW	1,580 MWh/year
DCWWTP (Smaller project)	Solar	Long	1MW	1,580 MWh/year
Bass Lake Ground	Solar	Long	2MW	3,160 MWh/year
Bass Lake Floating Arrays	Solar	Long	2MW	3,160 MWh/year
DCWWTP (Larger project)	Solar	Long	6MW	9,480 MWh/year

4.1.2. Increased Efficiency Potential

As previously discussed in TM#5 multiple pump stations have been identified in EID's system that have the potential to increase efficiency through pump replacement, changes to the system configuration and providing a closer match between the pump and the system curve. The following pump stations were recommended for upgrades or changes:

- Moosehall
- Reservoir 8
- Dolomite
- Outingdale RW
- Strawberry RW
- Oro Loma
- Log Cabin
- Sportsman
- Ridgeview
- Reservoir A

One of the key recommendations following TM#5 is the need to more accurately identify system curve information through the use of flow meters and pressure gages. Additional analysis was performed on the Oro Loma Pump Station where data was available from EID's Hydraulic model to allow for development of a system curve. The additional analysis is provided in TM #9.

4.2. Georgetown Divide Public Utility District

4.2.1. Overview

The Georgetown Divide Public Utility District (GDPUD) serves the communities located in northwestern El Dorado County among the foothills of the Sierra Nevada Mountain Range, situated in the heart of the Mother Lode. Its service area encompasses approximately 72,000 acres and includes irrigation and domestic water supplies along with on-site wastewater disposal. GDPUD serves approximately 15,000 people, and its system is mainly served by gravity flow with the use of multiple storage facilities.

4.2.2. Renewable Energy Projects Identified

The renewable projects identified for GDPUD include both hydroelectric and solar.

Project Name	Type of Renewable	Term (Near, mid or long)	Capacity	Potential Generation
GDPUD Sandtrap Siphon	RPS-Qualified Hydro	Near-term	180 kW	1,130 MWh/year
GDPUD Kaiser Siphon	RPS-Qualified Hydro	Long-term	580 kW	3,638 MWh/year
GDPUD Buffalo Siphon	RPS-Qualified Hydro	Mid-term	180 kW	860 MWh/year
GDPUD Stumpy Meadows Dam	RPS-Qualified Hydro	Long-term	485 kW	2,000 MWh/year
GDPUD Office site solar	Solar	Long-term	500 kW	800 MWh
Walton WTP Solar	Solar	Long-Term	1MW	1,600 MWh
Auburn Lake Trails WTP Solar	Solar	Mid-term	1MW	1,600 MWh

4.3. South Tahoe Public Utility District

4.3.1. Overview

The South Tahoe Public Utility District (STPUD), a public agency established in 1950, supplies drinking water and provides sewage collection, treatment, and export to protect Tahoe's delicate ecosystem.

STPUD serves portions of El Dorado County within the Tahoe Basin, and its service area extends from Hwy. 89 north to Cascade Lake; Hwy 89 south to Luther Pass; Hwy. 50 East to Nevada state line; and, Hwy. 50 West to Echo Lake. STPUD has over 14,000 residential water

connections, 660 commercial and government sites, and 16 active wells. Additionally STPUD has a recycled water export system which transports an average of 4.5 MGD of recycled water 27 miles to the Harvey Place Reservoir in eastern Alpine County where it is stored for agricultural use.

The projects identified below will be analyzed in more detail under a future PIER Grant project currently underway titled, "Renewable Energy Regional Exploration Study: PIR-12-502". It is expected that many of the numbers provided below will change as part of that study.

4.3.2. Renewable Energy Projects Identified

Project Name	Type of Renewable	Term (Near, mid or long)	Capacity	Potential Generation
STPUD C-Line Upper Project	RPS-Qualified Hydro	Mid-term	1.0 MW	8,000 MWh/year
STPUD C-Line Upper Project with Energy Storage Sub-Option	RPS-Qualified Hydro	Mid-term	1.5 MW	8,000 MWh/year
STPUD C-Line Lower Project	RPS-Qualified Hydro	Long-term	1.5 MW	13,000 MWh/year
STPUD C-Line Lower Project with Energy Storage Sub-Option	RPS-Qualified Hydro	Long-term	2.0 MW	13,000 MWh/year
STPUD B-Line Load Shifting Project	Energy Efficiency	Long-term	N/A (Load Shifting)	
STPUD Micro-Hydro Units on Existing PRVs	RPS-Qualified Hydro	Mid-term	5 to 25 kW	20 to 100 MWh/year*
STPUD Small Hydro Project at Diamond Valley Ranch	RPS-Qualified Hydro	Mid-term	55 kW	450 MWh/year
STPUD Solar Project at Diamond Valley Ranch (up to hundreds of acres)	Solar	Near-term	10 MW+	16,000+ MWh/year
STPUD Wind Generation Project at Diamond Valley Ranch (up to hundreds of	Wind	Long-term	TBD	TBD

acres)				
Angora Ridge Pumped Storage Project	Pumped Storage	Mid-term	N/A (Grid Balancing)	

4.4. Grizzly Flats Community Services District

4.4.1. Overview

The Grizzly Flats Community Services District (GFCSD) water system serves approximately 1,228 parcels. GFCSD has about 600 residential customers. Elevations of the service area vary from 3,600 feet at the southwesterly end of the area to 4,200 feet at the northeasterly end.

District Facilities:

- Primary water production from diversions of North Canyon Creek & Big Canyon Creek
- 31Ac-Ft HDPE lined raw water reservoir
- 2 Water Treatment Plants
- 2 Filter Units
- 4 Storage Tanks
- Distribution system is mainly by gravity, pumping is required in limited areas
- 150 Fire Hydrants

4.4.2. Renewable Energy Projects Identified

The survey response from GFCSD indicated that the greatest potential for renewable energy in their system includes the use of solar power at their water treatment plant facility.

Hydroelectric options for GFCSD were previously explored as part of the El Dorado County Hydro Development Options Study. The projects identified were dependent on portions of the facility being constructed as part of another project in order to reduce the capital costs. To date these projects have not been scheduled. The projects are considered long term and should be reconsidered as other improvements move forward. GFCSD is mainly fed by gravity and does not require the use of pressure reducing stations. Due to the size of GFCSD and the relatively low elevation drop from tanks to the system in-conduit hydro projects are not feasible.

Project Name	Type of Renewable	Term (Near, mid or long)	Capacity	Potential Generation
Water Treatment Plant Solar	Solar	Near	22kW	34,760kWh
Spring Flat Reservoir (400 ac-ft)	RPS-Qualified Hydro	Long	NA	<3MWh

Grizzly Flat Pipeline/Intertie	RPS-Qualified Hydro	Long	NA <1MWh

4.4.3. Increased Efficiency Potential

GFCSD recently completed a Water System Improvement Project in 2012 funded through the USDA Rural Community Grant Program that included improvements at their treatment plant, lining the storage reservoir and pipeline distribution improvements. Additionally, GFCSD has four pump stations; Tyler Tank Pump Station, South View Pump Station, Winding Way Pump Station and Forest View Pump Station. All pump stations are associated with a storage tank. GFCSD has indicated that the pumps do not require upgrades at this time. GFCSD had identified the need to reconfigure the piping at the Tyler Tank, however the project was not expected to yield any improvements to the pump efficiency.

4.5. Tahoe City Public Utility District

4.5.1. Overview

The Tahoe City Public Utility District (TCPUD) maintains sewer and water infrastructure on the west side of Lake Tahoe in both Placer and El Dorado Counties. The boundaries of TCPUD extend from Emerald Bay to Dollar Hill, and along the Truckee River to the Nevada County line. The service area encompasses over 31 square miles. TCPUD facilities include:

- Approximately 3,926 service connections
- 5 separate service areas
- 11 tanks (1@0.28mg, 1@0.50mg, 3@0.56mg, 6@3.7mg)
- 10 groundwater wells
- 1 active lake intake/treatment plant
- 6 booster pump stations
- 67 miles of water lines

4.5.2. Renewable Energy Projects Identified

A response was not received from TCPUD in regards to renewable energy opportunities identified in their district. A review of their facilities indicates that the greatest potential for renewables may be in solar projects at their treatment plant. There may be opportunities also for load shifting and grid balancing through operations changes and small scale pumped storage hydroelectric. The area has less elevation change than some of the larger districts and therefore has lower potential for hydroelectric facilities. Additionally, there is potential to add storage facilities for fire suppression and utilize the storage facilities for demand management to deliver water by gravity during the day and pump to storage at day during off-peak hours. This type of project has been proposed by outside consultants and would be a long term project for TCPUD to consider. It is recommended that TCPUD consider opportunities for solar to offset usage at some of their larger facilities such as their treatment plant.

4.6. City of Placerville

4.6.1. Overview

The City of Placerville is located along Highway 50 in central El Dorado County. Its city boundaries extend beyond its water service area (EID is solely responsible for the periphery area). The City serves a population of about 10,900, with 3,025 active service connections. All service connections are metered, and water uses include residential, commercial, and unbilled municipal water use. The City includes 8 separate service zones.

The City receives 100% of its water from EID and connects to EID's water supply through multiple water meters. The City's water distribution system consists of 37 miles of pipe of 4-inch or greater diameter, and 2 miles of pipe of less than 4-inch diameter. The City has three pump stations; one pump station is a hydro-pneumatic system, and the other two are small privately-operated facilities installed in new developments to provide adequate water pressure.

4.6.2. Renewable Energy Projects Identified

A response from the City indicated that they had previously considered solar power at their main parking structure and WWTP near Weber Creek; however it was determined to not be economically feasible at the time. Information was not provided on the potential generation of the facilities. The City also indicated that they were considering efficiency improvements at their pump stations however the potential for improvements were low. It is recommended that the City continue to pursue potential solar energy as a renewable source and consider grant or low interest loan opportunities to increase the economic feasibility of the projects.

5.0 Agencies outside of El Dorado County

5.1. Heavenly Ski Resort

5.1.1. Overview

Heavenly Ski Resort spans the California-Nevada border in South Lake Tahoe and owns the largest snow-making system on the West Coast. Heavenly Ski Resort is owned by Vail Resorts, the premier mountain resort company in the world and a leader in luxury, destination-based travel at iconic locations.

5.1.2. Renewable Energy Projects Identified

Project Name	Type of Renewable	Term (Near, mid or long)	Capacity	Potential Generation
Heavenly Ski Resort CA Base Pump Station	RPS-Qualified Hydro	Near-term	60 kW	175 MWh/year

5.2. Amador Water Agency

5.2.1. Overview

Amador County is located approximately 45 miles southeast of Sacramento in the foothills of the Sierra Nevada Mountains. The county is bordered on the north by the Cosumnes River and on the south by the Mokelumne River. The main water purveyor in the western portion of Amador County is Amador Water Agency (AWA). AWA was formed in 1959, and currently provides both water and wastewater services. It is comprised of four service areas: Amador Water System (AWS), Central Amador Water Project System (CAWP), La Mel Heights, and Lake Camanche Village (LCV). AWA serves a total population of 25,640, with about 7,465 retail service connections and about 5,535 wholesale service connections.

AWA utilizes a combination of both surface water and groundwater. Both AWS and CAWP receive surface water from the Mokelumne River. AWA has two water treatment plants located within the AWS service area. Because AWS supplies both potable and raw water, AWS includes 120 miles of potable water mains and 23 miles of conveyance canals for raw water. CAWP includes 90 miles of potable water piping for both wholesale and retail services. LCV has 4 groundwater wells treated with on-site chlorine injection, 6 storage tanks, and 2 pump stations. La Mel Heights has 2 groundwater wells, and the groundwater is treated at a water treatment plant.

5.2.2. Renewable Energy Projects Identified

Project Name	Type of Renewable	Term (Near, mid or long)	Capacity	Potential Generation
Tanner Powerhouse at WTP	RPS-Qualified Hydro	Near-term	110 kW	560 MWh/year
Ione Powerhouse	RPS-Qualified Hydro	Near-term	250 kW	1,566 MWh/year
Tanner WTP and AWA Office Solar	Solar	Long-term	1.0 MW	1,600 MWh/year

5.3. City of Folsom

5.3.1. Overview

The City of Folsom (City) covers about 15,170 acres. It is bordered by the El Dorado County line to the east, Folsom Reservoir and Folsom State Prison to the north, Lake Natoma and the American River to the west, and Highway 50 to the south. The area north of the American River and Folsom State Prison receives water from San Juan Water District (SJWD). The City has four distinct service areas: Folsom Service Area (West), Folsom Service Area (East), Ashland

Area, and Nimbus Area. To supply all of the Ashland Area's water, the City purchases wholesale water from SJWD.

All of the water supplied to the area south of the American River passes through the City of Folsom Water Treatment Plant, which has a capacity of 50MGD. Service elevations throughout the entire distribution system range from below 170 feet to 790 feet. Static pressure in the system ranges from about 32 to 114 psi, depending on the pressure zone. The distribution system south of the American River includes 250 miles of pipelines, ranging from 4 inches to 30 inches in diameter. The City operates a total of 18 PRV stations and one flow control valve station in its service area. There are ten treated water storage tanks/reservoirs located throughout the distribution system, with an additional two that are located at the City's WTP. In total, the 12 storage tanks have a capacity of 34.5 MG. The City also operates six booster pump stations, three of which are located at the WTP. These pump stations are equipped with multiple pumps to meet the varying demands in the pressure zones.

5.3.2. Renewable Projects Identified

A response was not received from the City of Folsom in regard to current renewable opportunities. The City of Folsom currently owns and operates a solar project at their sports complex which offsets energy usage at the site. The City should consider the use of solar at their treatment facilities. There is significant opportunity for solar usage at the new development south of Hwy 50 that was recently annexed into the City. The City also has some opportunity for small in-conduit hydroelectric facilities along their supply pipeline from Folsom Lake, which also could be modified for small scale pumped storage for grid balancing. It is recommended that the City consider these opportunities in the future.

5.4. Tuolumne Utilities District

5.4.1. Overview

Tuolumne Utilities District (TUD) was formed in 1992 as part of a state-mandated consolidation of local water systems. Today, TUD serves a population of 28,997 through a total of 11,428 service connections. TUD's service area encompasses a number of towns and communities, including Jamestown, Sonora, Columbia, Big Hill, Standard, Soulsbyville, Tuolumne City, Twain Harte, and Sugar Pine, all of which are located in Tuolumne County. The treated water system consists of 17 separate distribution systems with irregular boundaries.

TUD is heavily reliant on the ditch system, which was originally designed in the 1850s. The ditch system consists of 57 miles of open channels flowing from the Lyons Reservoir, which is operated by PG&E. Some water from the ditch system supplies raw water to customers for agricultural needs, while some of the water is treated by TUD to provide potable water. TUD also draws surface water from small reservoirs in the area and groundwater from its 26 wells. TUD owns and operates 14 surface WTPs and 7 well WTPs. TUD also has 71 treated water storage tanks, though 61% of these are in fair or poor condition. TUD's water distribution system includes 9 reservoirs, 31 pumps, and 20 hydroelectric systems.

5.4.2. Renewable Projects Identified

A response from TUD indicated that they have previously considered additional hydroelectric facilities including use of an existing Pelton Wheel at a facility that does not have an agreement with PG&E for power generation. Additional information on opportunities within TUD was not provided at this time. A brief review of their system indicates that there is potential for additional solar energy systems at their treatment plants. It is recommended that the District continue to consider opportunities for both solar and hydroelectric energy projects.

6.0 Projects Identified for Further Analysis

Based on the responses received from the agencies and information available at this time the following projects have been identified for further analysis. Additional information and detail is provided in *TM#9 – Preliminary Engineering, Economic and Environmental Analyses of Recommended Near and Mid-term System Alternatives*.

- EID – Pleasant Oak Main PRS 5 – Tank 7 Hydroelectric (Update to previous analysis)
- EID – Pleasant Oak Main – Reservoir B
- EID – El Dorado Main 2 PRS 1 (Tank 3)
- EID – Oro Loma Pump Station Efficiency Improvements
- GDPUD – Sandtrap Siphon
- GFCSD – WTP Reservoir Solar
- AWA – Tanner Powerhouse Hydroelectric

A number of the projects listed above are currently in various stages of the design and permitting process including EID – Tank 7 Hydroelectric, GDPUD – Sandtrap Siphon (in permitting), STPUD – Small Hydroelectric at Diamond Valley Ranch and AWA – Tanner Powerhouse Hydroelectric. TM#9 provides an overview of the projects along with the current status.

1.0 Appendix A – Project Descriptions

The following provides project descriptions for those projects indicated as near term or mid-term that have information available. The following is only for projects within El Dorado County. Table 5-1 – hydroelectric Development Options Project Screening Matrix from the 2009 Hydroelectric Options Study is also included to reference generation assumptions for long term projects not described below.

1.1. El Dorado Irrigation District

1.1.1. El Dorado Main 2 PRS 1 (Tank 3)

EID operates an existing PRS on EL Dorado Main 2 at the inlet to Reservoir 3, located adjacent to the U.S. Forest Service (USFS), property on Carson Road. PRS 1 splits in flow, and the proposed hydro station would be located prior to the split in flow. Flow in the pipeline varies from 5 cfs to 38 cfs. A flow control and pressure regulating system is required to maintain the required 50 psi downstream pressure. The structure housing the hydro station would require 400 square feet in area, and could be located either within the Reservoir 3 property or on the adjacent USFS property, with the former being the more expensive option. The hydro station would consist of three PATs with one turbine operating at a variable speed with a regenerative power converter. It has a projected average annual flow of 16 cfs and a projected average annual power generation of 1,700 MWh.

1.1.2. El Dorado Main 2 PRS 3

EID operates an existing PRS on El Dorado Main 2, located 4,500 feet downstream from Reservoir 3 on Whispering Wind Drive. The site has an elevation of 2,270 feet and is relatively flat, with good construction access and 3-phase power nearby. The hydro station would be located on the existing 24-inch pipeline adjacent to the existing PRS, and with the accompanying structure would require an area of 400 square feet. A flow control and pressure regulating system is required to maintain the required 78 psi downstream pressure. The hydro station would consist of three PATs with one turbine operating at a variable speed with a regenerative power converter. It has a projected average annual flow of 13 cfs and a projected average annual power generation of 890 MWh.

1.1.3. Oak Ridge Tanks to Bass Lake Tanks Pumped Storage

EID is currently designing a new pumping station at the Oak Ridge storage facilities located in El Dorado Hills. The Gold Hill intertie connects the Bass Lake tanks (8 MG) to the Oak Ridge tanks (6 MG). This project would be a pumped storage project, pumping flow from the Oak Ridge storage tanks to Bass Lake storage tanks during off-peak hours, then generating power at the Oak Ridge tanks site during peak energy demand periods. The hydro system would be located on the Oak Ridge storage tanks site near the pump station and would consist of one PAT with variable speed and a regenerative power converter. It would require 400 square feet in area with its accompanying structure. Though the site has a adequate power grid access, it is uncertain whether or not the available storage capacity at the Bass Lake Tanks is enough. Water would be pumped at a rate of 10 cfs for about 6 hours totaling about 1.5 million gallons. The

pumping station is projected to have an average annual pumping requirement of 410 MWh , with a projected average annual power generation of 380 MWh, resulting in negative annual generation.

1.1.4. Sly Park Dam

For this project, EID would replace a PRV on the Sly Park Dam outlet works with a hydroelectric facility. Sly Park Dam impounds Jenkinson Lake just to the southeast of Polluck Pines. The spillway releases water into the natural channel of Park Creek below the dam. There are two options for this project. The first option generates power solely from the Camino Conduit flows and the second option adds Jenkinson spillway flows. The new hydro station would be located on the main dam section, which has an elevation of 3,482 feet. The first option would enable the District to generate power whenever water is released through the outlet works. Flows through the Camino Conduit range from 10 to 65 cfs. The hydro station would consist of four vertical turbine PATs performing over heads and flows between 65 to 103 feet and 14 to 55 cfs, respectively. It has a projected average annual flow of 32 cfs and a projected average annual power generation of 1,800 MWh. The second option would operate at a higher capacity whenever Jenkinson would spill.

1.1.5. Pleasant Oak Main at Reservoir B (2 stations)

The Pleasant Oak Main (POM) at Reservoir B hydro option is a dual station project located off of Pleasant Valley Road. One unit would be upstream at the Reservoir B site and one unit downstream (west) of Reservoir B along the District access road. The two stations would share transmission line facilities and the same flow rates through the POM 36-inch pipeline. Each hydro station will have three PATs with one turbine operating at variable speed with a regenerative power converter, in addition to flow control and pressure regulating valves. Each station will be housed in a structure with an area of 400 square feet. The upstream site conveys the most flow and has a variable flow of 5 cfs to 28 cfs. The downstream site conveys a similar flow, with no laterals between the two sites. Combined, the two hydro sites are projected to have an average annual flow of 15 cfs and an average annual power generation of 2,600 MWh.

1.1.6. Pleasant Oak Main PRS 5 (Reservoir 7)

The POM PRS 5 hydro option would be located on the northeast side of the Reservoir 7 tank, off of Pleasant Valley Road. There is sufficient area for the 400-square foot station to be implemented. The site is approximately 2,230 feet in elevation, relative flat, has good construction access, and has a 3-phase electrical service adjacent to it. The surrounding area is low density residential with open space. The hydro station would have three PATs with one turbine operating at variable speed with a regenerative power converter, in addition to flow control and pressure regulating valves. Flow in the pipeline varies from 3 cfs to 24 cfs. The projected annual average flow is 14 cfs and the projected annual average power generation is 2,300 MWh.

1.1.7. Diamond Springs Main PRS 1 (Reservoir 8)

This hydro project is at an existing PRS on EID's Diamond Springs Main at the old Reservoir 8 Site. The site is relatively flat, has an elevation of 2,080 feet, has good construction access, and

has reasonable power grid access. The energy production is moderate at 690 MWh. The surrounding area consists of low and medium density residential and open space. The hydro station will consist of two PATs with one turbine operating at variable speed with a regenerative power converter. Flow control and pressure regulating valves will be required to maintain 50 psi downstream pressure. The building to house the hydro station will necessitate an area of 230 square feet, which is available on the site. Flow in the 24-inch pipeline varies from 3 cfs to 23 cfs. The projected annual average flow is 11 cfs and the projected annual average power generation is 690 MWh.

1.2. Georgetown Divide Public Utility District

1.2.1. Sandtrap Siphon

As part of the Stumpy Meadows Project, the GDPUD diverts water at the Pilot Creek Diversion Dam and conveys it in the Georgetown Ditch. The Georgetown Ditch conveyance system includes the inverted Sandtrap Siphon located east of the town of Georgetown. The site is located adjacent to Walton Lake and the Walton Lake Water Treatment Plant, and is within land zoned as commercial. Access to the project is very good. The elevation at the site is approximately 3,100 feet. The project would likely occur within the existing GDPUD easement area, but may require adjacent landowner right-of-way. The Sandtrap hydro option would be located where the Sandtrap Siphon pipeline enters Walton Lake and would include a new 230 kW hydroelectric generating facility, consisting of three units – two fixed and one variable pumps operated as turbines that would collectively have a design flow of 24 cfs. A small powerhouse would be constructed near the Walton Lake shoreline to house the generating equipment. The average annual generation would be approximately 1,130 MWh.

1.2.2. Kaiser Siphon

The Buffalo Hill inverted siphon is located on the Georgetown Ditch conveyance system just north of the town of Georgetown, near Highway 193. The Buffalo Hill Siphon hydro option would capture the energy available at the existing 24-inch Buffalo Hill Siphon with a 170 kW hydroelectric generating facility located near the energy dissipating structure at the terminus of the siphon. The project would be sized for a maximum flow of 20 cfs, which approximates the peak flows between May and October. Annual flows are expected to average 12 cfs due to lower demand in the winter. The operating head would be variable, depending on flow rate, but is expected to average about 115 feet (141 feet max.). The project would operate using existing and future water supplies required by the GDPUD distribution system. No reoperation of the Stumpy Meadows Project or the Georgetown Ditch is expected. The average annual generation expected from the Buffalo Hill Siphon option is about 860 MWh.

1.2.3. Buffalo Siphon

The Kaiser inverted siphon is located on the Georgetown Ditch conveyance system near Highway 193 just north of Greenwood, near the Auburn Lake Trails Water Treatment Plant. The existing siphon is a 24-inch diameter buried pipeline that flows to an energy dissipater at its terminus. This project option includes replacing an existing reinforced plastic mortar (Techite) pipe and an open channel section upstream of the siphon with new, 24-inch diameter pipe, for a

total distance of 8,000 feet. The extended pipe provides for a significant increase in available head and resulting project benefit. The proposed 580 kW generating facility would be located immediately adjacent to and downstream from the existing energy dissipating structure. The project is sized for an estimated maximum flow of 15 cfs, which would occur between May and October. Annual flows are expected to average 10 cfs due to lower demand in the winter. The operating head would be variable, depending on flow rate, but is expected to average about 540 feet. The proposed project would operate using existing and future water supplies required by the GDPUD distribution system. No reoperation of the Stumpy Meadows Project or the Georgetown Ditch is expected. The average annual generation expected from the Kaiser Siphon hydroelectric project is about 3,600 MWh.

1.2.4. Stumpy Meadows

Stumpy Meadows is a reservoir formed by Mark Edson Dam, an earthfill structure on Pilot Creek 5 miles east of Quintette in El Dorado County. It is owned and operated by the GDPUD. The dame conserves water for irrigation and domestic use. The net head varies from 127 feet to 154 feet, and the flow is 30 cfs for 9.5 months of the year. The potential capacity is 325 kW, and the average annual output would be about 2.2 million kWh. A single-phase, 35 kV transmission line is located about 4 miles from the site. Development of a hydroelectric plant at the site would require the construction of 4 miles of 13 kV transmission line and upgrading the existing 9-mile single-phase transmission line to a three-phase line

1.3. South Tahoe Public Utility District

1.3.1. STPUD C-Line Upper Project

This project consists of constructing a new pipeline to replace the existing C-Line and installing a hydropower generation facility at or near Sorensen's campground. The electricity would be transmitted via an underground 12.5 kV power transmission line along the same alignment as the C-Line pipeline to the Luther Pass Pump Station. The electricity generated would be used to power the Luther Pass Pump Station.

1.3.2. STPUD C-Line Upper Project with Energy Storage Sub-Option

STPUD pumps the treated wastewater from South Lake Tahoe to Luther Pass on Highway 89, from which it flows by gravity over 8 miles and about 2,100 feet down in elevation to the Woodfords area. Previous investigations of in-conduit hydro for the continuous 6 to 7 cfs of treated effluent concluded that it would not be feasible to install a pressurized pipeline, upgrade an existing single phase power line to three-phase, and construct one or two powerhouses for energy recapture. This project would recapture the gravity energy with two powerhouses, as was investigated previously, but it would also include two storage tanks to concentrate power generation during the on- and mid-peak electric grid hours. Based on initial estimates, elevation drops of roughly 850 feet and 1,300 feet, along with the installation of a 1 to 2 MG tank at Luther Pass, Sorensens, and/or Woodfords would support a 1 to 1.5 MW powerhouse near Sorensen's and a 2 to 2.5 MW powerhouse near Woodfords. Additional options exist for phasing, sizing, and locations of the tanks and power houses. The new pressurized pipeline could be routed adjacent to the existing gravity flow pipeline, and the

existing pipeline would remain to serve as back-up conveyance. Total average energy generation would be about 7,500 MWh annually for the upper segment (Luther Pass to Sorensen's) and about 11,500 MWh annually for the lower segment (Sorensens to Woodfords). Concentrating daily generation to the mid- and on-peak electric grid hours using "water as energy" storage would support and make electric grid operations more efficient, increase the revenue and electric grid value of the generated energy, reduce the need for on-peak fossil-fueled generation, create local fire suppression resources, and result in substantial reductions in pollutant and GHG emissions.

1.3.3. STPUD C-Line Lower Project

This project includes the construction of a new pipeline to replace the existing C-Line and installing a hydropower generation facility at Harvey Place Reservoir. Electricity would be transmitted via an underground 12.5 kV power transmission line running along the same alignment as the C-Line pipeline to Luther Pass Pump Station. The generated electricity would be used to power the Luther Pass Pump Station and to supplement the power supply.

1.3.4. STPUD C-Line Lower Project with Energy Storage Sub-Option

STPUD pumps the treated wastewater from South Lake Tahoe to Luther Pass on Highway 89, from which it flows by gravity over 8 miles and about 2,100 feet down in elevation to the Woodfords area. Previous investigations of in-conduit hydro for the continuous 6 to 7 cfs of treated effluent concluded that it would not be feasible to install a pressurized pipeline, upgrade an existing single phase power line to three-phase, and construct one or two powerhouses for energy recapture. This project would recapture the gravity energy with two powerhouses, as was investigated previously, but it would also include two storage tanks to concentrate power generation during the on- and mid-peak electric grid hours. Based on initial estimates, elevation drops of roughly 850 feet and 1,300 feet, along with the installation of a 1 to 2 MG tank at Luther Pass, Sorensens, and/or Woodfords would support a 1 to 1.5 MW powerhouse near Sorensen's and a 2 to 2.5 MW powerhouse near Woodfords. Additional options exist for phasing, sizing, and locations of the tanks and power houses. The new pressurized pipeline could be routed adjacent to the existing gravity flow pipeline, and the existing pipeline would remain to serve as back-up conveyance. Total average energy generation would be about 7,500 MWh annually for the upper segment (Luther Pass to Sorensen's) and about 11,500 MWh annually for the lower segment (Sorensens to Woodfords). Concentrating daily generation to the mid- and on-peak electric grid hours using "water as energy" storage would support and make electric grid operations more efficient, increase the revenue and electric grid value of the generated energy, reduce the need for on-peak fossil-fueled generation, create local fire suppression resources, and result in substantial reductions in pollutant and GHG emissions.

1.3.5. STPUD B-Line Load Shifting Project

Due to nutrient loading concerns in Lake Tahoe, wastewater is collected throughout the South Lake Tahoe Basin area and treated before being pumped out of the Basin over Luther Pass (Highway 99) to STPUD's Diamond Valley Ranch in eastern Alpine County near Woodfords. Pump stations for the effluent continuously run 365 days a year, 24 hours a day, to convey the

average 6 to 7 cfs of treated wastewater distance of over 15 miles and 1,500 feet up in elevation. This project would install two new storage tanks and a second pipeline up to the top of Luther Pass, to allow pumping of 12 to 14 cfs during off-peak hours for the electric grid. One tank and the start of the new pipeline would near the base of the Highway 89 Luther Pass grade, and the second tank and end point of the new pipeline would be near the summit of Luther Pass. Relieving Liberty Utilities of the daily electric grid peak period pumping loads, and utilizing low-cost, surplus off-peak baseload energy would greatly reduce STPUD pumping costs, help balance the electric grid, reduce the need for on-peak fossil-fueled generation, create local fire suppression resources, and result in substantial reductions of pollutants and GHG emissions.

1.3.6. STPUD Micro-Hydro Units on Existing PRVs

STPUD has 20 pressure reducing valves within its drinking water delivery system. These valves are necessary because after treatment, water gets highly pressurized and cannot be delivered to the consumer at such high pressure, so the valves bleed off the pressure. The PRV's have a constant water flow and micro-turbine generators could be installed in these PRV's to generate electricity. Power tie-ins and storage capability would also need to be identified and implemented as part of this project.

1.3.7. STPUD In-Line Hydro Generation Project on the Recycled Wastewater Delivery System

STPUD exports all its wastewater via a delivery system that originates in South Lake Tahoe at the wastewater treatment plant and is transferred over a 26.7 mile pipeline to Alpine County where it is stored in Harvey Place Reservoir for eventual use as irrigation on fields downstream of the reservoir. The 12 miles and 2175 vertical feet decline from Luther Pass Pump Station, known as the "C Line" offers opportunities for in-line hydroelectric power generation turbines. This project would identify the most feasible sites for the installation of in-line hydro turbines, as well as pressure upgrades to the existing pipeline. Power tie-ins would also need to be identified and a storage unit for pumped hydro energy would need to be constructed.

1.3.8. STPUD Solar Project at Diamond Valley Ranch

STPUD owns a 2300 acre parcel on Diamond Valley Road (in near proximity to the Woodfords Washoe Tribe community) in Woodfords, CA. The parcel is utilized for recycled wastewater storage and eventual irrigation of neighboring ranch properties. Although much of the 2300 has been designated for other projects, there is the possibility to allocate a large parcel of acreage to a solar farm project. A battery storage building would need to be constructed, as well as upgrades in the electrical delivery system to provide a three-tier delivery system. Liberty Energy would need to partner on the project for purchase of the energy generated.

1.3.9. STPUD Wind Generation Project at Diamond Valley Ranch

STPUD owns a 2300 acre parcel on Diamond Valley Road (in near proximity to the Woodfords Washoe Tribe community) in Woodfords, CA. The parcel is utilized for recycled wastewater storage and eventual irrigation of neighboring ranch properties. Although much of the 2300 has been designated for other projects, there is the possibility to allocate a large parcel of acreage to a wind farm project. A battery storage building would need to be constructed, as well as

upgrades in the electrical delivery system to provide a three-tier delivery system. Liberty Energy would need to partner on the project for purchase of the energy generated.

1.3.10. Angora Ridge Pumped Storage Project

This project involves the installation of a new 1 MG tank at Angora Ridge (Elev. 6,945 ft.), with a 1,000-foot (225-foot head) pipeline to the existing tank (6,720 ft.) or a 3,000-foot (555-ft. head) pipeline to the fire station (6,390 ft.). The project would then include a new 1 MG tank at the existing tank (Elev. 6,720 ft.) or at the fire station, and a pumps-as-turbines hydroelectric plant (~60 kW to ~140 kW) (about 500 to 1,100 kWh/day of peak period generation/load).

1.4. Grizzly Flats Community Services District

1.4.1. WTP Solar Project

The solar project identified at the District existing water treatment plant facility would be located at the HDPE lined reservoir adjacent to the reservoir. The project has the potential to offset the District's existing power consumption at all five of their meters. The capacity of the solar project would be approximately 22kW and generate 34,760 kWh each year.

1.5. Heavenly Ski Resort

1.5.1. Heavenly Ski Resort CA Base Pump Station

Heavenly Ski Resort currently receives treated water from STPUD through a re-regulating tank and gravity-pressurized pipeline that is located near the top of the First Ride ski run. Water flows from the tank to the snow-making pump station building where it is then pumped about halfway up the Resort's ski area to its California Dam Reservoir. This project would simply replace a pressure reduction valve at the Resort's pump station with an in-conduit generator. Generation would be limited to the October through January period when the Resort is making snow (flows are continuous during this period). A 60 kW in-conduit generator would operate at a high capacity and efficiency during the seasonal snow making period, and could be used to help pay for or offset pumping, snowmaking, and other Resort peak season energy loads. A total of 150 MWh/year of energy would be generated by this project.

El Dorado County Water Systems

TM#9 – Task 2.7 Prepare Preliminary Engineering, Economic & Environmental Analyses of Recommended Near and Mid-term System Alternatives

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1.0 Introduction

The purpose of this TM is to provide additional analysis and detail on multiple "near-term" projects in El Dorado County and adjacent areas that are representative of the renewable project opportunities in the County. The following projects were identified in TM#8 for further analysis and description:

- El Dorado Irrigation District
  - Pleasant Oak Main PRS 5 – Tank 7 Hydroelectric
  - Pleasant Oak Main – Reservoir B
  - El Dorado Main 2 PRS 1 (Tank 3)
  - Oro Loma Pump Station Efficiency Improvements
- Georgetown Divide Public Utility District
  - Sandtrap Siphon
- Grizzly Flats Community Services District
  - WTP Reservoir Solar
- Amador Water Agency
  - Tanner Powerhouse Hydroelectric

An overview of the environmental and permitting issues associated with hydroelectric projects is also provided and applies to the projects described in this TM. Any environmental issues specific to the project are described under that individual project description.

2.0 Permitting, Environmental and Financial Considerations for Hydroelectric Projects

2.1. Federal Energy Regulatory Commission

2.1.1. Conduit Exemption

On August 9, 2013, the President signed H.R. 267 (Hydropower Regulatory Efficiency Act of 2013) [1]. The legislation provides the following language:

1. Clarifies small-scale, non-federally owned hydropower exemption from FERC permitting for facilities.
    a. Amends PURPA to revise maximum capacity of qualifying conduit hydropower facilities from 5 MW to 10 MW
    b. Redefines "conduit" to any tunnel, canal, pipeline, aqueduct, flume, ditch or similar manmade conveyance built for the distribution of water for agricultural, municipal or industrial consumption which is not used primarily for the generation of electricity and is not federally-owned
    c. Amends Federal Power Act for qualified small conduit facilities via new filing procedures for qualified conduit hydropower site:
        i. File a Notice of Intent with FERC addressing "Qualifying Criteria":
            1. Uses only the hydroelectric power generation potential of the non-federally owned conduit
            2. Has a maximum capacity of 5 MWs
            3. Is not current licensed or exempted
                ii. FERC has 15 day review period
                iii. If sufficient, FERC will publish a public notice for 45 days. If after 45 days, there is no contest to the qualifying criteria, FERC will issue a conduit exemption.

Under the Hydropower Regulatory Efficiency Act of 2013, FERC is required to determine whether proposed projects meet the criteria to be considered "qualifying conduit hydropower facilities." Qualifying conduit hydropower facilities are not required to be licensed or exempted by the FERC; however, any person, State, or municipality proposing to construct a facility that meets the criteria must file a Notice of Intent to Construct a Qualifying Conduit Hydropower Facility with the Commission.

A "qualifying conduit hydropower facility" must meet the following provisions:

1. A conduit is any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption, and is not primarily for the generation of electricity.

2. The facility generates electric power using only the hydroelectric potential of a non-federally owned conduit.

3. The facility has an installed capacity that does not exceed 5 megawatts (MW).

4. The facility was not licensed or exempted from the licensing requirements of Part I of the FPA on or before August 9, 2013.

The projects described in this TM meet the requirements for a qualifying conduit hydropower facility: the nameplate capacities of the project are below the five MW limit; the conduits are not owned by a federal entity; and the conduit is operated as part of the water distribution system and was not built primarily for the purposes of generating electricity. It should be noted that the Tank 7 Hydroelectric project has an approved FERC application and the project went through the previous application process. It is expected that the new streamlined process will expedite these applications in the future.

In order to obtain approval from FERC for the proposed Project, the project owner would provide FERC with relevant project information by submitting a Notice of Intent to Construct a Qualifying Conduit Hydropower Facility (NOI). FERC would review the NOI, and upon approval allow a 45 day comment period on the decision. If there are no challenges to the NOI and FERC's determination, the proposed Project would be approved.

2.1.2. California Environmental Quality Act Categorical Exemption

CEQA allows for a "Small Hydroelectric Categorical Exemption" (Section 15328) [2], and applies to projects at existing facilities that meet certain criteria (listed verbatim):

- The capacity of the generating facilities is five megawatts or less;
- Operation of the generating facilities will not change the flow regime in the affected stream, canal, or pipeline including but not limited to:
  - Rate and volume of flow,
  - Temperature,
  - Amounts of dissolved oxygen to a degree that could adversely affect aquatic life, and
  - Timing of release;
- New power lines to connect the generating facilities to existing power lines will not exceed one mile in length if located on a new right-of-way and will not be located adjacent to a wild or scenic river;
- Repair or reconstruction of the diversion structure will not raise the normal maximum surface elevation of the impoundment;
- There will be no significant upstream or downstream passage of fish affected by the project;
- The discharge from the power house will not be located more than three hundred feet from the toe of the diversion structure;
- The project will not cause violations of applicable state or federal water quality standards;

- The project will not entail any construction on or alteration of a site included in or eligible for inclusion in the National Register of Historic Places; and construction will not occur in the vicinity of any rare or endangered species.

To meet CEQA's requirements for the exemption, an Environmental Checklist document needs to be prepared, signed by the project Owner, and posted with the County Clerk and State Clearinghouse within the Governor's Office of Planning and Research. If no comments are received during the 30-day posting period, then no further CEQA review requirements apply to the project.

2.1.2.1. *Biological and Cultural Resources Analysis*

Prior to the start of all projects a biological and cultural resources search should be conducted to determine any potential species of concern that should be avoided. Based on the location of the projects listed in this TM no projects are expected to impact and species or cultural resources. It is anticipated that any species or cultural resources of concern identified will be avoided in order to allow for a CEQA exemption.

3.0 El Dorado Irrigation District

The following three hydroelectric projects are all located within EID's potable water system and are proposed at pressure reducing stations to take advantage of the significant elevation change throughout the District's systems. All of the stations discharge into a tank or reservoir facility. The following figure shows the relative location of the three sites evaluated below.

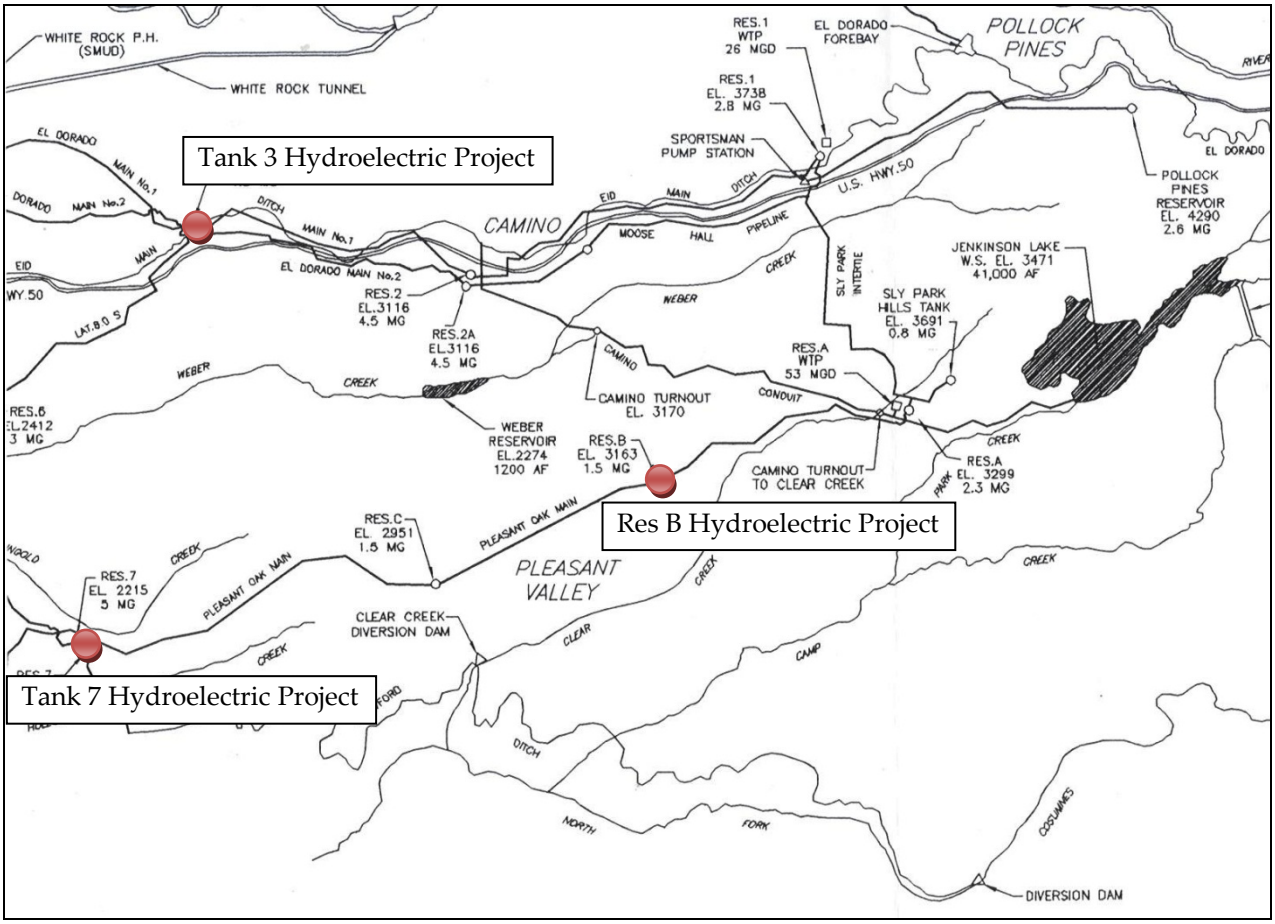


Figure 1. Proposed Hydroelectric Project Locations

3.1. Pleasant Oak Main PRS 5 – Tank 7 Hydroelectric – Update

3.1.1. Background

The Pleasant Oak Main PRS 5 – Tank 7 project was described earlier in *TM #6 – Hydroelectric Opportunities Technical Memorandum*. Possible reoperation scenarios were analyzed which determined that reoperation of the system would not provide sufficient benefits to warrant the changes. Since the completion of that TM (2011) the project has been reexamined multiple times. The following provides a brief overview of the project including a description of the necessary project components to make the project feasible.

3.1.2. Project Overview

The Pleasant Oak Main (POM) at Reservoir 7 hydroelectric station is within the El Dorado Irrigation District (EID) potable water system, located off of Pleasant Valley Road between Placerville and Pleasant Valley, CA (see Figure 1).

The existing pressure reducing station (PRS-5) is located on the northeast side of Tank 7 on the 24-inch pipeline conveying flow from Reservoir C to Tank 7. Pressure upstream of the PRS-5 varies from 150 psi to 90 psi. The PRS discharges essentially to atmosphere into the tanks at Tank 7. Flow in the pipeline varies from 3 cfs to 24 cfs throughout the year.

The site has area available for the hydro option (see the photo below). The site is located at the existing Tank 7 site which houses EID staff operations buildings. Three-phase electrical service is adjacent to the site for project interconnection.

Figure 2. Photo showing location of existing PRS at Tank 7 site

3.1.3. Final Turbine Selection

Final design for the project was completed in 2013. The final turbine selection for the project considered both a three turbine scenario and a two turbine scenario along with control scenarios for pressure versus flow control. The following table summarizes the design considerations for the different scenarios.

Table 1. Design consideration summary for turbine selection

Design	Operational Control	Turbine Combinations (Cornell PaTs)	Advantages	Disadvantages
Three Turbine	Pressure Control	10TR2 / 6TR4 /5TR2	1) Simpler operation than flow control 2) Greater revenue than two turbine design	1) More complicated control than two turbine design 2) Cost of the third turbine may outweigh revenue benefits
Two	Pressure	10TR2 / 5TR4	1) Simpler operation	1) Lowest revenue option

Turbine	Control		than the flow control design 2) Lower capital cost than three turbine design 3) Least on-off cycling of the turbines	
Three Turbine	Flow Control	10TR2/ 6TR4/5TR2	1) Greatest revenue of all the options	1) More complicated control than two turbine design 2) Cost of the third turbine may outweigh revenue benefits 3) Greatest on-off cycling of the turbines
Two Turbine	Flow Control	10TR2 / 5TR4	1) Simpler operation than three turbine design 2) Lower capital cost than three turbine design	1) Less revenue than the three turbine design

The analysis showed that although the pressure control strategy is a simpler operation than flow control, power generation and revenue are decreased by 10 to 20 percent for approximately the same project costs. The project costs are roughly the same because each turbine will require a control valve regardless of either pressure of flow control. Furthermore, for the three turbine flow control design, the third turbine adds 22 percent to the project costs, but only 10 percent to revenue when compared to the two turbine design. Therefore given the additional project costs for marginal revenue gain plus the added complexity by the third turbine as compared to a two turbine design, the two turbine flow control strategy design should be strongly considered as preferable to the three turbine design. An additional benefit of the two-turbine design is lower on-off cycling of the turbines resulting in lower O&M cost per turbine as compared to the three-turbine design.

The two turbine layout with a flow control strategy was selected for the final design. A layout from the final plans is provided in Appendix A for reference.

3.1.4. Interconnection Agreement

Based on the agreement negotiated with PG&E the estimated cost of the interconnection facilities is $170,000 and payment would be made by the District to PG&E in increments as their work progresses. Under the Agreement, PG&E also requires the District pay a monthly cost of ownership fee of $782 per month. Both the interconnection and monthly fees are included in the updated financial analysis.

Some of the major terms of the Agreement include:

- Effective date is upon execution by both Parties
- Term of agreement is for 30 years with automatic annual renewal thereafter
- EID can terminate the agreement at any time with 20 days written notice
- Cost of design, engineering, construction, procurement, and taxes of interconnection facilities and distribution upgrades of $170,000
- Guarantee, surety bond, or letter of credit required for interconnection upgrades cost
- Payment to be made by EID on a monthly basis as PG&E work progresses
- Final accounting and payment within 3 months of PG&E construction completion
- On-going monthly cost of $782 when transmitting power
- Standard clauses for insurance, liability, confidentially, right of access, indemnity, disputes, notices, etc

The Agreement also includes milestones for the project, which can be adjusted if needed, as follows:

- January 30, 2015 – completion of interconnection facilities by PG&E
- February 13, 2015 – in-service date
- February 27, 2015 – initial synchronization
- March 6, 2015 – written approval to EID for operation of the hydro station
- March 20, 2015 – commercial operation of the hydro station begins

3.1.5. Economic Evaluation

The following provides the final economic evaluation performed for the project based on the final design and generation calculations.

The final economic evaluation is summarized below in Tables 2 and 3 which assume the use of the RES-BCT program and the Feed-In-Tariff (ReMAT) program respectively. The estimated generation and construction costs are based on an evaluation provided by NLine Energy during the final design of the project. A detailed cost breakdown of the construction costs is included in Appendix A.

Table 2 Financial Summary with RES-BCT program

Description	With Incurred Costs	Without Incurred Costs
Annual Generation in kWh	1,765,000	1,765,000
Net Cost	$1,662,000	$1,262,000
Annual Cost	$16,384	$16,384
Annual Generation Revenue	$119,000	$119,000
30-year Projected Revenue	$3,429,000	$4,034,000
30-year NPV	$1,317,000	$1,727,000
Payback Period in years	17 - 18	14 - 15

Table 3. Financial Summary with ReMAT program

Description	With Incurred Costs	Without Incurred Costs
Annual Generation in kWh	1,765,000	1,765,000
Net Cost	$1,662,000	$1,262,000
Annual Cost	$21,384	$21,384
Annual Generation Revenue	$159,000	$159,000
30-year Projected Revenue	$1,500,000	$2,104,000
30-year NPV	$638,000	$1,048,000
Payback Period in years	18 - 19	13 - 14

Additionally, the project has received a Proposition 84 grant in the amount of $380,000. On February 25th, 2014 the Proposition 84 grant agreement was received by The Sierra Fund from the Department of Water Resources which is administering the grant. EID is working with The Sierra Fund to execute the agreement in March, 2014 to make the funds available prior to the start of construction.

3.1.6. Project Status/Conclusions

The final design and environmental exemptions for the project were completed in 2013. Most recently on March 10, 2014 EID voted to approve an interconnection. EID had previously gone through the FERC exemption process in 2010 and an extension on the exemption was granted in 2012. Based on the favorable economic evaluation as provided above the project is planned to bid in 2014.

This project demonstrates that a combination of the correct financing, grant programs and revenue agreement with PG&E can make a project economically feasible. The main differences between the final financial analysis and the initial one provided in past analyses include the following:

- Final turbine selection and more detailed generation calculation provided an increase in the generation estimates
- Project construction costs were optimized during final design to reduce costs
- A Prop 84 grant provided a decrease in the project costs of almost 30%
- Financing for the project was lower at 4.3% then the originally estimated 6% rate
- Final FIT pricing negotiations with PG&E yielded a price that was favorable to the project

This project will be EID's first in-conduit hydroelectric facility. Lessons learned from this project will be applied to other EID in-conduit hydroelectric projects that are currently being evaluated.

3.2. Pleasant Oak Main – Reservoir B

The following provides an overview of the Reservoir B Hydroelectric project.

3.2.1. Existing Facilities and General Description

The Pleasant Oak Main (POM) at Reservoir B hydroelectric project is within the El Dorado Irrigation District (EID) potable water system, located off of Pleasant Valley Road between Placerville and Pleasant Valley, CA (see Figure 1). The original project considered a dual station facility with two separate stations feeding the same transmission line.

One hydro station would be upstream at the Reservoir B site shown in the photo above, and the other 2,300 feet downstream (west) of Reservoir B along the District access road. The first station at Reservoir B will be at the existing pressure reducing station (PRS) at the reservoir inlet. The second site would be located by Reservoir C father down the pipeline. The sites are relatively flat and have good construction access.

Figure 3. View of PRS site at Reservoir B

Following a fatal flaw review of the two sites it was determined that Site 2 is not feasible due to the vineyard adjacent to Reservoir C which requires pressure to operate sprinklers, supply the residence and provide other functions at the site. Providing adequate pressures at this site would make the project financially infeasible and therefore the project was not evaluated further. The following provides a preliminary evaluation for the site at Reservoir B.

3.2.2. Project Facilities and Operation

There is sufficient area on the Reservoir B site for the project. A single phase transmission line follows the POM alignment and will have to be upgraded to three-phase for the new station.

Three-phase Pacific Gas & Electric (PG&E) transmission lines are approximately 10,000 feet from the furthest station along Pleasant Valley Road. Additional analysis of the interconnection points and costs are provided in a later section.

3.2.3. Final Turbine Selection

For this project two types of turbines were considered, Pumps-as Turbines (PaT) and Crossflow Turbines. A PaT consists of a pump "running backward" and the generator is simply the pump's induction motor. PaTs are classified as reaction-style turbines. A crossflow turbine is an impulse style turbine, whereby water flow discharges to atmosphere.

For this project either a single crossflow (Hydropower Turbine Systems, Inc. unit was considered versus three PaTs (combination of a Cornell 10TR1, 10TR2 and 6TR1). The final selection of a turbine type is still under consideration by the District. For a conservative analysis presented here the three PaTs were considered. This option will be similar to the one selected for the Tank 7 project, which EID will be familiar with following the construction of the project in 2014.

3.2.4. Power Generation Potential

Flow data was analyzed for 2011 and 2012. The data shows that flow rates average approximately 19 cfs and ranged from 6 to 40 cfs. The pressure head differential was analyzed for both years. Pressure head differentials available for power generation average approximately 123 feet and vary between 105 feet and 135 feet. The data showed a fairly consistent flow and head profile from year to year.

The following table displays the expected annual kWh generation and revenue per year for the three PaT scenario.

Table 4. Estimated annual generation and revenue

	2011	2012	Average
Generation (kWh)	1,035,000	1,135,000	1,085,000
REMAT ($)	$94,000	$102,000	$98,000
RESBCT ($)	$67,000	$74,000	$71,000

3.2.5. Interconnection

PG&E's interconnection map was accessed to determine if an interconnection is suitable at this site. The interconnection map indicates that there is both substation and 21-kilovolt (kV) distribution circuit with available capacity for the proposed hydro station to interconnect.

A PG&E pre-interconnection application report was requested. PG&E highlighted two potential interconnection points: the first interconnection point roughly 200 feet from the proposed powerhouse; the second interconnection point is approximately 1,800 linear feet to the southwest of the proposed powerhouse.

Interconnection point #1 would intertie to a two-phase 21-kV circuit located immediately east of Reservoir B that would require 24,000 linear feet of third wire in addition to normal interconnection equipment. At an estimated $80 per linear foot, the estimated cost of reconductoring the existing poles would be approximately $1,900,000.

Interconnection point #2 would intertie at a 21-kV, two-phase circuit located 1,800 linear feet southwest from the proposed hydrostation. New above or below-ground, three-phase circuit would be constructed to bring PG&E service to the hydrostation. In addition, PG&E highlights that a third wire will be required for a distance of 7,000 linear feet. The estimated cost of new service lines and reconductoring the existing lines is approximately $625,000.

The cost of reconductoring can depend on many things such as the size of the wire, the number of dead end poles required and type of existing pole hardware.

3.2.6. Environmental Analysis

3.2.6.1. *Site Specific Biological and Cultural Resources Analysis*

The proposed Project areas are on a ridgeline at approximately 3,100 ft elevation. The general vicinity has patchy cover of Blue oak-Foothill Pine forest interspersed with Mixed Chaparral shrubs. There are many open areas near the Project sites that prevent a closed plant canopy in the area.

Site 1 is entirely within the existing developed and fenced area of Reservoir B. Site 2 is within an undeveloped area of oak woodland habitat adjacent to the access road leading to Reservoir B.

3.2.6.2. *Biological Resources*

A search of the records in the California Natural Diversity Database (CNDDB), maintained by the California Department of Fish and Wildlife, showed that there were 15 special status species that could have suitable habitat within five miles of the Project sites (CNDDB 2013).

Of the 15 special species identified, four plants considered Rare by the California Native Plant Society (CNPS) could occur in the Project areas at the downstream site, which is comparatively undisturbed. The four plants are: Nissenan manzanita (Arctostaphylos nissenana); Pleasant Valley mariposa lily (Calochortus clavatus var. avius); Parry's horkelia (Horkelia parryi); and saw- toothed lewisia (Lewisia serrata). All four plant species are associated with pine forest, mixed oak or chaparral plant communities similar to the plant communities in the Project area (CNPS 2013).

Of the special status animal species identified in the database search, only three would have suitable habitat in the general vicinity of the proposed Project. These species are the California red-legged frog (Rana draytonii) (RLF), Bank swallow (Riparia riparia) and Fisher (Martes pennanti). However, these species are not likely to occur at the Project areas because essential components of their preferred habitat are lacking.

3.2.6.3. *California Red-Legged Frog*

RLF is a federally-listed Threatened species known to occur in El Dorado County. The closest known occurrence of RLF was at Spivey Pond on the North Fork of Weber Creek, as well as upstream of that site (CNDDB 2013). Spivey Pond is approximately 2 miles from the Project areas, which are on a dry ridgeline approximately one mile from the closest stream, the South fork of Weber Creek. The Project areas do not contain suitable habitat for this species (EPA 2002). Project activities would not be expected to impact RLF.

3.2.6.4. *Bank Swallow*

Bank swallow is a riparian species that is listed as Threatened by CDFW. The Project areas do not contain suitable nesting habitat of vertical stream banks or bluffs with friable soils. Foraging habitat for this species is primarily over water (streams, lakes, rivers) but occasionally is over forests and woodlands dominated by pines and firs. The Project area contains marginal foraging habitat for this species. Bank swallows are considered relatively insensitive to moderate levels of human activities, including agriculture, recreation, water conveyance and hydropower operations (Garrison 1998). The proposed Project activities, including construction and operation would not be expected to impact this species.

3.2.6.5. *Fisher*

Fisher (Martes pennanti) is a Candidate for federal listing. Fishers live in mixed conifer and hardwood forests and are found in mature forest cover with high canopy closure. Varied forest structure providing a range of tree sizes of both live and dead or downed trees provides den and rest sites for fishers. Riparian forests and habitat close to open water are important to fishers. Large diameter trees are selected for natal and maternal dens (CDFW 2013). The project site does not contain the important elements for preferred habitat for this species. Riparian habitat that could be used by this species occurs within one mile of the proposed Project sites. Fishers could travel through the Project area, but are unlikely to reside there.

3.2.6.6. *Cultural Resource Analysis*

The North Central Information Center (NCIC) of the California Historical Resource Information System conducted a complete records search for the Project areas in December 2013. The records search showed that there were several prehistoric and/or historic resources within ½ mile of the Project areas.

The search of State and Federal inventories found no historic properties within the proposed Project area. The recommendations from the NCIC were that there is low sensitivity for identifying prehistoric archaeological sites and moderate sensitivity for identifying historic period cultural resources in the Project areas. These determinations are based on the fact that the area was disturbed by the extensive mining activities that occurred in the area and could have destroyed artifacts.

3.2.7. Economic Evaluation

The construction costs for the PaT scenario are summarized below.

Table 5. Summary of construction cost estimate

Description	Estimated Cost
Mobilization and Site work	$74,760
Pipe, valves and fittings	$266,750
Turbine/Generator Units	$445,000
Electrical/SCADA/Interconnection	$1,200,000
Building/structural	$243,360

Subtotal	**$2,229,870**
Contingency (15%)	$334,480
Engineering/environmental/misc.	$662,210
Total Project Costs	**$3,226,560**

The following table summarizes the economic evaluation using the RES-BCT program and the ReMAT program. The analysis assumes an interest rate of 4% with an annual RES-BCT escalation rate of 5% and an inflation rate of 2.5%.

Table 6 Financial Summary with RES-BCT and ReMAT programs

Description	RES-BCT Program	ReMat Program
Annual Generation in kWh	1,085,000	1,085,000
Net Cost	$3,227,000	$3,227,000
Annual Maintenance Cost	$8,000	$8,000
Annual Generation Revenue	$98,000	$71,000
30-year NPV	-$1,758,000	-$1,113,000
Payback Period in years	Over 30	26.2

3.2.8. Conclusions/Recommendations

An initial evaluation of this project shows generation potential similar to that for Tank 7. However, it is important to note that the estimated construction costs are significantly higher for the Reservoir B Hydroelectric facility. This is due to the interconnection costs of over $900,000 which is 30% of the total project costs. This large capital cost to upgrade the PG&E facilities make this project infeasible. It is not recommended to pursue this project at the present time. However, the project may be eligible for grants or other financial incentive programs that would make the project feasible. Additionally, PG&E may make improvements to their system in the future that could reduce the costs for upgrading associated with this project. It is recommended that this project continue to be reevaluated in the future.

3.3. El Dorado Main 2 PRS 1 (Tank 3)

3.3.1. Project Overview

The proposed Project would be located on the El Dorado Main (EDM) 2 conduit near the existing PRS1 (see Figure 1). EDM2 is a 30-inch diameter pipeline that originates at EID Reservoir 2/2A (Tank 2) in Camino, California. Tank 2 is fed by potable water from EID Reservoir 1 and Reservoir A Water Treatment Plants. EDM2 conveys potable water from Tank 2 to several water demand zones in the EID system. The proposed hydroelectric station would be built approximately three miles from the point of origin of EDM2.

Figure 4. Photo showing the location of EDM2 PRS1 relative to Tank 3

The proposed hydroelectric facility would be installed on EDM2 upstream of the existing PRS1 at the Tank 3 site. Water would be diverted from the 30-inch pipeline to 24-inch pipes which would deliver water to the turbines on 16-inch pipelines. The turbines would discharge to 24-inch pipelines which would return flow back to EDM2.

The hydroelectric station would be housed in a small building, approximately 1,200 square feet in size and would have three pumps as turbines (PATs) and pressure regulating valves in addition to the turbine/generating units. This building would be sited on US Forest Service (USFS) lands. EID holds a Special Use Permit with the USFS to occupy and use USFS property for EDM2 for operations, maintenance and water development.

The water flow from the hydroelectric station would be controlled to regulate pressure during plant operation and to maintain the required 50 pounds per square inch (psi) downstream pressure. A bypass would be provided at the hydroelectric station to allow continuous flow in the EID system during an emergency and while the hydroelectric station is off-line for repairs or maintenance. The station would rely on a programmable control system to augment mechanical operation for regulating flows to the hydroelectric station.

The controller would split flow to the individual turbine units based on system flow read from an in-line flow meter. The flow-based control scheme would also regulate flow through the bypass valve during operation. A separate pressure relief valve would be included in the bypass in the event of a sudden shut down of the hydroelectric system.

Water discharged from the hydroelectric station would be returned to EDM2 upstream of PRS1 and would then be diverted to Tank 3 or to the distribution system to meet consumptive demands.

The hydroelectric station would be interconnected with the Pacific Gas and Electric (PG&E) electrical system at a site approximately 500 feet to the north.

3.3.2. Hydroelectric Station Features

The hydro station would consist of three pumps as turbines (PATs), with one turbine operating at variable speed with a regenerative power converter. The facilities would be housed in a masonry building approximately 400 square feet in area. A schematic layout for the project is provided in Appendix B.

The hydro station will include flow control and pressure regulating valves in addition to the turbine units to regulate the plant operation while maintaining the required 50 psi downstream pressure. A bypass will be provided at the hydro station to allow continuous flow in the EID system during an emergency and while the hydro station is off line for repairs or maintenance. Due to the degree of variability of flows, the station will rely on a programmable control system to augment mechanical operation for regulating flows to the hydro station.

The controller will split flow to the individual turbine units based on system flow read from an in-line flow meter. This flow based control scheme will also regulate flow through the motorized bypass valve during operation. A separate pressure relief valve is included in the bypass in case of a sudden shut down of the hydro system.

3.3.3. Design Data and Energy Production

Energy production for this project is approx. 1,700 MWh per year and would be delivered to a 3-phase Pacific Gas and Electric (PG&E) transmission line located along Carson Rd.

Flow records were examined to determine typical flow releases that would be available for hydropower generation at the EDM- 2 PRS -1. The average monthly and annual powerhouse flow expected to be available is shown below. Average power generation is estimated based on available water, head, efficiency, loss estimates and typical operation.

Table 7. El Dorado Main 2 PRS 1 Powerhouse Flow and Generation

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Projected Average Flow Through El Dorado Main 2 PRS 1 Powerhouse													
CFS	**15**	**14**	**8**	**10**	**9**	**12**	**14**	**21**	**24**	**24**	**24**	**21**	**16**
AF	900	800	500	600	500	700	900	1,300	1,400	1,500	1,500	1,300	11,900
Projected Average Power Generation of El Dorado Main 2 PRS 1													
MWh	160	140	90	110	110	130	150	180	160	160	160	180	1,700

Final turbine selection for this project has not been provided due to the data not being available at this time. However the project generation is expected to be similar to that found for the Tank 7 project. The original Tank 7 projections based on average monthly data was 2,321 MWh. After final design and turbine selection the final generation was reduced to 1,765 MWh (approximately 25% reduction). Assuming that a similar percentage of reduction would occur during a final analysis of Tank 3 a generation of 1,275MWh is assumed for the economic analysis. The following Table 9 provides project design and energy production data.

Table 8. Tank 3 Hydroelectric Design Criteria

Design Head (ft)	222
Design Flow (cfs)	24
Nameplate Capacity (kW)	360
Estimated Annual Generation (kWh)	1,739,000
Reduced Estimated Annual Generation (kWh)	1,275,000
Distance to 3-phase power (ft)	500

3.3.4. Economic Evaluation

The estimated capital cost to construct is $1,556,000. Project costs are summarized in the table below.

Table 9. Summary of construction cost estimate

Description	Estimated Cost
Mobilization and Site work	$66,500
Pipe, valves and fittings	$189,250
Turbine/Generator Units	$375,000
Electrical/SCADA/Interconnection	$260,000
Building/structural	$94,400
Subtotal	**$985,150**
Contingency (15%)	$147,773
Engineering/environmental/misc.	$423,000
Total Project Costs	**$1,556,000**

The total estimated project costs for the $1,556,000. The following table provides a summary of the economic evaluation for the Tank 3 Hydroelectric Project based on utilizing the FIT revenues of approximately $0.09/kWh (the current based load rate for the ReMAT Feed-In-Tariff. Costs may go up from there, however they cannot be guaranteed. The preliminary evaluation provided below does not include any escalation factors or inflation and assumes an interest rate of 4%.

Table 10. Financial Summary with ReMAT program

Description	ReMat Program
Annual Generation in kWh	1,275,000
Net Cost	$1,556,000
Annual Maintenance Cost	$15,000
Annual Generation Revenue	$114,750
30-year NPV	$224,406
Payback Period in years	16

3.3.5. Recommendations

Based on a positive NPV calculated above the project this project is recommended to move forward. EID has submitted the Notice of Intent for a FERC exemption application for the project and is in the process of determining the next steps for final design and financing. The project will follow the same process implemented for the Tank 7 facility.

3.4. Oro Loma Booster Pump Station Efficiency Improvements

The following provides an overview of the Oro Loma Booster Pump Efficiency Analysis.

3.4.1. Existing Facilities and General Description

The existing Oro Loma pump station is comprised of four centrifugal pumps, two 25hp main pumps, a 7.5hp off-peak pump and a 50hp fire flow pump. The 7.5hp pump is first to branch off the 6-inch line supplying the station. The 7.5hp pump and has its own 2-1/2-inch pressure reducing valve ahead of the pump. The 6-inch line continues and is reduced to 4-inches where a second pressure reducing valve is installed. After the valve, the pipes branching off for the 50hp, 25hp and 25hp are 4-inches, 2-1/2-inches and 2-1/2-inches respectively. The discharge of the 50hp booster pump passes through a 4-inch pump control valve before upsizing and exiting the station as a 6-inch line. The pump control valve dampens the surge into the system from the 50hp pump by opening slowly in response to the higher pressure created by this larger pump. The two 25hp pumps discharge to a single 3-inch line which connects to a 3-inch flow meter before joining with the single 6-inch discharge line exiting the station. The 7.5hp discharge connects directly to the main 6-inch station discharge pipe. As a result the flow from the 50hp pump and the 7.5hp pump are not monitored or tracked.

The existing 3-inch discharge header for the 25hp pumps should be eliminated. Instead, the discharge pipes should be connected directly to the existing 6-inch discharge pipe. A flow meter could then be installed in the main discharge pipe to track flows. The capacity of one pump is 100 gallons per minute (gpm) and, neglecting friction losses, two pumps produce 200 gpm. At these flow rates the velocities in a 3-inch pipe are 4.5 feet-per-second (fps) and 9.1 fps respectively. Even though the 3-inch pipe runs are relatively short, a head loss of nearly 2.6 feet occurs in the 20 foot long discharge pipe at the higher flow. An energy savings will be realized over time with a larger pipe serving as the discharge header.

The two existing pressure reducing valves installed on the intake side of the booster pumps create an inefficient system. These valves may have been installed to adjust the pressures in the system to better match the pump curves. A better solution is to cut losses by removing the pressure reducing valves and selecting pumps which fit the system curve appropriately. The effect of removing the pressure reducing valves should also be checked for the pump station supplying flow to the Oro Loma pump station.

3.4.2. Existing and Proposed Pump and System Curve Comparisons

To examine the existing system without the pressure reducing valves the existing pump curves were plotted against an estimated system curve. The system curve was estimated by calculating friction losses and minor losses at various flows, and adding these to the static head differential of the system. The system parameters were defined as: 1,800-feet of 6-inch pipe with a roughness coefficient of 120, a required static head 235-feet and minor losses of about 5.3-feet. These criteria add to produce a head requirement for the pump of approximately 245-feet at 100 gpm. The required static head was determined based on a supply pressure of 55psi at the station, a 235-feet increase in elevation exiting the station and a 40-psi minimum requirement at the high point of the system. The combined minor losses of 5.3-feet are assumed based on appurtenances typically used in similar pipelines and include losses for entrance, fittings, tees, valves and outlet. The plot of the existing pump curves shows that only the 50hp booster pump operates near its maximum efficiency point for this system. The 7.5hp off-peak pump is operating at its upper limits past its efficiency point. The analysis shows that the curves of the two 25hp pumps do not intersect the system curve and are likely not operating efficiently.

The analysis shows that the existing 50hp booster pump should be retained and the 7.5hp and both 25hp pumps should be replaced with pumps that better fit the system. The average demand of the system was calculated based on EID criteria of 0.61gpm per house for the central region and approximately 67 houses served by the system. Max day demand multiplier is 2.5. As a result the average day demand was calculated to be 41gpm and the max day is 102gpm. A daily curve for the max day demand was plotted with the max points at 8am and 8pm with negligible use from 10pm to 4am. The max day demand curve was used to estimate when and how many of the existing pumps would be running per hour. The analysis assumes that the existing 7.5hp pump supplies demands up to 40gpm and that during periods of decreased demand it will cycle on/off in proportion to the percent of demand per that hour. The analysis also assumes that one existing 25hp pump turns on to supply demands past 40gpm and will cycle on/off in proportion to the percent of demand per that hour.

To share peak loads and divide off-peak demands two pumps are proposed for use. Both of the proposed pumps would be 20hp, 3500rpm, and have an 8.25-inch impeller. When operating in parallel and factoring in system losses, the proposed pumps, when operating in parallel, have a curve that places the intersection point of the pump curve and the system curve near 200gpm. Use of variable frequency drives (VFD's) on both pumps will allow fine tuning of the flow rate to meet demand when either a single or both pumps are running.

3.4.3. Electricity Reduction and Cost Savings

To determine cost savings in electricity an analysis comparing the existing electric usage to the proposed usage was performed. The existing usage is based on simulated demand curve and the percentage of pump usage to meet the demand. It is estimated that for a max day scenario the 7.5hp pump supplies 68% of the 24hour demand while the remaining 32% comes from a 25hp pump. For the proposed configuration a single 20hp pump with an appropriate curve could supply 100% of the max day demand. Using a variable frequency drive allows the proposed pumps to better respond to the demands of the system. The new system could be run in a lead-lag or tandem scenario at a given demand.

The electricity usage for the existing site was estimated to use 119kw/hrs per day. Based on a typical cost of $0.20 per kw/hr the site is estimated to cost $23.88 per day in electricity. For comparison, the proposed system was estimated to use 46kw/hrs per day or $9.20 per day. The operational savings would be approximately $5,300.00 per year. The existing scenario experiences multiple motor starts per hour which would be eliminated in the proposed configuration. This was not analyzed in detail but is expected to provide an additional savings of approximately $500 per year.

The facility is estimated to save $14.68 per day in electricity costs, or $5,360.00 per year. The cost of two new 20hp pumps would be approximately $7,000.00 ($3,500.00 each). The savings in electricity the first year and a half would repay the pump cost and the ultimately provide reduced electricity costs and provide a more efficient facility better matched to the existing system curve.

4.0 Georgetown Divide Public Utility District

4.1. Sandtrap Siphon

The District provides water service to its customers using a system of pipelines and ditches. The system is approximately 27 years old. One section of this system contains the Sandtrap Siphon which drops approximately 250 feet from the intake at the El Dorado Ditch and rises 144 feet to deliver water to Walton Lake which serves as a forebay for the water treatment plant, located across the Lake from the terminus. The iron ductile pipe of the siphon currently operates at about 90 psi. In order to stop corrosion and to maintain the integrity of the pipe, the District plans to slip-line a section of the pipe at the lowest point where water pressures are highest. The slip-lining will allow the siphon to operate at a continuous pressure of approximately 120 psi, withstand surge pressures, and generate electricity through the proposed in-conduit turbine.

Figure 5. Location of proposed hydroelectric facility

The proposed Project would be located at the end of the existing 30-inch Sandtrap Siphon raw water supply pipe line into Walton Lake, which is a man-made reservoir. A 24-inch diameter transition "Y" pipe would be installed upstream of the existing energy dissipating structure to divert water to the hydroelectric turbine generator. The existing siphon outlet would be used as a bypass during station outages and provide surge protection for the hydroelectric turbine.

The Project components would be contained within a small powerhouse structure set back from the Walton Lake shoreline. A concrete tailrace would dissipate the discharge from the turbines into the Lake. Walton Lake serves as a forebay reservoir for the Walton Lake Water Treatment Plant which is owned and operated by the District. The intake for this facility is at the opposite end of the lake from where the hydroelectric structure would be located and would not be affected by the installation of the hydroelectric structure.

Pilot Creek is the natural source of water for the conduit. Water is diverted from Pilot Creek approximately 2 miles downstream from Stumpy Meadows Dam and is conveyed to the site through approximately 14 miles of ditches, pipelines, culverts, a tunnel, and the Sandtrap Siphon. The primary purpose of the conduit is to deliver raw water to Walton Lake, which serves as a forebay reservoir for the Walton Lake Water Treatment Plant (WTP).

The hydroelectric station would consist of a single generating unit. The nameplate capacity of the unit would be 180 kW. The unit would either be a cross-flow turbine or a pump-as-turbine (PAT). The control panel would allow for manual or automatic operation of the hydroelectric station via motorized control valves. It would operate automatically except during start-up and periods of maintenance. The Sandtrap Siphon currently flows 24 hours a day, with the rate varying by season and dependent on demands of the WTP. The facility is not designed to operate for peak power demands, but daily operation of the Project could be tailored to optimize power generation during peak demand hours due to the existing storage capacity of Walton Lake.

The average annual generation in kilowatt-hours: 647,000 kWh based on the following table.

Table 11. Estimated annual generation

	System Flow (cfs)	Turbine Flow (cfs)	Head (feet)	Eff (%)	Days Online	Power Generation* (mWh)
Jan	8.5	8.5	100	77%	21	27
Feb	7.5	7.5	100	77%	18	20
Mar	8.6	8.6	100	77%	19	24
Apr	11	11	100	77%	16	26
May	33.6	33.6	76	77%	31	118
Jun	35.1	35.1	76	77%	28	111
Jul	35.8	35.8	76	77%	30	121
Aug	34.5	34.5	76	77%	27	105
Sep	28.9	28.9	76	77%	27	88
Oct	6.2	6.2	100	77%	2	2
Nov	5.4	5.4	100	77%	3	2
Dec	6.07	6.07	100	77%	3	3
Total =						**647**

* Assumed at 95% plant factor

District flow records for the calendar year 2008 at the Sandtrap Siphon were reviewed and the maximum flow of 35cfs is expected during the irrigation season. Flows during the winter months will likely vary between 3 and 10cfs, depending on water demand, availability and operational requirements.

4.1.1. Project Specific Environmental Considerations

The following is a description of the environmental resources

The Project is located at the elevation of about 3,100 feet in the foothill region of the Central Sierra Nevada, in the north-central section of El Dorado County. The vegetation in this region is yellow-pine forest; representative species are Pinus ponderosa, P. lambertiana, Calocedrus decurrens, and Arbutus menziesii. The vegetation immediately surrounding the siphon outlet to Lake Walton, where the hydroelectric generator will be located, is highly disturbed. The area is graveled and only minor weed species are present. There are no special-status vegetation communities within or adjacent to the proposed Project area.

The California Natural Diversity Database (CNDDB), USFWS databases and reconnaissance field review of the affected Project area were completed. The March 2012 CNDDB GIS database update was used to identify all recorded special-status species occurrences within 5 miles of the Project (see Appendix B and Figure 1). The USFWS list for the Georgetown USGS 7.5 minute topographic quadrangle was also reviewed. The results of this database review are summarized in the Special Status Species table in Appendix B.

Multiple species with federal and/or California listing under the ESA or CESA are located within 5 miles of the Project, but not within the Project Area. The Project site itself does not provide suitable habitat for these special status species. The hydroelectric generation portion of the Project would be located on a highly disturbed area that has been subject to leveling, grading and regular weed abatement (see Appendix A). The siphon outlet for the water is into Walton Lake, which is regularly stocked with fish considered to be predators to special-status aquatic species including the California red-legged frog.

The Project site is located where the Sandtrap Siphon pipeline empties raw (untreated) water into Walton Lake. Maximum flow during the irrigation season is about 35 cfs through the 30-inch pipe. Flows through the pipeline range from 3 cfs to 35 cfs, depending on demands by District water customers and water availability. The District receives approximately 12,000 acre-feet per year through this system.

The North Central Information Center (NCIC) performed a cultural records search of the Project Area on March 7, 2012. The NCIC indicates that the proposed Project area contains no recorded prehistoric archaeological sites and one new historic-period resource listed with the California Historical Resources Information System (see Appendix C). The NCIC has one additional report of an archaeological study conducted within or adjacent to the current Project area. State and Federal inventories list one historic property (buildings, structures, or objects) within the general Project area. The NCIC notes that there is low to moderate sensitivity for identifying prehistoric archaeological sites, and moderate to high sensitivity for finding historic-period

cultural resources in the general Project area. Although the NCIC recommends further archival and/or field study by a cultural resource professional, such a study is not warranted because no buildings, structures, or objects are evident in the Project area and the area is already highly disturbed. The NCIC indicates that the Office of Historic Preservation has determined that buildings, structures, and objects 45 years or older may be of historical value, and that if the area of potential effect contains such properties not noted in NCIC's research, they should be assessed by an architectural historian before commencement of Project activities. Additionally, the NCIC notes that if cultural resources are encountered during the Project, workers should avoid altering the materials and their context until a cultural resource consultant has evaluated the situation.

The Native American Heritage Commission (NAHC) performed a Sacred Lands File Search on March 12, 2012, and indicated that they have no records of Native American cultural resources within the Project Area (see Appendix C). The NAHC provided a list of tribes in the area and recommended that they be notified of the proposed Project so that they can review their own records of the Project Area for recorded resources; therefore, these tribes are included on the attached mailing list.

The hydroelectric facility would be housed in a small structure adjacent to the existing pipeline that empties into Walton Lake. The Project will not detract from the aesthetics of the area, which includes the siphon outfall, Walton Lake WTP, picnic and man-made dam facilities, and existing power-line in the Project area.

Based on the review of the USFWS and CNDDB databases, there are no USFWS-designated Critical Habitat Areas for Federally Threatened or Endangered species present within 5 miles of the Project. As discussed in the Fish and Wildlife Resources Section above, the Project site does not provide suitable habitat for the special status species identified in the database searches for the USFWS or the CNDDB.

The proposed Project would have negligible adverse environmental effects. The turbine-generator building would be located adjacent to the existing buried siphon pipeline and set back from Walton Lake. This area is flat and is maintained annually to remove vegetation in the vicinity of the siphon outlet. Slip-lining to reinforce a portion of the existing siphon would be staged from existing access road crossings of the siphon and the siphon outlet location without the need for grading or vegetation removal. An on-site reconnaissance level biological survey and database reviews indicate no special status species or habitats of concern in the Project area. Construction would be scheduled to comply with the El Dorado County Noise Ordinance limitations on construction hours, and operation would not increase noise above ambient conditions. The turbine-generator would be enclosed within the power house building thereby reducing any ambient noise from operations. Furthermore, the power house building would be designed to minimize aesthetic effects and attraction as a public safety nuisance. Construction measures would include temporary fencing and physical barriers to contain construction materials, prevent stormwater runoff into the lake, and exclude recreationists and local residents that may be interested in construction activities.

Impacts to cultural and archaeological resources would not be expected because there are no identified resources in the area of Project disturbance and the Project would be added to the District's existing water pipeline. While the siphon is around 45 years old (i.e., the threshold for what could be considered an object of historical value), the Project would not affect the integrity or informational value of the siphon, which has remained in operation and would continue to remain in operation with the implementation of the Project. If cultural resources are found during the Project, avoid altering the materials and their context until a cultural resource consultant has evaluated the situation.

4.1.2. Economic Evaluation

The total estimated project costs for the $1,291,000. A summary of the costs are provided in the table below. A detailed cost estimate for the project is provided in Appendix C along with a preliminary layout of the site.

Table 12. Summary of construction cost estimate

Description	Estimated Cost
Mobilization and Site work	$74,500
Pipe, valves and fittings	$167,000
Turbine/Generator Units	$300,000
Electrical/SCADA/Interconnection	$260,000
Building/structural	$74,000
Subtotal	**$875,500**
Contingency (15%)	$131,325
Engineering/environmental/misc.	$284,000
Total Project Costs	**$1,291,000**

The following table provides a summary of the economic evaluation for the Sandtrap Siphon based on utilizing the FIT revenues of $0.09/kWh (the current based load rate for the ReMAT Feed-In-Tariff. Costs may go up from there, however they cannot be guaranteed. The preliminary evaluation provided below does not include any escalation factors or inflation and assumes an interest rate of 4%.

Table 13 Financial Summary with ReMAT program

Description	ReMat Program
Annual Generation in kWh	647,000
Net Cost	$1,291,000
Annual Maintenance Cost	$15,000
Annual Generation Revenue	$58,230
30-year NPV	-$543,465
Payback Period in years	Over 30

4.1.3. Conclusion/Recommendations

The project is not feasible at this time based on the calculated NPV. Programs that would help to make the project more feasible would be a lower interest loan or grant. For this particular project a grant would be necessary for a positive NPV to be calculated. The other option would be to negotiate a higher tariff rate with PG&E.

Additionally, a high cost associated with this project is the replacement of the existing pipeline that is aging and must be replaced to withstand the higher pressures associated with the hydroelectric project. As the infrastructure continues to age the District may replace the pipeline as part of a separate project. Once this pipeline is replaced the costs of the hydroelectric facility are reduced significantly. The project should be reevaluated once the pipeline is replaced.

5.0 Grizzly Flats Community Services District

5.1. WTP Reservoir Solar Project

Grizzly Flats Community Services District (GFCSD) has one uncovered raw reservoir that feeds its treatment plant located near their main office. Opportunities for solar projects at the site include the use of ground mounted arrays and the use of floating arrays within the reservoir.

5.1.1. Electrical Load Present

The District has a total on five (5) utility meters and a total annual usage of 34,890 kWh based on a PG&E summary from July 2011- July 2012. The intent of the solar project would be to offset the power usage from all five meters. The five meter locations and annual usage are summarized in the table below.

Table 14. Meter usage at District

Meter Location	Total Usage (July 2011-July 2012 (kWh)
Forest View drive	5,060
Sciaroni Road	19,015
N. Southview Drive	269
Tyler Drive	8,948
Winding Way	1,598
Total Usage (kWh)	34,890

5.1.2. Available Area

A review of the site indicates that there are several areas adjacent to the reservoir that are relatively flat provide sufficient area for a solar array system. Three areas were considered. The first site is north of the reservoir and is currently used access around the reservoir. This area is approximately 3,000 square feet in size. This area is closer to the District office and Treatment Plant. The reservoir is elevated above the District office and Treatment Plant as seen in the photo below. The solar arrays placed above on the sides of the reservoir would have minimal impact visually.

Figure 6. View of the GFCSD Reservoir from the District parking lot area.

The second area considered is an open area to the south of the reservoir. This area could also provide 3,000 square feet. The area has access off of South View Drive. The final area considered would be to utilize floating arrays within the uncovered reservoir. The bottom area of the reservoir is approximately 55,000 square feet in area which is more than required to offset existing usage. The three areas considered are shown on the aerial view of the facility below.

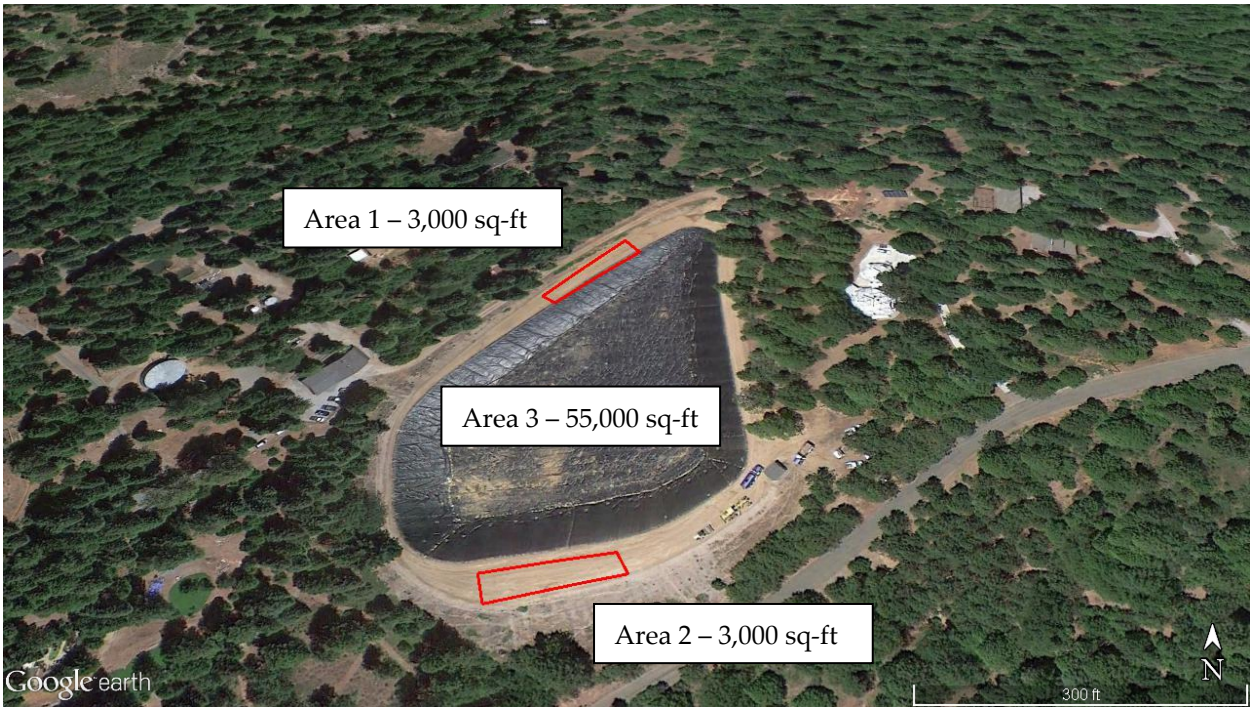


Figure 7. Location of potential solar sites at Grizzly Flats Reservoir site

5.1.3. Optimal size of the System

Optimal size of the system will depend on the metered service selected and the type of panel installed. Static inclined panels will be sized differently from automated tracker panels.

While it is possible to feed solar power behind each utility meter and offset usage, it may be more prudent to combine the services and feed behind a single utility meter that is large enough to handle the entire solar installation. PG&E needs to be contacted to confirm that one of the existing meters could be used or determine if a new meter installation is required.

Based on the existing usage of the District it is estimated that a 22kW system is required with a required area of approximately 1,500 square feet. All three of the areas could be utilized for this installation.

5.1.4. Capital Cost and Generation Estimates

Based on cost estimates previously performed as part of TM #7 and cost proposals received from solar vendors by the District it is recommended that a ground mounted array be utilized.

Type of System	Potential System Size	Average Cost ($/kW)	Total Estimated Capital Cost (1)	Potential Power Generation (2)
Ground Mounted	22kW	$6,500	$143,000	34,760 kWh
Floating Arrays	22kW	$8,000	$176,000	34,760 kWh

Note: (1) Capital Costs assume that the site work will be completed by an outside contractor as part of the overall project, (2) Potential power generation is based on a 1MW system producing approximately 1.580 MWh annually

5.1.5. Economic Feasibility Analysis

In order to determine the feasibility of solar opportunities at each site the different economic programs were considered for each site opportunity along with environmental impacts and capital costs. An evaluation and recommendation for each site is presented below.

The following is based on GFCSD owning and operating a solar project independently to offset their existing electrical uses. Additionally, an agreement with private investors could be pursued by GFCSD in the future to reduce initial costs, reduce risks and take advantage of tax incentive programs that GFCSD is not eligible for. The details of such an agreement would need to be worked out between GFCSD and the investor. This analysis does not speculate on the terms of such an agreement.

5.1.6. Operation and Maintenance costs

PV systems are extremely durable; having no moving parts and tend to degrade slowly over their 30-year lifespan. Maintenance consists of cleaning the modules at least once a year to prevent dirt, dust, and salt buildup. Inverters necessary to convert the direct current produced by the panels to alternating-current used by the plant require more maintenance that the panels themselves and need to be replaced every 10-15 years although larger inverters (> 50 kW) may

be "rebuilt". It is estimated that the annual maintenance costs for smaller systems such as the one proposed for GFCSD is approximately $500. This estimate includes cleaning, preventative maintenance, unscheduled maintenance, insurance, and rebuilding/replacing the inverter once in the 30-year life.

5.1.7. Criteria for Evaluation

In order to evaluate the feasibility of the project the criteria for evaluation must be established. Based on criteria used previously in TM #7 the project was evaluated based on the following criteria:

- Net Present Value (NPV) of the project
- Payback period for the project (must be less than 20-years)

The project was evaluated using a 30-year loan period with a 4% interest rate (based on recent agency loans). The following sections describe the programs used to determine the potential annual return for the project which was then used to determine the NPV and payback period.

5.1.8. Site Evaluation Data

The programs that could be applied at the GFCSD Facilities include:

- PG&E's Net Metering Program (NMP)

If the 22kW system is selected to offset the usage of the District's existing 5 meters it could utilize the NMP Programs. The economic evaluation assumes the worst case that the project would not utilize the California Solar Initiative program which was recently moved from the Energy Commission to the utility companies under the direction of the California Public Utility Commission (CPUC).

To determine the annual return of offset costs for the system it is assumed that GFCSD would have similar costs to their usage in 2011-2012 which yields an annual potential cost savings of approximately $7,500.

To determine the feasibility the annual payment for a 30-year loan at 4% interest was determined. For the 22W project the annual payment would be $8,270/year.

Table 15. Capital Cost and Estimated power generation for potential projects

Type of System	Total Estimated Capital Cost (1)	Potential Power Generation (2)	App. Programs	Potential Annual Return	Annual Debt Service (based on 4% interest)	O&M Costs
Ground Mounted 22kW	$143,000	34,760 kW	NMP	$7,500	$8,270	$500

Note: (1) Capital Costs assume that the site work will be completed by an outside contractor as part of the overall project; (2) Potential power generation is based on a 1MW system producing approximately 1.580 MWh annually

Based on the analysis above the Net Present Value for the project was calculated to be -21,960 and the payback is over 30 years.

5.1.9. Conclusion

Based on the feasibility criteria set for this project it is not recommended for implementation at this time. However, as with the other solar projects analyzed under TM#7 the project could be made feasible through the use of a reduced interest loan program in combination with a grant to reduce the capital cost. The table below describes the programs that would be needed to make this project feasible.

Project	Capital Cost	Reduced Cost Required (at 4% interest rate)	% Cost Reduction Required
WTP Solar	$143,000	$95,000	34%

6.0 Amador Water Agency

6.1. Tanner Powerhouse Hydroelectric Overview

The Tanner Powerhouse site is located at the Tanner Reservoir Dam. The Dam is adjacent to the Tanner Water Treatment Plant near the Amador Water Agency main office at 12800 Ridge Road in Sutter Creek. The water source for the project is the Amador Transmission Pipeline that terminated at a pressure reducing station on the crest of the dam. The transmission pipeline varies in size and terminates with a 20-inch pipeline at the pressure reducing station. Figure 8 below shows the site location in reference to the AWA office.

Figure 8. Location of Tanner Reservoir

The Tanner Powerhouse would operate in parallel with the existing pressure reducing station (PRS). The existing PRS reduces pressure from approximately 100psi to approximately 15psi. The differential head available for hydropower generation varies between 150feet and 200feet of head depending on the flow rate. Flow varies between zero and 5,800gpm depending on the demand of the WTP.

Data provided by AWA shows that flow rates change in a step-wise manner due to the operation of the WTP. When the WTP is called to change operation such as go into backwash mode, the flow rate briefly reduces to zero or near zero cfs. Then flow returns to a steady state

for a period of time. These steps generally occur in 3.3cfs (1500 gpm) increments. The operation of the hydropower station needs to see a steady flow and pressure in order to operate efficiently (assuming PaTs technology). This will be accomplished by controlling pressure coming into the hydropower station separately from the existing PRS, and controlling flow by allowing the existing PRS system to bypass flows in excess of the turbine capacity. Instead of flows going to zero or near zero, new valve operation at the existing PRS will divert flow into the Reservoir to maintain steady operation. This will result in the Reservoir water levels fluctuating more than they have historically.

6.1.1. Generation Estimates

Data was provided for two completed years, 2010 and 2011, for analysis. In order to calculate the generation potential several combinations of Cornell PaTs were modeled. Two units are necessary to maximize the annual generation. The final generation estimates for 2010 and 2011 are shown in the table below.

Table 16. Estimated generation for 2010 and 2011 data

Year	Estimated Generation (kWh)
2010	558,295
2011	554,006

6.1.2. Interconnection, Permitting and Environmental Evaluation

A preliminary evaluation of PG&E's facilities indicated that capacity exists for interconnection of the proposed facilities. Once final design begins a more detailed analysis of the facilities will be conducted. Based on the project scope and location it appears to fall under a FERC exemption and CEQA exemption processes as described earlier in this TM. A FERC exemption will need to be filed prior to project approval. For the CEQA exemption a Categorical Exemption will be prepared for approval by the AWA Board prior to the start of construction. A cursory review of the site did not identify any areas of concern for endangered species or historical significance.

6.1.3. Preliminary Economic Evaluation

In order to evaluate the economic feasibility of the project a preliminary construction cost estimate was prepared. The following is a breakdown of the costs.

Table 17. Estimated project costs

Description	Total Estimated Cost
Site work	$67,000
Pipe, valves, fittings	$283,120
Turbine/generator	$185,300
Electrical and Interconnection	$295,000
Building	$49,020
Subtotal	$879,440

Contingency (15%)	$131,916
Engineering/Admin/Environ, etc.	$376,400
Total Estimated Costs	**$1,387,756**

The preliminary financial analysis assumes the use of net-metering utilizing the energy generated on-site at the adjacent WTP. A 30-year NPV was first calculated assuming no escalation of utility costs and then assuming a 3% escalation rate. A positive NPV is calculated when inflation is taken into account for both the utility rate and the maintenance costs. This also assumes no financial incentives are obtained for the project. The preliminary analysis also assumes a financing rate of 4% based on recent projects with EID.

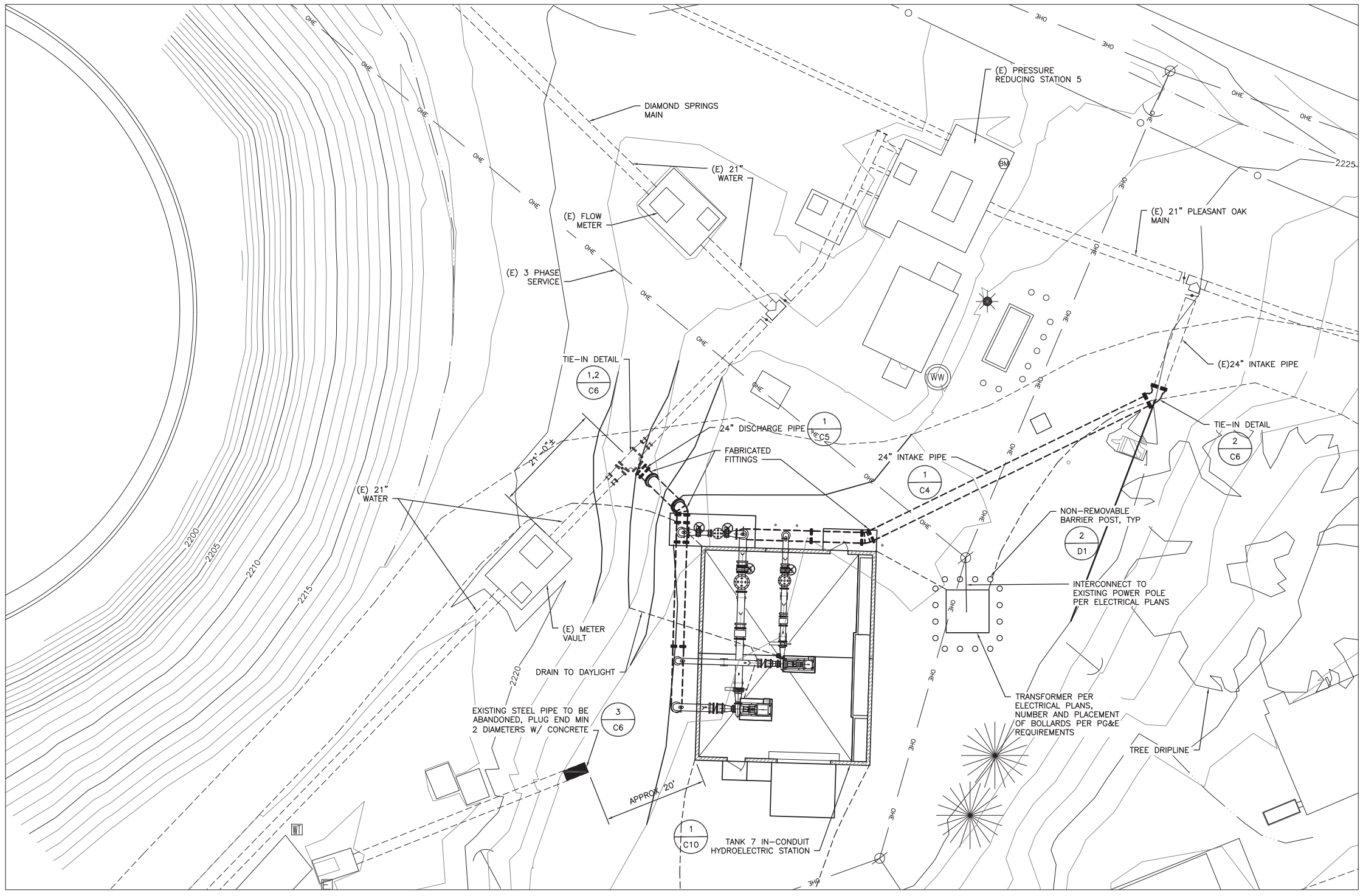
Table 18: Financial Summary with Net-metering program

Description	NMP
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]

6.1.4. Conclusion/Recommendations

Based on the preliminary financial analysis the project appears feasible if a grant or other financial incentive can be obtained. The project is currently proceeding to a 50% design stage which will provide a more detailed construction estimate and determine if financial incentives can be obtained. AWA is currently looking into multiple financial incentives including a Sel-Generating Incentive Program (SGIP) subsidy of $92,500 and a Renewable Energy Credit (REC) of $0.01/kWh (approximately $5,500/year). These incentives would greatly increase the economic feasibility of the project. As mentioned previously these type of financial incentives along with a lower interest rate on upfront costs are vital to making these projects work economically.

APPENDIX A – Project Layout for Tank 7 Hydro-electric Project



EID PROJECT NO.
13013
EID DRAWING NO.
6203

REV	DATE	BY	DESCRIPTION

SCALE: 1" = 10'

WARNING: 0 1/2 1 — IF THIS BAR DOES NOT MEASURE 1" THEN DRAWING IS NOT TO SCALE.

DESIGNED
DRAWN
CHECKED

DOMENICHELLI & ASSOCIATES
1107 Investment Blvd. Suite 145
El Dorado Hills, CA 95762
Ph: (916) 933-1997
Fax: (916) 933-4778

NLINE ENERGY — ENERGY OWNERSHIP ENERGY

REGISTERED PROFESSIONAL ENGINEER — DAVID EDWARD TOMELLI — NO. C38650 — Exp. 03/31/15 — CIVIL — STATE OF CALIFORNIA

REGISTERED PROFESSIONAL ENGINEER — JOSEPH M. DOMENICHELLI — NO. C38068 — Exp. 3/31/15 — CIVIL — STATE OF CALIFORNIA

TANK 7 IN-CONDUIT HYDROELECTRIC PROJECT

SITE PIPING & GRADING PLAN

SHEET C2

FERC PROJECT NO.: 13714

Z:\PROJECT FILES\INLINE RESERVOIR 7\DRAWINGS\RES 7 - C1, C2, & C3.DWG

20140116.150114

APPENDIX B – Cost estimate and schematic layout for Tank 3 Hydro-electric Project

EDM2-PRS1				
Hydroelectric Project				
Engineer's Preliminary Estimate of Probable Costs				
Element Description	**Estimated Quantity**	**Units**	**Unit Price (installed)**	**Estimated Amount**
Mobilization & Site work				
M[illegible]d[illegible]r[illegible]	1	[illegible]	[illegible]	[illegible]
[illegible]r[illegible]r[illegible]	1	[illegible]	[illegible]1[illegible]	[illegible]1[illegible]
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[illegible]	1	[illegible]	[illegible]1[illegible]	[illegible]1[illegible]
			Subtotal =	**$ 66,500**
Pipe, Valves and Fittings				
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[illegible]"[illegible]d[illegible]	[illegible]	[illegible]	[illegible]	[illegible]1[illegible]
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[illegible]"[illegible]r	1	[illegible]	[illegible]1[illegible]	[illegible]1[illegible]
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Turbine/Generator Units				
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			Subtotal =	**$ 375,000**
Electrical Equipment & Tie-in to Grid				
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			Subtotal =	**$ 260,000**
Building and Misc Structural				
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[illegible]d[illegible]r[illegible]r[illegible]r[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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			Materials/Installation Subtotal =	**$ 985,150**
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			TOTAL CONSTRUCTION COST:	**$ 1,133,000**
Non -Construction Costs				
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[illegible]r[illegible]M[illegible]r[illegible]	[illegible]	[illegible]		[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]1[illegible]
[illegible]r[illegible]d[illegible]r[illegible]r[illegible]	[illegible]	[illegible]		[illegible]
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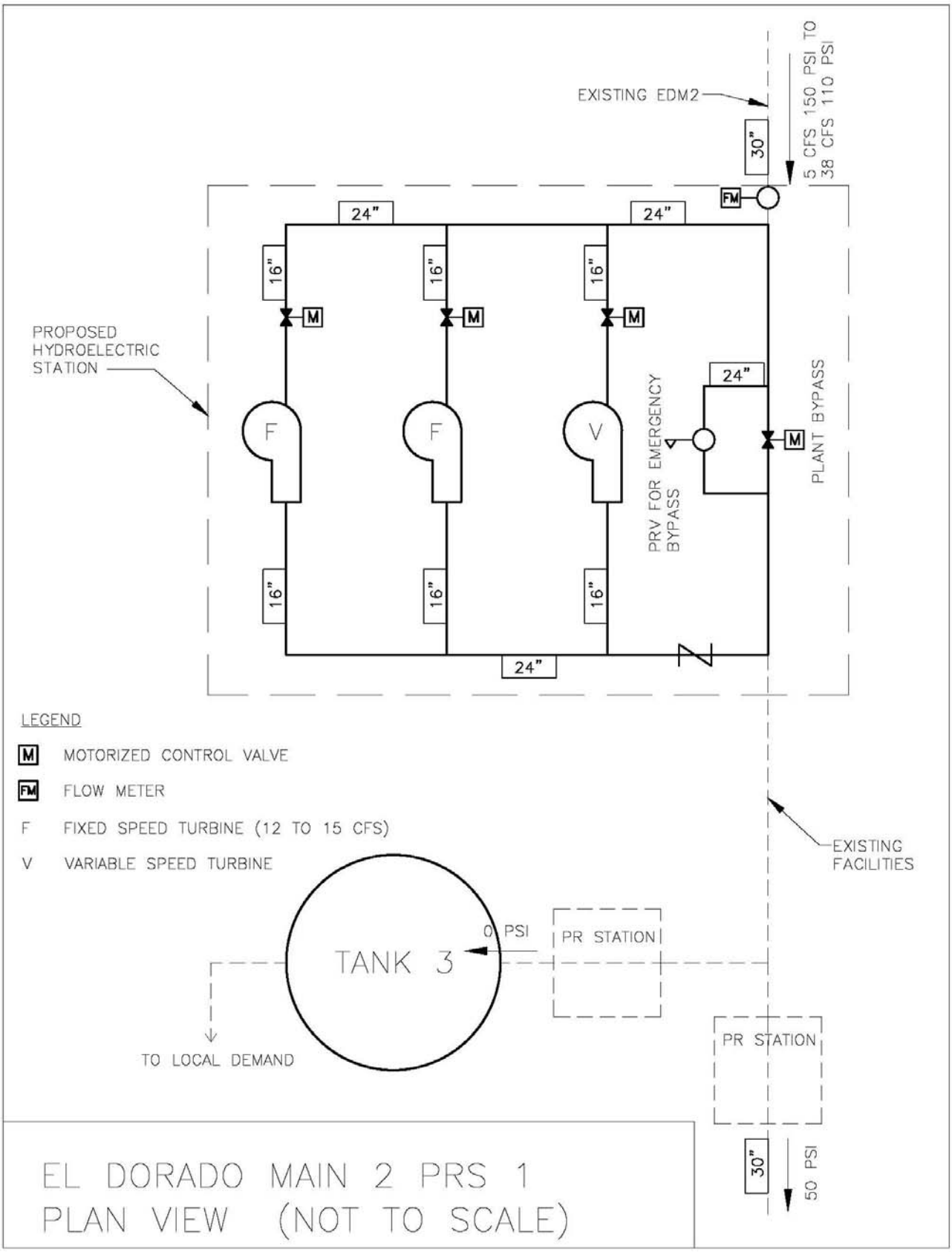
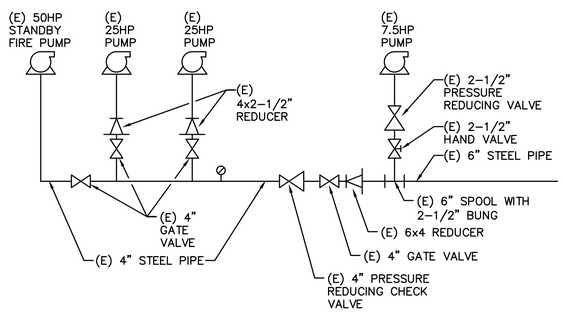
			TOTAL ESTIMATED COST =	**$ 1,556,000**

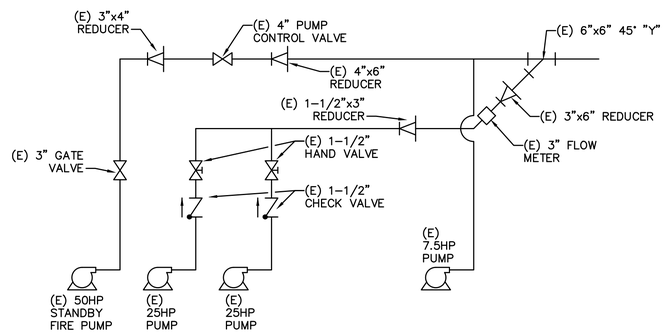
El Dorado Irrigation District


EXISTING EDM2
5 CFS 150 PSI TO
38 CFS 110 PSI
30"
FM
24"
24"
16"
16"
16"
M
M
M
PROPOSED
HYDROELECTRIC
STATION
F
F
V
24"
PRV FOR EMERGENCY
BYPASS
PLANT BYPASS
M
16"
16"
16"
24"
LEGEND
M MOTORIZED CONTROL VALVE
FM FLOW METER
F FIXED SPEED TURBINE (12 TO 15 CFS)
V VARIABLE SPEED TURBINE
EXISTING
FACILITIES
TANK 3
0 PSI
PR STATION
TO LOCAL DEMAND
PR STATION
30"
50 PSI
EL DORADO MAIN 2 PRS 1
PLAN VIEW (NOT TO SCALE)

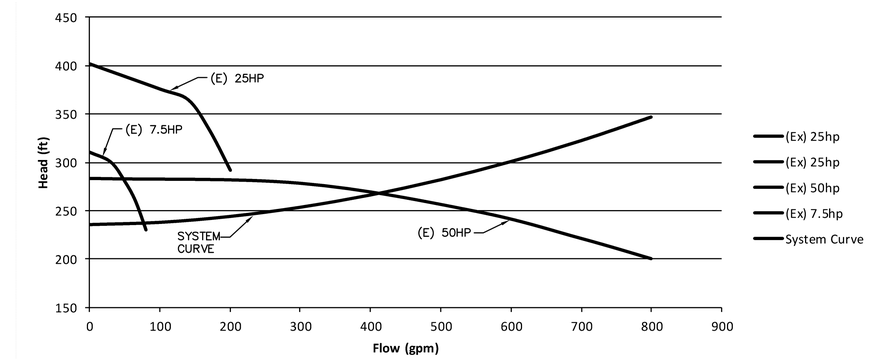
APPENDIX C – Layout for Oro Loma Pump Station Improvements



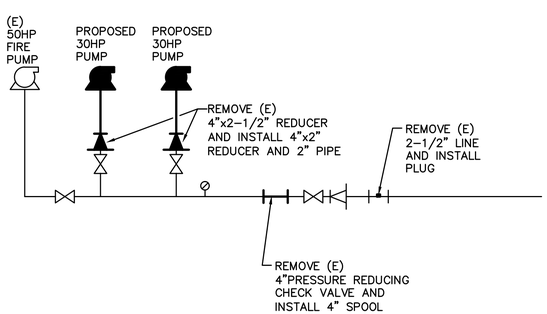
EXISTING PIPING PLAN SCHEMATIC



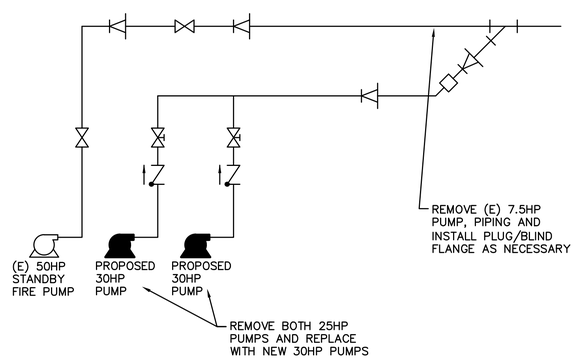
EXISTING PIPING PROFILE SCHEMATIC



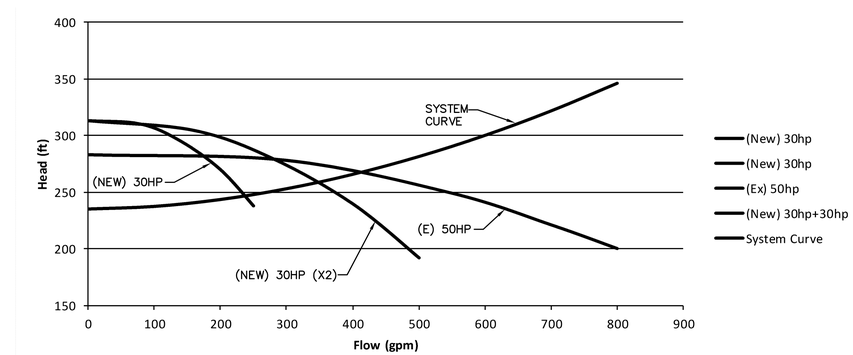
EXISTING SYSTEM AND PUMP CURVES



PROPOSED PIPING PLAN SCHEMATIC



PROPOSED PIPING PROFILE SCHEMATIC



PROPOSED SYSTEM AND PUMP CURVES

REV	DATE	BY	DESCRIPTION

SCALE: N.T.S.

WARNING 0 1/2 1 — IF THIS BAR DOES NOT MEASURE 1" THEN DRAWING IS NOT TO SCALE.

DESIGNED A. MOTIEJUNAS
DRAWN A. MOTIEJUNAS
CHECKED SARA ROGERS

DOMENICHELLI & ASSOCIATES
1101 Investment Blvd. Suite 115
El Dorado Hills, CA 95762
Ph: (916) 933-1997
Fax: (916) 933-4778

EL DORADO IRRIGATION DISTRICT
2890 MOSQUITO ROAD - P.O. BOX 1047
PLACERVILLE, CALIFORNIA 95667

ORO LOMA BOOSTER PUMP STATION

EXISTING AND PROPOSED PUMP/PIPING SCHEMATIC

SHEET 1 OF 1

APPENDIX D – Cost estimate and layout for GDPUD Sandtrap Siphon Hydro-electric Project

Sandtrap Siphon
Hydroelectric Project
Engineer's Preliminary Estimate of Probable Costs

Element Description	Estimated Quantity	Units	Unit Price (installed)	Estimated Amount
Mobilization & Site work				
M[illegible]d[illegible]r[illegible]	1	[illegible]	[illegible]	[illegible]
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Pipe, Valves and Fittings				
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[illegible]" [illegible]r	1	[illegible]	[illegible]1[illegible]	[illegible]1[illegible]
			Subtotal =	**$ 167,000**
Turbine/Generator Units				
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			Subtotal =	**$ 300,000**
Electrical Equipment & Tie-in to Grid				
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[illegible]r[illegible]d	1	[illegible]	[illegible]	[illegible]
[illegible]d[illegible]r[illegible]r[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
			Subtotal =	**$ 260,000**
Building and Misc Structural				
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[illegible]d[illegible]r[illegible]r[illegible]r[illegible]d[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]M[illegible]r[illegible]	1	[illegible]	[illegible]	[illegible]
			Subtotal =	**$ 74,000**
			Materials/Installation Subtotal =	**$ 875,500**
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			TOTAL CONSTRUCTION COST:	**$ 1,007,000**
Non -Construction Costs				
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[illegible]				[illegible]
			Subtotal =	**$ 284,000**
			TOTAL ESTIMATED COST =	**$ 1,291,000**

Annual Costs			
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[illegible]r[illegible]M[illegible]r[illegible]			[illegible]
[illegible]r[illegible]d[illegible]r[illegible]d/M[illegible]r[illegible]r[illegible]		[illegible]	[illegible]1
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[illegible]1[illegible]		1[illegible]	[illegible]1[illegible]
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SITE MAP
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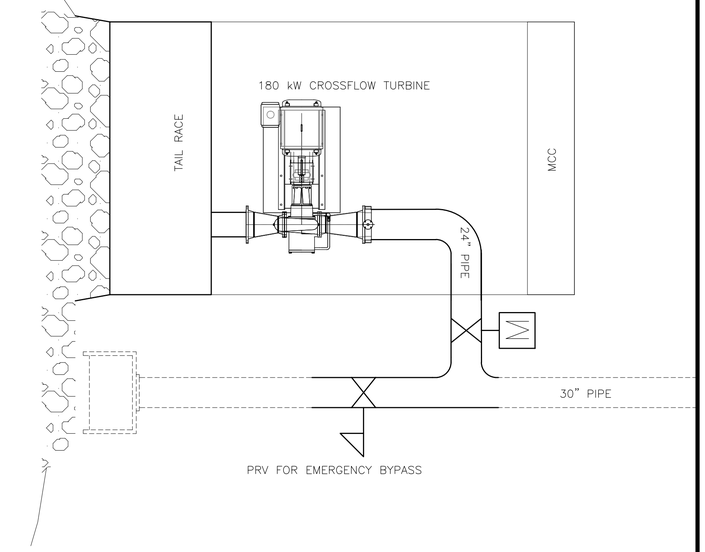

BUILDING PLAN
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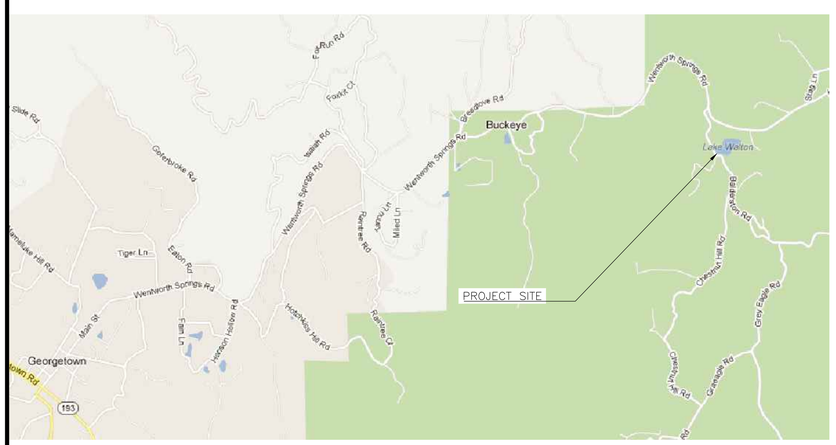

PROJECT LOCATION MAP
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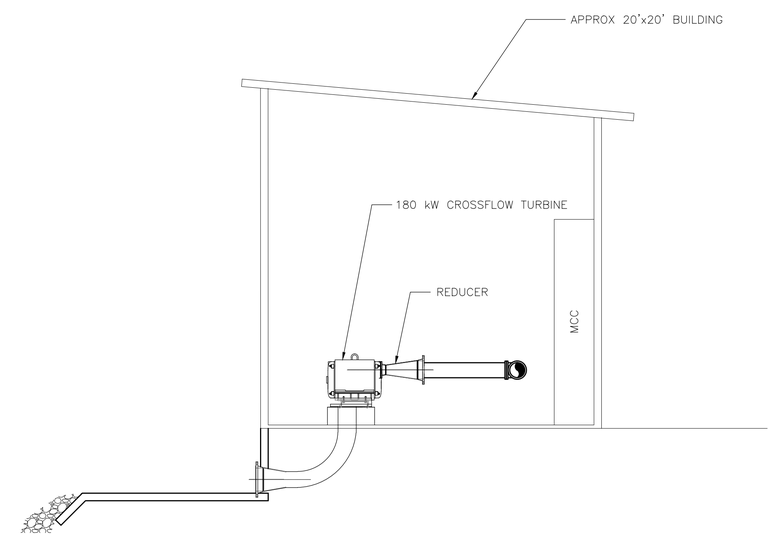

BUILDING PROFILE
1" = 5'

REVISIONS			
NO.	DESCRIPTION	DATE	BY

BENCH MARK DESCRIPTION ELEV. N/A

FIELD BOOK

SCALE
HORIZ: AS NOTED
VERT. AS NOTED

DRAWN BY: BTH DATE: 03/14/12
DESIGN BY: BTH R.C.E. C77713 DATE: 03/14/12
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GEORGETOWN DIVIDE PUBLIC UTILITY DISTRICT

SANDTRAP SIPHON IN-CONDUIT HYDROELECTRIC PROJECT
FERC EXEMPTION, EXHIBIT G

PN:

SHEET 1 OF 1