

Appendix D

Power Requirements Analysis

Power Requirements Analysis Technical Memorandum

Cadiz Groundwater Conservation and Storage Project
San Bernardino County, California
Phase I

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TECHNICAL MEMORANDUM

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Project: Cadiz Groundwater Conservation and Storage Project

Subject: Phase I – Power Requirements and Supply Analysis

Background

Cadiz, Inc. (Cadiz) is a publicly traded renewable resources company founded in 1983. Cadiz owns 34,000 acres of largely contiguous land in the Cadiz and Fenner valleys, located in the eastern Mojave Desert. In the early 1990's, Cadiz recognized the potential for developing a water supply project on its properties and reached out to partner with water supply agencies. In 1999, Black and Veatch conducted a feasibility study titled *Cadiz Groundwater Storage and Dry-Year Supply Program* (dated November 1999). The study evaluated the operation of a groundwater storage and transfer project, in collaboration with Metropolitan Water District of Southern California (MWD). The project would have involved transporting surplus Colorado River water to the project site, recharging it through a series of recharge basins, storing the water, and then extracting the stored water during times of drought. The feasibility study demonstrated a significant potential for water supply development, yet MWD decided not to pursue the project in 2001.

Cadiz continues to pursue the development of a water supply project which emphasizes water conservation by capturing natural recharge in the Fenner and northern Bristol valleys that would otherwise discharge to the Bristol and Cadiz dry lakes and evaporate. In July 2010, CH2MHill conducted additional studies to assess the quantity of groundwater flowing through the Fenner Gap area and published its findings in a study titled *Cadiz Groundwater Conservation and Storage Project* (dated July 2010). The additional studies and groundwater modeling demonstrated that several thousands of acre-feet of water could be recovered from the Fenner Gap area. These significant findings have led Cadiz to consider developing a well field extraction project, which would extract groundwater from the Fenner Gap area and convey it to the Colorado River Aqueduct (CRA) to be purchased by MWD as an additional regional water supply.

Introduction

Several studies (some mentioned previously), have proposed various project components for the Cadiz Groundwater Conservation and Storage Project. These components consist of a well field; large diameter conveyance pipeline; forebay(s), and high service pump station(s).

RBF Consulting (RBF) has been contracted to provide technical support for further development of the Cadiz Groundwater Conservation and Storage Project. The purpose of this technical memorandum (TM) is to develop the approximate power requirements for Phase I of the project. Phase I of the project consists of groundwater extraction and conveyance to the Colorado River Aqueduct (CRA). This would be accomplished with a well field, conveyance pipeline, and intermediate pump station (IPS). Each project component is briefly described below and illustrated in Exhibit A.

Cadiz Well Field

The well field would be approximately 4,000 acres located on Cadiz property in the Fenner Gap area (see Exhibit A). The well field would consist of approximately 30 wells, each well approximately 1,000 feet deep. Each well would pump approximately 2,500 gpm. The entire well field is anticipated to extract 50,000 – 100,000 acre-feet per year (afy) of groundwater from the Fenner Gap area.

Conveyance Pipeline

The extracted groundwater would be conveyed to the CRA through a large diameter pipeline. The pipeline is approximately 42 miles long, ranging in size from 60-inch to 96-inch diameter. In 2008, Tetra Tech provided a preliminary engineering analysis for the proposed pipeline alignment along the Arizona and California (ARZC) railroad alignment titled *ARZC Railroad Alignment* (dated July 2008). RBF has updated the pipeline hydraulics, using the previous Tetra Tech alignment study as a basis. The revised conveyance pipeline alignment can be divided into four (4) segments as listed in Table 1.

Table 1
Conveyance Pipeline Description

Pipeline Segment	Length		Diameter	Description	
	ft.	mi.	in.	From	To
1	63,000	12	60	Well Field	Tunnel
2	12,000	2	96	Chubbuck Tunnel	
3	69,000	13	60	Tunnel	IPS
4	79,330	15	84	IPS	CRA
Total	223,330	42			

Segment 1 consists of 63,000 linear feet (LF) of 60-inch diameter pipe to convey extracted groundwater from the well field to the newly proposed Chubbuck tunnel (Segment 2).

Segment 2 consists of a 96-inch diameter pipeline, tunneled approximately 12,000 LF through the Chubbuck area, which is the high point in the conveyance system (elev. ~ 1,021 ft MSL). The well field pumps would convey the extracted groundwater (Segment 1) to the horizontal storage tank (Segment 2), and the water would then gravity flow to the intermediate forebay (segment 3).

Although the Chubbuck Tunnel reduces the pumping head on the well field pumps by approximately 15-20 feet, the main purpose of the tunnel is to operate as a free water surface horizontal storage tank. Three options were considered to handle the high point in the system. Due to surge concerns, breaking head at the high point using a tank was the favorable option. The first (1) option was to not utilize storage (do not break head) and pump through the high point. This design would require air release valves which would be exposed to the harsh desert climate (very hot summers and very cold winters), and therefore would have to be routinely inspected to insure proper operation in the event of sudden pressure loss. If the air release valves fail, the potential impacts could be catastrophic. The second option (2) was to construct a vertical storage tank near the high point. This was determined not feasible since Cadiz does not own any land near Chubbuck and can not construct a tank in the railroad easement. The third (3) option was to tunnel a large diameter (96-inch) nearly horizontal pipeline that would operate as a storage tank. Stand pipes would be used to break head in the pipeline.

Segment 3 consists of 69,000 LF of 60-inch diameter pipe to convey groundwater from the Chubbuck Tunnel terminus to the intermediate forebay and pump station. The water would discharge from the horizontal storage tank (Segment 2) and gravity flow to the intermediate forebay. The IPS would then pump the water to the CRA (Segment 4).

Segment 4 consists of 79,330 LF of 84-inch diameter pipe, which conveys water from the IPS to the CRA. The pipeline diameter for Segment 4 is enlarged due to the pumping operations in the CRA as described in the following subsection (*intermediate pump station*).

Intermediate Forebay and Pump Station

The intermediate forebay and pump station (IPS) would be located on Cadiz owned property between the Milligan and Sablon areas (refer to Exhibit A). The extracted groundwater would gravity flow from the Chubbuck Tunnel to the proposed intermediate forebay, near the low point of the conveyance pipeline alignment. The forebay is approximately 15 acres in size and 10 feet deep, based on the pumping requirements of the MWD Colorado River Aqueduct. Refer to the *Operations and Hydraulics* section of this TM for IPS conceptual design criteria.

The proposed site to locate the IPS and forebay has several benefits. First, the Cadiz owned property is suitable to construct a large surface area forebay without purchasing additional parcels. Second, existing high voltage power lines, owned and operated by Southern California Edison (SCE), transect the Cadiz owned property. This is beneficial if electrical grid power would be used to operate the IPS and Cadiz well field.

Operation and Hydraulics

Cadiz Well Field

The Phase I Cadiz well field covers an approximate area of 4,000 acres and would operate at an average production rate of 50,000 afy. Peak production rates in wet years could reach 75,000 - 100,000 afy. The extracted water is pumped approximately 63,000 LF in a 60-inch diameter pipeline to the Chubbuck Tunnel. The well pumps are assumed to operate 24 hours/day, 365 days/year. The average ground surface elevation of the well field is approximately 900 ft MSL. The pumping water level is approximately 300 feet below ground surface (bgs). The crown of the proposed Chubbuck Tunnel is at an elevation of approximately 1,010 ft MSL. Therefore, the static lift of the well field pumps is approximately 420 feet, assuming 10 additional feet of head loss due to drawdown and well losses. Refer to Table 2 for the Cadiz well field conceptual design criteria.

Table 2
Cadiz Well Field Pumping Hydraulics Summary

Well Field Production	Pipeline Flow Rate¹	Pipeline Velocity²	Static Head	Dynamic Head	TDH
afy	mgd	ft/s	ft	ft	ft
50,000	45	3.5	420	40	460
75,000	67	5.3	420	85	505
100,000	90	7.0	420	145	565

1. Flow rate based on 24 hrs/day, 365 days/year, well field production.

2. Based on 60-inch diameter pipeline.

Intermediate Pump Station

The Phase I IPS would operate at a constant pumping rate of approximately 220 cfs (142.2 mgd) due to constraints by downstream MWD CRA pumping plants. The MWD CRA pumping plants contain constant speed pumps, which pump at a rate of approximately 220 cfs (142 mgd). Therefore, the water pumped from the IPS must be able to meet one 220 cfs MWD pump. The IPS would be located at an approximate ground elevation of 660 ft MSL and pump water to the CRA forebay, with an approximate elevation of 887 ft MSL, through approximately 79,330 LF of 84-inch diameter pipe. Therefore, the static lift of the IPS is approximately 227 feet.

The intermediate forebay would be receiving approximately 45 mgd (50,000 afy) extracted groundwater, 24 hours/day from the Cadiz Well Field. Since the constant speed IPS pumps would be operating at a much higher flow rate than the well field pumps, the forebay would fill and drain throughout a 24-hour period. The IPS is assumed to operate for 8 hours/day at a constant flow rate of approximately 220 cfs (142 mgd) to pump 50,000 afy to the Colorado River aqueduct. Refer to Table 3 for the IPS conceptual design criteria.

Table 3
Intermediate Pump Station Hydraulics Summary

Pipeline Flow Rate ¹		Pipeline Velocity ²	Static Head	Dynamic Head	TDH
cfs	mgd	ft/s	ft	ft	ft
220	142	5.7	227	83	310

1. Flow rate based on MWD CRA constant speed pumps.
2. Based on 84-inch diameter pipeline.

Power Requirements

Cadiz Well Field

As mentioned in the previous section, the Cadiz well field is assumed to extract groundwater from the Fenner Gap area 24 hours/day, 365 days/year. The average annual power requirements for the Phase I Cadiz well field are listed in Table 4.

Table 4
Cadiz Well Field Power Requirements

Well Field Production	TDH	Average Power Requirement ¹		Annual Power Requirement ²
		hp	kW	kWh
50,000	460	4,250	3,160	30,800,000
75,000	505	7,000	5,200	50,700,000
100,000	565	10,400	7,800	75,600,000

1. Average power requirement based on 85% pump efficiency.
2. Annual power requirement based on 90% motor transfer efficiency, 24hrs/day, 365 days/yr.

Intermediate Pump Station

As mentioned previously, the IPS is assumed to operate for 8 hours/day, 365 days/year, to pump approximately 50,000 afy of extracted groundwater to the Colorado River Aqueduct. The average annual power requirements for the Phase I IPS are listed in Table 5.

Table 5
Intermediate Pump Station Power Requirements

Flow rate		TDH	Average Power Requirement ¹		Annual Power Requirement ²
cfs	mgd		hp	kW	kWh
220	142	310	9,100	6,800	22,000,000

1. Average power requirement based on 85% pump efficiency.
2. Annual power requirement based on 90% motor transfer efficiency, 8hrs/day, 365 days/yr.

Power Delivery Options

This tech memo will examine three (3) options for supplying power to the well field and intermediate pump station (IPS), which are listed below. Additionally, methods to utilize hydro power as well as solar power generation will be addressed.

- All Electric
- All Natural Gas
- Hybrid Combinations

All Electric Power

Currently, no distribution voltage power lines are located in the vicinity of the well field or IPS with enough capacity to provide the needed power. One option for an electric supply is to take power from a 230kV power line that runs nearby the proposed location of the IPS. This is the same transmission power line that continues to the MWD Iron Mountain pumping plant. According to the Black & Veatch (B&V) report, this 230kV power line has sufficient capacity to feed this project, since a 10 MW load addition is only 25 amps at 230kV. A substation would need to be constructed as close as practical to the line to transform down to a sub-transmission voltage to distribute to the IPS and well field. Since a 230kV line represents a major SCE transmission line, and maintenance of a 230kV substation requires highly trained personnel, it is believed that SCE would design, construct, and maintain the substation. Depending on contractual agreements, Cadiz would pay for part or all of its cost.

The cost of a 230kV substation has significant variability depending on whether a new substation is built or an add-on to an existing substation can be done. The B&V report assumed that components could be added to the existing 230kV substation located at the MWD Iron Mountain pumping plant and a 69kV transmission line could be built from the pumping plant, back to the well field. This would be technically feasible but would require SCE/MWD buy in for construction at the substation and an easement through Bureau of Land Management (BLM) land from the pumping plant to the new pipeline alignment along the ARZC railroad. Construction of a high voltage transmission line along this route would encounter significant environmental permitting resistance and may not be feasible. Construction of a new 230kV substation near the IPS should solve this issue, as transmission lines could be located almost exclusively on Cadiz owned land. Therefore, a 34.5kV line would extend to the IPS and along the railroad alignment to the well field to provide power to these locations. The 34.5kV line allows the use of medium voltage switch gear at both locations without an additional substation.

The construction of a 230kV substation has two significant obstacles. The first is that SCE may refuse to construct a 230kV substation for the relatively small loads of the project. The loads of the Cadiz project would normally be fed from lines that would be 34.5kV or less, so it would be unusual to tap into a 230kV line. The second is that the design and construction of the substation could take up to two (2) years due to the uniqueness and complexity of the design. In addition, the control of design and construction of the substation would be totally out of Cadiz hands so that any problems or delays could adversely affect the project.

Phasing is another factor to consider, which allows the ability to put in and pay for partial system components in the first phase of the project and add components in later phases if the project grows in capacity. The all electric supply does not lend itself to this approach, as the least substation constructed at this voltage would have ample capacity for any ultimate project supply needs. Due to potential permitting, cost, and construction timeframes, it is suggested that this approach not be viewed as a primary desired approach.

Key conclusions concerning electric power:

- Substation expense could be very high.
- Substation design and construction not in Cadiz control.
- Ultimate supply capacity needs to be installed in first phase (no phasing).

All Natural Gas Power

In this option, all prime movers at both the well field and the IPS would be natural gas engines. A 30-inch high pressure gas line (#1903), owned and operated by El Paso Corporation, is located parallel to the ARZC railroad tracks, which is located near both the proposed well field and IPS locations. Brief discussions with El Paso Corp personnel, determined that the El Paso Natural Gas pipeline has a capacity of approximately 500 million scf/day and has sufficient capacity to supply gas to the project. The gas engines option would consume approximately 3 million scf/day. The application process to connect to the pipeline and construction of the tie-in connection would take approximately six (6) months. The application process takes approximately six (6) weeks, while construction could take upwards of 22 weeks.

Diesel fueled engines for powering the IPS pumps or for generating power is not recommended since diesel engines can not be permitted for permanent continuous operation. In addition, they assume to have higher costs and lower reliability of delivering large quantities of diesel fuel by truck compared to the availability of natural gas from the El Paso natural gas pipeline.

At the IPS, five (5) Waukesha P9390 engines (4 duty, 1 standby) would power each pump to convey the base case of 50,000 afy, or approximately 220 cfs for 8 hours a day. These engines are industrial rated units designed for continuous operation and can be air quality permitted using standard catalytic converters. The engines are specifically designed for natural gas applications and are capable of running continuously for 1.5 years with a minor overhaul and 3 years between a major overhaul. At the expected running demand of approximately one third, the maintenance intervals could be extended to several years. The economics section gives lifecycle costs for the engines for comparative purposes. A small microturbine unit could generate auxiliary power for the station.

Cost will be summarized in the economics analysis, but as a brief indication of operating costs, the Waukesha engines can produce power at the equivalent rate of \$0.07/kWh, which will be substantially cheaper than purchased power and other than the connection to the gas line, the project would be completely under Cadiz control.

While the Waukesha engines are ideal for the IPS, the high number, cost, and maintenance associated with the 20 or more engines required for direct pumping at each well head makes this option unrealistic. This is the major reason that the previous B&V study recommended the all electrical approach. A more practical approach that combines the advantages of gas and electric (hybrid) is presented in the next section.

Key conclusions concerning gas power:

- Connecting to the natural gas line (#1903) is considered feasible.
- Cost and maintenance of 20 or more gas engine well pumps is impractical.
- Gas engine driven pumps at the IPS does make sense.

Hybrid Power Combinations

As mentioned previously, a hybrid power combination, which combines the advantages of gas and electric is a more practical approach to supply power for this project. Several scenarios are possible, but two hybrid power combinations have been deemed practical for this project. Each hybrid option assumes five (5) Waukesha natural gas engines at the IPS, and electric motor drivers for each well head at the Cadiz Well Field.

Hybrid Option 1

The first hybrid option would upsize the existing 12kV power line that runs along the road near the well field. The viability of this approach would largely be determined by the ultimate load of the well field. For the 50,000 afy production, the 4,250 hp load could possibly be served by an upgraded power line. Typically, the substation that feeds the existing line should be within 10-15 miles of the site, but this would need to be verified by SCE as well as the capacity of the existing substation. SCE requires that an application for service be submitted to them prior to any action on their part. If the existing line could be upgraded, this would be the most cost effective solution for power at the well field. While some control over the power supply is lost as SCE would control the upgrading of their lines, this is not expected to present any major problems as low voltage power lines and substation upgrades are relatively standard for SCE.

Hybrid Option 2

The second hybrid option assumes a Solar® Turbine generator would be installed at the well field to generate sufficient power for each well pump motor. The turbine generators are rated for continuous operation and are readily permitted for air quality. These units produce power at an equivalent rate of \$0.07/kWh which makes them very attractive from an electrical cost standpoint. Power generated on site would be distributed at a voltage appropriate for the well pump motors. The turbines are designed to run continuously for several years without overhaul. The service agreement which would be purchased with the turbines includes all minor service needed on the unit as well as a complete replacement of the turbine every three years (two day downtime to install replacement turbine). A major advantage of this approach is that the total installed cost is less than the use of gas engine pumps and the control over the project remains in Cadiz hands.

The only significant issue is the connection to the gas line and the gas purchase agreement, which is not expected to be a major issue. Solar® was asked if they or anyone they work with would be willing to provide, install, and maintain the generating unit and supply power to Cadiz under a purchase power agreement and their response was that it is not practical for units in this size range. As previously mentioned, Solar® will provide the entire maintenance needs for the unit under their service agreement.

Key conclusions concerning hybrid power:

- Project control remains with Cadiz.
- Produced power cost is cheaper than if purchased (unless existing line can be upgraded at well field).
- Project can be phased. Additional engines or power producing turbines could easily be added for future increased capacity.

Hydro and Solar Power Options

Hydro Power Generation

Hydro power generation potentially exists at the IPS site under the current design scenario. As mentioned previously, extracted groundwater would gravity flow from the Chubbuck Tunnel to the intermediate forebay and pump station (Segment 3). This segment of pipeline would be 60-inch diameter, approximately 69,000 LF, with an elevation change of approximately 345 ft. Table 5 demonstrates potential energy that could be recovered (power generation) using turbines.

Table 5
Potential Conveyance Pipeline Recoverable Energy

Well Field Production	Static Drop	Dynamic Head Loss ¹	Recoverable Energy	
			Head (ft)	kW ²
50,000	345	45	300	1,230
75,000	345	95	250	1,530
100,000	345	160	185	1,510

1. 60-inch diameter pipeline.

2. Assuming combined turbine and generator efficiency of 70%.

Hybrid Option 3

In order to recover power the hydro unit would need a tie in to a power source which unfortunately would not exist if the gas engine option at the IPS were utilized. A power line would need to be constructed along the railway alignment to deliver the power back to the well field, and this will be assumed for purposes of the analysis. The total hydro power cost with a 12kV transmission power line would be approximately \$7.5 million (refer to Table 10 for a complete breakdown of costs for this option). A simple payback for 10,800,000 kWh per year at

\$0.07/kWh would be approximately 10 years, which would be appropriate if the Solar® turbine were producing power at the well field. If power was purchased at \$0.11/kWh from SCE, the payback would be approximately 6.5 years.

Solar Power Generation

Similar to hydro power, if solar power generation is installed at the IPS site, a transmission power line would need to be installed running back to the well field. For purposes of this analysis, the cost of the line will be included, but obviously, the cost of the line could be shared between solar and hydro if both were installed. The cost for a 1,000 kW solar unit and power line would be approximately \$10 million. The simple payback at \$0.07/kWh would be 40 years and at \$0.11/kWh would be 25 years, both assuming no tax credits. A 1,000 kW unit would supply less than 25% of the energy needs of the well field, and then only during daylight. The payback periods are very long partly due to having to compete with cheaply produced electricity rather than higher prices that SCE would pay for solar power.

Since it is clear that solar power generation is highly capital intensive and realistically never pays back, a small unit (less than 100 kW) could be considered for the well field area. It could connect to the well field power grid and supply some power as a demonstration of a good faith green effort. Another factor to consider is even if a significant amount of solar power were installed; all the remaining electrical generation would have to be installed at its full capacity regardless, as it would have to be available when solar was not producing.

Power Cost Analysis

This section will develop capital and operations and maintenance (O&M) costs directly associated with the four (4) power supply options previously proposed in this TM and listed below. In addition, a 20-year power supply cost life cycle analysis will be conducted to determine the total annual cost, dollars per acre-foot (\$/AF), and dollars per equivalent kWh (\$/kWh), based solely on power supply costs. These values **are not** representative of total project costs, since total project capital and O&M costs are not included which are assumed similar for each power supply option.

- **All Electric:** Power supplied to IPS and well field by new substation and power lines.
- **Hybrid Option 1:** Gas engines at IPS, upgrade power lines at well field.
- **Hybrid Option 2:** Gas engines at IPS, Solar® turbine power generation at well field.
- **Hybrid Option 3:** Gas engines at IPS, Solar® turbine power generation at well field, Hydro power generation at IPS.

Capital, Operations, and Maintenance Costs

The capital and O&M costs associated with each of the four power supply options listed above are provided in Table 7 through Table 10. The assumptions used to generate the capital and O&M costs are listed below:

- Costs provided in 2010 dollars;
- Electricity purchased at a rate of \$0.11/kWh (SCE);
- Natural gas purchased at a rate of \$0.45/therm (\$4.50/million BTU) (El Paso Corp.);
- Waukesha gas engines (IPS) capital and maintenance costs provided by Valley Power;
- Solar® Turbine capital and maintenance costs provided by Solar®.
- Additional capital cost provided by RBF electrical engineering department.

Table 7
All Electric – Capital and O&M Costs¹

Description	Capital Cost	Annual O&M Costs ²	
		Maintenance	Electricity ³
Pump motors, switchgear, distribution @ well field	\$1,800,000	\$45,000	\$3,390,000
Pump motors, switchgear, distribution @ IPS	\$1,250,000	\$12,000	\$2,420,000
230kV substation	\$6,000,000	-	-
34.5kV transmission line between IPS & well field	\$5,000,000	\$10,000	-
TOTALS	\$14,050,000	\$67,000	\$5,810,000

Table 8
Hybrid Option 1 – Capital and O&M Costs¹

Description	Capital Cost	Annual O&M Costs ²	
		Maintenance	Electricity/ Fuel ³
Pump motors, switchgear, distribution @ well field	\$1,800,000	\$45,000	\$3,390,000
Upgrade SCE power lines @ well field	\$1,000,000	-	-
Pump engines, gas site distribution, controls @ IPS	\$8,500,000	\$135,000	\$891,000
Gas connection, distribution, from main line to well field	\$750,000	-	-
TOTAL	\$12,050,000	\$180,000	\$4,281,000

Table 9
Hybrid Option 2 – Capital and O&M Costs¹

Description	Capital Cost	Annual O&M Costs ²	
		Maintenance	Fuel ³
Pump motors, switchgear, distribution @ well field	\$1,800,000	\$45,000	-
Solar® Turbine @ well field	\$4,500,000	\$450,000	\$1,247,400
Pump engines, gas site distribution, controls @ IPS	\$8,500,000	\$135,000	\$891,000
Gas connection, distribution, from main line to well field	\$750,000	-	-
TOTAL	\$15,550,000	\$630,000	\$2,138,400

¹ 2010 dollars.

² Based on 50,000 afy well field extraction and IPS pumping.

³ Electricity cost based on \$0.11/kWh. Fuel cost based on \$0.45/therm (\$4.50/million BTU).

Table 10
Hybrid Option 3 – Capital and O&M Costs¹

Description	Capital Cost	Annual O&M Costs ²	
		Maintenance	Fuel ³
Pump motors, switchgear, distribution @ well field	\$1,800,000	\$45,000	-
Solar® turbine @ well field	\$4,500,000	\$450,000	\$810,000
Pump engines, gas site distribution, controls @ IPS	\$8,500,000	\$135,000	\$891,000
Gas connection, distribution, from main line to well field	\$750,000	-	-
Hydro power generation system	\$5,000,000	\$25,000	-
12kV transmission line between IPS & well field	\$2,500,000	-	-
TOTAL	\$23,050,000	\$655,000	\$1,701,000

¹ 2010 dollars.

² Based on 50,000 afy well field extraction and IPS pumping.

³ Fuel cost based on \$0.45/therm (\$4.50/million BTU).

Life Cycle Analysis

A power supply cost life cycle (present worth) analysis was conducted for each power supply option described previously. The capital costs associated with each power option, which are presented in Table 7 through table 10, were amortized over a 20-year period using a net discount rate of 3%. The net discount rate is based on an assumed inflation rate of 3% and an assumed interest rate of 6%.

In addition to the annual maintenance and fuel costs associated with the Waukesha gas engines (listed in Table 7 through Table 10), the engines require additional maintenance overhaul costs every 7 years (based on 8 hours of operation per day). The Waukesha gas engines require approximately \$27,000 of annual maintenance, per engine. In year 7, the gas engines require approximately \$83,500 of additional maintenance (top end overhaul), per engine, and in year 14, approximately \$125,000 (bottom end overhaul), per engine.

Assumptions to conduct the life cycle power cost analysis are listed below:

- **Life Cycle Period:** 20 Years beginning year 2010;
- **Net Discount Rate:** 3.0% (based on 3% inflation and 6% interest);
- **Capital and O&M Costs:** Table 7 through Table 10;
- **Waukesha Gas Engines O&M:** Overhaul costs included every 7 years.
- **Well field extraction:** 1,000,000 acre-feet over 20 years;
- **Power requirements:** 1,056,000,000 kWh (equivalent) over 20 years.

Refer to Table 11 on the following page for a comparison of each power options life cycle cost analysis, based on 20-years of operation. Refer to Table A through Table D in the Appendix for the complete 20-year analysis (year by year) for each power option.

Table 11
Power Supply Cost Life Cycle Analysis Comparison¹

Power Option	Total Capital Cost ²	Total O&M Cost ³	Total Cost ³	Present Worth	Equivalent Annual Power Cost	
					\$/AF ³	\$/kWh ⁴
All Electric	\$18,900,000	\$117,500,000	\$136,400,000	\$104,500,000	\$136	\$0.13
Hybrid Option 1	\$16,200,000	\$90,300,000	\$106,500,000	\$81,500,000	\$106	\$0.10
Hybrid Option 2	\$20,900,000	\$56,600,000	\$77,500,000	\$59,400,000	\$78	\$0.07
Hybrid Option 3	\$31,000,000	\$48,200,000	\$79,100,000	\$60,600,000	\$79	\$0.07

¹ 2010 dollars.

² Based on total amortized payments for 20 years, assuming 3% net discount rate.

³ Based on 20 years of operation.

⁴ Based on 1,000,000 acre-feet well field extraction over 20 year period.

⁵ Based on 1,056,000,000 equivalent kWh consumed over 20 year period.

Conclusion and Recommendations

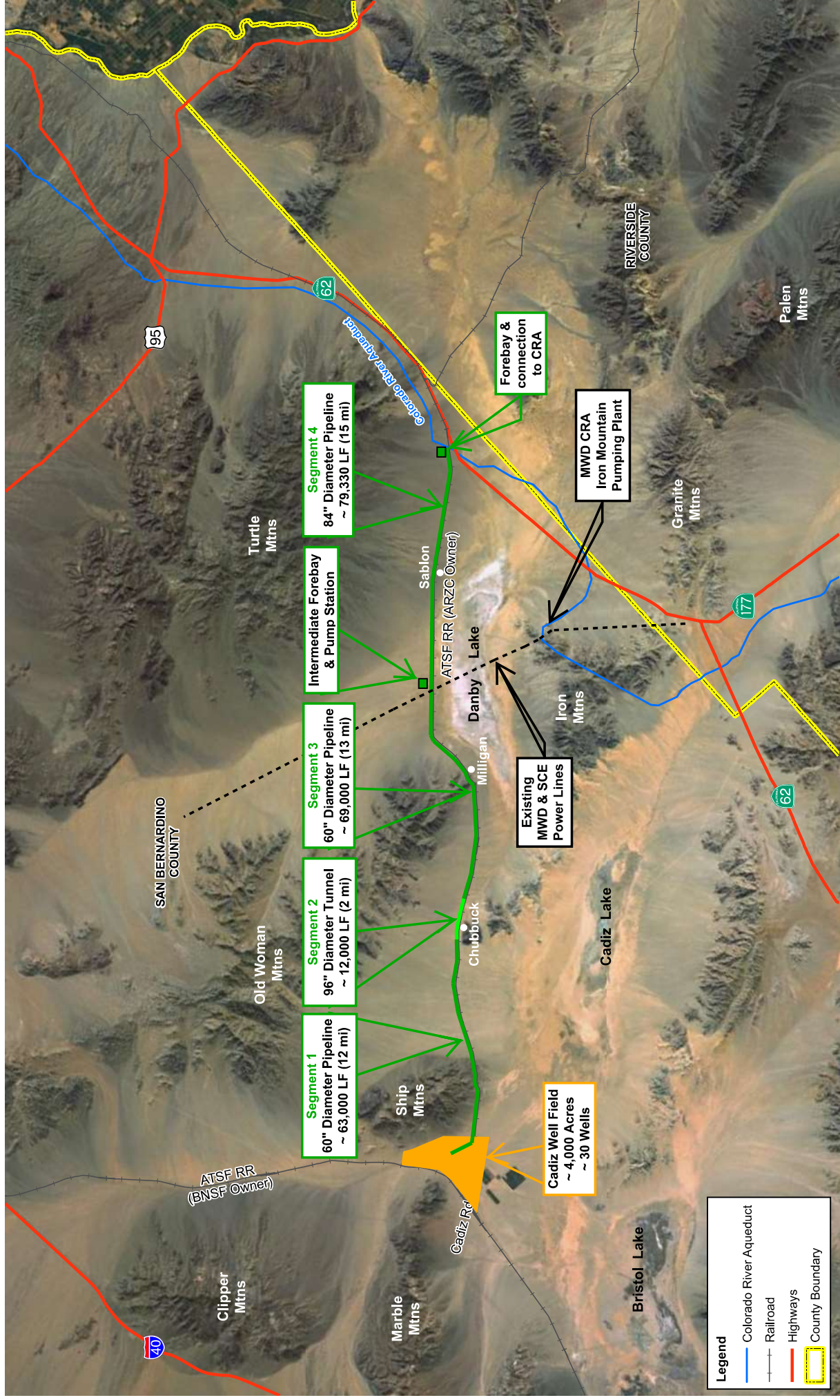
Supply of electric power from SCE at the well field and IPS is questionable. The ability to tie into 230kV SCE power line (which is the only major power line in the area) and construct a substation near the IPS is dubious and subjects Cadiz to unknowns regarding costs, design, and construction schedules. For this reason, it is recommended that gas engine driven pumps be considered for the IPS, especially since the equivalent cost of operation is cheaper than the cost of electrical pumping. At the well field, if the existing SCE power line could be realistically upgraded to supply the well field needs, this would be the most cost effective approach and does not subject Cadiz to any major risks. *It is suggested that Cadiz submit a formal application for service at the well field which will get SCE started and they will determine any cost or schedule implications for a new or modified service. A single line diagram for a proposed project would need to be prepared and submitted with other information for the application, which RBF is capable of doing for Cadiz.*

If the electrical power line upgrade turns out to be impractical, then the Solar® gas turbine generator is a viable option, which is ideally suited for 24/7 operation. The cost to produce power is cheaper than purchased power and all maintenance needs would be provided by the manufacturer. Cadiz would remain in control of design and construction of the facilities, making this a strong option. The only major risk associated with gas turbine power production is the cost of natural gas, and gas pricing is expected to remain stable into the near future, since additional economical sources of gas have come on line over the last few years. It would take virtually doubling of gas prices to make it more expensive than electricity, and even if this occurred, electricity costs would certainly go up as natural gas is used for a significant portion of utility electrical production.

Power generation options like hydro power and solar power are feasible options for this project, but do not boast substantial benefits. Each power generation option would require a connection point to a power source which unfortunately would not exist if the gas engine option at the IPS were utilized. A power line would need to be constructed along the railway alignment to deliver

the power back to the well field. As demonstrated in Table 11, additional up front capital is required to install the hydro turbines and power generation at the only viable location (upstream of the IPS), yet does not develop any major cost saving benefits.

Solar power generation is highly capital intensive and realistically never pays back. Therefore, a small unit (less than 100 kW) could be considered for the well field area. It would connect to the well field power grid and supply some power as a demonstration of a good faith green effort. Another factor to consider is even if a significant amount of solar power were installed, all the remaining electrical generation would have to be installed at its full capacity regardless, as it would have to be available when solar power was not producing.



APPENDIX

Power Cost - Life Cycle Analysis Tables A - D



PROJECT:
DESCRIPTION:
PREPARED BY:
ESTIMATE DATE:

CADIZ GROUNDWATER CONSERVATION AND STORAGE PROJECT
20-YR LIFE CYCLE POWER COST ANALYSIS
RBF CONSULTING
OCT 2010

NET DISCOUNT RATE: 3.0%
AMORTIZED PAYMENT: 20 Years

Table A
20-Year Life Cycle Power Cost Summary - All Electric Option

Calendar Year	n	Capital Cost		Annual O&M Cost	Total Annual Costs	2010 Present Worth (P/A, %, n)	Acre-Feet Extracted Per Year	kWh Used Per Year
		2010 Dollars	Payments (A/P, %, 20)					
2010	0	\$ 14,050,000	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 6,820,000	50,000	52,800,000
2011	1	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 6,620,000	50,000	52,800,000
2012	2	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 6,430,000	50,000	52,800,000
2013	3	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 6,240,000	50,000	52,800,000
2014	4	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 6,060,000	50,000	52,800,000
2015	5	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 5,880,000	50,000	52,800,000
2016	6	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 5,710,000	50,000	52,800,000
2017	7	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 5,550,000	50,000	52,800,000
2018	8	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 5,380,000	50,000	52,800,000
2019	9	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 5,230,000	50,000	52,800,000
2020	10	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 5,080,000	50,000	52,800,000
2021	11	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 4,930,000	50,000	52,800,000
2022	12	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 4,780,000	50,000	52,800,000
2023	13	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 4,640,000	50,000	52,800,000
2024	14	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 4,510,000	50,000	52,800,000
2025	15	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 4,380,000	50,000	52,800,000
2026	16	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 4,250,000	50,000	52,800,000
2027	17	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 4,130,000	50,000	52,800,000
2028	18	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 4,010,000	50,000	52,800,000
2029	19	\$ -	\$ 944,000	\$ 5,877,000	\$ 6,821,000	\$ 3,890,000	50,000	52,800,000
TOTALS		\$ 14,050,000	\$ 18,900,000	\$ 117,500,000	\$ 136,400,000	\$ 104,500,000	1,000,000	1,056,000,000

Avg Annual Present Worth \$/AF	Equivalent Annual Cost \$/AF	Equivalent Annual Cost \$/kWh
\$ 136	\$ 136	\$ 0.13
\$ 132	\$ 136	\$ 0.13
\$ 129	\$ 136	\$ 0.13
\$ 125	\$ 136	\$ 0.13
\$ 121	\$ 136	\$ 0.13
\$ 118	\$ 136	\$ 0.13
\$ 114	\$ 136	\$ 0.13
\$ 111	\$ 136	\$ 0.13
\$ 108	\$ 136	\$ 0.13
\$ 105	\$ 136	\$ 0.13
\$ 102	\$ 136	\$ 0.13
\$ 99	\$ 136	\$ 0.13
\$ 96	\$ 136	\$ 0.13
\$ 93	\$ 136	\$ 0.13
\$ 90	\$ 136	\$ 0.13
\$ 88	\$ 136	\$ 0.13
\$ 85	\$ 136	\$ 0.13
\$ 83	\$ 136	\$ 0.13
\$ 80	\$ 136	\$ 0.13
\$ 78	\$ 136	\$ 0.13
\$ 105	\$ 136	\$ 0.13



PROJECT:
DESCRIPTION:
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ESTIMATE DATE:

CADIZ GROUNDWATER CONSERVATION AND STORAGE PROJECT
20-YR LIFE CYCLE POWER COST ANALYSIS
RBF CONSULTING
OCT 2010

NET DISCOUNT RATE: 3.0%
AMORTIZED PAYMENT: 20 Years

Table B
20-Year Life Cycle Power Cost Summary - Hybrid Option 1

Calendar Year	n	Capital Cost		Annual O&M Cost	Total Annual Costs	2010 Present Worth (P/A, %, n)	Acre-Feet Extracted Per Year	Equivalent kWh Per Year
		2010 Dollars	Payments (A/P, %, 20)					
2010	0	\$ 12,050,000	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 5,270,000	50,000	52,800,000
2011	1	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 5,120,000	50,000	52,800,000
2012	2	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 4,970,000	50,000	52,800,000
2013	3	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 4,820,000	50,000	52,800,000
2014	4	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 4,680,000	50,000	52,800,000
2015	5	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 4,550,000	50,000	52,800,000
2016	6	\$ -	\$ 810,000	\$ 4,878,500	\$ 5,688,500	\$ 4,760,000	50,000	52,800,000
2017	7	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 4,290,000	50,000	52,800,000
2018	8	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 4,160,000	50,000	52,800,000
2019	9	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 4,040,000	50,000	52,800,000
2020	10	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 3,920,000	50,000	52,800,000
2021	11	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 3,810,000	50,000	52,800,000
2022	12	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 3,700,000	50,000	52,800,000
2023	13	\$ -	\$ 810,000	\$ 5,086,000	\$ 5,896,000	\$ 4,010,000	50,000	52,800,000
2024	14	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 3,480,000	50,000	52,800,000
2025	15	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 3,380,000	50,000	52,800,000
2026	16	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 3,280,000	50,000	52,800,000
2027	17	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 3,190,000	50,000	52,800,000
2028	18	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 3,100,000	50,000	52,800,000
2029	19	\$ -	\$ 810,000	\$ 4,461,000	\$ 5,271,000	\$ 3,010,000	50,000	52,800,000
TOTALS		\$ 12,050,000	\$ 16,200,000	\$ 90,300,000	\$ 106,500,000	\$ 81,500,000	1,000,000	1,056,000,000

Avg Annual Present Worth \$/AF	Equivalent Annual Cost \$/AF	Equivalent Annual Cost \$/kWh
\$ 105	\$ 105	\$ 0.10
\$ 102	\$ 105	\$ 0.10
\$ 99	\$ 105	\$ 0.10
\$ 96	\$ 105	\$ 0.10
\$ 94	\$ 105	\$ 0.10
\$ 91	\$ 105	\$ 0.10
\$ 86	\$ 114	\$ 0.11
\$ 83	\$ 105	\$ 0.10
\$ 81	\$ 105	\$ 0.10
\$ 78	\$ 105	\$ 0.10
\$ 76	\$ 105	\$ 0.10
\$ 74	\$ 105	\$ 0.10
\$ 80	\$ 118	\$ 0.11
\$ 70	\$ 105	\$ 0.10
\$ 68	\$ 105	\$ 0.10
\$ 66	\$ 105	\$ 0.10
\$ 64	\$ 105	\$ 0.10
\$ 62	\$ 105	\$ 0.10
\$ 60	\$ 105	\$ 0.10
\$ 82	\$ 106	\$ 0.10



PROJECT:
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ESTIMATE DATE:

CADIZ GROUNDWATER CONSERVATION AND STORAGE PROJECT
20-YR LIFE CYCLE POWER COST ANALYSIS
RBF CONSULTING
OCT 2010

NET DISCOUNT RATE: 3.0%
AMORTIZED PAYMENT: 20 Years

Table C
20-Year Life Cycle Powr Cost Summary - Hybrid Option 2

Calendar Year	n	Capital Cost		Annual O&M Cost	Total Annual Costs	2010 Present Worth (P/A, %, n)	Acre-Feet Extracted Per Year	Equivalent kWh Per Year
		2010 Dollars	Payments (A/P, %, 20)					
2010	0	\$ 15,550,000	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 3,810,000	50,000	52,800,000
2011	1	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 3,700,000	50,000	52,800,000
2012	2	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 3,590,000	50,000	52,800,000
2013	3	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 3,490,000	50,000	52,800,000
2014	4	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 3,390,000	50,000	52,800,000
2015	5	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 3,290,000	50,000	52,800,000
2016	6	\$ -	\$ 1,045,000	\$ 3,393,400	\$ 4,438,400	\$ 3,720,000	50,000	52,800,000
2017	7	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 3,100,000	50,000	52,800,000
2018	8	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 3,010,000	50,000	52,800,000
2019	9	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 2,920,000	50,000	52,800,000
2020	10	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 2,840,000	50,000	52,800,000
2021	11	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 2,750,000	50,000	52,800,000
2022	12	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 2,670,000	50,000	52,800,000
2023	13	\$ -	\$ 1,045,000	\$ 3,393,400	\$ 4,438,400	\$ 3,020,000	50,000	52,800,000
2024	14	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 2,520,000	50,000	52,800,000
2025	15	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 2,450,000	50,000	52,800,000
2026	16	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 2,380,000	50,000	52,800,000
2027	17	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 2,310,000	50,000	52,800,000
2028	18	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 2,240,000	50,000	52,800,000
2029	19	\$ -	\$ 1,045,000	\$ 2,768,400	\$ 3,813,400	\$ 2,170,000	50,000	52,800,000
TOTALS		\$ 15,550,000	\$ 20,900,000	\$ 56,600,000	\$ 77,500,000	\$ 59,400,000	1,000,000	1,056,000,000

Avg Annual Present Worth \$/AF	Equivalent Annual Cost \$/AF	Equivalent Annual Cost \$/kWh
\$ 76	\$ 76	\$ 0.07
\$ 74	\$ 76	\$ 0.07
\$ 72	\$ 76	\$ 0.07
\$ 70	\$ 76	\$ 0.07
\$ 68	\$ 76	\$ 0.07
\$ 66	\$ 76	\$ 0.07
\$ 74	\$ 89	\$ 0.08
\$ 62	\$ 76	\$ 0.07
\$ 60	\$ 76	\$ 0.07
\$ 58	\$ 76	\$ 0.07
\$ 57	\$ 76	\$ 0.07
\$ 55	\$ 76	\$ 0.07
\$ 53	\$ 76	\$ 0.07
\$ 60	\$ 89	\$ 0.08
\$ 50	\$ 76	\$ 0.07
\$ 49	\$ 76	\$ 0.07
\$ 48	\$ 76	\$ 0.07
\$ 46	\$ 76	\$ 0.07
\$ 45	\$ 76	\$ 0.07
\$ 43	\$ 76	\$ 0.07
\$ 59	\$ 78	\$ 0.07



PROJECT:
DESCRIPTION:
PREPARED BY:
ESTIMATE DATE:

CADIZ GROUNDWATER CONSERVATION AND STORAGE PROJECT
20-YR LIFE CYCLE POWER COST ANALYSIS
RBF CONSULTING
OCT 2010

NET DISCOUNT RATE: 3.0%
AMORTIZED PAYMENT: 20 Years

Table D
20-Year Life Cycle Power Cost Summary - Hybrid Option 3

Calendar Year	n	Capital Cost		Annual O&M Cost	Total Annual Costs	2010 Present Worth (P/A, %, n)	Acre-Feet Extracted Per Year	Equivalent kWh Per Year
		2010 Dollars	Payments (A/P, %, 20)					
2010	0	\$ 23,050,000	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 3,910,000	50,000	52,800,000
2011	1	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 3,790,000	50,000	52,800,000
2012	2	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 3,680,000	50,000	52,800,000
2013	3	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 3,570,000	50,000	52,800,000
2014	4	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 3,470,000	50,000	52,800,000
2015	5	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 3,370,000	50,000	52,800,000
2016	6	\$ -	\$ 1,549,000	\$ 2,773,500	\$ 4,322,500	\$ 3,620,000	50,000	52,800,000
2017	7	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 3,180,000	50,000	52,800,000
2018	8	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 3,080,000	50,000	52,800,000
2019	9	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 2,990,000	50,000	52,800,000
2020	10	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 2,910,000	50,000	52,800,000
2021	11	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 2,820,000	50,000	52,800,000
2022	12	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 2,740,000	50,000	52,800,000
2023	13	\$ -	\$ 1,549,000	\$ 2,981,000	\$ 4,530,000	\$ 3,080,000	50,000	52,800,000
2024	14	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 2,580,000	50,000	52,800,000
2025	15	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 2,510,000	50,000	52,800,000
2026	16	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 2,430,000	50,000	52,800,000
2027	17	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 2,360,000	50,000	52,800,000
2028	18	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 2,290,000	50,000	52,800,000
2029	19	\$ -	\$ 1,549,000	\$ 2,356,000	\$ 3,905,000	\$ 2,230,000	50,000	52,800,000
TOTALS		\$ 23,050,000	\$ 31,000,000	\$ 48,200,000	\$ 79,100,000	\$ 60,600,000	1,000,000	1,056,000,000

Avg Annual Present Worth \$/AF	Equivalent Annual Cost \$/AF	Equivalent Annual Cost \$/kWh
\$ 78	\$ 78	\$ 0.07
\$ 76	\$ 78	\$ 0.07
\$ 74	\$ 78	\$ 0.07
\$ 71	\$ 78	\$ 0.07
\$ 69	\$ 78	\$ 0.07
\$ 67	\$ 78	\$ 0.07
\$ 72	\$ 86	\$ 0.08
\$ 64	\$ 78	\$ 0.07
\$ 62	\$ 78	\$ 0.07
\$ 60	\$ 78	\$ 0.07
\$ 58	\$ 78	\$ 0.07
\$ 56	\$ 78	\$ 0.07
\$ 55	\$ 78	\$ 0.07
\$ 62	\$ 91	\$ 0.09
\$ 52	\$ 78	\$ 0.07
\$ 50	\$ 78	\$ 0.07
\$ 49	\$ 78	\$ 0.07
\$ 47	\$ 78	\$ 0.07
\$ 46	\$ 78	\$ 0.07
\$ 45	\$ 78	\$ 0.07
\$ 61	\$ 79	\$ 0.07